SAF GROUP

Energy Tidbits

Does Ukraine Fighting Success Create a Remote Chance For a Return of Russian Natural Gas To Europe This Winter?

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Independent Statistics & Analysis
U.S. Energy Information Administration

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Short-Term Energy Outlook

Forecast highlights

Global liquid fuels

- The Brent crude oil spot price in our forecast averages $98 per barrel (b) in the fourth quarter of 2022 (4Q22) and $97/b in 2023. The possibility of petroleum supply disruptions and slower-than-expected crude oil production growth continues to create the potential for higher oil prices, while the possibility of slower-than-forecast economic growth creates the potential for lower prices.
- U.S. crude oil production in our forecast averages 11.8 million barrels per day (b/d) in 2022 and 12.6 million b/d in 2023, which would set a record for the most U.S. crude oil production during a year. The current record is 12.3 million b/d, set in 2019.
- We estimate that 99.4 million b/d of petroleum and liquid fuels was consumed globally in August 2022, up by 1.6 million b/d from August 2021. We forecast that global consumption will rise by an average of 2.1 million b/d for all of 2022 and by an average of 2.0 million b/d in 2023. As a result of high natural gas prices globally, we increased our forecast for oil consumption in 4Q22 and 1Q23 as electricity providers, particularly in Europe, may switch to oil-based generating fuels.
- We expect retail gasoline prices will average $3.60 per gallon (gal) in 4Q22 and $3.61/gal in 2023. Retail diesel prices in our forecast average $4.90/gal in 4Q22 and $4.28/gal in 2023.

Natural gas

- In August, the Henry Hub spot price averaged $8.80 per million British thermal units (MMBtu), up from $7.28/MMBtu in July. Natural gas prices rose in August because of continued strong demand for natural gas in the electric power sector, which has kept natural gas inventories below their five-year (2017–2021) average. We expect the Henry Hub price to average about $9/MMBtu in 4Q22 and then fall to an average of about $6/MMBtu in 2023 as U.S. natural gas production rises.
- U.S. natural gas inventories ended August at 2.7 trillion cubic feet (Tcf), which was 12% below the five-year average. We forecast that inventories will end the injection season (April through October) at more than 3.4 Tcf, which would be 7% below the five-year average.

Note: EIA completed modeling and analysis for this report on Thursday, September 1, 2022

- U.S. LNG exports in our forecast average 11.7 billion cubic feet per day (Bcf/d) in 4Q22, up 1.7 Bcf/d from 3Q22. Factors that will affect the volume of LNG exports in the coming months include the planned outage at Cove Point in October and Freeport LNG resuming partial operations by mid- to late-November. We forecast LNG exports will average 12.3 Bcf/d in 2023.

- U.S. consumption of natural gas in our forecast averages 86.6 Bcf/d in 2022, up 3.6 Bcf/d from 2021, driven by increases across all consuming sectors. We expect consumption to fall by 1.9 Bcf/d in 2023 because of declines in consumption in the industrial and electric power sectors.

- Dry natural gas production has been rising relatively steadily since 1Q22, when it averaged 94.6 Bcf/d. We forecast U.S. dry natural gas production to average 99.0 Bcf/d in 4Q22 and then rise to 100.4 Bcf/d for 2023.

Electricity, coal, renewables, and emissions

- We expect U.S. sales of electricity to ultimate customers to rise by 2.6% in 2022, mostly because of more economic activity but also because of slightly hotter summer weather in than last year much of the country. We forecast U.S. sales of electricity to fall by 0.4% in 2023.

- The largest increases in U.S. electricity generation in our forecast come from renewable energy sources, mostly solar and wind. We expect renewable sources will provide 22% of U.S. generation in 2022 and 24% in 2023, up from 20% in 2021.

- Natural gas fuels 37% of U.S. electricity generation in 2022, a share similar to 2021, and we forecast it to fall to 36% in 2023. Coal-fired electricity generation in our forecast provides 21% of the U.S. total in 2022 and 19% in 2023. Growing generation from renewable sources limits growth in natural gas generation while coal's generation share declines due to the expected retirement of coal-fired capacity.

- We forecast the U.S. residential price of electricity will average 14.8 cents per kilowatthour in 2022, up 7.5% from 2021. Higher retail electricity prices largely reflect an increase in wholesale power prices driven by rising natural gas prices. The Southwest region has the lowest forecast wholesale prices in 2022, averaging $69 per megawatthour (MWh), up 25% from 2021. The highest forecast wholesale prices are at more than $100/MWh in ISO New England (up 96% from 2021) and New York ISO (up 124% from 2021).

- U.S. coal production in the forecast increases by 22 million short tons (MMst) in 2022 to total 600 MMst for the year. We expect production will total 590 MMst in 2023.

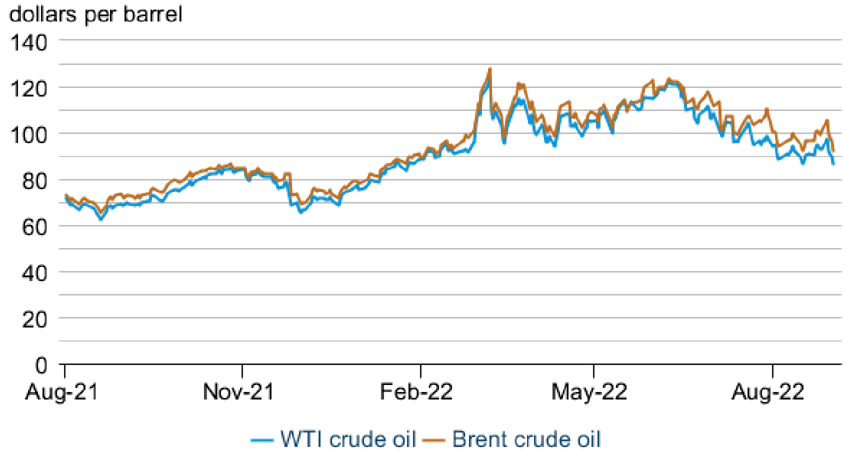
- We expect energy-related carbon dioxide (CO_2) emissions in the United States to increase by 1.7% in 2022 and then to decrease 1.8% back to around 2021 levels in 2023.

Petroleum and Natural Gas Markets Review

Crude oil

Prices: The front-month futures price for Brent crude oil settled at $92.36 per barrel (b) on September 1, a decrease of $7.67/b from the August 1 price of $100.03/b. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, decreased by $7.28/b during the same period, settling at $86.61/b on September 1 **(Figure 1)**.

Figure 1. Crude oil front-month futures prices



Data source: CME Group, Intercontinental Exchange, and Bloomberg L.P.
Note: WTI=West Texas Intermediate

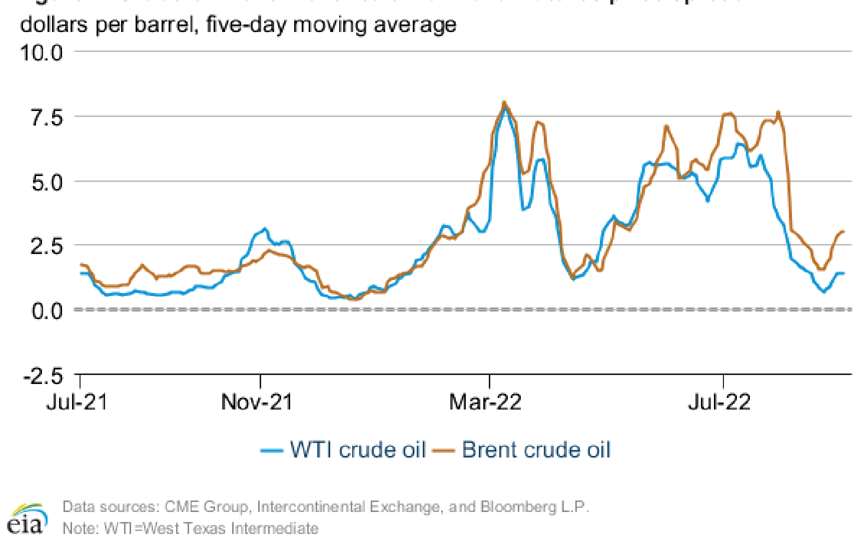
Crude oil prices were lower on average in August than they were in July before ending with a rapid decrease in the week before Labor Day. From August 29 through September 1, the Brent crude oil price decreased $13/b and the WTI price decreased $10/b. The monthly average Brent front-month futures price was $98/b in August, about $7/b lower than in July, and the WTI price was $91/b, $8/b lower than in July. The lower prices in August likely reflected overall increases in global petroleum inventories. The increase in inventories came with ongoing growth in global production of crude oil and other liquid fuels, which we estimate reached 101 million barrels per day (b/d) in August, the highest global production since December 2019.

We estimate that crude oil prices will generally remain near August average levels through the end of 2023. Although we expect average crude oil prices to mostly remain between $90/b–$100/b through next year, the possibility for significant volatility around those averages is high. Recent events contributing to increased uncertainty in the crude oil market and in our forecast include:

- The impact of the recent OPEC decision to reduce crude oil production by 0.1 million b/d in October and whether there will be further production cuts in the future
- The threat of increasing conflict following the outbreak of violent clashes in the Libyan capital of Tripoli
- Uncertainty around the potential expiration of the current coordinated petroleum release from strategic reserves in November
- The potential return to an Iran nuclear deal that could lift sanctions on the country and allow Iran's crude oil exports into the market
- The risk of hurricanes that could result in potential production outages and limited export traffic along the U.S. Gulf Coast

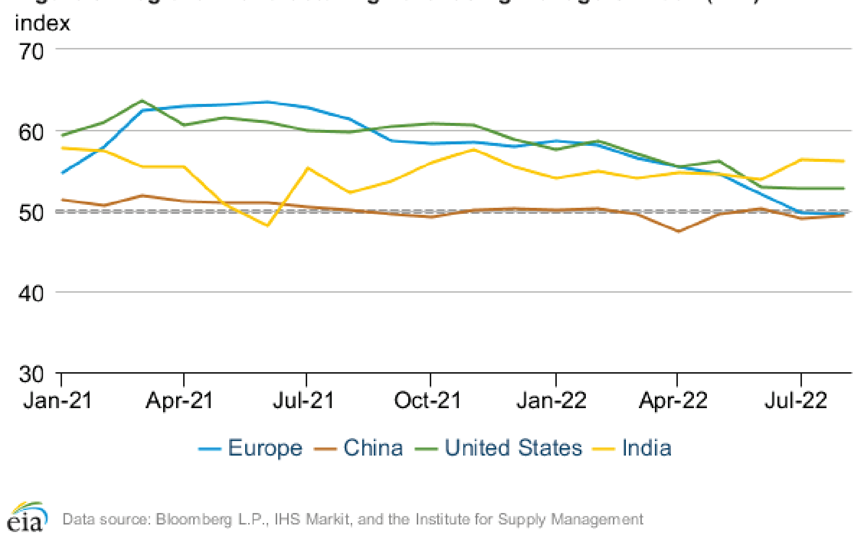
Crude oil front-month to third-month futures price spread: The front-month to third-month crude oil futures price spread (1-3 spread) is a measure of market backwardation, a market environment that encourages crude oil to flow out of inventories and into the market **(Figure 2)**. Backwardation occurs when crude oil futures contract prices in the near term are higher than crude oil prices in the long term. In response to Russia's full-scale invasion of Ukraine in the spring, the 1-3 spread for Brent increased from an average of $1/b in January to nearly $7/b in March. Following a decline in April, it returned to near $7/b levels in July. In August, the spread narrowed to $3/b, the narrowest spread since April. The decrease in backwardation in August suggests that the market call to draw oil from inventories has decreased since midsummer, indicating market conditions that are more balanced between supply and demand than earlier this year.

Figure 2. Crude oil front-month to third-month futures price spread



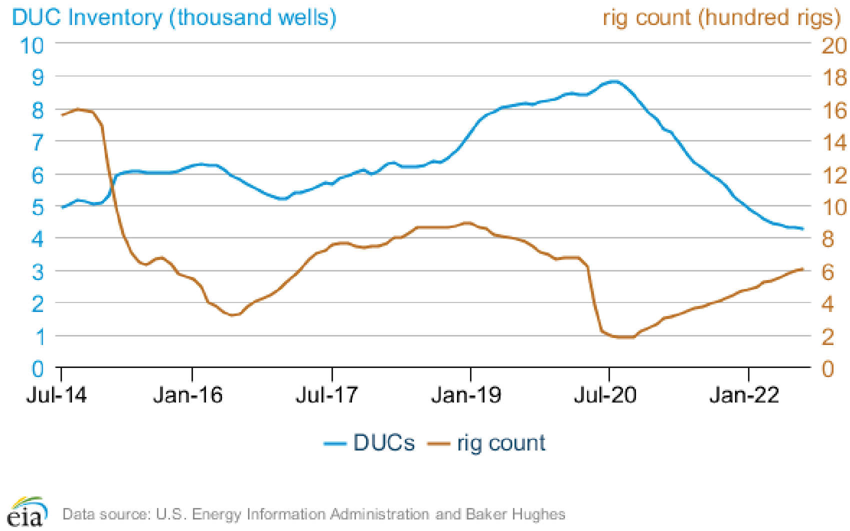
Manufacturing Purchasing Managers' Index: Regional Purchasing Managers' Indexes (PMIs) for manufacturing in July decreased in the United States, Europe, and China **(Figure 3**). A PMI serves as an indicator of increasing or decreasing manufacturing activities. An index rating above 50 represents growth in activity while a rating below 50 indicates a contraction. The U.S. manufacturing PMI decreased in July to 52.8, its lowest rating since June 2020, suggesting a slowing rate of growth. In Europe, the PMI value dropped to 49.8, also its lowest rating since June 2020, while the drop below 50 also suggests market contraction. The latest Europe and U.S. PMIs suggest that these conditions have continued into August, contributing to further concerns about economic conditions and petroleum demand. The low PMI signals a weakening economic environment in Europe, further exacerbated by the decreasing value of the euro, which fell to parity with the U.S. dollar in late August.

Figure 3. Regional Manufacturing Purchasing Managers' Index (PMI)



U.S. drilled but uncompleted wells and rig count: Since July 2020, the number of U.S. wells that are drilled but uncompleted (DUCs) has been decreasing and has fallen below the number in 2014 (the earliest year in our dataset) in 2022 **(Figure 4)**. DUCs are oil and natural gas wells that have undergone their drilling phase but have not yet undergone casing, cementing, and other procedures that are necessary to establish a fully operational well. Prior to the onset of the COVID-19 pandemic, the number of DUCs had been steadily growing since 2017 in the United States, driven primarily by new production in the Permian Basin. Since July 2020, however, the number of DUCs has been decreasing at a relatively steady pace. At the same time, the Baker Hughes rotary rig count for oil producing wells has been increasing, rising above 600 rigs in July, the highest it has been since March 2020.

Figure 4. U.S. drilled but uncompleted wells (DUC) and rig count



The number of DUCs serves as an indicator of the relative supply of wells that may be transitioned to operational status, and the increasing rig count reflects the higher number of wells being drilled. Growth in crude oil production in the United States since 2021 has largely consisted of completing wells from the available DUCs, while new drilling in response to high crude oil prices appears to be lagging the rate of completion. Continued U.S. production increases are likely to continue drawing on available DUCs that are viable candidates for completion at current prices. Continued increases in rig counts will contribute to more drilled wells, which could soon outpace well completions and increase the number of DUCs. However, on September 2, the latest weekly rig count indicated a decrease in 9 rigs from the previous week, down to 596, the largest week-on-week decrease since September 2021.

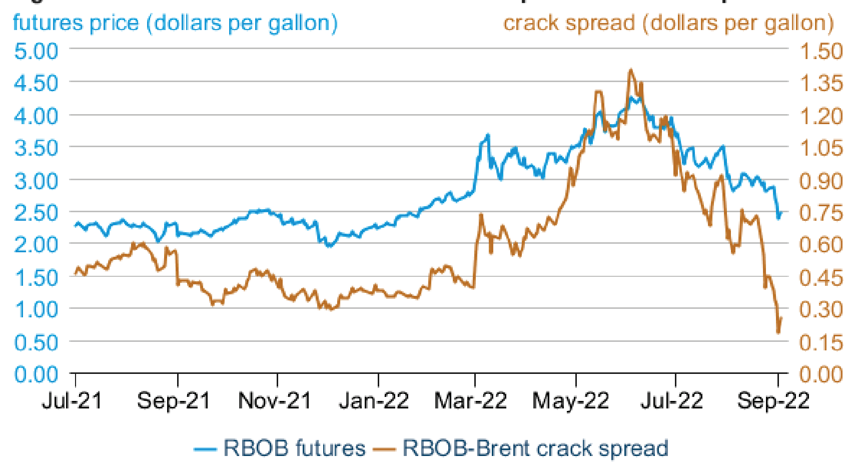
Our August *Drilling Productivity Report* showed the smallest monthly percentage decline in DUCs since July 2020. We currently forecast that U.S. crude oil production will increase to 12.2 million b/d in the fourth quarter and will rise to an average of 12.6 million b/d in 2023. This increase would constitute an annual increase of 0.5 million b/d in 2022 and an additional increase of 0.9 million b/d in 2023.

Petroleum products

Gasoline prices: The front-month futures price of RBOB (the petroleum component of gasoline used in many parts of the country) settled at $2.39 per gallon (gal) on September 1, down 61 cents/gal from August 1 **(Figure 5)**. The RBOB-Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) settled at $0.19/gal on September 1, down 43 cents/gal during the same period. The RBOB–Brent crack spread declined by 12 cents/gal on September 1 when the front-month RBOB contract rolled over to October delivery, which reflects winter grade gasoline that is cheaper for refineries to produce. Before the contract roll over, the RBOB–Brent crack spread had already decreased from an average of 85 cents/gal in

July to an average of 58 cents/gal in August, which could be the result of less-than-average seasonal demand and anticipation of the contract roll-over.

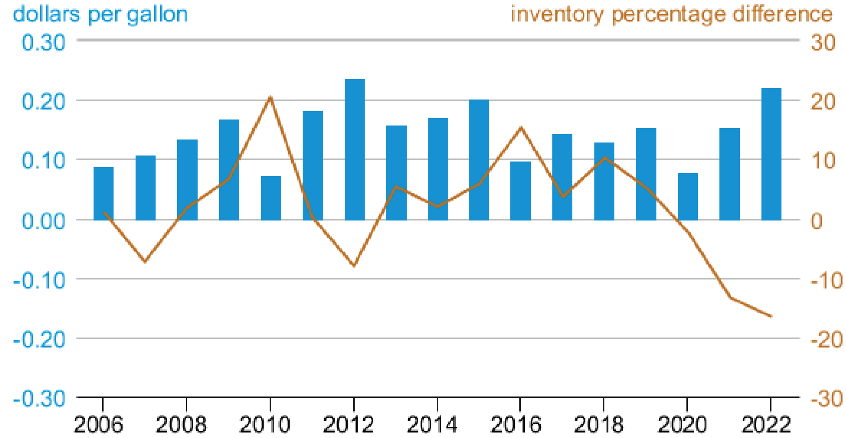
Figure 5. Historical RBOB front-month futures prices and crack spreads



Data source: CME Group and Bloomberg L.P.
Note: RBOB is the petroleum component of gasoline used in many parts of the country.

The front-month RBOB contract for September delivery sold at an average premium of 22 cents/gal to the second-month contract for October delivery during August trading. This price spread was the second-highest inflation-adjusted price spread since 2006, when the RBOB futures contract began trading **(Figure 6)**. Most of this premium was due to the difference between winter and summer grade gasoline, but market fundamentals also affected the spread. Typically, when inventories are lower, this premium is greater because low inventories add more pressure to prices in near-term contracts than long-term contracts. This dynamic occurs because low inventories occur during tight market conditions in which demand must be met from inventories, and, under these conditions, purchasers are willing to pay a premium to secure needed supply. We estimate that gasoline inventories in the East Coast (PADD 1) were 16% below their five-year (2017–2021) average at the end of August. In 2012, the year with the highest average front-month to second-month price spread, inventories were also below their five-year average, albeit by not as much as this year.

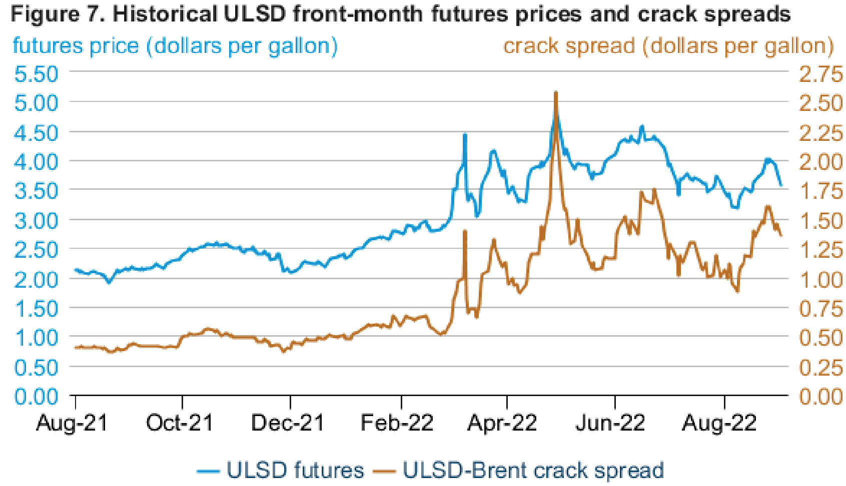
Figure 6. August front-month to 2nd month RBOB price spread and PADD 1 gasoline stocks compared with five-year average



Source: CME Group and Bloomberg L.P.
Note: Prices are based on inflation-adjusted monthly averages. Real prices are adjusted using the CPI.

Ultra-low sulfur diesel prices: The front-month futures price for ultra-low sulfur diesel (ULSD) for delivery in New York Harbor settled at $3.56/gal on September 1, a 12 cents/gal (4%) increase from August 1 **(Figure 7)**. The ULSD-Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) increased 30 cents/gal (29%) during the same period and settled at $1.36/gal on September 1.

Figure 7. Historical ULSD front-month futures prices and crack spreads



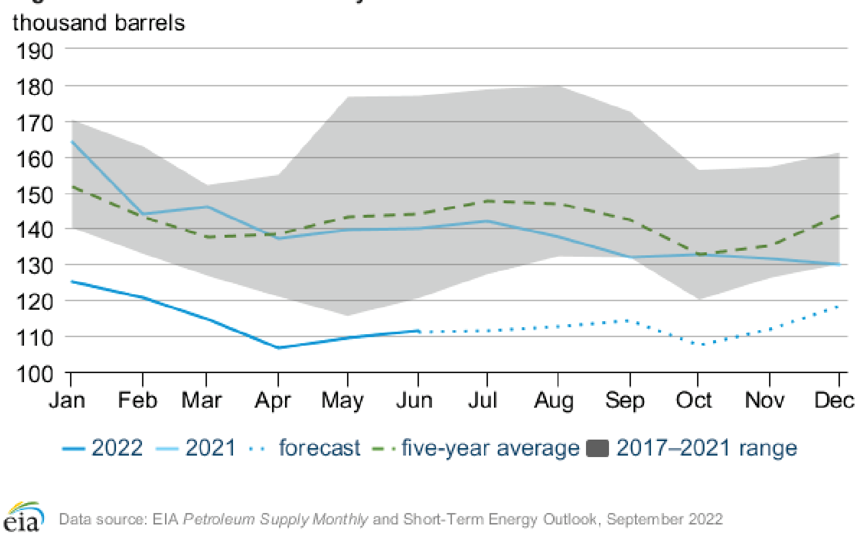
Data source: CME Group and Bloomberg L.P.
Note: ULSD=ultra-low sulfur diesel

ULSD prices increased this month as rapidly increasing natural gas prices in Europe and Asia increased demand for distillate fuel as a substitute fuel for power generation in those markets amid low distillate stocks globally. From August 8 to August 26, ULSD prices increased by 83 cents/gal (26%). This increase in ULSD prices occurred despite slowing economic and trucking activity in the United States. A recent decline in the American Trucking Association's *Truck Tonnage Index* suggests less consumption of goods, less home construction, and slower manufacturing activity contributed to a slight decline in diesel fuel demand. Although changes in crude oil prices normally account for most changes in ULSD prices, as crude oil is the single largest input cost for producing ULSD, the Brent crude oil price increased only 4% between August 8 and August 26. Because ULSD prices increased by more than crude oil prices, it resulted in the ULSD-Brent crack spread increasing by 73 cents/gal (83%) over the same period.

ULSD prices rose in August primarily due to increased interest in fuel switching from natural gas to distillate fuel oil caused by rising natural gas prices in Europe. From August 8 to August 26, front-month natural gas prices at the Dutch Title Transfer Facility (TTF) increased by 72%, reaching a record high. High natural gas prices are making it economical for European operators to switch from natural gas to distillate fuel oil in electricity generation. From August 26 to September 1, ULSD prices declined by 45 cents/gal (11%) as natural gas prices declined and concerns around an economic slowdown that could reduce distillate demand regained the focus of the market.

U.S. distillate inventories: Inventories in the United States began the year at 130 million barrels, 14% less than their five-year average **(Figure 8)**. As of June 2022, inventories decreased to 111 million barrels or 23% below the five-year average. We forecast U.S. distillate inventories will build to 118 million barrels or 17% below the five-year average by the end of this year, and will remain below their previous five-year low.

Figure 8. U.S. distillate inventory



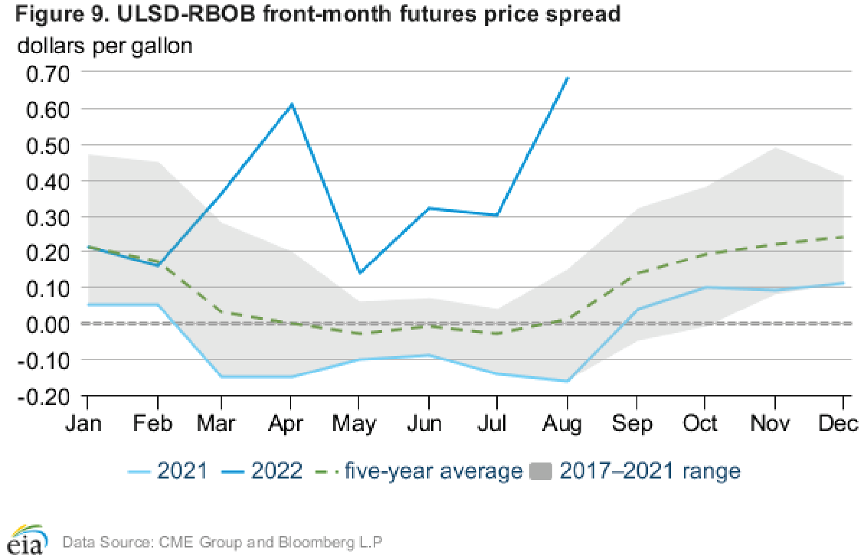
Data source: EIA *Petroleum Supply Monthly* and Short-Term Energy Outlook, September 2022

Western sanctions against Russia's petroleum product exports following its full-scale invasion of Ukraine in February have been a major driver of global distillate markets and subsequent inventory draws this year. Low inventories in New England (PADD 1A), the Central Atlantic (PADD 1B), and the Midwest (PADD 2) suggest both higher and more volatile ULSD prices in the coming months. In the Midwest, where distillate fuel is widely used for harvesting crops, *Weekly Petroleum Status Report* data for the week ending August 26 shows distillate inventories are

17% below the five-year average. In New England and the Central Atlantic, where heating oil is used as a primary source of heat in some homes, inventories are 56% below the five-year average.

ULSD-RBOB future price spread: ULSD front-month futures prices traded at an average monthly premium to RBOB of 68 cents/gal in August, the highest premium in real terms since November 2008 **(Figure 9)**. Although front-month ULSD and RBOB futures typically follow seasonal trends (RBOB trades at a premium in the summer, and ULSD trades at a premium in the winter), global demand for distillate and reduced exports from Russia, a major supplier of distillate fuel and natural gas to Europe, have disrupted this trend. This increased demand for distillate, as well as a concurrent decline in gasoline demand, has encouraged refiners to maximize distillate production. The monthly ULSD-Brent crack spread this August of $1.27/gal is 87 cents/gal (222%) higher than last August while the RBOB-Brent crack spread of 58 cents/gal is only 3 cents/gal (6%) higher compared with last year. Looking forward, we forecast that the combination of the upcoming switch to winter grade gasoline, which is less expensive for refiners to produce, and the typical decline in gasoline demand after the summer driving season will contribute to declining refiner margins for gasoline. We forecast diesel fuel refiner margins will remain above August levels through the end of the year.

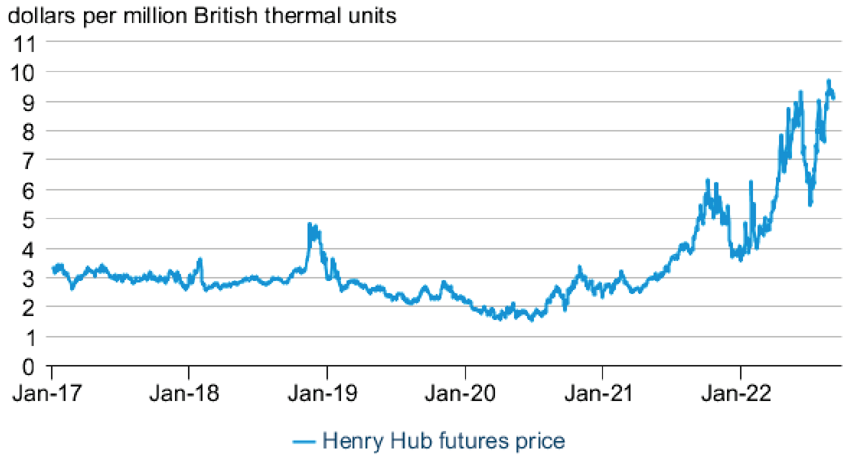
Figure 9. ULSD-RBOB front-month futures price spread



Natural Gas

Prices: The front-month natural gas futures contract for delivery at the Henry Hub closed at $9.26 per million British thermal units (MMBtu) on September 1, 2022, which was up 12% (98 cents/MMBtu) from August 1, 2022 **(Figure 10)**. Closing prices for front-month natural gas futures averaged $8.78/MMBtu during August, the highest August monthly average in real terms since 2008. Natural gas prices remained elevated throughout August as inventories remained below the five-year (2017–2021) average, and consumption in the electric power sector remained strong. Hotter-than-normal temperatures in much of the country increased demand for air conditioning, and constraints in the coal market limited coal-fired electricity generation, both increasing consumption of natural gas to produce electricity.

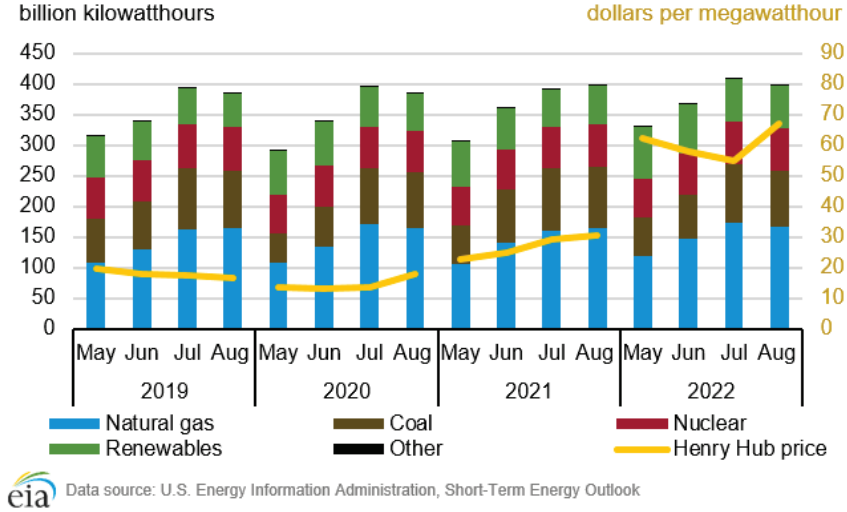
Figure 10. Historical nominal front-month U.S. natural gas prices



Data source: CME Group and Bloomberg L.P.

The United States generates more electricity during the summer compared with other times of the year. This summer, the percentage share of electricity generation from natural gas has been similar to previous years, despite high natural gas prices that have more than doubled from the same time last year **(Figure 11)**. Previously, high natural gas prices would have resulted in more coal-fired electricity generation. However, coal-fired power plants have been limited in their ability to increase power generation due to historically low inventories, constraints in fuel delivery to coal plants, and continued coal capacity retirements. Even as the capacity for renewable electricity generation has increased over recent years, power providers continue to use natural gas-fired electricity generation most often to meet fluctuations in electricity demand.

Figure 11. May-Aug electricity generation by fuel source and natural gas price for electricity



In the United States, natural gas is the most common fuel source used by power providers to quickly increase or decrease power supply to meet electricity demand from moment to moment. This instantaneous balance is crucial in U.S. power markets due to the lack of large-scale electricity storage. Most natural gas-fired turbine power plants can increase or decrease their electricity generation in a matter of minutes. In contrast, other sources of generation, such as nuclear power plants, generally provide a stable amount of electricity at all hours of the day, while renewable sources such as wind turbines and solar power facilities provide a fluctuating amount of electricity based on weather conditions. Natural gas was key to meeting electricity demand peaks throughout the country during the hot July, especially in Texas, where several records were set for daily peak electricity demand.

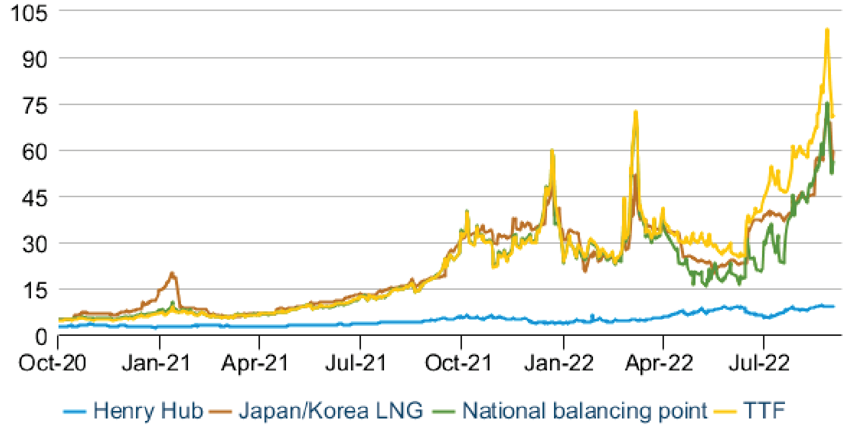
International natural gas prices: Real prices for natural gas futures for delivery at the Title Transfer Facility (TTF) in the Netherlands set a record high at more than $99/MMBtu in late August **(Figure 12)**. Prices in East Asia reached a record high of more than $69/MMBtu in August. International natural gas prices have been rising since June amid several factors:

- The June shutdown of the Freeport LNG facility in South Texas reduced global supply of liquefied natural gas (LNG) by about 2 billion cubic feet per day (Bcf/d). Prior to the shutdown, LNG exports from Freeport in the first five months of 2022 accounted for approximately 17% of total U.S. LNG exports.

- Natural gas pipeline exports from Russia to Europe have declined in 2022, reaching 1.2 Bcf/d in mid-July, the least in nearly 40 years.

- On August 19, Gazprom announced the Nord Stream 1 pipeline (which delivers natural gas from Russia to Europe) would be offline for three days for unplanned maintenance from August 31 to September 2.

Figure 12. International natural gas prices
dollars per million British thermal units



Data source: CME Group and Bloomberg L.P.
Note: TTF=Title Transfer Facility

Europe finished the 2021–2022 winter heating season with natural gas inventories at 26% full compared with the five-year average of 34%, according to data from Gas Infrastructure Europe's (GIE) Aggregated Gas Storage Inventory (AGSI+). Because of limitations in and uncertainty about natural gas pipeline imports from Russia, Europe has been importing record amounts of LNG in 2022 to refill inventory before the upcoming winter. The recent supply constraints affecting the global LNG market and the reduced pipeline flows into Europe have contributed to the increase in the TTF futures price and the increase in the price premium for LNG cargoes delivered to Europe relative to LNG cargoes delivered to East Asia.

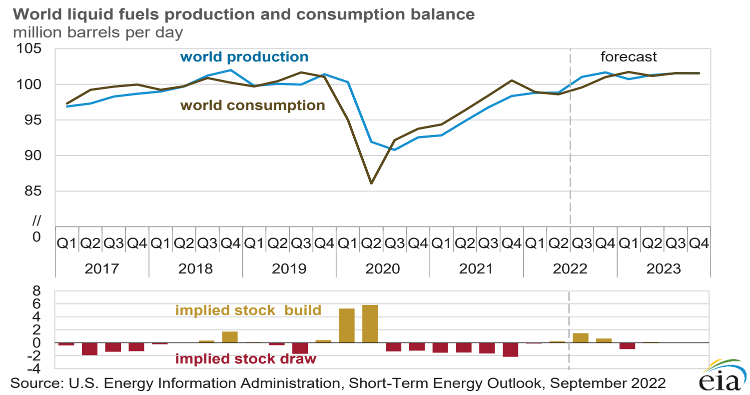
Strong demand for LNG in Europe continues to drive high international natural gas prices. The percentage of U.S. LNG exports to Europe has increased in 2022, averaging 69% in the first half of 2022 compared with 32% in the first half of 2021. U.S. facilities exported LNG at close to their combined capacity in August (excluding the offline Freeport LNG facility), with capacity utilization averaging 93% across all operating facilities.

Notable forecast changes

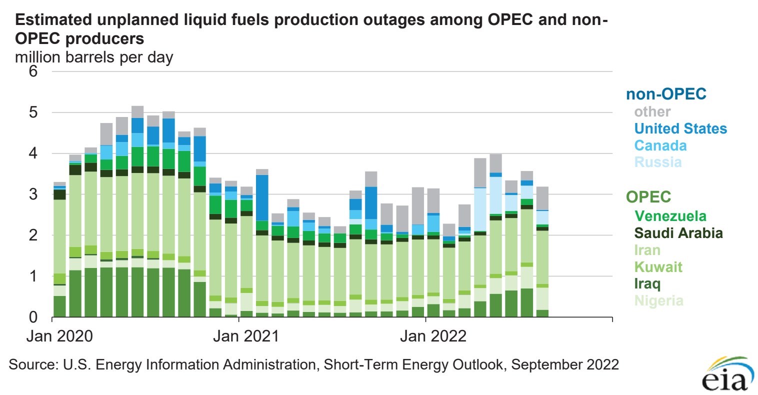
- We have updated several of the equations in the natural gas model, including those that forecast residential and commercial consumption of natural gas, natural gas pipeline imports and exports, and natural gas production in Alaska. The changes include updating the variables and sample periods on which these regression equations are evaluated. We also updated the liquefied natural gas imports forecast to better reflect recent trends. These changes contributed to 1.4 billion cubic feet per day (Bcf/d) more forecast consumption of natural gas in 2022 and 0.8 Bcf/d more consumption in 2023. In addition, we have increased our forecast for production of natural gas in Alaska by just under 0.1 Bcf/d in both years, and we have lowered our forecast of net exports of natural gas by 0.7 Bcf/d in 2022 and by 0.5 Bcf/d in 2023, mostly because of more expected pipeline imports.

- You can find more information in the detailed table of forecast changes.

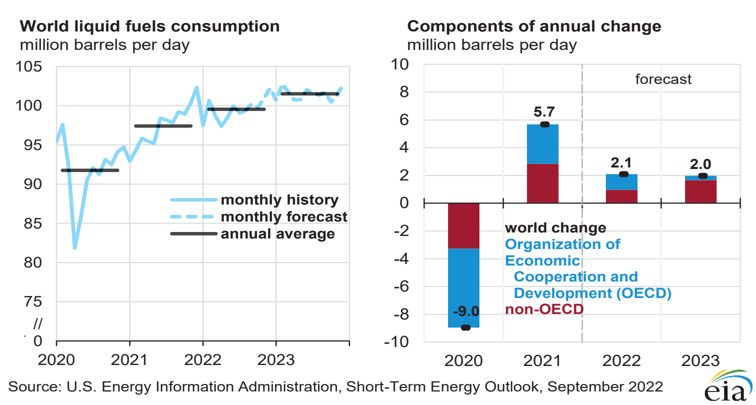
This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government. The views in this report therefore should not be construed as representing those of the U.S. Department of Energy or other federal agencies.



World liquid fuels production and consumption balance
million barrels per day
world production
world consumption
forecast
105
100
95
90
85
0
Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4
2017
2018
2019
2020
2021
2022
2023
implied stock build
implied stock draw
8
6
4
2
0
-2
-4
Source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2022

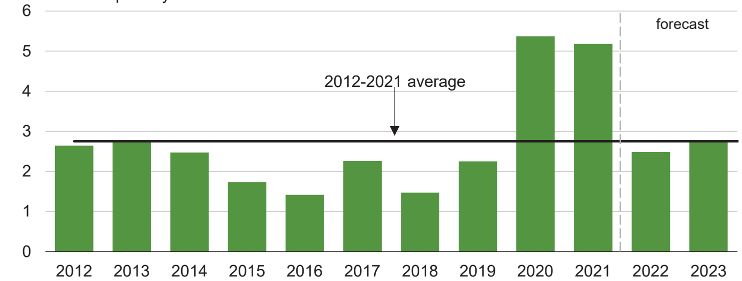


Estimated unplanned liquid fuels production outages among OPEC and non-OPEC producers
million barrels per day
6
5
4
3
2
1
0
Jan 2020
Jan 2021
Jan 2022
non-OPEC
other
United States
Canada
Russia
OPEC
Venezuela
Saudi Arabia
Iran
Kuwait
Iraq
Nigeria
Source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2022



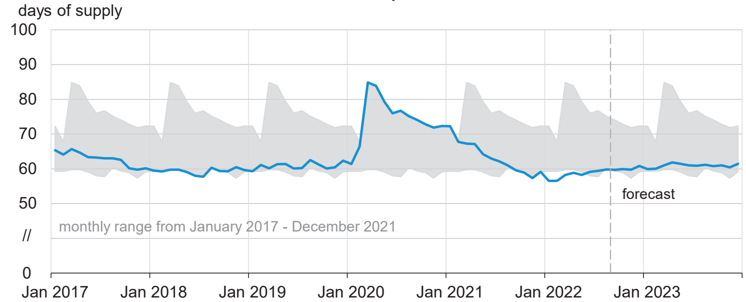
World liquid fuels consumption
million barrels per day
105
100
95
90
85
80
75
0
2020
2021
2022
2023
monthly history
monthly forecast
annual average
Components of annual change
million barrels per day
forecast
10
8
6
4
2
0
-2
-4
-6
-8
-10
5.7
2.1
2.0
-9.0
world change
Organization of Economic Cooperation and Development (OECD)
non-OECD
2020
2021
2022
2023
Source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2022

Organization of the Petroleum Exporting Countries (OPEC) surplus crude oil production capacity
million barrels per day



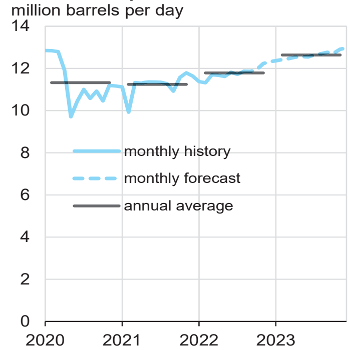
Note: Black line represents 2012-2021 average (2.8 million barrels per day).
Source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2022

Organization for Economic Cooperation and Development (OECD) commercial inventories of crude oil and other liquids
days of supply

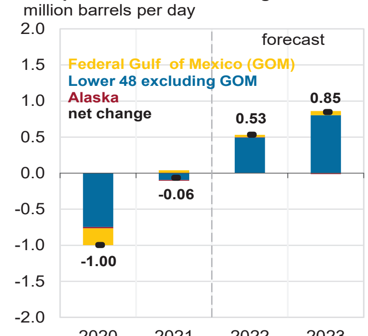


Source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2022

U.S. crude oil production
million barrels per day



Components of annual change
million barrels per day



Source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2022

Table 3a. International Petroleum and Other Liquids Production, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - September 2022

	2021				2022				2023				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2021	2022	2023
Production (million barrels per day) (a)															
OECD	30.26	30.85	31.15	32.23	31.60	31.86	32.62	33.38	33.80	33.91	33.94	34.43	31.13	32.37	34.02
U.S. (50 States)	17.79	19.16	19.03	19.91	19.44	20.12	20.40	20.94	21.16	21.32	21.44	21.77	18.98	20.23	21.43
Canada	5.62	5.37	5.49	5.68	5.66	5.53	5.72	5.85	5.92	5.88	5.90	5.92	5.54	5.69	5.91
Mexico	1.93	1.95	1.90	1.92	1.91	1.89	1.89	1.86	1.90	1.87	1.83	1.79	1.92	1.89	1.85
Other OECD	4.92	4.37	4.73	4.71	4.58	4.32	4.60	4.72	4.81	4.84	4.77	4.95	4.68	4.56	4.84
Non-OECD	62.57	63.98	65.61	66.11	67.20	66.97	68.41	68.30	66.92	67.38	67.60	67.13	64.58	67.72	67.26
OPEC	30.34	30.88	32.28	33.10	33.75	33.78	34.50	34.41	34.60	34.48	34.43	34.44	31.66	34.11	34.49
Crude Oil Portion	25.08	25.49	26.84	27.67	28.19	28.33	29.02	28.89	29.04	29.05	28.95	28.92	26.28	28.61	28.99
Other Liquids (b)	5.26	5.39	5.44	5.44	5.56	5.45	5.48	5.52	5.56	5.43	5.48	5.52	5.38	5.50	5.50
Eurasia	13.42	13.66	13.63	14.27	14.39	13.43	13.58	13.88	12.50	12.30	12.30	12.30	13.75	13.82	12.35
China	4.99	5.03	5.01	4.93	5.18	5.19	5.13	5.18	5.22	5.25	5.24	5.28	4.99	5.17	5.25
Other Non-OECD	13.81	14.41	14.69	13.80	13.89	14.58	15.21	14.83	14.59	15.36	15.63	15.10	14.18	14.63	15.17
Total World Production	92.83	94.83	96.76	98.34	98.80	98.83	101.03	101.68	100.72	101.30	101.55	101.56	95.71	100.09	101.28
Non-OPEC Production	62.48	63.95	64.47	65.24	65.05	65.04	66.52	67.27	66.12	66.82	67.11	67.12	64.05	65.98	66.79
Consumption (million barrels per day) (c)															
OECD	42.59	44.14	45.87	46.89	45.85	45.34	45.87	46.99	46.59	45.63	46.36	46.70	44.89	46.01	46.32
U.S. (50 States)	18.58	20.13	20.30	20.54	20.22	20.27	20.32	20.81	20.39	20.71	20.88	21.02	19.89	20.40	20.75
U.S. Territories	0.21	0.19	0.19	0.20	0.22	0.20	0.20	0.22	0.22	0.20	0.21	0.22	0.20	0.21	0.21
Canada	2.19	2.16	2.43	2.33	2.26	2.19	2.44	2.47	2.44	2.38	2.49	2.46	2.28	2.34	2.44
Europe	11.96	12.67	13.88	13.94	13.15	13.42	13.69	13.77	13.52	13.14	13.54	13.30	13.12	13.51	13.37
Japan	3.77	3.07	3.17	3.66	3.70	2.99	3.17	3.51	3.77	3.11	3.14	3.44	3.41	3.34	3.36
Other OECD	5.89	5.93	5.90	6.23	6.30	6.28	6.04	6.22	6.25	6.09	6.12	6.26	5.99	6.21	6.18
Non-OECD	51.78	52.21	52.53	53.64	53.06	53.25	53.70	54.03	55.12	55.55	55.20	54.83	52.54	53.51	55.17
Eurasia	4.66	4.73	5.09	4.95	4.48	4.33	4.69	4.62	4.28	4.44	4.75	4.67	4.86	4.53	4.54
Europe	0.74	0.74	0.74	0.76	0.75	0.75	0.76	0.76	0.75	0.77	0.77	0.77	0.75	0.76	0.76
China	15.27	15.48	14.99	15.33	15.14	15.12	15.13	15.67	16.37	16.27	15.64	15.56	15.27	15.27	15.96
Other Asia	13.43	12.98	12.84	13.69	13.82	13.78	13.46	13.89	14.46	14.43	13.85	14.15	13.23	13.74	14.22
Other Non-OECD	17.68	18.27	18.87	18.91	18.88	19.26	19.66	19.09	19.26	19.64	20.18	19.68	18.44	19.22	19.69
Total World Consumption	94.37	96.34	98.40	100.53	98.91	98.59	99.57	101.01	101.71	101.18	101.56	101.54	97.43	99.53	101.50
Total Crude Oil and Other Liquids Inventory Net Withdrawals (million barrels per day)															
U.S. (50 States)	0.36	0.51	0.37	0.83	0.81	0.51	0.41	0.60	0.02	-0.52	0.00	0.39	0.52	0.58	-0.03
Other OECD	0.87	0.15	0.97	0.67	-0.12	-0.62	-0.60	-0.41	0.32	0.12	0.00	-0.13	0.66	-0.44	0.08
Other Stock Draws and Balance	0.31	0.86	0.31	0.68	-0.57	-0.13	-1.27	-0.85	0.66	0.28	0.01	-0.28	0.54	-0.71	0.16
Total Stock Draw	1.55	1.52	1.65	2.18	0.12	-0.24	-1.46	-0.66	0.99	-0.12	0.01	-0.02	1.72	-0.56	0.21
End-of-period Commercial Crude Oil and Other Liquids Inventories (million barrels)															
U.S. Commercial Inventory	1,311	1,281	1,251	1,199	1,154	1,180	1,222	1,204	1,207	1,262	1,265	1,239	1,199	1,204	1,239
OECD Commercial Inventory	2,917	2,874	2,755	2,641	2,607	2,689	2,787	2,808	2,782	2,826	2,828	2,815	2,641	2,808	2,815

(a) Supply includes production of crude oil (including lease condensates), natural gas plant liquids, biofuels, other liquids, and refinery processing gains.

(b) Includes lease condensate, natural gas plant liquids, other liquids, and refinery processing gain. Includes other unaccounted-for liquids.

(c) Consumption of petroleum by the OECD countries is synonymous with "petroleum product supplied," defined in the glossary of the EIA *Petroleum Supply Monthly* , DOE/EIA-0109. Consumption of petroleum by the non-OECD countries is "apparent consumption," which includes internal consumption, refinery fuel and loss, and bunkering.

\- = no data available

OECD = Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Chile, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Latvia, Lithuania, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, Slovakia, Slovenia, South Korea, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.

OPEC = Organization of the Petroleum Exporting Countries: Algeria, Angola, Congo (Brazzaville), Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, the United Arab Emirates, Venezuela.

Notes: EIA completed modeling and analysis for this report on September 1, 2022.

The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration international energy statistics.

Minor discrepancies with published historical data are due to independent rounding.

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 4a. U.S. Petroleum and Other Liquids Supply, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - September 2022

	2021				2022				2023				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2021	2022	2023
Supply (million barrels per day)															
Crude Oil Supply															
Domestic Production (a)	10.82	11.34	11.18	11.66	11.47	11.70	11.81	12.16	12.42	12.55	12.70	12.87	11.25	11.79	12.63
Alaska	0.46	0.44	0.41	0.44	0.45	0.44	0.44	0.45	0.44	0.40	0.43	0.44	0.44	0.44	0.43
Federal Gulf of Mexico (b)	1.83	1.80	1.49	1.71	1.67	1.72	1.75	1.82	1.87	1.84	1.75	1.73	1.71	1.74	1.80
Lower 48 States (excl GOM)	8.54	9.10	9.29	9.50	9.35	9.54	9.62	9.90	10.10	10.31	10.52	10.70	9.11	9.60	10.41
Crude Oil Net Imports (c)	2.88	2.94	3.64	3.13	3.00	2.81	2.74	3.13	3.14	3.28	3.19	2.62	3.15	2.92	3.06
SPR Net Withdrawals	0.00	0.18	0.04	0.26	0.31	0.80	0.87	0.41	0.04	0.09	0.03	0.11	0.12	0.60	0.07
Commercial Inventory Net Withdrawals	-0.19	0.60	0.30	-0.01	0.08	-0.03	-0.03	-0.10	-0.34	0.02	0.28	-0.07	0.18	-0.02	-0.03
Crude Oil Adjustment (d)	0.30	0.59	0.44	0.44	0.71	0.81	0.77	0.16	0.22	0.22	0.23	0.16	0.44	0.61	0.21
Total Crude Oil Input to Refineries	13.81	15.65	15.61	15.49	15.56	16.09	16.16	15.76	15.48	16.15	16.42	15.69	15.15	15.89	15.94
Other Supply															
Refinery Processing Gain	0.85	0.98	0.96	1.04	0.95	1.07	1.06	1.05	1.03	0.98	0.99	0.99	0.96	1.03	1.00
Natural Gas Plant Liquids Production	4.89	5.50	5.56	5.74	5.61	5.92	6.12	6.28	6.29	6.35	6.32	6.42	5.42	5.99	6.34
Renewables and Oxygenate Production (e)	1.04	1.13	1.11	1.24	1.19	1.20	1.19	1.24	1.21	1.22	1.22	1.27	1.13	1.21	1.23
Fuel Ethanol Production	0.90	0.99	0.96	1.06	1.02	1.01	1.01	1.02	1.00	1.00	0.99	1.02	0.98	1.01	1.00
Petroleum Products Adjustment (f)	0.20	0.22	0.22	0.23	0.22	0.23	0.22	0.22	0.21	0.22	0.22	0.22	0.22	0.22	0.22
Product Net Imports (c)	-2.79	-3.07	-3.19	-3.79	-3.74	-3.99	-4.00	-4.03	-4.15	-3.59	-3.97	-3.92	-3.21	-3.94	-3.91
Hydrocarbon Gas Liquids	-1.95	-2.25	-2.15	-2.18	-2.14	-2.31	-2.39	-2.51	-2.55	-2.58	-2.58	-2.60	-2.14	-2.34	-2.57
Unfinished Oils	0.18	0.30	0.25	0.10	0.09	0.25	0.38	0.22	0.18	0.25	0.37	0.21	0.21	0.24	0.26
Other HC/Oxygenates	-0.08	-0.04	-0.03	-0.05	-0.09	-0.10	-0.07	-0.05	-0.06	-0.04	-0.04	-0.04	-0.05	-0.08	-0.04
Motor Gasoline Blend Comp.	0.55	0.79	0.67	0.43	0.40	0.60	0.49	0.23	0.38	0.63	0.35	0.43	0.61	0.43	0.45
Finished Motor Gasoline	-0.64	-0.64	-0.68	-0.88	-0.76	-0.73	-0.68	-0.46	-0.60	-0.53	-0.64	-0.70	-0.71	-0.66	-0.62
Jet Fuel	0.03	0.08	0.08	0.01	-0.04	-0.06	-0.03	-0.04	-0.08	0.09	0.07	0.05	0.05	-0.04	0.03
Distillate Fuel Oil	-0.48	-0.87	-0.91	-0.86	-0.81	-1.15	-1.25	-1.01	-0.90	-1.09	-1.14	-1.02	-0.78	-1.05	-1.04
Residual Fuel Oil	0.07	0.05	0.08	0.15	0.14	0.10	0.09	0.14	0.04	0.08	0.04	0.14	0.09	0.12	0.07
Other Oils (g)	-0.48	-0.49	-0.50	-0.50	-0.54	-0.59	-0.53	-0.56	-0.56	-0.41	-0.41	-0.39	-0.49	-0.56	-0.44
Product Inventory Net Withdrawals	0.55	-0.27	0.03	0.58	0.42	-0.25	-0.43	0.29	0.32	-0.62	-0.30	0.35	0.22	0.01	-0.07
Total Supply	18.54	20.13	20.30	20.53	20.22	20.27	20.32	20.81	20.39	20.71	20.88	21.02	19.88	20.40	20.75
Consumption (million barrels per day)															
Hydrocarbon Gas Liquids	3.43	3.33	3.34	3.66	3.87	3.43	3.46	3.94	4.04	3.54	3.53	3.93	3.44	3.67	3.76
Other HC/Oxygenates	0.11	0.13	0.13	0.16	0.13	0.17	0.16	0.22	0.21	0.21	0.21	0.26	0.13	0.17	0.22
Unfinished Oils	0.08	0.07	-0.05	0.00	0.13	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.00
Motor Gasoline	8.04	9.09	9.14	8.98	8.47	9.00	8.88	8.95	8.59	9.09	9.13	8.96	8.82	8.83	8.94
Fuel Ethanol blended into Motor Gasoline	0.81	0.93	0.94	0.95	0.87	0.93	0.91	0.92	0.88	0.93	0.93	0.94	0.91	0.91	0.92
Jet Fuel	1.12	1.34	1.52	1.50	1.45	1.61	1.62	1.55	1.48	1.64	1.64	1.60	1.37	1.56	1.59
Distillate Fuel Oil	3.99	3.96	3.90	4.03	4.14	3.89	3.82	3.98	4.04	3.90	3.87	3.96	3.97	3.96	3.94
Residual Fuel Oil	0.26	0.25	0.35	0.40	0.38	0.31	0.34	0.34	0.31	0.31	0.32	0.34	0.31	0.34	0.32
Other Oils (g)	1.54	1.95	1.98	1.81	1.65	1.82	2.05	1.82	1.73	2.03	2.18	1.97	1.82	1.83	1.98
Total Consumption	18.58	20.13	20.30	20.54	20.22	20.27	20.32	20.81	20.39	20.71	20.88	21.02	19.89	20.40	20.75
Total Petroleum and Other Liquids Net Imports	0.09	-0.13	0.45	-0.65	-0.74	-1.18	-1.26	-0.90	-1.01	-0.31	-0.79	-1.30	-0.06	-1.02	-0.85
End-of-period Inventories (million barrels)															
Commercial Inventory															
Crude Oil (excluding SPR)	502.5	448.1	420.3	421.2	414.4	417.5	420.0	429.6	460.4	458.8	433.5	440.1	421.2	429.6	440.1
Hydrocarbon Gas Liquids	176.9	205.3	235.5	193.1	142.0	186.7	233.2	189.2	151.7	204.4	246.3	204.6	193.1	189.2	204.6
Unfinished Oils	92.5	92.3	89.5	79.7	87.9	88.8	88.6	82.6	92.1	89.5	89.0	82.2	79.7	82.6	82.2
Other HC/Oxygenates	29.3	27.7	25.7	28.7	34.1	29.4	29.8	30.1	32.1	30.9	30.7	31.0	28.7	30.1	31.0
Total Motor Gasoline	237.8	237.3	227.0	232.2	238.5	221.0	216.3	234.1	233.3	236.1	224.0	238.4	232.2	234.1	238.4
Finished Motor Gasoline	20.3	18.5	18.5	17.8	17.3	17.1	19.7	24.0	21.3	22.9	23.7	26.4	17.8	24.0	26.4
Motor Gasoline Blend Comp.	217.6	218.7	208.5	214.4	221.2	203.8	196.5	210.1	212.0	213.2	200.4	212.0	214.4	210.1	212.0
Jet Fuel	39.1	44.7	42.0	35.8	35.6	39.3	40.1	37.5	37.4	38.6	41.3	38.2	35.8	37.5	38.2
Distillate Fuel Oil	146.1	140.1	132.1	130.0	114.6	111.4	114.1	118.4	108.1	113.3	120.2	122.4	130.0	118.4	122.4
Residual Fuel Oil	30.9	31.5	27.8	25.8	27.9	29.2	28.6	30.5	30.3	31.2	29.8	31.2	25.8	30.5	31.2
Other Oils (g)	55.8	54.3	51.0	52.2	58.5	56.4	51.1	52.5	61.5	59.3	49.9	51.3	52.2	52.5	51.3
Total Commercial Inventory	1310.9	1281.4	1250.9	1198.6	1153.6	1179.7	1221.8	1204.5	1206.9	1262.1	1264.7	1239.3	1198.6	1204.5	1239.3
Crude Oil in SPR	637.8	621.3	617.8	593.7	566.1	493.3	413.2	375.4	371.6	363.8	361.2	350.7	593.7	375.4	350.7

(a) Includes lease condensate.

(b) Crude oil production from U.S. Federal leases in the Gulf of Mexico (GOM).

(c) Net imports equals gross imports minus gross exports.

(d) Crude oil adjustment balances supply and consumption and was previously referred to as "Unaccounted for Crude Oil."

(e) Renewables and oxygenate production includes pentanes plus, oxygenates (excluding fuel ethanol), and renewable fuels. Beginning in January 2021, renewable fuels includes biodiesel, renewable diesel, renewable jet fuel, renewable heating oil, renewable naphtha and gasoline, and other renewable fuels. For December 2020 and prior, renewable fuels includes only biodiesel.

(f) Petroleum products adjustment includes hydrogen/oxygenates/renewables/other hydrocarbons, motor gasoline blend components, and finished motor gasoline.

(g) “Other Oils" includes aviation gasoline blend components, finished aviation gasoline, kerosene, petrochemical feedstocks, special naphthas, lubricants, waxes, petroleum coke, asphalt and road oil, still gas, and miscellaneous products.

\- = no data available

SPR: Strategic Petroleum Reserve

HC: Hydrocarbons

Notes: EIA completed modeling and analysis for this report on September 1, 2022.

The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Petroleum Supply Monthly* , DOE/EIA-0109; *Petroleum Supply Annual* , DOE/EIA-0340/2; and *Weekly Petroleum Status Report* , DOE/EIA-0208.

Minor discrepancies with published historical data are due to independent rounding.

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 5a. U.S. Natural Gas Supply, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - September 2022

	2021				2022				2023				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2021	2022	2023
Supply (billion cubic feet per day)															
Total Marketed Production	**97.65**	**101.12**	**101.89**	**104.86**	**102.77**	**105.47**	*106.52*	*107.76*	*108.38*	*109.35*	*109.44*	*109.54*	**101.40**	*105.65*	*109.18*
Alaska	**1.02**	**0.95**	**0.90**	**1.02**	**1.06**	**1.00**	*0.88*	*0.99*	*1.00*	*0.92*	*0.84*	*0.98*	**0.97**	*0.98*	*0.94*
Federal GOM (a)	**2.26**	**2.25**	**1.82**	**2.11**	**2.04**	**2.10**	*2.21*	*2.17*	*2.19*	*2.11*	*1.97*	*1.90*	**2.11**	*2.13*	*2.04*
Lower 48 States (excl GOM)	**94.37**	**97.92**	**99.17**	**101.73**	**99.67**	**102.37**	*103.43*	*104.60*	*105.19*	*106.33*	*106.63*	*106.66*	**98.32**	*102.53*	*106.21*
Total Dry Gas Production	**90.59**	**93.15**	**93.86**	**96.52**	**94.60**	**96.87**	*97.85*	*98.99*	*99.65*	*100.51*	*100.59*	*100.67*	**93.55**	*97.09*	*100.36*
LNG Gross Imports	**0.15**	**0.02**	**0.03**	**0.04**	**0.15**	**0.01**	*0.04*	*0.06*	*0.10*	*0.04*	*0.04*	*0.06*	**0.06**	*0.06*	*0.06*
LNG Gross Exports	**9.27**	**9.81**	**9.60**	**10.32**	**11.50**	**10.80**	*10.01*	*11.75*	*12.47*	*12.53*	*12.10*	*12.28*	**9.76**	*11.01*	*12.34*
Pipeline Gross Imports	**8.68**	**6.81**	**7.24**	**7.82**	**8.92**	**7.79**	*7.32*	*7.49*	*8.26*	*6.85*	*7.04*	*7.46*	**7.63**	*7.88*	*7.40*
Pipeline Gross Exports	**8.31**	**8.66**	**8.50**	**8.40**	**8.43**	**8.44**	*8.78*	*9.24*	*9.65*	*9.10*	*9.44*	*9.75*	**8.47**	*8.72*	*9.49*
Supplemental Gaseous Fuels	**0.17**	**0.15**	**0.15**	**0.17**	**0.19**	**0.13**	*0.16*	*0.17*	*0.17*	*0.17*	*0.17*	*0.17*	**0.16**	*0.16*	*0.17*
Net Inventory Withdrawals	**17.18**	**-9.12**	**-7.87**	**1.03**	**20.14**	**-10.23**	*-8.50*	*2.75*	*14.32*	*-12.84*	*-8.94*	*3.96*	**0.24**	*0.97*	*-0.93*
Total Supply	**99.18**	**72.53**	**75.31**	**86.86**	**104.07**	**75.33**	*78.08*	*88.48*	*100.37*	*73.09*	*77.35*	*90.29*	**83.42**	*86.43*	*85.23*
Balancing Item (b)	**0.26**	**-0.58**	**-0.21**	**-1.23**	**0.24**	**0.43**	*-0.25*	*0.11*	*0.33*	*-1.33*	*-1.24*	*-0.13*	**-0.45**	*0.13*	*-0.60*
Total Primary Supply	**99.44**	**71.95**	**75.10**	**85.62**	**104.30**	**75.77**	*77.83*	*88.59*	*100.70*	*71.76*	*76.11*	*90.16*	**82.97**	*86.56*	*84.63*
Consumption (billion cubic feet per day)															
Residential	**25.67**	**7.50**	**3.62**	**14.43**	**26.09**	**7.87**	*4.05*	*16.76*	*25.54*	*7.92*	*4.29*	*16.94*	**12.75**	*13.64*	*13.62*
Commercial	**14.87**	**6.23**	**4.68**	**10.08**	**15.62**	**6.72**	*5.04*	*11.46*	*15.23*	*6.75*	*5.22*	*11.66*	**8.94**	*9.69*	*9.69*
Industrial	**23.81**	**21.46**	**21.14**	**23.44**	**25.23**	**22.15**	*21.19*	*22.90*	*22.16*	*20.41*	*21.12*	*23.96*	**22.46**	*22.86*	*21.91*
Electric Power (c)	**26.79**	**29.20**	**37.94**	**29.47**	**28.65**	**31.12**	*39.52*	*29.00*	*28.84*	*28.71*	*37.36*	*28.98*	**30.88**	*32.09*	*30.99*
Lease and Plant Fuel	**4.87**	**5.04**	**5.08**	**5.23**	**5.12**	**5.26**	*5.31*	*5.37*	*5.40*	*5.45*	*5.46*	*5.46*	**5.05**	*5.27*	*5.44*
Pipeline and Distribution Use	**3.29**	**2.38**	**2.48**	**2.83**	**3.45**	**2.50**	*2.57*	*2.96*	*3.38*	*2.37*	*2.52*	*3.01*	**2.74**	*2.87*	*2.82*
Vehicle Use	**0.15**	**0.15**	**0.15**	**0.15**	**0.15**	**0.15**	*0.15*	*0.15*	*0.15*	*0.15*	*0.15*	*0.15*	**0.15**	*0.15*	*0.15*
Total Consumption	**99.44**	**71.95**	**75.10**	**85.62**	**104.30**	**75.77**	*77.83*	*88.59*	*100.70*	*71.76*	*76.11*	*90.16*	**82.97**	*86.56*	*84.63*
End-of-period Inventories (billion cubic feet)															
Working Gas Inventory	**1,801**	**2,585**	**3,306**	**3,210**	**1,401**	**2,324**	*3,106*	*2,853*	*1,564*	*2,732*	*3,555*	*3,190*	**3,210**	*2,853*	*3,190*
East Region (d)	**313**	**515**	**804**	**766**	**242**	**479**	*752*	*649*	*252*	*598*	*895*	*760*	**766**	*649*	*760*
Midwest Region (d)	**395**	**630**	**966**	**887**	**296**	**558**	*912*	*804*	*352*	*667*	*1,008*	*857*	**887**	*804*	*857*
South Central Region (d)	**760**	**993**	**1,053**	**1,143**	**587**	**889**	*987*	*999*	*711*	*1,056*	*1,132*	*1,101*	**1,143**	*999*	*1,101*
Mountain Region (d)	**113**	**175**	**205**	**171**	**90**	**137**	*170*	*146*	*80*	*130*	*198*	*180*	**171**	*146*	*180*
Pacific Region (d)	**197**	**246**	**248**	**218**	**165**	**239**	*258*	*228*	*142*	*255*	*295*	*265*	**218**	*228*	*265*
Alaska	**23**	**27**	**30**	**25**	**21**	**24**	*27*	*27*	*27*	*27*	*27*	*27*	**25**	*27*	*27*

(a) Marketed production from U.S. Federal leases in the Gulf of Mexico.

(b) The balancing item represents the difference between the sum of the components of natural gas supply and the sum of components of natural gas demand.

(c) Natural gas used for electricity generation and (a limited amount of) useful thermal output by electric utilities and independent power producers.

(d) For a list of States in each inventory region refer to *Weekly Natural Gas Storage Report, Notes and Definitions (http://ir.eia.gov/ngs/notes.html)* .

- = no data available

LNG: liquefied natural gas.

Notes: EIA completed modeling and analysis for this report on September 1, 2022.

The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Natural Gas Monthly* , DOE/EIA-0130; and *Electric Power Monthly* ,

Minor discrepancies with published historical data are due to independent rounding.

Forecasts: EIA Short-Term Integrated Forecasting System.

EPA Denies Cheniere Energy Request for LNG Pollution Waiver
2022-09-06 23:36:27.275 GMT

By MATTHEW DALY
Washington (AP) -- The Environmental Protection Agency on Tuesday denied a request by Cheniere Energy, a leading U.S. producer of liquefied natural gas, to exempt two Gulf Coast plants from a federal air pollution rule.

An EPA spokesman says the agency on Tuesday denied Cheniere's request to waive a rule that limits emissions of cancer-causing formaldehyde released by gas-fired turbines. Dozens of turbine operators faced a Monday deadline to comply with the formaldehyde rule, which is being reinstated after an 18-year stay.

"Controlling emissions of formaldehyde is important to protect public health. Though EPA is denying Cheniere's request for a special subcategory to comply with the turbines rule, the agency will continue to work with them and with other companies as needed to assure they meet Clean Air Act obligations,'' EPA spokesman Tim Carroll said in an e-mail Tuesday.

Cheniere, the largest LNG exporter in the U.S., had warned that new requirements on LNG plants in Texas and Louisiana could disrupt gas supplies to Europe, which has struggled with surging energy prices following Russia's invasion of Ukraine.

In a statement Tuesday, Cheniere said it strongly disagrees with EPA's decision but will work with state and federal regulators to "develop solutions that ensure compliance'' with the hazardous-pollution rule.

"Our conviction remains that these emissions do not pose a risk to public health, our workforce or the environment,'' company spokesman Eben Burnham-Snyder said in an email. "Although this decision may result in unwarranted expenditures, we believe that the steps needed to come into full compliance will not result in a material financial or operational impact. and that we will be able to continue to reliably supply LNG to customers and countries around the world."

Environmental activists said Cheniere was using the global gas shortage — and spiking prices in Europe — to try to avoid meeting EPA rules that many consider lax.

"Because it's costly, Cheniere is asking for exemptions to EPA rules so they can continue to release cancer-causing pollutants into our communities — the same poor neighborhoods President (Joe) Biden has vowed to protect," said James Hiatt of the Louisiana Bucket Brigade, an activist group that has worked with communities near oil refineries, chemical plants and other manufacturers to fight pollution.

Petrochemical plants, pipeline operators and other manufacturers will have to prove they've complied with EPA limits on formaldehyde under the National Emission Standards for Hazardous Air Pollutants, a 2004 rule that is being reinstated after an 18-year stay.

-0- Sep/06/2022 23:36 GMT To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/RHTAWRTP3SHS

https://www.bcogc.ca/news/peace-and-liard-watersheds-join-nicola-basin-in-suspension-of-water-diversions-dir-2022-02/

Peace and Liard Watersheds Join Nicola Basin in Suspension of Water Diversions (DIR 2022-02)

Due to continuing drought conditions, the suspension of water diversions has been expanded to some basins within the Peace River and Liard River watersheds

DATE ISSUED: Sept. 7, 2022

EFFECTIVE DATE: Immediately

The BC Oil and Gas Commission (Commission) is requiring the oil and gas industry to immediately suspend all previously approved water diversions under Section 10 of the Water Sustainability Act, due to drought conditions. This includes rivers, streams and lakes in the following basins within the Peace River and Liard River watersheds:

Peace River Watershed:

- Sukunka River
- Kiskatinaw River
- Beatton River (Doig River, Osborne River, Blueberry River)

Conditions are being closely monitored in the Halfway and Graham Rivers over the coming weeks for possible inclusion into this suspension.

Liard River Watershed:

- Tributaries to the Muskwa River, Fort Nelson River, and Sikanni Chief River (but does not include the Muskwa, Fort Nelson, and Sikanni Chief Rivers)

Diversion and use of water stored in dugouts or dams is not suspended and the suspension does not apply to the main channel of the Peace River or Dinosaur Lake. More information can be found on the B.C. Government Drought Information page.

Low stream flow conditions are escalating concerns for impacts to fish, aquatic resources and community supply in the above basins. Water levels are anticipated to continue dropping until significant rain falls in the area. The Commission will assist industry in identifying options for alternative short-term water supply should it be required during this period.

Applications for water diversion:

Given local variability, it is possible some streams in the areas under suspension will have recovered sufficiently to allow some water withdrawal. The Commission will review new applications for diversion, or requests to use existing approvals, on a site-specific basis.

Operators are requested to do the following to support their application or request to use an existing Section 10 approval:

1. Limit the application to water volumes and points of diversion that are realistic to the specific operational needs for the upcoming months.
2. For new applications for diversion for water from rivers and streams, or to request use of existing approvals, provide a good discharge measurement at the point(s) of diversion, to provide information on current flow conditions in relation to the volume of water requested. The discharge measurement will be collected to an acceptable hydrometric standard by a qualified individual.
3. For new applications for diversion from lakes, or reactivation of existing approvals, provide information on lake bathymetry:
    a. Surface area (hectares).
    b. Depth (metres). If lake depth information is not already available from provincial databases or previous surveys, obtain depth measurements at points along two transects representing the long and short lake axes, to determine maximum lake depth.
    c. Volume.

Requests for continued water use under an existing Section 10 approval can be submitted, with required documentation, via email to Ryan.Rolick@bcogc.ca

If you have any questions regarding this Directive, please contact:

Ryan Rolick, M.Sc., GIT

https://www.bcogc.ca/news/suspension-of-water-diversions-in-nicola-basin/

Suspension of Water Diversions in Nicola Basin (DIR 2022-01)

The oil and gas industry is required to immediately suspend all previously approved water diversion under Section 10 of the Water Sustainability Act within rivers, streams, and lakes in the Nicola Basin due to drought conditions.

DATE ISSUED: Aug. 31, 2022

EFFECTIVE DATE: Immediately

The BC Oil and Gas Commission (Commission) is requiring the oil and gas industry to immediately suspend all previously approved water diversion under Section 10 of the *Water Sustainability Act* within rivers, streams and lakes in the Nicola Basin, due to drought conditions. More information can be found on the B.C. Government Drought Information page and Drought Information portal.

Low stream flow conditions are escalating concerns for impacts to fish, aquatic resources, and community supply in the above basin. Water levels are anticipated to continue dropping until significant rain falls in the area. The Commission will assist industry in identifying options for alternative short-term water supply should it be required during this period.

Basins in other regions of B.C. are being monitored and further suspensions of water diversions are possible if drought conditions persist in coming weeks.

Applications for water diversion:

Given local variability, it is possible some streams in the areas under suspension will have recovered sufficiently to allow some water withdrawal. The Commission will review new applications for diversion, or requests to use existing approvals, on a site-specific basis.

Operators are requested to do the following to support their application or request to use an existing Section 10 approval:

1. Limit the application to water volumes and points of diversion that are realistic to the specific operational needs for the upcoming months.
2. For new applications for diversion for water from rivers and streams, or to request use of existing approvals, provide a good discharge measurement at the point(s) of diversion, to provide information on current flow conditions in relation to the volume of water requested. The discharge measurement will be collected to an acceptable hydrometric standard by a qualified individual.
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    a. Surface area (hectares).
    b. Depth (metres). If lake depth information is not already available from provincial databases or previous surveys, obtain depth measurements at points along two transects representing the long and short lake axes, to determine maximum lake depth.
    c. Volume.

Requests for continued water use under an existing Section 10 approval can be submitted, with required documentation, via email to Ryan.Rolick@bcogc.ca.

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Media Release

Monday, 5 September 2022

COMMONWEALTH LNG SIGNS AGREEMENTS WITH WOODSIDE

[HOUSTON, TX] Sept. 5, 2022 – Commonwealth LNG, a subsidiary of Commonwealth Projects (Commonwealth), and Woodside Energy Trading Singapore Pte Ltd, a subsidiary of Woodside Energy Group Ltd (Woodside), are pleased to announce the conversion of their non-binding heads of agreement (HOA) into two binding LNG Sale and Purchase Agreements (SPAs), signed 2 September 2022.

The SPAs are for the supply of up to 2.5 million tonnes per annum (Mtpa) of LNG over 20 years from Commonwealth's LNG export facility under development in Cameron Parish, Louisiana. Key terms in the HOA previously announced on 19 January 2022 remain unchanged in the binding SPAs, with first deliveries expected to commence in mid-2026. The SPAs will become fully effective upon the satisfaction of customary conditions including an affirmative final investment decision on the project.

"We're very pleased to have Woodside involved in our project," said Commonwealth Executive Chairman Paul Varello. "Woodside is known throughout the LNG industry for its keen technical capabilities and commercial agility. These SPAs establish Woodside as a cornerstone customer and mark a major milestone in the development of Commonwealth LNG."

Commonwealth President and CEO Farhad Ahrabi added: "Our modular construction approach allows Commonwealth LNG to provide greater cost and schedule certainty to customers as we deliver affordable, reliable, cleaner energy to meet global demands. We're proud to have an international LNG customer of Woodside's stature recognize these advantages and show this level of commitment."

Woodside CEO Meg O'Neill said the agreements provided the basis for a long-term partnership with Commonwealth LNG.

"The agreements secure for Woodside low-cost LNG volumes in the Atlantic Basin in a period of expected strong demand as Europe seeks alternatives to Russian pipeline gas," she said.

Attachment: Woodside and Commonwealth LNG sign HOA for LNG supply - 19 January 2022

About Commonwealth LNG
Commonwealth LNG is an 8.4 Mtpa liquefied natural gas (LNG) export terminal project located on the Calcasieu River at the Gulf of Mexico near Cameron, Louisiana. The project's leadership team is committed to building a world-class LNG facility by staying relentlessly focused on managing risk and lowering capital cost.
Website: www.CommonwealthLNG.com
LinkedIn:www.linkedin.com/company/commonwealth-lng/

About Woodside Energy
Woodside is a global energy company, proudly Australian with a spirit of innovation and determination. Woodside provides energy that the world needs to heat homes, keep lights on and support industry. The company aims to thrive through the global energy transition with a low-cost, lower-carbon, profitable, resilient and diversified portfolio.
Website: www.woodside.com

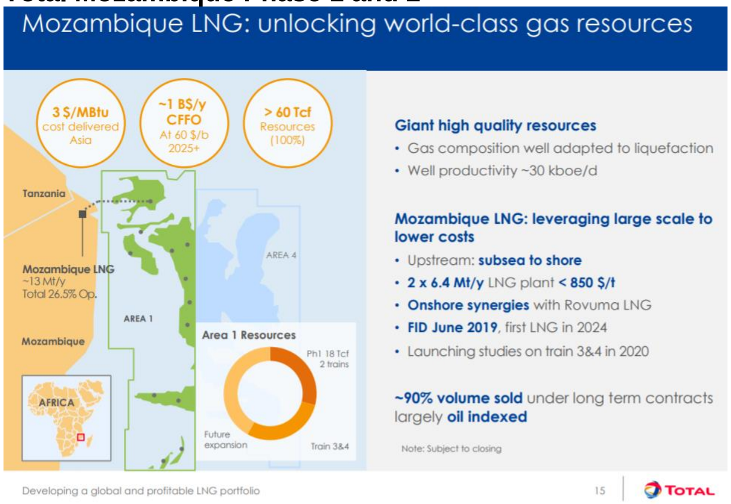
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

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



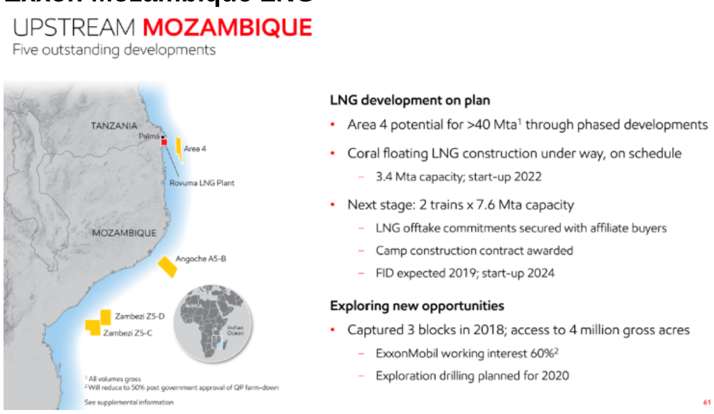
Source: Total Investor Day September 24, 2019

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

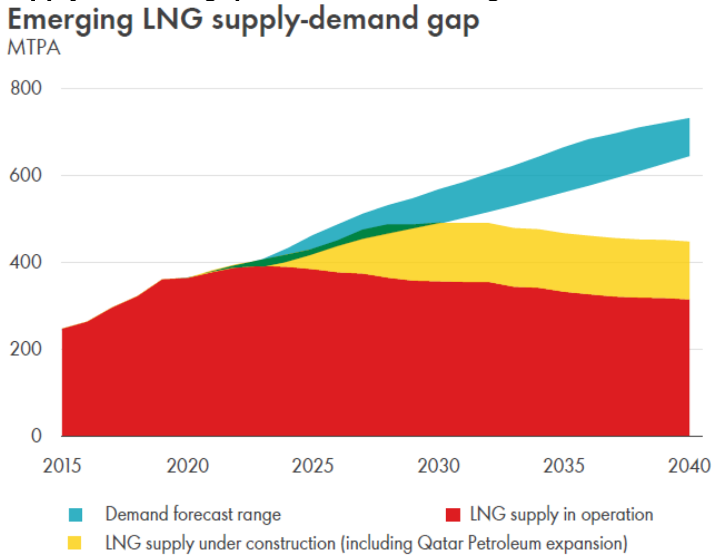
🟢 On Track 🟡 More Efforts Needed 🔴 Not on Track

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.

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? 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

A LNG Canada Phase 2 would be a big plus to Cdn natural gas. 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.*

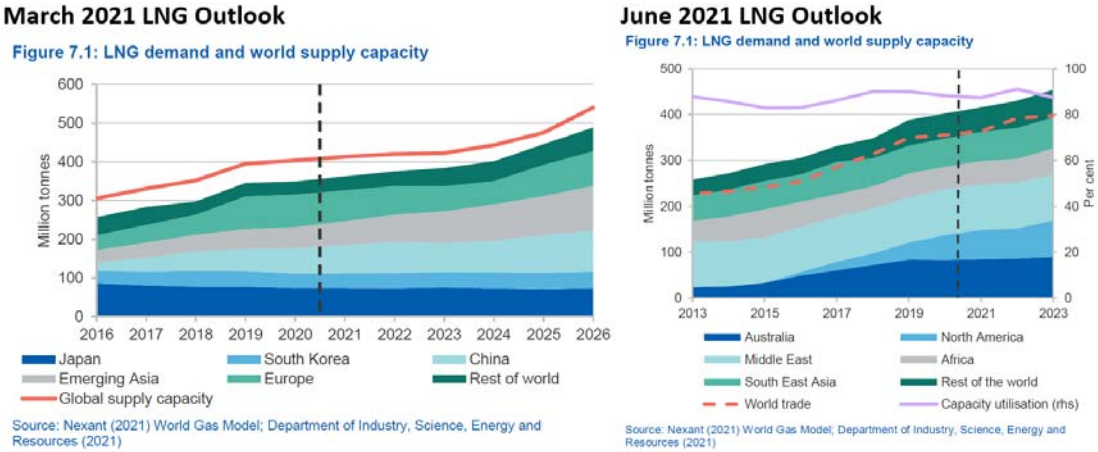
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required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

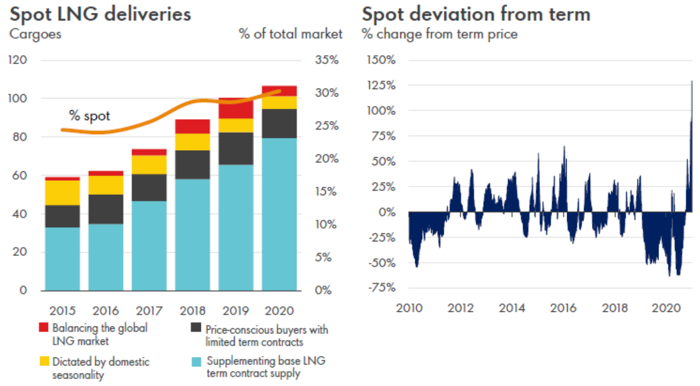


Source: Australia Resources and Energy Quarterly

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

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

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

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

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

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

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

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

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

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

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

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

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

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

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

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

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

https://www.energyintel.com/00000182-e464-d92d-a5b7-ecfcff270000

Technical Issues Could Delay Coral South Start-Up

Published:
Sun, Aug 28, 2022
Author
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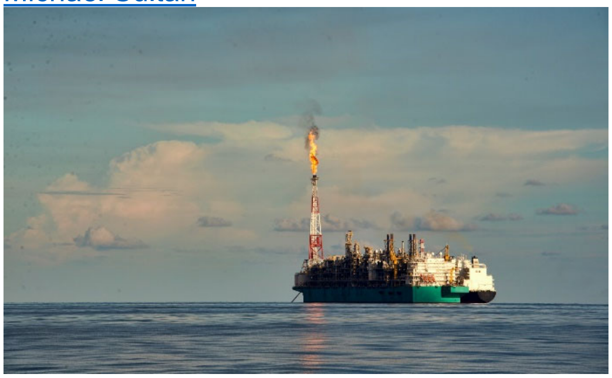


Mozambique's Coral South floating LNG plant is understood to have suffered technical issues, which could delay the start-up of the project, potentially further squeezing an already tight global LNG market.

"Serious issues [were] reported at Coral FLNG with one critical distillation column (demethanizer) suspected of having internal damage. Shutdown is required for inspection and repair, which will delay the start-up schedule by several days, if not weeks," a source told Energy Intelligence.

The 3.4 million ton/yr project, located in Area 4 of the Rovuma basin offshore Mozambique, is operated by Italian major Eni, with partners ExxonMobil, China's CNPC, Galp, Kogas and Mozambique's state-controlled ENH.

It is the only export project in the East African country which was expected to come online on time, with the onshore Mozambique LNG and Rovuma LNG projects facing multi-year delays due to security issues in the region.

Vessel Diversion

A recent vessel diversion from the Coral South FLNG plant is in line with the reported technical issues at the facility.

UK major BP's 173,400 cubic meter *British Mentor* LNG vessel had been broadcasting the Coral South FLNG as its destination since Aug. 7, according to ship-tracking data by Kpler, indicating that the project could load its first cargo sooner than previously expected.

BP has exclusive offtake rights for the entire output of the facility through a 20-year contract.

However, after arriving in proximity to the plant, on Aug. 26 the vessel switched its signal to Oman's Qalhat plant and left Mozambican waters. It is now heading north in the Indian Ocean, according to Kpler.

Eni earlier this month proposed a second FLNG project for Mozambique, signaling that that offshore route is going to increasingly become the path forward for LNG in Mozambique.

Technical issues with the first floating liquefaction off Mozambique cannot help but slow down future floating liquefaction.

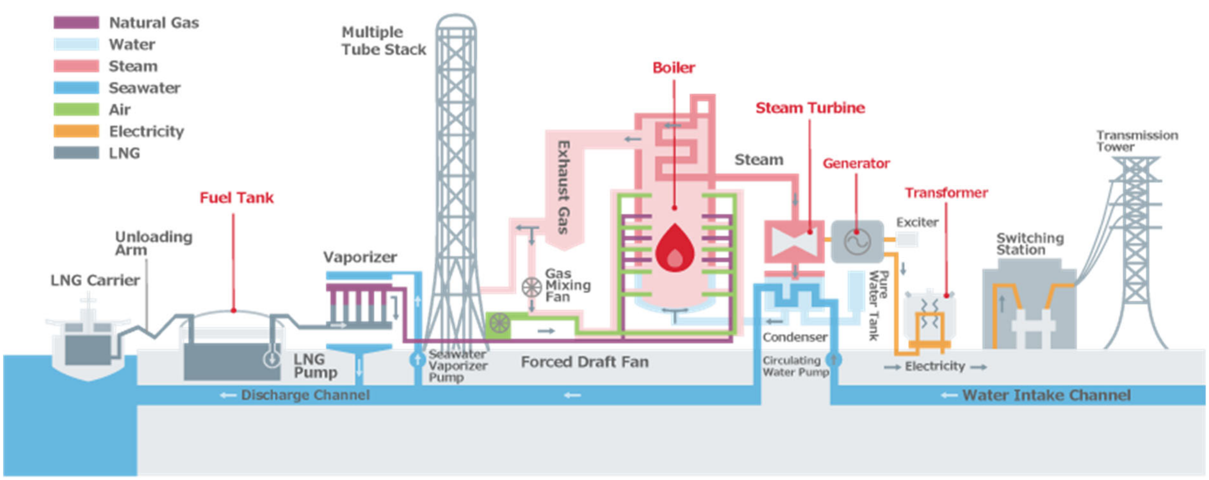
https://www.jera.co.jp/english/business/thermal-power/type/

Types and Mechanism of Thermal Power Generation

Thermal power generation is the process of obtaining thermal energy by burning fuels such as LNG etc., to convert into electric energy by using power- generating facilities.

Steam Power Generation

Steam power generation is a power generation method utilizing the expansion power of steam. Hot and high-pressure steam is generated from heat by burning heavy crude oil, LNG (liquefied natural gas), coal, etc. This steam is used to rotate the impeller in a turbine and activates a generator connected to the turbine to generate electricity. Steam power generation uses thermal energy with a relatively low temperature (600°C or lower).

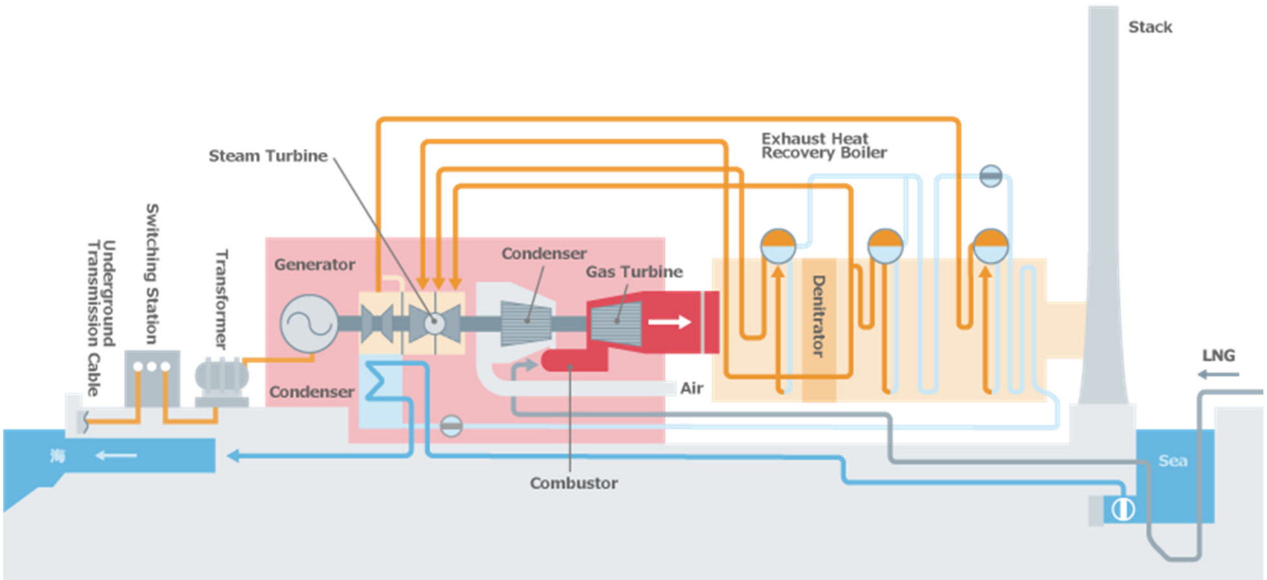


Power Stations Using Steam Power Generation

Hirono Thermal Power Station >	Hitachinaka Thermal Power Station >	Kashima Thermal Power Station >
Anegasaki Thermal Power Station >	Sodegaura Thermal Power Station >	Minami-Yokohama Thermal Power Station >
Yokohama Thermal Power Station >	Higashi-Ohgishima Thermal Power Station >	Oi Thermal Power Station >
Atsumi Thermal Power Station >	Hekinan Thermal Power Station >	Chita Thermal Power Station >
Kawagoe Thermal Power Station >	Yokkaichi Thermal Power Station >	

Combined Cycle Power Generation

Combined cycle power generation is a power-generation method combining a gas turbine and a steam turbine. High thermal efficiency can be achieved by combining two methods of power generation: gas turbine power generation from rotating a generator utilizing expansion power by generating combustion gas via burning fuels in the compressed air, and steam power generation from rotating a steam turbine collecting the residual heat of the exhaust gas. In addition, as combined cycle power generation comprises small gas turbines and steam turbines, operation /stoppage can be immediately switched and can be operated in response to changes in demand.

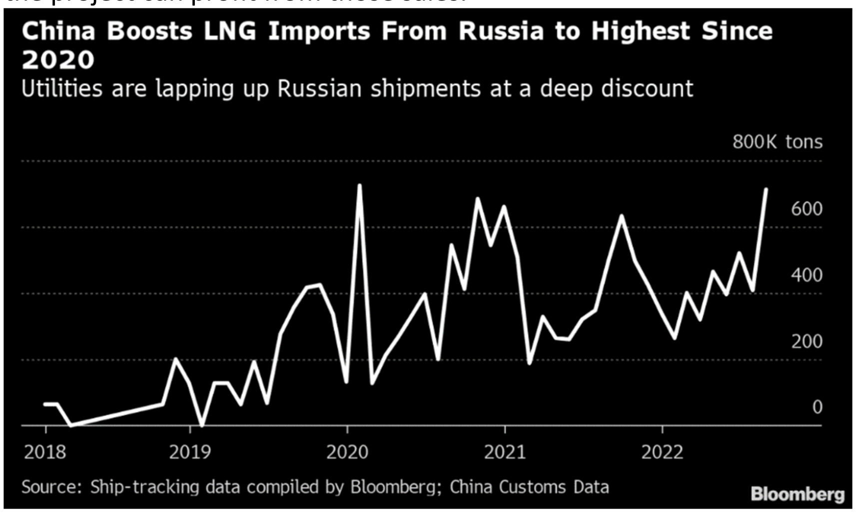


Power Stations Using Combined Cycle Power Generation

- Joetsu Thermal Power Station
- Kashima Thermal Power Station
- Chiba Thermal Power Station
- Futtsu Thermal Power Station
- Yokohama Thermal Power Station
- Kawasaki Thermal Power Station
- Shinagawa Thermal Power Station
- Chita Thermal Power Station
- Chita Daini Thermal Power Station
- Shin-Nagoya Thermal Power Station
- Nishi-Nagoya Thermal Power Station
- Kawagoe Thermal Power Station

China Snaps Up Half-Price Russian LNG as Europe Shuns Supplies
2022-09-08 03:14:37.679 GMT

By Stephen Stapczynski
(Bloomberg) -- China is lapping up liquefied natural gas shipments from Russia on the cheap.
The Sakhalin-2 LNG export plant in Russia's Far East sold several shipments to China for delivery through December at nearly half the current spot price in a tender that closed earlier this week, according to traders with knowledge of the matter. Still, global rates have soared so much this year that the project can profit from those sales.



The move is beneficial for both countries -- China is able to secure cheaper supply and resell shipments from more expensive exporters to utilities in Europe and Asia, while Russia can continue selling fuel at a profit. Japan and South Korea, traditionally the top destinations for Sakhalin LNG, have stopped buying spot shipments from the plant since Russia invaded Ukraine in February.
Read more: China's Checks on Gas Stockpiles Risk Triggering Push to Buy LNG
"Russian supply is still making its way into the market, just with a reorganization of trade flows via market participants who don't take issue with accepting Russian cargoes," said Saul Kavonic, an energy analyst at Credit Suisse. "It appears China is happy to take Russian LNG cargoes at discounts, swapping out alternative supply that can then be directed to Europe at higher prices."
China's LNG imports from Russia surged to the highest level in at least two years in August, according to ship-tracking data compiled by Bloomberg. Meanwhile, deliveries from the US have slumped as Chinese importers divert cargoes to Europe at a hefty profit.
The operator of Sakhalin-2 is primarily owned by Gazprom PJSC, and was recently redomiciled to Russia after a decree by President Vladimir Putin. The move forced Shell Plc to abandon its 27.5% stake in the project for nothing.
To contact the reporter on this story: Stephen Stapczynski in Singapore at sstapczynsk1@bloomberg.net

https://www.kommersant.ru/doc/5546868 09/05/2022, 00:41

Winter is declared

Key gas supply route to EU shut down

On the eve of the heating season, Gazprom finally stopped gas supplies via the Nord Stream pipeline, citing a malfunction of the last operating turbine at the Portovaya compressor station. Kommersant's sources do not expect deliveries to be resumed in the foreseeable future. This means a probable new surge in gas prices in Europe, and for Gazprom itself, a further decline in production.

On September 2, Gazprom announced a complete shutdown of the Nord Stream gas pipeline due to malfunctions in the operation of the Siemens Energy Trent 60 turbine identified during maintenance, which, according to the monopoly, create risks of explosion or fire. This is the last turbine operating at the Portovaya compressor station, which Gazprom sent for maintenance from August 31 to September 2. It was assumed that on September 3, deliveries to Europe will resume.

“During maintenance work on the Trent 60 gas compressor unit (GPA No. 24) of the Portovaya compressor station, carried out jointly with representatives of Siemens, an oil leak with an admixture of a sealing compound was detected at the connectors of the terminal connections of the cable lines of the low and intermediate pressure rotor speed sensors,”— the company said in a statement.

> **Gazprom claims that, according to Siemens, the complete elimination of oil leakage is possible only in the conditions of a specialized repair company.**

Siemens Energy responded by saying that the oil leak was not a technical reason for shutting down the turbine. “Such leaks usually do not affect the operation of the turbine and can be repaired on site. This is a normal maintenance procedure,” the company explained.

In the past, the occurrence of such leaks has also not led to a shutdown of work, stressed Siemens Energy, adding: “Regardless of this, we have repeatedly noted that there are a sufficient number of other turbines at the Portovaya compressor station for the operation of Nord Stream.”

> **According to Kommersant, Siemens Energy and Gazprom do not have a contract for unscheduled maintenance of engines; Portovaya employs resident engineers of the company who carry out technical supervision.**

One of these engineers was present when the machine was inspected. Overhaul of gas turbines should be carried out after 25 thousand hours of operation, subsequently its work is extended for the same period. According to Kommersant's sources, the running time of the stopped Trent 60 turbine at Portovaya is 33.4 thousand hours, thus, after the overhaul, the machine worked 8.9 thousand hours - only a third of the period of overhaul operation.

Now Russian gas supplies to Western Europe will continue only through the territory of Ukraine (through the Sudzha gas smeasuring station in the amount of just over 40 million cubic meters per day). Greece, Hungary, as well as non-EU Serbia, are now supplied through the Turkish Stream. According to Kommersant's sources, supplies via Nord Stream can be resumed only if sanctions are lifted, which is possible only if a more general political settlement is reached.

Gas prices in Europe have been declining in the last week, but the market was counting on the return of supplies via Nord Stream after an unscheduled repair. Energy Aspects gas analyst Leon Izbicki told Reuters he expects gas prices to rise significantly at the September 5 open.

> **For Gazprom, the cessation of supplies means a reduction in production by another 4 billion cubic meters by the end of the year, which will mainly come from the Bovanenkovskoye field in Yamal.**

In eight months, Gazprom's production has already fallen by 14.8%, to 288 billion cubic meters, but in the summer it was supported by the filling of UGS facilities in Russia, which is already almost completed, while usually pumping into storage continues until October.

How problematic the decline in production will be for the monopoly, however, is still unclear. Independent expert Alexander Sobko notes that in 2008-2009, Gazprom's production fell by 88 billion cubic meters, which did not prevent it from recovering later.

Tatyana Dyatel

https://twitter.com/GazpromEN/status/1567091085507166208/photo/1

On non-compliance of GCU No. 24 at Portovaya CS with mandatory industrial safety requirements under Russian legislation

On September 2, 2022, Rostekhnadzor of Russia issued to Gazprom a Warning on the inadmissibili of violating mandatory requirements and the need for the adoption of appropriate measures and suspension of the operation of the Trent 60 gas compressor unit (GCU No. 24) at the Portovaya CS due to a detected leakage of oil with a sealing compound along the terminal connections at the low-pressure and intermediate-pressure rotor speed sensors.

Unless the detected faults are eliminated, further operation of the gas compressor unit creates a risk of fire or explosion, thereby affecting the industrial safety of the entire station.

The oil leakage failed to be detected during the scheduled maintenance works that took place at GCU No. 24 in July 2022, as evidenced by the report signed by the Siemens representatives who performed the service works at the facility.

It should be noted that the working surfaces in the axial compressor of the gas turbine engine in the locations of the cable connections can heat up to temperatures above 300 °C while the fire point of oil is approximately 288 °C.

1/2

A similar leakage that was identified earlier at GCU No. 14 (engine No. 120) progressed and was more expansive. The fact that this fault has been detected on several units indicates that the problem is systemic. By resolution of Rostekhnadzor of Russia dated July 13, 2022, on the temporary ban against the operation of engine No. 120, GCU No. 14 was taken out of operation and put into forced downtime.

According to a letter from Siemens, the oil leakages cannot be fully eliminated unless repairs take place at a specialized repair facility.

The Portovaya CS is a hazardous production facility. In line with Article 9 of Federal Law No. 116-FZ "On Industrial Safety of Hazardous Production Facilities" dated July 21, 1997, an entity is obligated to "suspend the operation of a hazardous production facility... in case of newly discovered factors affecting industrial safety."

According to Item 13 of the Federal Rules and Regulations for Industrial Safety "Safety Rules for Hazardous Industrial Facilities of Gas Trunklines" approved by Order of Rostekhnadzor No. 517 dated December 11, 2020, operators must comply with the requirements on "providing explosion safety" at the facility. This refers to "prevention of explosions and fires at process equipment; preclusion of explosions and fires within industrial buildings, structures and outdoor facilities."

Therefore, further operation of GCU No. 24 with the faults described above will be in direct conflict with Russian legislation.

2/2

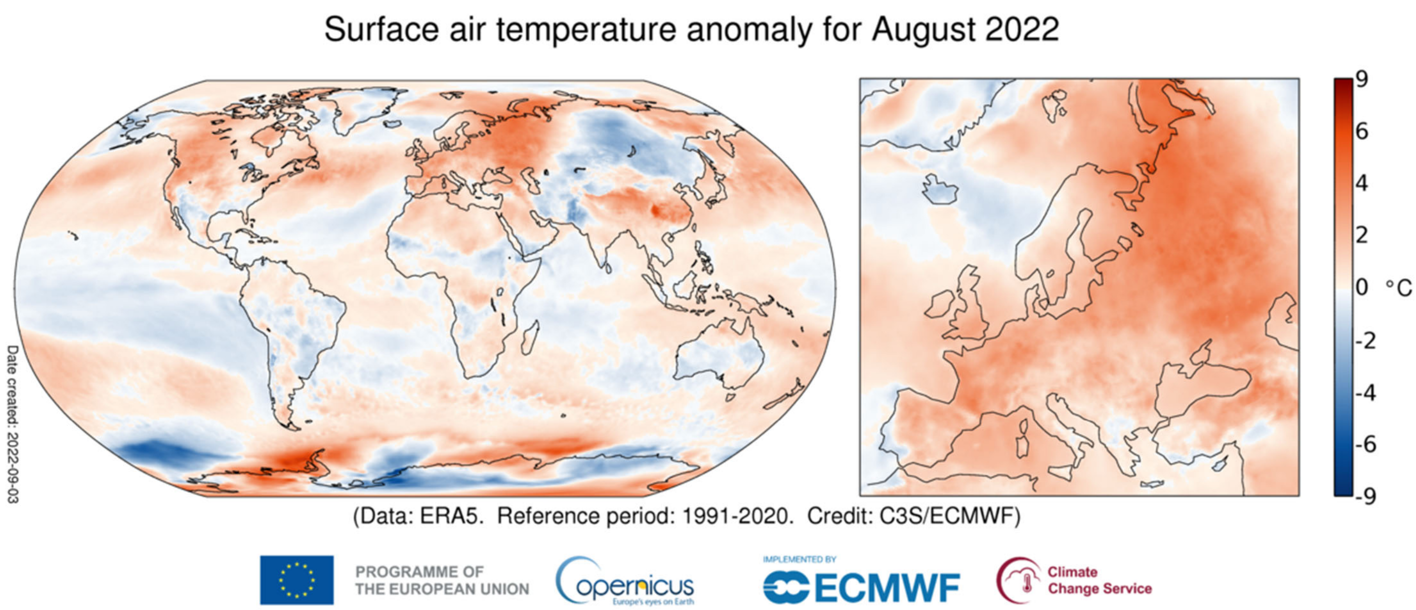
https://climate.copernicus.eu/copernicus-summer-2022-europes-hottest-record

Copernicus: Summer 2022 Europe's hottest on record

DATE:8th September 2022

Newsflash

Bonn, 08/09/2022



Surface air temperature anomaly for August 2022 relative to the August average for the period 1991-2020. Data source: ERA5. Credit: Copernicus Climate Change Service/ECMWF.

The Copernicus Climate Change Service (C3S), implemented by the European Centre for Medium-Range Weather Forecasts on behalf of the European Commission with funding from the EU, routinely publishes monthly climate bulletins reporting on the changes observed in global **surface air temperature**, **sea ice cover** and **hydrological variables**. All the reported findings are based on computer-generated analyses using billions of measurements from satellites, ships, aircraft and weather stations around the world.

August 2022 surface air temperature:

Globally, the average August 2022 temperature was:

- 0.3°C higher than the 1991-2020 average for the month, joint third warmest August on record

- similar to the values for August 2017 and 2021 and within about 0.1°C of the higher values reached in August 2016 and 2019

The average temperature over Europe in 2022 was:

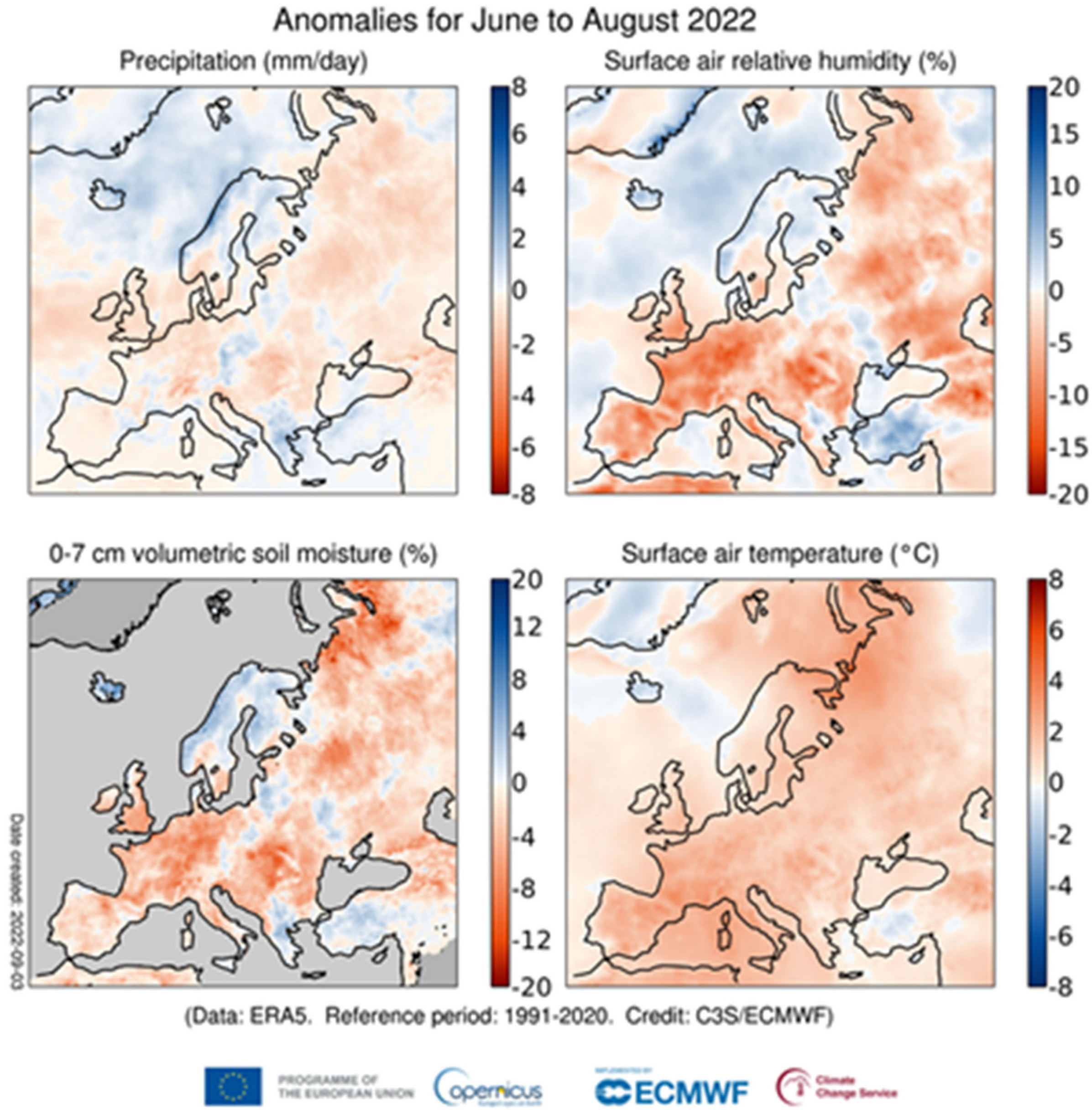
- the highest on record for both August and summer (June – August) by substantial margins of 0.8°C over 2018 for August and 0.4°C over 2021 for summer
- European temperatures were most above average in the east of the continent in August, but were still well above average in the south-west, where they had been high also in June and July
- Heatwaves were prevalent in this part of Europe and over central and eastern China for all three summer months. North America also experienced one of its warmest summers

August 2022 - Hydrological conditions:

- August 2022 was generally much drier than average in much of western and parts of eastern Europe.
- Conversely, it was wetter-than average over most of Scandinavia and parts of southern and southeastern Europe. Southern regions were hit by a “derecho” storm, with extreme winds and rainfall.
- Conditions were also wetter than average in many extratropical regions of North America and Asia: in many locations heavy precipitation triggered floods and inundations. Pakistan saw particularly severe conditions with record breaking rainfall.
- Among the drier-than-average extratropical regions, parts of China experienced severe drought.

Boreal summer 2022 - Hydrological conditions:

- The summer 2022 was characterised by hot and dry conditions over much of western Europe. In much of Scandinavia, regions of central and south-eastern Europe, Greece and western Turkey, conditions were predominantly wetter than average.
- In boreal summer 2022, it was drier than average in central North and South America and across central Asia. The Horn of Africa continued to experience drought. Conditions were predominantly wetter-than-average in south Asia, particularly in Pakistan, in eastern Australia and in most of southern Africa.



Anomalies in precipitation, the relative humidity of surface air, the volumetric moisture content of the top 7 cm of soil and surface air temperature for summer (June to August 2022) with respect to 1991-2020. The darker grey shading denotes where soil moisture is not shown due to ice cover or climatologically low precipitation. Data source: ERA5 Credit: Copernicus Climate Change Service/ECMWF.

Senior Scientist for the Copernicus Climate Change Service, Freja Vamborg, states: "An intense series of heatwaves across Europe paired with unusually dry conditions, have led to a summer of extremes with records in terms of temperature, drought and fire activity in many parts of Europe, affecting society and nature in various ways. The Copernicus Climate Change Service data shows that we've not only had record August temperatures for Europe but also for summer, with the previous summer record only being one year old."

Video material accompanying the maps can be found here.

More information about climate variables in August and climate updates of previous months as well as high-resolution graphics and the video can be downloaded here.

Answers to frequently asked questions regarding temperature monitoring can be found here.

Information about the C3S data set and how it is compiled

Temperature and hydrological maps and data are from ECMWF Copernicus Climate Change Service's ERA5 dataset.

Sea ice maps and data are from a combination of information from ERA5, as well as from the EUMETSAT OSI SAF Sea Ice Index v2.1, Sea Ice Concentration CDR/ICDR v2 and fast-track data provided upon request by OSI SAF.

Regional area average quoted here are the following longitude/latitude bounds:

Globe, 180W-180E, 90S-90N. over land and ocean surfaces.

Europe, 25W-40E, 34N-72N, over land surfaces only.

More information can be found here.

Information on national records and impacts

Information on national records and impacts are based on national and regional reports. For details see the respective temperature and hydrological C3S climate bulletin for the month.

C3S has followed the recommendation of the World Meteorological Organisation (WMO) to use the most recent 30-year period for calculating climatological averages and changed to the reference period of 1991-2020 for its C3S Climate Bulletins covering January 2021 onward. Figures and graphics for both the new and previous period (1981-2010) are provided for transparency.

More information on the reference period used, can be found here.

Notes to editors

Copernicus is a component of the European Union's space programme, with funding by the EU, and is its flagship Earth observation programme, which operates through six thematic services: Atmosphere, Marine, Land, Climate Change, Security and Emergency. It delivers freely accessible operational data and services providing users with reliable and up-to-date information related to our planet and its environment. The programme is coordinated and managed by the European Commission and implemented in partnership with the Member States, the European Space Agency (ESA), the European Organisation for the Exploitation of Meteorological Satellites (EUMETSAT), the European Centre for Medium-Range Weather Forecasts (ECMWF), EU Agencies and Mercator Océan, amongst others.

ECMWF operates two services from the EU’s Copernicus Earth observation programme: the Copernicus Atmosphere Monitoring Service (CAMS) and the Copernicus Climate Change Service (C3S). They also contribute to the Copernicus Emergency Management Service (CEMS), which is implemented by the EU Joint Research Council (JRC). The European Centre for Medium-Range Weather Forecasts (ECMWF) is an independent intergovernmental organisation supported by 35 states. It is both a research institute and a 24/7 operational service, producing and disseminating numerical weather predictions to its Member States. This data is fully available to the national meteorological services in the Member States. The supercomputer facility (and associated data archive) at ECMWF is one of the largest of its type in Europe and Member States can use 25% of its capacity for their own purposes.

ECMWF has expanded its location across its Member States for some activities. In addition to an HQ in the UK and Computing Centre in Italy, offices with a focus on activities conduct https://www.opec.org/opec_web/en/press_room/7002.htm

32nd OPEC and non-OPEC Ministerial Meeting

No 25/2022 Vienna, Austria 05 Sep 2022

The 32nd OPEC and non-OPEC Ministerial Meeting was held via videoconference on 5 September 2022.

The OPEC and non-OPEC Ministerial Meeting noted the adverse impact of volatility and the decline in liquidity on the current oil market and the need to support the market's stability and its efficient functioning.

The Meeting noted that higher volatility and increased uncertainties require continuous assessment of market conditions and readiness to make immediate adjustment to production in different forms, if needed, and that OPEC+ has the commitment, the flexibility, and the means within the existing mechanisms of the Declaration of Cooperation to deal with these challenges and provide guidance to the market.

The Meeting decided to:

1. Reaffirm the decision of the 10th OPEC and non-OPEC Ministerial Meeting on 12 April 2020 and further endorsed in subsequent meetings including the 19th OPEC and non-OPEC Ministerial Meeting on 18 July 2021.

2. Revert to the production level of August 2022 for OPEC and non-OPEC Participating Countries for the month of October 2022 as per the attached table, noting that the upward adjustment of 0.1 mb/d to the production level was only intended for the month of September 2022.

3. Request the Chairman to consider calling for an OPEC and non-OPEC Ministerial Meeting anytime to address market developments, if necessary.

4. Reiterate the critical importance of adhering to full conformity and to the compensation mechanism. Compensation plans should be submitted in accordance with the statement of the 15th OPEC and non-OPEC Ministerial Meeting.

5. Hold the 33rd OPEC and non-OPEC Ministerial Meeting on 5 October 2022.

October 2022 Required Production	
Algeria	1055
Angola	1525
Congo	325
Eq.Guinea	127
Gabon	186
Iraq	4651
Kuwait	2811
Nigeria	1826
Saudi Arabia	11004
UAE	3179
Azerbaijan	717
Bahrain	205
Brunei	102
Kazakhstan	1706
Malaysia	594
Mexico	1753
Oman	881
Russia	11004
Sudan	75
South Sudan	130
OPEC 10	26689
Non-OPEC	17165
OPEC+	43854

September 2022 Required Production	
Algeria	1057
Angola	1529
Congo	325
Eq.Guinea	127
Gabon	187
Iraq	4663
Kuwait	2818
Nigeria	1830
Saudi Arabia	11030
UAE	3186
Azerbaijan	718
Bahrain	205
Brunei	102
Kazakhstan	1710
Malaysia	595
Mexico	1753
Oman	883
Russia	11030
Sudan	75
South Sudan	130
OPEC 10	26753
Non-OPEC	17202
OPEC+	43955

https://www.auswaertiges-amt.de/en/newsroom/news/-/2551310

JCPoA: Joint Statement by France, Germany and the United Kingdom

10.09.2022 - Press release

Germany, France and the United Kingdom declared today (10 September):

We the governments of France, Germany and the United Kingdom have negotiated with Iran, in good faith, since April 2021 to restore and fully implement the Joint Comprehensive Plan of Action (JCPoA), along with other participants to the deal and the United States. In early August, after a year and a half of negotiations, the JCPoA Coordinator submitted a final set of texts which would allow for an Iranian return to compliance with its JCPoA commitments and a US return to the deal.

In this final package, the Coordinator made additional changes that took us to the limit of our flexibility. Unfortunately, Iran has chosen not to seize this critical diplomatic opportunity. Instead, Iran continues to escalate its nuclear program way beyond any plausible civilian justification.

While we were edging closer to an agreement, Iran reopened separate issues that relate to its legally binding international obligations under the Non Proliferation Treaty (NPT) and its NPT safeguards agreement concluded with the International Atomic Energy Agency (IAEA). This latest demand raises serious doubts as to Iran's intentions and commitment to a successful outcome on the JCPoA. Iran's position contradicts its legally binding obligations and jeopardizes prospects of restoring the JCPoA.

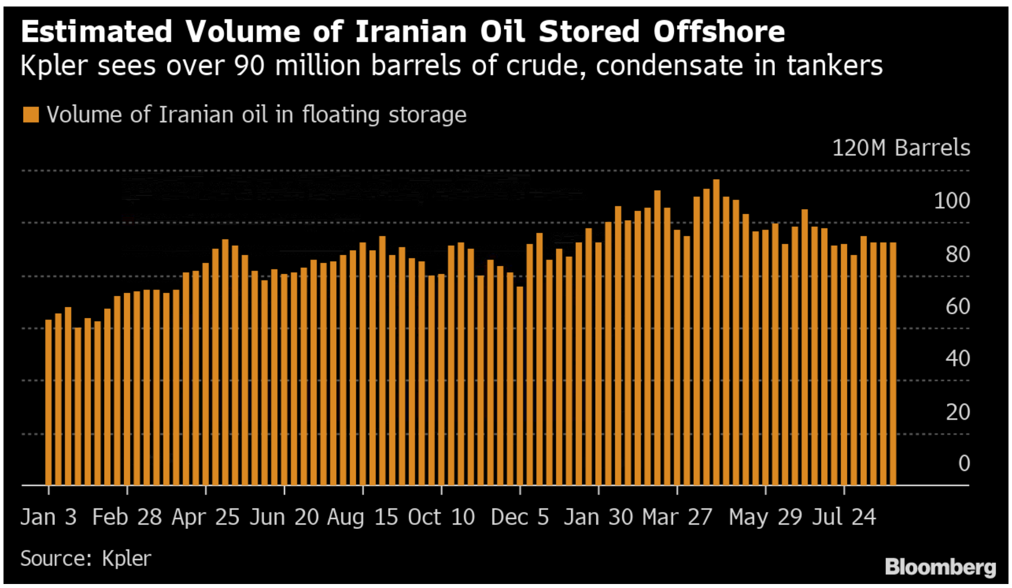
In June, the IAEA Board of Governors' adopted, by an overwhelming majority, a resolution calling on Iran to take urgent action to answer the Agency's outstanding questions. Three months later Iran has taken no steps at all as confirmed by the IAEA Director General's latest report.

Our position remains clear and steadfast. Iran must fully and, without delay, cooperate in good faith with the IAEA. It is up to Iran to provide technically credible answers to the IAEA's questions on the whereabouts of all nuclear material on its territory. The JCPoA can in no way be used to release Iran from legally binding obligations that are essential to the global non-proliferation Regime.

Given Iran's failure to conclude the deal on the table we will consult, alongside international partners, on how best to address Iran's continued nuclear escalation and lack of cooperation with the IAEA regarding its NPT safeguards Agreement.

Iran May Drain Offshore Crude Oil Cache If Nuclear Deal Reached
2022-08-28 23:34:37.544 GMT

By Sharon Cho
(Bloomberg) -- Progress toward an Iranian nuclear deal has thrown the spotlight onto a sizeable cache of crude held by Tehran that could be swiftly dispatched to buyers in the event an agreement gets hammered out.
About 93 million barrels of Iranian crude and condensate are currently stored on vessels in the Persian Gulf, off Singapore and near China, according to ship-tracking firm Kpler, while Vortexa Ltd. estimates the holdings at 60 to 70 million barrels. In addition, there are smaller volumes in onshore tanks.



“Iran has built up a sizable flotilla of cargoes that could hit the market fairly soon,” said John Driscoll, chief strategist at JTD Energy Services Pte. Still, it may take “a bit of time” to iron out insurance and shipping issues, as well as spot and term sales post-sanctions, he said.
The possible full readmittance of Iran to the global crude market, with the potential lifting of US sanctions, comes at complex moment for oil traders. Investors are juggling the countdown toward far tighter European Union curbs on Russian crude flows from December as part of the the bloc’s pushback against the war in Ukraine. In addition, the Biden administration’s mammoth sale from the Strategic Petroleum Reserve will end in October.
The potential return of Iranian barrels into global oil markets -- both from the volumes in floating storage and over the longer term -- has weighed on futures prices in recent weeks, offsetting signs of tightness elsewhere.
The focus for diplomats is the revival of a multinational accord that limited Iran’s nuclear program in exchange for the lifting of related sanctions, including on oil flows. The original deal collapsed after then-President Donald Trump

abandoned it. Last week, the US sent its response to the latest proposal, boosting speculation an agreement may soon be struck, although Tehran said Sunday that exchanges will now drag on into September.

Iran's offshore crude hoard compares with average daily global supply this year of about 100 million barrels a day, according to an estimate from the International Energy Agency. In the US, President Joe Biden has been releasing about 180 million barrels from the SPR over a six-month period.

Since former President Trump stopped granting waivers to import Iranian oil following American sanctions, Iran's daily shipments have held at about 1 million barrels, according to Emma Li, an analyst at Vortexa. China has remained among the top buyers, as other nations backed away.

Longer term after any deal is struck and the offshore cache is drained, Iran would seek to rebuild production and step up overseas sales. Goldman Sachs Group Inc., which is skeptical about a breakthrough in the near term, said even if a deal is reached, these wouldn't begin until 2023, according to a note.

While Iran may aim to fill the void left by Russia in Europe, namely in Spain, Italy, Greece and even Turkey, Tehran would also attempt to reclaim share in the prized Asian market, even if it takes a sweetening of terms, Driscoll said.

In 2017 and 2018, Europe consumed an average of 748,000 barrels and 528,000 barrels a day of Iranian oil, respectively, while Asia took 1.2 million and close to 1 million barrels a day, Kpler data showed.

"It's natural for Iran to want to supply Europe first to fill in the hole left by post-invasion sanctions against Russia," Driscoll said. "But in the longer run, they will be looking to place their barrels under long-term deals in Asia."

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Jake Lloyd-Smith, Ben Sharples

SAF Group created transcript of comments by Mike Muller, Head Vitol Asia, on Gulf Intelligence Daily Energy Markets PODCAST hosted by Sean Evers, Managing Partner Gulf Intelligence, on Sept 4, 2022 at 10:30am (UAE time).
https://soundcloud.com/user-846530307/podcast-daily-energy-markets-september-4

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

On lack of oil spare capacity

At 9:50 min mark, Muller "*what we do need to keep in mind is that people do worry about spare capacity, not just geopolitical disruptions, but weather disruptions. And, of course, the entire sanctions picture. So I guess we will come back to price caps on Russia in awhile. But I think on the gas, the TTF, the market has had a very clear demonstration of what happens to price when there is a concern about capacity and effectively a rationing mindset. I mean that explosive move in TTF up to 343 euros per megawatt hour is something obviously we haven't seen in oil. But we have to bear in mind that in oil, there is less oil in the US SPR. That's at something like 20, 30 year lows after the interventionist measures that were enacted by the Biden Administration with a whole bunch of other countries acting in concert with that. And, at the same time, the period of price stabilization after Covid, OPEC+, is also over. and there is a big question mark over the what's next. So, by expressing a willingness to take oil off the market in response to either oil coming into the market from Iran sanctions being dropped or from lack of demand in China due to Covid repression measures, it's just serves as a reminder that we're not going to see everybody producing flat out. And therefore, I think we do need to bear in mind that there needs to be a risk premium for the lack of spare capacity in oil markets*."

On G7 oil price cap

At 16:50 min mark, Muller "*it's probably the most discussed topic in the last 24 hours on social media or specialist on-line media, and it's awfully hard to say Sean. The industry has obviously been aware of this desire to put in place such a cap for the last month and a bit. And has largely dismissed the possibility of doing so in a way that actually works. I think we have to bear in mind that Russia's production is a much larger number than Iran's production so you can't draw parallels about sanctions taking effect in Russia in the same way as Iran because Russia has the capability to produce 11 mmb/d of oil. That's 11% of global supply. And its exports of 7 plus mmb/d of crude oil and products combined are an even greater percentage of the global supply picture. It is impossible, let me repeat, it is impossible for the world to get by without all of that. Yes. If you look at what's happening with Nord Stream 1 and Nord Stream 2, there have been moments, days, weeks where all the Russian supply has been shut off to certain countries for various technical and I would argue political reasons. So a way must be found to allow Russian oil to continue to flow into markets because, unlike the inventory build of gas in Europe and people saying they might just get by with rationing, austerity measures and hopefully a mild winter than last year – That does not apply to oil. It's impossible for the world to get by without not having 7%, 7.5 mmb/d of exports. So what a price cap might seek to accomplish is the Russian oil goes to a larger number of markets under a framework that is actually more fungible. In so doing of course, the 1, 2, 3, 4 markets where most Russian crude oil is flowing now will flow once the sanctions take further effect later this year. will be spread out more widely. So thereffore discounts we are currently seeing in place on Russian crude oil and exports will possibly diminish at the same time that more participants are brought into the fold. But I have my own idea on how the price cap will actually be enforced. There is talk, of course, of exerting pressure on those pieces of the supply chain where the G7 that are driving this, have a certain degree of control such as shipping and insurance. I guess those are the levers that need to be further understood*."

On China

At 27:15 min mark, Muller "*so much to say and so little time, Sean. The 16th of October has come as a bit of a relief so we know when that Congress is taking place and everyone expects some degree of opening up of the travel restrictions we have seen. The world bereft of the Chinese tourists and businessmen which is so important here in Asia.*"

At 29:00 min mark, Muller "*now for China, the hope and my constant input into this meeting, as I am more of a China bull than most, is that things will get better and demand will improve. But right now, the headlines are going the other way with 10 plus million people locked down in various parts of China. The epicenter of Covid seems to be Shenzhen, just the hinterland of Hong Kong, the great tech megalopolis if you like; so that is weighing on sentiment for sure*."

At 30:15 min mark, Muller "*Many forces here. I mean as people know the demographics of China thanks to the one-child policy is not a rampant growth in the population. But there is a rampant growth in the affluence of the economy in the growth of the middle class and their consumption patterns. So I think you are going to see headlines dominated by the ever-present, ever-grand story and the fact that it was the Chinese construction sector, which is energy intensive of course, etc which weighed down on all the various indices we are looking at. But that's the very sector the government is now looking to boost and bolster with their very formidable reserves. So I think they are taking steps to counter that and I look forward to seeing evidence of greater outputs in industries like cement, ashphalt and paving, road building, etc which China still has some ways to go in certain provinces that haven't yet seen the huge wave of investments where literally in the last two decades, they have built a highway system equivalent to the interstates in the USA, criss-crossing various affluent provinces. So I think there is some running room to go in China."*

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

https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/oil/090722-global-gas-to-oil-fuel-switching-to-jump-80-as-european-asian-gas-prices-soar

- 07 Sep 2022 | 22:45 UTC

Global gas-to-oil fuel switching to jump 80% as European, Asian gas prices soar

- Author**Robert Perkins**
- Editor**Robert Perkins**

HIGHLIGHTS

Switching to account for a 633,000 b/d demand growth in first quarter 2023

European gas, Asian LNG six times more costly than fuel oil on energy basis

European refiners heavily exposed to Russian-Ukraine wargas price hike

Global oil demand from gas-to-oil switching could jump by more than 80% over the next six months after soaring prices for natural gas and LNG push more power producers, refiners and industrial users to burn fuel oil and other liquid fuels, according to estimates by Platts Analytics.

Refiners, power producers, and major industries will account for 633,000 b/d incremental liquids demand in the first quarter of 2023, compared to around 350,000 b/d of incremental demand in Q3 2022, Platts Analytics estimated.

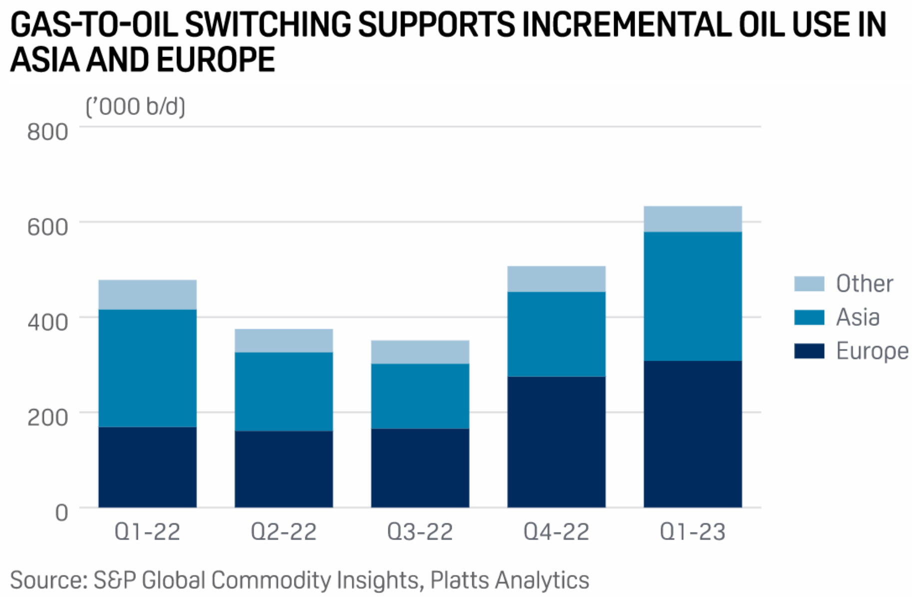
Day-ahead gas prices across Europe rose on Sept. 6, bolstered by continued market concerns around winter gas supply in Europe after Russia's Gazprom announced the indefinite suspension of gas flows to Germany via the Nord Stream pipeline.

Platts assessed Europe's gas price benchmark TTF month-ahead at a record-high Eur319.98/MWh on Aug. 26, which fell back to Eur237.98/MWh on Sept. 6 but was still four times higher year on year. S&P Global Commodity Insights data showed.

LNG prices have also climbed since the start of the Russia-Ukraine war, with facility outages worldwide adding to the increases.

As a result, most Asian countries have also been dealing with an energy crisis and refraining from purchases to cut soaring energy import bills as prices advance. Asian spot LNG prices have risen tracking a tight Atlantic Basin, with the JKM benchmark approaching all-time highs again in August. The daily physical assessment reached $71.01/MMBtu on Aug. 25, the highest level since March 7, when the benchmark hit a record-high $84.76/MMBtu.

On a Btu equivalent basis, benchmark Europe gas and Asian LNG prices currently stand five to six times higher than high sulfur fuel oil values, incentivizing widespread gas-to-oil switching at sites capable of using alternative fuel.



European switching

In Europe, refiners, power producers, and major industries will account for a 308,000 b/d growth in liquids demand in the first quarter of 2023, according to Platts Analytics, equivalent to about half the global share of gas-to-oil switching. The growth figure surpasses the 166,000 b/d, or 47%, in Q3 2022. Asian gas-to-oil switching demand growth will reach 271,000 b/d, or 43% of the total, according to the estimates, up from 136,000 b/d in the current quarter.

Residual fuel oil will account for 348,000 b/d, or 60%, of the incremental global shift to oil in Q1 2023, Platts Analytics data showed, with LPG accounting for 32% and gasoil making up the rest of the increase at 8%.

Power generators lead the fuel switching in terms of the single biggest sector, but refiners also purchase some natural gas for supplementary refinery fuel /feed for hydrogen production. Refiners can minimize their natural gas purchases by maximizing refinery still-gas production, using liquid feeds such as naphtha and LPG for hydrogen production, and substituting fuel gas used for process heaters and boilers by LPG and fuel oil.

"While natural gas prices are soaring, both naphtha and high sulfur fuel oil are currently weak. We know southern European countries are consuming more fuel oil due to switching away from gas." Rasool Barouni, head of refining economics at Platts Analytics, said.

Globally, Platts Analytics sees fuel oil demand rising 125,000 b/d quarter on quarter to 7.4 million b/d in Q3 2022, driven by higher power generation demand and waterborne trade picking up pace with the further opening of world economies. Growth will be driven by the Middle East, where it is expected to increase by 170,000 b/d, largely by the power sector due

Oil price outlook – Snapshot: September 6, 2022

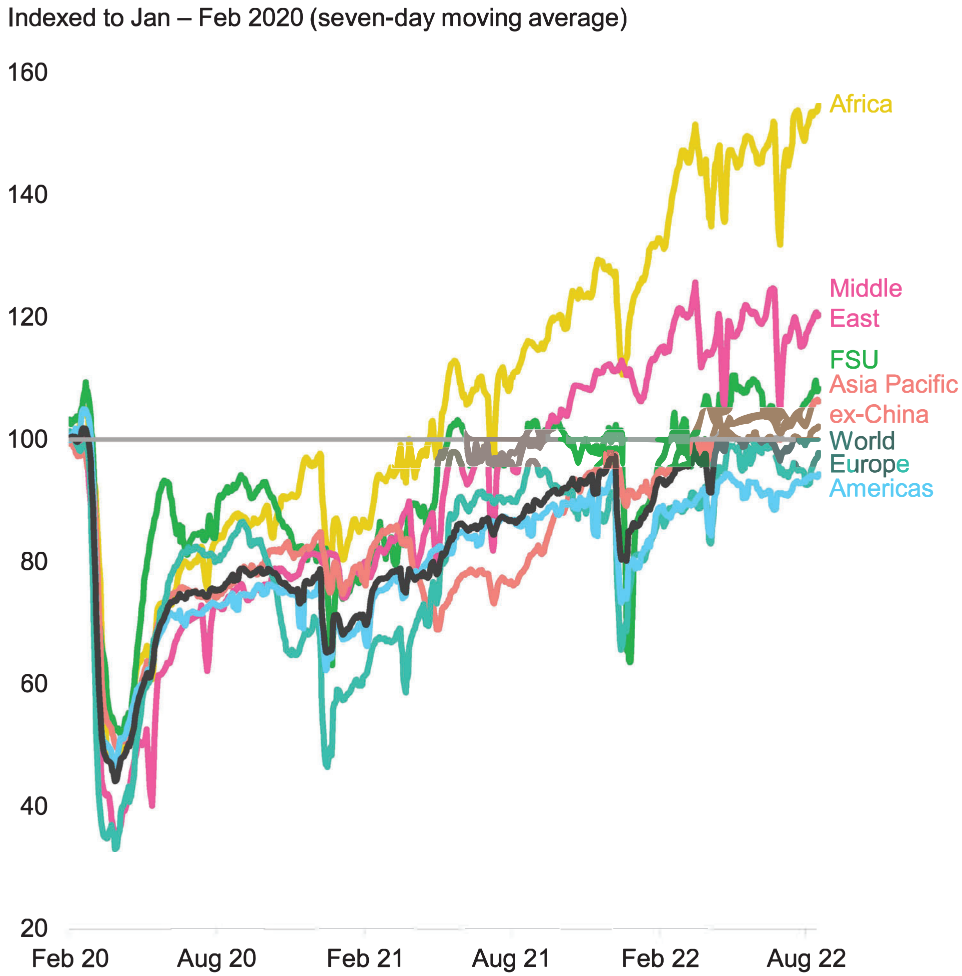
Disclaimer: Please note that BNEF does not offer investment advice. Clients must decide for themselves whether current market prices fully reflect the issues discussed in this note.

Category	Indicator	Signal	Comment
Fundamentals	Refinery margins		• Refinery margins fell over the past week as oil product cracks weakened.
	Crude stocks		• In the week ending August 26, land crude-oil storage levels in BloombergNEF's tracked regions (the US, ARA and Japan) dropped by 1.0% to 528.4 million barrels (m bbl). The stockpile **deficit** against the five-year average (2015-19) **widened from 53.5m bbl to 57.5m bbl**. • Including global floating crude stockpiles from the same week, total crude oil inventories decreased by 2.7% to 623.0m bbl, with the stockpile **surplus narrowing from 13.4m bbl to 0.6m bbl.**
	Product stocks		• In the week ending August 26, gasoline and light distillate stockpiles in BNEF's tracked regions (the US, ARA, Singapore, Japan and Fujairah) fell by 1.6% week-on-week to 258.9m bbl, with the stockpile **deficit** against the three-year average (2017-19) **widening from 5.4m bbl to 7.2m bbl**. Gasoil and middle distillate stockpiles in BNEF's tracked regions were up 0.5% to 144.4m bbl, with the stockpile **deficit** against the three-year average **narrowing from 39.1m bbl to 38.0m bbl**. • Oil product stockpiles in tracked regions grew by 0.2% to 964.8m bbl, with the stockpile **deficit** against the three-year seasonal average **widening from 53.0m bbl to 55.3m bbl**. Altogether, crude and product stockpiles dropped by 0.9% to 1,587.8m bbl, with the stockpile **deficit widening from 39.7m bbl to 54.8m bbl.**
	Demand indicators		• In the week to September 6, global jet fuel demand from commercial passenger flights fell by 1.5% to 5.62 million barrels per day. Jet fuel consumption by international passenger flight departures was down by 25,400 barrels per day (or -0.8%) week-on-week, while consumption by domestic passenger flight departures decreased by 60,200 barrels per day (or -2.5%). In the week to September 4, flight departures in the Eurocontrol area rose to 87.8% of the equivalent week in 2019, up from 87.2% last week. The four-week moving average, however, declined slightly to 87.3%, from 87.5%. Meanwhile, in the same week, US passenger throughput rose to 97.2% of the equivalent week in 2019, up from 96.2% last week. The four-week moving average increased to 93.6%, from 91.6%, the highest level since March 2020. • The oil-demand-weighted global mobility index (excluding China) rose over the past week, according to BNEF's calculation based on Google mobility data. It increased by 0.8% in the week to September 1, driven by growth in Asia Pacific ex-China (+0.6%), Europe (+2.0%) and the Americas (+0.3%). Meanwhile, in the week to August 31, TomTom's peak congestion data showed surges in Asia Pacific ex-China (+0.9%), Europe (+18.1%) and North America (+3.5%). Road congestion in China's 15 key cities was down by 1.2 percentage points to 103.7% of January 2021 levels in the week to August 31, according to BNEF's calculation based on Baidu data. Near-term driving activity in China is expected to be suppressed by sporadic Covid-19 lockdowns. • In the week to August 30, global daily average Covid-19 cases fell by 16% to 646,000 new cases. The Americas number decreased by 2% to 134,000 daily cases, Europe dropped by 21% to 111,000 daily cases, and Asia Pacific also fell by 21% to 346,000 daily cases (although the number in **China more recently rose by 16% to 1,804 cases** in the week to September 5).
Financial	Macro indicators		• The dollar index averaged 109.1 over the past week and was 0.4% higher than the week before. The Global Manufacturing PMI fell for the third consecutive month to 50.3 in August, from 51.1 in July. China's Manufacturing PMI slipped to 49.5, from 50.4 in the prior month.
	Hedge fund positioning		• In the week to August 30, Managed Money net positioning in the oil complex was up by 3.5m bbl (or +0.7%) week-on-week to 488.0m bbl, and rose to the 15th percentile (versus the 14th percentile in the prior week) of the past five years.
	Options chains and volatility		• There was a significant increase in open interest for Brent and WTI calls. Brent and WTI 1M volatility skews were higher over the past week.
Outlook	Weekly call		• BNEF is bearish on oil prices for the week ahead, with Brent Nov-22 trading at $94.06/bbl and WTI Oct-22 trading at $87.83/bbl at the time of writing. • The oil-demand-weighted global mobility index (ex-China) strengthened over the past week to reach the highest level since early 2020, with year-on-year growth virtually unchanged. Global jet fuel demand fell week-on-week. The four-week moving average for air traffic in Europe remains capped below 90% of 2019 levels, while four-week average passenger throughput in the US surged to 97.2% of 2019 levels, **the highest point since March 2020**. • Weekly crude and oil product inventories saw a bullish move over the past week as their deficits against their seasonal averages widened. The current crude and product stockpiles deficit level of 54.8m bbl is significantly lower than the peak of 142.1m bbl seen in early June. The middle distillate inventory deficit remains significant and could widen in the coming winter months in the Northern Hemisphere. • The OPEC+ output quota cut of 100,000 barrels a day (b/d) is likely to be more of a symbolic gesture than impactful on the physical oil markets, and may encourage some 'dip-buying', particularly when nearing the next meeting on October 5. In the meantime, lockdowns in China could continue to drive oil prices lower if the situation does not improve. China consumes over 15 million b/d of oil, and a hit to demand will require an outsized response by the few OPEC+ members whose output is keeping up with their targets, in order to keep oil flat prices at current levels.

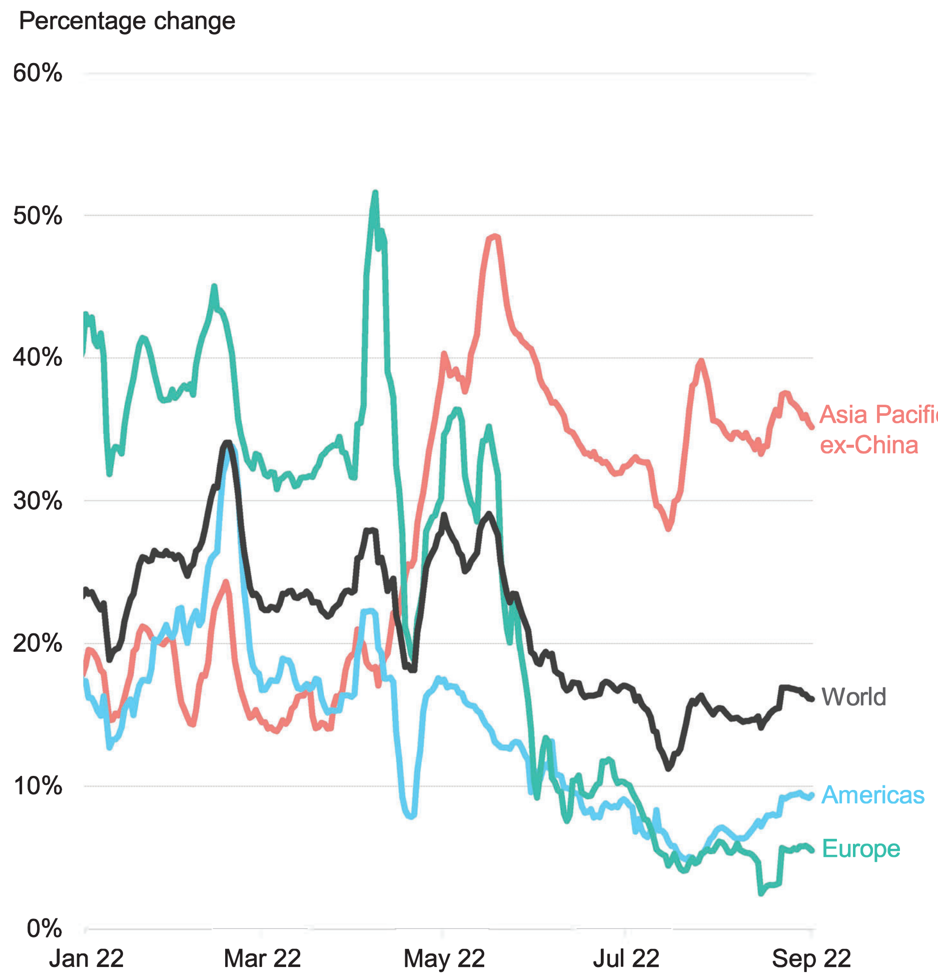
In the spotlight: Road mobility activity

Oil-demand-weighted global road mobility index surpasses early-2020 highs

Oil-demand-weighted road mobility indices



Year-on-year growth in road mobility indices



Source: Google Community Mobility Report, BloombergNEF. Note: ***Data exclude China and Russia.*** *Calculation includes retail and recreation, workplaces, transport hubs.* ***Data updated to September 1, 2022.*** *The world and regional index ratings are weighted by the 2019 gasoline and diesel demand of each country. 'FSU' stands for Former Soviet Union.*

Past outlooks

Disclaimer: Please note that BNEF does not offer investment advice. Clients must decide for themselves whether current market prices fully reflect the issues discussed in this note

Date of report	Refinery margins	Crude stocks	Product stocks	Demand indicators	Commitment of traders	Options chain and volatility	BNEF week ahead call	Brent/WTI price at time of writing ($/bbl)	Web Link
September 6	↓	↑	↔	↓	↔	↑	↓	Brent-Nov: 94.06 WTI-Oct: 87.83	
August 30	↔	↔	↓	↑	↑	↑	↑	Brent-Nov: 101.00 WTI-Oct: 95.40	
August 16	↔	↓	↔	↓	↓	↔	↓	Brent-Oct: 93.65 WTI-Sep: 87.83	
August 9	↔	↓	↔	↔	↓	↓	↔	Brent-Oct: 97.60 WTI-Sep: 91.50	
August 2	↔	↑	↔	↔	↔	↔	↓	Brent-Oct: 99.38 WTI-Sep: 93.42	
July 26	↔	↓	↔	↓	↑	↔	↔	Brent-Oct: 101.94 WTI-Sep: 98.46	
July 19	↔	↓	↓	↓	↔	↔	↓	Brent-Sep: 105.88 WTI-Sep: 99.03	
July 11	↓	↓	↑	↓	↓	↓	↓	Brent-Sep: 105.18 WTI-Aug: 102.34	
July 5	↓	↑	↓	↑	↓	↓	↔	Brent-Sep: 111.71 WTI-Aug: 107.91	
June 21	↑	↓	↑	↑	↓	↓	↔	Brent-Aug: 115.81 WTI-Aug: 110.34	
June 13	↔	↑	↔	↔	↑	↔	↔	Brent-Aug: 120.06 WTI-Jul: 118.58	
June 6	↔	↑	↑	↔	↑	↔	↔	Brent-Aug: 119.88 WTI-Jul: 118.94	
May 30	↔	↑	↓	↔	↔	↔	↔	Brent-Aug: 116.46 WTI-Jul: 115.81	
May 23	↑	↑	↑	↔	↑	↑	↑	Brent-Aug: 110.88 WTI-Jul: 111.11	

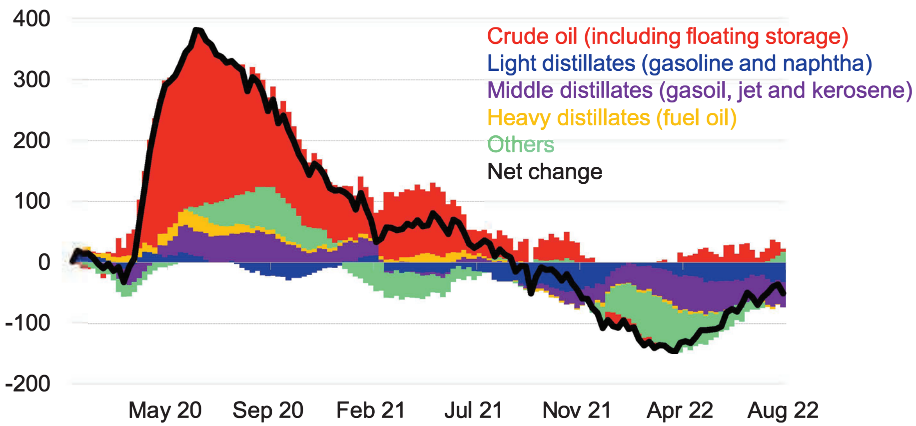
To view past reports on terminal, go to NI BNEFOIL, search for the report and click on the icon to the far right:

Weekly oil inventories

Uptrend in middle distillate stockpiles, though huge seasonal deficit persists

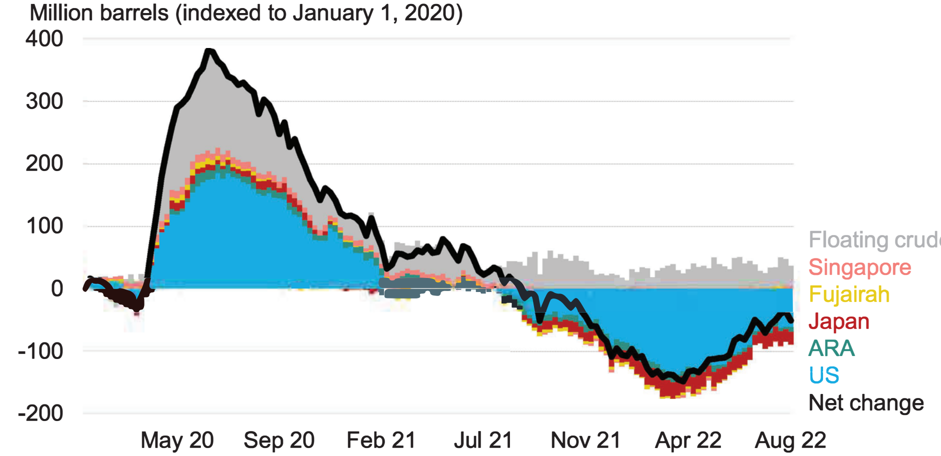
Weekly oil inventories by type

Million barrels (indexed to January 1, 2020)



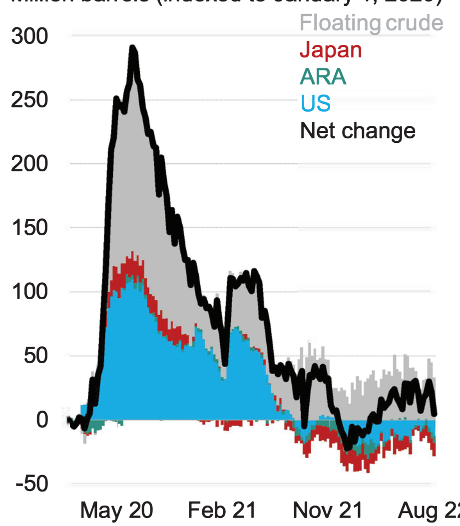
Weekly oil inventories by region

Million barrels (indexed to January 1, 2020)



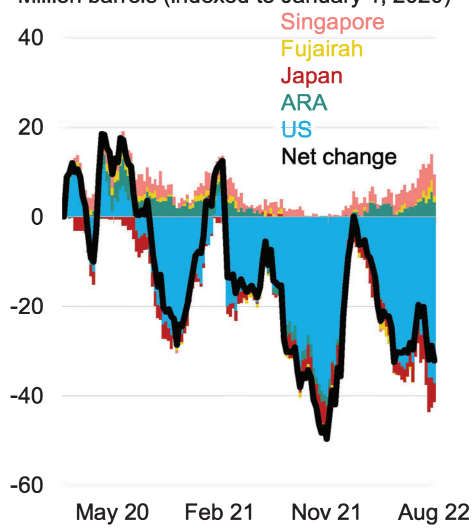
Crude inventories

Million barrels (indexed to January 1, 2020)



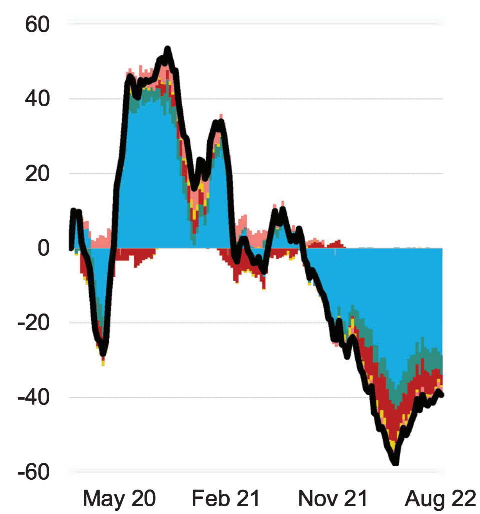
Light distillate inventories

Million barrels (indexed to January 1, 2020)



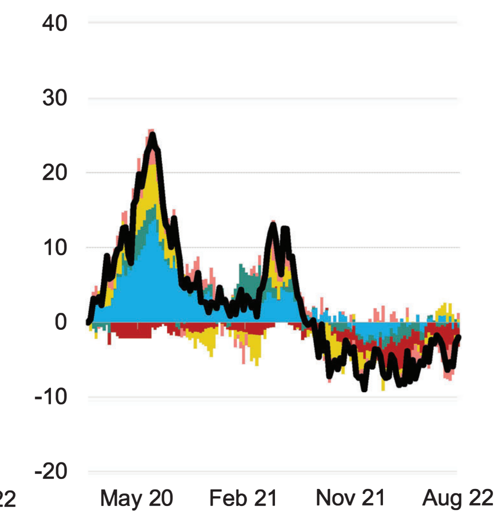
Middle distillate inventories

Million barrels (indexed to January 1, 2020)



Heavy distillate inventories

Million barrels (indexed to January 1, 2020)



*Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ ,Vortexa, Genscape. Note: As of the week ending **August 26, 2022**.*

BloombergNEF

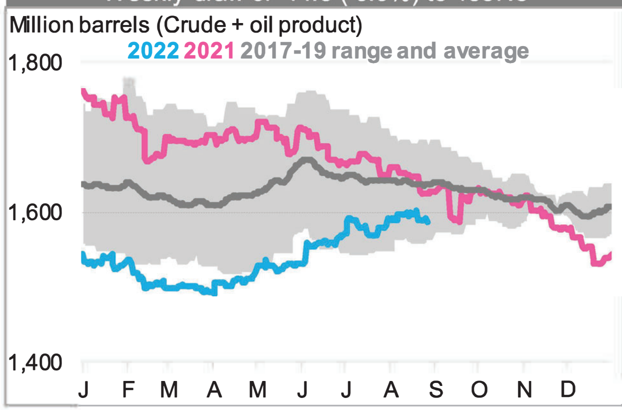
Aggregated oil stockpiles

Bullish: Stockpiles deficit widened from 39.7m bbl to 54.8m bbl

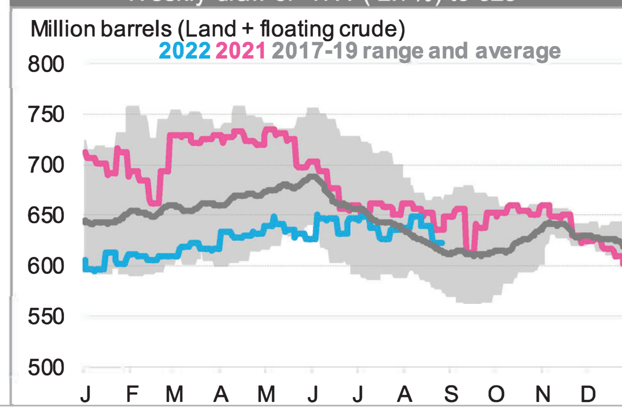
- Charts below use the **2017-19** (three-year) seasonal stockpiles. All calculations are recalibrated to measure against their respective three-year seasonal averages, so the values below may differ from the previous slides.
- Land crude inventories include the US, ARA, Japan and Shandong Teapots. Floating storage data are global. Oil product storage includes the US, ARA, Japan, Singapore, Shandong Teapots and Fujairah. Floating crude inventories may have been adjusted since the previous report – see slide 8 for further info.

Total oil and product stocks = Total crude stocks (land + floating) + Total oil product stockpiles

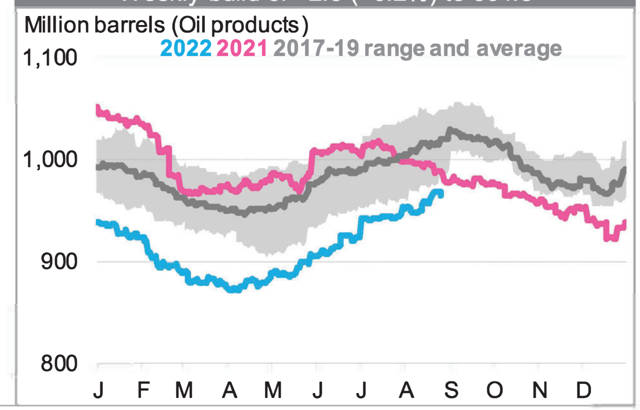
Weekly draw of -14.8 (-0.9%) to 1587.8



Weekly draw of -17.1 (-2.7%) to 623

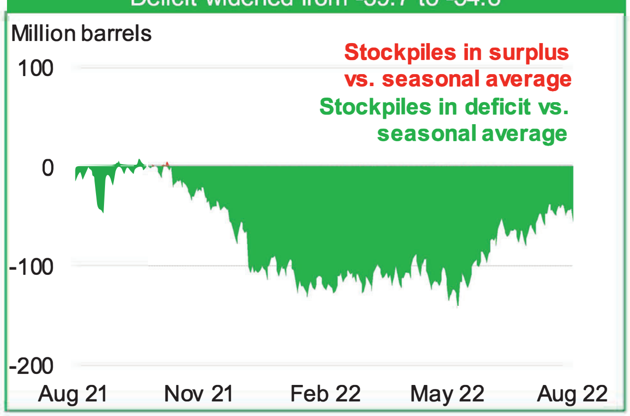


Weekly build of +2.3 (+0.2%) to 964.8

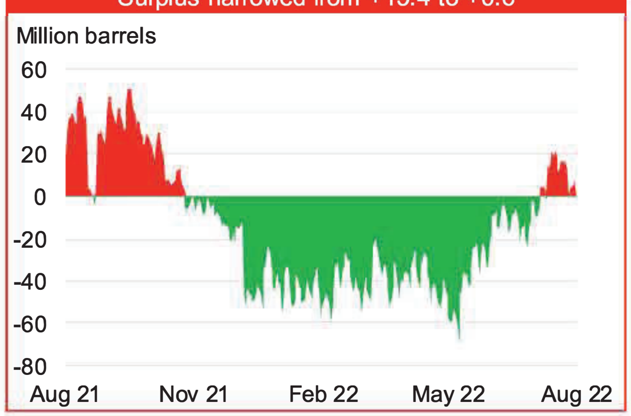


Charts below subtract current stockpiles by the 2017-19 (three-year) seasonal average

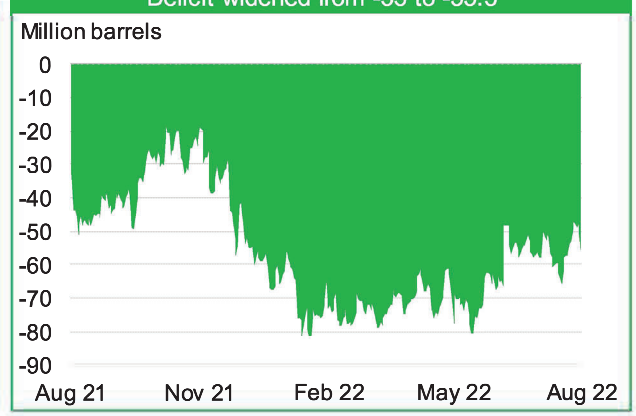
Deficit widened from -39.7 to -54.8



Surplus narrowed from +13.4 to +0.6



Deficit widened from -53 to -55.3



*Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ ,Vortexa, Genscape. Note: As of the **week ending August 26, 2022.***

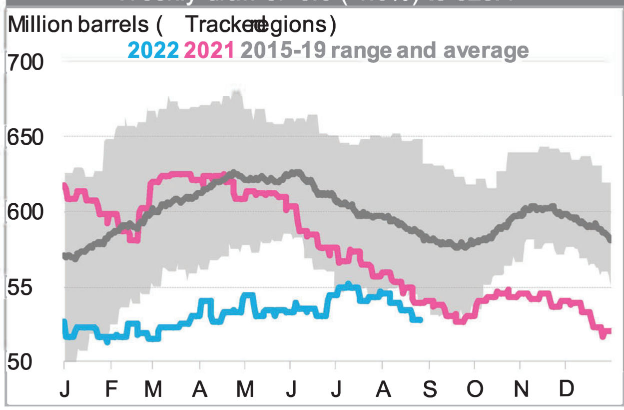
Crude stocks: Land

Bullish: Deficit widened from 53.5m bbl to 57.5m bbl against the seasonal average

- Crude inventory rises when supply outstrips demand (meaning more physical oil is available than is needed). High or rising inventories are therefore a bearish factor for oil prices. Every year, storage levels fluctuate due to seasonal demand trends. The intra-year directional movement of stockpile levels is somewhat predictable, yet the magnitude of movement can differ significantly from expectations.
- A useful way to gauge if the intra-year storage levels differ from the norm is to measure the difference between the current and seasonal average inventory levels.

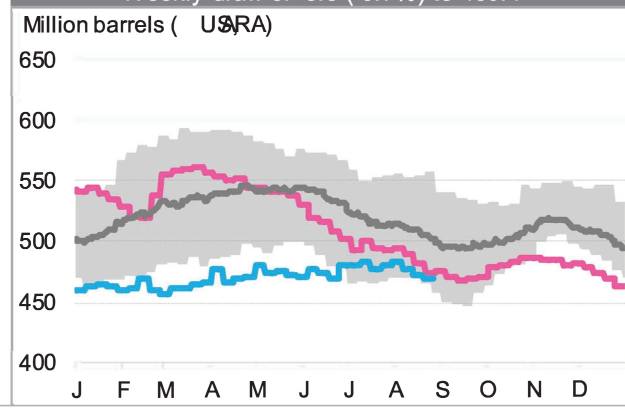
Land storage: Total

Weekly draw of -5.3 (-1.0%) to 528.4



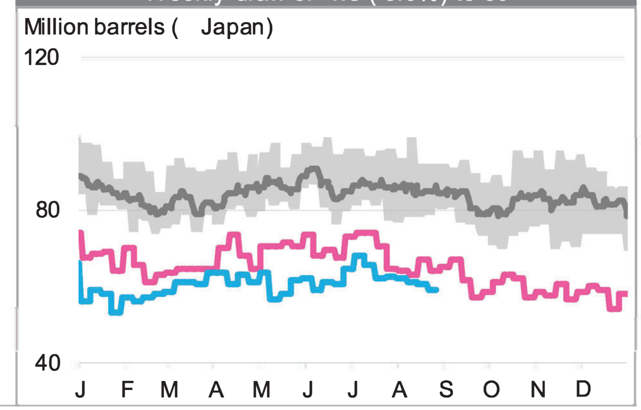
Land storage: West of Suez

Weekly draw of -3.5 (-0.7%) to 469.4



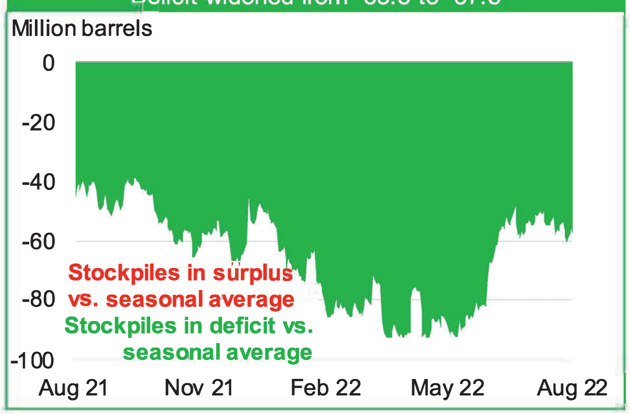
Land storage: East of Suez

Weekly draw of -1.8 (-3.0%) to 59



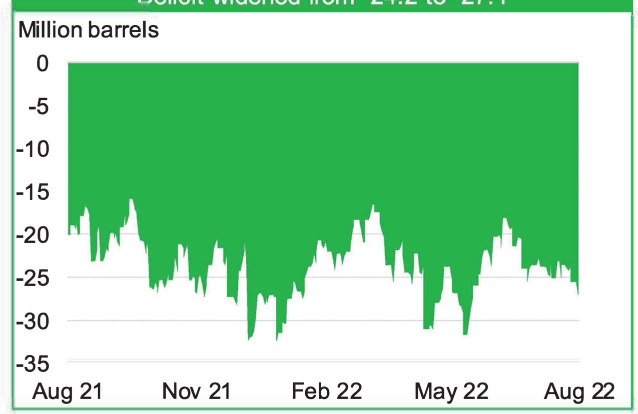
Charts below subtract current stockpiles by the 2015-19 (five-year) seasonal average

Deficit widened from -53.5 to -57.5



Deficit widened from -32.5 to -33.6

Deficit widened from -24.2 to -27.1



Source: BloombergNEF, US EIA, Genscape, PAJ. Note: As of the ***week ending August 26, 2022.***

Fundamentals | Financial

Crude stocks: Floating

Neutral: Surplus flat over the past week

- Floating storage is only profitable if the strength of contango (future versus prompt price) is greater than the tanker costs. Therefore, tankers become floating storage when the profit from a storage play exceeds the cost of the forward freight agreement (FFA).
- The floating storage data used in the "Oil Price Outlook" slide is for the previous week (ie, the week before the latest data shown below). That data are available in the table to the right.

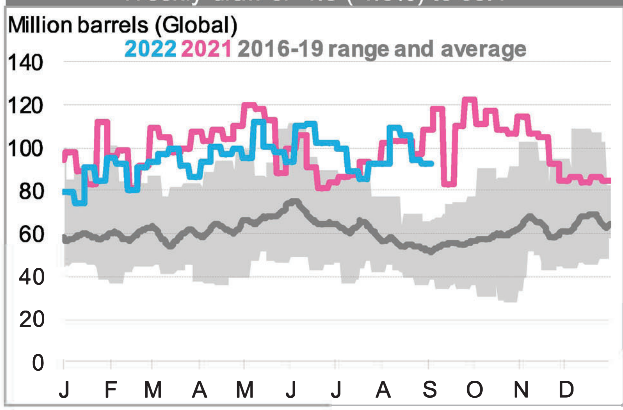
Vortexa's revision to global floating crude inventories

Million barrels	Previous report	Current report	Vortexa's revision
Inventories in week of Aug. 26	101.7	**94.6***	-7.1

*Note: *Figure used to aggregate total oil inventories on page 8.*

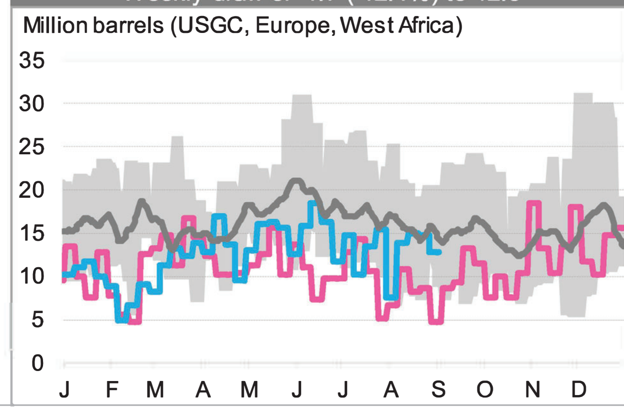
Floating storage: Total

Weekly draw of -1.5 (-1.5%) to 93.1



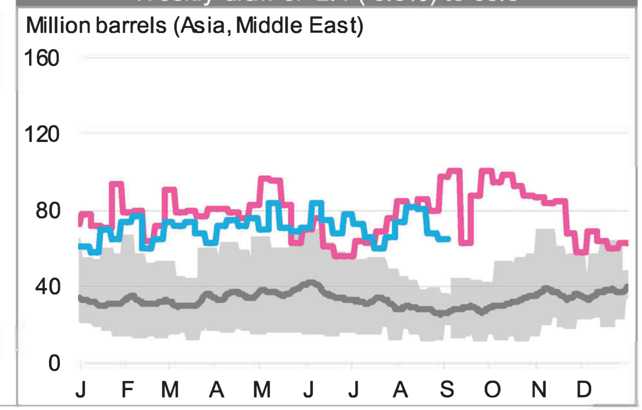
Floating storage: West of Suez

Weekly draw of -1.7 (-12.1%) to 12.9



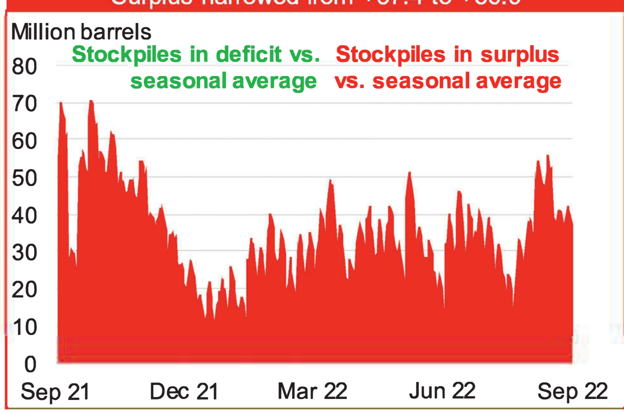
Floating storage: East of Suez

Weekly draw of -2.4 (-3.5%) to 65.3

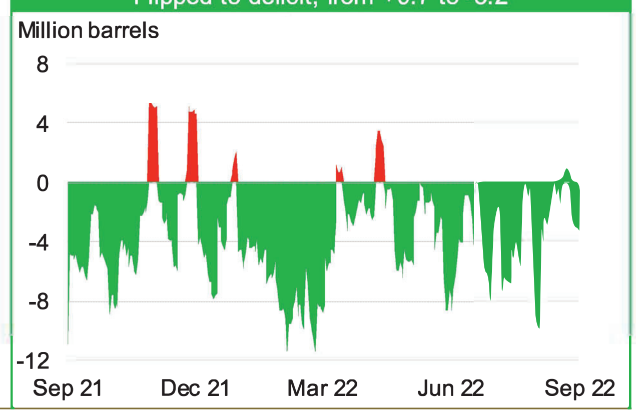


Charts below subtract current stockpiles by the 2016-19 (four-year) seasonal average

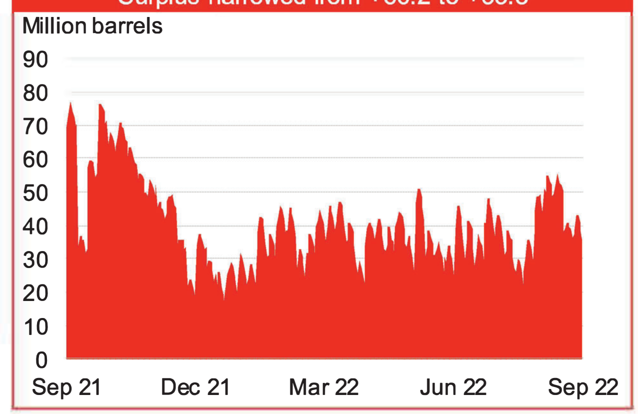
Surplus narrowed from +37.4 to +36.9



Flipped to deficit, from +0.7 to -3.2



Surplus narrowed from +36.2 to +35.8



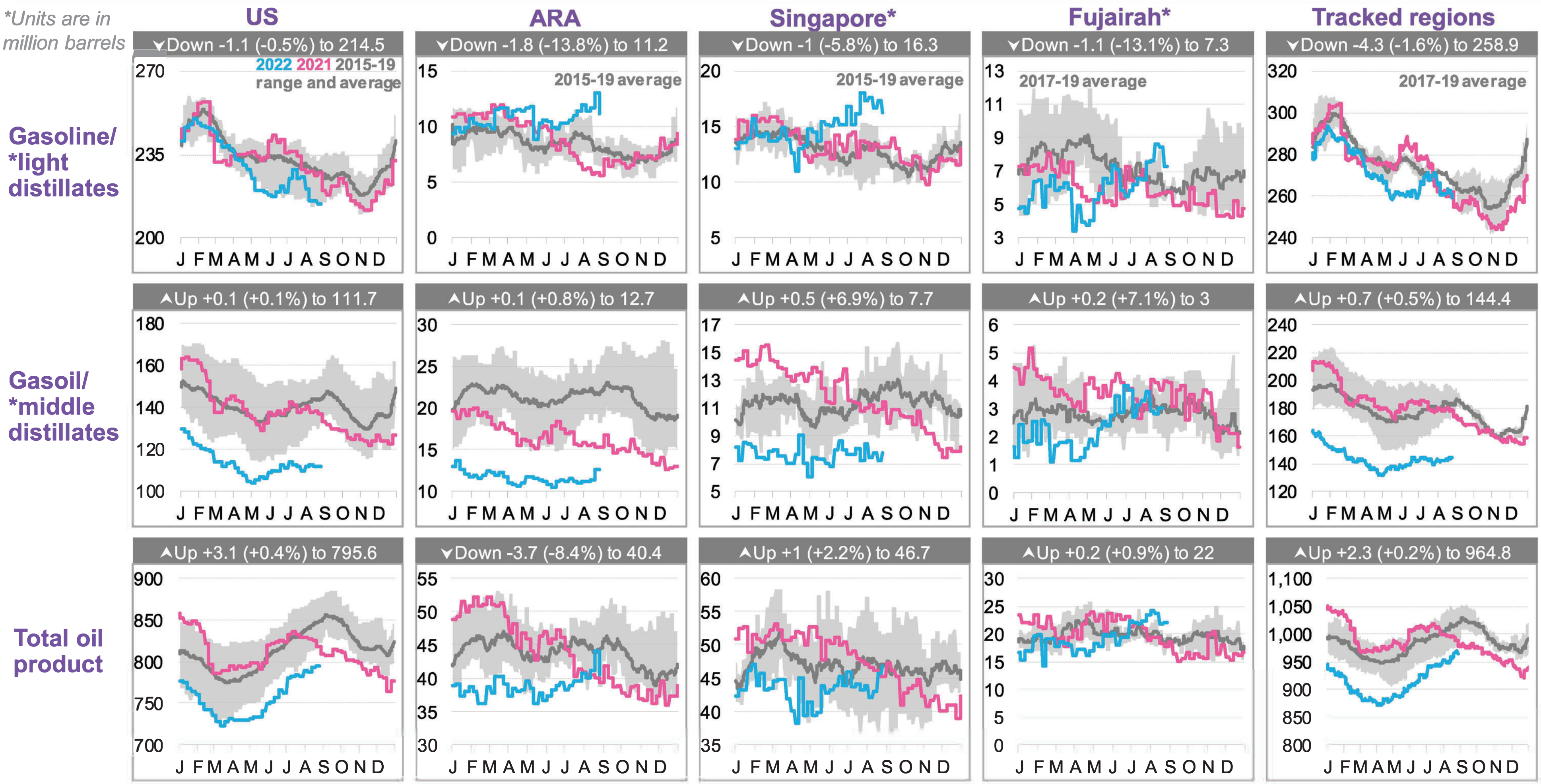
Source: BloombergNEF, Vortexa. Note: As of the ***week ending Sep. 2, 2022****. *Raw data from Vortexa are revised frequently, so the data in this report might change week-to-week.*

Fundamentals Financial

Product stocks: Current versus seasonal average

Neutral: Oil product stockpiles in tracked regions grew by 0.2% over the past week

- Chart legend are as follows: 2022, 2021 and the 2015-19 range and average. For Fujairah and tracked regions, the **2017-19 (three-year) seasonal range** is shown. Tracked regions include US, ARA, Singapore, Japan and Fujairah



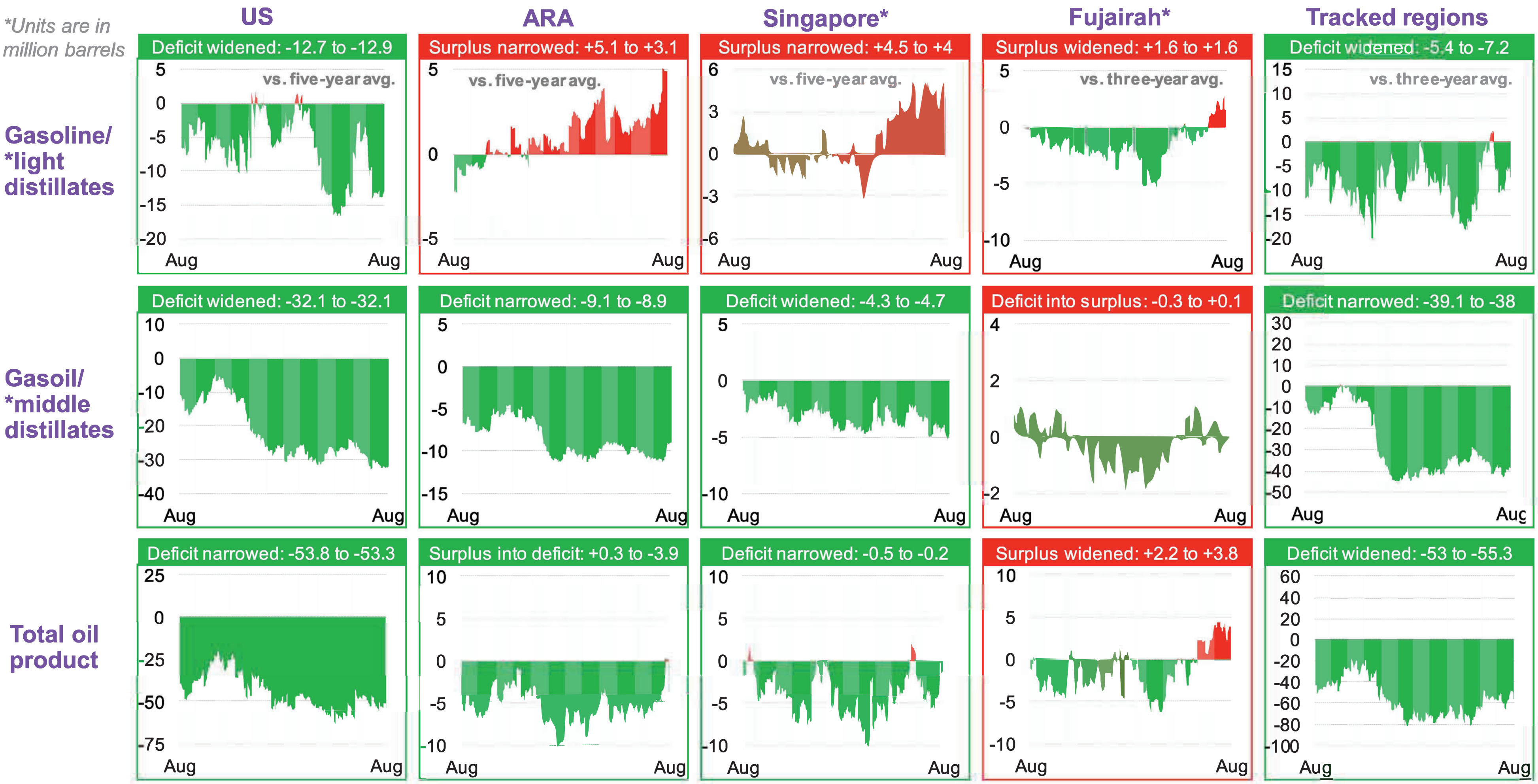
Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ. Note: As of the ***week ending August 26, 2022.***

BloombergNEF

Product stocks: Current versus seasonal average

Neutral: Oil product stockpile deficit against the seasonal average widened from 53.0m bbl to 55.3m bbl

- The charts below compare each respective regional product stockpile level against the seasonal average defined in the previous slide.
- **Red** signifies that the current stockpile levels are higher (in surplus) than the seasonal average, while **green** signals that the current stockpiles are lower (in deficit).



*Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ. Note: As of the **week ending August 26, 2022.***

Sep 06, 2022 07:45:24

OIL DEMAND MONITOR: Europe's Diesel Recovery Looks Shaky

- UK's diesel-to-gasoline demand ratio is changing, surveys show
- Global airline seat capacity slumps to a 12-week low: OAG data

By Stephen Voss

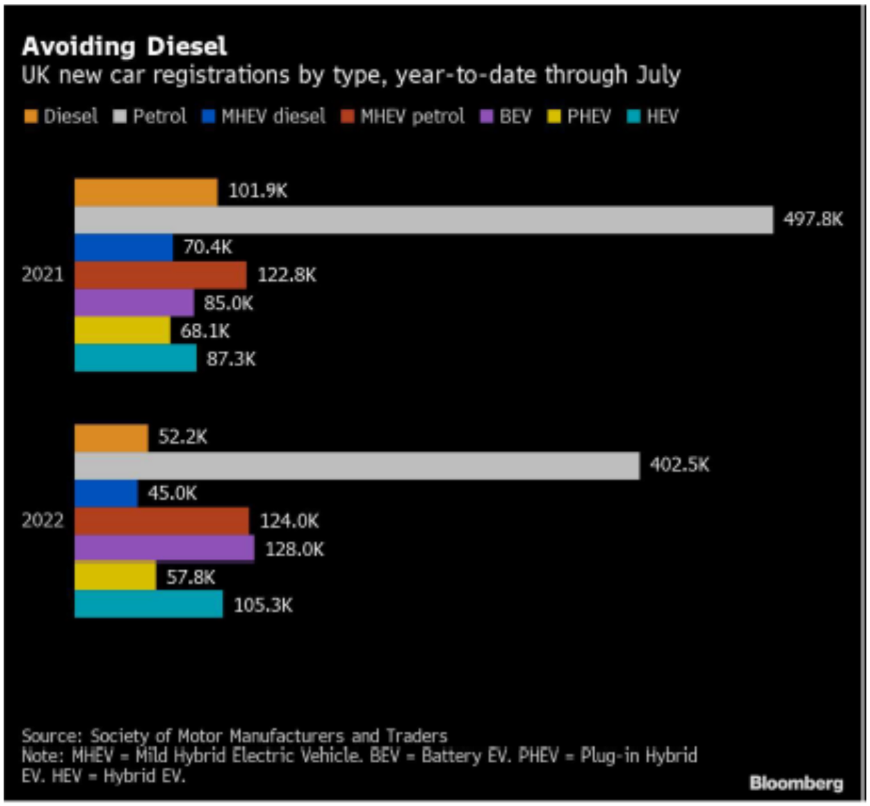
(Bloomberg) -- Demand for gasoline and diesel is weaker than before the pandemic in several key nations and faded toward the end of the summer vacations in North America and Europe. Renewed lockdowns in China took another bite out of airline travel.

The post-pandemic recovery in diesel demand lags that for gasoline, according to comparable road fuel data from three European nations.

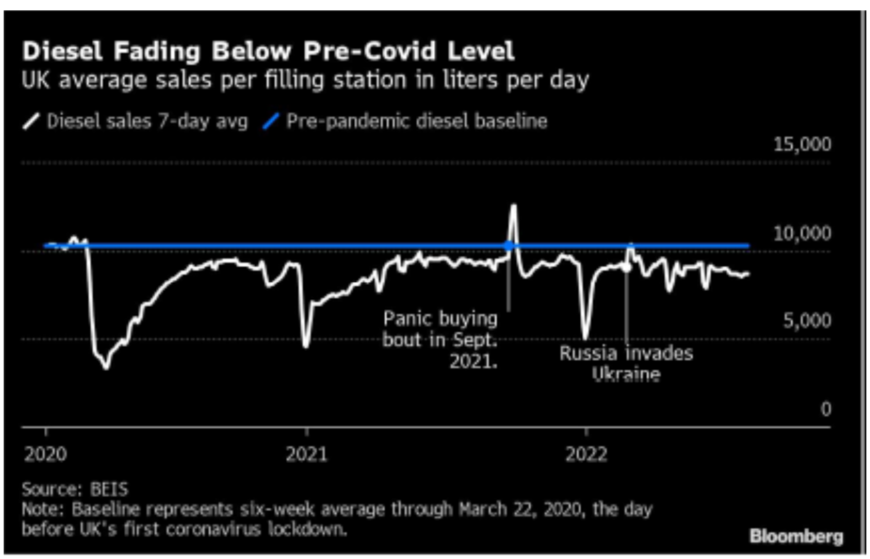
UK and Portuguese gasoline consumption is lower than before Covid struck, using data for the latest available periods, while Italian usage is up 4.3%. All three show a worse performance for diesel, though, and figures for France also show lower-than-2019 usage. Diesel deficits across those four European countries range from -4.2% to -17%.

This is part of an ongoing consumer trend across the continent favoring gasoline, or petrol, engines over more-polluting diesel, helped in part by high fuel prices and a steady increase in sales of hybrid and battery-only cars.

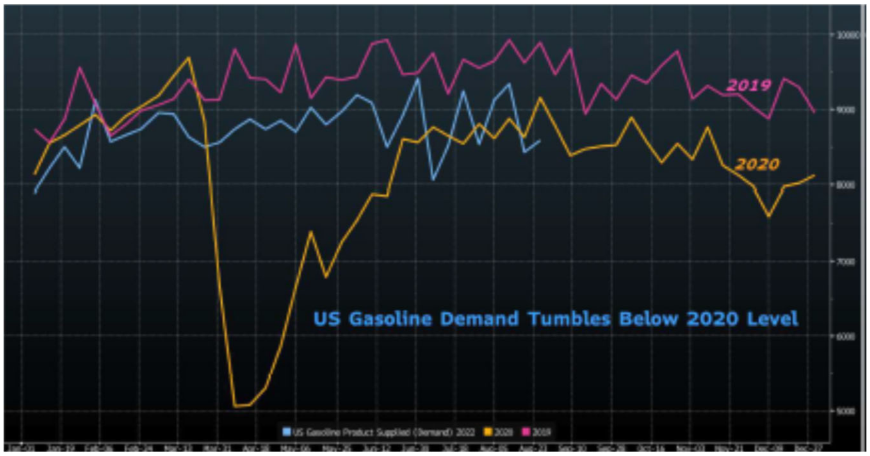
New car vehicle registrations in the UK for diesel cars during January through July were down 49% versus the same period of last year while the number for petrol engines was down only 19%, according to the Society for Motor Manufacturers and Traders. Battery-only electric vehicles were up 50% while the situation for the various kinds of hybrid car engines was more mixed.



Diesel accounted for 57% of total UK road fuel sales in the last week of August, down from about 59% in early 2020, in the six-week period just before the country's first lockdown, according to a survey of filling stations by the Department for Business, Energy and Industrial Strategy.



In the US, an end-of-summer malaise in the use of gasoline and distillate fuels including diesel continues, no doubt impacted in part by relatively high prices. Demand for both fuel groups is now struggling to keep pace with the same period of 2020 when the pandemic was in full swing.



City traffic levels around the world show a slight uptick in regular commuter activity this week. Three of the 13 cities regularly tracked in this monitor had congestion above typical 2019 levels at 8 a.m. local time on Monday morning, according to data from navigation technology company TomTom NV. That's the most since June 6 when four cities had reached that threshold.

Commuting activity may quickly intensify with vacations over, and Monday's figures were subdued in New York and Los Angeles -- two of the 13 cities -- by the Labor Day holiday. Similarly, a UK holiday lowered traffic levels in London on Aug. 29.

In China, an aggregate congestion index for 15 cities dipped slightly to 103 on Aug. 29, from 105 a week earlier, according to calculations by BloombergNEF, based on Baidu data.

Air Travel

Airlines around the world have scheduled 97.3 million seats on planes in the week starting Sept. 5, according to DAG Aviation data, which is the first time in 10 weeks that capacity has fallen below 100 million as the peak summer vacation travel season in the North Hemisphere ebbs away.

A sizeable chunk of the reduction, though, was due to a large week-on-week decline in North East Asia, including China. More than 30 Chinese cities, including Chengdu, have been fully or partially locked down to contain the spread of coronavirus, according to local media Caixin.
A broader measure of air traffic, the global number of commercial flights, has weakened slightly and remains stuck mid-way between the levels seen this time last year and in 2019.

The seven-day average for Sept. 4 was 103,387 worldwide flights a day, or 14% lower than the same period of 2019, according to tracking by Flightradar24. A separate estimate for European flights alone, from Eurocontrol, was 12% down.

Both those measures registered a 13% deficit in mid-August.

The Bloomberg oil-demand monitor uses a range of high-frequency data to help identify emerging trends.

Following are the latest indicators. The first three tables shows fuel demand and road congestion, the next shows air travel globally and the fifth is refinery activity:

Demand Measure	Location	% y/y	% vs 2020	% vs 2019	% m/m	Freq	Latest Date	Latest Value	Source
Gasoline product supplied	US	-10	-2.2	-13	+0.6	w	Aug. 26	8.59m b/d	EIA
Distillates product supplied	US	-19	-9	-12	-8	w	Aug. 26	3.57m b/d	EIA
Jet fuel product supplied	US	+1.5	+94	-1.4	+27	w	Aug. 26	1.82m b/d	EIA
Total oil products supplied	US	-12	+18	-9.7	+0.6	w	Aug. 26	20.07m b/d	EIA
All motor vehicle use index	UK	unch	+2.4	-16	-15	w	Aug. 29	84	DfT
Car use	UK	-1.1	+1.2	-13	-8.4	w	Aug. 29	87	DfT
Heavy goods vehicle use	UK	-8.2	-2.2	-55	-56	w	Aug. 29	45	DfT
Gasoline (petrol) avg sales per filling	UK	-6.5	+0.6	-9.5	+0.7	m	Aug. 22-28	6,483 liters/d	BEIS

Total road fuels sales per station	UK	-8.2	-4.5	-14	-0.4	m	Aug. 22-28	15,077 liters/d	BEIS
China 15 cities congestion	China				+4	d	Aug. 22	105	Baidu / BNEF
Gasoline	India	+16		+21	+6	2/m	Aug. 1-31	2.82m tons	Bberg
Diesel	India	+24		+12	-5	2/m	Aug. 1-31	6.12m tons	Bberg
LPG	India	+5		+2.5	-1	2/m	Aug. 1-31	2.44m tons	Bberg
Jet fuel	India	+51		-14	+1.1	2/m	Aug. 1-31	541k tons	Bberg
Total Products	India	+6.1	+13	-2.1	-5.7	m	July	17.6m tons	PPAC
Toll roads volume	France	+5.3		+3.8		m	July	n/a	Atlantia
Toll roads volume	Italy	+0.3		-2.2		m	July	n/a	Atlantia
Toll roads volume	Spain	+0.1		-1.9		m	July	n/a	Atlantia
Toll roads volume	Brazil	+7.3		+6.9		m	July	n/a	Atlantia
Toll roads volume	Chile	-1.7		+5.2		m	July	n/a	Atlantia

Toll roads volume	Mexico	+3.5		+6.3		m	July	n/a	Atlantia
Gasoline	Spain	+1.7			+6.3	m	July	555 m3	Exolum
Diesel (and heating oil)	Spain	-2			-1.4	m	July	2205k m3	Exolum
Jet fuel	Spain	+53			+12	m	July	647 m3	Exolum
Total oil products	Spain	+5.6			+2.2	m	July	3407 m3	Exolum
Road fuel sales	France	-6.2			-0.2	m	July	4.268m m3	UFIP
Gasoline	France	-0.6				m	July	n/a	UFIP
Road diesel	France	-8.2		-15		m	July	n/a	UFIP
Jet fuel	France	+38		-20	+12	m	July	688k m3	UFIP
All petroleum products	France	-2.6			+2.6	m	July	4.737m tons	UFIP
All vehicles traffic	Italy	-1.3			+1.7	m	July	n/a	Anas
Heavy vehicle traffic	Italy	-6.4			-6.9	m	July	n/a	Anas
Gasoline	Portugal	-0.2	+7	-5.4	+8.4	m	July	94k tons	ENSE
Diesel	Portugal	-6.3	-3.2	-11	+3.2	m	July	393k tons	ENSE
Jet fuel	Portugal	+85	+288	-5.6	+11	m	July	158k tons	ENSE
Total fuel sales	Italy	-2.4	+4.3	-8.7	+1.7	m	July	4.6m tons	Ministry
Gasoline	Italy	-2.1	+11	+4.3	+5.6	m	July	731k tons	Ministry
Diesel /gasoil	Italy	-2.7	+4.4	-4.2	+4.4	m	July	2.403m tons	Ministry
Jet fuel	Italy	+61	+169	-21	+6.3	m	July	403k tons	Ministry

Notes: Click here for a PDF with more information on sources, methods. The frequency column shows w for data updated weekly, 2/m for twice a month and m for monthly. The column showing "vs 2020" is used for some data, such as comparing Italian jet fuel sales for July 2022 vs July 2020.

In DtT UK daily data, which is updated once a week, the column showing versus 2019 is actually showing the change versus the first week of February 2020, to represent the pre-Covid era.

In BEIS UK daily data, the column showing versus 2019 is actually showing the change versus the average of Jan. 27-March 22, 2020, to represent the pre-Covid era. The data switched from weekly to monthly, after July 28.

Atlantia is publishing toll road data on a monthly basis, rather than the weekly format seen in 2021, and DoT also switched to monthly data after the week ended April 3.

City congestion:

Measure	Location	% chg vs avg 2019	% chg m/m	Sept 5	Aug 29	Aug 22	Aug 15	Aug 8	Aug 1	Jul 25	Jul 18	Jul 11	Jul 4
		(for Sept. 5)		Congestion mins added to 1 hr trip at 8am* local time									
Congestion	Tokyo	-16	-2	31	32	35	8	32	31	32	7	31	38
Congestion	Taipei	+3	+36	37	29	29	26	27	26	26	26	26	25
Congestion	Jakarta	-6	unch	37	36	38	39	37	37	34	35	26	29
Congestion	Mumbai	-54	-16	22	29	32	3	26	25	26	29	27	26
Congestion	New York	-100	-100	zero	17	13	14	17	20	17	21	17	zero
Congestion	Los Angeles	-95	+91	2	35	33	31	19	18	16	20	17	2
Congestion	London	-3	+110	37	2	20	18	17	17	21	26	32	35
Congestion	Rome	-15	+431	41	12	5	zero	8	19	25	32	32	33
Congestion	Madrid	-53	+460	17	9	4	zero	3	5	zero	11	13	14
Congestion	Paris	+1	+369	45	25	14	1	10	13	25	28	31	37
Congestion	Berlin	-18	+77	28	25	25	19	16	13	15	14	17	29
Congestion	Mexico City	+1	+57	50	44	37	37	32	26	23	23	25	26
Congestion	Sao Paulo	-26	-21	32	39	31	33	40	26	20	19	19	20

Source: TomTom. Click here for a PDF with more information on sources, methods.

* 9am statistics are used for Mumbai. All other cities use 8am.

NOTE: m/m comparisons are Sept. 5 vs Aug. 8. The US and UK had public holidays on Sept. 5 and Aug. 29, respectively. The Aug. 15 Assumption Day religious holiday likely cut traffic flows in Rome, Madrid and Paris. TomTom has been unable to provide Chinese data since April 2021. Taipei and Jakarta were added to the table in December 2021.

Chinese City Congestion:

Measure	Location	% chg vs Jan. 2021	% chg m/m	% chg w/w	Aug. 29	Aug. 22	Aug. 15	Aug. 8	Aug. 1	Jul. 25	Jul. 18	Jul. 11	Jul. 4	Jun. 27
		(compare vs Aug. 29)												
Congestion	Beijing	+20	+5.3	-3	120	124	111	109	114	109	116	124	130	109
Congestion	Chongqing	-27	-22	-13	73	84	83	88	93	96	101	105	113	113
Congestion	Guangzhou	+21	+11	+6	121	114	111	112	109	105	103	109	116	113
Congestion	Shanghai	+23	+14	+2.4	123	120	112	113	108	105	103	106	119	111
Congestion	China-15	+3	+2.3	-2	103	105	102	103	101	101	103	106	115	111

Source: BNEF calculations based on Baidu congestion data, showing a seven-day moving average indexed against a January 2021 baseline of 100. China-15 is the weighted average of the 15 cities with the highest number of vehicle registrations. m/m comparisons are Aug. 29 vs Aug. 1

Air Travel:

Measure	Location	y/y	vs 2 yrs ago	vs 2019	m/m	w/w	Freq.	Latest Date	Latest Value	Source
		changes shown as %								
Airline passenger throughput	US	+21	+186	-3.3	-19	-15	d	Sept 4	1.97m	TSA
Airline passenger throughput (7d avg)	US	+21	+182	-9.2	-11	-4.9	d	Sept 4	2.019m	TSA
All flights	Worldwide	+9.7	+41	+1.6	-4	-11	d	Sept 4	210,831	Flightradar24
Commercial flights	Worldwide	+11	+50	-14	-4.1	-7.1	d	Sept 4	103,387	Flightradar24
Air traffic (flights)	Europe			-12	+0.6	-0.7	d	Sept 4	30,197	Eurocontrol
Air traffic (flights)	UK			-14	+3	+1.1	d	Sept 4	5,605	Eurocontrol
Air traffic (flights)	Germany			-23	+3.2	+1.4	d	Sept 4	4,849	Eurocontrol
Seat capacity	Worldwide	+24	+70	-15	-5.1	-2.8	w	Sept. 5-11	97.28m	OAG
Seat capacity	North America			-6.7		-0.8	w	Sept. 5-11	n/a	OAG
Seat capacity	North East Asia			-30		-10	w	Sept. 5-11	n/a	OAG
Seat capacity	South East Asia			-28		+0.2	w	Sept. 5-11	n/a	OAG
Seat capacity	South Asia			-4.8		+0.3	w	Sept. 5-11	n/a	OAG
Seat capacity	Western Europe			-11		-0.7	w	Sept. 5-11	n/a	OAG
Seat capacity	Central America			+10		-3.2	w	Sept. 5-11	n/a	OAG
Heathrow airport passengers	UK	+318	+628	-19	+5.4		m	July 2022	6.31m	Heathrow

NOTE: Comparisons versus 2019 are a better measure of a return to normal for most nations, rather than y/y comparisons.

FlightRadar24 data shown above, and comparisons thereof, all use 7-day moving averages, except for w/w which uses single day data.

Measure	Location	y/y	chg vs 2019	m/m chg	Latest as of Date	Latest Value	Source
		Changes are in ppt unless noted					
Crude intake	US	+1.9%	-6.7%	+2.4%	Aug. 26	16.2m b/d	EIA
Utilization	US	+1.4	-2.5	+1.7	Aug. 26	92.7 %	EIA
Utilization	US Gulf	+2	-1.4	-0.9	Aug. 26	94.4 %	EIA
Utilization	US East	+13	+31	-0.6	Aug. 26	97.6 %	EIA
Utilization	US Midwest	-1.6	-7.9	+5.8	Aug. 26	92.7 %	EIA
Apparent Oil Demand	China	-9.7%	+5.5%	-6.7%	July 2022	12.16m b/d	NBS
Utilization (indep. refs)	Shandong, China	-9.9	-2.8	-9.3	Sept. 2	61.20 %	Oilchem

NOTE: US refinery data is weekly. China NBS apparent demand is usually monthly and China

NOTE: US refinery data is weekly. China NBS apparent demand is usually monthly and China Shandong is updated twice a month. Changes are shown in percentages for the rows on crude intake and Chinese apparent oil demand, while refinery utilization changes are shown in percentage points. SCI99 data on Chinese refinery run rates was discontinued in late 2021.

https://home.treasury.gov/news/press-releases/jy0939

Remarks by Secretary of the Treasury Janet L. Yellen at Ford Rouge Electric Vehicle Center

September 8, 2022

As prepared for delivery

Thank you for that introduction. It's great to be in Dearborn and, later today, in Detroit. As the global capital of the automobile industry, this region will experience significant growth and many good jobs from the recently enacted Biden economic plan.

I'd like to acknowledge Lieutenant Governor Gilchrist for hosting me here in Michigan today. Thank you to Senator Stabenow, whose leadership on many provisions of the Inflation Reduction Act and CHIPS Act made them a reality, including her critical work on the energy manufacturing tax credit. I'd also like to thank Senator Peters for his equally strong advocacy and leadership. Thank you, also, to the members of Congress who are here with us today – Congresswomen Stevens and Lawrence – who have worked very hard over the past few months on historic economic legislation. And I am grateful to the leaders at Ford for having me at this cutting-edge EV assembly plant.

As Treasury Secretary, over the past year and a half – among other things – I have been especially focused on addressing the pandemic-caused crisis. We have been rescuing the job market from the pandemic downturn and stabilizing the economy after its unprecedented disruptions.

The pandemic exposed our vulnerabilities, but our economy had long been suffering from soaring inequality, weak growth, and a sense of falling further behind for many – too many.

Sluggish productivity growth and declining labor force participation have weighed down our economic potential. And growing disparities in economic conditions across geographies and racial groups have exacerbated inequality. The pandemic and Putin's immoral war in Ukraine remind us of our vulnerability to global supply shocks. But beyond that, the threat of climate change looms very large.

Today, I will step back and describe the Administration's efforts to stabilize the economy amid a series of shocks and disruptions. We have brought the United States back to full employment in record time.

Then, I will discuss the meaning, for the future, of the historic economic legislation enacted by this Administration. Taken together, the Bipartisan Infrastructure Law, the CHIPS Act, and the Inflation Reduction Act authorize among the most significant investments our country has ever made. I believe firmly that they will help us achieve stable, sustainable growth. And they will move us toward a fairer and more resilient economy.

I. ECONOMIC STABILITY

When President Biden took office in January 2021, his immediate focus was to restore the economy while protecting Americans from the threat of a deadly virus. At the time of his inauguration, the pandemic had claimed over 400,000 lives.[1] And 3,000 additional lives were being lost each day.[2] Our public health crisis had triggered an economic calamity. The unemployment rate was over 6 percent with more than 800,000 new jobless claims, on average, per week.

It's important to remember the context for the President's actions. At that time, we faced unprecedented uncertainty about the fate of our economy. The truth is: in 2020 and 2021, the tail risk of the pandemic's impact on our economy was a downturn that could match the Great Depression. Our policy response had to sufficiently address all the potential outcomes. So the federal government intervened to keep businesses open, to keep Americans in their homes, and to keep local governments well-resourced.

Our plan has worked. Due to the American Rescue Plan and our vaccination campaign, the United States experienced the fastest pace of job creation in our history. Household balance sheets are strong. Businesses continue to invest. Our broad and inclusive recovery has outpaced that of many other large economies. And measured by gross domestic income, our economy continues to expand and is operating above levels that would have been predicted pre-pandemic.

It's fair to say: by any traditional metric, we have experienced one of the quickest economic recoveries in our modern history.

Now, Americans are rightfully concerned that higher prices are squeezing their day-to-day budgets and their longer-term savings. The causes of inflation are largely global. But the pain of inflation is personal. This Administration's top economic priority is to combat inflation, even as we know the Federal Reserve has the primary role to play in restoring price stability.

The President and his entire economic team have focused particularly on our supply chains and energy markets. Last year, when supply chain bottlenecks contributed to upward pressure on prices, the Administration worked with partners to recruit more truck drivers, to fund pop-up container yards, and to get several ports on 24/7 operations.[3] We also have released a million barrels of oil per day from our Strategic Petroleum Reserve. By Treasury estimates, the President's decision has reduced the price of gas by between around 17 and 42 cents per gallon this year.[4]

In markets where we could not help lower prices by expanding supply, we have aimed to mitigate the pain directly, through cost relief. The newly passed Inflation Reduction Act boldly reduces everyday costs for families across the country. Without the law, healthcare premiums would have spiked for millions of Americans in January. Instead, 13 million Americans will continue to save an average of $800 a year.[5]

In coming years, Medicare will be able to negotiate, and thereby lower the price of high-cost prescription drugs. That corrects a market distortion that has placed excessive pricing power in the hands of pharmaceutical companies.

In sum, while costs to American families remain unacceptably high, I believe this Administration's actions have made a meaningful difference. And they will continue to do so.

II. SUSTAINABLE GROWTH

As we continue to tackle inflation, President Biden has made clear: we cannot just return to the old normal. The recent trifecta of legislation our Administration has signed into law will strengthen the foundations of long-term growth at the core of our post-pandemic economy.

Earlier this year, I described many of these policies as "modern supply-side economics." I described how, prior to the pandemic, higher inequality was accompanied by slower growth. Now, with an economy at full employment, we are uniquely suited for a supply-side expansion that delivers sustainable growth and reduces inequality.

Just over half a year after we introduced this concept, the Biden Administration has delivered on key aspects of the modern supply-side agenda. In doing so, we are making a generational investment in the strength of our economy and in the prosperity of our citizens.

In particular, I want to touch upon three economic impacts of the newly passed Biden economic plan. They are: expanded productive capacity of our economy; increased resilience to global shocks; and greater fairness for workers and businesses.

A. Expanding the Productive Capacity of Our Economy

The Bipartisan Infrastructure Law, CHIPS Act, and Inflation Reduction Act will expand the productive capacity of our economy. They will raise the ceiling for what our economy can potentially produce. They will provide a historic injection of funding into investments that have been too-long neglected.

Economists have long stressed the importance of basic public infrastructure for economic growth. Yet more than 40,000 bridges[6] – and one in five miles of highways and major roads in America – are in poor condition.[7]

Our plan provides the funds to fix roads, ports, bridges, and public transit. People and goods will move faster – and with fewer bumps and costly supply-chain snarls such as the ones we have seen during the pandemic. These improvements will expand output. They will enhance the

productivity of American workers. Studies show that a 10 percent increase in government infrastructure investment grows national output by over 1 percent in the long run.[8]

Our plan will also bring high-speed internet to unserved and underserved communities across the country. During the pandemic, I heard heartbreaking stories about parents who drove each day to parking lots with wi-fi so their children could complete their homework online.[9] With this closing of the digital divide, more children will be able to complete their online schoolwork right at home. The economic opportunities for millions of Americans currently without adequate internet service will be broadened. Regardless of where they live, they will have access to new jobs or customers around the world.

Economists have also long underscored the contribution of investments in research and development to American productivity growth. While recent attention on the CHIPS Act has been focused on semiconductor manufacturing, our plan also authorizes tens of billions in federal government investment into research and development across a range of agencies.

This authorization could not come too soon: the United States now ranks tenth in the world in terms of R&D investments as a share of output. Over half a century ago, the federal government spent 1.9 percent of GDP on R&D, in part to fuel the race to the moon. In recent years, it has spent a third of that. The estimated cost of the retreat in public R&D is $200 billion per year in lost economic output.[10] Meanwhile, competitors in China and the rest of the world are marching forward. The Biden economic plan marks our government's intent to return to serious scientific research and innovation.

I've heard laments of the days when America built and America innovated. The Biden economic plan provides significant investments in the capacity of the American economy to do just that.

B. Building Economic Resilience

The second critical impact of the Biden Administration's modern supply-side agenda is to improve American economic resiliency. Americans know the unsettling feeling of seeing empty new car lots – or volatile gas prices due to supply shocks beyond our control. Since the private sector does not always optimize their supply chain to consider external risks, government has a critical role to play.

We have become too vulnerable to countries like China using their market advantages in certain technologies or natural resources to exercise leverage against other countries for their own benefit. Our plan takes significant steps toward reducing these economic and national security risks. At the same time, we will maintain mutually beneficial trade and keep our deep ties with other countries. This begins with two sectors that are core to 21st century resilience: semiconductors and energy.

While semiconductors are found everywhere in everyday goods, the United States produces only 12 percent of semiconductors today. That is down from more than a third in the 1990s.[11] The impact of a chip shortage has recently been felt acutely across our economy. Factories have been idled and consumers have faced skyrocketing prices for cars and other goods that rely on chips as a key input.

Our plan, which is powered by the CHIPS law, provides around $40 billion in incentives to onshore semiconductor manufacturing in the United States. That helps support the cost of investing here rather than elsewhere. There will be greater certainty in our increasingly technology-dependent economy. Progress has already been made: a number of semiconductor manufacturers have already announced expansions of their U.S. footprint since passage of the law.[12]

The past few years have also reminded us of our vulnerability to geopolitical and climate-related shocks. These shocks have increased in both frequency and scale. As I speak here, the southwest United States is in a "megadrought" – an ongoing 22-year drought that is the driest period in over 1,200 years.[13]As part of our plan, the Bipartisan Infrastructure Law allocates around $50 billion toward climate resilience and weatherization. It will protect farmers, homeowners, and communities against the increasing number and scale of droughts, heat waves, and floods.[14]

Given the existential threat posed by climate change, it is imperative that we address it. Our plan – powered by the Inflation Reduction Act – represents the largest investment in fighting climate change in our country's history. It will put us well on our way toward a future where we depend on the wind, sun, and other clean sources for our energy. We will rid ourselves from our current dependence on fossil fuels and the whims of autocrats like Putin.

In policy terms, experts estimate this law puts the United States on a path to reducing emissions relative to 2005 levels by approximately 40% within the next eight years. That places President Biden's goal of cutting our emissions in half by 2030 well within reach. While there is much more work to do, we can finally say to ourselves and to the world that we are on a path to a net-zero emissions economy.

I am proud that Treasury is at the forefront of implementing this plan. Today, countries representing around 90% of global GDP have made net-zero commitments by mid-century or soon thereafter.[15] By mobilizing private capital, the clean energy tax credits implemented by Treasury will propel our economy and workers to a leadership position in the fastest growing markets and technologies of today and the future, with positive spillovers to the rest of the world.

This includes the U.S. clean vehicle sector, where we can expect greater investment – and more good jobs, like the ones here at Ford – as we develop the supply chain here at home. Further, in the process of boosting domestic clean energy production, the law will support our energy security and insulate us from the type of fossil fuel-driven energy volatility that we've seen in the past year.

III. ECONOMIC FAIRNESS

I want to end by speaking about fairness in the economy. To me, fairness is a goal of policy. And it's a moral issue. But progress has been elusive: long before the virus arrived, we were living in an economy where wealth built upon wealth and a growing number of working families – and communities – were being left behind.

The modern supply-side policies that I spoke of are not just pro-growth. They are also pro-fairness. The traditional approach to supply-side economics – which focuses on providing tax incentives to owners of capital in order to boost private investment – has, in many cases, contributed to deepening income and wealth disparities. We saw that in the previous Administration's signature piece of economic legislation – a tax bill that overwhelmingly benefitted the wealthiest Americans and biggest corporations.

In contrast, the modern supply-side agenda is concerned with a broad range of productivity-boosting investments and with a broad distribution across sectors, people, and places. It recognizes that investing in disadvantaged communities often results in higher returns on investment. And it boosts growth by tapping all our resources. In layman's terms, this approach embraces the notion that some of the best opportunities for growth occur when we invest in people and places that have been forgotten and overlooked.

We know that a disproportionate share of economic opportunity has been concentrated in major coastal cities. Investments from the Biden economic plan have already begun shifting this dynamic. Given its manufacturing focus – and manufacturing's reliance on strong infrastructure and supply chains – we expect to see dollars catalyze innovative investments across cities and towns that haven't seen such investment in years.

As an example, to spur regional economic development, the Commerce Department will establish at least 20 regional technology and innovation hubs. They will be geographically dispersed with priority for underserved and underrepresented communities. Such dispersal of economic opportunity across the country will mean good new jobs in industries of the future. It will also lead to cascading economic progress for local communities that are so vital to the economic and social fabric of this country.

Beyond our growth strategy, the Administration is also focused on other ways to build fairness in our economy. That includes fixing the tax system.

With the President's leadership, we secured $80 billion of funding for the IRS. That reverses a decade of steep decline.[16] Billions of dollars will go toward tangible improvements that taxpayers will see when they interact with the IRS. We will have improved customer service; more answered calls; expedited return processing and refunds; updated computer systems; and simplified tax filings.

Furthermore, this funding will also help correct a two-tiered tax system by ensuring that large corporations and high-income earners cannot avoid paying the taxes they owe. The tax gap – the amount of money that is owed but not paid to the IRS – is huge. It is estimated at $7 trillion over the next decade. And it's disproportionately concentrated among high earners. These earners have more complex and opaque sources of income. And due to the IRS' resource constraints, they are very rarely audited. That means that an increased burden in funding our government and investing in our economy falls on working- and middle-class families that are doing everything right.

These resources will enable the IRS to increase audits of taxpayers at the high end and collect taxes from those who have not paid their full bill. I have made clear that this funding will not be used to raise audit rates relative to recent years for households making under $400,000 annually. Rather, with the right technological infrastructure in place, audit rates for honest taxpayers will actually decline.

This funding will help the IRS to collect billions in revenue, which can be used to reduce the deficit, fund additional public investments, or lower taxes for working families. Combined with the corporate tax reforms in the law, this funding also represents some of the most significant steps we've taken in recent years to build a fairer and more effective tax system.

IV. CLOSING

To summarize, the decisive actions taken by President Biden to vaccinate individuals and control the virus saved countless American lives. These lifesaving measures were accompanied by policies to revive and reinvigorate the economy. Over the past year and a half, the United States has experienced a historic jobs recovery; expanded our capacity for sustainable, resilient growth; and advanced economic fairness.

So – where do we go from here?

As we look to the fall and the months beyond, our Administration is ready to build on the achievements of the past year.

The most immediate challenge is to return to an environment of stable prices without sacrificing the economic gains of the past two years. To ensure our long-term economic stability, we must keep our public finances on sound footing. We will build on the momentum of the Inflation Reduction Act's corporate tax reforms to advocate for additional reforms of our tax code and the global tax system. This includes closing loopholes and returning tax rates for high earners and corporations to historical norms. By making everyone pay their fair share, these reforms will provide our government with additional fiscal room to make critical investments.

We will also continue to support sustainable, resilient growth. In the coming months, we expect to see significant movements of private capital into growing industries, such as clean energy production and semiconductor fabrication. We will coordinate permitting reform across the government to speed up these investments while upholding bedrock standards and laws. We also understand the importance of reliable and sustainable sourcing of raw minerals and materials – such as polysilicon, lithium and cobalt, and iron and steel – as we build the chips, batteries, and infrastructure of the future.

We especially understand the urgency of investing in and expanding America's most valuable economic asset: our workforce. Programs like free community college and expanded workforce training increase the productivity of our labor force. Further, we must invest in structural reforms that increase our labor force participation rate. A wide body of research has shown that high-quality, affordable childcare and free preschool increase the likelihood that parents, particularly mothers, will participate in the workforce. They also provide lasting benefits on the outcomes of their children.

Lastly, we will continue to pursue economic fairness. The policies I have just outlined – from the tax reforms to affordable childcare – are powerful tools to level the playing field. But there is more. In particular, I believe it is a national imperative to increase the affordability of housing, which will confer substantial health, social, and economic benefits on low- and middle-income families.

Simply put, it should be easy – not hard – to put a roof over your head. Even as the Administration's policies prevented the tsunami of pandemic-related evictions that we had feared, we must continue advancing our coordinated government approach to expand the supply of housing.

For all there is left to do, I will say this: after the progress we have made over the past few months, I am more optimistic about the course of our economy than I have been for quite a while. We are headed in the right direction.

Thank you.

US Oil Indicators Weekly

Takeaways: West Texas Intermediate crude prices plunged below $90 a barrel in the final days of August, sliding 11% over just three days. The sell-off comes amid tighter monetary policy worldwide and renewed ant-virus lockdowns in China spurring demand concerns, although WTI bounced back to $88.60/bbl, bolstered by setbacks in negotiations over Iran's nuclear program.

Data released by the US Energy Information Administration on Wednesday August 31 added to the broader demand concerns – implied gasoline demand is showing no signs of improvement in the final weeks of summer, despite gains in mobility metrics nationwide. The four-week moving average remains 800,000 barrels a day below the 2015-19 seasonal average after minimal growth in the weekly figure did little to overcome the previous week's plunge.

Jet fuel demand has proved far more resilient in recent weeks. Airport activity is approaching 2019 levels as it continues to stave off typical seasonal declines, boosting demand and driving down inventories to an 8-year seasonal low in this week's report.

	Frequency	Source	Snapshot: September 2, 2022
Overall market indicators:			
Mobility	Daily	Google and TomTom mobility	TomTom congestion levels continue to surge, outpacing the last year's end-of-summer rebound in city traffic
Economic activity	Daily	New York MTA, Moovit, OpenTable, Prodco	US restaurant ticked upwards last week, with a massive surge in Florida according to OpenTable data, as NYC subway ridership continues to slip
Crude oil prices	Daily	Bloomberg	West Texas Intermediate front-month prices plunged below $90 a barrel in the final days of August, sliding more than 11% over just three days
Oil demand:			
Road congestion and gasoline	Weekly, Hourly	US EIA, TomTom	Gasoline demand is showing no signs of improvement in the final weeks of summer, despite gains in mobility metrics nationwide, as minimal growth in the weekly figure was dwarfed by the previous week's plunge
Air travel and jet fuel	Daily	US TSA, FlightStats	Airport activity continues to stave off typical seasonal declines as it approaches 2019 levels, boosting demand and sinking inventories to an 8-year seasonal low
Refinery operations	Daily	US EIA	Refinery runs in the Midwest dropped after a fire knocked down 4 units at BP Whiting refinery, the largest inland fuelmaker in the US
Crude and product inventories	Weekly	US EIA	Crude inventories declined by over half a million barrels at Cushing, coinciding with a slowdown in Canadian imports likely stemmed from BP's refinery outage
Oil production	Weekly	US EIA	US production bounced back to 12.1 million b/d as the drilling rig count recorded its first monthly decline since the pandemic decimated activity in 2020

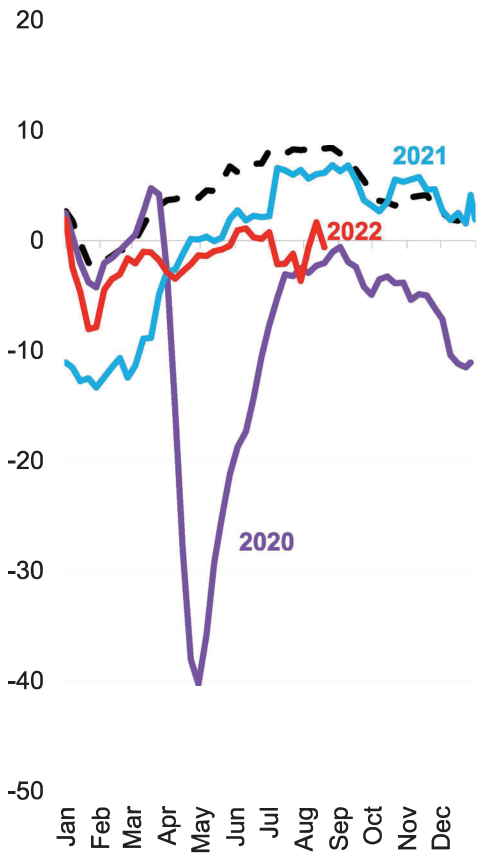
Source: BloombergNEF. Note: Green signals an upturn from the disruption caused by Covid-19, red indicates a downturn, orange indicates no or mixed change

Spotlight: Making sense of gasoline demand's disconnect to traffic and mobility indicators

EIA gasoline demand

Product supplied, 4-week MA

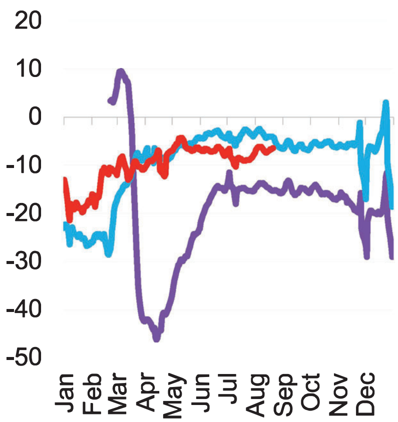
Indexed to Jan-Feb 2020



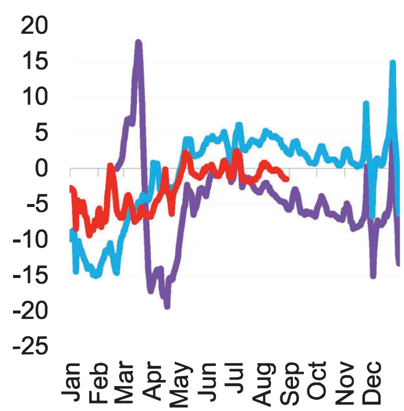
Source: BloombergNEF, US Energy Information Administration

Google mobility index

Retail and recreation



Grocery stores, pharmacies



Source: BloombergNEF, Google Community Mobility Report

The US Energy Information Administration has come under increased scrutiny in recent months regarding a crucial piece of data included in their weekly inventory report dubbed "implied gasoline demand" – which has seen a disconnect from various traffic and mobility indicators amid abnormally high weekly volatility.

- The figure is a rough estimate of weekly domestic gasoline demand – representing weekly motor gasoline 'product supplied' from US refineries. Exports are subtracted and imports are added to estimate US consumption.
- Despite stronger year-over-year traffic and workplace mobility indicators, demand has lagged 2021 levels ever since pump prices surged to record levels in April. Weekly data began to exhibit extreme volatility in June, as it fell to nearly 1 million barrels a day behind the 2015-19 seasonal average.

The agency heavily emphasizes the 'rough' aspect of the estimate for the weekly figure – still, over time you would expect the figure to be a fairly accurate representation of consumption, barring any adjustment the EIA makes in the more thorough monthly report. But despite expectations that the figure would edge closer to 2021 levels to reflect mobility indicators, it has not.

Mobility data collected by Google, which leverages geolocation data from millions of devices to track activity at various categorized locations, can provide valuable insight into US consumer behavior.

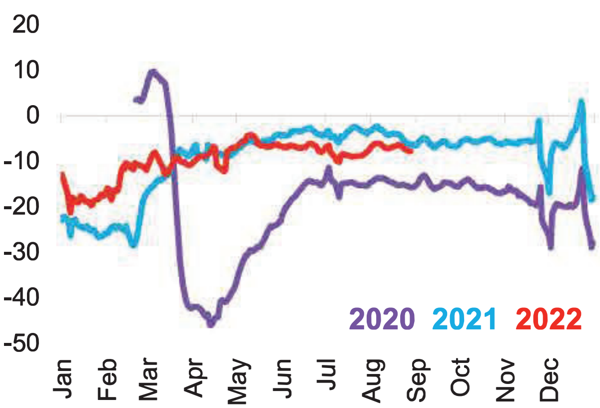
- Only two of the six bucketed categories – *retail and recreation* and *grocery stores and pharmacies* – seem to line up with the EIA's demand data.
- Both indexes dipped below 2021 levels this spring, about the same time EIA figures faltered, then fell further behind throughout the summer

Google doesn't provide much transparency into how each category is weighted and which locations are included, but these two metrics appear to represent how frequently Americans are running errands, shopping or spending time outside the home for some form of entertainment. This could suggest that reduced summer demand may not just be a result of shelved summer road trips, but that inflated costs at both the pump and the store has resulted in a curtailment or consolidation of day-to-day trips outside the home.

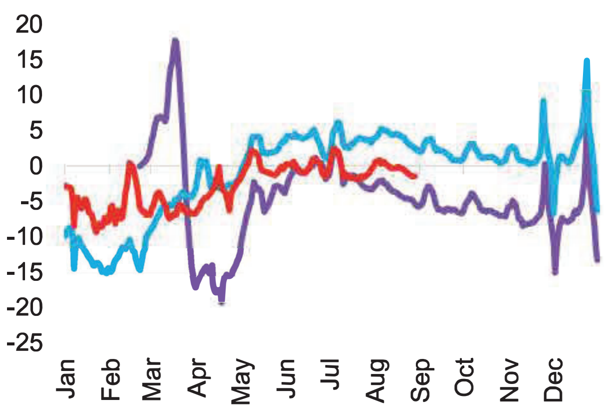
Google mobility index

US mobility activity by category

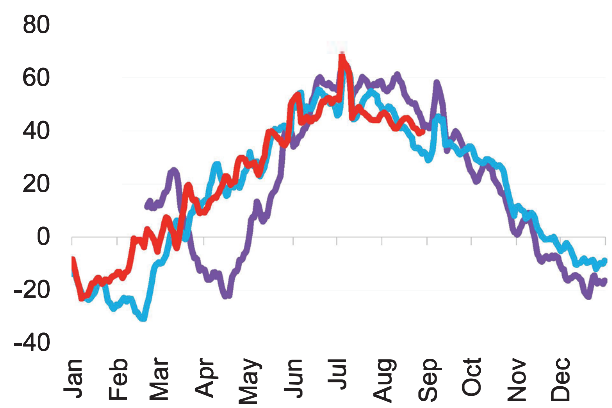
Retail and recreation



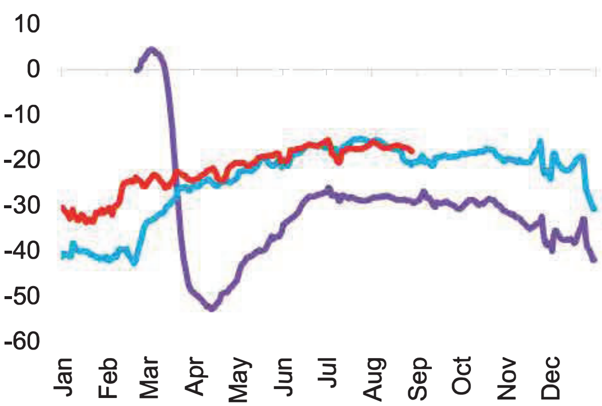
Grocery and pharmacy



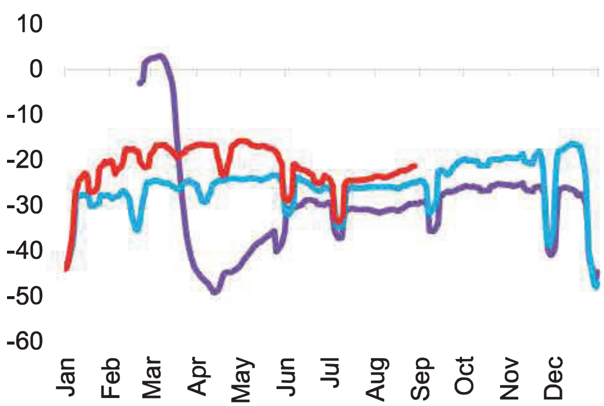
Parks



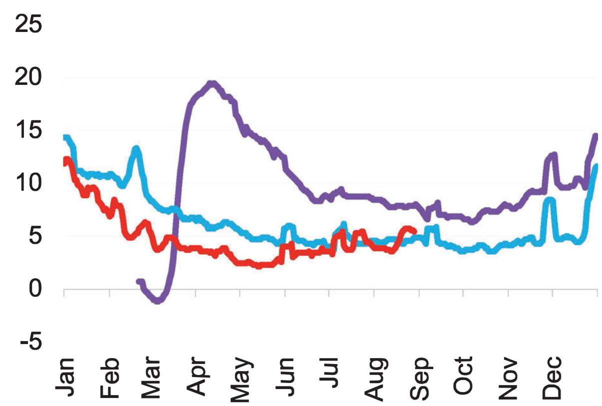
Transit stations



Workplace



Residential



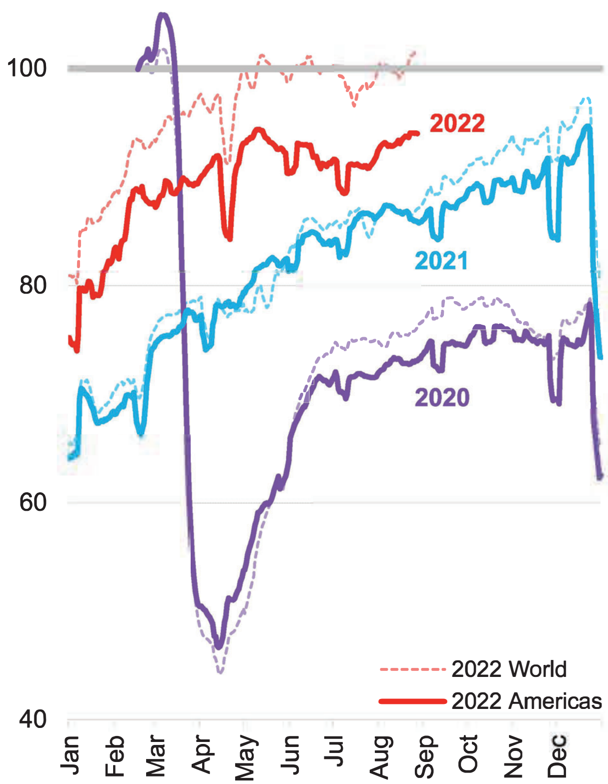
Source: BloombergNEF, Google Community Mobility Report

Mobility

TomTom congestion levels continue to surge, outpacing the last year's end-of-summer rebound in city traffic

Google mobility index

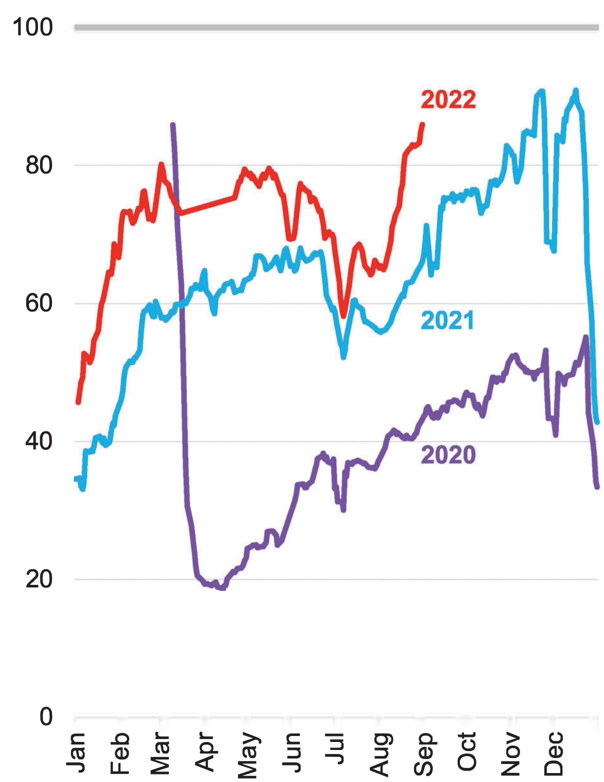
Indexed to Jan-Feb 2020



Source: Google Community Mobility Report, BloombergNEF. Note: Data exclude China and Russia. Calculation includes retail and recreation, workplaces, transport hubs. The world/regional index is weighted by the 2019 road fuels demand of each country. ***Data updated to August 27, 2022.***

TomTom congestion index

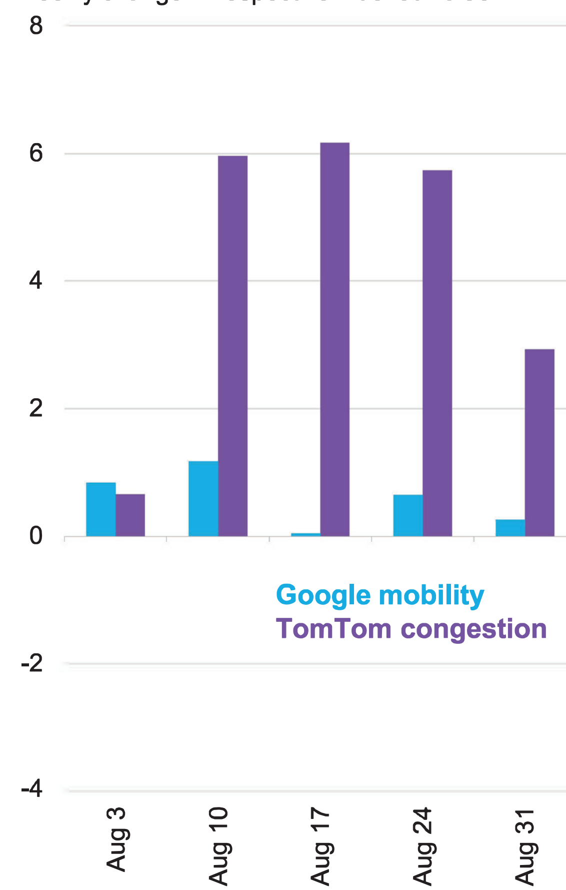
Indexed to 2019 to average peak levels



Source: BloombergNEF, TomTom Traffic Index. Note: 'Peak congestion index' is calculated by BNEF. Index is the arithmetic daily average of the hourly weekday peak congestion data of various cities in North America, compared to the 2019 average values. ***Data updated to August 31, 2022.***

Americas week-on-week change

Weekly change in respective indexed value



BloombergNEF

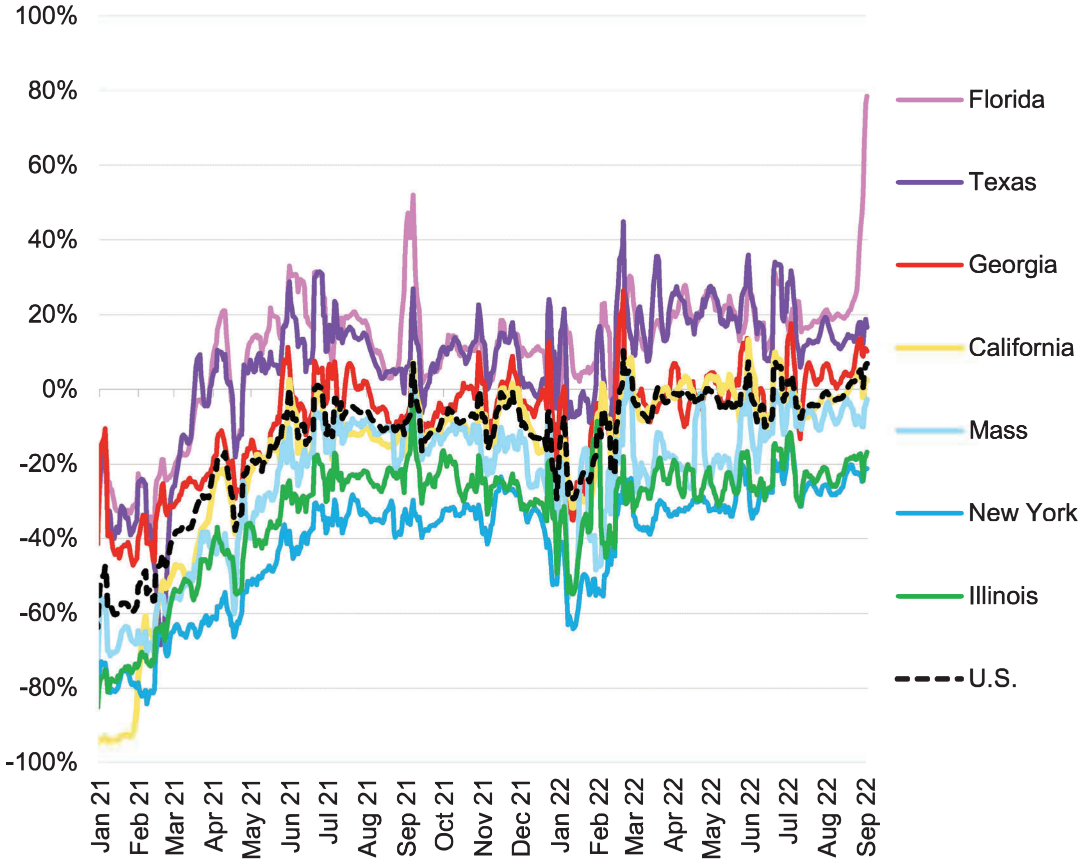
Economic activity

US restaurant ticked upwards last week, with a massive surge in Florida according to OpenTable data, as NYC subway ridership continues to slip

Restaurant activity

Data up to August 31, 2022

ALLX OPEN <GO>

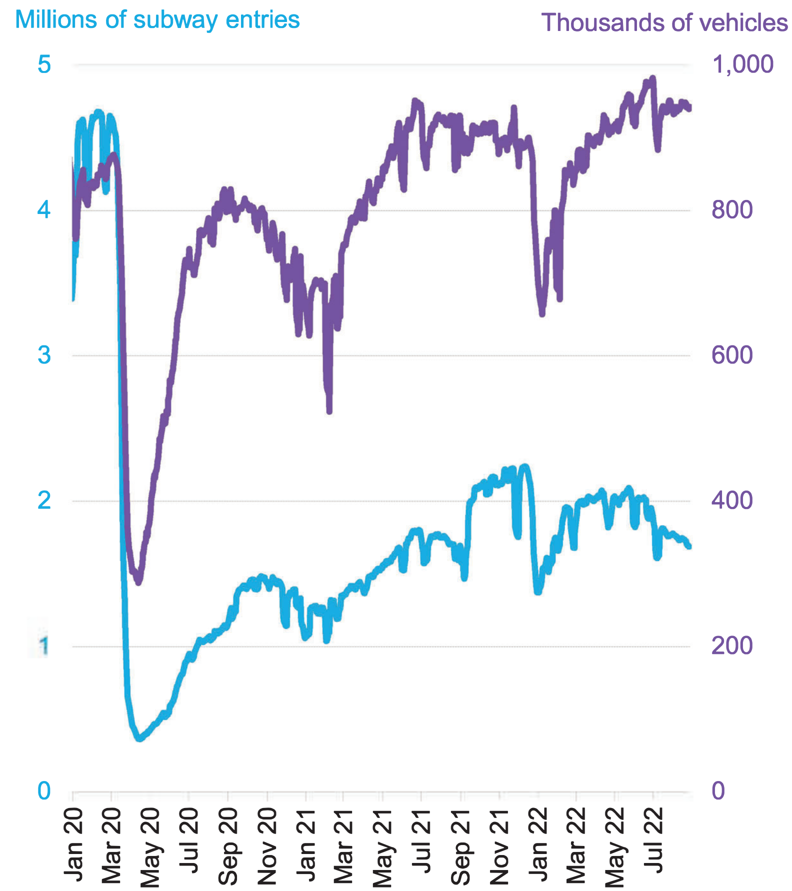


Source: BloombergNEF, OpenTable. Note: Data indicate the % change in seated diners at US restaurants in OpenTable's network compared with 2019 levels.

New York City subway, vehicle entries

Data up to August 26, 2022

ALLX MTAF



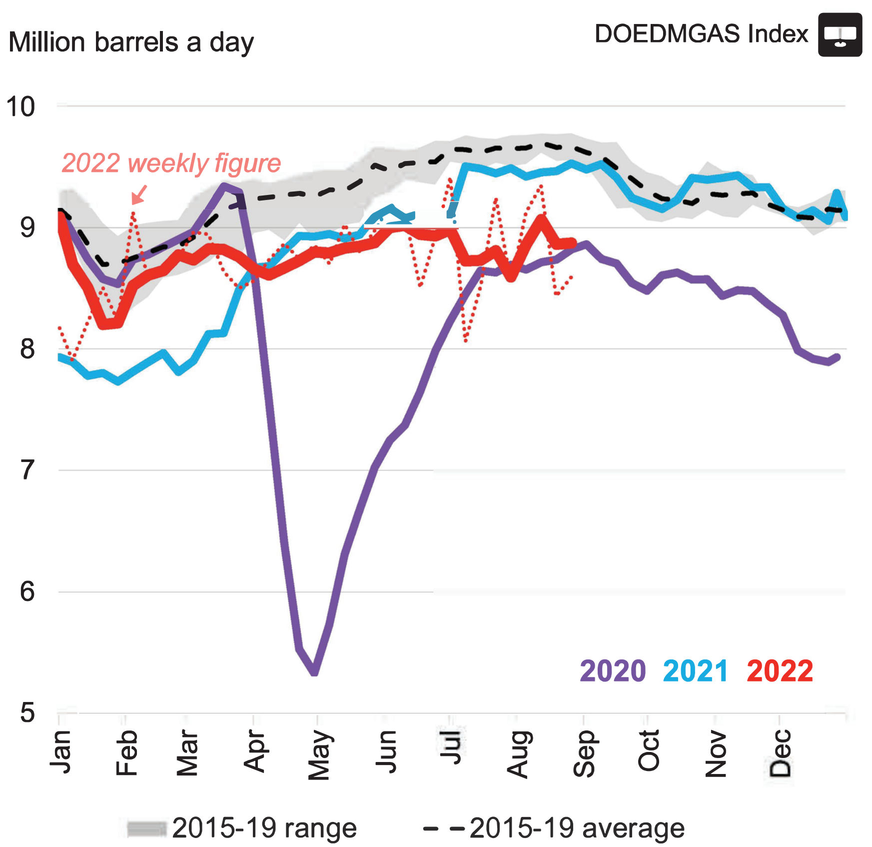
Source: BloombergNEF, ProdCo, and New York City Metropolitan Transportation Authority (MTA).

Gasoline demand

For more data on congestion around the world, see BNEF's Covid-19 Indicators: Road Traffic

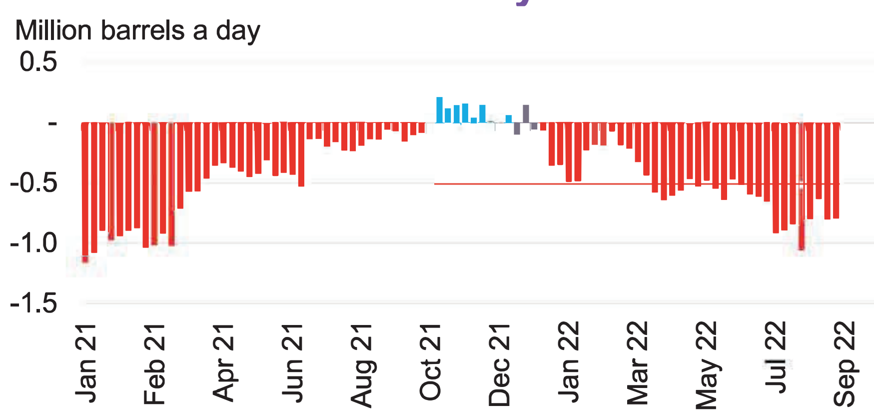
Gasoline demand is showing no signs of improvement in the final weeks of summer, despite gains in mobility metrics nationwide, as minimal growth in the weekly figure was dwarfed by the previous week's plunge

Implied gasoline demand*

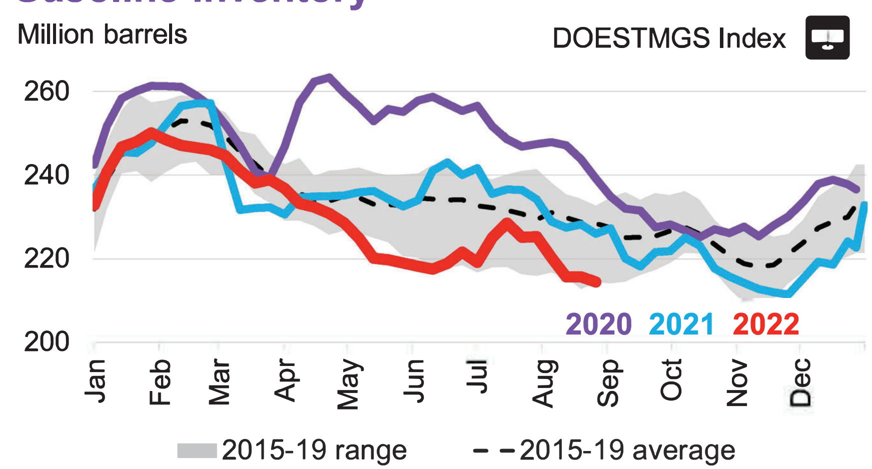


*Source: BloombergNEF, US Energy Information Administration (EIA). Note: *Based on the four-week moving average, except the 2022 weekly figure.*

Demand difference to five-year seasonal average



Gasoline inventory

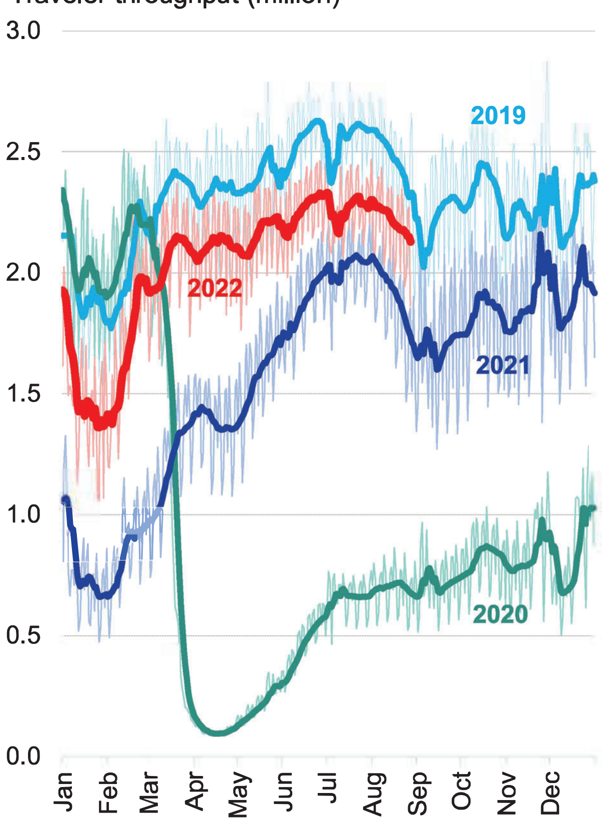


Source: BloombergNEF, US EIA

Jet fuel demand

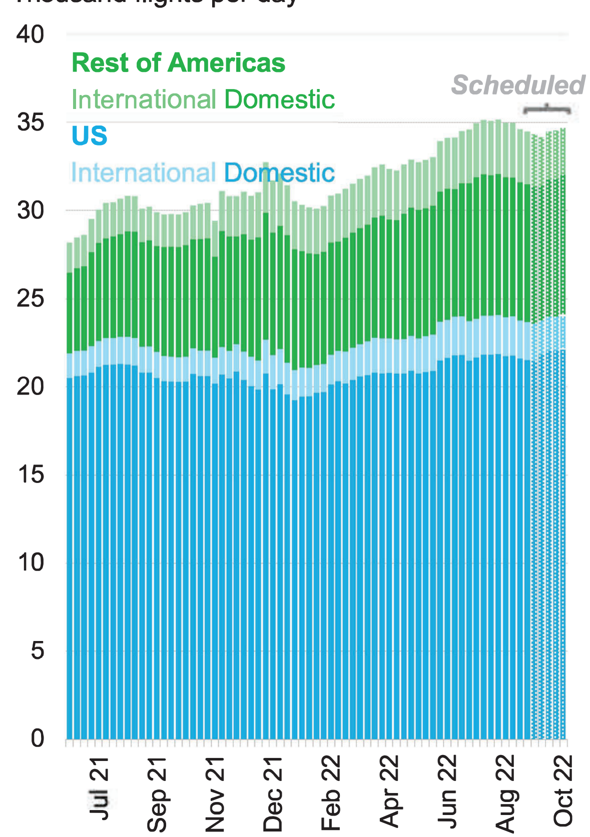
Airport activity continues to stave off typical seasonal declines as it approaches 2019 levels, boosting demand and sinking inventories to an 8-year seasonal low

TSA checkpoint traffic



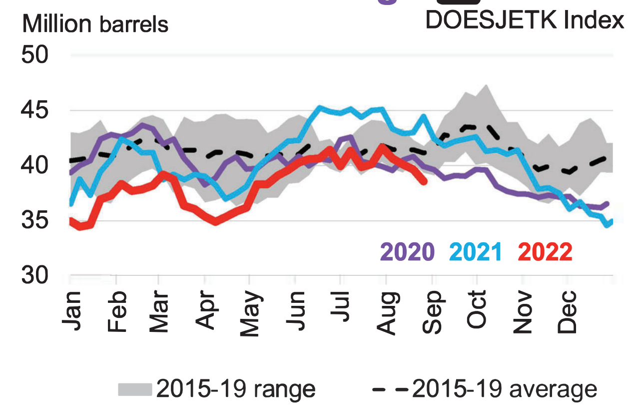
Source: BloombergNEF, US Transportation Security Administration (TSA)

Daily flight departures

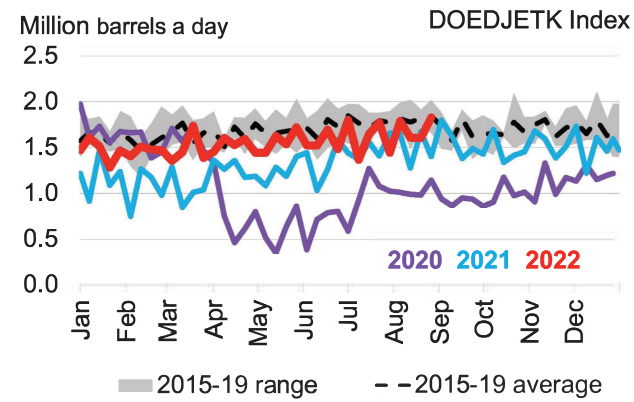


Source: BloombergNEF, FlightStats

Jet kerosene storage



Jet kerosene implied demand



Source: BloombergNEF, US EIA

For more data on congestion around the world, see BNEF's Covid-19 Indicators: Aviation

NACS - The Association for Convenience & Fuel Retailing

https://www.convenience.org/Research/FactSheets/IndustryStoreCount

NACS Advancing Convenience & Fuel Retailing

U.S. Convenience Store Count

Last Updated: January 19, 2022

Highlights

148,026 convenience stores

116,641 stores sell motor fuels

80% of the motor fuels sold in convenience stores

60.4% single-store operators

- There are **148,026 convenience stores operating in the United States**, a 1.5% decrease in the number of stores in operation (150,274) at the close of 2020, according to the 2022 NACS/Nielsen Convenience Industry Store Count.
- The number of convenience stores that **sell motor fuels is 116,641 stores**, which is about 78.8% of all convenience stores. Overall, convenience stores sell approximately **80% of the motor fuels** purchased in the United States.
- The industry decline was led by a 3.1% decrease in **single-store operators** (89,336 in 2021 vs. 92,196 in 2020), which account for **60.4% of all convenience stores**.The decline of single-store operators continues a multi-year trend; single-store operators made up a record 63.2% of the industry in 2017. Meanwhile, the percentage of single-store operators that sell fuel dropped to 54.6% in 2021, the lowest since the metric has been tracked in 2005.

U.S. Convenience Stores (as of December 2021)

- 2022 — 148,026 (-1.5%)
- 2021 — 150,274 (-1.6%)
- 2020 — 152,720 (-0.3%)
- 2019 — 153,237 (-1.1%)
- 2018 — 154,958 (+0.3%)
- 2017 — 154,535 (+0.2%)
- 2016 — 154,195 (+0.9%)
- 2015 — 152,794 (+0.9%)
- 2014 — 151,282 (+1.4%)
- 2013 — 149,220 (+0.7%)
- 2012 — 148,126 (+1.2%)

State Rankings

Among the states, **Texas continues to have the most convenience stores** (15,742 stores), or more than one in 10 stores in the United States. The remainder of the top 10 is the same from the year prior: California is second at 12,053 stores, followed by Florida (9,400), New York (7,848), Georgia (6,448), North Carolina (5,690), Ohio (5,537), Michigan (4,819), Pennsylvania (4,629) and Illinois (4,623). **Texas is the only state in the top 10 that added stores** (+47). Meanwhile, New York (-248), Florida (-219) and North Carolina (-200) lost the most stores. Alaska (174) has the fewest stores.

Performance vs. Other Channels

The decline in the convenience store count reflects the decline of other retail brick-and-mortar stores except for dollar stores.

Channel	**2022**	**2021**	**% Change**
Convenience	148,026	150,274	-1.5
Grocery	45,687	47,066	-2.9
Drug	40,402	41,000	-1.5
Dollar	35,501	34,215	+3.8

(Source: 2022 NACS/Nielsen Convenience Industry Store Count)

In addition, there are “gas station/kiosk” stores that sell fuel but not enough of an in-store product assortment to be considered convenience stores. Overall, there were 14,826 kiosks in 2021. The kiosk format continued to decline—down 5.2% the past year and 32.9% over the past six years—as more consumers sought out stores that have robust food and beverage offers.

Despite the fourth straight yearly decline in stores, the overall convenience store count is approximately the same as a decade ago (148,126 stores in 2012). With the U.S. population at 332.4 million according to the U.S. Census Bureau, there is one convenience store per every 2,245 people.

Media Inquiries

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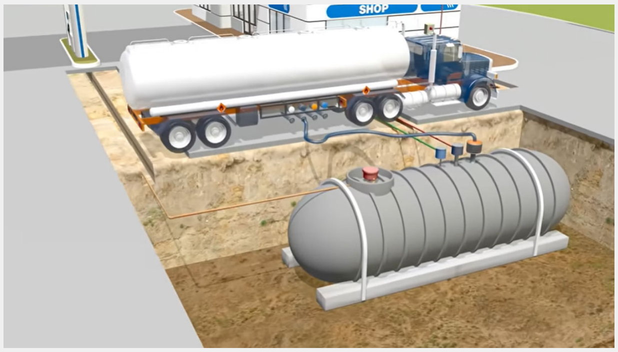
https://www.oilspillprevention.org/oil-spill-sources/gas-stations

OIL SPILL PREVENTION + RESPONSE

Gas Stations

A typical gasoline station has a storage capacity of 30,000 to 40,000 gallons in underground tanks. In the past, these tanks were sometimes subject to spills from overfilling and to leaks caused by corrosion. Today, station owners have taken several important steps to reduce these risks.



Overfill Protection Devices

- Sensors and alarms let the operator know when the tank is getting full, and automatic shut-off switches stop fuel from being pumped into the tank before the tank completely fills.
- An electronic alarm, triggered by a floating sensor within the tank, activates a warning light and/or sound to tell the operator when the tank reaches 90 percent capacity – the target fill level.
- As a backup, a so-called flapper valve attached to the delivery pipe uses a floating arm to trigger a shut-off valve when the petroleum product in the tank reaches a certain level, similar to the shutoff device of a toilet.
- A ball float valve consists of a ball floating on top of the petroleum product while inside of a cage, which is attached to the end of a ventilation pipe. As the product level rises, so too does the ball, until it is raised to the bottom of the vent, blocking the vent and restricting outward vapor flow before the tank is full. When closed, this valve can create enough pressure to stop the flow of product into the tank.

Cathodic Corrosion Prevention

When in contact with moisture in the air or ground, steel slowly rusts, causing corrosion of metal storage tanks and pipelines. When the moisture combines with the carbon dioxide in the air, a weak carbonic acid is formed, which dissolves the steel tanks or pipelines, appearing as rust. The application of a small positive electrical charge to the tank helps prevent this corrosion process.

New Tank Materials/Coatings

New fiberglass tanks and steel tanks coated with fiberglass or other durable casings help prevent corrosion caused by underground moisture. The same high-tech coatings and linings also protect the nation's pipelines and above-ground storage tanks.

Catchment Basins

All tanks are equipped with large "buckets" located around the fill pipe, which catch any motor fuel that may spill when the delivery hose is disconnected from the fill pipe.

Leak Detection Devices

Sensors can detect even small leaks in underground storage tanks and piping. An automatic tank gauging system monitors the volume of petroleum product within a storage tank versus the amount of product dispensed to consumers.

- Double-walled tanks provide an additional measure of spill protection – the space between the inner and outer walls is filled with brine. A float sensor can detect any increase in the brine level that results from product escaping the inner wall.
- Line leak detectors use a spring-loaded arm to test the pressure in the pipes carrying petroleum products from the tank to the dispenser. If the line pressure is low, which could possibly be due to a leak, the testing arm makes contact with the sensor pin below, triggering an alarm.

https://www.db.com/news/detail/20220907-christian-sewing-s-keynote-at-the-handelsblatt-banken-summit-2022?language_id=1
News September 7, 2022

Christian Sewing's keynote at the Handelsblatt Banken Summit 2022

- Check against delivery -

Dear Mr Matthes, Ladies and Gentlemen,

I am delighted to be with you today at a time that is more challenging than anything I have experienced in more than 30 years of banking. While the Covid pandemic proved to be a temporary shock to the world economy, Russia's war against Ukraine has destroyed a number of certainties on which we built our economic system over the past decades.

- The brakes have been applied to globalisation and, in the face of major geopolitical tensions, it is unlikely to pick up its old momentum any time soon.
- As a result, many seemingly perfect global value and supply chains have been disrupted.
- The workforce, which for a long time was thought to be available without limit, has become a bottleneck factor worldwide.
- At the same time, electricity and gas have become scarce and extremely expensive. Energy is set to stay an expensive commodity in Europe for some time. This represents a structural competitive drawback and it is a threat to our economy. In the long term, we will need to respond with structural solutions.

These points are the most important reasons for soaring inflation. As a result, we will no longer be able to avert a recession in Germany.

Yet we believe that our economy is resilient enough to cope well with this recession – provided the central banks act quickly and decisively now. Right now many people still have their savings to fall back on to pay the higher prices; many companies are still sufficiently financed. But the longer inflation remains high, the greater the strain and the higher the potential for social conflict.

Three lessons

This combination of short and longer-term challenges seems unique at this point. And while it is essential we meet the short-term needs, we also have to explore what this means for our long-term ability to compete. The greatest complexity still lies ahead of us when we begin to draw the real lessons of the past few years. In my view, there are three main lessons:

Firstly, we have seen how dangerous it is for us in Europe to become too dependent on individual countries or regions. At the moment the main focus is on energy and raw material imports from Russia – and rightly so. We must do everything we can to ensure that our cars, our heating and our factories are not only able to run when an autocrat in the Kremlin is favourably disposed towards us. All efforts by politicians and companies to change this deserve unconditional support.

That is not enough, though. When it comes to dependencies, we also have to face the awkward question of how to deal with China. Its increasing isolation and growing tensions, especially between China and the United States, pose a considerable risk for Germany.

China is a cornerstone of our economy. About 8 percent of our exports go to China and 12 percent of our imports are from the country. More than a tenth of the sales of all DAX-listed companies are from China. At the latest during the pandemic it has become clear just how much our supply chains rely on China. Reducing this dependency will require a change no less fundamental than decoupling from Russian energy.

At the same time – and this is my second lesson – we need to tackle the climate crisis with much more resolve than to date. Climate change is already causing damage of gigantic proportions. In light of Covid and the war in Ukraine, the danger is that the topic will slip down the list of priorities. That would be the biggest mistake we could make, though.

Fighting the climate crisis is a generational task that will radically change the economy and society. Every company will have to face the issue – not just out of its responsibility to society, but to secure its own continued existence. Those who fail today to put sustainability firmly at the centre of their strategy will – in ten years – have trouble selling their products, finding employees or attracting investors. They will disappear from the market.

The third lesson, I believe, is that we have been under the illusion for the past 30 years that we could live forever in an ever more globalised world with no major conflicts and with steady growth. Francis Fukuyama has often been criticised for equating the end of the Cold War with the "end of history". But de facto we acted as if this thesis was correct; we have been acting as if the world was on its way to becoming one big village where everyone is interested in economic cooperation because, after all, everyone benefits from it. That has stopped being the case for some time now, though.

The truth is that 30 years of presumed calm will now be followed by a period of heightened volatility with economic uncertainty, regular crises and geopolitical conflicts that are also likely to drag on for decades. Trouble spots are not cut off from the rest of the world; they impact other regions in a number of ways. As such, we must come up with holistic solutions that take this degree of interplay into account. Dealing with this complexity will be a great challenge for us. Good risk management is the order of the day.

“We must not leave the playing field and with it the access to global capital markets largely to foreign banks. The past few months should have taught us this. In Germany, we must not allow ourselves to add a further dependency – access to finance – to our current dependencies on gas, raw materials and supply chains.”Christian Sewing, CEO

National feat of strength

Let us not delude ourselves: we certainly have our work cut out for us if we are to accomplish these three tasks – reducing dependencies, dealing with permanently higher volatility and driving the historic transformation of our economy. We will only succeed through a concerted joint effort, with politics, business and society all working closely hand in hand.
The financial sector must and can play a crucial role.

We need banks that are able to finance these mammoth tasks, while protecting their clients against risks and being reliable partners, accompanying clients worldwide.

And for this we need a domestic financial sector that stands on its own two feet and can assert itself against its global competitors. We must not leave the playing field and with it the access to global capital markets largely to foreign banks. The past few years should have taught us this. In Germany, we must not allow ourselves to add a further dependency – access to finance – to our current dependencies on gas, raw materials and supply chains.

We have the means to prevent this, but we still have much to do. As a financial sector, we have already achieved a lot: we are much more stable and resilient today than we were ten years ago. We are profitable. Our industry has foregone relatively little profit in the first half of the year and even managed to increase revenues. And the loan defaults that the industry faces in the coming months should remain manageable because banks have taken the necessary provisions.

Progress in the financial sector is far from sufficient

That is far from enough, though, if the German financial sector is to play a leading role in the long term. What we need is:

- For us banks to work harder at becoming even more efficient and focusing even more on clients, especially in digital services.
- We need reliable regulation that does not always create higher hurdles and tie up more capital than necessary – capital that is needed right now to finance the economy.
- And sooner or later we will also need consolidation, not nationally, but Europe-wide. Size counts in banking – and if we don't want to hand over the playing field to the Americans, Europe must create the right conditions for big banks. I can only repeat what I’ve said before: both the European banking union and the capital markets union are essential here.

The above points are not new, but they are becoming more urgent. We are actually very well equipped so there is no reason to talk ourselves down. We are operating in an economy that has shown enormous resilience and that will also navigate the upcoming recession – because corporate balance sheets are strong, and debt is low by international standards. This economy has great potential as long as we focus now on aligning ourselves for the long term and on how to minimise the threat of de-industrialisation: with less regulation, more courage and more pragmatism; this attitude is incredibly important.

And that goes for banks, too. We have proven banks can be part of the solution. We can do much more, though. Before the financial crisis of 2007, just 15 years ago, Europe's banks were more profitable than their competitors in the US. Since then, the Americans have unrelentingly left us behind. We could, of course, agonise over this. Instead, we should rather see it as an incentive to buck the trend. The dominance of American banks is no law of nature.

At Deutsche Bank, we are convinced that the way to achieve this is by being a strong partner to our clients. They need a bank that supports them in all kinds of environments, in all markets and all over the world. This is what we emphasised when we formulated our Global Hausbank aspiration. We have radically transformed our business since 2019 and strategically repositioned ourselves in line with this aspiration.

We are convinced that this strategy will be especially effective in volatile times – because now is the moment when advice and expertise are highly sought after.

And this does not apply to us alone. Despite all the differences between the banks in Germany, we have one thing in common: we were there for our clients during the pandemic, we were there for our clients when Russia invaded Ukraine and we continue to be there – in these volatile times that urgently call for sustainable transformation. We have regained a great deal of trust. Let us work together to create the conditions for renewed dynamic growth across our entire economy.

Worldwide Oil Supply and Demand Remain Tight

Multi-Year Underinvestment Constrains Supply in a Rising Demand Environment

Oil supply remains constrained…

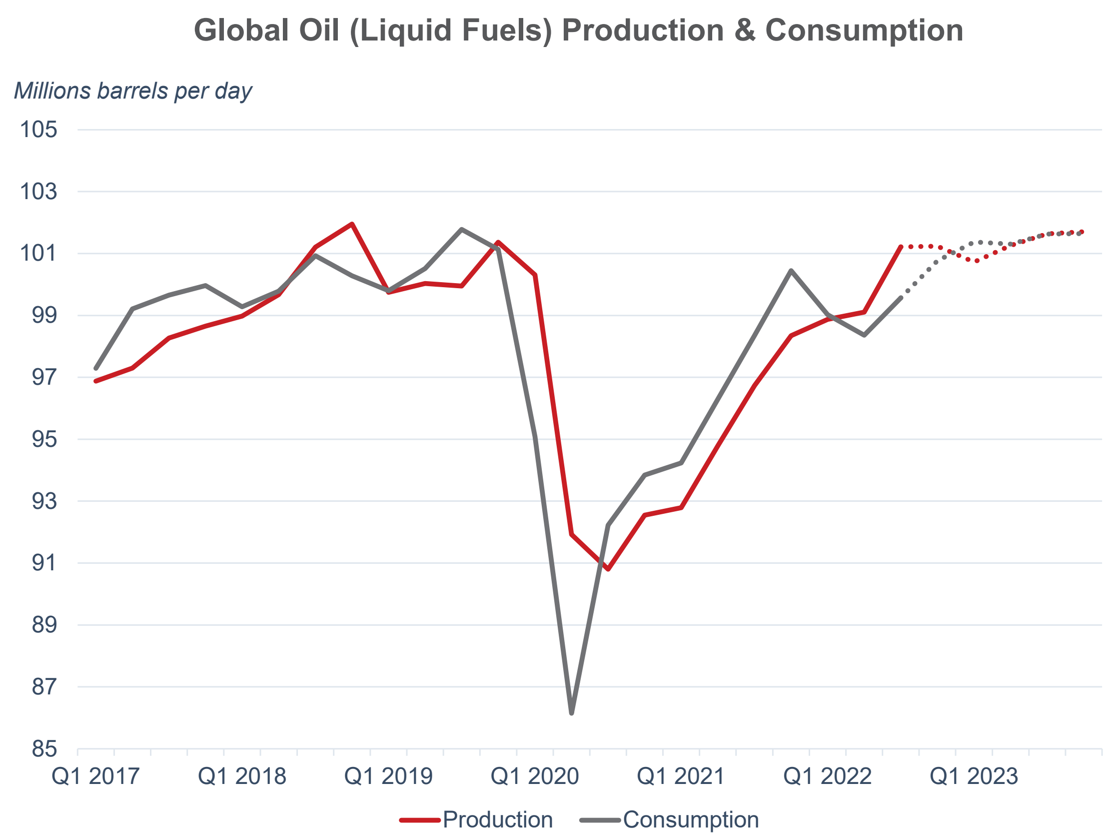
- Global underinvestment in energy infrastructure
- Low global inventories
- Limited OPEC spare production capacity
- Limited refining capacity

➢ *North America is expected to be the largest supplier of 2023 incremental supply*

… while demand continues to increase

- Recovery in travel (jet fuel)
- Modest global GDP growth
- China emergence from Covid lockdowns

➢ *Majority of 2023 incremental demand is expected to be from non-OECD countries*

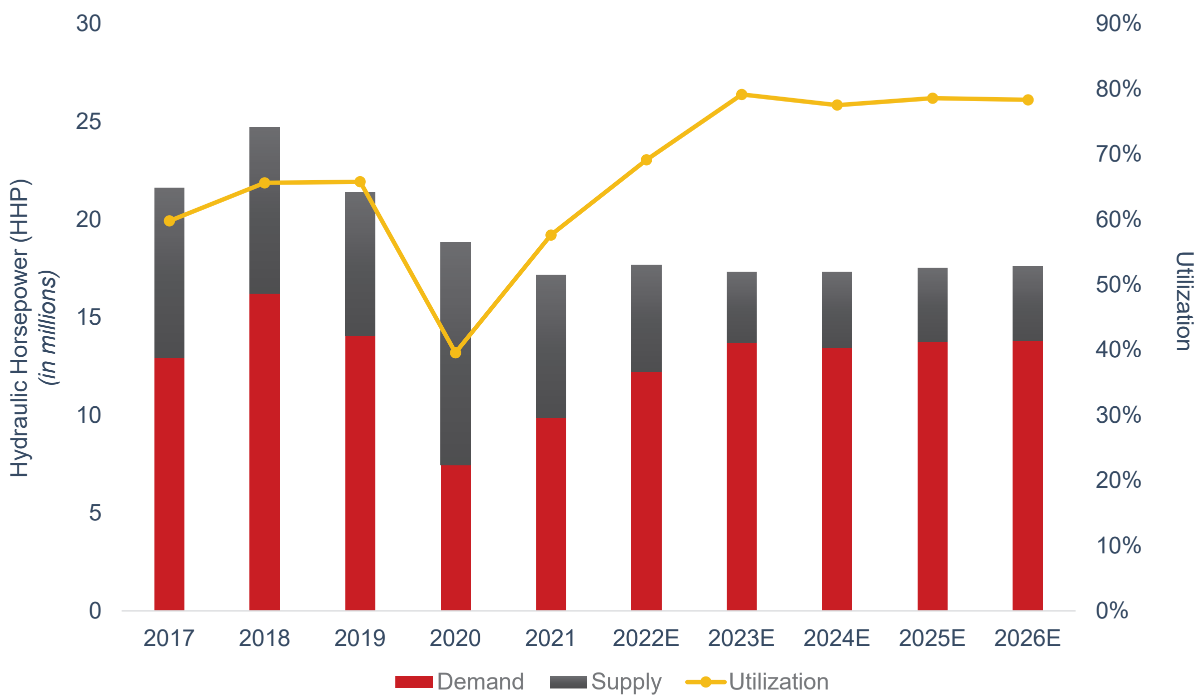


Source: U.S. Energy Information Administration (EIA): Short Term Energy Outlook August 2022

Frac Market Dynamics

Rapid Tightening Drives Pricing

Frac Horsepower at High Utilization



Source: Rystad and Company Estimates

Tight Frac Supply
E&P production growth bottleneck

Significant Attrition 2017-2021

Frac Capacity Utilization
Expected to exceed 2018 cycle peak

Flight to Quality
E&P demand for execution

Increased Frac Intensity
Equals increased demand for HHP

A Look Ahead: Shale Development Drives Higher Fleet Demand to Sustain Production

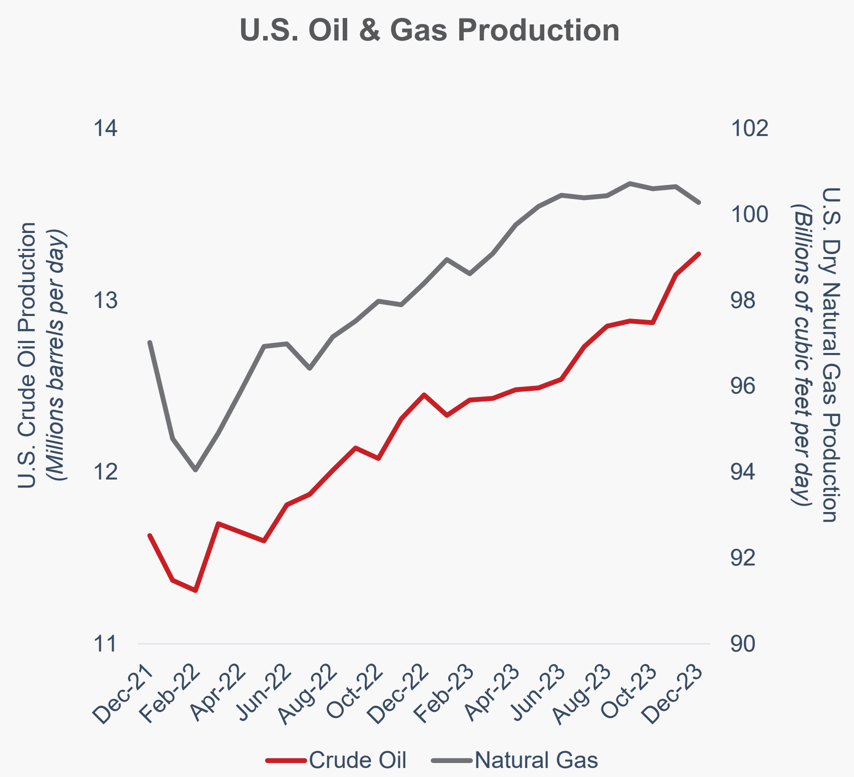
Higher Production in 2024 Demands Additional Fleets to Maintain Production

Current Environment

- Natural production decline in 2022 on YE21 oil production is ~2.8 mbpd
- Expected YE21 to YE22 production growth is ~0.8 mbpd
- 2022 average frac fleet count is ~250, of which **~210 fleets are oil-focused**
- Approximately 80% of frac crew count is dedicated to sustaining YE21 oil production, with the remainder tied to growth

Looking Ahead

- Oil production is anticipated to grow ~1.7mbpd by YE23, a 20%-25% increase in tight oil production.
- To *sustain* the increased production, 2024 would require oil focused frac fleet count of **~210 fleets**, matching today's frac fleet demand



Source: U.S. Energy Information Administration (EIA): Short Term Energy Outlook August 2022 & Company Estimates

Barclays CEO Energy-Power Conference

Company Participants

- Andy Hendricks, President, CEO & Director
- Derek Podhaizer, Equity Research Analyst

Presentation

Derek Podhaizer {BIO 19729121 <GO>}

Good morning, everyone. Going on with the next presentation here.

Next up, we have Patterson-UTI Energy. Joining me is Andy Hendricks, President and CEO of Patterson, a position he's held since 2012.

Our format today will be fireside chat.

So Andy, thank you for joining us.

Andy Hendricks {BIO 17576968 <GO>}

Derek, good to be here.

Questions And Answers

A - Derek Podhaizer {BIO 19729121 <GO>}

So I just want to start off with the recent volatility we've seen in oil prices due to the recessionary concern overhang. I'm just curious how this has affected your customer conversations? Do you get a sense that your customers are concerned? Any noticeable differences in behavior between the majors, the independents, the privates? Do you feel that there's an oil price that we would need to fall to, to see a significant change in activity?

A - Andy Hendricks {BIO 17576968 <GO>}

So that's a good way to start things off. Let me just clarify, we're still seeing very strong demand. We're still seeing opportunities to push pricing in both drilling and pressure pumping and other services that we have. So the market is definitely still in our favor. The recent volatility that we've seen, and we've all seen the ups and downs in WTI, it has not affected the conversations at all in the US with our customers.

And remember, in pressure pumping, we run mostly the high end, primarily natural gas, by fuel spreads. In drilling, it's Tier 1 super-spec rigs. And so the customers that are operating this level of technology are just not fazed by the volatility. None of them were really planning on $110 oil. I mean that was just a bonus for them. But the volatility has not changed the discussions at all in the US for our services.

A - Derek Podhaizer {BIO 19729121 <GO>}

No, that's encouraging here. I want to make sure that everyone is aware of the press release you put out yesterday, we just talked about it before we got up on stage here. I think the biggest thing that stood out to me was signing up, I believe it was five contracts, with a major customer for under 3-year contracts. Maybe just maybe talk to what's the strategy around that? What gave you the confidence to lock up rigs for three years with that customer? I just think that's a pretty big signals you're sending to the market where you feel the strength of the outlook.

A - Andy Hendricks {BIO 17576968 <GO>}

Yes. I'm really excited about the efforts from our teams on operations and marketing and what they've done. And if you look at the strength in the market, we're just calling that out in this press release. We're saying that, look, we signed in the range of 20 contracts since the end of the last quarter that totaled $335 million in additional backlog, that brings our backlog up to $690 million. And so we thought that was a huge effort. And the reason we pursued that, when you look at the leading edge day rates on a drilling rig, all in with rental pipe, extra people, the technology with our Cortex operating system, et cetera, you're into the mid-to-upper 30s. And we manage our rig contract portfolio just like an investor might manage a bond portfolio, and we started to layer in and we thought it was prudent to do that.

In the case of the five rigs under three years, that's just a signal to the market of where the strength lies in these negotiations. And it's really with the drilling contractor. And this was a great opportunity for us with a key customer that we already have who needed five more rigs from us, and they'll start to activate those rigs next year throughout the year and maybe one into 2024 as well under 3-year term contracts. And these are some rigs that aren't currently working today and it allows us to do upgrades within the term of these contracts and get a good return at the same time. So this will increase our activity. This will go into additional rig count for us next year and locks it up for a while at good leading-edge prices. And it doesn't mean to say at all that this is some kind of cap on what we think pricing will do.

Pricing in drilling rigs, pricing in pressure pumping, pricing in directional drilling, continues to go up. The demand is still strong. We see increasing activity in '23 and pricing is going to continue to move up.

A - Derek Podhaizer {BIO 19729121 <GO>}

That's exciting. So is that mid-to-upper 30s a good proxy to say what you sign these contracts up for? And then I know you said that these are not currently working, so you're able to do some upgrades, you're even able to get maybe some cash upfront to get those upgrades going?

FINAL

Bloomberg Transcript

A - Andy Hendricks {BIO 17576968 <GO>}

Yes. Like I said, we signed about 20 contracts and in a number of these contracts, there's some cash upfront. And so you just think about the strength of the negotiation and where we were a year ago, 1.5 years ago in our space in contract drilling and oilfield services, that was going to be unheard of but here we are today. And in these types of negotiations where we're trying to get a good return on the investment, getting cash upfront is a big deal and we certainly are able to do that in some of these agreements.

A - Derek Podhaizer {BIO 19729121 <GO>}

Great. So I want to turn to the rig count and more on the supply side. Based on the industry commentary with you and your peers, it sounds like rigs are about to approach 800 by year-end. Looking into 2023, reaching 900 may feel like a heavier lift. Can you talk about this? Is 900 achievable? How many would Patterson be able to add? What would be the biggest constraint about reaching that 900?

A - Andy Hendricks {BIO 17576968 <GO>}

So what we've said is we're going to put out roughly three more rigs towards the end of this year. So the activity for us is still going to continue to move up. Next year, with the five rigs that we have announced, we could put out still another 10 to 15 on top of that. So we could have 15 to 20 rig increase next year in 2023. And so that means, for the market, roughly another 100 rigs, we think, will go out. We think that the demand is there. When you look across the types of operators and E&Ps that have been bringing out rigs for the last 1.5 years, it was really the privates that led the way, then you've got mid-tier publics, but what's missing in the equation, and you're going to see more of in '23, are the large major E&Ps.

And so you're going to start to see increasing activity from that group. It doesn't mean the privates aren't going to continue to add because I think some of them will, especially the large privates, but you're going to see a little bit of shift more towards the major E&Ps as well.

A - Derek Podhaizer {BIO 19729121 <GO>}

Great. And those rigs aren't hot stacked, ready to go, brand new shiny, so I want to talk about the rig CapEx reactivation. And you laid out two different scenarios to get up to your Tier 1 super-spec. I believe it was the first 34 and then another 30 after that. Can you update on where you are in this program and what the CapEx is required for these upgrades? And I think the point I'm trying to make is that this provides upward support for day rates because you're not doing this for free, so maybe just talk a little bit about that as well?

A - Andy Hendricks {BIO 17576968 <GO>}

Yes. So we put out a presentation this week that you can download. It's got the details of our rig fleet. Our rig fleet today at Patterson-UTI is 184 rigs, all AC high-spec super-spec rigs. Very excited about where we are today in the market in terms of the quality of our rig fleet. We're working a 129 rigs today. The majority of these are Tier 1 super-spec. And when you look at our rigs that aren't working, we have about 50 rigs that we can upgrade to get from either high spec or super-spec all the way up to Tier 1 super-spec depending on what's required by a particular customer. So what that means is with approximately 50 rigs in our fleet available to either work or be upgraded, there's absolutely no reason for us to consider building new rigs. That's completely off the table.

And I think you'll hear that from our peers as well. And with us having 50 rigs and one of our other large peers having approximately the same number in that range, that means that this is a very consolidated market of available rigs to be upgraded. And so it puts us, as a drilling contractor, with this type of quality fleet in a really good position for negotiations with E&Ps. It's a type of market today, and I think the best way I can explain the tightness is to give you a scenario of what's been happening with us particularly over the last three weeks.

So if everybody is listening, this is a great story to explain how tight the market is. So we have a major customer that we do work for. They came to us about three weeks ago and said, look, we really need a rig before the end of this year. We want a Tier 1 super-spec rig and we need this in the fourth quarter. We don't have one available. If you need a Tier 1 super-spec from us, everything we have is committed.

We've got to do an upgrade on one of the existing rigs. It's going to take us in the range of six months to do this to get it ready to get it to go out. They need this rig in the fourth quarter. They're a little bit behind our production. They're trying to catch up. We've got Tier 1 super-spec rigs working for a variety of customers, small E&Ps that may have a couple of rigs, mid-tier publics that may have five or six of our rigs, large publics, large privates. And we have gone through our entire portfolio to say, okay, well, who's not on a term contract right now, who's lagging in the day rate? Everybody we've talked to in our customer base says, please don't take our rig, we'll pay the day rate, we'll sign a term contract, don't take our rig. So here's this really good customer that we're already working for calling us to help them out in the fourth quarter, and we can't free up a rig from any of our other customers because they're willing to pay leading edge, they're willing to sign term contracts.

So that's how tight the market is today.

A - Derek Podhaizer {BIO 19729121 <GO>}

No, that's very encouraging and good to hear. So I know you've been very vocal that we're nowhere near building new rigs but I want to ask you that anyway. So what would have to happen? What would that form look like? When could that even be a possibility?

A - Andy Hendricks {BIO 17576968 <GO>}

Like I said, we have 50 rigs in our fleet approximately that we could take from either high spec or super-spec all the way up to Tier 1 super-spec status, that could be something where we're adding another pump, adding an engine, upgrading the electrical controls, maybe increasing the rig structure capacity, something to that effect. And so with roughly 50 of those rigs, that's the best economics for our customers today to be able to do that. There's just no reason for us to look at new builds. And again, some of our large peers also have rigs they can upgrade too. So it's not in the mix, it's not in the cards for us to have to do that. And again, we think we can put out another 15 or 20 rigs next year, so there's just no reason for us to get into the economics of what a new build might be. The market is tight.

The market is got some discipline to it. I think more discipline then is appreciated but it's been like that for years now and we're very encouraged by the status of the market.

A - Derek Podhaizer {BIO 19729121 <GO>}

Got you. And those five rigs, could you maybe give us some numbers around what it would take to upgrade those, what the cost is and what that means to push up leading-edge day rates?

A - Andy Hendricks {BIO 17576968 <GO>}

Yes. If you look over the last 1.5 years, we were saying we were upgrading rigs in that $2 million to $3 million range, now, we're going to be into upgrades that are in the $4 million to $5 million to $6 million. There could be rigs down the road in this fleet that could be as high as 12, 15, 17, but we're not there yet. But even if we do get to that level, it's going to be covered by a term contract. It's not just going to be a return of capital but return on capital and we're going to make sure the economics are in the benefit of the shareholders.

A - Derek Podhaizer {BIO 19729121 <GO>}

Got you. So let's switch over to the pressure pumping side. Could you speak to the tightness in that overall market as well? Then specifically for Patterson, I believe your 12 feet, are you technically sold out right now or should we consider if we look at your total nameplate horsepower that we have some 6-ish fleets on the sidelines? And then leads you to my next question that if you choose to unlock fleet 13, what form would that come in?

A - Andy Hendricks {BIO 17576968 <GO>}

So we're up to 12 spreads. And we've chosen to work our way up to 12 and just hold that. We're very encouraged by how tight this market is, a little bit different from the drilling market, where the drilling market just has discipline around it, the pressure pumping market is literally sold out. If an E&P needs a frac spread tomorrow, it's just not available. And even with us working 12 spreads, it becomes a challenge to get to 13. The number of pumps that's required on a spread today has increased dramatically over the last few years. I visited one of our operations in Ohio the other day. Our CFO, Andy Smith, and I, were out there visiting drilling and completing in deep Utica. We have drilling rigs out there. We have pressure pumping equipment. Great-looking spread but it's 20 pumps.

And when you have 20 pumps working out in the field and you're pumping 23 hours a day with some of the highest level of efficiencies that we've ever had in pumping, you need another five or six pumps rotating through maintenance just to support that 20 that are in locations. So you've got really 26 pumps tied up supporting that operation. So for us to get to spread 13, we own pumps, we own blenders, we could get there, but we would

So if it's the higher end rotary steerables that operators want, we can offer that, but again, the bulk of what happens in the US onshore is motors and measurements and the skill sets at the well site. The other exciting thing that we've been able to do and deploy with combining technology that exists across all of our companies is data analytics and remote operations. And directional drilling is a type of service that lends itself to being able to do remote operations. It's a wider asset type business. You're not moving heavy assets in the field. It's lighter assets that are deployed and they go in the bottom of the well to steer and navigate the well. We've actually taken half of the measurements, people that we have in the field, and they actually work in the seventh floor below where I work in our office in Houston.

So there's an aspect of remote operations and reducing the number of people in the field and then allowing somebody in an office to manage four rigs as opposed to just that person on one rig in the field that improves efficiency. So in that particular business, through data analytics, some artificial intelligence and remote operations, we can be more efficient and more competitive.

A - Derek Podhaizer {BIO 19729121 <GO>}

That's exciting. So I want to just ask a quick question on new energy just because you made an investment in the unconventional geothermal player Criterion Energy Partners. They just announced their first acreage lease deal actually. Maybe just talk quickly about your involvement in this start-up and what you see unconventional geothermal, how significant this market can scale? Clearly, it's a natural crossover industry for the legacy oil and gas guys, so just maybe some thoughts around that?

A - Andy Hendricks {BIO 17576968 <GO>}

We've had a number of opportunities in geothermal to look at either various technologies or various business propositions that groups have come up with. And we've taken the approach that we just want to pick one that we think is a good one, a good opportunity, a good potential, and go with that and help them out as best we can. Criterion has a really interesting business model that pairs well with what we do. So they are looking at opportunities along the Gulf Coast of Texas, where as you get closer to the Gulf Coast, you have higher temperatures. Now, these aren't the same levels of high temp, super high temp that you have in Southern California around the Pacific Rim, but it's a high enough temperature to be able to drive geothermal energy through a special device at surface that is a ranking cycle generator.

And so this being in our backyard of South Texas using traditional oilfield technologies, drilling horizontal wells, completing horizontal wells, circulating water through that system to drive a ranking cycle generator, fits well with what we do. So really excited about this team's potential. They've made some announcements on land that they've acquired in South Texas to run some tests on some existing wells. That will move into some bigger projects that pair up with refineries and chemical plants along the Gulf Coast that are large users, large consumers of energy and electricity where geothermal on their properties makes sense. And so really excited about what the team is doing, the skill sets the team has, their background in oil and gas plus the technical people they brought in to do this. And we think, in terms of investments, this is the right one for us.

Barclays CEO Energy-Power Conference

Company Participants

- Olivier Le Peuch, CEO
- Unidentified Speaker, Company Representative

Presentation

Unidentified Speaker

Good morning. Welcome to the second day of the 36th annual Barclays CEO-Energy Power Conference. This morning, we're very pleased to be joined by Mr. Olivier Le who's been CEO of Schlumberger for almost four years now. Mr. Le Peuch joined Schlumberger in 1987 as electrical engineer.

Spending his early year -- spent his early career in custom software integration, wireline electronic development. States held numerous leadership and global management roles, including President of Cameron, President of Completions, and President of SIS.

Mr. Le Peuch has made great strides in a short time, including a rather timely deal with one Subsea and Aker announced last week. We look forward to hearing more about this and to see how the coming years are unfolding. We're going to be -- he is joining me here for a fireside chat right now.

Olivier Le Peuch {BIO 16885975 <GO>}

Good morning. Thank you. Good morning, days. Pleasure to be here. I'm back here.

Questions And Answers

A - Unidentified Speaker

So I just want to start off with something that you had said on the last call, which I thought was really, really important about talking about the decoupling of upstream spending from global demand. Can you talk about what that means? Everybody is worried about recessions or worried about global oil demand falling. So why aren't you concerned about that? Or at least, why aren't your customers concerned about that?

A - Olivier Le Peuch {BIO 16885975 <GO>}

I think there are many, many factors underlying this assessment that we have made on the market. So what it means first is that we believe that on the various economic scenario, we believe that the upstream outlook spent is extremely resilient. We show golf for years to come. And a multiple factor to that factored into this. The first, I think you have to look at -- we have been eight years and underinvesting into this sector, partly internationally. At the same time, the spare capacity, the inventory level, the SPR at very low level, combined level that is as low as the 70s. At the same time, you have liquid demands going. It will go between 2 million and 3 million by this year, will go between 2 million and 3 million by next year.

And last, I think that's -- what is the tipping factor into this is you have the energy security and divers diversification of supply coming back to the form for fraud and creating somehow, at least for the gas, trading a double [ph] sourcing in supply, a demand for double sourcing. So you combine all of this. We are carrying the condition to sustain community price for sustained investment incentive for the operators, for the national company while the market has been very resilient and very -- having growing ahead of expectation in North America in the last 12 months.

We are seeing international law market to accelerate with the potential to have the rate of growth of international going forward to outpace North America. there is a huge momentum. You have seen our results. Last quarter, we were running on four cylinder [ph], partly the offshore. I believe that this year to stay this short and long international in North America.

So the resilience of this investment spent due to these underlying factors will resist in our opinion. We resist the five economic scenario. If you look at the customer meet and I've been meeting quite a few in the last 10 days, they're not worried about this.

They're worried about securing capacity from us, assuring performance, assuring that they would have delivery of their committed gas and committed oil production that they have put in the pipeline. So that's their concern. The concern is not whether the old price will let tip up or tip down, and whether the recession will impact somehow in one region, the demand outlook.

A - Unidentified Speaker

So as an analyst, I'm always trying to look at the past for insight into the future. I guess the one I've been latching onto is this -- to me, it looks a lot like, 04, 05 when we saw the beginning. That cycle is starting to ramp up in particular on the international side.

And I'm thinking about the Middle East and how your MIDDLE EAST business is picking up. If I look about that time from 04 to 08, we have this multi-year steady growth of kind of 20% stream spending growth. It feels a lot like then. I mean could you just maybe compare the two? I mean are you seeing same defense here or --

A - Olivier Le Peuch {BIO 16885975 <GO>}

I think directionally, fully agree. Directionally, I think the trend of investment internationally, the pace of mobilization of rigs and of -- and commitment to both short and long cycle offshore Middle East is something that I've not seen for, for, for quite some time. I think again the pool on our capacity, the pool on the -- down to delivery is unique.

You have the combination of offshore short cycle happening, which is addressing infield learning, tieback, Subsea tieback, and assuring that the existing production hub internationally on offshore are performing at the top and exploiting the reserve they have. So you have some near feed [ph] exploration coming back. You have a lot (inaudible) activity near the hubs.

You have long cycle offshore accelerating as well. At the same time, a number of SID [ph] are coming back. Norway having a tax regime, some PSC has changed in West Africa, all combining to make the outlook of SID approval in 2022. In 2023, to be bigger than what we have seen for the last more than 10 years.

Then you have Middle East. Middle East has been holding, has been a little bit delayed in pace of growth in inflection. Manufacture and (inaudible) is happening. Wed only accelerate. So this commission are indeed similar to what we have seen during (inaudible) and Channel 8 [ph].

However there is one major change is the industry is no more the same. The industry on both sides is capital discipline. The industry has step change efficiency. And again the residents of this under different scenario is better than it was. And both sides, and we have made a capital pledge.

And we have step [ph] change our operating leverage. It shows into our margin expansion. It shows into our free cash flow generation. These are unique condition that we are facing. A market optic inactivity in the major basin, in the major operating environment, coupled with very discipline, very lean organization, and a capital light on balance. We used to run at low teens or higher in term of CapEx intensity.

We're at 5 to 7 today. So step change in capital intensity, step change in capital discipline, and free cash regeneration. So these are -- yes, the same outlook directionally from activity. But yet, at the same time, a much different industry environment that will play favorably for us.

A - Unidentified Speaker

So if I think about that, 04, 05 timeframe, you were already well-established in the Middle East at that time, and were able to take advantage of that market you had to yourself. But there was a big build out, in massive build out of facilities and equipment. You had to build all that equipment out. That's what's so different here. I mean I don't see that in your projections. You don't -- you have all facilities where you need --

A - Olivier Le Peuch {BIO 16885975 <GO>}

We have the facility. We have the global footprint we have established for the last decades. We have tuned this footprint for efficiency, for effectiveness. We use digital provision more than we have ever used to make sure that we maximize the use of hubs and where we do centralize the (inaudible), we do centralized remote operation, and hence, so its much more efficient in the (inaudible) resource, our people and the

A - Unidentified Speaker

Does your digital platform allow you to pull in other parts of Schlumberger? Does it work that way? If a customer is using I guess maybe the digital side on the front end, does that naturally pull in the rest of Schlumberger or do you think of it at two separate?

A - Olivier Le Peuch {BIO 16885975 <GO>}

No. We think that two ways to look at it. First, we have -- our digital business is successful is on right on its own, and is a business that is division if you like, that has a bright future within upstream and beyond into the energy solution. Because our platform is fairly unique.

It's open, scalable, and I think it's something that our customer recognized could be used beyond what they do today with it on the geo [ph] sounds. Secondly, we are using element of this platform to embed into our own operational workflow. And customer adopting it.

So yes on integrated to well construction particularly or integrated has our recovery. We are adopting solution that are DELFI-based, cloud-based solution, that our customer also licensing, and that are subscription-based. And for every well, they are paying a fee to get access to this automation capability, planning, digital planning capability. So that we can work with our customers step by step towards a future of autonomous trading.

That's what we are looking for. So step by step, we develop the IP day [ph], plug their own IP, and we transform digitally their operation, their well-construction operation, or their asset prediction so that we start to add more artificial intelligence. We start to add more automation, more workflows that can make a difference. This is pulling onto DELFI.

So DELFI is being adopted by some customer from that frontend rather than the geo sounds. They then connect. That's the (inaudible) connecting the automating and digitalizing all asset operation, well-construction operation, with the live evergreen subsurface model both using the same platform. That's really great. That's what customer are realizing they can do. There is a mutual (inaudible).

A - Unidentified Speaker

Interesting. Maybe if we can shift gears a little bit to the -- what's going on in the ground of the Middle East, what are core markets? We've been talking about this market for quite some time. Could you just give us an update as where we are in this ramp up the cycle?

We've seen reports that -- I believe Saudi is already at record levels of the recount. I think they're supposed to get to something like 270 by year end, a lot of it is offshore. Can you just talk about where that is? You'd said it's a little bit delayed. Usually, we see this mobilization issue. Have you seen -- I haven't heard anything about that. So unds like it's (inaudible).

A - Olivier Le Peuch {BIO 16885975 <GO>}

No. I think when I commented before that this has been delayed. I think we have been very clear from last year that Middle East would not be the first to humper up activity in 2021. It was not the case. It was north Jamaica, it was Latin America, it was early sign of offshore. This year, offshore have been the first to accelerate, but Middle East has come true and is already, I think passed inflection point, I would say. Because you have two things happening at the same time in the list.

You have short cycle activity that is necessary to supply the production that is now off quarter, that I would have to keep holding at capacity for -- particularly for liquid production. This has been resumed in the last 18 months, 24 months. And now, it's almost back to the level it was before.

You have gas. Gas has been strategic for many countries. I'm not talking about Qatar and the plan of Qatar to develop that north field with significant set of energy trains that have been going on for two or three years.

And it's set to continue. I'm talking about the other country that either for domestic reason, or for institution to oil or for domestic consumption are committing to develop their gas reserves. This includes Saudi, the Kingdom of Saudi with Jafurah and commercial gas development, which we are part of. And finally, all capacity expansion.

So we have three country that have committed and two (inaudible) that have committed all capacity program expansion that would take five to seven years to be realized. This has led to significant number of tenders that are outstanding for some, that are being awarded for some. In UAE and Saudi, that are aiming at mobilizing rigs, mobilizing ,resource mobilizing supply on our side, to commit to this capacity expansion of oil.

So this is just the beginning of this whereas the over two are really in full pledge. So this will add significant activity uptick, including offshore for Saudi in 2023, whereas there are two would continue to add and to sustain activity go off going forward. So yes, the inflection has already happen. But it set to certainly expand going forward.

A - Unidentified Speaker

You had touched on the Jafurah contract. Can you just touch on that a little bit in terms of -- so really, the first major unconventional project in the Middle East. what's the biggest challenge that you face? Is it supply chain? Is it the actual operations of unlocking the gas? Whats the -- obviously very, very different than North America. So what's the difference in terms of the challenge?

A - Olivier Le Peuch {BIO 16885975 <GO>}

No. I've been had the opportunity to visit that operation a few months back. I think it's a mastery of logistics and technology department in one single place. I think if anything, it's all about logistics, it's all about planning and sticking to a plan, and having a pace of stage per week, per month, that is steady. And as enough inventory [ph] of wealth ahead and enough inventory of equipment to fulfill from sand [ph] to technology to fulfill that pipeline.

And we have been elbowing [ph] in few months to stabilize this environments, and to work with our customers, very collaboratively to make sure that all the dead spots and the difficulty we had on logistics, on planning, and on execution were removed so that we could execute this. This contract are becoming much more effective and executive today than they were before.

A - Unidentified Speaker

Are you happy where the contract is today? Are you happy with (inaudible)?

A - Olivier Le Peuch {BIO 16885975 <GO>}

Nevr happy. I'm never happy with any contract. I think I'm always believing and then challenging my team to be putting and working with customers to extract more, to introduce more technology. So we keep this contract on the bench.

And we keep working with customers to show them what we can do differently with them, what they need to do to help us, what technology we have in the pipeline that from the U.S. or from elsewhere. We are dedicating some fit for Jafurah technology deployment there that we can integrate. But we are learning and we are improving. We expect this to continue for the duration of the compact. So we are pleased for the progress.

A - Unidentified Speaker

Yes. Obviously you have a very strong relationship with the customer to work (inaudible), right? Last question, Olivier, on shareholder returns, the competing dialogues here on the EMP side of the house here. They're giving out as much cash as they come in. Services hasn't seen it yet.

There's a lot of reasons why working capital, all sorts of reasons we'd have to get into that. But your balance sheet is now under two times leverage, 55% of revenues on CapEx. It feels like you're in this sweet spot, at least, starting to be a sweet spot for cash.

Can you just talk to investors about your plans for returning cash? What that would look like? I'm assuming it's going to be in the dividend form, but Schlumberger also done a lot of buybacks in the past.

A - Olivier Le Peuch {BIO 16885975 <GO>}

Yes. First, I wanted to come back on the -- what drove us there. I think we had started a very strong capital stewardship program back three years ago and returns focus strategy. I think step by step, we have been executing this curating the cash and focusing -- deleveraging. And I think last year we deleveraged up to $2 billion and make much progress into deleveraging target we have said. So now, the benefit of that is give us optionality, which is where we are. I think considering the strengths and the length of the of the cycle is clear that it will have ample opportunity to increase visibly and naturally the shoulder returns during the second.

https://www.repsol.com/en/press-room/press-releases/2022/repsol-boosts-multi-energy-transformation-partnering-with-eig-in-upstream-unit-for-4.8-billion/index.cshtml

Repsol boosts its multi-energy transformation by partnering with EIG in its Upstream unit for $4.8 billion

Press Release07/09/2022 08:009 min

- Repsol partners with U.S. institutional investor **EIG in its upstream business with a 25% stake for a total consideration of $4.8 billion (€4.8 billion)**.
- This transaction **crystalizes value in the upstream unit, reinforces Repsol's leadership in the energy transition and advances the fulfillment of key objectives of the 2021-2025 Strategic Plan**.
- The deal values the upstream business, one of the four business verticals of the multi-energy company, at **$19 billion (€19 billion)**.
- Repsol will **retain operational control of this business and consolidate it within the wider Repsol Group.** The unit will continue to focus growth on key regional hubs and with a diversified portfolio of exploration and production assets in OECD countries.
- The agreement contemplates **a potential IPO of this business** in the United States from 2026 onward, subject to favorable market conditions.
- "**Our ambition is to lead the energy transition**. This pioneering agreement allows us to **maintain the strategic direction of the upstream unit** and, **at the same time, to boost the transformation of the company and its multi-energy profile** to achieve zero net emissions by 2050," said Repsol CEO Josu Jon Imaz.
- Repsol was the **first company in its industry to target zero net emissions by 2050**. This deal is another game-changer. Its upstream business has set the **strategic goal of reducing its carbon intensity 75% by 2025**.

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07 September 2022 - 08:00 CEST | PDF | 578.64 KB

Repsol has boosted its multi-energy transformation, strengthened its leadership in the energy transition, and advanced the fulfillment of key objectives of its 2021-2025 Strategic Plan by partnering with EIG, a U.S. institutional investor in the global energy and infrastructure sectors, in its exploration and production business. EIG will acquire 25% of the upstream business for $4.8 billion (€4.8 billion). This transaction, approved by the Board of Directors of Repsol, values the upstream business at $19 billion (€19 billion), which exceeds analysts' consensus valuations of the unit. The agreement between Repsol and EIG includes the possibility of listing a minority stake of the business in the United States from 2026 onward, subject to favorable market conditions. With this agreement, Repsol advances its 2025 strategic goals of accelerating the energy transition, with flexibility, ambitious and profitable business growth, financial solidity and shareholder remuneration which is amongst the best in the industry and the Ibex 35 index. Repsol´s Strategic Plan contemplates the inclusion of partners or investors in some businesses to accelerate the achievement of objectives and maximize the return of company operations.

The plan deployed an operating model of four business areas; Upstream, Industrial, Client and Low Carbon Generation in a framework of increasing shareholder remuneration with investment oriented to achieving zero net emissions by 2050.

Repsol, as majority shareholder, will retain control of the upstream business, which will continue to be consolidated within the accounts of the Repsol Group. Repsol will appoint four directors to the eight-person board, including the chairman with a casting vote. EIG will appoint two board members and the other two will be independent directors.

The newly structured entity will maintain its workforce and existing management team as well as the current business plan, focused on further strengthening, high grading, and decarbonizing its global portfolio. EIG will contribute its unique track record of investing across the capital structure of the global E&P sector to seek to maximize value creation and boost the strengths of Repsol's Upstream unit. The newly structured global E&P entity will adopt existing Repsol ESG upstream targets and policies, further reinforcing and elevating them with EIG's ESG standards.

EIG is a provider of institutional capital to the global energy and infrastructure sectors and committed to influencing ESG industry best practices across its portfolio. With four decades of industry experience and a long-term track record of investing capital in energy, including upstream and energy-related infrastructure, EIG has committed more than $41.5 billion to the energy sector across 38 countries.

“Our ambition is to lead the energy transition. This pioneering agreement allows us to maintain the strategic direction of the upstream unit and, at the same time, to boost the transformation of the company and its multi-energy profile to achieve zero net emissions by 2050," said Repsol CEO Josu Jon Imaz.
“Energy transition informs every decision we make, and we are thrilled to partner with a global leader of Repsol’s stature on this compelling opportunity to lead change in our industry,” said R. Blair Thomas, EIG’s Chairman and CEO. “Evaluation of ESG impact is integrated into EIG’s core investment and portfolio management functions, and we look forward to working with Repsol, a world-class operator and energy transition leader, to continue building on the business’s ESG best practices. As the world looks to meet the twin goals of decarbonization and reliability, we believe this partnership is well positioned to help meet the growing global demand for accessible, efficient, and safe energy.”
The transaction is expected to close within the next six months once the corporate structure of the upstream business has been concluded, subject to customary regulatory approvals.

Delivering value and cash to accelerate investment
In line with the 2021-2025 Strategic Plan, Repsol has advanced the transformation of the company and has evolved its organization by deploying four business areas (Upstream, Industrial, Customer, and Low-Carbon Generation), supported by more efficient corporate and service units to favor increased results and value crystallization. This agreement enables an advancement of the company’s net zero emissions objective through a project that accelerates transformation and reinforces the multi-energy profile while reducing debt leverage and maintaining a strong cash flow to finance ambitious growth and attractive shareholder distribution.
In line with this objective, Repsol has forged alliances to enhance the growth and development of key areas, including the partnership with Credit Agricole Assurances and EIP in the renewable generation business, the inclusion of partners such as Pontegadea and The Renewables Infrastructure Group (TRIG) in solar and wind assets and the alliance with Saudi Aramco for the construction in the port of Bilbao of one of the world´s largest synthetic fuels plants as well as with Enerkem in a waste-to-products plant in Tarragona which has been included in the European Commission’s Innovation Plan.
The upstream business has consolidated recent growth in key geographic areas and with special focus on the US, prioritizing value over volume and reducing the emissions of its asset portfolio in line with its strategy through 2025. The business is leveraging its strengths such as its flexibility, efficiency, and an advanced technology to increase its contribution to the Group as a whole and to generate cash flow. The unit is prioritizing the development of short-cycle projects to be managed with flexibility and with a limited capital intensity that is among the lowest in the industry.
In addition, the upstream business has set the goal of becoming a leader in reducing CO_2 emissions in the sector, aiming to reduce carbon intensity by 75% by 2025 from a 2016 baseline. Its significant technologic prowess and the digitalization of its processes are key differentiators that will help meet these objectives, as well as its circular economy strategy, which includes the development of initiatives aimed at improving efficiency and process innovation.

Global Upstream Portfolio
Repsol will produce an average of approximately 570,000 barrels of oil equivalent per day in 2022 and has proven and probable reserves of 2.3 billion barrels of oil equivalent, of which nearly 70% is gas.
The portfolio of upstream assets is made up of strategic areas in North America (U.S., Canada, Mexico), South America (Brazil, Peru, Bolivia, Trinidad and Tobago, Colombia and Venezuela), Europe (Norway, UK), North Africa (Algeria, Libya), and Asia (Indonesia).
Repsol’s renowned exploration expertise, as well as its state-of-the-art technology, has allowed the company to make some of the most significant global discoveries of the last decade, which are now on track to be developed. Since 2020, Repsol has made 13 discoveries, with total gross resources of more than 900 million barrels of oil equivalent, mainly in the United States and Mexico.

https://www.latimes.com/business/story/2022-07-14/california-rooftop-solar-pv-panels-recycling-danger

California went big on rooftop solar. Now that's a problem for landfills

Solar panels purchased for home use under incentive programs many years ago are nearing the end of their life cycle. Many are already winding up in landfills.

(Jim Cooke / Los Angeles Times)

BY RACHEL KISELA

PUBLISHED JULY 14, 2022 **UPDATED** JULY 15, 2022 7:13 PM PT

California has been a pioneer in pushing for rooftop solar power, building up the largest solar market in the U.S. More than 20 years and 1.3 million rooftops later, the bill is coming due.

Beginning in 2006, the state, focused on how to incentivize people to take up solar power, showered subsidies on homeowners who installed photovoltaic panels but had no comprehensive plan to dispose of them. Now, panels purchased under those programs are nearing the end of their typical 25-to-30-year life cycle.

For the record:
7:13 p.m. July 15, 2022

An earlier version of this article mischaracterized the environmental risk posed by heavy metals in consumer photovoltaic arrays. This story has been edited to clarify that panels containing toxic materials are routed for disposal to landfills with extra safeguards against leakage, and to note that panels that contain cadmium and selenium are primarily used in utility-grade applications.

An earlier version of this article also misattributed a statement by Evelyn Butler, vice president of technical services at the Solar Energy Industries Assn., to Jen Bristol, the group's senior director of communications. It also misidentified the group as the Solar Energy Industry Assn.

An earlier version of this article also failed to properly attribute quotes by Jigar Shah, director of the Department of Energy's Loan Programs Office, to their source, a 2020 interview with PV

Magazine. The article has also been updated to reflect Shah's current professional affiliation as well as that of Sam Vanderhoof.

An earlier version of this article also stated that 25 years was the life cycle of photovoltaic panels; the text has been updated to reflect that 25 to 30 years is the typical service life but not a fixed limit. Additionally, in a discussion of transporting photovoltaic panels to recycling or hazardous waste disposal facilities, the word "cells" has been changed to "panels" for accuracy.

Many are already winding up in landfills, where in some cases, they could potentially contaminate groundwater with toxic heavy metals such as lead, selenium and cadmium.

Sam Vanderhoof, a solar industry expert and chief executive of Recycle PV Solar, says that only 1 in 10 panels are actually recycled, according to estimates drawn from International Renewable Energy Agency data on decommissioned panels and from industry leaders.

The looming challenge over how to handle truckloads of waste, some of it contaminated, illustrates how cutting-edge environmental policy can create unforeseen problems down the road.

"The industry is supposed to be green," Vanderhoof said. "But in reality, it's all about the money."

California came early to solar power. Small governmental rebates did little to bring down the price of solar panels or to encourage their adoption until 2006, when the California Public Utilities Commission formed the California Solar Initiative. That granted $3.3 billion in subsidies for installing solar panels on rooftops.

The measure exceeded its goals, bringing down the price of solar panels and boosting the share of the state's electricity produced by the sun. Because of that and other measures, such as requirements that utilities buy a portion of their electricity from renewable sources, solar power now accounts for 15% of the state's power.

But as California barreled ahead on its renewable-energy program, focusing on rebates and — more recently — a proposed solar tax, questions about how to handle the waste that would accrue years later were never fully addressed. Now, both regulators and panel manufacturers are realizing that they don't have the capacity to handle what comes next.

"This trash is probably going to arrive sooner than we expected and it is going to be a huge amount of waste," said Serasu Duran, an assistant professor at the University of Calgary's Haskayne School of Business in Canada. "But while all the focus has been on building this renewable capacity, not much consideration has been put on the end of life of these technologies."

Duran co-wrote a recent article in the Harvard Business Review that noted the industry's "capacity is woefully unprepared for the deluge of waste that is likely to come."

It's not just a problem in California but also nationwide. A new solar project was installed every 60 seconds in 2021, according to a fact sheet published by the Solar Energy Industries Assn., and the solar industry is expected to quadruple in size between 2020 and 2030.

Although 80% of a typical photovoltaic panel is made of recyclable materials, disassembling them and recovering the glass, silver and silicon is extremely difficult.

"There's no doubt that there will be an increase in the solar panels entering the waste stream in the next decade or so," said AJ Orben, vice president of We Recycle Solar, a Phoenix-based company that breaks down panels and extracts the valuable metals while disposing of toxic elements. "That's never been a question."

The vast majority of We Recycle Solar's business comes from California, but the company has no facilities in the state. Instead, the panels are trucked to a site in Yuma, Ariz. That's because California's rigorous permitting system for toxic materials makes it exceedingly difficult to set up shop, Orben said.

Recycling solar panels isn't a simple process. Highly specialized equipment and workers are needed to separate the aluminum frame and junction box from the panel without shattering it into glass shards. Specialized furnaces are used to heat panels to recover silicon. In most states, panels are classified as hazardous materials, which require expensive restrictions on packaging, transport and storage. (The vast majority of residential solar arrays in the U.S. are crystalline silicon panels, which can contain lead, although it's less prevalent in newer panels. Thin-film solar panels, which contain cadmium and selenium, are primarily used in utility-grade applications.)

Orben said the economics of the process don't make a compelling case for recycling.

Only about $2 to $4 worth of materials are recovered from each panel. The majority of processing costs are tied to labor, and Orben said even recycling panels at scale would not be more economical.

Most research on photovoltaic panels is focused on recovering solar-grade silicon to make recycling economically viable.

That skews the economic incentives against recycling. The National Renewable Energy Laboratory estimated that it costs roughly $20 to $30 to recycle a panel versus $1 to $2 to send it to a landfill.

Most experts assume that is where the majority of panels are ending up right now. But it's anyone's guess. Natalie Click, a doctoral candidate in materials science at the University of Arizona, said there is no uniform system "for tracking where all of these decommissioned panels are going."

The California Department of Toxic Substances collected its first data on panels recycled by universal waste handlers in 2021. For handlers that accepted more than 200 pounds or generated more than 10,000 pounds of panels, the DTSC counted 335 panels accepted for recycling, said Sanford Nax, a spokesman for the agency.

The department expects the number of installed solar panels in the next decade to exceed hundreds of millions in California alone, and that recycling will become even more crucial as cheaper panels with shorter life spans become more popular.

A lack of consumer awareness about the toxicity of materials in some panels and how to dispose of them is part of the problem, experts said.

"There's an informational gap, there's a technological gap, and there's a financial gap that we're working on," said Amanda Bybee, co-founder of SolarRecycle.org, a website aimed at helping people understand how to recycle solar panels and how the process works.

Last year, new DTSC regulation came into effect that reclassified the panels, changing the way they can be collected and transported. Previously, all panels were required to be treated as hazardous waste upon removal, which restricted transportation and storage.

Both business and residential consumers, or generators as they are called in the recycling industry, were supposed to transport the panels themselves to certified recycling or hazardous waste disposal facilities. With little tracking, it's unclear how frequently that occurred.

Solar panels are now classified as universal waste and can be collected at more than 400 universal waste handlers in California, where they are then assessed and transported to disposal, reuse or recycle facilities. Above, solar panels are installed on a roof.

(Irfan Khan / Los Angeles Times)

Now, panels are classified as universal waste and can be collected at more than 400 universal waste handlers in California, where they are then assessed and transported to disposal, reuse or recycle facilities. (In cases where panels containing toxic materials are relegated to landfills, they are sent to facilities with extra safeguards against leakage.) The new regulations were intended to make it easier for people to turn in their panels, but it does not directly address the next step — recycling.

"What that [rule] does is really just changes how that material is handled, managed, stored, and transported," said Orben of We Recycle Solar. "It doesn't change how that material is actually processed."

In 2016, the Solar Energy Industries Assn., a nonprofit trade association for the U.S. solar industry, started a recycling program for panels. Robert Nicholson, the manager of PV Recycling at the association, said it aims to help the industry group's recycling partners — five so far — "develop compliant, cost-effective recycling services for end-of-life modules."

"The majority of recyclers are already existing recyclers; they're primarily doing e-waste or they're doing glass," said Evelyn Butler, the association's vice president of technical services. "So we have had to work with them to kind of take that leap, to say: 'We believe that the processes you're using can accommodate the technology.'" The association also works with regulators to draft legislation that decreases the number of panels heading to landfills.

Government subsidies are one way to make solar panel recycling economically viable for the waste generators, who now bear much of the cost of recycling.

In Europe, a recently enacted regulation called the European Union Waste of Electrical and Electronic Equipment Directive places responsibility on producers for supporting their products through responsible end-of-life disposal. It requires all producers that manufacture panels for countries in the EU to finance end-of-life collection and recycling.

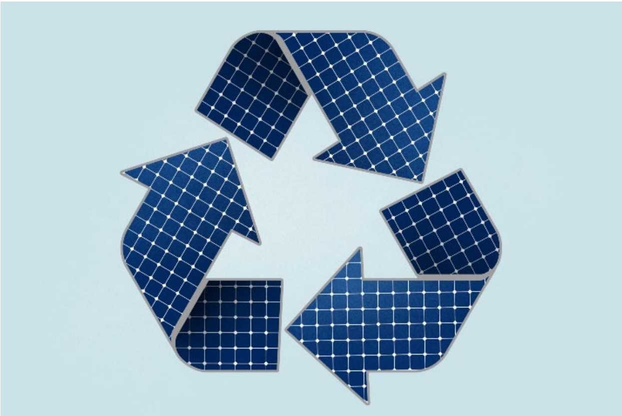
Similar legislation has been attempted in several U.S. states, including Washington, where the Photovoltaic Module Stewardship and Takeback Program will require solar panel manufacturers to finance end-of-life recycling. The initiative was passed in 2017 and will begin implementation in 2025. It's the only producer-responsibility law in the United States.

It's part of a larger strategy in the recycling industry called extended producer responsibility, in which the cost of recycling is built into the cost of a product at its initial purchase. Business entities in the product chain — rather than the general public — become responsible for end-of-life costs, including recycling costs.

In a 2020 interview with PV Magazine, Jigar Shah, co-founder of Generate Capital, a fund that invests in sustainable infrastructure, said the problem can be addressed at the very start of the product chain — by manufacturers. Shah, who is now director of the Department of Energy's Loan

Programs Office, said that policymakers need to require manufacturers to come up with a standard design that makes panels easier and cheaper to recycle.

“It’s far more cost-effective for manufacturers to be forced to work together … where they try to greatly reduce the cost of all that collectively. That happens through policy,” he said. “It doesn’t happen through people opting in.”



Although 80% of a typical photovoltaic panel is made of recyclable materials, disassembling a panel and recovering the glass, silver and silicon is extremely difficult.

(Jim Cooke / Los Angeles Times)

In April 2022, Santa Monica concluded a solar panel recycling pilot program in partnership with the California Product Stewardship Council, a public-private partnership. The stewardship council surveyed local residential solar owners and found that many, at a loss for what to do with end-of-life panels, called up installers for help.

“We did find that the solar installers were the best contact for us to learn about how many decommissioned panels were in our region,” said Drew Johnstone, a sustainability analyst for Santa Monica. “Some contractors did end up just having to pile them in their warehouses, because there’s no good solution for where to bring them.”

Johnstone says the universal waste reclassification has made a big difference, cutting down on cost and paperwork needed for handling modules, and more handlers can accept the panels from generators.

“It’s going to be a really large issue in a number of years,” Johnstone said. “So it would behoove local governments, county, state, and it can go federal too, to have a plan in place for all these panels that will reach their end of life in 10 to 15 years.”

Kisela is a special correspondent.

https://www.cnn.com/2022/09/05/world/thwaites-doomsday-glacier-sea-level-climate/index.html

'Doomsday glacier,' which could raise sea level by several feet, is holding on 'by its fingernails,' scientists say

By Angela Fritz, CNN

Updated 7:31 AM ET, Tue September 6, 2022

(CNN) Antarctica's so-called "doomsday glacier" -- nicknamed because of its high risk of collapse and threat to global sea level -- has the potential to rapidly retreat in the coming years, scientists say, amplifying concerns over the extreme sea level rise that would accompany its potential demise.

The Thwaites Glacier, capable of raising sea level by several feet, is eroding along its underwater base as the planet warms. In a study published Monday in the journal Nature Geoscience, scientists mapped the glacier's historical retreat, hoping to learn from its past what the glacier will likely do in the future.

They found that at some point in the past two centuries, the base of the glacier dislodged from the seabed and retreated at a rate of 1.3 miles (2.1 kilometers) per year. That's twice the rate that scientists have observed in the past decade or so.

That swift disintegration possibly occurred "as recently as the mid-20th century," Alastair Graham, the study's lead author and a marine geophysicist at the University of South Florida, said in a news release.

The floating ice edge at Thwaites Glacier margin in 2019.

It suggests the Thwaites has the capability to undergo a rapid retreat in the near future, once it recedes past a seabed ridge that is helping to keep it in check.

"Thwaites is really holding on today by its fingernails, and we should expect to see big changes over small timescales in the future -- even from one year to the next -- once the glacier retreats beyond a shallow ridge in its bed," Robert Larter, a marine geophysicist and one of the study's co-authors from the British Antarctic Survey, said in the release.

Rán, a Kongsberg HUGIN autonomous underwater vehicle, near the Thwaites Glacier after a 20-hour mission mapping the seafloor.

The US Antarctic Program research vessel Nathaniel B. Palmer working near the Thwaites Eastern Ice Shelf in in 2019.

The Thwaites Glacier, located in West Antarctica, is one of the widest on Earth and is larger than the state of Florida. But it's just a faction of the West Antarctic ice sheet, which holds enough ice to raise sea level by up to 16 feet, according to NASA.

As the climate crisis has accelerated, this region has been closely monitored because of its rapid melting and its capacity for widespread coastal destruction.

The Thwaites Glacier itself has concerned scientists for decades. As early as 1973, researchers questioned whether it was at high risk of collapse. Nearly a decade later, they found that -- because the glacier is grounded to a seabed, rather than to dry land -- warm ocean currents could melt the glacier from underneath, causing it to destabilize from below.

It was because of that research that scientists began calling the region around the Thwaites the "weak underbelly of the West Antarctic ice sheet."

A workboat recovering the Rán autonomous vehicle in one of the fjords of the Antarctic Peninsula during the expedition to Thwaites Glacier in 2019.

In the 21st century, researchers began documenting the Thwaites' rapid retreat in an alarming series of studies.

In 2001, satellite data showed the grounding line was receding by around 0.6 miles (1 kilometer) per year. In 2020, scientists found evidence that warm water was indeed flowing across the base of the glacier, melting it from underneath.

World's largest ice sheet crumbling faster than previously thought, satellite imagery shows

And then in 2021, a study showed the Thwaites Ice Shelf, which helps to stabilize the glacier and hold the ice back from flowing freely into the ocean, could shatter within five years.

"From the satellite data, we're seeing these big fractures spreading across the ice shelf surface, essentially weakening the fabric of the ice; kind of a bit like a windscreen crack," Peter Davis, an oceanographer with the British Antarctic Survey, told CNN in 2021. "It's slowly spreading across the ice shelf and eventually it's going to fracture into lots of different pieces."

Monday's findings, which suggest the Thwaites is capable of receding at a much faster pace than recently thought, were documented on a 20-hour mission in extreme conditions that mapped an underwater area the size of Houston, according to a news release.

Graham said that this research "was truly a once in a lifetime mission," but that the team hopes to return soon to gather samples from the seabed so they can determine when the previous rapid retreats occurred. That could help scientists predict future changes to the "doomsday glacier," which scientists had previously assumed would be slow to undergo change -- something Graham said this study disproves.

"Just a small kick to the Thwaites could lead to a big response," Graham said.

NVSS Vital Statistics Rapid Release

Report No. 23 ■ August 2022

Provisional Life Expectancy Estimates for 2021

Elizabeth Arias, Ph.D., Betzaida Tejada-Vera, M.S., Kenneth D. Kochanek, M.A., and Farida B. Ahmad, M.P.H.

Introduction

The National Center for Health Statistics (NCHS) collects and disseminates the nation's official vital statistics through the National Vital Statistics System. NCHS uses provisional vital statistics data for conducting public health surveillance and final data for producing annual national natality and mortality statistics. NCHS publishes annual and decennial national life tables based on final vital statistics data. To assess the effects of excess mortality related to the COVID-19 pandemic on life expectancy, NCHS published the first ever provisional life expectancy estimates for the year 2020 (1,2). Life expectancy estimates presented in this report are based on provisional mortality data for 2021 and final data for 2019 and 2020. Provisional data are early estimates based on death certificates received, processed, and coded but not finalized by NCHS. These estimates are considered provisional because death certificate information may be revised, and additional death certificates may be received until approximately 6 months after the end of the year.

This report presents life expectancy estimates calculated using complete period life tables based on provisional death counts for 2021 by sex and for the total, Hispanic, non-Hispanic American Indian or Alaska Native (AIAN), non-Hispanic Asian, non-Hispanic Black, and non-Hispanic White populations. Estimates for the Native Hawaiian or Other Pacific Islander population were not produced because data needed to evaluate race and ethnicity misclassification on death certificates for this population are not currently available (3). There are two types of life tables: the cohort (or generation) and the period (or current) life table. The cohort life table presents the mortality experience of a particular birth cohort from the moment of birth through consecutive ages in successive calendar years. The period life table does not represent the mortality experience of an actual birth cohort but rather presents what would happen to a hypothetical cohort if it experienced throughout its entire life the mortality conditions of a particular period. This report also presents contributions of causes of death to the changes in life expectancy using a life table partitioning technique (Technical Notes).

Keywords: Hispanic origin • race • cause of death • National Vital Statistics System

Data and Methods

Provisional life expectancy estimates were calculated using complete period life tables based on provisional death counts for 2021 from death records received and processed by NCHS as of April 24, 2022; provisional numbers of births for the same period based on birth records received and processed by NCHS as of May 3, 2022; and July 1, 2021, postcensal population estimates based on the 2010 decennial census. Provisional death rates are typically computed using death data after a 3-month lag, as completeness and timeliness of provisional death data can vary by many factors, including cause of death, month of the year, and age of the decedent (4,5). Mortality data used in this report include over 99% of the deaths that occurred in 2021, but certain jurisdictions and age groups may be underrepresented for later months (5). Deaths requiring investigation, including infant deaths and those from external injuries and drug overdose may be underestimated (6). See Technical Notes for more information about the calculation of the complete period life tables and life table partitioning by cause of death. Provisional 2021 life expectancy estimates are compared with final estimates for years 2019 and 2020 to describe changes in life expectancy in the United States since the start of the COVID-19 pandemic.

Results

Life expectancy in the United States

The Table summarizes life expectancy by age, race and Hispanic origin, and sex. Life expectancy at birth represents the average number of years a group of infants would live if they were to experience throughout life the age-specific death rates prevailing during a period. In 2021, life expectancy at birth was 76.1 years, declining by 0.9 year from 77.0 in 2020 (3). Life expectancy at birth for males in 2021 was 73.2 years, representing a decline of 1.0 year from 74.2 years in 2020. For females, life expectancy declined to 79.1 years, decreasing 0.8 year from 79.9 years in 2020 (Figure 1). Excess deaths due to COVID-19 and other causes in 2020 and 2021 led to an overall decline in life expectancy between 2019 and 2021 of 2.7 years for the total population, 3.1 years for males, and 2.3 years for females (Figure 1) (7).

Table. Provisional life expectancy, by age, race and Hispanic origin, and sex: United States, 2021

Age (years)	All races and origins			Hispanic			Non-Hispanic American Indian or Alaska Native			Non-Hispanic Asian			Non-Hispanic Black			Non-Hispanic White		
	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female
0	76.1	73.2	79.1	77.7	74.4	81.0	65.2	61.5	69.2	83.5	81.2	85.6	70.8	66.7	74.8	76.4	73.7	79.2
1	75.6	72.6	78.5	77.1	73.8	80.4	64.7	61.0	68.7	82.7	80.4	84.8	70.6	66.5	74.5	75.7	73.0	78.5
5	71.6	68.7	74.6	73.1	69.8	76.4	60.9	57.1	64.8	78.8	76.5	80.8	66.7	62.6	70.7	71.8	69.1	74.6
10	66.7	63.8	69.7	68.2	64.9	71.5	55.9	52.2	59.9	73.8	71.5	75.9	61.8	57.7	65.7	66.8	64.1	69.6
15	61.7	58.8	64.7	63.2	59.9	66.5	51.0	47.3	55.0	68.8	66.6	70.9	56.9	52.8	60.8	61.9	59.2	64.7
20	56.9	54.1	59.8	58.4	55.1	61.6	46.4	42.7	50.3	63.9	61.7	65.9	52.2	48.3	56.0	57.0	54.4	59.8
25	52.2	49.5	55.0	53.7	50.6	56.8	42.1	38.6	45.8	59.1	56.9	61.0	47.8	44.2	51.3	52.3	49.8	54.9
30	47.6	45.1	50.2	49.1	46.1	52.0	38.0	34.7	41.5	54.3	52.1	56.1	43.5	40.0	46.7	47.7	45.3	50.2
35	43.1	40.7	45.5	44.5	41.7	47.2	34.3	31.2	37.4	49.4	47.3	51.2	39.1	35.9	42.1	43.1	40.9	45.5
40	38.6	36.4	40.9	39.9	37.3	42.5	30.8	28.0	33.8	44.6	42.5	46.3	35.0	32.0	37.7	38.7	36.5	40.8
45	34.2	32.1	36.4	35.5	33.0	37.8	27.4	24.8	30.0	39.9	37.9	41.5	30.9	28.1	33.4	34.3	32.3	36.3
50	30.0	28.0	31.9	31.1	28.8	33.3	24.4	22.1	26.7	35.2	33.3	36.7	26.9	24.4	29.2	30.0	28.1	31.9
55	25.9	24.0	27.6	26.9	24.8	28.8	21.5	19.5	23.5	30.6	28.9	32.0	23.2	20.9	25.2	25.9	24.1	27.6
60	22.0	20.4	23.5	23.0	21.1	24.6	18.9	17.2	20.4	26.1	24.6	27.4	19.7	17.6	21.5	21.9	20.4	23.4
65	18.3	16.9	19.6	19.3	17.6	20.6	16.3	15.1	17.4	21.9	20.5	22.9	16.5	14.8	18.0	18.3	16.9	19.5
70	14.8	13.7	15.8	15.7	14.4	16.7	13.7	12.7	14.5	17.8	16.7	18.6	13.6	12.2	14.7	14.7	13.6	15.7
75	11.5	10.6	12.3	12.4	11.3	13.1	11.2	10.5	11.8	14.0	13.1	14.5	10.9	9.7	11.7	11.4	10.5	12.1
80	8.6	7.9	9.1	9.3	8.5	9.7	9.1	8.6	9.3	10.4	9.8	10.7	8.4	7.5	8.9	8.4	7.8	8.9
85	6.1	5.6	6.4	6.7	6.1	6.9	7.2	6.9	7.2	7.3	6.9	7.4	6.2	5.6	6.5	5.9	5.5	6.2
90	4.1	3.9	4.3	4.6	4.3	4.6	5.6	5.5	5.4	4.8	4.7	4.8	4.5	4.1	4.6	4.0	3.7	4.1
95	2.8	2.7	2.9	3.2	3.0	3.1	4.4	4.4	4.1	3.1	3.1	3.0	3.2	3.0	3.3	2.7	2.6	2.7
100	2.0	2.0	2.0	2.3	2.2	2.1	3.5	3.6	3.3	2.1	2.2	2.0	2.4	2.3	2.3	1.9	1.8	1.9

NOTES: Life tables by race and Hispanic origin have been adjusted for race and ethnicity misclassification on death certificates; see Technical Notes in this report. Estimates are based on provisional data for 2021. Provisional data are subject to change as additional data are received.

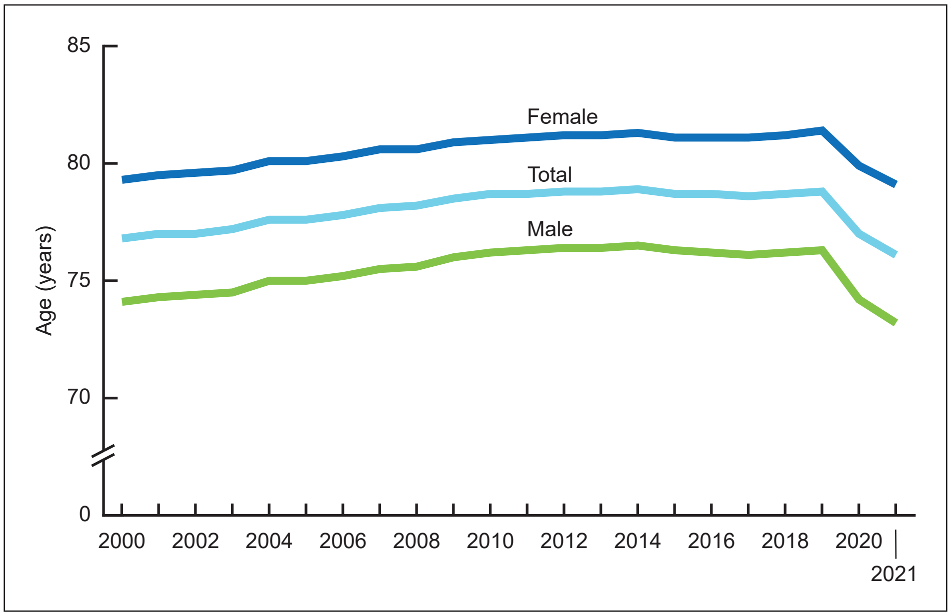
SOURCE: National Center for Health Statistics, National Vital Statistics System, Mortality.

The difference in life expectancy between the sexes was 5.9 years in 2021, increasing from 5.7 in 2020. Between 2000 and 2010, the difference in life expectancy between the sexes narrowed from 5.2 years to its lowest level of 4.8 years, but then increased in 2020 and 2021 to levels not seen since 1996 (when the difference was 6 years) (Figure 1).

Life expectancy by Hispanic origin and race

Between 2020 and 2021, life expectancy decreased by 1.9 years for the non-Hispanic AIAN population (67.1 to 65.2) (Figure 2). It decreased by 1.0 year for the non-Hispanic White population (77.4 to 76.4), by 0.7 year for the non-Hispanic Black population (71.5 to 70.8), by 0.2 year for the Hispanic population (77.9 to 77.7), and by 0.1 year for the non-Hispanic Asian population (83.6 to 83.5). Increases in excess deaths led to a decline in life expectancy between 2019 and 2021 of 6.6 years for the non-Hispanic AIAN population, 4.2 years for the Hispanic population, 4.0 years for the non-Hispanic Black population, 2.4 years for the non-Hispanic White population, and 2.1 years for the non-Hispanic Asian population.

Figure 1. Life expectancy at birth, by sex: United States, 2000–2021

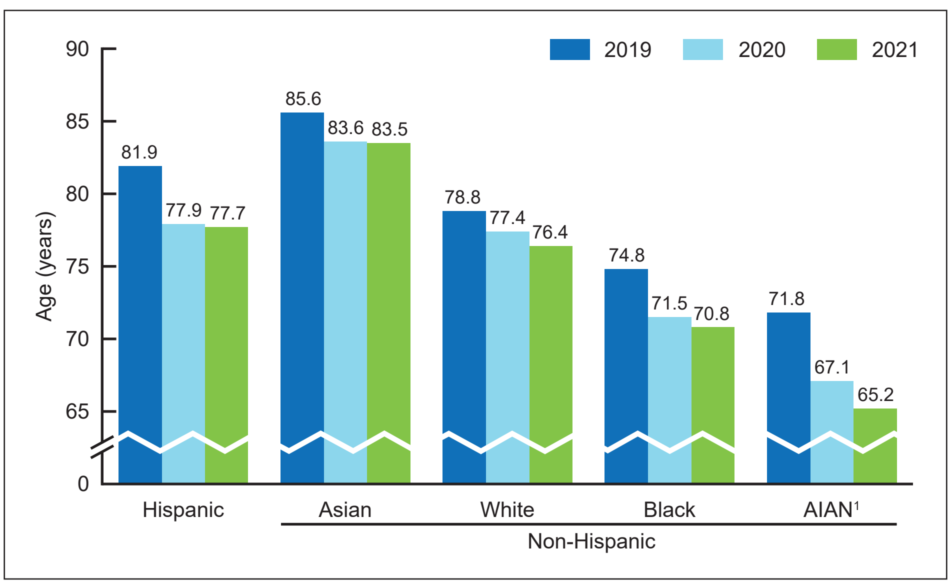


NOTES: Estimates are based on provisional data for 2021. Provisional data are subject to change as additional data are received. Estimates for 2000–2020 are based on final data.
SOURCE: National Center for Health Statistics, National Vital Statistics System, Mortality.

Among the 10 Hispanic-origin and race-sex groups (Figure 3), the decrease in life expectancy between 2020 and 2021 was greatest for non-Hispanic AIAN males, whose life expectancy declined by 2.3 years (63.8 to 61.5), followed by non-Hispanic AIAN females with a decline of 1.5 years (70.7 to 69.2), non-Hispanic Black and non-Hispanic White males with a decline of 1.1 years each (67.8 to 66.7) and (74.8 to 73.7), respectively, non-Hispanic White females with a decline of 0.9 year (80.1 to 79.2), non-Hispanic Black females with a decline of 0.6 year (75.4 to 74.8), Hispanic and non-Hispanic Asian females with a decline of 0.3 year each (81.3 to 81.0) and (85.9 to 85.6), respectively, and Hispanic males with a decline of 0.2 year (74.6 to 74.4). Non-Hispanic Asian males experienced an increase in life expectancy of 0.1 year (81.1 to 81.2) between 2020 and 2021.

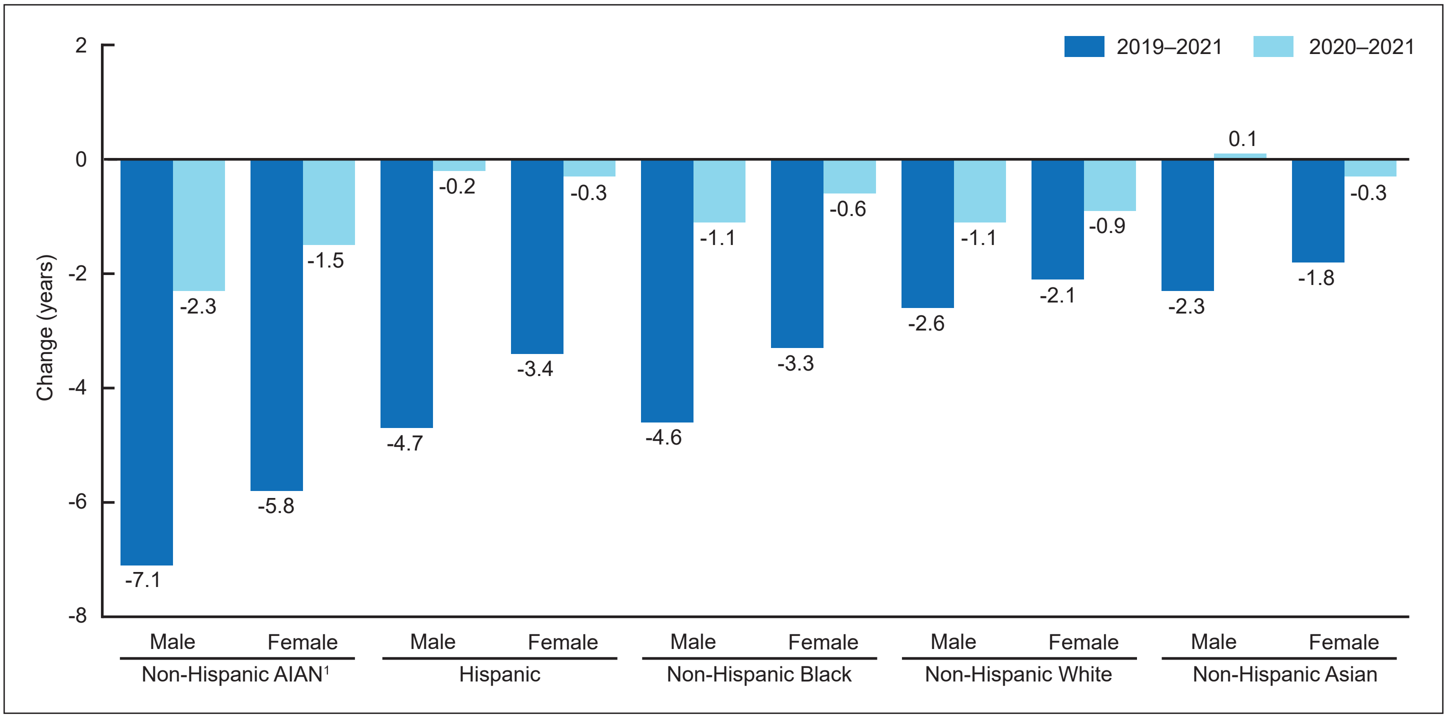
Overall, increases in excess deaths during 2020 and 2021 led to decreases in life expectancy at birth of 7.1 years for non-Hispanic AIAN males, 5.8 years for non-Hispanic AIAN females, 4.7 years for Hispanic males, 4.6 years for non-Hispanic Black males, 3.4 years for Hispanic females, 3.3 years for non-Hispanic Black females, 2.6 years for non-Hispanic White males, 2.3 years for non-Hispanic Asian males, 2.1 years for non-Hispanic White females, and 1.8 years for non-Hispanic Asian females.

Figure 2. Life expectancy at birth, by Hispanic origin and race: United States, 2019–2021



[1]American Indian or Alaska Native.
NOTES: Estimates are based on provisional data for 2021. Provisional data are subject to change as additional data are received. Estimates for 2019 and 2020 are based on final data. Life tables by race and Hispanic origin are based on death rates that have been adjusted for race and Hispanic-origin misclassification on death certificates; see Technical Notes in this report.
SOURCE: National Center for Health Statistics, National Vital Statistics System, Mortality.

Figure 3. Change in life expectancy at birth, by Hispanic origin and race: United States, 2019–2021 and 2020–2021



[1]American Indian or Alaska Native.
NOTES: Estimates are based on provisional data for 2021. Provisional data are subject to change as additional data are received. Estimates for 2019 and 2020 are based on final data. Life tables by race and Hispanic origin are based on death rates that have been adjusted for race and Hispanic-origin misclassification on death certificates; see Technical Notes in this report.
SOURCE: National Center for Health Statistics, National Vital Statistics System, Mortality.

Effect on life expectancy of changes in cause-specific mortality

Increases or decreases in life expectancy represent the sum of positive and negative contributions of cause-specific death rates. Declines in cause-specific mortality contribute to increases in life expectancy, while increases contribute to decreases in life expectancy. If the negative contributions (increases in cause-specific death rates) are greater than the positive contributions (decreases in cause-specific deaths rates), then the result is a decline in life expectancy. If negative and positive contributions offset each other, then there would be no change in life expectancy (see Technical Notes for a description of the partitioning method).

The decline of 0.9 year in life expectancy between 2020 and 2021 was primarily due to increases in mortality due to COVID-19 (50.0% of the negative contribution), unintentional injuries (15.9%), heart disease (4.1%), chronic liver disease and cirrhosis (3.0%), and suicide (2.1%) (Figure 4). The decline in life expectancy would have been even greater were it not for the offsetting effects of decreases in mortality due to influenza and pneumonia (38.5%), chronic lower respiratory diseases (28.8%), Alzheimer disease (18.3%), perinatal conditions (6.3%), and Parkinson disease (2.3%).

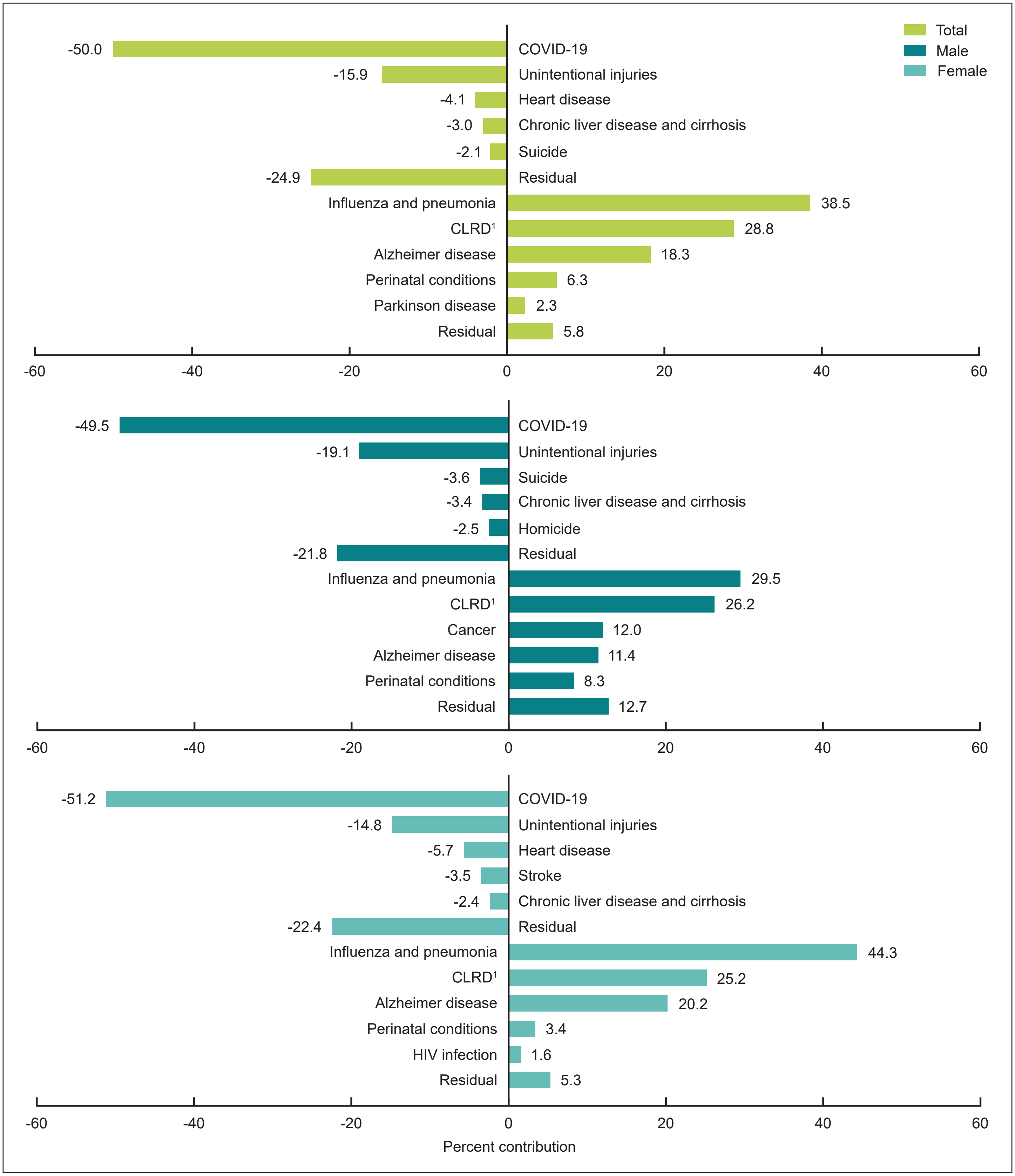
For the male population, the 1.0-year decline in life expectancy was mostly due to increases in mortality due to COVID-19 (49.5%), unintentional injuries (19.1%), suicide (3.6%), chronic liver disease and cirrhosis (3.4%), and homicide (2.5%). The decline in life expectancy was offset by decreases in mortality due to influenza and pneumonia (29.5%), chronic lower respiratory diseases (26.2%), cancer (12.0%), Alzheimer disease (11.4%), and perinatal conditions (8.3%).

For females, the decline in life expectancy of 0.8 year was primarily due to increases in mortality due to COVID-19 (51.2%), unintentional injuries (14.8%), heart disease (5.7%), stroke (3.5%), and chronic liver disease and cirrhosis (2.4%). The decline in life expectancy was offset by decreases in mortality due to influenza and pneumonia (44.3%), chronic lower respiratory diseases (25.2%), Alzheimer disease (20.2%), perinatal conditions (3.4%), and HIV infection (1.6%).

The non-Hispanic AIAN population experienced the greatest decline in life expectancy (1.9 years) between 2020 and 2021. The decline was due primarily to increases in mortality due to COVID-19 (21.4%), unintentional injuries (21.3%), chronic liver disease and cirrhosis (18.6), suicide (5.4%), and heart disease (3.4%). The decline in life expectancy would have been greater if not for the offsetting declines in mortality due to homicide (23.0%), influenza and pneumonia (21.2%), congenital malformations (12.4%), perinatal conditions (9.4%), and benign neoplasms (5.6%) (Figure 5).

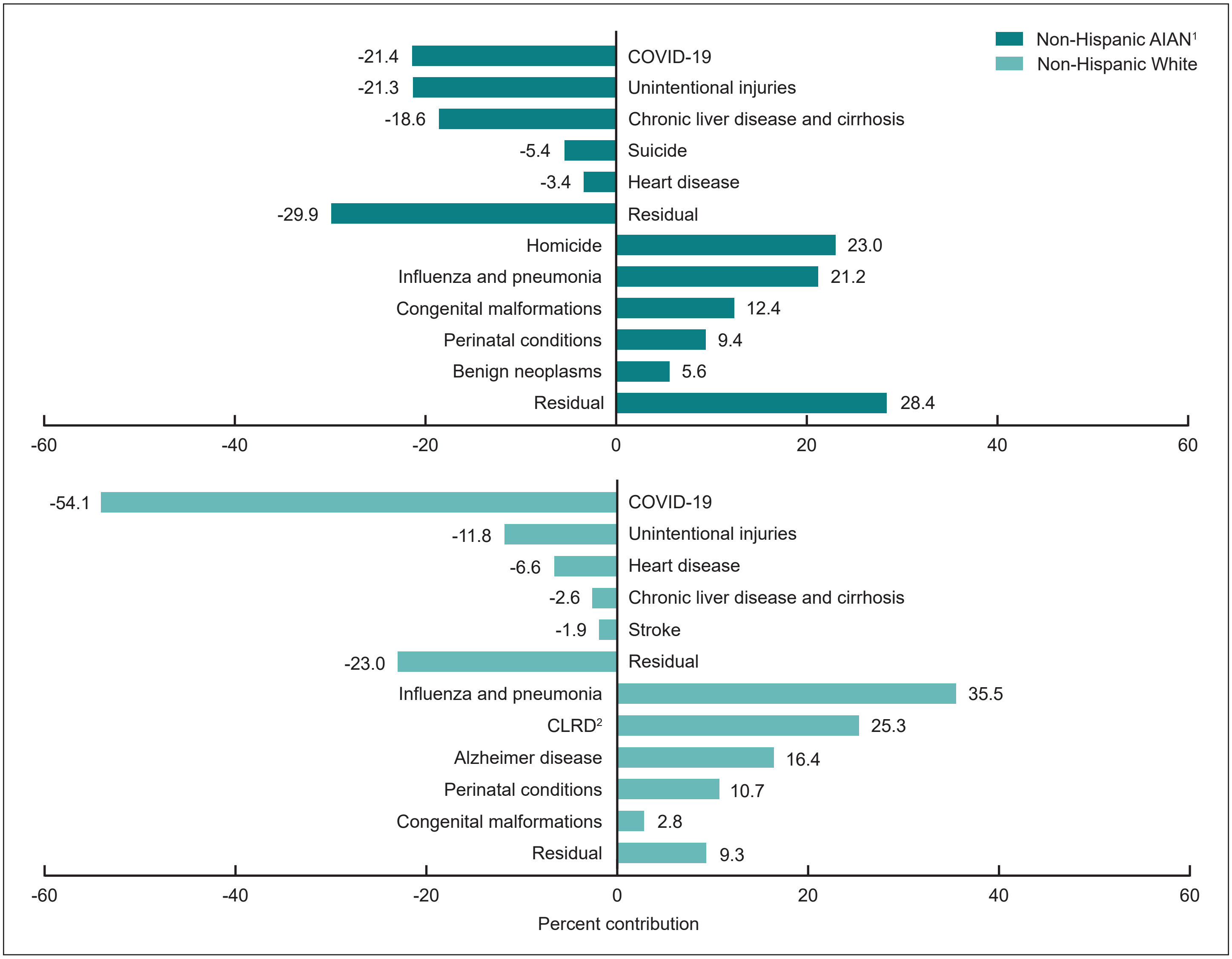
The second greatest decline in life expectancy between 2020 and 2021 was in the non-Hispanic White population (1.0 year). The decline was primarily due to increases in mortality due to

Figure 4. Contribution of leading causes of death to the change in life expectancy, by sex and total population: United States, 2020–2021



[1]Chronic lower respiratory diseases.
NOTES: Estimates are based on provisional data for 2021. Provisional data are subject to change as additional data are received. Estimates for 2020 are based on final data. Life tables by race and Hispanic origin are based on death rates that have been adjusted for race and Hispanic-origin misclassification on death certificates; see Technical Notes in this report.
SOURCE: National Center for Health Statistics, National Vital Statistics System, Mortality.

Figure 5. Contribution of leading causes of death to change in life expectancy, by Hispanic origin and race: Non-Hispanic American Indian or Alaska Native and non-Hispanic White populations, 2020–2021



[1]American Indian or Alaska Native.
[2]Chronic lower respiratory diseases.
NOTES: Estimates are based on provisional data for 2021. Provisional data are subject to change as additional data are received. Estimates for 2020 are based on final data. Life tables by race and Hispanic origin are based on death rates that have been adjusted for race and Hispanic-origin misclassification on death certificates; see Technical Notes in this report.
SOURCE: National Center for Health Statistics, National Vital Statistics System, Mortality.

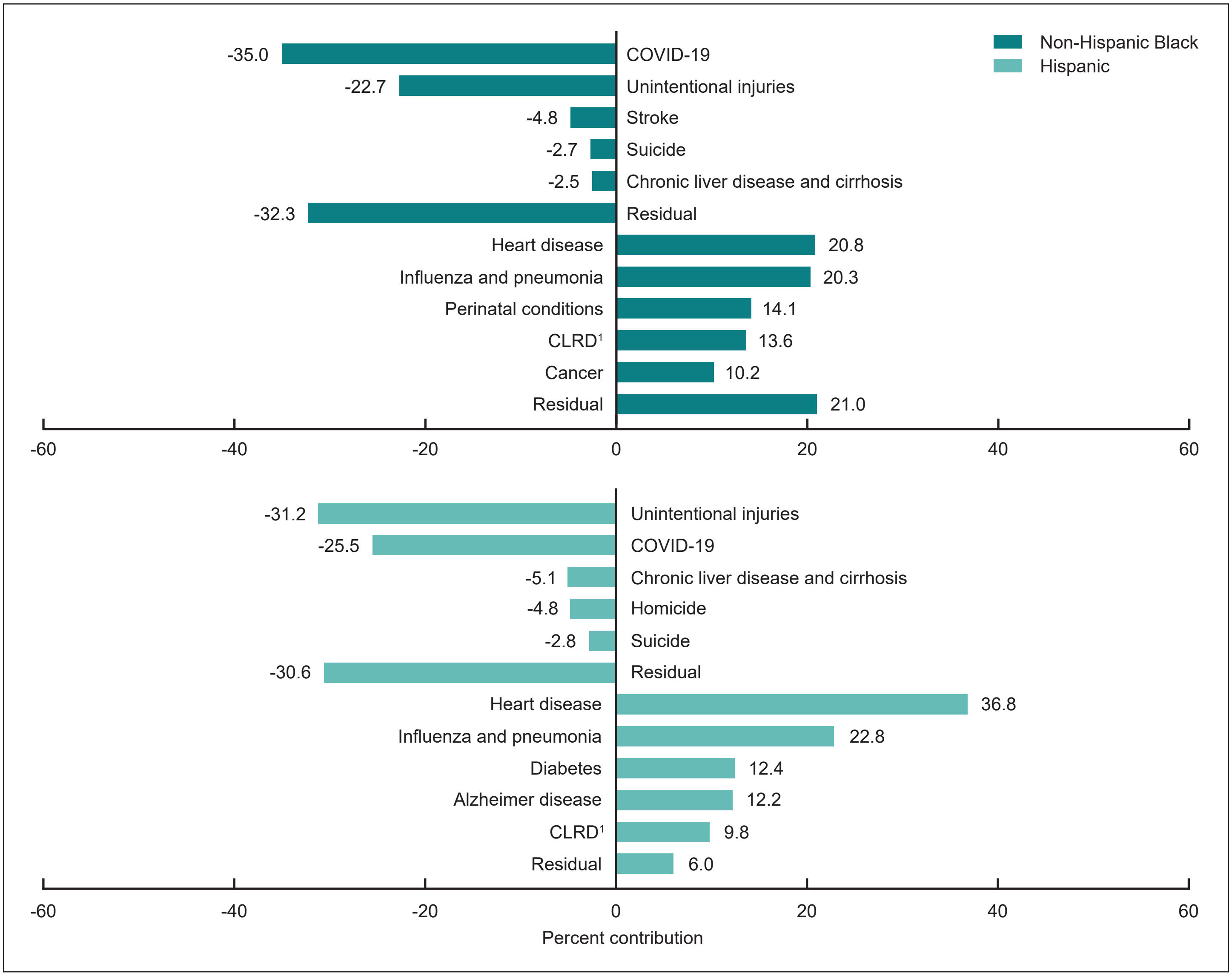
COVID-19 (54.1%), unintentional injuries (11.8%), heart disease (6.6%), chronic liver disease and cirrhosis (2.6%), and stroke (1.9%). The negative effects of these causes were offset by decreases in mortality due to influenza and pneumonia (35.5%), chronic lower respiratory diseases (25.3%), Alzheimer disease (16.4%), perinatal conditions (10.7%), and congenital malformations (2.8%) (Figure 5).

The non-Hispanic Black population had the third greatest decline in life expectancy (0.7 year). The decline was due primarily to increases in mortality due to COVID-19 (35.0%), unintentional injuries (22.7%), stroke (4.8%), suicide (2.7%), and chronic liver disease and cirrhosis (2.5%). The decrease in life expectancy was offset by decreases in mortality due to heart disease (20.8%), influenza and pneumonia (20.3%), perinatal conditions (14.1%), chronic lower respiratory diseases (13.6%), and cancer (10.2%) (Figure 6).

The Hispanic population had the fourth largest decline in life expectancy between 2020 and 2021 (0.2 year). This decrease was primarily due to increases in mortality due to unintentional injuries (31.2%), COVID-19 (25.5%), chronic liver disease and cirrhosis (5.1%), homicide (4.8%), and suicide (2.8%). The decline in life expectancy would have been greater were it not for the offsetting effects of decreases in mortality due to heart disease (36.8%), influenza and pneumonia (22.8%), diabetes (12.4%), Alzheimer disease (12.2%), and chronic lower respiratory diseases (9.8%) (Figure 6).

The non-Hispanic Asian population experienced the smallest decline in life

Figure 6. Contribution of leading causes of death to change in life expectancy, by Hispanic origin and race: Non-Hispanic Black and Hispanic populations, 2020–2021



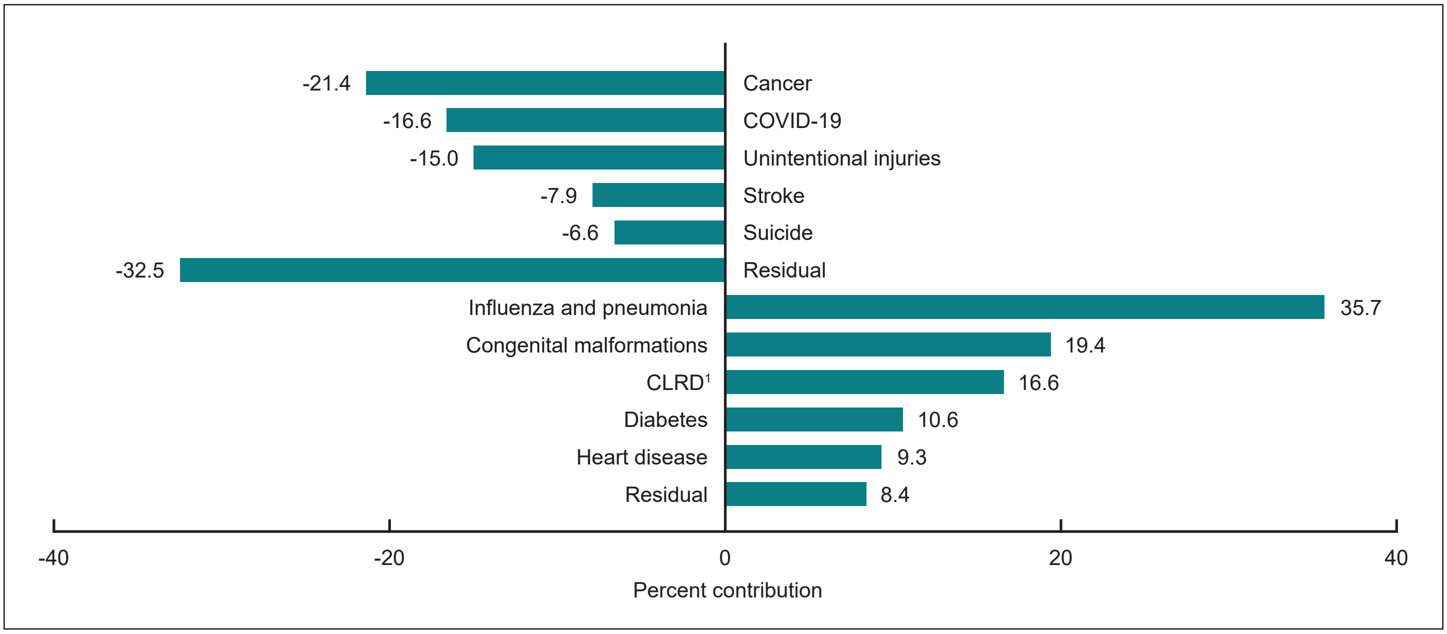
[1]Chronic lower respiratory diseases.
NOTES: Estimates are based on provisional data for 2021. Provisional data are subject to change as additional data are received. Estimates for 2020 are based on final data. Life tables by race and Hispanic origin are based on death rates that have been adjusted for race and Hispanic-origin misclassification on death certificates; see Technical Notes in this report.
SOURCE: National Center for Health Statistics, National Vital Statistics System, Mortality.

expectancy (0.1 year), primarily due to increases in mortality due to cancer (21.4%), COVID-19 (16.6%), unintentional injuries (15.0%), stroke (7.9%), and suicide (6.6%). The decline in life expectancy was offset by decreases in mortality due to influenza and pneumonia (35.7%), congenital malformations (19.4%), chronic lower respiratory diseases (16.6%), diabetes (10.6%), and heart disease (9.3%) (Figure 7).

Discussion and Conclusions

U.S. life expectancy at birth for 2021, based on nearly final data, was 76.1 years, the lowest it has been since 1996. Male life expectancy (73.2) and female life expectancy (79.1) also declined to levels not seen since 1996. The non-Hispanic AIAN population experienced the largest decline in life expectancy, from 67.1 in 2020 to 65.2 years in 2021, the same life expectancy of the total U.S. population in 1944 (8). The non-Hispanic White population had the second greatest decline in life expectancy (77.4 to 76.4) and was the lowest seen since 1995 for the White population (regardless of Hispanic origin). Life expectancy for the non-Hispanic Black population declined from 71.5 to 70.8 years, a level last seen in 1996 for the Black population (regardless of Hispanic origin). Life expectancy for the Hispanic population declined to 77.7 years, a level lower than in 2006 (80.3), the first year for which life expectancy estimates by Hispanic origin were produced (9). The

Figure 7. Contribution of leading causes of death to change in life expectancy, by Hispanic origin and race: Non-Hispanic Asian population, 2020–2021



[1]Chronic lower respiratory diseases.
NOTES: Estimates are based on provisional data for 2021. Provisional data are subject to change as additional data are received. Estimates for 2020 are based on final data. Life tables by race and Hispanic origin are based on death rates that have been adjusted for race and Hispanic-origin misclassification on death certificates; see Technical Notes in this report.
SOURCE: National Center for Health Statistics, National Vital Statistics System, Mortality.

non-Hispanic Asian population had the smallest decline in life expectancy (83.6 to 83.5) and maintained its status as the population with the highest life expectancy in the United States.

Between 2020 and 2021, racial and ethnic disparities in life expectancy increased in some cases and declined in others. For example, the non-Hispanic White advantage over the non-Hispanic AIAN population increased by 8.7% between 2020 (10.3 years) and 2021 (11.2). The non-Hispanic White advantage over the non-Hispanic Black population declined by 5.1% between 2020 (5.9) and 2021 (5.6). Life expectancy for the Black population has consistently been lower than that of the White population, but the gap had been narrowing during the past three decades, from 7.1 years in 1993 to 4.0 in 2019 (10).

The Hispanic life expectancy advantage over the non-Hispanic White population increased by 1.6% between 2020 (0.5 year) and 2021 (1.3). Between 2019 and 2020, the Hispanic population lost most of the life expectancy advantage (3.1 to 0.5) it had experienced relative to the non-Hispanic White population since first recorded in 2006 (8,10). The non-Hispanic Asian life expectancy advantage over the non-Hispanic White population increased by 14.5% between 2020 (6.2) and 2021 (7.1).

COVID-19 was the leading cause contributing negatively to the change in life expectancy for the total population and for three of the five Hispanic-origin and race groups shown in this report. Mortality due to COVID-19 contributed 54.1%, 35.0%, and 21.4% to the decline in life expectancy for the non-Hispanic White, non-Hispanic Black, and non-Hispanic AIAN populations, respectively. For the Hispanic and non-Hispanic Asian populations, COVID-19 was the second leading cause contributing to the decline in life expectancy by 25.5% and 16.6%, respectively. Unintentional injuries was the leading cause contributing to the decline in life expectancy for the Hispanic population (31.2%) and the second leading cause for the non-Hispanic Black, non-Hispanic AIAN, and non-Hispanic White populations, contributing to the decline by 22.7%, 21.3%, and 11.8%, respectively. It had the third largest effect on the decline in life expectancy for the non-Hispanic Asian population (15.0%). Increases in unintentional injury deaths in 2021 were largely driven by drug overdose deaths.

Between 2019 and 2021, life expectancy in the United States declined 2.7 years, with most of the decline (66.7%) occurring the first year of the COVID-19 pandemic. During the 2-year period, large disparities were seen in loss of life expectancy by Hispanic origin and race. The non-Hispanic AIAN population lost 6.6 years, followed by the Hispanic population with a loss of 4.2 years, the non-Hispanic Black population with a loss of 4.0 years, the non-Hispanic White population with a loss of 2.4 years, and the non-Hispanic Asian population with a loss of 2.1 years. The Hispanic and non-Hispanic Asian populations experienced over 95% of their respective declines during the first year of the pandemic. The non-Hispanic Black and non-Hispanic AIAN populations experienced 82.5% and 71.2% of their declines during the first year. Unlike these populations, the non-Hispanic White population experienced close to one-half of their decline (41.7%) during the second year of the pandemic.

The provisional mortality data on which the life tables are based have several

SAF

Dan Tsubouchi @Energy_Tidbits · 2h

Hmm! is there remote (<5%) potential for large #NatGas #LNG winter price risk? Expectation Putin escalates attacks, keeps #NatGas shut-in even if RUS retreat. But is there remote potential RUS/Putin negotiate & #NatGas flows to fund reparations? #OOTT

apnews.com

Ukraine pushes major counteroffensive as war marks 200 days

As the war in Ukraine marks 200 days, the country has reclaimed broad swaths of the south and east in a long-anticipated counteroffensive ...

1 2

SAF

Dan Tsubouchi @Energy_Tidbits · 3h

ICYMI. @PierrePoilievre acceptance speech after blow out win to be Conservatives leader. "fighting climate change with technology and not with taxes". "produce more energy right here in Canada", replace imported #Oil in eastern Canada, mine critical minerals for EVs. #OOTT

SAF Group created transcript of excerpts from new Conservatives party leader, Pierre Poilievre acceptance speech on Sept 10, 2022. https://www.youtube.com/watch?v=IdxABPcdSuU&t=1401s

Items in "italics" are SAF Group created transcript.

12:20 min *"it means fighting climate change with technology and not with taxes"*.

13:55 min *"and produce more energy right here in Canada"*.

15:20 min *"mine critical minerals for electric cars"*.

15:30 min *"right now, we lose wages because we import 130,000 barrels of overseas oil, mostly from dictators, every single day even though we have the third largest supply right here in Canada. And that is all because our government prefers dirty dictator oil to responsible Canadian energy. We will repeal this government's anti-energy laws and replace them with a law that protects our environment, consults First Nations, and gets things built. We will greenlight Newfoundland and Labrador's planned increase in oil production, which will allow us to fully replace every single barrel of oil we are importing from abroad. And within five years, we will set the goal to end dictator oil in Canada altogether"*.

17:15 min. *"we will greenlight mining and manufacture of minerals like lithium, cobalt and copper to make electric cars and batteries"*.

22:55 min *"we will restore Canada's promise in a country where it doesn't matter who you love, or if your name is Smith or Singh, Martin or Mohammed, Chang or Charles."*

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

1 2 9

SAF

Dan Tsubouchi @Energy_Tidbits · 5h

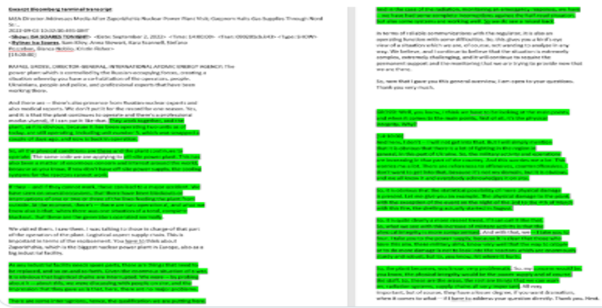
Item to watch as Ukraine counteroffensive bears big gains.

#TASS reporting #ZaporizhzhiaNPP now running on diesel as power lines down.

See 👇 Sept 3 tweet on @rafaelmgrossi's warning access to offset power is "matter of enormous concern"

#OOTT #NatGas

> **Dan Tsubouchi** @Energy_Tidbits · Sep 3
>
> ICYMI, @rafaelmgrossi post #ZaporizhzhiaNPP visit. Yes worries a lot military action could cause physical damage. But access to off-site power is "matter of enormous concern" as needed or "cooling systems for the reactors cannot work". Thx @IsaCNN @business. #OOTT



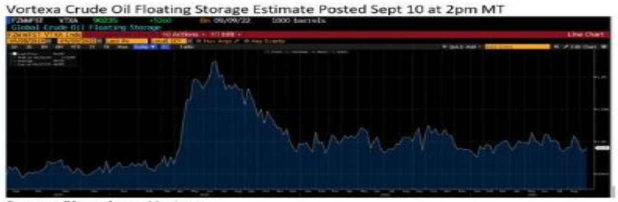
2

SAF

Dan Tsubouchi @Energy_Tidbits · 19h

#Vortexa crude #Oil floating storage at 09/09 est 90.24 mmb, +5.26 mmb WoW vs revised down 09/02 of 84.98 mmb. Last six weeks were revised lower. Floating storage mostly +/- 90 mmb other than 2 of last 7 weeks. Thx @Vortexa @business. #OOTT

Vortexa Crude Oil Floating Storage Estimate Posted Sept 10 at 2pm MT



Source: Bloomberg, Vortexa

Posted Sept 10, 2pm MT

FZWWFST VTXA Index 09/08/2019 - 09/09/2022

	Date	FZWWFST VT... Last Px
Fr	09/09/2022	90235
Fr	09/02/2022	84975
Fr	08/26/2022	88677
Fr	08/19/2022	102.252k
Fr	08/12/2022	109.215k
Fr	08/05/2022	91280
Fr	07/29/2022	91381
Fr	07/22/2022	84546
Fr	07/15/2022	87008
Fr	07/08/2022	99025
Fr	07/01/2022	102.525k

Sept 3, noon MT

FZWWFST VTXA Index 09/01/2019 - 09/02/2022

	Date	FZWWFST VT... Last Px
Fr	09/02/2022	90721
Fr	08/26/2022	96602
Fr	08/19/2022	107.78k
Fr	08/12/2022	110.311k
Fr	08/05/2022	92630
Fr	07/29/2022	94907
Fr	07/22/2022	83291
Fr	07/15/2022	89341
Fr	07/08/2022	99602
Fr	07/01/2022	102.815k
Fr	06/24/2022	103.064k

Aug 27, noon MT

FZWWFST VTXA Index 08/25/2019 - 08/26/2022

	Date	FZWWFST VT... Last Px
Fr	08/26/2022	99094
Fr	08/19/2022	110.429k
Fr	08/12/2022	110.706k
Fr	08/05/2022	94431
Fr	07/29/2022	96372
Fr	07/22/2022	87209
Fr	07/15/2022	89237
Fr	07/08/2022	99286
Fr	07/01/2022	102.682k
Fr	06/24/2022	102.696k
Fr	06/17/2022	111.583k

Source: Bloomberg, Vortexa

2 1

SAF

Dan Tsubouchi @Energy_Tidbits · Sep 10

Finally FR, DE, UK take clear stance on #JCPOA. Hope for deal is over unless Iran takes offered deal & resumes IAEA cooperation. Wasn't easy decision as means EU must scramble for oil as Iran #Oil can't fill the gap when EU Dec 5 sanctions on RUS oil kick in. #OOTT

> **German Mission to UN (New York)** ... @Germany... · Sep 10
> Germany government organization
> #JCPoA: Joint Statement by France, Germany and the United Kingdom
>
> "(...)We will consult, alongside international partners, on how best to address #Iran's continued nuclear escalation and lack of cooperation with the IAEA(...)."
>
> Full Statement: Diplo.de/2551310

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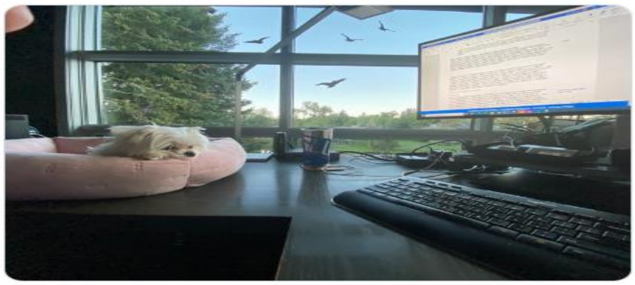
SAF

Dan Tsubouchi @Energy_Tidbits · Sep 10

our bored 3.5 lb maltese, chai, isn't too interested in watching me work on tomorrow's energy tidbits memo.



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SAF

Dan Tsubouchi @Energy_Tidbits · Sep 10

Give @SecYellen credit, not trying to give all credit to @POTUS for $1.28 drop from $5.01 peak in #Gasoline price. "By Treasury estimates, the President's decision has reduced the price of gas by between around 17 and 42 cents per gallon this year". #OOTT

home.treasury.gov

Remarks by Secretary of the Treasury Janet L. Yellen at Ford Rouge El...

As prepared for delivery Thank you for that introduction. It's great to be in Dearborn and, later today, in Detroit. As the global capital of the ...

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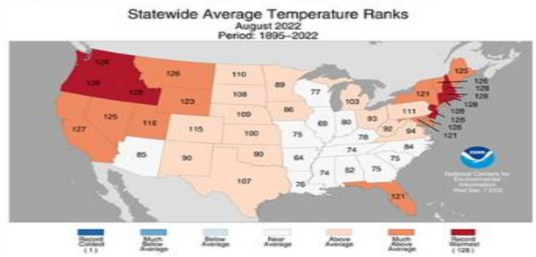
SAF

Dan Tsubouchi @Energy_Tidbits · Sep 9

Been a great summer for US HH #NatGas prices. Huge global #LNG prices flow back impact into US. And one of the best summers ever for heat driven #NatGas #Coal consumption in US. @NOAA says 3rd hottest Jun/Jul/Aug and 8th hottest Aug in last 128 years. #OOTT

https://www.ncei.noaa.gov/access/monitoring/us-maps/1/202208



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Dan Tsubouchi @Energy_Tidbits · Sep 9

Three potential storms off Africa. Forecasting Atlantic hurricane paths is impossible even for experts. But hurricane risk to GoM #Oil #NatGas #LNG #Refinery tends to increase if hurricanes are south of Puerto Rico. See 👇 excerpt SAF Group Dec 5, 2021 Energy Tidbits #OOTT

Excerpt SAF Group Dec 5, 2021 Energy Tidbits https://safgroup.ca/news-insights/

Oil & Natural Gas – Puerto Rico tends to be the marker for GoM hurricane risk

Is normally not a perfect correlation but the 2021 Atlantic hurricane season was for the early indicator for risk to the GoM oil and gas being if the tropical storm/hurricane hits north of Puerto Rico or not. This year, all the storms/hurricanes that were north of Puerto Rico went into the Atlantic and all that were south of Puerto Rico went into the GoM. Below is NOAA's 2021 tracking map.

Figure 32: North Atlantic Storm Tracking Map

Source: National Hurricane Center

Figure 33: Caribbean Sea

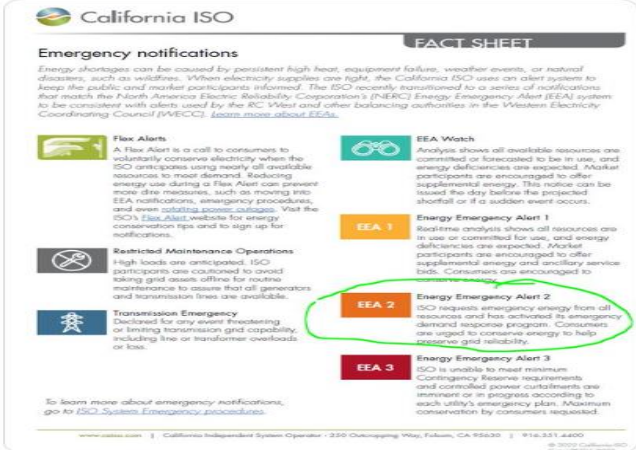
Source: Google Maps

2 6

SAF

Dan Tsubouchi @Energy_Tidbits · Sep 8

#Casiso calls EEA 2 - Energy Emergency Alert 2. Here are the #Caiso explanations of the various Energy Emergency Alert Levels. #NatGas #OOTT



California ISO

FACT SHEET

Emergency notifications

Energy shortages can be caused by persistent high heat, equipment failure, weather events, or natural disasters, such as wildfires. When electricity supplies are tight, the California ISO uses an alert system to keep the public and market participants informed. The ISO recently transitioned to a series of notifications that match the North America Electric Reliability Corporation's (NERC) Energy Emergency Alert (EEA) system to be consistent with alerts used by the RC West and other balancing authorities in the Western Electricity Coordinating Council (WECC). Learn more about EEAs.

Flex Alerts
A Flex Alert is a call to consumers to voluntarily conserve electricity when the ISO anticipates using nearly all available resources to meet demand. Reducing energy use during a Flex Alert can prevent more dire measures, such as moving into EEA notifications, emergency procedures, and even rotating power outages. Visit the ISO's Flex Alert website for energy conservation tips and to sign up for notifications.

Restricted Maintenance Operations
High loads are anticipated. ISO participants are cautioned to avoid taking grid assets offline for routine maintenance to assure that all generators and transmission lines are available.

Transmission Emergency
Declared for any event threatening or limiting transmission grid capability, including line or transformer overloads or loss.

EEA Watch
Analysis shows all available resources are committed or forecasted to be in use, and energy deficiencies are expected. Market participants are encouraged to offer supplemental energy. This notice can be issued the day before the projected shortfall or if a sudden event occurs.

EEA 1

Energy Emergency Alert 1
Real-time analysis shows all resources are in use or committed for use, and energy deficiencies are expected. Market participants are encouraged to offer supplemental energy and ancillary service bids. Consumers are encouraged to conserve energy.

EEA 2

Energy Emergency Alert 2
ISO requests emergency energy from all resources and has activated its emergency demand response program. Consumers are urged to conserve energy to help preserve grid reliability.

EEA 3

Energy Emergency Alert 3
ISO is unable to meet minimum Contingency Reserve requirements and controlled power curtailments are imminent or in progress according to each utility's emergency plan. Maximum conservation by consumers requested.

To learn more about emergency notifications, go to ISO System Emergency procedures.

www.caiso.com | California Independent System Operator · 250 Outcropping Way, Folsom, CA 95630 | 916.351.4400

California ISO @California_ISO · Sep 8

#ISO has issued an Energy Emergency Alert (EEA) 2 effective today, from 4 p.m. – 9 p.m. When an EEA 2 is called, @California_ISO requests emergency energy from all resources and may activate its demand response program. bit.ly/3AUKxZq

3 3

SAF

Dan Tsubouchi @Energy_Tidbits · Sep 8

For those not near their laptop, @EIAgov just released #Oil #Gasoline #Distillates inventory as of Sept 2. Table below compares EIA data vs expectations and vs @APIenergy yesterday. Prior to release, WTI was $83.14. #OOTT

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

s Inventory Sept 2: EIA, Bloomberg Survey Expectations, /

els)	EIA	Expectations	
	8.85	-1.90	
	0.33	-1.90	
	0.10	0.00	
	9.28	-3.80	

ommercial so builds in impact of 7.5 mmb draw from SPR for
ed in the oil data, Cushing had a draw of 0.50 mmb for Sept 2

Bloomberg

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

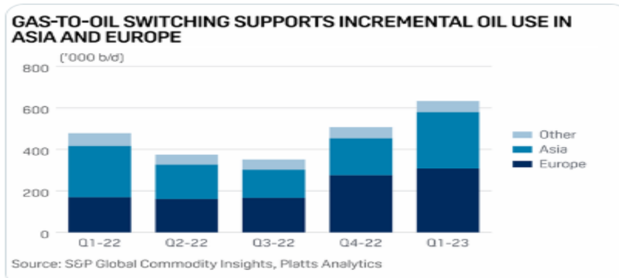
1 1 4

Dan Tsubouchi @Energy_Tidbits · Sep 8
Small modular #Nuclear reactors are an important part of our energy mix, just said by New PM Truss @10DowningStreet in House of Commons.
#NatGas #OOTT

2

Dan Tsubouchi @Energy_Tidbits · Sep 8
New PM Truss @10DowningStreet just said in House of Commons that won't give in to a windfall tax in her energy plan. #OOTT

Dan Tsubouchi @Energy_Tidbits · Sep 7
#NatGas to #Oil switching is increasing. #PlattsAnalytics estimates refiners, power producers & major industries will have 633,000 b/d incremental liquids demand in Q1/23 vs ~350,000 b/d incremental demand in Q3/22. Thx @RobPana #OOTT
spglobal.com/commodityinsig...

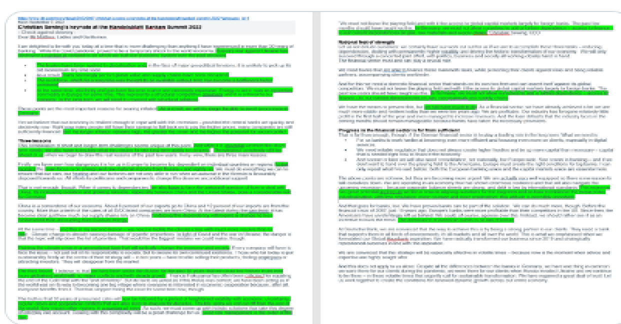


1 6 16

Dan Tsubouchi @Energy_Tidbits · Sep 7
1/2. Must Read @DeutscheBank CEO. RUS/UKR "destroyed a number of certainties on which we build our economic system over the past decades". NEXT UP, "awkward question on how to deal with China" in light of increasing CN/US isolation/tension, reducing China dependency will ..
#OOTT

1 1 5

Dan Tsubouchi @Energy_Tidbits · Sep 7
2/2.."require a change no less fundamental than decoupling from RUS energy". Globalization gone, labor a global bottleneck. Extremely expensive #Electricity #NatGas s a threat to economy. the longer inflation remains high the higher the potential for social unrest, etc. #OOTT



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SAF

Dan Tsubouchi @Energy_Tidbits · Sep 7

#Repsol sells 25% in upstream, reduces its emissions, but retains operational control ie. trading profits leverage. #EIG believes this upstream #Oil #NatGas partnership is "well positioned to help meeting the GROWING global demand for accessible, efficient & safe energy" #OOTT

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SAF

Dan Tsubouchi @Energy_Tidbits · Sep 6

#EPA rejects #Cheniere request. Feels like likely scenario will be staggered corrective shutdown by #LNG train. If so, not clear how much corrective time needed per train and if can be coordinated with a normal maintenance turnaround. #NatGas #OOTT

reuters.com

EPA denies Cheniere request to exempt LNG gas turbines from polluti...

The U.S. Environmental Protection Agency said on Tuesday it has denied a request by leading U.S. LNG firm Cheniere Energy Inc to ...

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SAF

Dan Tsubouchi @Energy_Tidbits · Sep 6

at 5:17pm PT, #Caiso issued an EEA 3 Notice effective immediately, "forecasting an energy deficiency" ie. some sort of blackouts are expected to happen. #NatGas #OOTT

caiso.com/informed/Pages...

Current Active Notice(s)

CAISO EEA 3 NOTICE [202202696]

The California ISO has issued an Energy Emergency Alert (EEA) 3 Notice for the CAISO Gric effective 09/06/2022 17:17 through 09/06/2022 20:00.

Reason:
The ISO is anticipating high loads and temperatures across the |CAISO Grid.

CAISO is forecasting an energy deficiency with all available resources in use for the specified time period.

Maximum conservation efforts are urged. During this time, participating customers will be directed by utilities to use generators approved for emergencies, or to reduce load following the protocols of each utility program.

Utility Distribution Companies and Metered Subsystems shall stand by for operating instructions from the CAISO for load curtailments, use of Interruptible Loads and requests Out-of-Market (OOM) and Emergency Energy from all available sources.

For more information, view the CAISO System Emergency fact sheet (http://www.caiso.com/Documents/Emergency-Notifications-Fact-Sheet.pdf).

Monitor system conditions on Today's Outlook (http://www.caiso.com/TodaysOutlook/Pages/default.aspx) and contact local electric utilities for details about their respective load reduction programs.

Notice issued at: 09/06/2022 17:26

------------------------------------ DISCLAIMER ------------------------------------

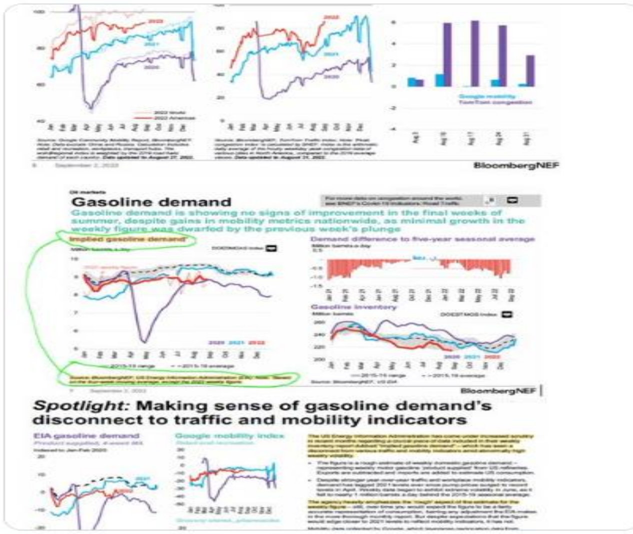
This CAISO notice is based on the current conditions of the transmission grid system. While this CAISO notice reflects the most current information available to the CAISO, because transmission grid system conditions are subject to sudden and rapid change without warning, the accuracy of this notice cannot be assured. This CAISO notice is provided solely for informational purposes. Reliance by any party on the contents of this CAISO notice, regardless of any errors, omissions, inaccuracies, and/or subsequent changed conditions shall not be made the basis for any claim, demand or cause for action against the CAISO. Any recipient's decisions or actions that may be based in any way whatsoever on the contents of this CAISO notice shall be the sole responsibility of the recipient.

2 3

SAF

Dan Tsubouchi @Energy_Tidbits · Sep 6

US drivers responded as #Gasoline prices went sub $5 & now $3.80. #TomTom congestion levels continue to surge. BNEF doesn't use retail gas pump sales, rather uses @EIAgov implied gasoline demand which "is showing no signs of improvement."Thx @BloombergNEF Danny Adkins. #Oil #OOTT



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SAF

Dan Tsubouchi @Energy_Tidbits · Sep 6

Reminder, Japan in particular is getting hit by strong US$ adding to its cost to import #LNG #Oil. Since Feb 28, US $ appreciation: +23.8% vs Yen, +13.3% vs Euro, +10.3% vs Renminbi, +6.0% vs Rupee. #OOTT

5

Dan Tsubouchi @Energy_Tidbits · Sep 6

Expect #NordStream #NatGas flows to stay at zero indefinitely.

Mon: 👇 Kommersant resumption "ONLY IF a more general political settlement is reached"

Just now: 👇 #Gazprom, RUS law says can't operate due to explosion risk.

#OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Sep 5
>
> ICYMI. why working assumption should be #NordStream #NatGas deliveries stay at zero. "According to Kommersant's sources, supplies via Nord Stream can be resumed only if sanctions are lifted, which is possible ONLY IF a more general ...

6

Dan Tsubouchi @Energy_Tidbits · Sep 5

ICYMI. why working assumption should be #NordStream #NatGas deliveries stay at zero. "According to Kommersant's sources, supplies via Nord Stream can be resumed only if sanctions are lifted, which is possible ONLY IF a more general political settlement is reached." #OOTT

https://www.kommersant.ru/doc/5546666 09/05/2022, 00:41

Winter is declared

Key gas supply route to EU shut down

On the eve of the heating season, Gazprom finally stopped gas supplies via the Nord Stream pipeline, citing a malfunction of the last operating turbine at the Portovaya compressor station. Kommersant's sources do not expect deliveries to be resumed in the foreseeable future. This means a probable new surge in gas prices in Europe, and for Gazprom itself, a further decline in production.

On September 2, Gazprom announced a complete shutdown of the Nord Stream gas pipeline due to malfunctions in the operation of the Siemens Energy Trent 60 turbine identified during maintenance, which, according to the monopoly, create risks of explosion or fire. This is the last turbine operating at the Portovaya compressor station, which Gazprom sent for maintenance from August 31 to September 2. It was assumed that on September 3, deliveries to Europe will resume.

"During maintenance work on the Trent 60 gas compressor unit (GPA No. 24) of the Portovaya compressor station, carried out jointly with representatives of Siemens, an oil leak with an admixture of a sealing compound was detected at the connectors of the terminal connections of the cable lines of the low and intermediate pressure rotor speed sensors,"— the company said in a statement.

Gazprom claims that, according to Siemens, the complete elimination of oil leakage is possible only in the conditions of a specialized repair company.

Siemens Energy responded by saying that the oil leak was not a technical reason for shutting down the turbine. "Such leaks usually do not affect the operation of the turbine and can be repaired on site. This is a normal maintenance procedure," the company explained.

In the past, the occurrence of such leaks has also not led to a shutdown of work, stressed Siemens Energy, adding: "Regardless of this, we have repeatedly noted that there are a sufficient number of other turbines at the Portovaya compressor station for the operation of Nord Stream."

According to Kommersant, Siemens Energy and Gazprom do not have a contract for unscheduled maintenance of engines; Portovaya employs resident engineers of the company who carry out technical supervision.

One of these engineers was present when the machine was inspected. Overhaul of gas turbines should be carried out after 25 thousand hours of operation, subsequently its work is extended for the same period. According to Kommersant's sources, the running time of the stopped Trent 60 turbine at Portovaya is 33.4 thousand hours, thus, after the overhaul, the machine worked 8.9 thousand hours - only a third of the period of overhaul operation.

Now Russian gas supplies to Western Europe will continue only through the territory of Ukraine (through the Sudzha gas measuring station in the amount of just over 40 million cubic meters per day). Greece, Hungary, as well as non-EU Serbia, are now supplied through the Turkish Stream. According to Kommersant's sources, supplies via Nord Stream can be resumed only if sanctions are lifted, which is possible only if a more general political settlement is reached.

Gas prices in Europe have been declining in the last week, but the market was counting on the return of supplies via Nord Stream after an unscheduled repair. Energy Aspects gas analyst Leon Izbicki told Reuters he expects gas prices to rise significantly at the September 5 open.

For Gazprom, the cessation of supplies means a reduction in production by another 4 billion cubic meters by the end of the year, which will mainly come from the Bovanenkovskoye field in Yamal.

In eight months, Gazprom's production has already fallen by 14.8%, to 258 billion cubic meters, but in the summer it was supported by the filling of UGS facilities in Russia, which is already almost completed, while usually pumping into storage continues until October.

How problematic the decline in production will be for the monopoly, however, is still unclear. Independent expert Alexander Sobko notes that in 2008-2009, Gazprom's production fell by 88 billion cubic meters, which did not prevent it from recovering later.

Tatyana Dyatel

7 13

Dan Tsubouchi @Energy_Tidbits · Sep 5

Europe #EnergyCrisis is worse than we in 🇨🇦🇺🇸 appreciate. Labor Day means @markets feed is London desk. Probably >2/3 of news is linked to sky-high #NatGas #Electricity prices & big hit impact on economy, industry & people. Need a mild winter in EU or will get real ugly. #OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Sep 5
>
> Add textiles to list of EU economy hits as sky-high #NatGas prices force reduced/closed production. #Lenzing likely closing 2/3 lines adds to high profile forced NatGas demand SAVINGS demand in steel, aluminum, fertilizer, metals, ceramic tiles, etc. Thx @virtualnomad #OOTT twitter.com/Energy_Tidbits...

4 4

Dan Tsubouchi @Energy_Tidbits · Sep 5

Add textiles to list of EU economy hits as sky-high #NatGas prices force reduced/closed production. #Lenzing likely closing 2/3 lines adds to high profile forced NatGas demand SAVINGS demand in steel, aluminum, fertilizer, metals, ceramic tiles, etc. Thx @virtualnomad #OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Sep 4
>
> Europe #NatGas storage fill up is ahead of schedule thanks to "Hard industry SAVINGS". Yes, but forced savings as sky-high #NatGas prices forced reduced/closed production of fertilizer, metals, ceramic tiles, etc). Economic activity is getting hammered. #LNG #OOTT twitter.com/Klaus_Mueller/...

1 6

Dan Tsubouchi @Energy_Tidbits · Sep 5

#Oil holds gains post #OPEC+ agreement to cut 100,000 b/d for Oct. Brent +$3.63 to $96.65. #OOTT

2 7

Dan Tsubouchi @Energy_Tidbits · Sep 4

Europe #NatGas storage fill up is ahead of schedule thanks to "Hard industry SAVINGS". Yes, but forced savings as sky-high #NatGas prices forced reduced/closed production of fertilizer, metals, ceramic tiles, etc). Economic activity is getting hammered. #LNG #OOTT

> **Klaus Müller** @Klaus_Mueller · Sep 3
>
> Mit 85,02 % erreicht 🇩🇪 bereits am 2.9. das Oktober Ziel für seine #Gasspeicher. Auch als #NordStream1 „gewartet" wurde, konnten wir einspeichern, aber es naht die Heizsaison. Jetzt kommt es nach den harten Industrieeinsparungen auf unser aller privates Heizverhalten an: -20%!

1 4 8

Dan Tsubouchi @Energy_Tidbits · Sep 4

Our weekly SAF Sept 4, 2022 Energy Tidbits memo is posted on SAF Group website. this 54-pg energy research memo expands upon & covers more items than tweeted this week. See news/insights section of SAF website #Oil #OOTT #LNG #NatGas #EnergyTransition safgroup.ca/news-insights/

SAF GROUP

Energy Tidbits

Sept 4, 2022

Produced by: Dan Tsubouchi

Vitol's Muller on Russia's 7+ mmbd Oil/Products Exports "It is Impossible, Let Me Repeat, It is Impossible for the World to Get By Without All of That"

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. Vitol's Asia Head Mike Muller reminds it is impossible for the world to get by without all of Russia's 7 plus mmb/d oil and products exports. (Click Here)
2. Gazprom shuts down all deliveries on Nord Stream, no idea if it will resume supply before winter. (Click Here)
3. Is Iran just haggling on JCPOA details and not reopening big issues that the US said were resolved? (Click Here)
4. Mixed opinions on OPEC+ meeting tomorrow if they will cut or not cut. (Click Here)
5. California extends Diablo nuclear plant for 5 years, follows last Aug approval for five natural gas plants. (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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