Energy Tidbits

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Produced by: Dan Tsubouchi

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Dan Tsubouchi
Principal, Chief Market Strategist
dtsubouchi@safgroup.ca

Ryan Dunfield
Principal, CEO
rdunfield@safgroup.ca

Aaron Bunting
Principal, COO, CFO
abunting@safgroup.ca

Ryan Haughn
Principal, Energy
rhaughn@safgroup.ca

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AccuWeather's 2021-2022 US winter forecast

By Brian Lada, AccuWeather meteorologist and staff writer
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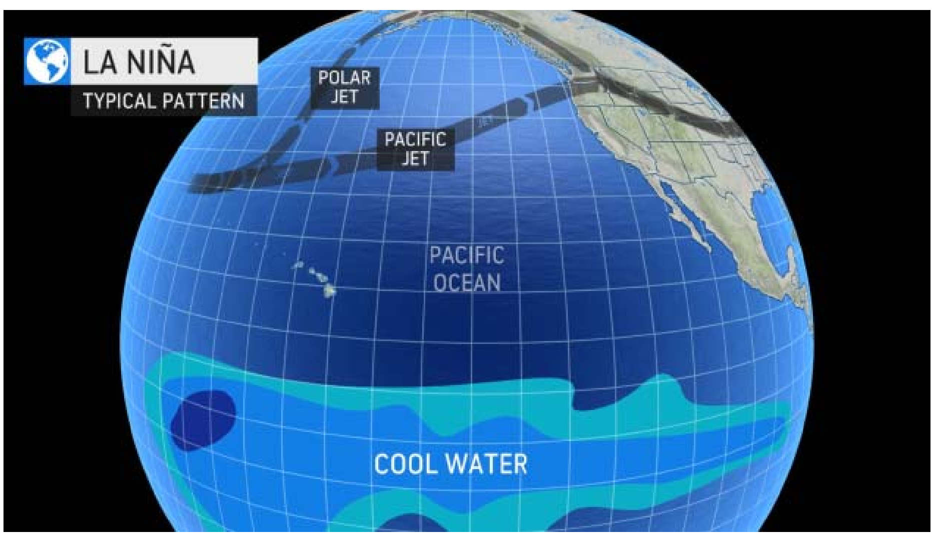
AccuWeather Lead Long-Range Forecaster Paul Pastelok breaks down what to expect across the country this season, and he draws similarities to last year's extreme weather.

It's that time of year again. The days are growing shorter and the temperatures are dropping, which means it's only a matter of time before the arrival of winter. As some welcome the return of snow, others may be wondering what the coldest time of the year has in store — and AccuWeather meteorologists have the answers. That's right -- it's time for the annual AccuWeather winter forecast.

Last winter was one that will not soon be forgotten, especially in the central U.S. where a snowstorm followed by extremely cold air left millions in the dark across Texas. Just days later, 73.2% of the country measured snow on the ground, the highest percentage since record-keeping on that metric began in 2003. Additionally, Denver experienced its snowiest winter in 37 years.

AccuWeather’s team of long-range forecasters, led by Senior Meteorologist Paul Pastelok, has made its annual prediction for the upcoming winter season, giving people all across the country time to prepare for what is expected to be a busy winter from coast to coast.

AccuWeather is predicting some similarities this year compared to last winter due to a weather phenomenon known as La Niña.



An illustration showing how water temperatures far out in the Pacific Ocean can influence weather patterns thousands of miles away. (AccuWeather)
AccuWeather

Last winter, La Niña was a driving force that shaped the weather patterns across the country throughout the season. La Niña is a phenomenon that occurs when the water near the equator of the Pacific Ocean is cooler than average. In turn, this influences the jet

stream and the track that storms take when moving across North America. It is also the counterpart to the more well-known El Niño.
La Niña is once again predicted to shape part of the overall weather patterns this winter, but Pastelok said that the upcoming La Niña will be weaker than the one experienced last winter. This "opens up the door" for other elements to factor into the winter forecast, especially during the second half of the season.

There are also indications entering this winter season that, unlike last year, the polar vortex can be weaker. This could allow colder air from the Arctic to slide southward into the U.S. before the official start of meteorological winter, which is on Dec. 1. Astronomical winter, the first official day of winter, arrives on Tuesday, Dec. 21.

Take a look at the complete region-by-region breakdown of the U.S. winter forecast below:

Northeast

Residents across the northeastern U.S. might want to dig out their winter coats sooner rather than later as winter weather could make an early arrival across the region this year.

"This winter, I think, is going to be a colder one, at least for the interior sections from the Appalachians to the Ohio Valley and Great Lakes," Pastelok said. Last winter, temperatures across these areas were right around normal, but this year, the winter as a whole is likely to average 1 to 3 degrees Fahrenheit below normal.

The first waves of cold air are anticipated to chill the Northeast in November when Pastelok said there could be "a couple of rounds of cold weather and some snow," particularly across the interior Northeast. The chance of a plowable snow is also anticipated to start early in the season with the early waves of cold air.

Areas closer to the coast, such as Boston, New York City and the rest of the Interstate-95 corridor, could also get the chance of early-season cold and snow, but it is not predicted to be as cold or as snowy as across areas farther inland.

The early arrival of chilly air will be just the first hill on the roller-coaster weather ride that is expected this winter.

The severity and frequency of the snow and cold air are likely to let up a bit by mid-December before returning with a vengeance in January.

"That's the month that stands out," Pastelok said. Heating bills could hit their highest point in January and people all across the Northeast, especially those who live along and west of the Appalachian Mountains, may notice the effects. This will come at a time when heating costs could be inflated anyway. The price for natural gas as of late September was up 180% compared to 12 months ago, CNN reported. At the time of the report, natural gas prices were at their highest since early 2014.
This is also the period of the winter when there will be ample cold air entrenched across the region for snowstorms to cause widespread disruptions.

Sometimes during January, there is a period during which the cold air lets up, referred to by some meteorologists as a "January thaw." But this coming winter, that respite from the frigid weather could occur a few weeks later, making it more of a "February thaw."

This will provide a window for snow and ice to melt before the end of winter when the polar vortex could pay a visit.

Winter could go out like a lion with another heightened risk for nor'easters at the tail end of the season.
“At the end of the winter into early spring, there could be another attempt of the polar vortex being displaced or split,” Pastelok said. This would send frigid Arctic air blowing across the eastern U.S., extending the wintry weather well past March 1, which marks the beginning of meteorological spring.

SNOWFALL PREDICTIONS
WINTER 2021-2022

LOCATION	PREDICTION 2021-2022	SNOWFALL 2020-2021	AVERAGE SNOWFALL
New York, NY	26-32"	38.6"	26.1"
Philadelphia, PA	20-26"	23.9"	22.6"
Boston, MA	45-55"	38.6"	44.3"
Washington, DC	7-11"	5.4"	15.6"
Pittsburgh, PA	45-50"	57.9"	41.8"

After measuring less than 1 inch of snow in the entire winter of 2019-2020 in Philadelphia, snowfall during the winter of 2020-2021 ended up being slightly above normal. This could be the case again this winter for the City of Brotherly Love with near- to slightly above-average snow in the offing.

A different story is likely to unfold a short drive south on I-95 with another below-normal year for snowfall in the nation's capital. AccuWeather is predicting between 7 and 11 inches of snow for the winter in Washington, D.C., which is slightly more than the 5.4 inches that fell last winter but still below the average of 15.6 inches. The city hasn't measured above-normal snowfall since the winter of 2018-2019.

Boston was another major I-95 city that ended up with less snowfall than average last winter, with a total of 38.6 inches compared to an average seasonal snowfall of 44.3 inches. This year, above-normal snowfall is expected, and amounts could reach as high as 55 inches.

Great Lakes & Northern Plains

Similar to the Northeast, folks across the Great Lakes and the north-central U.S. should brace for a colder-than-normal winter with snowy spells throughout most of the season.

“It’s going to be a busy one in the northern Plains and Great Lakes this year,” Pastelok said, adding that the regions will get a combination of bitterly cold air and above-normal snowfall.

Winter will start off strong with snowstorms tracking from the foothills of the Rockies through the Great Lakes, providing early-season snow for many of the favorite snow-related activities, such as skiing, snowmobiling or winter-themed festivals.

Closer to the Great Lakes, the big story this winter will be lake-effect snow.

“Lake-effect snow in the Great Lakes --- look out,” Pastelok warned. “If it all does come together, we could have a pretty busy season as far as lake-effect snow [goes] for all of the Great Lakes.”

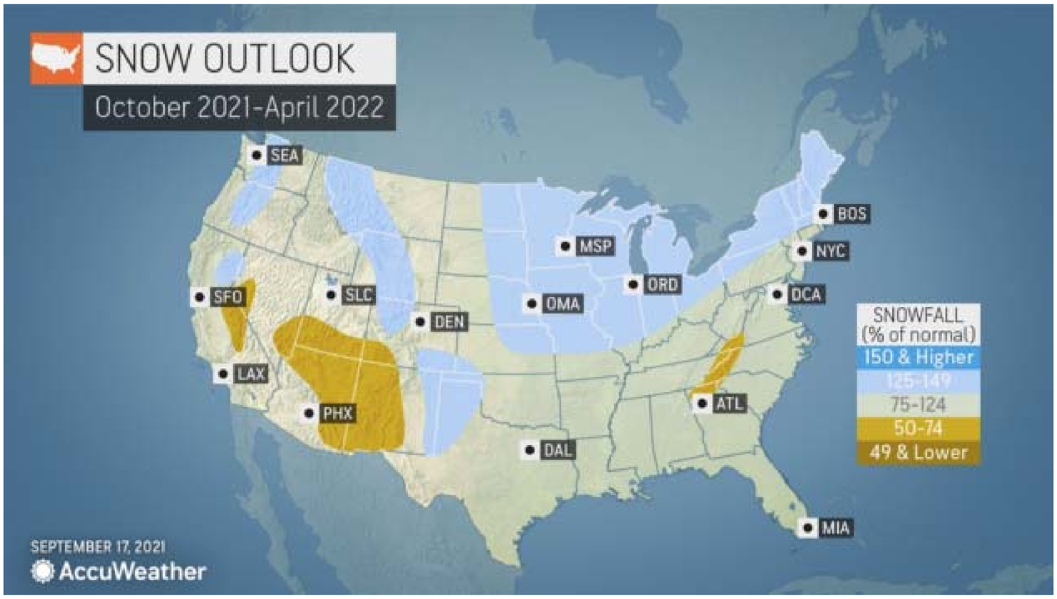
The first rounds of lake-effect snow are likely to start in late November and into December, but the pattern that meteorologists often refer to as "the lake-effect snow machine" will kick into high gear as the calendar turns to 2022.

One reason the worst of the lake-effect snow is expected to hold off until January is the state of the Great Lakes heading into the season. The water temperatures in all five lakes as of late September were above normal. Water temperatures were about 1 degree Fahrenheit above normal in Lake Erie and Lake Ontario, about 2.5 F above normal in Lake Huron and Lake Michigan, and 5 F above normal in Lake Superior, according to NOAA Coast Watch.

As of late September, some of the warmest waters in the Great Lakes were concentrated in Lake Erie, where readings at stations on the coast of Cleveland and Buffalo topped 67 degrees. In the southern parts of Lake Michigan, near Chicago, water temperatures remained above 60 degrees at the end of September.

With only intermittent intrusions of cold air before a persistent flow of Arctic air in January, the lakes will remain open for business well into winter.

Buffalo, New York, is predicted to measure around 100 inches of snow this winter, slightly above the average of 95 inches and noticeably above last season, during which the city measured a total of 77 inches.



Farther west, the bigger story will be the unrelenting waves of cold air.

“If you live in the northern Plains and Great Lakes, I think you really have to pay attention to the cold shots that come down," Pastelok said referring to Arctic air blasting down from Canada.

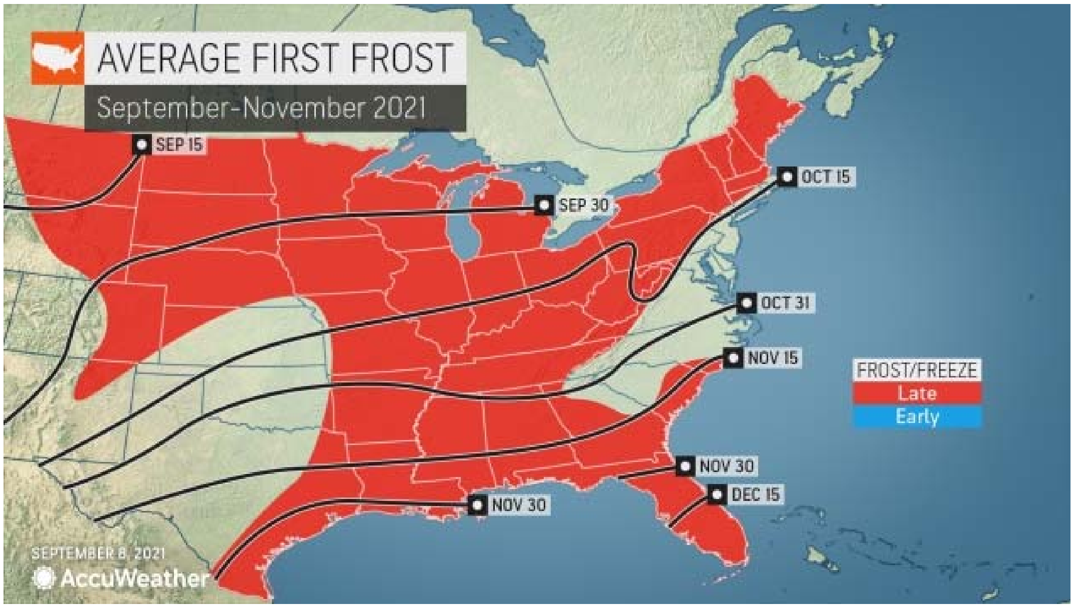
Temperatures in January could end up being 5 to 10 degrees Fahrenheit lower than they were last winter across the Plains -- and the Arctic air is likely to remain in place over the region into February.

Southeast & Southern Plains

Winter weather will take its time arriving across the southern U.S., but that doesn’t mean that people in that part of the country should let their guard down.

December could end up being rather mild from Texas through Florida with the first frost of the season occurring later than normal. Near the central Gulf Coast, the first frost is predicted to take place after Nov. 15, which is later than normal. In parts of southern Texas and central Florida, the first frost may not occur until after the start of December.

However, a big flip in the weather pattern is expected shortly after the start of 2022.



Pastelok said his team sees similarities to last year's pattern with another major cold snap potentially unfolding across the southern Plains this winter around late January or in February. The cold snap has the potential to be highly disruptive but not something on the historic level that was blamed for more than 200 fatalities last February.

A recent study published in the journal Science revealed a connection between the weather disaster in Texas last winter and climate change in the Arctic. Last February, the south-central U.S. was hit by devastating winter storms. Texas in particular was hit hard in February after extreme winter weather left millions without power for days and caused over $150 billion in damages, according to AccuWeather estimates.
In addition, some of the most extreme cold could envelop places farther to the east of those that took the worst of the cold snap last February. This winter, Pastelok is highlighting eastern Texas, eastern Oklahoma and Arkansas as the areas that could experience the worst of the cold and potential winter storms across the region. This includes some of the areas that experienced the deadly winter weather last February.

People walk down a street during a winter storm in Oklahoma City, Sunday, Feb. 14, 2021, in Oklahoma City. Snow and ice blanketed large swaths of the U.S. on Sunday, prompting canceled flights, making driving perilous and reaching into areas as far south as Texas' Gulf Coast, where snow and sleet were expected overnight. (AP Photo/Sue Ogrocki)

Farther east, the wintry weather is not anticipated to be as bad, but the risk of severe weather will loom throughout the season.

The primary storm track over the southern U.S. will send spells of rain and thunderstorms across the lower Mississippi and Tennessee valleys with the highest chance of severe weather focusing on a zone from Louisiana to Tennessee.

This is the same region that experienced a few rounds of severe thunderstorms late last winter. That was capped by the first “high risk” of severe weather in March in nine years. Louisiana, in particular, has been hit extremely hard by the weather over the past year and a half, dating back to Hurricane Laura and Hurricane Delta in the 2020 Atlantic hurricane season, severe flooding this past spring and Hurricane Ida over the summer.

Meanwhile, in the Southeast, the Atlantic coast is predicted to enjoy mild weather with drier-than-normal conditions. Places in Florida, like Miami and Jacksonville, up through Charleston, South Carolina, and Wilmington, North Carolina, could all receive below-average precipitation this winter.

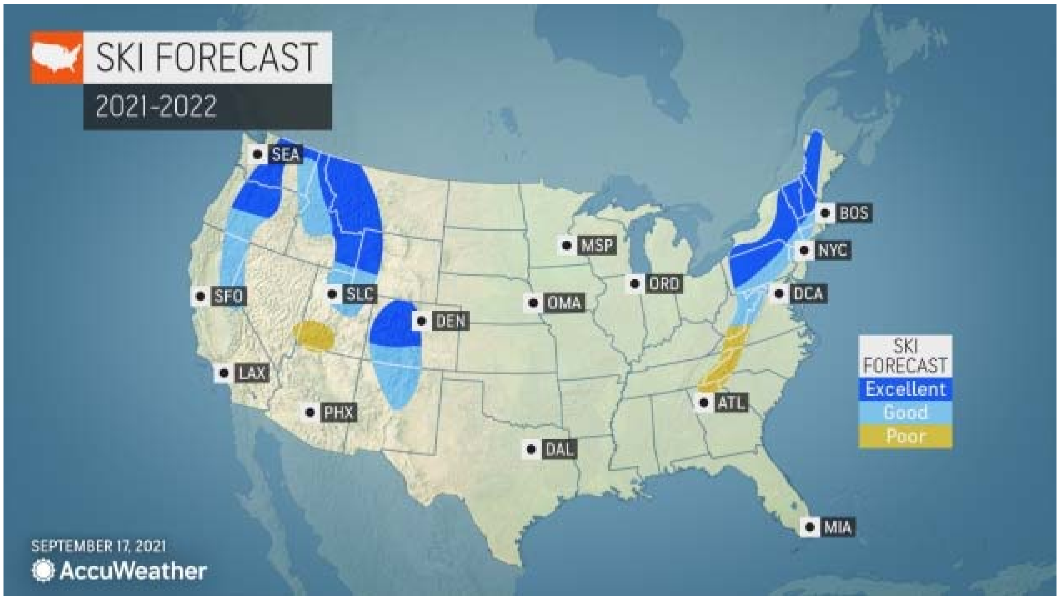
Pacific Northwest & Northern Rockies

A La Niña winter typically translates to a stormy season for the Pacific Northwest, and while La Niña is in the offing this winter, it may not trigger as much stormy weather as in years past.

“La Niña may not come and do the same things that we typically see because it’s weaker,” Pastelok explained.

A wet winter is still anticipated with plenty of snow in the mountains, but it might not total as much as last winter, and more breaks in the stormy pattern are projected. Still, there will be enough precipitation to lay down a healthy snowpack for ski resorts across the Pacific Northwest and the northern Rocky Mountains.

Snow from these storms could blanket Denver, but the city is not likely to have a repeat of last winter, which was the snowiest in 37 years with more than 80 inches of snow accumulating throughout the season. Snowfall this season in Denver should be closer to normal, which is 56.5 inches.



The early arrival of the winter storms will spell an end to the active wildfire season for the Pacific Northwest as rain and snow help to douse any flames that are still burning across the region. It will also help to saturate the parched ground following a dry summer.

Seattle endured its driest spring and summer in 77 years with the Emerald City experiencing just 41 days with rain, the lowest on record.
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In the long term, the winter storms will help with the drought that has developed across the region. Most of the Northwest and the northern Rockies as of late September were experiencing extreme to exceptional drought conditions, according to the U.S. Drought Monitor.
“I do feel that the drought will improve. It’s already improving in parts of Washington and northern Idaho, but it’s not going to be a drought-buster,” Pastelok said of the expected precipitation amounts this winter.

The amount of rain and snow that falls during the latter part of the winter will have implications well into 2022, especially over next summer and autumn following two active wildfire years in a row. If the wet season ends on a dry note, then it will allow the vegetation more time to dry out before the start of wildfire season, resulting in more fuel for fires that ignite.

Southwest

As waves of storms start to soak the Pacific Northwest periodically through autumn and into the first part of winter, people who live across areas farther south may be wondering when meaningful rain will reach California and the rest of the Southwest.

“Through November and December, I do not see much in the way of significant systems getting down to Southern California,” Pastelok said.

The lack of early-season precipitation will allow the ongoing wildfire season to extend all the way into December, an unusually late end to the season.

Several major fires were burning across California during late September, including one complex that scorched part of Sequoia National Park. Firefighters wrapped the largest tree on Earth in aluminum blankets to help it survive the intense blazes.
More fires will be possible across the Sierra and elsewhere in California before the arrival of the wet season.

As the calendar turns from December to January, the prospects for rain will increase for California. Typically during La Niña, storms from the Pacific Ocean generally track toward Washington and Oregon, leaving California high and dry, but a different story may unfold later this winter.

“This is not a typical La Niña," Pastelok said, adding that as La Niña weakens later in the winter, it will allow other factors to influence the storm track.

This will open the door for meaningful precipitation across California during the second half of the winter, but Pastelok warns that what does come down is "not going to be a drought buster."

The lack of persistent storms will lead to most of California and the rest of the Southwest being milder than normal this winter, although a few cold spells can’t be ruled out, particularly across the interior Southwest.

Pastelok said that there are some chances for storms to dive down from the Northwest across the Four Corners, bringing the chance of precipitation to the interior Southwest.

This will be beneficial for ski resorts across Utah, Colorado, New Mexico and Arizona, although these interior storms may not take place until later in December and into January.

Similar to California, the precipitation from these storms is not expected to end the long-term drought across the region, but it could bring minor relief in the short term.

The water level of Lake Mead reached its lowest level since the Hoover Dam was constructed this summer, and without significant precipitation, water levels could continue to decline.

“This is a long-term drought and it’s going to hold unless something out of the ordinary happens here late in the winter and the wet season continues longer than normal,” Pastelok said.

Table 1. Summary of natural gas supply and disposition in the United States, 2016-2021
(billion cubic feet)

Year and Month	Gross Withdrawals	Marketed Production	NGPL Production[a]	Dry Gas Production[b]	Supplemental Gaseous Fuels[c]	Net Imports	Net Storage Withdrawals[d]	Balancing Item[e]	Consumption[f]
2016 Total	**32,592**	**28,400**	**1,808**	**26,592**	**57**	**671**	**340**	**-216**	**27,444**
2017 Total	**33,292**	**29,238**	**1,897**	**27,341**	**66**	**-121**	**254**	**-400**	**27,140**
2018 Total	**37,326**	**33,009**	**2,235**	**30,774**	**69**	**-719**	**314**	**-300**	**30,139**
2019									
January	R3,377	R2,975	208	R2,767	5	-74	R722	R4	R3,424
February	R3,057	R2,705	189	R2,516	5	-97	R580	R16	R3,019
March	R3,383	R3,009	R210	R2,798	5	-121	R253	R-8	R2,928
April	R3,315	R2,926	205	R2,721	5	-132	R-389	R7	R2,212
May	R3,424	R3,046	213	R2,833	5	-161	R-480	R-63	R2,134
June	R3,300	R2,956	207	R2,750	5	-159	R-439	R-37	2,119
July	R3,396	R3,072	215	R2,857	5	-163	R-260	R-45	R2,394
August	R3,448	R3,146	220	R2,926	5	-165	R-292	R-40	R2,434
September	R3,397	R3,057	R214	R2,843	5	-186	R-427	R-28	R2,206
October	R3,552	R3,186	223	R2,963	5	-215	R-353	R-94	R2,307
November	R3,509	R3,134	R219	R2,915	5	-218	R156	R-74	R2,784
December	R3,623	R3,235	226	R3,009	5	R-226	R428	R-45	R3,171
Total	**R40,780**	**R36,447**	**2,548**	**R33,899**	**R61**	**R-1,916**	**R-503**	**R-408**	**R31,132**
2020									
January	R3,597	R3,194	R240	R2,954	6	-248	R581	R8	R3,300
February	R3,363	R2,985	R224	R2,761	R5	-216	R545	R-53	R3,041
March	R3,582	R3,196	R240	R2,956	6	-284	R53	R-24	R2,707
April	R3,374	R3,012	R226	R2,786	R5	-231	R-311	R-8	R2,241
May	R3,285	R2,927	R220	R2,707	5	-209	R-454	R18	R2,067
June	R3,217	R2,873	R216	R2,657	5	-151	R-363	R-18	R2,131
July	R3,374	R3,021	R227	R2,795	R5	-139	R-165	R-7	R2,489
August	R3,350	R3,012	R226	R2,786	R5	-148	R-232	R-9	R2,401
September	R3,265	R2,918	R219	R2,699	R5	-221	R-329	R18	R2,172
October	R3,364	R2,992	R225	R2,767	5	-282	R-96	R-74	R2,320
November	R3,352	R2,985	R224	R2,761	5	-316	R-6	R-8	R2,435
December	R3,490	R3,089	R232	R2,857	R5	-287	R597	R-5	R3,168
Total	**R40,614**	**R36,202**	**R2,717**	**R33,485**	**R63**	**-2,732**	**R-180**	**R-164**	**R30,472**
2021									
January	E3,506	E3,100	232	E2,868	5	-279	707	R-15	R3,286
February	E2,924	E2,577	170	E2,407	6	-152	781	*	R3,042
March	E3,482	E3,081	229	E2,852	5	-357	59	R47	R2,607
April	E3,409	E3,025	237	E2,788	5	R-356	-174	R-26	R2,237
May	RE3,510	RE3,119	245	RE2,874	3	R-373	-416	R5	R2,094
June	RE3,393	RE3,028	238	RE2,790	5	R-331	-248	R-1	R2,214
July	E3,491	E3,141	245	E2,896	5	-338	-170	-11	2,382
2021 7-Month YTD	**E23,714**	**E21,071**	**1,594**	**E19,476**	**34**	**-2,187**	**539**	**-1**	**17,862**
2020 7-Month YTD	**23,793**	**21,208**	**1,592**	**19,616**	**37**	**-1,478**	**-114**	**-85**	**17,976**
2019 7-Month YTD	**23,252**	**20,689**	**1,446**	**19,243**	**34**	**-906**	**-15**	**-126**	**18,231**

[a] Monthly natural gas plant liquid (NGPL) production, gaseous equivalent, is derived from sample data reported by gas processing plants on Form EIA-816, *Monthly Natural Gas Liquids Report*, and Form EIA-64A, *Annual Report of the Origin of Natural Gas Liquids Production*.

[b] Equal to marketed production minus NGPL production.

[c] Supplemental gaseous fuels data are collected only on an annual basis except for the Dakota Gasification Co. coal gasification facility which provides data each month. The ratio of annual supplemental fuels (excluding Dakota Gasification Co.) to the sum of dry gas production, net imports, and net withdrawals from storage is calculated. This ratio is applied to the monthly sum of these three elements. The Dakota Gasification Co. monthly value is added to the result to produce the monthly supplemental fuels estimate.

[d] Monthly and annual data for 2016 through 2020 include underground storage and liquefied natural gas storage. Data for January 2021 forward include underground storage only. See Appendix A, Explanatory Note 5, for discussion of computation procedures.

[e] Represents quantities lost and imbalances in data due to differences among data sources. Net imports and balancing item excludes net intransit deliveries. These net intransit deliveries were (in billion cubic feet): -24 for 2020; -8 for 2019; -12 for 2018; 14 for 2017; and 70 for 2016. See Appendix A, Explanatory Note 7, for full discussion.

[f] Consists of pipeline fuel use, lease and plant fuel use, vehicle fuel, and deliveries to consuming sectors as shown in Table 2.

R Revised data.

* Volume is between -500 MMcf and 500 MMcf.

E Estimated data.

RE Revised estimated data.

Notes: Data for 2016 through 2019 are final. All other data are preliminary unless otherwise indicated. Geographic coverage is the 50 states and the District of Columbia. Totals may not equal sum of components because of independent rounding.

Sources: 2016-2020: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2020*. January 2021 through current month: Form EIA-914, *Monthly Crude Oil and Lease Condensate, and Natural Gas Production Report*; Form EIA-857, *Monthly Report of Natural Gas Purchases and Deliveries to Consumers*; Form EIA-191, *Monthly Underground Gas Storage Report*; EIA computations and estimates; and Office of Fossil Energy, *Natural Gas Imports and Exports*. See Table 7 for detailed source notes for Marketed Production. See Appendix A, Notes 3 and 4, for discussion of computation and estimation procedures and revision policies.

Table 2. Natural gas consumption in the United States, 2016-2021

(billion cubic feet, or as indicated)

Year and Month	Lease and Plant Fuel[a]	Pipeline and Distribution Use[b]	Delivered to Consumers: Residential	Commercial	Industrial	Electric Power	Vehicle Fuel	Total	Total Consumption	Heating Value[c] (Btu per cubic foot)
2016 Total	**1,545**	**687**	**4,347**	**3,110**	**7,729**	**9,985**	**42**	**25,212**	**27,444**	**1,037**
2017 Total	**1,583**	**722**	**4,413**	**3,165**	**7,943**	**9,266**	**48**	**24,835**	**27,140**	**1,036**
2018 Total	**1,694**	**877**	**4,998**	**3,514**	**8,417**	**10,589**	**50**	**27,568**	**30,139**	**1,036**
2019										
January	R149	R114	R954	554	801	R849	R5	R3,162	R3,424	1,038
February	R135	R100	809	472	719	R779	4	R2,784	R3,019	1,037
March	R150	R96	R689	424	R750	R814	R5	R2,681	R2,928	1,037
April	R146	R72	R329	R247	R675	R740	4	R1,994	R2,212	1,037
May	R152	R69	212	185	675	R836	R5	R1,913	R2,134	1,035
June	R148	R68	129	145	R634	R991	4	R1,903	2,119	1,035
July	R154	R78	112	142	650	R1,255	R5	R2,162	R2,394	1,037
August	R157	R79	102	141	672	R1,278	R5	R2,197	R2,434	1,038
September	R153	R71	110	143	644	R1,081	4	R1,982	R2,206	1,037
October	R159	R75	232	216	684	R937	R5	R2,073	R2,307	1,036
November	R157	R91	589	389	735	819	4	2,536	R2,784	1,040
December	R162	R105	R753	457	779	R912	R5	R2,904	R3,171	1,040
Total	**R1,823**	**R1,018**	**R5,019**	**R3,515**	**R8,417**	**R11,288**	**R53**	**R28,291**	**R31,132**	**1,038**
2020										
January	R159	R110	R825	R491	R779	931	R4	R3,030	R3,300	1,039
February	R149	R102	R737	R448	R724	879	R4	2,791	R3,041	1,039
March	R159	R90	R527	R339	R710	879	R4	R2,459	R2,707	1,039
April	R150	R73	R378	R238	R633	764	R4	R2,017	R2,241	1,039
May	R146	R67	R237	R163	R616	834	R4	R1,854	R2,067	1,035
June	R143	R70	136	132	R600	1,046	R4	R1,918	R2,131	1,032
July	R151	R82	R118	R129	R633	1,372	R4	R2,257	R2,489	1,032
August	R150	R79	109	131	R648	1,280	R4	R2,172	R2,401	1,033
September	R145	R71	R127	R144	R643	1,038	R4	R1,955	R2,172	1,035
October	R149	R76	R242	R209	R686	954	R4	R2,095	R2,320	1,036
November	R149	R80	R440	R294	R701	767	R4	R2,206	R2,435	1,037
December	R154	R106	R800	R454	R778	873	R4	R2,908	R3,168	1,039
Total	**R1,805**	**R1,007**	**R4,674**	**R3,170**	**R8,151**	**11,616**	**R49**	**R27,660**	**R30,472**	**1,037**
2021										
January	RE155	RE109	R877	492	R783	866	RE4	R3,023	R3,286	1,038
February	RE128	RE101	R866	R492	R664	788	RE4	R2,813	R3,042	1,041
March	RE154	RE86	R568	R355	R696	744	RE4	R2,367	R2,607	1,038
April	RE151	RE74	R338	R244	R672	754	RE4	R2,012	R2,237	1,036
May	RE155	RE69	R217	R182	R651	816	RE4	R1,869	R2,094	1,035
June	RE151	RE73	128	142	R633	1,082	RE4	R1,990	R2,214	1,034
July	E157	E79	112	142	657	1,231	E5	2,146	2,382	1,035
2021 7-Month YTD	**E1,050**	**E590**	**3,105**	**2,048**	**4,756**	**6,281**	**E31**	**16,221**	**17,862**	**1,037**
2020 7-Month YTD	**1,057**	**594**	**2,958**	**1,939**	**4,695**	**6,705**	**29**	**16,325**	**17,976**	**1,037**
2019 7-Month YTD	**1,035**	**597**	**3,233**	**2,169**	**4,903**	**6,262**	**31**	**16,599**	**18,231**	**1,037**

[a] Plant fuel data and lease fuel data are collected only annually. Monthly lease and plant fuel use is estimated from monthly marketed production by assuming that the preceding annual percentage remains constant for the next 12 months.

[b] Published pipeline and distribution use data are based on reports collected on an annual basis. Monthly pipeline and distribution use data are estimated from monthly total consumption (excluding pipeline and distribution use) by assuming that the preceding annual percentage remains constant for the next 12 months. Pipeline and distribution use volumes include Line Loss, defined as known volumes of natural gas that were the result of leaks, damage, accidents, migration, and/or blow downs, as well as fuel used in liquefaction and regasification.

[c] Heating value is the average number of British thermal units per cubic foot of natural gas as reported on EIA-857 and EIA-176. See Appendix A, Explanatory Note 11, for further information.

[R] Revised data.

[E] Estimated data.

[RE] Revised estimated data.

Notes: Data for 2016 through 2019 are final. All other data are preliminary unless otherwise indicated. Geographic coverage is the 50 states and the District of Columbia. Totals may not equal sum of components because of independent rounding. See Appendix A, Explanatory Note 6, for definition of sectors.

Sources: 2016-2020: U.S. Energy Information Administration (EIA): Form EIA-857, *Monthly Report of Natural Gas Purchases and Deliveries to Consumers*; state and federal agencies; EIA estimates based on historical data; and *Natural Gas Annual 2020*. January 2021 through current month: Form EIA-914, *Monthly Crude Oil and Lease Condensate, and Natural Gas Production Report*; Form EIA-857; Form EIA-923, *Power Plant Operations Report*. See Appendix A, Explanatory Note 6, for computation procedures and revision policy.

Table 5. U.S. natural gas exports, 2019-2021

(volumes in million cubic feet; prices in dollars per thousand cubic feet)

	2021 7-Month YTD	2020 7-Month YTD	2019 7-Month YTD	2021 July	June	May	April	March
Exports								
Volume (million cubic feet)								
Pipeline								
Canada	537,347	540,931	543,948	68,264	69,528	70,561	74,567	91,301
Mexico	1,264,890	1,106,362	1,053,115	197,141	R198,329	R192,625	R183,004	183,051
Total Pipeline Exports	**1,802,237**	**1,647,293**	**1,597,064**	**265,405**	**R267,857**	**R263,186**	**R257,571**	**274,352**
LNG								
Exports								
By Vessel								
Argentina	65,059	12,819	39,293	22,798	19,312	16,226	4,485	2,238
Bahamas	281	123	100	46	48	45	46	39
Bangladesh	27,374	10,660	0	0	3,493	6,948	10,219	3,566
Barbados	151	157	113	31	22	19	30	14
Belgium	5,584	25,028	3,390	0	0	2,100	0	3,484
Brazil	159,499	25,762	28,688	39,637	32,293	19,726	11,615	21,977
Chile	85,432	50,028	56,949	19,913	0	17,598	10,293	21,320
China	239,941	63,732	6,851	42,222	42,319	37,731	46,837	28,476
Colombia	892	1,528	5,869	0	0	0	892	0
Croatia	20,619	0	0	3,299	2,923	3,364	3,666	7,367
Dominican Republic	32,825	7,264	4,049	1,806	4,670	5,283	2,905	5,577
Egypt	0	0	0	0	0	0	0	0
France	103,845	76,456	51,870	0	3,683	11,926	36,120	33,678
Greece	20,852	34,451	6,891	6,651	0	6,796	0	6,805
Haiti	74	61	6	8	18	12	3	10
India	123,127	65,267	48,849	13,090	16,503	28,259	13,752	17,381
Israel	6,051	9,791	0	0	0	0	3,225	2,826
Italy	30,809	58,636	40,235	6,826	3,425	2,923	6,896	10,739
Jamaica	16,752	9,554	6,048	0	2,927	2,925	2,370	2,458
Japan	228,768	139,751	91,941	24,895	39,783	25,058	28,756	27,673
Jordan	0	3,294	25,439	0	0	0	0	0
Kuwait	14,653	3,297	6,907	0	7,126	0	3,705	3,821
Lithuania	25,961	9,467	0	6,469	3,285	3,049	3,078	3,228
Malaysia	0	0	0	0	0	0	0	0
Malta	2,928	2,648	413	0	0	0	2,928	0
Mexico	14,112	16,968	99,842	758	0	0	0	0
Netherlands	107,227	65,298	44,282	10,597	3,030	26,611	17,060	24,204
Nicaragua	1	0	0	1	0	0	0	0
Pakistan	27,229	10,224	10,304	13,428	3,376	0	3,323	3,421
Panama	6,136	7,384	9,743	0	0	2,341	0	3,279
Poland	38,824	26,709	20,571	6,619	10,635	3,581	7,382	3,507
Portugal	30,317	16,964	31,401	3,296	5,538	10,765	7,358	0
Singapore	20,827	14,300	24,602	3,449	0	3,089	7,297	3,303
South Korea	269,182	167,328	136,878	39,314	55,918	46,033	21,683	32,203
Spain	69,682	143,930	65,323	8,630	7,833	5,234	22,974	13,900
Taiwan	64,271	33,035	9,658	20,653	3,097	10,157	6,594	13,450
Thailand	10,841	28,917	3,401	0	0	3,453	7,388	0
Turkey	59,537	87,341	19,281	5,591	0	3,017	0	3,619
United Arab Emirates	0	6,751	13,734	0	0	0	0	0
United Kingdom	97,682	82,422	17,753	0	0	10,586	13,877	17,440
By Truck								
Canada	56	2	1	16	7	18	15	0
Mexico	463	506	579	97	105	48	48	19
Re-Exports								
By Vessel								
Argentina	0	0	0	0	0	0	0	0
Brazil	0	0	0	0	0	0	0	0
Japan	0	305	221	0	0	0	0	0
South Korea	0	305	0	0	0	0	0	0
United Kingdom	0	0	0	0	0	0	0	0
Total LNG Exports	**2,027,864**	**1,318,466**	**931,473**	**300,143**	**271,368**	**314,922**	**306,818**	**321,023**
CNG								
Canada	197	259	150	16	R27	R25	R29	R36
Total CNG Exports	**197**	**259**	**150**	**16**	**R27**	**R25**	**R29**	**R36**
Total Exports	**3,830,297**	**2,966,017**	**2,528,687**	**565,564**	**R539,252**	**R578,132**	**R564,418**	**R595,411**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2019-2021

(volumes in million cubic feet; prices in dollars per thousand cubic feet) – continued

	2021		2020					
	February	January	Total	December	November	October	September	August
Exports								
Volume (million cubic feet)								
Pipeline								
Canada	78,198	84,927	902,449	84,307	81,358	72,833	62,211	60,810
Mexico	137,381	173,360	1,990,809	164,577	166,135	185,799	182,068	185,867
Total Pipeline Exports	**215,579**	**258,287**	**2,893,258**	**248,884**	**247,493**	**258,632**	**244,279**	**246,677**
LNG								
Exports								
By Vessel								
Argentina	0	0	15,068	0	0	0	0	2,249
Bahamas	29	28	257	36	31	25	20	21
Bangladesh	0	3,148	10,660	0	0	0	0	0
Barbados	19	17	241	25	15	17	14	14
Belgium	0	0	31,946	0	3,633	3,285	0	0
Brazil	13,118	21,132	111,826	29,927	30,191	22,427	0	3,520
Chile	6,524	9,784	80,615	9,793	3,252	6,836	3,277	7,428
China	3,415	38,940	214,401	45,525	45,083	35,115	11,245	13,699
Colombia	0	0	4,626	0	0	0	2,548	550
Croatia	0	0	3,275	3,275	0	0	0	0
Dominican Republic	5,689	6,895	26,050	5,000	5,106	5,909	0	2,772
Egypt	0	0	0	0	0	0	0	0
France	14,851	3,587	90,237	3,752	3,390	6,639	0	0
Greece	0	600	48,403	3,382	3,543	0	7,027	0
Haiti	11	12	118	17	11	9	8	11
India	13,776	20,367	124,402	10,241	10,299	17,762	10,514	10,319
Israel	0	0	15,834	0	0	0	3,041	3,001
Italy	0	0	68,453	0	3,083	0	0	6,734
Jamaica	2,365	3,708	17,052	2,374	0	2,514	2,610	0
Japan	18,271	64,331	287,672	54,004	32,967	31,554	6,855	22,541
Jordan	0	0	6,872	0	0	0	3,578	0
Kuwait	0	0	17,293	0	0	3,603	3,508	6,886
Lithuania	6,851	0	28,879	6,291	3,621	6,191	3,308	0
Malaysia	0	0	0	0	0	0	0	0
Malta	0	0	2,648	0	0	0	0	0
Mexico	13,354	0	34,408	0	3,056	7,398	3,285	3,701
Netherlands	22,777	2,949	85,573	3,316	6,684	3,603	6,671	0
Nicaragua	0	0	0	0	0	0	0	0
Pakistan	0	3,682	36,934	0	3,436	10,009	9,853	3,412
Panama	0	516	12,764	271	1,448	433	3,228	0
Poland	7,099	0	36,900	7,033	0	3,157	0	0
Portugal	3,360	0	36,922	3,711	5,830	3,564	6,853	0
Singapore	0	3,688	28,341	0	7,658	3,416	0	2,967
South Korea	18,094	55,936	316,227	39,617	49,103	14,239	32,126	13,814
Spain	3,733	7,377	199,966	13,583	9,907	14,118	15,206	3,222
Taiwan	0	10,319	64,363	12,470	6,216	3,636	9,007	0
Thailand	0	0	32,622	0	3,705	0	0	0
Turkey	20,652	26,659	123,957	20,188	12,817	0	3,611	0
United Arab Emirates	0	0	10,110	0	0	0	0	3,359
United Kingdom	34,343	21,436	160,199	30,378	26,544	17,191	3,664	0
By Truck								
Canada	0	0	10	8	0	0	0	0
Mexico	63	83	822	46	52	68	73	78
Re-Exports								
By Vessel								
Argentina	0	0	2,164	0	0	0	0	2,164
Brazil	0	0	82	0	0	82	0	0
Japan	0	0	387	0	0	82	0	0
South Korea	0	0	387	0	0	82	0	0
United Kingdom	0	0	0	0	0	0	0	0
Total LNG Exports	**208,394**	**305,196**	**2,389,963**	**304,263**	**280,682**	**222,963**	**151,128**	**112,462**
CNG								
Canada	R32	R32	386	29	35	26	17	20
Total CNG Exports	R**32**	R**32**	**386**	**29**	**35**	**26**	**17**	**20**
Total Exports	R**424,004**	R**563,515**	**5,283,607**	**553,176**	**528,210**	**481,621**	**395,424**	**359,159**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2019-2021

(volumes in million cubic feet; prices in dollars per thousand cubic feet) – continued

	2020							2019
	July	June	May	April	March	February	January	Total
Exports								
Volume (million cubic feet)								
Pipeline								
Canada	71,778	66,516	67,752	71,722	86,579	77,354	99,231	R972,519
Mexico	181,152	162,927	145,242	138,544	166,550	151,071	160,875	1,865,329
Total Pipeline Exports	**252,930**	**229,442**	**212,994**	**210,266**	**253,130**	**228,425**	**260,106**	**R2,837,848**
LNG								
Exports								
By Vessel								
Argentina	2,218	2,229	8,372	0	0	0	0	39,293
Bahamas	15	18	20	23	20	13	15	156
Bangladesh	3,614	0	3,406	0	0	0	3,640	3,419
Barbados	15	20	20	15	28	26	33	211
Belgium	0	0	1,348	3,324	3,724	9,872	6,761	23,897
Brazil	0	0	0	0	6,891	10,433	8,438	54,298
Chile	1,515	3,313	11,068	14,098	3,216	10,731	6,087	90,357
China	10,358	0	14,535	21,140	17,699	0	0	6,851
Colombia	0	0	0	0	0	1,003	525	6,518
Croatia	0	0	0	0	0	0	0	0
Dominican Republic	0	0	2,554	1,838	2,872	0	0	10,334
Egypt	0	0	0	0	0	0	0	0
France	0	0	9,546	16,336	23,491	20,520	6,563	117,791
Greece	6,544	1,076	3,430	3,233	8,892	0	11,276	14,643
Haiti	8	7	10	8	9	11	7	42
India	7,404	10,100	10,534	16,674	17,245	0	3,309	91,481
Israel	3,317	3,277	0	0	3,197	0	0	0
Italy	3,232	12,998	6,452	3,135	9,895	16,616	6,308	68,655
Jamaica	0	0	0	5,770	1	2,914	869	13,892
Japan	10,618	21,836	13,729	18,387	21,845	21,360	31,975	R200,864
Jordan	0	0	3,294	0	0	0	0	32,332
Kuwait	0	0	0	3,297	0	0	0	10,308
Lithuania	0	3,049	3,473	2,945	0	0	0	3,455
Malaysia	0	0	0	0	0	0	0	3,698
Malta	0	0	0	0	0	48	2,600	413
Mexico	0	0	0	0	7,037	3,167	6,764	143,371
Netherlands	6,746	6,870	6,826	10,305	13,772	14,099	6,681	81,361
Nicaragua	0	0	0	0	0	0	0	0
Pakistan	0	0	0	3,334	0	3,567	3,323	R26,935
Panama	0	0	3,070	0	906	3,408	0	10,221
Poland	0	3,385	6,258	3,523	3,583	6,677	3,282	38,042
Portugal	0	0	0	10,777	0	6,187	0	53,342
Singapore	3,690	0	0	0	10,610	0	0	31,440
South Korea	10,492	28,171	20,921	24,258	28,095	11,071	44,320	270,025
Spain	13,679	9,640	29,360	22,943	23,657	20,240	24,412	166,684
Taiwan	0	2,953	6,662	0	6,987	7,115	9,317	27,397
Thailand	3,254	0	7,397	11,049	3,783	3,435	0	6,635
Turkey	3,222	0	6,661	14,030	6,489	24,303	32,637	30,611
United Arab Emirates	3,277	0	3,474	0	0	0	0	20,561
United Kingdom	2,908	0	0	0	20,202	28,884	30,428	R118,357
By Truck								
Canada	0	0	0	0	0	0	2	25
Mexico	72	61	18	23	123	87	122	1,105
Re-Exports								
By Vessel								
Argentina	0	0	0	0	0	0	0	0
Brazil	0	0	0	0	0	0	0	0
Japan	0	0	0	0	0	0	305	R221
South Korea	0	0	0	0	0	0	305	0
United Kingdom	0	0	0	0	0	0	0	R305
Total LNG Exports	**96,200**	**109,002**	**182,438**	**210,466**	**244,269**	**225,786**	**250,305**	**R1,819,547**
CNG								
Canada	37	43	39	35	38	34	33	263
Total CNG Exports	**37**	**43**	**39**	**35**	**38**	**34**	**33**	**263**
Total Exports	**349,167**	**338,486**	**395,472**	**420,767**	**497,437**	**454,245**	**510,444**	**R4,657,657**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2019-2021
(volumes in million cubic feet; prices in dollars per thousand cubic feet) – continued

	2019							
	December	November	October	September	August	July	June	May
Exports								
Volume (million cubic feet)								
Pipeline								
Canada	R109,779	R92,671	76,246	71,573	78,302	68,613	61,809	70,182
Mexico	151,308	158,633	171,535	162,649	168,089	167,902	156,440	153,452
Total Pipeline Exports	**R261,086**	**R251,305**	**247,781**	**234,222**	**246,391**	**236,515**	**218,249**	**223,633**
LNG								
Exports								
By Vessel								
Argentina	0	0	0	0	0	13,066	13,120	8,737
Bahamas	11	14	8	2	20	11	25	14
Bangladesh	3,419	0	0	0	0	0	0	0
Barbados	20	20	25	17	17	17	13	21
Belgium	10,407	3,293	3,402	3,404	0	0	0	0
Brazil	0	3,279	3,345	6,117	12,868	6,949	9,116	4,905
Chile	7,207	3,484	6,608	9,811	6,297	9,382	19,012	6,188
China	0	0	0	0	0	0	0	0
Colombia	0	0	0	0	649	0	0	0
Croatia	0	0	0	0	0	0	0	0
Dominican Republic	501	0	2,927	2,857	0	0	1,108	0
Egypt	0	0	0	0	0	0	0	0
France	14,758	26,946	14,228	6,740	3,249	0	0	6,621
Greece	7,752	0	0	0	0	0	0	3,497
Haiti	12	8	4	9	3	2	3	0
India	7,090	6,933	6,961	14,355	7,294	3,485	3,215	13,942
Israel	0	0	0	0	0	0	0	0
Italy	12,764	6,345	0	3,230	6,082	9,963	3,072	6,560
Jamaica	2,435	2,464	0	0	2,946	837	0	2,890
Japan	21,226	17,603	24,504	28,084	17,506	21,242	14,582	7,149
Jordan	0	0	0	3,616	3,277	3,449	7,342	7,332
Kuwait	0	0	0	0	3,401	3,405	0	3,502
Lithuania	3,455	0	0	0	0	0	0	0
Malaysia	0	3,698	0	0	0	0	0	0
Malta	0	0	0	0	0	0	0	0
Mexico	9,696	3,273	6,437	10,442	13,681	24,209	16,955	20,244
Netherlands	13,405	10,099	3,456	3,431	6,688	3,386	3,310	10,734
Nicaragua	0	0	0	0	0	0	0	0
Pakistan	R3,400	3,247	3,472	6,512	0	3,656	0	0
Panama	0	478	0	0	0	0	3,282	0
Poland	7,013	3,432	3,489	0	3,537	3,694	0	0
Portugal	6,345	0	6,621	2,924	6,051	6,994	6,908	0
Singapore	3,375	0	3,463	0	0	3,570	3,435	3,397
South Korea	38,139	24,962	42,233	10,818	16,995	32,663	20,402	18,069
Spain	13,874	19,985	13,704	37,938	15,861	3,297	13,506	14,325
Taiwan	3,658	3,736	3,138	0	7,207	0	0	3,309
Thailand	0	0	0	3,234	0	0	0	3,401
Turkey	536	7,266	3,528	0	0	0	0	0
United Arab Emirates	0	0	0	3,325	3,502	3,487	3,459	0
United Kingdom	R29,749	39,957	26,260	3,303	1,335	0	0	0
By Truck								
Canada	0	1	14	9	0	0	0	0
Mexico	93	86	139	95	113	101	92	75
Re-Exports								
By Vessel								
Argentina	0	0	0	0	0	0	0	0
Brazil	0	0	0	0	0	0	0	0
Japan	0	0	0	0	0	0	0	0
South Korea	0	0	0	0	0	0	0	0
United Kingdom	R305	0	0	0	0	0	0	0
Total LNG Exports	**R220,646**	**190,610**	**177,966**	**160,274**	**138,578**	**156,865**	**141,956**	**144,913**
CNG								
Canada	25	30	28	15	15	20	20	22
Total CNG Exports	**25**	**30**	**28**	**15**	**15**	**20**	**20**	**22**
Total Exports	**R481,757**	**R441,944**	**425,775**	**394,511**	**384,983**	**393,400**	**360,226**	**368,568**

See footnotes at end of table.

Table 5

Table 5. U.S. natural gas exports, 2019-2021

(volumes in million cubic feet; prices in dollars per thousand cubic feet) – continued

	2019			
	April	March	February	January
Exports				
Volume (million cubic feet)				
Pipeline				
Canada	71,333	93,182	91,561	87,269
Mexico	139,750	149,514	135,514	150,544
Total Pipeline Exports	**211,083**	**242,696**	**227,074**	**237,813**
LNG				
Exports				
By Vessel				
Argentina	4,369	0	0	0
Bahamas	14	11	14	11
Bangladesh	0	0	0	0
Barbados	17	14	14	17
Belgium	0	3,390	0	0
Brazil	1,201	3,283	3,234	0
Chile	9,429	10,005	2,933	0
China	0	0	3,464	3,387
Colombia	0	2,935	0	2,934
Croatia	0	0	0	0
Dominican Republic	0	0	2,942	0
Egypt	0	0	0	0
France	17,092	20,853	0	7,303
Greece	0	0	3,394	0
Haiti	2	0	0	0
India	6,742	7,446	6,989	7,030
Israel	0	0	0	0
Italy	0	6,684	3,454	10,502
Jamaica	0	2,320	0	0
Japan	R14,010	7,143	10,320	17,495
Jordan	3,622	0	3,695	0
Kuwait	0	0	0	0
Lithuania	0	0	0	0
Malaysia	0	0	0	0
Malta	413	0	0	0
Mexico	10,406	7,038	6,681	14,310
Netherlands	13,010	10,452	3,390	0
Nicaragua	0	0	0	0
Pakistan	0	3,282	3,365	0
Panama	0	3,191	3,269	0
Poland	3,414	3,701	0	9,762
Portugal	3,489	0	3,720	10,289
Singapore	320	6,631	7,249	0
South Korea	13,000	18,013	17,750	16,981
Spain	10,139	10,678	6,748	6,631
Taiwan	6,349	0	0	0
Thailand	0	0	0	0
Turkey	2,969	0	6,483	9,829
United Arab Emirates	6,787	0	0	0
United Kingdom	0	3,669	3,711	10,373
By Truck				
Canada	0	0	1	0
Mexico	87	73	48	104
Re-Exports				
By Vessel				
Argentina	0	0	0	0
Brazil	0	0	0	0
Japan	R221	0	0	0
South Korea	0	0	0	0
United Kingdom	0	0	0	0
Total LNG Exports	**127,102**	**130,814**	**102,866**	**126,957**
CNG				
Canada	28	29	15	16
Total CNG Exports	**28**	**29**	**15**	**16**
Total Exports	**338,213**	**373,539**	**329,954**	**364,787**

See footnotes at end of table.

Table 7. Marketed production of natural gas in selected states and the Federal Gulf of Mexico, 2016-2021
(million cubic feet)

Year and Month	Alaska	Arkansas	California	Colorado	Kansas	Louisiana	Montana	New Mexico	North Dakota	Ohio
2016 Total	**332,749**	**823,196**	**205,025**	**1,685,755**	**244,795**	**1,784,396**	**47,921**	**1,229,647**	**531,997**	**1,437,285**
2017 Total	**344,385**	**694,676**	**212,458**	**1,706,364**	**219,639**	**2,139,830**	**46,311**	**1,299,732**	**593,998**	**1,791,359**
2018 Total	**341,315**	**589,985**	**202,617**	**1,847,402**	**201,391**	**2,832,404**	**43,530**	**1,493,082**	**706,552**	**2,403,382**
2019										
January	30,503	R47,443	16,800	R165,594	R16,055	R259,311	3,773	R137,940	R67,591	R213,280
February	26,728	R42,219	15,513	R148,543	14,237	R242,076	R3,095	R128,351	R58,573	R192,640
March	29,346	R46,211	16,922	R164,062	15,820	R266,649	R3,508	R144,805	R68,542	R213,280
April	28,816	R44,455	16,548	R161,046	15,613	R259,749	R3,552	R142,454	R67,985	R207,990
May	29,028	R44,906	16,754	R166,110	14,898	R270,060	R3,817	R147,013	R70,266	R214,923
June	26,889	R42,702	16,254	R162,072	R15,559	R265,302	R3,757	R142,093	R65,406	R207,990
July	25,348	R43,852	16,890	R165,821	15,695	R277,490	R3,783	R149,002	R70,039	R235,476
August	22,876	R43,505	16,969	R166,581	R15,637	R276,362	R3,739	R153,633	R75,266	R235,476
September	24,494	R41,798	16,262	R161,977	R15,039	R266,639	R3,675	R151,917	R72,439	R227,880
October	27,409	R43,093	16,228	R174,304	R15,151	R275,520	R3,617	R157,544	R78,027	R236,778
November	28,256	R41,738	15,659	R172,088	R14,439	R270,668	R3,559	R154,545	R77,473	R229,140
December	29,669	R42,834	16,024	R178,720	R14,945	R282,493	R3,660	R159,790	R79,218	R236,778
Total	**329,361**	**R524,757**	**196,823**	**R1,986,916**	**R183,087**	**R3,212,318**	**R43,534**	**R1,769,086**	**R850,826**	**R2,651,631**
2020										
January	30,018	R42,187	R15,908	R178,066	R14,623	R274,755	R3,527	R162,016	R78,798	R203,701
February	28,537	R39,093	R14,649	R166,620	R13,636	R255,885	R3,340	R155,323	R77,940	R190,559
March	29,219	R43,677	R15,376	R175,202	R14,486	R276,544	R3,527	R169,244	R83,892	R203,701
April	27,513	R39,748	R14,906	R168,438	R13,595	R264,869	R3,148	R156,722	R72,059	R193,050
May	27,076	R40,463	R15,172	R163,768	R14,012	R281,636	R2,692	R147,782	R52,874	R199,485
June	25,545	R38,742	R14,837	R159,601	R13,321	R264,072	R2,667	R153,276	R52,626	R193,050
July	26,779	R39,855	R15,061	R167,105	R13,674	R264,875	R3,322	R165,335	R64,860	R201,686
August	26,846	R40,295	R13,344	R165,091	R13,504	R260,226	R3,248	R168,311	R74,940	R201,686
September	26,978	R38,734	R12,857	R162,531	R13,030	R255,690	R3,009	R165,008	R78,195	R195,180
October	29,080	R40,172	R13,059	R164,462	R13,461	R263,120	R3,204	R171,376	R82,649	R201,097
November	29,575	R38,565	R12,934	R159,409	R12,917	R267,312	R3,143	R167,213	R80,112	R194,610
December	31,161	R39,452	R12,475	R160,168	R13,097	R277,178	R3,135	R166,561	R83,498	R201,097
Total	**338,329**	**R480,982**	**R170,579**	**R1,990,462**	**R163,356**	**R3,206,163**	**R37,963**	**R1,948,168**	**R882,443**	**R2,378,902**
2021										
January	31,632	E39,964	E12,033	E159,724	E12,578	E271,669	E3,168	E176,770	E69,019	E206,660
February	28,365	E30,061	E10,749	E143,329	E9,965	E220,985	E2,750	E149,598	E58,860	E170,668
March	31,481	E39,947	E12,028	E156,440	E12,340	E281,322	E3,099	E184,351	E69,028	E189,405
April	29,514	E37,926	E11,685	E155,915	E12,316	E276,847	E3,052	E182,003	E68,291	E183,444
May	29,005	RE38,775	RE12,215	RE162,103	RE12,648	RE284,261	RE3,180	RE193,111	RE72,117	RE187,668
June	27,715	RE37,098	RE11,778	RE154,273	RE12,353	RE272,989	RE2,886	RE186,796	RE69,634	RE183,585
July	26,280	E42,563	E12,005	E159,870	E12,828	E286,967	E3,113	E198,123	E70,575	E189,205
2021 7-Month YTD	**203,992**	**E266,336**	**E82,493**	**E1,091,655**	**E85,028**	**E1,895,040**	**E21,248**	**E1,270,752**	**E477,525**	**E1,310,636**
2020 7-Month YTD	**194,689**	**283,764**	**105,910**	**1,178,800**	**97,347**	**1,882,637**	**22,223**	**1,109,698**	**483,050**	**1,385,232**
2019 7-Month YTD	**196,658**	**311,789**	**115,681**	**1,133,247**	**107,877**	**1,840,637**	**25,284**	**991,657**	**468,402**	**1,485,579**

See footnotes at end of table.

Table 7. Marketed production of natural gas in selected states and the Federal Gulf of Mexico, 2016-2021

(million cubic feet) – continued

Year and Month	Oklahoma	Pennsylvania	Texas	Utah	West Virginia	Wyoming	Other States	Federal Gulf of Mexico	U.S. Total
2016 Total	**2,468,312**	**5,210,209**	**7,225,472**	**365,268**	**1,384,458**	**1,662,909**	**559,985**	**1,200,669**	**28,400,049**
2017 Total	**2,513,897**	**5,453,638**	**7,223,841**	**315,211**	**1,514,278**	**1,590,059**	**517,698**	**1,060,452**	**29,237,825**
2018 Total	**2,875,787**	**6,264,832**	**8,041,010**	**295,826**	**1,771,698**	**1,637,517**	**485,675**	**974,863**	**33,008,867**
2019									
January	R255,006	576,440	R737,375	R23,148	169,050	R125,391	R39,987	R90,143	R2,974,830
February	R229,666	519,802	R678,066	R21,007	154,910	R117,653	R35,427	R76,743	R2,705,249
March	R250,919	578,820	R758,646	R23,266	171,516	R125,044	R39,436	R92,017	R3,008,808
April	R250,314	560,062	R727,527	R22,751	167,816	R123,615	R38,348	87,201	R2,925,844
May	R266,014	571,803	R781,002	R23,531	171,305	R128,320	38,958	R87,738	R3,046,445
June	R243,339	556,708	R766,761	R22,780	174,784	R124,341	R37,968	R81,599	R2,956,304
July	R254,709	583,186	R804,899	R22,987	180,524	R116,782	R38,381	R66,834	R3,071,698
August	R257,498	585,405	R837,459	R23,261	181,927	R120,984	R38,570	R91,237	R3,146,384
September	R256,073	568,646	R798,191	R22,080	R181,334	R126,696	R37,301	R84,094	R3,056,535
October	R261,454	589,800	R828,390	R22,559	R201,814	R130,259	R37,566	R86,636	R3,186,150
November	R251,153	597,779	R815,089	R21,869	R196,055	R123,894	R36,861	R83,661	R3,133,926
December	R259,905	608,342	R845,084	R22,570	R204,178	R125,876	R37,220	R87,441	R3,234,746
Total	**R3,036,052**	**6,896,792**	**R9,378,489**	**R271,808**	**R2,155,214**	**R1,488,854**	**R456,024**	**R1,015,343**	**R36,446,918**
2020									
January	263,734	R603,836	R843,432	R21,944	R209,896	R124,274	R37,391	R86,071	R3,194,177
February	243,139	R569,721	R783,094	R20,373	R198,090	R108,722	R34,782	R81,114	R2,984,616
March	257,387	R607,689	R841,347	R21,765	R210,559	R117,977	R36,689	R87,955	R3,196,236
April	235,642	R586,955	R783,283	R20,379	R204,826	R111,744	R34,389	R80,574	R3,011,842
May	217,154	R592,126	R734,176	R20,326	R212,646	R107,288	R33,986	R64,374	R2,927,037
June	222,324	R560,390	R741,401	R19,244	R212,831	R103,890	R32,957	R62,227	R2,873,001
July	226,843	R604,716	R775,851	R20,312	R220,032	R108,679	R34,568	R67,778	R3,021,331
August	226,344	R607,221	R782,436	R19,814	R223,208	R107,320	R33,757	R43,988	R3,011,580
September	222,010	R567,029	R755,253	R19,283	R218,893	R104,520	R30,468	R48,900	R2,917,569
October	219,403	R595,653	R773,720	R20,042	R226,064	R104,787	R31,775	R38,702	R2,991,827
November	224,327	R605,244	R751,562	R19,200	R223,428	R103,236	R31,246	R60,496	R2,984,528
December	228,057	R647,714	R770,555	R19,307	R231,845	R103,933	R32,383	R67,085	R3,088,701
Total	**2,786,366**	**R7,148,295**	**R9,336,110**	**R241,989**	**R2,592,319**	**R1,306,368**	**R404,391**	**R789,262**	**R36,202,446**
2021									
January	E221,544	E657,704	E775,706	E19,235	E234,432	E105,897	E33,444	E68,505	E3,099,685
February	E163,094	E585,221	E588,953	E17,815	E208,571	E95,863	E29,898	E62,427	E2,577,173
March	E220,130	E647,681	E772,550	E20,356	E227,218	E106,480	E34,127	E72,986	E3,080,967
April	E214,334	E618,509	E777,007	E19,861	E229,075	E102,740	E32,841	E69,810	E3,025,171
May	RE223,372	E640,431	RE799,557	RE20,312	RE234,118	RE104,698	RE33,636	RE67,752	RE3,118,960
June	RE213,782	RE623,843	RE782,110	RE19,572	RE228,668	RE100,288	RE32,291	RE68,178	RE3,027,840
July	E221,489	E642,889	E815,779	E20,300	E230,207	E103,929	E33,419	E71,165	E3,140,707
2021 7-Month YTD	**E1,477,747**	**E4,416,277**	**E5,311,662**	**E137,452**	**E1,592,289**	**E719,895**	**E229,657**	**E480,822**	**E21,070,504**
2020 7-Month YTD	**1,666,224**	**4,125,435**	**5,502,584**	**144,343**	**1,468,880**	**782,572**	**244,762**	**530,092**	**21,208,240**
2019 7-Month YTD	**1,749,968**	**3,946,821**	**5,254,276**	**159,469**	**1,189,906**	**861,146**	**268,506**	**582,275**	**20,689,177**

[R] Revised data.

[E] Estimated data.

[RE] Revised estimated data.

Notes: For 2021 forward, state monthly marketed production is estimated from gross withdrawals using historical relationships between the two. Data for Arkansas, California, Colorado, Kansas, Louisiana, Montana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, Utah, West Virginia, Wyoming, and Federal Offshore Gulf of Mexico are individually collected on the EIA-914 report. The “Other States” category comprises states/areas not individually collected on the EIA-914 report (Alabama, Arizona, Federal Offshore Pacific, Florida, Idaho, Illinois, Indiana, Kentucky, Maryland, Michigan, Mississippi, Missouri, Nebraska, Nevada, New York, Oregon, South Dakota, Tennessee, and Virginia). Before 2021, Federal Offshore Pacific is included in California. All data for Alaska are obtained directly from the state. Monthly preliminary state-level data for all states not collected individually on the EIA-914 report are available after the final annual reports for these series are collected and processed. Final annual data are generally available in the third quarter of the following year. The sum of individual states may not equal total U.S. volumes due to independent rounding.

Sources: 2016-2020: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2020*, Bureau of Safety and Environmental Enforcement (BSEE), IHS Markit, Enverus DrillingInfo, and BENTEK Energy. January 2021 through current month: Form EIA-914, *Monthly Crude Oil and Lease Condensate, and Natural Gas Production Report*; and EIA computations.

Summer 2022 to finish at 3Tcf

U.S. L48 gas market supply-and-demand balance sheet

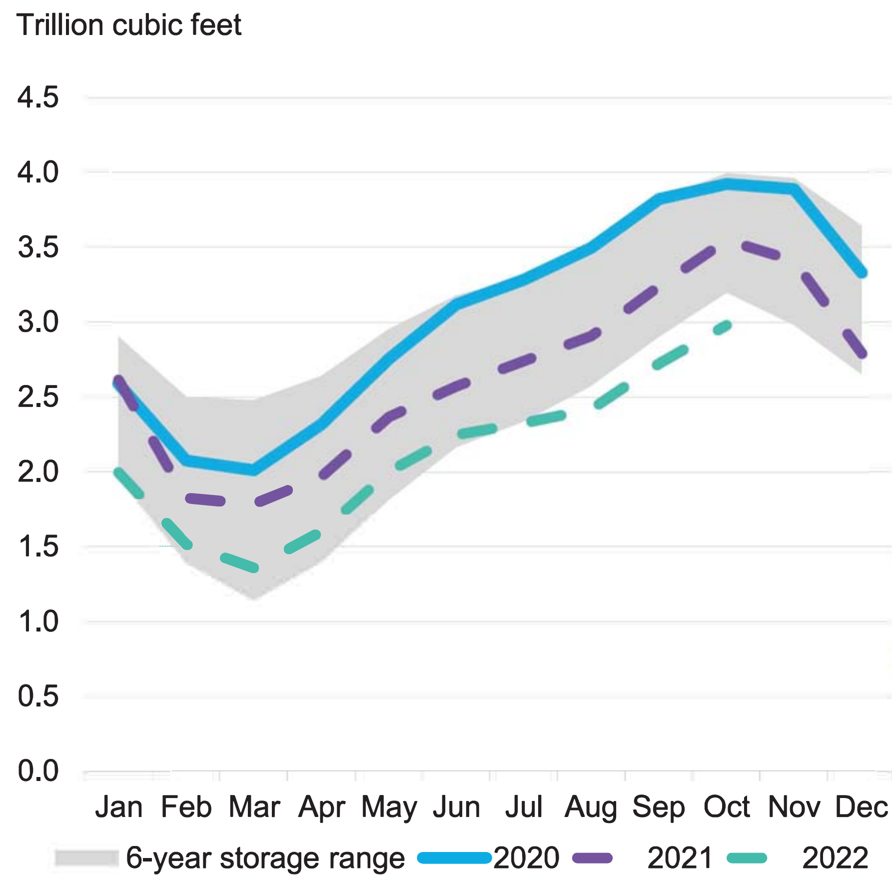
	Apr 21	May 21	Jun 21	Jul 21	Aug 21	Sep 21	Oct 21	Nov 21	Dec 21	Jan 22	Feb 22	Mar 22	Apr 22	May 22	Jun 22	Jul 22	Aug 22	Sep 22	Oct 22
Dry production	92.6	93.1	93.4	92.4	92.2	91.5	91.8	92.6	92.9	93.4	93.7	93.9	94.3	94.8	95.1	95.2	95.5	95.7	95.8
Net imports from Canada	4.7	4.5	4.8	5.2	5.1	4.9	4.9	4.8	5.5	6.2	5.8	5.2	5.0	5.2	5.2	5.4	5.2	4.9	5.2
Total supply	**97.2**	**97.6**	**98.3**	**97.6**	**97.3**	**96.4**	**96.7**	**97.4**	**98.4**	**99.6**	**99.5**	**99.1**	**99.3**	**99.9**	**100.3**	**100.6**	**100.7**	**100.5**	**100.9**
Power consumption	24.9	26.8	35.9	39.6	40.2	33.4	28.5	25.4	26.4	26.1	23.5	23.4	23.6	26.9	34.1	39.8	39.7	34.0	28.7
Industrial consumption	21.6	20.8	20.6	19.6	20.1	20.3	20.0	23.1	24.6	24.7	24.2	23.1	22.2	22.0	22.1	22.3	22.1	21.8	22.8
Rescom consumption	19.7	12.8	8.9	8.6	7.7	7.6	13.2	27.6	40.6	46.8	42.6	31.1	19.8	11.8	8.8	7.9	7.8	8.5	14.3
Plant fuel	5.1	5.1	5.1	5.1	5.1	5.1	5.3	5.3	5.3	5.4	5.3	5.4	5.4	5.4	5.4	5.4	5.4	5.5	5.5
Pipe losses	2.3	2.1	2.2	2.3	2.3	2.1	2.1	2.5	3.0	3.5	3.3	2.8	2.3	2.1	2.2	2.4	2.3	2.2	2.2
Exports to Mexico	6.5	6.6	7.2	6.8	6.7	6.6	7.0	7.0	6.8	6.9	6.3	6.7	6.8	6.8	7.1	7.0	6.9	7.0	7.1
LNG exports	11.1	10.5	9.9	10.5	10.2	10.2	10.7	10.9	11.6	11.7	11.6	11.7	11.3	11.8	12.5	13.4	13.4	11.4	12.0
Total demand	**91.2**	**84.7**	**89.8**	**92.4**	**92.3**	**85.2**	**86.9**	**102.0**	**118.4**	**125.1**	**116.9**	**104.1**	**91.3**	**86.8**	**92.2**	**98.1**	**97.7**	**90.4**	**92.7**
Balancing item	**-0.2**	**0.0**	**1.8**	**-0.3**	**-0.3**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Average daily storage change last year	10.2	14.0	12.1	5.3	6.9	10.8	3.3	-1.1	-18.0	-23.0	-28.3	-1.3	6.2	12.9	6.8	5.5	5.4	11.1	9.9
Average daily storage change	6.2	12.9	6.8	5.5	5.4	11.1	9.9	-4.6	-20.0	-25.5	-17.4	-5.0	8.0	13.1	8.1	2.6	3.0	10.1	8.3
Total monthly storage change	187	401	203	169	167	332	307	-137	-620	-792	-486	-154	240	408	243	79	92	304	256
Storage level (Bcf)	**1,968**	**2,369**	**2,572**	**2,741**	**2,908**	**3,240**	**3,546**	**3,410**	**2,790**	**1,998**	**1,512**	[illegible]	**1,598**	**2,006**	**2,249**	**2,328**	**2,421**	**2,724**	**2,980**

Source: BloombergNEF. Note: Based on forward curve as of September 22, 2021. Green indicates tightness, the market is either withdrawing more or injecting less than for the same month a year prior.

Balance: U.S. gas storage levels end winter 2021-22 at 1,358Bcf

Read previous monthly - U.S. Gas Monthly:
Defiant Demand Increases Market Pressure

Natural gas inventory forecast, 2021-22



Source: BloombergNEF

Inventories are still set for tightness over the next 12 months despite the higher gas price environment. Production growth is not enough to make up for gains from gas exports. Power burns are resilient due to coal plant retirements, lowering the price sensitivity of demand.

Summer 2021: BNEF's **3,546Bcf** end-of-summer inventory view is **86Bcf** higher than last months forecast. The deviance is driven by lower-than-anticipated industrial and rescom demand, which is tied to milder weather.

Winter 2021-22: The winter-end estimate increases to **1,358Bcf,** 313Bcf above our previous estimate. Gains are associated with lower power burn and industrial consumption estimates.

Summer 2022: Next summer ends at **2,980Bcf**, which is **550Bcf** higher than last month's report. Stronger production combined with slimmer power burn estimates combine to widen the forecast-on-forecast gap from the end of winter.

Year-on-year changes in major fundamental sectors

Sector	Summer 2021 (Bcf/d)	Winter 2021-22(Bcf/d)	Summer 2022 (Bcf/d)
Production	3.2	3.1	2.8
Power burns	-1.1	-1.8	-0.4
ResCom	-0.5	0.7	0.1
Industrial	-0.4	1.4	1.8
LNG	4.9	1.5	1.8

https://rbnenergy.com/go-west-red-hot-natural-gas-markets-help-push-north-american-lng-to-asia

Go West - Red-Hot Natural Gas Markets Help Push North American LNG To Asia

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Published by: Lindsay Schneider

With multiple energy markets around the world facing natural gas shortages, buyers are clamoring for more LNG. Pre-winter panic-buying has sent global gas prices to record highs yet again in the past couple of days, and even hauled Henry Hub gas futures up to new post-2008 records above $6/MMBtu in after-hours and intraday trading. With the incredible run in global gas prices, U.S. export economics have looked extremely attractive for nearly a year now, and you would think that buyers would be lining up for new liquefaction capacity in the U.S. Well, it has certainly drawn prospective offtakers back to the table. But they are wary of rising export costs and committing to projects long-term given the questionable future for hydrocarbon markets. Additionally, Europe's rising piped gas imports from Russia and overall declining demand in the region have put long-term prospects for European LNG imports, in particular, on shaky ground. So, access to Asia is more important than ever for new LNG development, a key selling point for projects on North America's Pacific Coast, both because of proximity to Asian markets and the absence of canal fees or constraints versus the Gulf Coast. There are no LNG export terminals on the Pacific Coast currently, but two projects — LNG Canada in British Columbia and Sempra Energy's Energía Costa Azul (ECA) LNG in Baja California, Mexico — are under construction and due online mid-decade. Those projects are unlikely to be the last, given the more than $1/MMBtu in cost savings due to shorter voyage times and canal-free access to Asia. In today's RBN blog, we begin a series looking at the state of LNG development on the North American Pacific Coast.

Back-to-back LNG blogs? We normally like to mix it up when it comes to blog topics. However, the past two days have been anything but normal in the gas markets. Global gas prices were already in the midst of the most epic bull run in modern times, if not ever, with gas prices abroad pushing to new highs all summer and into fall. This has been underpinned by strong global gas demand and a gas shortage in Europe (see **It's Too Late**), but now a coal shortage in China has sent the market into another upward spiral as the entire world weighs the impacts of multiple countries facing energy shortages and winter reliability fears. This has sent Asia's Japan Korea Marker (JKM), Europe's Dutch Title Transfer Facility (TTF) and the UK National Balancing Point (NBP) to all-time highs yet again this week. The U.S. gas market is tight as well, but it's not facing the same kind of shortages. Even so, gas prices here have been unable to escape the upward pull. The October Henry Hub gas futures surged nearly 60 cents (11%) on Monday — the biggest single-day gain in nearly three years — to record a new post-2008 high of $5.706/MMBtu, despite little change in domestic fundamentals. Then, in after-hours trading Monday night, the prompt contract blasted past the $6/MMBtu mark and again topped $6/MMBtu in early trading Tuesday before expiring at about $5.84/MMBtu. This, as JKM reached a high-water mark just under $30/MMBtu. The linchpin for these dramatic price moves is of course LNG. Yesterday, in **Hear My Train A Comin', Part 2**, we looked at the near-term impacts of rising LNG export capacity on U.S. gas demand, with commissioning for both Sabine Pass Train 6 expansion and the new Calcasieu Pass facility well underway and first LNG exports expected this winter. Next, we shift our focus longer-term to another aspect of the all-important LNG supply picture: the economics of North America's Pacific Coast vs. Gulf Coast export projects.

Before we dive into why the Pacific Coast is such an attractive location for LNG development, we need to review the basic economics around North American LNG exports. RBN utilizes an export cost model to track the economic viability of delivering U.S. LNG to destination markets. We first introduced this model in **Sultans of Swing**, where we went through the various costs in detail. Figure 1, below, shows a snapshot of our economic model for exports from the U.S. Gulf Coast (where a majority of exporters are located) to Asia via the Panama Canal, the lowest cost and most popular route for the bulk of U.S. LNG exports to Asia. Note that these costs are based on middle-of-the-road or midpoint assumptions, whereas, in reality, they can vary based on a host of factors and each offtaker's contract or even individual cargo sales.

The grey area in the stacked bar represents the liquefaction capacity charge or tolling fee, depending on what kind of contract the offtaker has with the specific LNG train or terminal, but this fee is fixed either way. On top of that, in the teal bar, is the vessel fee portion of the shipping charge. This can be fixed or marginal, meaning an offtaker only pays if it takes a cargo. The vessel fee is the cost of leasing the LNG tanker to deliver a cargo. Many offtakers have take-or-pay long-term contracts to lock in shipping rates and ship availability — the latter has increasingly **become a problem** for those without long-term contracts as the global LNG market has grown. Some major offtakers even own and operate their own fleet of tankers. In either case, the vessel fee is a fixed cost and not factored into the marginal economics of delivering cargoes. There is, however, an open market to charter tankers that can be used by offtakers without long-term shipping contracts or for spot market cargoes. In this case, the vessel charter is a marginal cost. This daily vessel charter rate moves in tandem with global gas prices, oil prices and ship availability, and operates much like any other commodity's market price. We show the average daily rate in $/MMBtu, converted based on an average LNG tanker size. On top of that, in various shades of green, are the marginal costs, which include feedgas costs and other shipping costs, including boil-off gas, bunker fuel, port fees and canal fees.

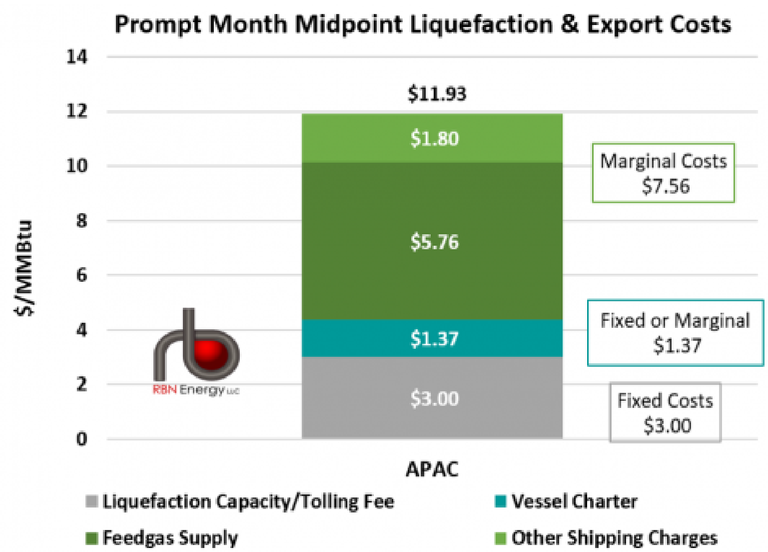


Figure 1: Midpoint Liquefaction & Export Costs. Source: **RBN LNG Voyager**

Of course, there will be differences in costs across all categories between the Pacific-based projects, and all new LNG in general, but the biggest difference will come down to proximity. The Pacific Coast is simply closer than the Gulf Coast to Asia. And, naturally, proximity is a huge driver of cost savings when it comes to shipping cargoes. The voyage from the Pacific Coast is about half the duration of that from the Gulf Coast, depending on the ports on either end of the voyage and tanker speed, and avoids the additional expense and wait time associated with transiting a canal. The difference in travel time and canal fees translates into a saving of more than $1/MMBtu. When global prices are high, exports from the U.S. Gulf Coast to Asia are extremely attractive, but when the arbitrage narrows, those savings offer the Pacific Coast a clear economic advantage and could keep cargoes economic even at lower gas prices. And there's an added bonus – reduced shipping times also mean fewer emissions from the LNG carriers.

A round-trip voyage between any of the Gulf Coast LNG terminals and Japan, China or South Korea — the Far East destinations where the bulk of LNG demand is concentrated — via the Panama Canal takes around 60 days, including port loading/unloading and transit time. Of course, delays at the Panama Canal, like those **seen last winter**, can add additional days to the voyage. If a vessel wants or needs to avoid the Panama Canal, the most common alternative would be to go around the Cape of Good Hope (CGH) in South Africa, which takes about 75 days for a round trip, 25% longer than the Panamanian route. The cost-saving from not having canal fees is more than negated by the additional voyage time. In the past year, according to our cost model, on average it is about $0.30/MMBtu more expensive to go around the CGH than via the Panama Canal.

Using our export cost model, we can simulate what the cost difference would be if there had been terminals operating from the Pacific Coast over the last year. Figure 2 below shows shipping costs for delivery to Asia from the Pacific Coast (orange line) vs. coming from the Gulf Coast via the Panama Canal (blue line) and around the CGH (grey line). On average, the Pacific Coast cost advantage would have been about $1.25/MMBtu compared with the Gulf Coast/Panama Canal route, with a little more than $1/MMBtu saved in shipping costs and the rest of the savings coming from the lack of canal fees. This spread could be even wider, particularly for spot market cargoes, because of high vessel charter fees. In general, vessel charter fees for non-contracted voyages tend to rise when global LNG prices are high as, during those times, demand for tankers outpaces supply.

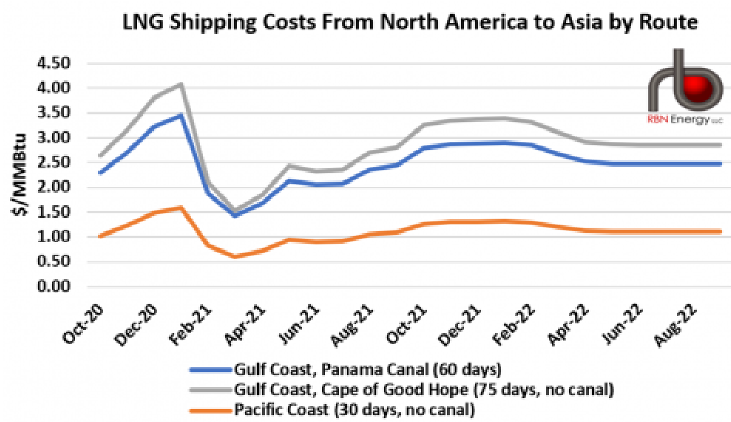


Figure 2: Pacific Coast Shipping Costs vs Gulf Coast Shipping Costs. Source: RBN

Despite the shorter voyage from the Pacific Coast, development of LNG projects on the U.S. West Coast is currently a non-starter because of regulatory difficulties. The only previously proposed project in the area, Jordan Cove in Oregon, is officially on pause after it failed to receive state and local permits. The project is unlikely to be revived unless there is a dramatic shift in regional politics. However, this still leaves Western Canada and Mexico, each of which, as we mentioned earlier, has a project currently under construction. Plus, additional projects have been proposed, and some of these projects could move quickly and bypass a number of previously announced Gulf Coast projects on their way to FID (see **Catch A Wave**). Of course, shipping isn't the only piece of the cost equation. There is also the cost of and access to feedgas supply which is, predictably, a huge factor in the LNG economics equation. We'll dig more into the specific feedgas and pipeline options for the projects in Western Canada and Mexico in Part 2 of this series, but in short, projects on the Gulf Coast still retain the feedgas cost advantage. The Gulf Coast has access to multiple low-cost supply basins and a robust pipeline grid. Pipeline capacity is more difficult to come by than it used to be, thanks to the first generation of LNG buildout, which added nearly 10 Bcf/d (and still growing) of feedgas demand (see **Such Great Heights**) along the Texas and Louisiana coastline since 2016. And as we discussed in yesterday's blog, **Hear My Train A Comin', Part 2**, that volume is going to be growing to more than 12 Bcf/d in the very near future. The pipeline grid can be expanded, however, with brownfield expansions of existing routes or short-haul, greenfield pipelines, lowering the cost as compared to other areas such as the Pacific Coast.

Ultimately, at least for now, it seems that there is room for additional LNG capacity in both regions, the Gulf Coast and the Pacific Coast, and a handful of projects across both areas are targeting FID next year – and could realistically achieve it. But access to Asia will only become more important as time goes on, and that presents a huge opportunity for projects on the Pacific Coast, particularly for those in Mexico, which face less regulatory scrutiny than those in the U.S. or Canada.

"Go West" was written by Jacques Morali, Henri Belolo, and Victor Willis. It appears as the second song on Village People's fourth studio album of the same name. Released as the first single from the LP in June 1979, it went to #14 on the Billboard Dance Club and #45 on the Billboard Hot 100 Singles charts. Personnel on the Village People record were: Victor Willis (lead vocals), Randy Jones, Glenn Hughes, Felipe Rose, David Hodo, Alex Briley (backing vocals), and Gypsy Lane (studio band). In September 1993, Pet Shop Boys released their version of the song as a single from their fifth studio album, *Very*. It went to #1 on the Billboard Dance Club chart and #25 on the Billboard Hot 100 Singles chart. Personnel on the Pet Shop Boys record were: Chris Lowe, Neal Tennant (vocals).

The Village People album, *Go West*, was produced by Jacques Morali and released in March 1979. It went to #8 on the Billboard 200 Albums chart and has been certified Platinum by the Recording Industry Association of America (RIAA). It would be the last Village People album of new material for Casablanca Records and the last album to feature Victor Willis on lead vocals. Two singles were released from the LP. The Pet Shop Boys album, *Very*, was released in September 1993 and went to #20 on the Billboard Top 200 Albums chart. It has been certified Gold by the RIAA. Five singles were released from the album.

Village People is an American disco group known for its costuming and clever lyrics. Formed in New York City in 1977 by French record producers Jacques Morali and Henri Belolo, and featuring the vocals of Victor Willis, the group released its debut album in July 1977. They have released eight studio albums, one live album, four compilation albums, and 25 singles. Twenty-four members have passed through the group since its inception. They still tour with original member Victor Willis on lead vocals, accompanied by James Kwong, Chad Freeman, Jeffrey James Lippold, and James Lee on backing vocals.

Pet Shop Boys are an English synth-pop duo formed in London in 1981, consisting of Chris Lowe and Neil Tennant. They have released 14 studio albums, five live albums, five soundtrack albums, seven compilation albums, three EPs, and 70 singles. They continue to record and tour.

https://www.reuters.com/business/energy/appec-baker-hughes-sees-global-required-lng-capacity-800-mln-tonnes-by-2030-2021-09-27/

September 26, 202111:00 PM MDTLast Updated 4 days ago

APPEC Baker Hughes sees global required LNG capacity at 800 mln tonnes by 2030

By Sonali Paul

MELBOURNE, Sept 27 (Reuters) - Oil and gas services giant Baker Hughes Co (BKR.N) sees the need for global liquefied natural gas (LNG) capacity to rise to 800 million tonnes by 2030, more than double current capacity, its chairman said on Monday.

Baker Hughes sees strong prospects for gas in the transition to cleaner energy, with LNG combined with carbon capture and storage helping to reduce the industry's carbon footprint.

"We've taken up our estimate of the required installed base of LNG by 2030 up to 800 million tonnes," Chairman and Chief Executive Officer Lorenzo Simonelli said at the Platts APPEC 2021 conference.

As of 2020, there was about 345 million tonnes of LNG capacity.

Baker Hughes' forecast compared with consultants Wood Mackenzie's forecast that the world will need 250 million tonnes in new LNG supply by 2040.

"We see a steady stream of final investment decisions and projects happening both in North America as well as internationally to really bring on between 100 and 150 million tonnes in the next few years as we go forward," Simonelli said.

Another potential boost for the oil and gas industry he said could come from demand for non-metallic pipes, which would increase demand for petrochemicals to make those pipes.

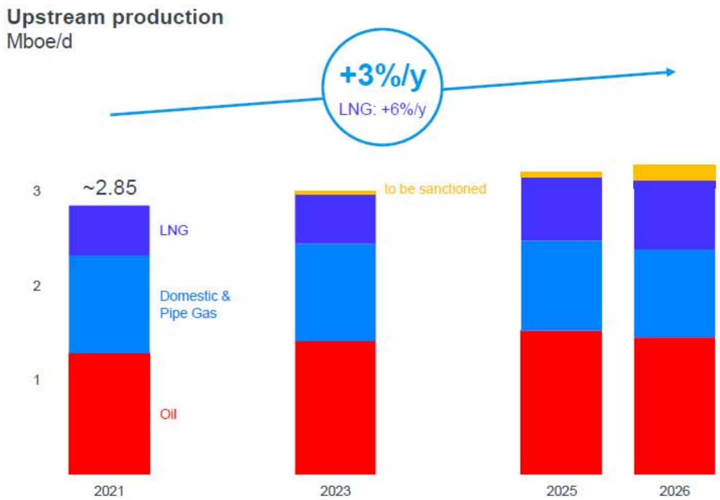
"We're big fans of non-metallic pipes," Simonelli said.

The main benefits of non-metallic pipes over steel pipes are they are lighter by weight, more durable and do not rust, which Simonelli said would be useful not just for new pipelines but also for installing inner shields to repurpose existing pipelines, as well as for platforms and other construction products.

"We see a wide array where composites from a life-cycle cost perspective are much better than a steel pipe or other metallic pipes, and we're seeing an increased interest from our customers."

Reporting by Sonali Paul; Editing by Tom Hogue and Christopher Cushing

Upstream production driven by LNG growth



2021-23 impact of OPEC quotas and Covid Capex reduction

Mozambique LNG postponed to 2026

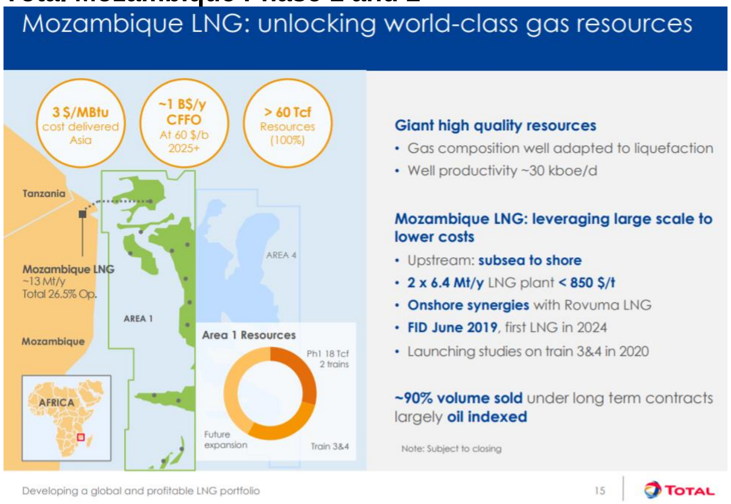
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

Posted Wednesday April 28, 2021. 9:00 MT

The next six months will determine the size and length of the new LNG supply gap that is hitting harder and faster than anyone expected six months ago. Optimists will say the Mozambique government will bring sustainable security and safety to the northern Cabo Delgado province and provide the confidence to Total to quickly get back to LNG development such that its LNG in-service delay is a matter of months and not years. We hope so for Mozambique's domestic situation, but will it be that easy for Total's board to quickly look thru what just happened? Total suspended LNG development for 3 months, restarted development on March 25, but then 3 days of violence led it to suspend development again on March 28, and announce force majeure on Monday April 26. Even if the optimists are right, Mozambique LNG is counted on for LNG supply and the major LNG supply project that are in LNG supply forecasts are now all delayed – Total Phase 1 of 1.7 bcf/d and its follow on Phase 2 of 1.3 bcf/d, and Exxon's Rozuma Phase 1 of 2.0 bcf/d. It is important to remember this 5.0 bcf/d of major LNG supply is being counted in LNG supply forecasts and starting in 2024. At a minimum, we think the more likely scenario is a delay of at least 2 years in this 5.0 bcf/d from the pre-Covid timelines. And this creates a much bigger and sooner LNG supply gap starting ~2025 and stronger outlook for LNG prices. Thermal coal in Asia will play a role in keeping a lid on LNG prices. But there will be the opportunity for LNG suppliers to at least review the potential for brownfield LNG projects to fill the growing supply gap. The thought of increasing capex was a non-starter six months ago, but there is a much stronger outlook for global oil and gas prices. Oil and gas companies are pivoting from cutting capex to small increases in 2021 capex and expecting for higher capex in 2022. We believe this sets the stage for looking at potential FID of brownfield LNG projects before the end of 2021 to be included in 2022 capex budgets. Mozambique is causing an LNG supply gap that someone will try to fill. And if brownfield LNG is needed, what about Shell looking at 1.8 bcf/d brownfield LNG Canada Phase 2? Cdn natural gas producers hope so as this would mean more Cdn natural gas will be tied to Asian LNG markets and not competing in the US against Henry Hub.

Total declares force majeure on Mozambique LNG, Yesterday, Total announced [LINK] "*Considering the evolution of the security situation in the north of the Cabo Delgado province in Mozambique, Total confirms the withdrawal of all Mozambique LNG project personnel from the Afungi site. This situation leads Total, as operator of Mozambique LNG project, to declare force majeure. Total expresses its solidarity with the government and people of Mozambique and wishes that the actions carried out by the government of Mozambique and its regional and international partners will enable the restoration of security and stability in Cabo Delgado province in a sustained manner".* Total is working Phase 1 is ~1.7 bcf/d (Train 1 + 2, 6.45 mtpa/train) and was originally expected to being LNG deliveries in 2024. There was no specific timeline for Phase 2 of 1.3 bcf/d (Train 3 + 4, 5.0 mtpa/train), but was expected to follow Phase 1 in short order to keep capital costs under control with a continuous construction process with a potential onstream shortly after 2026.

Total Mozambique Phase 1 and 2



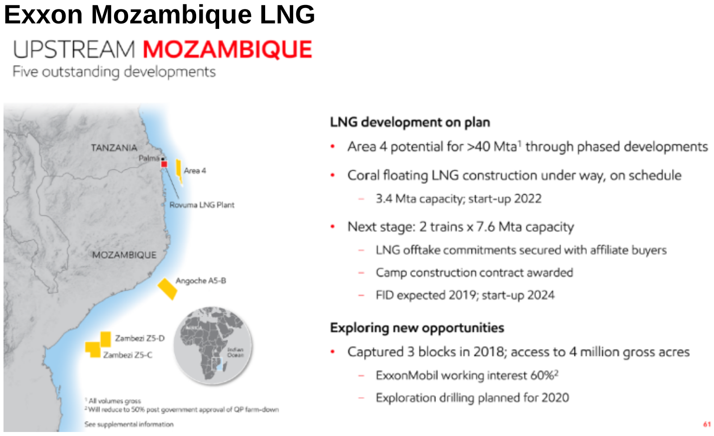
Source: Total Investor Day September 24, 2019

Total's Mozambique force majeure is no surprise, especially the need to the restoration of security and stability "in a sustained manner". Yesterday, Total announced [LINK] "*Considering the evolution of the security".* No one should be surprised by the force majeure or the sustained manner caveat. SAF Group posts a weekly Energy Tidbits research memo [LINK], wherein we have, in multiple weekly memos, that Total had shut down development in December for 3 months due to the violent and security risks. It restarted development on Wed March 24, violence/attacks immediately resumed for 3 consecutive days, and then Total suspended development on Sat March 27. Local violence/attacks shut development down in Dec, the situation gets settled enough for Total to restart in March, only to be shut down 3 days thereafter. No one should be surprised especially with Total's need to see security and stability "in a sustained manner".

Does anyone really think Total will risk another quick 2-3 month restart or even in 2021? The Mozambique government will be working hard to convince Total to restart soon. We just find it hard to believe Total board will risk a replay of March 24-27 in 2021. Unfortunately, Mozambique has had internal conflict for years. It reached a milestone to the positive in August 2019. Our SAF Group August 11, 2019 Energy Tidbits memo [LINK] highlighted the signing of a peace pact between Mozambique President Nyusi and leader of the Renamo opposition Momade. This was the official end to a 2013 thru 2016 conflict following a failure to hold up the prior peace pact. At that time, FT reported [LINK] "Mr Nyusi has said that "*the government and Renamo will come together and hunt" rebels who fail to disarm. The government has struggled to stem the separate insurgency in the north, which has killed or displaced hundreds near the gas-rich areas during the past two years. While the roots of the conflict remain murky, it is linked to a local Islamist group and appears to be drawing on disaffection over sharing gas investment benefits, say analysts*." This is just a reminder this is not a new issue. LNG is a game changer to Mozambique's economic future. It is, but also has been, a government priority to have the security and safety for Total and Exxon to move on their LNG developments. Its hard to believe the Mozambique government will be able to quickly convince Total and Exxon boards that they can be comfortable there is a sustained security/safety situation and they can send their people back in to develop the LNG. Total's board would allow any resumption of development before year end 2021. The last thing Total wants is a replay of March 24-27. The first question is how long will it take before the Total board is convinced its safe to restart. Could you imagine them doing a replay of what just happened? Wait three months, restart development and have to stop again right away? We have to believe that could lead the Total board to believe it is unfixable for years. We just don't think they are to prepared to risk that decision in 3 months. Its why we have to think there isn't a restart approval until at least in 2022 at the earliest ie. why we think the likely scenario is a delay of 2-3 years, and not a matter of months.

Mozambique's security issues pushes back 5.0 bcf/d of new LNG supply at least a couple years. The global LNG issue is that 5 bcf/d of new Mozambique LNG supply (apart from the Eni Coral FLNG of 0.45 bcf/d) won't start up in 2024 and continuing thru the 2020s. And we believe all LNG forecasts included this 5.0 bcf/d to be in service in the 2020s as Mozambique had been considered the best positioned LNG supply to access Asia after Australia and Papua New Guinea. (i) Eni Coral Sul (Rovuma Basin) FLNG of 0.45 bcf/d planned in service in 2022. [LINK] This is an offshore floating LNG vessel that is still expected to be in service in 2022. (ii) Total Phase 1 to add 1.7 bcf/d with an in service originally planned for 2024. We expect the in service data to be pushed back to at least 2026 assuming Total gives a development restart approval in Dec 2021. In theory, this would only be a 1 year loss of time. However, Total has let services go, the project will be idle for 9 months, it isn't clear if the need to get people out quickly let them do a complete put the project on hold, and how many people will be on site maintaining the status of the development during the force majeure. Also what new procedures and safety will be put in place for a restart. These all mean there will be added time needed to get the project back to where it was when force majeure was declared ie. why we think a 12 month time delay will be more like an 18 month project delay. (iii) Exxon's Rozuma Phase 1 LNG will add 2.0 bcf/d and, pre-Covid, was expected to be in service in 2025. We believe the delays related to security and safety at Total are also going to impact Exxon. We find it highly unlikely the Exxon board would take a different security and safety decision than Total. Pre-pandemic, Exxon's March 6, 2019 Investor Day noted their operated Mozambique Rovuma LNG Phase 1 was to be 2 trains each with 1.0 bcf/d capacity for total initial capacity of 2.0 bf/d with FID expected in 2019 and first LNG deliveries in 2024. The 2019 FID expectation was later pushed to be expected just before the March 2020 investor day. But the pandemic hit, and on March 21, 2020, we tweeted [LINK] on the Reuters story "*Exclusive: Coronavirus, gas slump put brakes on Exxon's giant Mozambique LNG plan"* [LINK] that noted Exxon was expected to delay the Rovuma FID. There was no timeline, but the expectation was that FID would now be in 2022 (3 years later than original timeline0 and that would push first LNG likely to 2027. (iv) Total Phase 2 was to add 1.3 bcf/d. There was no firm in service date but it was expected to follow closely behind Phase 1 to maintain services. That would have put it originally in the 2026/2027 period. But if Phase 1 is pushed back 2 years, so will Phase 2 so more likely 2028/2029.. (v) Total Phase 1 + 2 and Exxon Rozuma Phase 1 total 5.0 bcf/d and would have been (and still are) in all LNG supply forecasts for the 2020s. (vi) We aren't certain if the LNG supply forecasts include Exxon Rozuma Phase 2 ,which would be an additional 2.0 bcf/d on top of the 5.0 bcf/d noted above. Exxon Rozuma has always been expected to be at least 2 Phases. This has been the plan since the Anadarko days given the 85 tcf size of the resource on Exxon's Area 4. There was no firm in service data for Phase 2, but it was expected they would also closely follow Phase 1 to maintain services. We expect that original timeline would have been 2026/2027 and that would not be pushed back to 2029/2030. (vii) It doesn't matter if its only 5 bcf/ of Mozambique that is delayed 2 to 3 years, it will cause a bigger LNG supply gap and sooner. The issue for LNG markets is this is taking projects that are in development effectively out of the queue for some period.

Exxon Mozambique LNG



Source: Exxon Investor Day March 6, 2019

<u>Won't LNG and natural gas get hit by Biden's push for carbon free electricity?</u> Yes, in the US. For the last 9 months, we have warned on Biden's climate change plan that were his election platform and now form his administration's energy transition map. We posted our July 28, 2020 blog "*Biden To Put US On "Irreversible Path to Achieve Net-Zero Emissions, Economy-Wide" Is a Major Negative To US Natural Gas in 2020s* "[LINK] on Biden's platform "*The Biden Plan to Build a Modern, Sustainable Infrastructure and an Equitable Clean Energy Future*" [LINK]. Biden's new American Jobs Plan

[LINK] lines up with his campaign platform including to put the US "*on the path to achieving 100 percent carbon-free electricity by 2035*.". Our July 28, 2020 blog noted that it would require replacing ~60% of US electricity generation with more renewable and it could eliminate ~40% (33.5 bcf/d) of 2019 US natural gas consumption. If Biden is 25% successful by 2030, it would replace ~6.3 bcf/d of natural gas demand. It would be a negative to US natural gas and force more US natural gas to export markets. The wildcard when does US natural gas start to decline if producers are faced with the reality of natural gas being phased out for electricity. The other hope is that when Biden says "carbon-free", its not what ends up in the details of any formal policy statement ie. carbon electricity will be allowed with Biden's push for CCS.

Will Cdn natural gas be similarly hit by if Trudeau move to "emissions free" and not "net zero emissions" electricity? Yes and No. Our SAF Group April 25, 2021 Energy Tidbits memo [LINK] was titled ""*Bad News For Natural Gas, Trudeau's Electricity Goal is Now 100% "Emissions Free" And Not "Net Zero Emissions*". On Thursday, PM Trudeau spoke at Biden's global climate summit [LINK] and looks like he slipped in a new view on electricity than was in last Monday's budget and his Dec climate plan. Trudeau said "*In Canada, we've worked hard to get to over 80% emissions-free electricity, and we're not going to stop until we get to 100%."* Speeches, especially ones made on a global stage are checked carefully so this had to be deliberate. Trudeau said "*emissions free*" and not net zero emissions electricity. It seems like this language is carefully written to exclude any fossil fuels as they are not emissions free even if they are linked to CCS. Recall in Liberals big Dec 2020 climate announcement [LINK], Liberals said ""*Work with provinces, utilities and other partners to ensure that Canada's electricity generation achieves net-zero emissions before 2050*." There is no way Trudeau changed the language unless he meant to do so. And this is a major change as it would seem to indicate his plan to eliminate all fossil fuels used for electricity. If so this would be a negative to Cdn natural gas that would be stuck within Western Canada and/or continuing to push into the US when Biden is trying to switch to carbon free electricity. We recognize that there is still some ambiguity in what will be the details of policy and the Liberals aren't changing to no carbon sourced electricity at all. Let's hope so. But let's also be careful that politicians don't change language without a reason or at least with a view to setting up for some future hit. Plus Trudeau had a big warning in that same speech saying "*we will make it law to respect our new 2030 target and achieve net-zero emissions by 2050*". They plan to make it the law that Canada has to be on track for the Liberals 2030 emissions targets. This means that the future messaging will be that the Liberals have no choice but to take harder future emissions actions as it is the law. They will be just obeying the law as they will be obligated to obey the law. Everyone knows the messaging will be we have to do more get to Net Zero, that in itself will inevitably mean it will be the law if he actually does move to eliminate any carbon based electricity. So yes it's a negative, that is unless more Cdn natural gas can be exported via LNG to Asia. We believe this would be a plus to be priced against global LNG instead of Henry Hub.

Biden's global climate summit reminded there is too much risk to skip over natural gas as the transition fuel. Apart from the US and Canada, we haven't seen a sea shift to eliminating natural gas for power generation, especially from energy import dependent countries. There is a strong belief that hydrogen and battery storage will one day be able to scale up at a competitive cost to lead to the acceleration away from fossil fuels. But that time isn't yet here, at least not for energy import dependent countries. One of the key themes from last week's leader's speeches at the Biden global climate summit – to get to Net Zero, the world is assuming there wilt be technological advances/discoveries that aren't here today and that have the potential to immediately ramp up in scale. IEA Executive Director Faith Birol was blunt in his message [LINK] saying "*Right now, the data does not match the rhetoric – and the gap is getting wider*." And "*IEA analysis shows that about half the reductions to get to net zero emissions in 2050 will need to come from technologies that are not yet ready for market. This calls for massive leaps in innovation. Innovation across batteries, hydrogen, synthetic fuels, carbon capture and many other technologies.* US Special Envoy for Climate John Kerry said a similar point that half of the emissions reductions will have to come from technologies that we don't yet have at scale. UK PM Johnson [LINK] didn't say it specifically, but points to this same issue saying "*To do these things we've got to be constantly original and optimistic about new technology and new solutions whether that's crops that are super-resistant to drought or more accurate weather forecasts like those we hope to see from the UK's new Met Office 1.2bn supercomputer that we're investing in*." It may well be that the US and other self sufficient energy countries are comfortable going on the basis of assuming technology developments will occur on a timely basis. But, its clear that countries like China, India, South Korea and others are not prepared to do so. And not prepared to have the confidence to rid themselves of coal power generation. This is why there hasn't been any material change in the LNG demand outlook

We expect the IEA's blunt message that the gap is getting wider will be reinforced on May 18. We have had a consistent view on the energy transition for the past few years. We believe it is going to happen, but it will take longer, be a bumpy road and cost more than expected. This is why we believe the demise of oil and natural gas won't be as easy and fast as hoped for by the climate change side. The IEA's blunt warning on the gap widening should not be a surprise as they warned on this in June 2020. Birol's climate speech also highlighted that the IEA will release on May 18 its roadmap for how the global energy sector can reach net zero by 2050. Our SAF Group June 11, 2020 blog "*Will The Demise Of Oil Take Longer, Just Like Coal? IEA and Shell Highlight Delays/Gaps To A Smooth Clean Energy Transition*" [LINK] feature the IEA's June 2020 warning that the critical energy technologies needed to reduce emissions are nowhere near where they need to be. In that blog, we said "there was an excellent illustration of the many significant areas, or major pieces of the puzzle, involved in an energy transition by the IEA last week. The IEA also noted the progress of each of the major pieces and the overall conclusion is that the vast majority of the pieces are behind or well behind where they should be to meet a smooth timely energy transition. It is important to note that these are just what the IEA calls the "*critical energy technologies*" and does not get into the wide range of other considerations needed to support the energy transition. The IEA divides these "critical energy technologies "into major groupings and then ranked the progress of each of these pieces in its report "*Tracking Clean Energy Progress*" [LINK] by on track, more efforts needed, or not on track". Our blog included the below IEA June 2020 chart.

IEA's Progress Ranking For "Critical Energy Technologies" For Clean Energy Transition

🔴 Power	🟡 Renewable Power	🔴 Geothermal
	🟢 Solar PV	🔴 Ocean Power
	🟡 Onshore Wind	🔴 Nuclear Power
	🟡 Offshore Wind	🟡 Natural Gas-Fired Power
	🟡 Hydropower	🔴 Coal-Fired Power
	🟢 Bioenergy Power Generation	🔴 CCUS in Power
	🔴 Concentrating Solar Power	
🔴 Fuel Supply	🔴 Methane Emissions from O&G	🔴 Flaring Emissions
🟡 Industry	🟡 Chemicals	🟡 Pulp and Paper
	🟡 Iron and Steel	🟡 Aluminum
	🟡 Cement	🔴 CCUS in Industry and Transformation
🟡 Transport	🟢 Electric Vehicles	🔴 Transport Biofuels
	🟢 Rail	🟡 Aviation
	🔴 Fuel Consumption of Cars and Vans	🟡 International Shipping
	🟡 Trucks and Busses	
🔴 Buildings	🔴 Building Envelopes	🟢 Lighting
	🔴 Heating	🟡 Appliances and Equipment
	🟡 Heat Pumps	🟢 Data Centres and Data Transmission Networks
	🟡 Cooling	
🟡 Energy Integration	🟡 Energy Storage	🟡 Demand Response
	🟡 Hydrogen	🟡 Direct Air Capture
	🟡 Smart Grids	

Source: IEA

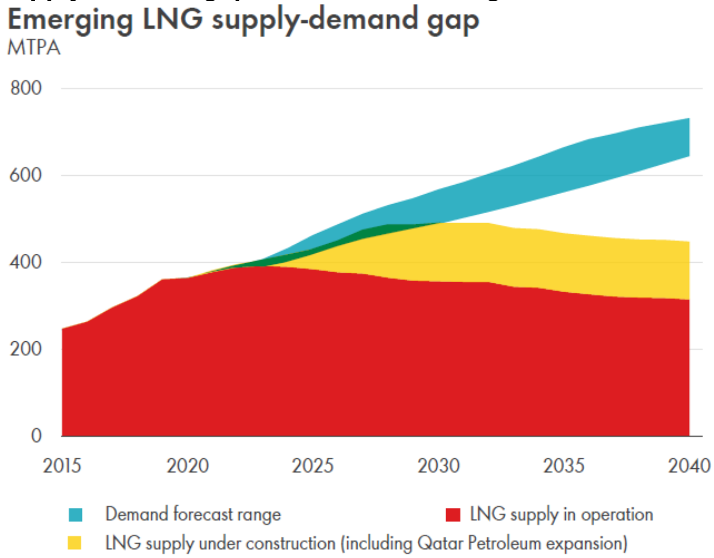
🟢 On Track 🟡 More Efforts Needed 🔴 Not on Track

Source: IEA Tracking Clean Energy Progress, June 2020

We are referencing Shell's long term outlook for LNG We recognize there are many different forecasts for LNG, but are referencing Shell' LNG Outlook 2021 from Feb 25, 2021 for a few reasons. (i) Shell's view on LNG is the key view for when and what decision will be made for LNG Canada Phase 2. (ii) Shell is one of the global leaders in LNG supply and trading. (iii) Shell provides on the record LNG outlooks every year so there is the ability to compare and make sure the outlook fits the story. It does. (iv) Shell, like other supermajors, has had to make big capex cuts post pandemic and that certainly wouldn't put any bias to the need for more capex.

Shell's March 2021 long term outlook for LNG demand was basically unchanged vs 2020 and leads to a LNG supply gap in mid 2020s Shell does not provide the detailed numbers in their Feb 25, 2021 LNG forecast. We would assume they would have reflected some delay, perhaps 1 year, at Mozambique but would be surprised if they put a 2-3 year delay in for the 5 bcf/d from Total Phase 1 +2 and Exxon Rozuma Phase 1. Compared to their LNG Outlook 2020, it looks like there was no change for their estimate of global natural gas demand growth to 2040, which looked relatively unchanged at approx. 5,000 bcm/yr or 484 bcf/d. Similarly, long term LNG demand looked unchanged to 2040 of ~700 mm tonnes (92 bcf/d) vs 360 mm tonnes (47 bcf/d) in 2020. In the 2021 outlook, Shell highlighted that the pandemic delayed project construction timelines and that the "*lasting impact expected on LNG supply not demand*". And that Shell sees a LNG "*supply-demand gap estimated to emerge in the middle of the current decade as demand rebounds*". Comparing to 2020, it looks like the supply-demand gap is sooner.

Supply-demand gap estimated to emerge in the middle of the current decade



Source: Shell LNG Outlook 2021, Feb 25, 2021

<u>Mozambique delays are redefining the LNG markets for the 2020s: Delaying 5 bcf/d of Mozambique new LNG supply 2-3 years means a much bigger supply gap starting in 2025..</u> Even if the optimists are right, there are now delays to all major Mozambique LNG supply from LNG supply forecasts. We don't have the detail, but we believe all LNG forecasts, including Shell's LNG Outlook 2021, would have included Total's Phase 1 and Phase 2 and Exxon Rozuma Phase 1. As noted earlier, we believe that the likely impact of the Mozambique security concerns is that these forecasts would likely have to push back 1.7 bcf/d from Total Phase 1 to at least 2026, 2.0 bcf/d Exxon Rozuma Phase 1 to at least 2027, and 1.3 bcf/d Total Phase 2 to at least 2028/2029 with the real risk these get pushed back even further. 5.0 bcf/d is equal to 38 mtpa. These delays would mean there is an increasing LNG supply gap in 2025 and increasingly significantly thereafter. And even if a new greenfield LNG project is FID's right away, it wouldn't be able to step in to replace Total Phase 1 prior startup timing for 2024 or likely the market at all until at least 2027. Its why the decision on filling the gap will fall on brownfield LNG projects.

<u>And does this bigger, nearer supply gap force LNG players to look at what brownfield LNG projects they could advance?</u> A greenfield LNG project would likely take at least until 2027 to be in operations. Its why we believe the Mozambique delays will effectively force major LNG players to look to see if there are brownfield LNG projects they should look to advance. Prior to the just passed winter, no one would think Shell or other major LNG players would be considering any new LNG FIDs in 2021. All the big companies are in capital reduction mode and debt reduction mode. But Brent oil is now solidly over $60 and LNG prices hit record levels in Jan and the world's economic and oil and gas demand outlook are increasing with vaccinations. And we are starting to see companies move to increasing capex with the higher cash flows. We would not expect any major LNG players to move to FID right away. But we see them watching to see if 2021 plays out to still support this increasing LNG supply gap. And unless new mutations prevent vaccinations from returning the world to normal, we suspect that major LNG players, like other oil and gas companies, will be looking to increase

capex as they approve 2022 budgets. The outlook for the future has changed dramatically in the last 5 months. The question facing Shell and others, should they look to FID new LNG brownfield projects in the face of an increasing LNG supply gap that is going to hit faster and harder than expected a few months ago. We expect these decisions to be looked at before the end of 2021. LNG prices will be stronger, but we expect the limiting cap in Asia will be that thermal coal will be used to mitigate some LNG price pressure.

<u>Back to Shell, does increasing LNG supply gap provide the opportunity to at least consider a LNG Canada Phase 2 FID over the next 9 months?</u> Shell is no different than any other major LNG supplier in always knowing the market and that the oil and gas outlook is much stronger than 6 months ago. No one has been or is talking about this Mozambique impact and how it will at least force major LNG players to look at if they should FID new brownfield LNG projects to take advantage of this increasing supply gap. We don't have any inside contacts at Shell or LNG Canada, but that is no different than when we looked at the LNG markets in September 2017 and saw the potential for Shell to FID LNG Canada in 2018. We posted a September 20, 2017 blog *"China's Plan To Increase Natural Gas To 10% Of Its Energy Mix Is A Global Game Changer Including For BC LNG*" [LINK]. Last time, it was a demand driven supply gap, this time, it's a supply driven supply gap. We have to believe any major LNG player, including Shell, will be at least looking at their brownfield LNG project list and seeing if they should look to advance FID later in 2021. Shell has LNG Canada Phase 2, which would add 2 additional trains or approx. 1.8 bcf/d. And an advantage to an FID would be that Shell would be able to commit to its existing contractors and fabricators for a continuous construction cycle following on LNG Canada Phase 1 ie. to help keep a lid on capital costs. No one is talking about the need for these new brownfield LNG projects, but, unless Total gets back developing Mozambique and keeps the delay to a matter of months, its inevitable that these brownfield LNG FID internal discussions will be happening in H2/21. Especially since the oil and gas price outlook is much stronger than it was in the fall and companies will be looking to increase capex in 2022 budgets

<u>A LNG Canada Phase 2 would be a big plus to Cdn natural gas.</u> A LNG Canada Phase 2 FID would be a big plus for Cdn natural gas. It would allow another ~1.8 bcf/d of Cdn natural gas to be priced against Asian LNG prices and not against Henry Hub. And it would provide demand offset versus Trudeau if he moves to make electricity "emissions free" and not his prior "net zero emissions". Mozambique may be in Africa, but, unless sustained peace and security is attained, it is a game changer to LNG outlook creating a bigger and sooner LNG supply gap. And with a stronger tone to oil and natural gas prices in 2021, the LNG supply gap will at least provide the opportunity for Shell to consider FID for its brownfield LNG Canada Phase 2 and provide big support to Cdn natural gas for back half of the 2020s. And perhaps if LNG Canada is exporting 3.6 bcf/d from two phases, it could help flip Cdn natural gas to a premium to US natural gas especially if Biden is successful in reducing US domestic natural gas consumption for electricity. The next six months will be very interesting to watch for LNG markets.

https://qp.com.qa/en/MediaCentre/Pages/ViewNews.aspx?NType=News

Qatar Petroleum signs 15-year SPA to supply 3.5 MTPA of LNG to China's CNOOC

DOHA, Qatar • 29 September 2021 – Qatar Petroleum entered into a long-term sale and purchase agreement (SPA) with CNOOC Gas and Power Trading & Marketing Limited, a subsidiary of China National Offshore Oil Corporation (CNOOC), for the supply of 3.5 million tons per annum (MTPA) of LNG over a 15-year period starting January 2022.

The SPA was signed during a virtual ceremony by His Excellency Mr. Saad Sherida Al-Kaabi, the Minister of State for Energy Affairs, the President and CEO of Qatar Petroleum, and Mr. Wang Dongjin, the Chairman of CNOOC.

Commenting on this occasion, His Excellency Minister Al-Kaabi said, "We are pleased to further build upon our strong relationship with CNOOC with the signing of this new long-term LNG supply agreement. We are especially proud to continue to meet the People's Republic of China's growing need for cleaner energy that LNG provides, and are thankful to CNOOC for partnering with us as their trusted LNG supplier."

His Excellency concluded his remarks by thanking Sheikh Khalid bin Khalifa Al Thani, the CEO of Qatargas, and the teams from both sides for the successful conclusion of this new long-term LNG supply agreement with CNOOC.

Qatar's relationship with CNOOC extends back to September 2009 when the first LNG cargo was delivered to CNOOC in China.

As of August 2021, Qatar has delivered a total of 715 LNG cargoes to China, of which 270 cargoes (more than 24 million tons of LNG) were delivered to CNOOC.

Asian LNG Buyers Abruptly Change and Lock in Long Term Supply – Validates Supply Gap, Provides Support For Brownfield LNG FIDs

Posted 11am on July 14, 2021

The last 7 days has shown there is a sea change as Asian LNG buyers have made an abrupt change in their LNG contracting and are moving to lock in long term LNG supply. This is the complete opposite of what they were doing pre-Covid when they were trying to renegotiate Qatar LNG long term deals lower and moving away from long term deals to spot/short term sales. Why? We think they did the same math we did in our April 28 blog "*Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?*" and saw a much bigger and sooner LNG supply gap driven by the delay of 5 bcf/d of Mozambique LNG that was built into most, if not all LNG supply forecasts. Asian LNG buyers are committing real dollars to long term LNG deals, which we believe is the best validation for the LNG supply gap. Another validation, Shell, Total and others are aggressively competing to invest long term capital to partner in Qatar Petroleum's massive 4.3 bcf/d LNG expansion despite plans to reduce fossil fuels production in the 2020s. And even more importantly to LNG suppliers, the return to long term LNG contracts provides the financing capacity to commit to brownfield LNG FIDs. The abrupt change by Asian LNG buyers to long term contracts is a game changer for LNG markets and sets the stage for brownfield LNG FIDs likely as soon as before year end 2021. It has to be brownfield LNG FIDs if the gap is coming bigger and sooner. And we return to our April 28 blog point, if brownfield LNG is needed, what about Shell looking at 1.8 bcf/d brownfield LNG Canada Phase 2? LNG Canada Phase 1 at 1.8 bcf/d capacity is already a material positive for Cdn natural gas producers. A FID on LNG Canada Phase 2 would be huge, meaning 3.6 bcf/d of Cdn natural gas will be tied to Asian LNG markets and not competing in the US against Henry Hub. And with a much shorter distance to Asian LNG markets. This is why we focus on global LNG markets for our views on the future value of Canadian natural gas.

<u>Sea change in Asian LNG buyers is also the best validation of the LNG supply gap and big to LNG supply FIDs.</u> Has the data changed or have the market participants changed in how they react to the data? We can't recall exactly who said that on CNBC on July 12, it's a question we always ask ourselves. In the LNG case, the data has changed with Mozambique LNG delays and that has directly resulted in market participants changing and entering into long term contracts. We can't stress enough how important it is to see Asian LNG buyers move to long term LNG deals. (i) Validates the sooner and bigger LNG supply gap. We believe LNG markets should look at the last two weeks of new long term deals for Asian LNG buyers as being the validation of the LNG supply gap that clearly emerged post Total declaring force majeure on its 1.7 bcf/d Mozambique LNG Phase 1 that was under construction and on track for first LNG delivery in 2024. Since then, markets have started to realize the Mozambique delays are much more than 1.7 bcf/d. They have seen major LNG suppliers change their outlook to a more bullish LNG outlook and, most importantly, are now seeing Asian LNG buyers changing from trying to renegotiate long term LNG deals lower to entering into long term LNG deals to have security of supply. Asian LNG buyers are cozying up to Qatar in a prelude to the next wave of Asian buyer long term deals. What better validation is there than companies/countries putting their money where their mouth is. (ii) Provides financial commitment to help push LNG suppliers to FID. We believe these Asian LNG buyers are doing much more than validating a LNG supply gap to markets. The big LNG suppliers can move to FID based on adding more LNG supply to their portfolio, but having more long term deals provides the financial anchor/visibility to long term capital commitment from the buyers. Long term contracts will only help LNG suppliers get to FID.

<u>It was always clear that the Mozambique LNG supply delay was 5.0 bcf/d, not just 1.7 bcf/d from Total Phase 1.</u> LNG markets didn't really react to Total's April 26 declaration of force majeure on its 1.7 bcf/d Mozambique LNG Phase 1. This was an under construction project that was on time to deliver first LNG in 2024. It was in all LNG supply forecasts. There was no timeline given but, on the Apr 29 Q1 call, Total said that it expected any restart decision would be least a year away. If so, we believe that puts any actual construction at least 18 months away. There will be work to do just to get back to where they were when they were forced to stop development work on Phase 1. Surprisingly, markets didn't look the broader implications, which is why we posted our 7-pg Apr 28 blog "*Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?*" [LINK] We highlighted that Mozambique LNG delays were actually 5 bcf/d, not 1.7 bcf/d. And this 5 bcf/d of Mozambique LNG supply was built into most, if not all, LNG supply forecasts. The delay in Total Phase 1 would lead to a commensurate delay in its Mozambique LNG Phase 2 of 1.3 bcf/d. Total Phase 2 was to add 1.3 bcf/d. There was no firm in service date, but it was expected to

follow closely behind Phase 1 to maintain services. That would have put it originally in the 2026/2027 period. But if Phase 1 is pushed back at least 2 years, so will the follow on Phase 2, so more likely, it will be at least 2028/2029. The assumption for most, if not all, LNG forecasts was that Phase 2 would follow Phase 1. Exxon Rozuma Phase 1 of 2.0 bcf/d continues to be pushed back in timeline especially following Total Phase 1. Exxon's Mozambique Rozuma Phase 1 LNG will add 2.0 bcf/d and, pre-Covid, was originally expected to be in service in 2025. The project was being delayed and Total's force majeure has added to the delays. Rozuma onshore LNG facilities are right by Total. On June 20, we tweeted [LINK] on the Reuters report "*Exclusive: Galp says it won't invest in Rovuma until Mozambique ensures security*" [LINK]. Galp is one of Exxon's partners in Rozuma. Reuters reported that Galp said they won't invest in Exxon's Rozuma LNG project until the government ensures security, that this may take a while, they won't be considering the project until after Total has reliably resumed work on its Phase 1, which likely puts any Rozuma decision until at least end of 2022 at the earliest. Galp has taken any Rozuma Phase 1 capex out of their new capex plans thru 2025 and will have to take out projects in their capex plan if Rozuma does come back to work. This puts Rozuma more likely 2028 at the earliest as opposed to before the original expectations of before 2025. Pre-pandemic, Exxon's March 6, 2019 Investor Day noted their operated Mozambique Rovuma LNG Phase 1 was to be 2 trains each with 1.0 bcf/d capacity for total initial capacity of 2.0 bf/d with FID expected in 2019 and first LNG deliveries sometime before 2025. LNG forecasts had been assuming Exxon Rozuma would be onstream around 2025. The 2019 FID expectation was later pushed to be expected just before the March 2020 investor day. But the pandemic hit, and on March 21, 2020, we tweeted [LINK] on the Reuters story "*Exclusive: Coronavirus, gas slump put brakes on Exxon's giant Mozambique LNG plan*" [LINK] that noted Exxon was expected to delay the Rovuma FID. There was no timeline, but now, any FID is not expected until late 2022 at the earliest, that would push first LNG likely to at least 2028. What this means is that the Mozambique LNG delays are not 1.7 bcf/d but 5.0 bcf/d of projects that were in all, if not most, LNG supply forecasts. There is much more in our 7-pg blog. But Mozambique is what is driving a much bigger and sooner LNG supply gap starting ~2025 and stronger outlook for LNG prices

<u>One of the reasons why it went under the radar is that major LNG suppliers played stupid on the Mozambique impact.</u> It makes it harder for markets to see a big deal when the major LNG suppliers weren't making a big deal of Mozambique or playing stupid in the case of Cheniere in their May 4 Q1 call. In our May 9, 2021 Energy Tidbits memo, we said we had to chuckle when we saw Cheniere's response in the Q&A to its Q1 call on May 4 that they only know what we know from reading the Total releases on Mozambique and its impact on LNG markets. It's why we tweeted [LINK] "*Hmm! $LNG says only know what we read on #LNG market impact from $TOT $XOM MZ LNG delays*. *Surely #TohokuElectric & other offtake buyers are reaching out to #Cheniere. MZ LNG delays is a game changer to LNG in 2020s, see SAF Group blog. Thx @olympe_mattei @TheTerminal #NatGas".* How could they not be talking to LNG buyers for Total and /or Exxon Mozambique LNG projects. In the Q1 Q&A, mgmt was asked about Mozambique and didn't know any more than what you or I have read. Surely, they were speaking to Asian LNG buyers who had planned to get LNG supply from Total Mozambique or Exxon Rozuma Mozambique or both. Mgmt is asked "*wanted to just kind of touch on the color use talking about for these supply curve. And are you able to kind of provide any thoughts on the Mozambique and a deferral with the project of that size on 13 and TPA being deferred by we see you have you noticed any impact to the market has is there any impact for stage 3 with that capacity? Thanks*." Mgmt replies "*No. Look, I only know about the Mozambique delay with what I read as well as what you read that from total and an Exxon. And it's a sad situation and I hope everybody is safe and healthy that were there to experience that unrest but no I don't think it's, again it's a different business paradigm than what we offer. So, we offer a full value product, the customer doesn't have to invest in equity, customer doesn't have to worry about the E&P side of the business because, we've been able to both the by at our peak almost 7 Dee's a day of US NAT gas from almost a 100 different producers on 26 different pipelines and deliver it to our to facilities. So we take care of a lot of what the customer needs".*

<u>There are other LNG supply delays/interruptions beyond Mozambique.</u> There have been a number of other smaller LNG delay or existing supply interruptions that add to Asian LNG buyers feeling less secure about the reliability of mid to long term LNG supply. Here are just a few examples. (i) Total Papua LNG 0.74 bcf/d. On June 8, we tweeted [LINK] *"Timing update Papua #LNG project. $OSH June 8 update "2022 FEED, 2023 FID targeting 2027 first gas". $TOT May 5 update didn't forecast 1st gas date. Papua is 2 trains w/ total capacity 0.74 bcf/d."* We followed the tweet saying [LINK] *"Bigger #LNG supply gap being created >2025. Papua #LNG originally expected FID in 2020 so 1st LNG is 2 years delayed.*

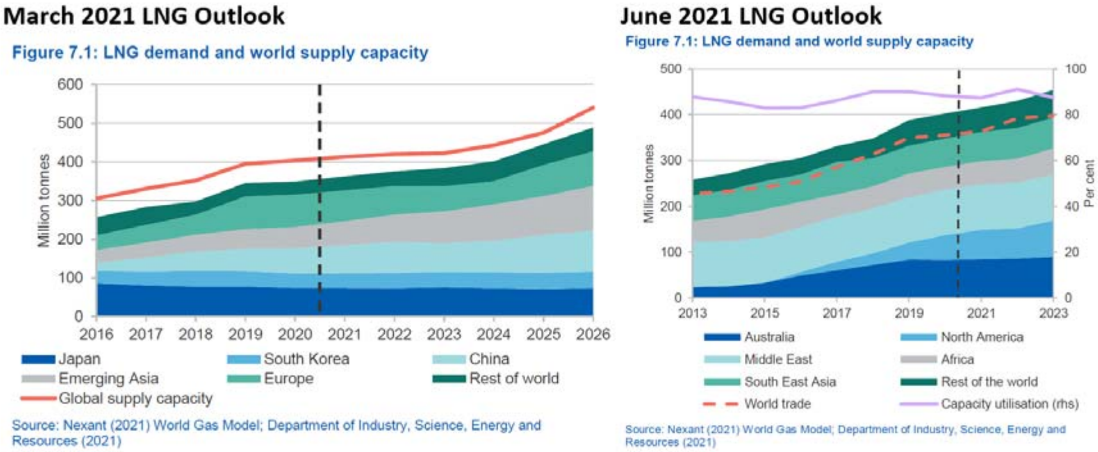
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required additional downtime for repair. Train 2 was shut on May 23 with an original restart of July 11, but the repairs to the weld quality issues meant it didn't restart until late Nov. The same issue was found in Train 1 but repairs were completed. However extended downtime for the trains led to lower LNG volumes. Gorgon produced ~2.3 bcf/d in 2019 but was down to 2.0 bcf/d in 2020. (iii) Equinor's Melkoeya 0.63 bcf/d shut down for 18 months due to a fire. A massive fire led to the Sept 28, 2020 shutdown of the 0.63 bcf/d Melkoeya LNG facility in Norway. On April 26, Equinor released "*Revised start-up date for Hammerfest LNG*" [LINK] with regard to the 0.63 bcf/d Melkoeya LNG facility. The original restart date was Oct 1, 2021 (ie. a 12 month shut down), but Equinor said "*Due to the comprehensive scope of work and Covid-19 restrictions, the revised estimated start-up date is set to 31 March 2022"*. When we read the release, it seemed like Equinor was almost setting the stage for another potential delay in the restart date. Equinor had two qualifiers to this March 31, 2022 restart date. Equinor said "*there is still some uncertainty related to the scope of the work*" and "*Operational measures to handle the Covid-19 situation have affected the follow-up progress after the fire. The project for planning and carrying out repairs of the Hammerfest LNG plant must always comply with applicable guidelines for handling the infection situation in society. The project has already introduced several measures that allow us to have fewer workers on site at the same time than previously expected. There is still uncertainty related to how the Covid-19 development will impact the project progress."*

<u>Cheniere stopped the game playing the game on June 30</u>. Our July 4, 2021 Energy Tidbits memo noted that it looks like Cheniere has stopped playing stupid with respect to the strengthening LNG market in 2021. We can't believe they thought they were fooling anyone, especially their competitors. Bu that week, they came out talking about how commercial discussions have picked up in 2021 and it's boosted their hope for a Texas (Corpus Christi) LNG expansion. On Wednesday, Platts reported "*Pickup in commercial talks boosts Cheniere's hopes on mid-scale LNG project*" [LINK] Platts wrote "*Cheniere Energy expects to make a "substantial dent" by the end of 2022 in building sufficient buyer support for a proposed mid-scale expansion at the site of its Texas liquefaction facility, Chief Commercial Officer Anatol Feygin said June 30 in an interview." " As a result, he said, " The commercial engagement, I think it is very fair to say, has really picked up steam, and we are quite optimistic over the coming 12-18 months to make a substantial dent in that Stage 3 commercialization."* Platts also reported that Cheniere noted this has been a tightening market all year (ie would have been known by the May 4 Q1 call). Platts wrote "*We obviously find ourselves at the beginning of this year and throughout in a very tight market where prices today into Asia and into Europe are at levels that we frankly haven't seen in a decade-plus," Feygin said. "We've surpassed the economics that the industry saw post the Fukushima tragedy in March 2011, and that's happened in the shoulder period."* It's a public stance as to a more bullish LNG outlook

<u>But we still see major LNG suppliers like Australia hinting but not outright saying that LNG supply gap is coming sooner.</u> We have to believe Australia will be unveiling a sooner LNG supply gap in their September forecast. On June 28, we tweeted [LINK] on Australia's Resources and Energy Quarterly released on Monday [LINK] because there was a major change to their LNG outlook versus their March forecast. We tweeted "*#LNGSupplyGap. AU June fcast now sees #LNG mkt tighten post 2023 vs Mar fcast excess supply thru 2026. Why? $TOT Mozambique delays. See below SAF Apr 28 blog. Means brownfield LNG FID needed ie. like #LNGCanada Phase 2. #OOTT #NatGas"*. Australia no longer sees supply exceeding demand thru 2026. In their March forecast, Australia said "*Nonetheless, given the large scale expansion of global LNG capacity in recent years, demand is expected to remain short of total supply throughout the projection period."* Note this is thru 2026 ie. a LNG supply surplus thru 2026. But on June 28, Australia changed that LNG outlook and now says the LNG market may tighten beyond 2023. Interestingly, the June forecast only goes to 2023 and not to 2026 as in March. Hmmm! On Monday, they said "*Given the large scale expansion of global LNG capacity in recent years, import demand is expected to remain short of export capacity throughout the outlook period. Beyond 2023, the global LNG market may tighten, due to the April 2021 decision to indefinitely suspend the Mozambique LNG project, in response to rising security issues. This project has an annual nameplate capacity of 13 million tonnes, and was previously expected to start exporting LNG in 2024*." 13 million tonnes is 1.7 bcf/d so they are only referring to Total Mozambique LNG Phase 1. So no surprise the change is Mozambique LNG driven but we have to believe the reason why they cut their forecast off this time at 2023 is that they are looking at trying to figure out what to forecast beyond 2023 in addition to Total Phase 1. And, importantly, we believe they will be changing their LNG forecast for more than Mozambique ie. India

demand that we highlight later in the blog. They didn't say anything else specific on Mozambique but, surely they have to also be delaying the follow on Total Phase 2 of 1.3 bcf/d and Exxon Rozuma Phase 1 of 2.0 bcf/d.

Australia's LNG Outlook: March 2021 vs June 2021 Forecasts

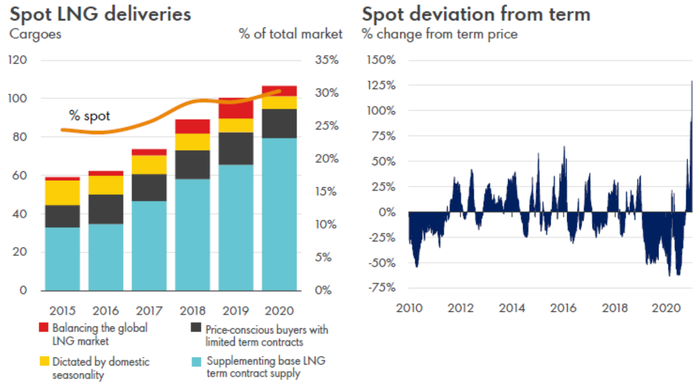


Source: Australia Resources and Energy Quarterly

Clearly Asian LNG buyers did the math, saw the new LNG supply gap and were working the phones in March/April/May trying to lock up long term supply. We wrote extensively on the Total Mozambique LNG situation before the April 26 force majeure as it was obvious that delays were coming to a project counted on for first LNG in 2024. Total had shut down Phase 1 development in December for 3 months due to the violence and security risks. It restarted development on Wed March 24, violence/attacks immediately resumed for 3 consecutive days, and then Total suspended development on Sat March 27. That's why no one should have been surprised by the April 26 force majeure. Asian LNG buyers were also seeing this and could easily do the same math we were doing and saw a bigger and sooner LNG supply gap. They were clearly working the phones with a new priority to lock up long term LNG supply. Major long term deals don't happen overnight, so it makes sense that we started to see these new Asian long term LNG deals start at the end of June.

A big pivot from trying to renegotiate down long term LNG deals or being happy to let long term contracts expire and replace with spot/short term LNG deals. This is a major pivot or abrupt turn on the Asian LNG buyers contracting strategy for the 2020s. There is the natural reduction of long term contracts as contracts reach their term. But with the weakness in LNG prices in 2019 and 2020, Asian LNG buyers weren't trying to extend long term contracts, rather, the push was to try to renegotiate down its long term LNG deals. The reason was clear, as spot prices for LNG were way less than long term contract prices. And this led to their LNG contracting strategy – move to increase the proportion of spot LNG deliveries out of total LNG deliveries. Shell's LNG Outlook 2021 was on Feb 25, 2021 and included the below graphs. The spot LNG price derivation from long term prices in 2019 and 2020 made sense for Asian LNG buyers to try to change their contract mix. Yesterday, Maeil Business News Korea reported on the new Qatar/Kogas long term LNG deal with its report "*Korea may face LNG supply cliff or pay hefty price after long-term supplies run out*" [LINK], which highlighted this very concept – Korea wasn't worried about trying to extend expiring long term LNG contracts. Maeil wrote "*Seoul in 2019 secured a long-term LNG supply contract with the U.S. for annual 15.8 million tons over a 15-year period. But even with the latest two LNG supply contracts, the Korean government needs extra 6 million tons or more of LNG supplies to keep up the current power pipeline. By 2024, Korea's long-term supply contracts for 9 million tons of LNG will expire - 4.92 million tons on contract with Qatar and 4.06 million tons from Oman, according to a government official who asked to be unnamed."*

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

Asian LNG buyers moving to long term LNG deals provide financing capacity for brownfield LNG FIDs. We believe this abrupt change and return to long term LNG deals is even more important to LNG suppliers who want to FID new projects. The big LNG players like Shell can FID new LNG supply without new long term contracts as they can build into their supply options to fill their portfolio of LNG contracts. But that doesn't mean the big players don't want long term LNG supply deals, as having long term LNG contracts provide better financing capacity for any LNG supplier. It takes big capex for LNG supply and long term deals make the financing easier.

Four Asian buyer long term LNG deals in the last week. It was pretty hard to miss a busy week for reports of new Asian LNG buyer long term LNG deals. There were two deals from Qatar Petroleum, one from Petronas and one from BP. The timing fits, it's about 3 months after Total Mozambique LNG problems became crystal clear. And as noted later, there are indicators that more Asian buyer LNG deals are coming.

Petronas/CNOOC is 10 yr supply deal for 0.3 bcf/d. On July 7, we tweeted [LINK] on the confirmation of a big positive to Cdn natural gas with the Petronas announcement [LINK] of a new 10 year LNG supply deal for 0.3 bcf/d with China's CNOOC. The deal also has special significance to Canada. (i) Petronas said "*This long-term supply agreement also includes supply from LNG Canada when the facility commences its operations by middle of the decade*". This is a reminder of the big positive to Cdn natural gas in the next 3 to 4 years – the start up of LNG Canada Phase 1 is ~1.8 bcf/d capacity. This is natural gas that will no longer be moving south to the US or east to eastern Canada, instead it will be going to Asia. This will provide a benefit for all Western Canada natural gas. (ii) First ever AECO linked LNG deal. It's a pretty significant event for a long term Asia LNG deal to now have an AECO link. Petronas wrote "*The deal is for 2.2 million tonnes per annum (MTPA) for a 10-year period, indexed to a combination of the Brent and Alberta Energy Company (AECO) indices. The term deal between PETRONAS and CNOOC is valued at approximately USD 7 billion over ten years.*" 2.2 MTPA is 0.3 bcf/d. (iii) Reminds of LNG Canada's competitive advantage for low greenhouse gas emissions. Petronas said "*Once ready for operations, the LNG Canada project paves the way for PETRONAS to supply low greenhouse gas (GHG) emission LNG to the key demand markets in Asia.*"

Qatar Petroleum/CPC (Taiwan) is 15 yr supply deal for 0.16 bcf/d. Pre Covid, Qatar was getting pressured to renegotiate lower its long term LNG contract prices. Now, it's signing a 15 year deal. On July 9, they entered in a new small long term LNG sales deal [LINK], a 15-yr LNG Sale and Purchase Agreement with CPC Corporation in Taiwan to supply it ~0.60 bcf/d of LNG. LNG deliveries are set to begin in January 2022. H.E. Minister for Energy Affairs & CEO of Qatar Petroleum Al-Kaabi said *"We are pleased to enter into this long term LNG SPA, which is another milestone in our relationship with CPC, which dates back to almost three decades. We look forward to commencing deliveries under this SPA and to continuing our supplies as a trusted and reliable global LNG provider."* The pricing was reported to be vs a basket of crudes.

BP/Guangzhou Gas, a 12-yr supply deal for 0.13 bcf/d. On July 9, there was a small long term LNG supply deal with BP and Guangzhou Gas (China). Argus reported [LINK] BP had signed a 12 year LNG supply deal with Guangzhou Gas (GG), a Chinese city's gas distributor, which starts in 2022. The contract prices are to be linked to an index of international crude prices. Although GG typically gets its LNG from the spot market, it used a tender in late April for ~0.13 bcf/d starting in 2022. BP's announcement looks to be for most of the tender, so it's a small deal. But it fit into the trend this week of seeing long term LNG supply deals to Asia. This was intended to secure deliveries to the firm's Xiaohudao import terminal which will become operational in August 2022.

Qatar/Korea Gas is a 20-yr deal to supply 0.25 bcf/d. On Monday, Reuters reported [LINK] "*South Korea's energy ministry said on Monday it had signed a 20-year liquefied natural gas (LNG) supply agreement with Qatar for the next 20 years starting in 2025. South Korea's state-run Korea Gas Corp (036460.KS) will buy 2 million tonnes of LNG annually from Qatar Petroleum".* There was no disclosure of pricing.

More Asian buyer long term LNG deals (ie. India) will be coming. There are going to be more Asian buyer long term LNG deals coming soon. Our July 11, 2021 Energy Tidbits highlighted how India's new petroleum minister Hardeep Singh Puri (appointed July 8) hit the ground running with what looks to be a priority to set the stage for more India long term LNG deals with Qatar. On July 10, we retweeted [LINK] "*New India Petroleum Minister hits ground running. What else w/ Qatar but #LNG. Must be #Puri setting stage for long term LNG supply deal(s). Fits sea change of buyers seeing #LNGSupplyGap (see SAF Apr 28 blog http://safgroup.ca) & wanting to tie up LNG supply. #OOTT".* It's hard to see any other conclusion after seeing what we call a sea change in LNG buyer mentality with a number of long term LNG deals this week. Puri tweeted [LINK] "*Discussed ways of further strengthening mutual cooperation between our two countries in the hydrocarbon sector during a warm courtesy call with Qatar's Minister of State for Energy Affairs who is also the President & CEO of @qatarpetroleum HE Saad Sherida Al-Kaabi".* As noted above, we believe there is a sea change in LNG markets that was driven by the delay in 5 bcf/d of LNG supply from Mozambique (Total Phase 1 & Phase 2, and Exxon Rozuma Phase 1) that was counted on all LNG supply projections for the 2020s. Puri's tweet seems to be him setting the stage for India long term LNG supply deals with Qatar.

Supermajors are aggressively competing to commit 30+ year capital to Qatar's LNG expansion despite stated goal to reduce fossil fuels production. It's not just Asian LNG buyers who are now once again committing long term capital to securing LNG supply, it's also supermajors all bidding to be able to commit big capex to part of Qatar Petroleum's 4.3 bcf/d LNG expansion. Qatar Petroleum received a lot of headlines following the their June 23 announcement on its LNG expansion [LINK] on how they received bids for double the equity being offered. And there were multiple reports that these are on much tougher terms for Qatar's partners. Qatar Petroleum CEO Saad Sherida Al-Kaabi specifically noted that, among the bidders, were Shell, Total and Exxon. Shell and Total have two of the most ambitious plans to reduce fossil fuels production in the 2020's, yet are competing to allocate long term capital to increase fossil fuels production. And Shell and Total are also two of the global LNG supply leaders. It has to be because they are seeing a bigger and sooner LNG supply gap.

Remember Qatar's has a massive expansion but India alone needs 3x the Qatar expansion LNG capacity. In addition to the competition to be Qatar Petroleum's partners, we remind that, while this is a massive 4.3 bcf/d LNG expansion, India alone sees its LNG import growing by ~13 bcf/d to 2030. The Qatar announcement reminded they see a LNG supply gap and continued high LNG prices. We had a 3 part tweet. (i) First, we highlighted [LINK] "*1/3. #LNGSupplyGap coming. big support for @qatarpetroleum expansion to add 4.3 bcf/d LNG. but also say "there is a lack of investments that could cause a significant shortage in gas between 2025-2030" #NatGas #LNG".* This is after QPC accounts for their big LNG expansion. The QPC release said "*However, His Excellency Al-Kaabi voiced concern that during the global discussion on energy transition, there is a lack of investment in oil and gas projects, which could drive energy prices higher by stating that "while gas and LNG are important for the energy transition, there is a lack of investments that could cause a significant shortage in gas between 2025-2030, which in turn could cause a spike in the gas market."* (ii) Second, this is a big 4.3 bcf/d expansion, but India alone has 3x the increase in LNG import demand. We tweeted [LINK] "*2/3. Adding 4.3 bcf/d is big, but dwarfed by items like India. #Petronet gave 1st specific forecast for what it means if #NatGas is to be 15%*

of energy mix by 2030 - India will need to increase #LNG imports by ~13 bcf/d. See SAF Group June 20 Energy Tidbits memo." (iii) Third, Qatar's supply gap warning is driven by the lack of investments in LNG supply. We agree, but note that the lack of investment is in great part due to the delays in both projects under construction and in FIDs that were supposed to be done in 2019. We tweeted [LINK] "3/*3. #LNGSupplyGap is delay driven. $TOT Mozambique Phase 1 delay has chain effect, backs up 5 bcf/d. See SAF Group Apr 28 blog Multiple Brownfield LNG FIDs Now Needed To Fill New #LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2? #NatGas*."

Seems like many missed India's first specific LNG forecast to 2030. Our June 20, 2021 Energy Tidbits memo highlighted the first India forecast that we have seen to estimate the required growth in natural gas consumption and LNG imports if India is to meet its target for natural gas to be 15% of its energy mix by 2030. India will need to increase LNG imports by ~13 bcf/d or 3 times the size of the Qatar LNG expansion. Our June 6, 2021 Energy Tidbits noted the June 4 tweet from India's Energy Minister Dharmendra Pradhan [LINK] reinforcing the 15% goal "*We are rapidly deploying natural gas in our energy mix with the aim to increase the share of natural gas from the current 6% to 15% by 2030."* But last week, Petronet CEO AK Singh gave a specific forecast. Reuters report "*LNG's share of Indian gas demand to rise to 70% by 2030: Petronet CEO"* [LINK] included Petronet's forecast if India is to hit its target for natural gas to be 15% of energy mix by 2030. Singh forecasts India's natural gas consumption would increase from current 5.5 bcf/d to 22.6 bcf/d in 2030. And LNG shares would increase from 50% to 70% of natural gas consumption ie. an increase in LNG imports of ~13 bcf/d from just under 3 bcf/d to 15.8 bcf/d in 2030. Singh did not specifically note his assumption for India's natural gas production, but we can back into the assumption that India natural gas production grows from just under 3 bcf/d to 6.8 bcf/d. It was good to finally see India come out with a specific forecast for 2030 natural gas consumption and LNG imports if India is to get natural gas to 15% of its energy mix in 2030. Petronet's Singh forecasts India natural gas consumption to increase from 5.5 bcf/d to 22.6 bcf/d in 2030. This forecast is pretty close to our forecast in our Oct 23, 2019 blog "*Finally, Some Visibility That India Is Moving Towards Its Target For Natural Gas To Be 15% Of Its Energy Mix By 2030*". Here part of what we wrote in Oct 2019. "*It's taken a year longer than we expected, but we are finally getting visibility that India is taking significant steps towards India's goal to have natural gas be 15% of its energy mix by 2030. On Wednesday, we posted a SAF blog [LINK] "Finally, Some Visibility That India Is Moving Towards Its Target For Natural Gas To Be 15% Of Its Energy Mix By 2030".* Our 2019 blog estimate was for India natural gas demand to be 24.0 bcf/d in 2030 (vs Singh's 22.6 bcf/d) and for LNG import growth of +18.4 bcf/d to 2030 (vs Singh's +13 bcf/d). The difference in LNG would be due to our Oct 2019 forecast higher natural gas consumption by 1.4 bcf/d plus Singh forecasting India natural gas production +4 bcf/d to 2030. Note India production peaked at 4.6 bcf/d in 2010.

Bigger, nearer LNG supply gap + Asian buyers moving to long term LNG deals = LNG players forced to at least look at what brownfield LNG projects they could advance and move to FID. All we have seen since our April 28 blog is more validation of the bigger, nearer LNG supply gap. And now market participants (Asian LNG buyers) are reacting to the new data by locking up long term supply. Cheniere noted how the pickup in commercial engagement means they "*are quite optimistic over the coming 12-18 months to make a substantial dent in that Stage 3 commercialization."* Cheniere can't be the only LNG supplier having new commercial discussions. It's why we believe the Mozambique delays + Asian LNG buyers moving to long term deals will effectively force major LNG players to look to see if there are brownfield LNG projects they should look to advance. Prior to March/April, no one would think Shell or other major LNG players would be considering any new LNG FIDs in 2021. Covid forced all the big companies into capital reduction mode and debt reduction mode. But Brent oil is now solidly over $70, and LNG prices are over $13 this summer and the world's economic and oil and gas demand outlook are increasing with vaccinations. And we are starting to see companies move to increasing capex with the higher cash flows. The theme in Q3 reporting is going to be record or near record oil and gas cash flows, reduced debt levels and increasing returns to shareholders. And unless new mutations prevent vaccinations from returning the world to normal, we suspect that major LNG players, like other oil and gas companies, will be looking to increase capex as they approve 2022 budgets. The outlook for the future has changed dramatically in the last 8 months. The question facing major LNG players like Shell is should they look to FID new LNG brownfield projects in the face of an increasing LNG supply gap that is going to hit faster and harder and Asian LNG buyers prepared to do long term deals. We expect these decisions to be looked at before the end of 2021 for 2022 capex budget/releases. One wildcard that could force these decisions sooner is the already stressed out global supply chain. We have to believe that discussion there will be pressure for more Asian LNG buyer long term deals sooner than later.

For Canada, does the increasing LNG supply gap provide the opportunity to at least consider a LNG Canada Phase 2 FID over the next 6 months? Our view on Shell and other LNG players is unchanged since our April 28 blog. Shell is no different than any other major LNG supplier in always knowing the market and that the oil and gas outlook is much stronger than 9 months ago. Even 3 months post our April 28 blog, we haven't heard any significant talks on how major LNG players will be looking at FID for new brownfield LNG projects. We don't have any inside contacts at Shell or LNG Canada, but that is no different than when we looked at the LNG markets in September 2017 and saw the potential for Shell to FID LNG Canada in 2018. We posted a September 20, 2017 blog *"China's Plan To Increase Natural Gas To 10% Of Its Energy Mix Is A Global Game Changer Including For BC LNG"* [LINK]. Last time, it was a demand driven supply gap, this time, it's a supply driven supply gap. We have to believe any major LNG player, including Shell, will be at least looking at their brownfield LNG project list and seeing if they should look to advance FID later in 2021. Shell has LNG Canada Phase 2, which would add 2 additional trains or approx. 1.8 bcf/d. And an advantage to an FID would be that Shell would be able to commit to its existing contractors and fabricators for a continuous construction cycle following on LNG Canada Phase 1 ie. to help keep a lid on capital costs. We believe maintaining a continuous construction cycle is even more important given the stressed global supply chain. No one is talking about the need for these new brownfield LNG projects, but, unless some major change in views happen, we believe its inevitable that these brownfield LNG FID internal discussions will be happening in H2/21. Especially since the oil and gas price outlook is much stronger than it was in the fall and companies will be looking to increase capex in 2022 budgets.

A LNG Canada Phase 2 would be a big plus to Cdn natural gas. LNG Canada Phase 1 is a material natural gas development as its 1.8 bcf/d capacity represents approx. 20 to 25% of Cdn gas export volumes to the US. The EIA data shows US pipeline imports of Cdn natural gas as 6.83 bcf/d in 2020, 7.36 bcf/d in 2019, 7.70 bcf/d in 2018, 8.89 bcf/d in 2017, 7.97 bcf/d in 2016, 7.19 bcf/d in 2015 and 7.22 bcf/d in 2014. A LNG Canada Phase 2 FID would be a huge plus for Cdn natural gas. It would allow another ~1.8 bcf/d of Cdn natural gas to be priced against pricing points other than Henry Hub. And it would provide demand offset versus Trudeau if he moves to make electricity "emissions free" and not his prior "net zero emissions". Mozambique has been a game changer to LNG outlook creating a bigger and sooner LNG supply gap. And with a stronger tone to oil and natural gas prices in 2021, the LNG supply gap will at least provide the opportunity for Shell to consider FID for its brownfield LNG Canada Phase 2 and provide big support to Cdn natural gas for the back half of the 2020s. And perhaps if LNG Canada is exporting 3.6 bcf/d from two phases, it could help flip Cdn natural gas to a premium vs US natural gas especially if Biden is successful in reducing US domestic natural gas consumption for electricity. The next six months will be very interesting to watch for LNG markets and Cdn natural gas valuations. Imagine the future value of Cdn natural gas is there was visibility for 3.6 bcf/d of Western Canada natural gas to be exported to Asia.

https://www.petronas.com/media/press-release/petronas-deliver-carbon-neutral-lng-china

30 · Sep · 2021

PETRONAS To Deliver Carbon Neutral LNG To China

Media Releases

Kuala Lumpur, 30 September 2021 – PETRONAS LNG Ltd., a subsidiary of PETRONAS, has signed an agreement with China's Shenergy Group Company Limited for the delivery of three carbon neutral liquefied natural gas (LNG) cargoes from the PETRONAS LNG Complex (PLC) in Bintulu, Sarawak.

The deal will see PETRONAS' first delivery of carbon neutral LNG to China, to Shenergy's terminals in Shanghai between October 2021 and March 2022. Last month, PETRONAS shipped its first carbon neutral LNG cargo to Japan.

PETRONAS Vice President of LNG Marketing & Trading, Shamsairi Ibrahim said, "PETRONAS is proud to elevate our 15-year partnership with Shenergy that now includes the supply of carbon neutral LNG, reflecting our commitment in offering decarbonised LNG solutions to the market. As an integrated energy player, PETRONAS actively seeks collaborations with buyers and end-users to achieve common sustainability goals."

Commenting on the agreement, Shenergy Vice President, Wang Zhehong said, "As a long-term LNG partner and consumer, we are excited to receive PETRONAS' delivery of carbon neutral LNG to China that aligns with the country's ambition of hitting peak carbon dioxide emissions by 2030. This is a meaningful milestone for both our companies in our respective endeavours to be more environmentally conscious and reducing our carbon footprints."

Shenergy remains a major LNG buyer and partner to PETRONAS since 2006 following the first long-term supply agreement with its subsidiary Shanghai LNG Co., Ltd. PETRONAS sustained its position as Shenergy's preferred LNG solutions provider when both parties concluded another new 12-year term deal last year.

Japan Utilities Help Ease China Fuel Crisis at Tidy Profit (1)
2021-10-01 08:01:42.164 GMT

By Ann Koh
(Bloomberg) -- Japanese utilities are stepping in to help ease China's fuel crisis, selling excess liquefied natural gas at sky-high prices as Beijing orders its top energy companies to secure supplies at all costs.
Vessels typically chartered by Japanese companies including Jera Co., Tokyo Gas Co. and Kyushu Electric Power Co. delivered as many as six spot cargoes to Chinese ports in September, said BloombergNEF analyst Lujia Cao. State-owned Chinese firms are among the buyers that have negotiated purchases, including Sinopec, which called a tender for November to March supplies earlier last week.
LNG Stockpiles to Shield Japan From Pressing Winter Crunch: BNEF
China is facing a shortage of everything from natural gas to coal, as supplies have struggled to keep up with a rebound in economic activity. That's providing lucrative profits for the Japanese companies amid a scorching price rally. North Asia's LNG spot benchmark has surged to a record high $34.47 per million British thermal units amid intensifying global competition between China and Europe for the super-chilled fuel.

Faced with a shrinking population and increased nuclear power generation, Japan -- the world's top LNG importer -- has seen declining demand for natural gas. After getting caught flat-footed by last winter's frigid temperatures, the utilities are now finding themselves in a sweet spot.
Japanese importers have been facing slower demand than usual from August as the weather has been milder than expected, reducing air-conditioning use in urban cities including Tokyo. That's left them sitting on seasonally high inventories as they maximize supplies to avoid a repeat of last winter. The result is a perfect scenario for taking advantage of the rally in prices.
The utilities have purchased a surplus of cargoes on long-term contracts linked to oil indexes that are almost $25 per million British thermal units lower than the price of spot shipments. Reselling oil-linked shipments into the spot market -- as with the China deals -- is a lucrative opportunity, as the spread between those two is near a record high.
Read more: Japan Set to Dodge Fuel Crunch After Getting Burned Last Winter
"I expect to see cargoes sold by these companies through October and November with an upside of $75 to $85 million profit per cargo," said Felix Booth, head of LNG at energy-intelligence firm Vortexa Ltd. "China's buyers are much more exposed to the spot market."
While it's unlikely that Japanese utilities will give up their cargoes during the peak months of January and February,

when temperatures are typically the coldest, at least one cargo
has been sold for March delivery to China, traders said.

--With assistance from Stephen Stapczynski.

To contact the reporter on this story:
Ann Koh in Singapore at akoh15@bloomberg.net
To contact the editors responsible for this story:
David Stringer at dstringer3@bloomberg.net
Stephen Stapczynski, Jeff Sutherland

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ENERGY COMPANY Uniper does not expect a quick operating permit for Nord Stream 2

Certification is still pending. But it will come so late that the pipeline will no longer be able to help this winter, says the Uniper boss.

10/01/2021 Update: 10/01/2021 - 10:46 a.m. Leave a Comment

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Klaus-Dieter Maubach

The CEO of the energy company Uniper assures: "All contracts that we have with the Russian Gazprom Group will be fulfilled."

(Photo: Reuters)

Düsseldorf According to its CEO Klaus-Dieter Maubach, the energy company Uniper does not expect the Federal Network Agency to obtain a quick operating license for the controversial Nord Stream 2 gas pipeline . "The certification of the pipeline, according to all that I know, will definitely be so late that this pipeline will no longer help us this winter," Maubach said on Thursday evening in front of the Düsseldorf Economic Publishers' Association (WPV). Russia completed the 1230-kilometer tube a few weeks ago . The Nord Stream 2 AG of Russian gas company Gazprom has in the Federal Network Agency for the operation in Germany applied for necessary certification. With effect from September 8th, there is a four-month period for this. The draft for the decision is then sent to the EU Commission.

Uniper is one of the financing partners of the politically controversial pipeline and, according to its own statements, is Gazprom's largest customer. Gas is currently scarce and expensive. The Baltic Sea pipeline could theoretically provide relief. Maubach pointed out that Russia has been a reliable partner for decades. "All the contracts we have with the Russian Gazprom group will be fulfilled." What the Russians are obviously not doing at the moment, is also to be delivered in substantial quantities. “There are big discussions about whether they can do it at all or whether they don't want to.” He wanted to hold back with an assessment.
As in Germany, the gas storage facilities in Russia are not as full as in the previous year. In addition to the location of the storage facilities, there are various reasons for the shortage and the sharp rise in prices. Domestic production in Europe has declined. Ships with liquefied natural gas (LNG) often head for Asia, such as Japan and Korea, where prices are even higher than in Europe.
Maubach also spoke about the future of Uniper's coal-fired power plants in Russia. “Our business in Russia must also contribute to decarbonization. We will not be able to exclude our Russian business from it, ”emphasized the manager. There are various options for Uniper. Renewable energies could be expanded or the power plants modernized.

“We can think about individual power plants, whether there is a buyer for them. We can think about the entire power plant blocks. ”The entire portfolio is available, from staying in until you go all the way out. In addition, there are still opportunities through the Russian business of the Finnish parent company Fortum .

Compensation in the event of an early exit from the Datteln IV power plant

In addition, the energy company Uniper insists on compensation if its Datteln IV hard coal power plant is to be shut down earlier than 2038. Anyone who wants to change the coal phase-out law must “take the question of compensation into account,” Maubach also said at the event on Wednesday evening.

Uniper is ready to talk on the subject. "We are aware that Datteln IV has become the symbol for the German coal phase-out," said Maubach. "But the ball is not with us."

Datteln IV was the last German hard coal power plant to go online last year. In the law on the end of coal-fired power generation, an earlier end than 2038 was waived with a view to possible compensation. Bringing the coal phase out ahead is likely to be an issue in the negotiations on the formation of a new federal government.

Attempts to force Datteln IV out of the market with a higher CO2 price would not work, stressed Maubach. Anyone who tries that will be disappointed. Uniper largely "leased" the generation capacity of the power plant to two major customers and concluded long-term contracts for them. The group therefore also gets money if these customers do not buy electricity because of variable costs that are too high. In addition to the energy group RWE , Deutsche Bahn has long-term contracts with Uniper.
More: What role Gazprom is playing in the rising energy prices in Europe

https://www.enbridge.com/media-center/news/details?id=123692&lang=en

Line 3 Replacement Project Substantially Completed and Set to be Fully Operational

September 29, 2021

CALGARY, AB and DULUTH, Minn., Sept. 29, 2021 /CNW/ - Enbridge Inc. (Enbridge or the Company) (TSX: ENB) (NYSE: ENB) announced today the achievement of a major milestone with the substantial completion of the Line 3 Replacement Project and the establishment of an in-service date of **October 1**. This step marks the full replacement of the entire 1,765-kilometre/1,097-mile-long pipeline from Edmonton, AB. to Superior, WI. With new state-of-the-art, thicker-walled pipe, its completion ensures a safe, reliable supply of North American crude oil to U.S. refineries, helping fuel the quality of life for millions of people.

"After more than eight years of many people working together, extensive community engagement, and thorough environmental, regulatory and legal review, we are pleased that Line 3 is complete and will soon deliver the low cost and reliable energy that people depend on every day," said Al Monaco, Enbridge President and Chief Executive Officer. "From day one, this project has been about modernizing our system and improving safety and reliability for the benefit of communities, the environment and our customers.

"Line 3 was developed and executed with the most state-of-the-art approach to design, construction and environmental management," Monaco added. "We're also very proud of the relationship of trust we've built with communities along the right-of-way in both Canada and the United States. Our goal is to continuously live up to the trust that all of our stakeholders have placed in us."

The new 542-kilometre/337-mile Minnesota segment of Line 3, which follows other segments already placed into service in Canada, North Dakota and Wisconsin, restores the full pipeline capacity of 760,000 barrels per day to meet the energy needs of refineries in the Midwest. Many labor groups, including the International Union of Operating Engineers (IUOE), Laborers' International Union of North America (LIUNA), United Association of Plumbers and Pipefitters (UA), and the International Brotherhood of Teamsters, and communities along the right-of-way made the successful completion of the project possible.

In Minnesota, the Line 3 replacement was the most studied pipeline project in state history, with input gathered from 71 public comment regulatory meetings and over 3,500 community engagement meetings. Exhaustive scientific review exceeding legal and regulatory requirements resulted in support and project approvals from federal, state, and local agencies, and Native American tribes.

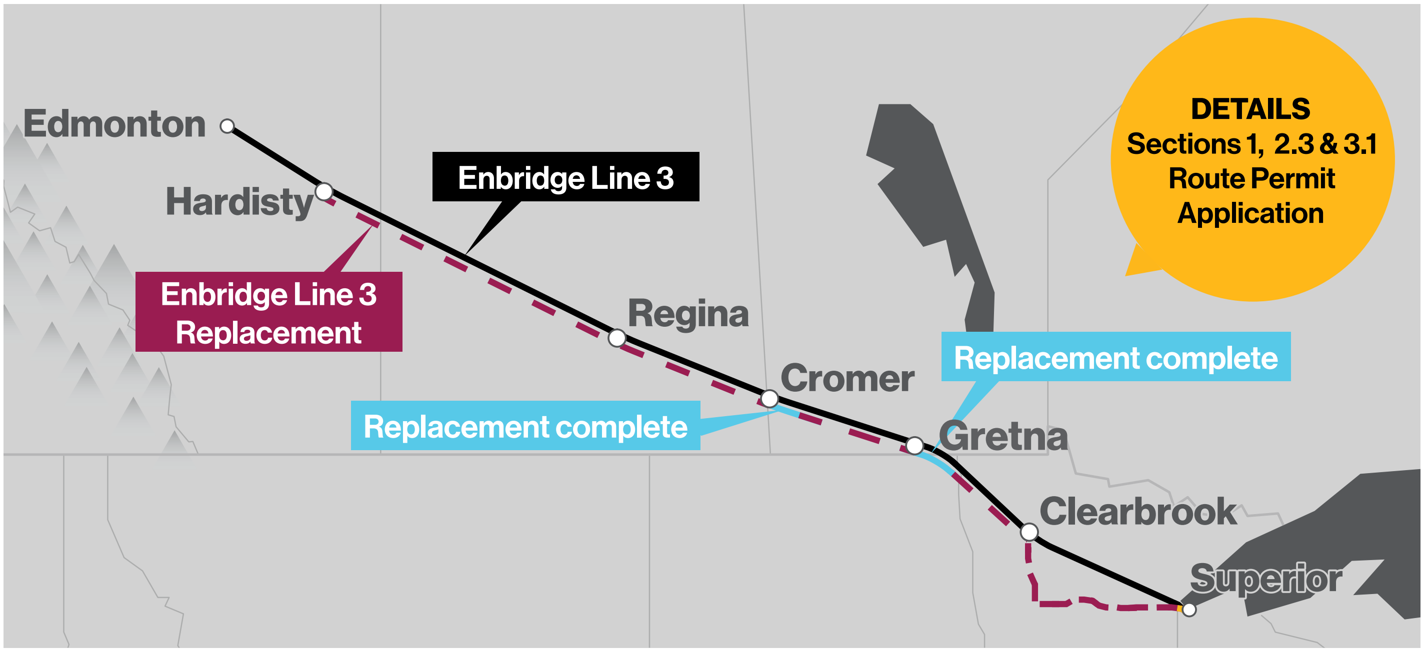
More than 1,500 Indigenous people worked on replacing Line 3 in the U.S. and Canada. Specifically, in Minnesota, where Native Americans made up seven percent of the Line 3 workforce, over US$300 million went directly to Native-owned contractors, tribal community investments and training and hiring Native individuals. In total, the Company invested CDN$750 million with Indigenous communities, individuals, and businesses.

Throughout the project, Enbridge has shown continuous respect for tribal sovereignty. In Minnesota, 30 tribes took part in the consultation process with the U.S. Army Corps of Engineers. The project included a first-of-its kind Tribal Cultural Resource Survey led by the Fond du Lac Band of Lake Superior Chippewa which employed tribal cultural experts who walked the full route identifying and recording significant cultural resources to be avoided. Construction was completed under the supervision of tribal monitors with authority to stop construction to ensure protection of important cultural resources.

Forward-Looking Information

Forward-looking information, or forward-looking statements, have been included in this news release to provide information about Enbridge Inc. ("Enbridge" or the "Company") and its subsidiaries and affiliates, including management's assessment of Enbridge and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ''anticipate'', ''expect'', ''project'', ''estimate'', ''forecast'', ''plan'', ''intend'', ''target'', ''believe'', "likely" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements in this news release include statements with respect to the Line 3 Replacement Project, including the benefits thereof and the expected in-service date.

Line 3 Replacement Program Background



Enbridge Energy, Limited Partnership's ("Enbridge") maintenance driven Line 3 replacement will reduce future maintenance activities and resulting disruptions to landowners and the environment, as well as restore the historical operating capabilities of Line 3. A new 36-inch diameter pipeline will replace the existing 34-inch diameter pipeline along most of the Line 3 route.

Purpose and Need

Safe and reliable operations have always been the foundation of Enbridge's business, and maintaining pipeline integrity is essential to continued safe and reliable operations.

As part of our maintenance program, Enbridge has gathered extensive integrity data on Line 3. The data has been analyzed, resulting in the need for a substantial number of integrity digs and repairs. Since 2008, Enbridge has safely operated and maintained Line 3 by implementing voluntary pressure restrictions reducing the average annual capacity of deliveries from 760,000 barrels per day (bpd) to 390,000 bpd.

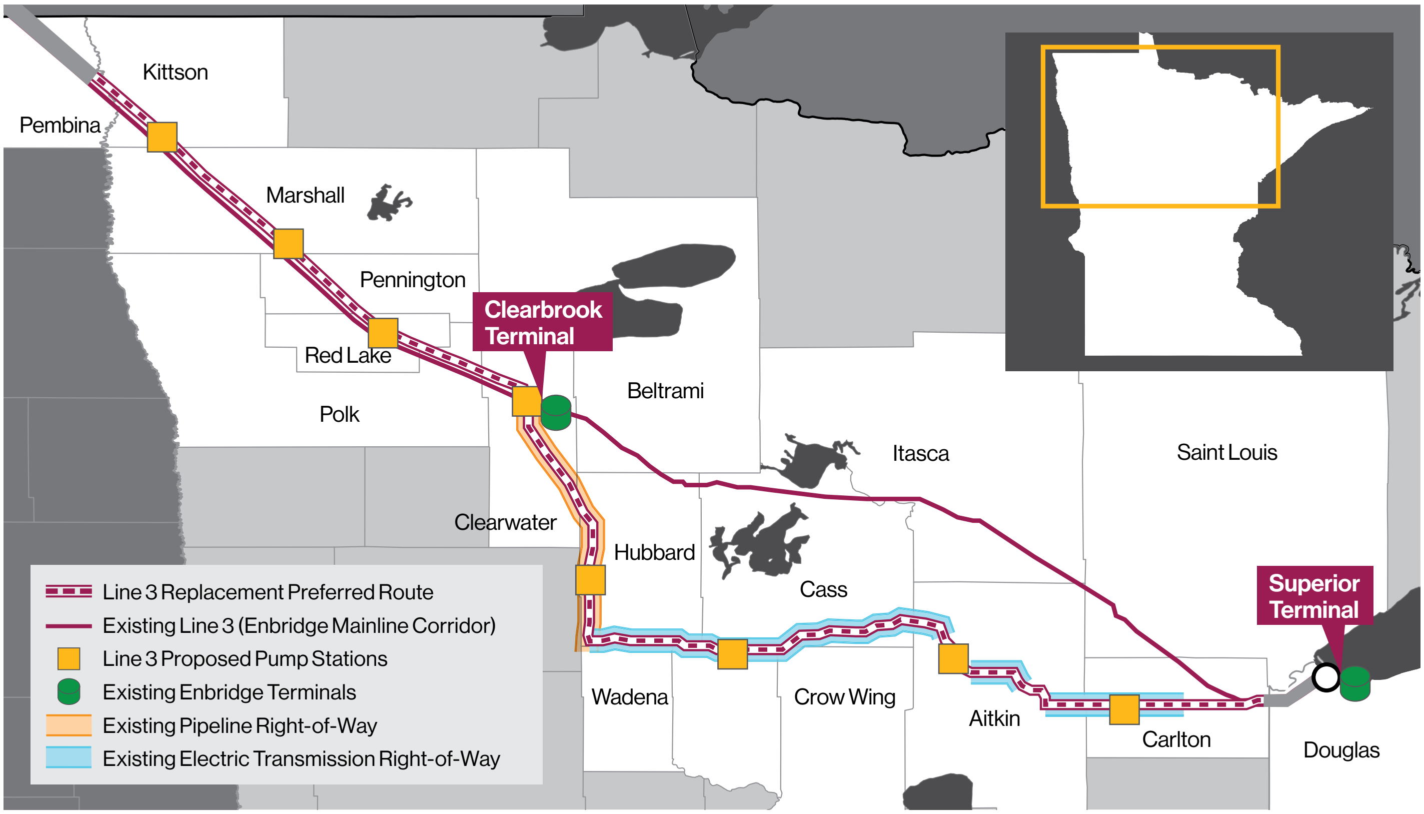
As a result of the integrity maintenance program, Enbridge concluded that replacement is the optimal alternative to the required ongoing and increasing maintenance activities.

Line 3 Replacement: Background

- Line 3 is a 1,097-mile crude oil pipeline extending from Edmonton, Alberta to Superior, Wisconsin, and is an integral part of Enbridge's Mainline System. Line 3 was installed in the 1960's.
- Line 3 Replacement Program consists of 1,031 miles of 36-inch diameter pipeline that begins in Hardisty, Alberta and ends in Superior, Wisconsin.
- The U.S. portion includes about 13 miles in North Dakota, 337 miles in Minnesota, and 14 Miles in Wisconsin.
- The Program is an approximate $7.5 billion private investment ($2.6 billion for the U.S. portion), making it one of North America's largest infrastructure programs, which supports North American energy independence.

This is an integrity and maintenance driven Program.

Line 3 Replacement Project



The U.S. portion of the Program Enbridge is proposing in this Application is the Line 3 Replacement Project.

- The Application will be reviewed by the Minnesota Public Utilities Commission (MPUC). Upon receipt of all applicable approvals, construction will begin

Project Description in Minnesota

- 36-inch diameter pipe in Minnesota.
- 337 miles in Minnesota to replace existing 282 miles of 34-inch diameter pipeline
- Construction of eight pump stations
- Restore historical operating capabilities and move 760,000 barrels per day (bpd)
- Includes 27 strategically placed valves
- $2.1 billion for the Minnesota portion of the design, permit and construction of Line 3
- In Minnesota, the replacement pipeline will follow existing utility corridors for more than 98 percent of the route west of Clearbrook and 75 percent east of Clearbrook

Anticipated Project Timeline in Minnesota (pending regulatory approval)

2016	Construction begins
Late 2017	The replacement pipeline is placed into service in late fall or winter
2018	The existing pipeline is taken out of service and restoration of land disturbed during construction continues

DETAILS
Section 4: Project Description Route Permit Application

https://twitter.com/AbasAslani/status/1444402953335545863

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Abas Aslani
@AbasAslani

Journalist; Senior research fellow at the Center for Middle East Strategic Studies (CMESS). DMs open

Tehran instagram.com/abasaslani/ Joined August 2010

2,173 Following 34.6K Followers

Thread

Abas Aslani
@AbasAslani

#Iran FM @Amirabdolahian: Americans tried to contact us in New York through various channels, and I told the intermediaries that if the US had serious intentions, it should issue a serious signal. The serious sign is releasing at least $ 10 billion of Iranian frozen money. #JCPOA

2:44 PM · Oct 2, 2021 · Twitter for iPhone

40 Retweets 24 Quote Tweets 71 Likes

Tweet your reply Reply

Abas Aslani @AbasAslani · 13h
Replying to @AbasAslani
#Iran FM @Amirabdolahian (on his meetings with #European officials in NY): We told them that the new Iranian government would not return to 8, or 5.5 years ago or even a year ago. We do not come to the negotiating table to drink coffee with you. You have to show your true will.

2 17 27

Abas Aslani @AbasAslani · 13h
#Iran FM @Amirabdolahian: We're now concluding [our assessment] & will return to negotiating table soon, but we told the other party to take action & to send a positive signal before [coming to] negotiating table…Method & behavior of the other party can impact result [of talks].

2 6 19

https://www.spglobal.com/platts/en/market-insights/latest-news/oil/092821-interview-just-resigned-libyan-deputy-oil-minister-says-foreign-support-critical-to-reviving-output?utm_source=twitter&utm_medium=social&utm_term=&utm_content=3ae7107c-1ea8-4d26-8509-bbaf0b2e7f2f&utm_campaign=einewsblast

- 28 Sep 2021 | 12:03 UTC

INTERVIEW: Just resigned Libyan deputy oil minister says foreign support critical to reviving output

HIGHLIGHTS

Abbar resigns amid continued strife between ministry factions

Libya aims to boost oil production to 1.6 mil b/d in 2022

Upgrades to storage facilities and ports needed

Author Eklavya Gupte Herman Wang

Libya's energy industry has seen no end to political upheaval, with deputy oil minister Refaat al-Abbar's abrupt Sept. 28 resignation the latest turmoil.

Abbar cited "special circumstances" in his resignation letter to Prime Minister Abdul Hamid Dbeibah and appears to be a casualty of the protracted struggle between the Benghazi-based Libyan National Army and the Tripoli-based Government of National Unity to control the country.

Abbar, who hails from Libya's east and has maintained close ties with the LNA, found the infighting within the ministry and with the state-owned National Oil Corporation to be untenable, sources working in the country said.

"He was the glue holding it together and managing interests of LNA and GNU," one said on condition of anonymity.

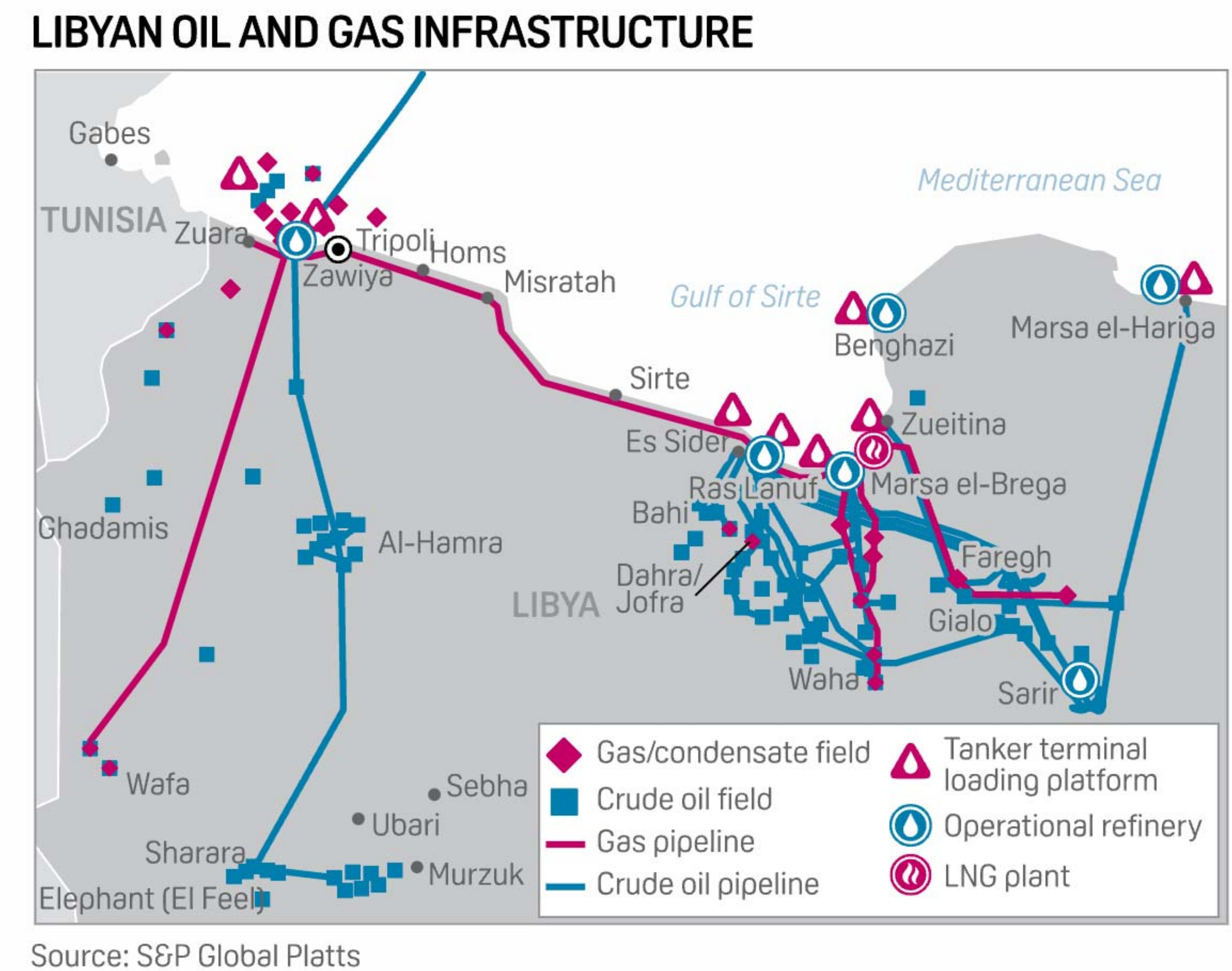
Just prior to his resignation, Abbar agreed to answer written questions from S&P Global Platts about the ministry's work to rebuild its beleaguered industry.

He said Libya, which has the largest oil reserves in Africa, would redouble its efforts to attract international financing to boost crude and gas production that has suffered in recent years from war, sabotage and underinvestment.

Libya is currently pumping about 1.2 million b/d of crude, Abbar said, and the ministry is aiming to hit 1.4 million b/d by December and 1.6 million b/d in 2022, depending on how much government funding NOC receives from the still unpassed national budget.

Even if that target is hit, it would still be well below Libya's peak crude production of about 1.75 million b/d in 2008.

"Despite the lack of budgets for years and the consequent shortage of spare parts and supplies to ensure stable production rates, there are serious efforts being made by the Ministry of Oil and the NOC," said Abbar, who had been appointed to his position in May.



Crude exports from three major Libyan oil terminals -- Es Sider, Ras Lanuf and Marsa el-Hariga -- resumed earlier in September after short-lived protests that have become a regular feature plaguing the country's reliability to supply key markets in Europe.

But as Abbar's resignation underlines, stability is elusive in Libyan politics, and the planned Dec. 24 election could be another flashpoint.

Meanwhile, tensions are still simmering between oil minister Mohamed Oun and NOC Chairman Mustafa Sanalla, in a power struggle over Libya's energy policy, leaving Libya's oil flows vulnerable to disruption.

Abbar, who formerly held high-level positions with Benghazi-based NOC subsidiary Arabian Gulf Oil Co., said the Oun and Sanalla camps must set aside their rivalry to improve Libya's investment environment.

Below is a transcript of Abbar's responses to Platts' questions, lightly edited for clarity.

PLATTS: How does Libya plan to raise its production capacity in the coming years?

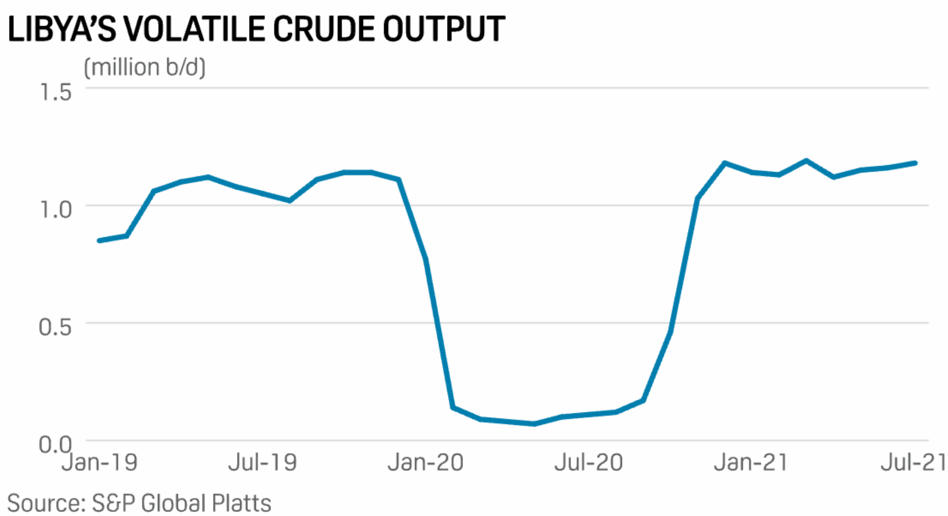
ABBAR: Despite the lack of budgets for years and the consequent shortage of spare parts and supplies to ensure stable production rates, there are serious efforts by the Ministry of Oil and the NOC.

Projects to increase storage and upgrade ports are strategic projects that support our call to raise exports to 2.2 million b/d, but it is tough currently because of the lack of adoption of the budget allocated to the oil and gas sector.

NOC and its companies continue their efforts to rehabilitate some of the storage facilities in the fields and Sidra port, Sirte Basin and Ghadames Basin, which have been destroyed in previous years.

PLATTS: What steps is the ministry taking to rehabilitate the country's oil and gas infrastructure?

ABBAR: We are working to achieve the plans of the Government of National Unity to support the only source of income in Libya, the oil and gas sector, by bringing investments and implementing strategic projects that are stalled due to the lack of funding and weak investments, which will be reflected positively in the development of surface equipment, construction works and the development of crude oil.



PLATTS: How are relations between the ministry and NOC progressing, and what has your role as deputy oil minister been during this difficult period?

ABBAR: We are working hard to raise the level of coordination between the higher authorities and between the NOC and the ministry in order to create harmony, ... implement strategic projects, and provide the necessary requirements to maintain the flow of production of oil and gas. We are working impartially to reconcile all the people of Libya without any political orientation, in order to serve the success of the NOC and the recovery of the national economy.

PLATTS: What is the latest on the stalled budget and allocating funding for Libya's oil and gas sector?

ABBAR: Production currently continues with the efforts of oil sector workers despite technical difficulties. To achieve our targets to raise the production of oil and gas, we need about $12 billion to carry out comprehensive rehabilitation operations. Efforts and cooperation continue with the unity government to find urgent solutions to funding problems.

PLATTS: Does the ministry have plans for reforming the country's downstream sector?

ABBAR: With regards to refining, the Ministry of Oil and Gas is considering a number of investment offers from foreign partners, as well as working to bring investors in coordination with the government and the NOC... to establish refineries in several areas that will promote fuel abundance and support development.

We also care about clean and renewable energy programs that support our environmental conservation priorities.

PLATTS: What steps is the ministry taking to attract foreign investment?

ABBAR: During October, we aspire to visit Germany, France, the UK and Russia in order to assess investment opportunities in oil and gas and the petrochemical industry, as well as open the prospects of cooperation that contribute to the development of reserves and enable new exploration in promising oil areas.

PLATTS: The US has been very involved in engaging with Libya on rebuilding the country. What role is the US playing in Libya's infrastructure rehabilitation?

ABBAR: The United States is a long-standing partner of Libya and we are working through oil conferences in Tripoli and Houston to encourage investment from major companies from the United States that have modern technologies, so that we can keep up with the developments in this industry. These will be an opportunity to share knowledge and strengthen the economic relations between the two countries.

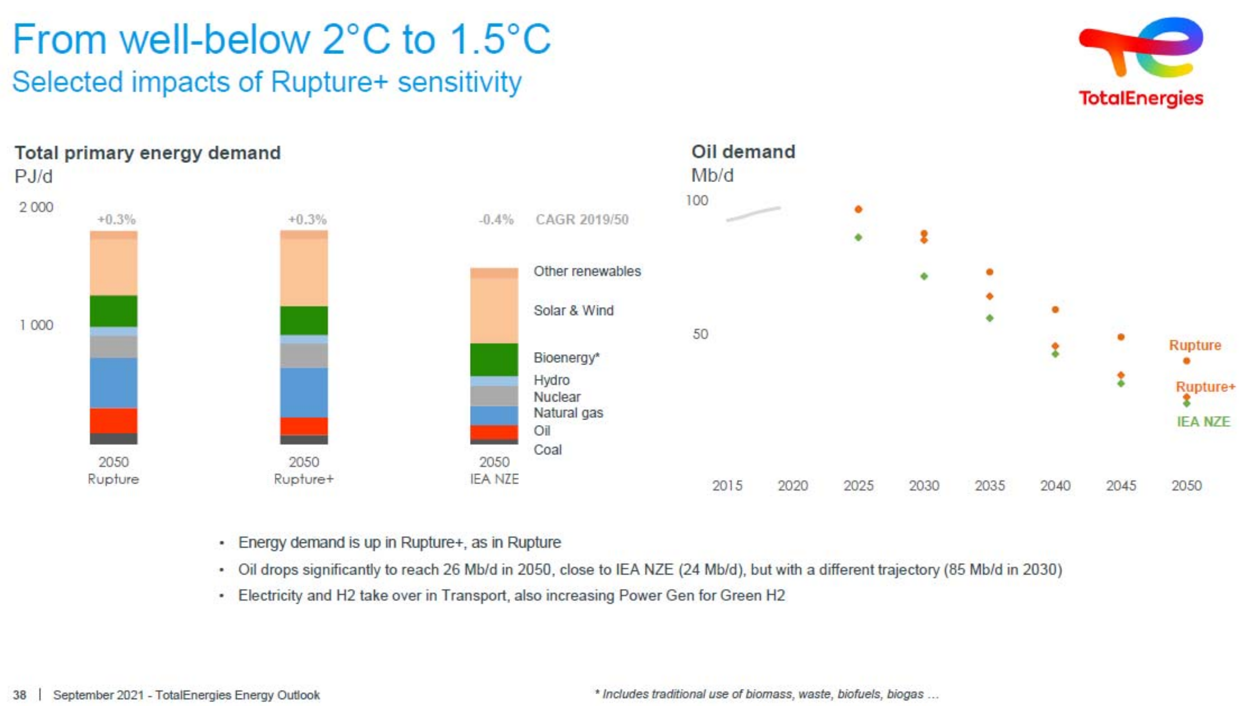
PLATTS: Has the ministry spoken to OPEC about a potential production quota for Libya in 2022?

ABBAR: Libya is part of OPEC and has always endeavored to cooperate with member states to ensure the stability of oil and gas markets. Libya is exempt from the production cut policy adopted by OPEC+ due to its production disruptions and frequent closures. Maintaining Libya's exempt status depends on what will happen to the oil market in the future, and we need today to make up for market share previously lost and to exploit the recovery in prices.

SAF Group created transcript of portion of Q&A from TotalEnergies "Energy Landscape & TotalEnergies Energy Outlook 2021" webcast on Sept 27, 2021. https://edge.media-server.com/mmc/p/8qtcrdyh

Items in "*italics*" are SAF Group created transcript.

In the Q&A, at 8:04am MT, CEO Patrick Pouyanne was talking about the below graph and the difference between TotalEnergies scenario and IEA views Pouyanne notes there isn't much difference in the 2050 oil demand outlook but there is in 2030. And he then says the main difference between Total and IEA "*is the trajectory between today when the demand for oil is around 100 million barrels per day, a little less this year and the 25 [?}. and the main difference is that the scenario by 2030, we still have something like we decrease by 10% I think compared to the IEA which decrease by 30%. And honestly, reducing the oil demand to 70 million barrels per day by 2030 compared to 100, we don't know of this decrease could happen. where is the demand would be erased in fact in 10 years. again if we took the assumption that the ICE ban in Europe represent 15 million barrels per day if it was in 2035, it was coming in 2035, not in 2030, not in 2025, so that's a key difference is the trajectory to get there. And of course, this has the main consequence of one of the spectacular conclusion which has been drawn by some of the IEA scenario, which is to say you must stop investing in oil and gas new investments because. Yes its true by the way, if you want to, is that demand is only 70 million barrels of oil per day in 10 years, which means a decrease of 3% per year, no need to invest much in the next 10 years in new projects but its not the supply will create demand, its not true, the demand is still 90 million like we anticipate by 2030, and not 70, if we produce only 70, the price will be at the roof, and more than at the roof. So maybe it's a good scenario for TotalEnergies and it shareholders, I am not sure it's a good scenario for all the customers and citizens of the planet. so that's why, to be clear, as ? reminded you, and you know very well Chris I think, and our auditors, if we do not invest we have a natural decline of 3 to 4%, and then we'll have a lack of supply. so according to our trajectory by 2030, we are more around 90 million that means we need to continue to invest in some oil and gas fields if we want to meet the demand. So, again the question in this transition, is not to think that we can change the pattern of demand by constraining the supply. if we just do that, we'll have a huge spike in the price and a huge instability, a social instability on this planet. So we cannot do that.*"



Prepared by SAF Group https://safgroup.ca/news-insights/

← Thread

Cathie Wood @CathieDWood

According to the EIA, global oil demand peaked at 101 million barrels per day (mbd) in 2019, dropped to 92 mbd during the coronavirus crisis in 2020, and has rebounded to 97 mbd in 2021. Based on our forecast for EV sales, @ARKInvest believes that oil demand has peaked.

> **QEBuble** @BubleQe · Jun 2
> Replying to @CathieDWood
> What a terrible call. Oil is nearly $70 & likely heading above $100. Supply shortage and demand is soaring.
>
> This call rivals only @JosefSchachter for missing out on one of the best trades in North America.
>
> Canadian Energy names up 400-600% since this call.

8:35 PM · Sep 30, 2021 · Twitter for iPhone

105 Retweets 39 Quote Tweets 795 Likes

SAF Tweet your reply Reply

Cathie Wood @CathieDWood · 7h
Replying to @CathieDWood
That said, based on ESG mandates, pension funds are demanding that oil companies cut back on capital spending while US banks, in response to the collapse in oil prices last year, are denying fracking companies of loans for capital spending, and OPEC is holding the line on supply.

12 20 297

Cathie Wood @CathieDWood · 7h
The rise in oil prices this year is a function more of supply than demand. At the turn of the 20th century, whale oil faced the same fate and whale oil prices fluctuated dramatically. If @ARKInvest's research is correct, oil prices will suffer the same fate as whale oil prices.

113 85 610

OIL DEMAND MONITOR: Road Fuels Near Pre-Covid, Jet Far Off (1)

- Busiest Monday morning traffic this year in London and Madrid
- Global airline seat capacity still down 30% from 2019: OAG

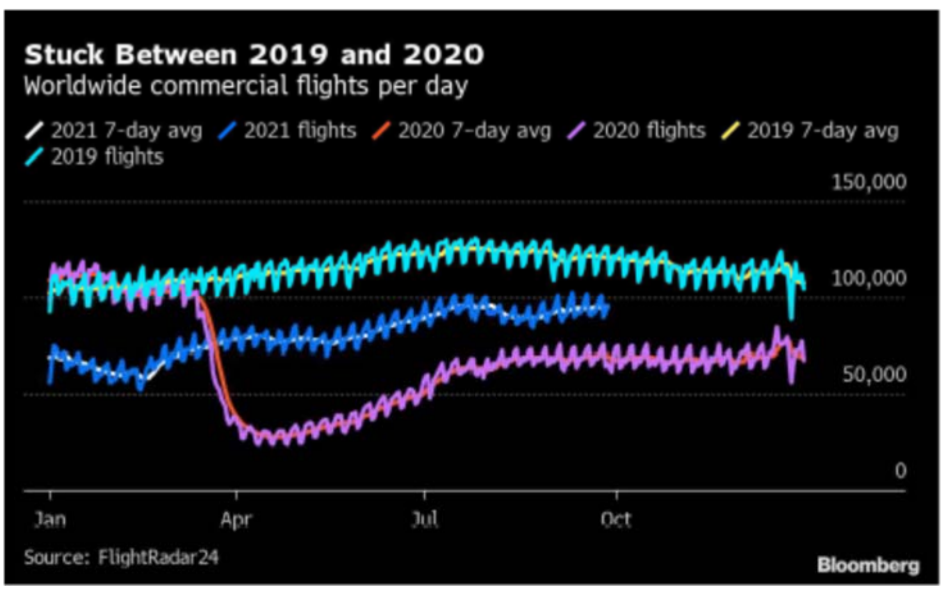
Sep 28, 2021 12:40:53

By Stephen Voss

(Bloomberg) -- Gasoline and diesel demand keeps oscillating above and below 207 9 levels in many countries, including the U.S. and India, without firmly settling back at pre-pandemic levels while jet fuel consumption still remains far below in many places.

Deliveries of jet fuel by India's three biggest retailers, for example, were 41 % below 207 9 levels in the first half of September and diesel down almost 7%, according to a recent Bloomberg survey. Gasoline demand last month was a few percentage points above 207 9 in Spain and a few below in Portugal, with aviation fuel more than one-third down in both countries.

A daily count of the number of commercial flights shows this year's tally is still midway between the pandemic-reduced schedules of 2020 and a full return to pre-Covid times. The 7-day average for Sept. 27 was 94,542 flights -- excluding the military, private jets and helicopters -- which is about 25,000 higher than a year ago and about 26,000 lower than the same period of 2019.

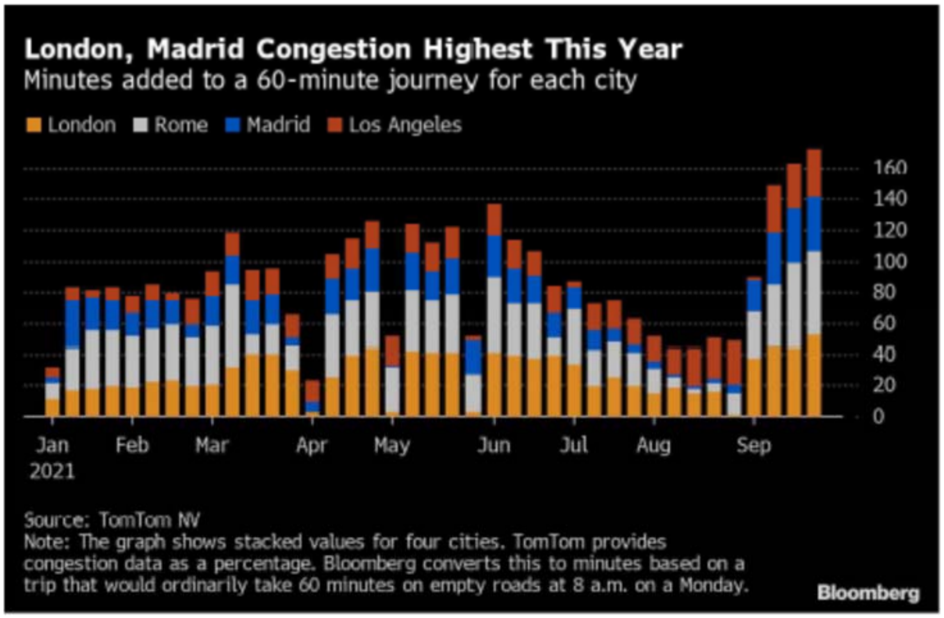


Airplane seat capacity estimates from OAG Aviation show the same general pattern. While a few nations, such as China and Mexico, are offering almost as many seats as they did before the coronavirus pandemic, the majority are not, and OAG's global estimate shows capacity is 30% lower than it was in the same week of 207 9.

Roads Keep Busy

Road use, meanwhile, continues to grind higher. Weekly toll-road data from Atlantia Group for six nations across Europe and Latin America show that all of them had higher traffic volume than the equivalent week in 2019, which is only the second week so far this year that that has happened. In the U.S., the number of miles traveled on interstate highways has been close to the same as 2019 levels for many weeks now, according to Department of Transportation data.

London and Madrid had their busiest Monday morning traffic so far this year while Tokyo, Los Angeles and Paris were just shy of the hitting the same milestone, according to Tom Tom NV, showing that a rebound in inner-city car usage is widespread.



Commuters in London at 8 a.m. Monday would've spent an additional 53 minutes in traffic on a trip that'd take just one hour on empty roads. To be sure, some of this congestion was due to panic buying and long lines at service stations amid a widely-publicized shortage of truck drivers to move fuel around the country.

READ: U.K. Puts Army Drivers on Standby to Tackle Damaging Fuel Crisis

BP Pie expects global oil consumption to return to pre-pandemic levels in the third quarter of 2022, with Asia continuing as the center for oil-product demand growth.
Gas Crisis Impact

The current crisis in natural gas supply, which has seen prices rocket, will also underpin oil demand, at least at the margin in the limited number of power stations that still have the ability to burn oil, consultant Energy Aspects said in a report.

"If sustained, the gas rally will deliver a 0.45m b/d boost to oil demand this winter (October 2027 -March 2022), and residual fuel will be the main beneficiary," according to the report.

Longer term, the outlook is starkly different, according to many analysts and fuel providers. French energy giant TotalEnergies SE expects global oil demand to peak before the end of this decade, as more nations crack down on fossil fuels and promote cleaner power in transport and industry to mitigate global warming.

"There is a key trend, which is electrification," mainly in renewables, Total Energies Chief Executive Officer Patrick Pouyanne said Monday on a conference call. "The energy world is moving quickly."
The Bloomberg weekly oil-demand monitor uses a range of high-frequency data series to help identify trends that may become clearer later in more comprehensive monthly figures.

Following are the latest indicators, in the four tables below. The first two show fuel demand and mobility, the next shows air travel globally and the last is refinery activity

Measure	Location	% y/y	% vs 2019	% m/m	Freq.	Latest as of Date	Latest Value	Source
Gasoline demand	U.S.	+4.5	-4.8	-7.1	w	Sept. 17	8.9m b/d	EIA
Distillates demand	U.S.	+12	+13.5	+7.8	w	Sept. 17	4.42m b/d	EIA
Jet fuel demand	U.S.	+59	-0.9	+6.3	w	Sept. 17	1.49m b/d	EIA
Total oil products demand	U.S.	+15	-0.3	-3.1	w	Sept. 17	21.1m b/d	EIA
All vehicles miles traveled	U.S.		-1.5		w	Sept. 19	16.5b miles	DoT
Passenger car VMT	U.S.		-4		w	Sept. 19	n/a	DoT
Truck VMT	U.S.		+10		w	Sept. 19	n/a	DoT
All motor vehicle use index	U.K.	+5.2	+1	+2	d	Sept. 20	101	DfT
Car use	U.K.	+5.4	-3	+1	d	Sept. 20	97	DfT
Heavy goods vehicle use	U.K.	+3.8	+10	+4.8	d	Sept. 20	110	DfT
Gasoline (petrol) avg sales per filling station	U.K.	+7.3	-3.6	+3.2	m	Aug. 29	7,001 liters/d	BEIS

Total road fuels sales per station	U.K.	+2.7	-6.5	+1.5	m	Aug. 29	16,545 liters/d	BEIS
Gasoline	India	+5.7	+8.3	+3.4	2/m	Sept. 1-15	1.02m tons	Bberg
Diesel	India	-1.5	-6.8	-0.9	2/m	Sept. 1-15	2.1m tons	Bberg
LPG	India	+2	+15	+8.7	2/m	Sept. 1-15	1.16m tons	Bberg
Jet fuel	India	+29	-41	+8.7	2/m	Sept. 1-15	181k tons	Bberg
Total Products	India	+11	-6.6	-4.9	m	August 2021	16m tons	PPAC
Passenger car traffic	Poland	+4	+3	-8.1	w	Sept. 26	23,712	GDDKiA
Heavy goods traffic	Poland	+4	+10	+5.6	w	Sept. 26	4,837	GDDKiA
Toll roads volume	Italy	+6.6	+1.1		w	Sept. 13-19	n/a	Atlantia
Toll roads volume	Spain	+25	+0.6		w	Sept. 13-19	n/a	Atlantia
Toll roads volume	France	+9.3	+2		w	Sept. 13-19	n/a	Atlantia
Toll roads volume	Brazil	+3.9	+4.2		w	Sept. 13-19	n/a	Atlantia
Toll roads volume	Chile	+84	+18		w	Sept. 13-19	n/a	Atlantia
Toll roads volume	Mexico	+13	+1.4		w	Sept. 13-19	n/a	Atlantia
All vehicles traffic	Italy	+5.4		+2.1	m	August	n/a	Anas
Heavy vehicle traffic	Italy	+5.5		-18	m	August	n/a	Anas
Gasoline	Portugal	+8	-7.7	+9.1	m	August	103k tons	ENSE
Diesel	Portugal	+5.5	-6.5	+0.5	m	August	421k tons	ENSE
Jet fuel	Portugal	+64	-36	+18	m	August	100k tons	ENSE
Gasoline	Spain	+14	+4.7		m	August	558k m3	Exolum
Diesel	Spain	+7.9	-2.3		m	August	2147k m3	Exolum
Jet fuel	Spain	+77	-41		m	August	448k m3	Exolum

NOTE: Click here for a PDF with more information on sources, methods. The frequency column shows d for data updated daily, w for weekly, 2/m for twice a month and m for monthly.

* In DfT U.K. data, the column showing versus 207 9 is actually showing the change versus the first week of February 2020, to represent the pre-Covid era. Table shows data for Aug. 27, 2027, rather than holiday-skewed information for Aug. 30.

** In BEIS U.K. data, which is only released once per month, the column showing versus 207 9 is actually showing the change versus the average of Jan. 27-March 22, 2020, to represent the pre-Covid era

City congestion:

Measure	Location	% chg vs 2019	% chg m/m	Sept. 27	Sept. 20	Sept. 13	Sept. 6	Aug. 30	Aug. 23	Aug. 16	Aug. 9	Aug. 2
		(Sept. 27)		Minutes of congestion at 8am local time								
Congestion	Tokyo	-5	+26	35	0	32	28	28	28	11	7	28
Congestion	Mumbai	-70	+100	11	12	11	10	5	8	7	7	9
Congestion	New York	unch	+108	31	35	39	0	15	16	13	17	16
Congestion	Los Angeles	-15	+4	30	28	31	2	29	27	24	17	16
Congestion	London	+40	+4300	53	44	44	37	1	16	15	19	15
Congestion	Rome	+10	+305	53	55	41	31	13	5	2	7	16
Congestion	Madrid	unch	+490	35	35	33	20	6	3	2	2	5
Congestion	Paris	+18	+93	52	53	52	49	27	14	9	7	17
Congestion	Berlin	-7	-4	31	29	32	38	32	38	29	26	16
Congestion	Mexico City	-48	+8	26	29	28	27	24	23	20	19	20
Congestion	Sao Paulo	-39	-12	26	26	27	10	30	26	25	25	21

Congestion Sao Paulo -39 -12 26 26 27 70 30 26 25 25 Source: Tom Tom. Click here for a PDF with more information on sources, methods.

NOTE: m/m comparisons are Sept. 27 vs Aug. 30. It was a public holiday in Tokyo on Sept. 20. Tom Tom has been unable to provide Chinese data since late April.

Air Travel:

Measure	Location	% chg y/y	% chg vs 2019	% chg m/m	Freq.	Latest as of Date	Latest Value	Source
Airline passenger throughput	U.S.	+132	-11	+13	d	Sept. 27	1.85 people	TSA
Commercial flights	Worldwide	+36	-22	+5.1	d	Sept. 27	94,542	FlightRadar24
Air traffic (flights)	Europe		-30	unch	d	Sept. 27	24,393	Eurocontrol
Seat capacity	Worldwide	+35	-30		w	Sept. 27	78.99m	OAG
Seat cap.	U.S.	+72	-16		w	Sept. 27	18.58m	OAG
Seat cap.	China	-6.1	-5		w	Sept. 27	15.54m	OAG
Seat cap.	India	+47	-27		w	Sept. 27	3.04m	OAG
Seat cap.	Spain	+107	-27		w	Sept. 27	2.47m	OAG
Seat cap.	Japan	-12	-53		w	Sept. 27	1.94m	OAG
Seat cap.	U.K.	+53	-46		w	Sept. 27	1.94m	OAG
Seat cap.	Brazil	+80	-27		w	Sept. 27	1.91m	OAG
Seat cap.	Germany	+73	-46		w	Sept. 27	1.85m	OAG
Seat cap.	Mexico	+54	-9.4		w	Sept. 27	1.61m	OAG
Seat cap.	France	+57	-38		w	Sept. 27	1.47m	OAG
Seat cap.	Australia	+33	-73		w	Sept. 27	569k	OAG
Seat cap.	S. Africa	+124	-43		w	Sept. 27	344k	OAG
Seat cap.	Singapore	+141	-81		w	Sept. 27	153k	OAG

NOTE: Comparisons versus 2019 are a better measure of a return to normal.

Refineries:

Measure	Location/area	y/y chg	vs 2019 chg	m/m chg	Latest as of Date	Latest Value	Source
		Changes in ppt unless noted					
Crude intake	U.S.	+15%	-7.1%	-4.5%	Sept. 17	15.3m b/d	EIA
Utilization	U.S.	+13	-2.3	-4.9	Sept. 17	87.5 %	EIA
Utilization	U.S. Gulf	+8.6	-11	-9.7	Sept. 17	82 %	EIA
Utilization	U.S. East	+27	+25	+3.9	Sept. 17	93 %	EIA
Utilization	U.S. Midwest	+17	+3.6	-0.6	Sept. 17	96.1 %	EIA
Apparent Oil Demand	China	+0.7%		+1.1%	August 2021	13.61 b/d	NBS
Indep. refs run rate	Shandong, China	-5.1	+2.5	+0.7	Sept. 24	69.2 %	SCI99
State refs run rate	East China	-3.4	-3.7	-1.7	Sept. 16	78.9 %	SCI99
State refs run rate	South China	+0.5	+1.8	+2.2	Sept. 16	84.1 %	SCI99

NOTE: All of the refinery data is weekly, except for SCI99 state refineries, which is twice per month, and the NBS apparent demand, which is usually monthly. Changes are shown in percentage point except for the rows on crude intake and apparent oil demand, which are shown in percent change

Caixin China General Manufacturing PMI™

Operating conditions stabilise in September

Latest PMI data indicated that business conditions across China's manufacturing sector stabilised in September, after a slight deterioration in August. The improved headline index reading was supported by a renewed upturn in total sales and a softer reduction in output. At the same time, purchasing activity also returned to growth, while confidence towards the year ahead also strengthened. Supply chain delays persisted, however, amid sustained reports of material shortages. This in turn drove sharper increases in both input costs and output prices.

The headline seasonally adjusted *Purchasing Managers' Index™ (PMI™)* – a composite indicator designed to provide a single-figure snapshot of operating conditions in the manufacturing economy – rose from 49.2 in August to 50.0 in September. This indicated that business conditions stabilised at the end of the third quarter, after a slight deterioration in the previous month. Nonetheless, the latest reading was the second-lowest seen for the past 17 months.

The higher headline index figure was partly driven by a renewed upturn in overall sales during September. Though only slight, it was the first time new work had increased for three months. Underlying data suggested this was largely driven by firmer domestic demand, as export sales continued to decline. A number of companies commented on improved customer numbers.

Although production fell for the second month in a row in September, the rate of decline eased to only a marginal pace. Firms indicated that relatively subdued demand and material shortages had weighed on production.

Efforts to improve efficiency contributed to a slight drop in employment in September. Rising workloads placed further pressure on capacity, however, as highlighted by a solid rise in backlogs of work. Notably, the rate of accumulation was the quickest since March 2020, with firms mentioning that material shortages and shipping delays had limited their ability to process and complete orders.

Manufacturers indicated a further lengthening of delivery times for inputs during September. The rate at which lead times increased was only modest, however. The deterioration in vendor performance was often linked to limited stock availability, transportation delays due to the pandemic and stretched capacity at suppliers.

In line with the trend for new work, buying activity returned to growth in September. Meanwhile, firms maintained a relatively cautious approach to their inventories of inputs, which declined marginally. In contrast, stocks of finished goods rose slightly, which was partly driven by difficulties shipping items to clients due to pandemic-related disruption.

Inflationary pressures picked up in September, with average input costs rising sharply overall. Moreover, the rate of inflation was the quickest seen for four months, amid reports of greater energy and raw material costs. This in turn led to a solid increase in prices charged.

Companies generally anticipate output to increase over the next year, with the level of positive sentiment improving to its highest since June. Optimism was underpinned by forecasts of an end to the pandemic, planned company expansions, rising customer demand and new product launches.

China General Manufacturing PMI

sa, >50 = improvement since previous month

Sources: Caixin, IHS Markit

Key findings:

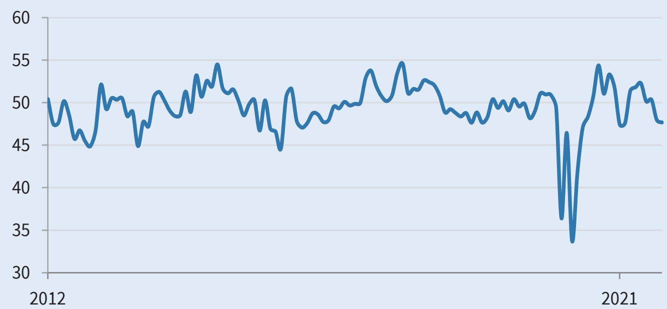
New orders return to growth

Output falls at softer pace

Inflationary pressures pick up amid material shortages

New Export Orders Index

sa, >50 = growth since previous month



Sources: Caixin, IHS Markit

Employment Index

sa, >50 = growth since previous month

Sources: Caixin, IHS Markit

Commenting on the China General Manufacturing PMI™ data, Dr. Wang Zhe, Senior Economist at Caixin Insight Group said:

“The Caixin China General Manufacturing PMI came in at 50 in September, showing that conditions in the manufacturing sector remained unchanged from the previous month. Factors including the reappearance of Covid-19 in several regions and raw material shortages continued to hurt the economy.

“Supply in the manufacturing sector continued to shrink, while demand improved. The resurgence of the epidemic in several regions and shortfalls in raw material supplies slowed production at manufacturing companies, with the gauge for output contracting for the second straight month in September. Demand improved, though marginally, with demand for consumer goods in the doldrums. Overseas demand was relatively weak as new export orders largely decreased in September. The epidemic again emerged overseas. Global shipping capacity was also clearly insufficient.

“The job market continued to come under pressure. The gauge for employment contracted for the second month in a row in September, and at a faster clip. Manufacturing enterprises reported that they were cautious about hiring new workers.

“Inflationary pressure surged. The gauge for input prices hit its highest level in four months in September, its 16th straight month in expansionary territory. The measure for output prices also reached its highest in three months. Surveyed enterprises said the rise in costs was mainly caused by a sharp increase in the prices of energy, industrial metals and electronic raw materials. The pressure of rising costs was partly transmitted downstream to consumers, as the demand was not weak.

“In logistics, delivery times grew longer. The gauge of suppliers’ delivery times remained in negative territory due to the lingering effects of some regions’ measures to contain local outbreaks of Covid-19. Consequently, inventories of finished manufacturing goods grew slightly.

“Entrepreneurs remained optimistic about the business outlook. The gauge for future output expectations bounced back to the long-term average. Manufacturing enterprises remained positive about the prospects for the market and for getting the Covid-19 outbreak under control.

“Overall, conditions in the manufacturing sector picked up in September from the previous month, though the improvement was limited. The Caixin China manufacturing PMI came in at 50, indicating the downward pressure on the economy was still high. On the one hand, the epidemic continued to impact demand, supply, and circulation in the manufacturing sector. The state of the epidemic overseas and the shortage of shipping capacity also dragged down total demand. Epidemic control measures have clearly impacted the logistics industry.

“Domestic demand varied based on different types of goods. The demand for intermediate goods and investment goods was relatively high, while the demand for consumer goods was weak, reflecting consumers’ lack of purchasing power. On the other hand, constraints to the supply side were strong as raw material prices remained high and some policy measures restricted production, squeezing employment and eventually weakening demand.

“In view of this, in the coming months, the government should focus on improving epidemic prevention and control and alleviating supply-side pressure. It should also find a balance among multiple objectives, such as promoting employment, maintaining the stability of raw material prices, ensuring a stable and orderly supply, and meeting targets for controlling energy consumption."

RHA

The Rt Hon Boris Johnson MP
Prime Minister
10 Downing Street
London
SW1A 2AA

23rd June 2021

Dear Prime Minister,

Critical supply chains failing due to the significant shortage of HGV drivers

We are urgently writing to ask for your personal intervention to help resolve the significant and rapidly deteriorating shortage of HGV drivers.

Prior to the pandemic, we estimated a shortage in excess of 60,000. At that time UK road transport businesses employed approximately 600,000 HGV drivers, including 60,000 from EU member states who were residing and working in the UK.

Several factors have exacerbated the shortage which is now at crisis point (over 100,000) and critical supply chains are failing. Those factors include:

COVID - Many drivers returned to their country of origin during extended periods of lockdown and restricted travel. The vast majority have not yet returned.

EU exit - The uncertainty of Brexit and future rights to live and work in the UK forced many drivers to do the same. Again, the vast majority have not returned nor are they expected to.

Retiring drivers - The average age of an HGV driver is 55, with less than 1% under the age of 25. Prolonged periods of inactivity have resulted in much of this aging workforce retiring early or finding employment in other, less demanding, sectors.

Test shortage - During a typical year, 72,000 candidates train to become HGV drivers with 40,000 succeeding. The complete shutdown of vocational driving tests throughout much of last year resulted in the loss of over 30,000 test slots and only 15,000 were able to complete training successfully - a drop of 25,000 from the previous year.

IR35 - The introduction of IR35 has resulted in agency labour withdrawing their services as low-profit margin logistics businesses (typically 2-3%) cannot sustain demands for £5-£6 per hour rate increases. For clarity, we welcome legislation that ensures fair and equal tax for all. However, Government must now recognise the repercussions of this and the other issues mentioned and urgently intervene to help us to resolve the resulting crisis.

We are grateful to Ministers from the Departments for Transport, and Work and Pensions, who have met with us to discuss solutions, but it is clear, despite best intentions, that there is no immediate plan. We firmly believe that intervention from the Prime Minister / Cabinet Office is the only way that we will be able to avert critical supply chains failing at an unprecedented and unimaginable level. Supermarkets are already reporting that they are not receiving their expected food stocks and, as a result, there is considerable wastage.

To make the situation even worse, summer holidays are fast approaching, and drivers will take their leave entitlement. The lack of agency drivers to help support their absence will exacerbate the problem even further as will continued unlocking of the economy and the spikes in demand for food and drink created by the hot weather and major sporting events. Furthermore, the Christmas build that retailers begin in August / September will be seriously affected – all of which will affect Government's ability to "build back better".

We are asking for your direct support as follows:

1) We need an immediate solution to this problem - we are not going to solve this now by training drivers and as such need access to EU and EEA labour. **We ask for the introduction of a temporary worker visa for HGV drivers and for this occupation to be added to the Home Office Shortage Occupation List.**

This will allow UK-registered transport operators to access a workforce that can live and work in the UK more easily and encourage those who have left to return - even if this is short-term measure whilst we concentrate on a longer-term plan. DEFRA already have arrangements in place that support our harvest periods when foreign labour restrictions are eased for specific demand. The same principles should be applied.

2) Government needs to work with the industry to help address the broader issues around the skills shortage. We must work collectively to achieve a sustainable way of recruiting and training a homegrown workforce so that our reliance on foreign labour dissipates over time. **We ask that a taskforce is immediately established to include representation from all of the relevant areas of Government and industry to help drive this change at the pace that is so desperately needed.**

3) The DEFRA Food Resilience Industry Forum, chaired by Chris Tyas, helped to ensure the nation's supply integrity throughout the pandemic. **This was recently disbanded. However, in view of the growing crisis, it must be re-established at the earliest opportunity.**

It is our collective view that there has never been a more challenging time for this industry and we urge you to take these decisive steps to ensure that we can continue to maintain the UK’s integrated and finely balanced supply chains.

Yours sincerely,

Richard Burnett
Chief Executive - RHA

Co signatories:

John Williams, Executive Chairman, Maritime Transport

Steve Granite, CEO, Abbey Logistics Group

David Pickering, CEO, Eddie Stobart

James Wroath, CEO, Wincanton

Thomas Van Mourik, CEO, Culina Group

Dan Myers, Managing Director, XPO Logistics

Paul Bennell, Managing Director, Samworth Brothers Supply Chain

Andrew Malcolm, CEO, The Malcolm Group

Mark Johnson, National Customs & Trade Control Director, KUEHNE + NAGEL

Andrew Howard, Managing Director, P C Howard

Kate Lester, Founder and CEO, Diamond Logistics Group

Lesley O’Brien OBE, Director, Freightlink Europe

Ian Wright CBE, Chief Executive, Food and Drink Federation

Richard Harrow, Chief Executive, British Frozen Food Federation

James Bielby, CEO, Federation of Wholesale Distributors

Shane Brennan, CEO, Cold Chain Federation

Emma McClarkin, Chief Executive, British Beer and Pub Association

Nick Allen, CEO, British Meat Producers Association

Angus Blundell, Marketing Director, Certas Energy UK

Mark Garner, Marketing Director, SNAP

James Anthony French MBE, Managing Director, Road to Logistics https://www.ics-shipping.org/press-release/joint-open-letter-transport-heads-call-on-world-leaders-to-secure-global-supply-chains/

Joint open letter – Transport heads call on world leaders to secure global supply chains

29 September 2021

Since the outset of the COVID-19 pandemic, the maritime, road and aviation industries have called loudly and clearly on governments to ensure the free movement of transport workers and to end travel bans and other restrictions that have had an enormously detrimental impact on their wellbeing and safety. Transport workers keep the world running and are vital for the free movement of products, including vaccines and PPE, but have been continually failed by governments and taken for granted by their officials.

Our calls have been consistent and clear: freedom of movement for transport workers, for governments to use protocols that have been endorsed by international bodies for each sector and to prioritise transport workers for vaccinations as called for in the World Health Organization's SAGE Roadmap for Prioritizing Uses of COVID-19 Vaccines in the Context of Limited Supply.

Heads of government have failed to listen, to end the blame-shifting within and between governments and take the decisive and coordinated action needed to resolve this crisis.

This is why IRU, the world road transport organisation, IATA, the International Air Transport Association, ICS, the International Chamber of Shipping, and ITF, the International Transport Workers' Federation, have come together to make an urgent plea to the world's heads of government and the United Nations Agencies to remove restrictions hampering the free movement of transport workers, and guarantee and facilitate their free and safe movement.

Our collective industries account for more than $20 trillion of world trade annually, and represent 65 million global transport workers, and over 3.5 million road freight and airline companies, as well as more than 80% of the world merchant shipping fleet. Seafarers, air crew and drivers must be able to continue to do their jobs, and cross borders, to keep supply chains moving. We ask heads of government to urgently take the leadership that is required to bring an end to the fragmented travel rules and restrictions that have severely impacted the global supply chain and put at risk the health and wellbeing of our international transport workforce. We also need the same urgent leadership to increase global vaccine supply by all means at our disposal, in order to expedite the recovery of our industries.

We ask that our transport workers are given priority to receive WHO recognised vaccines and heads of government work together to create globally harmonised, digital, mutually recognised vaccination certificate and processes for demonstrating health credentials (including vaccination status and COVID-19 test results), which are paramount to ensure transport workers can cross international borders.

We also call on the WHO to take our message to health ministries. Despite early engagement at the outset of the pandemic and issuance of guidance, health and transport ministries have not utilised it, resulting in the situation we face today. We need the WHO and governments to work together to ensure this guidance is accepted and followed.

The impact of nearly two years' worth of strain, placed particularly upon maritime and road transport workers, but also impacting air crews, is now being seen. Their continued mistreatment is adding pressure on an already crumbling global supply chain. We are witnessing unprecedented disruptions and global delays and shortages on essential goods including electronics, food, fuel and medical supplies. Consumer demand is rising and the delays look set to worsen ahead of Christmas and continue into 2022.

We have all continued to keep global trade flowing throughout the pandemic, but it has taken a human toll. At the peak of the crew change crisis 400,000 seafarers were unable to leave their ships, with some seafarers working for as long as 18 months over their initial contracts. Flights have been restricted and aviation workers have faced the inconsistency of border, travel, restrictions, and vaccine restrictions/requirements. Additional and systemic stopping at road borders has meant truck drivers have been forced to wait, sometimes weeks, before being able to complete their journeys and return home.

It is of great concern that we are also seeing shortages of workers and expect more to leave our industries as a result of the poor treatment they have faced during the pandemic, putting the supply chain under greater threat.

In view of the vital role that transport workers have played during the pandemic and continue to play during the ongoing supply chain crisis, we request, as a matter of urgency, a meeting with WHO and the ILO at the highest level to identify solutions before global transport systems collapse. We also ask that WHO and the ILO raise this at the UN General Assembly and call on heads of government to take meaningful and swift action to resolve this crisis now.

Dallas Fed Energy Survey

Third Quarter | September 29, 2021

Expansion Continues in Oil and Gas Activity; Cost Pressures Building

What's New This Quarter

Special questions this quarter ask about expectations for U.S. electric vehicle sales, purchases of carbon credits and/or carbon offsets, COVID-19-related operational delays and hiring challenges.

Solid oil and gas sector growth continued in third quarter 2021, according to oil and gas executives responding to the Dallas Fed Energy Survey. The business activity index—the survey's broadest measure of conditions facing Eleventh District energy firms—remained elevated but moved down from 53.0 in the second quarter to 44.3 in the third quarter.

Oil production increased but at a significantly slower pace, according to executives at exploration and production (E&P) firms. The oil production index remained positive but fell from 35.0 in the second quarter to 10.7 in the third. Similarly, the natural gas production index fell 16 points to 19.3.

For a second quarter in a row, costs rose sharply. Among oilfield services firms, the index for input costs increased to 60.8, a record high and indicative of significant cost pressures. Only one of the 47 responding oilfield services firms reported lower input costs this quarter. Among E&P firms, the index for finding and development costs advanced from 28.3 in the second quarter to 33.0 in the third. Additionally, the index for lease operating expenses increased, from 23.4 to 29.4.

It is also taking longer for companies to receive inputs. Among oilfield services firms, the index for supplier delivery time increased from 14.0 in the second quarter to 26.7 in the third, the highest reading since the survey's inception in 2016. The index measuring delays in deliveries increased to 26.7, also a record high. Similarly, among E&P firms, the index for supplier delivery time increased from 4.0 to 10.5.

The equipment utilization index of oilfield services firms rose from 42.0 in the second quarter to 47.8 in the third. Operating margins continued to widen, with the index remaining positive at 21.8. The index of prices received for services rose from 30.0 to 42.2.

Labor market indicators improved in the third quarter. The aggregate employment index posted a third consecutive positive reading, increasing from 9.9 to 14.0. Employment growth continues to be driven primarily by oilfield services firms. The employment index was 25.5 for services firms versus 8.4 for E&P firms. The aggregate employee hours index remained positive but dipped from 24.0 to 19.0. The aggregate wages and benefits index increased, from 20.6 to 30.3.

Six-month outlooks improved, with the index remaining positive but declining from 71.9 last quarter to 58.9. After two quarters of declining uncertainty, the uncertainty index moved up from -19.6 to 4.3, suggesting a slight rise in uncertainty this quarter.

On average, respondents expect a West Texas Intermediate (WTI) oil price of $70 per barrel by year-end 2021; responses ranged from $42 to $90 per barrel. Survey respondents expect Henry Hub natural gas prices of $4.74 per million British thermal units (MMBtu) at year-end. For reference, WTI spot prices averaged $72 per barrel during the survey collection period, and Henry Hub spot prices averaged $5.22 per MMBtu.

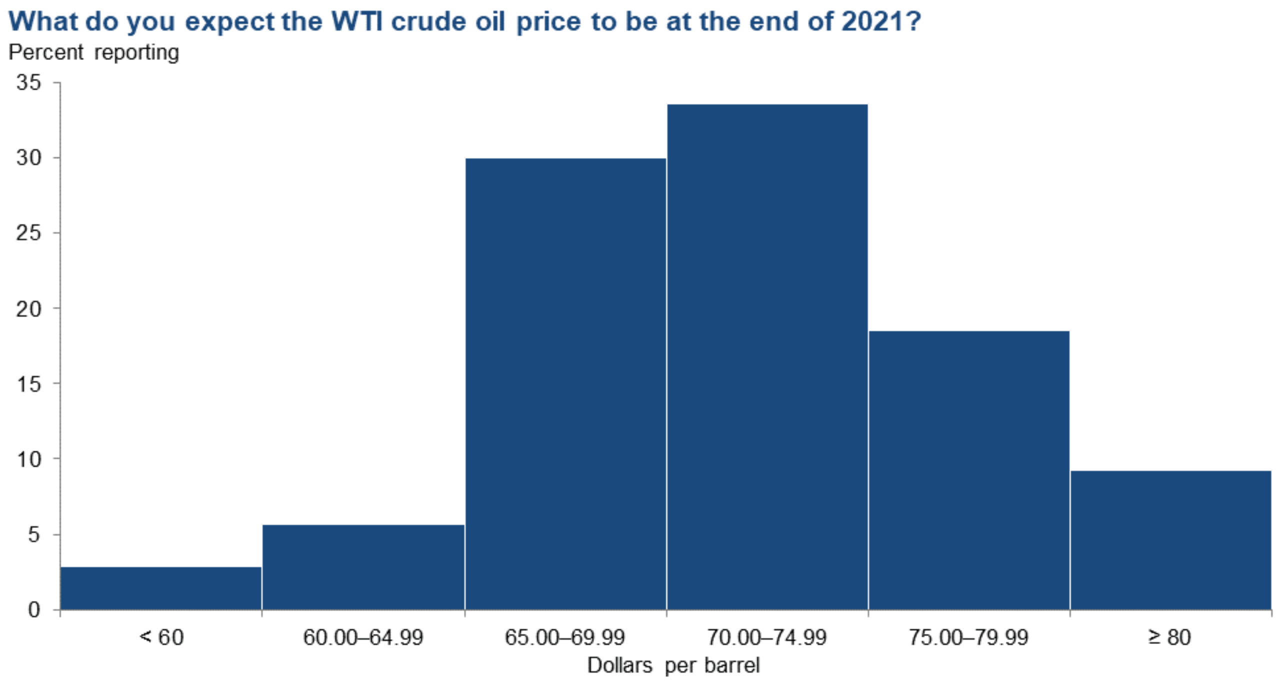
Next release: December 29, 2021

Data were collected Sept. 15–23, and 142 energy firms responded. Of the respondents, 95 were exploration and production firms and 47 were oilfield services firms.

The Dallas Fed conducts the Dallas Fed Energy Survey quarterly to obtain a timely assessment of energy activity among oil and gas firms located or headquartered in the Eleventh District. Firms are asked whether business activity, employment, capital expenditures and other indicators increased, decreased or remained unchanged compared with the prior quarter and with the same quarter a year ago. Survey responses are used to calculate an index for each indicator. Each index is calculated by subtracting the percentage of respondents reporting a decrease from the percentage reporting an increase. When the share of firms reporting an increase exceeds the share reporting a decrease, the index will be greater than zero, suggesting the indicator has increased over the previous quarter. If the share of firms reporting a decrease exceeds the share reporting an increase, the index will be below zero, suggesting the indicator has decreased over the previous quarter.

Price Forecasts

West Texas Intermediate Crude



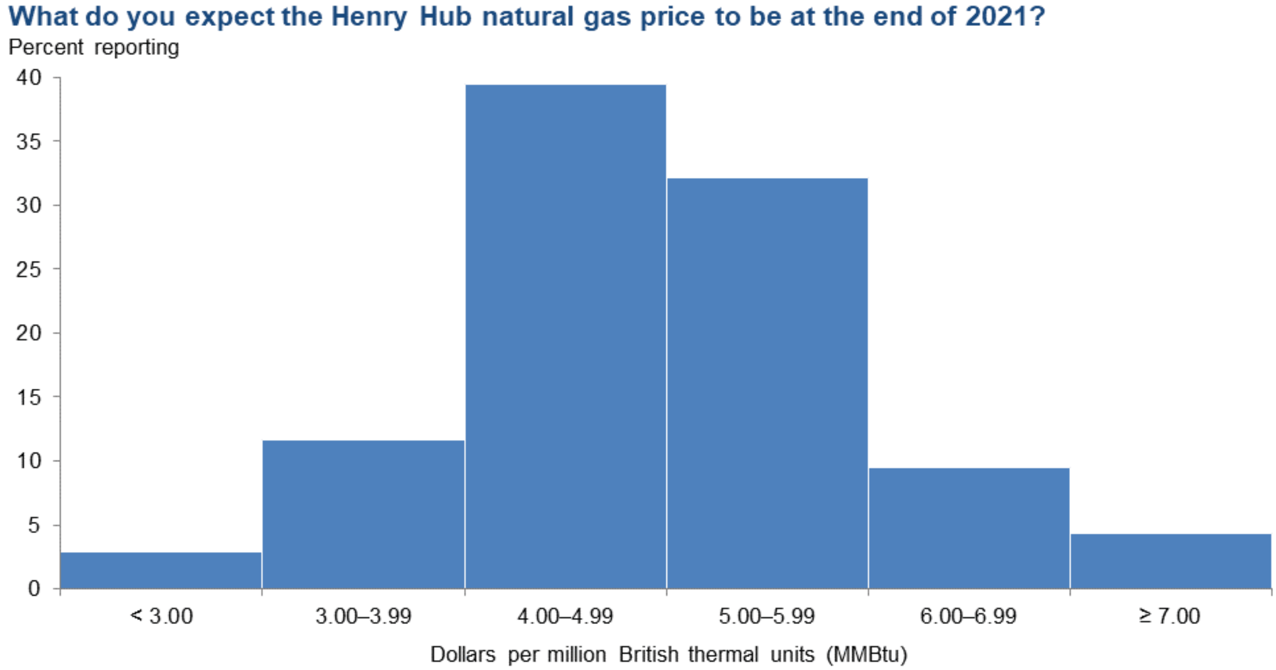
NOTES: Executives from 140 oil and gas firms answered this question during the survey collection period, Sept. 15–23, 2021. For reference, WTI (West Texas Intermediate) spot prices averaged $72.01 per barrel during the period.
SOURCES: Federal Reserve Bank of Dallas; Energy Information Administration (reference price).

West Texas Intermediate crude oil price (dollars per barrel), year-end 2021

Indicator	Survey Average	Low Forecast	High Forecast	Price During Survey
Current quarter	$69.99	$42.00	$90.00	$72.01
Prior quarter	$69.71	$49.00	$85.00	$71.05

NOTE: Price during survey is an average of daily spot prices during the survey collection period.
SOURCES: Energy Information Administration; Federal Reserve Bank of Dallas.

Henry Hub Natural Gas



NOTES: Executives from 137 oil and gas firms answered this question during the survey collection period, Sept. 15–23, 2021. For reference, Henry Hub spot prices averaged $5.22 per MMBtu during the period.
SOURCES: Federal Reserve Bank of Dallas; *Wall Street Journal* (reference price).

Henry Hub natural gas price (dollars per MMBtu), year-end 2021

Indicator	Survey Average	Low Forecast	High Forecast	Price During Survey
Current quarter	$4.74	$2.11	$9.50	$5.22
Prior quarter	$3.10	$2.20	$5.00	$3.24

NOTE: Price during survey is an average of daily spot prices during the survey collection period.
SOURCES: Federal Reserve Bank of Dallas; *Wall Street Journal*.

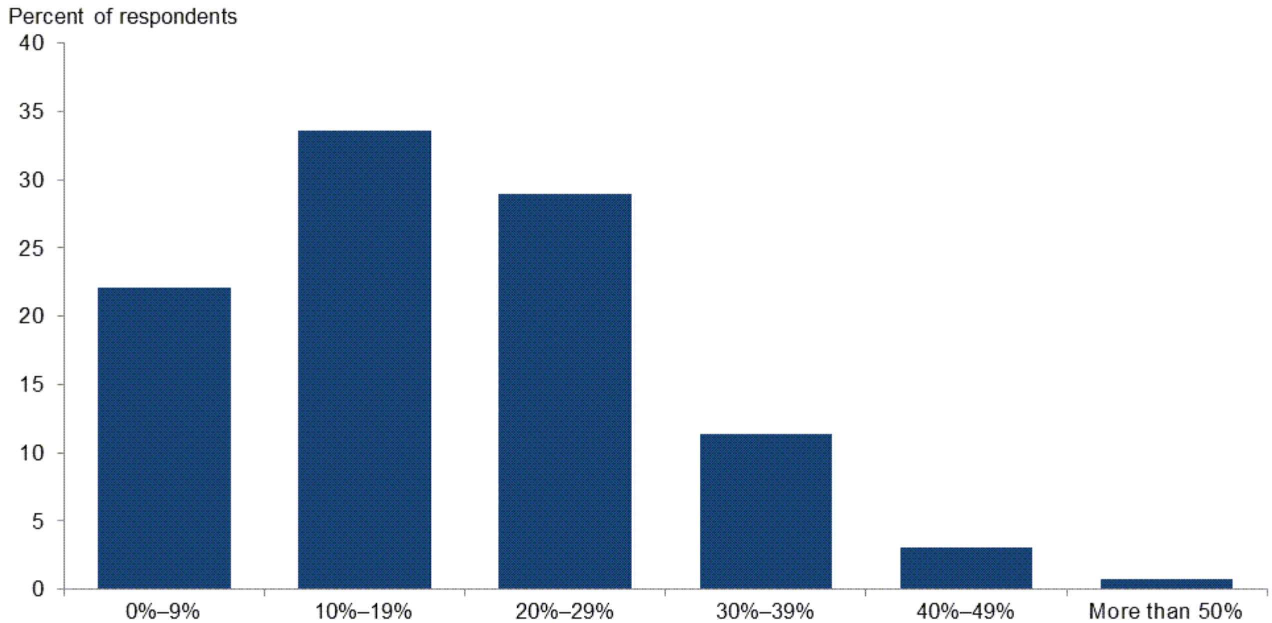
Special Questions

Data were collected Sept. 15–23; 142 oil and gas firms responded to the special questions survey.

All Firms

Regarding cars and light trucks, what percentage of all U.S. sales do you expect to be plug-in electric by 2030?

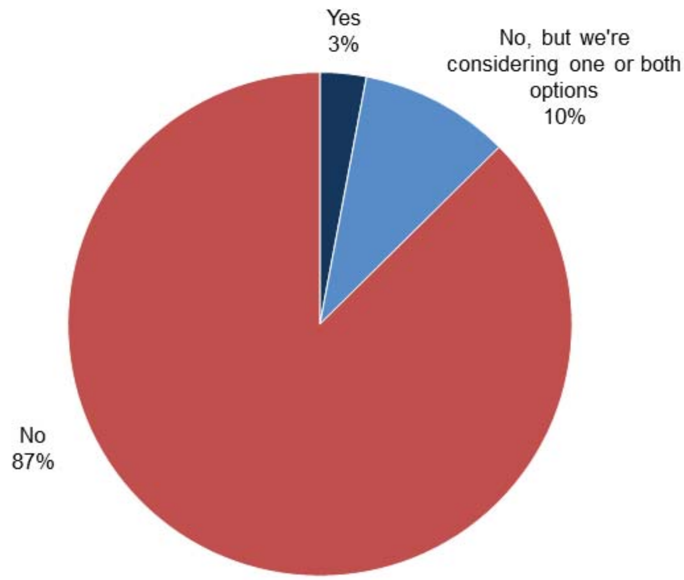
The most-selected response was 10–19 percent, chosen by 34 percent of executives. Twenty-nine percent of executives said they expect 20–29 percent of U.S. sales to be plug-in electric by 2030, while 22 percent said 0–9 percent. Fourteen percent expect 30–49 percent of all U.S. sales to be plug-in electric, and 1 percent expect sales to exceed 50 percent. For reference purposes, 2 percent of U.S. sales were plug-in electric in 2020, according to the International Energy Agency.



NOTE: Executives from 131 oil and gas firms answered this question during the survey collection period, Sept. 15–23, 2021.
SOURCE: Federal Reserve Bank of Dallas.

Is your firm currently purchasing carbon credits and/or carbon offsets?

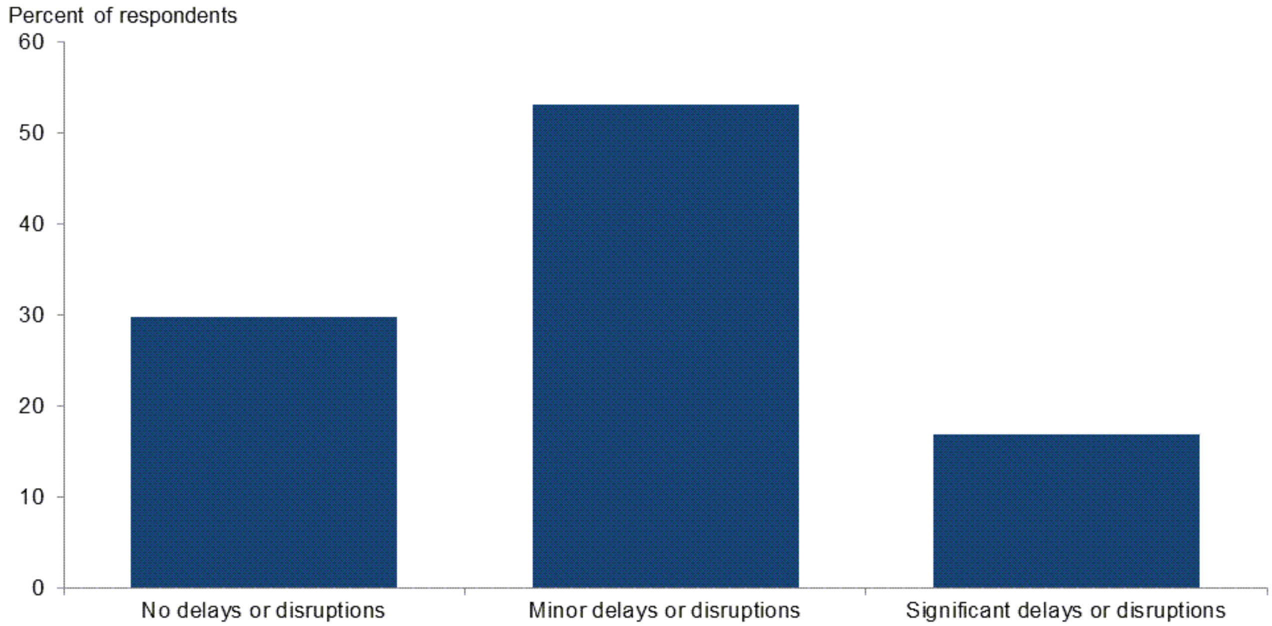
A majority of executives—87 percent—said their firms are not purchasing carbon credits and/or carbon offsets. Ten percent said they are purchasing neither but are considering purchasing one or both options. The remaining 3 percent said their firms are purchasing carbon credits and/or offsets.



NOTES: Executives from 135 oil and gas firms answered this question during the survey collection period, Sept. 15–23, 2021.
SOURCE: Federal Reserve Bank of Dallas.

Has your firm experienced delays or disruptions in your operations due to COVID-19 infections over the past quarter?

Slightly more than half of the executives—53 percent—said COVID-19 caused minor delays or disruptions in operations in the past quarter. Thirty percent noted no delays or disruptions, while 17 percent encountered significant delays or disruptions.



NOTE: Executives from 141 oil and gas firms answered this question during the survey collection period, Sept. 15–23, 2021.
SOURCE: Federal Reserve Bank of Dallas.

Oil and Gas Support Services

Over the past quarter, have you had difficulty hiring workers at your firm?

This question was only posed to executives at oil and gas support services firms. Slightly more than half of the executives—51 percent—said they had difficulty hiring workers over the past quarter. Twenty-four percent said they did not have difficulty. Another 24 percent stated they didn't have any job openings this past quarter. (Percentages don't sum to 100 due to rounding.)

Response	Percent of respondents
We have not had any job openings this quarter	24
No, we have been able to hire without difficulty	24
Yes, we have had difficulty hiring workers	51

NOTE: Executives from 45 oil and gas support services firms answered this question during the survey collection period, Sept. 15–23, 2021.
SOURCE: Federal Reserve Bank of Dallas.

If yes, what impediments is your firm facing when hiring or recalling workers? Please select all that apply.

Of those who responded that their firm experienced difficulty hiring, 70 percent noted a lack of qualified applicants, followed by 39 percent who cited workers looking for more pay than is offered. If “other” was selected, executives could provide a specific reason. Some of those responses included generous government unemployment benefits, customers of the firm requiring employees to be vaccinated, applicants looking for work-from-home flexibility, and people unwilling to work.

Response	Percent of respondents
A lack of qualified applicants	70
Workers looking for more pay than is offered	39
Applicants have failed or refused drug tests	17
Other	35

NOTE: Executives from 23 oil and gas support services firms answered this question during the survey collection period, Sept. 15–23, 2021.
SOURCE: Federal Reserve Bank of Dallas.

Special Questions Comments

Exploration and Production (E&P) Firms

- The more I become educated on EVs [electric vehicles] and the charging and battery disposal problems, the more I think they will have little effect on the market in the future. My investigation turns more toward the hydrogen cell as the long-term solution.
- Disruptions are due to government payments to the workforce. Possible workers are being paid very well not to work by our government. This policy must change if we want a stable workforce in the U.S.
- In order to pursue the climate goals of the U.S., we must incorporate traditional energy producers and industrial firms in the conversation. Labeling these firms as "the enemy" will not accelerate the energy transition or get buy-in from stakeholders across the South. The South has accounted for a large majority of energy-related CO_2 growth in the past 30 years—it has been the engine of industrial growth in the U.S. If you desire to have an impact on carbon, you can catch more flies with honey than vinegar. There is no amount of electrification (or carbon taxation) that will create plastics, cement or fertilizer. It is time for incentives like 45Q [tax credit for carbon dioxide sequestration] to be expanded and extended.
- The macho individualist in the oilfield has come face-to-face with a deadly virus. Our company has lost two employees, and the oilfield service company has lost three men just due to sheer stupidity. It is a tragedy for their families.
- We have had issues with contractors who are not vaccinated getting COVID-19 and then using federal-government-subsidized treatments in the hospital.
- Access to capital remains an issue. The Fed [Federal Reserve] picking winners and encouraging "green" with no real standards is problematic. The move to intermittent energy will have real, nontransitory impacts on consumer and/or business costs and inflation.
- My company is very small. I have made the decision to transition the work done by my employees to fully at home. I believe this serves as motivation to stay with my company and a benefit I can offer without increasing wages. Commuting times are becoming a significant complaint by my employees. Also, the expense of office rent can be eliminated.
- Our company is a nonoperator, so we rely upon our operators. They're struggling with "work from home," and everything is delayed. The resolution time for problems is greatly elongated. Responses to proposals are also greatly delayed. Invoicing and bill-paying by others have been delayed.
- Labor is a prime problem. Our work ethic is being destroyed. We exported our jobs of value. We are now importing labor with no skills. Dependency is seductive. It is a horrible way to kill the beacon of hope in this world. Our economy and capitalism are dying. I lived the best years of this country's life.
- We're planning to sell carbon offsets, not buy them.

Oil and Gas Support Services Firms

- Our business is to provide seismic data to E&P clients, or at least it used to be. We are increasingly seeing new customers who are interested in using seismic data to assist them in carbon-capture use and storage projects. It appears that regulatory bottlenecks and/or delays are slowing the potential for many of these carbon-capture projects.

Historical data are available from first quarter 2016 to the most current release quarter.

Business Indicators: Quarter/Quarter

Business Indicators: All Firms
Current Quarter (versus previous quarter)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	44.3	53.0	52.8	38.7	8.5
Capital Expenditures	37.1	36.6	47.1	42.9	10.0
Supplier Delivery Time	15.7	7.3	30.7	54.3	15.0
Employment	14.0	9.9	23.2	67.6	9.2
Employee Hours	19.0	24.0	27.5	64.1	8.5
Wages and Benefits	30.3	20.6	34.5	61.3	4.2

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	58.9	71.9	67.9	23.1	9.0

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Uncertainty	4.3	–19.6	29.8	44.7	25.5

Business Indicators: E&P Firms
Current Quarter (versus previous quarter)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	38.9	50.0	48.4	42.1	9.5
Oil Production	10.7	35.0	33.3	44.1	22.6
Natural Gas Wellhead Production	19.3	35.0	38.7	41.9	19.4
Capital Expenditures	36.6	42.4	49.5	37.6	12.9
Expected Level of Capital Expenditures Next Year	48.9	53.0	56.5	35.9	7.6
Supplier Delivery Time	10.5	4.0	26.3	57.9	15.8
Employment	8.4	2.0	15.8	76.8	7.4
Employee Hours	8.4	12.0	15.8	76.8	7.4
Wages and Benefits	19.0	17.0	23.2	72.6	4.2
Finding and Development Costs	33.0	28.3	36.2	60.6	3.2
Lease Operating Expenses	29.4	23.4	37.0	55.4	7.6

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	61.0	71.3	69.0	23.0	8.0

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Uncertainty	0.0	–22.7	27.7	44.7	27.7

Business Indicators: O&G Support Services Firms
Current Quarter (versus previous quarter)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	55.3	58.8	61.7	31.9	6.4
Utilization of Equipment	47.8	42.0	54.3	39.1	6.5
Capital Expenditures	38.3	25.5	42.6	53.2	4.3
Supplier Delivery Time	26.7	14.0	40.0	46.7	13.3
Lag Time in Delivery of Firm's Services	26.7	10.2	31.1	64.4	4.4
Employment	25.5	25.5	38.3	48.9	12.8
Employment Hours	40.5	48.0	51.1	38.3	10.6
Wages and Benefits	53.1	27.5	57.4	38.3	4.3
Input Costs	60.8	56.0	63.0	34.8	2.2
Prices Received for Services	42.2	30.0	44.4	53.3	2.2
Operating Margin	21.8	22.5	37.0	47.8	15.2

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	55.4	72.9	66.0	23.4	10.6

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Uncertainty	12.7	–13.8	34.0	44.7	21.3

Business Indicators: Year/Year

Business Indicators: All Firms

Current Quarter (versus same quarter a year ago)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	66.7	68.1	76.8	13.0	10.1
Capital Expenditures	55.5	46.5	65.9	23.7	10.4
Supplier Delivery Time	19.3	20.7	37.8	43.7	18.5
Employment	18.9	6.4	34.1	50.7	15.2
Employee Hours	27.1	29.0	38.0	51.1	10.9
Wages and Benefits	44.6	29.8	50.4	43.8	5.8

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	77.0	84.4	84.9	7.1	7.9

Business Indicators: E&P Firms

Current Quarter (versus same quarter a year ago)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	61.3	66.7	73.1	15.1	11.8
Oil Production	21.7	37.3	47.8	26.1	26.1
Natural Gas Wellhead Production	28.6	38.9	48.4	31.9	19.8
Capital Expenditures	52.3	51.6	66.7	18.9	14.4
Expected Level of Capital Expenditures Next Year	61.3	64.8	69.3	22.7	8.0
Supplier Delivery Time	13.0	18.9	32.6	47.8	19.6
Employment	9.7	−3.3	23.7	62.4	14.0
Employee Hours	16.3	19.5	25.0	66.3	8.7
Wages and Benefits	34.8	23.4	40.2	54.3	5.4
Finding and Development Costs	42.2	30.3	48.9	44.4	6.7
Lease Operating Expenses	43.7	28.9	52.9	37.9	9.2

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	77.8	84.0	85.2	7.4	7.4

Business Indicators: O&G Support Services Firms
Current Quarter (versus same quarter a year ago)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	77.7	70.6	84.4	8.9	6.7
Utilization of Equipment	70.5	58.0	77.3	15.9	6.8
Capital Expenditures	62.2	37.3	64.4	33.3	2.2
Supplier Delivery Time	32.5	24.0	48.8	34.9	16.3
Lag Time in Delivery of Firm's Services	30.2	22.5	37.2	55.8	7.0
Employment	37.8	23.6	55.6	26.7	17.8
Employment Hours	48.8	45.1	64.4	20.0	15.6
Wages and Benefits	64.4	41.2	71.1	22.2	6.7
Input Costs	72.7	65.3	75.0	22.7	2.3
Prices Received for Services	55.8	26.6	60.5	34.9	4.7
Operating Margin	37.2	24.0	53.5	30.2	16.3

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	75.5	85.1	84.4	6.7	8.9

SAF Group created transcript of excerpts from the TotalEnergies Energy Landscape webcast Sept 27, 2021

Items in "*italics*" are SAF Group created transcript. Note that our created transcript is a little different than other posted transcripts.

On growth in power supply really being driven by wind and solar. In their prepared remarks, mgmt said "*In Momentum, the overall power demand is up some 2.5% per annum over the next 30 years. So what about power generation to accommodate for this increase in demand? Generation more than doubles by 2050 with solar and wind making up 85% of new capacities. Gas is the only fossil fuel to grow in the power mix due to its key role in coping with intermittency and demand seasonality. To the right, you see our assumptions in terms of gigawatts of solar and wind. The capacities are multiplied by 10 in 30 years."* Note that in their more aggressive Rupture scenario, its even more growth. The transcript we prepared says "*The associated need for wind and solar to the right is staggering. Every year between now and 2050, every year over the next 30 years, the world has to add all of the existing installed solar capacity Over all of the existing installed wind capacity because those two bases are actually very close. This will also require, of course massive storage solution, again be they battery based or green hydrogen or some other new technology that will be invented".*

A key underlying issue/challenge for wind/solar is that it takes up way more space to produce energy. In their prepared remarks, mgmt said "*Footprint of different energies is also to be considered. The footprint is linked to the density of the energies and to their engineering characteristics, which in the end, boils down to planned production yield. It's illustrated here in terms of square meters of land needed to power a 100-watt flat TV screen. You don't see oil on the chart because it's not really a good way to use oil to produce power. So hydro, of course is a little specific because it's not at all modular. But what you can see here that for the same amount of power, the land use required for wind or solar is way way bigger than the square meters needed for a coal power plant, a nuclear power plant or a gas power plant. This is a way of showing why there are acceptability issues linked to wind and solar, not everywhere, but in Europe, for instance, it is a mounting issue that has to be overcome."*

Then on overcoming NIMBY (they don't use the term NIMBY) issues that cause delays for approvals. In the Q&A, mgmt is asked about overcoming local opposition to wind and solar projects in France, and replies "*The problem is not only in France. I think by the way you have issues with communities because it's a question again of land use. In fact, you have competition for use, and you have people. It's not only in France, by the way we observed the same, exactly the same problem in Germany, in Italy, by the way. And we begin to observe it in Spain as well. So I think the reality is that Europe is, I would say is a humanized civilization. And we have a density of population, which compared to many other countries like the U.S. or Australia, for example." "China" "Which is much, much, we are much more dense. So I'm not surprised, and it's why I was insisting that it's a question of scarcity above surface for renewables. So that has to be taken into account. I read there was a study. It's an interested study, which has been published in Italy by the Ambrosetti Foundation. We try to translate this. The target that the European Commission has assigned by 2030, 40% of renewable in our mix in terms of. they made a study how long could it take to get through all the administrative process to build such capacities? And is the answer in this study by Ambrosetti, it's not 2030, but 2043 [ph] There is a message there to policymakers, I think to everybody. If, and that I think that's very good this exercise. I mean this willingness of Europe to go for 55% by 2050 -- to 2030, sorry because it raised many issues. It puts the people in front of the reality. How do we do that? And if yes. If we want to reach 40% of renewable in our mix, we need to build massive renewable for the next 10 years. And we need to have the land, and we will need to have the administrative process going through. And that's true that in our democracies, which is good, that makes raise questions. I think there is only way to think to that, which will oblige governments to plan properly like I think the French government begins to think to that. We need to make some planning, but to do the planning properly, you need to put people around the table and not to antagonize people. If you let just people going, if it's a jungle, it will not work. So that's true that. and for, let's be clear for our strategy of TotalEnergies, this is one advantage of our company is that we think, when we think renewable, we think on a worldwide basis. I will come back on that concept tomorrow."*

Prepared by SAF Group https://safgroup.ca/news-insights/

https://www.rystadenergy.com/newsevents/news/press-releases/solar-powers-supply-chain-crisis-makes-15c-climate-target-a-major-challenge/?utm_source=Sugar+Market&utm_medium=newsletter&utm_campaign=RE+Insights+September

Solar power's supply chain crisis makes 1.5°C climate target a major challenge

September 10, 2021

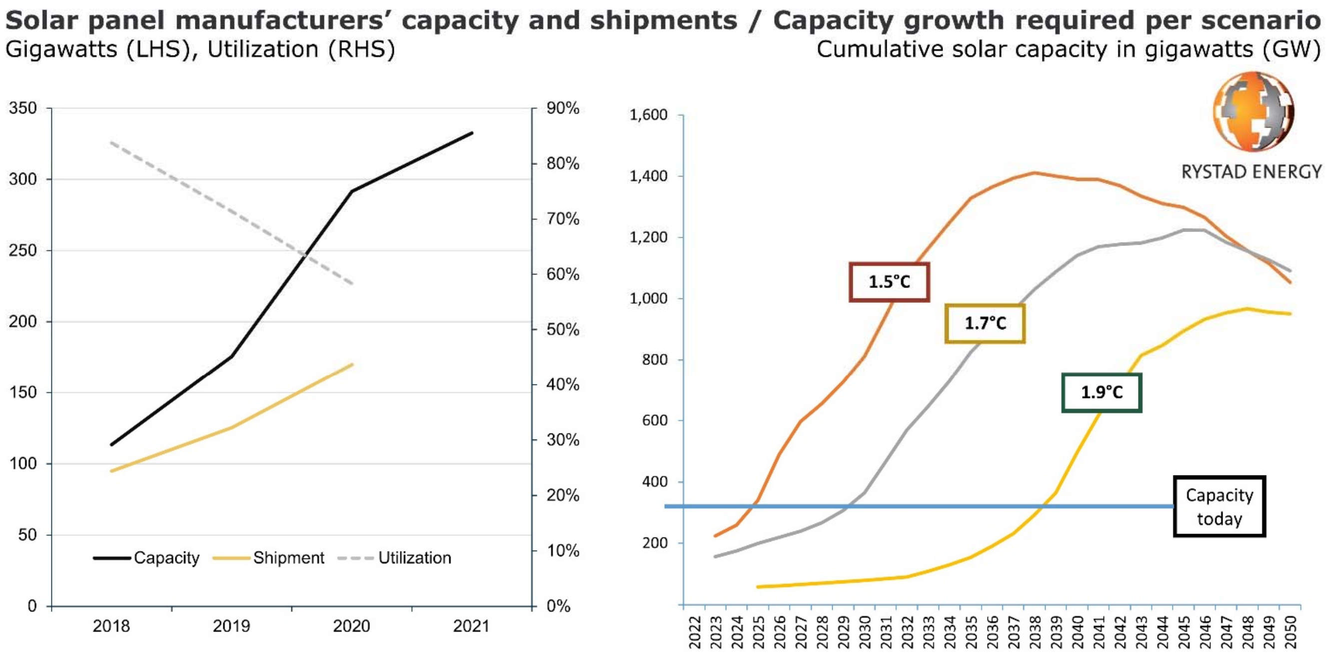
Grid parity, resilient networks and strategic partnerships have spurred growth in the world's solar panel manufacturing capacity in recent years, to 330 gigawatts (GW) in mid-2021. A Rystad Energy analysis reveals that to meet the 1.5°C 2050 scenario under the Paris Agreement, capacity has to quadruple to 1,200-1,400 GW by 2035 to handle the peak installations needed. This will be a challenging task, however, as manufacturers now see their utilization plummet due to rising costs and Covid-19 – a turn of events that could discourage the investments needed to expand capacity further.

The aggregated utilization rate for solar modules (the difference between manufacturing capacity and shipments) was 84% in 2018 and has been decreasing since, to 71% in 2019 and to 58% in 2020, when logistics efficiency and transportation was hampered by the pandemic in most parts of the world. The spread of Covid-19 has created a major economic disruption in the market and is expected to continue to impact utilization rates for most of 2021.

In the short to medium-term it will be challenging to keep solar costs down as prices for some input factors have spiked in the past few months. The cost of solar projects has declined considerably in recent years, but the cost reductions have now started to taper off and move closer to a floor, currently defined by the price of input factors such as labor, polysilicon, silver, copper, aluminum and steel.

These input factors have seen a clear rise in prices in 2020 and 2021. Mono-polysilicon, the key ingredient in photovoltaic panels, rose from $7.6 per kilogram in 2019 to $9 per kg in 2020, and is likely to average $18 per kg in 2021. The price of silver, which is important for the connections from the silicon cell to copper wires, has climbed from $550 per kg in 2019 to $850 per kg (on average) in 2021.

The combined effect of all input factors is that global solar panel prices have gone up 16% so far in 2021 from 2020. The weighted price inflation for solar projects, including labor – from installation and other equipment to construction work, which accounts for an increasing share of overall costs – means that total costs are up 12%, potentially limiting demand growth for the few next years.



Source: Rystad Energy Service Analytics, research and analysis

Learn more in Rystad Energy's Service Analytics.

"The entire industry is experiencing shortages in the supply of raw and auxiliary materials, especially polysilicon and silver. Covid-19-related restrictions have not only created supply shortages of essential raw materials, but have also led to higher prices, resulting in fewer shipments and impacting revenues for industry participants," says Audun Martinsen, Head of Energy Service Research at Rystad Energy.

A reduction in the mineral and metal intensities could be key to increasing the production capacity and addressing the supply chain challenge, Martinsen adds.

In the longer term, the solar industry must increase capacity and continue to fight cost escalation to meet climate change goals. Rystad Energy estimates that to maintain the global temperature increase below 1.5°C, solar panel manufactures should ideally grow 10% annually to meet the needed module production capacity of 1,200-1,400 GW by 2035.

In the past, module capacity has grown at a similar rate, however, with the current supply shortages in essential raw materials like polysilicon, silver and glass, and the price hike in auxiliary raw materials, 10% growth would be a very ambitious target for solar companies. In fact, by 2035, the solar PV industry would have to source seven times more silver than what it does today, when it already consumes 10% of global silver production.

Limiting global warming to 1.7°C instead is a more achievable scenario under the current supply constraints. As there is enough capacity for another eight years, this should give solar companies more time to expand production capacity. To accomplish the 1.7°C scenario, companies should be able to expand production capacity to 1,000-1,200 GW by

2045, while still consuming a large part of silver and polycrystalline, in a time frame that allows supply to adapt.

For more analysis, insights and reports, clients and non-clients can apply for access to Rystad Energy's Free Solutions and get a taste of our data and analytics universe.

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Contacts

http://otp.investis.com/clients/us/jetblue_airways/usn/usnews-story.aspx?cid=981&newsid=77357

JetBlue Accelerates Transition to Sustainable Aviation Fuel (SAF) With Plans for the Largest-Ever Supply of SAF in New York Airports for a Commercial Airline

Released : 09/29/2021

-- JetBlue to Outpace Industry in SAF Usage Based on Percentage of Total Fuel (a), Doubling Its Prior Commitment with SG Preston and On Pace to Achieve 10 Percent SAF Usage Years Ahead of Its Original Target --

-- Sustainability Commitment Goes Beyond Jet Fuel with Conversion of Airport Ground Vehicles to Electric at Newark Liberty International Airport and a Comprehensive LED Lighting Retrofit at New York's John F. Kennedy International Airport --

NEW YORK--(BUSINESS WIRE)-- JetBlue (Nasdaq: JBLU) today announced plans to speed up its transition to sustainable aviation fuel (SAF) with an offtake agreement with SG Preston, a leading bioenergy developer. With the addition of this SG Preston agreement to its previous SAF commitments, JetBlue is well ahead of pace on its target to convert 10 percent of its total fuel usage to SAF on a blended basis by 2030. The airline will reach nearly eight percent SAF usage by the end of 2023 when delivery of SAF under this agreement is expected. JetBlue is doubling its previous SAF commitment with SG Preston, which was first announced in 2016 as one of the largest SAF purchase agreements in aviation history.

JetBlue's agreement with SG Preston also marks a major milestone for SAF in New York's airports. This deal is expected to bring the first large-scale volume of domestically produced SAF for a commercial airline to New York's metropolitan airports. JetBlue will convert 30 percent of its fuel buy across John F. Kennedy International Airport (JFK), LaGuardia Airport (LGA) and Newark Liberty International Airport (EWR) from traditional Jet-A fuel to SAF (b), which is expected to reduce emissions by an estimated 80 percent per gallon of neat SAF, compared to traditional petroleum-based fuels.

Targeting a start in 2023 and continuing over a 10-year period, SG Preston will deliver at least 670 million gallons of blended SAF to JetBlue to fuel its flight operations at JFK, LGA and EWR, helping JetBlue avoid approximately 1.5 million metric tons of CO_2 emissions. JetBlue expects to invest more than $1 billion in purchasing SAF over the term of this agreement, at a price competitive to traditional Jet-A fuel, with no expected material impact to the airline's total fuel costs. This marks the largest-ever announced near-term SAF deal for delivery in the Northeast and will be become the airline's largest single jet fuel contract.

"We are well past the point of vague climate commitments and corporate strategies. Earlier this year, we set specific, dated, and aggressive emissions targets. And now we are physically changing the fuel in our aircraft to meet these commitments," said **Robin**

Hayes, chief executive officer, JetBlue. “At JetBlue, we’re heavily investing in SAF because we see it as our most promising means of rapidly and directly reducing aircraft emissions in the near-term. With this expanded agreement with SG Preston, nearly eight percent of JetBlue’s total fuel use will be SAF, putting us well ahead of pace in reaching our goal of 10 percent SAF usage by 2030.”

Sustainable aviation fuel is jet fuel produced from biological resources that can be replenished rapidly and without impacting food supply. Compared to traditional petroleum-based Jet-A fuel, renewable options can significantly reduce both greenhouse gas emissions and other air pollutants such as particulate matter and sulfur oxides. Safety is JetBlue’s number one priority, and SAF is functionally equivalent to conventional Jet-A fuel, posing no discernible difference in safety or performance. The fuel is fully compatible with existing jet engine technology and fuel distribution infrastructure when blended with fossil jet fuel, and is tested and transported the same way as regular Jet-A fuel.

SG Preston has made significant progress on a new facility in the Northeast to produce SAF at a large scale. SG Preston’s HEFA- (hydro-processed esters and fatty acids) based renewable jet fuel will be sustainably produced from waste fats, oils, greases, and non-food oilseeds. The fuel is expected to receive sustainability certification from ISCC, an independent, global certification body for sustainability and carbon reduction. SG Preston’s process utilizes industry-leading refining process technology, which has been FAA-approved for commercial flying since 2011. This SAF will be blended with Jet-A fuel at an estimated 30 percent blend ratio before being transported to JFK, LGA, and EWR.

“The SG Preston-JetBlue relationship is the blueprint for a balanced partnership designed to achieve both the airline’s and global aviation’s sustainability and pricing goals. The reality of achieving the US sustainability target of approximately 35 billion gallons of sustainable aviation fuel by 2050 is daunting. Engaging with, and addressing the concerns of all key stakeholders and contributors to the solution, is paramount to successfully reaching this target. JetBlue’s continued commitment to SG Preston’s development strategy illustrates continued confidence in our unique approach to this challenge. We’re honored by this demonstration of trust,” said **Randy Delbert Letang, CEO of SG Preston.**

JetBlue’s SAF Strategy

JetBlue’s revised deal with SG Preston is its third agreement for SAF. JetBlue recently entered into a new relationship with World Energy and World Fuel Services and began flying with SAF at Los Angeles International Airport (LAX) in July 2021. Additionally, JetBlue partnered with Neste in August 2020 to fuel its flights from San Francisco International Airport (SFO) with SAF. JetBlue’s SAF strategy was developed with support and consultancy from energy market experts at ICF.

While JetBlue views SAF as the most promising solution to rapidly and directly reduce aircraft emissions in the short and medium term, it is one piece of its larger decarbonization strategy including aircraft efficiency, fuel optimization, sustainable aviation fuel, electric ground operations, technology partnerships and carbon offsetting.

Hayes continued, “We recognize that airlines have a responsibility to decarbonize our operations and usher in an era of truly sustainable travel. We are therefore stepping up as an industry with commitments and clear actions. However, we can’t do it alone. In order for our industry to meet our ambitious targets, we are asking for collaboration and leadership from our key stakeholders – fuel suppliers, aircraft and engine manufacturers, and governments to play a critical role in helping the drive toward net zero.”

JetBlue’s Commitment to Grow Sustainably in New York

New York is JetBlue’s home and where more than 7,000 of its crewmembers live and work. The airline is experiencing significant growth in New York, and furthering plans to substantially increase flying and bring more low fares and jobs to JFK, LGA and EWR as part of its Northeast Alliance with American Airlines. As JetBlue increases its presence and brings more air service to the region’s three airports, it is more important than ever to grow sustainably.

With a focus on more sustainable operations, JetBlue was recently selected for a grant from the New Jersey Department of Environmental Protection’s transportation electrification initiativefor electric ground service equipment (eGSE) at EWR. With this grant, JetBlue will convert 38 ground service vehicles to electric, and install 16 dual-port charging stations, with additional support from the Port Authority of New York and New Jersey. Following this conversion and one in process at Boston Logan International Airport, JetBlue will have converted 39 percent of these three vehicle types to electric. This is significant progress towards JetBlue’s eGSE goal to convert 40 percent of its bag tugs, belt loaders, and pushbacks network wide to electric by 2025, and 50 percent by 2030.

Additionally, JetBlue is making significant updates to T5 by upgrading the entire terminal to LED lighting solutions provided by Brightcore Energy, a premier provider of turn-key energy efficiency projects from lighting to solar, renewable heating & cooling, EV chargers, and battery storage. The T5 upgrades will reduce JetBlue’s lighting-related energy use by approximately 66 percent, based on current usage. The project will have a significant impact, saving more than 2.1 million kWh annually, while improving aesthetics, lowering energy costs and reducing the terminal’s carbon footprint.

“We applaud JetBlue’s commitment to convert 30 percent of its fuel demand from traditional jet fuel to sustainable aviation fuel across the three major New York airports. This latest initiative from JetBlue is a critical step towards accelerating the production and adoption of SAF in the northeast, and achieving the associated environmental benefits in our region,” said **Rick Cotton, Executive Director of the Port Authority of NY & NJ**. “This initiative advances our continued collaboration with JetBlue on important sustainability measures, including energy efficiency upgrades and electrifying ground support equipment at our airports.”

JetBlue's Focus on the Environment

JetBlue depends on natural resources and a healthy environment to keep its business running smoothly. Natural resources are essential for the airline to fly and tourism relies on having beautiful, natural and preserved destinations for customers to visit. The airline focuses on issues that have the potential to impact its business. Customers, crewmembers and community are key to JetBlue's sustainability strategy. Demand from these groups for responsible service is one of the motivations behind changes that help reduce the airline's environmental impact. For more on JetBlue's sustainability initiatives, visit www.jetblue.com/sustainability.

About JetBlue Airways

JetBlue is New York's Hometown Airline®, and a leading carrier in Boston, Fort Lauderdale-Hollywood, Los Angeles, Orlando and San Juan. JetBlue carries customers across the U.S., Caribbean and Latin America, and between New York and London. For more information, visit jetblue.com.

(a) Based on publicly announced deals and volumes, as a percentage of US airlines' 2019 respective total fuel use.

(b) The 30 percent value is based on JetBlue's 2019 fuel usage across JFK, EWR, and LGA. The actual percentage may vary by the date of delivery, based on variations in JetBlue's future fuel requirements.

https://new.abb.com/news/detail/82941/abb-launches-the-worlds-fastest-electric-car-charger

ABB launches the world’s fastest electric car charger

Group press release | Zurich, Switzerland | 2021-09-30

- Can deliver 100km of range in less than three minutes
- Only charger designed explicitly to charge up to four vehicles at once
- Ideal for refueling stations, urban charging stations, retail parking and fleet applications

ABB is today launching an innovative all-in-one Electric Vehicle (EV) charger, which provides the fastest charging experience on the market.

ABB’s new Terra 360 is a modular charger which can simultaneously charge up to four vehicles with dynamic power distribution. This means that drivers will not have to wait if somebody else is already charging ahead of them. They simply pull up to another plug. The new charger has a maximum output of 360 kW and is capable of fully charging any electric car in 15 minutes or less, meeting the needs of a variety of EV users, whether they need a fast charge or to top their battery up while grocery shopping.

“With governments around the world writing public policy that favors electric vehicles and charging networks to combat climate change, the demand for EV charging infrastructure, especially charging stations that are fast, convenient and easy to operate is higher than ever,” said Frank Muehlon, President of ABB’s E-mobility Division. “The Terra 360, with charging options that fit a variety of needs, is the key to fulfilling that demand and accelerating e-mobility adoption globally.”

“It’s an exciting day for ABB, who as the global leader in electric vehicle fast charging, is playing a key role in enabling a low carbon society,” said Theodor Swedjemark, Chief Communications and Sustainability Officer at ABB. “With road transport accounting for nearly a fifth of global CO2 emissions, e-mobility is critical to achieving the Paris climate goal. We will also lead by example by switching our entire fleet of more than 10,000 vehicles to non-emitting vehicles.”

Available in Europe from the end of 2021, and in the USA, Latin America and Asia Pacific regions in 2022, Terra 360 is designed with the daily needs and expectations of EV drivers in mind. Leveraging the rich field experience gained by ABB E-mobility’s large installed base, the Terra 360 delivers speed and convenience along with comfort, ease-of-use and a sense of familiarity.

As well as serving the needs of private EV drivers at fueling stations, convenience stores and retail locations, Terra 360 chargers can also be installed on an organization’s commercial premises to charge electric fleet cars, vans and trucks.

Its innovative lighting system guides the user through the charging process and shows the State of Charge (SoC) of the EV battery and the residual time before the end of an optimal charge session. The world’s fastest EV charger is also wheelchair accessible and features an ergonomic cable management system that helps drivers plug in quickly with minimal effort.

As well as serving the needs of private EV drivers at fueling stations, convenience stores and retail locations, Terra 360 chargers can also be installed on an organization’s commercial premises to charge electric fleet cars, vans and trucks. This gives owners the flexibility to charge up to four vehicles overnight or to give a quick refill to their EVs in the day. Because Terra 360 chargers have a small footprint, they can be installed in small depots or parking lots where space is at a premium.

Terra 360 chargers are fully customizable. To personalize the appearance, customers can ‘brand’ the chargers by using different foiling or changing the color of the LED light strips. There is also the option to include an integrated 27” advertisement screen to play video and pictures.

ABB is a world leader in electric vehicle infrastructure, offering the full range of charging and electrification solutions for electric cars, electric and hybrid buses, vans, trucks, ships and railways. ABB entered the e-mobility market back in 2010, and today has sold more than 460,000 electric vehicle chargers across more than 88 markets; over 21,000 DC fast chargers and 440,000 AC chargers, including those sold through Chargedot.

ABB high-power chargers are already being deployed around the world through the company’s partnerships with international charging operators such as IONITY and Electrify America.

To explore ABB’s electric vehicle charging technology, visit www.abb.com/ev-charging.

ABB (ABBN: SIX Swiss Ex) is a leading global technology company that energizes the transformation of society and industry to achieve a more productive, sustainable future. By connecting software to its electrification, robotics, automation and motion portfolio, ABB pushes the boundaries of technology to drive performance to new levels. With a history of excellence stretching back more than 130 years, ABB’s success is driven by about 105,000 talented employees in over 100 countries. www.abb.com

Dan Tsubouchi @Energy_Tidbits · 5h

Iran's response to @SecBlinken that #JCPOA "ball remains in their court but not for long". @Amirabdolahian tells the US here is the ask if want to get back now to JCPOA negotiating table - release the $10b of frozen money. Thx @AbasAslani. #OOTT

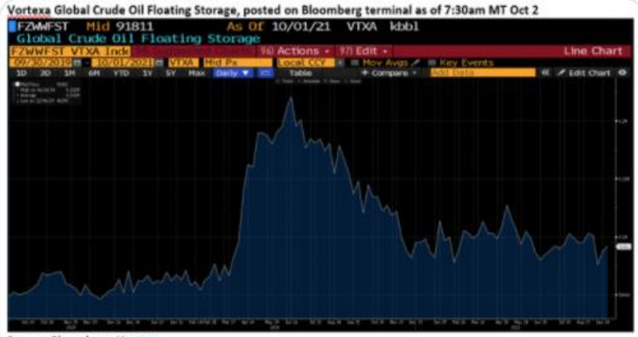
> **Abas Aslani** @AbasAslani · 19h
>
> #Iran FM @Amirabdolahian: Americans tried to contact us in New York through various channels, and I told the intermediaries that if the US had serious intentions, it should issue a serious signal. The serious sign is releasing at least $ 10 billion of Iranian frozen money.
> #JCPOA
>
> Show this thread

3 1

Dan Tsubouchi @Energy_Tidbits · Oct 2

#Vortexa crude oil floating storage for 10/01 est 91.81 mmb. Note 09/24 of 87.45 mmb was revised +13.8 mm vs 09/24 est posted 3pm MT on 09/25. Revisions mean #OPEC+ #Oil increases since June 1 not being fully absorbed as 06/25 trough was 80.04 mmb Thx @Vortexa @TheTerminal #OOTT

Vortexa Global Crude Oil Floating Storage, posted on Bloomberg terminal as of 7:30am MT Oct 2

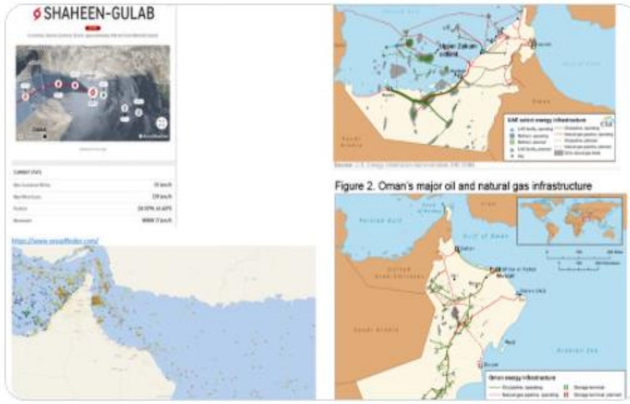


Source: Bloomberg, Vortexa

1 1

Dan Tsubouchi @Energy_Tidbits · Oct 2

Looks like #Shaheen is impacting tankers/ships. @accuweather est 69 mph. forecast to strengthen (assume to reach equivalent US hurricane cat 1 of 74 mph) before weakening at landfall in Oman, looking north of Oman oilfields. #OOTT Thx @VesselFinder



3 1

Dan Tsubouchi @Energy_Tidbits · Oct 1

just looked up from the screen to catch the last of the local #Camore elk going down to join the rest of the gang down by the Bow River on a great sunny morning in the Cdn Rockies

7

Dan Tsubouchi @Energy_Tidbits · Oct 1

typo, don't know how i screwed it up. emergence of US oil producing industry in 1860's, not 1980s. that is what killed whale oil for energy. thx @DavidLYager #OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Oct 1
>
> Wasn't the decline in whale oil demand as energy because of the emergence of a more reliable, available cheaper energy source - fuel oils such as kerosene that came with the rapid emergence of US oil producing industry in 1980s? note full thread. #OOTT #EVs #PeakOilDemand twitter.com/CathieDWood/st...
>
> What a terrible call. Oil is nearly $70 & likely heading above $100. Supply shortage and demand is soaring.
>
> This call rivals only @JosefSchachter for missing out on one of the best trades in North America.
>
> Canadian Energy names up 400-600% since this call.
>
> 8:35 PM · Sep 30, 2021 · Twitter for iPhone
>
> 105 Retweets 39 Quote Tweets 796 Likes
>
> Tweet your reply Reply

1 1 1

Dan Tsubouchi @Energy_Tidbits · Oct 1

No near term relief likely from #NordStream2. "certification of the pipeline, according to all that I know, will definitely be so late that this pipeline will no longer help us this winter" says @uniper_energy CEO. Support for #LNG #NatGas prices. #OOTT

handelsblatt.com/unternehmen/en...

> **Dan Tsubouchi** @Energy_Tidbits · Sep 13
>
> Europe better hope its not a cold start to winter. @business @bjennen1 report DE regulator BNA now has 4 mths to review on 5.3 bcfd #NordStream2 certification. Given high profile, hard to see a quick rubber stamp. if so, NS2 won't bring near term relief to #NatGas #LNG prices

6 4

Dan Tsubouchi @Energy_Tidbits · Oct 1

Wasn't the decline in whale oil demand as energy because of the emergence of a more reliable, available cheaper energy source - fuel oils such as kerosene that came with the rapid emergence of US oil producing industry in 1980s? note full thread. #OOTT #EVs #PeakOilDemand

> What a terrible call. Oil is nearly $70 & likely heading above $100. Supply shortage and demand is soaring.
>
> This call rivals only @JosefSchachter for missing out on one of the best trades in North America.
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>
> 8:35 PM · Sep 30, 2021 · Twitter for iPhone
>
> 105 Retweets 39 Quote Tweets 796 Likes
>
> Tweet your reply
>
> Reply

> **Cathie Wood** @CathieDWood · Sep 30
>
> According to the EIA, global oil demand peaked at 101 million barrels per day (mbd) in 2019, dropped to 92 mbd during the coronavirus crisis in 2020, and has rebounded to 97 mbd in 2021. Based on our forecast for EV sales, @ARKInvest believes that oil demand has peaked. twitter.com/BubleQe/status...
>
> Show this thread

6 1 13

Dan Tsubouchi @Energy_Tidbits · Sep 30

Why don't press remind @jrpsaki US #shale #Oil can ramp up quickly with capital when she says "obviously the price of oil is of concern, we have been in touch with OPEC, and I believe it was going to be raised" in US/KSA meet? Is US offering KSA something linked to Iran? #OOTT

2 4

Dan Tsubouchi @Energy_Tidbits · Sep 30

Potential game changer for #EVs? @ABB_EVCharging's new Terra 360 can deliver 100 km range in <3 min, "designed explicitly" to charge up to 4 vehicles at once. no cost disclosed, but would be as fast as filling up an ICE. #OOTT

ABB launches the world's fastest electric car charger
new.abb.com

3 2 2

Dan Tsubouchi @Energy_Tidbits · Sep 30

1/2. hugely bullish #LNG #NatGas for 2020s. @SonaliPaul2 reports "we've taken up our estimate of the required installed base of #LNG by 2030 up to 800 million tonnes" & need to bring on 100-150 mtpa in the next few years says @bakerhughesco @simonelli_l. can't be done ... #OOTT

Baker Hughes sees strong prospects for gas in the transition to cleaner energy, with LNG combined with carbon capture and storage helping to reduce the industry's carbon footprint.

"We've taken up our estimate of the required installed base of LNG by 2030 up to 800 million tonnes," Chairman and Chief Executive Officer Lorenzo Simonelli said at the Platts APPEC 2021 conference.

As of 2020, there was about 345 million tonnes of LNG capacity.

Baker Hughes' forecast compared with consultants Wood Mackenzie's forecast that the world will need 250 million tonnes in new LNG supply by 2040.

"We see a steady stream of final investment decisions and projects happening both in North America as well as internationally to really bring on between 100 and 150 million tonnes in the next few years as we go forward," Simonelli said.

Another potential boost for the oil and gas industry he said could come from demand for non-metallic pipes, which would increase demand for petrochemicals to make those pipes.

1 9 15

Dan Tsubouchi @Energy_Tidbits · Sep 30

2/2. think of massive demand pull for 2020s on #LNG #NatGas. Vs @GIIGNL liquefaction capacity 454 mtpa, that's growth of 346 mtpa (45 bcfd) to 2030. #Renewable can't fill in fast enough, will need #Coal for longer for reliable power. #EnergyTransition will be very expensive #OOTT

1 4

Dan Tsubouchi @Energy_Tidbits · Sep 30

"unprecedented supply chain challenges have been impacting the industry pervasively, and we saw steeper cost inflation escalating by month, especially later in the quarter" $BBBY in just out Q2. Stock -29% on open. not my energy focus but couldn't miss this open.

1

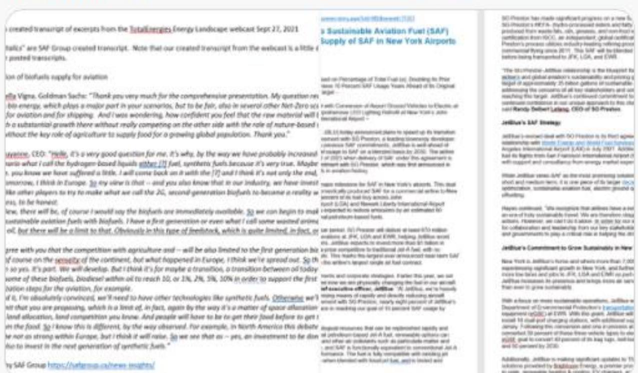
Dan Tsubouchi @Energy_Tidbits · Sep 29

#Caixin China PMI out at 7:45pm MT. Sept 50.0 vs est 49.5, vs 49.2 in Aug. "business conditions across China's manufacturing sector stabilised in September, after a slight deterioration in August." Aug was 1st contraction since Apr 2020. Thanks @IHSMarkitPMI #OOTT

1 1

Dan Tsubouchi @Energy_Tidbits · Sep 29

#SAF (Sustainable Aviation Fuel, not our SAF Group) news from @JetBlue. Yes, SAF reduces aviation emissions, but note @PPouyanne warning on 1st Generation #Biofuels supply "which is quite limited, in fact on the planet". #EnergyTransition will take longer than expected #OOTT



1 3

Dan Tsubouchi @Energy_Tidbits · Sep 29

Is this the 2020s scramble for #Oil supply? @JoeBiden asks OPEC for help, not TX, ND, AB. so busy on got to go faster to #NetZero scenario, didn't run scenario for impact of squeezing capital to #Oil #NatGas supply & no longer a big Covid demand hit? #OOTT

White House sounds alarm about rising gasoline pr...
The Biden administration continues to engage with OPEC producers and look "at every means we hav...
spglobal.com

2 2 14

Dan Tsubouchi @Energy_Tidbits · Sep 29

For those not at their laptop, @EIAgov weekly #Oil #Gasoline #Distillates inventory data as of Sept 24 was just released. Prior to release, WTI was $75.09. #OOTT

ir.eia.gov/wpsr/overview....

Oil/Products Inventory Sept 24: EIA, Bloomberg Survey Expectations, API

(million barrels)	EIA	Expectations	API
Oil	4.58	-2.15	4.13
Gasoline	0.19	1.50	3.56
Distillates	0.38	-1.40	2.48
	5.16	-2.05	10.17

Note: In addition, there was 0.9 mmb draw from SPR for Sept 24 week

Note: Included in the data, Cushing had a build of 0.13 mmb for Sept 24 week

Source EIA, Bloomberg

Prepared by SAF Group

4

Dan Tsubouchi @Energy_Tidbits · Sep 29

Key indicator for strong #LNG #NatGas thru 2020s. @qatarpetroleum 15-yr supply 0.5 bcfd w/ China #CNOOC. See SAF blog ""Asian LNG Buyers Abruptly Change and Lock in Long Term Supply – Validates Supply Gap, Provides Support For Brownfield LNG FIDs" #OOTT safgroup.ca/news-insights/

SA ?NType=News

Blog Summary

; Buyers Abruptly Change and Lock in Long Term Suppl
Supply Gap, Provides Support For Brownfield LNG FIDs

day, July 14, 2021 at 10:00 MT

For Details, Please See The 6 Page Blog

ly 3.5 MTPA of LNG to China's CNOOC

entered into a long-term sale and purchase agre
hore Oil Corporation (CNOOC), for the supply of 3

Excellency Mr. Saad Sherida Al-Kaabi, the Minist
nan of CNOOC.
r Al-Kaabi said, "We are pleased to further buil
We are especially proud to continue to meet the P
; for partnering with us as their trusted LNG suppl
ikh Khalid bin Khalifa Al Thani, the CEO of Qatar
nt with CNOOC.
tember 2009 when the first LNG cargo was delive
; LNG cargoes to China, of which 270 cargoes (

2 1

Dan Tsubouchi @Energy_Tidbits · Sep 28

NIMBY is why #EnergyTransition will take way longer. @PPouyanne stresses challenge to get approvals for assumed massive immediate ramp up in #Wind #Solar power. Its why #NatGas will be needed for power & be stronger thru 2020s & beyond. Lots in @TotalEnergies investor day. #OOTT

every year over the next 30 years, the world has to add all of the existing installed solar capacity Over all of the existing installed wind capacity because those two bases are actually very close. This will also require, of course massive storage solution, again be they battery based or green hydrogen or some other new technology that will be invented".

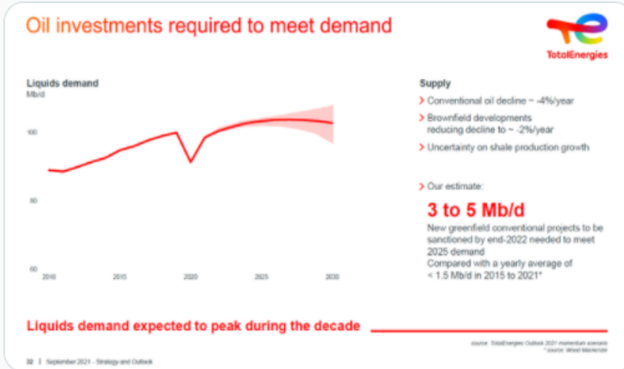
A key underlying issue/challenge for wind/solar is that it takes up way more space to produce energy. In their prepared remarks, mgmt said *"Footprint of different energies is also to be considered. The footprint is linked to the density of the energies and to their engineering characteristics, which in the end, boils down to planned production yield. It's illustrated here in terms of square meters of land needed to power a 100-watt flat TV screen. You don't see oil on the chart because it's not really a good way to use oil to produce power. So hydro, of course is a little specific because it's not at all modular. But what you can see here that for the same amount of power, the land use required for wind or solar is way way bigger than the square meters needed for a coal power plant, a nuclear power plant or a gas power plant. This is a way of showing why there are acceptability issues linked to wind and solar, not everywhere, but in Europe, for instance, it is a mounting issue that has to be overcome."*

Then on overcoming NIMBY (they don't use the term NIMBY) issues that cause delays for approvals. In the Q&A, mgmt is asked about overcoming local opposition to wind and solar projects in France, and replies *"The problem is not only in France. I think by the way you have issues with communities because it's a question again of land use. In fact, you have competition for use, and you have people. It's not only in France, by the way we observed the same, exactly the same problem in Germany, in Italy, by the way. And we begin to observe it in Spain as well. So I think the reality is that Europe is, I would say is a humanized civilization. And we have a density of population, which compared to many other countries like the U.S. or Australia, for example." "China" "Which is much, much, we are much more dense. So I'm not surprised, and it's why I was insisting that it's a question of scarcity above surface for renewables. So that has to be taken into account. I read there was a study. It's an interested study, which has been published in Italy by the Ambrosetti Foundation. We try to translate this. The target that the European Commission has assigned by 2030, 40% of renewable in our mix in terms of. they made a study how long could it take to get through all the administrative process to build*

1 3 9

Dan Tsubouchi @Energy_Tidbits · Sep 28

Yes @TotalEnergies said #Oil #PeakDemand in middle of decade. But webcast didn't give mmbd numbers and graph looks like oil demand >pre covid in 2025 & also still >pre covid in 2030. mgmt did say need 3-5 mmbd greenfield to meet 2025 demand. Positive for #Oil in 2020s #OOTT



1 3 8

Dan Tsubouchi @Energy_Tidbits · Sep 28

Positive for #LNG, continued tight supply thru at least 2026. @TotalEnergies Mozambique LNG delay at least 2 yrs, today shows 2026 start vs original 2024. Violence delayed 5 bcfd of Mozambique LNG in total, see SAF Group Apr 28/21 blog safgroup.ca/news-insights/ #NatGas #OOTT

5 11

Dan Tsubouchi @Energy_Tidbits · Sep 27

Don't see how can "invest all this trillion dollars to change fundamentally our energy system without an impact at the end of the customers" @PPouyanne on reality that the #EnergyTransition will cost more than govts are admitting. Attn @JoeBiden @JustinTrudeau #NatGas #OOTT

SAF Group created transcript of portion of Q&A from TotalEnergies "Energy Landscape & TotalEnergies Energy Outlook 2021" webcast on Sept 27, 2021. https://edge.media-server.com/mmc/p/8qtcrdyh

Items in "*italics*" are SAF Group created transcript.

Question: "*Are you concerned about the affordability of this transition for the consumer, even in the rich countries, especially as we need to rely on gas as a transition fuel?*"
CEO Patrick Pouyanne "*The question more fundamentally that you have asked for me is, I mean and you know that I'm trying to repeat it regularly in different conferences to, as a wake-up call to all the policymakers, but there is no, no miracle you know. We speak about a huge amount of investment. We speak about trillions and trillions of dollars. I don't see how people could think that we'll be able to invest all this trillion dollars to change fundamentally our energy system without an impact at the end of the customers. you know, even if we amortize these investments on 20 years, that's a lot of new investments, more, but what we do normally in the previous year. So if you invest more somewhere, it will have to be reflected in the cost. It's for the customers. So there is no reason not to -- I don't know why people don't want to accept it. That's, of course for governments, for policymakers, that's a major question.*"

Prepared by SAF Group https://safgroup.ca/news-insights/

3 8

Dan Tsubouchi @Energy_Tidbits · Sep 27

"question in this transition is not to think that we can change the pattern of demand by constraining the supply. if we just do that, we'll have a huge spike in the price [#Oil] & a huge instability, a social instability on this planet" @PPouyanne. Attn POTUS, 🇨🇦PM 🇬🇧PM #OOTT

a key difference is the trajectory to get there. And of course, this has the main consequence of one of the spectacular conclusion which has been drawn by some of the IEA scenario, which is to say you must stop investing in oil and gas new investments because. Yes its true by the way, if you want to, is that demand is only 70 million barrels of oil per day in 10 years, which means a decrease of 3% per year, no need to invest much in the next 10 years in new projects but its not the supply will create demand, its not true, the demand is still 90 million like we anticipate by 2030, and not 70, if we produce only 70, the price will be at the roof, and more than at the roof. So maybe it's a good scenario for TotalEnergies and it shareholders, I am not sure it's a good scenario for all the customers and citizens of the planet. so that's why, to be clear, as ? reminded you, and you know very well Chris I think, and our auditors, if we do not invest we have a natural decline of 3 to 4%, and then we'll have a lack of supply. so according to our trajectory by 2030, we are more around 90 million that means we need to continue to invest in some oil and gas fields if we want to meet the demand. So, again the question in this transition, is not to think that we can change the pattern of demand by constraining the supply. if we just do that, we'll have a huge spike in the price and a huge instability, a social instability on this planet. So we cannot do that."

From well-below 2°C to 1.5°C
Selected impacts of Rupture+ sensitivity

6 16

Dan Tsubouchi @Energy_Tidbits · Sep 27

couldn't miss seeing besides my screen the local #Calgary deer enjoying a great morning along the Elbow River.

9

Dan Tsubouchi @Energy_Tidbits · Sep 27

"Operators must devote additional capital towards new drills (soon) or risk a slow, but sure, decline in [#Oil] production. Will also impact Associated #NatGas outlook. DUCs need to be replenished soon. Positive for Oil. Thx @RaymondJames John Freeman, NickPocrnic. #OOTT

What is the optimal amount of DUC inventory? How close are we too it now?

As we mentioned above, there is a normal state of DUC inventory required for E&Ps to optimize operations and lower overall well costs. As such, the appropriate standard to judge the appropriate level of DUCs is "months of inventory" or the amount of time completions could continue unheeded without additional wells being drilled. As shown in the chart to the right, the "normal" level of DUC inventory has increased from around two-three months of drilling inventory to a "new normal" of between six and seven months worth of inventory over the past five years. Again, this step change in the right level of DUC "days of inventory" is largely due to 1) more pad drilling; 2) more wells per pad; and 3) the need for maximum frac crew hours pumped without waiting on well delays. Keep in mind that any delay a frac crew encounters due to a low backlog of wells to be completed creates

Source: EIA, Raymond James Research

massive cost inefficiencies. Because of this, today's operators are working more closely than ever with dedicated frac crews to maximize the

2 2 20

Dan Tsubouchi @Energy_Tidbits · Sep 27

Need to read carefully. enlightens, insights, etc. but @TotalEnergies doesı say this is what they use for capital allocation decisions. so the question i what does @TotalEnergies use for #Oil #NatGas peak demand & price forecast for capital allocation. #OOTT

1 2

Dan Tsubouchi @Energy_Tidbits · Sep 26

Our weekly SAF Sept 26, 2021 Energy Tidbits memo was just posted to our SAF Group website. This 47-pg energy research piece expands upon and covers many more items than tweeted this week. See the research section of the SAF website #Oil #OOTT #LNG #NatGas safgroup.ca/news-insights/

Welcome to new Energy Tidbits memo readers. We are continuing to add new readers to our Energy Tidbits memo, energy blogs and tweets. The focus and concept for the memo was set in 1999 with input from PMs, who were looking for research (both positive and negative items) that helped them shape their investment thesis to the energy space, and not just focusing on daily trading. Our priority was and still is to not just report on events, but also try to interpret and point out implications therefrom. The best example is our review of investor days, conferences and earnings calls focusing on sector developments that are relevant to the sector and not just a specific company results. Our target is to write on 48 to 50 weekends per year and to post by noon mountain time on Sunday.

This week's memo highlights:

1. Trafigura sees $100 oil, 50% less capex in oil & gas vs renewables yet oil & gas is 10x as of much of energy mix. (Click Here)
2. Vitol CEO sees high gas prices driving an extra 0.5 mmb/d oil demand this winter. (Click Here)
3. Looks like increasing geopolitical risk to Libya's oil production as Haftar plans to run for President. (Click Here)
4. Hard to see how real negotiations on JCPOA start soon after watching NBC interview with new Iran foreign minister. (Click Here)
5. Added 2.0 bcf/d draw in 2022 on US gas supply as feedgas to soon start for Sabine Pass Train 6 at 0.7 bcf/d and Calcasieu Pass 1.3 bcf/d. (Click Here)
6. Please follow us on Twitter at [LINK] for breaking news that ultimately ends up in the weekly Energy Tidbits memo

4 3