SAF GROUP

Energy Tidbits

Can or Will Anyone Stop Iran Adding ~600,000 b/d to Oil Markets in Next Few Months?

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Short-Term Energy Outlook

Overview

U.S. energy market indicators	2022	2023	2024
Brent crude oil spot price (dollars per barrel)	**$101**	**$83**	**$86**
Retail gasoline price (dollars per gallon)	**$3.97**	**$3.56**	**$3.45**
U.S. crude oil production (million barrels per day)	**11.91**	**12.76**	**13.09**
Natural gas price at Henry Hub (dollars per million British thermal units)	**$6.42**	**$2.58**	**$3.22**
U.S. liquefied natural gas gross exports (billion cubic feet per day)	**10.6**	**11.9**	**13.3**
Shares of U.S. electricity generation			
Natural gas	39%	42%	40%
Coal	20%	16%	15%
Renewables	22%	22%	25%
Nuclear	19%	19%	19%
U.S. GDP (percentage change)	**2.1%**	**1.9%**	**1.2%**
U.S. CO_2 emissions (billion metric tons)	**4.96**	**4.80**	**4.80**

Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook,* August 2023

- **Crude oil prices.** The Brent crude oil spot price averages $85 per barrel (b) in August in our forecast. Crude oil prices have increased since June, primarily because of extended voluntary cuts to Saudi Arabia's crude oil production and increasing global demand. We expect these factors will continue to reduce global oil inventories and put upward pressure on oil prices in the coming months, with the Brent price averaging $86/b in the second half of 2023 (2H23), up about $7/b from our July *Short-Term Energy Outlook* (STEO) forecast for the same period. Rising global oil production in 2024 in our forecast keeps pace with oil demand and puts moderate downward pressure on crude oil prices beginning in the second quarter of 2024 (2Q24).

- **Global oil production.** We forecast global liquid fuels production will increase by 1.4 million barrels per day (b/d) in 2023. Non-OPEC production increases by 2.1 million b/d in 2023, which is partly offset by a drop in OPEC liquid fuels production. In 2024, global production increases by 1.7 million b/d, with 1.2 million b/d coming from non-OPEC countries. Non-OPEC production growth in the forecast is led by the United States, Brazil, Canada, Guyana, and Norway.

- **U.S. crude oil production**. As a result of higher expected well-level productivity and higher crude oil prices, we expect U.S. crude oil production will average 12.8 million b/d in 2023 and 13.1 million b/d in 2024, both annual records.

- **Natural gas production.** Associated natural gas production growth in the Permian Basin, driven by higher oil prices, has supported U.S. dry natural gas production in 2023 despite a decline in natural gas prices. We expect production to average about 104 billion cubic feet per day (Bcf/d) through the end of 2024, compared with 103 Bcf/d in 2Q23. Flat production largely reflects continuing growth in associated natural gas production offset by declines in natural gas directed drilling.

- **Electricity generation**. Hot temperatures in July, especially in the southern states, pushed U.S. electricity demand to near-record levels. We estimate that electricity sales totaled 388 billion kilowatthours in July, roughly equal to the record electricity consumption in July and August 2022.

- **U.S. economy.** U.S. GDP growth in our forecast increases by 1.9% in 2023, up from 1.5% in last month's forecast. We apply energy price forecasts to the S&P Global macroeconomic model to generate the forecasts for the U.S. economy used in our STEO.

Notable forecast changes

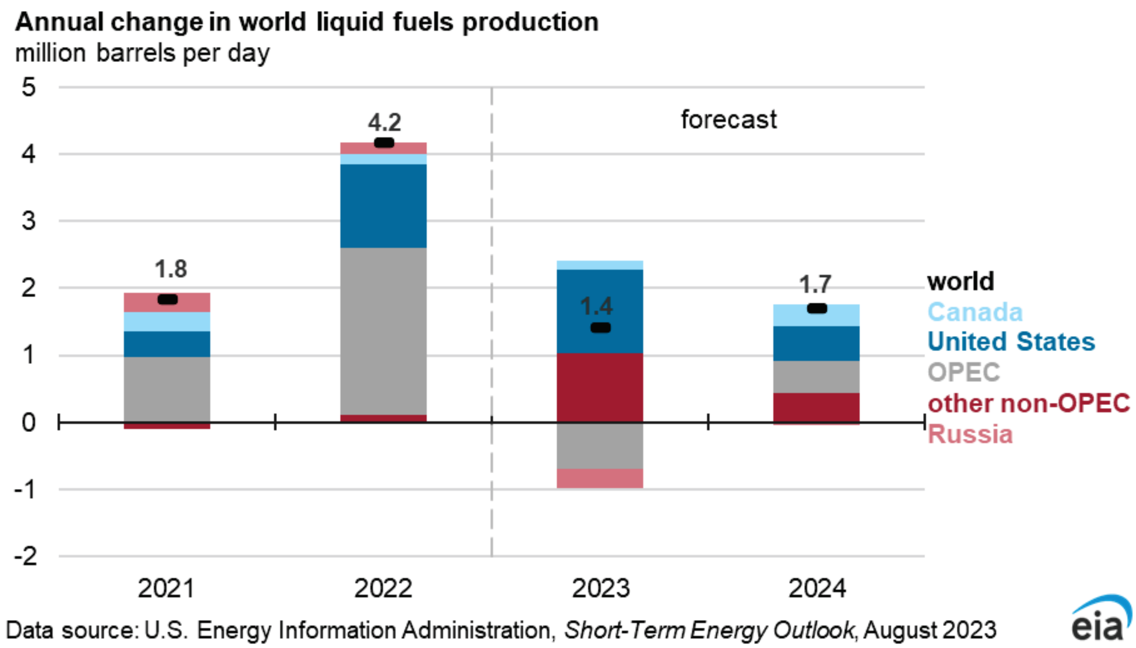
current forecast: August 8, 2023; previous forecast: July 11, 2023	**2023**	**2024**
U.S. crude oil production (current forecast) (million barrels per day)	**12.8**	**13.1**
Previous forecast	12.6	12.8
Percentage change	1.6%	1.9%
Brent crude oil spot price (current forecast) (dollars per barrel)	**$83**	**$86**
Previous forecast	$79	$84
Percentage change	4.1%	3.6%
U.S. gasoline inventories (current forecast) (million barrels)	**233.5**	**230.9**
Previous forecast	239.9	237.1
Percentage change	-2.7%	-2.6%
U.S. dry natural gas production (current forecast) (billion cubic feet per day)	**103.0**	**104.1**
Previous forecast	102.3	102.4
Percentage change	0.6%	1.7%
Real gross domestic product (current forecast) (percentage)	**1.9%**	**1.2%**
Previous forecast	1.5%	1.3%
Percentage point change	0.4	-0.1

Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, August 2023

Global Oil Markets

Global oil supply and prices

The Brent crude oil spot price in our forecast increases in the coming months, reflecting our expectations of tightening balances in global oil markets. The Brent crude oil spot price averaged $80 per barrel (b) in July, up $5/b from June. Crude oil prices increased primarily because of extended voluntary cuts to Saudi Arabia's crude oil production and expectations of higher global demand. We expect the production cuts, combined with increasing demand, will cause global oil inventories to fall and to put upward pressure on oil prices through the end of this year. The Brent price in our forecast averages $86/b in the second half of 2023 (2H23) and reaches $88/b in November and December and remains near that level in the first quarter of 2024 (1Q24). Crude oil prices begin to ease in 2Q24 as supply growth leads to some rebuilding of global oil inventories later in 2024. The Brent price in our forecast averages $86/b in 2024.



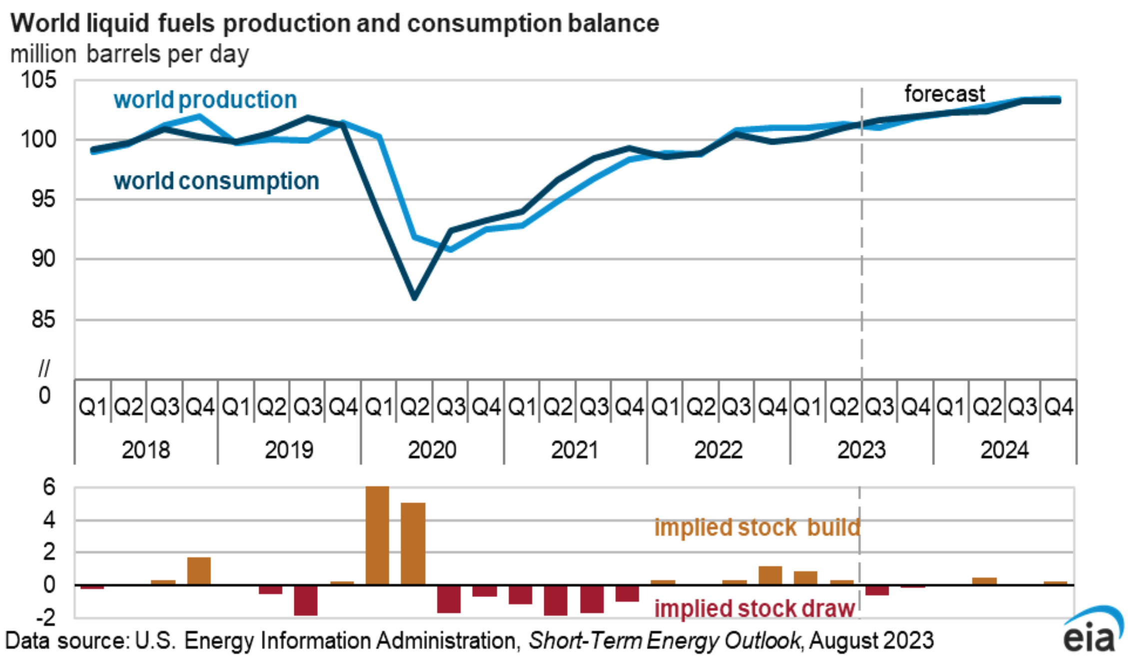
We forecast global liquid fuels production will increase by 1.4 million barrels per day (b/d) in 2023 because of strong growth from non-OPEC producers and despite decreases in production from OPEC and Russia. This forecast reflects Saudi Arabia's announcement on August 3 that it would extend its voluntary 1 million b/d product cut through September. We expect Russia's production will decline between 0.2 million b/d and 0.3 million b/d on average this year compared with 2022 and remain unchanged in 2024.

Global liquid fuels production in the forecast rises by 1.7 million b/d in 2024, which is more than 0.2 million b/d than we forecast last month. Despite production cuts that extend through 2024, OPEC crude oil production will likely increase in 2024 by an average of 0.6 million b/d. Higher production targets for the United Arab Emirates in 2024 and increasing production from Iran and Venezuela will drive this increase.

Non-OPEC countries are the main drivers of global production growth in the forecast. We expect that non-OPEC production will increase by 2.1 million b/d in 2023 and 1.2 million b/d in 2024. Although the United States is expected to lead non-OPEC growth, contributing 1.3 million b/d of supply growth in 2023 and 0.5 million b/d in 2024, we forecast strong growth from other non-OPEC producers as well. In South America, we forecast that Brazil will increase production by 0.5 million b/d from 2022 through 2024, driven by increased output from floating, production, storage, and offloading (FPSO) vessels. Other countries with significant growth in 2024 in our forecast include Canada, Guyana, and Norway.

Global oil inventories

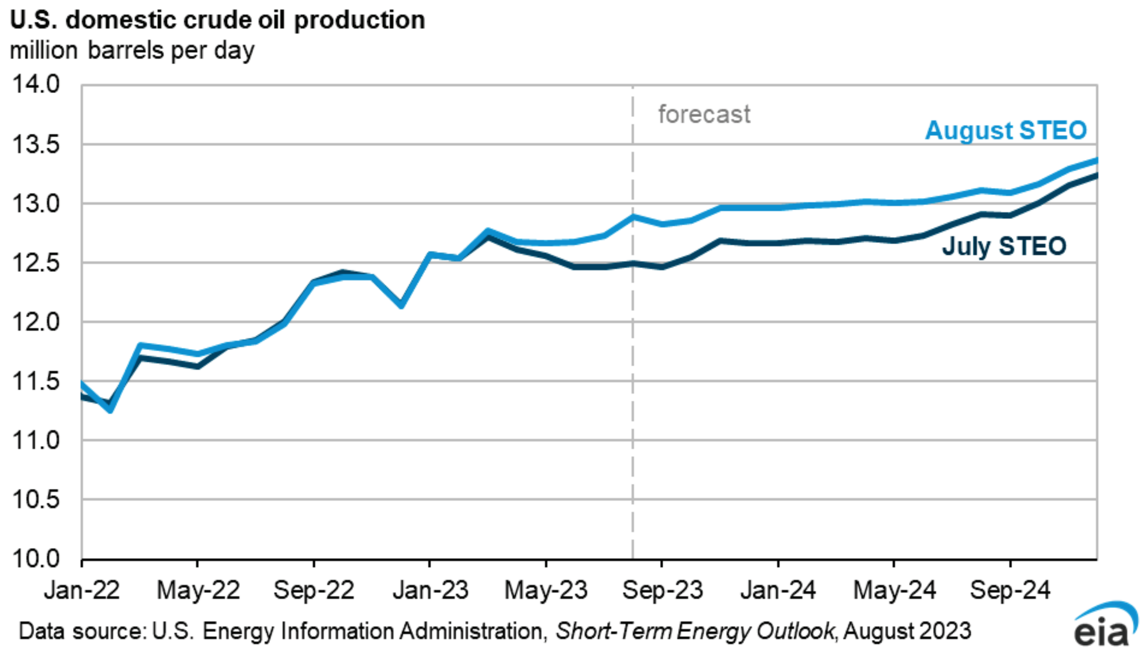
We estimate global oil inventories will transition from a period of inventory builds in 1H23 to inventory draws through the end of the year, placing upward pressure on global oil prices. Global oil inventories increased by an average of 0.6 million b/d in 1H23, and we forecast they will decrease by an average of 0.4 million b/d in 2H23. We expect slight inventory builds in 2024, which puts some downward pressure on oil prices in the forecast for next year.



Petroleum Products

U.S. crude oil production

In our August STEO, we now expect total U.S. crude oil production to average 12.8 million barrels per day (b/d) in 2023, an annual average increase of about 0.2 million b/d compared with our July STEO. Our higher production outlook reflects the effect of higher well productivity in recent historical data from the *Petroleum Supply Monthly*, which we have extended into our current forecast for July and forward through 2023. Our outlook for higher crude oil prices, beginning in July 2023 and continuing into 2024, supports higher production in 2024 because of the lagged effect of prices on rig additions and production.



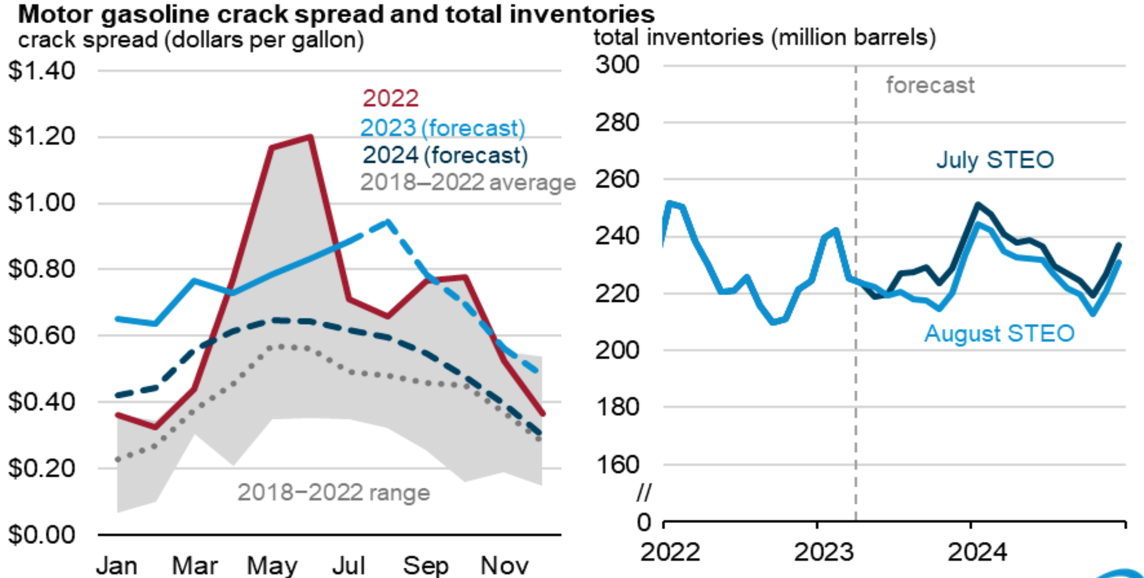
We estimate that increases in well-level productivity observed in recent data will drive increasing production through the end of 2023, before crude oil production stabilizes near 13.0 million b/d in 1H24. Production growth slows because we assume that growth in well-level productivity will slow.

Although production changes little in early 2024, we expect production next year will average 13.1 million b/d, more than 0.2 million b/d more than in the July STEO. Despite slowing growth in well-level productivity, our forecast for rising crude oil prices results in increased oil-directed rig activity in 2024. U.S. crude oil production picks up in 2H24 and approaches 13.4 million b/d in December 2024.

U.S. gasoline inventories and prices

In our August STEO, we expect lower gasoline production to reduce inventories and increase gasoline prices and crack spreads (the difference in price between a gallon of gasoline and a gallon of crude oil) in 2H23 compared with the July STEO. Previously, we assumed high crack spreads and more U.S. refining capacity in 2023 would contribute to rising gasoline production and inventory builds. However, a series of unplanned refinery outages this summer have limited increased refinery operations. Among the outages, a reformer outage occurred at Marathon's Galveston Bay refinery, and fluid catalytic cracking unit outages occurred at Phillips 66's Bayway refinery and ExxonMobil's Baton Rouge refinery. Many of the outages affected secondary conversion units, reducing the relative yields of gasoline from those facilities. We decreased our outlook for refinery utilization and refinery gasoline yield for the rest of the summer and the start of fall, which reduces our forecast of gasoline production. Lower gasoline production and lower net imports of gasoline contribute to lower total gasoline inventories in our forecast, which we now expect to remain near the five-year (2018–2022) low through the end of our forecast.

Motor gasoline crack spread and total inventories



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, August 2023
Note: Crack spread is equal to refiner price for resale of gasoline minus Brent spot average price.

In the August STEO, we estimate that persistent low gasoline inventories through the forecast period will contribute to higher gasoline crack spreads compared with last month's forecast. The annual average gasoline crack spread averages $0.73 dollars per gallon (gal) in 2023, compared with $0.63/gal in the July STEO. The increasing crack spread and higher crude oil prices both contribute to higher overall retail gasoline prices in this month's forecast as well. We now estimate 2023 U.S. retail gasoline prices to average $3.56/gal in 2023 and $3.45/gal in 2024.

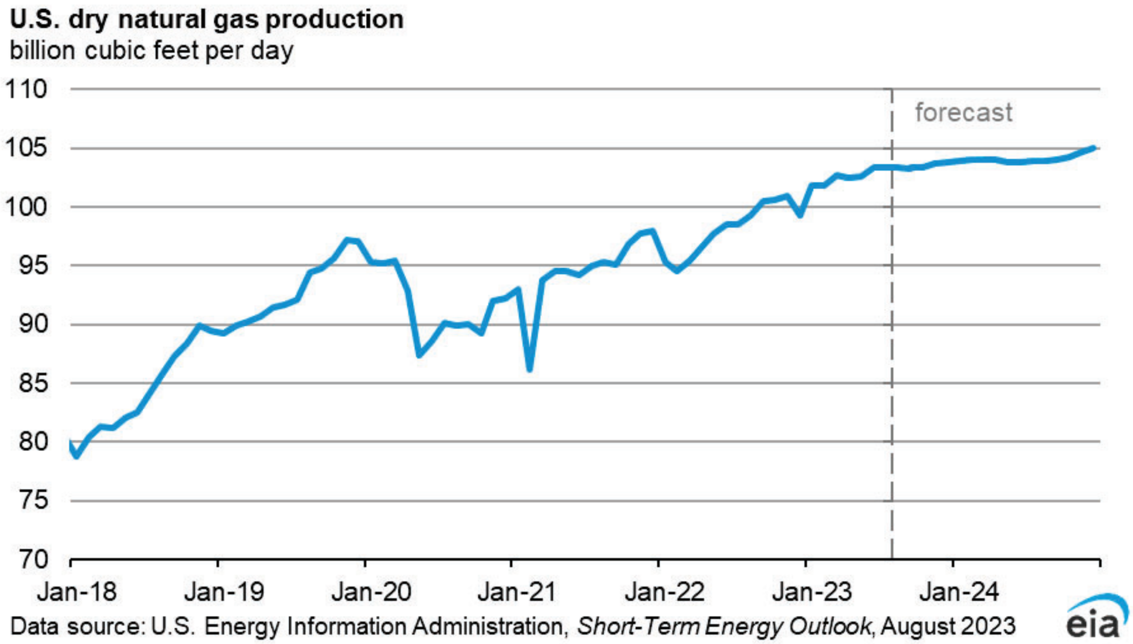
Natural Gas

Natural gas production

We forecast U.S. dry natural gas production to remain relatively flat for the rest of 2023 and 2024. Dry natural gas production averaged more than 102 billion cubic feet per day (Bcf/d) in the first half of 2023 (1H23), which is a 6 Bcf/d increase compared with the same period in 2022. We expect dry natural gas production will average about 104 Bcf/d through the end of the forecast in 2024. Production has remained at relatively high levels throughout 2023 despite a decline in U.S. natural gas prices. The U.S. benchmark Henry Hub spot price averaged $2.41 per million British thermal units (MMBtu) in 1H23, compared with an annual average of $6.42/MMBtu in 2022.

The Permian Basin has driven the growth in U.S. natural gas production in 2023. Most of the natural gas produced from the Permian Basin is associated natural gas produced from oil wells, meaning producers' oil-drilling activities in the region determine natural gas production levels. We expect increased oil-drilling activity to continue to drive increased natural gas production in the Permian Basin, although these increases will be offset by some small production declines in other large producing regions.

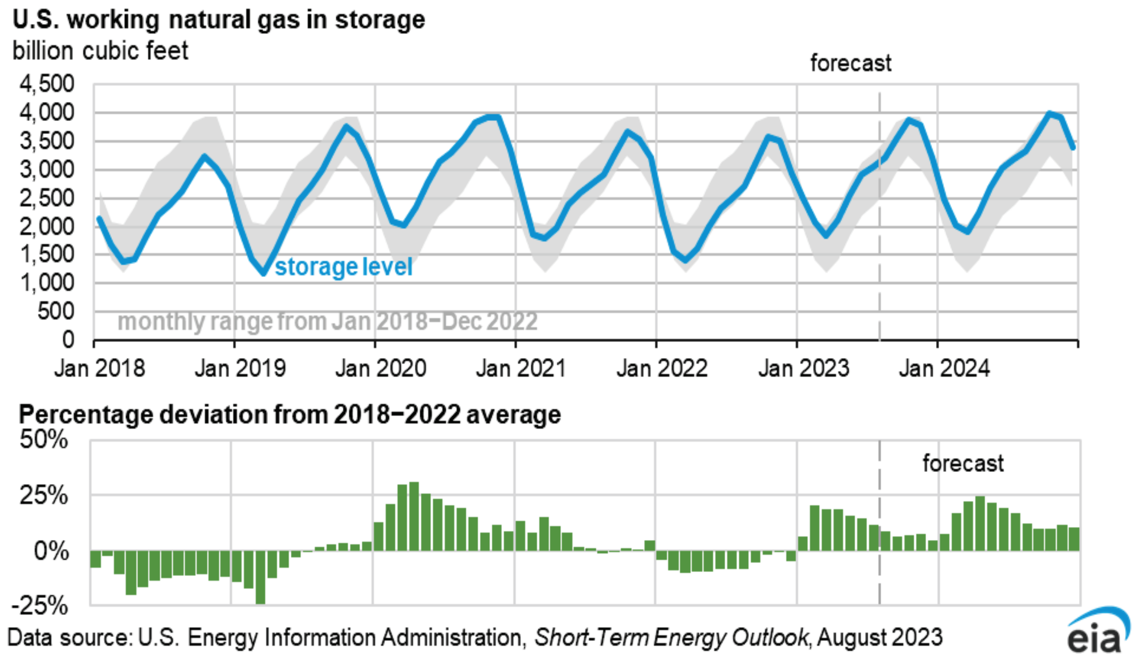
We expect dry natural gas production will remain near current levels over the next year, before it starts to rise in the fourth quarter of 2024 as new pipeline capacity comes online and demand for liquefied natural gas feed gas increases as developers expect two new facilities to come online at the end of 2024.



Natural gas inventories

U.S. working natural gas inventories totaled 3,051 billion cubic feet (Bcf) at the end of July, 12% above the five-year (2018–2022) average and 22% above the same period last year. Net injections of natural gas into storage have exceeded the five-year average by 3% so far this refill season (April 1–October 31), in part due to high natural gas production. The increased surplus of natural gas storage inventories reduced natural gas prices throughout 1H23 compared with 2022.

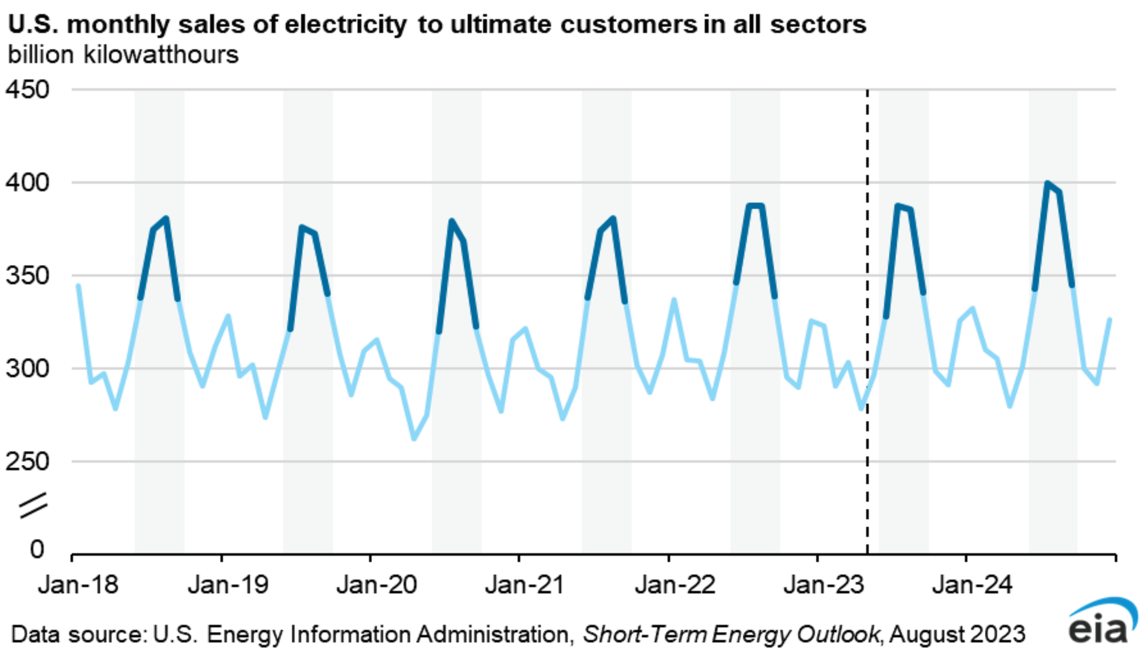
We forecast working natural gas inventories to end the refill season at nearly 3.9 trillion cubic feet (Tcf) which is 7%, or 250 Bcf, higher than the five-year average. We expect storage inventories to remain above the five-year average throughout 2024 as natural gas production remains high and natural gas consumption declines by 2% in 2024 compared with 2023.



Electricity, coal, and renewables

Electricity demand

Hot temperatures during July, especially in the southern states, pushed U.S. electricity demand to near-record levels. We estimate that U.S. electricity sales to ultimate customers in July 2023 totaled 388 billion kilowatthours, which would equal the record level of electricity consumed in July and August 2022.

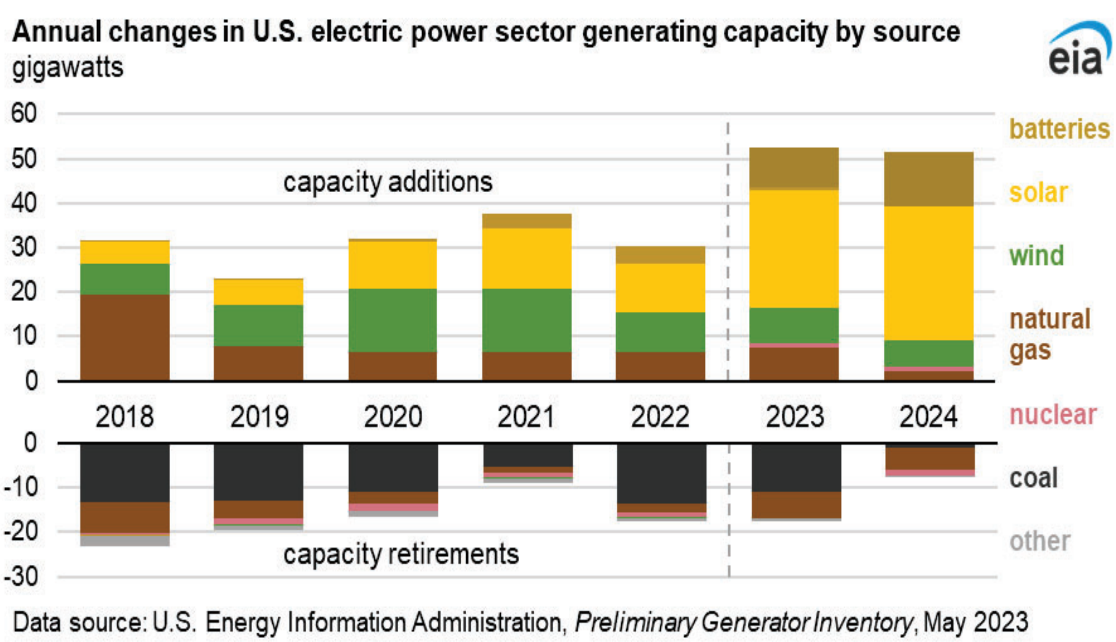


For all of 2023, we forecast 2% less sales of electricity to ultimate customers in the United States than in 2022. The increased electricity demand in July from space cooling was offset by low demand because of a relatively cool June and a mild winter in 1Q23. U.S. electricity sales in the forecast increase by 2% in 2024 based on our expectations for a hotter summer next year and growing demand for electricity in the industrial sector.

Electricity generation

The changing mix of generating capacity primarily drives which energy sources are used for electricity generation. Renewable energy capacity has been growing rapidly, and we expect this growth to continue because the electric power sector plans to add 27 gigawatts (GW) of new solar generating capacity by the end of 2023 and a further 31 GW in 2024. This new capacity leads to our forecast that renewables, other than hydropower, will account for a 16% share of total U.S. generation in 2023, up from 15% in 2022. That share grows to 18% in 2024.

In contrast, about 15 GW of coal-fired capacity is scheduled to retire by the end of 2023, so we forecast that coal's share will fall to 16% of total U.S. generation this year and 15% in 2024 (well below its generation share of 20% in 2022). The forecast natural gas generation share rises from 39% in 2022 to 42% this year due to low natural gas prices and net natural gas-fired generating capacity additions of 3 GW. We forecast the share of natural gas-fired generation to fall back to 40% in 2024 due to significant amounts of new renewable energy capacity coming online and displacing natural gas. A new 1.1 GW nuclear reactor in Georgia came online in July, so we forecast a slight increase in the amount of U.S. nuclear generation this year and a 2% increase in 2024, although the nuclear share of U.S. generation remains at 19%.

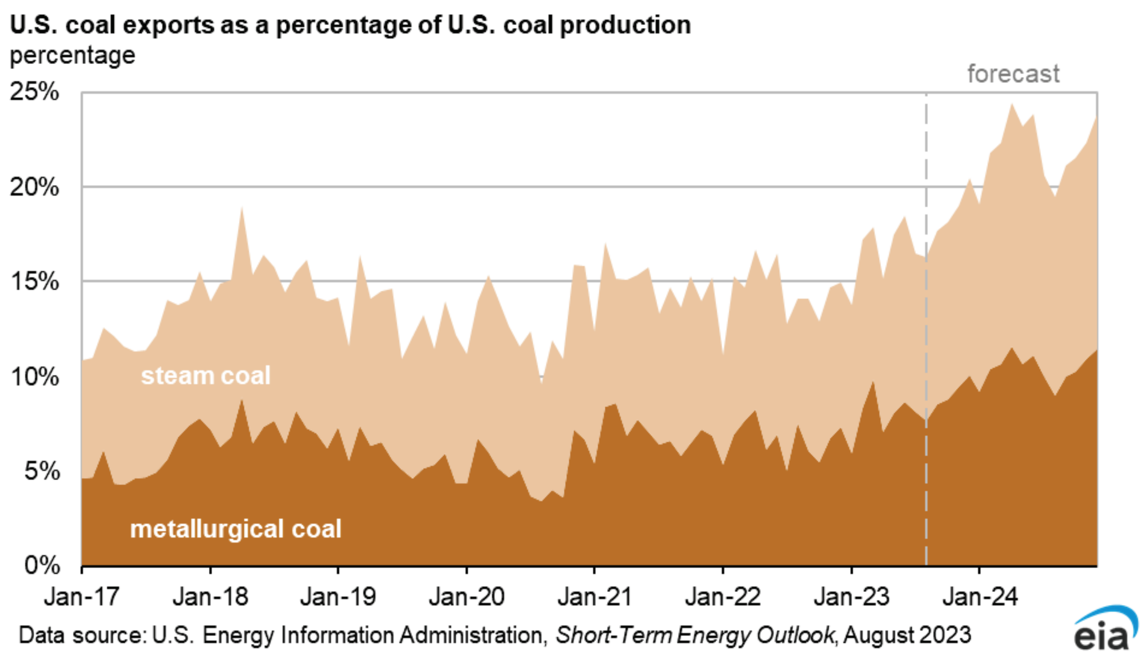


Coal markets

We expect coal production to decrease 3% from 597 million short tons (MMst) in 2022 to 578 MMst in 2023. Coal production will then fall 18% in 2024 to 472 MMst. The decreases in production reflect large decreases in coal consumption by the electric power sector because of ongoing coal plant retirements, increased natural gas-fired generation due to low natural gas prices, and difficultly competing with more generation from solar sources that have zero marginal dispatch cost.

Although most U.S. coal production is consumed domestically, 17% (50 MMst) was exported overseas in the first half of 2023 (1H23), up from 15% (44 MMst) in 1H22. We expect that share to rise further to 22% of production in 2024, with exports totaling 103 MMst for the entire year, due to a combination of much lower coal use domestically and stable demand overseas. The suspension of Europe's coal purchases from Russia beginning in August 2022 has increased U.S. exports of thermal coal to Europe, more than doubling over the past 18 months.

Stable overseas demand for metallurgical coal, which is used in steel production, supports U.S coal production. U.S. metallurgical coals usually sell for higher prices abroad due to having the quality desired by steelmakers when making blast furnace coke. The combination allows for a certain amount of U.S. coal production to be insulated from declining domestic demand.



Economy, Weather, and CO_2

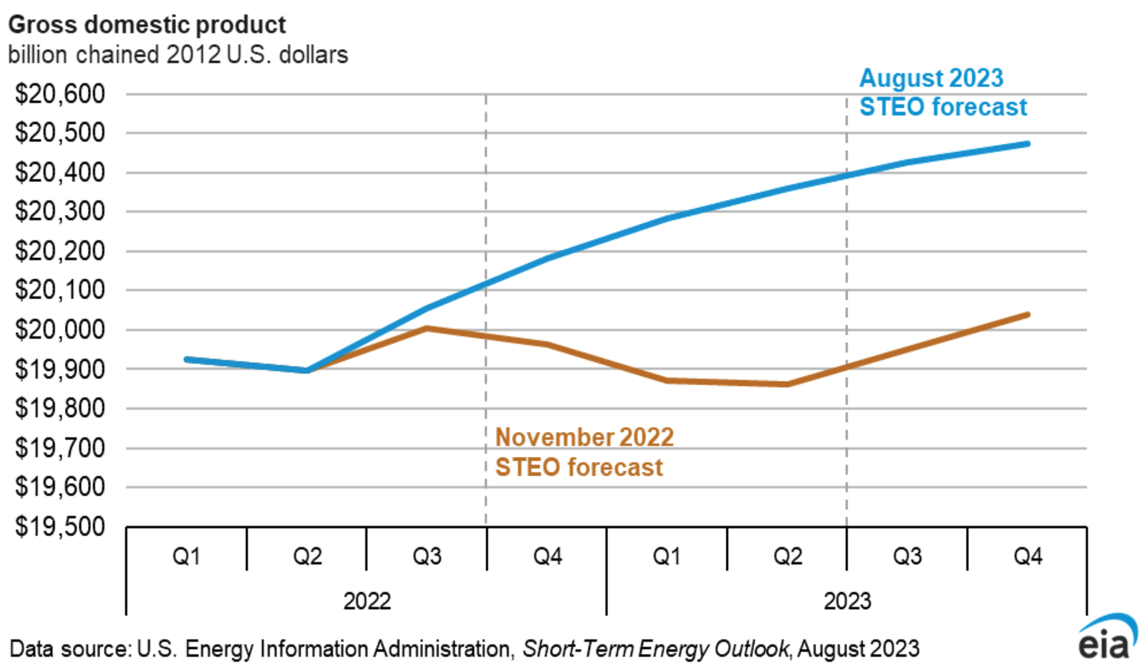
U.S. macroeconomics

Our U.S. macroeconomic forecasts are based on S&P Global's macroeconomic model. We incorporate STEO energy price forecasts into the model to obtain the final macroeconomic assumptions we use in the STEO.

Our forecast assumes real GDP growth will average 1.9% in 2023 and 1.2% in 2024. GDP is higher across the forecast compared with the July STEO. However, the upward revision to real GDP was more for 2023 than for 2024, reducing annual growth in 2024 compared with last month's forecast, even though 2024 GDP itself was revised higher.

The Bureau of Economic Analysis's (BEA) preliminary estimate of second-quarter 2023 (2Q23) GDP grew at an annualized rate of 2.4%. In addition, as more comprehensive data has been incorporated, the BEA's estimate of 1Q23 GDP growth has risen from an initial estimate of 1.1% to 2.0%. Consumer spending, aggregate investment, and exports have all contributed to this rise. Although identifying the source of this unexpected rise is difficult, it is likely because of a variety of factors. Among those factors are fiscal policy that resulted in rising savings for households and an increase in mortgage refinancing activity during 2020 and 2021 that allowed homeowners to take advantage of historically low interest rates to reduce their monthly mortgage payments, improving their cash flow.

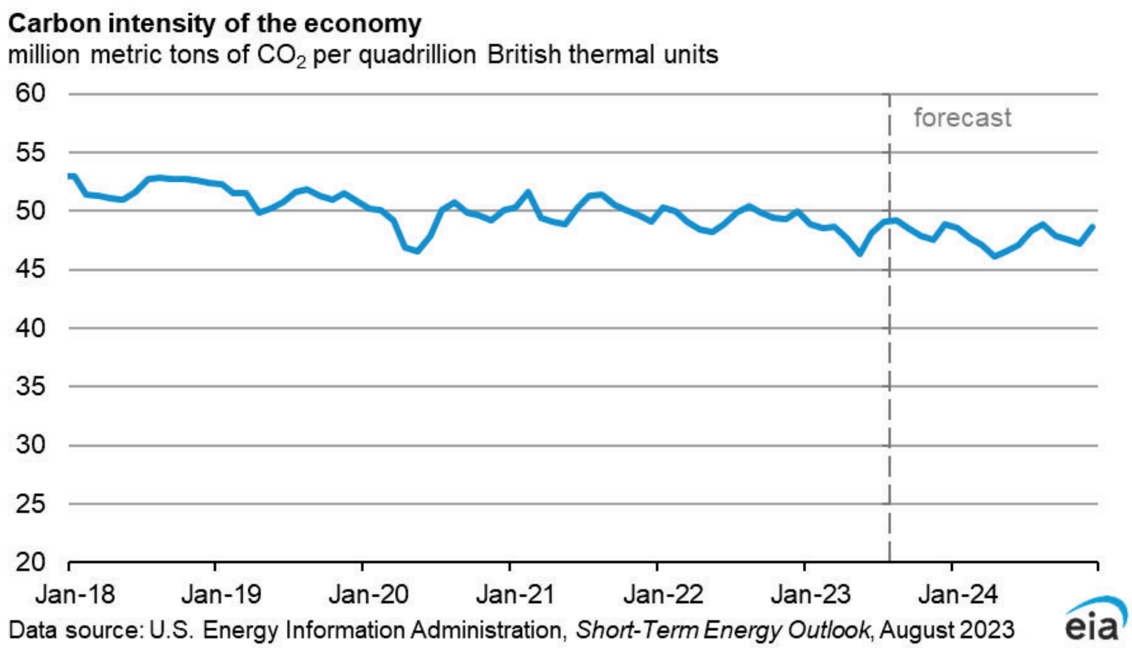
The upward revision this month is consistent with a trend that started last November, in which GDP and other macroeconomic indicators rise in the face of climbing interest rates and more restrictive monetary policy. The figure below shows the GDP forecasts for the August 2023 STEO and November 2022 STEO. Last November, the forecast called for GDP to decline starting in 4Q22, with a return to growth in 3Q23. Overall, the forecast in our November STEO was that GDP would contract by 0.1% in 2023. However, the economic contraction did not materialize, and GDP has grown each quarter since the November forecast.



Emissions

We expect total energy-related carbon dioxide (CO_2) emissions to decrease by 3% in 2023. CO_2 emissions from coal decrease 20%, the most relative to 2022, as a result of a notable decline in coal-fired electricity generation. Emissions from petroleum remain relatively unchanged, and emissions from natural gas increase by 1%. Total CO_2 emissions in 2024 remain flat, as small increases in petroleum emissions and coal emissions balance a decrease in natural gas emissions.

We forecast the carbon intensity of the economy (total CO_2 emissions relative to total energy consumption) will continue its generally declining trend into 2023 and 2024. Carbon intensity will decline by 2% in 2023 and by 1% in 2024. The decline in 2023 comes from both the significant drop in coal emissions and an increase in non-emitting energy consumption. Although overall energy consumption declines by about 1% in 2023, the share of renewable energy in U.S. energy consumption increases from around 13% in 2022 to 14% in 2023. While emissions increase in 2024, U.S. carbon intensity continues to decrease because economic activity increases more than emissions and because the renewable energy share continues to grow, making up 15% of total energy consumption in 2024.



Weather

The United States averaged 384 cooling degree days (CDDs) in July, 18 more CDDs than we estimated in our July STEO forecast due in large part to the heatwaves experienced across the South-Central United States. We expect CDDs to fall to 336 CDDs in August as the heatwaves subside. We expect 3Q23 with about 3% fewer CDDs than in 3Q22.

Table 3a. International Petroleum and Other Liquids Production, Consumption, and Inventories
U.S. Energy Information Administration | Short-Term Energy Outlook - August 2023

	2022				2023				2024				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2022	2023	2024
Production (million barrels per day) (a)															
OECD	**31.68**	**31.95**	**32.53**	**32.95**	**33.47**	**33.75**	*34.08*	*34.63*	*34.79*	*34.60*	*34.83*	*35.41*	**32.28**	*33.99*	*34.91*
U.S. (50 States)	**19.50**	**20.19**	**20.59**	**20.65**	**21.05**	**21.52**	*21.63*	*21.74*	*21.75*	*21.95*	*22.09*	*22.26*	**20.24**	*21.49*	*22.01*
Canada	**5.66**	**5.51**	**5.72**	**5.91**	**5.79**	**5.57**	*5.86*	*6.12*	*6.20*	*5.92*	*6.12*	*6.34*	**5.70**	*5.84*	*6.15*
Mexico	**1.91**	**1.89**	**1.90**	**1.90**	**2.07**	**2.16**	*2.14*	*2.12*	*2.12*	*2.11*	*2.07*	*2.02*	**1.90**	*2.12*	*2.08*
Other OECD	**4.61**	**4.35**	**4.32**	**4.49**	**4.56**	**4.51**	*4.45*	*4.66*	*4.72*	*4.62*	*4.54*	*4.79*	**4.44**	*4.55*	*4.67*
Non-OECD	**67.20**	**66.86**	**68.26**	**68.05**	**67.52**	**67.56**	*66.95*	*67.20*	*67.54*	*68.23*	*68.55*	*68.06*	**67.60**	*67.31*	*68.10*
OPEC	**33.75**	**33.76**	**34.71**	**34.43**	**33.95**	**33.71**	*32.91*	*33.33*	*33.96*	*33.98*	*34.07*	*33.81*	**34.17**	*33.47*	*33.96*
Crude Oil Portion	**28.19**	**28.33**	**29.23**	**28.92**	**28.46**	**28.37**	*27.51*	*27.89*	*28.43*	*28.58*	*28.63*	*28.33*	**28.67**	*28.06*	*28.50*
Other Liquids (b)	**5.56**	**5.43**	**5.48**	**5.52**	**5.49**	**5.34**	*5.40*	*5.44*	*5.53*	*5.40*	*5.44*	*5.48*	**5.50**	*5.42*	*5.46*
Eurasia	**14.39**	**13.39**	**13.56**	**13.90**	**14.00**	**13.56**	*13.43*	*13.60*	*13.62*	*13.60*	*13.54*	*13.65*	**13.81**	*13.64*	*13.60*
China	**5.18**	**5.18**	**5.05**	**5.09**	**5.32**	**5.32**	*5.28*	*5.32*	*5.27*	*5.30*	*5.29*	*5.33*	**5.12**	*5.31*	*5.30*
Other Non-OECD	**13.89**	**14.53**	**14.94**	**14.63**	**14.26**	**14.96**	*15.34*	*14.95*	*14.68*	*15.35*	*15.65*	*15.26*	**14.50**	*14.88*	*15.24*
Total World Production	**98.88**	**98.81**	**100.79**	**101.00**	**101.00**	**101.31**	*101.03*	*101.83*	*102.33*	*102.83*	*103.38*	*103.47*	**99.88**	*101.30*	*103.00*
Non-OPEC Production	**65.14**	**65.05**	**66.08**	**66.57**	**67.05**	**67.60**	*68.13*	*68.50*	*68.36*	*68.85*	*69.31*	*69.66*	**65.71**	*67.82*	*69.05*
Consumption (million barrels per day) (c)															
OECD	**45.76**	**45.38**	**46.58**	**45.95**	**45.53**	**45.59**	*46.31*	*46.63*	*46.06*	*45.60*	*46.60*	*46.58*	**45.92**	*46.02*	*46.21*
U.S. (50 States)	**20.22**	**20.27**	**20.47**	**20.16**	**20.00**	**20.68**	*20.53*	*20.65*	*20.47*	*20.67*	*21.03*	*20.82*	**20.28**	*20.47*	*20.75*
U.S. Territories	**0.11**	**0.12**	**0.13**	**0.12**	**0.12**	**0.12**	*0.12*	*0.12*	*0.11*	*0.11*	*0.11*	*0.11*	**0.12**	*0.12*	*0.11*
Canada	**2.24**	**2.21**	**2.38**	**2.30**	**2.24**	**2.24**	*2.34*	*2.31*	*2.28*	*2.23*	*2.33*	*2.31*	**2.28**	*2.28*	*2.29*
Europe	**13.19**	**13.43**	**14.04**	**13.35**	**13.06**	**13.30**	*13.87*	*13.63*	*13.22*	*13.37*	*13.79*	*13.55*	**13.50**	*13.47*	*13.48*
Japan	**3.70**	**3.03**	**3.19**	**3.56**	**3.72**	**3.01**	*3.12*	*3.45*	*3.55*	*2.94*	*3.04*	*3.37*	**3.37**	*3.32*	*3.22*
Other OECD	**6.30**	**6.33**	**6.37**	**6.45**	**6.39**	**6.24**	*6.34*	*6.47*	*6.42*	*6.28*	*6.30*	*6.43*	**6.36**	*6.36*	*6.36*
Non-OECD	**52.83**	**53.49**	**53.86**	**53.86**	**54.63**	**55.38**	*55.36*	*55.32*	*56.23*	*56.75*	*56.69*	*56.65*	**53.51**	*55.18*	*56.58*
Eurasia	**4.28**	**4.43**	**4.73**	**4.65**	**4.32**	**4.47**	*4.79*	*4.70*	*4.45*	*4.60*	*4.92*	*4.83*	**4.53**	*4.57*	*4.70*
Europe	**0.74**	**0.76**	**0.76**	**0.77**	**0.74**	**0.76**	*0.77*	*0.77*	*0.75*	*0.77*	*0.77*	*0.78*	**0.76**	*0.76*	*0.77*
China	**15.12**	**15.10**	**15.09**	**15.28**	**15.93**	**16.13**	*15.80*	*16.02*	*16.34*	*16.54*	*16.21*	*16.43*	**15.15**	*15.97*	*16.38*
Other Asia	**13.75**	**13.76**	**13.41**	**13.84**	**14.26**	**14.32**	*13.74*	*14.04*	*14.85*	*14.82*	*14.22*	*14.54*	**13.69**	*14.09*	*14.60*
Other Non-OECD	**18.95**	**19.45**	**19.86**	**19.32**	**19.38**	**19.70**	*20.26*	*19.80*	*19.84*	*20.02*	*20.57*	*20.09*	**19.39**	*19.79*	*20.13*
Total World Consumption	**98.59**	**98.87**	**100.45**	**99.80**	**100.16**	**100.97**	*101.67*	*101.95*	*102.29*	*102.36*	*103.29*	*103.24*	**99.43**	*101.19*	*102.80*
Total Crude Oil and Other Liquids Inventory Net Withdrawals (million barrels per day)															
U.S. (50 States)	**0.81**	**0.51**	**0.45**	**0.41**	**-0.09**	**-0.09**	*-0.14*	*0.33*	*-0.03*	*-0.37*	*0.00*	*0.38*	**0.54**	*0.00*	*0.00*
Other OECD	**-0.09**	**-0.29**	**-0.48**	**-0.26**	**0.32**	**-0.47**	*0.25*	*-0.07*	*0.00*	*-0.03*	*-0.03*	*-0.19*	**-0.28**	*0.01*	*-0.06*
Other Stock Draws and Balance	**-1.01**	**-0.16**	**-0.31**	**-1.34**	**-1.07**	**0.22**	*0.53*	*-0.14*	*-0.01*	*-0.07*	*-0.07*	*-0.42*	**-0.71**	*-0.11*	*-0.14*
Total Stock Draw	**-0.30**	**0.06**	**-0.34**	**-1.20**	**-0.84**	**-0.34**	*0.63*	*0.12*	*-0.04*	*-0.48*	*-0.09*	*-0.23*	**-0.45**	*-0.10*	*-0.21*
End-of-period Commercial Crude Oil and Other Liquids Inventories (million barrels)															
U.S. Commercial Inventory	**1,154**	**1,180**	**1,215**	**1,222**	**1,231**	**1,263**	*1,270*	*1,240*	*1,242*	*1,276*	*1,276*	*1,241*	**1,222**	*1,240*	*1,241*
OECD Commercial Inventory	**2,604**	**2,656**	**2,735**	**2,766**	**2,746**	**2,821**	*2,805*	*2,781*	*2,784*	*2,821*	*2,823*	*2,806*	**2,766**	*2,781*	*2,806*

(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 August 8, 2023.

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 - August 2023

	2022				2023				2024				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2022	2023	2024
Supply (million barrels per day)															
Crude Oil Supply															
Domestic Production (a)	11.52	11.77	12.05	12.30	12.63	12.67	12.81	12.93	12.98	13.01	13.08	13.27	11.91	12.76	13.09
Alaska	0.45	0.44	0.42	0.44	0.44	0.43	0.41	0.43	0.43	0.40	0.40	0.41	0.44	0.43	0.41
Federal Gulf of Mexico (b)	1.66	1.70	1.77	1.79	1.87	1.71	1.79	1.87	1.91	1.89	1.82	1.86	1.73	1.81	1.87
Lower 48 States (excl GOM)	9.42	9.63	9.85	10.06	10.31	10.53	10.61	10.63	10.64	10.71	10.87	11.00	9.74	10.52	10.81
Crude Oil Net Imports (c)	3.00	2.81	2.75	2.14	2.27	2.42	2.64	2.48	2.28	2.61	2.62	2.05	2.67	2.45	2.39
SPR Net Withdrawals	0.31	0.80	0.84	0.48	0.01	0.26	-0.06	0.00	0.00	0.00	0.00	0.00	0.61	0.05	0.00
Commercial Inventory Net Withdrawals	0.08	-0.03	-0.12	-0.01	-0.40	0.14	0.27	-0.04	-0.33	0.10	0.18	-0.09	-0.02	-0.01	-0.03
Crude Oil Adjustment (d)	0.65	0.74	0.75	0.89	0.68	0.61	0.55	0.46	0.56	0.60	0.51	0.47	0.76	0.57	0.53
Total Crude Oil Input to Refineries	15.56	16.09	16.26	15.80	15.19	16.10	16.21	15.83	15.50	16.33	16.39	15.71	15.93	15.84	15.98
Other Supply															
Refinery Processing Gain	0.95	1.07	1.05	1.01	0.97	0.99	1.01	1.02	0.98	1.01	1.02	1.00	1.02	1.00	1.00
Natural Gas Plant Liquids Production	5.61	5.92	6.09	5.90	6.01	6.36	6.31	6.30	6.30	6.40	6.44	6.44	5.88	6.25	6.39
Renewables and Oxygenate Production (e)	1.20	1.20	1.18	1.23	1.24	1.28	1.28	1.27	1.28	1.32	1.33	1.33	1.20	1.27	1.31
Fuel Ethanol Production	1.02	1.01	0.97	1.01	1.00	1.00	1.01	0.99	1.00	1.01	1.02	1.01	1.00	1.00	1.01
Petroleum Products Adjustment (f)	0.21	0.23	0.22	0.22	0.20	0.22	0.22	0.22	0.21	0.22	0.22	0.22	0.22	0.21	0.22
Product Net Imports (c)	-3.74	-3.99	-4.07	-3.93	-3.91	-3.77	-4.15	-4.36	-4.09	-4.13	-4.19	-4.34	-3.93	-4.05	-4.19
Hydrocarbon Gas Liquids	-2.14	-2.31	-2.16	-2.26	-2.47	-2.45	-2.57	-2.60	-2.61	-2.74	-2.62	-2.69	-2.22	-2.52	-2.66
Unfinished Oils	0.09	0.25	0.28	0.30	0.28	0.23	0.37	0.24	0.20	0.27	0.31	0.21	0.23	0.28	0.25
Other HC/Oxygenates	-0.09	-0.10	-0.07	-0.02	-0.05	-0.06	-0.03	-0.04	-0.06	-0.05	-0.04	-0.05	-0.07	-0.04	-0.05
Motor Gasoline Blend Comp.	0.40	0.60	0.48	0.40	0.45	0.61	0.53	0.39	0.50	0.66	0.51	0.32	0.47	0.50	0.50
Finished Motor Gasoline	-0.76	-0.73	-0.81	-0.83	-0.75	-0.52	-0.60	-0.68	-0.82	-0.69	-0.71	-0.67	-0.78	-0.64	-0.72
Jet Fuel	-0.04	-0.06	-0.11	-0.03	-0.05	0.01	-0.04	0.04	0.12	0.19	0.18	0.17	-0.06	-0.01	0.16
Distillate Fuel Oil	-0.81	-1.15	-1.29	-1.05	-0.76	-1.02	-1.21	-1.09	-0.86	-1.13	-1.23	-1.04	-1.07	-1.02	-1.07
Residual Fuel Oil	0.14	0.10	0.10	0.09	0.01	-0.04	0.01	0.08	0.04	0.05	0.06	0.13	0.11	0.02	0.07
Other Oils (g)	-0.54	-0.59	-0.49	-0.53	-0.58	-0.55	-0.61	-0.69	-0.59	-0.68	-0.66	-0.71	-0.54	-0.61	-0.66
Product Inventory Net Withdrawals	0.42	-0.25	-0.26	-0.06	0.30	-0.49	-0.34	0.36	0.30	-0.48	-0.18	0.46	-0.04	-0.04	0.03
Total Supply	20.22	20.27	20.47	20.16	20.00	20.68	20.53	20.65	20.47	20.67	21.03	20.82	20.28	20.47	20.75
Consumption (million barrels per day)															
Hydrocarbon Gas Liquids	3.87	3.43	3.48	3.57	3.68	3.66	3.53	3.83	4.00	3.48	3.63	3.87	3.59	3.67	3.75
Other HC/Oxygenates	0.13	0.17	0.17	0.19	0.22	0.27	0.22	0.24	0.23	0.25	0.25	0.27	0.16	0.24	0.25
Unfinished Oils	0.13	0.04	0.11	0.10	0.05	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.09	0.02	0.00
Motor Gasoline	8.47	9.00	8.88	8.75	8.67	9.15	9.00	8.82	8.60	9.08	9.13	8.84	8.78	8.91	8.91
Fuel Ethanol blended into Motor Gasoline	0.87	0.93	0.92	0.93	0.90	0.95	0.96	0.92	0.89	0.95	0.96	0.92	0.91	0.93	0.93
Jet Fuel	1.45	1.61	1.60	1.58	1.55	1.68	1.70	1.70	1.67	1.79	1.83	1.77	1.56	1.66	1.76
Distillate Fuel Oil	4.14	3.89	3.86	3.96	4.01	3.84	3.75	3.98	4.07	3.96	3.89	4.02	3.96	3.89	3.98
Residual Fuel Oil	0.38	0.31	0.39	0.30	0.29	0.20	0.32	0.35	0.27	0.27	0.32	0.34	0.34	0.29	0.30
Other Oils (g)	1.65	1.82	1.99	1.71	1.53	1.86	2.00	1.73	1.62	1.84	1.98	1.71	1.79	1.78	1.79
Total Consumption	20.22	20.27	20.47	20.16	20.00	20.68	20.53	20.65	20.47	20.67	21.03	20.82	20.28	20.47	20.75
Total Petroleum and Other Liquids Net Imports	-0.74	-1.18	-1.32	-1.79	-1.64	-1.36	-1.51	-1.88	-1.81	-1.51	-1.57	-2.28	-1.26	-1.60	-1.80
End-of-period Inventories (million barrels)															
Commercial Inventory															
Crude Oil (excluding SPR)	414.4	417.5	428.8	429.6	465.4	453.0	428.3	431.5	461.3	452.0	435.5	443.4	429.6	431.5	443.4
Hydrocarbon Gas Liquids	142.0	186.7	243.6	211.1	174.3	225.8	267.2	223.7	181.4	228.7	267.0	222.7	211.1	223.7	222.7
Unfinished Oils	87.9	88.8	82.3	86.1	88.6	88.1	88.6	81.1	91.0	87.9	87.1	79.4	86.1	81.1	79.4
Other HC/Oxygenates	34.1	29.4	27.3	31.7	34.3	30.5	30.9	31.2	33.3	32.0	31.7	32.0	31.7	31.2	32.0
Total Motor Gasoline	238.5	221.0	209.6	224.3	225.3	219.5	217.8	233.5	234.9	231.7	219.9	230.9	224.3	233.5	230.9
Finished Motor Gasoline	17.3	17.1	17.6	17.4	14.7	17.5	21.2	21.7	19.0	19.3	20.4	22.6	17.4	21.7	22.6
Motor Gasoline Blend Comp.	221.2	203.8	192.0	206.9	210.6	201.9	196.6	211.7	216.0	212.4	199.4	208.3	206.9	211.7	208.3
Jet Fuel	35.6	39.3	36.2	35.0	37.7	41.4	41.0	39.7	38.7	40.5	41.5	38.6	35.0	39.7	38.6
Distillate Fuel Oil	114.6	111.4	110.5	118.8	112.3	114.1	119.4	121.2	112.8	117.1	117.9	118.1	118.8	121.2	118.1
Residual Fuel Oil	27.9	29.2	27.3	30.7	29.6	30.9	26.3	26.1	27.8	27.3	25.6	25.0	30.7	26.1	25.0
Other Oils (g)	58.5	56.4	49.5	54.2	63.3	59.8	50.5	51.8	60.8	58.7	49.4	50.7	54.2	51.8	50.7
Total Commercial Inventory	1153.6	1179.7	1215.1	1221.6	1230.8	1263.2	1270.0	1239.8	1242.0	1275.9	1275.7	1240.9	1221.6	1239.8	1240.9
Crude Oil in SPR	566.1	493.3	416.4	372.0	371.2	347.1	353.1	353.1	353.1	353.1	353.1	353.1	372.0	353.1	353.1

(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 August 8, 2023.

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 - August 2023

	2022				2023				2024				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2022	2023	2024
Supply (billion cubic feet per day)															
Total Marketed Production	103.27	106.18	108.27	108.90	110.87	112.30	112.96	113.25	113.65	113.54	113.61	114.35	106.67	112.35	113.79
Alaska	1.06	1.00	0.96	1.07	1.08	1.00	0.87	0.98	1.00	0.92	0.84	0.98	1.02	0.98	0.94
Federal GOM (a)	2.05	2.11	2.19	2.12	2.14	1.95	2.10	2.14	2.16	2.10	1.98	2.00	2.12	2.08	2.06
Lower 48 States (excl GOM)	100.16	103.07	105.12	105.71	107.65	109.36	109.98	110.12	110.50	110.51	110.79	111.37	103.53	109.29	110.79
Total Dry Gas Production	95.09	97.59	99.46	100.29	102.13	102.78	103.36	103.63	104.00	103.89	103.96	104.64	98.13	102.98	104.13
LNG Gross Imports	0.15	0.01	0.07	0.05	0.09	0.03	0.04	0.06	0.10	0.04	0.04	0.06	0.07	0.06	0.06
LNG Gross Exports	11.50	10.80	9.74	10.35	11.45	11.85	11.80	12.34	12.72	12.82	13.09	14.61	10.59	11.86	13.31
Pipeline Gross Imports	8.89	7.73	7.84	8.41	8.45	7.10	7.10	7.45	8.18	6.81	7.04	7.44	8.22	7.52	7.36
Pipeline Gross Exports	8.46	8.52	8.13	8.19	8.88	8.49	8.89	9.23	9.50	8.88	9.21	9.64	8.32	8.87	9.31
Supplemental Gaseous Fuels	0.21	0.17	0.18	0.16	0.19	0.17	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Net Inventory Withdrawals	20.14	-10.25	-8.94	2.35	11.95	-11.84	-6.94	3.70	14.34	-12.34	-6.78	2.71	0.75	-0.82	-0.53
Total Supply	104.52	75.94	80.72	92.73	102.48	77.90	83.06	93.45	104.58	76.87	82.15	90.78	88.43	89.18	88.58
Balancing Item (b)	0.30	0.19	0.05	-0.11	0.57	0.97	0.59	-1.46	-1.35	-1.26	0.18	-0.38	0.10	0.16	-0.70
Total Primary Supply	104.83	76.13	80.77	92.62	103.05	78.87	83.65	91.99	103.23	75.60	82.33	90.39	88.53	89.34	87.88
Consumption (billion cubic feet per day)															
Residential	26.09	7.86	3.57	17.37	23.48	7.86	4.21	16.64	24.82	7.86	4.32	16.64	13.67	13.01	13.39
Commercial	15.61	6.67	4.74	11.69	14.53	6.65	5.11	11.59	15.19	6.87	5.17	11.63	9.66	9.45	9.71
Industrial	25.46	22.25	21.47	23.51	24.68	22.28	21.43	23.33	23.93	20.86	20.71	22.93	23.16	22.92	22.11
Electric Power (c)	28.39	30.99	42.36	30.94	30.78	33.30	43.89	31.09	29.48	31.31	43.14	29.84	33.20	34.79	33.46
Lease and Plant Fuel	5.26	5.41	5.51	5.55	5.65	5.69	5.71	5.73	5.75	5.74	5.75	5.78	5.43	5.69	5.75
Pipeline and Distribution Use	3.86	2.80	2.98	3.41	3.80	2.93	3.14	3.47	3.91	2.82	3.09	3.42	3.26	3.33	3.31
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	104.83	76.13	80.77	92.62	103.05	78.87	83.65	91.99	103.23	75.60	82.33	90.39	88.53	89.34	87.88
End-of-period Inventories (billion cubic feet)															
Working Gas Inventory	1,401	2,325	3,146	2,927	1,850	2,912	3,550	3,210	1,904	3,028	3,651	3,402	2,927	3,210	3,402
East Region (d)	242	482	759	698	334	643	848	743	354	667	860	776	698	743	776
Midwest Region (d)	296	557	917	831	417	705	1,026	883	429	729	1,014	920	831	883	920
South Central Region (d)	587	885	1,006	1,042	919	1,144	1,165	1,132	815	1,168	1,213	1,198	1,042	1,132	1,198
Mountain Region (d)	90	137	184	158	79	173	224	186	119	161	223	193	158	186	193
Pacific Region (d)	165	240	247	169	74	216	253	234	161	274	308	286	169	234	286
Alaska	21	25	32	30	27	31	34	31	25	28	33	29	30	31	29

(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 August 8, 2023.

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.

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Announcement

Tuesday, 8 August 2023

WOODSIDE TO SELL 10% SCARBOROUGH INTEREST TO LNG JAPAN

Woodside has established a strategic relationship with LNG Japan which involves three elements: equity in the Scarborough Joint Venture, potential LNG offtake and collaboration on opportunities in new energy.

Woodside has entered into a sale and purchase agreement with LJ Scarborough Pty Ltd (LNG Japan) for the sale of a 10% non-operating participating interest in the Scarborough Joint Venture (the Transaction).[1]

The purchase price is US$500 million, subject to adjustments. LNG Japan will reimburse Woodside for its share of expenditure for the Scarborough project from the Transaction effective date of 1 January 2022. On completion of the Transaction, expected in the first quarter of 2024, the estimated total consideration comprising the purchase price, reimbursed expenditure and escalation is approximately US$880 million.

Completion of the Transaction is subject to conditions precedent including Foreign Investment Review Board approval, National Offshore Petroleum Titles Administrator approvals and Western Australian Government approvals.

As part of the broader strategic relationship, Woodside and LNG Japan Corporation have entered into a non-binding heads of agreement for the sale and purchase of 12 LNG cargoes per year (approximately 0.9 million tonnes per annum) for 10 years commencing in 2026.

Woodside has also entered into non-binding agreements to collaborate with Sumitomo Corporation and Sojitz Corporation on global opportunities in new energy which could include ammonia, hydrogen, carbon capture and storage (CCS) and carbon management technology.

Following completion, Woodside will hold a 90% interest in the Scarborough Joint Venture and remain as operator. Scarborough gas will be processed at the Pluto LNG facility, where Woodside is currently constructing Pluto Train 2. Woodside is also operator of the Pluto Train 2 Joint Venture and holds a 51% participating interest.

[1] LJ Scarborough Pty Ltd is currently a wholly owned subsidiary of LNG Japan Corporation, which is a 50:50 joint venture between Sumitomo Corporation and Sojitz Corporation.

Woodside CEO Meg O’Neill welcomed LNG Japan to the Scarborough Joint Venture.

“The support of LNG Japan is testament to the quality of the Scarborough project. It also underscores the ongoing demand from Japanese buyers for new supplies of gas and the role of gas in supporting Japan’s energy security.

“Our new energy agreements with Sumitomo and Sojitz provide further opportunities for us to work closely together on our shared decarbonisation and energy security ambitions.

“Scarborough will be an important source of gas for both the Western Australian and international markets, supporting domestic jobs and providing taxation revenue for the State and Federal Governments.

“We look forward to working with LNG Japan to deliver this world-class project,” she said.

LNG Japan CEO Mr Kyo Onojima said he was excited to form the strategic relationship between LNG Japan and Woodside.

“We are very pleased to join the Scarborough Joint Venture and are looking forward to finalising the LNG offtake agreement and exploring business opportunities in the new energy sector,” he said.

About Scarborough

The Scarborough Joint Venture comprises the Scarborough field and associated offshore and subsea infrastructure. The Scarborough field is located approximately 375 km off the coast of Western Australia and the reservoir contains less than 0.1% carbon dioxide.

The Scarborough project will include the installation of a floating production unit with eight wells drilled in the initial phase and thirteen wells drilled over the life of the Scarborough field. The gas will be transported for processing at Pluto LNG through a new trunkline of approximately 430 km in length. The final investment decision was made in November 2021 and first LNG cargo is targeted for 2026.

About LNG Japan

LJ Scarborough Pty Ltd is currently a wholly owned subsidiary of LNG Japan Corporation, which is a 50:50 joint venture between Sumitomo Corporation and Sojitz Corporation.

Sumitomo Corporation (“SC”) is a leading Fortune 500 global trading and business investment company with 129 locations (Japan:20, Overseas:109) in 66 countries and regions. SC’s core business areas include six business units: Metal Products; Transportation & Construction Systems; Infrastructure; Media & Digital; Living Related & Real Estate; and Mineral Resources, Energy, Chemical & Electronics, and one initiative: Energy Innovation.

Sojitz Corporation consists of approximately 400 subsidiaries and affiliates located in Japan and throughout the world, developing wide-ranging general trading company operations in a multitude of countries and regions.

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This announcement was approved and authorised for release by Woodside's Disclosure Committee

Forward-looking statements

This announcement contains forward-looking statements with respect to Woodside's business and operations, market conditions, results of operations and financial condition, including, for example, but not limited to, statements regarding the Transaction (including statements concerning the timing and completion of the Transaction, the expected benefits of the Transaction and other future arrangements between Woodside and LNG Japan), the timing of completion of Woodside's projects and expectations regarding future expenditures and future results of projects. All forward-looking statements contained in this announcement reflect Woodside's views held as at the date of this announcement. All statements, other than statements of historical or present facts, are forward-looking statements and generally may be identified by the use of forward-looking words such as 'guidance', 'foresee', 'likely', 'potential', 'anticipate', 'believe', 'aim', 'estimate', 'expect', 'intend', 'may', 'target', 'plan', 'forecast', 'project', 'schedule', 'will', 'should', 'seek' and other similar words or expressions.

Forward-looking statements in this announcement are not guidance, forecasts, guarantees or predictions of future events or performance, but are in the nature of aspirational targets that Woodside has set for itself and its management of the business. Those statements and any assumptions on which they are based are only opinions, are subject to change without notice and are subject to inherent known and unknown risks, uncertainties, assumptions and other factors, many of which are beyond the control of Woodside, its related bodies corporate and their respective officers, directors, employees, advisers or representatives.

Details of the key risks relating to Woodside and its business can be found in the "Risk" section of Woodside's most recent Annual Report released to the Australian Securities Exchange and the London Stock Exchange and in Woodside's most recent Annual Report on Form 20-F filed with the United States Securities and Exchange Commission and available on the Woodside website at https://www.woodside.com/investors/reports-investor-briefings. You should review and have regard to these risks when considering the information contained in this announcement.

Investors are strongly cautioned not to place undue reliance on any forward-looking statements. Actual results or performance may vary materially from those expressed in, or implied by, any forward-looking statements.

All information included in this announcement, including any forward-looking statements, speak only as of the date of this announcement and, except as required by law or regulation, Woodside does not undertake to update or revise any information or forward-looking statements contained in this announcement, whether as a result of new information, future events, or otherwise.

Announcement contains inside information

This announcement contains inside information. Matthew Turnbull, Vice President Investor Relations is responsible for release of this announcement.

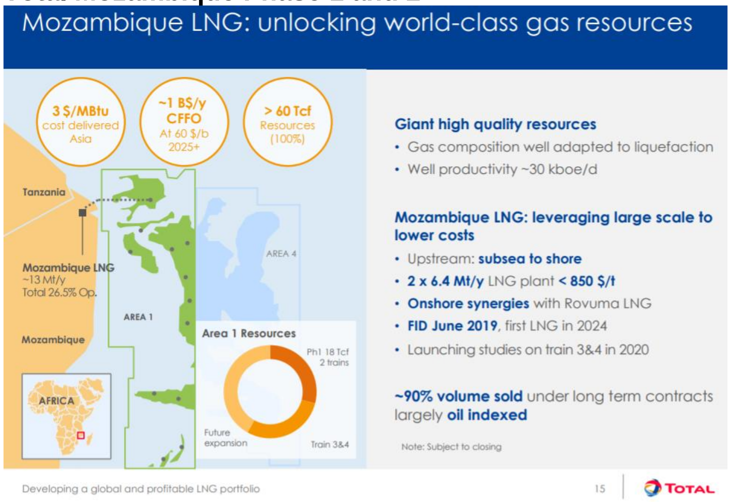
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

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



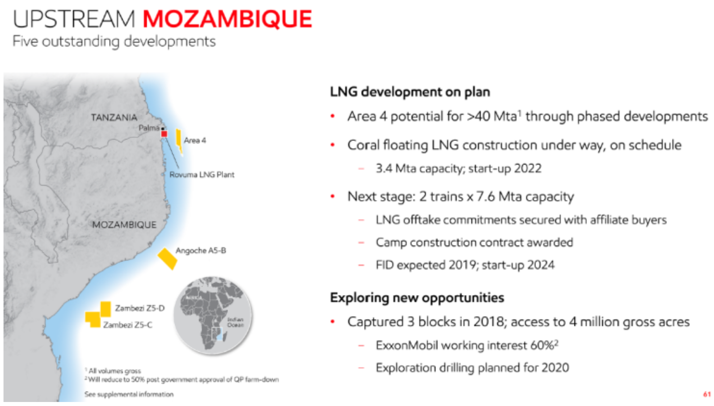
Source: Total Investor Day September 24, 2019

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

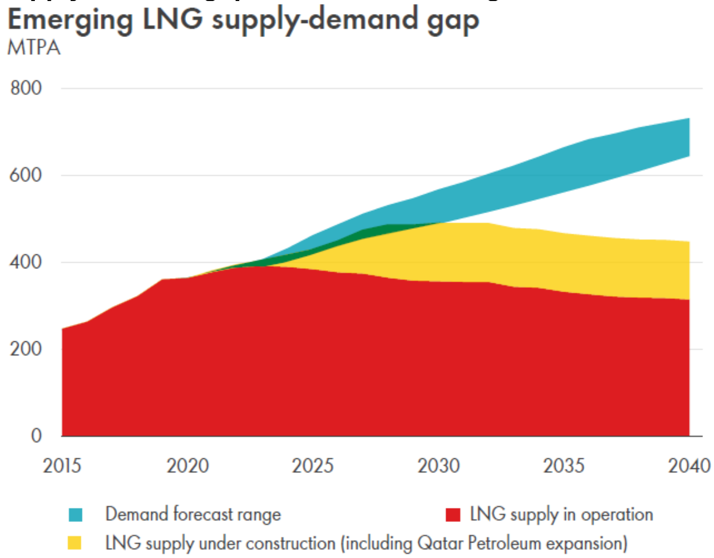
🟢 On Track 🟡 More Efforts Needed 🔴 Not on Track

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.*

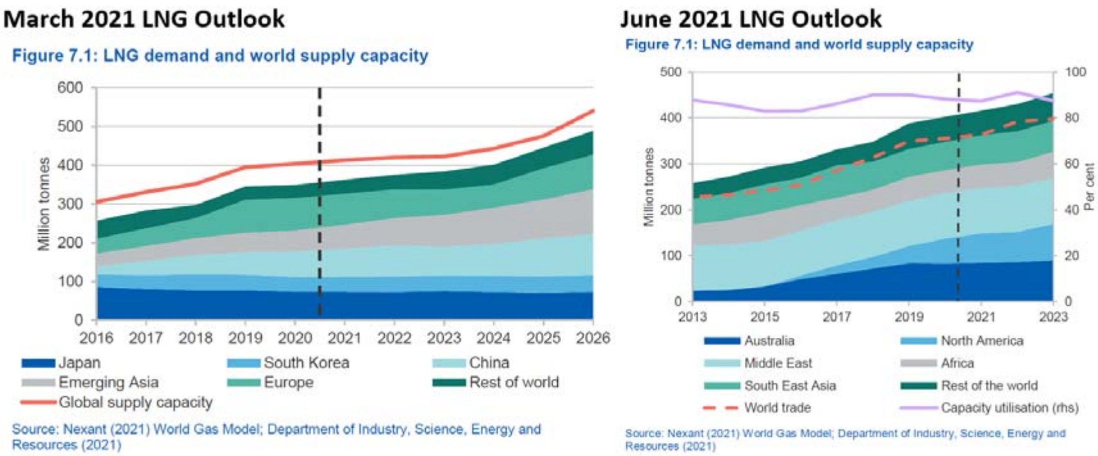
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required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

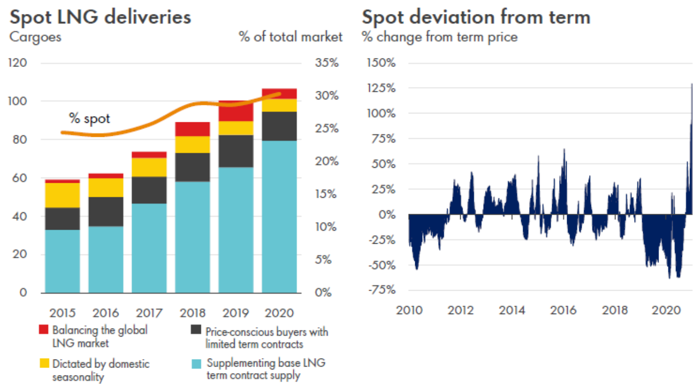


Source: Australia Resources and Energy Quarterly

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

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

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

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

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

> Petronas/CNOOC is 10 yr supply deal for 0.3 bcf/d. On July 7, we tweeted [LINK] on the confirmation of a big positive to Cdn natural gas with the Petronas announcement [LINK] of a new 10 year LNG supply deal for 0.3 bcf/d with China's CNOOC. The deal also has special significance to Canada. (i) Petronas said "*This long-term supply agreement also includes supply from LNG Canada when the facility commences its operations by middle of the decade*". This is a reminder of the big positive to Cdn natural gas in the next 3 to 4 years – the start up of LNG Canada Phase 1 is ~1.8 bcf/d capacity. This is natural gas that will no longer be moving south to the US or east to eastern Canada, instead it will be going to Asia. This will provide a benefit for all Western Canada natural gas. (ii) First ever AECO linked LNG deal. It's a pretty significant event for a long term Asia LNG deal to now have an AECO link. Petronas wrote "*The deal is for 2.2 million tonnes per annum (MTPA) for a 10-year period, indexed to a combination of the Brent and Alberta Energy Company (AECO) indices. The term deal between PETRONAS and CNOOC is valued at approximately USD 7 billion over ten years.*" 2.2 MTPA is 0.3 bcf/d. (iii) Reminds of LNG Canada's competitive advantage for low greenhouse gas emissions. Petronas said "*Once ready for operations, the LNG Canada project paves the way for PETRONAS to supply low greenhouse gas (GHG) emission LNG to the key demand markets in Asia.*"
>
> Qatar Petroleum/CPC (Taiwan) is 15 yr supply deal for 0.16 bcf/d. Pre Covid, Qatar was getting pressured to renegotiate lower its long term LNG contract prices. Now, it's signing a 15 year deal. On July 9, they entered in a new small long term LNG sales deal [LINK], a 15-yr LNG Sale and Purchase Agreement with CPC Corporation in Taiwan to supply it ~0.60 bcf/d of LNG. LNG deliveries are set to begin in January 2022. H.E. Minister for Energy Affairs & CEO of Qatar Petroleum Al-Kaabi said *"We are pleased to enter into this long term LNG SPA, which is another milestone in our relationship with CPC, which dates back to almost three decades. We look forward to commencing deliveries under this SPA and to continuing our supplies as a trusted and reliable global LNG provider."* The pricing was reported to be vs a basket of crudes.

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

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

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

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

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

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

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

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

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

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

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

Offshore Alliance

1d · ·

Chevron and Woodside are actively looking for non-competent scab labour to fill the void of highly skilled Licence to Operate OA members, in their anticipation of Protected Industrial Action.

Judging by the panicked phone calls OA members have received over the few days, Chevron and Woodside must think they can pluck oil & gas workers off the back of the KFC employment queue – and still maintain full production.

Good story Chevron and Woodside, but it fools no-one.

The Union is getting plenty of supportive messages from crew who have been approached by Chevron and Woodside to provide scab labour.

Oil and gas workers have made it clear that they won't scab. Under any circumstances.

It is a lifetime decision to scab and workers who aren't on facility have made it clear that they won't be used and abused by HR bosses desperate for self-survival to mask their incompetent management of their respective EBA negotiations.

Chevron's HR bosses have spent the last 10 months trying to convince anyone who listens, that their Richmond Refinery dispute in the US in 2022 was a good template for any Protected Industrial on their remote major hazard facilities on the West Coast of Australia.

They even had a little scab planning room set up in their previous Terrace. The photos of this provided to the Union highlight the lunacy of the Chevron bosses running their HR asylum.

They are dumber than we first thought if they actually believe their own spin and rhetoric about the successful use of scab labour.

There is fat chance of untrained, inexperienced or incompetent workers being able to keep all trains operating for long. When shit hits the fan, shit will hit the fan.

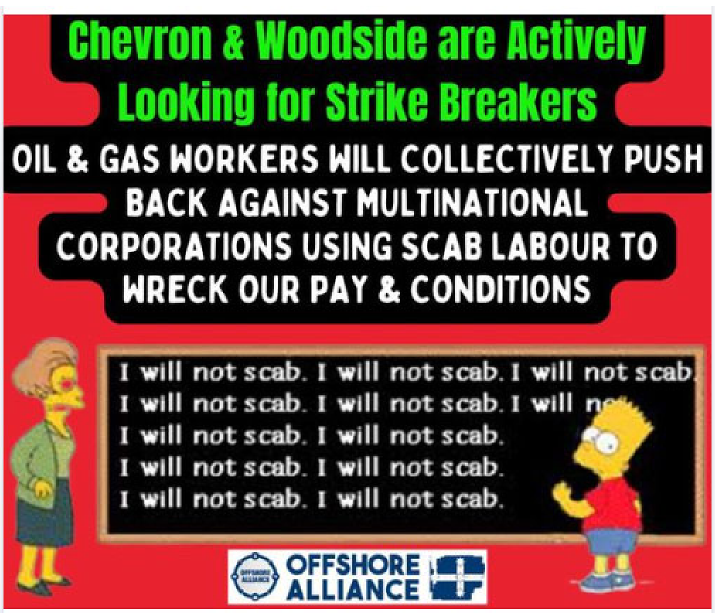
There will be no get out of jail for Chevron or Woodside in these circumstances.

Woodside are in exact same position as Chevron in this regard and they will find out the hard way that highly skilled and experienced workers are not 'expendable units of production' as seen through the prism of their HR bosses and bean counters.

They can contact Shell to see how well that strategy worked.

The only way Woodside and Chevron can avoid the inevitable train wreck (no pun intended) of PIA, is to reach agreement on job security provisions, salaries and employment conditions.

The Offshore Alliance and our members will never blink. Shell, Jadestone, Santos and scores of oil and gas contractors can attest to that.



Offshore Alliance
2d ·

Up Late's Ben Harvey always has an interesting take on news events and has rightly pointed to last years' 76 day industrial dispute with Shell on Prelude, as the potential end game for Chevron and Woodside in our dispute about pay, condiitons and job security.

Chevron and Woodside have the benefit of hindsight in looking at how the bargaining dispute about EBA outcomes played out for Shell, and are making the same dumb IR mistakes which Shell made on Prelude.

Except this makes Chevron and Woodside signficantly dumber as they know that the Prelude bargaining dispute last year cost Shell $1.5 billion in lost production and profit.

Chevron and Woodside's production on the NW Shelf, Gorgon and Wheatstone dwarfs that of the Prelude operations and the cost to both Companies in the OA taking Prorected Industrial Action, will be in the realm of several $billion if they don't resolve our outstanding bargaining claims in a hurry.

Any company which tests the resolve of the Offshore Alliance and our members to go one day longer and one day stronger in our fight for fair industrial outcomes, will get the same IR lesson as every other recalcitrant employer which has gone before them.

IF YOU DON'T FIGHT, YOU LOSE!

Offshore Alliance
3d ·

Offshore Alliance members on the GWA, NRC and Angel Platforms have voted 99% in favour of Protected Industrial Action in support of our EBA campaign. Great work by members who have demonstrated the necessary collective unity to ensure we are well placed to locking in a benchmark industry-standard Enterprise Bargaining Agreement.

Bargaining for the EBA continues today and members have made it clear that secure jobs and getting paid 100 cents in the dollar for highly skilled work on major hazard facilities are key bargaining outcomes which need to be resolved.

Union conditions, Union rates, Union jobs.👊👊

IF YOU DON'T FIGHT, YOU LOSE!

https://offshorealliance.org.au/members/join

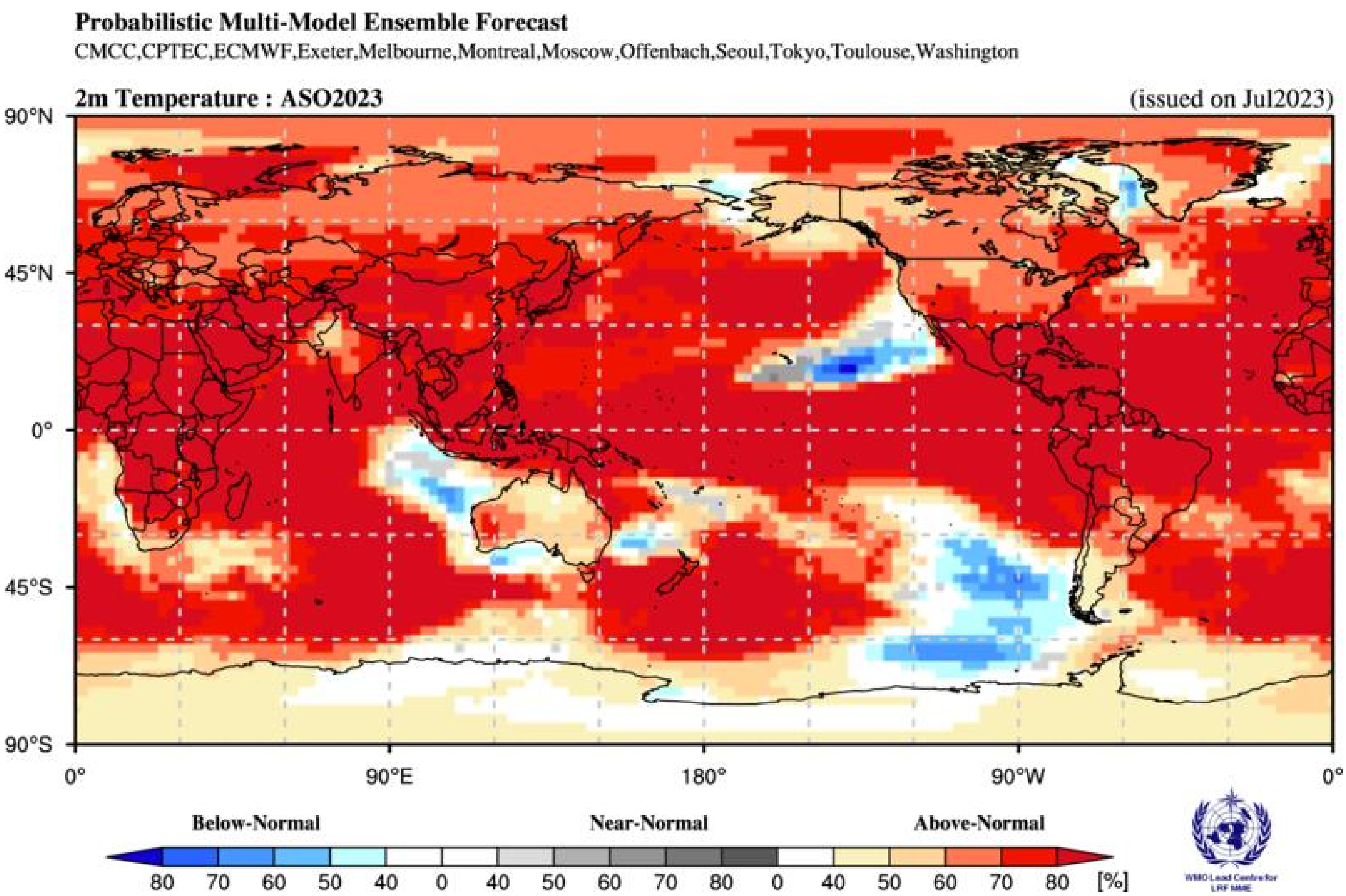
https://public.wmo.int/en/our-mandate/climate/global-seasonal-climate-update

Latest Update

GSCU for August-September-October 2023

During April-June 2023, Pacific Niño sea-surface temperature (SST) index in the eastern Pacific (Niño 1+2) were much above-normal and the other three indices in the central Pacific were also positive. The observed SST conditions in the equatorial Pacific were characterized by a weak El Niño state. The Indian Ocean Dipole (IOD) was near normal. The North Tropical Atlantic (NTA) and the South Tropical Atlantic (STA) SST indices were also positive and reflected widespread warmth in the tropical Atlantic above the equator.

For the August-October 2023 (ASO 2023) season, the sea-surface temperature anomalies in the Niño 3.4 and Niño 3 regions in the central and eastern Pacific are predicted to become warmer to reach moderate El Niño conditions.



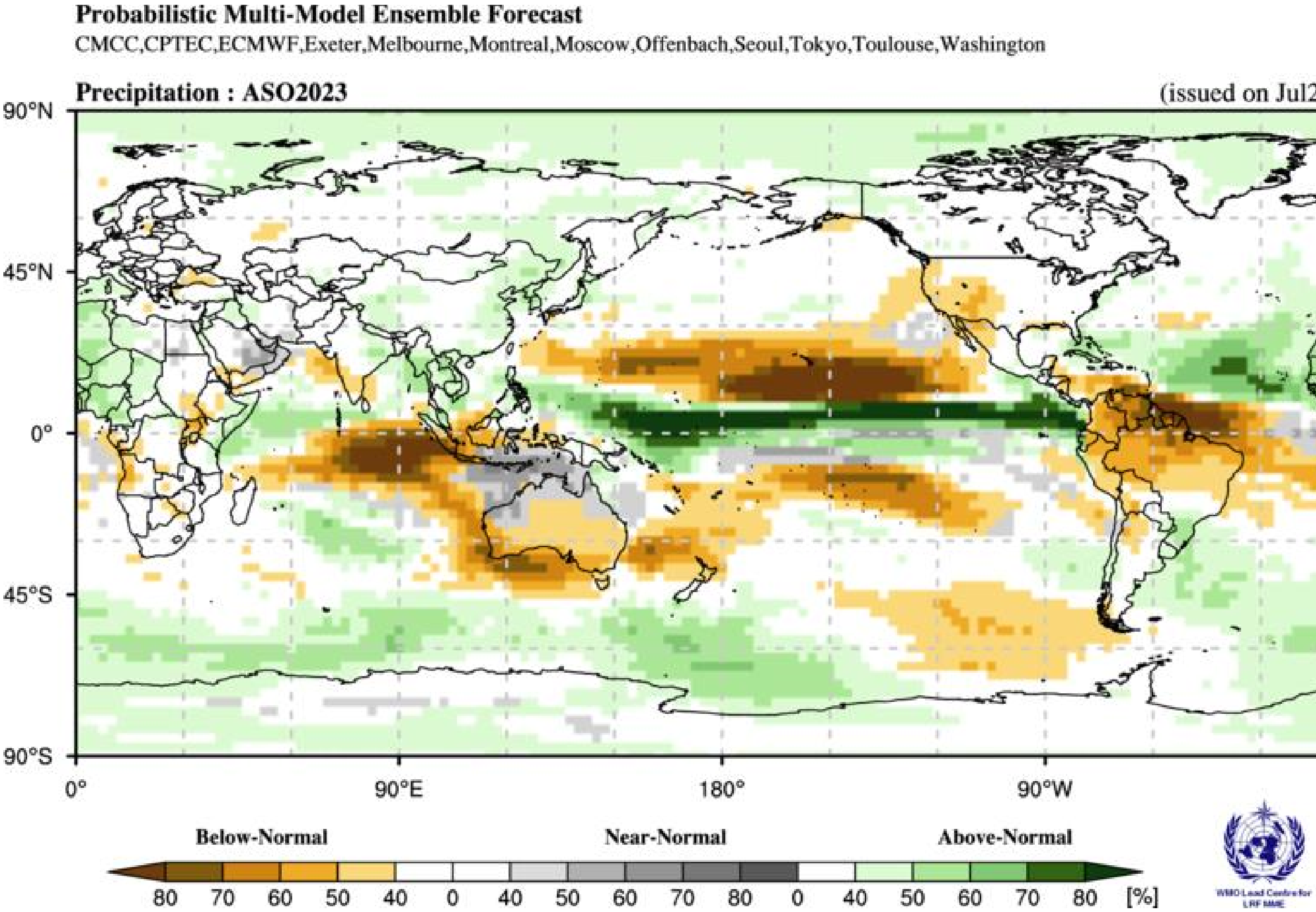


Figure 1: Probabilistic forecasts of surface air temperature and precipitation for the season August-September 2023. The tercile category with the highest forecast probability is indicated by shaded areas. The most likely category for below-normal, above-normal and near-normal is depicted in blue, red and grey shadings respectively for temperature, and orange, green and grey shadings respectively for precipitation. White areas indicate equal chances for all categories in both cases. The baseline period is 1993–2009.

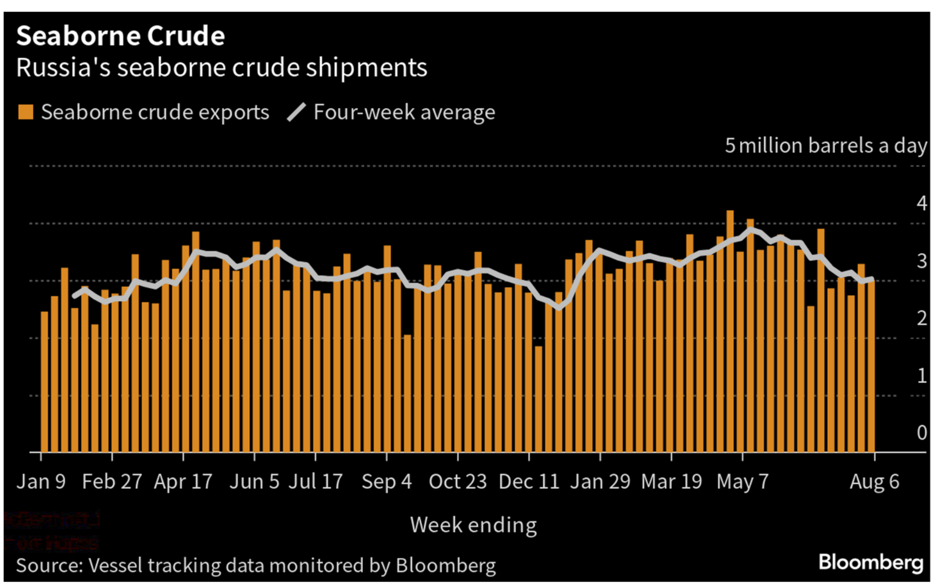
As warmer-than-average SSTs are generally predicted over oceanic regions for the ASO 2023 season, they contribute to widespread prediction of above-normal temperatures over land areas. Without exception, the likelihood of above-normal temperature anomalies is expected over all land areas in the Northern and Southern Hemisphere. The largest increase in probabilities for above-normal temperatures extend around the globe within the 50° S and 60° N band that includes the Maritime continent, New Zealand, Central America, the Caribbean, southern regions of North America, northern regions of South America, Africa, southern Europe, the Arabian Peninsula, east and southeast Asia. Over these regions the model consistency is high. There are also enhanced probabilities for abovenormal temperatures over other regions of Asia and North America, Europe, and southern regions of South America. Over these regions, however, the probabilities for above-normal temperature have a moderate increase. Strongly enhanced probabilities for above-normal temperatures are predicted in a band from north of Australia, extending to the south-eastern South Pacific, and in an arc extending over New Zealand to the vicinity of Tasmania. Over Australia, there is a weak enhancement in the likelihood of above-normal temperature.

Predictions for rainfall in the ASO 2023 season are similar to some of the canonical rainfall impacts of El Niño. Probabilities for above-normal rainfall are enhanced over a narrow band along and just north of the equator from the Philippines extending along the equator to the west coast of South America. This anomalously wet area extends discontinuously westward and with weaker signal and is most evident in south-east Asia, eastern parts of the Indian subcontinent, and along the southern part of West Africa, extending most of the way across the Atlantic Ocean. Across most of the Pacific Ocean south of about 30°

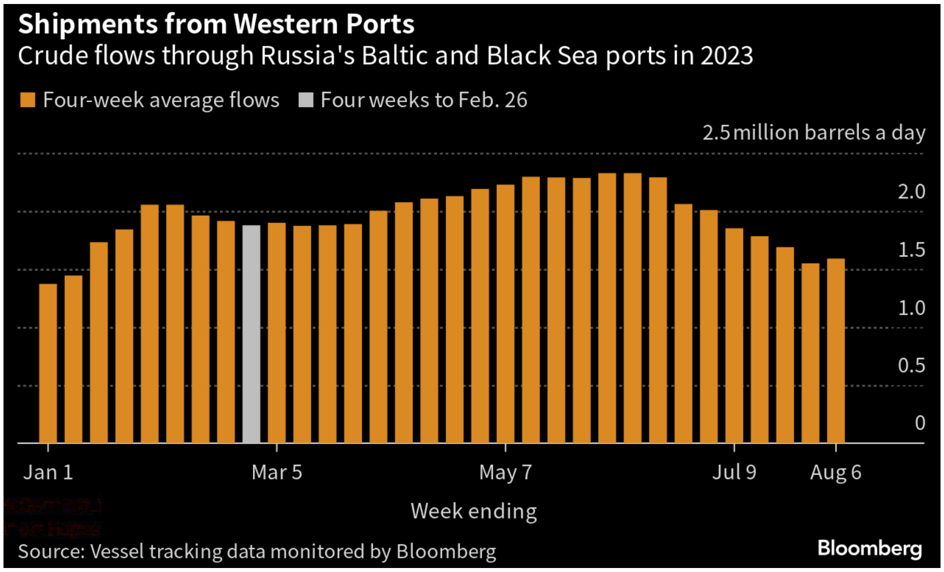
N, and immediately to the north of the equatorial wet band, rainfall is predicted to be below-normal. This area of dryness extends eastward across much of the northern part of South America north of about 10° S, the southern Caribbean, south-western region of North America, and the northern region of Central America. There is another band of predicted below-normal rainfall in the Central South Pacific east of the Dateline and extending in a narrowband to a little beyond 120° W. Over the south-central and western parts of the Maritime continent, below-normal rainfall is also predicted. This area extends along the equator almost to the east coast of Africa, but also to the south and east, so that most of Australia and the northern part of New Zealand have increased probabilities of below-normal rain. Over much of Africa north of the equator the probabilities for above-normal rainfall are weakly to moderately increased. Outside of the tropics, there are no large-scale strong indications of anomalous rainfall over land.

Russia Seaborne Crude Steady Before Ukraine’s Black Sea Attack
2023-08-08 12:24:53.451 GMT

By Julian Lee
(Bloomberg) -- Russia’s seaborne crude flows stabilized in the four weeks to Aug. 6, before Ukrainian naval drones attacked two Russian ships in the Black Sea — a move that could prompt Moscow to divert cargoes.
Average shipments during the period steadied at 3.02 million barrels a day, about 870,000 barrels a day below the peak in mid-May, tanker-tracking data compiled by Bloomberg show. More volatile weekly numbers slipped, with no cargoes leaving from the Arctic port of Murmansk after the previous week’s record-equaling flow.
The figures support the notion that Moscow is now honoring a pledge to keep supply off the global market alongside its allies in the OPEC+ producer coalition. Russia initially said it would cut oil production in retaliation for Western sanctions and price caps on its oil imposed after the invasion of Ukraine, using February as a baseline. But seaborne flows had continued to rise, dropping significantly only in the last few weeks.
The drone attacks targeted a Ropucha-class large landing vessel off the port of Novorossiysk and a Russian-flagged oil tanker that Ukraine said had been en route to deliver fuel to Russian forces in Crimea’s Kerch Strait. The incidents briefly halted activity at Novorossiysk.
By Monday the attack — and a warning from Kyiv that more could follow — had little impact on insurance costs for oil and commodity carriers in the key Black Sea region, as rates were already unusually high. Vessels waiting to load crude at Novorossiysk or the nearby CPC terminal were doing so much further south than they would normally, although none had turned away from the port.



Weekly data are affected by the scheduling of tankers and loading delays caused by bad weather. Port and pipeline maintenance can also disrupt exports for several days at a time. Four-week average shipments, which smooth out some of the volatility in the weekly numbers, edged up by 36,000 barrels a day. In contrast, weekly shipments dropped by 279,000 barrels a day to 3 million barrels a day.

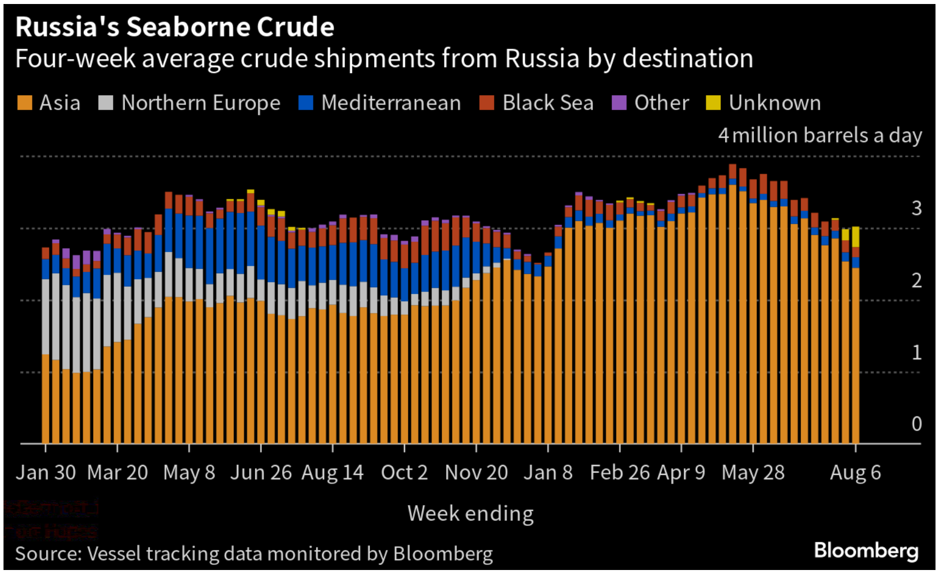


Moscow's initial pledge to cut production by 500,000 barrels a day in March had no immediate effect on exports. Flows from western ports actually rose, peaking in late May. The subsequent reduction came after fellow OPEC+ oil producer Saudi Arabia made and then extended its own unilateral output cut, putting pressure on Russia to implement its own reduction. Moscow eventually followed through on its pledge to cut shipments from western ports, with flows from the region now down by about 290,000 barrels a day from their average February level. That month was the baseline for Russia's output cut. Flows from the Baltic and Black Sea edged higher in the four weeks to Aug. 6 — the first increase in nine weeks.

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

Crude Flows by Destination

Russia's seaborne crude flows are now at a lower level than they've been for most of this year. It was only in the second half of June that shipments began to fall significantly. With few buyers left in Europe, the impact is being felt in shipments to Asia. On a four-week average basis, overall seaborne exports to Asian countries — plus the volumes on ships showing no final destination — are now about 870,000 barrels a day below their peak in mid-May. That's despite a small uptick of about 40,000 barrels a day in the most recent period.

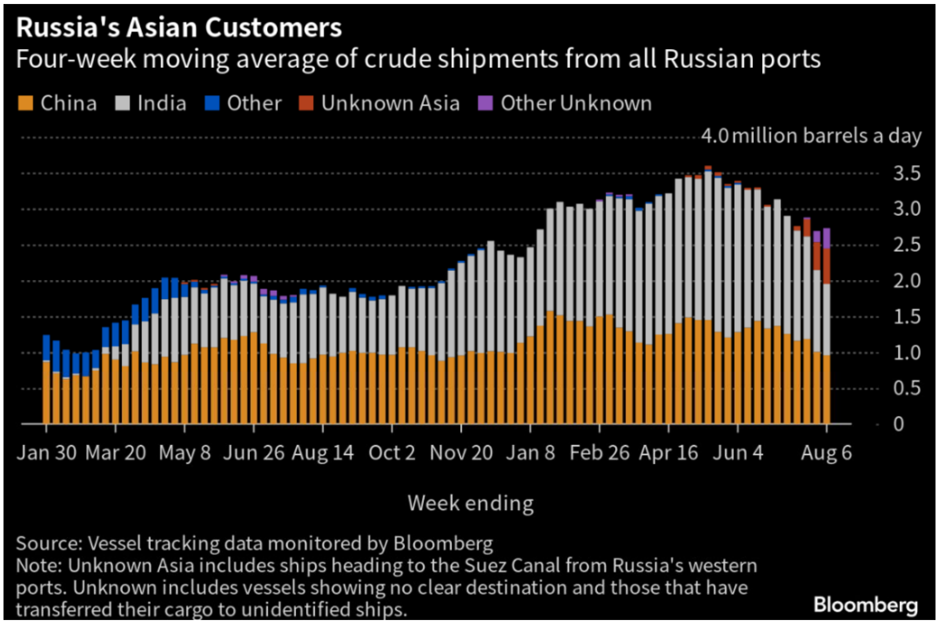


All figures exclude cargoes identified as Kazakhstan's KEBCO grade. Those are shipments made by KazTransoil JSC that transit Russia for export through the Baltic port of Ust-Luga and Novorossiysk on the Black Sea.
The Kazakh barrels are blended with crude of Russian origin to create a uniform export grade. Since Russia's invasion of Ukraine, Kazakhstan has rebranded its cargoes to distinguish them from those shipped by Russian companies. Transit crude is specifically exempted from European Union sanctions.

*** Asia**

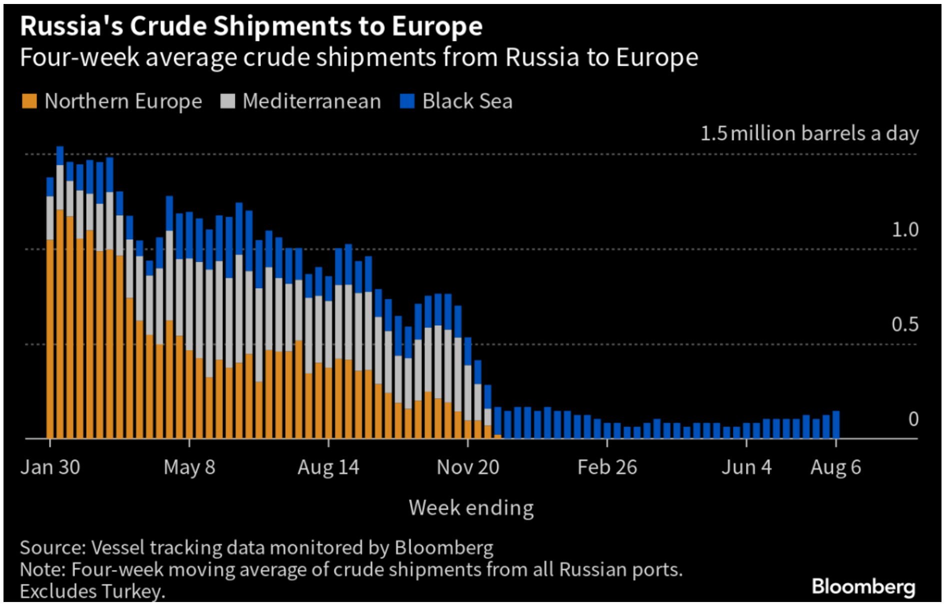
Observed shipments to Russia's Asian customers, including those showing no final destination, edged up to 2.73 million barrels a day in the four weeks to Aug. 6, from a revised 2.69 million barrels a day in the period to July 30, which was the lowest since January.
Most of the cargoes on ships without an initial destination eventually end up in India. Even so, the volumes heading to the country that has become the biggest buyer of Russia's seaborne crude are down from their recent highs. Adding the "Unknown Asia" and "Other Unknown" volumes to the total for India gives a figure of 1.77 million barrels a day in the four weeks to Aug. 6, from a high of 2.2 million barrels a day in the period to May 21.
The equivalent of 492,000 barrels a day was on vessels signaling Port Said or Suez in Egypt, or which already have been or are expected to be transferred from one ship to another off the South Korean port of Yeosu. Those voyages typically end at ports in India or China and show up in the chart below as

“Unknown Asia” until a final destination becomes apparent.
The “Other Unknown” volumes, running at 285,000 barrels a day in the four weeks to Aug. 6, are those on tankers showing no clear destination. Most of those cargoes originate from Russia’s western ports and go on to transit the Suez Canal, but some could end up in Turkey. Others could be transferred from one vessel to another, either in the Mediterranean or, more recently, in the Atlantic Ocean.

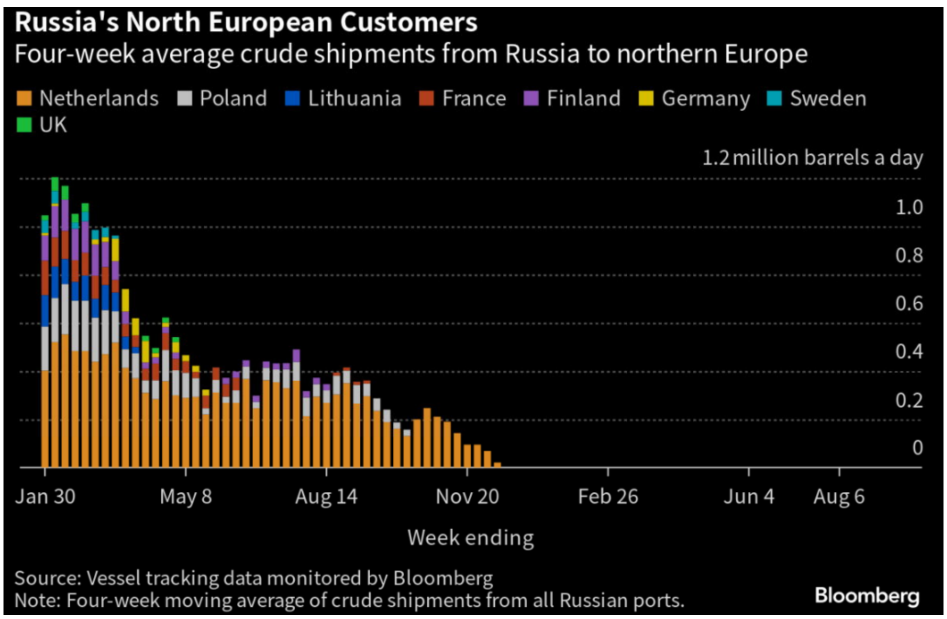


* Europe

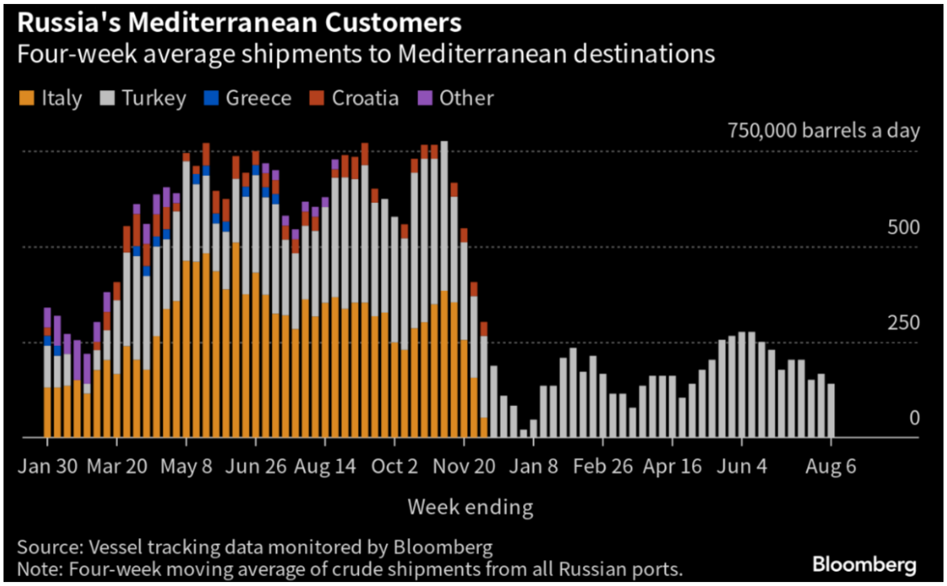
Russia’s seaborne crude exports to European countries edged up to 146,000 barrels a day in the 28 days to Aug. 6, with Bulgaria the sole destination. These figures do not include shipments to Turkey.
A market that consumed about 1.5 million barrels a day of short-haul seaborne crude, coming from export terminals in the Baltic, Black Sea and Arctic has been lost almost completely, to be replaced by long-haul destinations in Asia that are much more costly and time-consuming to serve.



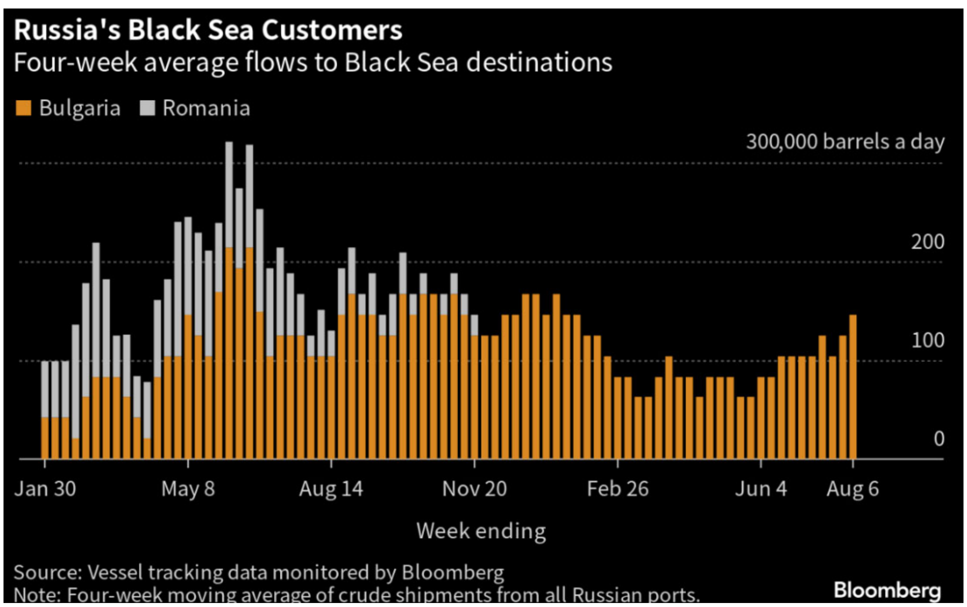
No Russian crude was shipped to northern European countries in the four weeks to Aug. 6



Exports to Turkey, Russia's only remaining Mediterranean customer, slipped to about 140,000 barrels a day in the four weeks to Aug. 6, their lowest since April. Flows to the country had topped 425,000 barrels a day in October.



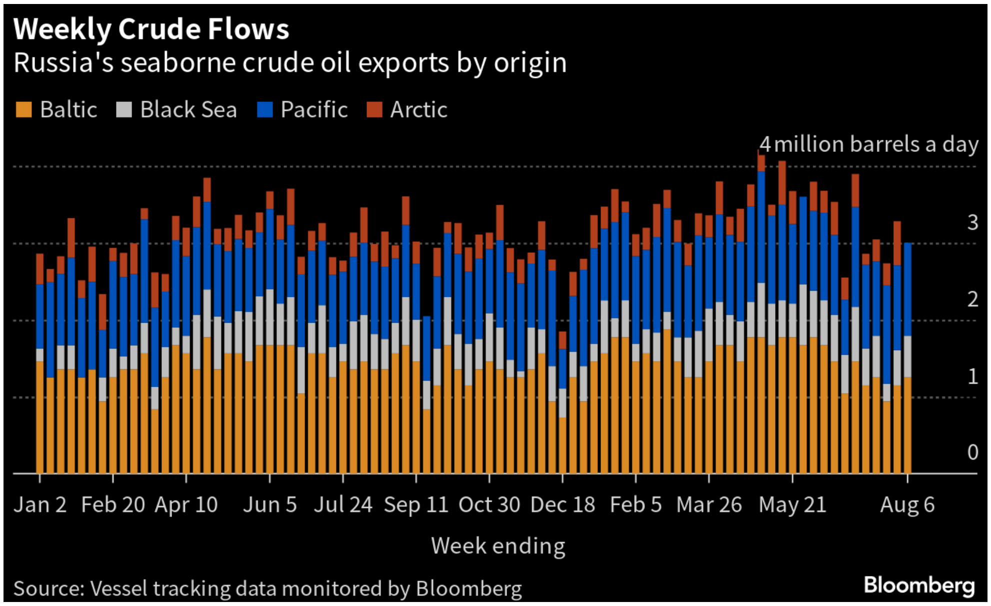
Flows to Bulgaria, now Russia's only Black Sea market for crude, rose to 146,000 barrels a day, equaling their highest since January. The increase comes even as the country's parliament voted to terminate Lukoil PJSC's 35-year lease of a terminal serving the Russian company's refinery near the coast.



Flows by Export Location

Aggregate flows of Russian crude slipped to 3 million barrels a day in the seven days to Aug. 6, from 3.28 million barrels a day the previous week. The drop came entirely from the Arctic, with a slump to zero partly offset by higher flows from the Baltic, Black Sea and Pacific.

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

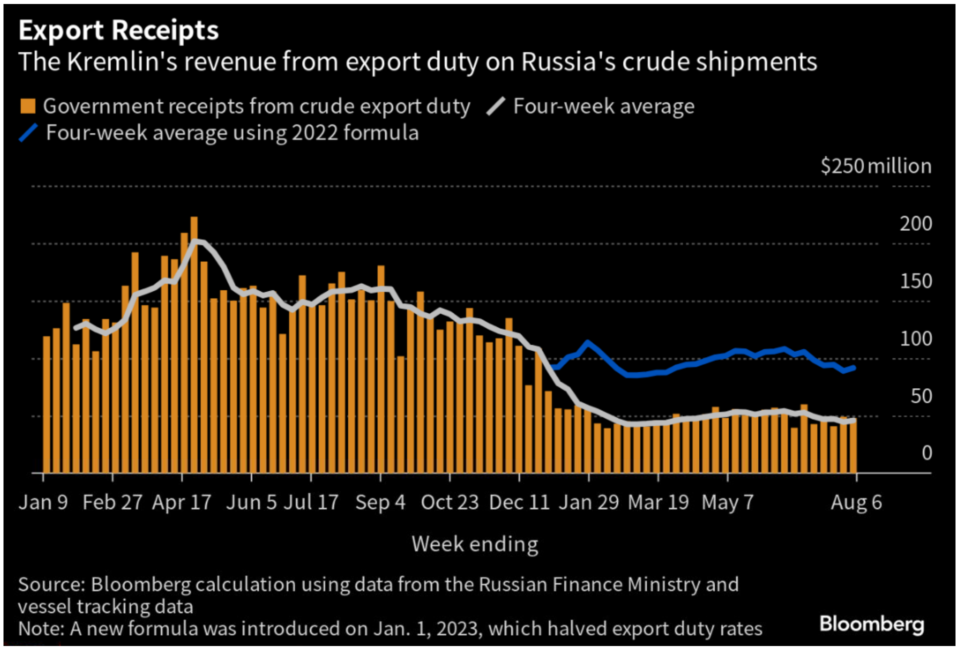


Vessel-tracking data are cross-checked against port agent reports as well as flows and ship movements reported by other information providers including Kpler SAS and Vortexa Ltd.

Export Revenue

Inflows to the Kremlin's war chest from its crude-export duty slipped to $48 million in the seven days to Aug. 6, a decrease of $1 million or 2%. Four-week average income moved in the opposite direction, rising to almost $46 million.

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



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

Origin-to-Location Flows

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

A total of 30 tankers loaded 21.01 million barrels of Russian crude in the week to Aug. 6, vessel-tracking data and port agent reports show. That’s down by 1.95 million barrels from the previous week’s figure.

Shipments from the Arctic port of Murmansk dropped to zero from a record-equaling 571,000 barrels a day the previous week. But two tankers were loading cargoes as the week ended, so there will be a bounce in the amount exported from the port in the coming week.

Shipments from all other regions rose on a weekly basis.

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

Tankers Loading Crude at Russian Terminals

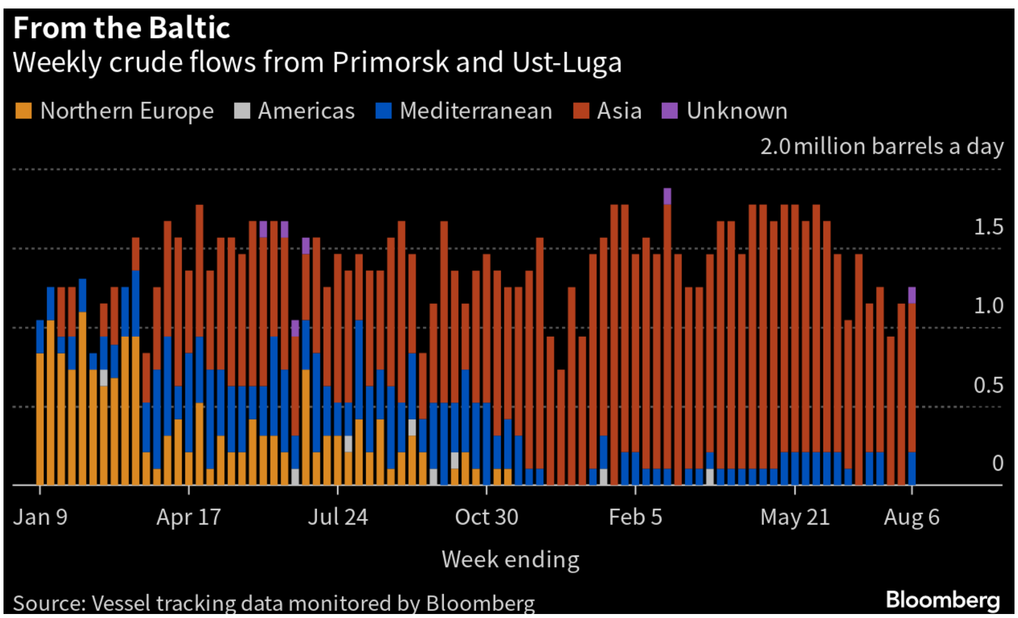
30 tankers loaded Russian crude in the week to August 6

Week ending	August 6	July 30	July 23
Primorsk (Baltic)	6	5	7
Ust-Luga (Baltic)	6	6	2
Novorossiysk (Black Sea)	5	4	2
Murmansk (Arctic)	0	4	2
Kozmino (Pacific)	9	8	10
De Kastri (Pacific)	2	2	2
Prigorodnoye (Pacific)	2	2	1
Total	**30**	**31**	**26**

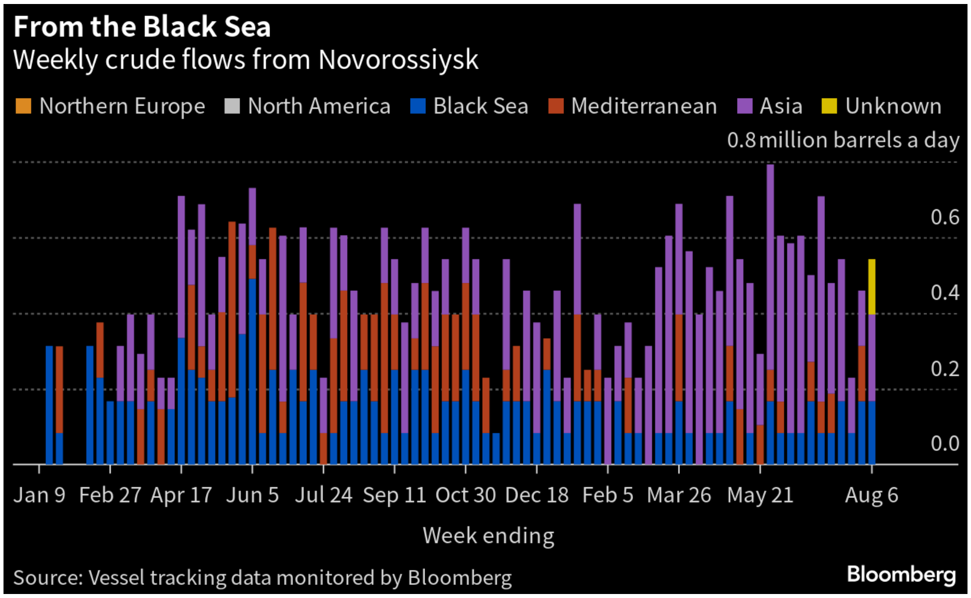
Source: Vessel tracking data monitored by Bloomberg
Note: Based on date of completion of cargo loading. Excludes ships loading cargoes identified as Kazakhstan's KEBCO grade.

Bloomberg

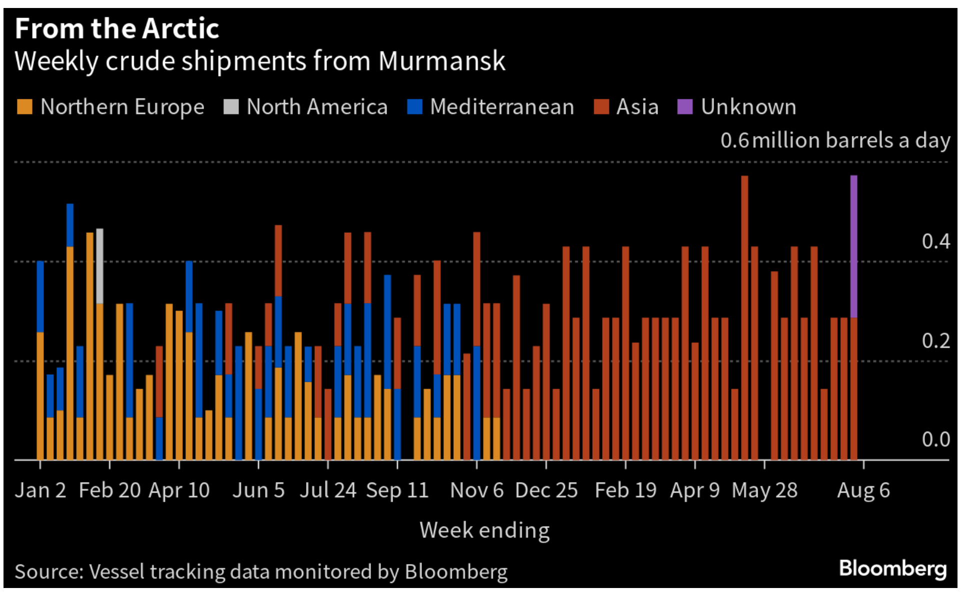
The total volume on ships loading Russian crude from the Baltic terminals continued to recover, rising to equal its highest level since the start of July. No cargoes of Kazakhstani crude were loaded at Ust-Luga during the week. Shipments from the Baltic are down by about 520,000 barrels a day from the highs seen between April and June.



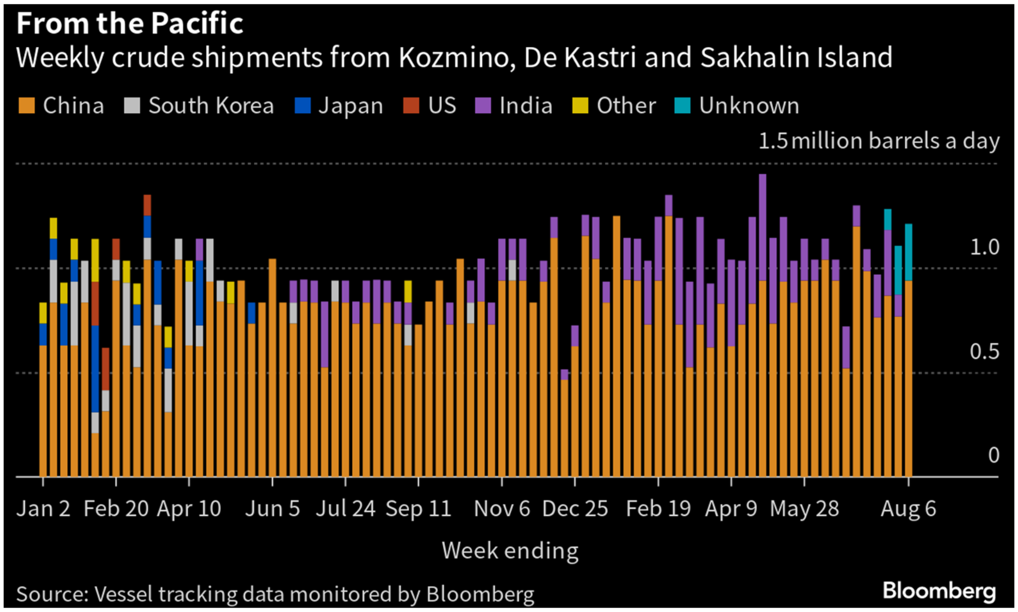
Shipments of Russian crude from Novorossiysk in the Black Sea also continued to recover before the Ukrainian drone strike on a Russian naval vessel near the port. As in the Baltic, flows rose to equal their highest level since the start of July.
One cargo of Kazakhstani crude was also loaded at the port during the week.



Arctic shipments slumped to zero in the week to Aug. 6, dropping from a record equaling high the previous week. The slump is most likely the result of cargo scheduling with one Suezmax and one Aframax tanker taking on cargoes as the week ended.



Thirteen tankers loaded at Russia's three Pacific export terminals, up from 12 the previous week. The volume of crude shipped from the region rose to 1.21 million barrels a day. The total includes one vessel, the Alita I, that loaded at Kozmino while sending false tracking signals indicating that it was at Niigata in Japan, a process known as spoofing. Shipments from the Sakhalin Island terminal remained low last week, due to maintenance at one of the Sakhalin 2 project's oil production platforms. The work is set to run until September. One vessel loaded two part cargoes of Sakhalin Blend crude from the terminal.



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

Some Sokol cargoes are now being transferred a second time in the waters off southern Malaysia. A small number of ESPO shipments are also being moved from one vessel to another in the same area. All bar one of these cargoes have, so far, gone on to India. That one cargo was transferred onto a floating storage vessel off Malaysia. It was then transferred onto another tanker, which is now showing a destination in China, though the vessel remains anchored off Johor, to the east of Singapore.

Shipments of flagship Sokol crude to India have picked up again after slumping to zero in June. Shipments in July averaged about 140,000 barrels a day.NOTES

Note: This story forms part of a weekly series tracking shipments of crude from Russian export terminals and the export duty revenues earned from them by the Russian government. It will not be published next week; the next update will be on Tuesday, Aug. 22.

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

Note: Weeks have been revised to run from Monday to Sunday, rather than Saturday to Friday. This change has been implemented throughout the data series and previous weeks' figures have been revised.

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

--With assistance from Sherry Su.

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Oil Market Highlights

Crude Oil Price Movements

The OPEC Reference Basket (ORB) rose by $5.87, or 7.8%, m-o-m to an average of $81.06/b in July. The ICE Brent front-month contract increased by $5.18, or 6.9%, m-o-m to $80.16/b, and NYMEX WTI front-month contract rose by $5.76, or 8.2%, m-o-m to average $76.03/b. The DME Oman front-month contract rose by $6.25, or 8.3%, m-o-m to settle at $81.16/b. The front-month ICE Brent/NYMEX WTI spread narrowed in July m-o-m by 58¢ to average $4.13/b. The futures forward curves of ICE Brent, NYMEX WTI and DME Oman steepened in backwardation during the month on improving oil market fundamental outlooks, and money managers including hedge funds raised bullish positions in ICE Brent and NYMEX WTI.

World Economy

World economic growth is revised up slightly for both 2023 and 2024 to stand at 2.7% and 2.6%, respectively. US GDP growth for 2023 is revised up to stand at 1.8%, followed by 0.7% growth in 2024. Euro-zone economic growth for 2023 is revised down to stand at 0.6%, while growth in 2024 remains at 0.8%. Japan's GDP growth in 2023 remains at 1.1%, followed by growth of 1% in 2024. China's GDP growth remains at 5.2% in 2023 and 4.8% in 2024. India's GDP growth remains at 5.6% for 2023 and 5.9% for 2024. Brazil's GDP growth is revised up to 1.7% and is expected to increase by 1.2% in 2024. For Russia, both the 2023 and 2024 GDP growth forecasts are revised up to stand at 0.6% and 1.0%, respectively.

World Oil Demand

World oil demand in 2023 is expected to grow by 2.4 mb/d, unchanged from the last month's assessment. Upward revisions to the 1Q23 based on actual data received for OECD America and OECD Europe were completely offset by downward revisions to 2Q23, mainly in Europe and Other Asia. In the OECD region, oil demand in 2023 is anticipated to rise by 74 tb/d, to an average of 46.0 mb/d, while in the non-OECD region, total oil demand is anticipated to rise by nearly 2.4 mb/d, to average 56.0 mb/d. For 2024, world oil demand is forecast to grow by a healthy 2.2 mb/d, unchanged from the previous assessment. The OECD is anticipated to expand by about 0.3 mb/d, with OECD Americas contributing the largest increase. The non-OECD is set to drive growth, increasing by around 2.0 mb/d, with China, the Middle East and Other Asia contributing the largest share, with further support from India, Latin America, and Africa.

World Oil Supply

Non-OPEC liquids supply is expected to expand by 1.5 mb/d in 2023, a slight upward revision from the previous assessment. The main drivers of liquids supply growth for 2023 are expected to be the US, Brazil, Norway, Kazakhstan Guyana and China, while the largest decline is expected from Russia. There remain uncertainties associated with US shale oil output potential and unplanned maintenance in 2023. For 2024, non-OPEC liquids production is projected to grow by 1.4 mb/d, unchanged from the previous assessment. For 2024, the main drivers for liquids supply growth are expected to be the US, Canada, Guyana, Brazil, Norway and Kazakhstan, mainly due to existing project ramp-ups. The largest declines are expected from Mexico and Azerbaijan. OPEC NGLs and non-conventional liquids are forecast to grow by 46 tb/d in 2023 to an average of 5.4 mb/d and by another 65 tb/d to an average of 5.5 mb/d in 2024. In July, OPEC-13 crude oil production decreased by 836 tb/d m-o-m to an average of 27.31 mb/d, according to available secondary sources.

Product Markets and Refining Operations

Refinery margins in July continued to rise, with solid gains across all regions. In the US Gulf Coast, margins increased for the second consecutive month, mainly driven by the robust performance of transport fuels, particularly gasoline. In Rotterdam, product markets were boosted by firm product exports to the US and high middle distillate requirements in the region. In Singapore, margin gains were driven by sizeable stock draws and healthy regional product demand, with notable strength registered at the middle and bottom sections of the barrel. Global refinery intake in July continued to trend upwards, moving 793 tb/d higher m-o-m to average 81.9 mb/d, according to preliminary estimates. In the coming months, refinery intakes are expected to be supported by seasonal fuel consumption levels during the summer season.

Tanker Market

The tanker market drifted lower in July, with Aframax and Suezmax spot freight rates approaching the lowest levels seen so far this year amid slowing of activities in the Atlantic basin for these vessels. Aframax spot freight rates on the Mediterranean-to-Northwest Europe route declined 22%, while Suezmax rates on the US Gulf Coast-to-Europe route fell 11%. VLCC rates experienced less of a decline as a pick-up in long-haul demand out of the Atlantic basin offset reduced activities out of the Middle East. Spot freight rates on the Middle East-to-East route declined 15% m-o-m. However, freight rates overall remain at elevated levels amid trade shifts supporting tonne-mile growth. Clean rates were mixed, with activities in the Atlantic basin supporting the West of Suez routes, while the return of Asian refineries from maintenance weighed on East of Suez flows. Clean freight rates on the intra-Med route rose 23% m-o-m, while rates on the Middle East-to-East route declined 15%.

Crude and Refined Products Trade

Preliminary data show US crude imports remained at strong levels in July, averaging 6.5 mb/d, while US crude exports fell below 4 mb/d amid reduced flows to Asia. China crude imports jumped to the second-highest on record in June, averaging 12.7 mb/d, although preliminary customs data shows crude inflows dropped to 10.3 mb/d in July, as the previous month's arrivals dampened crude needs for the month. China's product imports were broadly steady near the previous month's high levels, averaging 2.4 mb/d, while product exports declined, led by sharp falls in gasoline and diesel outflows. India's crude imports declined for the fourth month in a row in June to average 4.7 mb/d, as the country moved towards the lower-demand monsoon season. Japan's crude imports declined for the second-consecutive month to reach a 12-month low of 2.3 mb/d in June. Preliminary estimates indicate OECD Europe crude imports picked up at the start of 3Q23. Product imports into the region were seen down slightly as a decline in gasoline inflows outpaced an increase in diesel imports.

Commercial Stock Movements

Preliminary data for June 2023 sees total OECD commercial oil stocks up m-o-m by 4.2 mb. At 2,828 mb, they were 74 mb lower than the latest five-year average and 119 mb below the 2015–2019 average. Within the components, crude stocks fell by 5.1 mb, m-o-m, while product stocks rose by 9.3 mb. OECD commercial crude stocks stood at 1,395 mb in June. This is 18 mb below the latest five-year average and 70 mb lower than the 2015–2019 average. Total product inventories rose by 9.3 mb in June to stand at 1,433 mb. This is 55 mb lower than the latest five-year average and 49 mb below the 2015–2019 average. In terms of days of forward cover, OECD commercial stocks fell m-o-m by 0.1 days to stand at 60.4 days in June. This is 2.7 days lower than the latest five-year average and 1.4 days below the 2015–2019 average.

Balance of Supply and Demand

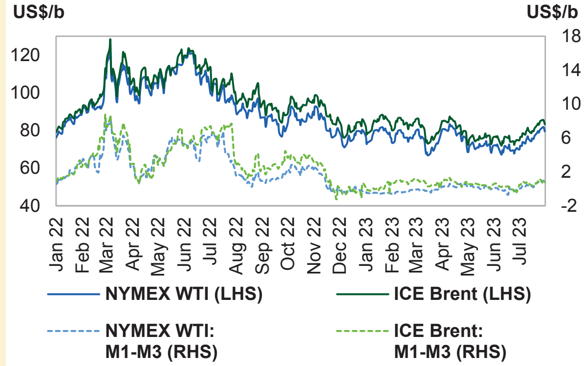
Demand for OPEC crude in 2023 is revised down by 0.1 mb/d from the previous month's assessment to stand at 29.3 mb/d. This is around 0.9 mb/d higher than in 2022. Demand for OPEC crude in 2024 is also revised down by 0.1 mb/d from the previous month's assessment to stand at 30.1 mb/d. This is around 0.8 mb/d higher than in 2023.

Feature Article

Crude and product price movements

In 1H23, negative sentiment dominated the oil futures markets, amid macroeconomic uncertainties and concerns about considerable interest rate hikes from major central banks, including the US Federal Reserve (Fed) and the European Central Bank (ECB), as they attempt to reduce high inflation levels. Moreover, investors remained cautious due to the temporary turmoil in the banking system earlier in the year and data showing slower manufacturing activity in major economies, in particular the US, Europe and China.

Graph 1: Crude futures prices and first-to-third spreads



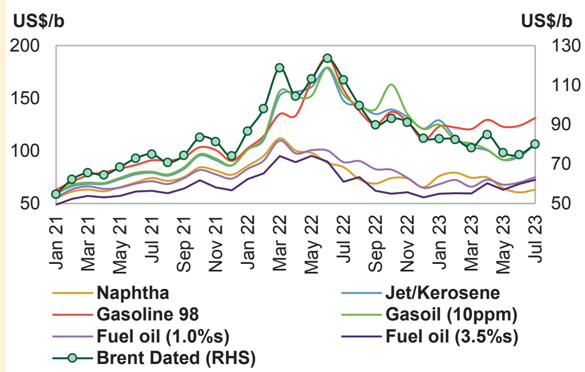
Sources: CME and ICE.

On a monthly basis, between January and June, ICE Brent and NYMEX WTI declined by $8.93 and $7.89, or 10.6% and 10.1%, respectively, to an average of $74.98/b and $70.27/b (***Graph 1***). However, market liquidity continued to recover from low levels seen in 2H22, as the actions of OPEC and countries participating in the 'Declaration of Cooperation' continue to contribute to market stability, reduce volatility and provide long-term guidance to the market.

In July, the outlook for oil market fundamentals improved further, which was reflected in the strengthening of the market structure as all major oil futures prices turned to a firm backwardation structure. For the month, ICE Brent increased by $5.18, or 6.9%, m-o-m, to stand at $80.16/b, and the NYMEX WTI front-month contract increased by $5.76, or 8.2% m-o-m, to an average of $76.03/b

On the product side, fuel prices, in general, have eased from the record-high levels witnessed in the previous year across all regions, on greater product availability.

Graph 2: Wholesale refined product prices in Rotterdam



Sources: Argus Media and OPEC.

In the USGC, gasoline prices are once again supported by peak summer demand to average $129.29/b in July, however, this is considerably lower than the same time last year. Jet/kerosene prices have also retracted to follow a more usual seasonal pattern, while gasoil prices are gradually recovering from a multi-year low of $57.56/b in May, to average $71.68/b in July.

In Rotterdam, despite firm gasoline exports, gasoil stock draws led to a significant contraction of the gasoline-middle distillate price differential of $24.85/b in July, compared to $31.21/b seen in May (***Graph 2***).

In Singapore, middle distillates prices trended lower on improved availability amid rising refinery runs in the Atlantic Basin. Naphtha's prices' overall performance remains weak, as firm supplies from the Middle East and Russia caused the discount to Dubai to widen from $8.23/b in January to $17.90/b in July. In July, transportation fuel prices rebounded on the back of trans-Atlantic product exports and residual fuel prices responded positively to demand from the Middle East for power generation. These transatlantic product exports could further benefit from a slower-than-expected economic recovery in China, the impact of the Monsoon season on oil demand in the region, and soft demand from the petrochemical sector.

Despite the current elevated level of global refinery runs, gasoline and middle distillate stocks remain well below the latest five-year averages in the US and Europe. Looking forward, refinery maintenance and potential production outages during the US hurricane season could potentially tighten the Atlantic Basin market, hence prompting stronger economic incentives for East-to-West product flows. Similarly, prospects for healthy oil fundamentals in the second half of the year, along with the preemptive, proactive and precautious approach of OPEC and non-OPEC producing countries to assess market conditions and take necessary measures at any time and as needed, will ensure stability of the global oil market.

World Oil Demand

For 2023, world oil demand is foreseen to rise by 2.4 mb/d to an average of 102.0 mb/d, unchanged from last month's estimate. Upward revisions to the 1Q23 based on actual data received for OECD America and OECD Europe were completely offset by downward revisions to 2Q23, mainly in Europe and Other Asia.

In the OECD region, oil demand in 2023 is anticipated to rise by 74 tb/d to an average of 46.0 mb/d. OECD Americas' demand is anticipated to have the largest regional rise in 2023, led by the US, on the back of recovering jet fuel demand and improvements in gasoline requirements. Light distillates are also projected to support demand growth this year.

In the non-OECD region, total oil demand is anticipated to rise by nearly 2.4 mb/d, to average 56.0 mb/d in 2023. A steady increase in transportation and industrial fuel demand, supported by a recovery in activity in China and other non-OECD regions, is projected to boost demand in 2023.

In 2024, solid global economic growth amid continued improvements in China is expected to boost the consumption of oil. World oil demand is anticipated to rise by 2.2 mb/d y-o-y, with total world oil demand projected to average 104.3 mb/d.

In the OECD, oil demand is anticipated to rise by 0.26 mb/d, to average 46.3 mb/d. Oil demand in the US is forecast to exceed the pre-pandemic level at 20.6 mb/d, mainly due to the recovery in jet fuel requirements and improvements in gasoline and light distillates demand. OECD Europe and the OECD Asia Pacific are anticipated to remain below pre-pandemic levels at 13.5 mb/d and 7.5 mb/d, respectively, due to anticipated slower economic activity in the two regions and ongoing supply chain bottlenecks that are expected to weigh on industrial activity, particularly in OECD Europe.

In the non-OECD, oil demand is forecast to show an increase of almost 2.0 mb/d y-o-y in 2024, to an average of 58.0 mb/d. China and India are anticipated to see the largest growth by country. Other regions, particularly the Middle East and Other Asia, are also expected to see considerable gains, supported by a positive economic outlook. In terms of fuels, jet kerosene, gasoline and diesel are assumed to lead oil demand growth next year.

Table 4 - 1: World oil demand in 2023*, mb/d

							Change 2023/22	
World oil demand	**2022**	**1Q23**	**2Q23**	**3Q23**	**4Q23**	**2023**	**Growth**	**%**
Americas	25.01	24.61	25.22	25.59	25.09	25.13	0.12	0.47
of which US	*20.43*	*20.12*	*20.60*	*20.83*	*20.37*	*20.48*	*0.05*	*0.24*
Europe	13.50	13.07	13.25	13.98	13.37	13.42	-0.08	-0.62
Asia Pacific	7.43	7.86	7.08	7.27	7.69	7.47	0.04	0.55
Total OECD	**45.95**	**45.53**	**45.54**	**46.84**	**46.16**	**46.02**	**0.07**	**0.16**
China	14.85	15.63	15.96	15.38	16.11	15.77	0.92	6.19
India	5.14	5.40	5.40	5.21	5.50	5.38	0.24	4.69
Other Asia	9.02	9.40	9.57	9.14	9.24	9.33	0.31	3.45
Latin America	6.44	6.60	6.55	6.73	6.68	6.64	0.20	3.18
Middle East	8.30	8.63	8.47	8.86	8.73	8.67	0.38	4.55
Africa	4.40	4.69	4.32	4.43	4.88	4.58	0.18	4.09
Russia	3.56	3.69	3.45	3.60	3.87	3.65	0.09	2.49
Other Eurasia	1.15	1.24	1.17	1.02	1.23	1.16	0.01	1.16
Other Europe	0.77	0.84	0.76	0.75	0.83	0.80	0.03	3.61
Total Non-OECD	**53.62**	**56.12**	**55.64**	**55.13**	**57.06**	**55.99**	**2.36**	**4.41**
Total World	**99.57**	**101.65**	**101.18**	**101.96**	**103.21**	**102.01**	**2.44**	**2.45**
Previous Estimate	99.56	101.61	101.22	101.95	103.21	102.00	2.44	2.45
Revision	0.00	0.05	-0.04	0.01	0.01	0.00	0.00	0.00

*Note: * 2023 = Forecast. Totals may not add up due to independent rounding.*

Source: OPEC.

Table 4 - 2: World oil demand in 2024*, mb/d

World oil demand	2023	1Q24	2Q24	3Q24	4Q24	2024	Change 2024/23 Growth	%
Americas	25.13	24.79	25.39	25.79	25.25	25.31	0.18	0.72
of which US	*20.48*	*20.25*	*20.74*	*20.99*	*20.51*	*20.62*	*0.14*	*0.70*
Europe	13.42	13.12	13.31	14.05	13.41	13.48	0.06	0.41
Asia Pacific	7.47	7.89	7.09	7.30	7.70	7.49	0.02	0.29
Total OECD	**46.02**	**45.81**	**45.79**	**47.15**	**46.36**	**46.28**	**0.26**	**0.56**
China	15.77	16.20	16.42	16.00	16.78	16.35	0.58	3.68
India	5.38	5.63	5.64	5.44	5.69	5.60	0.22	4.09
Other Asia	9.33	9.66	9.82	9.50	9.60	9.64	0.31	3.32
Latin America	6.64	6.79	6.73	6.95	6.84	6.83	0.19	2.86
Middle East	8.67	8.91	8.91	9.41	8.98	9.05	0.38	4.38
Africa	4.58	4.80	4.51	4.60	5.01	4.73	0.15	3.27
Russia	3.65	3.75	3.56	3.75	3.94	3.75	0.10	2.75
Other Eurasia	1.16	1.27	1.20	1.08	1.28	1.21	0.04	3.81
Other Europe	0.80	0.86	0.77	0.77	0.84	0.81	0.01	1.73
Total Non-OECD	**55.99**	**57.88**	**57.56**	**57.50**	**58.96**	**57.97**	**1.99**	**3.55**
Total World	**102.01**	**103.68**	**103.35**	**104.64**	**105.32**	**104.25**	**2.25**	**2.20**
Previous Estimate	102.00	103.64	103.39	104.63	105.31	104.25	2.25	2.20
Revision	0.00	0.04	-0.05	0.01	0.01	0.00	0.00	0.00

*Note: * 2024 = Forecast. Totals may not add up due to independent rounding.*
Source: OPEC.

OECD

OECD Americas

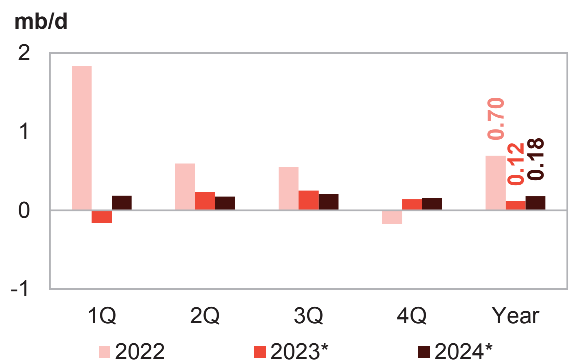
Update on the latest developments

Oil demand in **OECD Americas in May** soared y-o-y by 839 tb/d, y-o-y, up from y-o-y growth of 386 tb/d in April. The US and Canada accounted for the increase in demand, while Mexico recorded an annual decline. Details of the contribution of various products are discussed in the sub-section for the US.

Oil demand in the **US** saw y-o-y growth of 699 tb/d in May, which was supported by demand for petrochemical feedstock and jet kerosene.

General inflation has continued to retract significantly in the US, with the general price index having slowed for eleven consecutive months to stand at 4% in May, following 4.9% y-o-y in April. However, core inflation persists. The services PMI was at 50.3 in May, spending more than 13 months in the expansion zone.

Graph 4 - 1: OECD Americas oil demand, y-o-y change



*Note: * 2023 and 2024 = Forecast.*
Source: OPEC.

Data from Federal Highway Administration shows that travel miles on all roads increased by 2.5% (+7.1 billion vehicle miles) for May 2023 as compared with May 2022. It also represents a 0.8% change (2.1 billion vehicle miles) compared with April 2023. Furthermore, the International Air Transport Association's (IATA) Air Passenger Market Analysis reported that domestic air travel in North America recorded a passenger load factor of 86.3% y-o-y in May. At the same time, the US domestic market experienced a 7.1% annual rise in passenger traffic this month.

However, the manufacturing PMI stood at 46.9 in May, remaining below 50 for the eighth consecutive month.

Oil demand growth in the US in May was driven by LPG, which recorded y-o-y growth of 472 tb/d, up from 153 tb/d, y-o-y growth in the previous month. The strong demand for LPG was supported by a weak baseline and the lower prices relative to naphtha, which led to increased demand as feedstock in petrochemical plants.

Similarly, the ´other products´ category also saw y-o-y growth of 164 tb/d, y-o-y, in May, compared with 438 tb/d, y-o-y growth seen in the previous month. On the back of sustained air travel activity, jet/kerosene posted y-o-y growth of 113 tb/d from 86 tb/d, y-o-y, growth in the previous month. Diesel saw a y-o-y growth of 56 tb/d, slightly lower than the 92 tb/d y-o-y growth seen in April. Finally, naphtha grew by 16 tb/d, y-o-y, in May, following y-o-y growth of 6 tb/d, y-o-y in April. Gasoline demand was flat y-o-y, down from y-o-y growth of 242 tb/d in April. Nevertheless, gasoline demand in the US is holding up well, with increasing vehicle miles travelled in May y-o-y. M-o-m, gasoline demand was higher than in April.

Table 4 - 3: US oil demand, mb/d

			Change May 23/May 22	
By product	**May 22**	**May 23**	**Growth**	**%**
LPG	3.30	3.77	0.47	14.3
Naphtha	0.14	0.16	0.02	11.3
Gasoline	9.11	9.11	0.00	0.0
Jet/kerosene	1.58	1.69	0.11	7.2
Diesel	3.87	3.93	0.06	1.4
Fuel oil	0.34	0.22	-0.12	-35.0
Other products	2.03	2.20	0.16	8.1
Total	**20.37**	**21.07**	**0.70**	**3.4**

Note: Totals may not add up due to independent rounding. Sources: EIA and OPEC.

Near-term expectations

In **3Q23**, GDP growth in the **US** is expected to remain healthy. Furthermore, inflation is expected to continue to decline. In terms of oil demand, the US is anticipated to see a boost in driving mobility and air travel during the summer holiday season, with transportation fuels – gasoline and jet kerosene – anticipated to drive growth. Accordingly, in this quarter, oil demand is anticipated to grow by 215 tb/d y-o-y. However, continued weakening manufacturing activity is likely to impact on demand for industrial fuels, particularly diesel

In **4Q23**, continued weak manufacturing activity is expected to impact the demand for industrial fuels. Consequently, the US is projected to grow y-o-y by 51 tb/d in this quarter. Transportation fuels, particularly, jet kerosene, and, to a lesser extent, gasoline, are anticipated to continue to drive oil demand.

In **2024**, the GDP of the US is anticipated to remain positive, in continuation of the growth seen in 2023. In addition, in line with anticipated rising services business activity in 1Q24, US oil demand is anticipated to grow by 135 tb/d. Transportation fuels and petrochemical feedstock, particularly LPG, are anticipated to be the main drivers of products demand. Overall, in 2024, the US is expected to see y-o-y growth of around 140 tb/d. However, the risks are still skewed to the downside with a focus on the macroeconomic performance of the US economy.

OECD Europe

Update on the latest developments

Oil demand in OECD Europe declined by 90 tb/d y-o-y in May, showing an improvement from the 309 tb/d y-o-y drop seen in April. All the oil products were in contraction, except for transportation fuels.

The Eurozone has been witnessing prolonged lacklustre oil demand, driven by weak industrial sector performance combined with persistently high core inflation which stood at 6.8% y-o-y in June, higher than the long-term average. The apparent weakness in industrial activity is impacting gasoil demand, whereas the services sector and personal consumption are driving gasoline and jet uptake.

The May manufacturing PMI declined to 44.8 in May, after a level of 45.8 in April, remaining below the growth-indicating level for the eighth consecutive month. Nevertheless, the PMI for services, the largest sector in the Eurozone, stood at a level of 55.1 in May.

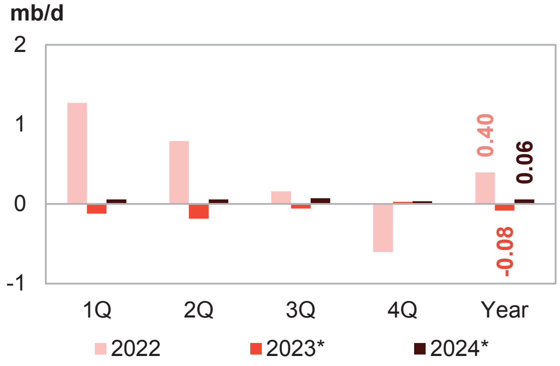
IATA reported that the region's domestic airline revenue passenger kilometres (RPKs) stood above pre-pandemic levels for the 11th consecutive month. European airlines stood out in May with a 22.4% increase in domestic traffic compared to 2019 levels, which was the highest growth recorded across all regions.

Naphtha demand in the region contracted further by 193 tb/d y-o-y, from a y-o-y decline of 52 tb/d seen in April. European ethylene and derivatives have been under pressure due to low margins. Also putting pressure on the region are US exports, as supply chain disruptions, sharply lower freight costs and the lack of extreme weather events allow the US to be competitive in Europe's higher-cost market.

Europe, where naphtha is the dominant feedstock for crackers, has been seeing high production costs. Diesel and the 'other products' category saw a y-o-y decline by around 100 tb/d and 120 tb/d, respectively.

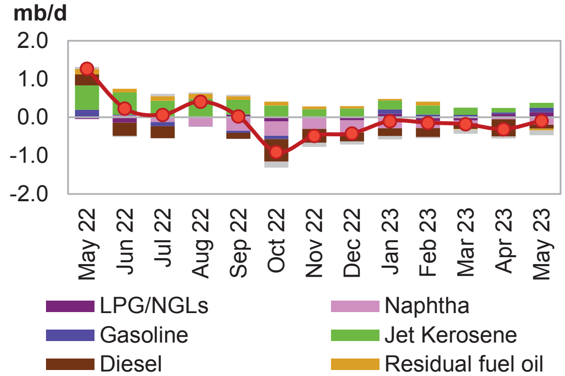
Nevertheless, diesel has shown a sign of improvement as compared to a plunge of 445 tb/d, y-o-y in the previous month. Residual fuels also contracted by around 50 tb/d, y-o-y.

Graph 4 - 2: OECD Europe's oil demand, y-o-y change



*Note: * 2023 and 2024 = Forecast.*
Source: OPEC.

Graph 4 - 3: OECD Europe's oil demand by main petroleum product category, y-o-y change



Sources: IEA, JODI, OPEC and national sources.

On the positive side, continued improvements in airline activity and driving mobility supported transportation fuels. Accordingly, jet/kerosene grew by 123 tb/d, y-o-y. Gasoline also saw y-o-y growth of around 120 tb/d, a significant improvement from the 42 tb/d, y-o-y growth in the previous month. Finally, on the back of weaker naphtha demand, LPG demand also saw a y-o-y increase of more than 136 tb/d, up from the 90 tb/d y-o-y in the previous month.

Near-term expectations

In **3Q23** and **4Q23**, GDP growth in the region is projected to remain positive, albeit lower than what was seen in the previous quarters. Additionally, weakening manufacturing activity is also anticipated to continue due to slow economic activity and supply chain bottlenecks. These factors are anticipated to weigh on oil demand in the region to record a y-o-y decline of 58 tb/d in 3Q23 and slight growth of 26 tb/d in 4Q23. Moreover, in 4Q23, there is little indication of an industry recovery due to supply chain bottlenecks related to constraints with growth in the second half of the year to be entirely driven by the services sector. Thereby, oil demand is anticipated to be mainly supported by jet fuel and gasoline, while diesel and petrochemical feedstock will remain weak.

In **2024**, GDP growth in the region is anticipated to improve modestly, compared with the current year. Consistent with this expected uptick in GDP growth and relatively healthy performance of the services business activity, 1Q24 oil demand is forecast to grow by 57 tb/d, y-o-y. This is forecast to be mostly driven by jet fuel, and also supported by expected growth in demand for gasoline. Overall, the region is expected to see y-o-y growth of 55 tb/d, y-o-y in 2024. However, risks are skewed to the downside, hinging on the possibility of a further economic slowdown in the region.

OECD Asia Pacific

Update on the latest developments

Oil demand in OECD Asia Pacific increased by 49 tb/d y-o-y in May, down from 193 tb/d y-o-y growth seen in April. The bulk of oil demand growth in the region was seen in Japan and Australia. Oil demand growth in South Korea remained negative for a second consecutive month on the back of macroeconomic headwinds and continued low manufacturing activity.

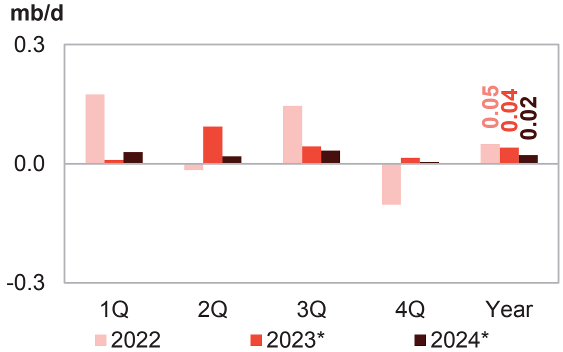
In Japan, the services sector PMI, which constitutes around two-thirds of the Japanese economy, rose to 55.9 in May, slightly up from 55.4 in April. The manufacturing PMI also improved in May to stand at 50.6 points, following 49.5 in April.

The Australian services PMI dipped to 51.8 in May, after 52.6 points in April, yet remained in expansionary territory. The manufacturing PMI, however, remains in the contraction zone at 48 points in May. According to the latest data from the Australian Bureau of Statistics (ABS), the monthly Consumer Price Index (CPI) indicator rose by 5.6% y-o-y in May 2023, down from 6.8% in April 2023.

The South Korean manufacturing PMI in April stood at 48 points for a third consecutive month. The consumer price index in South Korea increased 3.3% in May 2023 from a year ago, compared to a 3.7% rise in April and easing for a fourth consecutive month.

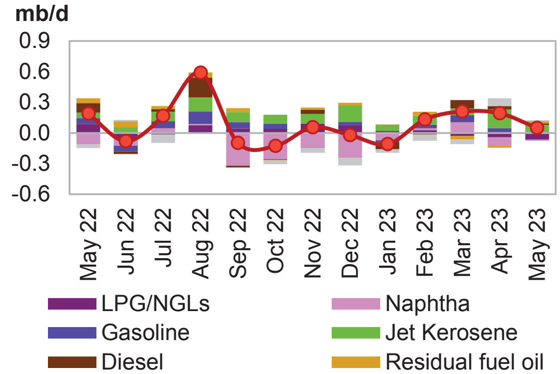
Airline activity in the OECD Asia Pacific region remains healthy, according to a report from IATA, as passenger load factors stood at 77.3% in May. Similarly, domestic RPKs of carriers in Asia Pacific maintained a positive momentum and surpassed their pre-pandemic levels by 4.7%.

Graph 4 - 4: OECD Asia Pacific oil demand, y-o-y change



*Note: * 2023 and 2024 = Forecast.*
Source: OPEC.

Graph 4 - 5: OECD Asia Pacific oil demand, y-o-y change



Sources: IEA, JODI, METI and OPEC.

On the back of healthy air travel activity, jet kerosene led oil demand by 77 tb/d, y-o-y. Diesel and residual fuels saw y-o-y growth of 15 tb/d and 23 tb/d, respectively. The ´other product´ category posted y-o-y growth of 10 tb/d, down from a y-o-y growth of 74 tb/d in April.

However, demand for LPG as a petrochemical feedstock showed a y-o-y decline by 67 tb/d, y-o-y in May. Demand for naphtha was broadly flat, as average run rates at the major naphtha cracking centres had been declining due to the slowdown in the manufacturing and construction sectors in the region. Gasoline demand was also broadly unchanged y-o-y, following a growth of 45 tb/d y-o-y a month earlier.

Near-term expectations

GDP in OECD Asia Pacific is projected to remain positive in 2023, with variations among the countries of the region. The services PMIs in Japan and Australia are in the expansion zone, reaching 56 and 52.6 points, respectively, in June. Furthermore, petrochemical feedstock requirements in the region are likely to get a boost from renewed activity in the Chinese economy.

Relatively healthy economic activity in the region, combined with improvements in air traffic, driving and petrochemical industry operations are anticipated to support oil demand to grow by 44 tb/d y-o-y in **3Q23**. However, by **4Q23**, the oil demand growth momentum is expected to lessen, whereby the region is anticipated to see a y-o-y growth of 15 tb/d in the last quarter of the year.

In **2024**, the growth rate of the region's GDP is anticipated to increase on the back of healthy services business activity. Continued growth in air travel and petrochemical sector requirements in the region is projected to support oil demand to grow by 30 tb/d, y-o-y, in 1Q24. Overall, in 2024, the region is anticipated to see y-o-y growth of 22 tb/d.

Non-OECD

China

Update on the latest developments

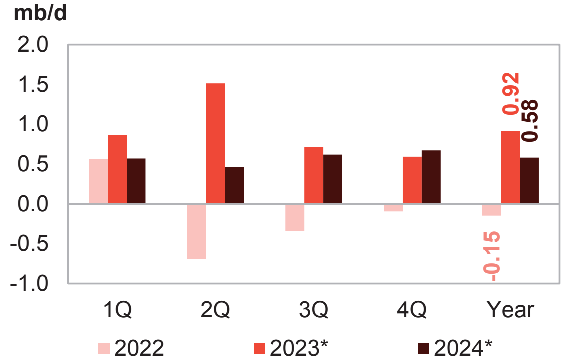
Oil demand in China in June posted y-o-y growth of more than 2.0 mb/d for the second consecutive month, following stellar growth of more than 3.0 mb/d in April. Transportation fuels were the main drivers of demand growth amid healthy economic activity, supported by robust petrochemical feedstock requirements. Growth in June oil demand was also supported by a weak baseline from a year earlier.

The annual inflation rate in China retracted considerably to stand at 0% in June, following 0.2% y-o-y in May. June PMI readings show that the services sector is performing very well, with the services sector index posting 53.9. The manufacturing PMI moved back into the expansionary territory to stand at 50.5.

Driving mobility in China continued increasing and air travel activity remained healthy. A report from China's Civil Aviation Industry in June indicates that the domestic passenger volume in China increased y-o-y by 131% and international passenger volume grew by a staggering 2,067% y-o-y, considering that international air travel was locked down a year ago.

Oil demand in terms of products in June shows that transportation fuels – diesel, gasoline and jet kerosene – were the main drivers of demand growth. Diesel posted y-o-y growth of 473 tb/d, up from the annual growth of 275 tb/d seen in the previous month. Similarly, gasoline saw y-o-y growth of 385 tb/d, increasing for a sixth consecutive month. On the back of steady air travel recovery, jet kerosene grew by about 327 tb/d, y-o-y, down from 540 tb/d seen in the previous month. Healthy petrochemical feedstock requirements supported LPG and naphtha to post y-o-y growth of 342 tb/d and 146 tb/d, respectively. Finally, residual fuels saw y-o-y growth of 278 tb/d, slightly less than in the previous month of May, while the "other products" category increased by 82 tb/d.

Graph 4 - 6: China's oil demand, y-o-y change



*Note: * 2023 and 2024 = Forecast.*
Source: OPEC.

Table 4 - 4: China's oil demand*, mb/d

By product	Jun 22	Jun 23	*Change Jun 23/Jun 22* Growth	%
LPG	2.51	2.85	0.34	13.6
Naphtha	1.50	1.65	0.15	9.7
Gasoline	3.35	3.74	0.38	11.5
Jet/kerosene	0.40	0.73	0.33	81.6
Diesel	3.63	4.10	0.47	13.0
Fuel oil	0.75	1.03	0.28	37.2
Other products	2.34	2.42	0.08	3.5
Total	**14.47**	**16.51**	**2.03**	**14.0**

*Note: * Apparent oil demand. Totals may not add up due to independent rounding.*
Sources: Argus Global Markets, China OGP (Xinhua News Agency), Facts Global Energy, JODI, National Bureau of Statistics China and OPEC.

Near-term expectations

China's GDP growth is anticipated to remain firm at 5.2% in 2023. With inflation at almost zero, it seems likely that the central government, together with the People's Bank of China (PBOC), may become engaged in near-term stimulus measures seeking to boost consumption in support of the economy's recovery. This is particularly likely when considering that youth unemployment stood above the 20% level for the second consecutive month in May, reaching 20.8%. Nevertheless, China is anticipated to see lower-than-expected oil demand growth in 2H23. Recent economic indicators for the Chinese economy have shown a slowing trend in industrial production. Accordingly, these factors are likely to reduce the momentum of oil demand from the earlier anticipated strong growth. Oil demand in **3Q23** is anticipated to grow by 710 tb/d, y-o-y and by 590 tb/d, y-o-y in **4Q23**, slightly moderated from the strong y-o-y growth seen in the first half of the year.

In **2024**, China's GDP growth is anticipated to decelerate slightly. Continued healthy services sector activity, including leisure, travel and tourism, as well as a recovery of manufacturing activity and petrochemical sector requirements are expected to support oil demand. Thereby, oil demand is forecast to see y-o-y growth of 570 tb/d in 1Q24. Jet fuel will again drive oil demand growth in this quarter, with millions of air passengers expected to support air travel activity for local and business travellers from and into China throughout the 40-day spring festival travel season. Light distillates are also expected to continue rising, with the continued expansion of petrochemical industries. Increased mobility and rising construction activity will boost demand for gasoline and diesel. For the year, China is anticipated to see y-o-y growth of 580 tb/d on average.

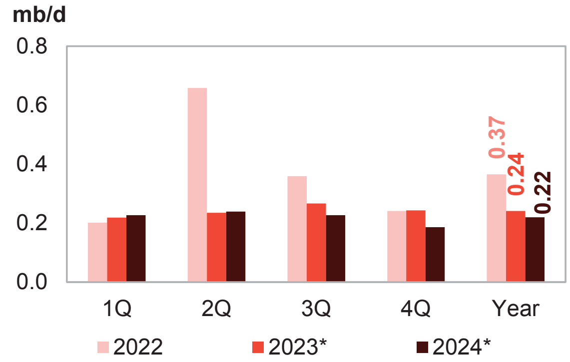
India

Update on the latest developments

Oil demand in India in June grew by 184 tb/d y-o-y, after an annual increase of 476 tb/d in May. The demand growth in June was affected by a comparison with a strong baseline a year earlier.

Both the manufacturing and services sectors in India have significantly been in expansion territory for over one year, thereby supporting oil demand. The manufacturing PMI reached a strong level of 57.8 in June. Similarly, the services PMI remained at a high level, standing at 58.5 in June, compared with 61.2 in May. India's consumer price index (CPI) inflation rose to 4.81% in June 2023, higher than expectations, but still below the RBI's upper tolerance limit of 6%.

Graph 4 - 7: India's oil demand, y-o-y change



*Note: * 2023 and 2024 = Forecast.*
Source: OPEC.

According to the Indian automotive content creator, autopunditz.com, India's car sales increased by over 2% in June when compared to the same period last year, and declined by 2% on a m-o-m comparison with May 2023.

Similarly, a report from business-standard.com shows that 76.93 million passengers were carried by Indian domestic airlines during January-June 2023, compared with 57.25 million during the corresponding period of 2022. Thereby, domestic airlines in India registered an annual growth of 32.92% and monthly growth of 18.78%.

Table 4 - 5: India's oil demand, mb/d

			Change Jun 23/Jun 22	
By product	**Jun 22**	**Jun 23**	**Growth**	**%**
LPG	0.89	0.89	0.00	0.3
Naphtha	0.31	0.31	0.01	2.6
Gasoline	0.86	0.91	0.05	6.1
Jet/kerosene	0.19	0.20	0.02	8.2
Diesel	1.93	1.99	0.06	3.0
Fuel oil	0.16	0.15	-0.01	-4.4
Other products	0.97	1.02	0.05	5.5
Total	**5.30**	**5.48**	**0.18**	**3.5**

Note: Totals may not add up due to independent rounding.

Sources: JODI, Petroleum Planning and Analysis Cell of India and OPEC.

In terms of oil products in June, diesel led oil demand growth by 60 tb/d, y-o-y, down from 220 tb/d y-o-y growth seen in May. Gasoline and the 'other fuels' category grew y-o-y by 52 tb/d and 54 tb/d, respectively in June. Growth in demand for petrochemical feedstock – LPG and naphtha – was insignificant in June and residual fuels declined slightly y-o-y.

Near-term expectations

Looking forward, with steady and healthy economic activity and ongoing air travel recovery, India's demand for oil products is anticipated to remain strong at an average of around 250 tb/d y-o-y in 2H23.

In **3Q23**, oil demand is projected to rise by around 270 tb/d, y-o-y. The government's proposed increase in capital spending in construction and manufacturing is expected to boost the momentum of economic activity. These factors, combined with a steady rise in airline activity, will support healthy oil demand growth. Transportation fuels – gasoline and jet fuel – are anticipated to be the main drivers of demand growth in this quarter. However, diesel demand is anticipated to be affected by the impact of the monsoon season from July to September.

In **4Q23**, oil demand is expected to decelerate slightly, but will show y-o-y growth of around 240 tb/d, with transportation fuels, notably gasoline, transportation diesel and jet/kerosene expected to drive oil demand growth.

In **2024**, India is projected to record better GPD growth than in 2023. Further, the positive momentum in oil demand, due to the ongoing healthy services business activity, including air travel recovery and mobility as well as manufacturing and agricultural activity, is expected to support oil demand in 1Q24 to grow by around 230 tb/d, y-o-y. In this quarter, diesel is anticipated to be the major driver of oil demand growth, supported by transportation fuels. For the year, India is anticipated to see y-o-y growth of oil demand by an average of 220 tb/d.

Latin America

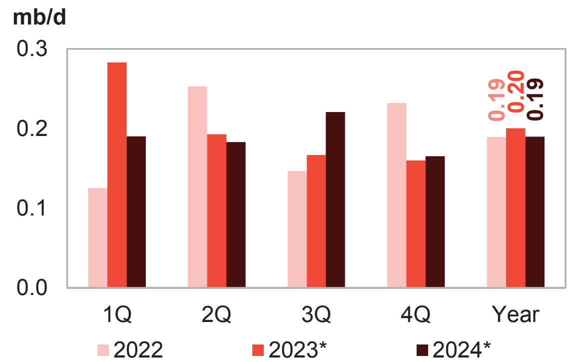
Update on the latest developments

Oil demand in Latin America increased y-o-y by 357 tb/d in May from 216 tb/d y-o-y growth seen in April. Brazil and Venezuela continue to be the main drivers of oil demand in the region.

The annual inflation rate in **Brazil** retracted further to reach 3.8% y-o-y in May from 4.2% in April, the lowest since October 2020, however remaining above the central bank's current inflation target of 3.25%. The services PMI in Brazil stood at 54.1 points in May. At the same time, the manufacturing PMI index in May remained below the growth-indicating level, to stand at 47.1 in May.

In terms of domestic RPKs, **Latin American** carriers continued to outperform their pre-pandemic levels by around 10% in May, while showing improvements in passenger load factor to average 81.1% y-o-y in the same month. Similarly, international RPKs saw y-o-y growth of 25.8% in May.

Graph 4 - 8: Latin America's oil demand, y-o-y change



Note: * 2023 and 2024 = Forecast.
Source: OPEC.

For the fifth consecutive month, gasoline remained the main driver of oil demand in the region, supported by a recovery in mobility, as gasoline grew by 196 tb/d, up from 106 tb/d y-o-y growth in the previous month. Residual fuels also saw 88 tb/d y-o-y growth in May, slightly lower than what was seen in the previous month. Similarly, diesel saw a y-o-y growth of 51 tb/d, from zero growth in April. Finally, jet/kerosene saw y-o-y growth of 34 tb/d, broadly the same as what was seen in the previous month. In terms of petrochemical feedstock, LPG saw a marginal y-o-y decline of 5 tb/d, albeit seeing improvement from an annual decline of 16 tb/d in the previous month. Finally, demand for naphtha remained broadly flat y-o-y in both May and April.

Near-term expectations

Since the beginning of 2023, the economy of **Brazil**, one of the largest contributors to oil demand in the region, has enjoyed better-than-expected growth. GDP growth in 1Q23 was strong at 4% y-o-y. The latest available 2Q23 data points to a continuation of this robust momentum. Positively, inflation has also slowed and both consumer and business confidence have risen. These factors are anticipated to support oil demand in the region. Oil demand in **Latin America** is projected to grow y-o-y by 170 tb/d in 3Q23 and by 160 tb/d in 4Q23.

In **2024**, the GDP of the region is projected to remain at the previous year's growth rate. Furthermore, services business activity is expected to continue improving. In particular, mobility and air travel are expected to support transportation fuels demand to continue with greater momentum and show overall y-o-y oil demand growth of 190 tb/d y-o-y in 1Q24. On average, the region is anticipated to grow by 190 tb/d, y-o-y. The outlook for oil demand growth sees transportation fuels grow the most, followed by diesel and petrochemical feedstock.

Middle East

Update on the latest developments

Oil demand in the Middle East grew y-o-y by 275 tb/d in May, up from 176 tb/d, y-o-y of growth in April. The demand growth was led by requirements from Iraq for the second consecutive month.

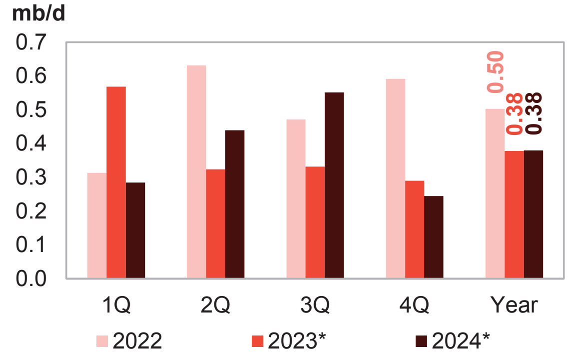
The economic activity in the two largest economies has been healthy and supportive of oil demand in the region. The **Saudi Arabian** economy is estimated to have expanded by 3.8% y-o-y in 1Q23, with indications of a 5.4% rise in non-oil activities. 1Q23 government expenditures remained strong and rose by 16.2% y-o-y. Similarly, the composite purchasing managers' indices (PMIs) for May stood at 58.5.

The **UAE's** economy remains robust, with constant contributions from the non-oil sector, especially from tourism, leisure and real estate. The country's PMI rose again in May to stand at 55.5.

In terms of air travel, IATA reported that Middle East carriers have made remarkable progress in recovering from the pandemic. Passenger load factors stood at 79.9% in May. Similarly, International RPKs continued to climb, with Middle Eastern carriers experiencing a surge in traffic to now stand at 17.2% above 2019 levels in May.

The contributions of oil products in May oil demand for the **Middle East** show that diesel was the main driver of oil demand by 107 tb/d, y-o-y, up from a decline of 13 tb/d, y-o-y seen in the previous month. Gasoline recorded growth of 87 tb/d, y-o-y, from annual growth of 38 tb/d in April. Residual fuels saw y-o-y growth of 80 tb/d, y-o-y for the second consecutive month. Jet/kerosene and LPG saw y-o-y growth of 10 tb/d each. However, naphtha and the ´other fuels´ category softened by around 10 tb/d, y-o-y each.

Graph 4 - 9: Middle East's oil demand, y-o-y change



*Note: * 2023 and 2024 = Forecast.*
Source: OPEC.

Table 4 - 6: Saudi Arabia's oil demand, mb/d

By product	Jun 22	Jun 23	*Change Jun 23/Jun 22* Growth	%
LPG	0.04	0.05	0.01	26.1
Gasoline	0.53	0.51	-0.02	-3.9
Jet/kerosene	0.08	0.11	0.03	32.7
Diesel	0.59	0.60	0.01	1.6
Fuel oil	0.79	0.75	-0.04	-5.5
Other products	0.76	0.61	-0.15	-19.4
Total	**2.79**	**2.63**	**-0.17**	**-5.9**

Note: Totals may not add up due to independent rounding.

Sources: JODI and OPEC.

Near-term expectations

Ongoing steady economic activity combined with strong composite PMIs are supporting the major consuming countries in the **Middle East**. Together with strong growth in airline activity, the dynamic is expected to support oil demand in the region to grow by more than 300 tb/d, y-o-y on average in both **3Q23** and **4Q23**. Moreover, demand growth in the region is expected to be supported by direct crude burning and fuel oil for electricity generation, particularly in Iraq and Saudi Arabia, in the hot summer months as air conditioning demand hits peak summer levels. Transportation fuels are expected to provide additional support.

In **2024**, the GDP of the region is projected to remain strong, albeit slightly below the growth 2023 rates for all the major consuming countries of the region. In 1Q24, the region is anticipated to see y-o-y growth of 285 tb/d. Transportation fuels – gasoline, transportation diesel and jet kerosene – are expected to be the main drivers of oil demand. Overall, in 2024, the Middle East is anticipated to see y-o-y growth of nearly 380 tb/d, y-o-y. The bulk of demand growth is expected to come from Iraq and Saudi Arabia.

World Oil Supply

Non-OPEC liquids production in 2023 is expected to grow y-o-y by 1.5 mb/d to an average of 67.3 mb/d. Downward revisions to Canada, Azerbaijan and OECD Europe were more than offset by upward revisions to liquids production in Russia and the US.

The main growth drivers for 2023 are anticipated to be the US, Brazil, Norway, Kazakhstan Guyana and China, whereas oil production is forecast to decline primarily in Russia. Nevertheless, there remain uncertainties related to US shale oil output potential and unplanned maintenance across the rest of the year.

Non-OPEC liquids production in 2024 is forecast to grow by 1.4 mb/d to an average of 68.7 mb/d (including 50 tb/d in processing gains), unchanged from the previous month. OECD liquids supply is forecast to increase next year by 0.9 mb/d, and the non-OECD region is projected to grow by 0.4 mb/d. The main drivers for liquids supply growth are expected to be the US, Canada, Guyana, Brazil, Norway and Kazakhstan, with the majority of the increase expected to come from existing project ramp-ups. At the same time, production is forecast to see the largest declines in Mexico and Azerbaijan.

OPEC NGLs and non-conventional liquids production in 2023 is forecast to grow by around 50 tb/d to an average of 5.4 mb/d. For 2024, it is forecast to grow by 65 tb/d to an average of 5.5 mb/d. OPEC-13 crude oil production in July decreased by 836 tb/d m-o-m to average 27.31 mb/d, according to available secondary sources.

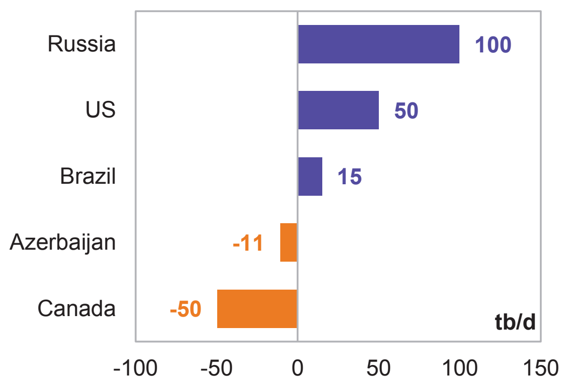
Non-OPEC liquids production in July, including OPEC NGLs, is estimated to have risen m-o-m by 0.7 mb/d to an average of 73.4 mb/d. This is up by 2.2 mb/d y-o-y. As a result, preliminary data indicates that July's global oil supply decreased by 0.2 mb/d m-o-m to average 100.7 mb/d, up by 0.6 mb/d y-o-y.

Non-OPEC liquids production in 2023 is forecast to expand by 1.5 mb/d. This is up by 0.1 mb/d from the previous month's growth assessment, mainly due to some upward revisions in Russia. It is worth noting that this expected contraction takes into account the recently announced voluntary production adjustment to the end of 2023.

Overall **OECD supply growth** expectations for 2023 were revised down slightly. While OECD Europe saw a downward revision mainly due to the UK, OECD Americas and OECD Asia Pacific remained unchanged.

Non-OECD supply growth projections for 2023 have been revised up by 0.1 mb/d. It is now expected to remain largely unchanged y-o-y.

Graph 5 - 1: Major revisions to annual supply change forecast in 2023*, MOMR Aug 23/Jul 23

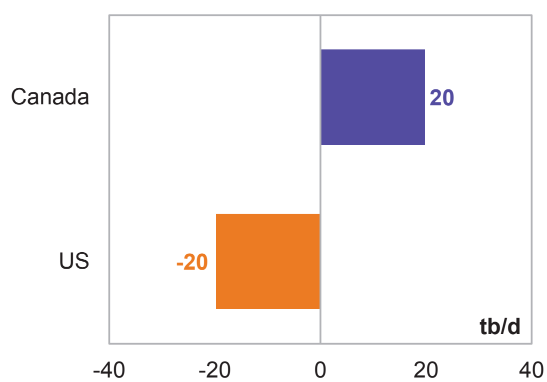


*Note: * 2023 = Forecast. Source: OPEC.*

Non-OPEC liquids production growth in **2024** remained broadly unchanged compared to the previous month's assessment.

The upward revision to the supply forecast for Canada was entirely offset by the downward revision to the US supply.

Graph 5 - 2: Major revisions to annual supply change forecast in 2024*, MOMR Aug 23/Jul 23

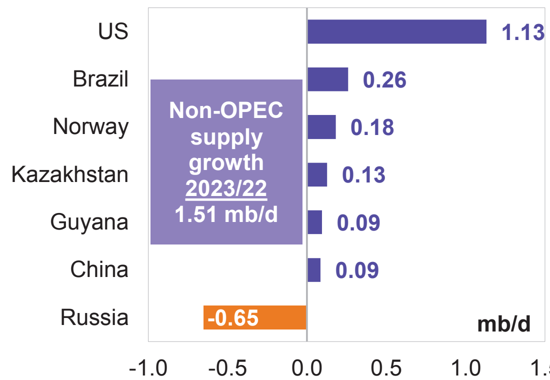


*Note: * 2024 = Forecast. Source: OPEC.*

Key drivers of growth and decline

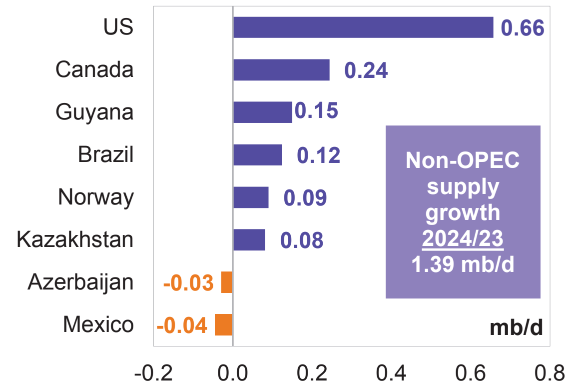
The **key drivers of non-OPEC liquids supply growth in 2023** are projected to be the US, Brazil, Norway, Kazakhstan, Guyana and China, while oil production is projected to see the largest decline in Russia.

Graph 5 - 3: Annual liquids production changes y-o-y for selected countries in 2023*



Note: * 2023 = Forecast. Source: OPEC.

Graph 5 - 4: Annual liquids production changes y-o-y for selected countries in 2024*



Note: * 2024 = Forecast. Source: OPEC.

For **2024**, the key drivers of non-OPEC supply growth are forecast to be the US, Canada, Guyana, Brazil, Norway and Kazakhstan, while oil production is projected to see the largest declines in Mexico and Azerbaijan.

Non-OPEC liquids production in 2023 and 2024

Table 5 - 1: Non-OPEC liquids production in 2023*, mb/d

							Change 2023/22	
Non-OPEC liquids production	**2022**	**1Q23**	**2Q23**	**3Q23**	**4Q23**	**2023**	**Growth**	**%**
Americas	26.87	27.90	27.97	28.25	28.45	28.14	1.28	4.76
of which US	*19.23*	*20.10*	*20.56*	*20.34*	*20.45*	*20.36*	*1.13*	*5.88*
Europe	3.57	3.66	3.62	3.80	3.94	3.75	0.18	4.97
Asia Pacific	0.48	0.45	0.45	0.48	0.47	0.46	-0.01	-2.83
Total OECD	**30.92**	**32.01**	**32.04**	**32.53**	**32.86**	**32.36**	**1.44**	**4.67**
China	4.48	4.63	4.63	4.50	4.50	4.56	0.09	1.91
India	0.77	0.76	0.78	0.79	0.78	0.78	0.00	0.58
Other Asia	2.30	2.31	2.27	2.34	2.36	2.32	0.02	0.82
Latin America	6.34	6.69	6.76	6.70	6.79	6.74	0.40	6.30
Middle East	3.29	3.27	3.29	3.29	3.30	3.29	0.00	0.08
Africa	1.29	1.24	1.28	1.33	1.31	1.29	0.00	-0.17
Russia	11.03	11.20	10.85	9.93	9.57	10.38	-0.65	-5.91
Other Eurasia	2.83	3.00	2.93	2.98	2.98	2.97	0.14	4.93
Other Europe	0.11	0.11	0.11	0.11	0.10	0.11	0.00	-0.85
Total Non-OECD	**32.44**	**33.22**	**32.89**	**31.96**	**31.70**	**32.44**	**-0.01**	**-0.02**
Total Non-OPEC production	63.36	65.23	64.92	64.49	64.56	64.80	1.44	2.27
Processing gains	2.40	2.47	2.47	2.47	2.47	2.47	0.07	2.96
Total Non-OPEC liquids production	**65.76**	**67.70**	**67.39**	**66.96**	**67.03**	**67.27**	**1.51**	**2.30**
Previous estimate	65.73	67.69	67.39	66.51	67.00	67.14	1.41	2.15
Revision	0.02	0.00	0.01	0.45	0.03	0.12	0.10	0.15

*Note: * 2023 = Forecast. Totals may not add up due to independent rounding.*

Source: OPEC.

Table 5 - 2: Non-OPEC liquids production in 2024*, mb/d

Non-OPEC liquids production	2023	1Q24	2Q24	3Q24	4Q24	2024	Change 2024/23 Growth	%
Americas	28.14	28.66	28.70	29.16	29.47	29.00	0.86	3.04
of which US	*20.36*	*20.68*	*20.90*	*21.17*	*21.33*	*21.02*	*0.66*	*3.23*
Europe	3.75	3.94	3.78	3.79	3.89	3.85	0.10	2.54
Asia Pacific	0.46	0.47	0.44	0.45	0.44	0.45	-0.01	-2.87
Total OECD	**32.36**	**33.07**	**32.92**	**33.40**	**33.80**	**33.30**	**0.94**	**2.90**
China	4.56	4.58	4.57	4.54	4.54	4.56	-0.01	-0.11
India	0.78	0.79	0.79	0.79	0.78	0.79	0.01	1.69
Other Asia	2.32	2.30	2.27	2.25	2.25	2.27	-0.05	-2.26
Latin America	6.74	6.91	6.98	7.10	7.18	7.04	0.31	4.54
Middle East	3.29	3.34	3.33	3.32	3.32	3.33	0.04	1.14
Africa	1.29	1.30	1.33	1.36	1.37	1.34	0.05	3.77
Russia	10.38	10.20	10.32	10.45	10.56	10.38	0.00	-0.01
Other Eurasia	2.97	3.03	3.02	3.00	3.04	3.02	0.06	1.85
Other Europe	0.11	0.10	0.10	0.10	0.10	0.10	0.00	-1.13
Total Non-OECD	**32.44**	**32.55**	**32.72**	**32.92**	**33.15**	**32.84**	**0.40**	**1.23**
Total Non-OPEC production	64.80	65.62	65.64	66.32	66.96	66.14	1.34	2.07
Processing gains	2.47	2.52	2.52	2.52	2.52	2.52	0.05	2.03
Total Non-OPEC liquids production	**67.27**	**68.14**	**68.16**	**68.84**	**69.48**	**68.66**	**1.39**	**2.06**
Previous estimate	67.14	68.01	68.03	68.72	69.35	68.53	1.39	2.07
Revision	0.12	0.12	0.12	0.12	0.12	0.12	0.00	0.00

*Note: * 2024 = Forecast. Totals may not add up due to independent rounding.*

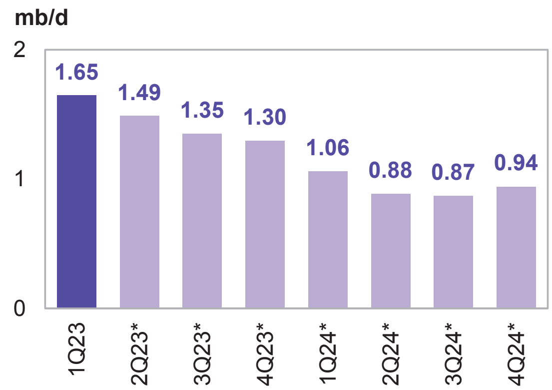
Source: OPEC.

OECD

OECD liquids production in 2023 is forecast to expand by 1.4 mb/d to an average of 32.4 mb/d. This is revised lower by a minor 7 tb/d, mainly due to downward revisions in OECD Europe.

Growth is set to be led by OECD Americas, which is forecast to expand by 1.3 mb/d to an average of 28.1 mb/d. This is largely unchanged compared with last month's assessment. Yearly liquids production in OECD Europe is anticipated to grow by 0.2 mb/d to an average of 3.8 mb/d. This is down by 7 tb/d compared with the previous month. OECD Asia Pacific is expected to drop by around 10 tb/d to an average of 0.5 mb/d.

Graph 5 - 5: OECD quarterly liquids supply, y-o-y changes



*Note: * 2Q23-4Q24 = Forecast. Source: OPEC.*

For **2024**, oil production in the OECD is likely to grow by 0.9 mb/d to an average of 33.3 mb/d. Again, the growth will be led by OECD Americas, with an expected increase of 0.9 mb/d to an average of 29.0 mb/d. Yearly oil production in OECD Europe is anticipated to grow by 0.1 mb/d to an average of 3.8 mb/d, while OECD Asia Pacific is expected to decline by 13 tb/d y-o-y to an average of 0.5 mb/d.

OECD Americas

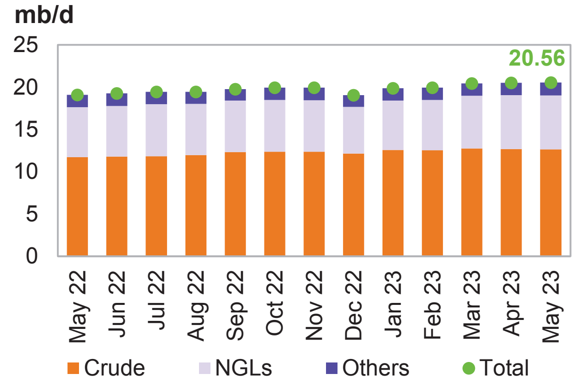
US

US liquids production in **May** rose m-o-m by 52 tb/d to an average of 20.6 mb/d, the highest level on record. This was up by 1.5 mb/d compared with May 2022.

Crude oil and condensate production dropped m-o-m by 15 tb/d in **May 2023** to average 12.7 mb/d. This was up y-o-y by 0.9 mb/d.

In terms of the **crude and condensate production breakdown by region (PADDs)**, production decreased mainly in the US Gulf Coast (USGC) region, which dropped by 44 tb/d to an average of 9.2 mb/d. Production in the Midwest and Rocky Mountain regions, rose by around 20 tb/d and 14 tb/d, respectively. Output in the East Coast and West Coast remained broadly unchanged m-o-m.
Production growth in the main regions was primarily driven by a strong recovery in Texas and North Dakota fields, while output in onshore New Mexico and the offshore Gulf of Mexico (GoM) declined.

Graph 5 - 6: US monthly liquids output by key component



Sources: EIA and OPEC.

NGLs production was largely unchanged m-o-m at an average of 6.4 mb/d in May. This was higher y-o-y by 0.5 mb/d. According to the US Department of Energy (DoE), production of **non-conventional liquids** (mainly ethanol) rose by 64 tb/d to an average of 1.5 mb/d. Preliminary estimates see non-conventional liquids averaging around 1.5 mb/d in June, largely unchanged from May.

GoM production fell m-o-m by 30 tb/d to an average of 1.7 mb/d in May. Normal production was seen in most Gulf Coast offshore platforms with the exceptions being BP's Thunder Horse platform due to planned maintenance. In the **onshore Lower 48**, crude and condensate production increased m-o-m by 19 tb/d to an average of 10.5 mb/d in May.

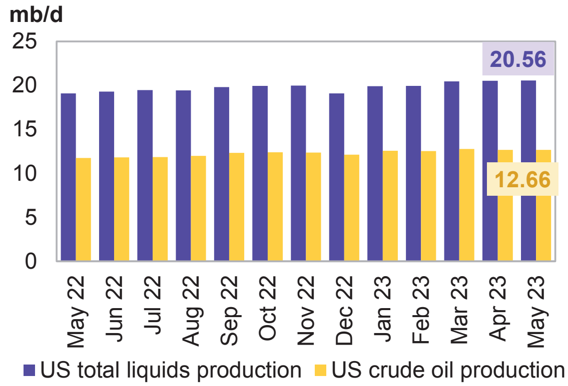
Table 5 - 3: US crude oil production by selected state and region, tb/d

				Change	
State	**May 22**	**Apr 23**	**May 23**	**m-o-m**	**y-o-y**
Texas	5,029	5,446	5,494	*48*	*465*
New Mexico	1,561	1,861	1,803	*-58*	*242*
Gulf of Mexico (GOM)	1,607	1,735	1,705	*-30*	*98*
North Dakota	1,050	1,104	1,114	*10*	*64*
Colorado	440	450	453	*3*	*13*
Oklahoma	433	441	445	*4*	*12*
Alaska	447	434	430	*-4*	*-17*
Total	**11,734**	**12,677**	**12,662**	***-15***	***928***

Sources: EIA and OPEC.

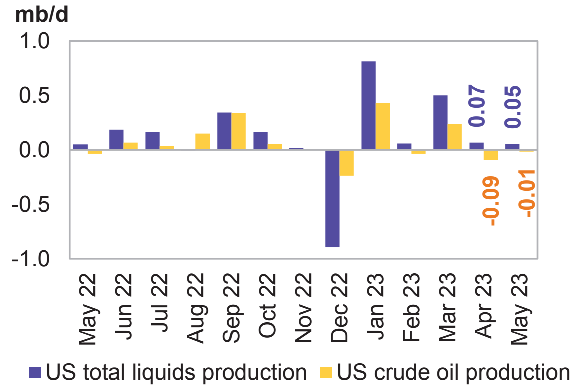
Looking at **individual states**, New Mexico's oil production fell by 58 tb/d to an average of 1.8 mb/d, which is 242 tb/d higher than a year ago. Production from Texas was up by 48 tb/d to an average of 5.5 mb/d, which is 465 tb/d higher than a year ago. In the Midwest, North Dakota's production rose m-o-m by 10 tb/d to an average of 1.1 mb/d, up y-o-y by 64 tb/d. Oklahoma's production was up m-o-m by a minor 4 tb/d to an average of 0.4 mb/d. Production in Alaska and Colorado remained largely unchanged.

Graph 5 - 7: US monthly crude oil and total liquids supply



Sources: EIA and OPEC.

Graph 5 - 8: US monthly crude oil and total liquids supply, m-o-m changes



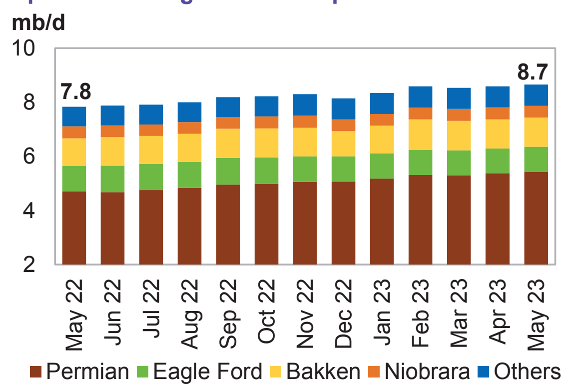
Sources: EIA and OPEC.

US tight crude output in **May** is estimated to have risen m-o-m by 61 tb/d to an average of 8.7 mb/d, according to the latest estimate from the US Energy Information Administration (EIA). This was 0.8 mb/d higher than in the same month last year.

The m-o-m increase from shale and tight formations using horizontal wells came mainly from Permian shale production in Texas, where output rose by 68 tb/d to an average of 5.4 mb/d. This was up y-o-y by 740 tb/d.

In North Dakota, Bakken shale oil output remained largely unchanged m-o-m at an average of 1.1 mb/d, up by 58 tb/d y-o-y. Tight crude output at Eagle Ford in Texas dropped by a minor 4 tb/d to an average of 0.9 mb/d, which is down y-o-y by 36 tb/d. Production in Niobrara-Codell in Colorado and Wyoming was unchanged at an average of 0.4 mb/d.

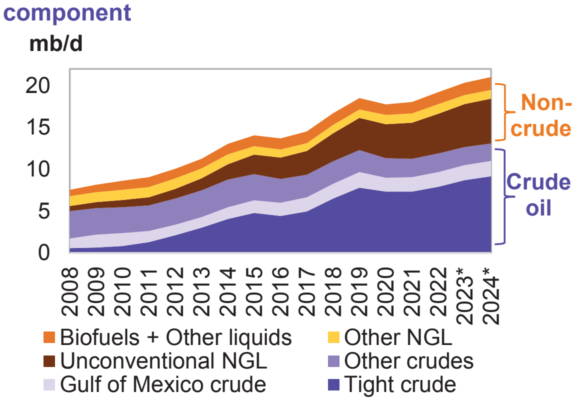
Graph 5 - 9: US tight crude output breakdown



Sources: EIA and OPEC.

US liquids production in 2023, excluding processing gains, is forecast to expand y-o-y by 1.1 mb/d to an average of 20.4 mb/d. This is up by 50 tb/d compared with the previous assessment due to higher-than-expected output in previous months. Despite declining drilling activity since the start of this year, fewer supply chain/logistical issues in the prolific Permian, Eagle Ford and Bakken shale sites are still assumed for the remainder of 2023. Given a sound level of oil field drilling and well completions, **crude oil and condensate** output is anticipated to increase y-o-y by 0.8 mb/d to average 12.7 mb/d. Average tight crude output in 2023 is forecast at 8.7 mb/d, up y-o-y by 0.8 mb/d. At the same time, NGLs production and non-conventional liquids, particularly ethanol, are forecast to increase y-o-y by 0.3 mb/d and 40 tb/d, to average 6.2 mb/d and 1.5 mb/d, respectively.

Graph 5 - 10: US liquids supply developments by component



*Note: * 2023 and 2024 = Forecast.*
Source: OPEC.

US liquids production in 2024, excluding processing gains, is expected to grow y-o-y by 0.7 mb/d to average 21.0 mb/d, assuming a modest level of drilling activities and less supply chain issues in the prolific Permian, Bakken and Eagle Ford shale sites. Crude oil output is anticipated to jump by 0.4 mb/d y-o-y to an average of 13.1 mb/d. At the same time, NGLs production and non-conventional liquids, particularly ethanol, are projected to increase by 0.2 mb/d and 30 tb/d y-o-y to average 6.4 mb/d and 1.5 mb/d, respectively. Average tight crude output in 2024 is expected at 9.2 mb/d, up by 0.5 mb/d.

The 2024 forecast assumes ongoing capital discipline and less inflationary pressure, as well as moderating supply chain issues and oil field service constraints (labour and equipment).

Table 5 - 4: US liquids production breakdown, mb/d

US liquids	2022	Change 2022/21	2023*	Change 2023/22	2024*	Change 2024/23
Tight crude	7.93	0.58	8.69	0.76	9.18	0.49
Gulf of Mexico crude	1.73	0.02	1.82	0.09	1.84	0.02
Conventional crude oil	2.25	0.04	2.16	-0.09	2.06	-0.10
Total crude	**11.91**	**0.64**	**12.66**	**0.75**	**13.08**	**0.42**
Unconventional NGLs	4.74	0.43	5.13	0.39	5.37	0.24
Conventional NGLs	1.14	0.03	1.09	-0.05	1.06	-0.03
Total NGLs	**5.88**	**0.46**	**6.22**	**0.33**	**6.43**	**0.21**
Biofuels + Other liquids	1.44	0.08	1.48	0.04	1.52	0.03
US total supply	**19.23**	**1.18**	**20.36**	**1.13**	**21.02**	**0.66**

*Note: * 2023 and 2024 = Forecast.*

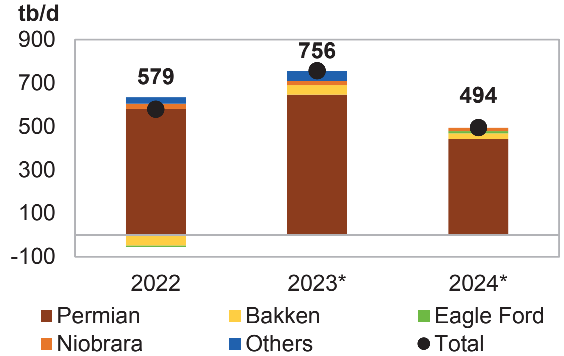
Sources: EIA, OPEC and Rystad Energy.

US tight crude production in the **Permian** in 2023 is expected to increase y-o-y by 0.6 mb/d to 5.4 mb/d. It is forecast to grow y-o-y by 0.4 mb/d to an average of 5.9 mb/d in 2024.

In **North Dakota**, the **Bakken** shale production is still expected to remain below the pre-pandemic average of 1.4 mb/d. In 2023, growth is forecast at just 44 tb/d to an average of 1.1 mb/d. Growth of 25 tb/d for 2024 is anticipated, to average 1.1 mb/d, demonstrating signs of maturity in the basin.

The **Eagle Ford** in Texas saw an output of 1.2 mb/d in 2019, followed by declines in the period 2020 to 2022. Having no growth expected for 2023, the output rests at an average of 0.95 mb/d. Marginal growth is expected for 2024, with an increase of 10 tb/d to average 0.96 mb/d.

Graph 5 - 11: US tight crude output by shale play, y-o-y changes



*Note: * 2023 and 2024 = Forecast.*
Sources: EIA and OPEC.

Niobrara's production is expected to have grown y-o-y by 19 tb/d in 2023 to an average of 456 tb/d. It is then forecast to increase by 17 tb/d in 2024 to an average of 473 tb/d. Given a moderate pace of drilling and completion activities, production in other tight plays is expected to show an increase of 48 tb/d in 2023 and then remain steady in 2024.

Table 5 - 5: US tight oil production growth, mb/d

US tight oil	2022	Change 2021/20	2023*	Change 2023/22	2024*	Change 2024/23
Permian tight	4.78	0.58	5.42	0.65	5.87	0.44
Bakken shale	1.03	-0.05	1.07	0.04	1.10	0.03
Eagle Ford shale	0.95	-0.01	0.95	0.00	0.96	0.01
Niobrara shale	0.44	0.02	0.46	0.02	0.47	0.02
Other tight plays	0.73	0.03	0.78	0.05	0.78	0.00
Total	**7.93**	**0.58**	**8.69**	**0.76**	**9.18**	**0.49**

*Note: * 2023 and 2024 = Forecast.*

Source: OPEC.

US rig count, spudded, completed, DUC wells and fracking activity

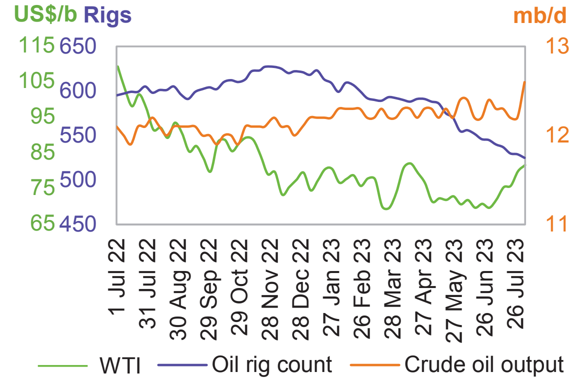
Total **active US drilling rigs** in the week ending 28 July 2023 fell by 5 to 664, according to Baker Hughes. This was down by 103 rigs compared with a year ago. The number of active offshore rigs rose by one w-o-w to 19. This was higher by two compared with the same month a year earlier. Onshore oil and gas rigs were lower w-o-w by 7 to stand at 640 rigs, with five rigs in inland waters. This is down by 106 rigs y-o-y.

The **US horizontal rig count** fell w-o-w by 8 to 592, compared with 697 horizontal rigs a year ago. The number of drilling rigs for oil dropped w-o-w by one to 529. At the same time, gas-drilling rigs fell w-o-w by three to 128.

The Permian's rig count rose by one w-o-w to 334. Rig counts dropped by two in Eagle Ford to 55. The rig counts remained unchanged w-o-w in the Williston, Cana Woodford and DJ-Niobrara at 35, 22 and 14, respectively.

No operating oil rig remained in the Barnett basin, down by one w-o-w, for the first time since February 2022.

Graph 5 - 12: US weekly rig count vs. US crude oil output and WTI price



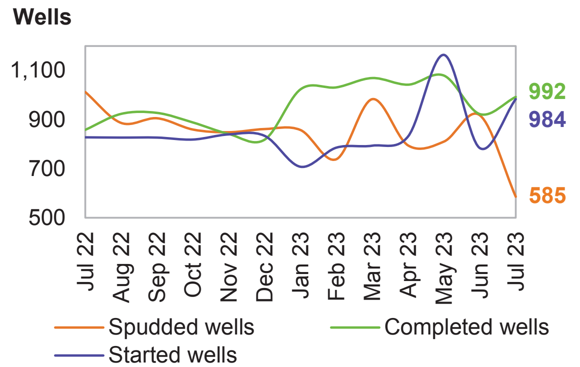
Sources: Baker Hughes, EIA and OPEC.

Drilling and completion (D&C) activities for spudded, completed and started oil-producing wells in all US shale plays, based on EIA-DPR regions, including 917 horizontal wells spudded in June (as per preliminary data). This is up m-o-m by 107, and 4% higher than in June 2022.

Preliminary data for June indicates a lower number of completed wells at 922, which is up y-o-y by 11%. The number of started wells is estimated at 784, which is 11% higher than a year earlier.

Preliminary data for July 2023 sees 585 spudded, 992 completed and 984 started wells, according to Rystad Energy.

Graph 5 - 13: Spudded, completed and started wells in US shale plays

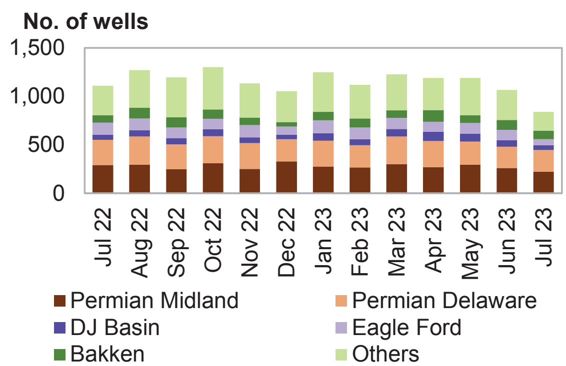


Note: Jun 23-Jul 23 = Preliminary data.
Sources: Rystad Energy and OPEC.

In terms of identified **US oil and gas fracking operations by region**, Rystad Energy reported that 1,188 wells were fracked in May 2023. In June and July, it stated that 1,188 and 1,066 wells began fracking, respectively. Preliminary numbers are based on analysis of high-frequency satellite data.

Preliminary June data showed that 261 and 219 wells were fracked in the Permian Midland and Permian Delaware, respectively. Compared with May, there was a decline of 33 wells in the Midland and a drop of 19 in the Delaware. Data also indicated that 69 wells were fracked in the DJ Basin, 105 in the Eagle Ford and 101 in the Bakken in June.

Graph 5 - 14: Fracked wells count per month



Note: Jun 23-Jul 23 = Preliminary data.
Sources: Rystad Energy Shale Well Cube and OPEC.

Canada

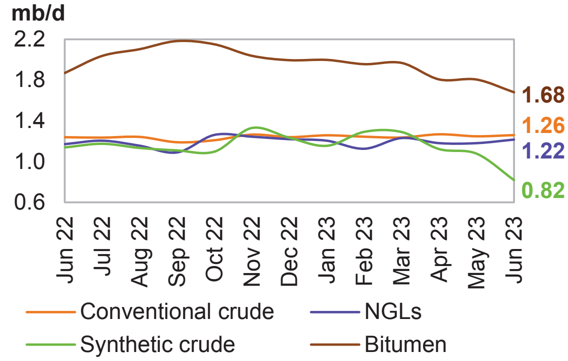
Canada's liquids production in **June** is estimated to have dropped significantly m-o-m by 337 tb/d to an average of 5.0 mb/d. This is the lowest output seen since October 2020.

Conventional crude production rose m-o-m in June by 12 tb/d to an average of 1.3 mb/d, while NGLs output increased by 35 tb/d to an average of 1.2 mb/d.

Crude bitumen production output fell m-o-m by 259 tb/d, and synthetic crude declined m-o-m by 125 tb/d. Taken together, crude bitumen and synthetic crude production dropped by 384 tb/d to 2.5 mb/d.

The drop in June was related to significant maintenance at the oil sands mines and the upgraders including Suncor's Syncrude, Imperial's Kearl, and Canadian Natural Resources Horizon mines.

Graph 5 - 15: Canada's monthly liquids production development by type

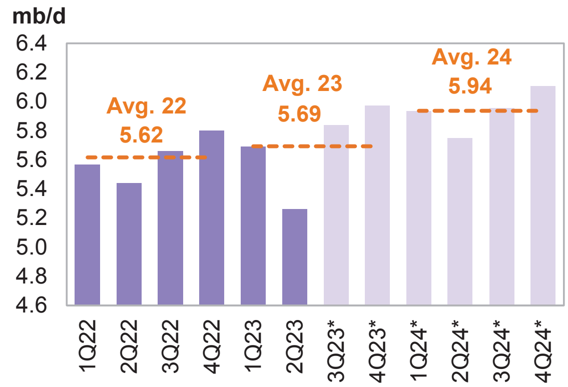


Sources: Statistics Canada, Alberta Energy Regulator and OPEC.

For **2023**, Canada's liquids production is forecast to increase by 80 tb/d to an average of 5.7 mb/d. This is down by 50 tb/d compared with the previous assessment. Canada's production in 2Q23 was considerably lower-than-expected and under pressure due to maintenance and seasonal wildfires.

The recent wildfire has been the worst fire season for some decades disrupting operations across northwest Alberta throughout May to July. At the same time, scheduled maintenance programmes during 2Q23 and 3Q23 are expected to soften output. However, lower maintenance is expected for 3Q23 and the Terra Nova Floating Production Storage and Offloading unit (FPSO) is also expected to restart production in mid-2023.

Graph 5 - 16: Canada's quarterly liquids production and forecast



*Note: * 3Q23-4Q24 = Forecast. Source: OPEC.*

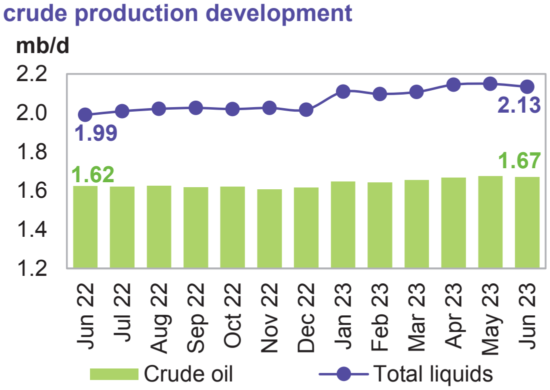
For **2024**, Canada's liquids production is forecast to gradually increase at a higher pace compared with 2023, rising by 0.2 mb/d to an average of 5.9 mb/d. Incremental production is expected to come through oil sands project ramp-ups and debottlenecks, in areas like Montney, Kearl, and Fort Hills, together with some conventional field growth.

Mexico

Mexico's crude output decreased m-o-m by a minor 4 tb/d in **June** to an average of 1.7 mb/d, and NGLs output fell by 11 tb/d. Mexico's total June liquids output m-o-m dropped by 15 tb/d to an average of 2.1 mb/d, according to the Comisión Nacional de Hidrocarburos (CNH). This was in line with our expectation, as the ramp-up of some new fields and a minor recovery in production from the Xanab field were offset by declines elsewhere.

For **2023**, liquids production is now forecast to rise by around 80 tb/d to an average of 2.1 mb/d. This is unchanged from the previous assessment. However, in addition to the recent outages after the explosion at the Nohoch Alfa oil platform at the Bay of Campeche, declines from other fields could start offsetting monthly gains from new fields once again in 2H23.

Graph 5 - 17: Mexico's monthly liquids and crude production development



Sources: Mexico Comision Nacional de Hidrocarburos (CNH) and OPEC

For **2024**, liquids production is forecast to decline by 45 tb/d to an average of 2.0 mb/d. In general, it is expected that declines from mature fields offset gains from new fields. Pemex's total crude production decline in mature areas like Ku-Maloob-Zaap and Integral Yaxche-Xanab is forecast to outweigh production ramp-ups in Area-1 and El Golpe-Puerto Ceiba, and a few start-ups, namely TM-01, Paki, and AE-0150-Uchukil.

OECD Europe

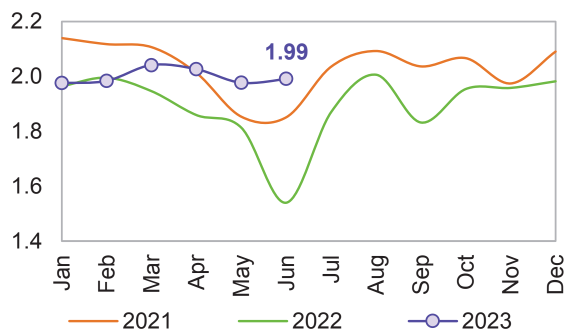
Norway

Norwegian liquids production in **June** rose by 14 tb/d m-o-m to an average of 2.0 mb/d. While the main oil fields have been produced on schedule, there were some unexpected declines due to outages and maintenance in a number of gas fields.

Norway's crude production increased by 29 tb/d m-o-m in June to an average of 1.8 mb/d, albeit higher y-o-y by 480 tb/d. Monthly oil production was 0.6% more than the Norwegian Petroleum Directorate's (NPD) forecast.

Production of NGLs and condensates, however, dropped m-o-m by 15 tb/d to an average of 0.2 mb/d, according to NPD data.

Graph 5 - 18: Norway's monthly liquids production development



Sources: The Norwegian Petroleum Directorate (NPD) and OPEC.

For **2023**, Norwegian liquids production is forecast to expand by 0.2 mb/d, largely unchanged compared with last month's forecast, to an average of 2.1 mb/d. The Johan Sverdrup ramp-up is projected to be the main source of growth following its phase 2 start-up in December 2022. Norway's Nyhamna gas processing plant and some of the other gas fields were under extended maintenance in June. The maintenance activity is assumed to impact around 78 million cf/d of gas export capacity.

For **2024**, Norwegian liquids production is forecast to grow by 90 tb/d to an average of 2.2 mb/d. Some small-to-large projects are scheduled to ramp up in 2024. At the same time, project start-ups are expected from offshore projects like Balder/Ringhorne, Eldfisk, Kristin, Alvheim FPSO, Hanz, Aasgard FPSO, and PL636. Kobra East and Gekko (KEG) is planned to come online in early 2024 which will be tied back to the Alvheim FPSO. Johan Castberg is projected to be the main source of output increases, with the first oil planned for 4Q24.

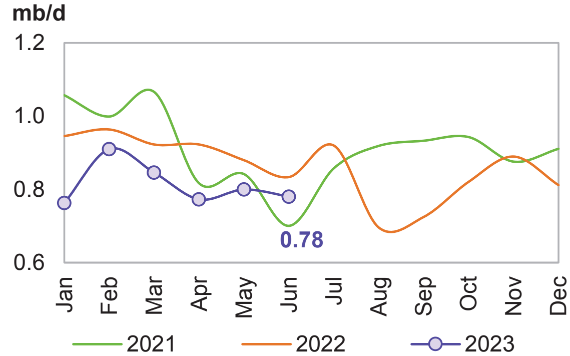
UK

In **June, UK liquids production** fell m-o-m by 20 tb/d to an average of 0.8 mb/d. Crude oil output decreased m-o-m by 10 tb/d to an average of 0.7 mb/d, which was lower by 27 tb/d y-o-y, according to official data. NGLs output also dropped by 10 tb/d to an average of 72 tb/d. UK liquids output in June was down 6% compared to June 2022, mainly due to natural declines and outages.

For **2023**, UK liquids production is forecast to average 0.9 mb/d, down by a minor 5 tb/d from the previous assessment due to lower-than-expected June 2023 output.

For **2024**, UK liquids production is forecast to stay steady at an average of 0.9 mb/d. Production ramp-ups will be seen in the ETAP and Clair, as well as the Anasuria and Captain EOR start-up projects. The start-up for Penguins redevelopment is now expected in 1Q24. However, liquids production in the UK is expected to continue to face challenges, given an inadequate number of new projects and low investment levels.

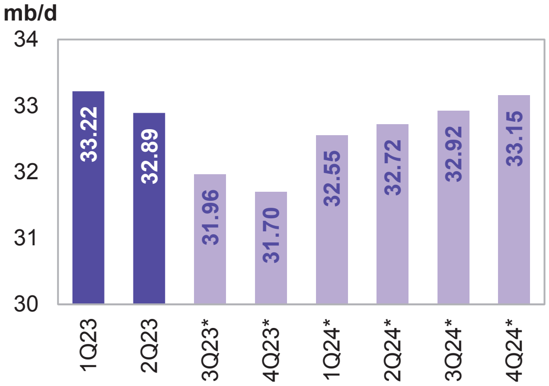
Graph 5 - 19: UK monthly liquids production development



Sources: UK Department for Business, Energy and Industrial Strategy and OPEC.

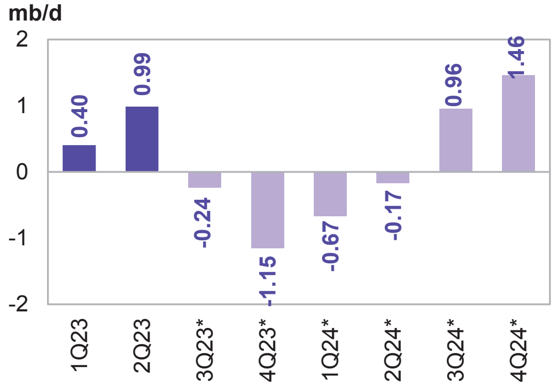
Non-OECD

Graph 5 - 20: Non-OECD quarterly liquids production and forecast



*Note: * 3Q23-4Q24 = Forecast. Source: OPEC.*

Graph 5 - 21: Non-OECD quarterly liquids supply, y-o-y changes



*Note: * 3Q23-4Q24 = Forecast. Source: OPEC.*

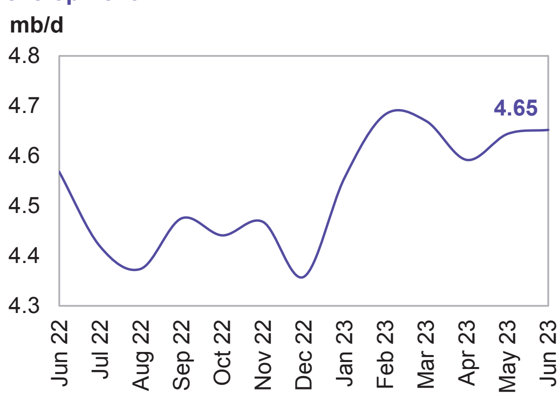
China

China's liquids production rose m-o-m in **June** by a minor 8 tb/d to an average of 4.7 mb/d. This is up by 84 tb/d y-o-y, according to official data. Crude oil output in June averaged 4.3 mb/d, up by 8 tb/d compared with the previous month, and higher y-o-y by 81 tb/d. NGLs and condensate production was largely stable m-o-m, averaging 48 tb/d.

For **2023**, y-o-y growth of 85 tb/d is forecast for an average of 4.6 m/d. This is unchanged from last month's assessment. Natural decline rates are expected to be offset by additional growth through more infill wells and EOR projects amid efforts by state-owned oil companies to safeguard energy supplies. Chinese companies have special attention towards ultra-deep drilling in search of energy security. CNPC's recent record-breaking 11 km exploration borehole in the Taklamakan Desert could represent their focus on one of the world's deepest reservoirs.

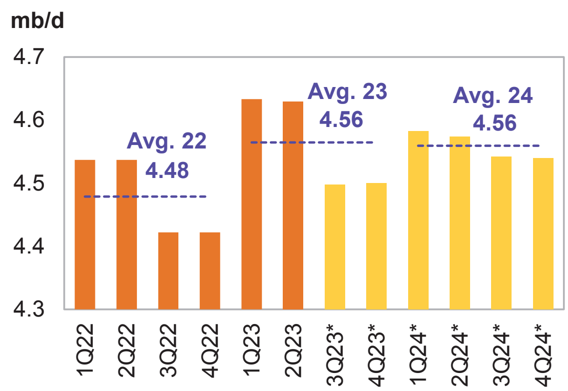
For **2024**, Chinese liquid production is expected to remain steady y-o-y and is forecast to average 4.6 m/d. For next year, Liuhua 11-1, Shayan and Liuhua 4-1 (redevelopment) are planned to come on stream under CNOOC and PetroChina. At the same time, the main ramp-ups are expected from the Changqing, Kenli 10-2, Wushi 17-2 and Kenli 6-4.

Graph 5 - 22: China's monthly liquids production development



Sources: CNPC and OPEC.

Graph 5 - 23: China's quarterly liquids production and forecast



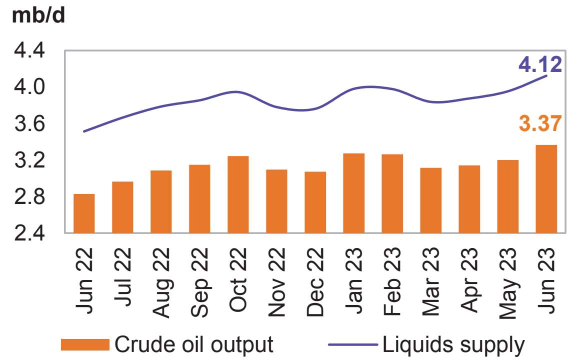
*Note: * 3Q23-4Q24 = Forecast. Sources: CNPC and OPEC.*

Latin America

Brazil

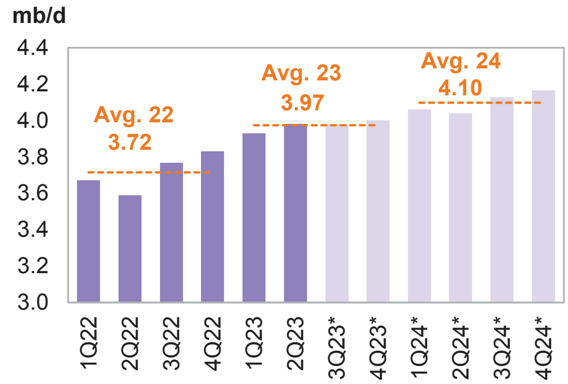
Brazil's crude output in **June** rose m-o-m by 166 tb/d to an average of 3.4 mb/d, mainly due to new project start-ups. NGLs production, however, was broadly unchanged at an average of 85 tb/d and it is expected to remain flat in July. Biofuels output (mainly ethanol) remained broadly unchanged at an average of 671 tb/d, with preliminary data showing a stable trend in July. The country's total liquids production increased by 170 tb/d in June to an average of 4.1 mb/d. This is the new highest liquid production rate on record after a peak of 4.0 mb/d in January 2023.

Graph 5 - 24: Brazil's monthly liquids production development by type



Sources: Brazilian National Agency of Petroleum, Natural Gas and Biofuels (ANP) and OPEC.

Graph 5 - 25: Brazil's quarterly liquids production



*Note: * 3Q23-4Q24 = Forecast. Sources: ANP and OPEC.*

For **2023**, Brazil's liquids supply, including biofuels, is forecast to rise y-o-y by 0.3 mb/d to an average of 4.0 mb/d, revised up by 15 tb/d from the previous forecast due to strong output in June. Crude oil output is set to increase through production ramp-ups in major offshore fields.

Two new FPSOs started production during May, with Petrobras pumping the first oil from the FPSO Anna Nery installed at the Marlim complex in the offshore Campos Basin. According to Petrobras, the Buzios subsalt fields also received its fifth production unit, with the FPSO Almirante Barroso. Petrobras' oil output fell by around 0.6% in the 2Q23 y-o-y due to losses from maintenance, in addition to the natural decline of mature oil fields and some asset sales. However, the crude oil output is expected to be supported by offshore start-ups announced at the beginning of the year.

For **2024**, Brazil's liquids supply forecast, including biofuels, is forecast to increase by around 120 tb/d y-o-y to an average of 4.1 mb/d. Crude oil output is expected to increase through production ramp-ups in the Mero (Libra NW), Buzios (Franco), Tupi (Lula), Peregrino and Itapu (Florim) fields. Oil project start-ups are anticipated in Atlanta, Pampo-Enchova Cluster and Vida.

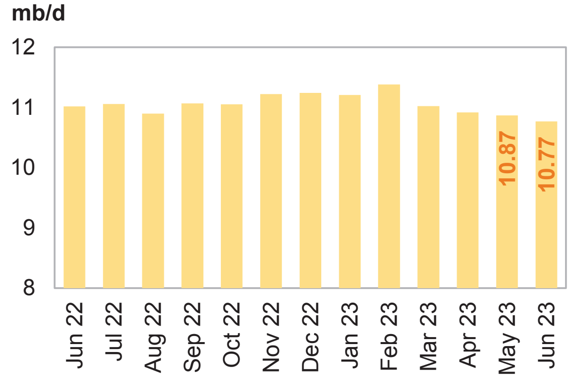
Russia

Russia's liquids production in June fell m-o-m by 100 tb/d to an average of 10.8 mb/d. This includes 9.5 mb/d of crude oil and 1.3 mb/d of NGLs and condensate.

For **2023**, Russian liquids production is forecast to drop by 0.65 mb/d to an average of 10.4 mb/d, revised up by 100 tb/d from the previous month's assessment. It is worth noting that the expected contraction takes into account recently announced voluntary production adjustments to the end of 2023.

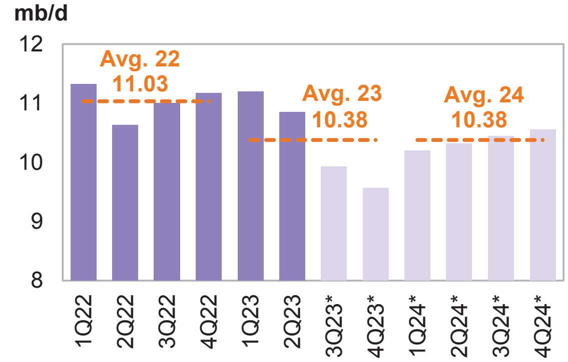
For **2024**, Russian liquids production is forecast to remain unchanged y-o-y and average 10.4 mb/d. In addition to project ramp-ups from several oil fields, there will be some start-ups by Rosneft, Russneft, Lukoil, Gazprom, Neftisa and TenderResurs. However, the overall additional liquids production is expected to be offset by declines from mature fields. It should be noted that the Russian oil forecast is subject to uncertainty.

Graph 5 - 26: Russia's monthly liquids production



Sources: Nefte Compass and OPEC.

Graph 5 - 27: Russia's quarterly liquids production



Note: * 3Q23-4Q24 = Forecast.
Sources: Nefte Compass and OPEC.

Caspian

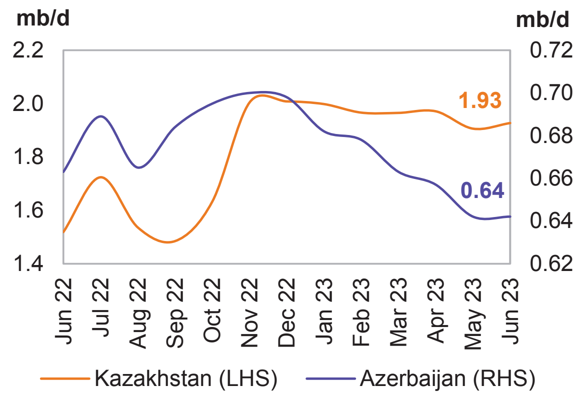
Kazakhstan & Azerbaijan

Liquids output in Kazakhstan rose by 21 tb/d m-o-m to an average of 1.9 mb/d in **June**. Crude production was up m-o-m by 16 tb/d to an average of 1.6 mb/d, while NGLs and condensate output rose m-o-m by a minor 5 tb/d to an average of 0.4 mb/d.

For **2023**, liquids supply is forecast to increase by 0.1 mb/d to an average of 1.9 mb/d, revised up by 9 tb/d compared with the previous forecast mainly due to better-than-expected output in June.

Oil production in early July has been disrupted at several oil fields in Kazakhstan due to a major power outage at fields in key oil-producing regions of Mangistau and Atyrau in Western Kazakhstan but the oil exports are estimated to be unaffected.

Graph 5 - 28: Caspian monthly liquids production development by selected country



Sources: Nefte Compass, JODI and OPEC.

For **2024**, liquids supply is forecast to increase by around 80 tb/d to an average of 2.0 mb/d, mainly due to production ramp-ups in the Tengiz oil field through expansion at the Tengizchevroil Future Growth Project (FGP) and wellhead pressure management project. Oil production in the Kashagan field and gas condensate output in the Karachaganak field are also expected to rise marginally.

Azerbaijan's liquids production in **June** remained broadly stable m-o-m, averaging 0.6 mb/d, which is a drop of 26 tb/d y-o-y. Crude production averaged 500 tb/d, with NGLs output at 142 tb/d, according to official sources.

Azerbaijan's liquids supply for **2023** is forecast to rise by 11 tb/d to an average of 0.7 mb/d. This is a downward revision of 11 tb/d, due to lower-than-expected major oil field production in June.

The main declines in legacy reservoirs, like Azeri-Chirag-Guneshli (ACG) oil fields, are expected to be offset by ramp-ups in other fields this year.

Azerbaijan's liquids supply for **2024** is forecast to decline by around 30 tb/d to an average of 0.7 mb/d. Growth is forecast to partly come from the Shah Deniz, Absheron, and Umid-Babek gas condensate projects. Production in Azerbaijan's ACG oil fields should also get a boost next year with a seventh ACG platform. However, the overall decline rate will be higher than the planned ramp-ups.

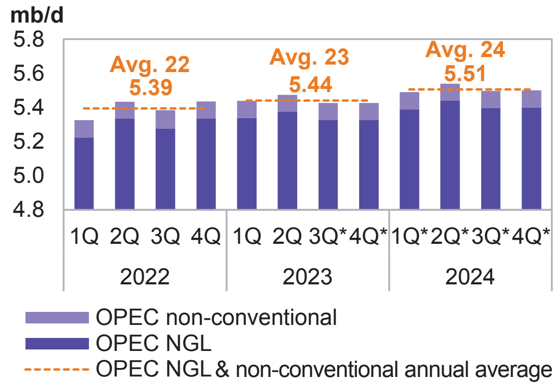
OPEC NGLs and non-conventional oils

OPEC NGLs and non-conventional liquids are forecast to expand by around 50 tb/d in **2023** to an average of 5.4 mb/d. NGLs production is projected to grow by 50 tb/d to average 5.3 mb/d, while non-conventional liquids are projected to remain unchanged at 0.1 mb/d.

NGLs output in 2Q23 is expected to have averaged 5.37 mb/d, while non-conventional output remained steady at 0.1 mb/d. Taken together, 5.48 mb/d is expected for June, according to preliminary data.

The preliminary **2024** forecast indicates a growth of 65 tb/d to an average of 5.5 mb/d. NGLs production is projected to grow by 65 tb/d to an average of 5.4 mb/d, while non-conventional liquids are projected to remain unchanged at 0.1 mb/d.

Graph 5 - 29: OPEC NGLs and non-conventional liquids quarterly production and forecast



*Note: * 3Q23-4Q24 = Forecast. Source: OPEC.*

Table 5 - 6: OPEC NGL + non-conventional oils, mb/d

OPEC NGL and non-coventional oils	2022	Change 22/21	2023	Change 23/22	1Q24	2Q24	3Q24	4Q24	2024	Change 24/23
OPEC NGL	**5.29**	*0.11*	**5.34**	*0.05*	5.39	5.44	5.40	5.40	**5.41**	*0.07*
OPEC non-conventional	**0.10**	*0.00*	**0.10**	*0.00*	0.10	0.10	0.10	0.10	**0.10**	*0.00*
Total	**5.39**	***0.11***	**5.44**	***0.05***	**5.49**	**5.54**	**5.50**	**5.50**	**5.51**	***0.07***

Note: 2023 and 2024 = Forecast.
Source: OPEC.

OPEC crude oil production

According to secondary sources, total **OPEC-13 crude oil production** averaged 27.31 mb/d in July 2023, lower by 836 tb/d m-o-m. Crude oil output production declined mainly in Saudi Arabia, Libya and Nigeria, while production in IR Iran, Angola and Iraq increased.

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

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

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

Source: OPEC.

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

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

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

Source: OPEC.

Commercial Stock Movements

Preliminary June 2023 data sees total OECD commercial oil stocks up m-o-m by 4.2 mb. At 2,828 mb, they were 74 mb lower than the latest five-year average and 119 mb below the 2015–2019 average. Within the components, crude stocks fell by 5.1 mb, m-o-m, while products stocks rose by 9.3 mb.

OECD commercial crude stocks stood at 1,395 mb in June. This was 18 mb below the latest five-year average and 70 mb lower than the 2015–2019 average. Total product inventories rose by 9.3 mb in June to stand at 1,433 mb. This is 55 mb lower than the latest five-year average and 49 mb below the 2015–2019 average.

In terms of days of forward cover, OECD commercial stocks fell m-o-m by 0.1 days in June to stand at 60.4 days. This is 3.2 days above the June 2022 level, but 2.7 days lower than the latest five-year average and 1.4 days less than the 2015–2019 average.

Preliminary data for July 2023 showed that total US commercial oil stocks rose m-o-m by 4.9 mb to stand at 1,266 mb. This is 50.6 mb, or 4.2%, higher than the same month in 2022, but 27.8 mb, or 2.1%, below the latest five-year average. Crude stocks fell by 12.4 mb, while product stocks rose by 17.3 mb, m-o-m.

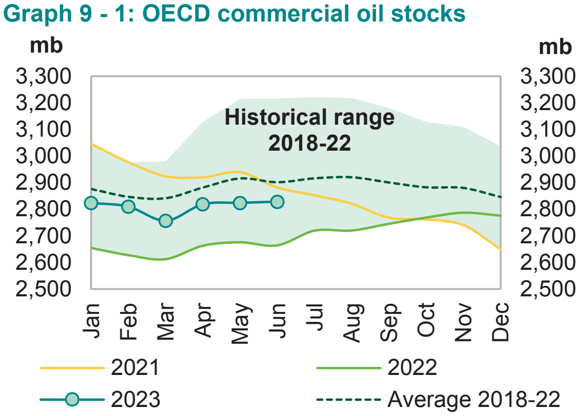
OECD

Preliminary **June 2023** data sees **total OECD commercial oil stocks** up m-o-m by 4.2 mb. At 2,828 mb, they were 164 mb higher than the same time one year ago, but 74 mb lower than the latest five-year average and 119 mb below the 2015–2019 average.

Within the components, crude stocks fell by 5.1 mb, m-o-m, while products stocks rose by 9.3 mb. Within OECD regions, total commercial oil stocks in June increased in OECD America and OECD Asia Pacific, while they fell in OECD Europe.

OECD commercial **crude stocks** stood at 1,395 mb in June. This was 96 mb higher than the same time a year ago, but 18 mb below the latest five-year average and 70 mb lower than the 2015–2019 average.

Graph 9 - 1: OECD commercial oil stocks



Sources: Argus, EIA, Euroilstock, IEA, METI and OPEC.

M-o-m, OECD Americas saw a crude stock draw of 8.6 mb, while stocks in OECD Asia Pacific rose by 3.5 mb. Meanwhile, OECD Europe stocks in June remained unchanged m-o-m.

Total product inventories rose by 9.3 mb in June to stand at 1,433 mb. This is 68 mb above the same time a year ago, but 55 mb lower than the latest five-year average and 49 mb below the 2015–2019 average. M-o-m, product stocks in OECD Americas and OECD Asia Pacific witnessed a product stock build of 9.9 mb and 1.4 mb, respectively, while product stocks in OECD Europe fell by 2.0 mb.

Table 9 - 1: OECD commercial stocks, mb

OECD stocks	Jun 22	Apr 23	May 23	Jun 23	Change Jun 23/May 23
Crude oil	1,299	1,407	1,400	1,395	*-5.1*
Products	1,365	1,411	1,424	1,433	*9.3*
Total	**2,664**	**2,819**	**2,824**	**2,828**	***4.2***
Days of forward cover	**57.2**	**61.1**	**60.5**	**60.4**	***-0.1***

Note: Totals may not add up due to independent rounding.

Sources: Argus, EIA, Euroilstock, IEA, METI and OPEC.

In terms of **days of forward cover**, OECD commercial stocks fell m-o-m by 0.1 days in June to stand at 60.4 days. This is 3.2 days above the June 2022 level, but 2.7 days lower than the latest five-year average and 1.4 days less than the 2015–2019 average.

Within OECD regions, OECD Americas stood 3.5 and OECD Europe 2.9 days below the latest five-year average, standing at 59.2 days and 67.4 days respectively, while OECD Asia-Pacific was 0.6 days above the latest five-year average, standing at 51.1 days.

OECD Americas

OECD Americas' total commercial stocks rose by 1.3 mb m-o-m in June to settle at 1,515 mb. This is 78 mb higher than the same month in 2022, but 33 mb below the latest five-year average.

Commercial **crude oil stocks** in OECD Americas dropped m-o-m by 8.6 mb in June to stand at 758 mb, which is 25 mb higher than in June 2022, but 18 mb below the latest five-year average. The monthly drop in crude oil stocks can be attributed to higher crude runs in the US, which increased by around 150 tb/d to 16.91 mb/d.

By contrast, **total product stocks** in OECD Americas rose m-o-m, increasing by 9.9 mb in June to stand at 757 mb. This is 54 mb higher than the same month in 2022, but 15 mb below the latest five-year average. Lower overall consumption in the region was behind the product stock build.

OECD Europe

OECD Europe's total commercial stocks fell m-o-m by 2.0 mb in June to settle at 942 mb. This is 32 mb higher than the same month in 2022, but 40 mb below the latest five-year average.

OECD Europe's **commercial crude stocks** remained unchanged m-o-m to end June at 435 mb. This is 21 mb higher than one year ago, but 2.3 mb below the latest five-year average.

Europe's **product stocks** fell m-o-m by 2.0 mb to end June at 508 mb. This is 11 mb above the same time a year ago, but 38 mb below the latest five-year average.

OECD Asia Pacific

OECD Asia Pacific's total commercial oil stocks rose m-o-m by 4.9 mb in June to stand at 371 mb. This is 53 mb higher than the same time a year ago, but in line with the latest five-year average.

OECD Asia Pacific's **crude inventories** rose m-o-m by 3.5 mb to end June at 202 mb. This is 50 mb higher than one year ago, and 2.0 mb above the latest five-year average.

OECD Asia Pacific's **product inventories** also rose by 1.4 mb m-o-m to end June at 169 mb. This is 3.3 mb higher than one year ago, but 2.0 mb below the latest five-year average.

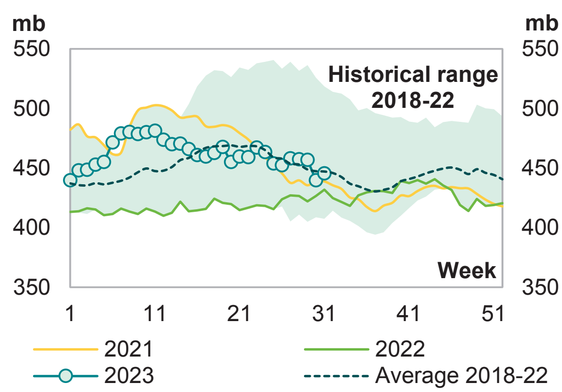
US

Preliminary data for **July 2023** showed that **total US commercial oil stocks** rose m-o-m by 4.9 mb to stand at 1,266 mb. This is 50.6 mb, or 4.2%, higher than the same month in 2022, but 27.8 mb, or 2.1%, below the latest five-year average. Crude stocks fell by 12.4 mb, while product stocks rose by 17.3 mb.

US commercial **crude stocks** in July stood at 439.8 mb. This is 15.6 mb, or 3.7%, higher than the same month of 2022, but 7.1 mb, or 1.6%, less than the latest five-year average. The monthly drop in crude oil stocks can be attributed to higher crude runs, which increased by around 190 tb/d to 17.09 mb/d.

By contrast, **total product stocks** rose in July to stand at 826.3 mb. This is 35.1 mb, or 4.4%, higher than July 2022 levels, but 20.7 mb, or 2.4%, lower than the latest five-year average. The product stock build could be attributed to lower product consumption.

Graph 9 - 2: US weekly commercial crude oil inventories



Sources: EIA and OPEC.

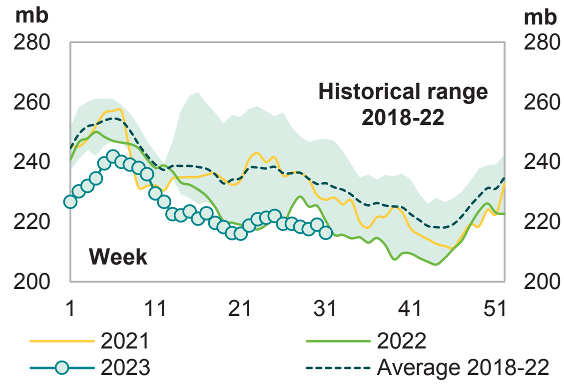
Gasoline stocks fell m-o-m by 0.4 mb in July to settle at 219.1 mb. This is 6.5 mb, or 2.9%, less than the same month of 2022 and 16.2 mb, or 6.9%, below the latest five-year average.

Residual fuel oil stocks also fell m-o-m by 3.4 mb in July. At 27.5 mb, this was 1.6 mb, or 5.5%, lower than a year earlier, and 3.4 mb, or 10.9%, below the latest five-year average

Jet fuel stocks also fell m-o-m by 0.3 mb, ending July at 41.1 mb. This is 0.2 mb, or 0.4%, lower than the same month in 2022, and 0.9 mb, or 0.2%, below the latest five-year average.

By contrast, distillate stocks rose m-o-m, increasing by 3.8 mb in July to stand at 117.2 mb. This is 4.6 mb, or 4.1%, higher than the same month of 2022, but 22.5 mb, or 16.1%, below the latest five-year average.

Graph 9 - 3: US weekly gasoline inventories



Sources: EIA and OPEC.

Table 9 - 2: US commercial petroleum stocks, mb

US stocks	Jul 22	May 23	Jun 23	Jul 23	Change Jul 23/Jun 23
Crude oil	**424.2**	**460.8**	**452.2**	**439.8**	***-12.4***
Gasoline	225.6	222.1	219.5	219.1	*-0.4*
Distillate fuel	112.5	113.1	113.4	117.2	*3.8*
Residual fuel oil	29.1	32.8	30.9	27.5	*-3.4*
Jet fuel	41.2	42.5	41.4	41.1	*-0.3*
Total products	**791.2**	**799.2**	**809.0**	**826.3**	***17.3***
Total	**1,215.4**	**1,260.0**	**1,261.2**	**1,266.1**	***4.9***
SPR	**468.0**	**354.4**	**347.2**	**346.8**	***-0.4***

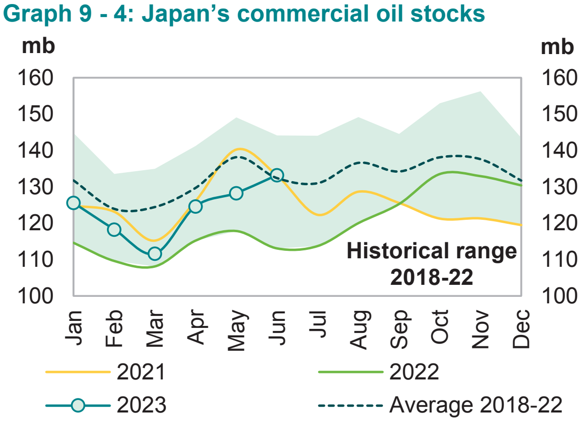
Sources: EIA and OPEC.

Japan

In **Japan**, **total commercial oil stocks** in **June** rose m-o-m by 4.9 mb to settle at 133.2 mb. This is 20.1 mb, or 17.8%, higher than the same month in 2022, and 0.8 mb, or 0.6%, above the latest five-year average. Crude and products stocks rose m-o-m by 3.5 mb and 1.4 mb respectively.

Japanese **commercial crude oil stocks** rose m-o-m by 3.5 mb in June to stand at 77.8 mb. This is 17.9 mb, or 30.0%, higher than the same month of 2022, and 3.0 mb, or 4.1%, above the latest five-year average. This crude stock build came on the back of lower crude runs, which decreased m-o-m by around 148 tb/d, or 6.4%, to stand at 2.32 mb/d.

Graph 9 - 4: Japan's commercial oil stocks



Sources: METI and OPEC.

Gasoline stocks fell m-o-m by 0.4 mb to stand at 10.2 mb in June. This was 0.3 mb, or 2.8%, above a year earlier, but 0.8 mb, or 7.6%, lower than the latest five-year average. The fall came on the back of higher gasoline consumption, which increased m-o-m by 0.2%.

By contrast, **total residual fuel oil stocks** rose m-o-m by 0.7 mb to end June at 12.7 mb. This is 1.3 mb, or 11.6%, higher than in the same month of 2022, and 0.4 mb, or 3.5%, above the latest five-year average. Within the components, fuel oil A and fuel oil B.C stocks rose by 0.5% and 8.6% m-o-m respectively.

Meanwhile**, distillate stocks** remained unchanged m-o-m to end June at 23.2 mb. This is 0.9 mb, or 3.9%, above the same month of 2022, but 1.7 mb, or 6.7%, below the latest five-year average.

Within distillate components, jet fuel and gasoil stocks dropped by 4.2% or 4.1% respectively, while kerosene stocks rose m-o-m by 6.1%.

Table 9 - 3: Japan's commercial oil stocks*, mb

Japan's stocks	Jun 22	Apr 23	May 23	Jun 23	*Change Jun 23/May 23*
Crude oil	**59.8**	**70.0**	**74.2**	**77.8**	***3.5***
Gasoline	10.0	10.5	10.6	10.2	*-0.4*
Naphtha	9.6	10.7	8.3	9.4	*1.1*
Middle distillates	22.3	22.1	23.2	23.2	*0.0*
Residual fuel oil	11.3	11.5	12.0	12.7	*0.7*
Total products	**53.3**	**54.7**	**54.1**	**55.5**	***1.4***
Total**	**113.1**	**124.7**	**128.3**	**133.2**	***4.9***

*Note: * At the end of the month. ** Includes crude oil and main products only.*

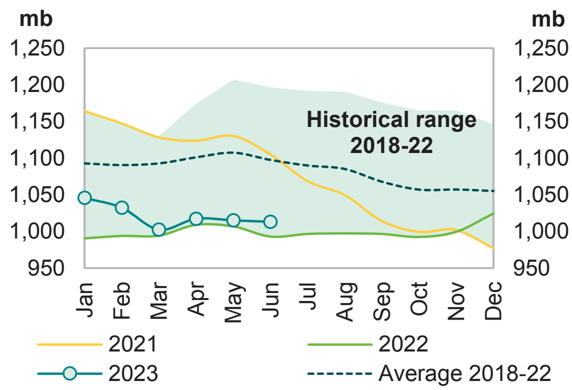
Sources: METI and OPEC.

EU-14 plus UK and Norway

Preliminary data for **June** showed that **total European commercial oil stocks** fell m-o-m by 2.0 mb to stand at 1,013 mb. At this level, they were 20.0 mb, or 2.0%, above the same month of 2022, but 84.5 mb, or 7.7%, lower than the latest five-year average. Crude stocks remained unchanged m-o-m, while product stocks fell by 2.0 mb m-o-m.

European **crude inventories** stood at 436.0 mb in June. This is 2.0 mb, or 0.5%, lower than the same month in 2022, and 42.4 mb, or 8.9%, below the latest five-year average. Crude oil inventories in June remained unchanged m-o-m, despite higher refinery throughput in the EU-14, plus the UK and Norway increasing m-o-m by around 100 tb/d to stand at 9.52 mb/d in June.

Graph 9 - 5: EU-14 plus UK and Norway total oil stocks



Sources: Argus, Euroilstock and OPEC.

By contrast, **total European product stocks** fell by 2.0 mb m-o-m to end June at 577.0 mb. This is 22.0 mb or 1.0% higher than the same month of 2022, but 42.1 mb, or 6.8%, below the latest five-year average.

Gasoline stocks fell m-o-m by 1.0 mb in June to stand at 107.0 mb. At this level, they were 1.0 mb, or 0.9%, higher than the same time in 2022, but 3.7 mb, or 3.3%, below the latest five-year average.

Middle distillate stocks also fell m-o-m by 1.0 mb in June to stand at 382.0 mb. This is 24.0 mb, or 6.7%, higher the same month in 2022, but 31.8 mb, or 7.7%, lower than the latest five-year average.

Meanwhile, **residual fuel stocks** remained unchanged m-o-m in June to stand at 59.0 mb. This is 1.0 mb, or 1.7%, lower than the same month in 2022, and 5.8 mb, or 8.9%, below the latest five-year average.

Naphtha stocks also remained unchanged in June, ending the month at 29.0 mb. This is 2.0 mb, or 6.5%, lower than the June 2022 level, and 0.9 mb, or 2.9%, below the latest five-year average.

Table 9 - 4: EU-14 plus UK and Norway's total oil stocks, mb

EU stocks	Jun 22	Apr 23	May 23	Jun 23	*Change Jun 23/May 23*
Crude oil	**438.0**	**431.4**	**436.0**	**436.0**	***0.0***
Gasoline	106.0	109.1	108.0	107.0	*-1.0*
Naphtha	31.0	30.3	29.0	29.0	*0.0*
Middle distillates	358.0	384.9	383.0	382.0	*-1.0*
Fuel oils	60.0	61.5	59.0	59.0	*0.0*
Total products	**555.0**	**585.8**	**579.0**	**577.0**	***-2.0***
Total	**993.0**	**1,017.2**	**1,015.0**	**1,013.0**	***-2.0***

Sources: Argus, Euroilstock and OPEC.

Singapore, Amsterdam-Rotterdam-Antwerp (ARA) and Fujairah

Singapore

In **June**, **total product stocks in Singapore** rose m-o-m by 0.4 mb to reach 42.4 mb. This is 1.9 mb, or 4.3%, lower than the same month in 2022 and 4.0 mb, or 8.6%, below the latest five-year average.

Light distillate stocks fell m-o-m by 0.9 mb in June to stand at 14.2 mb. This is 1.3 mb, or 8.4%, lower than the same month of 2022, but 0.7 mb, or 5.6 %, above the latest five-year average.

Middle distillate stocks also fell by 0.1 mb m-o-m in June to stand at 7.9 mb. This is in line with the last year at the same time, but 3.2 mb, or 28.7%, lower than the latest five-year average.

By contrast, **residual fuel oil stocks** rose m-o-m by 1.4 mb, ending June at 20.3 mb. This is 0.6 mb, or 2.9% lower than June 2022 and 1.6 mb, or 7.2%, less than the latest five-year average.

ARA

Total product stocks in ARA fell m-o-m by 2.1 mb in **June.** At 43.7 mb, they were 4.3 mb, or 10.9%, higher than the same month in 2022, but 2.0 mb, or 4.4%, lower than the latest five-year average.

Gasoline stocks in June rose by 0.1 mb m-o-m to stand at 11.5 mb. This is 1.2 mb, or 11.1%, higher than the same month of 2022 and 1.7 mb, or 17.5%, higher than the latest five-year average.

Fuel oil stocks also increased by 1.1 mb m-o-m in June to stand at 9.2 mb, which is 1.2 mb, or 14.3%, higher than in June 2022 and 0.1 mb, or 1.4% above the latest five-year average.

By contrast, **gasoil stocks** fell by 2.2 mb m-o-m, ending June at 14.9 mb. This is 3.6 mb, or 31.6%, higher than June 2022, but 2.1 mb, or 12.4%, less than the latest five-year average.

Jet oil stocks also fell by 0.7 mb m-o-m to stand at 6.0 mb. This is 0.3 mb, or 5.2%, lower than levels of June 2022 and 0.8 mb, or 12.1% less than the latest five-year average.

Fujairah

During the week ending 31 July 2023, **total oil product stocks in Fujairah** rose w-o-w by 0.95 mb to stand at 19.72 mb, according to data from Fed Com and S&P Global Commodity Insights. At this level, total oil stocks were 3.67 mb lower than at the same time a year ago.

Light distillate stocks rose w-o-w by 1.35 mb to stand at 7.58 mb, which is 0.01 mb lower than a year ago.

By contrast, **middle distillate stocks** fell w-o-w by 0.17 mb to stand at 2.65 mb, which is 0.66 mb lower than the same time last year.

Heavy distillate stocks also fell by 0.23 mb w-o-w to stand at 9.49 mb, which is 2.99 mb lower than the same period a year ago.

Balance of Supply and Demand

Demand for OPEC crude in 2023 is revised down by 0.1 mb/d from the previous assessment to stand at 29.3 mb/d. This is around 0.9 mb/d higher than in 2022.

According to secondary sources, OPEC crude production averaged 28.8 mb/d in 1Q23, which is 0.3 mb/d higher than the demand for OPEC crude. In 2Q22, OPEC crude production averaged 28.3 mb/d, which is 0.1 mb/d lower than the demand for OPEC crude.

Demand for OPEC crude in 2024 is also revised down by 0.1 mb/d from the previous assessment to stand at 30.1 mb/d, 0.8 mb/d higher than the estimated level in 2023.

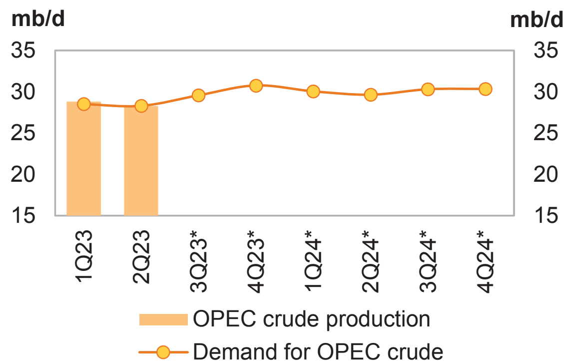
Balance of supply and demand in 2023

Demand for OPEC crude in 2023 is revised down by 0.1 mb/d from the previous assessment to stand at 29.3 mb/d. This is around 0.9 mb/d higher than in 2022.

Compared with the previous assessment, 2Q23 and 3Q23 were revised down by 0.1 mb/d and 0.4 mb/d, respectively, while both 1Q23 and 4Q23 remained unchanged.

Compared with the same quarters in 2022, demand for OPEC crude in 2Q23, 3Q23 and 4Q23 are expected to be higher by 0.3 mb/d, 1.3 mb/d and 2.0 mb/d, respectively. Meanwhile, OPEC crude in 1Q23 is estimated to remain as the same level as in 1Q22.

Graph 10 - 1: Balance of supply and demand, 2023–2024*



*Note: * 3Q23-4Q24 = Forecast.*
Source: OPEC.

According to secondary sources, OPEC crude production averaged 28.8 mb/d in 1Q23, which is 0.3 mb/d higher than demand for OPEC crude. In 2Q23, OPEC crude production averaged 28.3 mb/d, which is 0.1 mb/d lower than demand for OPEC crude.

Table 10 - 1: Supply/demand balance for 2023*, mb/d

	2022	1Q23	2Q23	3Q23	4Q23	2023	Change 2023/22
(a) World oil demand	**99.57**	**101.65**	**101.18**	**101.96**	**103.21**	**102.01**	***2.44***
Non-OPEC liquids production	65.76	67.70	67.39	66.96	67.03	67.27	*1.51*
OPEC NGL and non-conventionals	5.39	5.44	5.47	5.43	5.43	5.44	*0.05*
(b) Total non-OPEC liquids production and OPEC NGLs	**71.15**	**73.13**	**72.87**	**72.39**	**72.45**	**72.71**	***1.56***
Difference (a-b)	**28.42**	**28.52**	**28.31**	**29.57**	**30.76**	**29.30**	***0.88***
OPEC crude oil production	**28.85**	**28.82**	**28.25**				
Balance	**0.44**	**0.30**	**-0.06**				

*Note: * 2023 = Forecast. Totals may not add up due to independent rounding.*
Source: OPEC.

Table 11 - 1: World oil demand and supply balance, mb/d

World oil demand and supply balance	2020	2021	2022	1Q23	2Q23	3Q23	4Q23	2023	1Q24	2Q24	3Q24	4Q24	2024
World demand													
Americas	22.45	24.32	25.01	24.61	25.22	25.59	25.09	25.13	24.79	25.39	25.79	25.25	25.31
of which US	*18.35*	*20.03*	*20.43*	*20.12*	*20.60*	*20.83*	*20.37*	*20.48*	*20.25*	*20.74*	*20.99*	*20.51*	*20.62*
Europe	12.41	13.11	13.50	13.07	13.25	13.98	13.37	13.42	13.12	13.31	14.05	13.41	13.48
Asia Pacific	7.17	7.38	7.43	7.86	7.08	7.27	7.69	7.47	7.89	7.09	7.30	7.70	7.49
Total OECD	**42.03**	**44.80**	**45.95**	**45.53**	**45.54**	**46.84**	**46.16**	**46.02**	**45.81**	**45.79**	**47.15**	**46.36**	**46.28**
China	13.94	15.00	14.85	15.63	15.96	15.38	16.11	15.77	16.20	16.42	16.00	16.78	16.35
India	4.51	4.77	5.14	5.40	5.40	5.21	5.50	5.38	5.63	5.64	5.44	5.69	5.60
Other Asia	8.13	8.67	9.02	9.40	9.57	9.14	9.24	9.33	9.66	9.82	9.50	9.60	9.64
Latin America	5.90	6.25	6.44	6.60	6.55	6.73	6.68	6.64	6.79	6.73	6.95	6.84	6.83
Middle East	7.45	7.79	8.30	8.63	8.47	8.86	8.73	8.67	8.91	8.91	9.41	8.98	9.05
Africa	4.08	4.22	4.40	4.69	4.32	4.43	4.88	4.58	4.80	4.51	4.60	5.01	4.73
Russia	3.39	3.62	3.56	3.69	3.45	3.60	3.87	3.65	3.75	3.56	3.75	3.94	3.75
Other Eurasia	1.07	1.21	1.15	1.24	1.17	1.02	1.23	1.16	1.27	1.20	1.08	1.28	1.21
Other Europe	0.70	0.75	0.77	0.84	0.76	0.75	0.83	0.80	0.86	0.77	0.77	0.84	0.81
Total Non-OECD	**49.16**	**52.28**	**53.62**	**56.12**	**55.64**	**55.13**	**57.06**	**55.99**	**57.88**	**57.56**	**57.50**	**58.96**	**57.97**
(a) Total world demand	**91.19**	**97.08**	**99.57**	**101.65**	**101.18**	**101.96**	**103.21**	**102.01**	**103.68**	**103.35**	**104.64**	**105.32**	**104.25**
Y-o-y change	***-9.09***	***5.89***	***2.49***	***2.20***	***2.88***	***2.47***	***2.20***	***2.44***	***2.03***	***2.17***	***2.68***	***2.10***	***2.25***
Non-OPEC liquids production													
Americas	24.87	25.46	26.87	27.90	27.97	28.25	28.45	28.14	28.66	28.70	29.16	29.47	29.00
of which US	*17.76*	*18.06*	*19.23*	*20.10*	*20.56*	*20.34*	*20.45*	*20.36*	*20.68*	*20.90*	*21.17*	*21.33*	*21.02*
Europe	3.92	3.79	3.57	3.66	3.62	3.80	3.94	3.75	3.94	3.78	3.79	3.89	3.85
Asia Pacific	0.52	0.51	0.48	0.45	0.45	0.48	0.47	0.46	0.47	0.44	0.45	0.44	0.45
Total OECD	**29.31**	**29.77**	**30.92**	**32.01**	**32.04**	**32.53**	**32.86**	**32.36**	**33.07**	**32.92**	**33.40**	**33.80**	**33.30**
China	4.16	4.32	4.48	4.63	4.63	4.50	4.50	4.56	4.58	4.57	4.54	4.54	4.56
India	0.78	0.78	0.77	0.76	0.78	0.79	0.78	0.78	0.79	0.79	0.79	0.78	0.79
Other Asia	2.53	2.42	2.30	2.31	2.27	2.34	2.36	2.32	2.30	2.27	2.25	2.25	2.27
Latin America	6.02	5.96	6.34	6.69	6.76	6.70	6.79	6.74	6.91	6.98	7.10	7.18	7.04
Middle East	3.15	3.19	3.29	3.27	3.29	3.29	3.30	3.29	3.34	3.33	3.32	3.32	3.33
Africa	1.41	1.34	1.29	1.24	1.28	1.33	1.31	1.29	1.30	1.33	1.36	1.37	1.34
Russia	10.54	10.80	11.03	11.20	10.85	9.93	9.57	10.38	10.20	10.32	10.45	10.56	10.38
Other Eurasia	2.91	2.93	2.83	3.00	2.93	2.98	2.98	2.97	3.03	3.02	3.00	3.04	3.02
Other Europe	0.12	0.11	0.11	0.11	0.11	0.11	0.10	0.11	0.10	0.10	0.10	0.10	0.10
Total Non-OECD	**31.64**	**31.85**	**32.44**	**33.22**	**32.89**	**31.96**	**31.70**	**32.44**	**32.55**	**32.72**	**32.92**	**33.15**	**32.84**
Total Non-OPEC production	60.95	61.61	63.36	65.23	64.92	64.49	64.56	64.80	65.62	65.64	66.32	66.96	66.14
Processing gains	2.16	2.29	2.40	2.47	2.47	2.47	2.47	2.47	2.52	2.52	2.52	2.52	2.52
Total Non-OPEC liquids production	**63.11**	**63.90**	**65.76**	**67.70**	**67.39**	**66.96**	**67.03**	**67.27**	**68.14**	**68.16**	**68.84**	**69.48**	**68.66**
OPEC NGL + non-conventional oils	5.17	5.28	5.39	5.44	5.47	5.43	5.43	5.44	5.49	5.54	5.50	5.50	5.51
(b) Total non-OPEC liquids production and OPEC NGLs	**68.27**	**69.18**	**71.15**	**73.13**	**72.87**	**72.39**	**72.45**	**72.71**	**73.63**	**73.70**	**74.34**	**74.98**	**74.16**
Y-o-y change	***-2.55***	***0.91***	***1.97***	***2.23***	***2.59***	***1.22***	***0.21***	***1.56***	***0.49***	***0.83***	***1.95***	***2.52***	***1.45***
OPEC crude oil production (secondary sources)	25.72	26.35	28.85	28.82	28.25								
Total liquids production	94.00	95.53	100.01	101.96	101.12								
Balance (stock change and miscellaneous)	2.81	-1.55	0.44	0.30	-0.06								
OECD closing stock levels, *mb*													
Commercial	3,037	2,649	2,776	2,757	2,828								
SPR	1,541	1,484	1,214	1,217	1,195								
Total	**4,578**	**4,133**	**3,990**	**3,973**	**4,023**								
Oil-on-water	1,148	1,202	1,399	1,413	1,291								
Days of forward consumption in OECD, *days*													
Commercial onland stocks	68	58	60	61	60								
SPR	34	32	26	27	26								
Total	**102**	**90**	**87**	**87**	**86**								
Memo items													
(a) - (b)	**22.92**	**27.90**	**28.42**	**28.52**	**28.31**	**29.57**	**30.76**	**29.30**	**30.05**	**29.65**	**30.31**	**30.34**	**30.09**

Note: Totals may not add up due to independent rounding.

Source: OPEC.

https://www.iea.org/reports/oil-market-report-august-2023

Oil Market Report - August 2023

Highlights

- World oil demand is scaling record highs, boosted by strong summer air travel, increased oil use in power generation and surging Chinese petrochemical activity. Global oil demand is set to expand by 2.2 mb/d to 102.2 mb/d in 2023, with China accounting for more than 70% of growth. With the post-pandemic rebound running out of steam, and as lacklustre economic conditions, tighter efficiency standards and new electric vehicles weigh on use, growth is forecast to slow to 1 mb/d in 2024.

- Global oil supply plunged by 910 kb/d to 100.9 mb/d in July. A sharp reduction in Saudi production in July saw output from the OPEC+ bloc fall 1.2 mb/d to 50.7 mb/d, while non-OPEC+ volumes rose 310 kb/d to 50.2 mb/d. Global oil output is projected to expand by 1.5 mb/d to a record 101.5 mb/d in 2023, with the US driving non-OPEC+ gains of 1.9 mb/d. Next year, non-OPEC+ supply is also set to dominate world supply growth, up 1.3 mb/d while OPEC+ could add just 160 kb/d.

- Refinery throughputs are set to reach a summer peak of 83.9 mb/d in August, up 2.4 mb/d since May and 2.6 mb/d higher than a year ago. The increase in refined product output has failed to ease product market tightness, pushing gasoline and middle distillate cracks to near record-highs. High sulphur fuel oil cracks provided further support to margins, which pushed above 2022 levels in July.

- Russian oil exports held steady at around 7.3 mb/d in July, as a 200 kb/d decline in crude oil loadings was offset by higher product flows. Crude exports to China and India eased m-o-m but accounted for 80% of Russian shipments. Higher oil prices, combined with narrowing discounts for Russian grades, pushed estimated export revenues up by $2.5 bn to $15.3 bn, $4.1 bn below year-ago levels.

- Global observed oil inventories declined by 17.3 mb in June, led by the OECD. Non-OECD stocks and oil on water were largely unchanged. OECD industry stocks fell by 14.7 mb, in line with the seasonal trend, to 2 787 mb. Industry stocks were 115.4 mb below the five-year average, with product inventories particularly tight. Preliminary data suggest global inventories drew further in July and August.

- ICE Brent futures rallied by $11/bbl to $86/bbl in July as macroeconomic sentiment improved markedly with inflation easing. Tightening physical balances in the wake of Saudi output cuts and lower Russian loadings added additional momentum to the price rebound, pushing crude forward curves deeper into backwardation. At the time of writing, Brent traded around $87/bbl, close to 2023 highs.

Tightening up

Global oil prices moved steadily higher during July and into early August, reflecting a market tightening long projected by this Report. Deepening OPEC+ supply cuts have collided with improved macroeconomic sentiment and all-time high world oil demand. North Sea Dated rose by $10/bbl over the month to around $85/bbl, its highest since April. With output cuts hitting the heavy sour crude market hard, Dubai crude is trading at a rare premium to Brent, while the price of Urals crude has breached the G7-led price cap now making all Russian oil exports ineligible for G7 and EU maritime services.

In July, oil supply from the OPEC+ alliance fell by 1.2 mb/d to a near two-year low as a voluntary reduction from Saudi Arabia came into effect. At 50.7 mb/d, the bloc's production was down more than 2 mb/d from the start of the year. Over the same period, producers outside the group ramped up output by 1.6 mb/d to 50.2 mb/d but limited non-OPEC+ gains are expected for the remainder of the year. The US, Brazil and Guyana lead the expansion, with exports from the trio rising by roughly 15% y-o-y to more than 9 mb/d in July, boosting the availability of light sweet grades in the Atlantic Basin. The US accounts for nearly 80% of global 2023 supply growth, or 1.2 mb/d of the 1.5 mb/d total. Next year, that share is set to slip as activity slows in the shale patch.

World oil demand hit a record 103 mb/d in June and August could see yet another peak. After months of lacklustre readings, OECD demand was revised up for May and June, with overall consumption returning to growth in 2Q23 after two quarters of contraction. Chinese demand was also stronger than expected, reaching fresh highs despite persistent concerns over the health of the economy. For the year, global oil demand looks on track to expand by 2.2 mb/d to 102.2 mb/d, its highest ever annual level. With the post-pandemic recovery having largely run its course and as the energy transition gathers pace, growth will slow to 1 mb/d in 2024.

Refiners are struggling to keep up with demand growth, as the shift to new feedstocks, outages and high temperatures have forced many operators to run at reduced rates. Tight gasoline and diesel markets have pushed margins to six-month highs. While naphtha remains under pressure, due to competition from cheap LPG and weak petrochemical activity outside of China, high-sulphur fuel oil has tightened significantly as refiners replace lost OPEC+ crude with lighter and sweeter grades. High sulphur fuel oil in Rotterdam rose above North Sea Dated for the first time in 28 years.

As a result, crude and products inventories have drawn sharply. In July, observed oil stocks decreased for a third consecutive month, with OECD industry stocks more than 100 mb below the five-year average. Market balances are set to tighten further into the autumn as Saudi Arabia and Russia extend supply cuts at least through September. An ample OPEC+ spare capacity cushion of 5.7 mb/d means there is significant scope for the alliance to raise output later in the year. Additional supplies of heavy sour crude would allow refiners to boost activity and help ease product market tensions. But if the bloc's current targets are maintained, oil inventories could draw by 2.2 mb/d in 3Q23 and 1.2 mb/d in the fourth quarter, with a risk of driving prices still higher.

OPEC+ crude oil production[1]

	Jun 2023 Supply	Jul 2023 Supply	Jul Prod vs Target	Jul-2023 Target	Sustainable Capacity[2]	Eff Spare Cap vs Jul[3]
Algeria	0.95	0.96	-0.05	1.01	1.0	0.04
Angola	1.12	1.15	-0.31	1.46	1.11	-0.04
Congo	0.28	0.28	-0.03	0.31	0.27	-0.01
Equatorial Guinea	0.07	0.07	-0.05	0.12	0.06	-0.01
Gabon	0.21	0.21	0.03	0.18	0.19	-0.02
Iraq	4.19	4.27	-0.16	4.43	4.75	0.48
Kuwait	2.55	2.55	-0.13	2.68	2.83	0.28
Nigeria	1.24	1.1	-0.64	1.74	1.33	0.23
Saudi Arabia	9.98	9.06	-1.42	10.48	12.25	3.19
UAE	3.24	3.24	0.22	3.02	4.2	0.96
Total OPEC-10	**23.83**	**22.89**	**-2.53**	**25.42**	**28.0**	**5.18**
Iran[4]	3.04	3.04			3.8	
Libya[4]	1.15	1.12			1.22	0.1
Venezuela[4]	0.79	0.81			0.8	-0.01
Total OPEC	**28.81**	**27.86**			**33.82**	**5.28**
Azerbaijan	0.5	0.5	-0.19	0.68	0.54	0.04
Kazakhstan	1.6	1.51	-0.12	1.63	1.67	0.16
Mexico[5]	1.67	1.59		1.75	1.68	0.09
Oman	0.8	0.8	-0.04	0.84	0.85	0.05
Russia	9.45	9.4	-0.55	9.95	9.98	
Others [6]	0.85	0.81	-0.25	1.06	0.87	0.08
Total Non-OPEC	**14.88**	**14.6**	**-1.14**	**15.91**	**15.58**	**0.43**
OPEC+ 19 in cut deal[4]	**37.04**	**35.9**	**-3.67**	**39.57**	**41.9**	**5.52**
Total OPEC+	**43.69**	**42.46**			**49.41**	**5.71**

1. Excludes condensates. 2. Capacity levels can be reached within 90 days and sustained for an extended period. 3. Excludes shut in Iranian, Russian crude. 4. Iran, Libya, Venezuela exempt from cuts. 5. Mexico excluded from OPEC+ compliance. Only cut in May, June 2020. 6. Bahrain, Brunei, Malaysia, Sudan and South Sudan.

IEA World Oil Supply and Demand Forecasts: Summary (Table)
2023-08-11 08:00:00.9 GMT
By Kristian Siedenburg
(Bloomberg) -- Following is a summary of world oil supply and demand forecasts from the International Energy Agency in Paris:

	4Q 2024	3Q 2024	2Q 2024	1Q 2024	4Q 2023	3Q 2023	2Q 2023	1Q 2023	2024	2023
	Demand									
Total Demand	104.3	104.2	102.6	101.5	103.1	102.9	102.0	100.6	103.2	102.2
Total OECD	46.0	46.6	45.2	45.0	46.3	46.7	45.9	45.6	45.7	46.1
Americas	25.0	25.4	25.0	24.4	25.2	25.5	25.5	24.7	24.9	25.2
Europe	13.3	13.8	13.2	12.9	13.3	13.9	13.5	13.1	13.3	13.4
Asia Oceania	7.8	7.4	7.0	7.8	7.7	7.3	6.9	7.8	7.5	7.4
Non-OECD countries	58.3	57.5	57.4	56.5	56.8	56.2	56.1	55.0	57.4	56.0
FSU	5.0	5.0	4.8	4.9	5.0	5.0	4.9	4.9	4.9	4.9
Europe	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
China	17.1	16.7	16.9	16.6	16.6	16.3	16.5	15.6	16.8	16.2
Other Asia	15.2	14.4	14.7	14.7	14.7	13.9	14.4	14.4	14.8	14.4
Americas	6.5	6.5	6.4	6.2	6.3	6.5	6.3	6.2	6.4	6.3
Middle East	9.1	9.7	9.3	8.9	9.0	9.5	9.0	8.8	9.2	9.1
Africa	4.6	4.4	4.4	4.5	4.4	4.2	4.2	4.4	4.5	4.3
	Supply									
Total Supply	n/a	n/a	n/a	n/a	n/a	n/a	101.5	101.8	n/a	n/a
Non-OPEC	69.0	69.1	68.7	67.9	67.8	67.5	67.2	67.0	68.7	67.3
Total OECD	31.5	31.2	31.1	31.1	31.0	30.6	30.4	30.4	31.2	30.6
Americas	27.8	27.6	27.5	27.3	27.3	27.1	26.7	26.7	27.5	27.0
Europe	3.2	3.1	3.2	3.3	3.2	3.0	3.2	3.3	3.2	3.2
Asia Oceania	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.5	0.5	0.5
Non-OECD	31.8	31.7	31.7	31.7	31.2	31.0	31.2	31.6	31.7	31.3
FSU	13.8	13.7	13.7	13.7	13.6	13.4	13.7	14.1	13.7	13.7
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	4.3	4.4	4.3	4.4	4.2	4.3	4.3	4.3	4.3	4.3
Other Asia	2.6	2.6	2.6	2.6	2.6	2.7	2.6	2.7	2.6	2.7
Americas	6.6	6.5	6.5	6.4	6.2	6.1	6.0	6.0	6.5	6.1
Middle East	3.1	3.1	3.1	3.2	3.1	3.1	3.1	3.1	3.1	3.1
Africa	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.2	1.3	1.3
Processing Gains	2.4	2.4	2.4	2.4	2.4	2.4	2.3	2.3	2.4	2.4
Total OPEC	n/a	n/a	n/a	n/a	n/a	n/a	34.3	34.8	n/a	n/a
Crude	n/a	n/a	n/a	n/a	n/a	n/a	28.8	29.4	n/a	n/a
Natural gas liquids NGLs	5.5	5.5	5.6	5.6	5.5	5.5	5.5	5.4	5.5	5.5
Call on OPEC crude and stock change *	29.8	29.6	28.4	28.1	29.8	30.0	29.3	28.2	29.0	29.3

NOTE: Figures are in million of barrels per day. (*) equals total demand minus non-OPEC supply and OPEC natural gas liquids.
IEA changed the way it measures OPEC supply, adopting the industry-standard approach of counting most of Venezuela's Orinoco heavy oil as "crude oil."
SOURCE: International Energy Agency

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IEA: July Crude Oil Production in OPEC Countries (Table)
2023-08-11 08:00:00.7 GMT
By Kristian Siedenburg
(Bloomberg) -- Following is a summary of oil production in OPEC countries from the International Energy Agency in Paris:

	July 2023	June 2023	July MoM
Total OPEC	27.86	28.81	-0.95
Total OPEC10	22.89	23.83	-0.94
Algeria	0.96	0.95	0.01
Angola	1.15	1.12	0.03
Congo	0.28	0.28	0.00
Equatorial Guinea	0.07	0.07	0.00
Gabon	0.21	0.21	0.00
Iraq	4.27	4.19	0.08
Kuwait	2.55	2.55	0.00
Nigeria	1.10	1.24	-0.14
Saudi Arabia	9.06	9.98	-0.92
UAE	3.24	3.24	0.00
Iran	3.04	3.04	0.00
Libya	1.12	1.15	-0.03
Venezuela	0.81	0.79	0.02

NOTE: Figures are in million of barrels per day. Monthly level change calculated by Bloomberg. Production data excludes condensates.
OPEC10 excludes Iran, Libya and Venezuela.
SOURCE: International Energy Agency

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IEA REPORT WRAP: Global Demand Hits Record; Russian Revenue Up
2023-08-11 10:04:23.502 GMT
By Prejula Prem
(Bloomberg) -- Summary of stories from IEA's monthly Oil Market Report:
* Global Oil Demand Hits Record and Prices May Climb
** 2023 demand to rise by 2.2m b/d to 102.2m b/d, growth forecast to slow to 1m b/d in 2024

** World oil output set to rise to record 101.5m b/d in 2023
** Global stocks declined 17.3m b/d in June, lead by OECD
* Russian Oil Revenue at Eight-Month High as Price Cap Breached
** Crude exports fall as domestic refinery runs rise
** Crude price breached cap at avg $64.41 in July
** Russia more than fulfilled oil-cut pledge last month
* OPEC Crude Output Tumbles 950k B/D on Saudi Cutbacks
** OPEC+ oil supply fell 1.2m b/d in July, near two-year low
** Click here for table
* IEA World Oil Supply/Demand Key Forecasts
** Click here for detailed quarterly forecast table by region
** Click here for revisions to supply/demand forecast
* Refiners Set to Enjoy ‘Elevated’ Margins for Rest of 2023
* Europe Refining Runs to Decline Y/y in 3Q, Americas Steady
** Refinery throughputs to rise 2.6m b/d y/y in August
* Offshore Oil Rig Market Enters New Growth Cycle
* West African Crude Prices Gained After Forcados Outage

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IEA World Oil Supply/Demand Key Forecasts
2023-08-11 08:00:00.10 GMT
By Kristian Siedenburg
(Bloomberg) -- World oil demand 2024 forecast was unrevised at 103.2m b/d in Paris-based Intl Energy Agency’s latest monthly report.
* 2023 world demand was revised to 102.2 from 102.1m b/d
* Demand change in 2024 est. 1% y/y or 1m b/d
* Non-OPEC supply 2024 was revised to 68.7m b/d from 68.5m b/d
* Call on OPEC crude 2024 was revised to 29.0m b/d from 29.2m b/d
* Call on OPEC crude 2023 was unrevised at 29.3m b/d
** OPEC crude production in July fell by 27.86m b/d
* Detailed table: FIFW NSN RZ7THIGQITJ4 <GO>
* NOTE: Fcasts based off IEA’s table providing one decimal point

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Global Oil Demand Hits Record and Prices May Climb, IEA Says
2023-08-11 08:00:00.36 GMT
By Grant Smith
(Bloomberg) -- Global oil demand has surged to a record amid robust consumption in China and elsewhere, threatening to push prices higher, the International Energy Agency said.
World fuel use averaged 103 million barrels a day for the first time in June and may soar even higher in August, the agency said in a report. As Saudi Arabia and its partners constrict supplies, oil markets are tightening significantly.
“Oil demand is scaling record highs, boosted by strong summer air travel, increased oil use in power generation and surging Chinese petrochemical activity,” the Paris-based IEA said. “Crude and products inventories have drawn sharply” and “balances are set to tighten further into the autumn.”
Oil this week touched a six-month high above $88 a barrel in London amid the post-pandemic resurgence in fuel use and supply restraint by the Saudi-led OPEC+ alliance. Brent futures eased back a little to trade below $87 on Friday.
The plunge in world oil demand during the Covid-19 crisis three years ago spurred speculation that consumption may be close to a peak as remote working gained in popularity and governments sought to shift away from fossil fuels to avert catastrophic climate change.
But the IEA data shows that, despite growing evidence of a warming planet shown by this summer’s heat waves and wildfires in the Northern Hemisphere, oil use is stronger than ever. China will account for 70% of this year’s demand growth, but surprisingly resilient developed nations added to the latest surge.

Energy Shift

The energy transition looks set to have an impact next year, when global demand growth will roughly halve to 1 million barrels a day due to improved vehicle efficiency and the adoption of electric cars, the IEA said.
But in the meantime, world markets are tightening, leaving oil inventories in developed nations about 115 million barrels below their five-year average, according to the report. Global

stockpiles are set to deplete by a hefty 1.7 million barrels a day in the second half of the year, and preliminary data appears to confirm declines in July and August, the IEA said.

Major consuming nations have criticized the Saudis and their allies in OPEC+ for constricting supplies, warning that a renewed inflationary spike would squeeze consumers and endanger the global recovery. Nonetheless, Riyadh has said it could deepen current cutbacks if necessary.

Output from the Organization of Petroleum Exporting Countries and its partners plunged last month to near a two-year low as the Saudis implemented a unilateral cut of 1 million barrels a day. Russia, a fellow member of the coalition, is also reducing exports.

The need for OPEC's crude during the fourth quarter looks a little less pressing compared with last month's report, as a slightly weaker demand outlook for the period and a little extra supply elsewhere shave the requirement for OPEC production by 400,000 barrels a day.

Nonetheless, an average of 29.8 million barrels a day is needed from the cartel's 13 members between October and December — far more than the 27.9 million a day they pumped in July, according to the IEA.

"If the bloc's current targets are maintained, oil inventories could draw" significantly, the agency warned, "with a risk of driving prices still higher."

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OPEC Crude Output Tumbles 950k B/D on Saudi Cutbacks, IEA Says
2023-08-11 08:00:00.2 GMT
By Amanda Jordan

(Bloomberg) -- OPEC's July crude output sank 950k b/d from a month earlier to 27.86m b/d as Saudi Arabia slashed supply, the IEA said in its monthly market report.

* Saudi Arabia cut output by 920k b/d to 9.06m b/d, leaving production trailing behind Russia for the first time since early 2022

* UAE and Kuwaiti volumes were unchanged at 3.24m b/d and 2.55m b/d, respectively
* Iraqi output climbed 80k b/d to 4.27m b/d
* Iranian supply held near a five-year high at 3.04m b/d
* Nigerian production fell 140k b/d to 1.1m b/d on suspended Forcados loadings
* Angolan supply rose 30k b/d to 1.15m b/d
* Algerian output inched up to 960k b/d
* Libyan production slipped 30k b/d to 1.12m b/d
* Supply in Venezuela edged up 20k b/d to 810k b/d
* NOTE: OPEC released its own figures for July on Thursday, estimating output from its 13 members declined by 836k b/d

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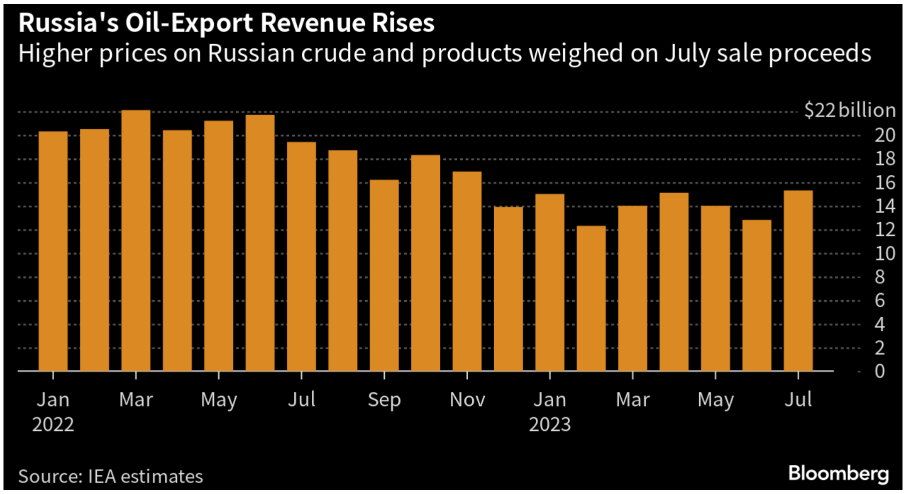
Russian Oil Revenue at Eight-Month High as Price Cap Breached
2023-08-11 08:00:37.507 GMT
By Bloomberg News
(Bloomberg) -- Russia’s oil-export revenue rose last month to the highest since November, as the country’s crude exceeded a price cap set by Group of Seven nations, according to the International Energy Agency.
In July, Russia’s crude topped $60 a barrel, breaching the G-7 price cap intended to keep the nation’s supplies in global markets while limiting the inflow of petrodollars to Moscow. The weighted average price for Russian seaborne crude exports rose $8.84 a barrel to $64.41 a barrel, the IEA data shows.
Russia benefited from higher global prices and narrowing discounts on the nation’s crude and petroleum products, the IEA said. The nation earned $15.3 billion from exports of its crude and fuel in July, up by almost 20% from previous month, the IEA said in its monthly market report.
Still, Russia’s oil revenues were down by more than a fifth from a year earlier, according to the IEA. Oil is a key source of revenue for Russian state coffers, which have been strained by the cost of its war in Ukraine and Western sanctions.



The discount of the nation's main Urals blend to Brent narrowed by some $4 barrels a day, despite North Sea dated prices rising $5 a barrel in July from previous month, according to the IEA. The agency's estimates are for the so-called free-on-board, or FOB, price which excludes shipping and insurance costs.

"Urals price strength versus the light sweet European marker reflects heightening sour grade supply tensions following OPEC+ supply cuts and a post-maintenance rise in refinery demand," the IEA said.

Russian crude exports fell amid production curbs and rising supplies to domestic market after major seasonal maintenance was completed.

Read: Russia Raises July Oil Processing as Major Maintenance is Over

Daily crude overseas supplies fell by 200,000 barrels to 4.6 million, the IEA said. Available data show exports eased to China and India, but those countries still accounted for about 80% of Russian shipments, according to the agency.

The decline in crude oil loadings was offset by higher product flows that allowed Russia to keep total oil exports at 7.3 million barrels a day, the same as June, according to the IEA. That matched the lowest in at least a year.

The agency estimated Russia's crude output at 9.4 million barrels a day in July, down 50,000 barrels from June. That means the nation over-complied with its pledge to cut production by 500,000 barrels day from the February baseline assessed by OPEC secondary sources at 9.949 million barrels a day.

In addition to output curbs, Russia also pledged to reduce its overseas supplies by 500,000 barrels a day this month and taper the cuts to 300,000 barrels a day in September.

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Russian Crude Exports Fall as Domestic Refinery Runs Rise: IEA
2023-08-11 08:00:00.12 GMT
By Sherry Su
(Bloomberg) -- Russian crude exports fell by 300k b/d from pre-war level in July, the lowest since December 2022, following production cuts and rising domestic refinery runs, the IEA said in its monthly Oil Market Report.
* Russian crude and product exports held largely steady in July at 7.3m b/d: product trade rose 200k b/d m/m to 2.7m b/d while crude exports fell by 200k b/d to 4.6m b/d
* For cargoes that have shown final destinations, crude exports eased 200k b/d m-o-m for both China and India, though they still accounted for nearly 80% of total Russian crude exports in July.
** Shipments into East Europe rose by 40k b/d to 420k b/d but fell 45k b/d over the month for Turkey to 150k b/d
* Increases for fuel oil (+100k b/d to 560k b/d), gasoil (+160k b/d to 1.1m b/d), gasoline (+50k b/d to 190k b/d) and VGO (+70k b/d to 360k b/d) were partially offset by a sharp drop for naphtha (-180k b/d to 350k b/d)
* Product exports to the Middle East fell sharply (-200k b/d to 260k b/d) and eased to Turkey (-40k b/d to 480k b/d) but they rose to India (+80k b/d to 230k b/d), Africa (+55k b/d to 410k b/d) and OECD Asia Oceania (+50k b/d to 60k b/d).
* China, India, Turkey and the Middle East take a third of Russian product exports despite being large exporters themselves

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Offshore Oil Rig Market Enters New Growth Cycle, IEA Says
2023-08-11 08:00:00.11 GMT
By Alex Longley
(Bloomberg) -- The offshore rig market has rallied due to developments in Guyana, Brazil, the Middle East, as well as

exploration in Namibia, India and the Eastern Mediterranean, the
IEA said in its monthly report.
* The market is also buoyed by infill drilling in West Africa
* Offshore fleet has consolidated since 2014 from 270 rigs to
146
* High-spec ultra-deepwater harsh environment rigs are fully
booked for the first time since 2014

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Refiners Set to Enjoy "Elevated" Margins for Rest of 2023: IEA
2023-08-11 08:00:00.13 GMT
By Julian Lee
(Bloomberg) -- Refiners "could see sustained elevated
margins" in the coming months as they "operate in a deficit
market environment of 2m b/d this quarter and 1.3m b/d next
quarter," the IEA said in its latest monthly report.
* Lack of OECD product inventories has "left cracks vulnerable
to unplanned outages and the threat of supply curtailment from
other factors, such as the recent extreme heat events"
* Refineries are "currently benefiting from a margin environment
that eclipses almost any other period except 2022"
** Situation "is reminiscent of 2005-07 when strong middle
distillate demand growth combined with a lack of upgrading
capacity underpinned exceptional margins for complex refineries"
* Margins rose above 2022 levels after a late-July spike in
gasoline, diesel cracks
* HSFO turned positive in early August against light, sweet
crude in Europe and Dubai crude in Singapore
* Hydroskimming margin on light sweet crude in Europe averaged
over $8/bbl in July, rising above $13/bbl in early August
** That's the highest level of profitability with the exception
of the post-Russia Ukraine invasion period
** Margins are being boosted by the absence of the usual drag of
negative fuel oil cracks
* "Compression of the spread between hydroskimming and cracking
margins suggests that crude market fundamentals have improved,
as the OPEC+ production cuts start to bear fruit"

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Europe Refining Runs to Decline Y/y in 3Q, Americas Steady: IEA
2023-08-11 08:00:00.33 GMT
By Jack Wittels
(Bloomberg) -- OECD European crude processing is expected to decline by 600k b/d y/y in 3Q, the IEA said in its monthly Oil Market Report.
* Runs to average 11.2m b/d, with "a consequential impact on regional product supply"
** OECD Asia Oceania refinery throughputs expected to be nearly 250k b/d lower y/y
* "OECD Americas crude runs are forecast to hold steady from a year ago during 3Q"
** OECD Americas refinery crude throughput forecast at 19m b/d

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West African Crude Prices Gained After Forcados Outage: IEA
2023-08-11 08:00:00.34 GMT
By Bill Lehane
(Bloomberg) -- West African crude differentials gained in July as regional supply losses buoyed sentiment, particularly the outage at Nigeria's Forcados terminal, IEA says in monthly oil market report.
* Qua Iboe crude differential added 87 cents month-on-month to a $1.97/bbl premium to North Sea Dated
** Brass +94c to +62c/bbl, Bonny +48c to +$1.12/bbl
* "The narrow Brent-to-Dubai spread and strong values for the bottom of the barrel boosted Asian demand for heavy-sweet Angolan crudes"
** Girassol + 43c to $+2/bbl, Cabinda +2c $1.24/bbl

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

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

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

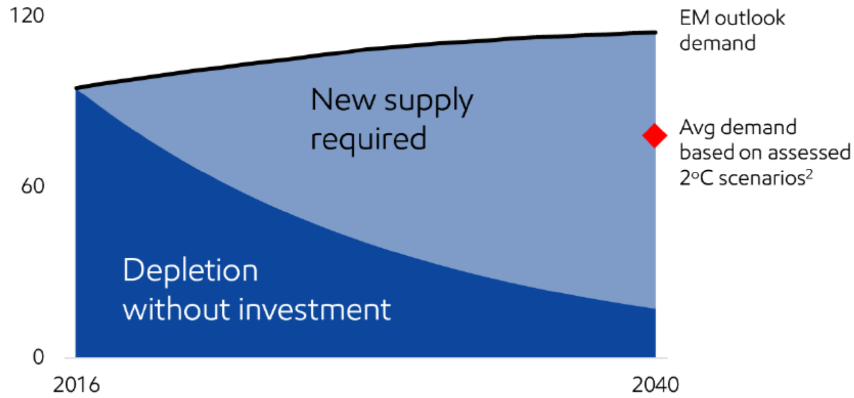
<u>The 2019/2020 oil story - oil inventories still above the 5 yr ave and OPEC+ need to work together in 2020.</u> There is increasing geopolitical risk to oil in a range of regions (Iran/Saudi Arabia, Libya, Venezuela, etc.) yet the prevailing tone to oil in the past month is negative with the concerns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

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

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

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

Oil Supply/Demand (moebd)

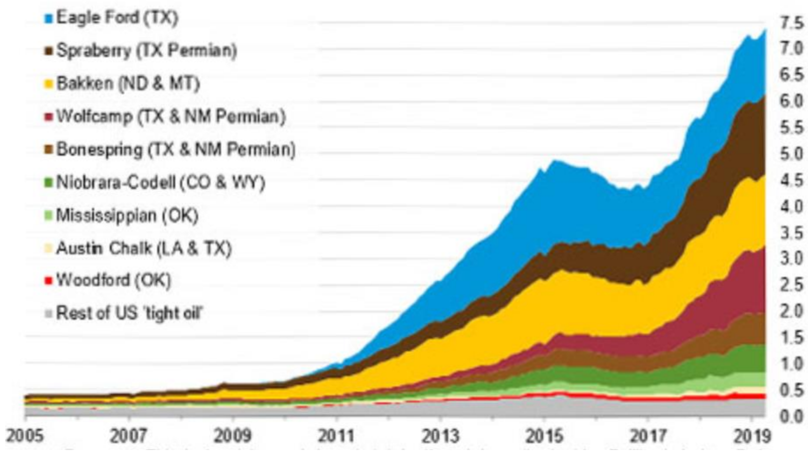


Source: Exxon US Sellside Conference Presentation June 18, 2019

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

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

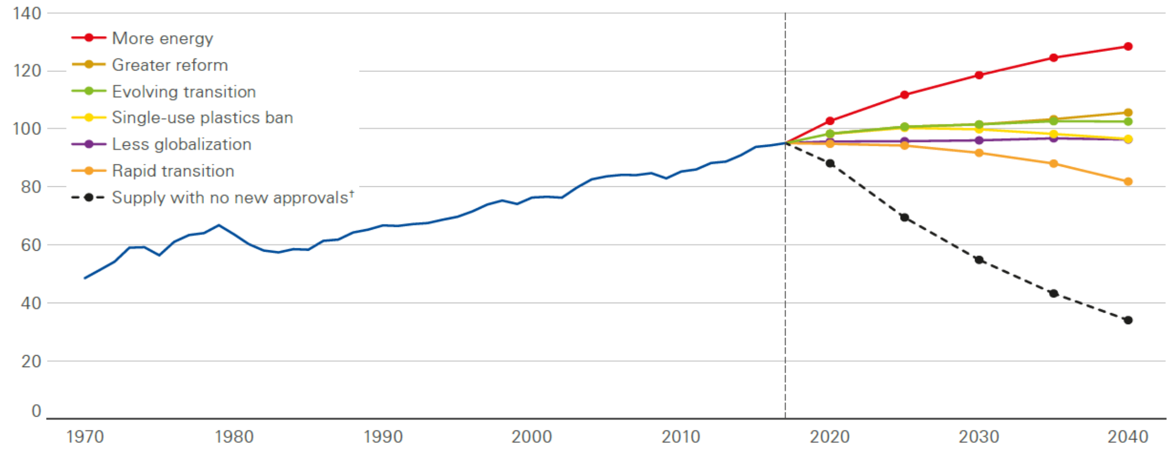
US Tight Oil Production – Selected Plays (Million barrels of oil per day)



Source: EIA

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

Demand and Supply of Oil (Mbd)



Source: BP Energy Outlook 2019 Edition

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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https://www.globaltimes.cn/page/202308/1296026.shtml

China resumes group tours to another 78 countries, including US, Japan, India, Australia

By Global Times
Published: Aug 10, 2023 12:56 PM

Photo:VCG

China on Thursday announced the resumption of a third round of group tours to some 78 countries including the US, Japan, South Korea, Australia, India and the majority of European countries.

The Ministry of Culture and Tourism made the announcement with immediate effect, specifying that the outbound group tour services to these countries will be resumed at all national travel agencies and online travel companies.

The 78 countries include 12 in Asia, 27 in Europe, 18 in Africa and others from North America, South America and Oceania, according to the notice.

"Since the trial resumption of outbound group tours for Chinese citizens, the overall operation of outbound tourism market has remained stable and orderly, which has played a positive role in promoting tourism exchanges and cooperation," the ministry said.

China has previously resumed group tours to 60 countries over two stages earlier this year, including groups to Russia, France, Spain, Italy and other European countries, as well as countries in Southeast Asia and Africa.

Chinese travelers' enthusiasm for outbound trips, pent up over three years, has been unleashed with a surge continuing from the beginning of the year until now, especially as students entered summer vacation.

While Southeast Asia remains the most popular destination for Chinese travelers with its relatively short distance and cheap prices, Iran, the Caucasus region, Central Asia, the Balkans, and New Zealand have become the "dark horses" in this year's summer outbound tourism market.

Global Times

Air Passenger Market Analysis

June 2023

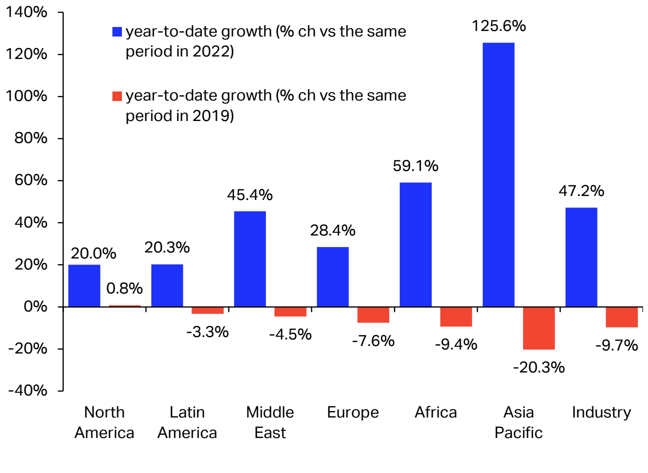
Strong first half of the year ends on a positive note for the industry

- In the first half of 2023, global revenue passenger-kilometers (RPKs) rose by 47.2% compared to the same period last year. The strong recovery trend persisted through June, as passenger traffic grew by 31.0% year-on-year (YoY), reaching 94.2% of pre-Covid levels.
- Domestic traffic increased 27.2% YoY in June, surpassing pre-pandemic RPKs by 5.1%. This result was driven by the robust performance of major domestic markets.
- While different regions experienced varying recovery patterns, total international RPKs grew 33.7% from June 2022 levels, maintaining the strong recovery seen this year. Notably, Asia Pacific carriers sustained their growth momentum, buoyed by the region's resilient air travel demand.

Global industry recovered significantly in H1 2023…

During the first half (H1) of 2023, all regions achieved strong passenger traffic growth and made significant progress towards restoring pre-pandemic traffic levels. Although recovery trends varied across regions, industry-wide RPKs grew 47.2% YoY and were only 9.7% below 2019 levels. (**Chart 1**).

Chart 1 – Revenue-passenger kilometer (RPK) growth by airline region of registration, YTD June 2023 (% ch)



Sources: IATA Sustainability and Economics, IATA Monthly Statistics

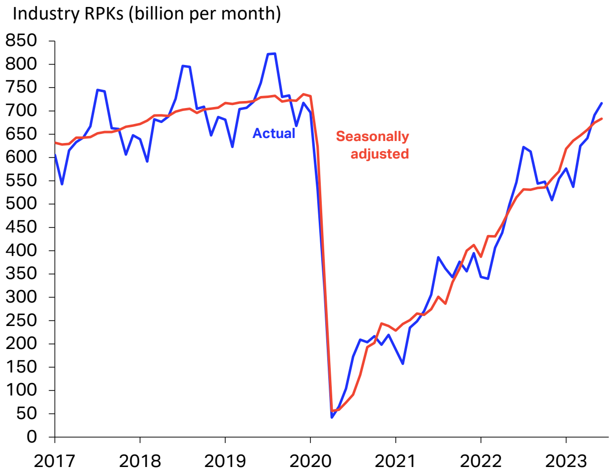
In H1 2023, Asia Pacific airlines saw a sharp recovery, as passenger traffic surged by 125.6% compared to 2022 levels. This recovery was driven by the reopening of China, the largest passenger market in the region, and the steady restoration of international travel in the region over the past year. RPKs for the Asia Pacific airlines jumped from 35.1% of 2019 levels in H1 2022 to 79.7% in H1 2023.

North American carriers, being among the first airlines to resume operations, led the way in terms of recovery. With an additional 20.0% growth over 2022 levels in the first six months of the year, their RPKs outperformed pre-pandemic traffic by 0.8%. While other regions also experienced notable traffic recovery year-to-date (YTD) through June, the pace of growth moderated across all regions as RPKs approached their 2019 levels.

…with the positive momentum maintained in June

In June, industry-wide RPKs grew by 31.0% YoY, while available seat-kilometers (ASKs) rose by 28.8%. On a seasonally-adjusted basis, RPKs continued their growth trend, increasing by 1.2% month-on-month, maintaining the momentum seen this year (**Chart 2**).

Chart 2 – Global air passengers, revenue-passenger kilometers (RPKs), billions per month



Sources: IATA Sustainability and Economics, IATA Monthly Statistics

Air passenger market overview - June 2023

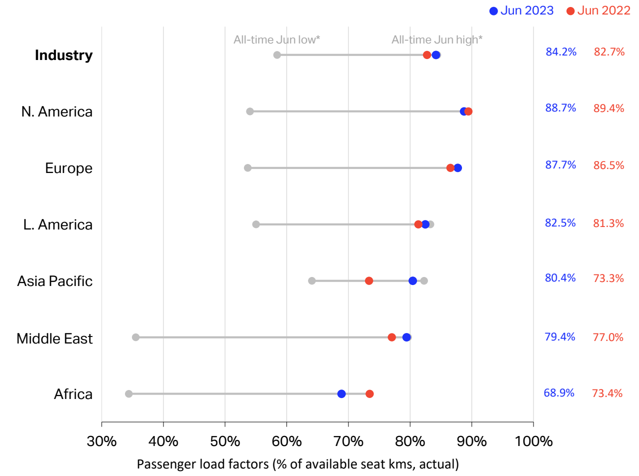
	World	June 2023 (% year-on-year)				June 2023 (% ch vs the same month in 2019)			
	share [1]	RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]	RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]
TOTAL MARKET	***100.0%***	**31.0%**	**28.8%**	**1.4%**	**84.2%**	**-5.8%**	**-5.5%**	**-0.2%**	**84.2%**
International	*58.0%*	33.7%	31.7%	1.3%	85.0%	-11.8%	-13.2%	1.4%	85.0%
Domestic	*42.0%*	27.2%	24.7%	1.6%	82.9%	5.1%	8.7%	-2.8%	82.9%

[1]% of industry RPKs in 2022 [2]Change in load factor [3]Load factor level

Despite these positive trends, passenger traffic remains 5.8% below 2019 levels. This decline signifies a contraction of 1.7 percentage points (ppts) from the performance recorded in May.

The passenger load-factor (PLF) reached 84.2% globally, which was only 0.2 ppts down from the 2019 level. Most regions have experienced strong traffic recovery, with their PLFs approaching their June all-time highs. European carriers, in particular, achieved a record load factor level of 87.7% for the month of June. Asia Pacific carriers also saw a noticeable improvement in their load factors, which increased by 7.1 ppts compared to June 2022, reaching 80.4% (**Chart 3**).

Chart 3 – Passenger load factors, by airline region of registration

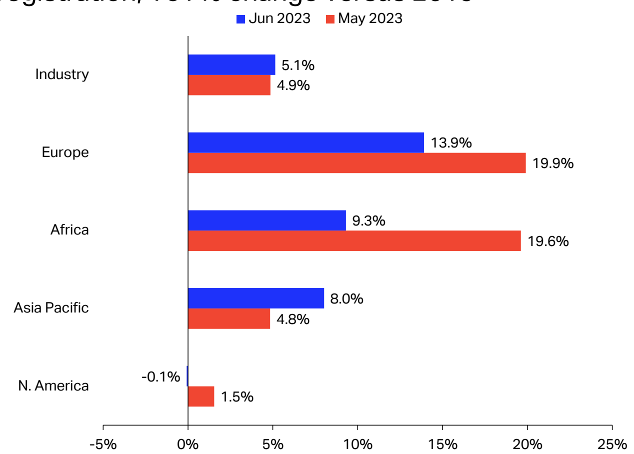


Sources: IATA Sustainability and Economics, IATA Monthly Statistics *Data from 1990 onwards

Domestic traffic recovery remained resilient

In June, domestic traffic continued to trend above pre-pandemic levels, with RPKs rising by 27.2% YoY and standing 5.1% higher than the levels seen in 2019 (**Chart 4**). However, the domestic PLF fell short by 2.8 ppts compared to June 2019, as the growth in ASKs slightly outpaced the recovery in passenger traffic.

Chart 4 – Domestic RPK growth by airline region of registration, YoY% change versus 2019



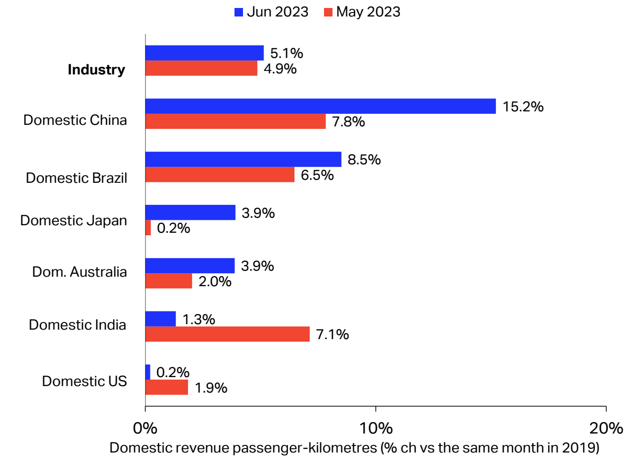
Sources: IATA Sustainability and Economics, IATA Monthly Statistics

European airlines continued to lead the growth in domestic traffic, showing a substantial 13.9% increase in domestic RPKs compared to 2019. Latin America and Asia Pacific airlines followed with growth rates of 12.7% and 6.0%, respectively. In contrast, domestic traffic for North American carriers fell 0.1% below the pre-pandemic threshold this month (**Chart 4**).

The US domestic market, however, conserved its momentum, growing 0.2% over June 2019 levels. Throughout the first half of the year, this market has shown robust performance, standing 2.2% above pre-Covid levels. The positive trend observed in Brazil persisted, with domestic RPKs experiencing a second consecutive month of full recovery, after the initial rebound seen in May. June passenger traffic in Brazil was 8.5% higher than pre-Covid levels, after growing 13.3% YoY (**Chart 5**).

For Asia Pacific carriers, the increase in domestic traffic continued to be driven by growth in China. Domestic RPKs in the region rose by 8.0% over pre-pandemic levels, with the world's second-largest domestic market surpassing 2019 levels by 15.2%.

Chart 5 – Domestic RPK growth by market, YoY% change versus 2019



Sources: IATA Sustainability and Economics, IATA Monthly Statistics

The other major domestic markets in the Asia Pacific region have achieved similar results in June. Passenger traffic in India grew 14.8% YoY and stood 1.3% above pre-pandemic RPKs. Japan also experienced a remarkable 33.8% annual growth in domestic RPKs and continued to trend above 2019 levels. Australia's RPKs contracted slightly by 1.7% over the year but remained 3.9% higher than their pre-Covid benchmark (**Chart 5**). Notably, these three markets have also demonstrated significant year-to-date growth in H1 2023, approaching traffic levels similar to those observed in H1 2019.

International recovery stayed on course…

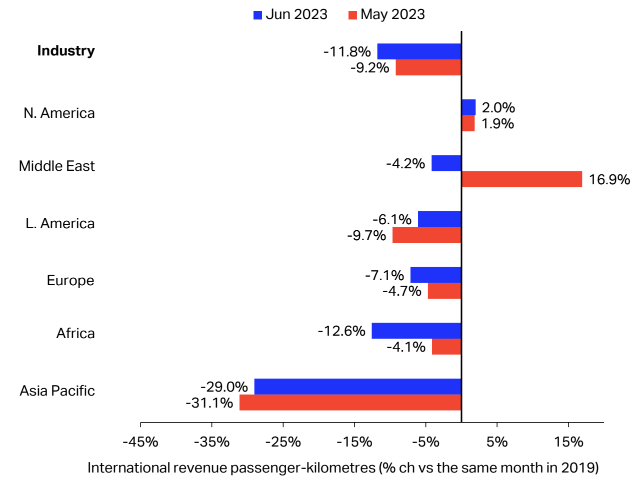
Despite the 2.6 ppt contraction in recovery performance from May to June (**Chart 7Chart 6**), international passenger traffic showed resilience, climbing by 1.5% MoM in seasonally-adjusted terms, indicating sustained positive momentum. In addition, industry-wide international RPKs grew by 33.7% YoY, with the load factor surpassing the previous year and pre-pandemic levels by 1.3 and 1.4 ppts, respectively. The first six months of 2023 witnessed strong growth in international passenger traffic, with RPKs rising 58.6% over H1 2022 and sitting 16.1% below H1 2019 levels.

...while regions experienced mixed results

In June, carriers based in North America kept their leading position in terms of recovery to 2019 levels with 2.0% growth over June 2019 international RPKs. Meanwhile, Asia Pacific airlines sustained their strong passenger traffic rebound, leading in growth with international RPKs and ASKs surging by 128.1% and 115.6% YoY, respectively. As of June, international RPKs for Asia Pacific carriers were 29.0% below pre-Covid levels (**Chart 6**).

For European airlines, international traffic recovery showed signs of steadying, with a slowdown in annual growth. Both passenger traffic and seat capacity continued to trend sideways compared to 2019 levels. In June, international RPKs grew 14.0% YoY and remained 7.1% under pre-covid levels (**Chart 6**).

Chart 6 – International RPK growth by airline region of registration, YoY% change versus 2019



Sources: IATA Sustainability and Economics, IATA Monthly Statistics

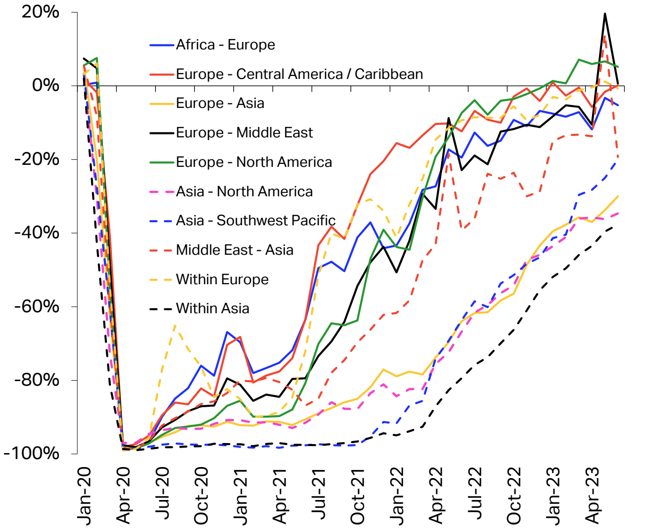
Middle Eastern carriers experienced a significant surge in international traffic growth last month, rebounding from a low base due to structural changes in the region in May 2019. Nevertheless, in June, international RPKs for this region's carriers remained 4.2% below pre-pandemic levels (**Chart 6**). Meanwhile, Latin America airlines have consistently expanded their international seat capacity with rising passenger traffic in recent months. By June, their passenger traffic remained 6.1% below pre-pandemic levels.

Although African carriers achieved robust annual passenger traffic growth of 34.7%, their recovery in June remained further behind, trailing 2019 levels by 12.6%. The region's carriers also saw seat capacity rise faster than RPKs, leading to a decreased load factor when compared to the same months in 2019 and 2022 (**Chart 6**).

Major international passenger flows were on track to full recovery

Overall, the most traffic-intense route areas of 2019 have experienced diverse outcomes. International passenger traffic between the Americas, Europe and the Middle East have recovered the fastest. On the other hand, tremendous growth in Asia Pacific is rapidly closing the gap with the rest of the world as airlines resume normal operations. Notably, passenger flows from Europe have made substantial progress in the recovery (**Chart 7, Chart 8**).

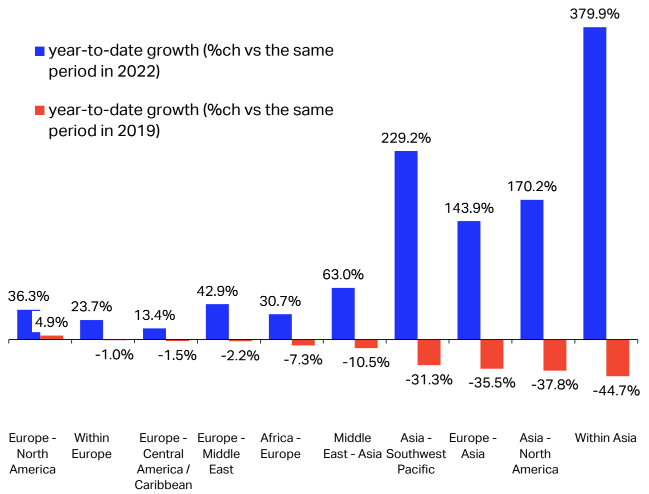
Chart 7 – International RPKs, YoY% change versus 2019 – Top 10 route areas in 2019



Source: IATA Sustainability and Economics, IATA Monthly Statistics

Europe – North America took the lead in recovery among the route areas, experiencing a 4.9% growth over H1 2019 and a remarkable 36.3% increase in RPKs compared to H1 2022. Meanwhile, passenger traffic within Asia Pacific achieved significant growth over the first half of 2023, with a 379.9% increase over the period (**Chart 8**).

Chart 8 - International RPKs, YTD June 2023 (% ch) – Top 10 route areas, ranked by 2019 traffic level



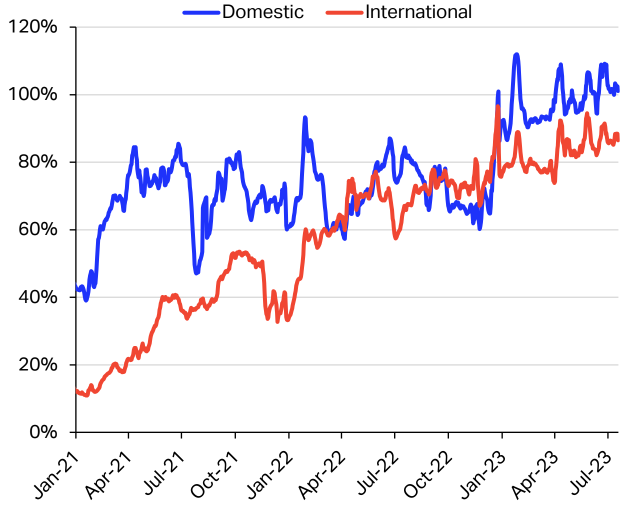
Sources: IATA Sustainability and Economics, IATA Monthly Statistics

Ticket sales indicate sustained demand in upcoming months

Despite macroeconomic challenges affecting households, ticket sales suggest that the demand for air travel was robust in June, at the start of the Northern Summer Travel Season. The increase in ticket sales preceding the peak season played a significant role in this resilience, with domestic ticket sales surpassing pre-pandemic levels through July **(Chart 9)**.

International ticket sales also continued to approach 2019 levels as the increase in demand remained robust, marking a strong start for the travel peak season. These developments also signal that passenger traffic recovery will be sustained in the near future.

Chart 9 – Ticket sales by purchase date, 7-day moving average - % share of 2019 levels



Sources: IATA Sustainability and Economics, DDS

Air passenger market in detail - June 2023

	World share[1]	June 2023 (% year-on-year)				June 2023 (% ch vs the same month in 2019)			
		RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]	RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]
TOTAL MARKET	***100.0%***	**31.0%**	**28.8%**	**1.4%**	**84.2%**	**-5.8%**	**-5.5%**	**-0.2%**	**84.2%**
Africa	*2.1%*	31.8%	40.5%	-4.6%	68.9%	-9.8%	-6.9%	-2.2%	68.9%
Asia Pacific	*22.1%*	90.1%	73.3%	7.1%	80.4%	-12.4%	-10.4%	-1.8%	80.4%
Europe	*30.8%*	13.0%	11.5%	1.2%	87.7%	-4.9%	-5.3%	0.3%	87.7%
Latin America	*6.4%*	18.7%	17.1%	1.1%	82.5%	2.6%	3.6%	-0.8%	82.5%
Middle East	*9.8%*	28.3%	24.5%	2.4%	79.4%	-4.5%	-8.1%	3.0%	79.4%
North America	*28.8%*	12.9%	13.8%	-0.7%	88.7%	0.6%	0.8%	-0.2%	88.7%
International	***58.0%***	**33.7%**	**31.7%**	**1.3%**	**85.0%**	**-11.8%**	**-13.2%**	**1.4%**	**85.0%**
Africa	*1.8%*	34.7%	44.8%	-5.1%	68.1%	-12.6%	-8.9%	-2.9%	68.1%
Asia Pacific	*8.9%*	128.1%	115.6%	4.6%	82.9%	-29.0%	-30.4%	1.5%	82.9%
Europe	*26.5%*	14.0%	12.6%	1.1%	87.8%	-7.1%	-7.2%	0.0%	87.8%
Latin America	*2.8%*	25.8%	25.0%	0.6%	84.8%	-6.1%	-7.0%	0.9%	84.8%
Middle East	*9.4%*	29.2%	25.9%	2.0%	79.8%	-4.2%	-8.3%	3.4%	79.8%
North America	*8.7%*	23.3%	19.5%	2.7%	90.2%	2.0%	-0.5%	2.2%	90.2%
Domestic	***42.0%***	**27.2%**	**24.7%**	**1.6%**	**82.9%**	**5.1%**	**8.7%**	**-2.8%**	**82.9%**
Dom. Australia[4]	*1.0%*	-1.7%	1.7%	-2.8%	79.4%	3.9%	2.4%	1.1%	79.4%
Domestic Brazil[4]	*1.5%*	13.3%	8.2%	3.5%	78.9%	8.5%	12.4%	-2.8%	78.9%
Dom. China P.R.[4]	*6.4%*	129.6%	95.7%	11.4%	77.2%	15.2%	26.5%	-7.6%	77.2%
Domestic India[4]	*2.0%*	14.8%	0.8%	10.9%	89.9%	1.3%	0.9%	0.4%	89.9%
Domestic Japan[4]	*1.2%*	33.8%	6.3%	15.1%	73.4%	3.9%	0.9%	2.1%	73.4%
Domestic US[4]	*19.2%*	8.0%	11.2%	-2.6%	87.8%	0.2%	2.3%	-1.8%	87.8%

[1]% of industry RPKs in 2022 [2]Change in load factor [3]Load factor level

4 Note: the six domestic passenger markets for w hich broken-dow n data are available account for approximately 31.3% of global total RPKs and 74.6% of total domestic RPKs

Note: The total industry and regional grow th rates are based on a constant sample of airlines combining reported data and estimates for missing observations. Airline traffic is allocated according to the region in w hich the carrier is registered; it should not be considered as regional traffic.

Air passenger market in detail - June 2023

	World share[1]	Year-to-date (% ch vs the same period in 2022) RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]	Year-to-date (% ch vs the same period in 2019) RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]
TOTAL MARKET	***100.0%***	**47.2%**	**36.1%**	**6.1%**	**80.9%**	**-9.7%**	**-8.4%**	**-1.1%**	**80.9%**
Africa	*2.1%*	59.1%	49.8%	4.2%	72.0%	-9.4%	-10.6%	0.9%	72.0%
Asia Pacific	*22.1%*	125.6%	88.4%	13.0%	78.8%	-20.3%	-17.4%	-2.9%	78.8%
Europe	*30.8%*	28.4%	19.8%	5.5%	81.8%	-7.6%	-5.3%	-2.0%	81.8%
Latin America	*6.4%*	20.3%	18.9%	0.9%	81.5%	-3.3%	-2.3%	-0.8%	81.5%
Middle East	*9.8%*	45.4%	29.8%	8.5%	79.0%	-4.5%	-9.2%	3.9%	79.0%
North America	*28.8%*	20.0%	16.0%	2.8%	83.9%	0.8%	1.5%	-0.5%	83.9%
International	***58.0%***	**58.6%**	**42.5%**	**8.3%**	**81.4%**	**-16.1%**	**-16.3%**	**0.2%**	**81.4%**
Africa	*1.8%*	64.7%	55.0%	4.2%	71.1%	-11.4%	-12.2%	0.6%	71.1%
Asia Pacific	*8.9%*	219.4%	147.3%	18.7%	82.7%	-35.7%	-37.2%	1.9%	82.7%
Europe	*26.5%*	30.5%	21.3%	5.7%	81.2%	-9.9%	-6.4%	-3.1%	81.2%
Latin America	*2.8%*	34.6%	31.0%	2.3%	83.4%	-12.4%	-13.2%	0.7%	83.4%
Middle East	*9.4%*	47.5%	31.7%	8.5%	79.2%	-4.4%	-9.3%	4.0%	79.2%
North America	*8.7%*	43.9%	28.9%	8.8%	84.2%	-1.3%	-2.5%	1.0%	84.2%
Domestic	***42.0%***	**33.3%**	**27.9%**	**3.2%**	**80.1%**	**1.6%**	**5.7%**	**-3.3%**	**80.1%**
Dom. Australia[4]	*1.0%*	27.4%	19.0%	5.1%	78.3%	-4.3%	-4.2%	-0.1%	78.3%
Domestic Brazil[4]	*1.5%*	8.0%	7.6%	0.3%	78.9%	0.4%	4.6%	-3.3%	78.9%
Dom. China P.R.[4]	*6.4%*	136.1%	100.6%	11.1%	74.1%	0.6%	15.2%	-10.7%	74.1%
Domestic India[4]	*2.0%*	30.6%	17.9%	8.5%	88.0%	6.5%	6.7%	-0.2%	88.0%
Domestic Japan[4]	*1.2%*	55.2%	11.5%	20.5%	72.8%	-4.9%	-6.8%	1.5%	72.8%
Domestic US[4]	*19.2%*	10.4%	10.4%	0.0%	83.5%	2.2%	4.3%	-1.7%	83.5%

[1] % of industry RPKs in 2022 [2] Change in load factor [3] Load factor level

4 Note: the six domestic passenger markets for which broken-down data are available account for approximately 31.3% of global total RPKs and 74.6% of total domestic RPKs

Note: The total industry and regional growth rates are based on a constant sample of airlines combining reported data and estimates for missing observations. Airline traffic is allocated according to the region in which the carrier is registrated; it should not be considered as regional traffic.

IATA Sustainability & Economics
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08 August 2023

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Air Cargo Market Analysis

June 2023

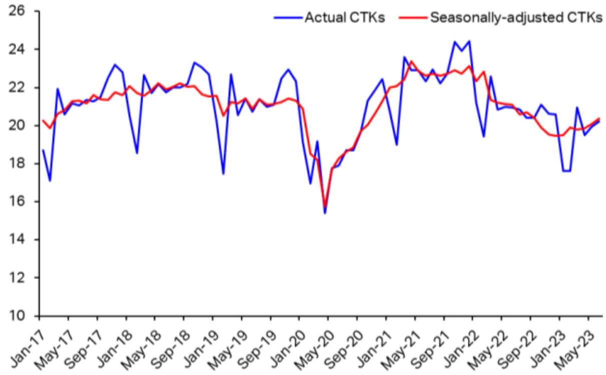
Air cargo records the smallest contraction since Feb 2022

- Global air cargo demand fell by 3.4% year-on-year in June, the smallest decline since February 2022. Year-to-date cargo tonne-kilometers (CTKs) were 8.1% below last year's level.
- Air cargo capacity, measured in available cargo tonne-kilometers (ACTKs), saw a slower annual growth of 9.7% in June, compared to double-digit growth between March and May. Year-to-date ACTKs exceeded 2022 levels by 9.9%.
- Leading indicators of air cargo demand, including global goods trade, manufacturing PMIs, and inventory-to-sales ratio, continued to point to contractions. However, improvements in inflation in major economies could provide a tailwind to the global economy and air cargo demand.
- Major trade lanes including Europe-North America and Asia-North America experienced smaller annual contractions in international air cargo demand in June, improving by 2.1 percentage points compared to May.

June recorded the smallest annual decline in global CTKs since February 2022

Industry air cargo demand, measured by cargo tonne-kilometers (CTKs), registered 20.2 billion in June and was 3.4% lower than the same month in 2022. This was the smallest annual decline since February 2022 **(Chart 1).** In comparison to June 2019 levels, industry CTKs contracted by 2.4%, which is a 4.4 percentage point (ppt) improvement from the May level. Seasonally adjusted (SA) CTKs also recorded a 3.4% annual decline in June, improving by 1.6 ppts compared to the previous month.

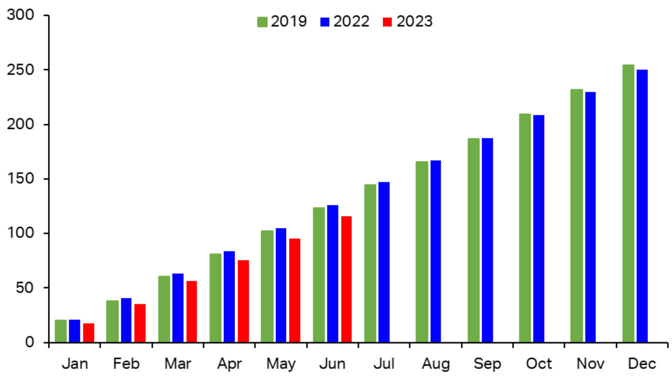
Chart 1 – Global CTKs (billions per month)



Sources: IATA Sustainability and Economics, IATA Monthly Statistics

The year-on-year (YoY) contractions of global CTKs have been continuously improving over the past six months. As a result, the year-to-date (YTD) CTKs reached 115.8 billion in June, and the gap with the 2022 YTD CTK levels narrowed from -16.8% in January to -8.1% this month **(Chart 2)**.

Chart 2 – Year-to-date monthly industry CTKs, billions



Sources: IATA Sustainability and Economics, IATA Monthly Statistics

Air cargo capacity growth slowed in June

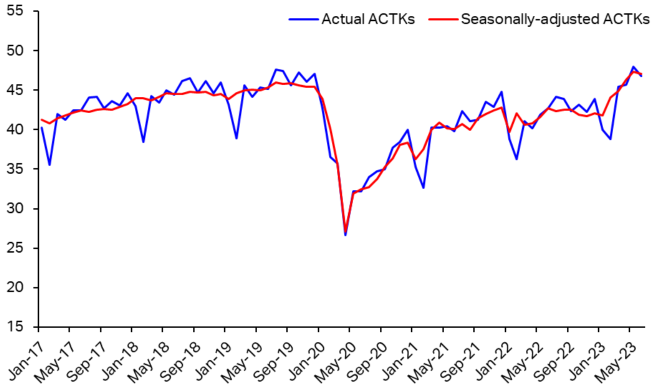
Industry-wide available cargo tonne-kilometers (ACTKs) stood at 46.8 billion this month, exceeding the 2022 level by 9.7% and growing 3.7% above the same month in 2019. Although air cargo capacity continued to increase in June, the annual growth rate slowed to 9.7% this month compared to the double-digit growth observed between March and May. This slowdown reflects the strategic capacity adjustments airlines are making amid a weakened demand environment. SA ACTKs grew by 10.4% YoY and were also 3.9% above the 2019 levels **(Chart 3)**.

Air cargo market overview - June 2023

	World	June 2023 (% year-on-year)				June 2023 (% ch vs the same month in 2019)			
	share [1]	CTK	ACTK	CLF (%-pt) [2]	CLF (level) [3]	CTK	ACTK	CLF (%-pt) [2]	CLF (level) [3]
TOTAL MARKET	***100.0%***	**-3.4%**	**9.7%**	**-5.8%**	**43.2%**	**-2.4%**	**3.7%**	**-5.7%**	**43.2%**
International	*86.9%*	-3.7%	7.7%	-5.8%	48.6%	-3.2%	0.9%	-4.5%	48.6%

[1] % of industry CTKs in 2022 [2] Change in load factor [3] Load factor level

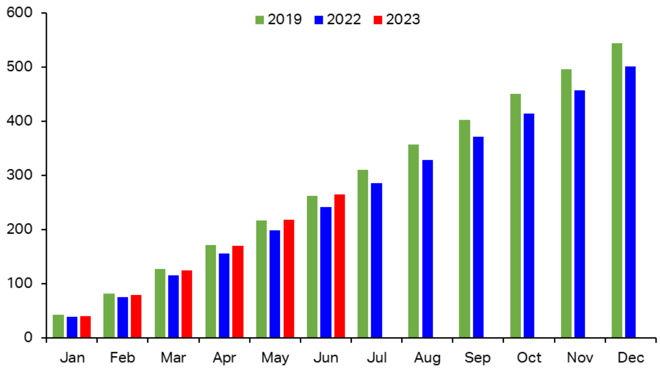
Chart 3 – Global ACTKs (billions per month)



Sources: IATA Sustainability and Economics, IATA Monthly Statistics

Despite the slower growth in capacity this month, YTD ACTKs through June have already surpassed their 2022 levels by 9.9%, reaching 264.7 billion. This level of YTD capacity was also slightly (0.9%) above the pre-pandemic levels in 2019 **(Chart 4)**. Given the current softening of air cargo demand, it is expected that the growth of YTD air cargo capacity will continue to slow down in the coming months.

Chart 4 – Year-to-date monthly industry ACTKs, billions



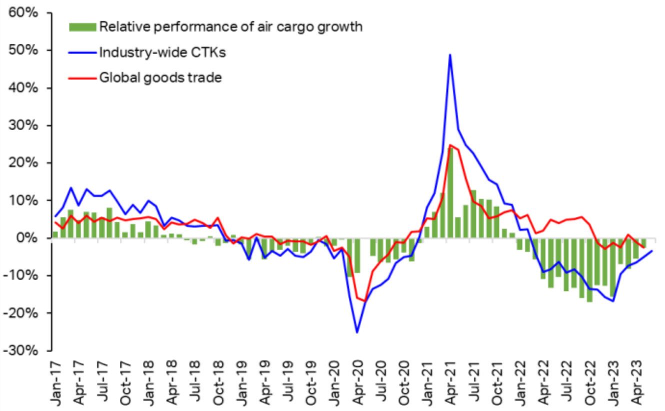
Sources: IATA Sustainability and Economics, IATA Monthly Statistics

Relative performance of air cargo growth improved while global goods trade softened

Global cross-border trade continued to decline by 2.4% in May, reflecting the cooling demand environment and challenging macroeconomic conditions. The relative performance of air cargo growth, measured by the difference between the growth in global goods trade and industry CTKs, narrowed to -2.6 ppts in May, the smallest gap since January 2022. However, this gap still indicates that air cargo is being more affected by the slowdown in global trade compared to container cargo **(Chart 5)**.

The weaker performance in global air cargo demand compared to maritime shipping in part reflects the trends in the relative pricing between the two modes. Container yields in May declined by 82.5% YoY and were only 13.3% higher than their 2019 levels. In comparison, air cargo yields declined by 38.3% YoY over the same period and remained 39.5% higher than their 2019 levels.

Chart 5 – Growth in global goods trade and CTKs (YoY)



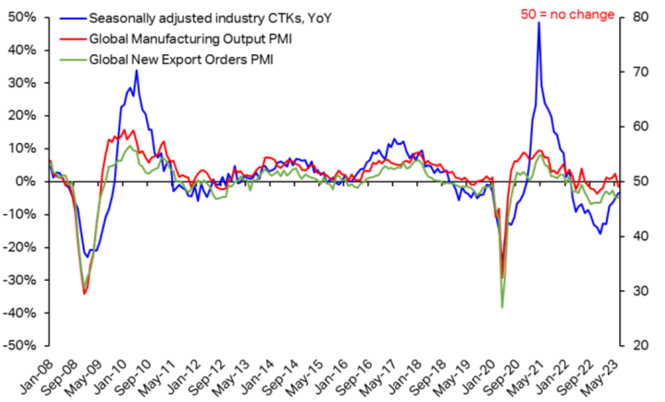
Sources: IATA Sustainability and Economics, IATA Monthly Statistics, Macrobond

Both manufacturing output and new export orders experienced contractions in June

The manufacturing Purchasing Managers Index (PMI) has historically served as a useful indicator of growth in global air cargo demand. Therefore, we have been closely monitoring the manufacturing PMIs at a global level **(Chart 6)** and for major economies **(Chart 7).**

In June, both manufacturing output PMI (49.2) and new export orders PMI (47.1) were below the critical threshold represented by the 50 mark, indicating a decline in global manufacturing production and exports **(Chart 6)**. Notably, the manufacturing output PMI saw a 2.3 ppt decline compared to May, as companies reduced production due to limited global demand.

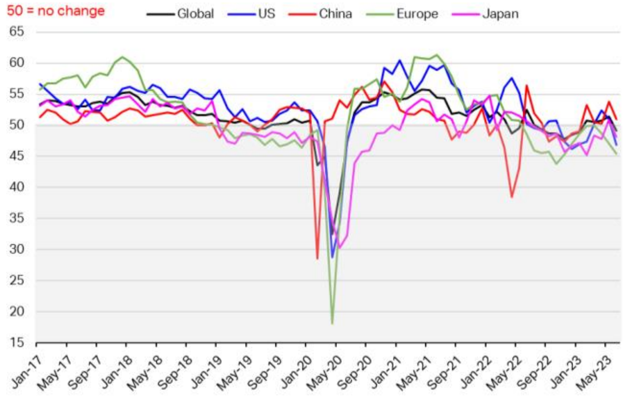
Chart 6 – CTK (SA) growth and global manufacturing output and new export order PMIs (50 = no change)



Sources: IATA Sustainability and Economics, IATA Monthly Statistics, S&P Global Markit

The sharp contraction of global manufacturing output PMIs was also reflected by the downward trends observed in major economies **(Chart 7)**. In June, China was the only major economy that kept the manufacturing output PMI above the 50 mark, at 51.0. However, this was still 2.9 ppts lower than its May level. In contrast, the US and Japan both saw their manufacturing output PMIs change from an expansion in May to a deterioration in June, down to 46.9 and 48.1, respectively. The contraction of manufacturing output in Europe worsened in June, with the region's PMI dropping to 45.4, from 47.0 in May. The declines in manufacturing output and export orders in large part explain the current weak demand for air cargo.

Chart 7 – Global manufacturing output, component of the manufacturing PMI (50 = no change)

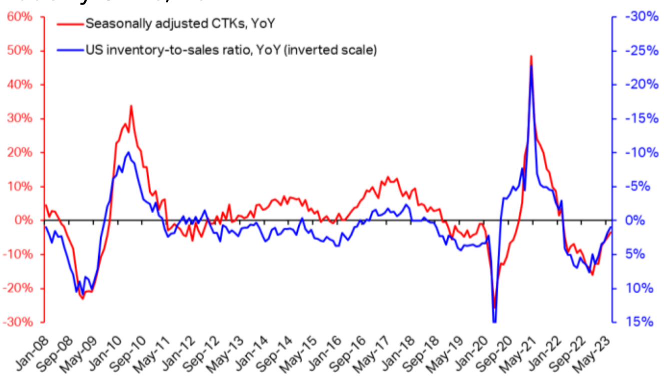


Sources: IATA Sustainability and Economics, S&P Global Markit

Inventory-to-sales ratio also pointed to weak global demand

The inventory-to-sales ratio (inverted) is historically strongly correlated with industry CTK growth rates and can provide more perspective on the weak demand for air cargo **(Chart 8)**. A higher inventory-to-sales ratio indicates either excess stock due to supply chain challenges or insufficient product demand. On the other hand, when the ratio declines, it suggests an impending upturn in demand, and shippers may need to rely on air transportation to expedite the refill of inventory to avoid shortages.

Chart 8 – Growth in inventory-to-sales ratio and industry CTKs, YoY



Source: IATA Sustainability and Economics, IATA monthly statistics, Macrobond

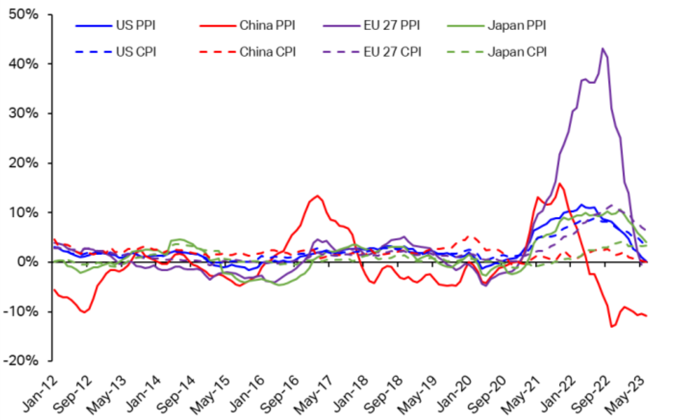
In March and April 2020, the inventory-to-sales ratio surged by almost 20% due to the Covid-19 lockdowns and supply chain congestion. Subsequently, the ratio dropped significantly in 2021, resulting in a boost in air cargo demand to historically high levels. Starting from March 2022, inventories have been elevated again. However, unlike the lockdown period, there is sufficient air cargo capacity this time. Thus, the high inventory-to-sales ratio likely reflects the weakened demand for products and a lower level of sales. The growth of the ratio, however, has been continuously slowing down since February 2023.

Inflation continued to ease in major economies

Major economies experienced decelerating inflation rates in June. The YoY change in the headline Consumer Price Index (CPI) stood at 3.1% in the US, 0.1% in China, 3.3% in Japan and in 6.4% the EU 27 countries **(Chart 9)**. Compared with the previous month, the CPI increased by 0.1 ppts in Japan, while it declined by 1.0 ppt in the US, 0.2 ppts in China and 0.7 ppts in the EU 27 countries. The slowdown in inflation can be attributed to the tightened monetary policies implemented by central banks and the recent declines in both food and non-food commodity prices. While inflation in the US is approaching pre-pandemic rates, the EU 27 countries still suffer from relatively high inflation rates compared to other major economies.

Changes in producer prices in June, as measured by the Producer Price Index (PPI), were recorded at 0.2% in the US, 4.1% in Japan, and -10.8% in China. June PPI data for EU 27 countries has not been released yet, but it was -0.5% in May and 2.1% in April. China's PPI remained in negative territory, partially due to a higher base in 2022 when global commodity prices surged following the war in Ukraine. However, it also reflects the challenge for China to revive demand following the zero-Covid restrictions.

Chart 9 – Headline CPI and PPI inflation (YoY) in major economies



Sources: IATA Sustainability and Economics, Macrobond

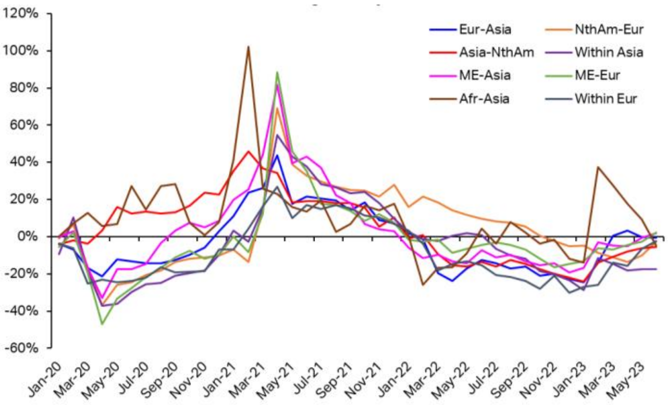
International air cargo demand improved on major trade lanes

In June, there were several positive developments in international air cargo demand on major trade lanes **(Chart 10)**. Route areas connecting Middle East-Asia and Middle East-Europe saw YoY growths, with their CTKs increasing by 1.8% and 2.1%, respectively. Moreover, annual contractions of international CTKs in Europe-North America and Asia-North America markets both improved. Specifically, Europe-North America CTKs only contracted by 2.7% in June, a significant improvement compared to the double-digit declines seen in the previous three months. The Asia-North America trade lane also continued to see smaller annual declines, with a contraction of 5.4% in June, showing improvement from the sharp 24.2% decline seen in January.

Within Europe, trade lanes registered a 2.2% decline in June, which is the smallest annual contraction for this market in three years. In contrast, the within Asia market remained weak this month, with an annual decline of 17.4%, similar to the drop in May.

The international CTKs on the Africa-Asia trade lane contracted by 4.9% YoY, which contrasts sharply with the strong growth of 18%-37% observed between February and April, albeit from a relatively low base in 2022.

Chart 10 –International CTK growth by route area, YoY



Sources: IATA Sustainability and Economics, IATA Monthly Statistics

International CTKs by Latin America and Middle East airlines grew, while demand also improved in North America and Europe

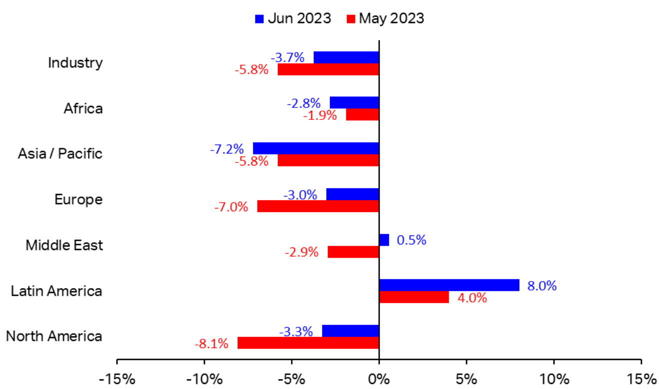
In June, international CTKs contracted by 3.7% YoY globally. However, this marked an improvement of 2.1 ppts from the decline seen in May. The smaller annual decline was driven by the CTK growth achieved by airlines in Latin America (8.0% in June vs. 4.0% in May) and Middle East (0.5% in June vs. -2.9% in May), along with improved performance by airlines based in North America and Europe **(Chart 11)**.

The positive development in air cargo demand on the Europe-North America trade lane **(Chart 10)** had an impact on North America airlines, which experienced a 3.3% annual decline in June, much smaller than the 8.1% contraction in May. European airlines also benefited from this trend, seeing a 3.0% decline in June compared to a 7.0% annual drop in the previous month.

In contrast, the performance of international cargo demand for Asia Pacific and Africa airlines continued to deteriorate in June. Asia Pacific carriers registered the largest annual decline among the regions at 7.2% YoY in June, compared to the 5.8% annual contraction in May. This decline was mainly due to the weak demand of the within Asia market. International CTKs for African airlines also declined further, from -1.9% YoY in May to -2.8% in June, largely affeced by the worsening situation on the Africa-Asia trade lane.

Chart 11 – Growth in international CTKs by airline region of registration (YoY)

International CTK growth (by airline region of registration)



Sources: IATA Sustainability and Economics, IATA Monthly Statistics

Air cargo market in detail - June 2023

	World share [1]	June 2023 (% year-on-year) CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]	June 2023 (% ch vs the same month in 2019) CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]
TOTAL MARKET	***100.0%***	**-3.4%**	**9.7%**	**-5.8%**	**43.2%**	**-2.4%**	**3.7%**	**-2.7%**	**43.2%**
Africa	*2.0%*	-2.8%	-3.7%	0.4%	44.6%	5.3%	-20.3%	10.8%	44.6%
Asia Pacific	*32.4%*	-3.6%	24.4%	-13.6%	46.8%	-6.1%	5.5%	-5.8%	46.8%
Europe	*21.8%*	-2.8%	4.4%	-3.5%	47.6%	-12.9%	-8.7%	-2.3%	47.6%
Latin America	*2.7%*	7.3%	15.4%	-2.5%	33.7%	3.8%	12.7%	-2.9%	33.7%
Middle East	*13.0%*	0.5%	11.1%	-4.7%	44.6%	5.2%	6.6%	-0.6%	44.6%
North America	*28.1%*	-6.5%	0.7%	-2.9%	37.4%	8.1%	10.5%	-0.8%	37.4%
International	***86.9%***	**-3.7%**	**7.7%**	**-5.8%**	**48.6%**	**-3.2%**	**0.9%**	**-2.1%**	**48.6%**
Africa	*2.0%*	-2.8%	-3.6%	0.4%	45.4%	6.5%	-19.1%	10.9%	45.4%
Asia Pacific	*29.7%*	-7.2%	12.8%	-11.6%	54.0%	-6.8%	1.3%	-4.7%	54.0%
Europe	*21.5%*	-3.0%	4.5%	-3.9%	50.0%	-13.2%	-9.9%	-1.9%	50.0%
Latin America	*2.3%*	8.0%	19.5%	-4.0%	37.9%	6.7%	23.5%	-6.0%	37.9%
Middle East	*13.0%*	0.5%	11.2%	-4.8%	44.9%	5.2%	6.7%	-0.6%	44.9%
North America	*18.4%*	-3.3%	2.1%	-2.5%	44.6%	9.4%	9.0%	0.1%	44.6%

Air cargo market in detail - June 2023 Year-to-date

	World share[1]	Year-to-date (% ch vs the same period in 2022) CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]	Year-to-date (% ch vs the same period in 2019) CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]
TOTAL MARKET	***100.0%***	**-8.1%**	**9.9%**	**-8.5%**	**43.8%**	**-5.9%**	**0.9%**	**-3.2%**	**43.8%**
Africa	*2.0%*	-4.4%	1.6%	-2.9%	45.9%	10.0%	-11.4%	8.9%	45.9%
Asia Pacific	*32.4%*	-6.5%	27.0%	-16.2%	45.1%	-9.7%	3.3%	-6.5%	45.1%
Europe	*21.8%*	-10.2%	2.5%	-7.4%	52.3%	-14.2%	-14.8%	0.4%	52.3%
Latin America	*2.7%*	0.9%	18.0%	-5.9%	34.7%	-1.9%	-2.2%	0.1%	34.7%
Middle East	*13.0%*	-5.6%	11.2%	-7.7%	43.3%	-3.8%	3.8%	-3.4%	43.3%
North America	*28.1%*	-10.5%	-0.7%	-4.2%	38.5%	4.7%	10.3%	-2.1%	38.5%
International	***86.9%***	**-8.7%**	**7.4%**	**-8.8%**	**50.1%**	**-6.3%**	**3.0%**	**-1.7%**	**50.1%**
Africa	*2.0%*	-4.6%	1.0%	-2.7%	47.0%	11.1%	-10.4%	9.1%	47.0%
Asia Pacific	*29.7%*	-8.8%	14.2%	-13.8%	54.8%	-8.1%	-2.7%	-3.2%	54.8%
Europe	*21.5%*	-10.5%	2.1%	-7.6%	54.3%	-14.6%	-15.6%	0.6%	54.3%
Latin America	*2.3%*	1.3%	22.9%	-8.5%	39.8%	-0.1%	5.5%	-2.2%	39.8%
Middle East	*13.0%*	-5.5%	11.3%	-7.8%	43.6%	-3.7%	4.3%	-3.6%	43.6%
North America	*18.4%*	-10.1%	0.2%	-5.3%	46.3%	4.4%	6.3%	-0.8%	46.3%

[1]% of industry CTKs in 2022 [2]Change in load factor [3]Load factor level

Note: the total industry and regional growth rates are based on a constant sample of airlines combining reported data and estimates for missing observations. Airline traffic is allocated according to the region in which the carrier is registered; it should not be considered as regional traffic. Historical statistics are subject to revision.

IATA Sustainability & Economics
economics@iata.org
07 August 2023

https://www.noaa.gov/news-release/noaa-forecasters-increase-atlantic-hurricane-season-prediction-to-above-normal

NOAA forecasters increase Atlantic hurricane season prediction to ‘above normal’

Likelihood of greater activity rises due to record-warm sea surface temperatures

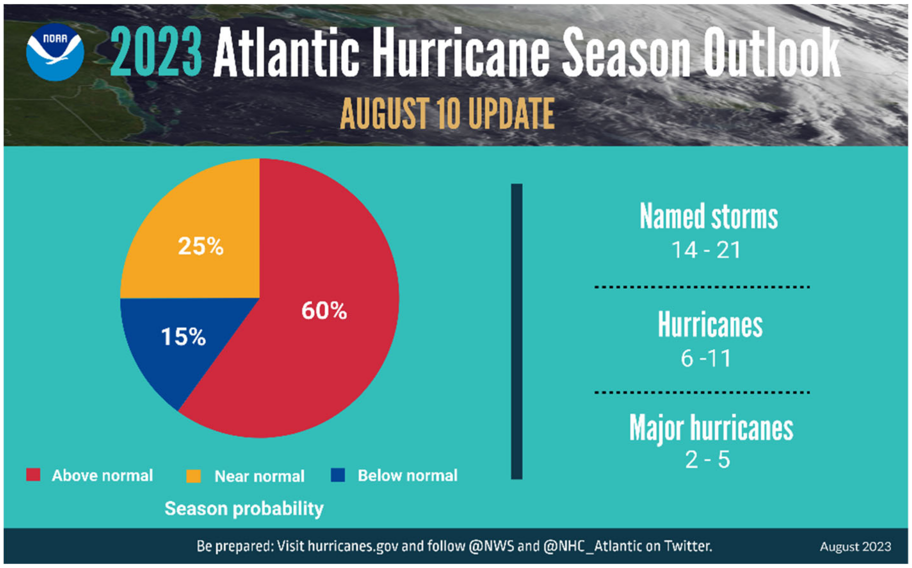
August 10, 2023

A GOES-16 (GOES East) visible satellite image of Hurricane Don at 6:20 PM EDT on July 22, 2023 in the Atlantic. Don was the first hurricane of the 2023 Atlantic hurricane season. (Image credit: NOAA)
Download Image

Scientists at NOAA’s Climate Prediction Center — a division of the National Weather Service — have increased their prediction for the ongoing 2023 Atlantic hurricane season from a near-normal level of activity to an above-normal level of activity with today’s update. Forecasters believe that current ocean and atmospheric conditions, such as record-warm Atlantic sea surface temperatures, are likely to counterbalance the usually limiting atmospheric conditions associated with the ongoing El Nino event.

NOAA forecasters have increased the likelihood of an above-normal Atlantic hurricane season to 60% (increased from the outlook issued in May, which predicted a 30% chance). The likelihood of near-normal activity has decreased to 25%, down from the 40% chances outlined in May's outlook. This new update gives the Atlantic a 15% chance of seeing a below-normal season.

NOAA’s update to the 2023 outlook — which covers the entire six-month hurricane season that ends on Nov. 30 — calls for 14-21 named storms (winds of 39 mph or greater), of which 6-11 could become hurricanes (winds of 74 mph or greater). Of those, 2-5 could become major hurricanes (winds of 111 mph or greater). NOAA provides these ranges with a 70% confidence. These updated ranges include storms that have already formed this season.



The updated 2023 Atlantic hurricane season probability and number of named storms. (Image credit: NOAA)
Download Image

The Atlantic basin experienced an active start to the hurricane season with five storms that have reached at least tropical storm strength, including one hurricane already. An average hurricane season produces 14 named storms, of which seven become hurricanes, including three major hurricanes.

“The main climate factors expected to influence the 2023 Atlantic hurricane activity are the ongoing El Nino and the warm phase of the Atlantic Multi-Decadal Oscillation, including record-warm Atlantic sea surface temperatures,” said Matthew Rosencrans, lead hurricane season forecaster with NOAA’s Climate Prediction Center. “Considering those factors, the updated outlook calls for more activity, so we urge everyone to prepare now for the continuing season.”

El Nino conditions are currently being observed and there is a greater than 95% chance that El Nino will continue through the Northern Hemisphere winter, according to the latest ENSO discussion from the Climate Prediction Center. El Nino usually results in atmospheric conditions that help to lessen tropical activity during the Atlantic hurricane season. So far, those limiting conditions have been slow to develop and climate scientists are forecasting that the associated impacts that tend to limit tropical cyclone activity may not be in place for much of the remaining hurricane season.

A below-normal wind shear forecast, slightly below-normal Atlantic trade winds and a near- or above-normal West African Monsoon were also key factors in shaping this updated seasonal forecast.

The 2023 Atlantic tropical cyclone names selected by the World Meteorological Organization. (Image credit: NOAA)
Download Image

More about hurricane season outlooks

NOAA's hurricane outlooks are forecasts of overall season activity, not landfalls. A storm's landfall is usually the result of mesoscale weather patterns and are typically predictable within roughly one week of a storm approaching a landmass.

"The National Weather Service is dedicated to providing timely and accurate forecasts to empower individuals, families and communities to take proactive measures this hurricane season," said Ken Graham, director of NOAA's National Weather Service. "New tools such as a new hurricane model, the Hurricane Analysis and Forecast System and the expansion of the National Hurricane Center's Tropical Weather Outlook to seven days are examples of our commitment to enhancing our forecasting capabilities and services."

In June, NOAA deployed a new model to help produce hurricane forecasts. The Hurricane Analysis and Forecast System was put into operations on June 27 and will run alongside existing models for the 2023 season before replacing them as NOAA's premier hurricane forecasting model.

NOAA urges everyone in vulnerable areas to have a well-thought-out hurricane plan and stay informed through official channels as this season progresses.

Media contact

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https://www.energy.gov/articles/biden-harris-administration-announces-12-billion-nations-first-direct-air-capture

Biden-Harris Administration Announces Up To $1.2 Billion For Nation’s First Direct Air Capture Demonstrations in Texas and Louisiana

AUGUST 11, 2023

President Biden’s Investing in America Agenda Will Fund Projects to Kickstart Critical New Industry, Remove Historic Climate-Harming Carbon Emissions Out of the Air, and Create 4,800 Good-Paying Jobs

WASHINGTON, D.C. — As part of President Biden’s Investing in America **agenda**, the U.S. Department of Energy (DOE) today announced up to $1.2 billion to advance the development of two commercial-scale direct air capture facilities in Texas and Louisiana. These projects—the first of this scale in the United States—represent the initial selections from the President’s Bipartisan Infrastructure Law-funded Regional Direct Air Capture (DAC) Hubs program, which aims to kickstart a nationwide network of large-scale carbon removal sites to address legacy carbon dioxide pollution and complement rapid emissions reductions. These emissions are already in the atmosphere, fueling climate change and extreme weather and jeopardizing public health and ecosystems across the globe. The Hubs are expected to ensure meaningful community and labor engagement and contribute to the President’s **Justice40 Initiative**. Together, these projects are expected to remove more than 2 million metric tons of carbon dioxide (CO2) emissions each year from the atmosphere—an amount equivalent to the annual emissions from roughly 445,000 gasoline-powered cars—and create 4,800 good-paying jobs in Texas and Louisiana.

Today’s announcement will be the world’s largest investment in engineered carbon removal in history and each Hub will eventually remove more than 250 times more carbon dioxide than the largest DAC facility currently operating. Their development will help inform future public and private sector investments and jumpstart a new industry critical to addressing the climate crisis on a global scale—highlighting how **Bidenomics** is driving a manufacturing boom that is delivering new economic opportunities, positioning America to be a global leader in the industries of the future, and accelerating efforts to meet the President’s goal of a net-zero economy by 2050.

“Cutting back on our carbon emissions alone won’t reverse the growing impacts of climate change; we also need to remove the CO2 that we’ve already put in the atmosphere—

which nearly every climate model makes clear is essential to achieving a net-zero global economy by 2050," said **U.S. Secretary of Energy Jennifer M. Granholm.** "With this once-in-a-generation investment made possible by President Biden's Investing in America agenda, DOE is laying the foundation for a direct air capture industry crucial to tackling climate change—transforming local economies and delivering healthier communities along the way."

DAC is a process that separates CO2 from the air, helping to reduce legacy CO2 in the atmosphere. The separated CO2 can then be safely and permanently stored deep underground or converted into useful carbon-containing products like concrete that prevent its release back into the atmosphere. Widespread deployment of DAC and other innovative technologies that capture emissions are key to combatting the climate crisis and reinforcing America's global competitiveness in the zero-carbon economy of the future. DOE **estimates** that reaching President Biden's ambitious plan for a net-zero emissions economy will require that between 400 million and 1.8 billion metric tons of CO2 be removed from the atmosphere and captured from emissions sources annually by 2050. The two DAC Hubs selected for award negotiations today will help further demonstrate the ability to capture and store atmospheric CO2 at scale.

Selected projects include:

- **Project Cypress (Calcasieu Parish, LA):** Battelle, in coordination with Climeworks Corporation and Heirloom Carbon Technologies, Inc., aims to capture more than 1 million metric tons of existing CO2 from the atmosphere each year and store it permanently deep underground. This hub intends to rely on Gulf Coast Sequestration for offtake and geologic storage of captured atmospheric CO2. The project is estimated to create approximately 2,300 jobs, with a goal to hire workers formerly employed by the fossil fuel industry for 10% of the overall workforce. Project Cypress will implement a robust two-way communication program with local communities and stakeholders to solicit input into the project while also generating new employment opportunities and advancing diversity, equity, inclusion, and accessibility principles.
- **South Texas DAC Hub (Kleberg County, TX):** 1PointFive, a subsidiary of Occidental, and its partners, Carbon Engineering Ltd. and Worley, seek to develop and demonstrate a DAC facility designed to remove up to 1 million metric tons of CO2 annually with an associated saline geologic CO2 storage site. The project is estimated to create approximately 2,500 jobs in construction, operations, and maintenance with existing agreements for local hiring. The selectees will also establish a Citizen Advisory Board to ensure meaningful community engagement.

DOE is dedicated to ensuring that the selected Regional DAC Hubs projects deliver community benefits and avoid harm in those communities while also advancing the development of carbon capture, transport, and storage systems. The Hubs are expected to ensure meaningful community and labor engagement and contribute to the President's Justice40 Initiative, which set a goal that 40% of the overall benefits of certain federal investments, such as climate and clean energy, go to disadvantaged communities that have been marginalized and overburdened by pollution and underinvestment. DOE, in coordination with the selected project teams, is planning to co-host in-person community briefings to engage with local stakeholders in Texas and Louisiana in September. Learn more about the two Regional DAC Hubs projects selected for award negotiations **here**.

Potential Future DAC Hub Studies
To assess the viability of future DAC Hub demonstrations, DOE also announced 19 additional projects selected for award negotiations that will support earlier stages of project development, including feasibility assessments and front-end engineering and design (FEED) studies. Fourteen projects will enable early-stage efforts to explore the feasibility of a potential DAC Hub location, ownership structure, and business model. Five projects will perform FEED studies that establish and define technical requirements focused on project scope, schedule, and costs to reduce risk during later project phases. Learn more about these 19 projects selected for award negotiations **here**.

DOE intends to issue additional funding opportunity announcement in the coming years to fully implement the Regional DAC Hubs mandate from Congress. Selection for award negotiations is not a commitment by DOE to issue an award or provide funding. Before funding is issued, DOE and the applicants will undergo a negotiation process, and DOE may cancel negotiations and rescind the selection for any reason during that time.

Carbon Negative Shot Pilots
DOE also announced its intent to publish a series of funding opportunities for projects and prizes focused on supporting the development and commercialization of a suite of carbon dioxide removal technologies. These efforts will collectively support the **Carbon Negative Shot**, part of DOE's larger **Energy Earthshots Initiative** and the U.S. government’s first major effort to help spur innovation and position U.S. enterprises as leaders in research, manufacturing, and deployment in the carbon dioxide removal industry. The Earthshot sets a goal to remove CO2 from the atmosphere and store it at meaningful scales for less than $100 per net metric ton of CO2-equivalent within the decade. **Read the full NOI**.

The DOE **Office of Clean Energy Demonstrations** (OCED), in collaboration with the DOE **Office of Fossil Energy and Carbon Management** (FECM), manages the **Regional DAC Hubs Program** and will provide project management oversight for the DAC Hubs projects selected to demonstrate the capture, processing, delivery, and storage or end-use of captured carbon as well as community benefit plans and environmental safety.

Excerpt https://investors.sixflags.com/news-and-events/press-releases/2023/08-10-2023-110035367

Six Flags Reports Second Quarter 2023 Performance

August 10, 2023

The company had net income of $21 million in second quarter 2023, compared to net income of $45 million in second quarter 2022. The net income per share was $0.25 compared to net income per share of $0.53 in second quarter 2022, driven primarily by an increase in self-insurance reserves in second quarter 2023. Our self-insurance reserves are periodically reviewed for changes in facts and circumstances and adjustments are made as necessary. During the second quarter of 2023, we revised the estimate of our ultimate loss indications for both identified claims and incurred but not reported ("IBNR") claims in connection with our general liability and worker's compensation self-insurance reserves. The increase in our revised estimate was based on greater than previously estimated reserve adjustments on certain identified claims as well as an observed pattern of increasing litigation and settlement costs and changes to key actuarial assumptions utilized in determining estimated ultimate losses, including loss development factors. The change in estimate resulted in an increase to "selling, general and administrative expense" in our condensed consolidated statements of operation of $38 million during the three and six months ended July 2, 2023. The reduction in net income and net income per share were also driven by higher interest expense in second quarter 2023 versus prior year due to higher floating rate debt costs and increased borrowing under the revolver. Excluding the $38 million self-insurance reserves estimate adjustment, cash operating costs (4) increased by less than $1 million in second quarter 2023, driven by higher advertising expense and seasonal wages, offset by a reduction in full-time headcount and other cost-saving initiatives. Adjusted EBITDA in second quarter 2023, which excludes the $38 million self-insurance reserves estimate adjustment, was $161 million, a $7 million increase from the prior year (3).

Excerpt https://otp.tools.investis.com/clients/us/sixflags3/SEC/sec-show.aspx?FilingId=16850686&Cik=0000701374&Type=PDF&hasPdf=1

	As of		
	July 2, 2023	January 1, 2023	July 3, 2022
(Amounts in thousands, except share data)	*(unaudited)*		*(unaudited)*
ASSETS			
Current assets:			
Cash and cash equivalents	$ 51,580	$ 80,122	$ 74,802
Accounts receivable, net	93,077	49,405	70,473
Inventories	43,172	44,811	47,531
Prepaid expenses and other current assets	84,808	66,452	69,990
Total current assets	272,637	240,790	262,796
Property and equipment, net:			
Property and equipment, at cost	2,666,636	2,592,485	2,552,144
Accumulated depreciation	(1,410,480)	(1,350,739)	(1,297,710)
Total property and equipment, net	1,256,156	1,241,746	1,254,434
Goodwill	659,618	659,618	659,618
Intangible assets, net of accumulated amortization	344,153	344,164	344,176
Right-of-use operating leases, net	154,182	158,838	180,836
Debt issuance costs	6,110	2,764	3,832
Deposits and other assets	20,737	17,905	8,101
Total assets	$ 2,713,593	$ 2,665,825	$ 2,713,793
LIABILITIES AND STOCKHOLDERS' DEFICIT			
Current liabilities:			
Accounts payable	$ 54,174	$ 38,887	$ 67,925
Accrued compensation, payroll taxes and benefits	21,571	15,224	24,968
Self-insurance reserves	68,633	34,053	37,017
Accrued interest payable	33,216	38,484	24,713
Other accrued liabilities	79,959	67,346	102,626
Deferred revenue	176,811	128,627	171,238
Short-term borrowings	169,000	100,000	200,000
Short-term lease liabilities	11,730	11,688	11,394
Total current liabilities	615,094	434,309	639,881
Noncurrent liabilities:			
Long-term debt	2,183,325	2,280,531	2,277,910
Long-term lease liabilities	163,950	164,804	175,786
Other long-term liabilities	29,077	30,714	5,476
Deferred income taxes	172,849	184,637	152,041
Total liabilities	3,164,295	3,094,995	3,251,094
Redeemable noncontrolling interests	544,764	521,395	543,719
Stockholders' deficit:			
Preferred stock, $1.00 par value	—	—	—
Common stock, $0.025 par value, 280,000,000 shares authorized; 83,464,774, 83,178,294 and 83,026,556 shares issued and outstanding at July 2, 2023, January 1, 2023 and July 3, 2022, respectively	2,086	2,079	2,075
Capital in excess of par value	1,109,779	1,104,051	1,103,534
Accumulated deficit	(2,034,736)	(1,985,500)	(2,114,697)
Accumulated other comprehensive loss, net of tax	(72,595)	(71,195)	(71,932)
Total stockholders' deficit	(995,466)	(950,565)	(1,081,020)
Total liabilities and stockholders' deficit	$ 2,713,593	$ 2,665,825	$ 2,713,793

https://www.dw.com/en/dont-overstate-15-degrees-c-threat-new-ipcc-head-says/a-66386523

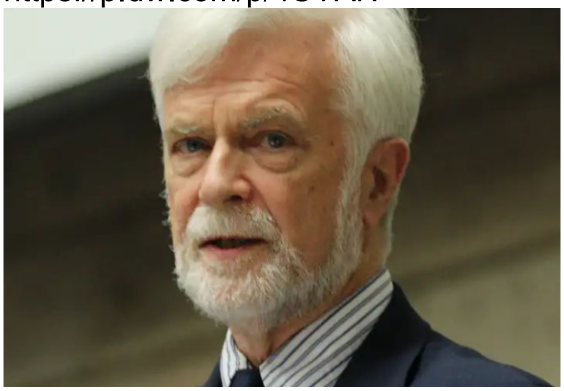
CLIMATEGLOBAL ISSUES

Don't overstate 1.5 degrees C threat, new IPCC head says

23 hours ago23 hours ago

Jim Skea, the new head of the UN's IPCC climate panel, said it was not helpful to imply that temperature increases of 1.5 degrees Celsius posed an existential threat to humanity.

https://p.dw.com/p/4UYAN



Jim Skea was named the new chairman of the IPCC earlier this week*Image: Melissa Walsh/IPCC/dpa/picture alliance*

The newly appointed head of **the UN's Intergovernmental Panel on Climate Change (IPCC)**, Jim Skea, spoke to two major German news outlets over the weekend, soon after his appointment to the role.

Speaking to weekly magazine *Der Spiegel*, in an interview first published on Saturday, Skea warned against laying too much value on the international community's current nominal target of **limiting global warming to 1.5 degrees Celsius compared the pre-industrial era**.

"We should not despair and fall into a state of shock" if global temperatures were to increase by this amount, he said.

In a separate discussion with German news agency DPA, Skea expanded on why.

"If you constantly communicate the message that we are all doomed to extinction, then that paralyzes people and prevents them from taking the necessary steps to get a grip on **climate change**," he said.

"The world won't end if it warms by more than 1.5 degrees," Skea told *Der Spiegel*. "It will however be a more dangerous world."

Surpassing that mark would lead to many problems and social tensions, he said, but still that would not constitute an existential threat to humanity.

The international community's stated target is currently to limit global warming to the 1.5 degrees Celsius target, even though UN estimates suggest that the current commitments made by countries **are actually likely to fall far short of their nominal goal**.

The UN estimates that within roughly a decade, the target is liable to be breached

What else did Skea say?

James "Jim" Skea is a physics graduate born in Dundee in Scotland who did his doctoral thesis in energy research and has worked at Imperial College London since 2009.

The 69-year-old, who has been involved with the IPCC since its foundation in the 1990s, was named its new chairman on Wednesday.

He told *Der Spiegel* that there remained good reasons to be optimistic in the battle against climate change.

"Every measure we take to weaken climate change helps," he said, adding that measures were also becoming "ever more cost-effective."

Skea said that one short-term focus should remain expanding renewable electricity to reduce emissions from fossil fuel electricity generation and from internal combustion engine vehicles.

"Longer term, we probably will not be able to do without technological solutions **like the underground capture of CO2**," he said, referring to the greenhouse gas **carbon dioxide.**

Individual abstinence is good, but new infrastructure required

Skea predicted that one difficult area might prove to be changing people's lifestyles. He said that no scientist could tell people how to live or what to eat.

"Individual abstinence is good, but it alone will not bring about the change to the extent it will be necessary," Skea said. "If we are to live more climate consciously, we need entirely new infrastructure. **People will not get on bikes if there are no cycle paths**."

Skea said he also wanted to adapt the IPCC so that it could provide better and more targeted advice to specific groups of people on how they could act to combat climate change.

He named groups like town planners, landowners and businesses: "With all these things it's about real people and their real lives, not scientific abstractions. We need to come down a level," he told DPA.

He said he also hoped to make progress during his tenure on how and where money was sent and spent to tackle the problem globally.

"There's enough money in the world, the challenge is getting it to flow to the right places," he said.

msh/sri (AFP, dpa)

https://www.cnbc.com/2023/08/09/i-am-101-years-old-and-the-worlds-oldest-practicing-doctor-my-no-1-tip-for-keeping-your-brain-sharp.html

At 101 years old, I'm the 'world's oldest practicing doctor': My No. 1 rule for keeping your brain sharp

Published Wed, Aug 9 202310:01 AM EDTUpdated Thu, Aug 10 20233:51 PM EDT

Dr. Howard Tucker, Contributor

Dr. Howard Tucker has been practicing medicine since 1947.

Photo: Austin Tucker for "What's Next?"

I've been a practicing doctor and neurologist for more than seven decades. And at 101 years old, people often ask me how I keep my brain sharp.

Good genes and a bit of luck can give you a head start, but there is one principle I live by that anyone can implement: Keep your mind engaged through work, social and entertainment activities.

As we age, we go through natural changes that affect our mental processing abilities. Some areas of the brain may shrink, communication between neurons may become less effective, and blood flow may decrease.

But like any other muscle in the body, our mind needs consistent exercise to thrive. I use three daily rituals to boost my brain health.

---

1. I go to work.

Research shows a correlation between retiring and increased cognitive decline — which is why I still haven't retired.

I was named the world's oldest practicing doctor by the Guinness World Records. Sara, my wife of 66 years, also still practices psychoanalysis and psychiatry at age 89.

My job requires me to review a number of medical subjects and think through problems. Staying up to date with the latest advancements in neurology keeps my brain busy.

Volunteering, pursuing a hobby and learning new skills can provide great mental stimulation. In my early 60s, for example, I attended law school at night, after conducting my full-time medical practice. I passed the Ohio Bar Exam at 67.

---

2. I stay social.

Research has indicated that strong relationships may help maintain our memory and cognitive function.

Unfortunately, at my age, many of my closest friends, family members and colleagues have passed away. But I am fortunate that my job has allowed me to build relationships with younger colleagues.

Sara and I also make it a priority to have dinner with people in our community.

At least twice a week, we eat with my daughter and her husband and my son and his wife. We enjoy trying new restaurants with friends and colleagues, too.

---

3. I read for entertainment.

When I'm not reading about the latest advancements and treatments in neurology, I like to read biographies and detective stories.

Immersing yourself in a good book, fiction or non-fiction, requires your brain to process a bulk of new information. I believe this is key to keeping your mind sharp.

***Dr. Howard Tucker** is a neurologist from Cleveland, Ohio and was named the "Oldest Practicing Doctor" by Guinness World Records. He received his law degree and passed the Ohio Bar Exam in his late 60s, and served as chief of neurology of the Atlantic fleet during the Korean War. A feature documentary about Dr. Tucker is in the works. Follow him on TikTok, Instagram and Facebook.*

Don't miss:

SAF

Dan Tsubouchi @Energy_Tidbits · 3h

Near term Oil hold back.

Another Iran reminder today that at 3.2 mmb/d & to exceed 3.3 mmb/d by late Aug.

Vs #OPEC MOMR Secondary Sources had Iran at 2.828 mmb/d in July.

Who can or will stop Iran from adding up 0.6 mmb/d to #Oil markets in next few mths?

#OOTT

Iran producing nearly 3.2 mln bpd of oil: Minister

> SAF **Dan Tsubouchi** @Energy_Tidbits · 22h
>
> Who can or will stop Iran from adding up to 0.6 mmbd to #OIl markets over coming mths?
>
> Iran not subject to #OPEC quota.
>
> ...

1 · 3 · 1,796

SAF

Dan Tsubouchi @Energy_Tidbits · 15h

#LNG Supply risk

Would Chevron take on the risk to safely operate its Wheatstone & Gorgon #LNG downstream facilities with replacement workers & other non-union?

Offshore Alliance postings don't suggest any quick resolve.

Thx @David_Stringer
#OOTT #NatGas

By David Stringer
(Bloomberg) -- Producer will continue to engage with "employees and their representatives" after Australia's Fair Work Commission authorized some workers at the Wheatstone and Gorgon downstream facilities to vote on taking industrial action, Chevron Corp. said in a statement on Friday.
* Chevron is aware that the Australian Workers' Union has also made a similar application in relation to a potential vote on action by workers at the Wheatstone offshore platform: statement
* Co. "is taking steps to ensure safe and reliable operations are maintained in the event of disruption," Chevron said
* NOTE: Workers at Chevron and Woodside LNG facilities in Australia are in dispute over issues including pay and conditions, raising a threat of strikes that could disrupt as much as 10% of global supply
* READ: Strike Threats Put 10% of LNG at Risk of New Price Shocks

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Jake Lloyd-Smith

Offshore Alliance

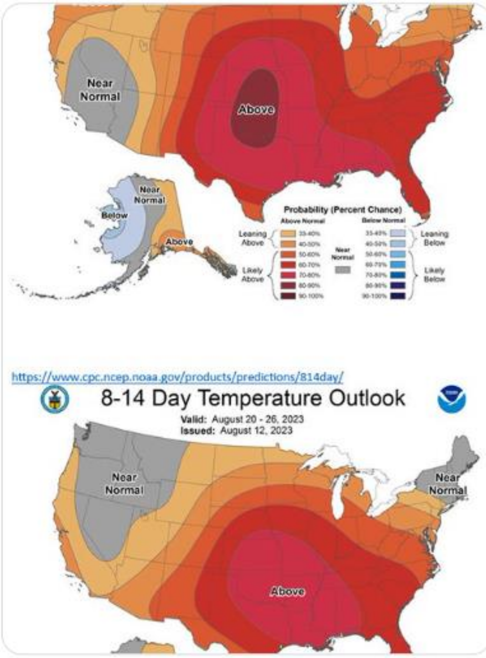
1 · 4 · 7 · 2,487

Dan Tsubouchi @Energy_Tidbits · 19h

Today's @NOAA updated 6-10 & 8-14 day temperature outlook covering Aug 18-26.

Warmer than normal temperatures expected thru most of the US.

Should be supportive for US #NatGas.
#OOTT



2 10 18 4,574

Dan Tsubouchi @Energy_Tidbits · 22h

Who can or will stop Iran from adding up to 0.6 mmbd to #Oil markets over coming mths?

Iran not subject to #OPEC quota.

US negotiating with Iran on prisoners & releases of Iranian funds.

See 👇 08/09/23 thread - Iran is #oil supply risk in H2.

#OOTT @DanialRahmat12

> **Dan Tsubouchi** @Energy_Tidbits · Aug 9
>
> Iran near term #Oil supply adds!
>
> Given #Biden doesn't have any stroke over #MBS & tapped SPR, wonder if he effectively turns a blind eye as he sees this as a replacement for an SPR release to try to help keep a lid on oil/#Gasoline prices for 2024.
>
> Thx @DanialRahmat12!
>
> #OOTT twitter.com/DanialRahmat12...

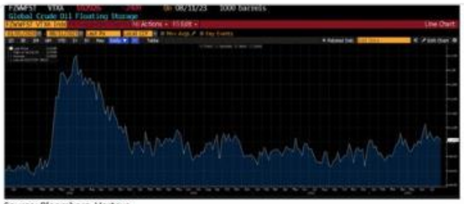
4 6 7 6,440

Dan Tsubouchi @Energy_Tidbits · Aug 12

#Vortexa crude #Oil floating storage at 08/12 est 102.93 mmb, -2.41 mmb WoW vs revised up by +3.59 mmb 08/04 of 105.34 mmb.

Last 7-wk ave 106.13 mmb, WoW vs 110.86 mmb, but would have expected lower with Saudi/Russia cuts

Thx @Vortexa @business. #OOTT



Source: Bloomberg, Vortexa

Posted Aug 12, 9am MT

FZWWFST VTXA Index — 01/01/2020 – 08/11/2023

Date	Last Px
Fr 08/11/2023	102.926k
Fr 08/04/2023	105.335k
Fr 07/28/2023	107.492k
Fr 07/21/2023	101.807k
Fr 07/14/2023	107.016k
Fr 07/07/2023	113.739k
Fr 06/30/2023	104.561k
Fr 06/23/2023	125.059k
Fr 06/16/2023	114.605k
Fr 06/09/2023	98183
Fr 06/02/2023	101.73k

Aug 5, 9am MT

FZWWFST VTXA Index — 01/01/2020 – 08/04/2023

Date	Last Px
Fr 08/04/2023	101.748k
Fr 07/28/2023	107.366k
Fr 07/21/2023	106.429k
Fr 07/14/2023	109.407k
Fr 07/07/2023	119.648k
Fr 06/30/2023	105.631k
Fr 06/23/2023	125.781k
Fr 06/16/2023	114.804k
Fr 06/09/2023	98560
Fr 06/02/2023	102.284k
Fr 05/26/2023	95875

July 30, 5am MT

FZWWFST VTXA Index — 01/01/2020 – 07/28/2023

Date	Last Px
Fr 07/28/2023	104.126k
Fr 07/21/2023	107.703k
Fr 07/14/2023	111.066k
Fr 07/07/2023	123.918k
Fr 06/30/2023	110.308k
Fr 06/23/2023	133.236k
Fr 06/16/2023	118.616k
Fr 06/09/2023	102.426k
Fr 06/02/2023	104.266k
Fr 05/26/2023	96902
Fr 05/19/2023	97833

Source: Bloomberg, Vortexa

Vortexa Crude Oil Floating Storage by Region (mmb)				Original Posted	Recent Peak	
Region	Aug 11/23	Aug 4/23	WoW	Aug 4/23	June 23/23	Aug 11 vs June 23
Asia	50.10	45.91	4.19	44.07	68.04	-17.94
Europe	6.63	10.15	-3.52	8.69	6.36	0.27
Middle East	6.86	10.14	-3.28	10.11	9.06	-2.20
West Africa	6.99	8.17	-1.18	10.36	3.85	3.14
US Gulf Coast	0.79	1.40	-0.61	1.50	1.23	-0.44
Other	31.56	29.57	1.99	27.02	36.52	-4.96
Global Total	102.93	105.34	-2.41	101.75	125.06	-22.13

Vortexa crude oil floating storage posted on Bloomberg 9am MT on Aug 12

Source: Vortexa, Bloomberg

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

3 12 1,870

SAF

Dan Tsubouchi @Energy_Tidbits · Aug 11

Is #IEA's Q1/24 #Oil demand still low? if so, then likely subsequent quarters likely low.

Aug OMR Q1/24 -1.6 mmbd QoQ
July OMR Q1/24 -1.9 mmbd QoQ
June OMR Q1/24 -2.0 mmbd QoW

Still >~1.5x normal seasonal QoQ drop from Q4 to Q1.

Thx @business K Siedenburg for table.

#OOTT

IEA World Oil Supply and Demand Forecasts: Summary (Table)
2023-08-11 08:00:00.9 GMT
By Kristian Siedenburg
(Bloomberg) -- Following is a summary of world oil supply and demand forecasts from the International Energy Agency in Paris:

NOTE: Figures are in million of barrels per day. (*) equals total demand minus non-OPEC supply and OPEC natural gas liquids.
IEA changed the way it measures OPEC supply, adopting the industry-standard approach of counting most of Venezuela's Orinoco heavy oil as "crude oil."
SOURCE: International Energy Agency

To contact the reporter on this story: Kristian Siedenburg in Vienna at [illegible]@bloomberg.net
To contact the editors responsible for this story: Joshua Robinson at [illegible]@bloomberg.net
Mark Evans

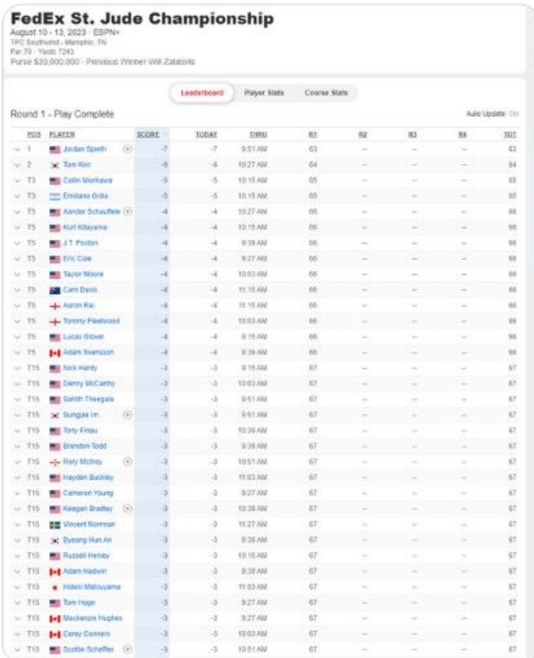
Dan Tsubouchi @Energy_Tidbits · Jun 14

Key question from @IEA OMR?

What led to the -2 mmbd QoQ drop in @IEA fcst demand from Q4/23 to Q3/24? Probably 2x normal pre-Covid QoQ drop. ...

Dan Tsubouchi @Energy_Tidbits · Aug 10

It's only 1st round @FedExChamp but great to see our 🇨🇦 stars off to a solid start. @adamsvensson59 T5 at -4. @ahadwingolf, @MacHughesGolf & @coreconn T15 at -15. @ntaylorgolf59 T54 at +1. All have won on @PGATOUR and are great ambassadors of Canada! Hoping for good TV weekend!



FedEx St. Jude Championship
August 10 - 13, 2023 · ESPN+
TPC Southwind · Memphis, TN
Par 70 · Yards 7243
Purse $20,000,000 · Previous Winner Will Zalatoris

Leaderboard | Player Stats | Course Stats

Round 1 - Play Complete

Auto Update: On

POS	PLAYER	SCORE	TODAY	THRU	R1	R2	R3	R4	TOT
1	Jordan Spieth	-7	-7	9:51 AM	63	–	–	–	63
2	Tom Kim	-6	-6	10:27 AM	64	–	–	–	64
T3	Collin Morikawa	-5	-5	10:15 AM	65	–	–	–	65
T3	Emiliano Grillo	-5	-5	10:15 AM	65	–	–	–	65
T5	Xander Schauffele	-4	-4	10:27 AM	66	–	–	–	66
T5	Kurt Kitayama	-4	-4	10:15 AM	66	–	–	–	66
T5	J.T. Poston	-4	-4	9:39 AM	66	–	–	–	66
T5	Eric Cole	-4	-4	9:27 AM	66	–	–	–	66
T5	Taylor Moore	-4	-4	10:03 AM	66	–	–	–	66
T5	Cam Davis	-4	-4	11:15 AM	66	–	–	–	66
T5	Aaron Rai	-4	-4	11:15 AM	66	–	–	–	66
T5	Tommy Fleetwood	-4	-4	10:03 AM	66	–	–	–	66
T5	Lucas Glover	-4	-4	9:15 AM	66	–	–	–	66
T5	Adam Svensson	-4	-4	9:39 AM	66	–	–	–	66
T15	Nick Hardy	-3	-3	9:15 AM	67	–	–	–	67
T15	Denny McCarthy	-3	-3	10:03 AM	67	–	–	–	67
T15	Sahith Theegala	-3	-3	9:51 AM	67	–	–	–	67
T15	Sungjae Im	-3	-3	9:51 AM	67	–	–	–	67
T15	Tony Finau	-3	-3	10:39 AM	67	–	–	–	67
T15	Brendon Todd	-3	-3	9:39 AM	67	–	–	–	67
T15	Rory McIlroy	-3	-3	10:51 AM	67	–	–	–	67
T15	Hayden Buckley	-3	-3	11:03 AM	67	–	–	–	67
T15	Cameron Young	-3	-3	9:27 AM	67	–	–	–	67
T15	Keegan Bradley	-3	-3	10:39 AM	67	–	–	–	67
T15	Vincent Norrman	-3	-3	11:27 AM	67	–	–	–	67
T15	Byeong Hun An	-3	-3	9:39 AM	67	–	–	–	67
T15	Russell Henley	-3	-3	10:15 AM	67	–	–	–	67
T15	Adam Hadwin	-3	-3	9:39 AM	67	–	–	–	67
T15	Hideki Matsuyama	-3	-3	11:03 AM	67	–	–	–	67
T15	Tom Hoge	-3	-3	9:27 AM	67	–	–	–	67
T15	Mackenzie Hughes	-3	-3	9:27 AM	67	–	–	–	67
T15	Corey Conners	-3	-3	10:03 AM	67	–	–	–	67
T15	Scottie Scheffler	-3	-3	10:51 AM	67	–	–	–	67

5 1,415

Dan Tsubouchi @Energy_Tidbits · Aug 10

For those watching the opening focus on deepwater drilling, see 👇 tweets on big service co's seeing multi year across the globe deepwater drilling upcycle.

Schlumberger twitter.com/Energy_Tidbits...

Weatherford twitter.com/Energy_Tidbits...

NOV twitter.com/Energy_Tidbits...

#OOTT @TheDomino

> **CNBC Halftime Report** @HalftimeReport · Aug 10
> Join Dominic Chu @TheDomino and the committee today at 12p ET on #HalftimeReport
>
> @Downtown @GilmanHill

1 · 3 · 1,947

SAF

Dan Tsubouchi @Energy_Tidbits · Aug 10

Surely, a rising cost for companies in any sector to some degree?

#SixFlags doubles self-insurance reserves for ultimate loss indications "... *in connection with our general liability and worker's compensation self-insurance reserves*"

Thx @KellyCNBC @SquawkCNBC
#OOTT

Excerpt https://investors.sixflags.com/news-and-events/press-releases/2023/08-10-2023-110035367

Six Flags Reports Second Quarter 2023 Performance

August 10, 2023
The company had net income of $21 million in second quarter 2023, compared to net income of $45 million in second quarter 2022. The net income per share was $0.25 compared to net income per share of $0.53 in second quarter 2022, driven primarily by an increase in self-insurance reserves in second quarter 2023. Our self-insurance reserves are periodically reviewed for changes in facts and circumstances and adjustments are made as necessary. During the second quarter of 2023, we revised the estimate of our ultimate loss indications for both identified claims and incurred but not reported ("IBNR") claims in connection with our general liability and worker's compensation self-insurance reserves. The increase in our revised estimate was based on greater than previously estimated reserve adjustments on certain identified claims as well as an observed pattern of increasing litigation and settlement costs and changes to key actuarial assumptions utilized in determining estimated ultimate losses, including loss development factors. The change in estimate resulted in an increase to "selling, general and administrative expense" in our condensed consolidated statements of operation of $38 million during the three and six months ended July 2, 2023. The reduction in net income and net income per share were also driven by higher interest expense in second quarter 2023 versus prior year due to higher floating rate debt costs and increased borrowing under the revolver. Excluding the $38 million self-insurance reserves estimate adjustment, cash operating costs (4) increased by less than $1 million in second quarter 2023, driven by higher advertising expense and seasonal wages, offset by a reduction in full-time headcount and other cost-saving initiatives. Adjusted EBITDA in second quarter 2023, which excludes the $38 million self-insurance reserves estimate adjustment, was $161 million, a $7 million increase from the prior year (3).

Excerpt https://cllp.tools.investis.com/clients/us/sixflags3/SEC/sec-show.aspx?FilingId=16850686&Cik=0000701374&Type=PDF&hasPdf=1

1 1,029

Dan Tsubouchi @Energy_Tidbits · Aug 10

China summer holidays ending = city traffic increasing and domestic air travel down.

China Baidu city-level road congestion +0.4% WoW to 110.3% of Jan/21 levels.

But 👇 08/09 tweet, 1st WoW decline since early June in domestic flights.

Thx @BloombergNEF

#OOTT

Dan Tsubouchi @Energy_Tidbits · Aug 9

China scheduled domestic flights -0.4% WoW to 104,000 flights, following 6 consecutive WoW increases.

Chinese consumer stepped up to fly this summer....

3 4 4,680

Dan Tsubouchi @Energy_Tidbits · Aug 10

Wonder how much Chinese consumer has been saving for first international air travel since Covid?

China announced resumption of "group tours to some 78 countries including the US, Japan, South Korea, Australia, India and the majority of European countries".

#OOTT #JetFuel

https://www.globaltimes.cn/page/202308/1296026.shtml

China resumes group tours to another 78 countries, including US, Japan, India, Australia

By Global Times
Published: Aug 10, 2023 12:56 PM

Photo:VCG

China on Thursday announced the resumption of a third round of group tours to some 78 countries including the US, Japan, South Korea, Australia, India and the majority of European countries.

The Ministry of Culture and Tourism made the announcement with immediate effect, specifying that the outbound group tour services to these countries will be resumed at all national travel agencies and online travel companies.

The 78 countries include 12 in Asia, 27 in Europe, 18 in Africa and others from North America, South America and Oceania, according to the notice.

"Since the trial resumption of outbound group tours for Chinese citizens, the overall operation of outbound tourism market has remained stable and orderly, which has played a positive role in promoting tourism exchanges and cooperation," the ministry said.

China has previously resumed group tours to 60 countries over two stages earlier this year, including groups to Russia, France, Spain, Italy and other European countries, as well as countries in Southeast Asia and Africa.

Chinese travelers' enthusiasm for outbound trips, pent up over three years, has been unleashed with a surge continuing from the beginning of the year until now, especially as students entered summer vacation.

While Southeast Asia remains the most popular destination for Chinese travelers with its relatively short distance and cheap prices, Iran, the Caucasus region, Central Asia, the Balkans, and New Zealand have become the "dark horses" in this year's summer outbound tourism market.

Global Times

2 · 7 · 2,007

Dan Tsubouchi @Energy_Tidbits · Aug 9

1/2.

EU energy crisis is not over.

"we see a little bit of less headwinds from the market and more tailwind when it comes to the energy transition" says $EOAN CEO Birnbaum to @TomMackenzieTV

BUT also "the [EU Energy} crisis is not over"

#OOTT #natGas

0:39

1 · 5 · 10 · 3,349

Dan Tsubouchi @Energy_Tidbits · Aug 9

2/2. Elevated EU #natgas prices here for awhile

Germany has "roughly a doubling to tripling of prices on the gas side [natural gas] and that is a fact that is not going to go away anymore I am afraid. Not in the short term" says $EOAN CEO Birnbaum
#OOTT #natgas @TomMackenzieTV

1 4 1,199

Dan Tsubouchi @Energy_Tidbits · Aug 9

3/3.

Germany energy infra buildout not on track!

" this acceleration enough? The answer is clearly No. We are not & we still not fast enough in the expansion of the infrastructure. Across EU by the way, we need to further improve" says $EOAN CEO Birnbaum.

#OOTT #natgas

1 4 1,220

Dan Tsubouchi @Energy_Tidbits · Aug 9

Iran near term #Oil supply adds!

Given #Biden doesn't have any stroke over #MBS & tapped SPR, wonder if he effectively turns a blind eye as he sees this as a replacement for an SPR release to try to help keep a lid on oil/#Gasoline prices for 2024.

Thx @DanialRahmat12!

#OOTT

> Danial Rahmat دانیال رحمت @DanialRahmat12 · Aug 9
> CEO of #NIOC: Iran's crude prod. to increase by 150 k b/d in a week.
> By the end of Sep. 100k b/d will be added and output will reach 3.5 mil. b/d.
> In H2, about $8 b deals will be signed to develop 2 joint fields.
> #OOTT
> @Energy_Tidbits @sean_evers @FrankKaneDubai @imannasseri

2 2 10 8,113

Dan Tsubouchi @Energy_Tidbits · Aug 9

For those not near their laptops. At 8:30am MT, @EIAgov released its #Oil #Gasoline #Distillates inventory as of Aug 4. Table below compares EIA data vs @business expectations and vs @APIenergy yesterday. Prior to release, WTI was $84.01.
#OOTT

Oil/Products Inventory Aug 4: EIA, Bloomberg Survey Expectations, API

(million barrels)	EIA	Expectations	API
Oil	5.85	2.30	4.07
Gasoline	-2.66	-0.20	0.41
Distillates	-1.71	0.39	-2.10
	1.48	2.49	2.38

Note: Oil is commercial so builds in a build of 1 mmb in SPR for the Aug 4 week
Note: Included in the oil data, Cushing had a 0.16 mmb build for Aug 4 week
Source EIA, Bloomberg
Prepared by SAF Group https://safgroup.ca/news-insights/

3 7 2,024

Dan Tsubouchi @Energy_Tidbits · Aug 9

China scheduled domestic flights -0.4% WoW to 104,000 flights, following 6 consecutive WoW increases.

Chinese consumer stepped up to fly this summer.

But focus now shifts to watch flights post Aug summer holiday peak.

Thx @BloombergNEF Claudio Lubis.
#OOTT #JetFuel


May 30-Jun 5: +0.2% WoW to 94,486
May 23-29: -0.1% WoW to 94,321
May 16-22: -2.8% WoW to 94,417
May 9-15: basically flat at 97,040
May 2-8: +2.8% WoW to 97,087
Apr 25-May 1: +0.04% to 94,471
Apr 18-24: +2.1% WoW to 94,138
Apr 11-17: +0.7% WoW to 92,231
Apr 3-10: -4.2% WoW to 91,567
Mar 28-apr 3: +6.8% WoW to 95,624
Mar 21-27: +1.5% WoW to 89,515
Mar 14-20: -0.6% WoW to 88,166
Mar 7-13 week: -0.8% WoW to 88,675
Feb 27-Mar 3 week: -2.6% WoW to 89,430
Feb 21-27 week: +0.0% WoW to 91,828
Feb 14-20 week -0.5% WoW to 91,561
Feb 7-13 week -0.7% WoW to 92,007
Jan 31- Feb 6 week +10.9% WoW
Jan 24-30 week -9.2% WoW to 83,500
Jan 17-23 week +7% WoW to 91,959
Jan 10-16 week +20% WoW to 85,910
Jan 3-9 week: -5.3% WoW to 71,642
Dec 27-Jan 2 week: -5.6% WoW to 75,652

BNEF Aviation Indicators Weekly Aug 8 vs March 28.

2 · 3 · 6,064

Dan Tsubouchi @Energy_Tidbits · Aug 8

Russia complying!

RUS average seaborne crude flows for 4-weeks to Aug 6 were 3.02 mmb/d, ~870,000 b/d below recent mid-May peak.

Small 40,000 b/d WoW increase vs 4-weeks to July 30 of 3.02 mmb/d.

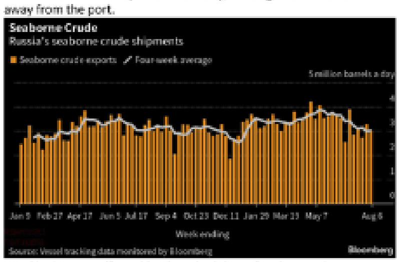
Thx @JLeeEnergy.
#OOTT

Average shipments during the period steadied at 3.02 million barrels a day, about 870,000 barrels a day below the peak in mid-May, tanker-tracking data compiled by Bloomberg show. More volatile weekly numbers slipped, with no cargoes leaving from the Arctic port of Murmansk after the previous week's record-equaling flow.

The figures support the notion that Moscow is now honoring a pledge to keep supply off the global market alongside its allies in the OPEC+ producer coalition. Russia initially said it would cut oil production in retaliation for Western sanctions and price caps on its oil imposed after the invasion of Ukraine, using February as a baseline. But seaborne flows had continued to rise, dropping significantly only in the last few weeks.

The drone attacks targeted a Ropucha-class large landing vessel off the port of Novorossiysk and a Russian-flagged oil tanker that Ukraine said had been en route to deliver fuel to Russian forces in Crimea's Kerch Strait. The incidents briefly halted activity at Novorossiysk.

By Monday the attack — and a warning from Kyiv that more could follow — had little impact on insurance costs for oil and commodity carriers in the key Black Sea region, as rates were already unusually high. Vessels waiting to load crude at Novorossiysk or the nearby CPC terminal were doing so much further south than they would normally, although none had turned away from the port.



Weekly data are affected by the scheduling of tankers and

Dan Tsubouchi @Energy_Tidbits · Aug 2

Russia finally complying!

RUS seaborne crude flows in the 4-weeks to July 30 fell to the lowest since early Jan. 4-week ave shipments dropped to 2.98 mmb/d, smallest since t...

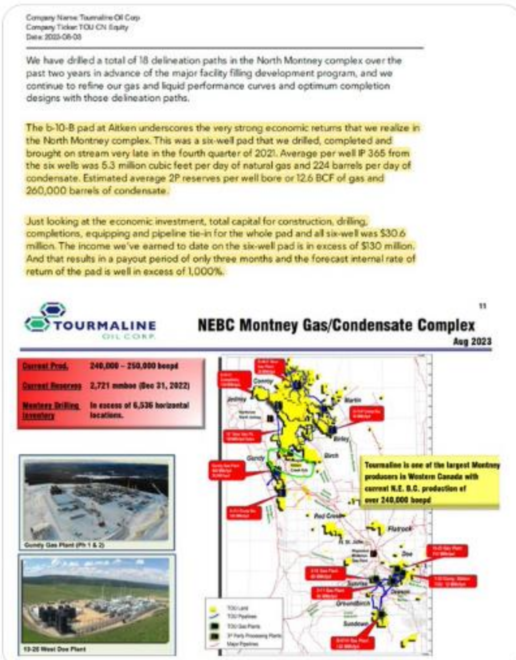
1 · 6 · 17 · 4,221

Dan Tsubouchi @Energy_Tidbits · Aug 7

Here's why #Montney is likely #1 #NatGas play in CAN/US, maybe in the world!

$TOU Q2 call: 6-well 10b Aitken Creek Montney pad. Drill/complete/onstream in Q4/21, cost $30.6mm, payout of 3 months, income to date >$130 mm, forecast IRR is >1,000%.

#OOTT



Company Name: Tourmaline Oil Corp
Company Ticker: TOU CN Equity
Date: 2023-08-03

We have drilled a total of 18 delineation paths in the North Montney complex over the past two years in advance of the major facility filling development program, and we continue to refine our gas and liquid performance curves and optimum completion designs with those delineation paths.

The b-10-B pad at Aitken underscores the very strong economic returns that we realize in the North Montney complex. This was a six-well pad that we drilled, completed and brought on stream very late in the fourth quarter of 2021. Average per well IP 365 from the six wells was 5.3 million cubic feet per day of natural gas and 224 barrels per day of condensate. Estimated average 2P reserves per well bore or 12.6 BCF of gas and 260,000 barrels of condensate.

Just looking at the economic investment, total capital for construction, drilling, completions, equipping and pipeline tie-in for the whole pad and all six-well was $30.6 million. The income we've earned to date on the six-well pad is in excess of $130 million. And that results in a payout period of only three months and the forecast internal rate of return of the pad is well in excess of 1,000%.

3 · 12 · 104 · 16.6K

SAF

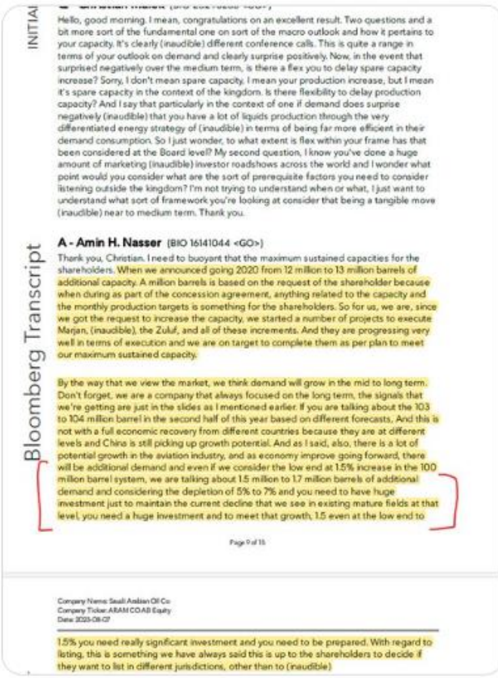
Dan Tsubouchi @Energy_Tidbits · Aug 7

#Oil 101.

Decline rates. Every barrel produced has to be replaced just to keep production flat.

#Aramco CEO "*considering the depletion of 5% to 7% and you need to have huge investment just to maintain the current decline that we see in existing mature fields*"

Oil looks good... Show more



INITIAL

Bloomberg Transcript

Hello, good morning. I mean, congratulations on an excellent result. Two questions and a bit more sort of the fundamental one on sort of the macro outlook and how it pertains to your capacity. It's clearly (inaudible) different conference calls. This is quite a range in terms of your outlook on demand and clearly surprise positively. Now, in the event that surprised negatively over the medium term, is there a flex you to delay spare capacity increase? Sorry, I don't mean spare capacity. I mean your production increase, but I mean it's spare capacity in the context of the kingdom. Is there flexibility to delay production capacity? And I say that particularly in the context of one if demand does surprise negatively (inaudible) that you have a lot of liquids production through the very differentiated energy strategy of (inaudible) in terms of being far more efficient in their demand consumption. So I just wonder, to what extent is flex within your frame has that been considered at the Board level? My second question, I know you've done a huge amount of marketing (inaudible) investor roadshows across the world and I wonder what point would you consider what are the sort of prerequisite factors you need to consider listening outside the kingdom? I'm not trying to understand when or what, I just want to understand what sort of framework you're looking at consider that being a tangible move (inaudible) near to medium term. Thank you.

A - Amin H. Nasser (BIO 16141044 <GO>)

Thank you, Christian. I need to buoyant that the maximum sustained capacities for the shareholders. When we announced going 2020 from 12 million to 13 million barrels of additional capacity. A million barrels is based on the request of the shareholder because when during as part of the concession agreement, anything related to the capacity and the monthly production targets is something for the shareholders. So for us, we are, since we got the request to increase the capacity, we started a number of projects to execute Marjan, (inaudible), the Zuluf, and all of these increments. And they are progressing very well in terms of execution and we are on target to complete them as per plan to meet our maximum sustained capacity.

By the way that we view the market, we think demand will grow in the mid to long term. Don't forget, we are a company that always focused on the long term, the signals that we're getting are just in the slides as I mentioned earlier. If you are talking about the 103 to 104 million barrel in the second half of this year based on different forecasts. And this is not with a full economic recovery from different countries because they are at different levels and China is still picking up growth potential. And as I said, also, there is a lot of potential growth in the aviation industry, and as economy improve going forward, there will be additional demand and even if we consider the low end at 1.5% increase in the 100 million barrel system, we are talking about 1.5 million to 1.7 million barrels of additional demand and considering the depletion of 5% to 7% and you need to have huge investment just to maintain the current decline that we see in existing mature fields at that level, you need a huge investment and to meet that growth, 1.5 even at the low end to

Page 9 of 15

Company Name: Saudi Arabian Oil Co
Company Ticker: ARAMCO AB Equity
Date: 2023-08-07

1.5% you need really significant investment and you need to be prepared. With regard to listing, this is something we have always said this is up to the shareholders to decide if they want to list in different jurisdictions, other than to (inaudible)

3 · 53 · 221 · 39K