Energy Tidbits

RWE CEO “Worst-Case Scenario for the Energy Transition” as Offshore Wind Projects in EU and US have been Stopped

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September 3, 2023

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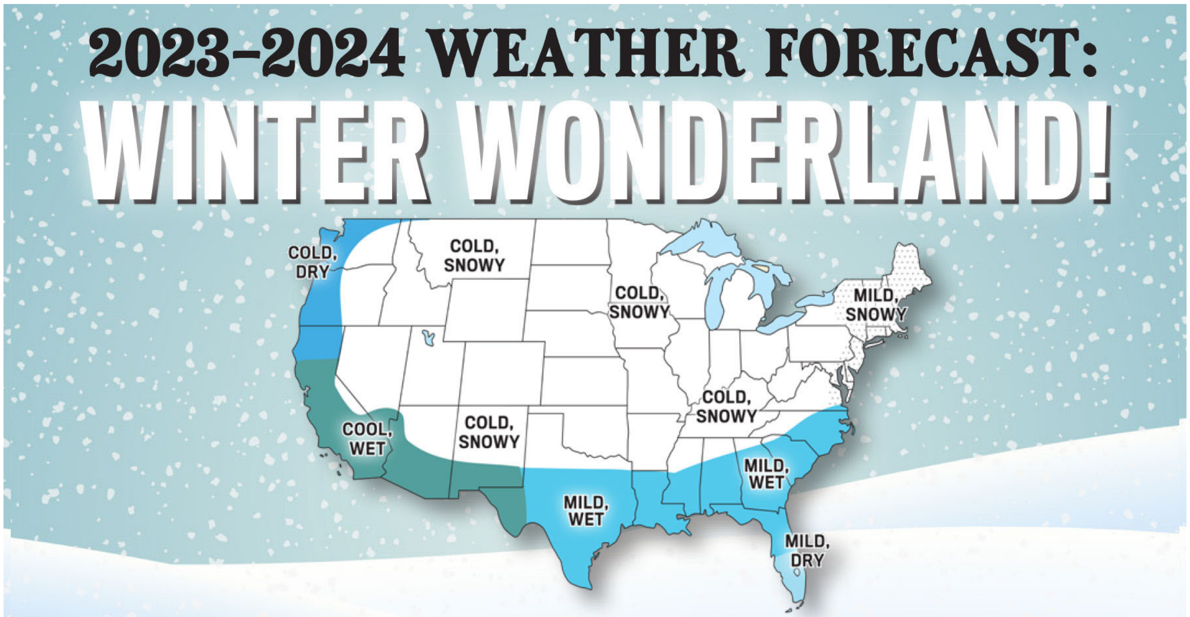
https://www.almanac.com/winter-extended-forecast-farmers-almanac

The Old Farmer's Almanac Winter Forecast 2023–2024

Get Ready for a Winter Wonderland!



The 2024 Old Farmer's Almanac is **now available** everywhere from sea to shining sea! With our official debut, we can unveil the complete **2023–2024 winter weather forecast**! We'll share the General Weather Report and Forecast for the U.S. as well as all 18 regional summaries, including the final reveal of the East Coast regions, Alaska, and Hawaii.

Also, see our Canadian winter forecast here!

The Old Farmer's Almanac 2023-2024 Winter Forecast

Here at the *Almanac,* we are long-term planners and prognosticators! Winter arrives this year on December 21, 2023. On the winter solstice, those of us who live in the Northern Hemisphere are tilted as far away from our Sun as possible. Winter brings cooler weather, the joy of winter sports, curling by the fire, and the holiday spirit. It also brings shoveling, snowblowing, dealing with bad roads, and sometimes unbearable temperatures. What will winter bring this year??

A WINTER WONDERLAND!

The 2024 Old Farmer's Almanac predicts snow, seasonable cold, and all of winter's delights! This winter's forecast is sure to excite snow bunnies and sweater lovers alike, promising a whole lot of cold and snow across North America!

Snowfall will be above normal across most snow-prone areas (except for the Pacific Northwest). Get prepared for oodles of fluffy white throughout the season! Keep a shovel at the ready early, especially in the Northeast and Midwest, where snow will arrive beginning in November with storms, showers, and flurries continuing through the start of spring.

Along with above-normal snow, we'll see **normal to colder-than-normal temperatures** in areas that typically receive snow. Expect just the right amount of chill in the air for an afternoon of adventurous snow sports or enjoying a big ol' mug of hot cocoa by a crackling fire. Only snowy New England and the Atlantic Corridor will enjoy winter temperatures which are milder than what's typical for their regions.

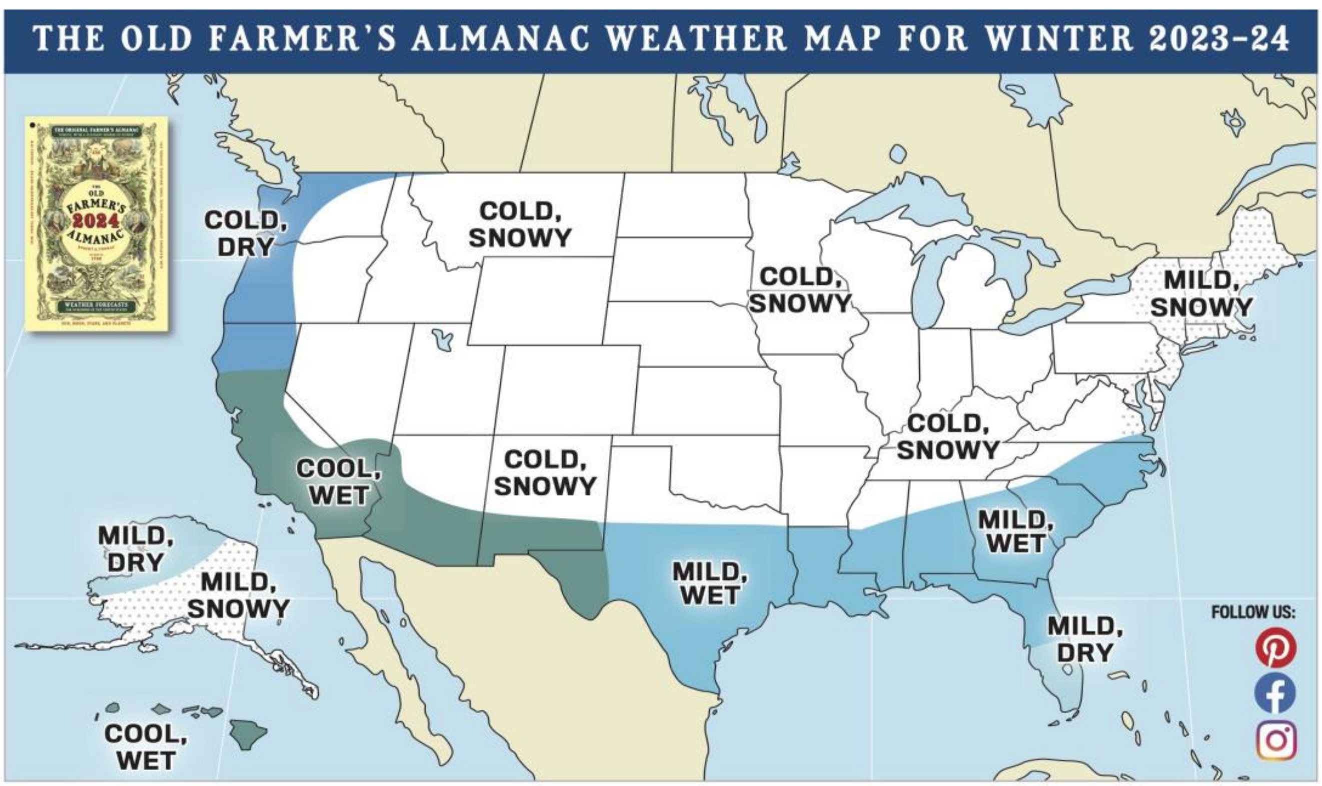
REFRESHING RELIEF

Wetter-than-usual weather is coming to the southern portions of the Deep South, Texas, and California, with potentially drought-quenching rain. As the winter map shows, much of the U.S. coastline, from New England down to Florida across the Gulf Coast to the Pacific Southwest will experience mild to cool temperatures.

SWEATER WEATHER

This is the theme for the coastline of the Pacific Northwest, which will be relatively dry and cold throughout the season. While storm clouds will typically deliver rain, snow is possible for late December and mid-January.

***The Old Farmer's Almanac*, which has been issuing its 80 percent–accurate forecasts since 1792, can be found** anywhere books and magazines are sold **starting on August 29, 2023.**



THIS ILLUSTRATION IS AVAILABLE TO DOWNLOAD FOR PUBLICATION AT ALMANAC.COM/MEDIA.

What Influences This Winter Forecast

We are approaching the middle of Solar Cycle 25, which is increasing in its intensity and already as strong as Solar Cycle 24, which possibly had the lowest solar activity in about 200 years. Such low activity has historically meant cooler-than-average temperatures across Earth, but this connection has become weaker since the last century.

The expected El Niño has emerged and should gradually strengthen into the winter. El Niño is a natural climate phenomenon marked by warmer-than-average sea surface temperatures in the Pacific Ocean. Typically, El Niño conditions result in wetter-than-average conditions from southern California to along the Gulf Coast and drier-than-average conditions in the Pacific Northwest. We also expect a warm Atlantic Multidecadal Oscillation (AMO) and cool Pacific Decadal Oscillation (PDO). Also important are the equatorial stratospheric winds involved in the Quasi-Biennial Oscillation, or QBO.

Under certain combinations of meteorological conditions, the polar vortex can be displaced from the North Pole, which could open the door for cold blasts to hit southern Canada and the central and eastern United States during this upcoming winter.

Regional Forecasts

Look below for the regional forecast summaries for the 18 U.S. regions. You can find weekly details for all 12 months of the year in *The 2024 Old Farmer's Almanac*.

Region 1: NORTHEAST

Will There Be Snow?
Yes! Precipitation and snowfall will be above normal. The snowiest stretches occur in mid-to late November, mid-December and early to mid-January. There will be a white Christmas in the mountains, but it's less likely in the foothills and along I-95.
How Cold Will Winter Be?
Winter temperatures will be above normal. The coldest periods will occur in mid- to late November, early to mid-January, and early to mid-February.

Region 2: ATLANTIC CORRIDOR

Will There Be Snow?
Yes! Winter precipitation and snowfall will be above normal (2 to 3 inches above monthly averages). The snowiest periods will occur at the end of December, late January, and mid-February. We don’t expect a white Christmas.
How Cold Will Winter Be?
Winter temperatures will be above normal overall. Specifically, December is slightly above average temps; temperatures for January and February are below average. The coldest spell will run from late January into mid-February.

Region 3: APPALACHIANS

Will There Be Snow?
Expect above-normal precipitation and snowfall. The snowiest spells will occur in late December, mid- to late January, and early to mid-February. We expect a white Christmas in the higher terrain of West Virginia in the north, but not elsewhere in the region.
How Cold Will Winter Be?
Winter temperatures will be below normal overall. December temperatures are just 1 degree below

average; January and February temperatures are 3 to 4 inches below average, respectively. The coldest period will run from early January through mid-February.

Region 4: SOUTHEAST (Region 4)

Precipitation:
We expect a wet winter with above-normal precipitation and snowfall for the Southeast (most of North Carolina, South Carolina, and Georgia). The best chances for snow occur in late January and mid-February. We do not expect a white Christmas.

Temperature:
Unlike much of the U.S., the Southeast will have a mild winter with above-normal temperatures overall. The coldest periods will arrive in late December and early and mid-February.

Region 5: FLORIDA

Precipitation
Winter rainfall will be above normal for most of Florida, so expect a wet winter along with those mild temperature. The southern end of Florida will be drier-than-normal but remember that's all relative in a tropical climate! We don't expect a white Christmas.

Temperature
Florida's winter temperatures will be milder than normal this year—great news for all those snowbirds! The coolest temperatures occur in late December, late January, and early February.

Region 6: LOWER LAKES

Will There Be Snow?
Snowfall will be above normal, with the snowiest periods will occur in late December through most of January and in mid-February. There will be a white Christmas from New York westward to Wisconsin, but it's not as likely south of I-90.
How Cold Will Winter Be?
Winter will be colder than average for the Lower Lakes. The coldest periods will fall in early and late December and from January all the way through mid-February.

Region 7: OHIO VALLEY

Will There Be Snow?
We'll see above-normal precipitation and snowfall overall. The snowiest periods will be in late December through mid-January and late January through mid-February. Christmas week may be mild but snow's expected in much of the region that week!
How Cold Will Winter Be?
Winter will be colder than normal. The coldest spells will occur in late December, early January, and late January through mid-February.

Region 8: DEEP SOUTH

Precipitation
Precipitation will be above normal, coming mainly in the form of rain given temperatures in the mid- to high ’40s. The highest threats of snow in the north are in mid- and late January and mid-February. We do not expect a White Christmas.

Temperature
Winter will be colder than normal in the north and warmer than normal in the south, with the coldest periods in late December, early January, late January, and early February.

Region 9: UPPER MIDWEST

Will There Be Snow?
Precipitation in the form of snowfall will be above normal. The snowiest periods will be in late November, mid- to late December, mid-January, and early February. Expect a white Christmas this year!
How Cold Will It Get?
Winter temperatures will be below normal, with average temperatures in January and February of 8°F. The coldest periods fall in mid- to late November, most of December, early and late January, and early February.

Region 10: HEARTLAND

Will There Be Snow?
Precipitation and snowfall will be slightly above average. The snowiest period will occur late December and early to mid-January. Expect a white Christmas this year!

How Cold Will It Get?
Winter will be colder than normal. The coldest periods fall in early and late December, early and late January, and early February.

Region 11: TEXAS-OKLAHOMA

Will There Be Snow?
Precipitation is leaning above normal; it is not extreme. The best snow chances are in the north in late December and late January. We do not expect a white Christmas across the region, though possible snow in the north.

How Cold Will Winter Be?
winter will be colder than average in the northern part of the region. In the south, temperatures will be slightly milder than normal. The coldest periods will occur in early and late December, early and late January, and mid-February.

Region 12: HIGH PLAINS

Will There Be Snow?
Precipitation and snowfall will be slightly above normal, with the snowiest periods in late November, mid-December, and mid-January. There will be a white Christmas, but mainly north of I-70.

How Cold Will Winter Be?
But it will be extra cold! Winter temperatures are well below average overall, with the coldest periods in late November, late December, and early to mid-January, as well as early February in the north only.

Region 13: INTERMOUNTAIN

Will There Be Snow?
Yep, it’s a whiteout! We’re looking at above-normal snowfall. The snowiest periods will be in mid- to late November, early and late January, and mid-February. Expect a white Christmas!

How Cold Will Winter Be?
Winter will be colder than normal in December (4° below average) and January (4° below average), although February will be just slightly below average. The coldest periods will be in early and late November, late December, and late January.

Region 14: DESERT SOUTHWEST

Precipitation
Precipitation will be above normal, as will snowfall in most areas that normally receive snow. The snowiest periods are expected to occur in mid- to late January and mid-February. There will be a white Christmas in the highest terrain of central Arizona, but not elsewhere in the region.

Temperature
Overall, in the Desert Southwest region, we’re looking at a winter that’s cooler than normal. The coldest periods will be in late November, early and late December, and late January.

Region 15: PACIFIC NORTHWEST

Will There Be Snow?
Though famous for its consistently heavy precipitation, our forecasts for the Northwest call for a drier-than-normal winter, thanks largely to this year's winter El Niño. The snowiest periods will occur in mid- to late December and mid-January. Expect a white Christmas across the mountains and foothills, but not along coastal locations.

How Cold Will Winter Be?
Winter temperatures will be colder than normal. The coldest periods will occur in mid-November, late December, and mid-January.

Region 16: PACIFIC SOUTHWEST

Precipitation
A strong El Niño means winter will be wetter than normal, with above-normal mountain snow. The stormiest, wettest periods will be in early and late January, early to mid-February, and mid-March. There will be a white Christmas across the Sierra Nevada mountains, but not in the valleys or along the coast.

Temperature
Winter will be colder than normal throughout the region. The coldest temperatures will occur in early and late November, early and late December, and late January.

Region 17: ALASKA

Precipitation
This winter, precipitation will be slightly below normal. Snowfall will be normal to slightly above normal, with the snowiest periods in late November, mid-December, mid- to late January, and early March. Expect a white Christmas!

Temperature
Winter temperatures will be milder than normal in Alaska overall. Specifically, temperatures are 4° above average in December, 5° above in January, and 3° below in February. The coldest periods occur in mid-December, late January, and early to mid-February.

Region 18: HAWAII

Precipitation
Rainfall will be above normal this winter season. Expect the stormiest periods in early November in the east and early January and mid-February throughout. Who needs a white Christmas when you have that aloha spirit?

Temperature
Winter temperatures will be slightly milder than normal in Hawaii. The coolest periods will fall in mid-December through early January and early February.

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How Does the Almanac Predict the Weather?

By tradition, *The Old Farmer's Almanac* employs three scientific disciplines to make long-range predictions: solar science, the study of sunspots and other solar activity; climatology, the study of prevailing weather patterns; and meteorology, the study of the atmosphere. We predict weather trends and events by comparing solar patterns and historical weather conditions with current solar activity. Our forecasts emphasize temperature and precipitation deviations from averages, or normals. These are based on 30-year statistical averages prepared by government meteorological agencies. Read more about how we predict the weather.

How Accurate Are *The Old Farmer's Almanac's* Forecasts?

Every year, we publish the results with a full analysis of last year's long-range predictions. We believe that nothing in the universe happens haphazardly, that there is a cause-and-effect pattern to all phenomena. However, although neither we nor any other forecasters have as yet gained sufficient insight into the mysteries of the universe to predict the weather with total accuracy, our results are almost always close to our traditional claim of 80% accuracy.

Table 1. Summary of natural gas supply and disposition in the United States, 2018-2023

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]
2018 total	**37,326**	**33,009**	**2,235**	**30,774**	**69**	**-719**	**314**	**-300**	**30,139**
2019 total	**40,780**	**36,447**	**2,548**	**33,899**	**61**	**-1,916**	**-503**	**-408**	**31,132**
2020 total	**40,614**	**36,202**	**2,710**	**33,493**	**63**	**-2,734**	**-180**	**-129**	**30,513**
2021									
January	3,517	3,118	235	2,884	6	-279	719	16	3,344
February	2,950	2,609	196	2,412	5	-152	795	40	3,099
March	3,518	3,144	237	2,907	6	-357	64	30	2,649
April	3,438	3,069	231	2,838	5	-356	-180	-42	2,265
May	3,535	3,168	239	2,930	6	-373	-424	-21	2,117
June	3,400	3,056	230	2,826	5	-331	-254	-8	2,238
July	3,514	3,182	240	2,943	6	-338	-175	-23	2,412
August	3,545	3,196	241	2,956	6	-343	-164	-20	2,434
September	3,423	3,087	232	2,854	5	-315	-398	-4	2,142
October	3,600	3,245	244	3,001	6	-317	-368	-60	2,263
November	3,545	3,170	239	2,931	6	-315	137	-66	2,693
December	3,680	3,284	247	3,037	6	-368	330	3	3,007
Total	**41,666**	**37,328**	**2,811**	**34,518**	**66**	**-3,845**	**82**	**-157**	**30,665**
2022									
January	E3,591	E3,199	246	E2,953	7	-315	994	-47	3,592
February	E3,227	E2,870	223	E2,647	6	-288	R659	38	3,061
March	E3,614	E3,225	267	E2,958	6	-380	163	33	2,781
April	E3,520	E3,152	257	E2,895	6	-342	-214	23	2,367
May	E3,667	E3,296	266	E3,030	6	-386	-403	R-4	2,242
June	E3,557	E3,215	259	E2,956	4	-325	-324	7	2,318
July	E3,690	E3,330	276	E3,055	6	-303	-180	5	2,583
August	E3,699	E3,349	270	E3,079	6	-322	-206	3	2,560
September	E3,638	E3,281	265	E3,016	4	-293	-436	-4	2,289
October	E3,769	E3,394	275	E3,119	5	-315	-422	-21	2,366
November	E3,683	E3,297	269	E3,029	4	-308	71	-23	2,773
December	E3,729	E3,328	249	E3,079	5	-304	573	29	3,382
Total	**E43,385**	**E38,936**	**3,120**	**E35,816**	**65**	**-3,880**	**275**	**37**	**32,314**
2023									
January	E3,820	E3,419	264	E3,156	6	R-333	455	R24	3,309
February	E3,456	E3,094	242	E2,852	5	R-330	399	R27	2,952
March	E3,858	E3,465	281	E3,184	6	R-401	224	*	3,013
April	RE3,729	RE3,352	279	RE3,073	5	R-400	R-268	R13	R2,423
May	RE3,865	RE3,486	287	RE3,198	5	R-423	-454	R-12	R2,315
June	E3,721	E3,367	284	E3,083	4	-375	-342	-11	2,359
2023 6-month YTD	**E22,449**	**E20,183**	**1,637**	**E18,546**	**31**	**-2,262**	**14**	**42**	**16,371**
2022 6-month YTD	**E21,176**	**E18,957**	**1,517**	**E17,439**	**34**	**-2,036**	**875**	**49**	**16,362**
2021 6-month YTD	**20,358**	**18,164**	**1,368**	**16,796**	**32**	**-1,849**	**720**	**13**	**15,713**

[a] We derive monthly natural gas plant liquid (NGPL) production, gaseous equivalent, 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] We only collect supplemental gaseous fuels data on an annual basis except for the Dakota Gasification Co. coal gasification facility, which provides data each month. We calculate the ratio of annual supplemental fuels (excluding Dakota Gasification Co.) to the sum of dry gas production, net imports, and net withdrawals from storage. We apply this ratio to the monthly sum of these three elements. We add the Dakota Gasification Co. monthly value to the result to produce the monthly supplemental fuels estimate.

[d] Monthly and annual data for 2018 through 2020 include underground storage and liquefied natural gas storage. Data for January 2021 forward include underground storage only. Appendix A, Explanatory Note 5, contains a 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): 212 for 2021; 209 for 2020; -8 for 2019; and -12 for 2018. Appendix A, Explanatory Note 7, contains a full discussion of balancing item calculations.

[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.

Source: 2018-2021: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2021*. January 2022 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 and Carbon Management, *Natural Gas Imports and Exports*. Table 7 includes detailed source notes for Marketed Production. Appendix A, Notes 3 and 4, includes discussion of computation and estimation procedures and revision policies.

Note: Data for 2018 through 2020 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.

Table 2. Natural gas consumption in the United States, 2018-2023

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)
2018 total	**1,694**	**877**	**4,998**	**3,514**	**8,417**	**10,589**	**50**	**27,568**	**30,139**	**1,036**
2019 total	**1,823**	**1,018**	**5,019**	**3,515**	**8,417**	**11,288**	**53**	**28,291**	**31,132**	**1,038**
2020 total	**1,809**	**1,018**	**4,674**	**3,170**	**8,161**	**11,632**	**49**	**27,686**	**30,513**	**1,037**
2021										
January	159	125	895	497	791	872	5	3,060	3,344	1,038
February	133	116	876	497	686	787	4	2,850	3,099	1,041
March	160	98	574	358	703	752	5	2,392	2,649	1,038
April	156	83	342	248	676	756	4	2,026	2,265	1,036
May	161	77	218	183	658	816	5	1,879	2,117	1,035
June	156	82	130	144	638	1,085	4	2,001	2,238	1,034
July	162	88	113	143	666	1,235	5	2,162	2,412	1,035
August	163	89	106	142	669	1,261	5	2,182	2,434	1,034
September	157	78	118	150	639	995	4	1,907	2,142	1,035
October	165	82	193	197	677	944	5	2,015	2,263	1,035
November	161	99	482	338	726	882	4	2,432	2,693	1,037
December	167	112	669	402	767	886	5	2,729	3,007	1,038
Total	**1,901**	**1,130**	**4,716**	**3,298**	**8,295**	**11,271**	**54**	**27,634**	**30,665**	**1,037**
2022										
January	E163	E132	961	553	817	961	E5	3,296	3,592	1,038
February	E146	E113	796	465	722	815	E4	2,802	3,061	1,038
March	E164	E102	591	387	753	779	E5	2,515	2,781	1,036
April	E161	E87	390	277	700	748	E4	2,120	2,367	1,035
May	E168	E83	201	183	677	925	E5	1,992	2,242	1,034
June	E164	E85	124	147	648	1,146	E4	2,069	2,318	1,033
July	E170	E95	110	145	658	1,400	E5	2,318	2,583	1,033
August	E171	E94	103	141	670	1,375	E5	2,295	2,560	1,035
September	E167	E84	114	150	646	1,122	E4	2,037	2,289	1,036
October	E173	E87	242	224	686	950	E5	2,106	2,366	1,036
November	E168	E102	516	356	723	903	E4	2,503	2,773	1,036
December	E169	E125	840	496	754	993	E5	3,088	3,382	1,041
Total	**E1,983**	**E1,190**	**4,990**	**3,525**	**8,455**	**12,118**	**E53**	**29,140**	**32,314**	**1,036**
2023										
January	E174	E122	799	475	766	968	E5	3,013	3,309	1,039
February	E158	E109	682	423	704	872	E4	2,686	2,952	1,038
March	E176	E111	632	408	R750	930	E5	2,726	3,013	1,036
April	E171	E89	337	253	R701	867	E4	R2,163	R2,423	1,035
May	RE178	E85	R197	182	674	995	E5	R2,052	R2,315	1,034
June	E171	E87	127	148	649	1,172	E4	2,100	2,359	1,034
2023 6-month YTD	**E1,028**	**E603**	**2,775**	**1,891**	**4,244**	**5,804**	**E26**	**14,740**	**16,371**	**1,036**
2022 6-month YTD	**E966**	**E603**	**3,063**	**2,013**	**4,317**	**5,375**	**E26**	**14,794**	**16,362**	**1,036**
2021 6-month YTD	**925**	**581**	**3,035**	**1,927**	**4,151**	**5,068**	**27**	**14,208**	**15,713**	**1,040**

[a] We only collect plant fuel data and lease fuel data annually. We estimate monthly lease and plant fuel use from monthly marketed production by assuming that the preceding annual percentage remains constant for the next 12 months.

[b] We base published pipeline and distribution use data on reports collected on an annual basis. We estimate monthly pipeline and distribution use data 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. Appendix A, Explanatory Note 11, contains further information.

[R] Revised data.

[E] Estimated data.

[RE] Revised estimated data.

Source: 2018-2021: 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 2021*. January 2022 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*. Appendix A, Explanatory Note 6, contains an explanation of computation procedures and revision policy.

Note: Data for 2018 through 2020 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. Appendix A, Explanatory Note 6, contains a definition of sectors.

Table 5. U.S. natural gas exports, 2021-2023

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

	2023 6-month YTD	2022 6-month YTD	2021 6-month YTD	2023 June	2023 May	2023 April	2023 March
Exports							
Volume (million cubic feet)							
Pipeline							
Canada	536,270	491,075	469,082	75,320	R77,984	R75,674	R106,178
Mexico	1,062,036	1,045,829	1,067,501	203,526	R194,352	R169,179	177,150
Total pipeline exports	**1,598,306**	**1,536,904**	**1,536,583**	**278,846**	**R272,337**	**R244,853**	**R283,328**
LNG							
Exports							
By vessel							
Antigua and Barbuda	15	11	0	3	3	3	2
Argentina	65,759	55,290	42,261	22,663	26,930	11,536	2,343
Bahamas	254	232	235	45	45	43	53
Bangladesh	10,555	12,663	27,374	3,624	3,561	0	0
Barbados	0	92	120	0	0	0	0
Belgium	34,622	57,027	5,584	6,953	3,809	4,844	8,053
Brazil	17,755	52,825	119,861	8,628	4,196	3,598	1,334
Chile	21,007	19,849	65,519	4,011	6,419	0	7,271
China	59,175	28,430	201,356	23,562	6,593	3,426	5,132
Colombia	2,847	1,398	892	0	2,847	0	0
Croatia	18,709	41,542	17,320	0	2,932	3,163	3,694
Dominican Republic	30,248	27,624	31,019	7,443	7,871	6,901	876
Egypt	0	0	0	0	0	0	0
Finland	15,407	0	0	1,622	6,935	0	6,850
France	252,600	295,203	103,845	45,569	51,658	53,211	28,581
Germany	97,702	0	0	15,769	16,002	18,546	24,841
Greece	24,471	37,631	14,201	2,924	4,498	3,905	3,156
Haiti	56	79	65	6	12	11	8
India	67,465	56,542	110,037	14,488	7,140	14,585	10,230
Indonesia	805	717	0	0	0	0	0
Israel	0	0	6,051	0	0	0	0
Italy	91,214	72,105	23,983	13,959	18,542	17,378	13,699
Jamaica	1,131	616	16,752	3	289	31	540
Japan	118,197	108,255	203,873	24,729	27,923	13,687	20,102
Jordan	0	0	0	0	0	0	0
Kuwait	18,179	34,884	14,653	10,670	3,802	3,707	0
Lithuania	24,401	44,084	19,492	3,629	7,048	3,412	3,599
Malaysia	0	0	0	0	0	0	0
Malta	2,592	2,345	2,928	0	0	0	0
Mexico	6,270	3,292	13,354	0	0	0	3,051
Netherlands	303,563	164,508	96,630	45,866	60,691	60,234	61,017
Nicaragua	0	0	0	0	0	0	0
Pakistan	0	3,074	13,801	0	0	0	0
Panama	9,215	9,676	6,136	0	3,289	0	3,209
Poland	71,754	61,390	32,204	18,046	17,422	7,165	7,236
Portugal	36,941	33,400	27,021	3,194	10,424	4,237	6,133
Singapore	10,009	10,077	13,740	10,009	0	0	0
South Korea	110,722	125,007	229,868	17,044	10,958	24,734	10,807
Spain	122,440	258,196	61,051	12,274	12,266	13,680	38,096
Taiwan	47,221	56,895	43,618	6,848	10,262	9,774	10,311
Thailand	18,283	18,708	10,841	4,242	0	4,225	4,249
Turkiye	75,344	126,866	53,947	0	0	13,908	11,866
United Arab Emirates	0	0	0	0	0	0	0
United Kingdom	313,442	195,870	97,682	0	32,374	75,836	70,499
By truck							
Canada	37	48	40	17	7	7	7
Mexico	452	790	366	34	26	58	96
Re-exports							
By vessel							
Argentina	0	0	0	0	0	0	0
Brazil	0	0	0	0	0	0	0
Japan	0	0	0	0	0	0	0
South Korea	0	0	0	0	0	0	0
United Kingdom	0	0	0	0	0	0	0
Total LNG exports	**2,100,861**	**2,017,243**	**1,727,720**	**327,872**	**366,774**	**375,843**	**366,941**
CNG							
Canada	1	*	181	0	0	0	*
Total CNG exports	**1**	*****	**181**	**0**	**0**	**0**	*****
Total exports	**3,699,168**	**3,554,147**	**3,264,484**	**606,719**	**R639,111**	**R620,697**	**R650,270**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2021-2023

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

	2023		2022				
	February	January	Total	December	November	October	September
Exports							
Volume (million cubic feet)							
Pipeline							
Canada	R95,691	R105,422	959,630	98,718	90,179	72,738	61,926
Mexico	152,318	165,511	2,078,627	158,638	160,986	171,766	169,159
Total pipeline exports	**R248,009**	**R270,933**	**3,038,257**	**257,355**	**251,165**	**244,505**	**231,086**
LNG							
Exports							
By vessel							
Antigua and Barbuda	2	4	22	1	2	2	3
Argentina	2,287	0	66,939	0	0	0	0
Bahamas	27	42	489	42	35	40	43
Bangladesh	0	3,369	12,663	0	0	0	0
Barbados	0	0	93	0	1	0	0
Belgium	7,322	3,640	80,245	3,274	0	7,190	9,165
Brazil	0	0	71,998	0	0	3,439	0
Chile	0	3,307	30,131	0	0	0	3,365
China	2,565	17,896	96,659	6,992	17,308	22,598	10,275
Colombia	0	0	5,703	0	0	3,699	0
Croatia	6,006	2,913	77,286	6,204	5,122	2,922	9,073
Dominican Republic	3,514	3,643	50,824	6,644	0	3,469	3,196
Egypt	0	0	0	0	0	0	0
Finland	0	0	329	329	0	0	0
France	39,457	34,124	571,399	38,311	50,655	41,959	57,943
Germany	8,229	14,314	7,113	7,112	1	0	0
Greece	6,781	3,207	69,031	2,869	421	4,424	0
Haiti	11	8	115	9	0	0	8
India	14,064	6,956	122,518	14,139	10,138	7,005	10,528
Indonesia	0	805	6,579	3,256	505	625	509
Israel	0	0	0	0	0	0	0
Italy	17,555	10,082	116,034	6,992	3,205	0	8,355
Jamaica	161	107	1,516	147	137	144	240
Japan	14,058	17,696	209,220	20,535	24,396	10,684	7,005
Jordan	0	0	0	0	0	0	0
Kuwait	0	0	57,018	0	0	3,299	7,038
Lithuania	0	6,713	77,212	3,281	3,708	7,072	3,541
Malaysia	0	0	0	0	0	0	0
Malta	0	2,592	5,273	0	2,928	0	0
Mexico	0	3,219	3,832	539	0	0	0
Netherlands	39,301	36,453	378,329	39,893	20,645	39,703	30,924
Nicaragua	0	0	0	0	0	0	0
Pakistan	0	0	3,074	0	0	0	0
Panama	0	2,718	13,759	249	3,833	0	0
Poland	10,347	11,538	127,404	13,885	3,453	7,095	16,917
Portugal	6,138	6,816	69,583	10,025	3,732	7,005	5,806
Singapore	0	0	22,980	0	0	6,628	0
South Korea	22,672	24,507	292,732	24,700	14,069	38,844	19,736
Spain	32,138	13,987	426,657	33,847	26,445	26,369	21,263
Taiwan	6,557	3,471	106,738	9,203	3,592	9,041	9,753
Thailand	1,829	3,738	25,988	0	0	0	3,673
Turkiye	13,444	36,126	192,067	17,979	31,430	10,333	5,458
United Arab Emirates	0	0	0	0	0	0	0
United Kingdom	71,702	63,032	464,462	69,332	76,693	46,040	51,467
By truck							
Canada	0	0	76	8	0	19	0
Mexico	106	133	1,552	160	153	175	94
Re-exports							
By vessel							
Argentina	0	0	0	0	0	0	0
Brazil	0	0	0	0	0	0	0
Japan	0	0	0	0	0	0	0
South Korea	0	0	0	0	0	0	0
United Kingdom	0	0	0	0	0	0	0
Total LNG exports	**326,275**	**337,155**	**3,865,643**	**339,960**	**302,608**	**309,823**	**295,379**
CNG							
Canada	*	*	2	0	*	1	*
Total CNG exports	*	*	**2**	**0**	*	**1**	*
Total exports	**R574,284**	**R608,088**	**6,903,902**	**597,316**	**553,774**	**554,328**	**526,465**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2021-2023

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

	2022						
	August	July	June	May	April	March	February
Exports							
Volume (million cubic feet)							
Pipeline							
Canada	75,220	69,774	70,105	79,214	80,475	105,074	74,630
Mexico	182,596	189,652	182,995	186,003	176,447	169,885	155,032
Total pipeline exports	**257,816**	**259,426**	**253,100**	**265,217**	**256,922**	**274,958**	**229,662**
LNG							
Exports							
By vessel							
Antigua and Barbuda	2	2	3	2	3	2	0
Argentina	2,202	9,448	25,246	20,111	9,933	0	0
Bahamas	53	45	47	42	34	43	31
Bangladesh	0	0	0	3,346	0	3,421	5,896
Barbados	0	0	0	0	0	34	31
Belgium	3,589	0	7,023	3,441	7,341	17,743	7,691
Brazil	10,542	5,192	3,857	15,303	3,448	2,236	10,660
Chile	0	6,917	0	9,943	3,530	3,214	0
China	10,272	784	7,329	0	10,217	7,527	3,357
Colombia	606	0	912	0	0	0	0
Croatia	7,824	4,600	7,925	8,543	6,763	3,358	5,870
Dominican Republic	3,357	6,532	5,838	4,964	3,645	6,530	0
Egypt	0	0	0	0	0	0	0
Finland	0	0	0	0	0	0	0
France	33,885	53,443	37,564	47,150	56,343	64,415	39,646
Germany	0	0	0	0	0	0	0
Greece	10,763	12,922	9,633	12,650	1,336	4,116	8,094
Haiti	11	8	13	9	11	10	16
India	10,265	13,902	10,653	7,152	14,223	10,438	7,210
Indonesia	967	0	0	0	0	0	717
Israel	0	0	0	0	0	0	0
Italy	15,462	9,914	7,137	21,696	15,519	7,088	13,629
Jamaica	110	121	48	144	135	92	111
Japan	20,156	18,189	21,561	24,024	13,231	17,697	10,214
Jordan	0	0	0	0	0	0	0
Kuwait	6,415	5,382	8,105	14,204	7,298	0	5,277
Lithuania	7,579	7,947	6,729	11,237	13,770	5,700	3,131
Malaysia	0	0	0	0	0	0	0
Malta	0	0	0	0	0	0	2,345
Mexico	0	0	3,292	0	0	0	0
Netherlands	50,020	32,637	34,420	28,902	28,395	24,922	31,591
Nicaragua	0	0	0	0	0	0	0
Pakistan	0	0	0	0	3,074	0	0
Panama	0	0	623	1,192	1,536	0	3,069
Poland	6,885	17,780	14,282	18,224	13,882	3,831	7,475
Portugal	3,202	6,412	5,582	3,888	6,632	10,728	3,703
Singapore	0	6,275	3,352	0	0	6,725	0
South Korea	36,033	34,342	25,054	17,538	13,813	19,289	27,489
Spain	26,140	34,396	29,639	40,337	40,259	59,224	39,359
Taiwan	8,901	9,353	6,892	15,975	9,541	12,161	6,115
Thailand	3,607	0	6,920	3,419	0	0	4,880
Turkiye	0	0	7,542	7,281	6,637	16,629	43,697
United Arab Emirates	0	0	0	0	0	0	0
United Kingdom	21,263	3,797	3,326	10,608	39,775	56,799	25,301
By truck							
Canada	0	0	8	8	15	0	4
Mexico	103	76	105	115	122	144	157
Re-exports							
By vessel							
Argentina	0	0	0	0	0	0	0
Brazil	0	0	0	0	0	0	0
Japan	0	0	0	0	0	0	0
South Korea	0	0	0	0	0	0	0
United Kingdom	0	0	0	0	0	0	0
Total LNG exports	**300,215**	**300,415**	**300,659**	**351,448**	**330,463**	**364,116**	**316,766**
CNG							
Canada	*	1	*	0	0	*	0
Total CNG exports	*****	**1**	*****	**0**	**0**	*****	**0**
Total exports	**558,031**	**559,842**	**553,760**	**616,665**	**587,385**	**639,074**	**546,428**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2021-2023

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

	2022	2021					
	January	Total	December	November	October	September	August
Exports							
Volume (million cubic feet)							
Pipeline							
Canada	81,577	937,124	108,568	85,136	62,464	72,023	71,586
Mexico	175,467	2,154,457	166,956	165,449	184,472	178,746	193,710
Total pipeline exports	**257,045**	**3,091,580**	**275,524**	**250,585**	**246,936**	**250,769**	**265,296**
LNG							
Exports							
By vessel							
Antigua and Barbuda	2	8	3	2	0	3	0
Argentina	0	83,449	2,077	0	0	1,950	14,363
Bahamas	34	486	36	34	36	43	56
Bangladesh	0	37,734	0	0	0	3,276	7,085
Barbados	28	297	34	27	25	33	27
Belgium	13,786	5,584	0	0	0	0	0
Brazil	17,322	307,714	24,246	10,715	40,769	38,282	34,204
Chile	3,162	121,881	2,938	2,956	6,364	7,929	16,262
China	0	453,304	17,050	50,228	42,202	48,584	51,662
Colombia	486	2,247	0	0	0	436	919
Croatia	9,084	36,133	3,117	9,416	0	0	2,980
Dominican Republic	6,647	53,095	5,969	2,780	5,619	0	5,901
Egypt	0	0	0	0	0	0	0
Finland	0	0	0	0	0	0	0
France	50,084	170,780	33,892	10,021	9,333	6,578	7,111
Germany	0	0	0	0	0	0	0
Greece	1,802	39,708	5,305	7,629	1,515	799	3,607
Haiti	20	137	4	8	17	10	24
India	6,866	196,218	3,203	14,807	10,548	23,941	20,592
Indonesia	0	3,269	1,218	456	477	1,118	0
Israel	0	8,906	0	0	0	2,855	0
Italy	7,037	34,210	0	0	0	0	3,401
Jamaica	86	25,276	113	715	1,858	2,931	2,907
Japan	21,527	354,948	24,297	33,947	37,666	10,290	19,979
Jordan	0	0	0	0	0	0	0
Kuwait	0	34,476	0	0	6,193	10,333	3,298
Lithuania	3,518	30,919	0	0	0	3,282	1,677
Malaysia	0	0	0	0	0	0	0
Malta	0	5,427	0	0	0	2,498	0
Mexico	0	15,200	0	0	1,088	0	0
Netherlands	16,279	174,339	23,354	8,829	17,157	10,424	7,347
Nicaragua	0	1	0	0	0	0	0
Pakistan	0	45,818	0	2,490	3,138	9,642	3,319
Panama	3,255	8,436	0	0	911	0	1,390
Poland	3,695	56,320	7,159	7,068	3,270	0	0
Portugal	2,868	65,865	9,630	5,380	10,459	3,696	6,382
Singapore	0	20,918	0	3,728	0	0	0
South Korea	21,824	453,483	38,201	30,787	33,836	31,375	50,101
Spain	49,379	215,062	32,579	22,821	35,638	31,274	23,068
Taiwan	6,211	99,350	12,034	3,404	7,123	5,789	6,728
Thailand	3,490	14,548	0	0	0	0	3,707
Turkiye	45,081	188,849	38,420	47,330	19,385	24,176	0
United Arab Emirates	0	0	0	0	0	0	0
United Kingdom	60,060	195,046	60,315	30,648	3,302	3,099	0
By truck							
Canada	13	128	20	8	8	19	18
Mexico	148	1,250	148	160	182	150	147
Re-exports							
By vessel							
Argentina	0	0	0	0	0	0	0
Brazil	0	0	0	0	0	0	0
Japan	0	0	0	0	0	0	0
South Korea	0	0	0	0	0	0	0
United Kingdom	0	0	0	0	0	0	0
Total LNG exports	**353,791**	**3,560,818**	**345,363**	**306,397**	**298,119**	**284,813**	**298,262**
CNG							
Canada	0	211	0	0	0	0	14
Total CNG exports	**0**	**211**	**0**	**0**	**0**	**0**	**14**
Total exports	**610,836**	**6,652,609**	**620,886**	**556,982**	**545,055**	**535,583**	**563,572**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2021-2023

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

							2021
	July	June	May	April	March	February	January
Exports							
Volume (million cubic feet)							
Pipeline							
Canada	68,264	69,528	70,561	74,567	91,301	78,198	84,927
Mexico	197,623	198,242	192,549	182,918	183,051	137,381	173,360
Total pipeline exports	**265,887**	**267,770**	**263,110**	**257,485**	**274,352**	**215,579**	**258,287**
LNG							
Exports							
By vessel							
Antigua and Barbuda	0	0	0	0	0	0	0
Argentina	22,798	19,312	16,226	4,485	2,238	0	0
Bahamas	46	48	45	46	39	29	28
Bangladesh	0	3,493	6,948	10,219	3,566	0	3,148
Barbados	31	22	19	30	14	19	17
Belgium	0	0	2,100	0	3,484	0	0
Brazil	39,637	32,293	19,726	11,615	21,977	13,118	21,132
Chile	19,913	0	17,598	10,293	21,320	6,524	9,784
China	42,222	42,319	37,731	50,474	28,476	3,415	38,940
Colombia	0	0	0	892	0	0	0
Croatia	3,299	2,923	3,364	3,666	7,367	0	0
Dominican Republic	1,806	4,670	5,283	2,905	5,577	5,689	6,895
Egypt	0	0	0	0	0	0	0
Finland	0	0	0	0	0	0	0
France	0	3,683	11,926	36,120	33,678	14,851	3,587
Germany	0	0	0	0	0	0	0
Greece	6,651	0	6,796	0	6,805	0	600
Haiti	8	18	12	3	10	11	12
India	13,090	16,503	28,259	13,752	17,381	13,776	20,367
Indonesia	0	0	0	0	0	0	0
Israel	0	0	0	3,225	2,826	0	0
Italy	6,826	3,425	2,923	6,896	10,739	0	0
Jamaica	0	2,927	2,925	2,370	2,458	2,365	3,708
Japan	24,895	39,783	25,058	28,756	27,673	18,271	64,331
Jordan	0	0	0	0	0	0	0
Kuwait	0	7,126	0	3,705	3,821	0	0
Lithuania	6,469	3,285	3,049	3,078	3,228	6,851	0
Malaysia	0	0	0	0	0	0	0
Malta	0	0	0	2,928	0	0	0
Mexico	758	0	0	0	0	13,354	0
Netherlands	10,597	3,030	26,611	17,060	24,204	22,777	2,949
Nicaragua	1	0	0	0	0	0	0
Pakistan	13,428	3,376	0	3,323	3,421	0	3,682
Panama	0	0	2,341	0	3,279	0	516
Poland	6,619	10,635	3,581	7,382	3,507	7,099	0
Portugal	3,296	5,538	10,765	7,358	0	3,360	0
Singapore	3,449	0	3,089	3,660	3,303	0	3,688
South Korea	39,314	55,918	46,033	21,683	32,203	18,094	55,936
Spain	8,630	7,833	5,234	22,974	13,900	3,733	7,377
Taiwan	20,653	3,097	10,157	6,594	13,450	0	10,319
Thailand	0	0	3,453	7,388	0	0	0
Turkiye	5,591	0	3,017	0	3,619	20,652	26,659
United Arab Emirates	0	0	0	0	0	0	0
United Kingdom	0	0	10,586	13,877	17,440	34,343	21,436
By truck							
Canada	16	7	18	15	0	0	0
Mexico	97	105	48	48	19	63	83
Re-exports							
By vessel							
Argentina	0	0	0	0	0	0	0
Brazil	0	0	0	0	0	0	0
Japan	0	0	0	0	0	0	0
South Korea	0	0	0	0	0	0	0
United Kingdom	0	0	0	0	0	0	0
Total LNG exports	**300,143**	**271,368**	**314,922**	**306,818**	**321,023**	**208,394**	**305,196**
CNG							
Canada	16	27	25	29	36	32	32
Total CNG exports	**16**	**27**	**25**	**29**	**36**	**32**	**32**
Total exports	**566,046**	**539,165**	**578,056**	**564,333**	**595,411**	**424,004**	**563,515**

See footnotes at end of table.

Table 7. Marketed production of natural gas in selected states and the Federal Gulf of Mexico, 2018-2023

million cubic feet

Year and month	Alaska	Arkansas	California	Colorado	Kansas	Louisiana	Montana	New Mexico	North Dakota	Ohio
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 total	**329,361**	**524,757**	**196,823**	**1,986,916**	**183,087**	**3,212,318**	**43,534**	**1,769,086**	**850,826**	**2,651,631**
2020 total	**338,329**	**480,982**	**170,579**	**1,990,462**	**163,356**	**3,206,163**	**37,963**	**1,948,168**	**882,443**	**2,378,902**
2021										
January	31,667	39,285	11,467	160,766	12,900	276,873	3,292	173,929	83,193	193,911
February	28,365	30,183	10,846	143,192	10,142	223,268	2,859	144,804	70,129	175,146
March	31,483	42,466	12,136	157,254	13,251	282,668	3,299	180,669	83,243	193,911
April	29,514	37,756	11,791	156,092	12,842	273,643	3,078	178,912	82,917	185,964
May	29,005	38,563	12,342	162,416	13,063	283,576	3,328	187,994	85,384	192,163
June	27,715	36,918	11,885	154,617	12,716	276,142	2,975	184,732	82,520	185,964
July	26,280	38,045	12,141	160,287	13,215	299,939	3,321	195,904	80,072	189,515
August	27,864	37,753	12,076	158,586	13,224	292,784	3,343	199,365	84,297	189,515
September	28,534	36,508	11,617	153,270	12,769	290,606	3,283	194,290	85,041	183,401
October	30,458	37,626	11,655	160,291	13,213	307,744	3,460	200,567	87,446	199,379
November	30,735	36,079	11,279	155,653	12,722	310,363	3,291	195,365	87,089	192,947
December	33,039	37,006	11,371	157,031	12,928	313,823	3,163	201,176	87,692	199,379
Total	**354,660**	**448,187**	**140,604**	**1,879,457**	**152,986**	**3,431,429**	**38,693**	**2,237,706**	**999,025**	**2,281,193**
2022										
January	32,865	E37,302	E11,186	E151,815	E12,255	E311,786	E3,092	E196,780	E81,699	E196,005
February	30,014	E33,465	E9,336	E138,369	E10,930	E284,177	E2,801	E183,345	E74,429	E172,829
March	32,473	E37,518	E11,388	E155,246	E12,194	E313,229	E3,214	E219,028	E86,190	E187,872
April	30,910	E36,247	E11,212	E151,319	E12,037	E313,229	E3,042	E215,953	E68,484	E179,444
May	31,677	E37,042	E11,489	E155,982	E12,469	E340,363	E3,152	E223,843	E80,563	E189,214
June	28,644	E35,573	E11,057	E150,046	E12,037	E335,290	E3,464	E214,602	E86,013	E190,021
July	29,654	E36,446	E11,651	E153,067	E12,457	E345,647	E3,465	E227,099	E89,572	E193,519
August	29,380	E36,659	E11,970	E154,806	E12,526	E355,454	E3,634	E230,690	E88,700	E196,604
September	29,288	E34,405	E11,100	E151,415	E11,565	E346,479	E3,572	E233,548	E88,797	E189,795
October	31,122	E35,354	E11,358	E155,354	E12,749	E363,490	E3,540	E247,855	E90,617	E195,926
November	30,934	E33,777	E10,905	E151,562	E12,036	E354,732	E3,342	E237,280	E84,563	E195,571
December	36,181	E33,198	E11,167	E150,545	E11,556	E355,671	E3,277	E249,384	E76,094	E186,258
Total	**373,141**	**E426,986**	**E133,818**	**E1,819,526**	**E144,811**	**E4,019,547**	**E39,595**	**E2,679,408**	**E995,720**	**E2,273,058**
2023										
January	33,391	E34,788	E11,061	E151,836	E11,783	E363,830	E3,526	E252,664	E82,392	E198,189
February	30,726	E31,085	E10,048	E135,227	E10,528	E352,432	E3,221	E231,359	E79,805	E174,917
March	32,676	E34,429	E10,906	E150,125	E11,441	E370,124	E3,553	E266,229	E87,680	E199,571
April	31,313	RE32,911	E10,657	RE146,844	E11,228	RE363,504	RE3,463	RE257,234	RE87,018	RE187,566
May	31,262	RE33,709	RE11,225	RE152,583	E11,519	RE379,945	RE3,566	RE260,512	RE91,094	RE193,534
June	28,991	E32,317	E10,782	E148,935	E10,762	E346,564	E3,464	E249,216	E90,787	E181,935
2023 6-month YTD	**188,358**	**E199,238**	**E64,680**	**E885,551**	**E67,260**	**E2,176,398**	**E20,793**	**E1,517,214**	**E518,776**	**E1,135,711**
2022 6-month YTD	**186,582**	**E217,147**	**E65,667**	**E902,777**	**E71,922**	**E1,898,074**	**E18,765**	**E1,253,551**	**E477,378**	**E1,115,385**
2021 6-month YTD	**177,749**	**225,171**	**70,466**	**934,338**	**74,915**	**1,616,170**	**18,832**	**1,051,040**	**487,388**	**1,127,058**

See footnotes at end of table.

Table 7. Marketed production of natural gas in selected states and the Federal Gulf of Mexico, 2018-2023

million cubic feet – continued

Year and month	Oklahoma	Pennsylvania	Texas	Utah	West Virginia	Wyoming	Other states	Federal Gulf of Mexico	U.S. total
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 total	**3,036,052**	**6,896,792**	**9,378,489**	**271,808**	**2,155,214**	**1,488,854**	**456,024**	**1,015,343**	**36,446,918**
2020 total	**2,786,366**	**7,148,295**	**9,336,110**	**241,989**	**2,592,319**	**1,306,368**	**404,391**	**789,262**	**36,202,446**
2021									
January	221,544	652,640	798,426	19,392	234,432	97,657	35,223	71,772	3,118,370
February	163,094	585,371	609,757	18,126	208,571	89,337	31,366	64,024	2,608,580
March	220,130	645,407	826,381	20,404	227,218	95,164	34,671	74,200	3,143,955
April	214,334	615,899	820,570	19,783	229,075	92,340	34,427	69,762	3,068,700
May	223,372	635,584	844,723	20,313	234,118	94,341	35,868	72,053	3,168,206
June	213,314	616,270	815,947	19,502	227,987	90,259	29,234	67,429	3,056,126
July	221,002	638,200	858,526	20,601	229,376	93,644	30,467	71,744	3,182,278
August	222,329	646,169	863,509	20,347	241,373	89,749	32,659	61,377	3,196,320
September	216,455	622,275	855,425	19,928	216,452	91,662	30,611	34,559	3,086,687
October	223,093	645,126	873,479	20,457	240,446	93,162	37,663	60,037	3,245,301
November	214,361	646,233	836,104	20,014	229,812	90,176	32,023	65,610	3,169,856
December	218,805	677,331	872,543	20,538	241,569	91,741	36,962	67,903	3,283,998
Total	**2,571,834**	**7,626,504**	**9,875,390**	**239,405**	**2,760,429**	**1,109,232**	**401,172**	**780,471**	**37,328,378**
2022									
January	E213,419	E660,345	E853,214	E20,789	E234,795	E85,192	E31,292	E65,454	E3,199,287
February	E192,596	E581,432	E766,441	E18,966	E209,707	E76,605	E28,839	E55,884	E2,870,165
March	E219,732	E635,076	E871,961	E21,315	E239,344	E84,319	E31,519	E63,547	E3,225,163
April	E223,078	E616,181	E856,759	E21,254	E235,580	E81,405	E29,705	E65,810	E3,151,649
May	E237,032	E640,189	E887,465	E22,840	E247,179	E82,036	E31,011	E62,326	E3,295,871
June	E230,337	E616,632	E862,817	E22,278	E240,568	E80,395	E31,237	E63,627	E3,214,637
July	E239,295	E641,726	E887,919	E23,066	E251,625	E85,506	E32,355	E66,393	E3,330,463
August	E238,265	E632,014	E897,401	E23,500	E255,603	E81,633	E32,294	E68,280	E3,349,415
September	E236,726	E613,657	E882,979	E22,110	E245,734	E81,528	E31,485	E66,585	E3,280,768
October	E241,688	E629,461	E915,309	E22,164	E251,647	E87,030	E31,961	E67,352	E3,393,976
November	E235,873	E605,505	E885,128	E21,326	E255,298	E84,565	E30,838	E63,917	E3,297,153
December	E236,429	E611,037	E914,687	E22,688	E253,533	E81,550	E30,737	E63,662	E3,327,655
Total	**E2,744,470**	**E7,483,257**	**E10,482,08**	**E262,297**	**E2,920,613**	**E991,764**	**E373,272**	**E772,838**	**E38,936,202**
2023									
January	E241,437	E646,645	E928,236	E22,346	E256,931	E80,638	E31,512	E67,908	E3,419,111
February	E217,813	E572,742	E835,949	E19,000	E231,585	E70,453	E27,351	E59,703	E3,093,944
March	E240,498	E642,354	E953,243	E22,789	E266,638	E79,606	E27,899	E65,103	E3,464,863
April	RE232,276	RE619,656	RE924,962	RE22,629	RE256,029	RE76,148	E30,086	RE58,664	RE3,352,188
May	RE237,525	RE648,103	RE968,667	RE23,788	RE268,361	RE83,024	RE30,683	RE56,520	RE3,485,620
June	E233,375	E627,891	E940,862	E24,031	E267,376	E82,191	E30,136	E57,164	E3,366,777
2023 6-month YTD	**E1,402,924**	**E3,757,392**	**E5,551,919**	**E134,582**	**E1,546,919**	**E472,060**	**E177,666**	**E365,061**	**E20,182,503**
2022 6-month YTD	**E1,316,194**	**E3,749,856**	**E5,098,658**	**E127,443**	**E1,407,173**	**E489,952**	**E183,602**	**E376,648**	**E18,956,773**
2021 6-month YTD	**1,255,790**	**3,751,170**	**4,715,803**	**117,521**	**1,361,400**	**559,098**	**200,788**	**419,241**	**18,163,937**

E Estimated data.

RE Revised estimated data.

Source: 2018-2021: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2021*, Bureau of Safety and Environmental Enforcement (BSEE), IHS Markit, and Enverus. January 2022 through current month: Form EIA-914, *Monthly Crude Oil and Lease Condensate, and Natural Gas Production Report*; and EIA computations.

Note: For 2022 forward, we estimate state monthly marketed production from gross withdrawals using historical relationships between the two. We collect 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 individually 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 2022, Federal Offshore Pacific is included in California. We obtain all data for Alaska 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 because of independent rounding.

Summary

Overview of Activity for June 2023

- **Top five countries of destination, representing 49.5% of total U.S. LNG exports in June 2023**
  - Netherlands (45.9 Bcf), France (45.6 Bcf), Japan (24.7 Bcf), China (23.6 Bcf) and Argentina (22.7 Bcf)
- **327.8 Bcf of exports in June 2023**
  - 10.6% decrease from May 2023
  - 9.1% more than June 2022
- **108 cargos shipped in June 2023**
  - Cameron (29), Sabine Pass (27), Freeport (21), Corpus Christi (18), Cove Point (7), and Elba (6)
  - 127 cargos in May 2023
  - 96 cargos in June 2022

1a. Table of Exports of Domestically-Produced LNG Delivered by Region (Cumulative from February 2016 through June 2023)

Region	Number of Countries Receiving Per Region	Volume Exported (Bcf)	Percentage Receipts of Total Volume Exported (%)	Number of Cargos*
East Asia and Pacific	8	4,841.8	30.8%	1436
Europe and Central Asia	15	7,268.0	46.3%	2274
Latin America and the Caribbean**	13	2,290.4	14.6%	832
Middle East and North Africa	5	394.8	2.5%	115
South Asia	3	901.5	5.7%	267
Sub-Saharan Africa	0	0.0	0.0%	0
Total LNG Exports	**44**	**15,696.5**	**100.0%**	**4,924**

*Split cargos counted as both individual cargos and countries

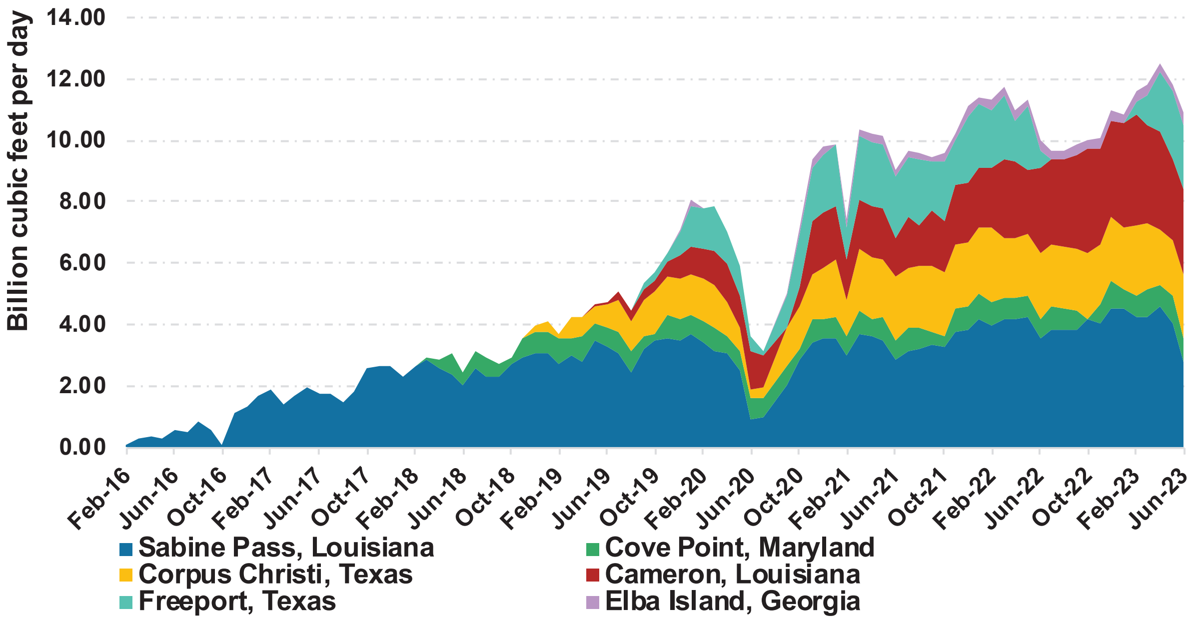
**Number of cargos does not include the shipments by ISO container

1b. Shipments of Domestically-Produced LNG Delivered – by Country
(Cumulative from February 2016 through June 2023)

	Country of Destination	Region	Number of Cargos	Volume (Bcf of Natural Gas)	Percentage of Total U.S LNG Exports (%)
1.	South Korea*	East Asia and Pacific	529	1,832.5	11.7%
2.	Japan*	East Asia and Pacific	401	1,364.1	8.7%
3.	United Kingdom*	Europe and Central Asia	390	1,295.6	8.3%
4.	France*	Europe and Central Asia	377	1,224.3	7.8%
5.	Spain*	Europe and Central Asia	375	1,173.3	7.5%
6.	Netherlands*	Europe and Central Asia	308	1,042.2	6.6%
7.	China*	East Asia and Pacific	307	1,041.5	6.6%
8.	India*	South Asia	205	697.6	4.4%
9.	Turkiye*	Europe and Central Asia	210	670.8	4.3%
10.	Brazil*	Latin America and the Caribbean	226	626.1	4.0%
11.	Mexico*	Latin America and the Caribbean	166	553.1	3.5%
12.	Chile*	Latin America and the Caribbean	139	440.3	2.8%
13.	Italy*	Europe and Central Asia	125	402.6	2.6%
14.	Taiwan*	East Asia and Pacific	117	370.8	2.4%
15.	Poland*	Europe and Central Asia	103	340.6	2.2%
16.	Argentina*	Latin America and the Caribbean	137	330.9	2.1%
17.	Portugal*	Europe and Central Asia	94	298.4	1.9%
18.	Greece*	Europe and Central Asia	87	200.0	1.3%
19.	Dominican Republic*	Latin America and the Caribbean	79	188.0	1.2%
20.	Belgium*	Europe and Central Asia	55	175.9	1.1%
21.	Kuwait	Middle East and North Africa	50	174.5	1.1%
22.	Lithuania	Europe and Central Asia	56	171.7	1.1%
23.	Croatia	Europe and Central Asia	45	135.4	0.9%
24.	Pakistan*	South Asia	40	128.9	0.8%
25.	Jordan*	Middle East and North Africa	36	124.2	0.8%
26.	Singapore*	East Asia and Pacific	36	117.4	0.7%
27.	Germany	Europe and Central Asia	32	101.2	0.6%
28.	Thailand*	East Asia and Pacific	29	101.2	0.6%
29.	Bangladesh*	South Asia	22	75.0	0.5%
30.	Panama*	Latin America and the Caribbean	33	61.2	0.4%
31.	Jamaica*	Latin America and the Caribbean	30	58.2	0.4%
32.	United Arab Emirates	Middle East and North Africa	15	51.1	0.3%
33.	Israel*	Middle East and North Africa	9	28.0	0.2%
34.	Colombia*	Latin America and the Caribbean	22	27.0	0.2%
35.	Malta*	Europe and Central Asia	11	20.1	0.1%
36.	Egypt*	Middle East and North Africa	5	16.9	0.1%
37.	Finland	Europe and Central Asia	6	15.7	0.1%
38.	Indonesia*	East Asia and Pacific	16	10.7	0.1%
39.	Malaysia	East Asia and Pacific	1	3.7	0.0%
	Total Exports by Vessel		**4,924**	**15,690.9**	
	Jamaica	Latin America and the Caribbean	177	2.0	0.0%
40	Bahamas	Latin America and the Caribbean	750	1.8	0.0%
41	Barbados	Latin America and the Caribbean	305	1.3	0.0%
42	Haiti	Latin America and the Caribbean	146	0.5	0.0%
43	Antigua and Barbuda	Latin America and the Caribbean	51	0.0	0.0%
44	Nicaragua	Latin America and the Caribbean	1	0.0	0.0%
	Germany	Europe and Central Asia	1	0.0	0.0%
	Total Exports by ISO		**1431**	**5.6**	
	Total Exports by Vessel and ISO		**6,355**	**15,696.5**	

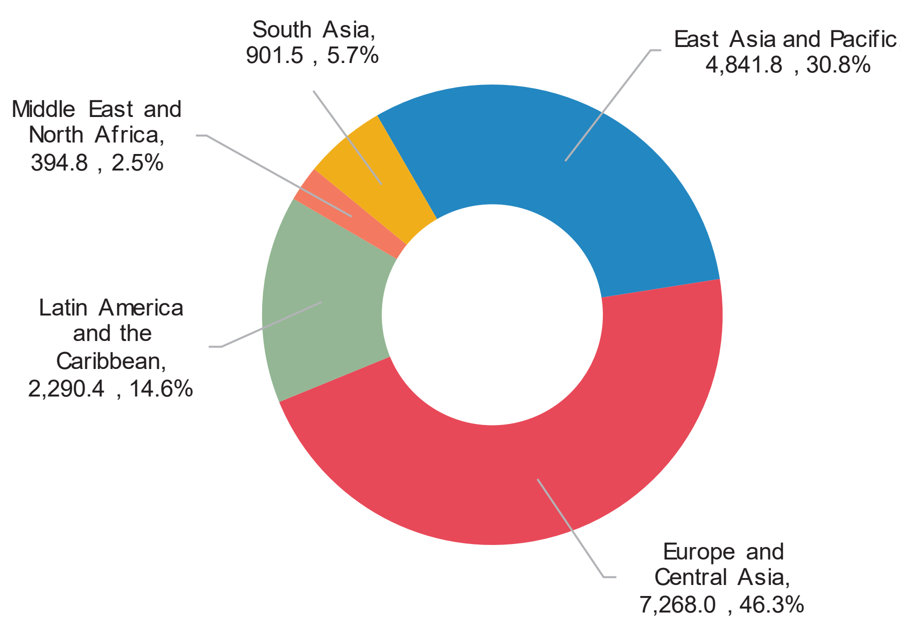
Note:
Volume and Number of Cargos are the cumulative totals of each individual Country of Destination by Region starting from February 2016.
Jamaica has received U.S. LNG exports by both vessel and ISO container. The volumes are totaled separately
* Split cargos counted as both individual cargos and countries.
Vessel = LNG Exports by Vessel and ISO container = LNG Exports by Vessel in ISO Containers.
Does not include re-exports of previously-imported LNG. See table 2c for re-exports data.
Totals may not equal sum of components because of independent rounding.

1c. Domestically-Produced LNG Exported by Point of Exit
(February 2016 through June 2023)



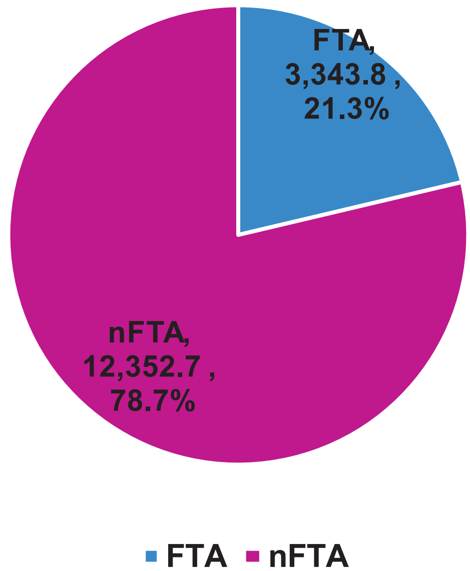
The Cameron, LA point of exit includes exports from Cameron LNG and Venture Global Calcasieu Pass.

1d. Domestically-Produced LNG Exported by Region
(Cumulative from February 2016 through June 2023)
(Bcf, %)



1e. Volumes and Percentages of FTA and nFTA Shipments of Domestically-Produced LNG Delivered
(Cumulative from February 2016 through June 2023)

	Volume (Bcf)	Percentage of Total Volume	Number of Countries
FTA	3,343.8	21.3%	8
nFTA	12,352.7	78.7%	36
Total LNG Exports	**15,696.5**	**100.0%**	**44**



Spot cargos total 722.9 Bcf - or 4.6 percent - of the 15, 696.5 Bcf total volume of shipments.

These totals are cumulative starting from February 2016 through June 2023 - a cumulative listing of cargos and regions in Table 1b and a cumulative list of FTAs and nFTAs in Table 1h.

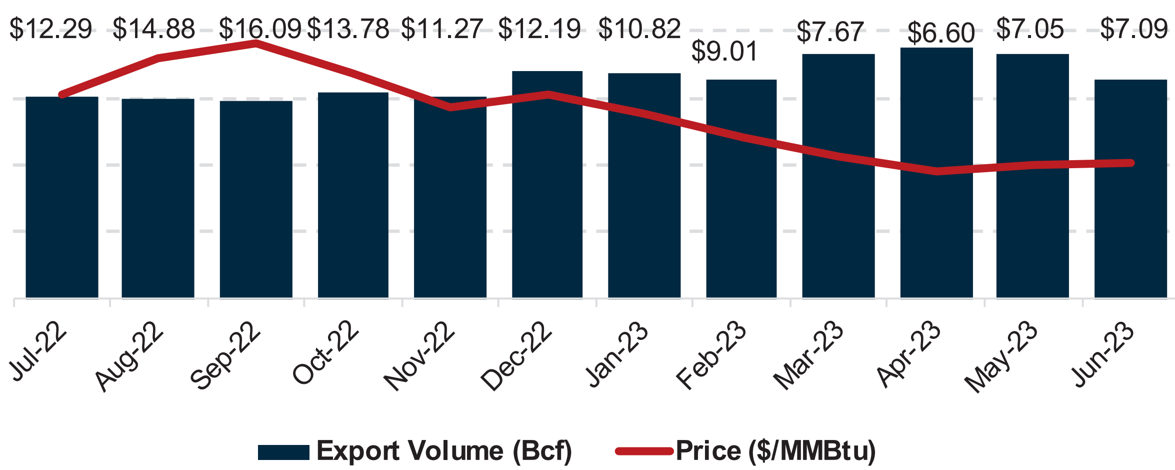
FTA Countries that Require National Treatment for Trade in Natural Gas -As of October 31, 2012, the United States has FTAs that require national treatment for trade in natural gas with Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, Republic of Korea and Singapore. Panama is the most recent country with which the United States has entered into a FTA that requires national treatment for trade in natural gas, effective October 31, 2012. Not all countries that have a FTA with the United States require national treatment for trade in natural gas (i.e. Costa Rica and Israel). A list of all countries with which the United States has a FTA can be found at: http://www.ustr.gov/trade-agreements/free-trade-agreements.

More information can be found on DOE's website - https://energy.gov/fe/services/natural-gas-regulation/how-obtain-authorization-import-andor-export-natural-gas-and-lng

Totals may not equal sum of components because of independent rounding.

1f. Domestically-Produced LNG Exported – Volume (Bcf) and Weighted Average price ($/MMBtu) by Point of Exit per month

		Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Total
Sabine Pass, LA		118.5	118.7	115.6	130.4	120.1	139.2	139.2	119.5	131.0	137.0	126.2	83.7	**1,479.1**
		$10.50	$12.71	$13.71	$10.85	$9.26	$10.43	$8.67	$6.72	$5.86	$5.45	$5.26	$5.35	**$8.76**
Cove Point, MD		24.2	21.4	18.8	0	20.4	29.8	20.8	19.4	27.8	21.2	26.3	23.3	**653.3**
		$11.28	$12.36	$13.61	0	$10.10	$10.98	$8.67	$8.35	$6.96	$6.55	$6.32	$6.48	**$9.15**
Corpus Christi, TX		63.1	63.4	59.8	66.8	57.0	64.1	62.6	64.1	67.1	55.6	57.7	62.4	**743.8**
		$12.17	$14.70	$15.99	$12.42	$10.36	$10.60	$10.74	$7.06	$6.26	$5.51	$5.62	$5.82	**$9.81**
Cameron, LA		85.2	87.2	91.1	104.9	94.1	97.1	104.8	100.8	100.0	94.5	80.7	82.0	**1,122.6**
		$15.15	$18.92	$19.89	$18.38	$14.82	$16.34	$14.33	$12.99	$11.65	$9.86	$12.87	$11.71	**$14.76**
Freeport, TX		0	0	0	0	0	0	0	11.6	29.0	58.9	68.4	63.3	**231.1**
		0	0	0	0	0	0	0	$8.23	$6.14	$5.34	$5.25	$5.38	**$5.57**
Elba Island, GA		9.1	9.2	9.7	7.4	10.6	9.4	9.4	10.6	11.4	7.3	7.4	13.0	**114.6**
		$12.20	$11.58	$14.31	$12.53	$9.62	$10.14	$8.81	$10.72	$7.54	$4.75	$4.55	$4.77	**$9.25**
Total		**300.2**	**299.9**	**295.1**	**309.4**	**302.3**	**339.6**	**336.9**	**326.0**	**366.3**	**374.4**	**366.7**	**327.8**	**3,944.5**
		$12.29	**$14.88**	**$16.09**	**$13.78**	**$11.27**	**$12.19**	**$10.82**	**$9.01**	**$7.67**	**$6.60**	**$7.05**	**$7.09**	**$10.52**



Notes:

Prices are free on board (FOB) and are inclusive of all costs of the LNG up to the point of export, including commodity costs and liquefaction fees.

Does not include re-exports of previously-imported LNG. See table 2c for re-exports data.

Totals may not equal sum of components because of independent rounding.

The Cameron, LA point of exit includes exports from Cameron LNG and Venture Global Calcasieu Pass.

W - Withheld to avoid disclosure of individual company data.

DOE has a confidentiality policy for certain data elements collected on Form FE-746R that allows DOE to publish a monthly volume-weighted average price for each point of LNG import or export, but not a price for each individual imported or exported LNG cargo. For additional information, please see the Federal Register Notice concerning this Information Collection Extension at https://www.federalregister.gov/documents/2018/08/30/2018-18829/information-collection-extension.

https://totalenergies.com/media/news/press-releases/australia-totalenergies-acquires-26-interest-cash-maple-gas-discoveries

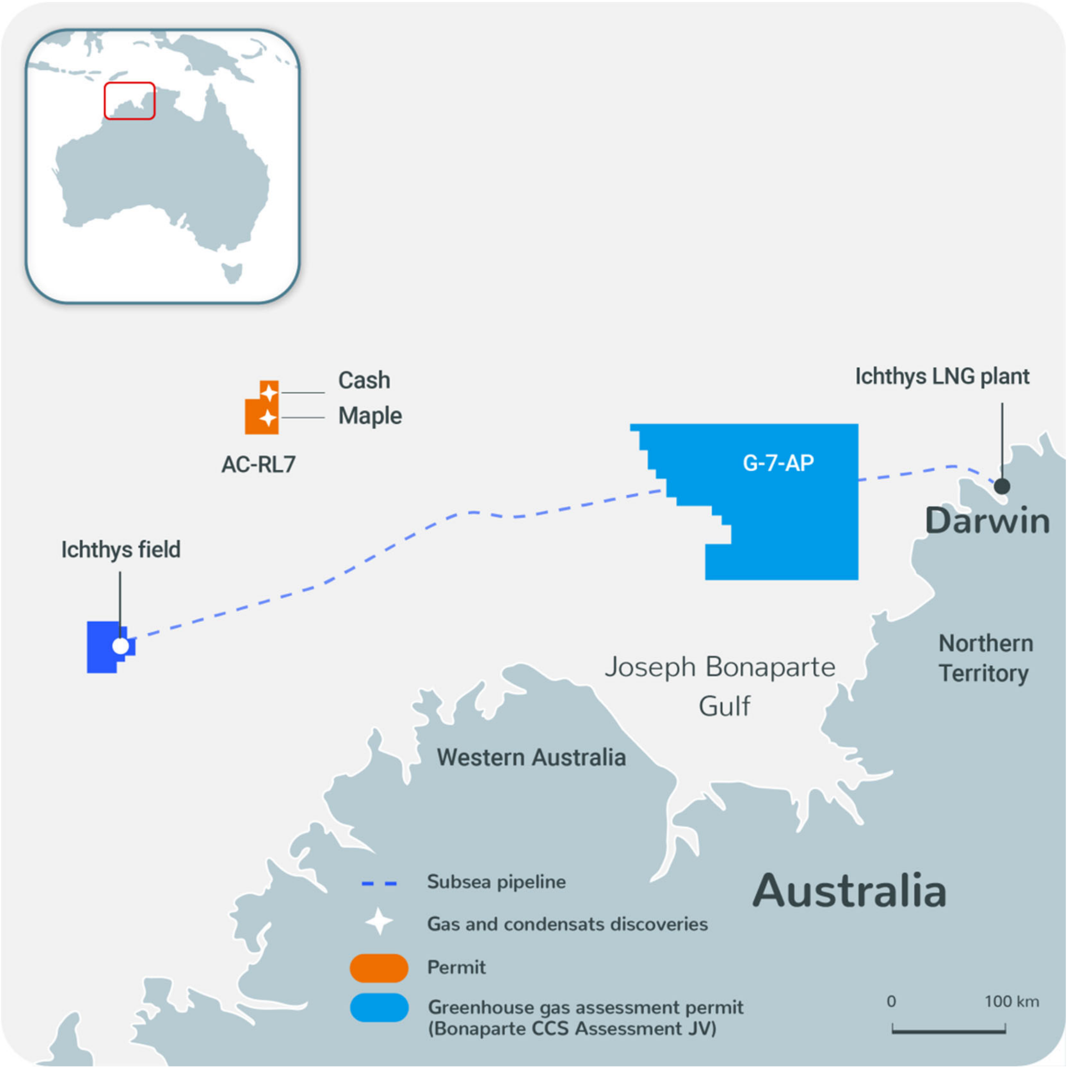
Australia: TotalEnergies acquires a 26% interest in the Cash-Maple gas discoveries for the long-term supply of Ichthys LNG

08/21/2023

Paris, August 21, 2023 – TotalEnergies and INPEX have signed an agreement with PTTEP in order to acquire the 100% interest held by PTTEP in the AC-RL7 permit in Australia. Under the terms of the agreement, which is subject to approval by the relevant authorities, TotalEnergies will acquire a 26% interest in the permit in line with its equity in Ichthys LNG, while INPEX will acquire the remaining 74% and assume operatorship.

The permit covers an area of 418 sq.km in the Timor Sea, approximately 250 kilometers northeast of the Ichthys offshore facilities. This permit includes the Cash and Maple gas and condensate fields, discovered in 2002 and 1989 respectively, and subsequently appraised by several wells. The development of these fields is expected to contribute to the long-term supply of the Ichthys LNG natural gas liquefaction plant, in which TotalEnergies is a 26% partner while INPEX and other Asian minority shareholders hold the remaining 74%.

“Thanks to this joint acquisition together with our partner INPEX, we are pleased to secure additional resources for the future supply of the Ichthys LNG plant. These resources will help us to meet the long-term demand of our customers in the Asia-Pacific region for LNG. This acquisition is also supported by the efforts undertaken with INPEX in the Bonaparte CCS Assessment joint venture to appraise the area’s potential for geological storage of CO_2, in order to abate CO_2 emissions from the Ichthys LNG project”, said **Julien Pouget, Senior Vice President Asia-Pacific, Exploration & Production at TotalEnergies**.



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TotalEnergies, the world's third largest LNG player

TotalEnergies is the world's third largest LNG player with a market share of around 12% and a global portfolio of about 50 Mt/y thanks to its interests in liquefaction plants in all geographies. The Company benefits from an integrated position across the LNG value chain, including production, transportation, access to more than 20 Mt/y of regasification capacity in Europe, trading, and LNG bunkering. TotalEnergies' ambition is to increase the share of natural gas in its sales mix to close to 50% by 2030, to reduce carbon emissions and eliminate methane emissions associated with the gas value chain, and to work with local partners to promote the transition from coal to natural gas.

About TotalEnergies

TotalEnergies is a global multi-energy company that produces and markets energies: oil and biofuels, natural gas and green gases, renewables and electricity. Our more than 100,000 employees are committed to energy that is ever more affordable, cleaner, more reliable and accessible to as many people as possible. Active in nearly 130 countries, TotalEnergies puts sustainable development in all its dimensions at the heart of its projects and operations to contribute to the well-being of people.

https://omannews.gov.om/topics/en/80/show/113923

Oman LNG Signs Two Binding Term-sheet Agreements to Supply More Than 1.5 mtpa of LNG

Muscat, 30 Aug (ONA) --- Oman LNG has announced the signing of two binding term sheet agreements to supply 0.8 million metric tonnes per annum of LNG to Shell International Trading Middle East FZE and 0.75 million metric tonnes per annum of LNG to OQ Trading.

The step comes to leverage the strategic partnership between Oman LNG and other energy firms.

Based on these agreements, Shell International Trading Middle East FZE will receive 0.8 million metric tonnes per annum of LNG from the company for 10 years starting from 2025 whereas OQ Trading will receive 0.75 million metric tonnes per annum of LNG under a 4-year deal beginning in 2026.

Both agreements form significant steps in the history of Oman LNG and a major milestone, where they mark the completion of delivering 10.4 mtpa per annum and a total of 80 mtpa over a period of 10 years. This achieves Oman LNG's goal to renew its contract beyond the year 2024 successfully in less than 12 months since the kickoff of this campaign.

With the previously agreed term sheet with Shell International Trading Middle East FZE for the offtake of another 0.8 million metric tonnes per year in January 2023, this additional term sheet makes Shell the biggest off-taker from Oman LNG beyond 2024. Additionally, it comes as a promising step for further collaborations with Oman's primary oil and gas trading arm, OQ Trading.

Under the presence of Eng. Salim Al Aufi, Minister of Energy and Minerals, the agreements were signed by Hamed Al Naamany, CEO of Oman LNG, Walid Hadi, Senior Vice President and Country Chair Oman Shell, (on behalf of Shell International Trading Middle East FZE), and Wail Al Jamali, CEO of OQ Trading at Oman LNG Head Office in Muscat.

Speaking after the signing ceremony, Hamed Al Naamany, CEO of Oman LNG, said " The term sheet agreements contribute to global energy security and sustain our position as a trusted supplier of reliable energy, where it facilitates business opportunities, and complements our objectives to establish partnerships and add value to the local economy. Additionally, this Global Marketing Campaign comes as an exceptional milestone in Oman LNG's rather stellar history despite the unprecedented volatile markets due to the geopolitical events and post covid challenges”.

The agreements are strengthened by the reputation and credibility of Oman LNG as a reliable and trusted LNG supplier around the globe, coupled with the effective management of business processes to produce clean energy delivered to customers around the world safely and reliably.

From his end, Walid Hadi, Senior Vice President and Country Chair, Oman Shell said: “Shell is proud of the role it has played sin Oman LNG to date, as a shareholder and a technical advisor since its inception. We are proud that we will now become Oman LNG’s largest LNG purchaser as well as its largest private shareholder. This additional off-take term sheet signifies our deep commitment to continue pulling on all levers of Oman’s energy system to address the pressing trilemma of sustainability, affordability, and security. Simultaneously, it serves as a pivotal step in the evolution of our hydrocarbon enterprise, steering it toward a future characterized by both low carbon emissions and financial viability.”

Wail Al Jamali, CEO of OQT, added: “As the international energy and commodity trading vehicle of the Government of Oman, we are delighted to add this strategic off-take to our portfolio. The execution of this term sheet represents the first long-term agreement between our two organisations following many years of cooperation. We are committed to developing a strong, sustainable relationships for the long-term benefit of our respective shareholders and the Sultanate of Oman”.

--- Ends/Khalid

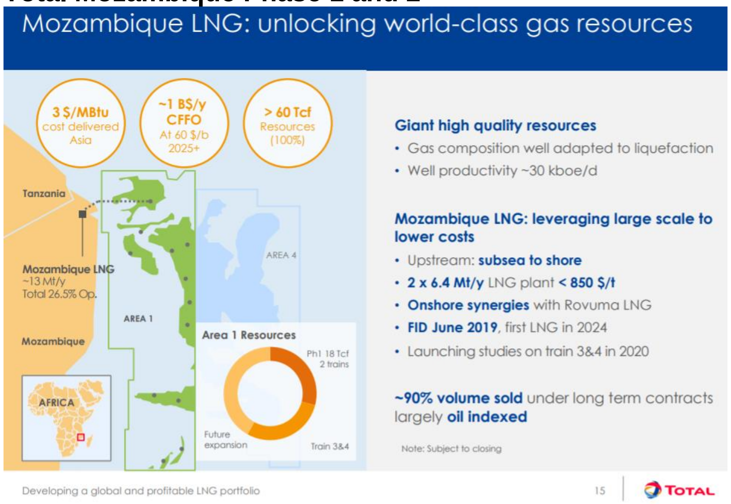
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

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



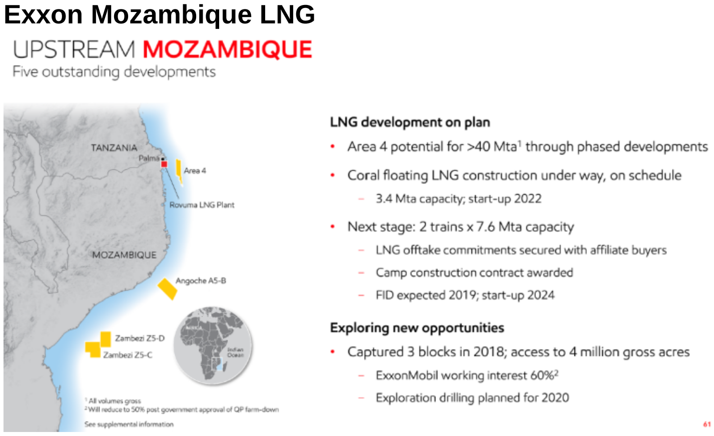
Source: Total Investor Day September 24, 2019

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

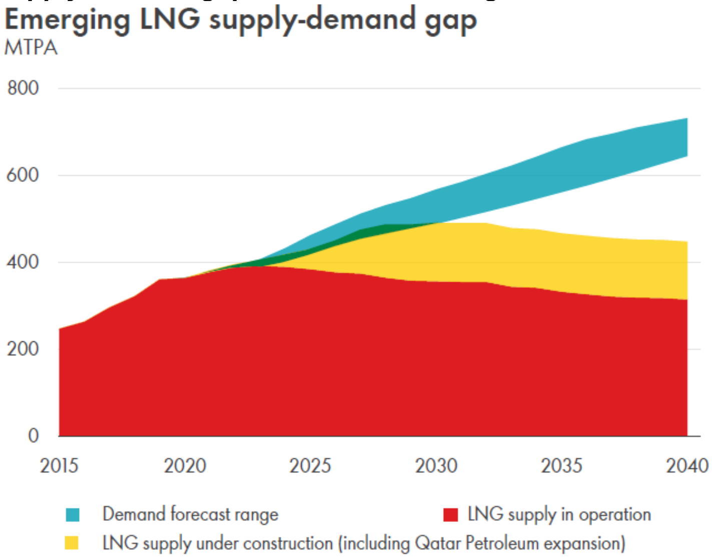
🟢 On Track 🟡 More Efforts Needed 🔴 Not on Track

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.

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.*

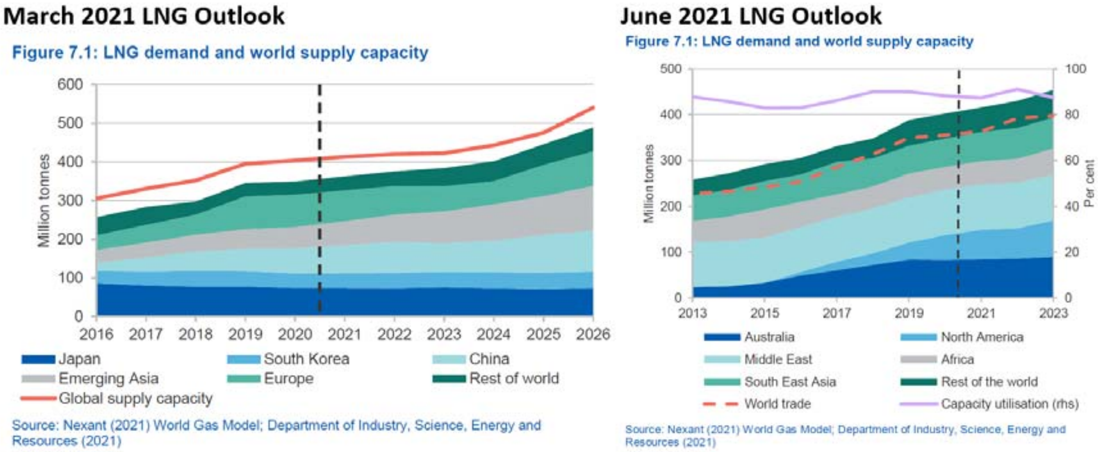
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required 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

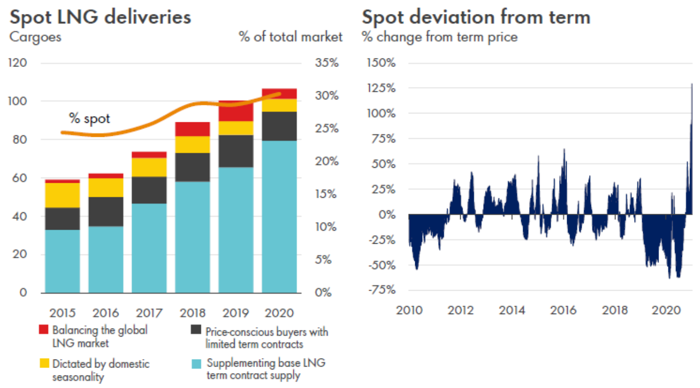


Source: Australia Resources and Energy Quarterly

<u>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.</u> 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.

<u>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</u>. 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.

Timestamped as of 4am MT on Sept 1

https://www.facebook.com/people/Offshore-Alliance/100063786371409/

Offshore Alliance

6h ·

Chevron's mismanagement of EBA negotiations on the Gorgon and Wheatstone Facilities has passed the point of being a train wreck waiting to happen, and has now been officially called a train wreck.

Chevron have been completely smashed up in an EA Ballot designed to circumvent EBA negotiations with the Offshore Alliance.

The Chevron genius who thought up the idea to postpone bargaining with the Union to put a dodgy EA out to vote with zero prospect of it being voted up, is odds on favourite to be awarded HR Manager of the year by the Offshore Alliance when we present our annual awards to the oil and gas corporations and contractors.

Despite the Ballot for Chevron's sub-standard Non-Union EA closing at 7:00 PM last night, Chevron (despite having access to the live ballot results for the entire period of their 36-hour ballot), took 16 hours to release the Ballot results to OA members on the Gorgon and Wheatstone Downstream facilities.

Even Robert Mugabe would have done a better job than this mob in this regard.

Less than 1% of the Wheatstone Downstream and Gorgon workforce voted 'YES' to Chevron's rubbish EA.

That's just 3 workers out of 461 workers voting 'YES'

When the Wheatstone Platform EA Ballot results are factored in, just 4 out of 518 Chevron employees have voted 'YES' to their rubbish non-union EA proposal.

Great work Chevron HR – They have no idea, no clue and are completely out of touch with our members.

Chevron HR reckon that their dodgy non-union EA proposal had "closed the gap" but the Ballot results show that they are out of touch with OA members and haven't listened to a word spoken in their discussions with members, Reps and the Offshore Alliance.

Protected Industrial Action commences on all 3 Chevron facilities at 06:00 Thursday 7th September.

Offshore Alliance

12h ·

Chevron claim that they have contingency plans to deal with Protected Industrial Action, yet they have already cancelled the Wheatstone Turbine Turnaround without a shot being fired.

Chevron's plan to use inexperienced and incompetent office jockeys in place of competent and experienced operations personnel is a train wreck waiting to happen (no pun intended).

Protected Industrial Action accross all Chevron West Coast facilities commences Thursday 07 September and there is almost zero chance of Chevron not losing $billions of profit and production when PIA ramps up.

The OA members will go one day longer and one day stronger than Chevron.

Offshore Alliance

2d ·

In December 2022, Altrad bought out AGC's Chevron contracts and picked up a 'never-used' Baseline Agreement from AGC subsidiary outfit Workforce Logistics. This dodgy Baseline Agreement is subject to an Appeal by the Offshore Alliance before the Full Bench of the FWC, and the Agreement has a repugnant stench to it.

Altrad have been using this dodgy EA to employ and exploit workers on Chevron's Wheatstone and Gorgon facilities.

The Full Bench of the FWC are currently Hearing our Appeal against the approval of the Altrad Enterprise Agreement and plenty will be said about this Baseline Agreement in due course.

Whilst the Full Bench are delving into how the former Altrad entity Workforce Logistics created its Baseline Agreement, Chevron are seeking support for a sub-standard EA of its own.

Chevron's proposed EA on the Gorgon and Wheatstone Downstream facilities, also has a repugnant stench to it. It fails almost every possible test by:

1. Not having job security measures of any real value to employees;

2. No roster certainty;

3. Sub-standard REM at every level (significantly behind salaries and other remuneration standards of other operators);

4. Travel entitlements which leave employees out of pocket;

5. Training rates which are less than those paid by Chevron 12 months ago;

6. No protection from forced transfers to other sites;

7. Employees can be coerced to work overcycle for zero pay on demob day;

8. Employees can be coerced to work overcycle with inadequate remuneration or parameters on the working of overcycle;

9. No late demob payments (unless by the good grace of Chevrong);

The Offshore Alliance is asking members to give Chevron a big fat zero in their EA Ballot by voting 'NO' to their rubbish EA proposal.

Offshore Alliance

3d ·

Unions call strike action at Chevron gas operations

Australian Financil Review

By David Marin-Guzman and Angela Macdonald-Smith

Unions have given notification they will undertake rolling stoppages and work bans at Chevron's Gorgon and Wheatstone LNG projects in Western Australia that will start next week and escalate every week after that, in a key threat to global gas supply.

The Offshore Alliance – including the Australian Workers Union and Maritime Union of Australia – served Chevron late on Monday with protected action notices at all three of its west coast facilities, starting on Thursday, September 7, and covering 500 workers.

Wheatstone is one of Australia's largest resource developments and the nation's first LNG hub.

The facilities, including the Gorgon and Wheatstone onshore processing plants and the Wheatstone offshore platform, supply about 7 per cent of globally traded LNG.

Dutch front-month futures, Europe's gas benchmark, rose 10.5 per cent to €38.41 a megawatt-hour overnight after Chevron said it was alerted of the action.

The market has been on edge this month amid labour disputes in Australia – one of the world's top producers of liquefied natural gas – as strikes could limit global supplies during a crucial period as Europe prepares for winter.

Last week, prices whipsawed after Woodside Energy had a breakthrough with unions, avoiding strikes that could have shut the country's biggest production plant for LNG.

The latest news suggests it isn't clear if Chevron will be able to do the same.

"International gas companies operating in Australia, like Chevron and Shell, who are unable to fully make decisions locally, can tend to see industrial action escalate more so than local companies like Woodside," energy analyst Saul Kavonic said.

Shell suffered a total shutdown that lasted more than two months at its Prelude floating LNG project off WA last year due to the same type of industrial dispute.

'Inept and incompetent performance'

Unions said on Tuesday that "members will be participating in rolling stoppages, bans and limitations which will escalate each week until Chevron agrees to our bargaining claims".

"Chevron's bargaining efforts have been the most inept and incompetent performance we have seen to date from any of the outfits we have dealt with since the formation of the Offshore Alliance in October 2018," they said.

"It's set to cost Chevron their LNG exports as protected industrial action starts to bite."

A Chevron spokesman confirmed that "we've received notices for protected industrial action at our Gorgon and Wheatstone facilities for activities commencing Thursday, September 7".

"While we don't believe that industrial action is necessary for agreement to be reached, we recognise employees have the right to take protected industrial action and we will continue to take steps to maintain safe and reliable operations in the event of disruption at our facilities," he said.

"We will also continue to work through the bargaining process as we seek outcomes that are in the interests of both employees and the company."

Unions are seeking to lock in benchmark industry conditions, control over rosters and restrictions on contractors.

However, the threat of strikes has gone further at Chevron than with Woodside LNG platform workers, who withdrew plans to notify industrial action last week after reaching a midnight deal.

Chevron has decided to bypass unions at its Gorgon and Wheatstone plants and put its proposed offer to a direct staff vote.

A previous attempt to do the same for the Wheatstone platform resulted in a 2 per cent "yes" vote.

Mr Kavonic said that with three major union negotiation precedents to narrow the range of outcomes for negotiations, "a resolution is still likely without materially impacting global supply, but it may prove a more painful process to arrive at than we saw with the Woodside negotiations".

He said initial strike action such as work stoppages for short periods and bans on specific work such as helicopter unloading could create inefficiencies and lead to minor production disruptions.

"They are designed to show the seriousness of the unions' resolve, and to pressure Chevron into a deal, without having to resort to prolonged large-scale production disruptions that could jeopardise international and local energy security and create a political crisis for the local, state and federal governments," Mr Kavonic said.

The Gorgon and Wheatstone plants are also by far the biggest suppliers of gas to the WA domestic market, and a shutdown would hit several industrial and mining operations across the state.

They accounted for 29 per cent and 18 per cent, respectively, of WA domestic gas supplies in the March quarter of 2023, according to figures from energy consultancy EnergyQuest. Domestic customers of Gorgon and Wheatstone include gold miner Newcrest and South32's Worsley alumina refinery.

AFR.COM

Unions call strike action at Chevron gas operations

Unions say they will undertake rolling stoppages of up to 11-hours ...

Offshore Alliance

3d ·

Late yesterday, the Offshore Alliance lawyers served Chevron with formal Notice of Protected Industrial Action on all 3 West Coast facilities, commencing Thursday 7th September 2023. OA members will be participating in rolling stoppages, bans and limitations which will escalate each week until Chevron agrees to our bargaining claims.

Chevron's bargaining efforts have been the most inept and incompetent performance we have seen to date from any of the outfits we have dealt with since the formation of the Offshore Alliance in October 2018.

And this is despite Chevron having an army of HR bosses and lawyers at their disposal.

It's set to cost Chevron their LNG exports as PIA starts to bite.

Great work by the OA Chevron rank and file in sticking tight in their fight for benchmark industry standards. Plus job security.

The OA Chevron crew won't be intimidated by an outfit which think they can exploit our resources, rip off Australian taxpayers and underpay highly skilled oil and gas workers engaged on remote major hazard facilities.

The OA members will go one day longer and one day stronger than Chevron in our EBA campaign.

Offshore Alliance

4d ·

With a 100% 'YES' vote for Protected Industrial Action on Chevron's Wheatstone Platform, we have now got 100% support for PIA from members accross all 3 Chevron facilities. Our members are locked and loaded and ready for PIA.

The Offshore Alliance will be fighting from the front with Protected Industrial Action to secure an industry standard EBA.

All 500 OA members on the 3 Chevron facilities are backing in PIA.

PIA Notices will be filed shortly as will members lining up to vote 'NO' against Chevron's third rate EA proposal on the Gorgon and Wheatstone Downstream facilities.

There is no get out of jail for Chevron on this one.

Offshore Alliance

4d ·

With the Offshore Alliance about to kick off Protected Industrial Action across Chevron's 3 offshore and onshore facilities, the Offshore Alliance have made it clear to Chevon that no member will be left behind in our eventual settlement of our bargaining claims.

A settlement which is increasingly likely to come after we jam up Chevron's LNG exports with Chevron losing $billions of revenue in a misguided ideological war against their West Coast workforce.

Whilst Chevron have a decade of standing over and bullying its entire West Coast oil and gas workforce, they have made an artform of screwing over individuals and smaller cohorts of workers.

In 2020, Chevron put an “Offer and Accept” proposal to lab-chemists/analysts and maintenance planner/schedulers which was along the lines that if workers didn’t accept Chevron’s ‘offer’ to increase rostered days worked by 20% with no additional salary, they would be sacked and replaced by contractors.

This is typical of the ‘back of the axe’ approach taken by Chevron HR in their attack on employees.

The OA Chevron membership are unbending in ensuring that all members who were coerced into signing even time roster contracts, get back onto the 40% roster.

And we are equally committed to ensuring that the employment terms of our Onslow members are included in the Wheatstone Downstream EBA.

Chevron’s decision to put an Enterprise Agreement out to vote on the Gorgon and Wheatstone Downstream facility is an act of industrial stupidity in light of the PIA Ballot results which were supported by 98% of the Gorgon and Wheatstone workforce and by 100% of Offshore Alliance members who voted in the Ballot (98% union density).

The reason OA members are taking PIA is because of Chevron's intransigent, arrogant and belligerent approach to EBA negotiations.

In the case of the Wheatstone Platform, our members have had to put up with this rubbish for approximately 3 1/2 years and enough is enough.

Chevron’s shrill bargaining demands include:

1. Roster flexibility where Chevron can unilaterally change rosters;

2. The "right" of line management to indiscriminately block level progression;

3. The "right" of Chevron to coerce employees to work on other facilities;

4. The lack of job security;

5. The right of Chevron to force employees onto different panels and not re-imburse them for expenses incurred;

6. Sub-standard overcycle arrangements, including mandatory overcycle;

7. Employees working for free on demob day;

8. REM standards which are well below industry standards.

All this plus more will result in support for Chevron's garbage EA proposal being somewhere in the vicinity of 0%.

The mob of industrial troglodytes got 2% support for their rubbish EA on the Wheatstone Platform and the bookies have Chevron at odds on favourite to get 0% support on Gorgon and Wheatstone Downstream.

The scraps Chevron have thrown their FL5 and FL6 employees shows Chevron’s absolute contempt for some of the highest skilled and experienced hydrocarbon workers in the world.

The Offshore Alliance has the back of all members and no-one will be left behind as we push onto the next stage of our bargaining campaign with Chevron.

Excerpt https://www.transmountain.com/news/2023/trans-mountain-corporation-releases-second-quarter-2023-results

Trans Mountain Corporation Releases Second Quarter 2023 Results

Aug. 29, 2023

As of June 30, 2023, construction of the Project is approximately 90 per cent complete, with $24.0 billion in construction capital spending incurred plus $3.3 billion in financial carrying costs capitalized since the inception of the Project. TMC continues to target the end of 2023 for mechanical completion with commercial service of the Project anticipated to occur in the first quarter of 2024.

As of August 19, 2023, construction of the Project is 94 per cent mechanically complete with approximately 42 kilometres of pipe left to install. Berth 1 at the Westridge Marine Terminal has been operating since mid-July. We made significant progress on watercourse and highway crossings and construction in the Lower Mainland is 93 per cent complete and 97 per cent of our facilities in Alberta and B.C. (including Edmonton Terminal and Alberta/B.C. pump stations) are also complete. We have mitigation and contingency plans in place due to construction challenges in areas including Burnaby Mountain Tunnel, Jacko Lake and Mountain 3 in Spread 5B. We are currently planning and targeting the commencement of service on the expanded pipeline system near the end of the first quarter of 2024.

Excerpt https://www.transmountain.com/news/2023/trans-mountain-corporation-releases-first-quarter-2023-financial-results

Trans Mountain Corporation Releases First Quarter 2023 Financial Results

May 30, 2023

As of March 31, 2023, construction of the Trans Mountain Expansion Project (“the Project”) is approximately 82 per cent complete, with $21.5 billion in construction capital spending incurred plus $2.8 billion in financial carrying costs capitalized since the inception of the Project.

Trans Mountain anticipates mechanical completion of the Project to occur at the end of 2023 with commercial service expected to occur in the first quarter of 2024. The company’s projected Adjusted EBITDA is expected to be approximately $2.4 billion in the first full year of the expanded assets operation and expected to grow annually thereafter. These projections are underpinned by long-term contractual commitments for 80 per cent of the system’s 890,000 barrels a day of capacity and expected utilization of uncontracted capacity of the system once in service.

Excerpt https://www.transmountain.com/news/2023/trans-mountain-corporation-releases-fourth-quarter-and-year-end-2022-financial-results

Trans Mountain Corporation Releases Fourth Quarter and Year End 2022 Financial Results

May 9, 2023

As of December 31, 2022, construction of the Trans Mountain Expansion Project (“the Project”) is approximately 75 per cent complete, with $18.9 billion in construction capital spending incurred. Trans Mountain anticipates mechanical completion of the Project to occur at the end of 2023 with commercial service expected to occur in the first quarter of 2024. The company’s projected Adjusted EBITDA is expected to be approximately $2.4 billion in the first full year of the expanded assets operation and expected to grow annually thereafter. These projections are underpinned by long-term contractual commitments for 80 per cent of the system’s 890,000 barrels a day of capacity and expected utilization of uncontracted capacity of the system once in service.

File OF-Fac-Oil-T260-2013-03 61

CANADA ENERGY REGULATOR

IN THE MATTER OF the *Canadian Energy Regulator Act,* SC 2019, c 28, s 10 ("**CER Act**") and the Regulations thereunder;

AND IN THE MATTER OF the Certificate of Public Convenience and Necessity OC-065 and related orders held by Trans Mountain Pipeline ULC as General Partner of Trans Mountain Pipeline L.P. ("**Trans Mountain**"), in respect of the Trans Mountain Expansion Project ("**TMEP**" or "**Project**");

AND IN THE MATTER OF the deviation application filed on August 10, 2023, pursuant to section 211 of the CER Act ("**Application**").

REPLY EVIDENCE OF TRANS MOUNTAIN

August 31, 2023

To: The Secretary
Canada Energy Regulator
Suite 210, 517 – 10th Avenue S.W.
Calgary, AB T2R 0A8

TABLE OF CONTENTS

I. INTRODUCTION

1. Trans Mountain is in receipt of the written submissions from Stk'emlúpsemc te Secwépemc Nation ("SSN") and its constituent First Nations[1] in respect of the Application.[2]

2. In accordance with the procedural schedule set out in the letter of the Commission of the Canada Energy Regulator ("Commission") dated August 16, 2023,[3] and the revised process and schedule established by the Commission on August 30, 2023,[4] Trans Mountain provides herein its reply evidence to the submissions of SSN.

3. Having regard to the process established by the Commission for its consideration of the Application,[5] Trans Mountain's submissions are focused on replying to the evidence contained in SSN's submissions that is relevant to the determinations that the Commission is required to make in respect of the Application. Trans Mountain is not replying to the legal submissions or legal arguments contained in the submissions of SSN, which Trans Mountain will address as part of its legal arguments during the hearing.

4. Further, the evidence that Trans Mountain has already submitted on the record of this proceeding largely addresses many of the submissions from SSN. Therefore, rather than repeating that evidence, Trans Mountain provides references to that evidence where appropriate in this reply to identify where it can be found on the record of this proceeding. That Trans Mountain does not respond herein to all matters raised or positions taken by SSN in its submissions should not be interpreted as acceptance by Trans Mountain of any of the submissions set forth therein.

II. IMPORTANCE OF THE PÍPSELL/JACKO LAKE AREA AND IMPACTS FROM THE TMEP

5. Trans Mountain appreciates and acknowledges the cultural significance of the Pípsell/Jacko Lake area to SSN, and the values that the area holds for past, current and future generations. The importance of this area to SSN is reflected in the extensive engagement efforts that Trans Mountain has undertaken with SSN to date (as discussed in the Application and further below in this reply evidence), as well as the Mutual Benefits Agreement entered into by Trans Mountain and SSN (the "MBA"), which was the basis on which SSN agreed to provide its consent for the Project.[6]

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[1] Filing ID C25999, as amended by the refiling of Appendix D, Filing ID C26001.

[2] Filing ID C25832.

[3] Filing ID C25914.

[4] Filing ID C26015.

[5] Filing ID C25914 and Filing ID C26015.

[6] See, for example, Filing ID C25999-2 at paras 3, 5, 29, 31, 45, 49, 51, 61, 71, 133.

6. As part of its engagement with SSN, Trans Mountain has worked closely and proactively with SSN and placed a high priority on carrying out TMEP construction in a manner that minimizes impacts on these lands and their cultural values, consistent with the MBA. It is for this reason that Trans Mountain agreed to pursue trenchless construction within the Pípsell/Jacko Lake area where feasible, has taken costly steps to address the challenges it has experienced with micro-tunneling to date, and has proposed an extensive suite of mitigation measures for the proposed deviation, as described in Trans Mountain's response to CER IR No. 1.1,[7] including reclaiming the disturbed land to National Park standards.

7. Throughout its submissions, SSN claims that its support for the Project – as reflected in the MBA – was premised on the Project being constructed through the Pípsell/Jacko Lake area using trenchless methods only,[8] and that the reasons for Trans Mountain's Application "do not meet the standards required for a deviation as agreed between SSN and Trans Mountain in the [MBA] … in respect of the Project".[9] SSN also claims that proceeding with open trench construction in the Pípsell/Jacko Lake area would be contrary to SSN's laws.[10]

8. Trans Mountain disagrees with SSN's characterizations of the MBA. Most notably, the MBA allows Trans Mountain to make a determination that trenchless construction is either not technically feasible or is economically infeasible, and thereafter to proceed with an alternative construction methodology. The MBA establishes a specific formula for Trans Mountain to provide financial compensation to SSN for any portion of TMEP construction in the Pípsell/Jacko Lake area for which Trans Mountain does not use trenchless construction.

9. Trans Mountain also rejects SSN's characterization of its efforts to implement trenchless construction within the Pípsell/Jacko corridor – and to propose the deviation – as not meeting the requirements of the MBA.

10. The evidence in this proceeding is that Trans Mountain's determination, that micro-tunneling is "economically infeasible", is based on the fact that the conditions being encountered in the subject micro-tunneling segment are such that continuing to implement the micro-tunneling for this discrete segment would require Trans Mountain to incur costs that are unreasonably in excess of the construction costs normally associated with trenchless construction. This determination accords with the framework agreed to in the MBA.

11. Further, Trans Mountain's determination that micro-tunneling is not "technically feasible" is based on significant physical, geological and financial impediments to utilizing the currently contemplated micro-tunneling methodology, materials, technologies, equipment

[7] Filing ID C25972-2.

[8] See, for example, Filing ID C25999-2 at paras 3, 5, 29, 31, 45, 49, 51, 61, 71, 133.

[9] See, for example, Filing ID C25999-2 at para 5(c). See also paras 45, 49, 51, 61, 71, 133.

[10] Filing ID C25999-2 at para 15.

and practices. This determination is similarly consistent with the framework agreed to in the MBA.

12. Trans Mountain's determination that micro-tunneling within the impacted section of the Pípsell/Jacko Lake corridor is not technically or economically feasible as contemplated in the framework of the MBA was made based on the evidence already before the Commission that confirms the significant technical challenges being encountered on the micro-tunnel drive between pads 1 and 2 and the associated risks to completing construction in that regard.[11] Trans Mountain has also previously identified the fact that the costs of micro-tunneling will significantly exceed the construction costs normally associated with trenchless construction.[12]

13. As indicated in the Application, Trans Mountain has made several unsuccessful, costly attempts to address the problem of upward Reinforced Concrete Jacking Pipe ("RCJP") migration associated with tunnel drive #2 to date. Those attempts are summarized in Trans Mountain's response to CER IR No. 1.2b).[13] In response to paragraph 103 of SSN's submissions, the considerable costs that Trans Mountain has incurred in its attempts to address the problem of upward RCJP migration are set out in Table 1 below.

Table 1 – Costs to Address Upward RCJP Migration

Mitigation	Description	Estimated Cost Impact
Stage 1	Invert flushing	$0.75 million
Stage 2	Apply ballast weight at the inverts of pipes	$9.12 million
Stage 3	Shaft construction (Shaft-6) and abandonment of impacted tunnel drive segment	$22.17 million

14. For context, prior to starting micro-tunneling, Trans Mountain expected the total construction costs for tunnel drive #2 to be approximately $23 million.

15. Trans Mountain further notes that continuing with micro-tunneling would likely delay the in-service date for the TMEP, for the reasons described in Trans Mountain's response to CER IR No. 1.2.[14] Each month of delay in the TMEP in-service date results in roughly $200 million in lost revenues and roughly $190 million in carrying charges for Trans Mountain. Trans Mountain's shippers and other parties relying on the TMEP will also incur losses with each month that the Project is delayed.

[11] Filing ID C25832-1 at paras 18-22; Filing ID C25972-2, Trans Mountain response to CER IR No. 1.2.

[12] Filing ID C25832-1 at paras 18-22; Filing ID C25972-2, Trans Mountain response to CER IR No. 1.2.

[13] Filing ID C25972-2.

[14] Filing ID C25972-2.

16. For all of the above reasons, Trans Mountain made the determination that trenchless construction within the impacted section of the Pípsell/Jacko Lake area is not technically feasible and is economically infeasible, a determination that Trans Mountain is expressly authorized to make under the framework agreed to with SSN under the MBA, and for which a compensation formula has been established. The Application that is before the Commission is precisely the scenario contemplated within the MBA, and consistent with the basis upon which SSN provided its consent to the Project.

17. With respect to SSN's statement that proceeding with open trench construction in the Pípsell/Jacko Lake area would be contrary to SSN's laws, Trans Mountain notes that the trenchless construction methodology for the Pípsell/Jacko Lake area that SSN has expressly supported includes sections of open trench, as well as various other types of surface disturbance, within the Pípsell/Jacko Lake area, including:

(a) approaching from the north, an open cut portion of the TMEP extending for approximately 4.0 kilometres to pad 1;

(b) an open cut portion of the TMEP south of pad 5 extending for approximately 3.7 kilometres to the southern extent of the Pípsell/Jacko Lake area;

(c) 28 geotechnical boreholes;

(d) six pads for tunnel operations; and

(e) five roads.

18. Regardless of the construction methodology, the TMEP in this area will also require power supply for cathodic protection, including an above-ground power transmission line, 17 power poles, and an above-ground transformer, as well as associated access.

19. The pads and roads listed above associated with the micro-tunneling comprise roughly 5.18 hectares of disturbance (i.e., items (d) and (e) above, not including items (a) through (c)). In contrast, the proposed deviation will consist of roughly 4.83 hectares of new disturbance. All of this new disturbance will occur on privately held, previously disturbed lands.

III. MICRO-TUNNELING IS NOT TECHNICALLY FEASIBLE

20. Trans Mountain provided extensive details about why continuing with micro-tunneling for tunnel drive #2 is not technically feasible in the Application and its response to CER IR No. 1.2. Trans Mountain maintains that position.

21. SSN's submissions state that, in SSN's view, micro-tunneling remains viable because (1) Trans Mountain agreed to use micro-tunneling as the construction method for this area, (2)

there have been no "insurmountable" issues with this methodology to date, and (3) there have been no "surprise" geological or hydrological issues found.[15]

22. On SSN's first point, the fact that Trans Mountain previously agreed to construct the pipeline using micro-tunneling in this area, based on its understanding of the geotechnical conditions at that time, has no bearing on whether micro-tunneling remains feasible today. As noted above, Trans Mountain's agreement to use trenchless construction methods in the MBA was contingent on trenchless construction being technically and economically feasible. Again, Trans Mountain's evidence is that micro-tunneling is no longer technically or economically feasible.

23. On SSN's second point, SSN seems to be conflating "infeasibility" with "impossibility". While Trans Mountain agrees that it may be physically *possible* to complete the pipeline in this area using micro-tunneling, it is no longer reasonable or prudent for Trans Mountain to continue with micro-tunneling because of the significant risks, costs and delays associated with this approach. That is what Trans Mountain means when it says that it is not technically or economically feasible to continue with micro-tunneling, and that approach is also consistent with the framework agreed to in the MBA.

24. On SSN's third point, SSN relies on a geotechnical report in which its subject-matter expert incorrectly claims that three other drives have been successfully completed within Spread 5A of the TMEP using the same micro-tunneling machine in very similar ground conditions.[16] In fact, only two drives have been completed at the time of this filing (tunnel drive #1 and tunnel drive #3), and the ground conditions being experienced in tunnel drive #2 are different, and more challenging, than the conditions experienced on tunnel drives #1 and #3. The technical challenges experienced to date on tunnel drive #2 (as described in the Application and Trans Mountain's response to CER IR No. 1.2c))[17] were not reasonably foreseeable at the time Trans Mountain agreed to pursue micro-tunneling for this segment of the TMEP.

25. Given the length of tunnel remaining to be completed and the formations expected to be encountered, Trans Mountain maintains that proceeding with tunnel drive #2 is highly risky. If the risks identified in Trans Mountain's response to CER IR No. 1.2c)[18] materialize, they have the potential to delay tunnel completion by months or jeopardize Trans Mountain's ability to complete the tunnel at all. As such, Trans Mountain no longer considers micro-tunneling to be a reasonable or prudent construction method for this segment.

[15] Filing ID C25999-2 at para 75.

[16] Filing ID C25999-17.

[17] Filing ID C25832-1 at paras 18-22; Filing ID C25972-2, Trans Mountain response to CER IR No. 1.2.

[18] Filing ID C25972-2.

IV. TRANS MOUNTAIN'S PROPOSED CONSTRUCTION METHODS ARE FEASIBLE AND APPROPRIATE

A. Horizontal Direction Drill (HDD)

26. In the portion of its submissions titled "Trans Mountain Previously Raised Serious Concerns Regarding HDD Feasibility", commencing on page 18, SSN references a March 2021 slide deck, which identified potential methods of installing the pipeline in the Pípsell/Jacko Lake area. Of the methods discussed, a preliminary review of the HDD of the Jacko Lake Hill was completed, and general comments were provided on geometry and risks (which were noted to be moderate to high). The preliminary design at the time of the 2021 slide deck contemplated an 800-metre long HDD. Further, site-specific geotechnical investigations had not yet been completed at the time of this 2021 preliminary report.

27. Since the time of the 2021 presentation, Trans Mountain has completed further design iterations and investigative reviews of the HDD for the proposed deviation, which would be approximately 450 metres long. Trans Mountain has also completed site-specific geotechnical investigations.

28. The findings of the June 2023 geotechnical assessment for the trenchless crossing at Jacko Hill[19] indicate that the proposed HDD installation is feasible, as noted in the Application and Trans Mountain's response to CER IR No. 1.2. That report also notes that the same rock that tunnel drive #2 encountered will be intersected with the proposed HDD. Tunnel drive #2 did not note any highly fractured zones impacting forward progress. The HDD is expected to be successfully installed in this formation, similar to other HDDs completed in similar rock conditions on the Project.

29. In the report provided as Appendix D to SSN's submissions, SSN's subject-matter expert states that they do not consider the HDD to be feasible for a borehole with a nominal diameter of 2,000 millimetres, in soil or in rock.[20] However, the proposed HDD for Jacko Hill would be completed using a final borehole diameter of 48 inches (1,219 millimetres) with the 36 inch (914 mm) product pipe installed inside. SSN's subject-matter expert acknowledged that they had "extremely little informative material, especially on the geology, to work with"[21] in conducting their review of the proposed HDD.

30. Trans Mountain is currently successfully executing several hard rock crossings with similar rock quality designations over lengths that are much greater than the 450 metres for the HDD that is part of the proposed deviation. Based on Trans Mountain's experience completing HDD crossings within bedrock over greater lengths elsewhere along the route of the Project, Trans Mountain expects the proposed HDD crossing of the Jacko Lake Hill will be successful.

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[19] Filing ID C25972-6.

[20] Filing ID C26001-2 at PDF 17.

[21] Filing ID C26001-2 at PDF 17.

B. Culturally Significant Features

31. At paragraph 88 of its submissions, SSN identifies two culturally significant features close to the area of disturbance for the proposed deviation, including a directional tree within the proposed construction footprint for the applied-for deviation. Trans Mountain confirms that all culturally significant features identified by SSN will be avoided and protected during construction of the applied-for deviation. With respect to the directional tree, this feature is located within the HDD section of the proposed deviation and will be avoided by installing the pipeline without surface disturbance in that area.

V. HISTORY OF TMEP PLANNING IN THE PÍPSELL/JACKO LAKE AREA

A. Reasons for Timing of Commencement of Trenchless Construction

32. In section 3.1 of its submissions titled "Trans Mountain Delayed Implementing Trenchless Construction", SSN states that following execution of the MBA in October 2019, "Trans Mountain delayed conducting meaningful work to plan trenchless construction methods in collaboration with SSN" and that Trans Mountain "did not begin substantially planning the current trenchless construction methods with SSN until the spring of 2021."[22] Based on these assertions, SSN concludes that the "nearly two-year delay is the responsibility of Trans Mountain", which it says is a "critical detail" given that "impacts of a delayed in-service date are among Trans Mountain's primary concerns …".[23] The asserted "two-year delay" is a reference to the time-period between the date of SSN's withdrawal of the 2019 Statement of Opposition and the filing of the previous deviation application in February 2022.

33. SSN's characterization of the above-mentioned two-year period as a "delay" is incorrect. This characterization fails to acknowledge the complexities involved in staging the construction of a roughly 1,000 kilometre pipeline through multiple spreads and multiple construction seasons while determining a new construction methodology for the segment of pipeline in the Pípsell/Jacko Lake area. Detailed construction and engineering cannot be advanced for the entire route simultaneously and must proceed in sequence. Trans Mountain advanced its construction plans for the Pípsell/Jacko Lake area appropriately, based on the expected duration of that construction work and its sequencing within the overall TMEP execution plan.

34. The commencement of trenchless construction was also impacted by several factors that were outside of Trans Mountain's control, including severe flooding, forest fires and air quality, and the onset of the global COVID-19 pandemic in early 2020, which delayed planning along the entire TMEP route, including the Pípsell/Jacko Lake area, and which delayed construction across the Project due to shortages and delays in the global supply

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[22] Filing ID C25999-2 at paras 32, 33.

[23] Filing ID C25999-2 at paras 37, 38.

chain. While flooding did not occur in the Pípsell/Jacko Lake area, flooding in British Columbia in late 2021 delayed construction across the TMEP route.

35. Trans Mountain's engagement records, which are summarized in the engagement log filed with the Application, show that Trans Mountain reasonably advanced development of trenchless construction plans for the Pípsell/Jacko Lake area. These engagement records can be summarized as follows:

(a) Following execution of the MBA in October 2019, Trans Mountain immediately proceeded in November 2019 to engage with SSN regarding land access requirements for geotechnical work in advance of snowfall.

(b) In assessing various trenchless construction methodologies, Trans Mountain considered a variety of factors including but not limited to: constructability, grading plans, construction schedule, availability in the market of the required specialized equipment and spare parts, availability of contractors, geotechnical formations and engineering. This work commenced in November 2019 and continued through 2020 and 2021.

(c) In mid-April 2020, Trans Mountain emailed SSN to request a meeting to discuss Pípsell construction and followed up in early June 2020 with additional information regarding an HDD trenchless construction methodology in advance of a call that had been scheduled for the week of June 8, 2020. Mobilization for Spread 5A began in June 2020, and on July 11, 2020, Trans Mountain and SSN conducted a joint site visit of the Pípsell construction area.

(d) During September and into the fall of 2020, Trans Mountain began preparing a grading plan for construction in the Pípsell area and proposed a trenchless construction methodology to SSN. Meetings were held and communications exchanged between Trans Mountain and SSN during November 2020 and December 2020 regarding the HDD trenchless construction proposal.

(e) In November 2020, Trans Mountain confirmed that, at the request of SSN, it was gathering more information on trenchless construction for the Pípsell/Jacko Lake area. On that basis, and at the request of SSN, a prescheduled meeting for December 18, 2020 was cancelled. However, Trans Mountain continued to gather information on trenchless construction and continued to respond to further SSN technical requests for information.

(f) In January 2021, SSN provided Trans Mountain with its assessment of the HDD proposal, which SSN rejected. Following receipt of the SSN assessment, Trans Mountain continued to gather more information on trenchless methodologies and undertook further work to assess trenchless methods, including the preparation of an assessment of risk between trenchless and conventional construction methods in the Pípsell area.

(g) Throughout 2021, Trans Mountain continued engagement with SSN and continued with the extensive work it was conducting regarding trenchless methodologies. This engagement is detailed in the engagement log included in the Application.

(h) While some activity in the early spring of 2021 was delayed due to a construction stand down and pending determination of final construction design, Trans Mountain continued to progress trenchless construction in the Pípsell area throughout the period. This included the preparation of a detailed comparison of a number of trenchless construction options, including micro-tunneling. Trans Mountain commenced Phase 1 boreholes in August 2021 and completed them in September 2021.

(i) In October 2021 at a meeting between Trans Mountain and SSN leadership, Trans Mountain confirmed to SSN that micro-tunneling was a feasible option for pipeline construction in the Pípsell area, subject to detailed design. With this confirmation, and SSN's acceptance of this construction methodology, Trans Mountain proceeded to prepare final design for access roads and pads, began plans for mobilization, completed Phase 4 boreholes, and continued to develop final design and plans for commencement of construction.

36. When TMEP construction started in the Pípsell/Jacko Lake area in Q4 2021, tunnel drive #2 was scheduled to be completed by April 24, 2023. The remainder of the micro-tunneling was to be completed by May 17, 2023, with pipe insertion and final tie-ins to be completed by August 2023 (i.e., approximately 1.5 years after the commencement of construction in the area). This schedule allowed for micro-tunneling to be completed in the Pípsell/Jacko Lake area in alignment with the overall TMEP construction schedule.

B. Recent Engagement with SSN

37. At paragraphs 58 and 59 of its submissions, SSN highlights that during its engagement with Trans Mountain, Trans Mountain discussed the proposed combination of HDD and open trench construction as its "preferred" means of completing construction. SSN characterizes the use of the word "preferred" as supporting its argument that Trans Mountain can complete construction using micro-tunneling but would "prefer" not to. Trans Mountain confirms that its use of the word "preferred" in this context was intended to convey that Trans Mountain wished to work collaboratively with SSN regarding the revised construction methodology. Trans Mountain did not use the word "preferred" because micro-tunneling is still feasible. It is not feasible, for the reasons discussed above.

38. At paragraphs 38 and 62 of its submissions, SSN emphasizes the following statement by Trans Mountain's President and Chief Executive Officer, during a meeting with SSN leadership on July 6, 2023: "If we could turn back the clock and we could have started [Micro-Tunnelling in the Pípsell (Jacko Lake) Corridor] two or three years ago, which is like everything at Trans Mountain, we would have the time to finish this."[24] Trans Mountain notes that it does not have access to any transcript or recording of the meeting

[24] Filing ID C25999-2 at paras 38, 62.

between Trans Mountain and SSN leadership on July 6, 2023 and therefore cannot verify the accuracy of any statements that are attributed to Trans Mountain in SSN's submissions. Regardless, SSN has taken Mrs. Farrell's statements out of context. In her comments, Mrs. Farrell was expressing regret that Trans Mountain could not start micro-tunneling earlier due to factors that were outside of its control (including severe flooding, forest fires, and the global COVID-19 pandemic, as discussed above), which affected every aspect of TMEP construction. If Trans Mountain could turn back the clock and somehow avoid construction delays due to those factors, it would. But it cannot.

39. Even if continuing with the micro-tunneling did not result in a delay to the Project, Trans Mountain is still of the view that it is not technically and economically feasible to continue with micro-tunneling, for the reasons described above.

Trans Mountain Pipeline ULC
Trans Mountain Expansion Project
Certificate of Public Convenience and Necessity OC-065
Application pursuant to section 211 of the *Canadian Energy Regulator Act* – Segment 5.3 (Pipsell area)
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Information Request No. 1 to the applicant

1.1 Mitigation measures

Reference: C25832-1, Trans Mountain Pipeline ULC (**Trans Mountain**), Application, PDF page 5 of 14

Preamble: In the reference, Trans Mountain states that, in light of its suite of proven mitigation measures to avoid or minimize potential environmental, traditional land use, and cultural impacts, including in other important cultural areas for Indigenous communities, it is confident that its proposed combination of horizontal directional drilling and conventional open trench construction will allow it to reasonably avoid or minimize impacts on the lands in question.

Request: Describe Trans Mountain's suite of proven mitigation measures to avoid or minimize potential environmental, traditional land use, and cultural impacts resulting from the proposed deviation.

1.2 Construction methods

Reference:
i) C25832-1, Trans Mountain, Application, PDF pages 3 and 4 of 14
ii) C25832-3, Trans Mountain, Application, Appendix B – Differences mapping

Preamble: In Reference i), Trans Mountain indicates the following:

- Trans Mountain is encountering significant technical challenges with micro-tunnelling along an approximately 1.3-kilometre-long portion of the approved route, specifically with the micro-tunnel drive between pads 1 and 2.
- The micro-tunnel drive has been particularly difficult with abnormal upward migration of the Reinforced Concrete Jacking Pipe (**RCJP**) that has substantially limited the ability to apply jacking force to the micro-tunnelling machine (from 1400 tons to 300 tons). As a result, RCJP deflection at the joints has increased over time as micro-tunnelling has progressed, which has increased the risk of losing watertight seal and/or damage to the RCJPs. If either of these risks were to materialize, successful completion of the micro-tunnel could be jeopardized.

- Trans Mountain has made several unsuccessful, costly attempts to address the problem of upward RCJP migration to date. Trans Mountain is currently constructing a new launch shaft along the alignment and abandoning the section of RCJP that has been affected by the vertical deflection. Construction of this new shaft requires a shutdown of tunnelling activities. During this downtime, the annular space between the tunnel wall and RCJP may restrict in diameter or drain of lubrication fluids, which will require high jacking forces to move the tunnel forward. This may create significant delays in restarting tunnelling.
- If the construction of the new shaft is successful and the tunnel commences forward progression, there remains approximately 800 metres of tunnel length to be constructed in medium to hard rock formations (with the potential to encounter other unfavourable construction conditions), which has its own material risk to the project and schedule.
- Trans Mountain has determined that the only feasible option is to change the construction methodology for an approximately 1.3-kilometre-long segment to a combination of horizontal directional drilling (**HDD**) and conventional open trench.

Reference ii) shows the location of the revised route in relation to the route approved by the Commission in Order AO-001-OPL-003-2020.

Request:

a) Provide the length of the section of RCJP affected by the vertical deflection, which Trans Mountain would abandon.

b) Describe the unsuccessful attempts that Trans Mountain has made to address the problem of upward RCJP migration to date.

c) Describe the mitigation measures that Trans Mountain could implement to complete the remaining 800 metres of tunnel if construction of the new shaft is successful.

d) Provide geotechnical reports and HDD feasibility and design reports, along with final design drawings.

e) Provide the contingency method that will be used should HDD be unsuccessful.

f) Provide an updated Reference ii) showing the start and end points for the HDD and conventional open trench portions.

https://www.nato.int/cps/en/natohq/topics_110496.htm

NATO OTAN NORTH ATLANTIC TREATY ORGANIZATION #

Collective defence and Article 5

- Last updated: 04 Jul. 2023 11:47

The principle of collective defence is at the very heart of NATO's founding treaty. It remains a unique and enduring principle that binds its members together, committing them to protect each other and setting a spirit of solidarity within the Alliance.

- Collective defence means that an attack against one Ally is considered as an attack against all Allies.
- The principle of collective defence is enshrined in Article 5 of the North Atlantic Treaty.
- NATO invoked Article 5 for the first and only time in its history after the 9/11 terrorist attacks against the United States.
- NATO has taken collective defence measures on several occasions, including in response to the situation in Syria and the Russian invasion of Ukraine.
- NATO has standing forces on active duty that contribute to the Alliance's collective defence efforts on a permanent basis.

A cornerstone of the Alliance

Article 5

In 1949, the primary aim of the North Atlantic Treaty – NATO's founding treaty – was to create a pact of mutual assistance to counter the risk that the Soviet Union would seek to extend its control of Eastern Europe to other parts of the continent.

Every participating country agreed that this form of solidarity was at the heart of the Treaty, effectively making Article 5 on collective defence a key component of the Alliance.

Article 5 provides that if a NATO Ally is the victim of an armed attack, each and every other member of the Alliance will consider this act of violence as an armed attack against all members and will take the actions it deems necessary to assist the Ally attacked.

Article 5

"The Parties agree that an armed attack against one or more of them in Europe or North America shall be considered an attack against them all and consequently they agree that, if such an armed attack occurs, each of them, in exercise of the right of individual or collective self-defence recognized by Article 51 of the Charter of the United Nations, will assist the Party or Parties so attacked by taking forthwith, individually and in concert with the other Parties, such action as it deems necessary, including the use of armed force, to restore and maintain the security of the North Atlantic area.

Any such armed attack and all measures taken as a result thereof shall immediately be reported to the Security Council. Such measures shall be terminated when the Security Council has taken the measures necessary to restore and maintain international peace and security."

This article is complemented by Article 6, which stipulates:

Article 6[1]

"For the purpose of Article 5, an armed attack on one or more of the Parties is deemed to include an armed attack:

- *on the territory of any of the Parties in Europe or North America, on the Algerian Departments of France* [2]*, on the territory of Turkey or on the Islands under the jurisdiction of any of the Parties in the North Atlantic area north of the Tropic of Cancer;*
- *on the forces, vessels, or aircraft of any of the Parties, when in or over these territories or any other area in Europe in which occupation forces of any of the Parties were stationed on the date when the Treaty entered into force or the Mediterranean Sea or the North Atlantic area north of the Tropic of Cancer."*

The principle of providing assistance

With the invocation of Article 5, Allies can provide any form of assistance they deem necessary to respond to a situation. This is an individual obligation on each Ally and each Ally is responsible for determining what it deems necessary in the particular circumstances.

This assistance is taken forward in concert with other Allies. It is not necessarily military and depends on the material resources of each country. It is therefore left to the judgment of each individual member country to determine how it will contribute. Each country will consult with the other members, bearing in mind that the ultimate aim is to "to restore and maintain the security of the North Atlantic area".

At the drafting of Article 5 in the late 1940s, there was consensus on the principle of mutual assistance, but fundamental disagreement on the modalities of implementing this commitment. The European participants wanted to ensure that the United States would automatically come to their assistance should one of the signatories come under attack; the United States did not want to make such a pledge and obtained that this be reflected in the wording of Article 5.

Invocation of Article 5

The 9/11 terrorist attacks

The United States was the object of brutal terrorist attacks on 11 September 2001. The Alliance's 1999 Strategic Concept had already identified terrorism as one of the risks affecting NATO's security. The Alliance's response to 9/11, however, saw NATO engage actively in the fight against terrorism, launch its first operations outside the Euro-Atlantic area and begin a far-reaching transformation of its capabilities. Moreover, it led NATO to invoke Article 5 of the North Atlantic Treaty for the very first time in its history.

An act of solidarity

On the evening of 12 September 2001, less than 24 hours after the attacks, the Allies invoked the principle of Article 5. Then NATO Secretary General Lord Robertson subsequently informed the Secretary-General of the United Nations of the Alliance's decision.

The North Atlantic Council – NATO's principal political decision-making body – agreed that if it determined that the attack was directed from abroad against the United States, it would be regarded as an action covered by Article 5. On 2 October, once the Council had been briefed on the results of investigations into the 9/11 attacks, it determined that they were regarded as an action covered by Article 5.

By invoking Article 5, NATO members showed their solidarity toward the United States and condemned, in the strongest possible way, the terrorist attacks against the United States.

Taking action

After 9/11, there were consultations among the Allies and collective action was decided by the Council. The United States could also carry out independent actions, consistent with its rights and obligations under the United Nations Charter.

On 4 October, once it had been determined that the attacks came from abroad, NATO agreed on a package of eight measures to support the United States. On the request of the United States, it launched its first ever anti-terror operation – Eagle Assist – from mid-October 2001 to mid-May 2002. It consisted in seven NATO AWACS radar aircraft that helped patrol the skies over the United States; in total 830 crew members from 13 NATO countries flew over 360 sorties. This was the first time that NATO military assets were deployed in support of an Article 5 operation.

On 26 October, the Alliance launched its second counter-terrorism operation in response to the attacks on the United States, Operation Active Endeavour. Elements of NATO's Standing Naval Forces were sent to patrol the Eastern Mediterranean and monitor shipping to detect and deter terrorist activity, including illegal trafficking. In March 2004, the operation was expanded to include the entire Mediterranean.

The eight measures to support the United States, as agreed by NATO were:

- to enhance intelligence-sharing and cooperation, both bilaterally and in appropriate NATO bodies, relating to the threats posed by terrorism and the actions to be taken against it;
- to provide, individually or collectively, as appropriate and according to their capabilities, assistance to Allies and other countries which are or may be subject to increased terrorist threats as a result of their support for the campaign against terrorism;

- to take necessary measures to provide increased security for facilities of the United States and other Allies on their territory;
- to backfill selected Allied assets in NATO's area of responsibility that are required to directly support operations against terrorism;
- to provide blanket overflight clearances for the United States and other Allies' aircraft, in accordance with the necessary air traffic arrangements and national procedures, for military flights related to operations against terrorism;
- to provide access for the United States and other Allies to ports and airfields on the territory of NATO member countries for operations against terrorism, including for refuelling, in accordance with national procedures;
- that the Alliance is ready to deploy elements of its Standing Naval Forces to the Eastern Mediterranean in order to provide a NATO presence and demonstrate resolve;
- that the Alliance is similarly ready to deploy elements of its NATO Airborne Early Warning Force to support operations against terrorism.

Enhanced collective defence measures

Although NATO Allies have only invoked Article 5 once, they have coordinated collective defence measures on several occasions.

On the request of Türkiye, on three occasions, NATO has put collective defence measures in place:

- in 1991 with the deployment of Patriot missiles during the Gulf War,
- in 2003 with the agreement on a package of defensive measures and conduct of Operation Display Deterrence during the crisis in Iraq, and
- in 2012 in response to the situation in Syria with the deployment of Patriot missiles.

Following Russia's illegal annexation of Crimea in 2014 and the rise of security challenges from the south, including brutal attacks by ISIL and other terrorist groups across several continents, NATO implemented the biggest increase in collective defence since the Cold War. For instance, it tripled the size of the NATO Response Force (NRF), a highly ready and technologically advanced multinational force; established a 5,000-strong Spearhead Force within the NRF; and deployed multinational battlegroups in Estonia, Latvia, Lithuania and Poland. NATO also increased its presence in the southeast of the Alliance, centred on a multinational brigade in Romania. The Alliance further stepped up air policing over the Baltic and Black Sea areas and continues to develop key military capabilities, such as Joint Intelligence, Surveillance and Reconnaissance. At the 2016 Warsaw Summit, Allies recognised cyberspace as a new operational domain, to enable better protection of networks, missions and operations. At their meeting in November 2019, NATO Foreign Ministers agreed to recognise space as a new operational domain, to "allow NATO planners to make requests for Allies to provide capabilities and services, such as hours of satellite communications."

Following Russia's full-scale invasion of Ukraine – which started in February 2022 – and in line with its defensive planning to protect all Allies, NATO is taking additional steps to further strengthen deterrence and defence across the Alliance. This includes the deployment of the NRF for the first time in a deterrence and defence role. Allies have placed thousands of additional forces at high readiness, ensuring that the NRF continues to have the speed, responsiveness and capability to defend NATO territory and populations. Moreover, at an extraordinary Summit on 24 March 2022, NATO Leaders agreed to significantly strengthen the Alliance's longer-term deterrence and defence posture. They agreed to reinforce the existing battlegroups and to establish four more multinational battlegroups in Bulgaria, Hungary, Romania and Slovakia. This has brought the total number of multinational battlegroups to eight, effectively doubling the number of troops on the ground and extending NATO's forward presence along the Alliance's eastern flank – from the Baltic Sea in the north to the Black Sea in the south.

At the 2022 Madrid Summit, Allies committed to further concrete measures, such as deploying additional in-place combat-ready forces on the eastern flank, to be scaled up from the existing battlegroups to brigade-size units where and when required, underpinned by rapidly available reinforcements, prepositioned equipment, and enhanced command and control. They also made initial offers to NATO's new force model, which will strengthen and modernise the NATO Force Structure and will resource a new generation of military plans. All these steps, together with the release of the 2022 Strategic Concept, which identified Russia as "the most significant and direct threat to Allies' security and to peace and stability in the Euro-Atlantic area" will substantially strengthen NATO's deterrence and forward defences.

Standing forces

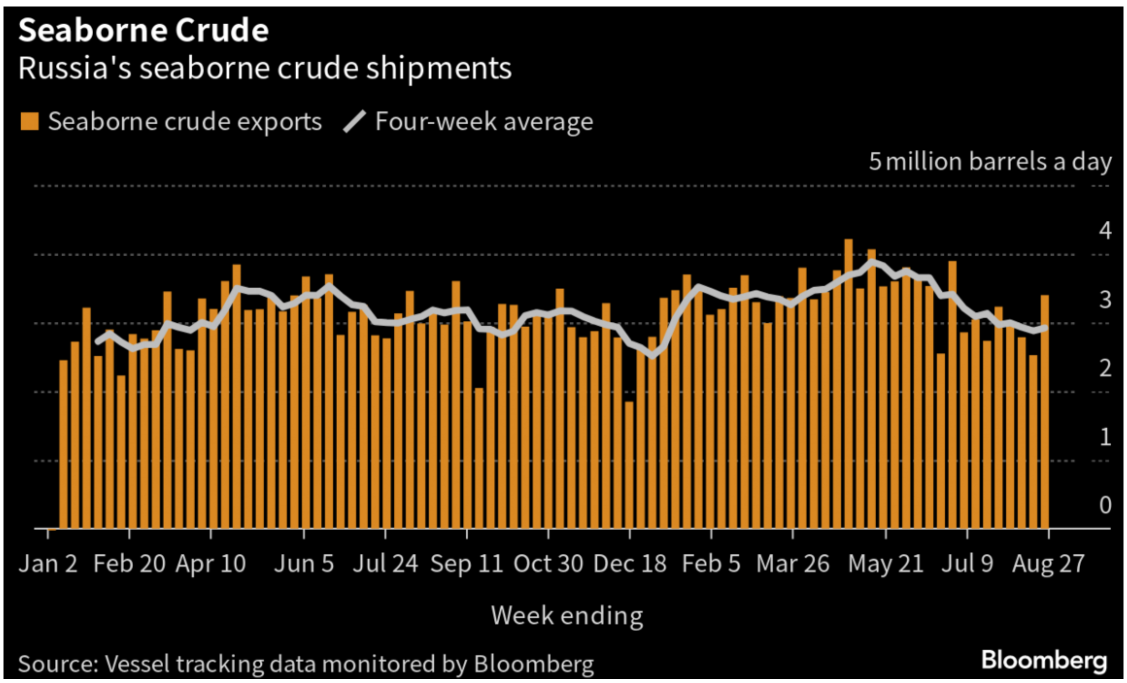
Collective defence measures are not solely event-driven. NATO has a number of standing forces on active duty that contribute to the Alliance's collective defence efforts on a permanent basis. These include NATO's standing maritime forces, which are ready to act when called upon. They perform different tasks ranging from exercises to operational missions, in peacetime and in periods of crisis and conflict.

Additionally, NATO has an integrated air and missile defence system to protect Alliance territory, populations and forces against any air or missile threat or attack. NATO also conducts several air policing missions, which are collective peacetime missions that enable NATO to detect, track and identify all violations and infringements of its airspace and to take appropriate action. As part of such missions, Allied fighter jets patrol the airspace of Allies who do not have fighter jets of their own. They run on a 24/7 basis, 365 days a year.

1. Article 6 has been modified by Article 2 of the Protocol to the North Atlantic Treaty on the Accession of Greece and Türkiye.
2. On January 16, 1963, the North Atlantic Council modified this Treaty in its decision C-R(63)2, point V, on the independence of the Algerian departments of France.

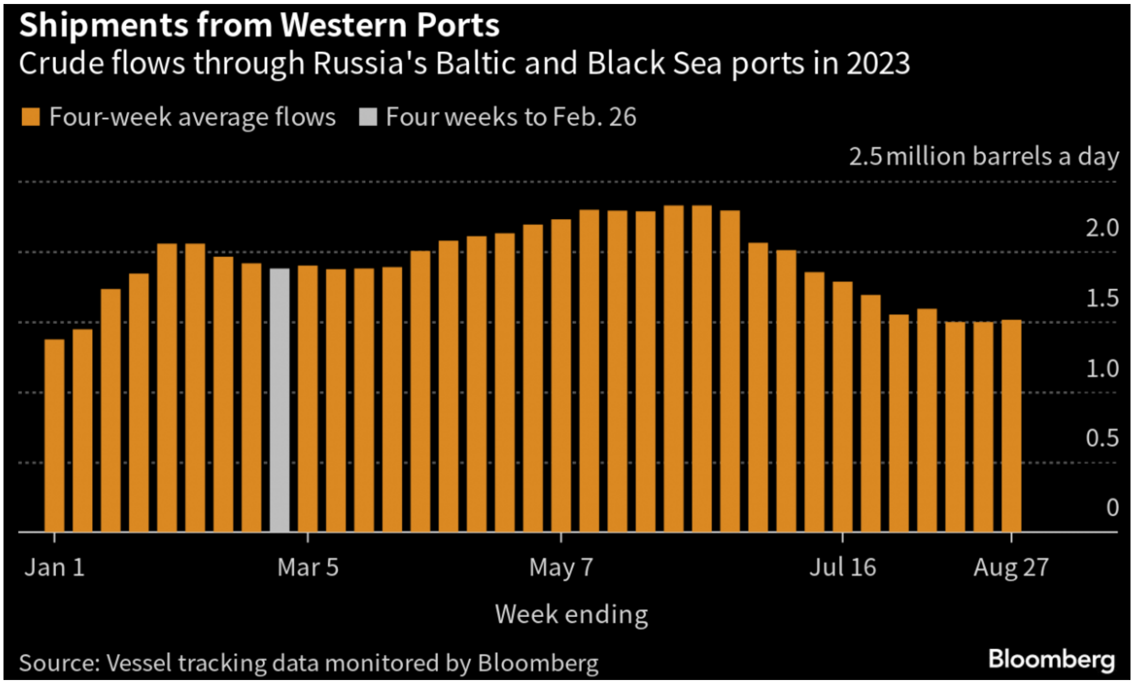
Russia’s Seaborne Crude Flow Surges to Hit an Eight-Week High
2023-08-29 09:55:43.458 GMT

By Julian Lee
(Bloomberg) -- Russia’s seaborne crude flows soared to an eight-week high ahead of a planned easing of an export cut Moscow began to implement in June.
Average nationwide shipments in the week to Aug. 27 rose to 3.4 million barrels a day, tanker-tracking data compiled by Bloomberg show. That’s a jump of about 880,000 barrels a day from the previous week, with the biggest increases seen at the Baltic ports of Primorsk and Ust-Luga. Flows from Novorossiysk on the Black Sea also recovered after the previous week’s storms. Less volatile four-week average numbers increased by a modest 40,000 barrels a day.



It’s too soon to be sure how sustained the increase will be because weekly data can be volatile. The jump in crude flows comes as shipments of refined fuels are set to slump to a 15-month low, amid strong domestic demand for road fuels and as some products exceeded Group of Seven price caps.
Despite last week’s jump, the figures support the notion that Moscow is now honoring a pledge to keep supply off the global market alongside its allies in the OPEC+ producer coalition. Russia initially said it would cut oil production in retaliation for Western sanctions and price caps on its oil imposed after the invasion of Ukraine, using February 2023 figures as a baseline.

But Moscow’s initial commitment to cut production by 500,000 barrels a day in March had no immediate effect on exports. Flows from western ports actually rose, peaking in late May. A subsequent reduction came after fellow OPEC+ oil producer Saudi Arabia made and then extended its own unilateral output cut, putting pressure on Russia to implement its own reduction.



Moscow eventually followed through on its pledge, with flows from western ports now down by about 420,000 barrels a day from their average February level.

Output cuts by several major oil producers in the OPEC+ group have boosted global oil prices and narrowed the discounts for Russian grades against global benchmarks, boosting oil the Kremlin’s revenues. Prices for Russia’s Urals crude rose above the $60 a barrel cap imposed by Group of Seven countries, above which cargoes cannot be carried on Western vessels or use services such as financing or insurance provided by Western firms.

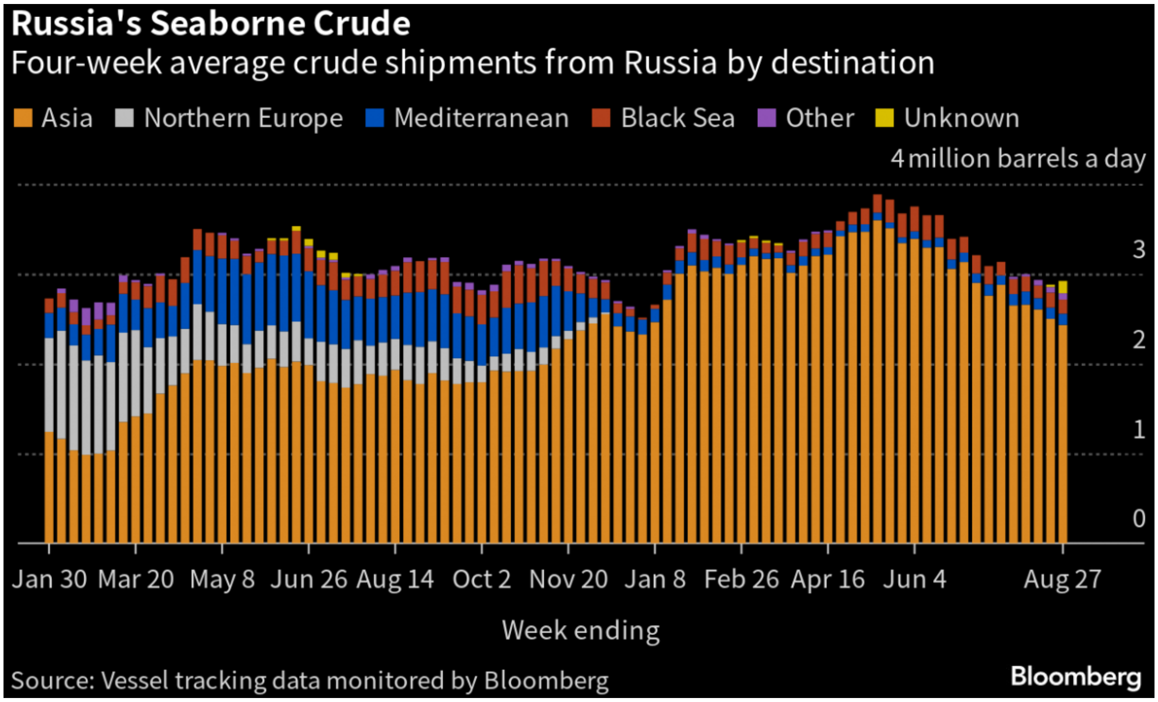
Russia will extend its export cut into September, Deputy Prime Minister Alexander Novak said earlier this month, following a similar announcement from Saudi Arabia. However, the size of the supply reduction will be tapered to 300,000 barrels a day, from 500,000 barrels a day in August. Russia has given no baseline from which the export cut is to be measured.

The latest drop in overseas flows comes as Russia's oil refineries increased crude-processing rates in the first half of August — before a sharp cut to state subsidies that's about to take effect in September. The rise also comes ahead of the next maintenance season, with several refineries due to start work this month.

Flows by Destination

Russia's seaborne crude flows appear to have plateaued at a level just below 3 million barrels a day on a four-week average basis. That's about 450,000 barrels a day below the average level seen in February.

With few buyers left in Europe, the impact is being felt in shipments to Asia. On a four-week average basis, overall seaborne exports to Asian countries — plus the volumes on ships showing no final destination — are now more than 1 million barrels a day lower than their mid-May peak, although flows to the region edged up in the most recent period.



All figures exclude cargoes identified as Kazakhstan's KEBCO grade. Those are shipments made by KazTransoil JSC that transit Russia for export through Novorossiysk and the Baltic port of Ust-Luga.

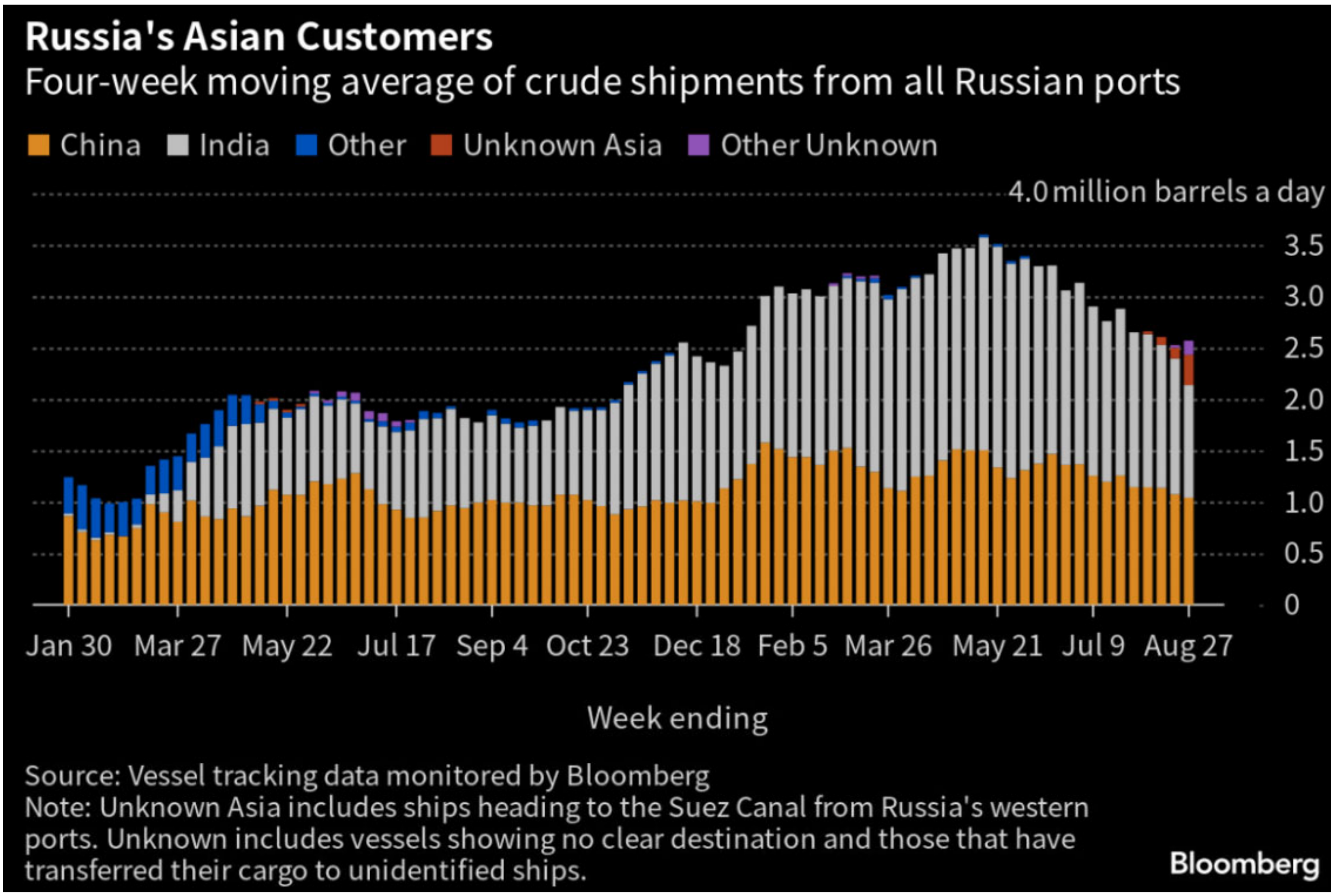
The Kazakh barrels are blended with crude of Russian origin to create a uniform export grade. Since Russia's invasion of Ukraine, Kazakhstan has rebranded its cargoes to distinguish them from those shipped by Russian companies. Transit crude is specifically exempted from European Union sanctions.

*** Asia**

Observed shipments to Russia's Asian customers, including those showing no final destination, edged higher to 2.57 million barrels a day in the four weeks to Aug. 27, from 2.53 million barrels a day in the period to Aug. 20.

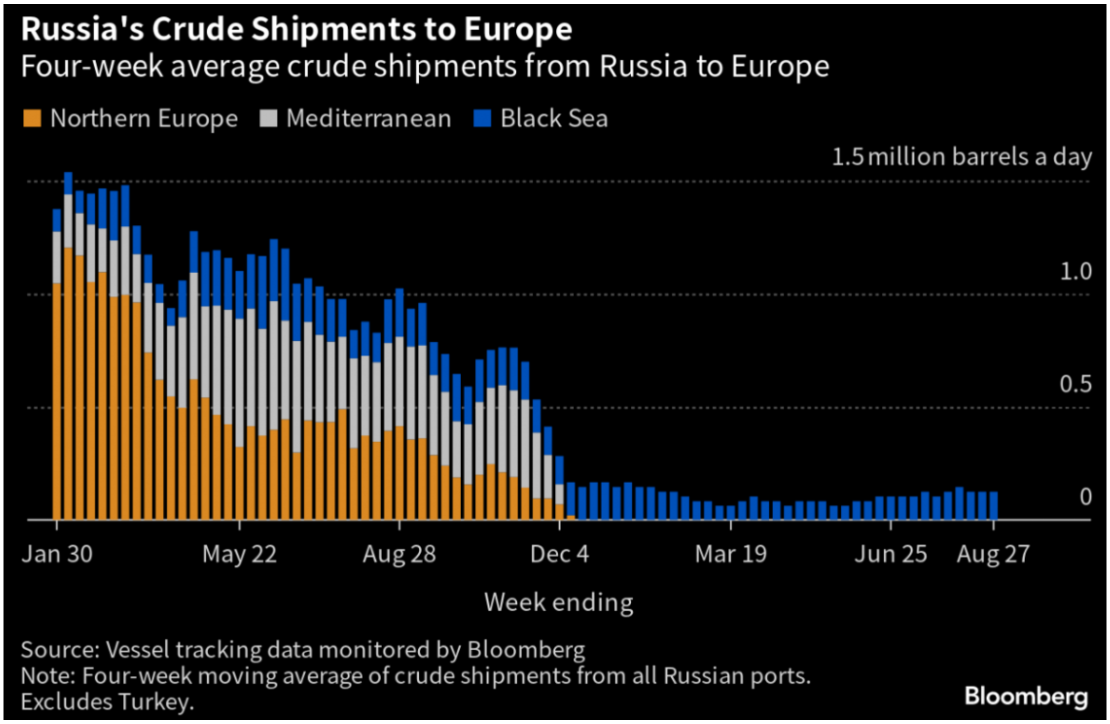
Most of the cargoes on ships without an initial destination eventually end up in India. Even so, the volumes heading to the country that has become the biggest buyer of Russia's seaborne crude are down from their recent highs. Adding the "Unknown Asia" and "Other Unknown" volumes to the total for India gives a figure of 1.53 million barrels a day in the four weeks to Aug. 27, down from a high of 2.15 million barrels a day in the period to May 21, but up from 1.45 million barrels a day in the period to Aug. 20.

The equivalent of 296,000 barrels a day was on vessels signaling Port Said or Suez in Egypt, or which already have been or are expected to be transferred from one ship to another off the South Korean port of Yeosu. Those voyages typically end at ports in India or China and show up in the chart below as "Unknown Asia" until a final destination becomes apparent. The "Other Unknown" volumes, running at 137,000 barrels a day in the four weeks to Aug. 27, are those on tankers showing no clear destination. Most of those cargoes originate from Russia's western ports and go on to transit the Suez Canal, but some could end up in Turkey. Others could be transferred from one vessel to another, either in the Mediterranean or, more recently, in the Atlantic Ocean.

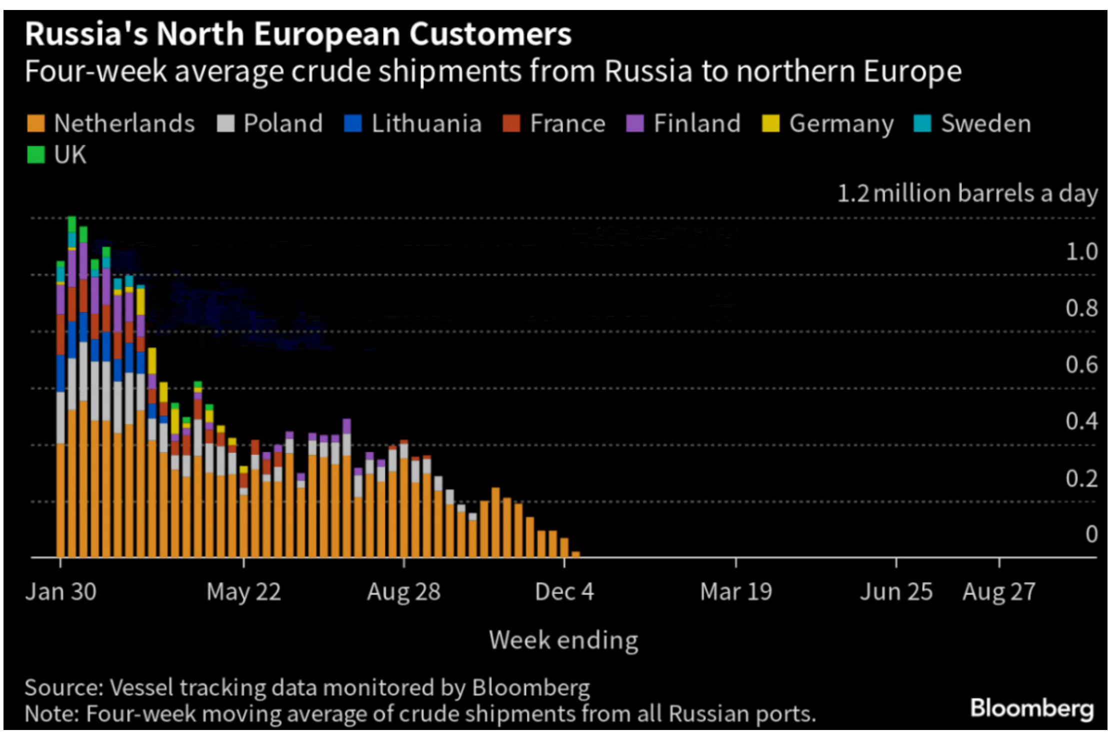


*** Europe**

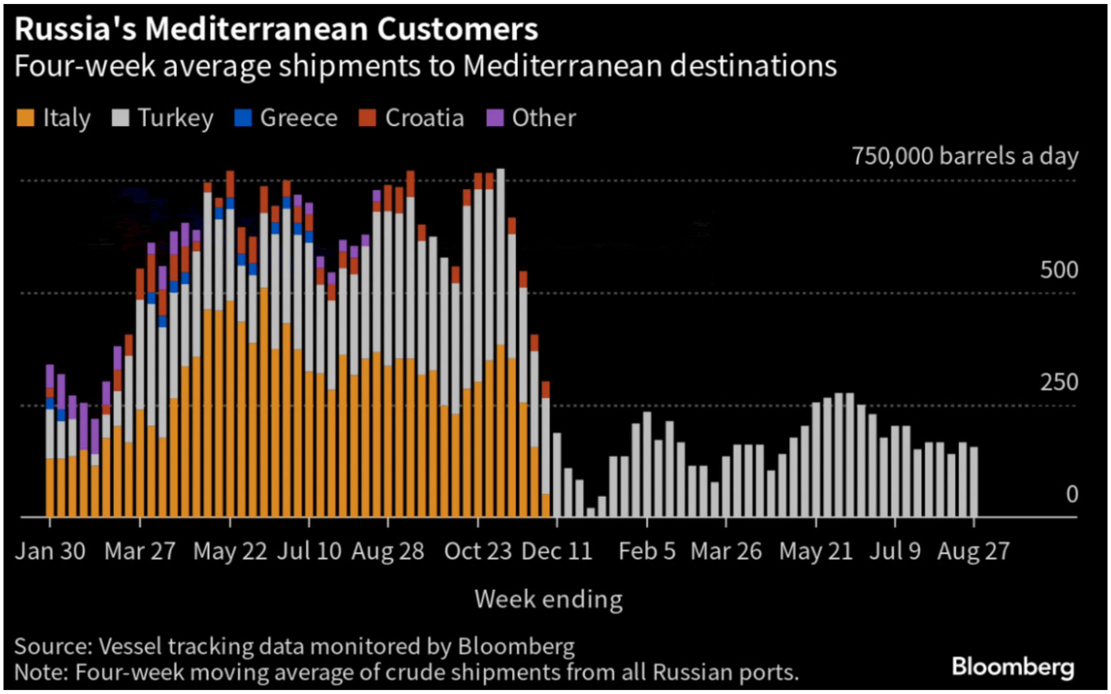
Russia's seaborne crude exports to European countries were unchanged at 125,000 barrels a day in the 28 days to Aug. 27, with Bulgaria the sole destination. These figures do not include shipments to Turkey.
A market that consumed about 1.5 million barrels a day of short-haul seaborne crude, coming from export terminals in the Baltic, Black Sea and Arctic has been lost almost completely, to be replaced by long-haul destinations in Asia that are much more costly and time-consuming to serve.



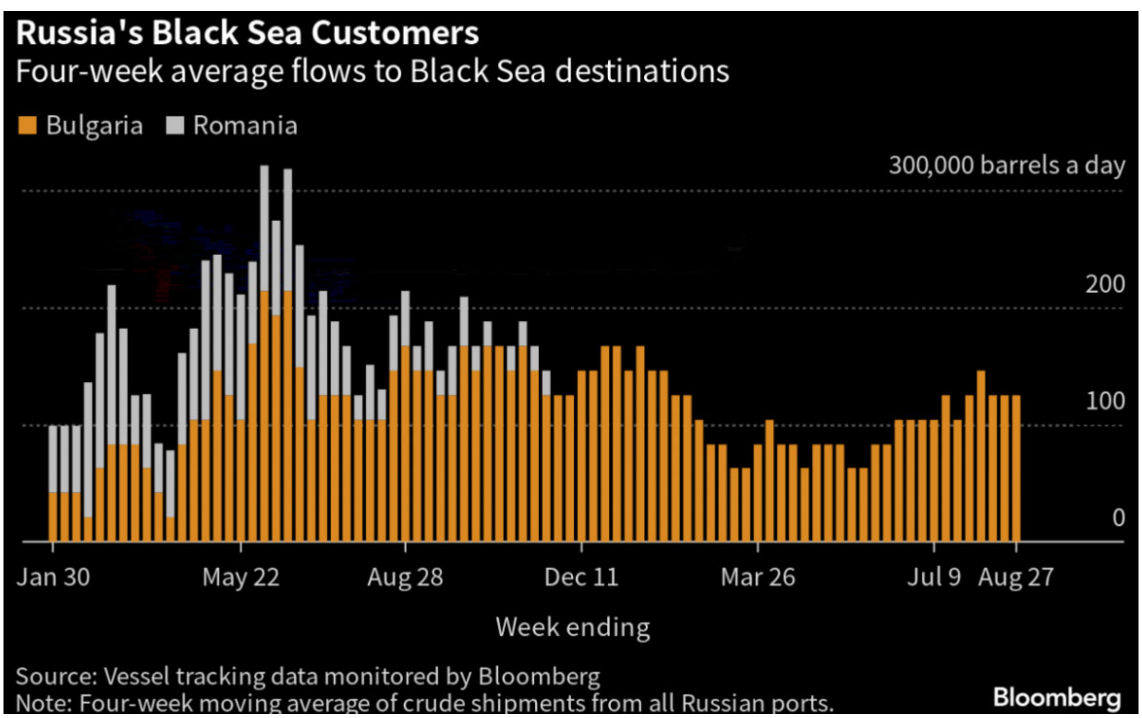
No Russian crude was shipped to northern European countries in the four weeks to Aug. 27.



Exports to Turkey, Russia's only remaining Mediterranean customer, edged lower to about 156,000 barrels a day in the four weeks to Aug. 27. They had topped 425,000 barrels a day in October.



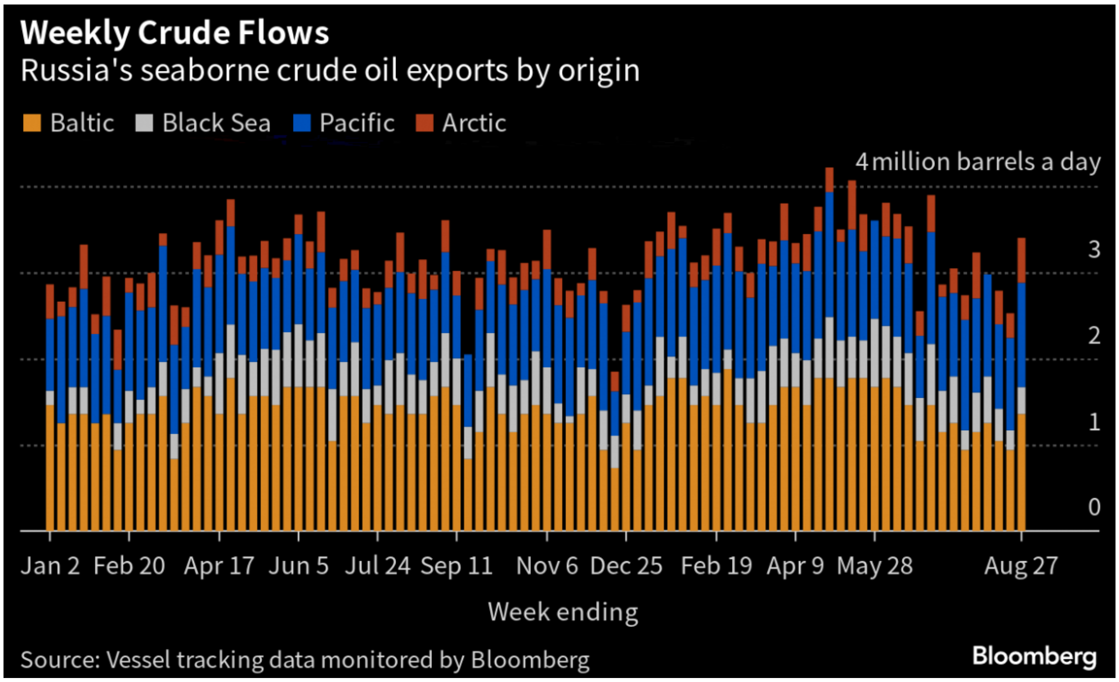
Flows to Bulgaria, now Russia's only Black Sea market for crude, were unchanged at 125,000 barrels a day. That's about twice as much as the country was importing at the lowest points between March and May.



Flows by Export Location

Aggregate flows of Russian crude jumped to 3.4 million barrels a day in the seven days to Aug. 27, up from 2.53 million barrels a day the previous week. The increase was spread across all regions, with shipments from the Baltic accounting for nearly half of the additional barrels.

Figures exclude volumes from Ust-Luga and Novorossiysk identified as Kazakhstan's KEBCO grade.

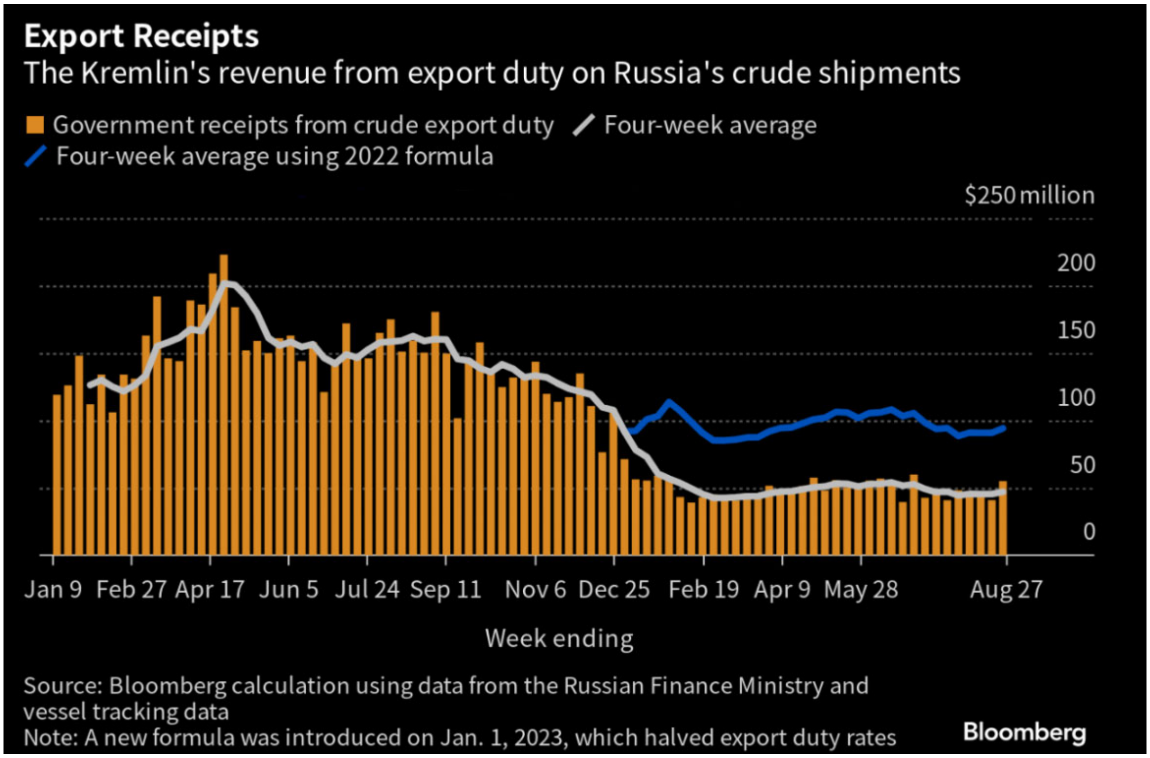


Vessel-tracking data are cross-checked against port agent reports as well as flows and ship movements reported by other information providers including Kpler and Vortexa Ltd

Export Revenue

Inflows to the Kremlin's war chest from its crude-export duty jumped to $55 million in the seven days to Aug. 27, an increase of $14 million or 35%. Four-week average income rose to $47 million.

Russia's government calculates oil taxes — including export duty — using a discount to global benchmark Brent, which sets the floor price for the nation's crude for budget purposes. If Russian oil trades above that threshold, the Finance Ministry uses the market price for tax calculations, as has been the case in recent months. The discount used to calculate taxes including export duty is set at $25 a barrel for July and August, but will narrow to $20 a barrel from September.



The duty rate for August has been set at $2.31 a barrel, based on an average Urals price of $58.03 during the calculation period between June 15 and July 14. That was $18.02 a barrel below Brent during the same dates.

For September, the duty has been set at $2.92 a barrel, based on an average Urals price of $70.33 during the calculation period between July 15 and Aug. 14. That was $13.90 a barrel below Brent over the same period. September's duty rate is the highest this year.

Origin-to-Location Flows

The following charts show the number of ships leaving each export terminal and the destinations of crude cargoes from the four export regions.

A total of 33 tankers loaded 123.8 million barrels of Russian crude in the week to Aug. 27, vessel-tracking data and port agent reports show. That's up by 6.12 million barrels from the previous week's figure and the most in eight weeks.

Shipments increased from all regions, with two-thirds of the increase coming from the Baltic ports of Primorsk and Ust-

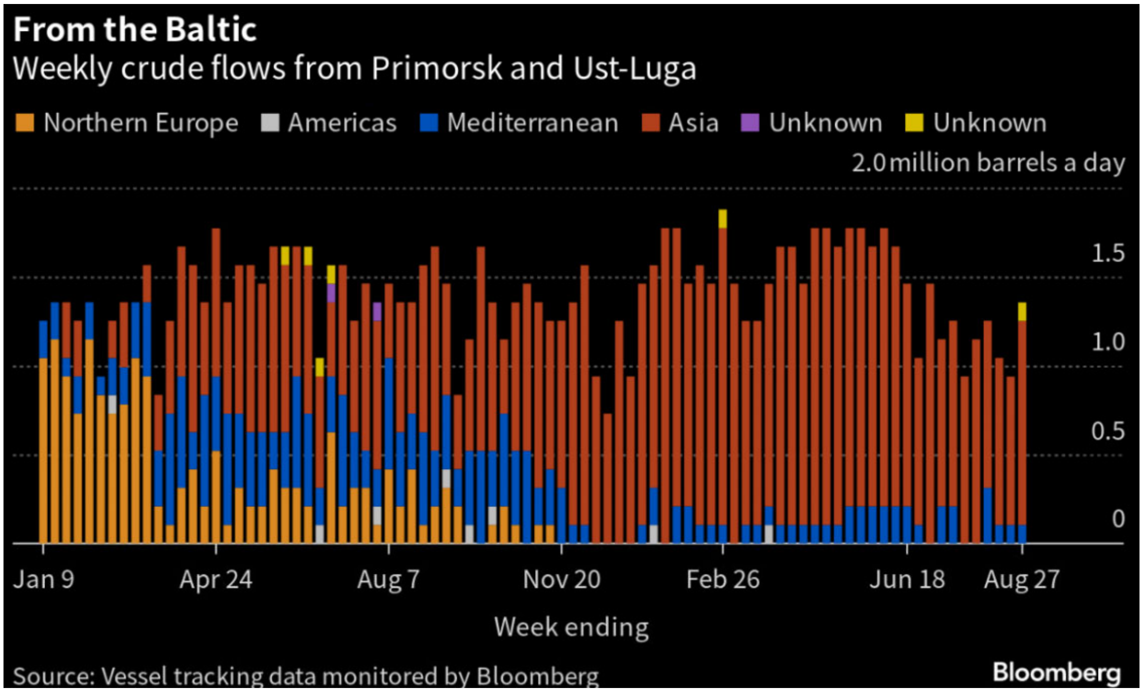
Luga.
Destinations are based on where vessels signal they are heading at the time of writing, and some will almost certainly change as voyages progress. All figures exclude cargoes identified as Kazakhstan's KEBCO grade.

Tankers Loading Crude at Russian Terminals
33 tankers loaded Russian crude in the week to August 27

Week ending	Aug. 27	Aug. 20	Aug. 13
Primorsk (Baltic)	9	6	6
Ust-Luga (Baltic)	4	3	4
Novorossiysk (Black Sea)	3	2	3
Murmansk (Arctic)	4	2	3
Kozmino (Pacific)	9	8	8
De Kastri (Pacific)	2	2	1
Prigorodnoye (Pacific)	2	1	2
Total	**33**	**24**	**27**

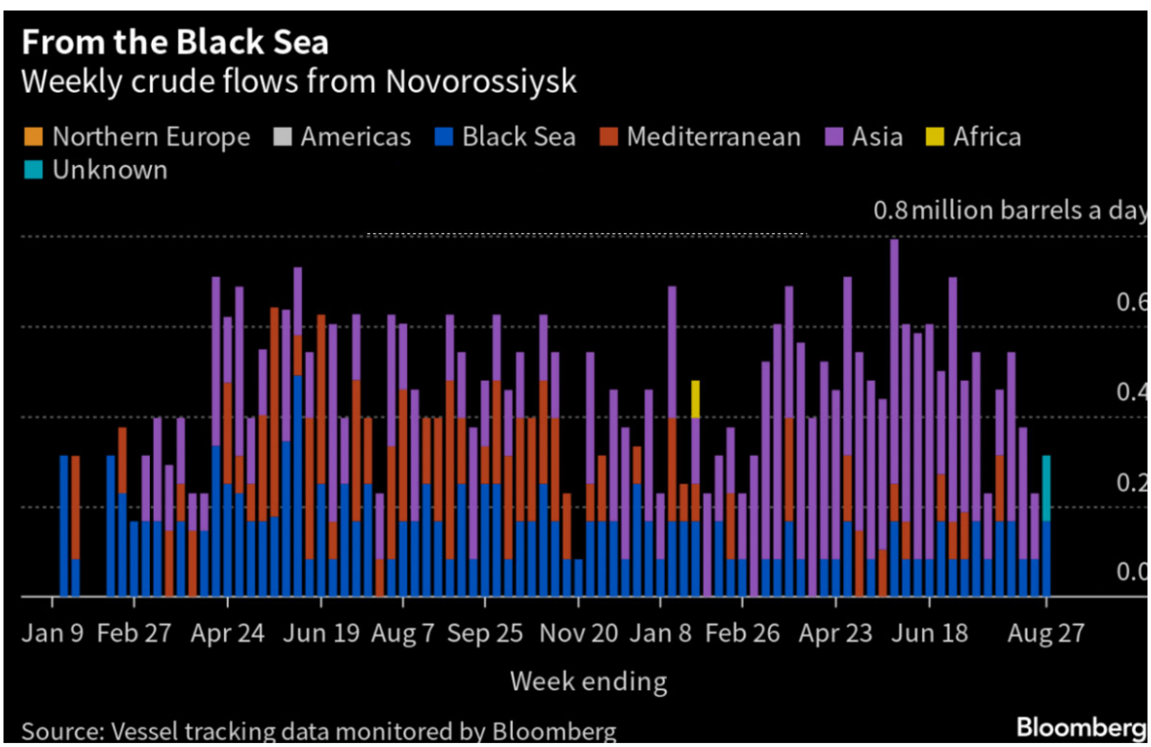
Source: Vessel tracking data monitored by Bloomberg
Note: Based on date of completion of cargo loading. Excludes ships loading cargoes identified as Kazakhstan's KEBCO grade.
Bloomberg

The total volume on ships loading Russian crude from the Baltic terminals jumped to an eight-week high of 1.36 million barrels a day. In addition, one cargo of Kazakh crude was loaded at Ust-Luga during the week. Shipments from the Baltic remain about 420,000 barrels a day down from the highs seen between April and June.

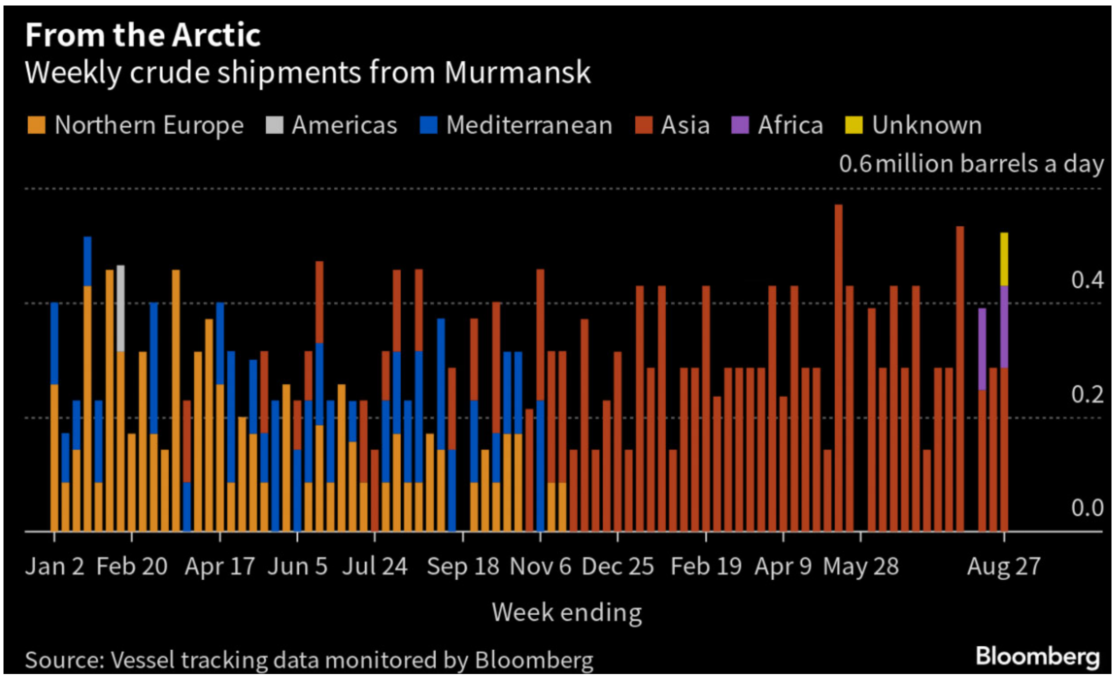


Shipments of Russian crude from Novorossiysk also rebounded, with three tankers loading Russian crude. Shipments were running back in line with the loading program for the port by the end of the week, having fallen behind during the previous seven days.

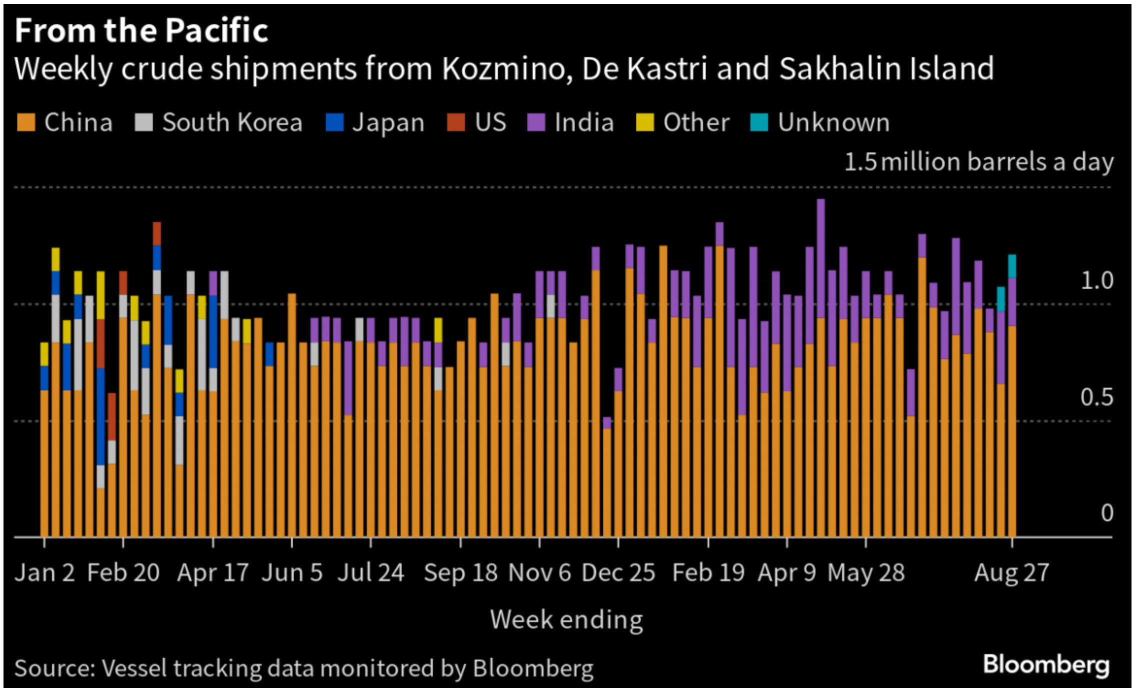
Two cargoes of Kazakh crude were also loaded at the port during the week.



Three Suezmax tankers and one Aframax completed loading cargoes at the Arctic port of Murmansk in the week to Aug. 27, boosting flows to a four-week high.
One tanker that loaded in the week to Aug. 27 is headed to Ghana, following another that loaded two weeks previously, that is now idling off the coast of neighboring Ivory Coast. A previous cargo, loaded at Novorossiysk in January, discharged in the West African nation after a six-week wait off the port of Tema.



Thirteen tankers loaded at Russia’s three Pacific export terminals, up by three from the previous week. The volume of crude shipped from the region rose to a five-week high of 1.21 million barrels a day.
Shipments from the Sakhalin Island terminal continue to be affected by maintenance at one of the Sakhalin 2 project’s oil production platforms. The work is set to run until September. One vessel completed loading a cargo of Sakhalin Blend crude from the terminal.



The volumes heading to unknown destinations are mostly Sokol cargoes that recently have been transferred to other vessels at Yeosu, or are currently being shuttled to an area off the South Korean port from the loading terminal at De Kastri. Most of these are ending up in India.

Some Sokol cargoes are now being transferred a second time in the waters off southern Malaysia. A small number of ESPO shipments are also being moved from one vessel to another in the same area. All bar one of these cargoes have, so far, gone on to India. That one cargo was transferred three times before ending up in China.

Shipments of Sokol crude to India have picked up again after slumping to zero in June. Flows in July averaged about 140,000 barrels a day and at least four cargoes are heading there this month.NOTES

Note: This story forms part of a weekly series tracking shipments of crude from Russian export terminals and the export duty revenues earned from them by the Russian government. Weeks run from Monday to Sunday. The next update will be onTuesday, Sep. 19.

Note: All figures exclude cargoes owned by Kazakhstan's KazTransOil JSC, which transit Russia and are shipped from Novorossiysk and Ust-Luga as KEBCO grade crude.

If you are reading this story on the Bloomberg terminal, click here for a link to a PDF file of four-week average flows from Russia to key destinations.

--With assistance from Sherry Su

SAUDI TANKER TRACKER: Exports Plunge as Kingdom Slashes Output
2023-09-01 10:33:09.9 GMT

By Brian Wingfield and Julian Lee
(Bloomberg) -- Observed crude shipments from Saudi Arabia plunged in August, with flows to most major destinations slumping to multiyear lows as the kingdom limits output.
* Total exports were about 5.6m b/d in August, the lowest observed since March 2021, tanker-tracking data compiled by Bloomberg show; compares with a revised 6.3m b/d in July
* For comparison, Vortexa data show Saudi crude exports last month at 5.58m b/d; Kpler estimates flows of 5.22m b/d
* Saudi officials weren't immediately available to comment on August's export figures
* Click here for a PDF of flows

* When Saudi Arabia and its partners in the OPEC+ group met in Vienna in early June, the kingdom said it would make an additional unilateral production cut of 1m b/d in July; the reduction was subsequently extended to August and September
** That takes the target for those two months to 8.978m b/d, the lowest since July 2020

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Highlights (data are preliminary):
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Exports to primary destination China fell to the lowest since June 2020

Based on current vessel destinations, shipments to both Japan and South Korea declined to the lowest since Bloomberg began tracking Saudi exports at the start of 2017

Cargoes to the
US and Egypt — the latter home to a storage hub and transit

point for flows westward — also plunged to the lowest observed levels in Bloomberg tracking

Observed exports to India edged higher
Figures are subject to revision as vessels signal final destinations

With 780k b/d whose destination is unknown, flows to some countries are likely to be revised up
*T

* Saudi Arabia issued big price increases for its crude to Europe and the Mediterranean in August, while also unexpectedly lifting the cost of supplies to Asia
** The kingdom further raised almost all prices for September to Asia and Europe
* Key crude flows to selected destinations from Saudi Arabia ('000s of b/d):

Destination	Aug.	July	June	May
China	1,274	1,522	1,608	1,613
S. Korea	613	973	956	785
India	569	552	659	832
Japan	543	828	828	796
US	81	430	350	306
Egypt	65	645	533	806
Unknown	780	0	0	0
All destinations	5,552	6,266	6,657	6,551

* NOTE: Figures subject to revision as vessels indicate final destinations
* Includes VLCC, ULCC, Suezmax and Aframax tankers and exports from the Saudi-Kuwait Neutral Zone; from December 2021, calculations also take into consideration tanker-tracking data from Vortexa and Kpler
* Run LINE GBLCRUDE for an overview of Bloomberg tanker tracking and to find Bloomberg tickers; see NI TANTRA for related stories

--With assistance from Grant Smith, Prejula Prem and John Deane.

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To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/RYRRY5DWRGG0

Iran’s Oil Exports Surge in August Even With Final Week Dip
2023-08-31 12:48:26.407 GMT

By Alex Longley and Alaric Nightingale
(Bloomberg) -- Iran’s oil exports ballooned in August, even though they didn’t maintain the pace set in the first part of the month.
The increase in Iranian shipments to the highest this year comes in the same month that key OPEC+ producers Saudi Arabia and Russia kept a lid on their own oil exports in a bid to tighten the market.
Shipments of Iranian crude and condensate climbed to 1.85 million barrels a day in August, according to TankerTrackers.com Inc., which provides data on oil cargoes to governments, insurers and other institutions.
That represents a pullback from the first 20 days of August, when exports topped 2 million barrels a day. Figures for the earlier period were likely inflated by sales of barrels in storage, according to TankerTrackers’s co-founder Samir Madani.

Iran has been steadily ramping up its oil shipments this year, finding buyers for its discounted supplies in Asia. The country’s production is now at the highest level since a ban on its exports kicked in five years ago, with US officials privately acknowledging they’ve gradually relaxed enforcement on some of the measures.
The latest figures cover the first 30 days of August.
TankerTrackers studies images from satellites and collates data manually, meaning it doesn’t rely on Automatic Identification System, or AIS, signals.

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Dylan Griffiths

https://www.presstv.ir/Detail/2023/08/09/708652/Iran-oil-output-increase-plan-NIOC-CEO

Iran’s oil output to reach 3.5 mln bpd by late September: NIOC chief

Wednesday, 09 August 2023 6:24 PM **[Last Update: Wednesday, 09 August 2023 6:24 PM]**

CEO of Iran’s state-run NIOC says oil output in the country will reach 3.5 million bpd in late September.

Iran will reach a milestone oil production figure of 3.5 million barrels per day (bpd) in late September, according to the CEO of state oil company NIOC, despite sanctions imposed on the country by the US.

Mohsen Khojasteh Mehr said on Wednesday that Iran’s oil output will increase by 150,000 bpd within the next week and by another 100,000 bpd by the end of the month to September 22 to reach a total of 3.5 million bpd.

The figure would be a major increase from 2.2 million bpd of oil production reported in August 2021 when the current administrative government led by President Raeisi took office, said Khojasteh Mehr.

He said the growth in oil output will entirely serve Iran’s plans to increase its oil exports.

The comments, which came in a meeting with reporters at the headquarters of the National Iranian Oil Company, is the latest sign that Iran is pumping increased amounts of oil to the international markets despite continued pressure of the US sanctions.

Reports earlier this year had indicated that Iran’s nominal oil production capacity had been restored to levels above 3.8 million bpd for a first time since 2018 when Washington imposed its sanctions on the country.

However, reaching an actual output of 3.5 million bpd shows Iran is effectively nearing export levels seen before the sanctions when the country used to sell 2.2 million bpd of oil to international customers.

Central Bank of Iran Governor Mohammad Reza Farzin also said on Wednesday that Iran’s oil exports had risen by 41% year on year in the calendar month to late July to reach a record high in five years.

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https://www.rudaw.net/english/business/29082023

Iraq, Kurdistan Region have lost $5bn due to oil exports halt: Official

29-08-2023

Chenar Chalak@Chenar_Qader

ECONOMY

Safeen Dizayee, head of the KRG's Department of Foreign Relations, speaking to reporters in Erbil on August 29, 2023. Photo: Rudaw/screengrab

Also in ECONOMY

ERBIL, Kurdistan Region - Iraq and the Kurdistan Region have so far lost around five billion dollars due to the halt in the Region's oil exports through Turkey's Ceyhan port since March, a Kurdistan Regional Government (KRG) official told reporters on Tuesday, adding that Baghdad has not taken any "practical steps" to resume the exports.

Turkey stopped the flow of Kurdish oil through the Iraq-Turkey pipeline after a Paris arbitration court ruling on March 23 ruled in favor of Baghdad against Ankara, saying the latter had breached a 1973 pipeline agreement when it allowed the Kurdistan Region to begin independent oil exports in 2014.

Several meetings have been held between Iraqi and Turkish delegations since March, aimed at continuing the exports, but they have not yielded any results.

"Turkey supports the resumption of exporting the Kurdistan Region's oil, the Kurdistan Region is definitely very eager, and Baghdad, officially, say they are ready but they have not really taken any practical steps yet," Safeen Dizayee, head of the KRG's Department of Foreign Relations, told reporters on Tuesday.

Dizayee said that efforts are ongoing to reach a common ground and an understanding with Baghdad to restart the exports, adding that the resumption was needed for Erbil to fulfill its obligations within the federal budget law of handing over at least 400,000 barrels of crude oil per day to Iraq's State Oil Marketing Organization (SOMO).

The arbitration court ordered Turkey to pay a penalty of $1.5 billion in damages to Baghdad for allowing the KRG to independently export its oil between 2014 and 2018.

Dizayee said it was "mathematically illogical" for Baghdad to cost itself and Erbil five billion dollars in protest to not receiving $1.5 billion from Ankara.

Erbil and Baghdad signed an agreement to resume the Region's exports in April, but there is still no oil flowing through the pipeline to Turkey over four months later, as Ankara claims to be inspecting the port tubes that might have been damaged following February's earthquake.

Turkey Seeks Iraq Revenue-Sharing Deal to Restart Oil Exports
2023-08-25 10:12:01.470 GMT

By Selcan Hacaoglu and Onur Ant
(Bloomberg) -- Turkey is attempting to broker a deal between the central Iraqi government and the semi-autonomous Kurdish administration over how to resume Iraqi crude-oil exports via its territory, according to two Turkish officials.
Turkey halted flows through a twin-pipeline in March after an arbitration court ordered it to pay about $1.5 billion in damages to Iraq for transporting oil without Baghdad's approval. Ankara has no intention of paying the fine and is asking the Kurds to pay it to Baghdad as they were the benefactors, the officials said.
A compromise over competing demands from Iraq and the Kurdish administration over revenue-sharing from oil exports is being sought, the officials who are familiar with the matter said. The two sides have been quarreling for years over rights to Kurdistan oil sales, part of Baghdad's long-running attempt to rein in the semi-autonomous region.
Officials from the Baghdad government didn't comment, while the KRG declined to comment.
Turkey's Foreign Minister Hakan Fidan discussed energy, economic and security relations both with the president and prime minister of the Kurdish government in Erbil on Thursday, after holding talks with his Iraqi counterpart in Baghdad earlier in the week. Turkish Energy Minister Alparslan Bayraktar also traveled to Erbil and has had discussions with Iraqi Oil Minister Hayyan Abdul Ghani.

Repairing Ties

Turkey is reaching out to Baghdad to repair ties after years of estrangement as part of a reset in relations with Arab nations. Ankara is offering the Kurdistan Regional Government, or KRG, as well as the central government in Baghdad help in building power plants and other infrastructure.
Baghdad has asked Turkey to collect the money from oil exports and transfer it to Iraq after deducting 12.6% of the share allocated to the KRG, said the officials, speaking on condition of anonymity. The KRG, however, has told Turkey that it wants to claim the entire revenue from exports via its territory, arguing that it has been unable to collect funds from separate Iraqi oil exports, they said.
The pipeline running from Kirkuk to Turkey's Mediterranean port of Ceyhan remains operational and Iraqi crude exports could start quickly once there is a deal in place, the Turkish officials said, adding that Turkey aims to resolve the conflict as soon as possible.
The closure of the pipeline has cut off nearly half a million barrels of crude from global markets as Ankara refused to pay the $1.5 billion fine. Iraq had been exporting about 400,000 to 500,000 barrels a day from fields in the country's

north, including in the Kurdish region, via the now-halted pipeline.
It's unclear how much of that oil would flow back onto world markets if there was a deal, since Iraq is already pumping at very close to the limit under its OPEC quota.

--With assistance from Khalid Al-Ansary.

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Exxon's Math Calls For Overall Global Oil Decline Rate of ~7%, A Very Bullish Argument For Post 2020 Oil Prices

Posted: Thursday June 20, 2019. 5:30pm Mountain

We believe Exxon presented a very bullish argument for oil prices beyond 2020 and that it has been overlooked because most readers only flip thru a slide deck and don't listen to or read transcripts of management's spoken words. Exxon's spoken words highlighted one of the forgotten (and perhaps most important) oil supply/demand concerns for post 2020 - the mid term challenge to replace increasing rate of overall global oil declines. And what is eye opening is Exxon's estimated overall global oil decline rate, which is way higher than any we can ever remember seeing. Its impossible to tell from the small oil supply/demand graph in the slide deck, but Exxon's spoken words says long term oil demand is 0.7% per year and then "*When you factor in depletion rates, the need for new oil grows at close to 8% per year and new gas at close to 6% per year*." Exxon may not specifically say what the global decline rate is, but their math is that the world needs new oil supply to grow annually at close to 8% to meet the 0.7% annual increase in oil demand and offset declines ie. an overall global decline rate of approx. 7%. This is an overall global oil decline rate for OPEC and non-OPEC. This compares to BP's estimate of overall global oil decline rate of 4.5% and we expect most are probably assuming something around 5%, certainly not above 6%. No one should be surprised by the increased decline rate given that high decline US shale and tight oil have increased by ~2.5 mmb/d in the last ~2 years. But an implied ~7% overall global oil decline rate is way higher than expectations. There is a big difference between needing to offset oil declines of ~7 mmb/d vs declines of ~4.5 mmb/d ie. an additional 2.5 mmb/d of new oil supply every year. Even if the implied difference was to 6%, it would still be an additional 1.5 mmb/d of new oil supply and that would also be very bullish for post 2020 oil. We recognize that the 2019/2020 oil supply demand story is the need for OPEC+ to keep cuts thru 2020, but Exxon's math implying ~7% overall global oil decline rate sets up a very bullish view for oil post 2020. We believe the reality to replace oil declines post 2020 is overlooked.

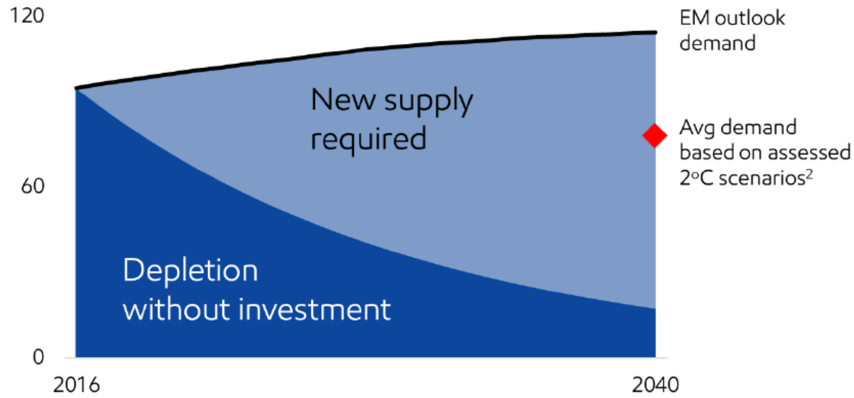
<u>The 2019/2020 oil story - oil inventories still above the 5 yr ave and OPEC+ need to work together in 2020.</u> There is increasing geopolitical risk to oil in a range of regions (Iran/Saudi Arabia, Libya, Venezuela, etc.) yet the prevailing tone to oil in the past month is negative with the concerns on trade wars/lower economic growth leading to weakness in oil demand. This was reinforced in the past week with the view that there is the need for OPEC+ to continue to work together in H2/19 and in 2020. Our SAF June 16, 2019 Energy Tidbits memo [LINK] reviewed the IEA's new monthly Oil Market Report [LINK], which included (i) "*OECD oil stocks remain at comfortable levels 16 mb above the five-year average*", (ii) the EIA lowered its 2019 oil demand growth rate by 0.1 mmb/d to +1.2 mmb/d, and (iii) a negative first look at 2020 oil supply/demand. The EIA's first 2020 forecast puts more pressure on OPEC+ to continue with cuts through 2020. IEA says oil demand growth rate will grow from +1.2 mmb/d in 2019 to +1.4 mmb/d in 2020. This is a positive, however, it is more than offset as the IEA forecasts another year of big non-OPEC oil supply growth of +2.3 mmb/d in 2020. In theory a lesser call on OPEC of 0.9 mmb/d. The IEA writes "*A clear message from our first look at 2020 is that there is plenty of non-OPEC supply growth available to meet any likely level of demand, assuming no major geopolitical shock, and the OPEC countries are sitting on 3.2 mb/d of spare capacity".*

<u>Exxon sees modest annual growth in oil demand, but peak oil demand sometime after 2040.</u> Exxon presented at a US sellside energy conference on Tues. We expect a big reason why Exxon's oil outlook was ignored was that the presentation was almost all about providing a great detailed look at the Guyana oil play. Plus its headline annual growth rate for oil demand of 0.7% per year wouldn't have made anyone bullish, if anything maybe even more so so on oi. Exxon only provided some brief comments on their oil supply and demand outlook. Exxon said *"In this scenario, oil demand is expected to grow 0.7% per year, driven by commercial transportation and chemical"*. This compares to 2018 oi demand growth of 1.45% and even this year's lower oil demand growth rates of 1.15%. However, we recognize it is tough to get data from a small graph, but a positive tn the graph is that it seems to indicate that peak oil demand doesn't happen before 2040.

<u>However, Exxon says new oil supply of 8% per year is needed to meet demand growth and offset decline rates.</u> On one hand, we continue to be surprised that Exxon's view on new oil supply has received no attention. On the other, it makes sense because the vast majority of readers only flip thru a slide deck so will miss the spoken word that gives numbers and context to a slide. That was clearly the case with the Exxon presentation. If Exxon is anywhere near right, this is a hugely bullish view for mid/long term oil ie post 2020 oil. Exxon highlighted one of the forgotten oil supply/demand concerns is

the mid term challenge to replace global oil declines. And what is eye opening is Exxon's estimated decline rate, which is way higher than any we can ever remember seeing. Exxon says long term oil demand is 0.7% per year and then says "*When you factor in depletion rates, the need for new oil grows at close to 8% per year and new gas at close to 6% per year*." Exxon didn't specifically say that the overall global decline rate was ~7%, but the math looks straightforward. The world needs new oil supply to growth at close to 8% per year to meet 0.7% annual demand growth and to offset declines in global (OPEC and non-OPEC) oil production ie. the overall global oil decline rate is approx. 7%. This is an overall OPEC and non-OPEC global decline rate.

Oil Supply/Demand (moebd)

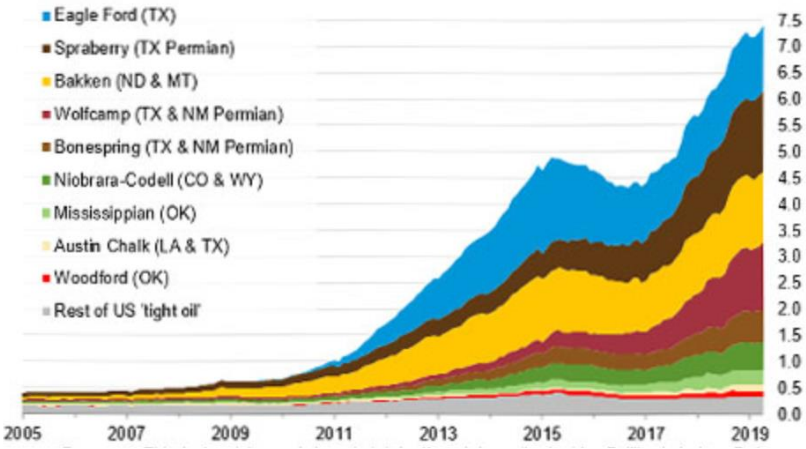


Source: Exxon US Sellside Conference Presentation June 18, 2019

Implies a huge overall global decline rate of ~7% - way higher than other estimates. It may well be the case that forecasters haven't updated their global oil decline models to reflect the impact of the US adding ~2.5 mmb/d of high decline shale and tight oil in the past two years. But we aren't aware of anyone who is using an overall global oil decline rate as high as 7%. We have seen estimates for 7% for decline rates for non-OPEC oil, but not for the decline rates overall for global oil. Rather, we expect that most have been assuming overall global oil decline rates of 4% to 5%. Later in the blog, we note our peak oil demand comment from Nov 6, 2017 (prior to the big ramp up in US shale and tight oil) that used Core Laboratories spring 2017 estimate for overall global oil decline of ~3.3%.

Exxon's global leadership position, especially in shale, is why we should pay attention to this view of significantly higher global oil decline rates. Everyone knows Exxon is the largest public international oil company and is in all major oil regions and all types of plays from conventional, oil sands, middle east, deepwater oil and shale oil, We believe that Exxon is viewed as the global leader in the Permian, and this shale oil leadership is critical to understand as we believe that the growth of US shale is the key reason for the increasing overall global oil decline rates. Exxon's shale oil leadership is why we should be paying attention to this estimate. The game changer to global oil decline rates has been the increasing oil production from high decline US shale and tight oil. The EIA estimates [LINK] that US shale and tight oil plays are up over 6 mmb/d this decade and ~2.5 mmb/d n the past two years alone.

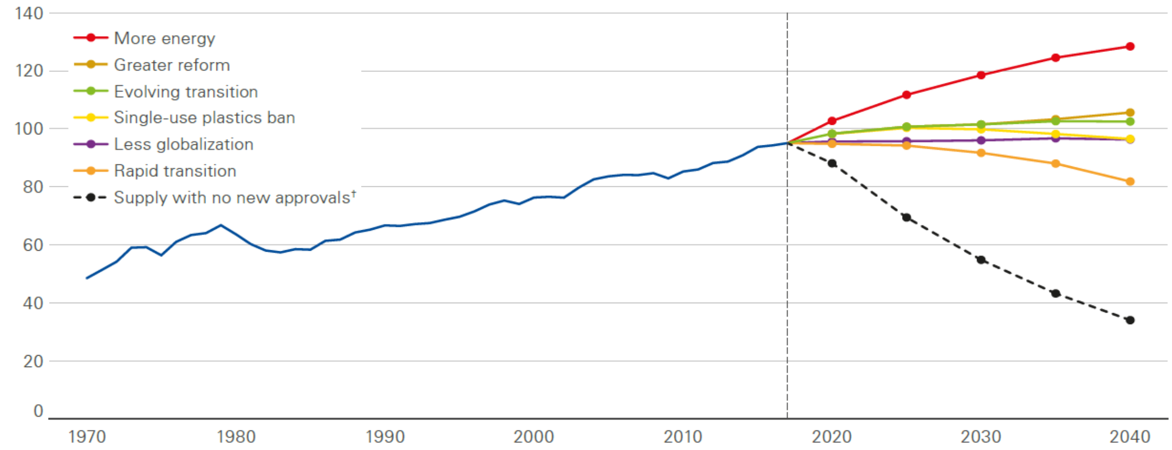
US Tight Oil Production – Selected Plays (Million barrels of oil per day)



Source: EIA

<u>BPs recent forecast for overall global oil decline rate is 4.5% per year.</u> BP's Energy Outlook 2019 Edition (Feb 14, 2019) [LINK] included their outlook for oil supply and demand and specifically on overall global oil decline rates. BP wrote "*Second, significant levels of investment are required for there to be sufficient supplies of oil to meet demand in 2040. If future investment was limited to developing existing fields and there was no investment in new production areas, global production would decline at an average rate of around 4.5% p.a. (based on IEA's estimates), implying global oil supply would be only around 35 Mb/d in 2040."* Below is the graph from their Energy Outlook 2019 Edition report.

Demand and Supply of Oil (Mbd)



Source: BP Energy Outlook 2019 Edition

<u>If Exxon is anywhere close, this is a hugely bullish signal for mid/long term oil ie. post 2020 oil</u>. We recognize that this significantly higher than expected overall global oil decline rate will take a year or two to work thru the current supply/demand fundamentals given where markets are today. However, over the mid term, the need to add ~7 mmb/d of new oil supply is a huge challenge for the world. The difference between an Exxon type view of ~7% declines vs BP's 4.5% declines is approx. 2.5 mmb/d of an additional new oil supply every year is needed to balance the markets. In reality, even if Exxon's implied overall global decline rate was ~6%, it would still be very bullish for mid/long term oil as this means an additional ~1.5 mmb/d of new global oil supply per year.

<u>Its even more bullish for post 2020 oil than we thought in our Nov 6, 2017 peak oil demand blog.</u> We have always been in the camp that believes peak oil demand is coming, but we have also been of the view that the post 2020 challenge to replace oil declines would be getting tougher. We believe Exxon's view of higher global oil decline rates is consistent with the ~2.5 mmb/d increase in US shale and tight oil in the past two years. And is way more bullish than we wrote in our Nov 6, 2017 blog "*Peak Oil Demand Is Coming, But >4 Mmb/d Of New Oil Supply Will Be Needed Every Year To Replace Declines To Get There*" [LINK], and "*We buy into the narrative of peak oil demand, believe it is inevitable, its visible and will happen before 2030. Peak oil demand will be from the cumulative impact of a number of factors including EVs, battery/storage, LNG for power, LNG for transportation, increased energy efficiency, etc. But the peak oil demand narrative forgets the most basic fundamentals of oil – industry has to add new oil supply every year to replace declines just to keep production flat. Even after today's big oil rally, long dated strips are still under $52 from 2020 thru 2025. We don't believe long dated 2020 thru 2025 strips are predictive of future prices or indicative of the marginal supply costs to add 4 to 5 million b/d every year in 2020 to 2025 or to add >3 million b/d every year once peak oil demand is reached and is in plateau. We believe these marginal supply costs are significantly higher and >$60. We believe oil can quickly move to a base of >$60 with this supply challenge and there will be longevity to this call as markets appreciate this challenge and that the marginal supply cost to add this much new oil production every year is well over $60. Peak oil demand won't take away from the challenge to add significant new oil production every year.*" Note that our Nov 6, 2017 blog was based on the spring 2017 Core Laboratories estimate that the global world wide annual decline rate in oil was then 3.3%. But to Core Laboratories support, this estimate would have been before the ~2.5 mmb/d of added US shale and tight oil in the past two years.

Caixin China General Manufacturing PMI™

Operating conditions improve for manufacturers in August

August PMI data signalled that operating conditions across China's manufacturing sector strengthened, and at the quickest rate for six months. Firms recorded fresh increases in both output and total new work amid reports of firmer market demand. This was despite a further drop in new export business, albeit one that was modest. As a result, manufacturers expanded their purchasing activity and staffing levels, with the latter growing at the fastest rate since March 2010. Cost pressures picked up slightly, however, with average input prices rising for the first time in six months. Competition for new work meant that firms continued to reduce their selling prices, though the pace of discounting was only marginal.

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 July to above the neutral 50.0 threshold at 51.0 in August. This signalled a fresh improvement in the health of the sector, which has strengthened in three of the past four months. Though only mild, the rate of growth was the best seen since February.

Supporting the improvement in overall business conditions was a renewed increase in new order intakes. Companies indicated that firmer underlying market conditions had helped to boost client spending. The modest upturn in overall sales occurred despite a further drop in new business from abroad in August, suggesting that stronger domestic demand was the main source of growth. The downturn in new export orders did ease compared to July, however, and was only mild.

Companies responded to greater amounts of new work by expanding production during August. Though modest, the rate of output growth was among the best seen over the past year.

Improved intakes of new business encouraged firms to increase their purchasing activity, thereby offsetting a slight reduction in July. However, caution around stock building led to a slight reduction in inventories of inputs. In contrast, finished goods stocks increased slightly for the second month running.

Planned company expansions meanwhile supported a fresh rise in employment across China's manufacturing sector in August. Though modest, the rate of job creation was the most pronounced since March 2010. Despite higher payroll numbers, backlogs of work rose marginally for the third straight month. Increased sales and, in some cases, temporary closures due to high temperatures, reportedly pushed up unfinished workloads.

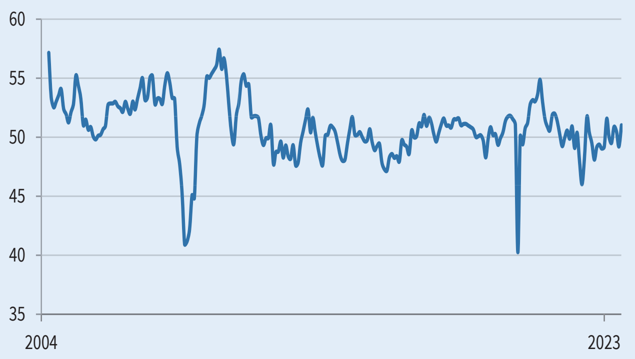
Supplier performance improved slightly in August, following a deterioration in July. Quicker lead times were generally linked to increased material availability and greater supplier capacity.

The higher cost of some raw materials, including metals, led to a renewed rise in operating expenses during August. Though marginal, the latest data marked the first upturn in input costs since February. However, competition for new business and client requests for discounts meant that average selling prices fell slightly.

Expectations regarding the 12-month outlook for output remained positive in August. Manufacturers often hoped that stronger global economic conditions and new product launches would support higher output over the coming months. That said, the overall degree of positive sentiment slipped to an 11-month low.

China General Manufacturing PMI

sa, >50 = improvement since previous month



Sources: Caixin, S&P Global PMI

Key findings:

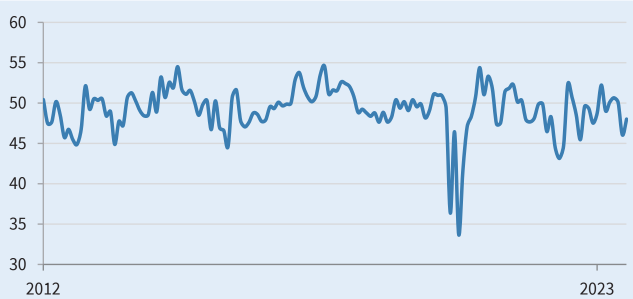
Fresh increases in output and new business

Employment returns to growth

Input costs rise for first time since February

New Export Orders Index

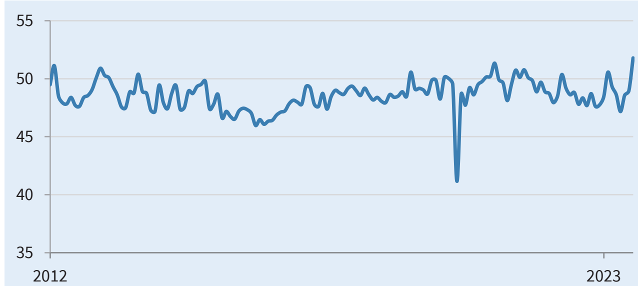
sa, >50 = growth since previous month



Sources: Caixin, S&P Global PMI

Employment Index

sa, >50 = growth since previous month



Sources: Caixin, S&P Global PMI

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 51 in August, 1.8 points higher than the July reading. It was the third time in four months that Chinese manufacturing conditions expanded, indicating that the sector was improving.

"Both supply and demand expanded. Despite the impact of high temperature on some manufacturers' production, overall market demand improved, and supply increased, with the gauges for total new orders and output both returning to expansionary territory. Overseas demand continued to drag on performance. Although the reading for new export orders rebounded, it was still well below 50, as the growing risk of recession in major economies subdued China's external demand.

"The job market in the sector also improved. As the sector expanded, the employment situation picked up accordingly for manufacturers of consumer goods, investment goods, and intermediate goods. In August, the reading for manufacturing employment rose into expansionary territory for the first time in six months, recording its highest level since March 2010. The reading for backlogs was slightly above 50, impacted modestly by extreme weather conditions.

"The gauges for prices rose marginally. Rising prices of raw materials, especially industrial metals, led the reading for manufacturing input costs to stand at or above 50 for the first time since March, but the expansion was limited. The fierce competition among manufacturers still restricted their bargaining space, and the gauge for prices charged by manufacturers to customers remained in contraction for the 15th time in the past 16 months.

"The time it took for suppliers to deliver products was shorter in August. The shortage in suppliers' inventory improved, as did the logistics situation, and the reading for suppliers' delivery times rose above 50. Manufacturers boosted their purchases, but to a limited degree due partly to rising costs of raw materials. The inventory level of raw materials thus dropped slightly.

"Manufacturers remained optimistic. The August reading for their expectations for future output stayed above 50, though the figure was the lowest since September. Surveyed companies expressed concerns about prospects of domestic and external demand in the next 12 months.

"In August, the manufacturing sector showed overall improvement. Apart from sluggish exports, the gauges for supply, total demand, and employment were all in expansionary territory. The slight rise in prices buffered the pressure of deflation, logistics remained smooth, inventory of raw materials fell, and manufacturers held on to their optimism, although to a limited extent.

"At the beginning of the third quarter, economic indicators including those for consumption, investment, and industrial production, came in generally lower than market expectations again. The National Bureau of Statistics explained the situation with three reasons: the impact of normal seasonal fluctuations; high temperature and severe flooding in some regions; and complicated global political and economic situations, coupled with insufficient domestic demand.

"Looking ahead, seasonal impacts will gradually subside, but the problem of insufficient internal demand and weak expectations may form a vicious cycle for a longer period of time. Combined with the uncertainty in external demand, the downward pressure on the economy may continue to increase. Stabilizing expectations and increasing household income should still be the policy focus. The internal and external economic environments are becoming increasingly complex, adding to the urgency and necessity of implementing relevant supportive policies."

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Is there a perfect storm brewing in the offshore wind industry?

In recent weeks, for the first time, offshore wind projects in Europe and the U.S. have been stopped, mainly citing cost increases. In other news, turbine manufacturers were once again in the red in their latest quarterly reports, with losses running into billions.

This is not good news, it's in fact the worst-case scenario for the energy transition when large projects that have already been awarded are not realised as planned. Happening at a time when the entire offshore industry has to scale up to achieve expansion targets, this quickly calls into question the achievement of climate protection goals.

This dilemma is fuelled by a combination of factors, including cost increases due to ongoing inflation and rising interest rates, as well as structural supply shortages and the strained state of supply chains.

This development must serve as a wake-up call for policymakers to adapt the regulatory framework to market realities. Five areas of action can help navigate through the storm.

1. A frontloaded auction schedule can increase the investment certainty for the whole industry. That includes the early auctioning of large sea areas.

2. Grid connection of offshore wind farms have to be accelerated and developers need to have certainty about connection dates.

3. Allowance for dual route-to-market: 2-sided Contracts for Difference (CfDs) with inflation indexation as one element, and a second element which allows the marketing of offshore power to industrial customers through private PPAs. In addition, qualitative auction criteria can strengthen the European supply chain, sustainability, and deliverability.

4. When auction schemes cap budgets, for example like CfDs in the UK, governments need to recognise the inflationary environment and that costs have gone up significantly. Sticking with the old assumptions of nominal cost reduction will simply slow down or stop offshore technology deployment.

5. Direct and indirect financial support to stimulate investments in European manufacturing capacities and a master plan to secure access to vital raw materials.

In a nutshell: we need a framework that allows for more investment certainty for both manufacturers and developers.

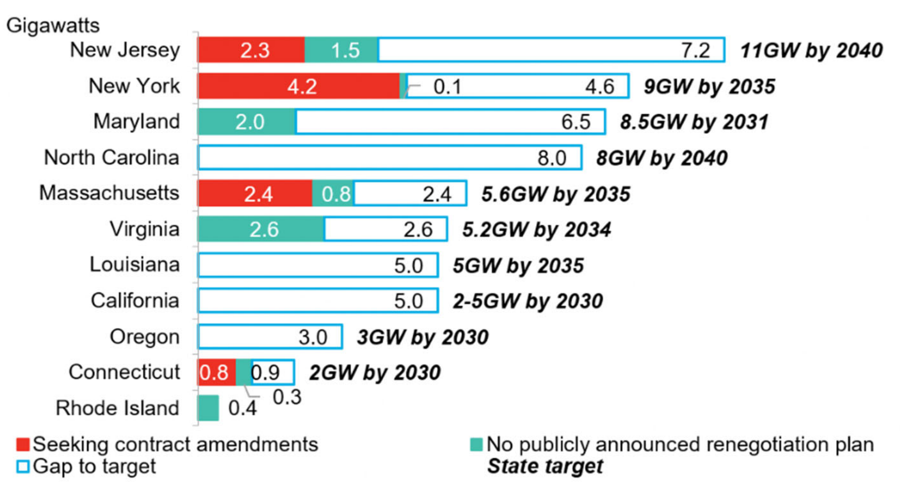
At [RWE](), we are building and driving forward the development of several projects where we have been awarded the seabeds: in Germany, the UK, the Netherlands, Denmark, Ireland, Poland and the U.S. To deal with the challenging market situation, securing financing and strong relationships with your supply chain are key.

However, the right framework and policies, as outlined here, are imperative for offshore wind energy to realise its fullest potential in the future.

Offshore Wind Goals in US Are Imperiled by Deal Revisions: BNEF
2023-07-10 14:00:00.0 GMT

By Atin Jain
(BloombergNEF) -- Several US states face a growing risk of missing their offshore wind goals due to a spate of contract renegotiation or cancellation attempts by project developers citing rising costs.
New York state has a target to add 9 gigawatts of cumulative offshore wind capacity by 2035 and contracted 4.36GW of projects in its two concluded solicitations. But renegotiation attempts mean that 95% of the contracted capacity is at risk of delays. Neighboring Massachusetts sees 75% of contracted capacities being delayed by renegotiation attempts. In Connecticut it's 73%. New Jersey, which is targeting of 11GW, risks delays to 60% of its contracted pipeline.
About 9.7GW of US offshore wind projects, or just over half of the 17.8GW total contracted, face delays, and more projects may soon face the same fate. Developers such as Avangrid, Shell-Ocean Winds, BP-Equinor and Orsted-Eversource have cited deteriorating economics due to rising costs in trying to renegotiate or cancel contracts.
The renegotiation efforts mean ambitious goals by state governments and the Biden administration to achieve 30GW of offshore wind capacity by 2030 are drifting further away from reality. The current situation highlights the challenges and complexities inherent in developing large-scale offshore wind projects.

Status of contracted offshore wind capacity and targets across US states



Source: BloombergNEF, news reports, company petitions

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Excerpt Vattenfall interim report on July 20, 2023

CEO's comment

A positive development for the customer business and challenges in offshore wind power

Vattenfall's business is in general progressing well. We benefit from our integrated business model with better results from Distribution, Heat and Customers & Solutions. However, overall we report a lower result for the half year, mainly due to an impairment in offshore wind power. Falling market prices were partly compensated by our price hedges.

Lower market prices and effects of price hedging

Compared to 2022, electricity prices in the Nordics have almost halved, while the difference between electricity price areas have decreased significantly. In northern Sweden, spot prices have nevertheless been higher, which together with the effects of price hedging has contributed to Vattenfall being paid more for its electricity in the Nordics. On the continent, electricity prices have also been significantly lower, which affects the result from the Wind segment. This has an additional impact on the Power Generation segment where the results from our continental price hedges are reported. These have not been as effective as in the Nordics.

Higher costs, especially in offshore wind power

Although demand for fossil-free electricity is greater than ever, the market for offshore wind power is challenging. Higher inflation and capital costs are affecting the entire energy sector, but the geopolitical situation has made offshore wind and its supply chain particularly vulnerable. Overall, we see cost increases up to 40%. This development affects future profitability and means that Vattenfall makes an impairment for wind power in Norfolk, UK, with a total impact on earnings of SEK 5.5 billion. We have decided to stop the development of Norfolk Boreas in its current form and not take an investment decision now due to mentioned factors, which triggers the impairment.

We will examine the best way forward for the entire Norfolk Zone, which in addition to Boreas also includes the Vanguard East and West projects. Over the past decade, Vattenfall has built up its wind operations which today is a valuable and profitable business generating an underlying profit of more than SEK 16 billion last year. We have attractive wind power projects in the pipeline, and investment decisions will always be based on profitability. We are convinced that offshore wind power is crucial for energy security and meeting the climate goals in Europe.

The profit for the period in the first half of the year amounted to SEK 6.9 billion, which is SEK 3.4 billion lower than in 2022. The impairment of Norfolk Boreas is partly offset by a positive financial net due to higher returns from the Nuclear Waste Fund.

A profitable and sustainable business model

Vattenfall reports higher contributions from both the heat and customer business. In Germany, we now have over 5 million customers, which makes Vattenfall one of the three largest energy suppliers for private customers in the country. However, lower contributions from Power Generation and Wind generate a lower underlying profit for the first half of 2023. The underlying profit for Vattenfall is SEK 14.6 billion, which is SEK 1.7 billion less compared to the same period in 2022.

Overall, Vattenfall has a continued stable capital structure with reassuring cash flow in relation to our financial commitments. The return on capital employed amounted to 0.5% and is affected by impairments and the valuation of electricity and fuel contracts at fair value. On an underlying basis, the figure however amounted to 10.7%, which demonstrates that our diversified and integrated business model is working.

Additional steps towards a fossil-free future

Vattenfall's goal is to enable fossil-free living. This permeates all of our operations and means we stand strong as a company. In June, Vattenfall was one of nine companies globally to have its net-zero emissions targets by 2040 verified by the Science Based Target Initiative (SBTI). We also recently inaugurated Vattenfall's largest onshore wind farm in the UK, South Kyle, and have completed the construction of the offshore wind farm Hollandse Kust Zuid in the Netherlands.

We continue to work on our preliminary study on the feasibility regarding new construction of small modular nuclear reactors (SMR) in Sweden, a study which is scheduled to be completed by the end of the year. New nuclear power, alongside other fossil-free energy sources, will be crucial in ensuring that Sweden will meet the increasing demand for electricity in the long-term.

Anna Borg
President and CEO

Profit for the period	Underlying operating profit	FFO/adjusted net debt	Return on capital employed
First half of 2023	First half of 2023	Last 12 months	Last 12 months
6.9 SEK billion	**14.6** SEK billion	**30.6%**	**0.5%**
(10.3)	(16.3)	(103.0)	(19.3)

Excerpt Vattenfall March 29, 2023 Corporate Factbook

Main projects in our 5 core countries

Country	Name	Capacity (MW)	Support scheme	Awarded	Duration of support	Owner-ship (%)	Commission-ing	Current status
NL	Hollandse Kust Zuid 1-4	1,520	-	X	-	51	2023	Under construction, Partnering with BASF
DK	Vesterhav	344	FIT	X	50.000hrs	100	2023/2024	Under construction
UK	South Kyle	240	-	N/A	-	100	2023	Under construction
NL	Windplan Blauw	77	SDE+	X	15 yrs	100	2023	Under construction
UK	Battery@Ray	20	-		-	100	2023	Under construction
In construction		**2,201**						
UK	Norfolk projects	3,600	CfD		15 yrs	100	2027-2029	Norfolk Boreas received CfD in AR4, Norfolk Vanguard is preparing for CfD bid in AR5
UK	Scotwind	750	CfD			50	2030	Under development with consenting and permitting progressing to ensure participation in the CfD bid, JV with Fred Olsen
GE	N-7.2 (Global Tech II)	980	-		-	100	2027	Development rights received in September 2022, FID planned for 2023
In development (in mature stage)		**5,330**						

Offshore Onshore Solar Batteries

[1] The project has been sold but Vattenfall will build and operate the wind farm

VATTENFALL

https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-takes-action-to-enhance-energy-affordability-for-ratepayers-in-southern-california-2023

CPUC Takes Action to Enhance Energy Affordability For Ratepayers in Southern California

Progress continues in reducing reliance on natural gas and phasing out Aliso Canyon

August 31, 2023 -

The California Public Utilities Commission (CPUC) acted this week to enhance energy resiliency and protect ratepayers in Southern California from potential volatile wholesale natural gas prices this upcoming winter season. Today, the CPUC increased the inventory levels of natural gas at the Aliso Canyon Natural Gas Storage Facility up to the safety limit set by the state's Geologic Energy Management Division to guard ratepayers from the type of natural gas price spikes that occurred last winter. In a concurrent action, the CPUC issued a Ruling on August 29, 2023, that outlines the steps toward releasing a plan by the first quarter of 2024 to reduce the state's reliance on Aliso Canyon.

This decision allows more natural gas to be injected and stored at Southern California Gas Company's (SoCalGas) Aliso Canyon in the fall season, which acts as a financial hedge against potential high winter market prices; this decision does not impact how much natural gas will be consumed. The Western region of the U.S. saw substantial increases in wholesale natural gas prices from November 2022 to March 2023. Preliminary estimates from stakeholders suggest that the CPUC's decision to temporarily increase natural gas storage at Aliso Canyon could lead to savings ranging from $200 to $450 million for Southern California natural gas customers during the winter of 2023-2024. Electricity customers may also see savings due to the close connection between natural gas and electricity prices.

As the energy landscape continues to evolve, the CPUC remains dedicated to taking steps across a wide array of proceedings to reduce the state's demand for natural gas through such measures as electrification deployment and building decarbonization programs.

More information is available on today's decision in the CPUC's fact sheet. The proposal voted on is available here. Documents related to the proceeding are on the Docket Card.

Reducing dependence on Aliso Canyon in the long-term

Today's decision is part of the CPUC's ongoing proceeding to assess the feasibility of reducing or eliminating the use of Aliso Canyon while supporting energy reliability, affordability, and advancing towards a zero-emission energy landscape. Importantly, today's decision does not hinder the progress of the proceeding aimed at phasing out the need for Aliso Canyon.

As highlighted in the CPUC's August 29, 2023 Ruling, this ongoing proceeding is on track to present a Proposed Decision on alternatives to replace Aliso Canyon, which would be issued for public comment in the first quarter of 2024. This Proposed Decision will address the CPUC's statutory responsibility to outline the feasibility and pathway to lessen or eliminate the state's reliance on Aliso Canyon from its current interim level. A previously published CPUC Staff Proposal outlines potential strategies to diminish the reliance on Aliso Canyon by augmenting electricity generation, battery storage, building electrification, and energy efficiency initiatives and a biennial process to assess progress.

The CPUC has proactively taken measures across various initiatives to decrease the reliance on Aliso Canyon. In 2021, the CPUC solicited public input on preliminary actions that could be undertaken before the comprehensive Alison Canyon analysis concludes. And in February 2022, the CPUC's Integrated Resource Plan proceeding committed to the development of a modeling toolkit capable of local analysis that could assist with decisions such as Aliso Canyon replacement. Additionally, ongoing proceedings are underway to chart a course for statewide decarbonization and reduced fossil gas usage.

Furthermore, in a study exploring the evolution of California's electric transmission system to achieve the State's target of serving 100 percent clean energy by 2045, the CPUC, in collaboration with the California Energy Commission and the California Independent System Operator, explored scenarios that consider the absence of the Aliso Canyon facility.

Comprehensive Response to the Aliso Canyon Leak

Separately, the CPUC has taken action to hold SoCalGas accountable for the Aliso Canyon leak. On Aug. 10, 20203, the CPUC adopted a settlement between SoCalGas, the CPUC's Safety and Enforcement Division (SED), and the Public Advocates Office (Cal Advocates) for the Aliso Canyon leak. The settlement included a penalty of $71 million and required that SoCalGas forgo cost recovery for a significant number of costs related to the incident.

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About the California Public Utilities Commission

The CPUC regulates services and utilities, protects consumers, safeguards the environment, and assures Californians access to safe and reliable utility infrastructure and services.
Visit www.cpuc.ca.gov for more information.

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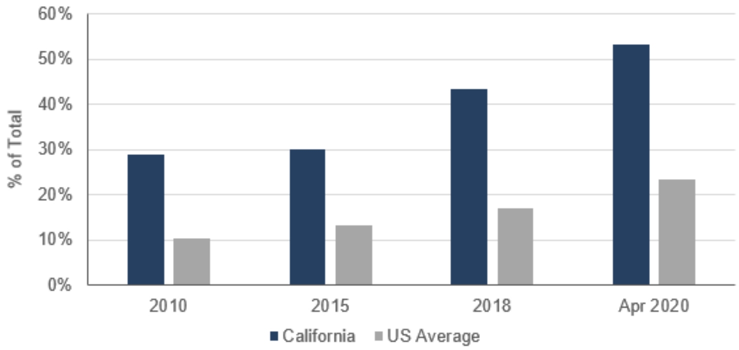
Time To Pay Attention, Electricity Crisis Leads To California's Reality Check On Renewable Energy Shortfalls To Deliver Reliable Electricity

Posted Wednesday August 19, 2020. 3:15pm MT

Its time for everyone on both sides of the clean energy push to pay attention when a renewable energy advocate of the North American leader in the energy transition makes a emergency public address to highlight shortfalls in solar/wind and that changes are needed if they want to provide reliable energy. This is what we saw on Monday in California Governor Newsom's public address. We had to replay it before we tweeted [LINK] "*Need reality check on #solarenergy for reliability. Surprise, from CA @GavinNewsom, not an oilman. CA will be diligent "to guarantee protocols, processes, forecasting that's more sober, around the potency of solar". #NatGas will be needed*." It seems like the rotating blackouts have exposed the shortfalls in California's energy mix related to solar power capacity inefficiencies, wind power inconsistencies, insufficient battery storage, insufficient natural gas power reserve, and less import potential after July. And a planning issue as these are all well known risks. It can't be easy for Newson, a strong renewable energy advocate, to acknowledge these items. Give him credit for placing an urgency to deal with this electricity crisis before the November 2022 California governor election. The world's economy has taken a huge hit and government's debt has massively increased from COVID-19 impact. But that hasn't seemed to deter the world's energy transition. Its why Newsom's underlying message should be noted by both sides. This is real data, real life impact, and its reaffirms that the energy transition will be bumpier and take longer than aspirations and expectations. This should not be a surprise. And its not a warning of doom from anti climate change people. This is not just a California issue, it's a world issue. Our 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*" highlighted the recent IEA reports that the world is behind in its energy transition. Newsom's reality check comments is more than a pause, rather he realizes they need to take a step back in items like phasing out natural gas if California is to have reliable, but expensive, electricity. It also means oil and natural gas should surprise to the upside post 2020. But most of all, its time for governments, companies and investors on both sides of the energy transition to pay attention.

<u>California has been the US leader in the energy transition.</u> The reason to pay attention is that California has been leading North America in the energy transition whether it be in renewable energy, pollution, auto emissions, reducing natural gas for cooking, etc. It is the leader and really accelerated its push following the smog problems of the 1970's. And it shows up in the data. The below table shows how renewables % of total electricity net generation have increased from 29% in 2010 to 53% in April 2020, compared to total US of 10% in 2010 to 23% in April 2020.

Renewables % of Total Electricity Net Generation



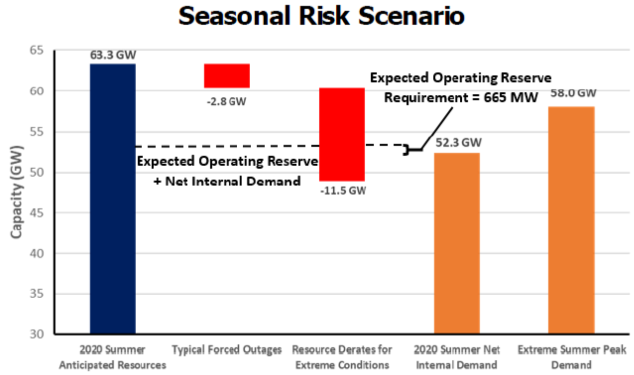
Source: EIA

<u>It was a tough 4 days for California and, to his credit, Gov Newsom recognizes changes are needed.</u> The heat wave across the west coast has been causing serious issues for California's electric grid as air conditioners are used heavily and more people are spending time inside due to COVID, with total cases now topping 600,000 in California. This combination pushed the limits of the California power grid, a grid that gets over 50% of its electricity from renewable sources. Beginning on Friday, a series of rolling blackouts have been making their way through California as renewable generation faulters and natural gas generation capacity, which has been decreased in recent years, cannot make up for

the lost power. California ISO warned at 2:30 pm on Friday that 3.3 million homes and businesses could lose power. They declared the first Stage 2 power emergency since 2006 due to excessive heat at 6:59 MT. The announcement warned that if people do not limit their electricity consumption that they could move to Stage 3. Half an hour after the Stage 2 warning, they declared a Stage 3 power emergency which was *"ordering utilities to implement rotating power outages to protect the stability of the grid".* Bloomberg terminal reported that up to 2 million customers may have been hit in rotating blackouts. California was hit with another Stage 3 emergency on Saturday night which came with yet another round of rotating blackouts, though to a lesser extent, affecting ~200,000 customers. On Monday, they issued yet another Stage 2 Emergency alert, though it was lifted later that day *"thanks to consumer conservation and cooler than expected weather".* The situation was much the same on Tuesday with a reverted Stage 2 Emergency. This situation has prompted Gov Newsom to open an investigation into the reliability of the power grid, stating they need to have *"forecasting that's more sober, around the potency of solar".*

<u>California looked to have adequate reserves coming into the summer.</u> On June 2, NERC issued its "*2020 Summer Reliability Assessment"* [LINK], which forecast a 20.9% Anticipated Reserve Margin vs a 13.7% Reference Margin Level. California was viewed as one of the better off regions coming into the summer. The problem with seasonal analysis is that NERC is the summary numbers and graphs are based on the season and don't show the risk within the season. The NERC graph warned there could be shortages under extreme conditions. But their text does get address some of the timing issues that we note below on why say its no one should be surprised by the risk in solar, and hydro for power delivery in California in mid-August.

WECC-California/Mexico Seasonal Risk Scenario

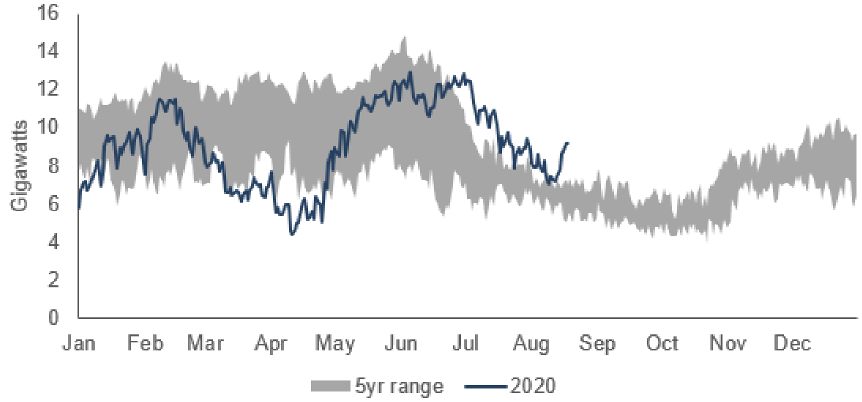


Source: NERC

<u>The risks to relying on renewable energy were well known – its late in the summer, its hot, its humid, winds have been mild, and not enough battery storage capacity.</u> California Governor Newsom made a major address on Monday to address the California electricity crisis. We listened to the address [LINK] and made a transcript of some key sections. In the address, Gov Newsom said California has '*to understand the conditions that led up to it"*, referring to the Friday and Saturday rotating blackouts. We have to believe his need to understand are more related to forecasts, coordination, etc because the risks to renewables are well known. Putting aside the issue of reducing natural gas peaking plants for reserve, there were no surprises in the key factors that impacted power reserve and force the rotating blackouts. (i) Its late in the summer. California and Pacific Northwest hydro generation always peaks earlier in the summer. This happens every year. And means that in mid August, there is less California hydro generation and less available Pacific NW hydro generation for imports after late June/early July. (ii) Its hot. Every solar view says that solar panel lose efficiency in very hot weather. This is not a secret. Solar panel efficiency is normally rated based on 25C/77F and really hot weather can hurt efficiency by 10-20%. (iii) It was humid. Gov Newsom said they have they have to understand "*what it means when there's higher humidity like we've experienced, and the impact that has on solar".* Every solar view says that humidity reduces solar panel efficiency This is not a secret. Most estimates also tend to be in the 10-20% range. (iv) Wind power is unpredictable. This is not a secret. Newsom said "*The fact that while we've had some peak gust winds. wind events across the state have been relatively mild. By the way, that's a good thing from a fire suppression perspective. That's*

unfortunate moment more broadly as it relates to addressing the episodic nature of the renewable portfolio." (v) California's battery storage for electricity is immaterial to its supply needs. In our later graph, battery storage is a faint red line and is basically nothing in the total supply scheme. On Monday, Newsom said California has to understand its energy mix and "*our current protocols with exports of energy to west coast states, and our capacity on storage, in particular, that needs to be substantially improved. Technology is catching up our efforts and needs to be advanced in this space."*

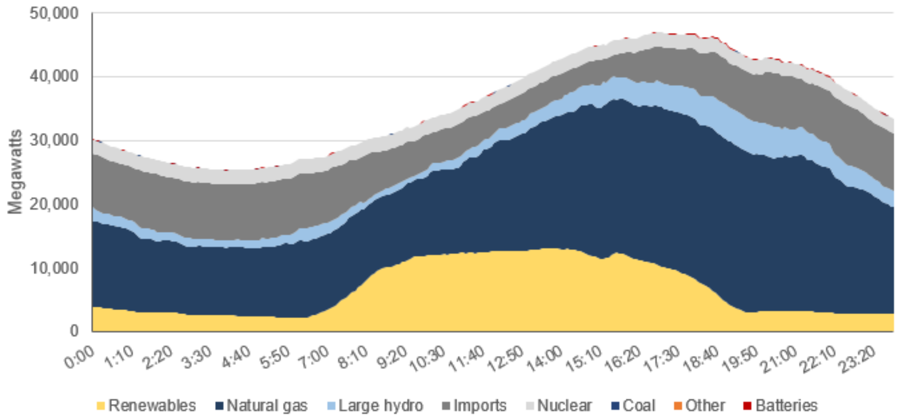
Northwest Hydroelectric Output by Month



Source: Bonneville Power Association

<u>And the risks to renewable power's daily cycle were well known – not enough reserves from "polluting" gas plant to offset solar's daily power crash after 5pm.</u> We should note that Newsom made a point of referring to natural gas plants as "polluting gas plants". The big increase in solar power has changed the peak risk period for power outages. Traditionally, the peak risk period is when there is peak demand, which is 5-6pm. Who hasn't heard the requests from utilities to do things like don't run your dishwasher at dinner time. And normally, as power demand declines after dinner, the power crisis is over. That is different now in areas like California with significant solar. Newsom said "*we identify the peak hours roughly 3 pm about to 9, 10 pm. say 3 to 10 pm are the peak hours. I can explain in a moment why those evening hours become the most precious as regards to our concerns. Particularly as it relates to the sun going down, utilization of solar.*" And this means that more natural gas reserves are needed after the peak demand 5-6pm period. Not having sufficient gas plant capacity is a key factor to what forced CAISO to implement rotating blackouts on Friday and Saturday nights once the known capacity constraints were impacting solar.

Sources of California Electricity on Aug 14, 2020

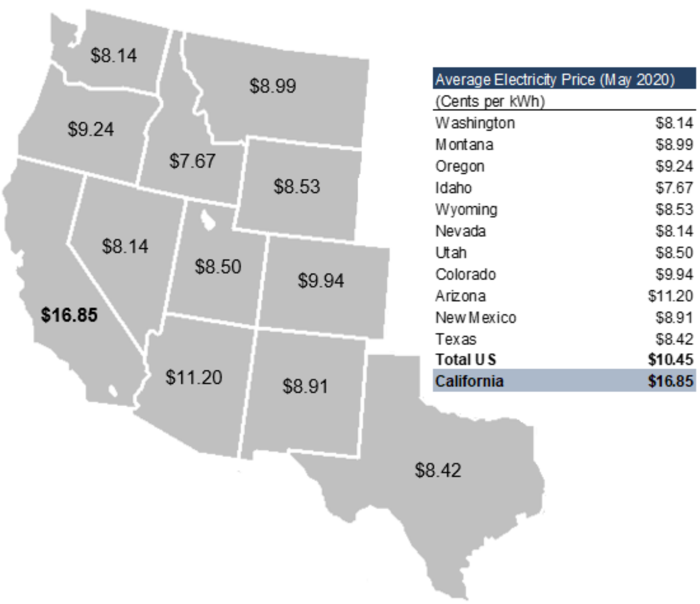


Source: CAISO

<u>Newsom says California has to be aggressive to have an energy mix that provides reliable electricity.</u> The key message from Newsom's Monday speech was that California needs to be able to provide reliable electricity. He isn't changing the game plan of an energy transition, but he is saying what they are doing isn't meeting the primary goal of an energy mix that provides reliable electricity. And that they will be more aggressive in providing reliability. He has to deal with the shortfalls of solar and wind, and the lack of storage noted earlier. He even grudgingly acknowledges the need for natural gas, he can't get rid of the existing gas power, he needs more. Newsom said "*but in the process of the transition. In the process of shutting down. Understandably, the desire and need to shut down polluting gas plants. And the desire to go from old to the new. In that transition and the need to shut those down, comes the need to have more insurance. Comes the need to recognize that there has been by definition, demonstrably in the last few days, and what we expect over the next few days, gaps in terms of that reliability. We cannot sacrifice reliability as we move forward in this transition. And we're going to be much more aggressive in focusing our efforts. And our intention in making sure that is the case. We need to make sure that we have a demand response system, and we have reliability that meets the expectation that we've all forecasted around issues of climate change. and around the prospects that this is not the last quote unquote record breaking historic heat dome, an experience that we will have in this state, in this region or in this nation or in our hemisphere in our lifetime. Quite the contrary, this is exactly what so many scientists have predicted for decades. Its manifesting quite acutely here on the west coast of the US. also manifesting in droughts, not just wildfires, and not just the issue of concerns around high quality, low cost, reliable energy for people that must have that support for their health, for our economic prosperity and the like.*"

<u>No wonder, he wants to provide reliable electricity, California electricity is expensive.</u> Its easy to see why Newsom believes it is important to deliver reliable electricity to Californians. At the price of electricity in California, its fair for Californians to expect reliable electricity. California's move to renewable has brought California the 6th highest electricity prices in the US and its electricity prices are only exceeded by Hawaii, Alaska, Connecticut, Rhode Island, and Massachusetts, .Its electricity prices are about double its As a general rule, California's electricity prices are generally double its neighbours Nevada, Oregon and Washington, and 50% higher than Arizona.

Average Electricity Price For All Sectors (Cents per kWh) - Western US States and Total US



Average Electricity Price (May 2020) (Cents per kWh)	
Washington	$8.14
Montana	$8.99
Oregon	$9.24
Idaho	$7.67
Wyoming	$8.53
Nevada	$8.14
Utah	$8.50
Colorado	$9.94
Arizona	$11.20
New Mexico	$8.91
Texas	$8.42
Total US	**$10.45**
California	**$16.85**

Source: EIA

<u>California's lack of sufficient storage reminds there is the need for an integrated electricity system that needs more than solar and wind power</u>. One of the key themes from our 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] was that the energy transition is massively complex, its not just adding more wind/solar. On June 9, Bloomberg Green story "*Shell's CEO Worries About a Disorderly Energy Transition: Q&A"* noted the Shell CEO comment that is over looked by most everyone. He said "*the energy transition is massively complex. It will require orchestration on a scale that the world has never seen*." We think the most overlooked aspect of the energy transition is that it is much more than just adding more solar and wind to replace some portion of the fuel supply. One of the major challenges is replacing an electricity grid that has been built on fossil fuels, nuclear and hydro delivering high intensity energy on a continuous as needed for whatever is needed basis. Again, its not just adding solar and wind, its having the proper electricity storage, generation and delivery system to support this fossil fuels out/renewables in switch. One of the shortfalls of California's energy mix is the lack of electricity storage. Our graph earlier Sources of California Electricity on Aug 14, 2020 showed battery storage (faint red line) was negligible.

<u>We don't expect California's lesson being learned will deter most national governments climate change ambition.</u> We don't think California's realty check will have any significant impact on national governments (ie. Canada) that are pro climate change. Our view has been that, if having to deal with the historic impact of COVID-19 on economies and national debt levels, isn't deterring climate change ambitions, then nothing will. But the reason why we don't see California's warning solar potency impact a country like Canada is that the national government isn't the one to take the blame for power interruptions or high electricity costs. Rather any failure on power tends to be placed on a state or province or local level. Yesterday, we saw that example in Canada in the press conference post the appointment of Chrystia Freeland as Canada's Finance Minister. There was no concerns on record national debt levels, rather Freeland said "*Canadians understand that the restart of our economy needs to be green"* and Trudeau said "*This is our chance to build a more resilient Canada, a Canada that is healthier and safer, greener and more competitive", "This is our moment to change the future for the better," and "We can't afford to miss it because this window of opportunity won't be open for long.".*

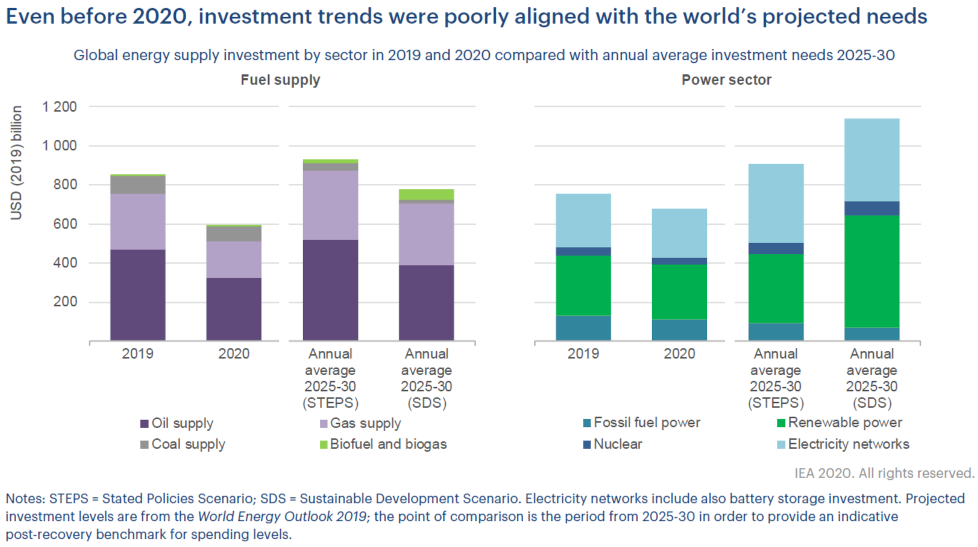
<u>But other states and provinces will likely at least pay attention to California's pivot and warning on renewable energy shortfalls</u>. California has been the leader in the energy transition in the US with others following in their footsteps. California's reality check on solar potency and wind variability should be acknowledged by others, but we won't be surprised if other states and provinces don't see California's energy mix reliability problems as their potential risks. But we do believe Newsom's pivot and reality check on solar, wind and storage will get some attention at state and province level governments ie. where voter blame is ultimately placed. The challenge is that they will be up against national government initiatives. Newsom is not up for re-election until November 2022. But we suspect he wants to have the reliability concerns dealt with before that election. He likely hasn't heard of former Ontario Premier Kathleen Wynne, whose Liberal party was blown out of the water by Conservatives led by Doug Ford in great part due to Ontario's high electricity prices from its move to shut down natural gas power. There is a setup for increasing conflict in Canada and in the US. In Canada, we have already seen some of the provinces push back on the carbon tax. That will only increase with any increased carbon push in Canada as implied by Trudeau yesterday. In the US, 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] would see a major acceleration of any renewable risk if Biden is elected. We expect California's realty check will inevitably cause that timetable to be delayed.

<u>Everyone should pay attention, California's reality check on solar/wind reaffirm the energy transition will be bumpier and take longer than expected.</u> We believe governments, companies, and investors on both sides of the energy transition should pay attention to Newsom's straight talk and reality check. California has been the North America leader in clean energy transition. This week's rotating blackouts and power capacity shortfalls and Newsom's reality check that they need to provide reliable electricity is really more than a pause, it's a step backward that will inevitably lead to items like more "polluting gas plants", at least for in reserve. This is real life data and a major acknowledgement (admission) that their leading renewable energy mix can't provide reliable electricity. Newsom didn't mention a focus to provide reasonably priced electricity. This won't change the world being on a path to a clean energy transition. But it is real data that shows

its not on track to deliver what it thought was in position to deliver. Look at California identifying two major linked shortfalls: an energy mix that doesn't have sufficient capacity to deliver reliable electricity, and forecasting that doesn't seem to take into account some fundamental risks from solar, wind and hydro generation. Give Newsom credit, he making sure they do this reality check now to prevent bigger problems in the future. It has to inevitable that there will be some slow down in the pace of the energy transition process. Perhaps just as important, we expect California's forecast will have greater element of risk or conservatism, which should allow outsiders to see a slow down in the energy transition.

Its not just California, the world is way behind on its clean energy transition. This reality check is that its more than California, it's the world is behind on energy transition. On May 27, we tweeted [LINK] "*Seems clean energy supply + related grid/infra won't be anywhere close to meet aspirational goals of many countries"* based on the IEA's just released that morning major report "*World Energy Investment 2020*" [LINK]. The IEA reviews investment in the full spectrum of energy including in 2020 and provided some excellent insight into the implications of the capital, or lack thereof, for the future. The IEA notes the required investment capital for clean energy wasn't being spent in 2019 and COVID-19 made the investment gap larger in 2020. Prior to 2020, the IEA estimated clean energy spending was relatively flat for 2015-2019, before declining in 2020. As is happening in almost every sector, the world economy crash in 2020 has led to be declines in invested capital in all energy sectors, including power and clean energy. In discussing renewables, one of the many shortfall IEA comments was on slide 90 "*Current investment levels are not aligned with a sustainable pathway. Compared with the average annual investments projected in the IEA SDS, power sector spending in 2019 was about 35% short of the level required a decade from now. There is a continued need for capital reallocation to meet energy security and sustainability goals, to bring in more low-carbon power and to ensure that renewable-rich systems can operate with sufficient system flexibility. The largest projected growth in investment to align with such a pathway would be required in solar PV and wind, on average an extra USD 160 billion of spending each year. Electricity networks would require an extra USD 150 billion from today's levels, in addition to a higher level of capital for other renewables and nuclear."*

IEA's Estimated 2019 and 2020 Invested Vs Future Required Investment



Source: IEA Tracking Clean Energy Progress, June 2020

Oil and natural gas should surprise to the upside over the midterm - the demise of oil and natural gas will take longer, just like coal. Newsom has had to acknowledge there weren't enough "polluting gas plants" to provide the reserve to avoid the rotating blackouts on Friday and Saturday. The simple conclusion is that it means oil and natural gas will be needed longer than expected to fill the gaps and provide the critical support for electricity system. Oil and natural gas markets have been crushed in 2020 by the massive hit to demand from COVID-19. Demand is recovering but it will take time to eliminate the surplus oil and natural gas/LNG inventory. But we expect to see a jump up in prices as markets get visibility for the surplus to be eliminated. The other reason to be bullish on oil and natural gas in 2021/2022 is that its not just the delayed energy transition will be mean stronger mid term demand for oil and natural gas. It will happen as the impact of low oil and natural gas exploration and development spending hits global oil and natural gas supply. The impact isn't felt today with the demand loss and surplus inventory. But yesterday's BHP's economic and commodity outlook [LINK] included a simple but fundamental reminder of the basics of commodities supply "*COVID–19 has altered many things but it does not alter geology or define the frontier of operational efficiency in each commodity sector. Besides demand, these are the two most critical factors for identifying marginal sources of long run supply*." BHP sees "*an expected structural demand-supply gap through at least the mid-2030's*" for oil. One reminder is that oil prices typically gap up or down as markets have visibility towards the near term. Look for oil and natural gas to jump up as markets have visibility that the surplus is on track to be eliminated.

Will The Demise Of Oil Take Longer, Just Like Coal? IEA and Shell Highlight Delays/Gaps To A Smooth Clean Energy Transition

Posted Thursday June 11, 2020. 1:45 MT

We expect one of the major global energy themes in 2021 will be that the world is not on track for a smooth energy transition to a world of clean energy. And this will be elevated to the #1 global energy theme if Joe Biden becomes President and moves to "r*ally the rest of the world to meet the threat of climate change."* There has been no pull back from the aspirational goal of almost every country for a clean energy transition, even in the face of a global economic crash. It is going to happen. The world is on a path for clean energy at the cost of fossil fuels. But this transition is not just adding more wind and solar. Rather it is complex, requires advancing a wide range of "*critical energy technologies*" and, most of all, a major jump up in investment capital. The IEA has just provided data to show the world is far behind in "*critical energy technologies*" and in invested capital for the energy transition. And this week, Shell's CEO noted his concerns (similar to the IEA) that also point to a disorderly energy transition. If the world isn't ready for this energy transition, it should point to a need for more oil and gas to fill the delay gap, and this should lead to delays in oil demand declines on the path to peak oil demand. We don't think the energy transition will impact oil demand by millions b/d. However, even if the energy transition delay only reduces oil demand declines by 0.5 mmb/d or more, it should help push back peak oil demand a few years. And this should be happening as non-OPEC oil supply sees an impact from the lower upstream capex over the past couple years and the massive capex cuts in 2020. And we think this helps support a higher WTI oil price by $5 for the 2022 to 2027 period whether you believe in the current forward strip for WTI averages ~$44 for 2022 thru 2027, or, if you are like us, believe in oil above the strip. Its support for a view that oil in the 2022 to 2027 period will stronger than expected. And maybe the demise of oil will be like the expected demise of coal – it will take longer than expected.

<u>Shell warned the world is not ready for a smooth energy transition</u>. Shell CEO's message was very clear and was captured clearly in the title of the Bloomberg Green Tuesday story "S*hell's CEO Worries About a Disorderly Energy Transition: Q&A".* The Shell CEO said "*The energy transition is massively complex. It will require orchestration on a scale that the world has never seen. If you don't start with it soon, it's going to be highly disruptive at the end or it's not going to happen. And both are unpalatable conclusions".*

<u>"The energy transition is massively complex", its not just adding more wind/solar</u>. The Shell CEO reminded of something that is overlooked by almost everyone, he said "t*he energy transition is massively complex. It will require orchestration on a scale that the world has never seen."* We think the most overlooked aspect of the energy transition is that it is much more than just adding more solar and wind to replace some portion of the fuel supply. One of the major challenges is replacing an electricity grid that has been built on fossil fuels, nuclear and hydro delivering high intensity energy on a continuous as needed for whatever is needed basis. Again, its not just adding solar and wind, its having the proper electricity storage, generation and delivery system to support this fossil fuels out/renewables in switch.

<u>The IEA reminds the energy transition has many "*critical energy technologies*", the vast majority of which are not on track</u>. 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

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	

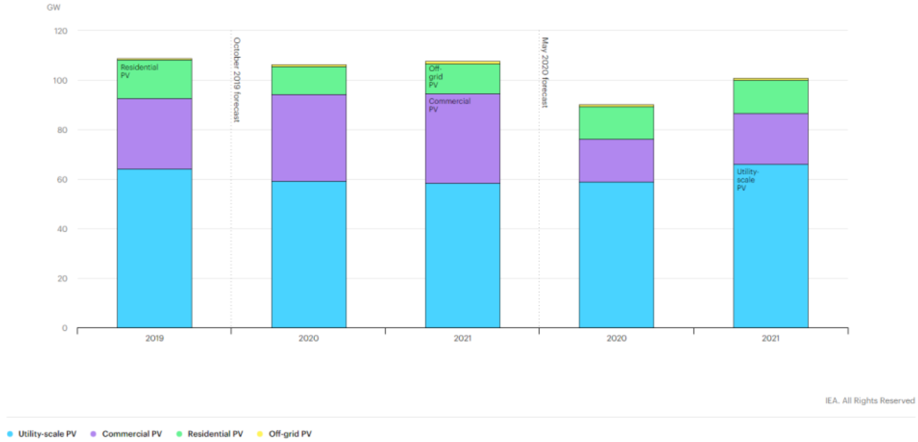
Source: IEA

On Track   More Efforts Needed   Not on Track

Source: IEA Tracking Clean Energy Progress, June 2020

<u>Even the "on track" items like solar PV are seeing a pause in growth especially with lower 2019 and 2020 investment capital</u>. As noted in the above chart, the IEA ranks Solar PV as one of its few green dots "on track" critical energy technologies. However, the IEA's tracking update also shows how COVID-19 has led to the IEA revising down its solar PV capacity additions forecast down by ~15% for 2020 and by ~5% for 2021 ie. solar PV additions won't get back to 2019 levels at least until 2022 or possibly 2023. The IEA explains "*Covid-19 has led to construction delays and weaker than anticipated investment, requiring us to revise capacity addition projections down by over 15% for 2020".*

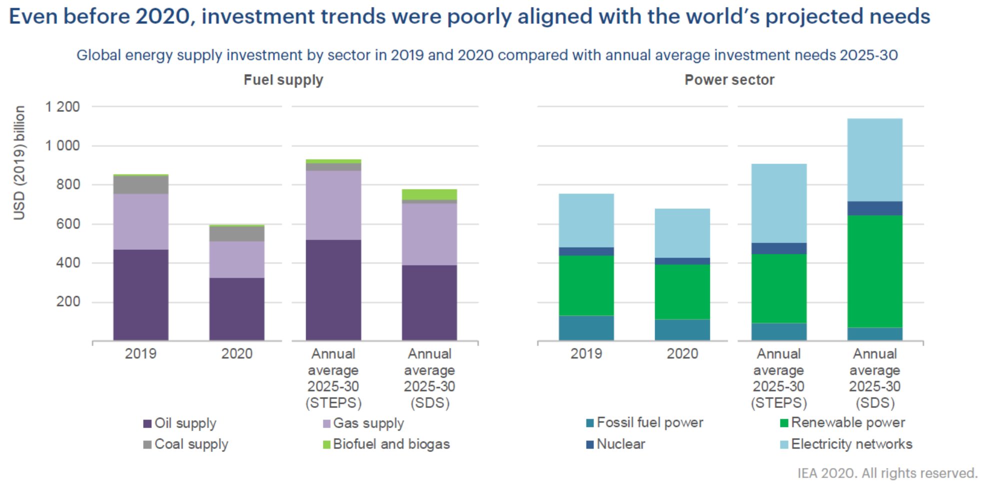
IEA's Solar PV Capacity Additions, 2019-2021, October 2019 Forecast vs May 2020 Forecast



Source: IEA Tracking Clean Energy Progress, June 2020

No surprise the energy transition is not on track, there hasn't been enough capital invested in the transition even before COVID-19. On May 27, we tweeted [LINK] "*Seems clean energy supply + related grid/infra won't be anywhere close to meet aspirational goals of many countries*" based on the IEA's just released that morning major report "*World Energy Investment 2020*" [LINK]. The IEA reviews investment in the full spectrum of energy including in 2020 and provided some excellent insight into the implications of the capital, or lack thereof, for the future. The IEA notes the required investment capital for clean energy wasn't being spent in 2019 and COVID-19 made the investment gap larger in 2020. Prior to 2020, the IEA estimated clean energy spending was relatively flat for 2015-2019, before declining in 2020. As is happening in almost every sector, the world economy crash in 2020 has led to be declines in invested capital in all energy sectors, including power and clean energy. In discussing renewables, one of the many shortfall IEA comments was on slide 90 "*Current investment levels are not aligned with a sustainable pathway. Compared with the average annual investments projected in the IEA SDS, power sector spending in 2019 was about 35% short of the level required a decade from now. There is a continued need for capital reallocation to meet energy security and sustainability goals, to bring in more low-carbon power and to ensure that renewable-rich systems can operate with sufficient system flexibility. The largest projected growth in investment to align with such a pathway would be required in solar PV and wind, on average an extra USD 160 billion of spending each year. Electricity networks would require an extra USD 150 billion from today's levels, in addition to a higher level of capital for other renewables and nuclear.*"

IEA's Estimated 2019 and 2020 Invested Vs Future Required Investment



Notes: STEPS = Stated Policies Scenario; SDS = Sustainable Development Scenario. Electricity networks include also battery storage investment. Projected investment levels are from the *World Energy Outlook 2019;* the point of comparison is the period from 2025-30 in order to provide an indicative post-recovery benchmark for spending levels.

Source: IEA Tracking Clean Energy Progress, June 2020

Massive government intervention will be needed to get the energy transition closer to its energy transition miss. It doesn't make a difference what side of the clean energy fence someone is on, everyone knows that the energy transition has been, and must continue to be, driven by governments if there is to be any shot of trying to get closer to the energy transition target. The Shell CEO said something everyone knows – leaving it to the private sector to somehow fit all the pieces together on a timely basis won't work. It will require increasing government intervention. Bloomberg asked the Shell CEO "*All that will need a very heavy-handed government. Do you support that?*" And he replied "*If we believe that somehow the market is going to take care of this, that you put a price on carbon and everything will sort itself out, or that we can shame companies into doing it by having ESG frameworks that will tell them what is right and what is wrong, then I think we're kidding ourselves. This needs a very significant interventionist approach, and all industries have to be part of the intervention.*"

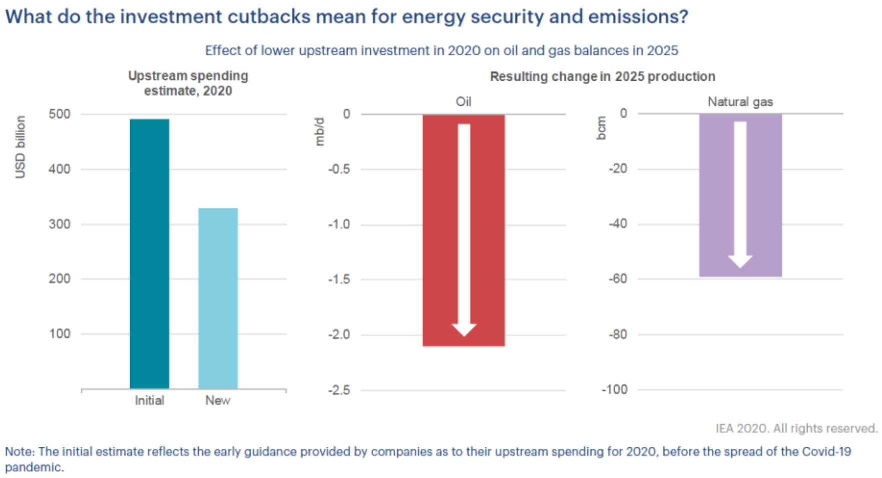
<u>2021 could see a major global (and Canada) renewal push and commitment to the energy transition aspirational goal</u>. The Nov 3 US presidential elections will determine if there is a renewed and urgent global push on climate change. The united global push for climate change was given a major kick in the pants when, on Nov 4, 2019, the Trump administration announced it was starting the formal process to withdraw from the Paris Accord. The official withdraw date would be Nov 4, 2020, one day after the upcoming US presidential election. And the reality is that the US had effectively ceased to have any interest in working on climate change since President Trump was elected in Nov 2016. It still ~5 months to the election, but Joe Biden is currently running well ahead. One of his climate change priorities [LINK] is to "*Rally the rest of the world to meet the threat of climate change"* and he also tries to deal with the need to catch up investment saying "*the United States urgently needs to embrace greater ambition on an epic scale to meet the scope of this challenge*". But, at least in the US, we see Biden's initial 2021 push for climate change initiatives to be more aspirational than specific programs as he will be restrained to some degree by the increasing US debt and the expected slower recovery of the US economy as noted by Fed Chair Powell yesterday. In Canada, we believe we could see a similar new urgency to climate change in 2021. We recognize it isn't a major topical item today, but we believe there is a good chance for an early fall federal election and, if the polls hold, the Liberals would likely have a majority government. We believe that, even with the massive debt increases, this would lead to increasing federal government support for clean energy initiatives in Canada and possibly (likely?) to support clean energy initiatives in developing countries.

<u>The aspiration to spend more will be there, but increasing government debt levels will have to limit government incentives that require government capital or hurt government revenues</u>. The reason why the IEA report caught our attention is that the investing gap was worse in 2020 when 2019 was already lagging Its hard to see the scenario where 2021 investing jumps up significantly above 2019 to start to close the gap. Rather, we have to believe the gap will, at best, be maintained in 2021. No one has to be an economist to know that every country in the world is taking on massive debt in its fight against the economic shut down from COVID-19. Our concern is that the increased debt has to force all governments to go slower than they would want on the clean energy transition. This will just widen the gap. The countries that have a reasonable financial position will continue to support clean energy advancement, but their pace will inevitably be slowed down due to balance sheets. Its why we think a Biden presidency will be more aspirational in 2021. Yesterday, the US Treasury Dept [LINK] reported there continues to be an accelerating in US federal government debt. It reached $26 trillion, after hitting $25 trillion on May 5, and $24 trillion on April 7. US debt is up over $6 trillion since the Nov 2016 elections. Our SAF June 7, 2020 Energy Tidbits [LINK] highlighted the Thurs June 4 German government $145b stimulus package and that it included a doubling of EV purchase incentives, but did not include any incentives for ICE vehicles. It was also interesting to see how the German government targeted cheaper EVs as the priority to get a broader EV penetration. But then there are most countries, such as Mexico, that are having a much tougher time with the economic hit from COVID-19. On May 16, we tweeted [LINK] "*Not yet law, but seems Mexico will move to "temporarily" limit renewables. COVID-19 has been impacting near term power/#NatGas demand, but any limit on renewables should restore Mexico's steady increase in #NatGas consumption as economy restarts and need for US #NatGas supply".* Mexico's concern was that it needed to maintain the reliability of the electricity grid in the face of the COVID-19 health crisis, but the reality is that it doesn't have any financial flexibility to support any new renewable initiatives for the time being. If governments are going to provide some form of incentive, they need to have the financial capacity to do so and many governments do not have that luxury. COVID-19 is only going to increase the gap and put the energy transition further behind. This is a key point from the IEA's reports.

<u>We think the decline rate in oil demand on the path to peak oil demand will be like coal's demise – slower than expected, especially with the delays and gaps in the clean energy transition</u>. We believe the world is on the path to a clean energy transition and there will be peak oil demand. But we always think about coal when we think about the energy transition that will lead to peak oil demand. No one ever disagreed that governments will going to intervene to move to eliminate coal power generation. But it hasn't happened anywhere near as quickly as expected. When we see the Shell CEO comments and IEA reports, its clear that the energy transition isn't going as smoothly and quickly as expected. Most importantly, the IEA highlighted that investment in clean energy is too low and there are too many "*critical energy technologies*" that are not on track. And to use the demise of coal analogy, this should point to better demand for oil for a good portion of the 2020s. Our May 27 tweet on the IEA investment report also said "*Seems clean energy supply + related grid/infra won't be anywhere close to meet aspirational goals of many countries. Good for oil/gas prices in mid 20's, will need more oil/gas just as impact of big capex cuts kick in*." It doesn't have to be a huge change in demand, even

if demand is only 0.5 mmb/d or a little better than the expected decline in oil demand growth rates in the 2020s on the path to peak oil demand. It will be a positive to oil price expectations as it will happen during the period that will see the impact of underinvestment in oil today from the past couple years, and more so from the massive upstream underinvestment in 2020. Below is the IEA's May 27 below graph showing how the underinvestment in oil in 2020 will hurt 2025 production by ~2 mmb/d. Plus the global oil industry has moved away from long cycle projects like major 100,000 b/d oil sands projects so there aren't an inventory of large long cycle projects in inventory. And even if oil prices are much stronger than expected, oil companies won't re-add long cycle oil projects given that that the energy transition (while delayed) is solidly the goal.

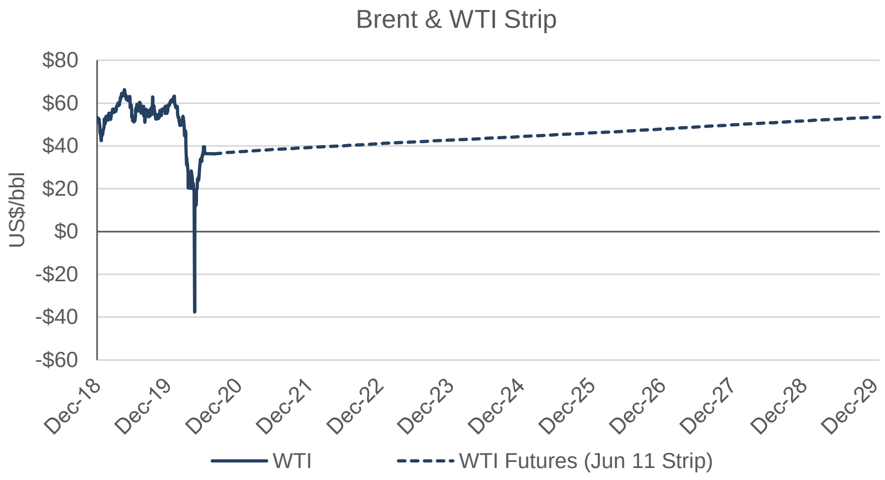
IEA Impact of Lower Upstream Spending In 2020



Source: IEA World Energy Investment 2020

There is a big difference for oil if WTI is >$50 versus >$40. There is a big difference to the US/Canada oil sector if WTI is >$50 or >$40. We don't think we need to see hugely better oil prices, just better visibility looking to oil for 2022 thru 2027. We think the IEA and Shell views will become more broadly accepted once there is a focus on a post COVID-19 world. We don't see a huge impact, but rather believe its reasonable to see this clean energy transition delay will lead to a lesser decline in oil demand growth rates on the way to peak oil demand. It doesn't have to be a huge impact, but even if its only delaying oil demand decline by 0.5 mmb/d thru 2027, we could see the potential to impact oil by $5 whether you believe in the WTI forward strips (currently average ~$44 for the 6 years 2022 thru 2027, before WTI reaches $50 in 2028), or if you are already more bullish (as we are) expecting oil above these forward strips. As noted above, these delays should happen when the impact of upstream underinvestment kicks in. In addition, we don't expect to see any major oil company approve a large long cycle oil project like the former +100,000 b/d oil sands projects, especially as these major oil companies are all committing to reduce emissions and be leaders in the clean energy transition. If there is stronger oil demand in the 2022 to 2027 period and WTI >$50, it means that the likely winners will be those with spare capacity (ie. OPEC+), or effective spare capacity from short cycle quality shale/tight oil in US and Canada, and also oil projects that have multi phase quick cycle development like Exxon in offshore Guyana, or even small scale SAGD.

WTI Oil Price Futures

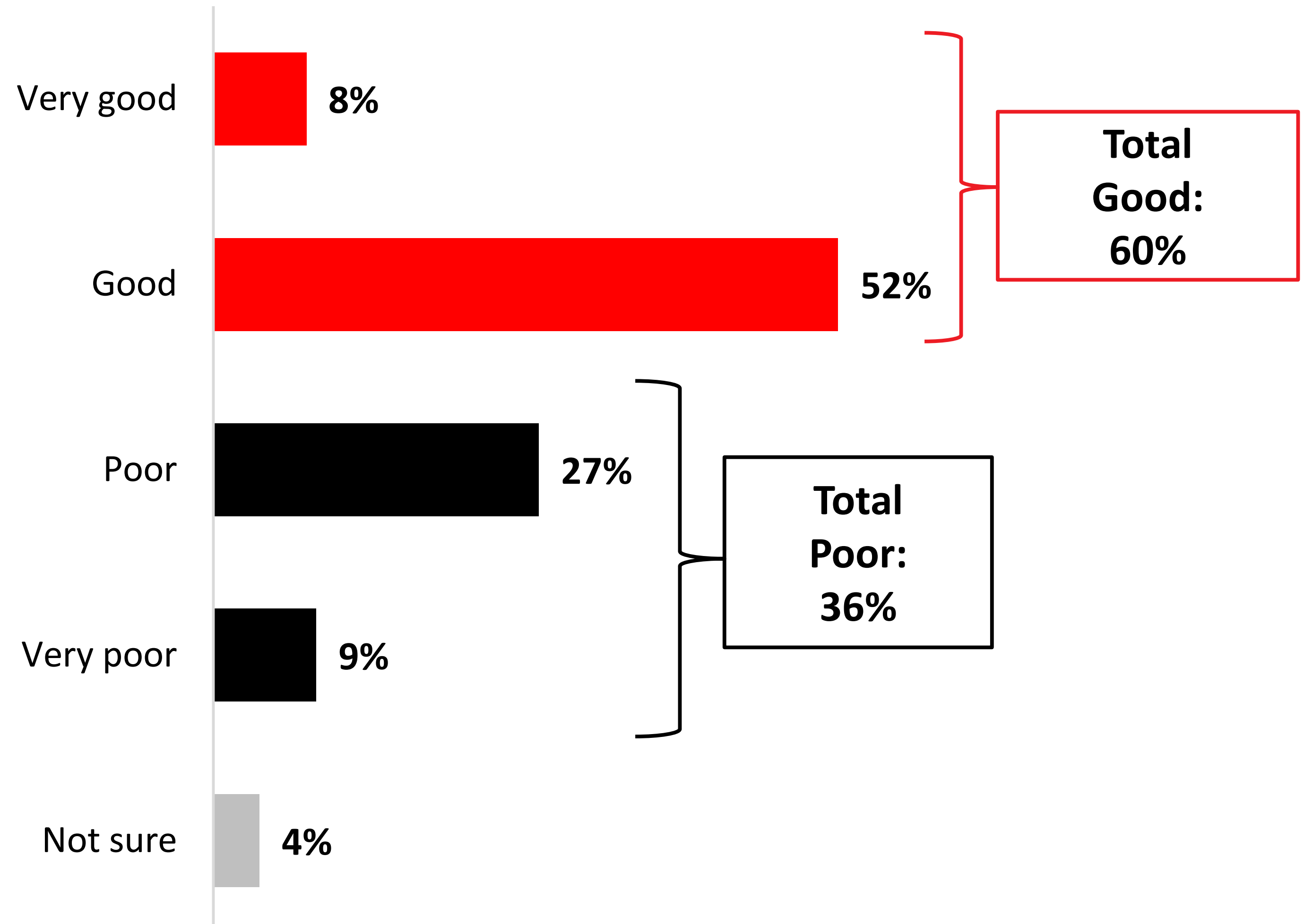


Source: Bloomberg

STATE OF HOUSEHOLD FINANCES (1/2)

Q3. How would you describe your own household's finances today?

Base: All respondents (n=1,597)



STATE OF HOUSEHOLD FINANCES (2/2)

Q3. How would you describe your own household's finances today?

Base: All respondents

	TOTAL CANADA	ATL	QC	ON	MB/SK	AB	BC	18-34	35-54	55+	Male	Female	Urban	Sub-urban	Rural
Weighted n=	1,597	108	369	619	102	177	222	424	515	658	778	819	736	554	283
Unweighted n=	1,597	105	416	628	135	154	159	396	523	678	780	817	724	563	290
Total Good	**60%**	57%	**70%**	58%	55%	63%	53%	**55%**	**54%**	**69%**	62%	58%	60%	63%	57%
Very good	**8%**	8%	7%	8%	7%	10%	7%	6%	**5%**	**11%**	9%	7%	8%	7%	9%
Good	**52%**	49%	**63%**	49%	49%	53%	46%	49%	49%	**58%**	53%	51%	52%	56%	48%
Total Poor	**36%**	39%	**26%**	38%	41%	35%	**44%**	40%	**43%**	**28%**	35%	37%	37%	34%	38%
Poor	**27%**	27%	**20%**	29%	37%	23%	**35%**	29%	**31%**	**23%**	28%	27%	28%	27%	28%
Very poor	**9%**	12%	6%	9%	**4%**	12%	9%	11%	**11%**	**5%**	7%	10%	9%	7%	10%
Not sure	**4%**	4%	4%	5%	4%	2%	3%	5%	3%	4%	**3%**	**5%**	3%	3%	5%

STATE OF HOUSEHOLD FINANCES (CANADA VS UNITED STATES)

Q3. How would you describe your own household's finances today?

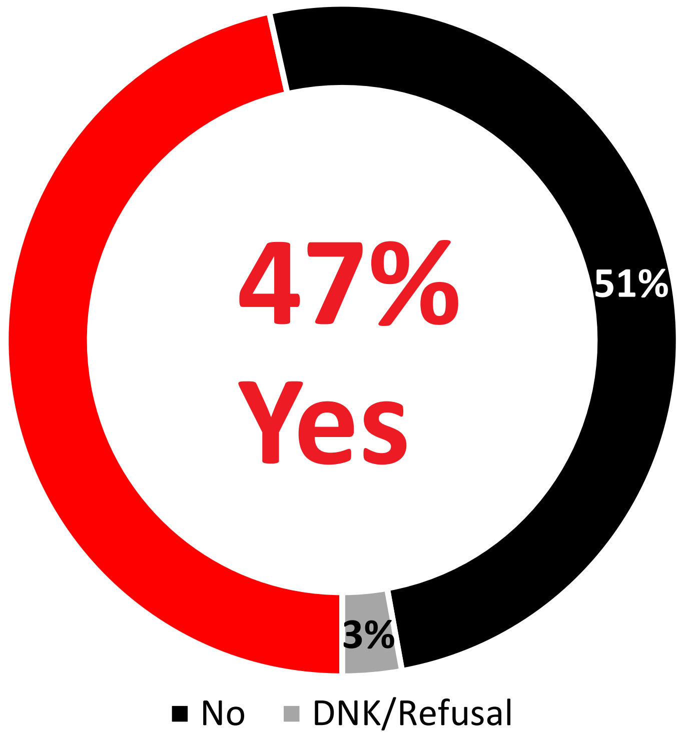
Base: All respondents

	TOTAL CANADA	TOTAL USA	Gap
Weighted n=	1,597	1,001	
Unweighted n=	1,597	1,001	
Total Good	60%	64%	4
Very good	8%	14%	6
Good	52%	50%	2
Total Poor	36%	31%	5
Poor	27%	24%	3
Very poor	9%	7%	2
Not sure	4%	5%	1

LIVING PAYCHECK TO PAYCHECK

Q4. Are you currently living paycheck to paycheck?

Base: All respondents (n=1,597)



	TOTAL CANADA	ATL	QC	ON	MB/SK	AB	BC	18-34	35-54	55+	Male	Female	Urban	Sub-urban	Rural
Weighted n=	1,597	108	369	619	102	177	222	424	515	658	778	819	736	554	283
Unweighted n=	1,597	105	416	628	135	154	159	396	523	678	780	817	724	563	290
Yes	47%	55%	38%	50%	53%	47%	42%	53%	57%	34%	42%	51%	47%	44%	48%
No	51%	44%	60%	45%	45%	53%	54%	42%	41%	64%	54%	47%	49%	55%	49%
Don’t know/Refusal	3%	1%	2%	4%	2%	0%	3%	6%	2%	1%	4%	2%	3%	1%	4%

LIVING PAYCHECK TO PAYCHECK (CANADA VS UNITED STATES)

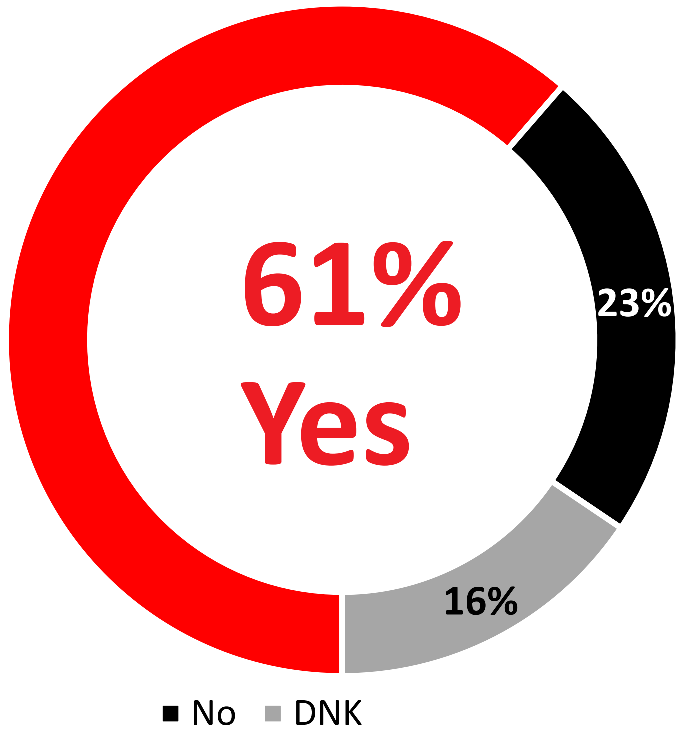
Q4. Are you currently living paycheck to paycheck?
Base: All respondents

	TOTAL CANADA	TOTAL USA	Gap
Weighted n=	1,597	1,001	
Unweighted n=	1,597	1,001	
Yes	47%	46%	1
No	51%	48%	3
Don't know/Refusal	**3%**	**7%**	4

ECONOMIC RECESSION IN THE COUNTRY

Q5. Do you believe Canada is currently in an economic recession?

Base: All respondents (n=1,597)

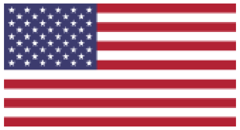


	TOTAL CANADA	ATL	QC	ON	MB/SK	AB	BC	18-34	35-54	55+	Male	Female	Urban	Sub-urban	Rural
Weighted n=	1,597	108	369	619	102	177	222	424	515	658	778	819	736	554	283
Unweighted n=	1,597	105	416	628	135	154	159	396	523	678	780	817	724	563	290
Yes	61%	55%	65%	62%	56%	63%	59%	67%	64%	56%	58%	65%	57%	65%	66%
No	23%	24%	21%	20%	24%	27%	30%	14%	23%	29%	28%	18%	27%	19%	21%
Don't know	16%	21%	14%	18%	20%	10%	11%	19%	13%	15%	14%	17%	15%	16%	13%

ECONOMIC RECESSION IN THE COUNTRY (CANADA VS UNITED STATES)

Q5. Do you believe Canada/the United States is currently in an economic recession?

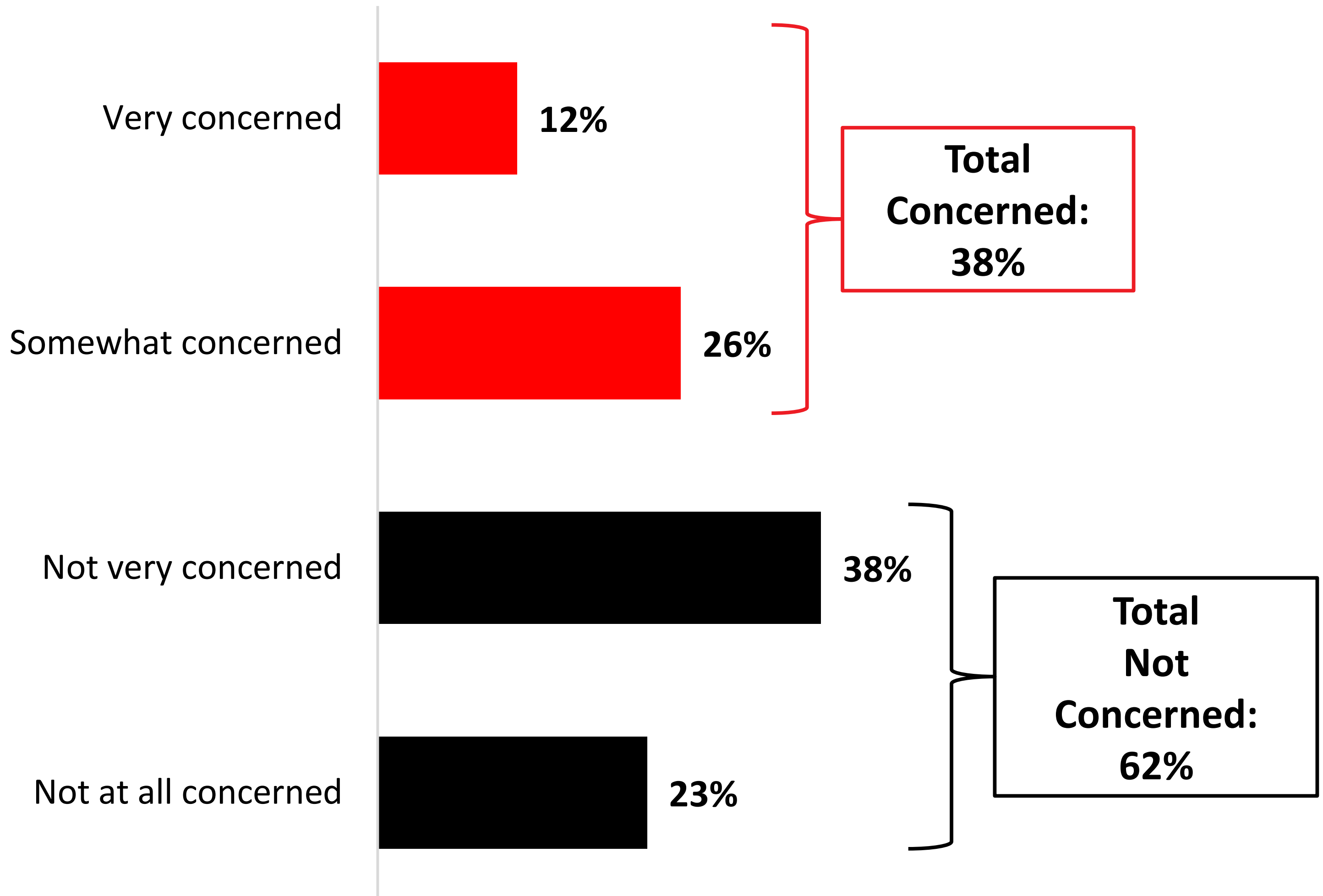
Base: All respondents



	TOTAL CANADA	TOTAL USA	Gap
Weighted n=	1,597	1,001	
Unweighted n=	1,597	1,001	
Yes	**61%**	**51%**	10
No	**23%**	**27%**	4
Don’t know	**16%**	**22%**	6

CONCERNS ABOUT LOSING JOB (1/2)

Q6. How concerned are you about losing your job in the next 12 months?
Base: Respondents who are currently employed (n=823)



CONCERNS ABOUT LOSING JOB (2/2)

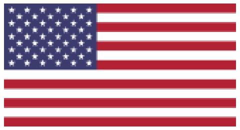
Q6. How concerned are you about losing your job in the next 12 months?

Base: Respondents who are currently employed

	TOTAL CANADA	ATL	QC	ON	MB/SK	AB	BC	18-34	35-54	55+	Male	Female	Urban	Sub-urban	Rural
Weighted n=	788	48	176	304	51	103	106	273	385	130	411	377	378	288	116
Unweighted n=	823	57	222	313	72	84	75	269	410	144	423	400	389	301	127
Total Concerned	38%	39%	22%	46%	37%	46%	35%	47%	35%	31%	43%	33%	40%	39%	33%
Very concerned	12%	14%	8%	13%	12%	19%	7%	18%	11%	4%	13%	11%	15%	9%	10%
Somewhat concerned	26%	25%	14%	33%	25%	27%	28%	29%	24%	26%	30%	22%	25%	29%	23%
Total Not Concerned	62%	61%	78%	54%	63%	54%	65%	53%	65%	69%	57%	67%	60%	61%	67%
Not very concerned	38%	36%	45%	35%	44%	36%	39%	34%	42%	38%	36%	41%	37%	42%	35%
Not at all concerned	23%	25%	33%	19%	19%	18%	26%	19%	24%	32%	21%	26%	24%	19%	32%

CONCERNS ABOUT LOSING JOB (CANADA VS UNITED STATES)

Q6. How concerned are you about losing your job in the next 12 months?
Base: Respondents who are currently employed

	TOTAL CANADA	TOTAL USA	Gap
Weighted n=	788	567	
Unweighted n=	823	569	
Total Concerned	38%	36%	2
Very concerned	12%	11%	1
Somewhat concerned	26%	25%	1
Total Not Concerned	62%	64%	2
Not very concerned	38%	34%	4
Not at all concerned	**23%**	**30%**	7

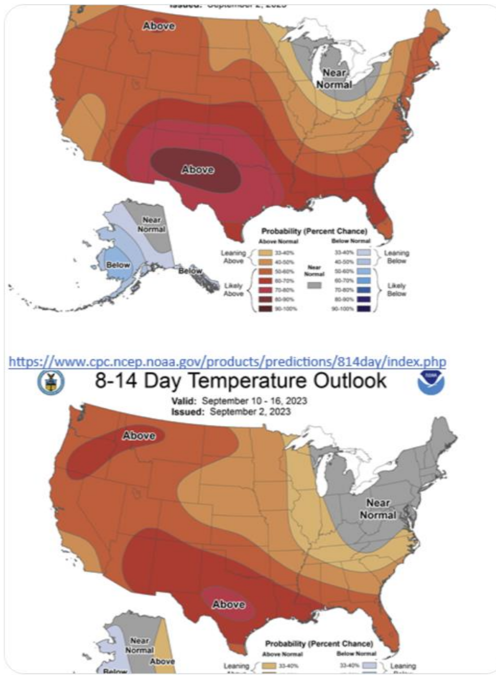
Dan Tsubouchi @Energy_Tidbits · 18h

Today's @NOAA updated 6-10 & 8-14 day temperature outlook covering Sept 8-16.

Very hot pretty well across Lower 48 for next week,

Then back to normal for NE US, with rest staying hot.

Should provide support for #NatGas this week.
#OOTT



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Dan Tsubouchi @Energy_Tidbits · 23h

Support for #Oil prices.

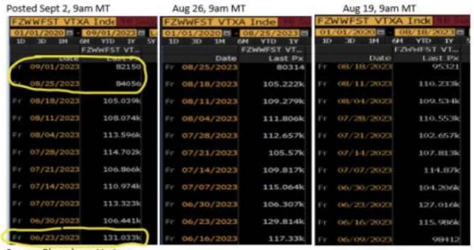
#Vortexa crude #Oil floating storage at 09/01 est 82,15 mmb, -1.91 mmb WoW vs revised up by +3.75 mmb 08/25 of 84.06 mmb.

09/01 of 82.15 mmb is down a whopping -48.88 mmb vs recent 06/23/23 peak of 131.03 mmb.

Thx @Vortexa @business.
#OOTT

Source: Bloomberg, Vortexa

Posted Sept 2, 9am MT — Aug 26, 9am MT — Aug 19, 9am MT



Source: Bloomberg, Vortexa

Vortexa Crude Oil Floating Storage by Region (mmb)				Original Posted	Recent Peak	
Region	Sep 1/23	Aug 25/23	WoW	Aug 25/23	Jun 23/23	Sep 1 vs Jun 23
Asia	37.80	38.09	-0.29	37.87	73.36	-35.56
Europe	4.96	7.26	-2.30	7.79	6.54	-1.58
Middle East	7.36	7.17	0.19	6.84	9.08	-1.72
West Africa	8.42	8.39	0.03	8.17	3.96	4.46
US Gulf Coast	1.48	1.59	-0.11	2.26	0.92	0.56
Other	22.13	21.56	0.57	17.38	37.17	-15.04
Global Total	82.15	84.06	-1.91	80.31	131.03	-48.88
Vortexa crude oil floating storage posted on Bloomberg 9am MT on Sept 2						
Source: Vortexa, Bloomberg						

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

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SAF | GROUP

Dan Tsubouchi @Energy_Tidbits · Sep 2

Iran ramped up #Oil exports in Aug & more to come in Sept.

@TankerTrackers Iran shipments look up ~0.4 mmb/d crude oil only MoM.

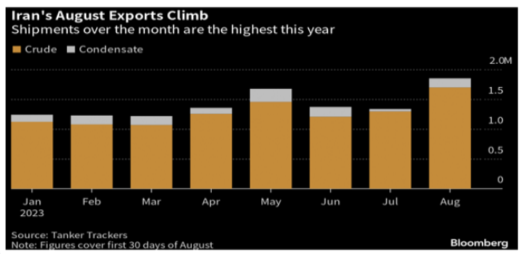
Recall Iran adding ~0.6 mmb/d in Aug/Sept. See 👇 SAF Group Aug 13/23 Energy Tidbits

Maybe 0.3 mmb/d to come?

Thx @alexlongley1 @AlaricN
#OOTT

Iran's Oil Exports Surge in August Even With Final Week Dip
2023-08-31 12:48:26.407 GMT

By Alex Longley and Alaric Nightingale
(Bloomberg) -- Iran's oil exports ballooned in August, even though they didn't maintain the pace set in the first part of the month.
The increase in Iranian shipments to the highest this year comes in the same month that key OPEC+ producers Saudi Arabia and Russia kept a lid on their own oil exports in a bid to tighten the market.
Shipments of Iranian crude and condensate climbed to 1.85 million barrels a day in August, according to TankerTrackers.com Inc., which provides data on oil cargoes to governments, insurers and other institutions.
That represents a pullback from the first 20 days of August, when exports topped 2 million barrels a day. Figures for the earlier period were likely inflated by sales of barrels in storage, according to TankerTrackers's co-founder Samir Madani.



Dan Tsubouchi @Energy_Tidbits · Aug 13

SAF Group Aug 13, 2023 Energy Tidbits memo is posted on SAF Group website. this 63-pg energy research memo expands upon & covers more items than tweeted this week. Available at news/insights section of SAF website #Oil #OOTT #LNG #NatGas ...

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Dan Tsubouchi @Energy_Tidbits · Sep 1

could have been clearer

low saudi oil shipments in aug = approx 40 days later less saudi oil landing on US = less in EIA weekly oil inventories on sept and early oct = support to sept and early oct prices

#OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Sep 1
>
> Reminder quickest way for Saudi to impact #Oil prices is cut exports to US so it shows up in weekly US oil inventory data.
>
> Saudi cut crude shipments to US to 81,000 b/d in Aug vs 430,000 b/d in July. Provide support to Sept/early Oct prices.
>
> #OOTT @JLeeEnergy @bwingfield

* Key crude flows to selected destinations from Saudi Arabia ('000s of b/d):

Destination	Aug.	July	June	May
China	1,274	1,522	1,608	1,613
S. Korea	613	973	956	785
India	569	552	659	832
Japan	543	828	828	796
US	81	430	350	306
Egypt	65	645	533	806
Unknown	780	0	0	0
All destinations	5,552	6,266	6,657	6,551

* NOTE: Figures subject to revision as vessels indicate final destinations
* Includes VLCC, ULCC, Suezmax and Aframax tankers and exports from the Saudi-Kuwait Neutral Zone; from December 2021, calculations also take into consideration tanker-tracking data from Vortexa and Kpler
* Run LINE GBLCRUDE for an overview of Bloomberg tanker tracking and to find Bloomberg tickers; see NI TANTRA for related stories

--With assistance from Grant Smith, Prejula Prem and John Deane.

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Brian Wingfield, John Deane

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/RYRRY5DWRGG0

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Dan Tsubouchi @Energy_Tidbits · Sep 1

Potential Sept 7 start of staggered industrial action at Chevron AUS LNG: Gorgon 2.1 bcfd, Wheatstone 1.2 bcfd.

Union voted down Chevron EA proposal.

Collective bargaining didn't start during the vote.

Chevron cancelled Wheatstone turnaround.

#OOTT #LNG #NatGas

Timestamped as of 4am MT on Sept 1

https://www.facebook.com/people/Offshore-Alliance/100063786371409/

Offshore Alliance
6h

Chevron's mismanagement of EBA negotiations on the Gorgon and Wheatstone Facilities has passed the point of being a train wreck waiting to happen, and has now been officially called a train wreck.

Chevron have been completely smashed up in an EA Ballot designed to circumvent EBA negotiations with the Offshore Alliance.

The Chevron genius who thought up the idea to postpone bargaining with the Union to put a dodgy EA out to vote with zero prospect of it being voted up, is odds on favourite to be awarded HR Manager of the year by the Offshore Alliance when we present our annual awards to the oil and gas corporations and contractors.

Despite the Ballot for Chevron's sub-standard Non-Union EA closing at 7:00 PM last night, Chevron (despite having access to the live ballot results for the entire period of their 36-hour ballot), took 16 hours to release the Ballot results to OA members on the Gorgon and Wheatstone Downstream facilities.

Even Robert Mugabe would have done a better job than this mob in this regard.

Less than 1% of the Wheatstone Downstream and Gorgon workforce voted 'YES' to Chevron's rubbish EA.

That's just 3 workers out of 401 workers voting 'YES'.

When the Wheatstone Platform EA Ballot results are factored in, just 4 out of 518 Chevron employees have voted 'YES' to their rubbish non-union EA proposal.

Great work Chevron HR – They have no idea, no clue and are completely out of touch with our members.

Chevron HR reckon that their dodgy non-union EA proposal had "closed the gap" but the Ballot results show that they are out of touch with OA members and haven't listened to a word spoken in their discussions with members, Reps and the Offshore Alliance.

Protected Industrial Action commences on all 3 Chevron facilities at 06:00 Thursday 7th September.

Offshore Alliance
12h

Chevron claim that they have contingency plans to deal with Protected Industrial Action, yet they have already cancelled the Wheatstone Turbine Turnaround without a shot being fired.

Chevron's plan to use inexperienced and incompetent office jockeys in place of competent and experienced operations personnel is a train wreck waiting to happen (no pun intended).

Protected Industrial Action across all Chevron West Coast facilities commences Thursday 07 September and there is almost zero chance of Chevron not losing $billions of profit and production when PIA ramps up.

The OA members will go one day longer and one day stronger than Chevron.

Offshore Alliance
2d

In December 2022, Altrad bought out AGC's Chevron contracts and picked up a 'never-used' Baseline Agreement from AGC subsidiary outfit Workforce Logistics. This dodgy Baseline Agreement is subject to an Appeal by the Offshore Alliance before the Full Bench of the FWC, and the Agreement has a repugnant stench to it.

Altrad have been using this dodgy EA to employ and exploit workers on Chevron's Wheatstone and Gorgon facilities.

The Full Bench of the FWC are currently Hearing our Appeal against the approval of the Altrad Enterprise Agreement and plenty will be said about this Baseline Agreement in due course.

Whilst the Full Bench are delving into how the former Altrad entity Workforce Logistics created its Baseline Agreement, Chevron are seeking support for a sub-standard EA of its own.

Chevron's proposed EA on the Gorgon and Wheatstone Downstream facilities, also has a repugnant stench to it. It fails almost every possible test by:

1. Not having job security measures of any real value to employees.
2. No roster certainty.
3. Sub-standard REM at every level (significantly behind salaries and other remuneration standards of other operators).
4. Travel entitlements which leave employees out of pocket.
5. Training rates which are less than those paid by Chevron 12 months ago.
6. No protection from forced transfers to other sites.
7. Employees can be coerced to work overcycle for zero pay on demob day.
8. Employees can be coerced to work overcycle with inadequate remuneration or parameters on the working of overcycle.
9. No late demob payments (unless by the good grace of Chevrong).

The Offshore Alliance is asking members to give Chevron a big fat zero in their EA Ballot by voting 'NO' to their rubbish EA proposal.

2 · 4 · 2,005

Dan Tsubouchi @Energy_Tidbits · Sep 1

Reminder quickest way for Saudi to impact #Oil prices is cut exports to US so it shows up in weekly US oil inventory data.

Saudi cut crude shipments to US to 81,000 b/d in Aug vs 430,000 b/d in July. Provide support to Sept/early Oct prices.

#OOTT @JLeeEnergy @bwingfield

* Key crude flows to selected destinations from Saudi Arabia ('000s of b/d):

Destination	Aug.	July	June	May
China	1,274	1,522	1,608	1,613
S. Korea	613	973	956	785
India	569	552	659	832
Japan	543	828	828	796
US	81	430	350	306
Egypt	65	645	533	806
Unknown	780	0	0	0
All destinations	5,552	6,266	6,657	6,551

* NOTE: Figures subject to revision as vessels indicate final destinations
* Includes VLCC, ULCC, Suezmax and Aframax tankers and exports from the Saudi-Kuwait Neutral Zone; from December 2021, calculations also take into consideration tanker-tracking data from Vortexa and Kpler
* Run LINE GBLCRUDE for an overview of Bloomberg tanker tracking and to find Bloomberg tickers; see NI TANTRA for related stories

--With assistance from Grant Smith, Prejula Prem and John Deane.

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Julian Lee in London at jlee1627@bloomberg.net
To contact the editors responsible for this story:
Alaric Nightingale at anightingal1@bloomberg.net
Brian Wingfield, John Deane

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/RYRRY5DWRGG0

3 · 15 · 62 · 21.8K

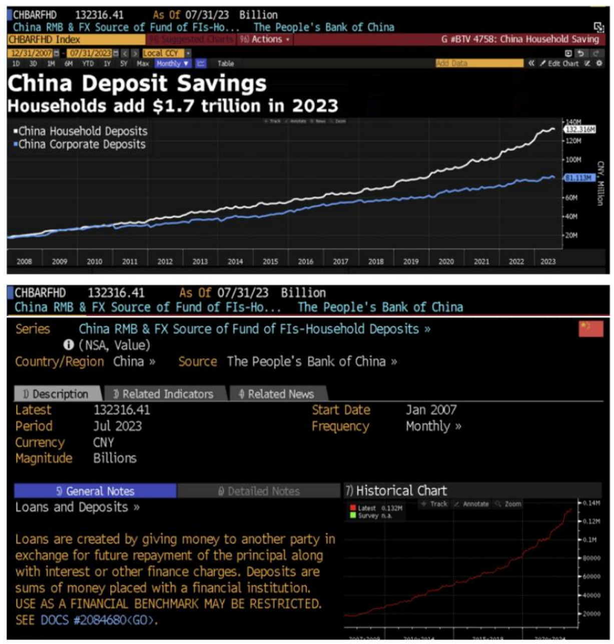
Dan Tsubouchi @Energy_Tidbits · Aug 31

Is this a good indicator that there is still more risk than reward to near term China economy?

Xi and politburo haven't yet been able to convince the Chinese people that it's time to spend the pent up savings!

Thx @business.

#OOTT



1 2 6 1,829

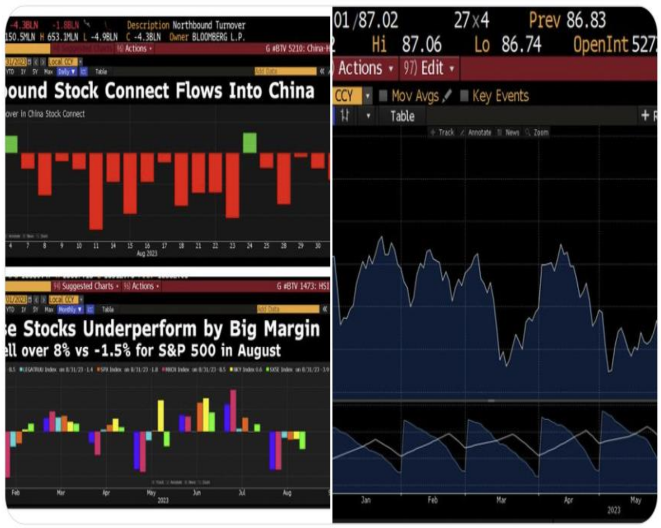
Dan Tsubouchi @Energy_Tidbits · Aug 31

Chinese stocks underperform by big margin as foreign investors have record net outflows in mainland China stocks:"

#Oil normally is weaker when Chinese economy & markets are weaker. But Brent is up small for the month.

Thx @business.

#OOTT

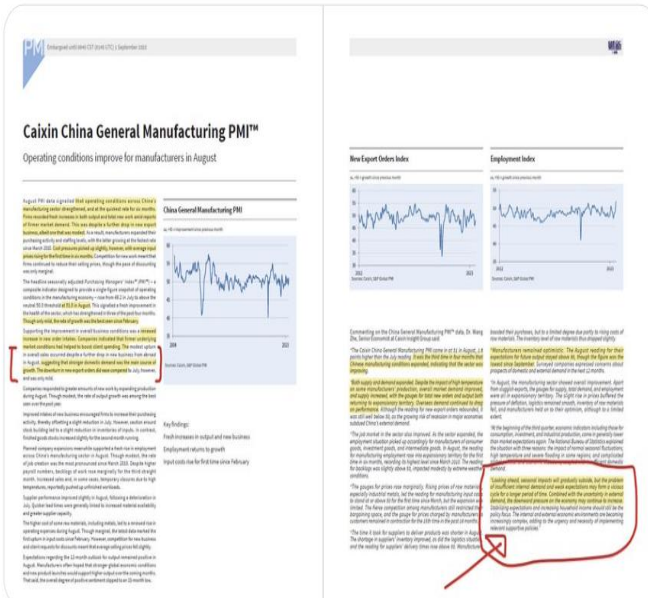


1 1 9 2,021

Dan Tsubouchi @Energy_Tidbits · Aug 31

Positive as China Caixin Manufacturing PMI Aug 51.0 beats Est 49.0, July 49.2, June 50.5, May 50.9, Apr 49.5, Mar 50.0, Feb 51.6, Jan 49.2.

BUT warns "*Looking ahead .... the problem of insufficient internal demand & weak expectations may form a vicious cycle for a longer period...* Show more



5 10 3,406

Dan Tsubouchi @Energy_Tidbits · Aug 31

#Oil demand is record in 2023 despite lagging air travel

China Airlines (Taiwan) CEO to @YvonneManTV

Passenger volume vs pre-Covid. H1/23 at 50%, "*very confident*" H2/23 to 70-80% . Hit 100% in 2025.

Cargo, big win in 2021/22, "*demand for cargo is not as high as before*" #OOTT

1 4 21 3,472

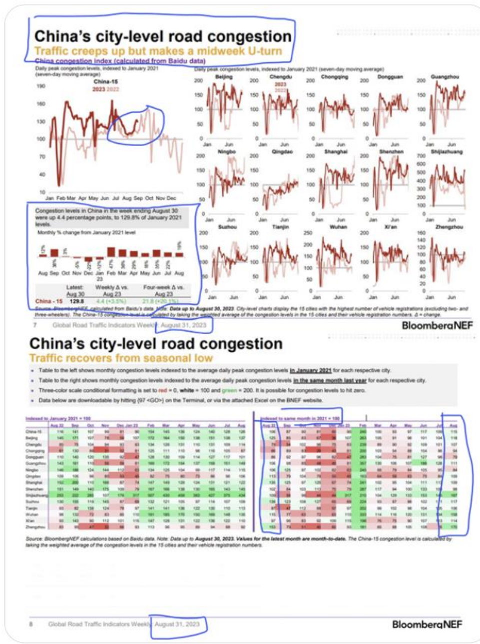
Dan Tsubouchi @Energy_Tidbits · Aug 31

China summer holidays ended so 4th consecutive WoW increase in Baidu city-level road congestion.

City-level road congestion +4.4% WoW to 129.8% of Jan/21 levels. But "m*akes a midweek U-turn*".

Still waiting on Sep/Oct expected big ramp up.

Thx @BloombergNEF
#OOTT



4 · 8 · 2,369

Dan Tsubouchi @Energy_Tidbits · Aug 30

WOW!

Must read 👇 RWE CEO post

"... #OffshoreWind *projects in EU & US have been stopped, mainly citing cost increases*"

"*worst case scenario for the* #EnergyTransition *when large projects that have already been awarded are not realised as plan*ned"

#NatGas needed for longer
#OOTT

https://www.linkedin.com/feed/update/urn:li:activity:7097872804829646848/

Markus Krebber Markus Krebber • 2nd• 2ndCEO, RWE AGCEO, RWE AG

1w • 1w •

Follow

Is there a perfect storm brewing in the offshore wind industry?

In recent weeks, for the first time, offshore wind projects in Europe and the U.S. have been stopped, mainly citing cost increases. In other news, turbine manufacturers were once again in the red in their latest quarterly reports, with losses running into billions.

This is not good news, it's in fact the worst-case scenario for the energy transition when large projects that have already been awarded are not realised as planned. Happening at a time when the entire offshore industry has to scale up to achieve expansion targets, this quickly calls into question the achievement of climate protection goals.

This dilemma is fuelled by a combination of factors, including cost increases due to ongoing inflation and rising interest rates, as well as structural supply shortages and the strained state of supply chains.

This development must serve as a wake-up call for policymakers to adapt the regulatory framework to market realities. Five areas of action can help navigate through the storm.

1. A frontloaded auction schedule can increase the investment certainty for the whole industry. That includes the early auctioning of large sea areas.

2. Grid connection of offshore wind farms have to be accelerated and developers need to have certainty about connection dates.

3. Allowance for dual route-to-market: 2-sided Contracts for Difference (CfDs) with inflation indexation as one element, and a second element which allows the marketing of offshore power to industrial customers through private PPAs. In addition, qualitative auction criteria can strengthen the European supply chain, sustainability, and deliverability.

4. When auction schemes cap budgets, for example like CfDs in the UK, governments need to recognise the inflationary environment and that costs have gone up significantly. Sticking with the old assumptions of nominal cost reduction will simply slow down or stop offshore technology deployment.

5. Direct and indirect financial support to stimulate investments in European manufacturing capacities and a master plan to secure access to vital raw materials.

In a nutshell: we need a framework that allows for more investment certainty for both manufacturers and developers.

At RWE, we are building and driving forward the development of several projects where we have been awarded the seabeds: in Germany, the UK, the Netherlands, Denmark, Ireland, Poland and the U.S. To deal with the challenging market situation, securing financing and strong relationships with your supply chain are key.

However, the right framework and policies, as outlined here, are imperative for offshore wind energy to realise its fullest potential in the future.

11 27 90 34K

Dan Tsubouchi @Energy_Tidbits · Aug 30

"Record selling in mainland China stocks: Northbound channel on track for record outflows in August" @business.

Foreign investors big net sellers of China stocks in Aug.

#Oil gets dragged down with China weakness so Brent flat in Aug at $85 is good price performance.
#OOTT

2 1 5 2,413

SAF

Dan Tsubouchi @Energy_Tidbits · Aug 30

Hmmm!

Note 👇 Trans Mountain's new Q2 language on #TMX start vs Q1 & Q4.

Q2. "*We are currently planning and targeting the commencement* ....."

Q1 & Q4, didn't use "currently", just "*expected to* ..."

Hinting a new start date is coming given 👇 08/23 tweet challenge? #OOTT

Excerpt https://www.transmountain.com/news/2023/trans-mountain-corporation-releases-second-quarter-2023-results

Trans Mountain Corporation Releases Second Quarter 2023 Results

Aug. 29, 2023

As of June 30, 2023, construction of the Project is approximately 90 per cent complete, with $24.0 billion in construction capital spending incurred plus $3.3 billion in financial carrying costs capitalized since the inception of the Project. TMC continues to target the end of 2023 for mechanical completion with commercial service of the Project anticipated to occur in the first quarter of 2024.

As of August 19, 2023, construction of the Project is 94 per cent mechanically complete with approximately 42 kilometres of pipe left to install. Berth 1 at the Westridge Marine Terminal has been operating since mid-July. We made significant progress on watercourse and highway crossings and construction in the Lower Mainland is 93 per cent complete and 97 per cent of our facilities in Alberta and B.C. (including Edmonton Terminal and Alberta/B.C. pump stations) are also complete. We have mitigation and contingency plans in place due to construction challenges in areas including Burnaby Mountain Tunnel, Jacko Lake and Mountain 3 in Spread 5B. We are currently planning and targeting the commencement of service on the expanded pipeline system near the end of the first quarter of 2024.

Excerpt https://www.transmountain.com/news/2023/trans-mountain-corporation-releases-first-quarter-2023-financial-results

Trans Mountain Corporation Releases First Quarter 2023 Financial Results

May 30, 2023

As of March 31, 2023, construction of the Trans Mountain Expansion Project ("the Project") is approximately 82 per cent complete, with $21.5 billion in construction capital spending incurred plus $2.8 billion in financial carrying costs capitalized since the inception of the Project.

Trans Mountain anticipates mechanical completion of the Project to occur at the end of 2023 with commercial service expected to occur in the first quarter of 2024. The company's projected Adjusted EBITDA is expected to be approximately $2.4 billion in the first full year of the expanded assets operation and expected to grow annually thereafter. These projections are underpinned by long-term contractual commitments for 80 per cent of the system's 890,000 barrels a day of capacity and expected utilization of uncontracted capacity of the system once in service.

Excerpt https://www.transmountain.com/news/2023/trans-mountain-corporation-releases-fourth-quarter-and-year-end-2022-financial-results

Trans Mountain Corporation Releases Fourth Quarter and Year End 2022 Financial Results

May 9, 2023

As of December 31, 2022, construction of the Trans Mountain Expansion Project ("the Project") is approximately 75 per cent complete, with $18.9 billion in construction capital spending incurred. Trans Mountain anticipates mechanical completion of the Project to occur at the end of 2023 with commercial service expected to occur in the first quarter of 2024. The company's projected Adjusted EBITDA is expected to be approximately $2.4 billion in the first full year of the expanded assets operation and expected to grow annually thereafter. These projections are underpinned by long-term contractual commitments for 80 per cent of the system's 890,000 barrels a day of capacity and expected utilization of uncontracted capacity of the system once in service.

SAF **Dan Tsubouchi** @Energy_Tidbits · Aug 23

Looks like more Trans Mountain #TMX delays & higher capital costs.

@CER_REC filing.

...

3 10 4,873

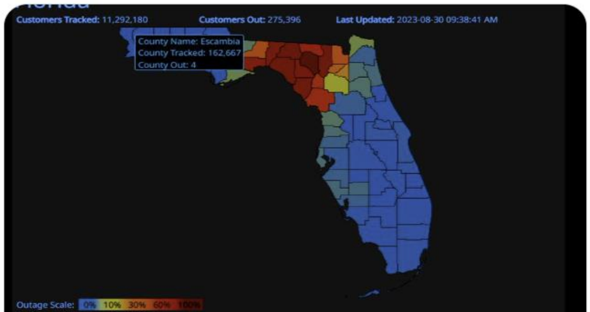
Dan Tsubouchi @Energy_Tidbits · Aug 30

#Idalia now CAT 1 hurricane.

~275,000 without power per @PowerOutage_us at 9:38am MT

hope everyone has stayed safe!

#OOTT



Electric Providers for Florida

Provider	Customers Tracked	Customers Out	Last Updated
Central Florida Electric Cooperative	36,185	24,324	2023-08-30 09:38:01 AM
Choctawhatchee Electric Coop	66,311	0	2023-08-30 09:38:05 AM
City of Tallahassee	105,440	31,989	2023-08-30 09:38:27 AM
Clay Electric Coop	190,278	37,466	2023-08-30 09:38:32 AM
Duke Energy	1,953,577	42,728	2023-08-30 09:33:23 AM
Escambia River Electric Coop	12,537	0	2023-08-30 06:23:52 AM
Florida Keys Electric Coop	33,721	20	2023-08-30 09:37:14 AM
Florida Power & Light Company	5,841,776	39,594	2023-08-30 09:38:31 AM
Florida Public Utilities	30,016	58	2023-08-30 09:38:41 AM
Fort Pierce Utilities Authority	28,872	0	2023-08-30 08:56:17 AM
Gainesville Regional Utilities	100,600	507	2023-08-30 09:38:30 AM
Glades Electric Cooperative	17,590	5	2023-08-30 09:38:28 AM
Grady EMC	21	13	2023-08-30 09:37:04 AM
Gulf Coast Electric Coop	21,707	2	2023-08-30 09:38:04 AM
Jacksonville Electric Authority	520,683	7,152	2023-08-30 09:38:06 AM
Keys Energy Services	31,803	0	2023-08-30 08:27:32 AM
Kissimmee Utility Authority	90,000	0	2023-08-30 07:57:43 AM
Lake Land Electric	135,055	21	2023-08-30 09:38:37 AM
Lee County Electric Coop	240,773	464	2023-08-30 09:38:29 AM
New Smyrna Beach Utilities	30,225	0	2023-08-30 03:53:21 AM
Ocala Electric Utility	52,146	12	2023-08-30 09:38:31 AM
Okefenoke REMC	11,505	3,620	2023-08-30 09:36:53 AM
Orlando Utilities Commission	274,672	1,857	2023-08-30 09:38:07 AM
Peace River Electric Coop	59,096	8	2023-08-30 09:38:02 AM
SECO Energy	233,914	593	2023-08-30 09:38:40 AM
Suwannee Valley Electric Cooperative	28,627	28,281	2023-08-30 09:38:03 AM
Talquin Electric Cooperative	54,839	23,169	2023-08-30 09:38:28 AM
Tampa Electric	797,574	4,309	2023-08-30 09:38:37 AM
Tri-County Electric Coop	20,003	19,229	2023-08-30 09:38:02 AM

1 3 1,735

Dan Tsubouchi @Energy_Tidbits · Aug 30

For those not near their laptops. At 8:30am MT, @EIAgov released its #Oil #Gasoline #Distillates inventory as of Aug 25 Table below compares EIA data vs @business expectations and vs @APIenergy yesterday. Prior to release, WTI was $81.70. #OOTT

Oil/Products Inventory Aug 25: EIA, Bloomberg Survey Expectations, API			
(million barrels)	EIA	Expectations	API
Oil	-10.58	-2.19	-11.49
Gasoline	-0.21	-1.25	1.40
Distillates	1.24	-1.00	2.46
	-9.55	-4.44	-7.63
Note: Oil is commercial so builds in a build of 0.6 mmb in SPR for the Aug 25 week			
Note: Included in the oil data, Cushing had a 1.50 mmb draw for Aug 25 week			
Source EIA, Bloomberg			
Prepared by SAF Group https://safgroup.ca/news-insights/			

1 6 2,144

Dan Tsubouchi @Energy_Tidbits · Aug 30

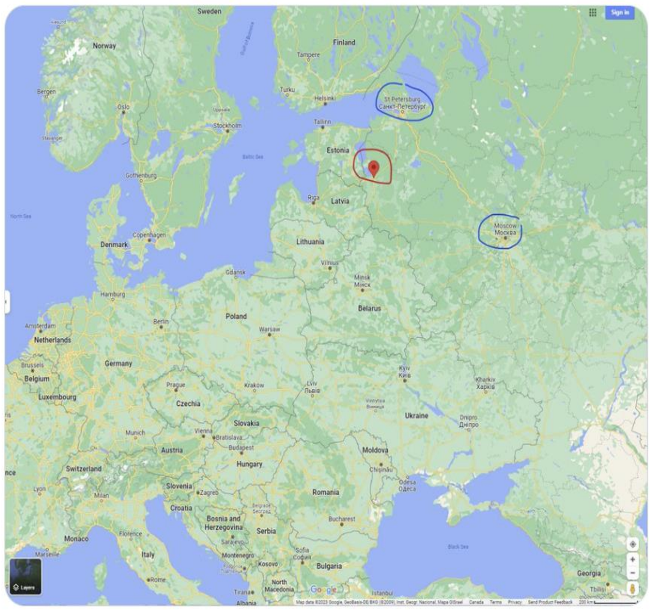
Ukraine reminds Russia everything is in reach and drones can hit beyond Moscow.

Drone attacks at Pskov airfield.

Pskov is basically on the Baltic Sea, at border with Estonia and Latvia.

#OOTT #Oil

washingtonexaminer.com/policy/foreign...



2 1 2 1,959

Dan Tsubouchi @Energy_Tidbits · Aug 30

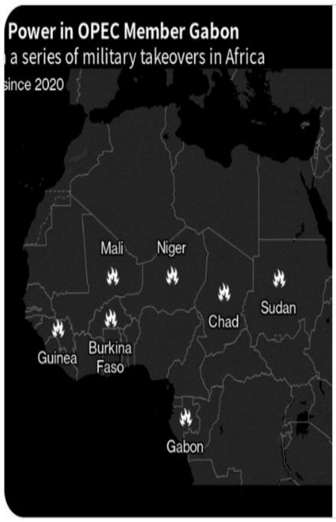
Military coup in Gabon.

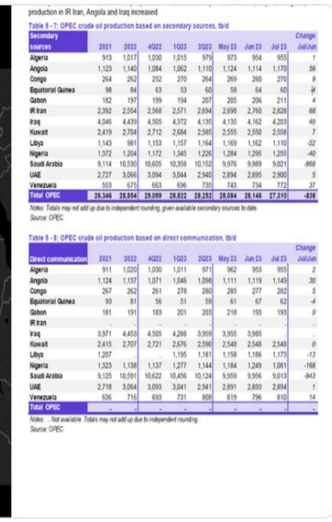
Gabon is #OPEC member, but only producing 200,000 b/d.

The latest in the military coups across central Africa. See 👇 @business map per @katarinah reporting.

#OOTT

bloomberg.com/news/articles/...





production in IR Iran, Angola and Iraq increased.

Table 5 - 7: OPEC crude oil production based on secondary sources, tb/d

Secondary sources	2021	2022	4Q22	1Q23	2Q23	May 23	Jun 23	Jul 23	Change Jul/Jun
Algeria	913	1,017	1,030	1,015	979	973	954	955	1
Angola	1,123	1,140	1,084	1,062	1,110	1,124	1,114	1,170	56
Congo	264	262	252	270	264	269	260	270	9
Equatorial Guinea	98	84	63	53	60	58	64	60	-4
Gabon	182	197	199	194	207	205	206	211	4
IR Iran	2,392	2,554	2,568	2,571	2,694	2,698	2,760	2,828	68
Iraq	4,046	4,439	4,505	4,372	4,135	4,135	4,162	4,203	40
Kuwait	2,419	2,704	2,712	2,684	2,585	2,555	2,550	2,558	7
Libya	1,143	981	1,153	1,157	1,164	1,169	1,162	1,110	-52
Nigeria	1,372	1,204	1,172	1,345	1,226	1,284	1,295	1,255	-40
Saudi Arabia	9,114	10,530	10,605	10,358	10,152	9,976	9,989	9,021	-968
UAE	2,727	3,066	3,094	3,044	2,940	2,894	2,895	2,900	5
Venezuela	553	675	663	696	735	743	734	772	37
Total OPEC	**26,346**	**28,854**	**29,099**	**28,822**	**28,252**	**28,084**	**28,146**	**27,310**	**-836**

Notes: Totals may not add up due to independent rounding, given available secondary sources to date.
Source: OPEC.

Table 5 - 8: OPEC crude oil production based on *direct communication*, tb/d

Direct communication	2021	2022	4Q22	1Q23	2Q23	May 23	Jun 23	Jul 23	Change Jul/Jun
Algeria	911	1,020	1,030	1,011	971	962	953	955	2
Angola	1,124	1,137	1,071	1,046	1,098	1,111	1,119	1,149	30
Congo	267	262	261	278	280	285	277	282	5
Equatorial Guinea	93	81	56	51	59	61	67	62	-4
Gabon	181	191	183	201	203	218	193	193	0
IR Iran	..	..	..	..	..	..	..	..	..
Iraq	3,971	4,453	4,505	4,288	3,959	3,955	3,985	..	..
Kuwait	2,415	2,707	2,721	2,676	2,590	2,548	2,548	2,548	0
Libya	1,207	..	..	1,195	1,181	1,158	1,186	1,173	-13
Nigeria	1,323	1,138	1,137	1,277	1,144	1,184	1,249	1,081	-168
Saudi Arabia	9,125	10,591	10,622	10,456	10,124	9,959	9,956	9,013	-943
UAE	2,718	3,064	3,093	3,041	2,941	2,891	2,893	2,894	1
Venezuela	636	716	693	731	808	819	796	810	14
Total OPEC	..	..	..	..	..	..	..	..	..

Notes: .. Not available. Totals may not add up due to independent rounding.
Source: OPEC.

5 · 10 · 2,058

SAF GROUP

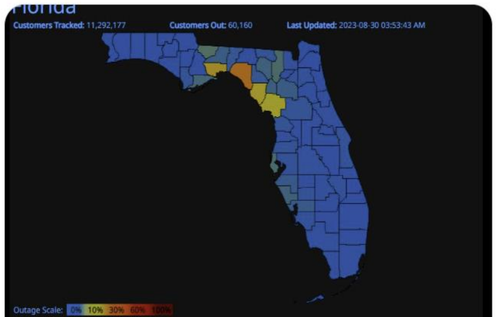
Dan Tsubouchi @Energy_Tidbits · Aug 30

Here is link to poweroutage.us for live reporting on power outages in Florida. poweroutage.us/area/state/flo...

Currently 60,000 without power but #Idalia hasn't hit yet.

hoping everyone can stay safe!!

#oott



Electric Providers for Florida

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City of Tallahassee	105,440	235	2023-08-30 03:53:27 AM
Clay Electric Coop	190,280	2,509	2023-08-30 03:53:37 AM
Duke Energy	1,953,579	23,136	2023-08-30 03:50:25 AM
Escambia River Electric Coop	12,529	0	2023-08-29 08:51:59 PM
Florida Keys Electric Coop	33,722	0	2023-08-29 10:08:08 PM
Florida Power & Light Company	5,841,776	16,111	2023-08-30 03:53:37 AM
Florida Public Utilities	30,013	0	2023-08-30 03:53:43 AM
Fort Pierce Utilities Authority	28,872	1	2023-08-30 03:53:28 AM
Gainesville Regional Utilities	100,600	10	2023-08-30 03:53:29 AM
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Tampa Electric	797,574	2,808	2023-08-30 03:53:38 AM

2 5 1,959

Dan Tsubouchi @Energy_Tidbits · Aug 30

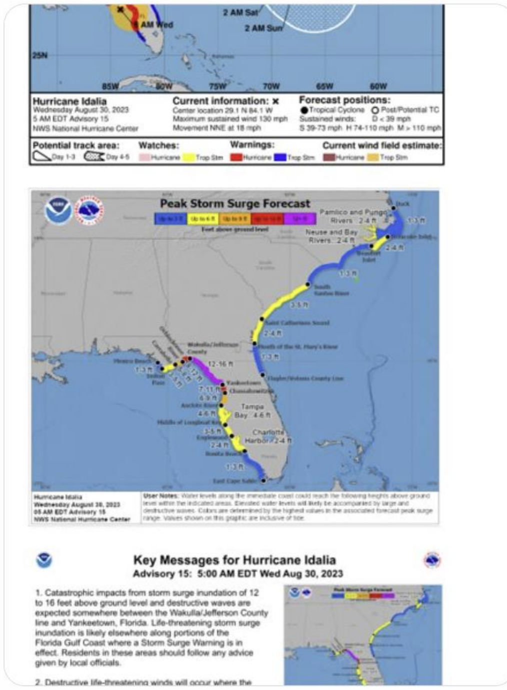
#Idalia @NHC_Atlantic 5am ET update

About to make landfall as Category 4 at 130 mph.

Massive storm surge.

Nothing is positive about a Cat 4 but hopefully being fast moving at 18 mph means less water being dumped on people

Please stay safe as possible.
#OOTT



2 · 5 · 2,355

Dan Tsubouchi @Energy_Tidbits · Aug 29

China "*summer travel season comes to an end*"

China scheduled domestic flights +0.2% WoW to 104,932.

How low will flights go in Sep/Oct with weak economy/consumer? Currently expect -2.5% over next 4-wks to 102,276. How much lower?

Thx @BloombergNEF Claudio Lubis.
#OOTT


Jul 4-10: +2.4% WoW to 99,904
Jun 27-Jul 3: +1.9% WoW to 97,572
Jun 20-26: +3.4% WoW to 95,724
Jun 13-19: -0.9% WoW to 92,568
June 6-12: -1.2% WoW to 93,328
May 30-Jun 5: +0.2% WoW to 94,486
May 23-29: -0.1% WoW to 94,321
May 16-22: -2.8% WoW to 94,417
May 9-15: basically flat at 97,049
May 2-8: +2.8% WoW to 97,087
Apr 25-May 1: +0.04% to 94,471
Apr 18-24: +2.1% WoW to 94,138
Apr 11-17: +0.7% WoW to 92,231
Apr 3-10: -4.2% WoW to 91,567
Mar 28-apr 3: +6.8% WoW to 95,624
Mar 21-27: +1.5% WoW to 89,513
Mar 14-20: -0.6% WoW to 88,166
Mar 7-13 week: -0.8% WoW to 88,675
Feb 27-Mar 3 week: -2.6% WoW to 89,430
Feb 21-27 week: +0.0% WoW to 91,828
Feb 14-20 week -0.5% WoW to 91,561
Feb 7-13 week -0.7% WoW to 92,007
Jan 31- Feb 6 week +10.9% WoW
Jan 24-30 week -9.2% WoW to 83,500
Jan 17-23 week +7% WoW to 91,959
Jan 10-16 week +20% WoW to 85,910
Jan 3-9 week: -5.3% WoW to 71,642
Dec 27-Jan 2 week: -5.6% WoW to 75,652

BNEF Aviation Indicators Weekly Aug 29 vs March 28.

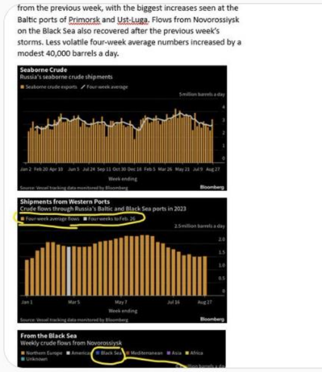
1 2 1 2,370

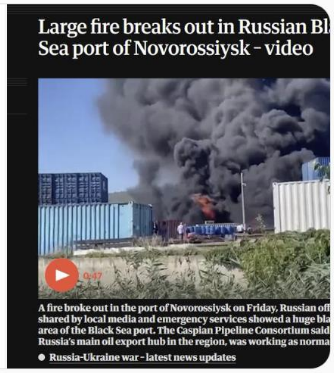
Dan Tsubouchi @Energy_Tidbits · Aug 29

Russian #Oil shjpments from major Black Sea port of Novorossiysk recovered WoW reports @JLeeEnergy.

Recovered since Aug 18 fire/explosion interruptions reportedly hit oil/fuel in stored barrels & not the big tanks that are used to load tankers.

Thx @JLeeEnergy.
#OOTT


from the previous week, with the biggest increases seen at the Baltic ports of Primorsk and Ust-Luga. Flows from Novorossiysk on the Black Sea also recovered after the previous week's storms. Less volatile four-week average numbers increased by a modest 40,000 barrels a day.



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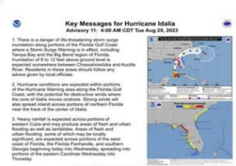
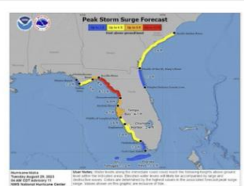
Dan Tsubouchi @Energy_Tidbits · Aug 29

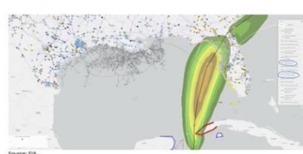
Hurricane Idalia "danger of life-threatening storm surge inundation along portions of the Florida Gulf Coast" "inundation of 8 to 12 feet above ground level is expected somewhere between Chassahowitzka and Aucilla River".

Well east of #Oil #NatGas #LNG infra.

Hoping... Show more







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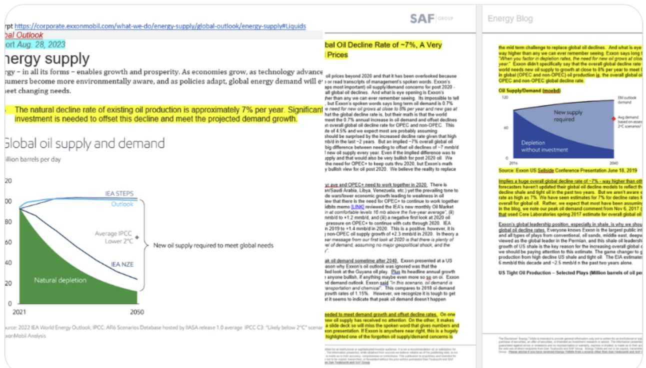
Dan Tsubouchi @Energy_Tidbits · Aug 28

Key factor why #Oil looks good for 2020s.

#Exxon today "*natural decline rate of existing oil production is approx 7% per yr.*"

WTI was $52 on 06/17/19, when Exxon warned on 7% decline. See 👇 SAF 06/20/19 blog. "*Exxon's Math Calls For Overall Global Oil Decline Rate of ~7%, A...* Show more



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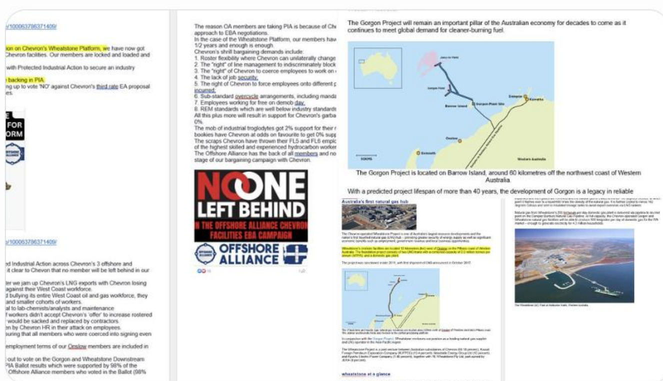
Dan Tsubouchi @Energy_Tidbits · Aug 28

3.3 bcfd #LNG supply now at risk of strike at #Chevron's 2.1 bcfd Gorgon & 1.2 bcfd Wheatstone.

Workers can now give 7-day notice for industrial action

Seems like still a gap still to close based on 👇 Offshore Alliance list.

#NatGas #OOTT



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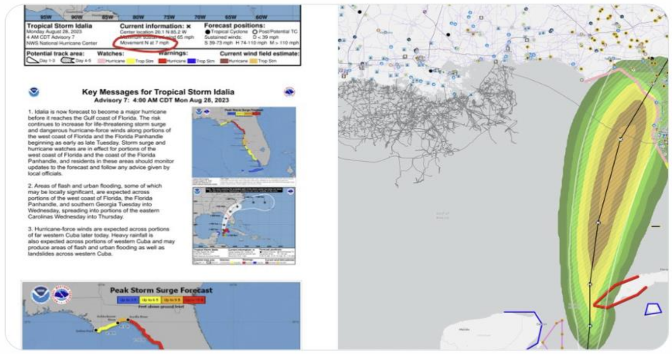
Dan Tsubouchi @Energy_Tidbits · Aug 28

Tropical Storm Idalia "now forecast to become a major hurricane" before it hits Florida.

Forecast major storm surge.

@EIAgov's great mapping system shows Idalia is well east of #Oil #NatGas #LNG wells, refineries, export.

Hoping people can prepare and stay safe!
#OOTT



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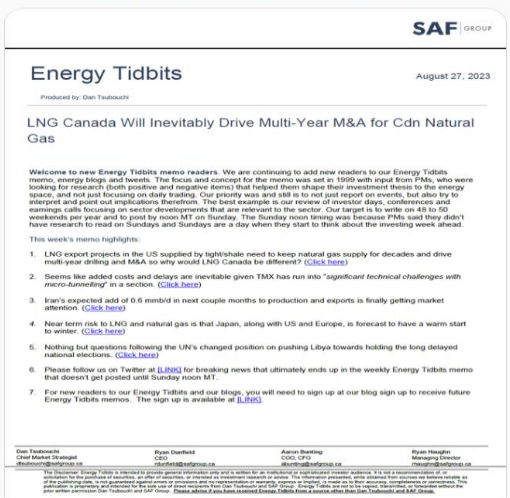
Dan Tsubouchi @Energy_Tidbits · Aug 27

SAF Group Aug 27, 2023 Energy Tidbits memo is posted on SAF Group website. this 63-pg energy research memo expands upon & covers more items than tweeted this week. Available at news/insights section of SAF website #Oil #OOTT #LNG #NatGas #EnergyTransition



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Energy Tidbits

August 27, 2023

Produced by: Dan Tsubouchi

LNG Canada Will Inevitably Drive Multi-Year M&A for Cdn Natural Gas

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. Our target is to write on 48 to 50 weekends per year and to post by noon MT on Sunday. The Sunday noon timing was because PMs said they didn't have research to read on Sundays and Sundays are a day when they start to think about the investing week ahead.

This week's memo highlights:

1. LNG export projects in the US supplied by tight/shale need to keep natural gas supply for decades and drive multi-year drilling and M&A so why would LNG Canada be different? (Click here)
2. Seems like added costs and delays are inevitable given TMX has run into "*significant technical challenges with micro-tunnelling*" in a section. (Click here)
3. Iran's expected add of 0.6 mmb/d in next couple months to production and exports is finally getting market attention. (Click here)
4. Near term risk to LNG and natural gas is that Japan, along with US and Europe, is forecast to have a warm start to winter. (Click here)
5. Nothing but questions following the UN's changed position on pushing Libya towards holding the long delayed national elections. (Click here)
6. Please follow us on Twitter at [LINK] for breaking news that ultimately ends up in the weekly Energy Tidbits memo that doesn't get posted until Sunday noon MT.
7. For new readers to our Energy Tidbits and our blogs, you will need to sign up at our blog sign up to receive future Energy Tidbits memos. The sign up is available at [LINK].

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