Energy Tidbits

Saudi Aramco CEO "*Risks of Underinvestment in our Industry are Real – Including Contributing to Higher Energy Prices*"

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Short-Term Energy Outlook

March 2023

Overview

U.S. energy market indicators	2022	2023	2024
Brent crude oil spot price (dollars per barrel)	**$101**	**$83**	**$78**
Retail gasoline price (dollars per gallon)	**$3.97**	**$3.36**	**$3.11**
U.S. crude oil production (million barrels per day)	**11.88**	**12.44**	**12.63**
Natural gas price at Henry Hub (dollars per million British thermal units)	**$6.42**	**$3.02**	**$3.89**
U.S. liquefied natural gas gross exports (billion cubic feet per day)	**10.6**	**12.1**	**12.7**
Shares of U.S. electricity generation			
Natural gas	39%	39%	37%
Coal	20%	17%	17%
Renewables	22%	24%	26%
Nuclear	19%	20%	19%
U.S. GDP (percentage change)	**2.1%**	**0.9%**	**2.0%**
U.S. CO_2 emissions (billion metric tons)	**4.96**	**4.79**	**4.82**

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

- **Electricity generation capacity.** Beginning with the March *Short-Term Energy Outlook* (STEO), we will publish electricity generation capacity for all fuels. These data will appear in the newly created Table 7e. More information about this change is available in *Between the Lines*.
- **Weather.** Preliminary data from the National Oceanic and Atmospheric Administration for January and February indicate the first two months of 2023 may be close to the warmest on record for that period in data going back to 1895. The mild weather was concentrated in the eastern part of the United States.
- **Natural gas consumption.** We expect U.S natural gas consumption to average 99.1 billion cubic feet per day (Bcf/d) in the first quarter of 2023 (1Q23), down 5% from 1Q22. The decline in consumption is the result of very mild temperatures that have reduced demand for space heating. The largest decline is in residential and commercial consumption, which we expect will be 11% less in 1Q23 than in 1Q22.
- **Natural gas inventories and price.** As a result of less natural gas consumption than we had expected, we forecast that the United States will close the withdrawal season at the end of March with more than 1.9 trillion cubic feet of natural gas in storage, 23% more than the five-year average and 27% more than we forecast in the January STEO. The Henry Hub natural gas spot price in our forecast averages about $3 per million British thermal units (MMBtu) in 2023, down by more than 50% from last year. We had expected almost $5/MMBtu in the January STEO forecast.

- **Electric power prices**. Our forecast indicates that wholesale electricity prices fall in 2023. The decline in price reflects the forecast drop in natural gas prices from 2022 to 2023. Natural gas is the most-used fuel for power generation in the United States. In addition, increasing electricity generation from renewable sources contributes to lower power prices.

- **Global Liquid fuels consumption.** We expect global liquid fuels consumption to increase by 1.5 million barrels per day (b/d) in 2023 from 2022 and by an additional 1.8 million b/d in 2024. China is the main driver of growth in 2023 as the country shifts away from its zero-COVID policy, a shift that will increase travel. Growth in 2024 is more evenly distributed among countries as global GDP growth accelerates from 2.0% in 2023 to 3.2% in 2024.

- **Global liquid fuels production.** Our previous forecast of oil production in Russia included a steep decline in the coming months resulting from the EU's ban on seaborne petroleum products from Russia that began February 5. Russia recently announced a crude oil production cut of 0.5 million b/d for March, and we expect declines to be more than that, with Russia's production falling by 0.7 million b/d in March. Despite the declines in March, recent petroleum exports from Russia have outpaced expectations, and we have revised our oil production forecast for Russia upwards by 0.4 million b/d in 2023. Overall, we expect global oil and liquid fuels production will average 101.5 million b/d in 2023, up 1.6 million b/d from 2022.

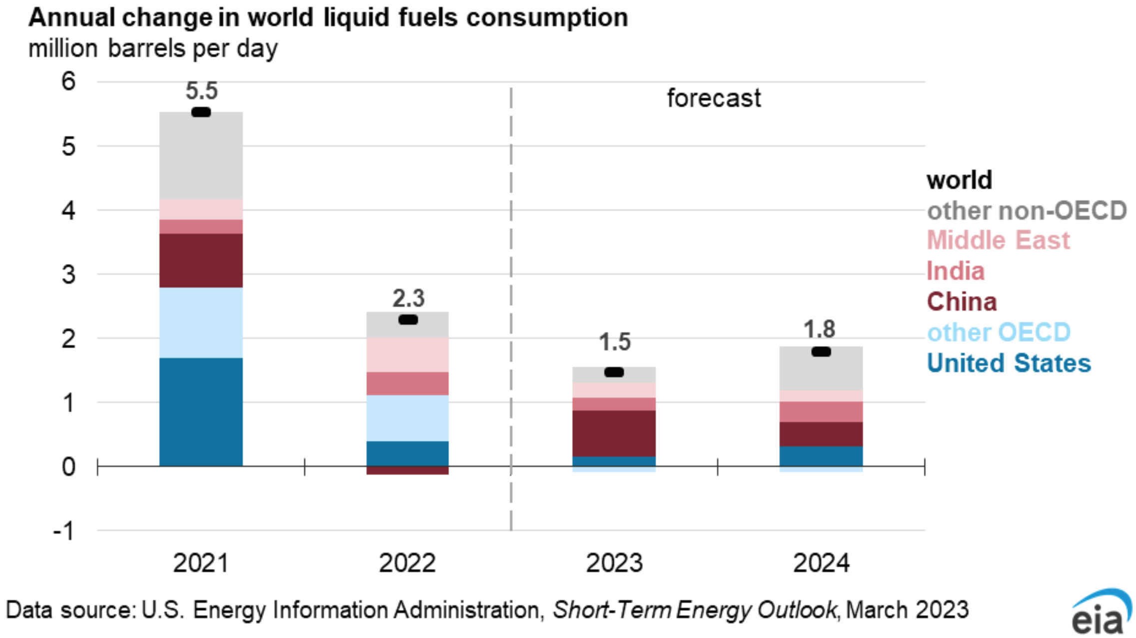
- **U.S. gasoline consumption.** We raised our forecast for U.S. gasoline consumption in 2023 and 2024 by about 2% compared with last month's outlook. Data revisions from the Federal Highway Administration resulted in a lower estimate of 2022 vehicle miles traveled (VMT). We now estimate VMT fell in 2022 compared with 2021. For the same period, we also reduced our estimate of vehicle fuel efficiency. The reduction in our vehicle efficiency estimate more than offset the lower VMT. These changes to historical data carried through to the forecast and resulted in us raising our forecast for gasoline consumption.

Notable forecast changes

current forecast: March 7, 2023; previous forecast: February 7, 2023	2023	2024
Natural gas price at Henry Hub (current forecast) (dollars per million British thermal units)	**$3.02**	**$3.89**
Previous forecast	$3.40	$4.04
Percentage change	-11.2%	-3.8%
U.S. vehicle miles traveled (current forecast) (million miles per day)	**8,935**	**9,098**
Previous forecast	9,059	9,183
Percentage change	-1.4%	-0.9%
U.S. gasoline consumption (current forecast) (million barrels per day)	**8.9**	**8.9**
Previous forecast	8.8	8.7
Percentage change	1.6%	2.3%
Russia petroleum and liquid fuels production (current forecast) (million barrels per day)	**10.3**	**10.1**
Previous forecast	9.9	9.8
Percentage change	4.2%	3.4%
U.S. coal production (current forecast) (million short tons)	**552.3**	**502.6**
Previous forecast	518.0	493.9
Percentage change	6.6%	1.8%
U.S. secondary coal inventories (current forecast) (million short tons)	**123.6**	**98.4**
Previous forecast	105.6	81.7
Percentage change	17.0%	20.4%
U.S. heating degree days (current forecast)	**3,960**	**4,156**
Previous forecast	4,083	4,201
Percentage change	-3.0%	-1.1%

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

Global oil markets



Global liquid fuels consumption

Globally, liquid fuels consumption in our forecast increases from an average of 99.4 million barrels per day (b/d) in 2022 to 100.9 million b/d in 2023, which is 0.4 million b/d higher than in last month's outlook. The higher consumption forecast is primarily driven by upward revisions to global economic growth. We expect China will account for about half of the growth in global liquid fuels consumption in 2023. Forecast consumption in China increases by 0.7 million b/d in 2023. We forecast consumption in India to increase by 0.2 million b/d and other non-OECD consumption to grow by 0.5 million b/d on average. This growth in non-OECD countries counteracts almost no consumption growth among OECD countries in 2023. OECD consumption remains largely unchanged as the effects of inflation continue to limit GDP and oil demand growth.

We forecast global liquids fuel consumption will grow by an additional 1.8 million b/d in 2024, and non-OECD countries will account for 1.6 million b/d of the growth. However, significant uncertainty around our demand forecast remains because a wide range of possible outcomes exist for both global economic conditions this year and travel and oil demand in China following its pivot away from a zero-COVID strategy.

Global liquid fuels production

World liquid fuels production averaged about 100 million b/d in 2022, and we forecast it will rise by an average of 1.6 million b/d in both 2023 and 2024. Despite upward revisions to increasing our forecast of global liquid fuels consumption, we still expect consistent global oil inventory builds over the forecast period as global oil production continues to outpace consumption.

In February, Russia announced it will cut oil production by 0.5 million b/d in March. We already accounted for oil production declines in Russia during this period in our past outlooks. However, Russia's liquids fuel production and exports continue to outpace our expectations as Russia finds buyers in alternative markets. As a result, we have raised our forecast for oil production in Russia through the end of 2024. We expect production of petroleum and other liquids in Russia will decline to 10.3 million b/d in 2023 from 10.9 million b/d in 2022 and then average 10.1 million b/d in 2024, about 0.4 million b/d and 0.3 million b/d more respectively, than we forecast in last month's STEO. More output in Russia contributes to our higher global liquid fuels production forecast. Given this revision to production, we expect that global oil inventories, which rose by 0.4 million b/d in 2022, will grow by an additional 0.6 million b/d in 2023 and 0.3 million b/d in 2024, putting downward pressure on oil prices later in 2023.

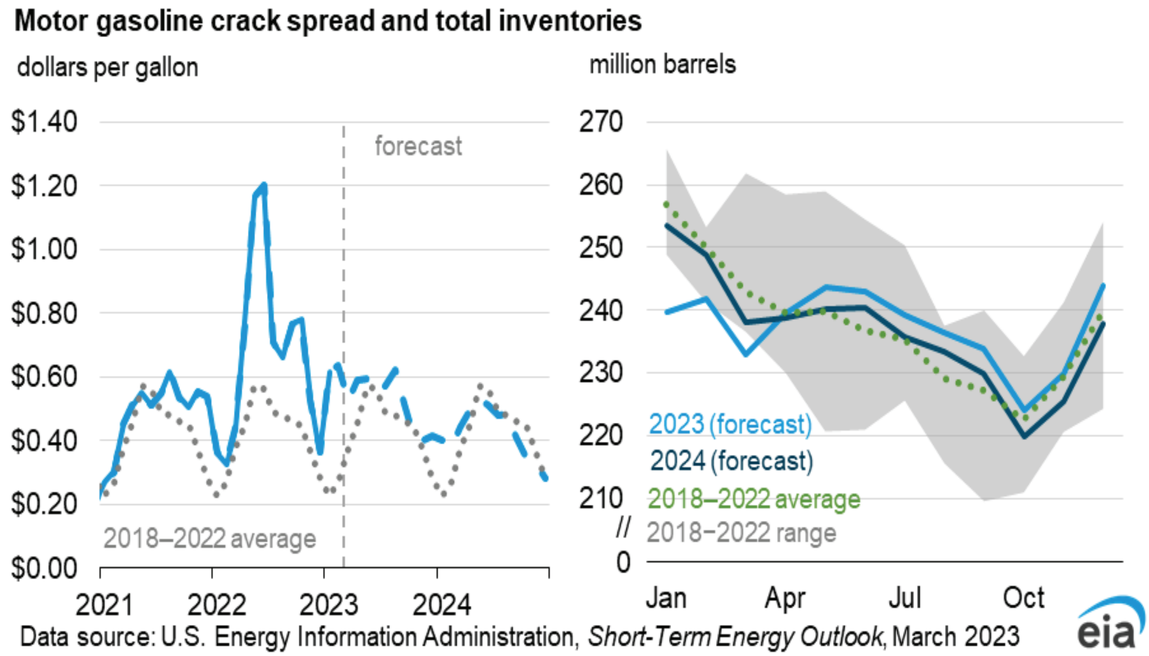
Crude oil prices

We expect that the Brent crude oil spot price will fall from an average of $84/b in the second quarter of 2023 (2Q23) to $81/b in 4Q23 and then average $78/b in 2024. Although we expect global oil inventories will build throughout the forecast period, we expect that high demand for crude oil from refineries because of elevated refining margins will limit downward pressure on crude oil prices through 2Q23 as refiners maintain high levels of crude oil inputs to maximize distillate fuel production. Russia was a key supplier of distillate fuel to Europe, and changes in distillate trade flows as Europe reduced imports of distillate from Russia in recent months have kept distillate fuel margins well-above five-year averages. However, we forecast that increasing global oil inventories will contribute to falling crude oil prices beginning in 3Q23.

Petroleum products

Gasoline prices and inventories

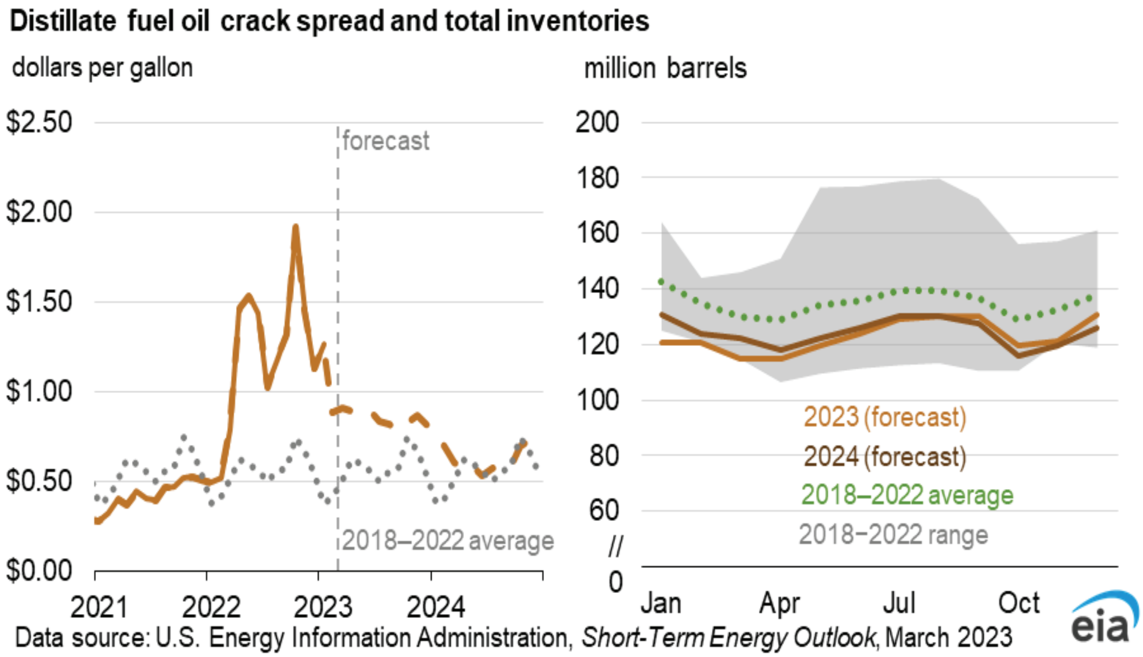
Typically, from February to May or June the U.S. gasoline crack spread (the difference between the wholesale price of gasoline and the price of Brent crude oil) increases because of the shift to the more expensive, summer-grade gasoline and rising gasoline demand leading up to the summer. Over the past five years, the increase in the gasoline crack spread from February to June averaged almost 30 cents per gallon (gal). Also because of the seasonal increase in gasoline demand from February to June, gasoline inventories have fallen by 13 million barrels on average over the past five years. From February to June this year, however, we expect increasing refining to offset seasonal increases in demand, generating slight gasoline inventory builds and a small decline in gasoline crack spreads. We forecast that U.S. gasoline inventories will decrease by 9 million barrels in March because of postponed refinery maintenance. However, as refineries complete turnarounds, we expect inventories will end June with 10 million barrels more gasoline than at the end of March.



Our U.S. gasoline inventory forecast for February through June 2023 reflects increasing refining activity and gasoline production, as well as gasoline consumption that remains below pre-pandemic levels. Although we expect distillate refining margins to remain higher than gasoline refining margins, the limited ability of refiners to shift their product yields will keep gasoline inventories within the 2018–2022 range from April through the end of the forecast. ExxonMobil's planned startup of a 250,000 b/d capacity expansion at its Beaumont, Texas, refinery in the first half of this year will also contribute to increased production. We expect that rising gasoline inventories, along with falling crude oil prices, will gradually decrease gasoline prices throughout the forecast period. We forecast retail gasoline prices to average near $3.20/gal in the fourth quarter of 2023 (4Q23), down more than 30 cents/gal from 4Q22, and to decrease further to an average of about $3.10/gal in 2024.

Distillate prices and inventories

We forecast U.S. distillate crack spreads to decrease through our forecast period, averaging almost 90 cents/gal in 2023, down 30 cents/gal from 2022. Crack spreads fall further to almost 60 cents/gal in 2024. Partly as a result of a warm start to 2023 and inventory builds at the Amsterdam, Rotterdam, and Antwerp (ARA) hub in Northwest Europe, the U.S. distillate crack spread decreased by almost 40 cents/gal from January to February.



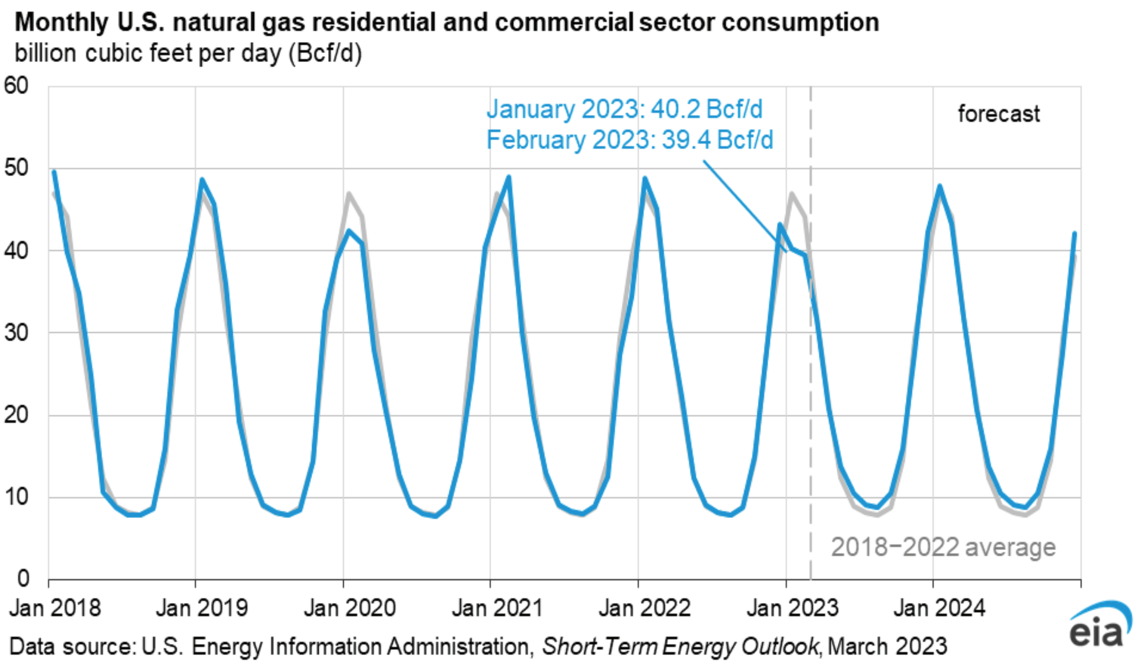
Demand for U.S. diesel exports amid shifting trade flows and increased freight costs following responses to Russia's full-scale invasion of Ukraine have reduced diesel inventories in the United States and driven up diesel prices globally. We expect U.S. distillate inventories to remain below the five-year average in 2023 but to increase slightly compared with 2022 as refinery runs increase and U.S. distillate fuel demand falls.

U.S. distillate inventories in our forecast remain similar to this year in 2024, but we expect U.S. distillate crack spreads to continue falling because more distillate fuel supplies will be available in markets outside of the United States, particularly at the ARA and Singapore hubs, limiting growth in demand for U.S. exports. Supply has increased because of more diesel exports from the Middle East as a result of expanded refinery capacity. Since lifting its zero-COVID policy, China has also increased diesel exports compared with this time last year. Despite recent increases in diesel supplies, the impact of changing economic conditions and the longer-term impact of Europe's ban on petroleum product imports from Russia continue to present significant uncertainty in our distillate outlook.

Natural gas

Natural gas consumption

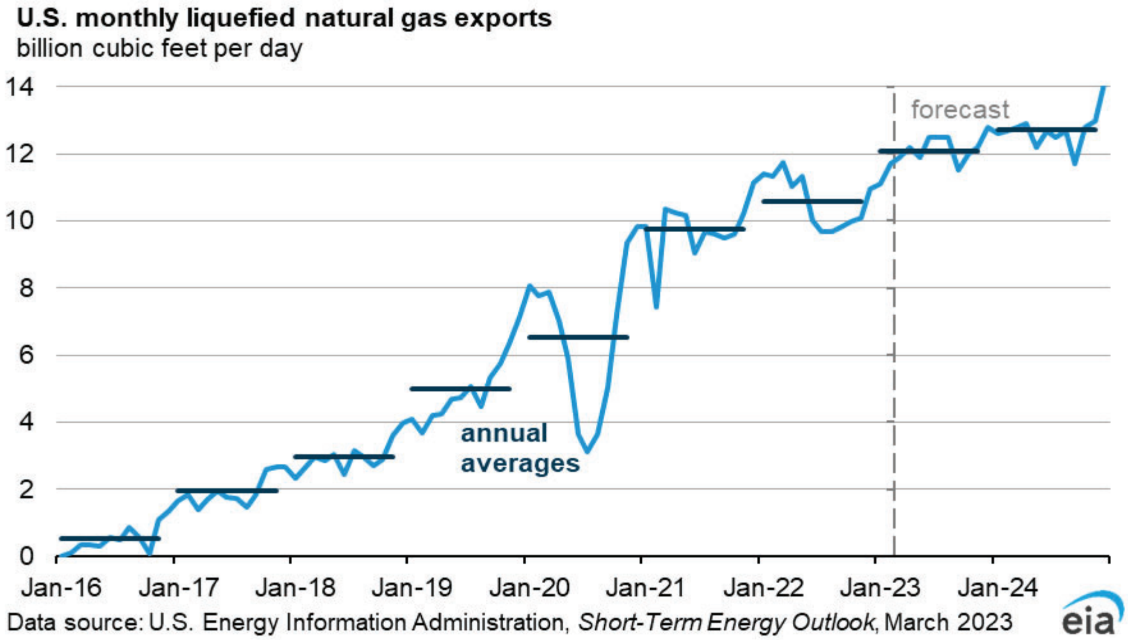
In January and February, below-average U.S. natural gas consumption in the residential and commercial sectors was driven by mild winter weather across large parts of the country, particularly in the Northeast and the Midwest. Based on preliminary data from the National Oceanic and Atmospheric Administration for January and February, the first two months of 2023 combined were among the three warmest on record for that period going back to 1895. In March, we expect natural gas consumption in the residential and commercial sectors to average almost 32 billion cubic feet per day (Bcf/d), which is close to the five-year average, because we expect more normal temperatures in March with a close to average number of heating degree days.



As a result of the mild winter and low natural gas consumption in the residential and commercial sectors, we expect 2.4% (2 Bcf/d) less U.S. natural gas consumption in 2023 than in 2022. Reduced natural gas consumption in January and February slowed withdrawals from natural gas inventories to less than the five-year average and reduced natural gas prices. The spot price of natural gas at the U.S. benchmark Henry Hub averaged $2.38 per million British thermal units (MMBtu) in February, the lowest monthly average since September 2020. Although we reduced our Henry Hub price forecast from last month's STEO, we still expect natural gas prices to increase in the coming months. Price increases in the forecast result from rising demand from Freeport LNG reopening, which shut down last June due to a fire, and seasonal increases in natural gas demand in the electric power sector. In addition, we expect natural gas production will be relatively flat for the rest of 2023 as producers reduce drilling in response to lower prices.

Liquefied natural gas exports

U.S. liquefied natural gas (LNG) exports in our forecast average about 12 Bcf/d in 2023, up 14% from last year. We expect LNG exports to increase by an additional 5% in 2024. The Freeport LNG export terminal's return to service and LNG export projects under construction that will come online by the end of 2024 contribute to rising exports.



The Freeport LNG terminal can produce more than 2.1 Bcf/d of LNG for export on a peak day, and exports from Freeport averaged 1.9 Bcf/d from January 2021 through May 2022, prior to the full shutdown of the facility in June 2022, according to our *Natural Gas Monthly*. Because of the Freeport shutdown, U.S. LNG exports averaged 10.0 Bcf/d from June 2022 through December 2022, after peaking at 11.7 Bcf/d in March. The new Calcasieu Pass LNG export facility partially offset the decline in exports from Freeport LNG, with exports from Calcasieu Pass averaging 1.2 Bcf/d since June 2022.

This year, once all three trains at Freeport LNG return to service, we forecast U.S. LNG exports to exceed 12 Bcf/d in most months for the rest of the forecast period. We forecast that U.S. LNG exports will increase to 14 Bcf/d by December 2024 because new LNG export capacity from three major projects under construction are scheduled to come online.

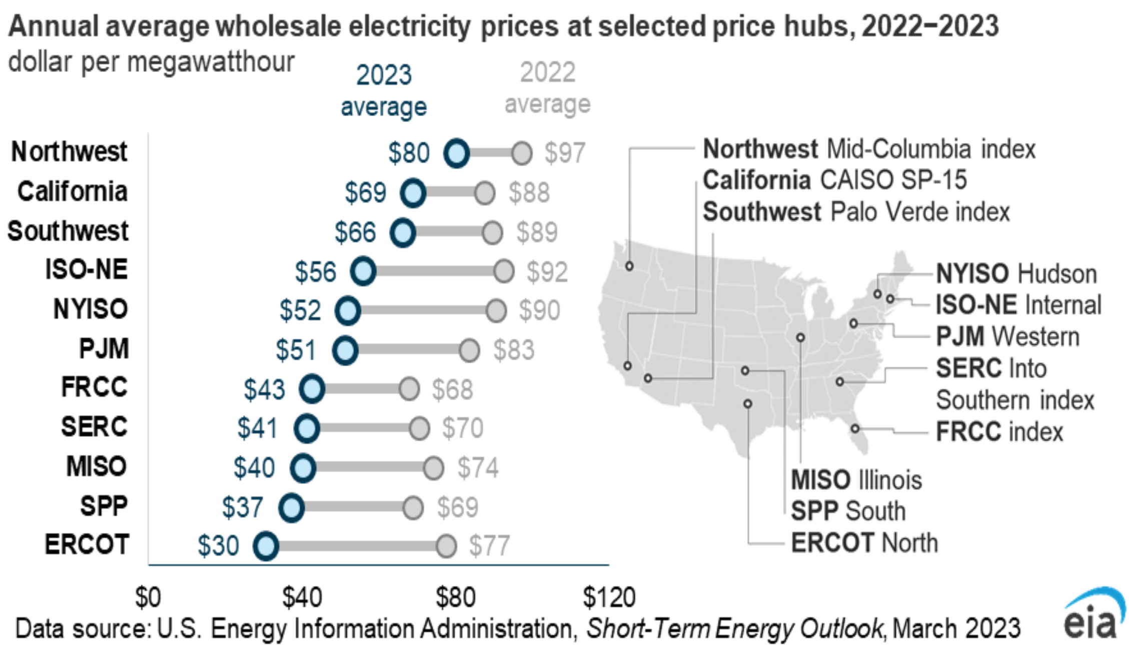
Electricity, coal, and renewables

Electricity markets

We expect that natural gas will continue to be the predominant source of U.S. electricity generation through 2024, as it has been over the past five years, accounting for an average of around 38% of total generation in 2023 and 2024. However, renewable energy sources will grow the most during the next two years, with about 7 gigawatts (GW) of new wind capacity and 29 GW of new solar PV capacity being installed in 2023. These additions will result in renewable energy resources other than hydropower accounting for 19% of generation in 2024 compared with 15% in 2022. To better show how the U.S. generation mix is changing, beginning with this month's STEO, we have begun publishing forecasts of the operational generating capacity for all types of energy sources.

Natural gas's current place as the largest source of U.S. electricity generation means that its fuel costs are a significant driver of wholesale electricity prices. For 2023, we forecast that the cost of natural gas delivered to U.S. electric generators will average around $3.50/MMBtu, which would be about half the average in 2022. Although wholesale power prices can be extremely volatile in the short-term, we expect that average wholesale prices this year will be lower than in 2022 as a result of lower natural gas costs.

The western United States experienced increases in natural gas prices late in 2022, which pushed monthly average power prices above $250 per megawatthour (MWh) in December 2022 at the main western price hubs. Although prices have come down in recent weeks, and we forecast prices to remain lower, on average, than in 2022, we expect that growth in overall electricity demand will keep wholesale power prices in that region relatively high compared with other parts of the country. We forecast wholesale prices will decrease by an average of around 20% between 2022 and 2023 at California's SP-15 hub and by slightly less at the Mid-Columbia hub in the Pacific Northwest.



We expect wholesale electricity prices will average between $50/MWh and $60/MWh in New England, New York, and the PJM power markets in 2023. The Northeast power markets also had some of the highest wholesale prices last year as a result of regional constraints on receiving natural gas. Electricity prices during 2022 averaged close to $90/MWh in the ISO-New England and New York ISO markets.

We expect the lowest U.S. wholesale prices to occur in Texas's ERCOT market, averaging $30/MWh in 2023 compared with $77/MWh last year. Because of the nearby abundance of natural gas production, Texas tends to have lower fuel costs than other regions. In addition, it will also have some of the fastest growth in renewable generating capacity, which we expect will put downward pressure on wholesale power prices.

Coal markets

Coal stocks held by the power sector rise in our forecast by more than 30% from the end of December 2022 through May 2023, after which they decline as electric power generation ramps up to meet summer air-conditioning needs. Coal stocks increased over the past two months because warmer-than-average temperatures and falling natural gas prices reduced the need for coal generation. Monthly coal production had been rising in response to relatively strong coal demand in the fourth quarter of 2022, due in, part, to a colder-than-average December in 2022.

Coal production declined by 14% in February 2023 compared with January 2023, from 52 million short tons (MMst) to 45 MMst, because the mild weather reduced coal-fired generations. After increasing in both 2021 and 2022, we expect U.S. coal production to decline by 7% from more than 590 MMst in 2022 to about 550 MMst in 2023, with a further 9% decline to around 500 MMst in 2024. Among the drivers of the steady decline is the on-going retirement of coal-fired generating plants. We expect 11 GW of coal-fired capacity will close from the end of 2022 to the end of 2024.

The average price of coal to electric generators reached $2.67 per million British thermal units (MMBtu) in January 2023, rising 41% from $1.89/MMBtu in May 2021. The rise in coal price over that period was a result of upward pressures on coal demand due to high natural gas prices and several extreme weather-related events, which occurred amid constrains on coal production and transportation capacity. Prices fell slightly in February to $2.65/MMBtu, and we expect them to fall slightly throughout the forecast to $2.54/MMBtu by December 2024.

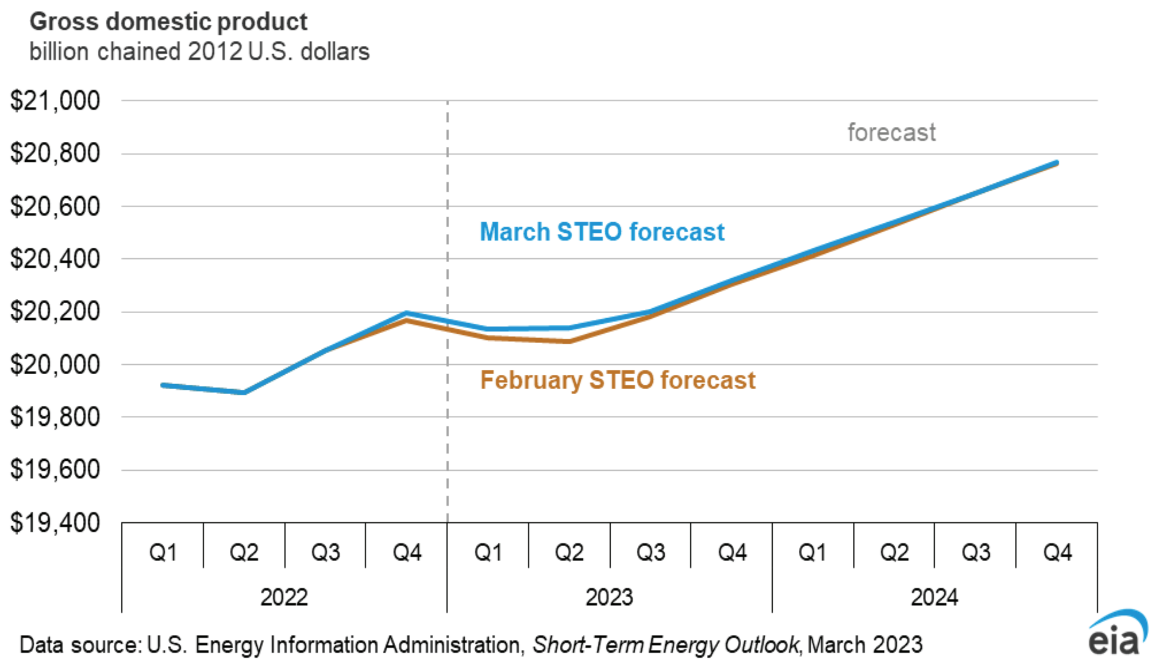
Economy, weather, and CO_2

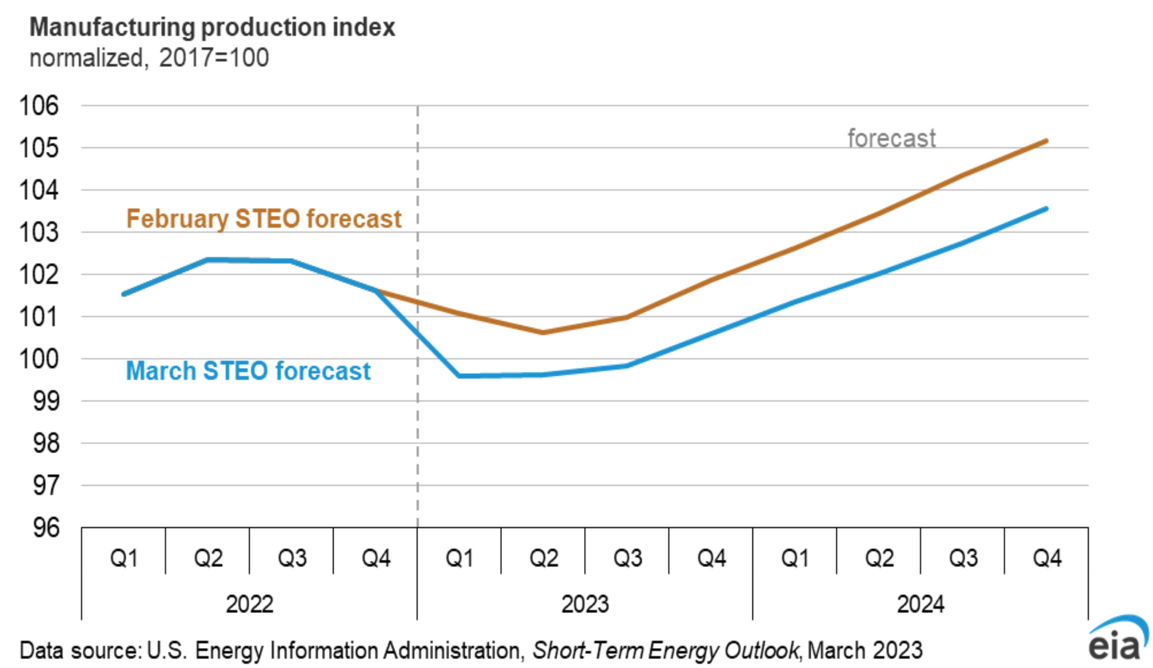
U.S. macroeconomics

We base our U.S. macroeconomic forecasts on S&P Global's macroeconomic model. We incorporate STEO energy price forecasts into the model to obtain the final macroeconomic assumptions.

The forecast continues to show U.S. GDP contracting in the first quarter of 2023 (1Q23), with a return to positive growth in 2Q23. Residential fixed investment, private business inventories of goods, and industrial production continue to limit growth. Real GDP for 2Q23 was revised upward from our previous STEO by 0.3%, with forecast growth of almost 1% in 2023.

The U.S. economy is experiencing a sectoral shift as the economy emerges from the COVID-19 pandemic. U.S. Consumer spending is moving away from goods and toward services. Although the forecast for GDP is high than in last month STEO, we revised the forecast for manufacturing activity downward, reflecting this reallocation of economic activity. Our forecast includes a contraction in U.S. manufacturing production in 1Q23, resulting in an overall decline of 2.0% for the year.

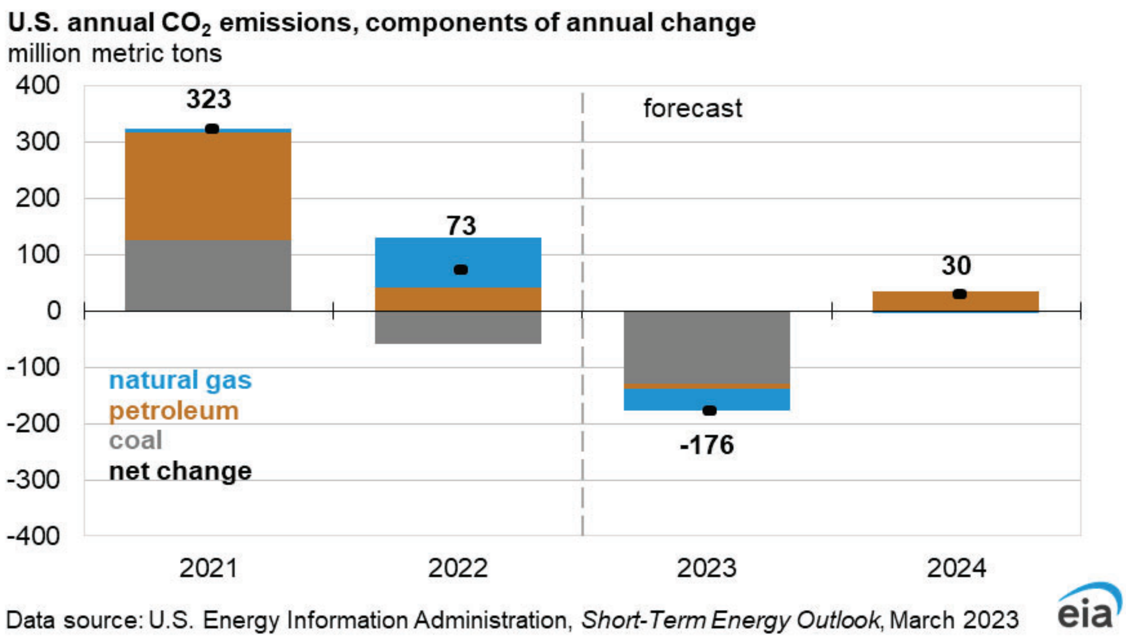




Emissions

We expect U.S. energy-related carbon dioxide (CO_2) emissions to decrease by about 4% in 2023. This reduction in emissions is driven by weak economic growth and less electricity generation from fossil fuels. Coal-fired electricity generation falls by almost 16% and coal-related CO_2 emissions by about 14%. Natural gas-fired generation and natural gas CO_2 emissions both decrease by about 2%. Generation from both fuels is replaced by renewable sources. We expect petroleum emissions to remain about the same.

We expect CO_2 emissions in 2024 to rise slightly from 2023. Petroleum CO_2 emissions increase by about 1% as a result of increases in air and road travel. Rising petroleum emissions in 2024 are partly offset by small decreases in coal and natural gas emissions, which fall as a growing share renewable sources are used for electricity generation.



Weather

Preliminary data indicate January and February were among the mildest first two months of any year on record. Mild weather was most prevalent across the Northeast and Midwest. Based on forecasts from the National Oceanic and Atmospheric Administration, we expect 7% fewer HDDs in the United States in 2023 compared with 2022 and 5% fewer than the 10-year average. We have updated our expectations for winter heating fuel expenditures based on the most recent temperature and price forecasts.

Table 3a. International Petroleum and Other Liquids Production, Consumption, and Inventories
U.S. Energy Information Administration | Short-Term Energy Outlook - March 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	31.62	31.88	32.54	32.96	33.32	33.79	34.00	34.50	34.59	34.46	34.60	35.16	32.25	33.91	34.70
U.S. (50 States)	19.44	20.12	20.60	20.65	20.64	21.17	21.21	21.34	21.30	21.56	21.61	21.75	20.21	21.09	21.56
Canada	5.66	5.51	5.72	5.91	6.00	5.72	5.93	6.14	6.21	5.92	6.13	6.34	5.70	5.95	6.15
Mexico	1.91	1.89	1.90	1.90	1.92	1.95	1.96	1.94	1.96	1.96	1.93	1.89	1.90	1.94	1.93
Other OECD	4.61	4.35	4.32	4.49	4.76	4.96	4.89	5.07	5.11	5.02	4.93	5.18	4.44	4.92	5.06
Non-OECD	67.21	66.87	68.26	68.07	67.41	67.49	67.92	67.42	67.68	68.39	68.83	68.36	67.61	67.56	68.32
OPEC	33.75	33.76	34.71	34.43	33.92	34.10	34.20	33.99	34.75	34.78	34.86	34.60	34.17	34.05	34.75
Crude Oil Portion	28.19	28.33	29.23	28.92	28.43	28.74	28.80	28.56	29.22	29.37	29.42	29.12	28.67	28.63	29.29
Other Liquids (b)	5.56	5.43	5.48	5.52	5.49	5.36	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	13.91	13.96	13.09	13.15	13.24	13.25	13.23	13.21	13.29	13.81	13.36	13.24
China	5.18	5.18	5.05	5.09	5.21	5.24	5.23	5.28	5.21	5.24	5.23	5.27	5.12	5.24	5.24
Other Non-OECD	13.90	14.54	14.95	14.64	14.32	15.06	15.33	14.91	14.47	15.15	15.53	15.20	14.51	14.91	15.09
Total World Production	98.83	98.75	100.80	101.03	100.73	101.28	101.92	101.93	102.27	102.85	103.43	103.53	99.86	101.47	103.02
Non-OPEC Production	65.09	64.99	66.10	66.59	66.81	67.19	67.72	67.93	67.51	68.07	68.56	68.93	65.70	67.42	68.27
Consumption (million barrels per day) (c)															
OECD	45.78	45.37	46.62	45.89	45.90	45.66	46.18	46.29	46.15	45.78	46.49	46.54	45.92	46.01	46.24
U.S. (50 States)	20.22	20.27	20.47	20.16	19.93	20.67	20.63	20.55	20.53	20.84	20.92	20.76	20.28	20.45	20.76
U.S. Territories	0.14	0.12	0.12	0.13	0.13	0.12	0.12	0.13	0.13	0.12	0.12	0.13	0.13	0.12	0.13
Canada	2.24	2.21	2.38	2.30	2.28	2.23	2.33	2.31	2.31	2.26	2.36	2.33	2.28	2.29	2.31
Europe	13.19	13.42	14.09	13.45	13.47	13.37	13.77	13.54	13.25	13.40	13.80	13.57	13.54	13.54	13.50
Japan	3.70	3.03	3.19	3.53	3.69	3.05	3.07	3.37	3.54	2.93	3.03	3.36	3.36	3.29	3.22
Other OECD	6.30	6.33	6.37	6.32	6.39	6.23	6.25	6.39	6.39	6.23	6.25	6.40	6.33	6.31	6.32
Non-OECD	52.99	53.32	53.83	53.86	54.04	54.93	55.29	55.27	55.90	56.53	56.75	56.59	53.50	54.89	56.44
Eurasia	4.46	4.35	4.71	4.58	4.25	4.40	4.71	4.62	4.41	4.56	4.89	4.79	4.53	4.50	4.66
Europe	0.75	0.75	0.76	0.77	0.74	0.76	0.76	0.77	0.75	0.77	0.77	0.77	0.76	0.76	0.76
China	15.12	15.10	15.09	15.28	15.50	15.85	15.93	16.16	16.01	16.32	16.28	16.37	15.15	15.86	16.25
Other Asia	13.74	13.76	13.46	13.93	14.25	14.29	13.71	14.01	14.88	14.86	14.26	14.57	13.72	14.06	14.64
Other Non-OECD	18.92	19.36	19.81	19.29	19.30	19.64	20.17	19.70	19.84	20.02	20.56	20.08	19.35	19.71	20.13
Total World Consumption	98.77	98.69	100.45	99.75	99.94	100.60	101.47	101.56	102.04	102.31	103.25	103.14	99.42	100.90	102.69
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	-0.37	-0.33	-0.13	0.35	-0.10	-0.53	-0.07	0.34	0.54	-0.12	-0.09
Other OECD	-0.09	-0.29	-0.48	-0.35	-0.14	-0.11	-0.10	-0.23	-0.04	0.00	-0.03	-0.23	-0.30	-0.14	-0.08
Other Stock Draws and Balance	-0.78	-0.29	-0.33	-1.34	-0.29	-0.24	-0.22	-0.49	-0.09	-0.01	-0.07	-0.51	-0.68	-0.31	-0.17
Total Stock Draw	-0.06	-0.06	-0.35	-1.28	-0.79	-0.69	-0.44	-0.37	-0.22	-0.54	-0.18	-0.39	-0.44	-0.57	-0.33
End-of-period Commercial Crude Oil and Other Liquids Inventories (million barrels)															
U.S. Commercial Inventory	1,154	1,180	1,215	1,222	1,255	1,310	1,321	1,288	1,291	1,334	1,334	1,297	1,222	1,288	1,297
OECD Commercial Inventory	2,604	2,656	2,735	2,774	2,819	2,884	2,904	2,893	2,900	2,942	2,946	2,930	2,774	2,893	2,930

(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 March 2, 2022.
The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.
Historical data: Latest data available from Energy Information Administration international energy statistics.
Minor discrepancies with published historical data are due to independent rounding.
Forecasts: EIA Short-Term Integrated Forecasting System.

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

U.S. Energy Information Administration | Short-Term Energy Outlook - March 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)	11.47	11.70	12.06	12.30	12.31	12.43	12.48	12.54	12.58	12.58	12.64	12.71	11.88	12.44	12.63
Alaska	0.45	0.44	0.42	0.44	0.45	0.39	0.41	0.42	0.42	0.35	0.38	0.40	0.44	0.42	0.39
Federal Gulf of Mexico (b)	1.67	1.70	1.80	1.80	1.86	1.95	1.85	1.84	1.89	1.87	1.81	1.83	1.74	1.87	1.85
Lower 48 States (excl GOM)	9.35	9.56	9.84	10.05	10.00	10.10	10.23	10.28	10.27	10.36	10.45	10.49	9.70	10.15	10.39
Crude Oil Net Imports (c)	3.00	2.81	2.75	2.14	2.73	3.43	3.82	3.54	2.99	3.30	3.30	2.75	2.67	3.38	3.08
SPR Net Withdrawals	0.31	0.80	0.84	0.48	-0.01	0.27	-0.01	0.00	-0.07	-0.07	-0.07	-0.07	0.61	0.06	-0.07
Commercial Inventory Net Withdrawals	0.08	-0.03	-0.12	-0.01	-0.70	0.14	0.16	-0.09	-0.34	0.09	0.17	-0.11	-0.02	-0.12	-0.05
Crude Oil Adjustment (d)	0.71	0.81	0.74	0.89	0.89	0.58	0.49	0.44	0.54	0.60	0.49	0.46	0.79	0.60	0.52
Total Crude Oil Input to Refineries	15.56	16.09	16.26	15.80	15.23	16.85	16.94	16.43	15.70	16.51	16.53	15.75	15.93	16.37	16.12
Other Supply															
Refinery Processing Gain	0.95	1.07	1.05	1.01	0.94	1.05	1.06	1.06	0.99	1.02	1.02	1.01	1.02	1.03	1.01
Natural Gas Plant Liquids Production	5.61	5.92	6.09	5.90	5.95	6.21	6.22	6.24	6.24	6.40	6.39	6.42	5.88	6.16	6.36
Renewables and Oxygenate Production (e)	1.20	1.20	1.18	1.23	1.23	1.26	1.23	1.27	1.28	1.33	1.34	1.38	1.20	1.25	1.33
Fuel Ethanol Production	1.02	1.01	0.97	1.01	1.00	1.01	0.98	1.02	1.01	1.02	1.00	1.03	1.00	1.00	1.02
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	0.22	0.22
Product Net Imports (c)	-3.74	-3.99	-4.07	-3.93	-3.96	-4.18	-4.77	-5.13	-4.21	-4.09	-4.40	-4.54	-3.93	-4.51	-4.31
Hydrocarbon Gas Liquids	-2.14	-2.31	-2.16	-2.26	-2.53	-2.51	-2.54	-2.57	-2.53	-2.69	-2.63	-2.69	-2.22	-2.54	-2.63
Unfinished Oils	0.09	0.25	0.28	0.30	0.13	0.25	0.37	0.19	0.19	0.25	0.30	0.18	0.23	0.24	0.23
Other HC/Oxygenates	-0.09	-0.10	-0.07	-0.02	-0.07	-0.04	-0.03	-0.04	-0.06	-0.05	-0.04	-0.05	-0.07	-0.05	-0.05
Motor Gasoline Blend Comp.	0.40	0.60	0.48	0.40	0.49	0.70	0.36	0.39	0.39	0.63	0.36	0.37	0.47	0.48	0.44
Finished Motor Gasoline	-0.76	-0.73	-0.81	-0.83	-0.63	-0.75	-0.97	-1.17	-0.77	-0.59	-0.70	-0.91	-0.78	-0.88	-0.74
Jet Fuel	-0.04	-0.06	-0.11	-0.03	-0.09	0.00	0.04	0.03	0.11	0.14	0.17	0.15	-0.06	0.00	0.14
Distillate Fuel Oil	-0.81	-1.15	-1.29	-1.05	-0.80	-1.23	-1.43	-1.39	-1.00	-1.25	-1.35	-1.16	-1.07	-1.21	-1.19
Residual Fuel Oil	0.14	0.10	0.10	0.09	0.07	0.07	0.06	0.12	0.05	0.07	0.07	0.15	0.11	0.08	0.08
Other Oils (g)	-0.54	-0.59	-0.49	-0.53	-0.52	-0.67	-0.63	-0.68	-0.59	-0.61	-0.57	-0.57	-0.54	-0.63	-0.59
Product Inventory Net Withdrawals	0.42	-0.25	-0.26	-0.06	0.34	-0.74	-0.27	0.45	0.31	-0.55	-0.18	0.52	-0.04	-0.06	0.02
Total Supply	20.22	20.27	20.47	20.16	19.93	20.67	20.63	20.55	20.53	20.84	20.92	20.76	20.28	20.45	20.76
Consumption (million barrels per day)															
Hydrocarbon Gas Liquids	3.87	3.43	3.48	3.57	3.76	3.48	3.50	3.80	4.00	3.50	3.60	3.84	3.59	3.63	3.74
Other HC/Oxygenates	0.13	0.17	0.17	0.19	0.21	0.21	0.20	0.22	0.22	0.25	0.27	0.30	0.16	0.21	0.26
Unfinished Oils	0.13	0.04	0.11	0.10	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00
Motor Gasoline	8.47	9.00	8.88	8.75	8.64	9.18	8.98	8.80	8.68	9.20	9.04	8.81	8.78	8.90	8.93
Fuel Ethanol blended into Motor Gasoline	0.87	0.93	0.92	0.93	0.90	0.95	0.93	0.94	0.90	0.96	0.94	0.95	0.91	0.93	0.94
Jet Fuel	1.45	1.61	1.60	1.58	1.51	1.70	1.75	1.67	1.65	1.76	1.81	1.74	1.56	1.66	1.74
Distillate Fuel Oil	4.14	3.89	3.86	3.96	3.92	3.90	3.84	3.96	4.06	3.95	3.84	3.98	3.96	3.91	3.96
Residual Fuel Oil	0.38	0.31	0.39	0.30	0.33	0.34	0.36	0.37	0.31	0.34	0.37	0.39	0.34	0.35	0.35
Other Oils (g)	1.65	1.82	1.99	1.71	1.55	1.85	1.99	1.74	1.62	1.84	1.98	1.72	1.79	1.78	1.79
Total Consumption	20.22	20.27	20.47	20.16	19.93	20.67	20.63	20.55	20.53	20.84	20.92	20.76	20.28	20.45	20.76
Total Petroleum and Other Liquids Net Imports	-0.74	-1.18	-1.32	-1.70	-1.23	-0.74	-0.95	-1.59	-1.22	-0.79	-1.10	-1.80	-1.24	-1.13	-1.23
End-of-period Inventories (million barrels)															
Commercial Inventory															
Crude Oil (excluding SPR)	414.4	417.5	428.8	429.6	492.7	480.3	465.6	474.0	505.0	496.9	481.3	491.5	429.6	474.0	491.5
Hydrocarbon Gas Liquids	142.0	186.7	243.6	211.1	167.9	218.3	257.3	213.7	176.0	226.7	263.0	218.8	211.1	213.7	218.8
Unfinished Oils	87.9	88.8	82.3	86.1	91.9	89.4	88.9	81.2	91.2	88.5	87.4	79.5	86.1	81.2	79.5
Other HC/Oxygenates	34.1	29.4	27.3	31.7	31.4	30.2	29.9	30.2	32.3	31.0	30.7	31.0	31.7	30.2	31.0
Total Motor Gasoline	238.5	221.0	209.6	224.3	233.0	243.0	233.8	243.8	238.0	240.3	229.9	237.8	224.3	243.8	237.8
Finished Motor Gasoline	17.3	17.1	17.6	17.4	14.5	16.2	18.2	20.8	17.8	18.8	20.2	22.3	17.4	20.8	22.3
Motor Gasoline Blend Comp.	221.2	203.8	192.0	206.9	218.5	226.8	215.5	223.0	220.2	221.5	209.7	215.5	206.9	223.0	215.5
Jet Fuel	35.6	39.3	36.2	35.0	37.1	41.2	42.0	40.0	40.8	41.3	42.4	39.2	35.0	40.0	39.2
Distillate Fuel Oil	114.6	111.4	110.5	118.8	114.7	123.9	130.0	130.7	122.3	125.7	127.5	125.8	118.8	130.7	125.8
Residual Fuel Oil	27.9	29.2	27.3	30.7	31.8	30.8	28.9	28.2	29.8	29.0	27.2	26.5	30.7	28.2	26.5
Other Oils (g)	58.5	56.4	49.5	54.2	54.1	52.5	43.8	45.7	55.2	53.3	44.3	46.0	54.2	45.7	46.0
Total Commercial Inventory	1153.6	1179.7	1215.1	1221.6	1254.6	1309.7	1320.1	1287.5	1290.5	1332.9	1333.7	1296.1	1221.6	1287.5	1296.1
Crude Oil in SPR	566.1	493.3	416.4	372.0	372.5	347.5	348.5	348.5	354.6	360.6	366.6	372.6	372.0	348.5	372.6

(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 March 2, 2022.

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

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

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

Forecasts: EIA Short-Term Integrated Forecasting System.

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

U.S. Energy Information Administration | Short-Term Energy Outlook - March 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**	**108.76**	*109.46*	*108.65*	*109.03*	*109.47*	*109.92*	*109.94*	*110.54*	*110.63*	**106.64**	*109.15*	*110.26*
Alaska	**1.06**	**1.00**	**0.96**	**1.07**	*1.08*	*0.95*	*0.85*	*0.98*	*1.00*	*0.92*	*0.84*	*0.97*	**1.02**	*0.96*	*0.93*
Federal GOM (a)	**2.05**	**2.11**	**2.19**	**2.13**	*2.23*	*2.25*	*2.10*	*2.04*	*2.06*	*1.99*	*1.87*	*1.84*	**2.12**	*2.16*	*1.94*
Lower 48 States (excl GOM)	**100.16**	**103.07**	**105.12**	**105.57**	*106.15*	*105.45*	*106.08*	*106.45*	*106.86*	*107.03*	*107.83*	*107.82*	**103.50**	*106.03*	*107.39*
Total Dry Gas Production	**95.09**	**97.59**	**99.46**	**100.15**	*100.97*	*100.21*	*100.56*	*100.96*	*101.37*	*101.40*	*101.95*	*102.04*	**98.09**	*100.67*	*101.69*
LNG Gross Imports	**0.15**	**0.01**	**0.06**	**0.04**	*0.10*	*0.04*	*0.04*	*0.06*	*0.10*	*0.04*	*0.04*	*0.06*	**0.06**	*0.06*	*0.06*
LNG Gross Exports	**11.50**	**10.80**	**9.74**	**10.35**	*11.56*	*12.20*	*12.17*	*12.33*	*12.70*	*12.60*	*12.31*	*13.30*	**10.59**	*12.07*	*12.73*
Pipeline Gross Imports	**8.89**	**7.73**	**7.84**	**8.41**	*8.16*	*6.81*	*7.04*	*7.48*	*8.24*	*6.84*	*7.05*	*7.48*	**8.22**	*7.37*	*7.40*
Pipeline Gross Exports	**8.45**	**8.46**	**8.08**	**8.19**	*8.84*	*8.43*	*8.78*	*9.20*	*9.49*	*8.88*	*9.21*	*9.64*	**8.29**	*8.81*	*9.31*
Supplemental Gaseous Fuels	**0.21**	**0.17**	**0.18**	**0.16**	*0.18*	*0.18*	*0.18*	*0.18*	*0.19*	*0.19*	*0.19*	*0.19*	**0.18**	*0.18*	*0.19*
Net Inventory Withdrawals	**20.14**	**-10.25**	**-8.94**	**2.35**	*11.12*	*-11.04*	*-7.12*	*4.67*	*16.47*	*-13.00*	*-9.42*	*3.80*	**0.75**	*-0.63*	*-0.55*
Total Supply	**104.54**	**75.99**	**80.78**	**92.59**	*100.13*	*75.57*	*79.75*	*91.83*	*104.17*	*73.98*	*78.29*	*90.62*	**88.42**	*86.78*	*86.76*
Balancing Item (b)	**0.29**	**0.14**	**-0.01**	**0.08**	*-0.99*	*-1.32*	*0.40*	*0.38*	*-0.39*	*-1.30*	*-0.83*	*-0.24*	**0.12**	*-0.37*	*-0.69*
Total Primary Supply	**104.83**	**76.13**	**80.77**	**92.67**	*99.14*	*74.25*	*80.15*	*92.21*	*103.78*	*72.68*	*77.46*	*90.39*	**88.54**	*86.40*	*86.06*
Consumption (billion cubic feet per day)															
Residential	**26.09**	**7.86**	**3.57**	**17.43**	*22.93*	*8.01*	*4.25*	*17.19*	*25.65*	*8.09*	*4.30*	*17.24*	**13.69**	*13.06*	*13.80*
Commercial	**15.61**	**6.67**	**4.74**	**11.69**	*14.07*	*6.98*	*5.26*	*11.43*	*15.28*	*6.88*	*5.19*	*11.32*	**9.66**	*9.41*	*9.66*
Industrial	**25.46**	**22.25**	**21.47**	**23.51**	*23.29*	*21.33*	*21.60*	*24.03*	*24.41*	*20.94*	*20.50*	*22.72*	**23.16**	*22.56*	*22.14*
Electric Power (c)	**28.39**	**30.99**	**42.36**	**30.94**	*29.50*	*29.56*	*40.43*	*30.45*	*28.88*	*28.39*	*38.88*	*30.01*	**33.20**	*32.51*	*31.56*
Lease and Plant Fuel	**5.26**	**5.41**	**5.51**	**5.54**	*5.57*	*5.53*	*5.55*	*5.58*	*5.60*	*5.60*	*5.63*	*5.63*	**5.43**	*5.56*	*5.62*
Pipeline and Distribution Use	**3.86**	**2.80**	**2.98**	**3.41**	*3.64*	*2.70*	*2.92*	*3.38*	*3.82*	*2.64*	*2.81*	*3.31*	**3.26**	*3.16*	*3.15*
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**	**92.67**	*99.14*	*74.25*	*80.15*	*92.21*	*103.78*	*72.68*	*77.46*	*90.39*	**88.54**	*86.40*	*86.06*
End-of-period Inventories (billion cubic feet)															
Working Gas Inventory	**1,401**	**2,325**	**3,146**	**2,927**	*1,926*	*2,931*	*3,586*	*3,157*	*1,658*	*2,841*	*3,708*	*3,359*	**2,927**	*3,157*	*3,359*
East Region (d)	**242**	**482**	**759**	**698**	*350*	*641*	*872*	*714*	*272*	*603*	*887*	*759*	**698**	*714*	*759*
Midwest Region (d)	**296**	**557**	**917**	**831**	*446*	*707*	*1,008*	*844*	*339*	*675*	*1,039*	*902*	**831**	*844*	*902*
South Central Region (d)	**587**	**885**	**1,006**	**1,042**	*929*	*1,214*	*1,213*	*1,149*	*744*	*1,101*	*1,207*	*1,174*	**1,042**	*1,149*	*1,174*
Mountain Region (d)	**90**	**137**	**184**	**158**	*82*	*125*	*194*	*178*	*113*	*157*	*220*	*199*	**158**	*178*	*199*
Pacific Region (d)	**165**	**240**	**247**	**169**	*94*	*218*	*273*	*247*	*165*	*281*	*329*	*299*	**169**	*247*	*299*
Alaska	**21**	**25**	**32**	**30**	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	**30**	*25*	*25*

(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 March 2, 2022.

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

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

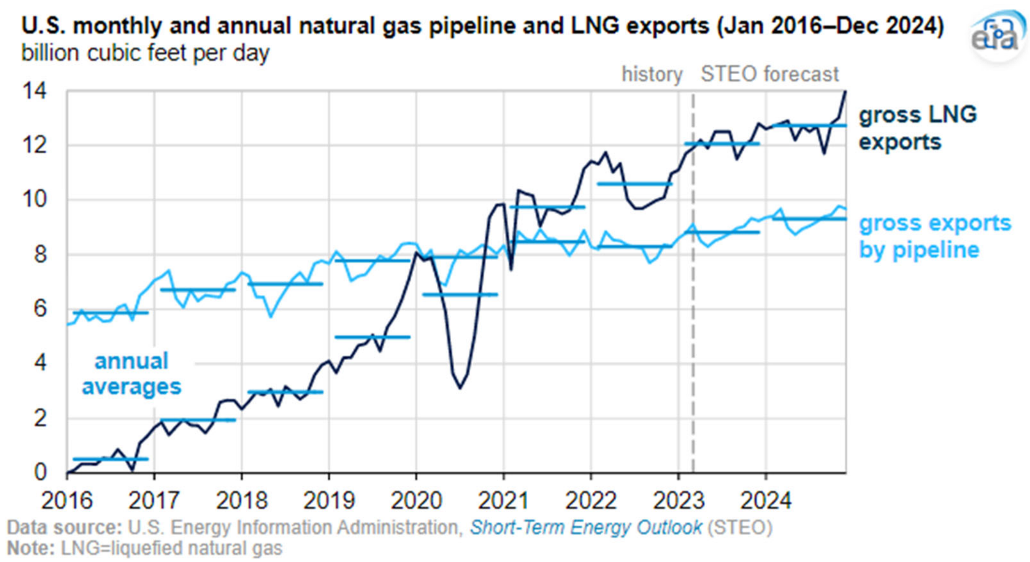
Minor discrepancies with published historical data are due to independent rounding.

Forecasts: EIA Short-Term Integrated Forecasting System.

https://www.eia.gov/todayinenergy/detail.php?id=55741

MARCH 8, 2023

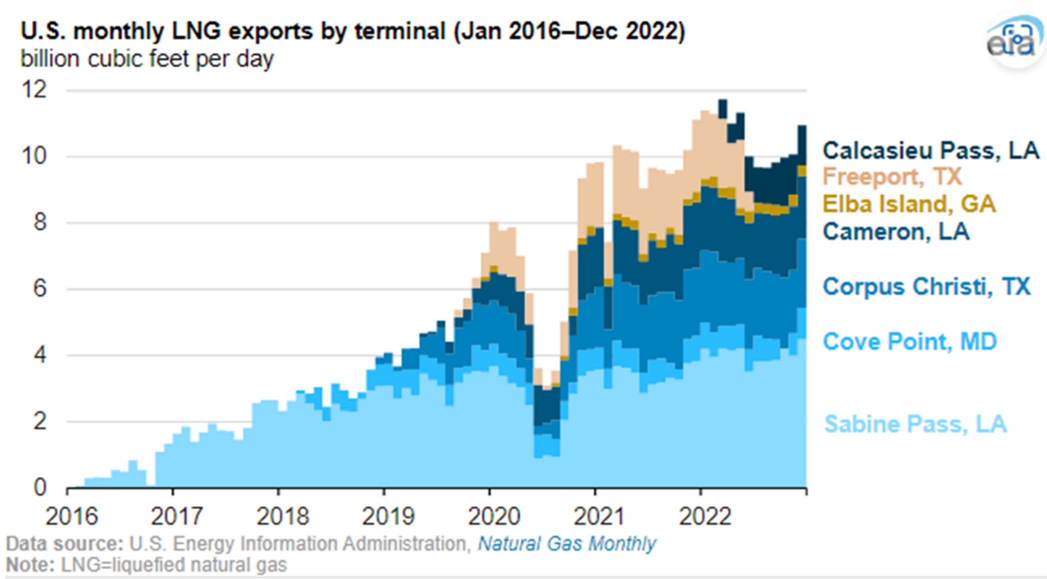
Liquefied natural gas will continue to lead growth in U.S. natural gas exports



Exports of liquefied natural gas (LNG) will continue to drive growth in U.S. natural gas exports over the next two years, according to our recently released *Short-Term Energy Outlook* (STEO).

In our March STEO, we forecast that U.S. LNG exports will average 12.1 billion cubic feet per day (Bcf/d) in 2023, a 14% (1.5 Bcf/d) increase compared with last year. We expect LNG exports to increase by an additional 5% (0.7 Bcf/d) next year.

We forecast U.S. LNG exports to rise because of high global demand as LNG will continue to displace pipeline natural gas exports from Russia to Europe. So far this year, mild winter temperatures and fuller-than-average storage resulted in reduced LNG prices, which could be an incentive to import more LNG, especially in the price-sensitive countries of Southeast Asia. The Freeport LNG export terminal's return to service and the new LNG export projects that will commissioned by the end of 2024 support our forecast increase in exports.



The Freeport LNG terminal is one of seven U.S. LNG export facilities; it can produce 2.14 Bcf/d of LNG on a peak day. Prior to the full shutdown of the facility in June 2022, exports from the facility averaged 1.9 Bcf/d from January 2021 through May 2022, according to our *Natural Gas Monthly*.

Because of the Freeport shutdown, U.S. LNG exports declined to an average 10.0 Bcf/d from June 2022 through December 2022, after peaking at 11.7 Bcf/d in March. When the new Calcasieu Pass LNG export facility was commissioned, it partially offset the decline in exports from Freeport LNG; exports from Calcasieu Pass have averaged 1.2 Bcf/d since June 2022.

This year, once all three trains at Freeport LNG return to service, we forecast U.S. LNG exports to exceed 12 Bcf/d, and the United States will remain the world's largest LNG exporter. We forecast that U.S. LNG exports will increase further, to approximately 14 Bcf/d, by December 2024 because some LNG export projects under construction are expected to start operations by then.

We expect U.S. natural gas exports by pipeline to grow by 0.5 Bcf/d in both 2023 and 2024, mainly because of increased exports to Mexico. Several new pipelines in Mexico—Tula-Villa de Reyes, Guaymas-El Oro, the Mayakan pipeline on the Yucatán Peninsula, as well as some other minor interconnects—are scheduled to come online in 2023–24. We also expect an increase in exports via the Sur de Texas-Tuxpan underwater pipeline to supply the proposed floating liquefaction (FLNG) project off the east coast of Mexico.

Principal contributor: Victoria Zaretskaya

Tags: international, monthly, natural gas, STEO (Short-Term Energy Outlook), exports/imports, United States, Europe, LNG (liquefied natural gas), capacity https://investors.chk.com/2023-03-06-CHESAPEAKE-ENERGY-CORPORATION-AND-GUNVOR-SIGN-LONG-TERM-LNG-SUPPLY-AGREEMENT-INDEXED-TO-JAPAN-KOREA-MARKER

CHESAPEAKE ENERGY CORPORATION AND GUNVOR SIGN LONG-TERM LNG SUPPLY AGREEMENT INDEXED TO JAPAN KOREA MARKER

OKLAHOMA CITY, March 6, 2023 /PRNewswire/ -- Chesapeake Energy Corporation (NASDAQ: CHK) and Gunvor Group Ltd today announced that Gunvor Singapore Pte Ltd ("Gunvor") has entered into a Heads of Agreement ("HOA") with Chesapeake Energy Marketing L.L.C. ("Chesapeake") a subsidiary of Chesapeake Energy Corporation.

Under the HOA, Chesapeake will supply up to 2 million tonnes of LNG per annum to Gunvor with the purchase price indexed to Japan Korea Marker ("JKM") for a period of 15 years. Following the execution of the HOA, Chesapeake and Gunvor will jointly select the most optimal liquefaction facility in the United States to liquify the gas produced by Chesapeake and deliver the LNG to Gunvor on a Free-on-Board ("FOB") basis with a targeted start date in 2027.

Nick Dell'Osso, Chesapeake President and Chief Executive Officer, said "This agreement reflects the powerful combination of the premium rock, returns, and runway of our competitively positioned Haynesville natural gas assets combined with the strength of our balance sheet and financial position to securely supply global LNG markets. We are pleased to partner with Gunvor, a leading global commodity and energy logistics company with a deep LNG track record, to deliver independently certified reliable, affordable, lower carbon energy to markets in need. Today marks an important initial step on our path to being LNG ready and we look forward to entering into additional agreements while export capacity continues to come online."

Kalpesh Patel, Co-Head of LNG Trading and a member of the Executive Committee of Gunvor, said, "We are excited to establish this partnership with Chesapeake which will further enhance our global LNG portfolio. We believe our trading expertise together with our robust shipping fleet will not only contribute to the competitive shipping costs, but also ensure reliable offtake operations for Chesapeake and the liquefaction facility which we will jointly select. We very much look forward to the long-term relationship with Chesapeake."

About Chesapeake:

Headquartered in Oklahoma City, Chesapeake Energy Corporation is powered by dedicated and innovative employees who are focused on discovering and responsibly developing our leading positions in top U.S. oil and gas plays. With a goal to achieve net zero GHG emissions (Scope 1 and 2) by 2035, Chesapeake is committed to safely answering the call for affordable, reliable, lower carbon energy.

About Gunvor:

Gunvor is one of the world's largest independent commodities trading houses by turnover, creating logistics solutions that safely and efficiently move physical energy from where it is

sourced and stored to where it is demanded most. Gunvor has strategic investments in industrial infrastructure — refineries, pipelines, storage and terminals — that complement our core trading activity and generate sustainable value across the global supply chain for our customers. The company, which in 2021 generated U.S. $135 billion in revenue on 240 million MT of volumes, is the leading independent global trader of liquefied natural gas (LNG).

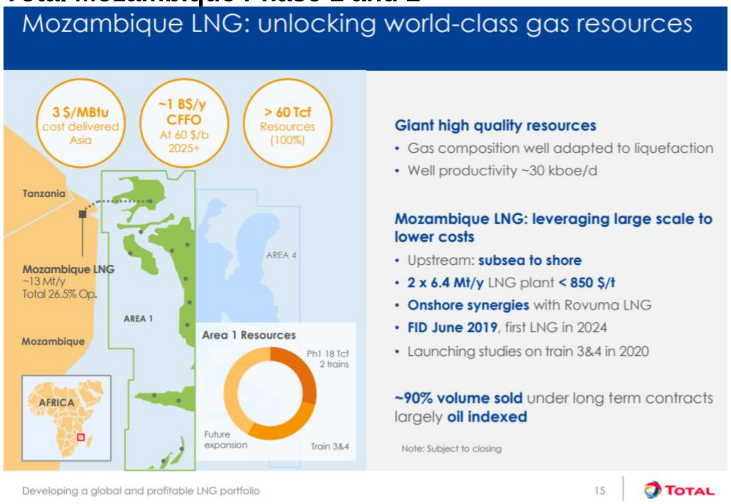
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

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

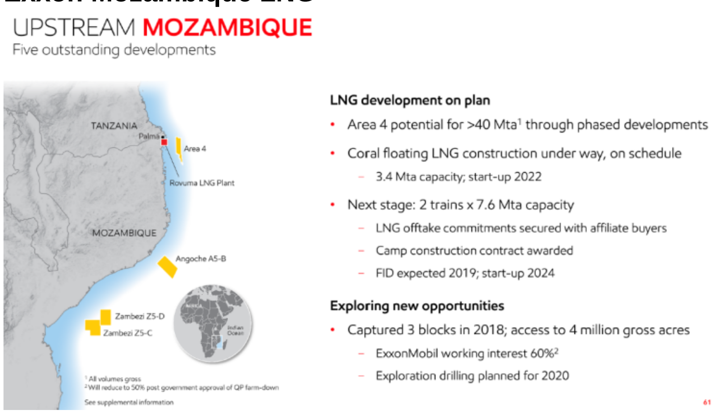
<u>Total's Mozambique force majeure is no surprise, especially the need to the restoration of security and stability "in a sustained manner"</u>. Yesterday, Total announced [LINK] "*Considering the evolution of the security".* No one should be surprised by the force majeure or the sustained manner caveat. 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".

<u>Does anyone really think Total will risk another quick 2-3 month restart or even in 2021?</u> 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.

<u>Mozambique's security issues pushes back 5.0 bcf/d of new LNG supply at least a couple years.</u> 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.

<u>Will Cdn natural gas be similarly hit by if Trudeau move to "emissions free" and not "net zero emissions" electricity?</u> 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.

<u>Biden's global climate summit reminded there is too much risk to skip over natural gas as the transition fuel.</u> 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

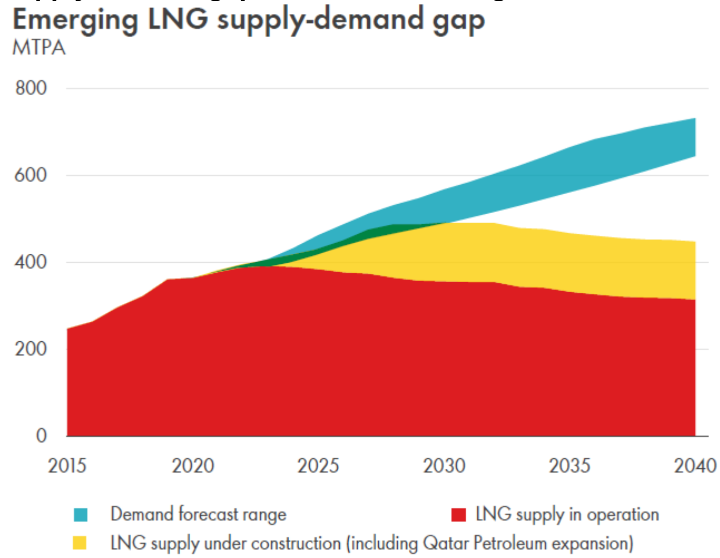
On Track   More Efforts Needed   Not on Track

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.*

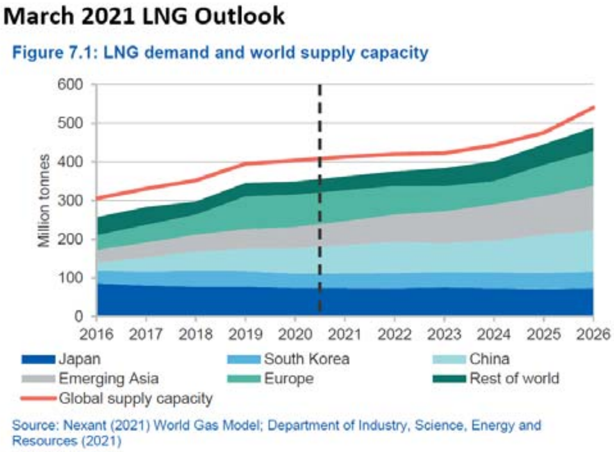
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required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

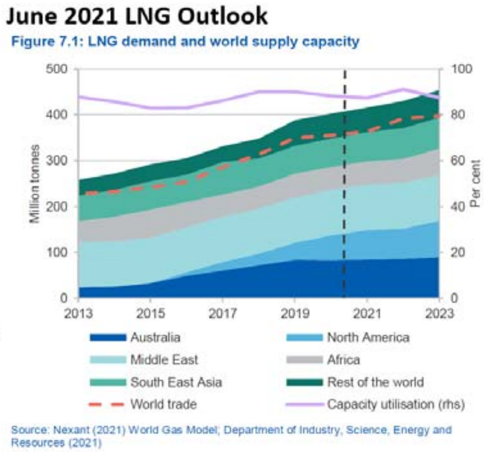
<u>Cheniere stopped the game playing the game on June 30</u>. Our July 4, 2021 Energy Tidbits memo noted that it looks like Cheniere has stopped playing stupid with respect to the strengthening LNG market in 2021. We can't believe they thought they were fooling anyone, especially their competitors. Bu 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



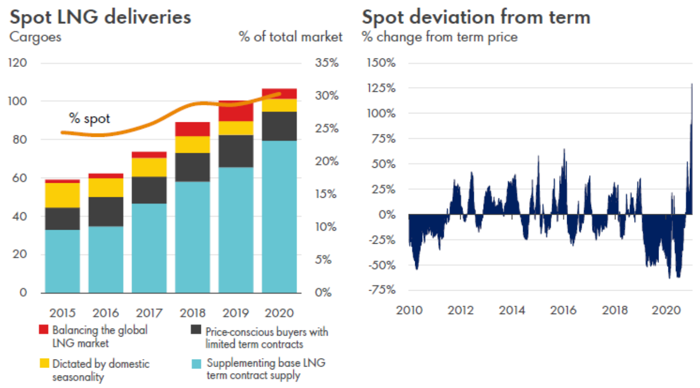


Source: Australia Resources and Energy Quarterly

<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.

EDF Told to Review Reactor-Check Plans After New Crack Found (1)
2023-03-08 11:55:32.342 GMT

By Francois de Beaupuy

(Bloomberg) -- Electricite de France SA must review its program of reactor checks after finding yet another crack earlier this year, the country's nuclear safety authority said.

It's not clear how the review will affect nuclear output, which EDF expects to recover this year after plunging in 2022 amid multiple halts for repairs. The shutdowns, caused by stress corrosion cracks on cooling-system pipes, added pressure to Europe's strained energy system as Russian gas supplies dwindled.

EDF said last month it found a crack on a pipe at its Penly-1 reactor, which was already offline for maintenance and repairs. The defect is located near a weld that had been mended twice during construction of the plant, which was commissioned in the early 1990s.

The latest crack, as much as 23 millimeters (almost 1 inch) deep, means the resilience of the pipe can't be assured, the Autorite de Surete Nucleaire said in a statement Tuesday. Given that EDF hadn't previously expected that section to be prone to stress corrosion, it must now revise its strategy, the ASN said.

"The discovery of this materially worse-than-expected defect is likely to lead to more rigorous quality control and potentially longer outages," JPMorgan Chase & Co. analyst Vincent Ayral wrote in a note. "If this were to be the case, we would expect the French power-price outlook to increase," with some "spillover effect" into neighboring markets.

Read more: European Energy Prices Jump as French Nuclear Concerns Return

Following the discovery of corrosion cracking at a reactor in 2021, EDF opened a wide-ranging investigation. The probe found that the company's 16 newest units — including its two Penly reactors — were more prone to the phenomenon mostly because of the sinuous design of their emergency cooling pipes. Yet cracks may also be caused by welding and other defects.

The fissure at Penly-1 "was probably generated by a targeted double-repair operation during the initial pipe layout," EDF said Feb. 24. "This will lead to repairs to the affected area."

EDF is currently checking welds on other emergency cooling lines that have been mended in the past, according to the ASN.

The utility's nuclear output sank last year to the lowest since 1988 as it halted about a dozen of its 56 reactors to replace cracked pipes. Repairs continue at several units and more pipe replacements are planned later this year at a handful of plants, while the rest of the fleet is due to be progressively checked up until 2025.

Read more: Cracking Under Pressure - The Race to Fix France's Nuclear Plants

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BN 03/09 18:32 EDF Finds New Defects at Two Reactors, Stoking Power-Supply Woes
BN 03/09 18:03 *EDF FINDS THERMAL FATIGUE DEFECTS AT PENLY2, CATTENOM3 REACTORS

EDF Finds New Flaws at 2 Reactors, Stoking Power-Supply Woes (2)
2023-03-09 19:38:13.732 GMT

By Francois de Beaupuy
(Bloomberg) -- Electricite de France SA discovered new defects at two of its nuclear reactors that were halted for maintenance and repairs, raising fresh concerns that its electricity output will remain largely constrained this year after plunging in 2022.
Flaws tied to so-called thermal fatigue have been found on the pipes of the Penly-2 and Cattenom-3 reactors, the utility said in a statement. The pipes have been replaced as part of broader repairs related to "stress corrosion" cracks — a different type of faults — that are affecting emergency cooling pipes of some of the EDF's atomic plants, according to the nuclear safety authority.
The nuclear giant has been forced to halt more than a dozen of its 56 reactors for months of repairs since it first found signs of such stress corrosion phenomenon in late 2021.
The announcement comes just days after the country's nuclear safety authority asked EDF to revise its program of reactor checks following the utility's discovery of a "significant" stress corrosion crack earlier this year on its Penly-1 reactor. EDF said it will propose an update of its reactor check strategy to the watchdog in the coming days.
The fresh setbacks could force EDF to carry out more extensive checks on its atomic plants, reviving concern that France will have to import large amounts of power this year.
Last year, worries about electricity shortages combined with dwindling deliveries of Russian gas pushed European energy prices to records.
French power for delivery in 2024 jumped as much as 9% to 176.50 euros a megawatt-hour, the biggest increase since Jan. 20 on EEX.

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https://www.linternaute.com/actualite/depeches/2796669-grosse-fissure-dans-un-reacteur-edf-mis-sous-pression-par-le-gendarme-du-nucleaire/

Big crack in a reactor: EDF put under pressure by the nuclear gendarme

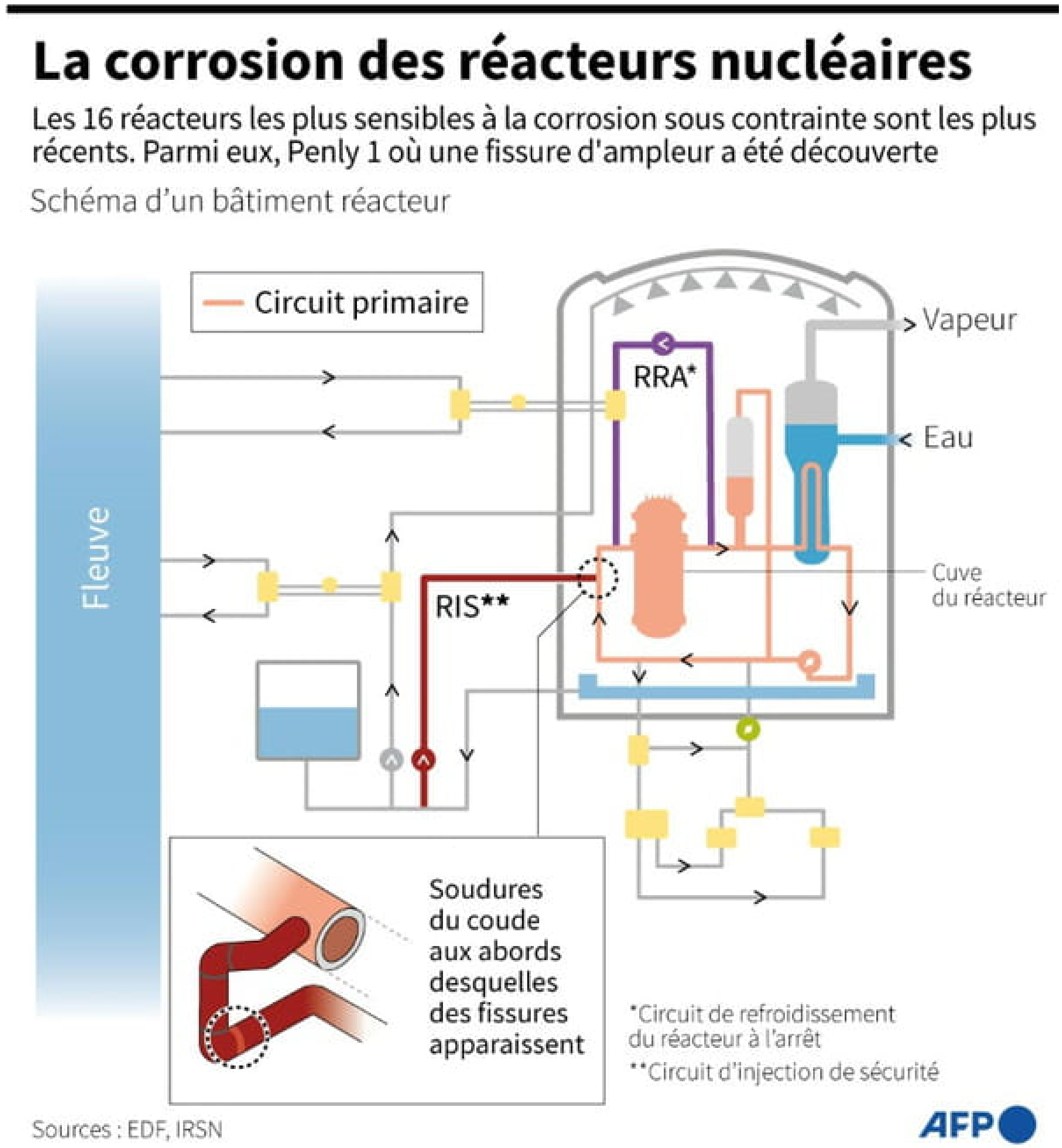
Source AFP, Updated on 08 March 2023 10:47

EDF was summoned Tuesday by the nuclear gendarme to "review its strategy" to solve the problems that have heavily disrupted its plants since the end of 2021, after the discovery of a major crack on an emergency circuit of a shutdown reactor, Penly 1, in Seine-Maritime.

Passed unnoticed until its media coverage Tuesday by the site Context, a note from EDF published on February 24 indicates having detected at Penly 1 a "significant defect of corrosion under stress" on an emergency pipe used to cool the reactor in case of emergency.

In view of this new information, the Nuclear Safety Authority (ASN) on Tuesday asked EDF to "revise its strategy" on the treatment of stress corrosion of some of its reactors. EDF, which declined to comment, may have to conduct more comprehensive research and inspections in its nuclear fleet.

"This event had no impact on staff or the environment. However, it affects the safety function linked to the cooling of the reactor", stresses ASN in its information note.



At a time when EDF estimated to be out of crisis on the treatment of this phenomenon, this discovery throws new uncertainties on the nuclear production of the electrician for 2023, after a black year weighed down by the setbacks of its nuclear fleet.

EDF's nuclear fleet (56 reactors) has indeed suffered an unprecedented industrial crisis since the discovery in October 2021 of this phenomenon of stress corrosion on pipelines crucial for the safety of power plants.

This problem had forced EDF to shut down many reactors for large-scale control and repair operations, contributing to the colossal losses recorded by the electrician in 2022.

- 15.5 cm -

In the Seine-Maritime reactor, the new defect was detected during "metallurgical expertise" on "a weld deposited in January," according to the note published on the group's website.

Until now in the phenomenon observed at EDF, it was only a question of micro-cracks, of the order of a few millimeters.

But the new crack which is located near a weld, "extends over 155 mm, or about a quarter of the circumference of the pipe, and its maximum depth is 23 mm, for a thickness of piping of 27 mm", details the ASN.

The piping could have been weakened by a repair operation aimed at "realigning" circuits, at the very time of the construction of the reactor in the 80s.

Penly 1 was one of the 16 reactors identified as the most sensitive to this phenomenon of stress corrosion. But the portion of the circuit now in question had not been targeted as sensitive.

"This line was considered by EDF to be insensitive to stress corrosion cracking due in particular to its geometry. However, this weld was the subject of a double repair during the construction of the reactor, which is likely to modify its mechanical properties and the internal stresses of the metal at the level of this zone", explains ASN.

- Crack depth -

"Because of its potential consequences and the increased probability of a rupture", ASN classified this safety event "at level 2 of the INES scale", the international scale for the classification of civil nuclear incidents which has 8, ASN said.

"What is new is the depth of the crack, i.e. 85% of the thickness of the pipe, and the explanatory factor linked to this notion of double repair during a circuit realignment operation," Yves Marignac, an energy expert and member of ASN's permanent groups of experts, told AFP.

For the expert, "the fact that larger cracks are possible raises the question of maintaining the operation of the 6 reactors of the same type P'4", pending their preventive repair scheduled for 2023.

Of the 16 reactors, the most recent and identified as the most sensitive, 10 reactors still have to be checked and repaired in 2023: 6 must be repaired automatically, without going through the control phase and 4 will continue the work started in 2022, EDF told AFP.

https://www.wsj.com/articles/u-s-shale-boom-shows-signs-of-peaking-as-big-oil-wells-disappear-2adef03f

U.S. Shale Boom Shows Signs of Peaking as Big Oil Wells Disappear

America's biggest oil gushers are shrinking, evidence that companies have drilled through much of their best wells

By Collin Eaton Follow and Benoît Morenne Follow

March 8, 2023 5:30 am ET

HOUSTON—The boom in oil production that over the last decade made the U.S. the world's largest producer is waning, suggesting the era of shale growth is nearing its peak.

Frackers are hitting fewer big gushers in the Permian Basin, America's busiest oil patch, the latest sign they have drained their catalog of good wells. Shale companies' biggest and best wells are producing less oil, according to data reviewed by The Wall Street Journal.

The Journal reported last year companies would exhaust their best U.S. inventory in a handful of years if they resumed the breakneck drilling pace of prepandemic times.

Now, recent results out of the Permian, spread across West Texas and New Mexico, are mimicking the onset of a production plateau that has taken place at other, more mature U.S. shale plays.


ConocoPhillips CEO Ryan Lance warned that OPEC would soon supply more of the world's oil.PHOTO: AARON M. SPRECHER/BLOOMBERG NEWS

At a major industry conference here this week, executives cited the stagnation in shale, saying it signaled a return to more dependence on foreign energy sources and more challenging times ahead for major U.S. companies, after most of them posted record earnings last year.

"The world is going back to a world that we had in the '70s and the '80s," said ConocoPhillips Chief Executive Ryan Lance, during a panel at the conference called CERAWeek by S&P Global. He warned that OPEC would soon supply more of the world's oil.

Oil production from the best 10% of wells drilled in the Delaware portion of the Permian was 15% lower last year, on average, than top 2017 wells, according to data from analytics firm FLOW Partners LLC. Meanwhile, the average well put out 6% less oil than the prior year, according to an analysis of data from analytics firm Novi Labs.

The atrophy of once-booming sweet spots has big implications for the global oil market, which years ago could count on rapidly growing U.S. oil production to blunt the effects of supply disruptions and rising demand. Without successful exploration or technological advances, the industry's inventory constraints are expected eventually to push companies to tap lower quality wells that would require higher oil prices to attract investment, industry executives say.

Oil production in the U.S. rose from about 7.2 million barrels a day a decade ago to a high of about 13 million barrels a day before the pandemic. But domestic output last year grew at one-third of the annual average pace seen in shale's heyday from 2017 to 2019, and hasn't yet caught up with prepandemic levels.


Oil output from the best 10% of wells in the Permian Basin's Delaware portion was 15% lower last year on average than 2017's top wells.PHOTO: ANGUS MORDANT/REUTERS

The slowdown was mostly because of investor pressure on companies to curtail spending and limit growth in favor of generating higher returns. At the same time, weaker well results in the Delaware basin contributed to flattening output.

U.S. output grew about half as fast as many forecasters initially expected last year, and is projected to increase by about the same amount this year, according to the Energy Information Administration.

The recent degradation in well performance has stoked executives and investors' concerns about the industry's runway for growth, and has led companies to consider mergers this year.

Companies such as Chevron Corp., CVX -0.63%decrease; red down pointing triangle Devon Energy Corp. and others that have held the Permian up as a central pillar of their future plans saw top wells yield less crude last year than the previous year.
Chevron, one of the largest landholders in the Permian, drilled some of the region's most prolific wells in Culberson County, Texas, but some of its newer wells there have seen productivity decline.

The wells Chevron brought online in Culberson County last year are ultimately expected to produce 42% less oil, on average, than wells that began producing in 2018, according to FLOW's estimates. The top 10% of wells Chevron brought online across the Delaware last year were about 25% less productive on average than its wells the year before, according to Novi Labs data.

Chevron executives said last week the company missed its oil-production target in the Delaware, citing higher-than-expected depletion rates. The company plans to revise its approach in the Permian, they said, shifting some drilling into New Mexico, and targeting areas that are likely more productive—moves that will reduce its pace of activity somewhat.

Chevron drilled some of the Permian's most prolific wells in Culberson County, Texas, but some of its newer wells there have seen productivity decline.PHOTO: ADRIA MALCOLM FOR THE WALL STREET JOURNAL

Chevron Chief Executive Mike Wirth said last week the rate of production growth and drilling activity the U.S. shale industry saw a decade ago "is unlikely to be repeated," though the Permian still has areas that haven't been developed. Chevron plans to boost production in the Permian to 1 million barrels a day by 2025, eventually plateauing at 1.2 million later this decade.

Devon has drilled some of the most productive wells the Delaware had ever seen, in an area the company dubbed Boundary Raider. In 2020, its average well pumped more than 342,000 barrels over a nine-month period, but the following year, its average fell to more than 167,000 barrels, according to FLOW President Tom Loughrey. Companies' midlevel wells are still producing steadily, but gushers are harder to come by, Mr. Loughrey said.

"The big well is coming down hard right now," he said.

Rick Muncrief, Devon's chief executive, attributed the productivity decline to maturing U.S. oil-and-gas fields. "I'm not terribly surprised, and I'm not terribly alarmed," he said, saying that wells drilled in the Boundary Raider area still generated excellent returns for the company. Mr. Muncrief said that tight crude supplies pushing oil prices higher would make tapping into less productive formations economically viable for operators.

Investment bank Raymond James Financial Inc. estimated in a September report that public producers and private operators in the Delaware hold about 7.2 years of sweet spots, and less than eight years in the Midland basin, the other major portion of the Permian.

Shale's sluggishness means global oil markets will have to rely on Middle Eastern crude over the next decades, said Scott Sheffield, CEO of Pioneer Natural Resources Co.

"We're just not gonna have that big growth pump like we used to," he said of U.S. crude production.

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Trans Mountain Corporation Provides Update on the Expansion Project

Mar. 10, 2023

Trans Mountain Corporation today announced an update for the Trans Mountain Expansion Project (the Project). Construction of the Project is close to 80 per cent complete, with mechanical completion expected to occur at the end of 2023, and the pipeline will be in-service in the first quarter of 2024. Once completed, the pipeline system will have nearly tripled its capacity, representing an increase of 590,000 barrels per day to a total of 890,000 barrels per day.

The expanded pipeline will be a key piece of Canada's energy infrastructure that provides a much-needed route to west coast tidewater for direct access to international markets, including the United States and Asia. Such access will achieve global market pricing for Canadian crude oil, which is periodically sold at a discount, while supporting Canada's energy security.

The total Project cost is now estimated to be approximately $30.9 billion. Trans Mountain is in the process of securing external financing to fund the remaining cost of the Project. The Project capacity is primarily committed to 11 shippers representing a mix of Canadian and international producers and refiners who are contracted for 80 per cent of the available capacity under long-term, take-or-pay transportation contracts for 15 and 20 years. The remaining 20 per cent of the capacity on the expanded system will be available through market mechanisms.

Estimated costs are attributed to several factors including Trans Mountain's commitment to ensuring Project and community safety, protection of culturally significant sites for Indigenous Peoples, environmental preservation, and completing a quality long-term pipeline. Specific factors for cost increases include high global inflation and global supply chain challenges; unprecedented floods in British Columbia; unexpected major archaeological discoveries; challenging terrain between Merritt and Hope; earthquake standards in the Burnaby Mountain tunnel; unexpected water disposal costs in the Sumas Prairie; and issues regarding densely populated areas between Sumas and Burnaby.

"Canada has among the world's highest standards for the protection of people, the environment, and Indigenous participation when building major infrastructure projects. By including these commitments into the Project design and development from the beginning, we have ensured the Project will provide economic benefits to Canadians well into the future," said Dawn Farrell, President and CEO of Trans Mountain Corporation.

An independent economic impact assessment for the Project was conducted by Ernst & Young LLP (EY) in March 2023. The assessment stated that during construction between 2018-2023, the Project is estimated to contribute $52.8 billion in gross output, $26.3 billion in gross domestic product (GDP), including $11 billion in wages and more than 67,423 full-time equivalents (FTEs), and $2.9 billion in tax revenue. After completion, EY expects that Trans Mountain's expanded operations will contribute $17.3 billion in gross output, $9.2 billion in GDP, including $3.7 billion in wages and more than 36,066 FTEs, and $2.8 billion in tax revenue over the next 20 years.

Trans Mountain has generated more than $4.8 billion in contracts with Indigenous businesses, which is 25 per cent of total contracts awarded to date and has employed over 3,000 Indigenous workers.

"I am particularly proud that throughout development and construction, Trans Mountain has maintained unprecedented levels of Indigenous collaboration and partnership. Over 140 Indigenous groups have been engaged to ensure we protect the land, the water, the wildlife, and significant archaeological sites. Trans Mountain has gone far beyond simple engagement by creating economic partners for generations to come," continued Farrell.

Project Construction Background:

The Project consists of installing approximately 992 kilometres of 36-inch and 42-inch diameter pipe, reactivating 193 kilometres of pipe, and constructing 12 new pump stations, 19 new storage tanks at existing terminals in Burnaby, Sumas, and Edmonton, and three new berths at Westridge Marine Terminal in Burnaby, B.C. Once completed, the capacity of the pipeline system will increase by 590,000 barrels per day to a total of 890,000 barrels per day.

Trans Mountain plans to deliver oil to its Westridge Marine Terminal in Burnaby during the first quarter of 2024. The Alberta portion of the Project is complete. All pump stations across both provinces are complete. Berth 1 at the Westridge Marine Terminal is scheduled to be commissioned in May 2023.

The revised cost estimate is a result of several factors:

- Increased global inflationary pressures and global supply chain challenges over the period.
- Cost escalations associated with required construction solutions for the Burnaby Mountain Tunnel.
- Significant cost increases associated with building major infrastructure in densely populated areas from Sumas to Burnaby.
- Cultural preservation activities following significant archaeological discoveries through sacred spaces in the Lower Mainland resulted in over 83,000 artifacts rightfully being returned to Indigenous communities for cultural protection.
- The expanded Project scope and construction schedule adjustments ultimately required as a result of the catastrophic flooding in B.C. were extensive and included redeployment of resources into urgent civil recovery operations.
- Challenging terrain and geography from Merritt to Hope that required significant geotechnical engineering and innovation in construction practices to ensure Project completion in 2023.
- Significantly increased water disposal costs associated with the high-water table in the Sumas Prairie.
- Lower than expected contractor productivity resulting from:
    - Demanding geography and challenging weather conditions.
    - Unavoidable external factors such as wildfires and catastrophic floods in B.C., high water tables, and additional archaeological finds.
    - Labour shortages and an increase in "green-hand" labourers as markets tightened for skilled workers.

As with all projects of this size, risks to the final costs and schedule will remain as work is completed through 2023. The current cost estimate does not include reserves for extraordinary risks that can impact projects of this nature.

Excerpt https://www.aramco.com/en/news-media/news/2023/aramco-announces-full-year-2022-results

Aramco announces record full-year 2022 results

DHAHRAN, March 12, 2023
Commenting on the results, Aramco President & CEO Amin H. Nasser, said:

“Aramco delivered record financial performance in 2022, as oil prices strengthened due to increased demand around the world. We also continued to focus on our long-term strategy, building both capacity and capability across the value chain with the aim of addressing energy security and sustainability.

“Given that we anticipate oil and gas will remain essential for the foreseeable future, the risks of underinvestment in our industry are real — including contributing to higher energy prices. To leverage our unique advantages at scale and be part of the global solution, Aramco has embarked on the largest capital spending program in its history, and last year our capex rose by 18.0% to reach $37.6 billion.

“Our focus is not only on expanding oil, gas and chemicals production, but also investing in new lower-carbon technologies with potential to achieve additional emission reductions — in our own operations and for end users of our products.”

Excerpt https://www.aramco.com/en/news-media/news/2022/aramco-announces-third-quarter-2022-results

Aramco announces third quarter 2022 results

DHAHRAN, November 01, 2022
Commenting on the results, **Aramco President & CEO Amin H. Nasser, said**:

“Aramco’s strong earnings and record free cash flow in the third quarter reinforce our proven ability to generate significant value through our low cost, low-carbon intensity Upstream production and strategically integrated Upstream and Downstream business. While global crude oil prices during this period were affected by continued economic uncertainty, our long-term view is that oil demand will continue to grow for the rest of the decade given the world’s need for more affordable and reliable energy.

“Against the backdrop of global underinvestment in our sector, we are extending our long-term oil and gas production capabilities while also working towards our previously stated ambition to achieve net-zero Scope 1 and Scope 2 greenhouse gas emissions from our wholly-owned operated assets.

“Our plans for our Downstream expansion continue to move forward as we seek to leverage the significant potential of our products to meet rising global demand for petrochemicals, which will be critical to the materials transition that is required to support a lower-carbon future. In addition, we continue to develop new, lower-carbon energy solutions as we work to be part of a more practical, stable and inclusive energy transition.”

https://www.spa.gov.sa/viewstory.php?lang=en&newsid=2433231

Joint Trilateral Statement by the Kingdom of Saudi Arabia, the Islamic Republic of Iran, and the People's Republic of China

Friday 1444/8/18 - 2023/03/10

Riyadh, March 10, 2023, SPA -- In response to the noble initiative of His Excellency President Xi Jinping, President of the People's Republic of China, of China's support for developing good neighborly relations between the Kingdom of Saudi Arabia and the Islamic Republic of Iran;

And based on the agreement between His Excellency President Xi Jinping and the leaderships in the Kingdom of Saudi Arabia, and the Islamic Republic of Iran, whereby the People's Republic of China would host and sponsor talks between the Kingdom of Saudi Arabia and the Islamic Republic of Iran;

Proceeding from their shared desire to resolve the disagreements between them through dialogue and diplomacy, and in light of their brotherly ties;

Adhering to the principles and objectives of Charters of the United Nations and the Organization of Islamic Cooperation (OIC), and International conventions and norms;

The delegations from the two countries held talks during the period 6-10 March 2023 in Beijing - the delegation of the Kingdom of Saudi Arabia headed by His Excellency Dr. Musaad bin Mohammed Al-Aiban, Minister of State, Member of the Council of Ministers, and National Security Advisor, and the delegation of the Islamic Republic of Iran headed by His Excellency Admiral Ali Shamkhani, Secretary of the Supreme National Security Council of the Islamic Republic of Iran.

The Saudi and Iranian sides expressed their appreciation and gratitude to the Republic of Iraq and the Sultanate of Oman for hosting rounds of dialogue that took place between both sides during the years 2021-2022. The two sides also expressed their appreciation and gratitude to the leadership and government of the People's Republic of China for hosting and sponsoring the talks, and the efforts it placed towards its success.

The three countries announce that an agreement has been reached between the Kingdom of Saudi Arabia and the Islamic Republic of Iran, that includes an agreement to resume diplomatic relations between them and re-open their embassies and missions within a period not exceeding two months, and the agreement includes their affirmation of the respect for the sovereignty of states and the non-interference in internal affairs of states. They also agreed that the ministers of foreign affairs of both countries shall meet to implement this, arrange for the return of their ambassadors, and discuss means of enhancing bilateral relations. They also agreed to implement the Security Cooperation Agreement between them, which was signed on 22/1/1422 (H), corresponding to 17/4/2001, and the General Agreement for Cooperation in the Fields of Economy, Trade, Investment, Technology, Science, Culture, Sports, and Youth, which was signed on 2/2/1419 (H), corresponding to 27/5/1998.

The three countries expressed their keenness to exert all efforts towards enhancing regional and international peace and security.

Issued in Beijing on 10 March 2023.

For the Islamic Republic of Iran

Ali Shamkhani

For the Kingdom of Saudi Arabia

Musaad bin Mohammed Al-Aiban

Minister of State, Member of the Council of Ministers, and National Security Advisor

For the People's Republic of China

Wang Yi

Member of the Political Bureau of the Communist Party of China (CPC) Central Committee and Director of the Foreign Affairs Commission of the CPC Central Committee

--SPA

15:45 LOCAL TIME 12:45 GMT

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https://en.irna.ir/news/85052808/Iran-Saudi-Arabia-agree-to-resume-ties
Mar 10, 2023, 4:04 PM

Iran, Saudi Arabia agree to resume ties

Tehran, IRNA – Following the recent visit of President Ebrahim Raisi to China, Secretary of Iran's Supreme National Security Council (SNSC) Ali Shamkhani traveled to Beijing on Monday (March 6) to launch an intensive negotiation with the Saudi delegation to settle issues between Tehran and Riyadh.

After several days of intensive negotiations between Shamkhani and Saudi Arabia's national security adviser Musaid Al Aiban in Beijing, an agreement was reached on Friday aimed at resuming relations between the two countries.

In the meantime, a joint statement was issued by Iran, Saudi Arabia, and China in an official ceremony on Friday.

As per the joint statement reached by the three countries, Iran and Saudi Arabia have agreed to resume diplomatic relations within two months and reopen embassies and agencies in both countries.

The foreign ministers of the two countries are to hold talks aimed to carry out the decision and make the necessary arrangements for the exchange of ambassadors.

Stressing respect for sovereignty and non-interference in the internal affairs of each other, the two countries agreed to implement the agreement on security cooperation signed on April 17, 2001, and the general agreement reached on May 27, 1998, aimed at fostering ties in economic, commercial, investment, technical, scientific, cultural, sports, and youth arenas.

The three countries also expressed firm resolve to make every effort to strengthen regional and international peace and security.

Iran and Saudi Arabia also appreciated Iraq and Oman for their efforts and for hosting the talks between the two sides in 2021 and 2022 and thanked the Chinese leadership and government for hosting and supporting this round of talks, the statement noted.

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https://www.thestar.com/politics/2021/01/24/a-timeline-of-covid-19-in-canada.html

A timeline of COVID-19 in Canada

By The Canadian Press

Sun., Jan. 24, 2021timer10 min. read

Here's a timeline of key developments in the COVID-19 pandemic in Canada since the first presumptive case was reported on Jan. 25, 2020:

Jan. 25: A Toronto man in his 50s who returned from the Chinese city of Wuhan — the initial epicentre of the outbreak — becomes the first presumptive case of the novel coronavirus in Canada. The man is placed in isolation in Toronto's Sunnybrook Hospital.

Jan. 26: The man's wife, who had travelled with him from Wuhan, also tests positive, becoming the country's second presumptive case. The woman is allowed to self-isolate at home.

Jan. 27: The National Microbiology Lab in Winnipeg confirms that the Toronto man being treated at Sunnybrook Hospital is the first confirmed case of COVID-19 in Canada.

Jan. 28: The Toronto man's wife is declared the second confirmed case of COVID-19. Health officials in British Columbia say a man in his 40s who travels to China for work is presumed to have COVID-19. The man is in self-isolation at his Vancouver home.

Feb. 4: There is another presumptive case reported in B.C. — a woman who had family visiting from China's Hubei province. She is in isolation at her home.

Feb. 7: A plane carrying more than 200 Canadians from Wuhan arrives at CFB Trenton in eastern Ontario, where they start a 14-day quarantine.

Feb. 20: A woman who returned from Iran becomes B.C.'s sixth case of COVID-19 and the first person in Canada diagnosed with the illness who did not recently visit China or have close contact with someone who did. The Toronto man who was the country's first confirmed case is cleared after testing negative for the virus.

Feb. 27: Quebec public health officials report the province's first presumptive case, a woman from the Montreal region who recently returned from Iran.

March 5: B.C. announces eight new cases, including Canada's first-ever case possibly contracted within the community, rather than through travel or contact with other cases.

March 8: Canada records its first death from COVID-19. A man in his 80s died in a North Vancouver nursing home.

March 11: The World Health Organization declares COVID-19 a pandemic. Canada has more than 100 cases. A Utah Jazz player tests positive two days after a game against the Toronto Raptors, causing the NBA to suspend its season.

March 12: Prime Minister Justin Trudeau self-isolates after his wife Sophie Gregoire Trudeau tests positive for COVID-19. The NHL and most other sports leagues suspend seasons. The Juno Awards are shelved. Minor hockey across the country is cancelled. The Ontario government announces schools across the province will be closed for two weeks after March break. Manitoba and Saskatchewan report their first cases.

March 13: The federal government announces Parliament will go on break.

March 14: The federal government urges Canadians currently abroad to return home as soon as possible

March 15: Nova Scotia reports its first three cases.

March 16: Canada announces it is closing its borders to non-Canadians, apart from Americans and a few other exceptions.

March 17: Ontario and Alberta declare states of emergency.

March 18: Canada and the United States announce they will close their shared border to non-essential traffic. B.C. and Saskatchewan declare states of emergency.

March 19: New Brunswick declares a state of emergency.

March 20: COVID-19 cases pass 1,000 across the country. Manitoba declares state of emergency.

March 22: Canada says it won’t compete in the Tokyo Olympics or Paralympics.

March 23: Ottawa announces repatriation flights for Canadians stranded in foreign countries.

March 24: Olympics officially postponed until 2021.

March 25: Emergency aid bill passes. Canada makes it mandatory for all travelers arriving in the country to quarantine for 14 days.

March 30: Trudeau says a new wage subsidy program will cover all businesses whose revenue has dropped by at least 30 per cent because of COVID-19.

April 2: COVID-19 death toll passes 100 in Canada.

April 3: Ontario projects COVID-19 death toll could reach 15,000.

April 4: U.S. company 3M told by the White House to stop exporting N95 respirators to Canada.

April 6: 3M makes a deal with the White House to provide N95 masks to Canada. Dr. Theresa Tam, Canada's chief public health officer, says wearing masks is a way for people who might have COVID-19 without realizing it to keep from spreading the illness.

April 9: Ottawa projects 4,400 to 44,000 Canadians could die of COVID-19. Government announces more than one million people lost their jobs in March.

April 13: Federal government announces nearly 5.4 million Canadians are receiving emergency aid.

April 15: Canada passes 1,000 virus-related deaths.

April 22: Ontario and Quebec, the hardest-hit provinces, call on the military to help out in long-term care homes.

April 23: Canadian death toll passes 2,000 as country announces it will pour $1.1 billion into vaccine testing.

April 25: New Brunswick introduces a two-household bubble, allowing people to interact with others.

April 28: Canada hits 50,000 cases.

May 4: Restrictions begin to lift in several provinces including Quebec and Manitoba.

May 8: The unemployment rate rockets up to 13 per cent, the second-highest figure on record in Canada.

May 11: Some Quebec schools reopen and Ontario stores start offering curbside pickup.

May 12: Death toll passes 5,000.

May 13: The country's top doctor says Canadians in communities where COVID-19 is still spreading should wear non-medical masks when they can't stay physically distant from others.

May 14: Many stores, child-care centres and hair salons open in Alberta.

May 19: Many stores reopen in Ontario, B.C. and Saskatchewan.

May 23: Thousands pack a park on a sunny day in Toronto, creating fears of a new outbreak.

May 26: A new report from the military helping battle COVID-19 in five long-term care facilities in Ontario reveals extreme neglect and exposes the extent of the horrific conditions facing residents.

May 29: At least 41 staff and students test positive for COVID-19 in the first two weeks after elementary schools outside the Montreal area reopen.

June 12: Ontario enters Stage 2 of its reopening, except for Toronto, Windsor-Essex and Peel region.

June 18: Canada officially records more than 100,000 cases of COVID-19 over the length of the pandemic.

June 26: The Canadian Red Cross sends 900 people to work in Quebec's long-term care homes until mid-September, replacing Canadian Armed Forces members.

June 26: The Nova Scotia government announces all bars and restaurants can operate at full capacity after more than two weeks without a single new case of COVID-19.

July 3: P.E.I., Newfoundland and Labrador, New Brunswick and Nova Scotia begin allowing their Atlantic neighbours to visit without self-isolating for 14 days after entering. The so-called "Atlantic bubble" as a way to boost struggling local economies.

July 16: Trudeau says the federal, provincial and territorial governments reached a deal on billions of dollars in transfers to continue reopening economies amid the COVID-19 pandemic. Trudeau says the federal government will contribute $19 billion to the effort.

July 18: The Blue Jays are denied approval to play in Toronto due to the COVID-19 pandemic.

July 18: Quebec becomes the first province in Canada to require mask-wearing in all indoor public places.

July 28: Remdesivir becomes the first drug to be approved by Health Canada for treatment of patients with severe COVID-19 symptoms.

July 31: COVID Alert, A voluntary smartphone app that can warn you if you've come into close proximity to someone who has tested positive for COVID-19, becomes available to download.

Aug. 3: Quebec increases the limits on indoor and outdoor public gatherings from 50 people to 250 people. The province's health minister says despite the relaxed rules, COVID-19 continues to circulate in Quebec, especially among young people.

Aug. 17: The Canadian Football League cancels its 2020 season, making it the first year since 1919 that the Grey Cup won't be awarded.

Sept. 8: Hundreds of thousands of children and teenagers across Canada re-enter classrooms for the first time in six months. Alberta and Quebec are among the first to report new cases of COVID-19 related to the reopening of schools.

Sept. 14: The Bloc Quebecois caucus, including leader Yves-Francois Blanchet, enters self-isolation after a member of Blanchet's staff tested positive for COVID-19.

Sept. 16: Federal Conservative Leader Erin O'Toole says he, his family and some party workers are in self-isolation after an aide tested positive for COVID-19.

Sept. 19: Nunavut reports its first confirmed cases of COVID-19. The territory's chief public health officer says there are two cases at the Hope Bay gold mine 125 kilometres southwest of Cambridge Bay. Top public health official Dr. Michael Patterson says both miners were exposed in their home jurisdictions.

Sept. 22: Rebecca O'Toole, the wife of Conservative Leader Erin O'Toole, tests positive for COVID-19.

Sept. 23: In an address to the country, Trudeau says the second wave of COVID-19 is underway. He says families won't likely be able to gather for Thanksgiving, but it is not too late to save Christmas.

Sept. 25: Tougher COVID-19 restrictions are also reimposed in Winnipeg due to a spike in cases. In Ontario, Ford says bars and restaurants will have to stop serving booze at 11 p.m.

Sept. 30: Parliamentarians unanimously pass Bill C-4 to usher in a new batch of COVID-19 benefits. For Canadians left jobless or underemployed because of the pandemic, the legislation supplants the CERB support program with a more flexible and generous employment insurance regime.

Oct. 1: Stringent new rules take effect in three Quebec regions at the heart of rising COVID-19 case counts in the province. Bars, cinemas and restaurant dining rooms are ordered closed for at least 28 days in Montreal, Quebec City and Chaudiere-Appalaches. Restaurants are still allowed to offer takeout. The strictest of the new measures include prohibiting private gatherings.

Oct. 19: Canada's COVID-19 case count surpasses the 200,000 mark. The development comes just over four months after Canada reached the 100,000-case threshold.

Oct. 28: A report from Canada's chief public health officer focusing on the first wave of the COVID-19 pandemic says Canada ranks 26th in the world for total deaths per million population.

Nov. 10: The Manitoba government forces non-essential stores to close and bans social gatherings in an effort to stop a surge of COVID-19 cases.

Nov. 16: Canada's COVID-19 case count tops 300,000 less than a month after it crossed the 200,000 threshold.

Nov. 23: The premiers of Prince Edward Island and Newfoundland and Labrador announce they will temporarily pull out of the so-called "Atlantic Bubble" for two weeks due to a resurgence of COVID-19 cases in Atlantic Canada.

Nov. 26: Federal health officials say Canada has purchase agreements with seven COVID-19 vaccine producers.

Nov. 26: New Brunswick becomes the latest Atlantic province to opt out of the so-called bubble and demand anyone entering the province self-isolate for 14 days. The province also introduces heightened public health measures in the Fredericton area.

Nov. 27: Trudeau says most Canadians should receive the COVID-19 vaccine by September 2021. The prime minister says Canada's vaccine distribution program would be led by former NATO commander Maj.-Gen. Dany Fortin.

Dec. 2: Johnson & Johnson begins the process of applying for emergency approval of its COVID-19 vaccine from Health Canada and the European

Medicines Agency, while Pfizer-BioNTech's COVID-19 vaccine is given permission for emergency use in the U.K.

Dec. 4: Canada records more than 400,000 cases of COVID-19, just 18 days after it hits the 300,000 mark.

Dec. 7: Trudeau says Canada will receive up to 249,000 doses of Pfizer-BioNTech's COVID-19 vaccine in December.

Dec. 8: Partial results published in the medical journal Lancet suggest the COVID-19 vaccine candidate from Oxford University and AstraZeneca is safe and about 70 per cent effective.

Dec. 9: Health Canada approves national use of Pfizer-BioNTech's COVID-19 vaccine.

Dec. 14: The first doses of the Pfizer-BioNTech vaccine are administered to people in Quebec and Ontario.

Dec. 20: Canada surpasses 500,000 total cases of COVID-19 as Nunavut reports its first two deaths. The federal government restricts travel from the U.K. for 72 hours in an effort to keep a contagious new strain out of Canada.

Dec. 23: Health Canada says the COVID-19 vaccine from U.S. biotech firm Moderna is safe for use in Canada.

Dec. 26: Ontario confirms its two first Canadian cases of a more contagious variant of COVID-19 first identified in the United Kingdom. The province also re-enters a lockdown that shutters non-essential businesses and closes schools to in-person learning for at least two weeks.

Dec. 28: Canada surpasses 15,000 deaths related to COVID-19.

Dec. 30: The federal government announces plans to require air travellers to test negative for COVID-19 before landing in Canada.

Jan. 3, 2021: Canada surpasses 600,000 total cases of COVID-19.

Jan. 6: Quebec becomes the first province to announce a curfew to curb soaring COVID-19 infections. The provincial government says it's to be enforced for four weeks.

Jan. 8: A new variant of COVID-19 that first surfaced in South Africa is reported in Alberta. Nova Scotia and New Brunswick tighten their boundaries, requiring people entering the provinces to quarantine for 14 days.

Jan. 9: The Quebec curfew comes into effect, barring most residents from leaving their homes between 8 p.m. and 5 a.m.

Jan. 11: Ontario’s death toll surpasses 5,000.

Jan. 14: A stay-at-home order takes effect in Ontario days after the daily case tally nearly hit 4,000. Among the added measures is a requirement for people to wear a mask inside businesses and restrictions on the size of gatherings. All non-essential retail stores may only open between 7 a.m. and 8 p.m.

Jan. 15: Pfizer says it will temporarily cut vaccine delivery to Canada because of issues with its European production lines.

Jan. 16: Canada surpasses 700,000 cases of COVID-19.

Jan. 23: Health Canada confirms it’s approved a rapid COVID-19 test from Spartan Bioscience for use across the country. The company had previously recalled its rapid testing technology last spring over concerns expressed by the federal agency.

Jan. 24: New Brunswick’s Edmundston region enters lockdown in a bid to quash a rise in local COVID-19 case numbers.

Air Passenger Market Analysis

January 2023

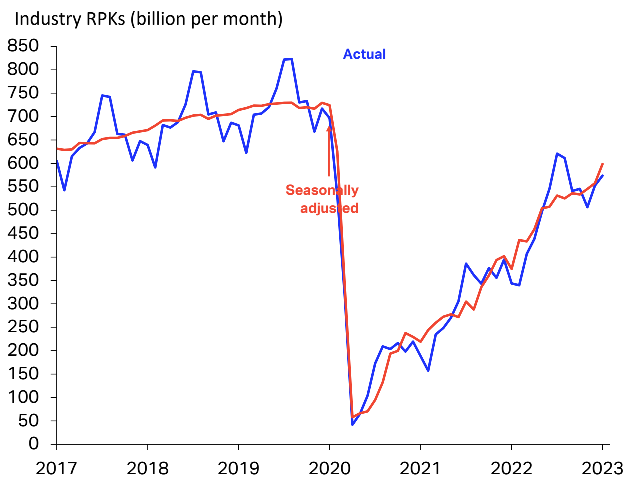
Global passenger recovery accelerates in January

- The annual growth in industry-wide revenue passenger kilometers (RPKs) rose to 67.0% in January, recovering global passenger demand to 84.2% of pre-pandemic levels. Domestic RPKs in the US climbed 0.8% above their 2019 levels.
- Capacity, measured in available seat kilometers (ASKs), also increased by 35.5% year-over-year, placing passenger load factors at 77.7% for the month. Carriers in North America expanded ASKs to exceed their January 2019 capacity.
- Helped by the swift reopening of China from Covid-19 restrictions, the annual growth of global domestic RPKs accelerated to 32.7% in January, reaching 97.4% of pre-pandemic levels. International passenger traffic also continued its steady growth to reach 77.0% of January 2019 levels.

Global recovery accelerates as China reopens

The start of 2023 was marked by an acceleration in passenger demand recovery. Industry-wide revenue-passenger kilometers (RPKs) grew by 67.0% year-on-year (YoY) and stood at 84.2% of January 2019 levels (**Chart 1**). In seasonally adjusted terms, the global recovery trend gained further momentum as RPKs increased 7.4% month-on-month (MoM). These positive developments were driven, in large part, by the reopening of China's domestic market.

Chart 1 – Global air passengers, revenue passenger kilometers (RPKs), billions

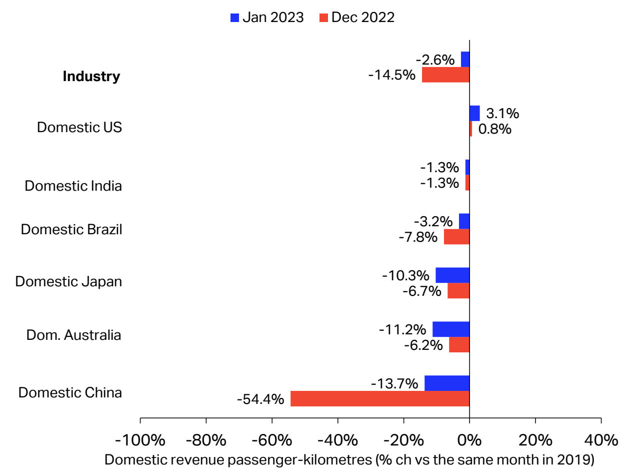


Sources: IATA Economics, IATA Monthly Statistics

Industry-wide available seat-kilometers (ASKs) increased 35.5% YoY following the increase in passenger demand, while the global passenger load factor (PLF) continued to trend near pre-pandemic levels at 77.7% for the total industry.

Strong recovery in China, US domestic traffic grows above pre-pandemic levels

Chart 2 – Domestic RPK growth by airline region of registration, YoY% change versus 2019



Sources: IATA Economics, IATA Monthly Statistics

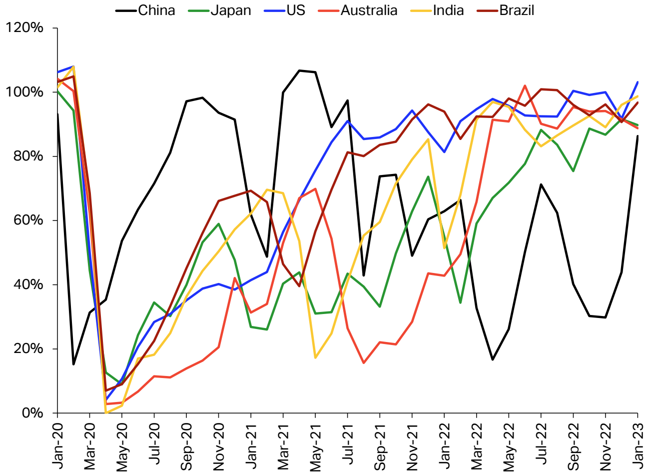
With the lifting of the zero-Covid policy in China, domestic traffic picked up pace in January. RPKs reached 86.3% of their January 2019 levels (**Chart 2**). The dynamic nature of travel restrictions in China has been reflected in volatile domestic passenger traffic trends since 2020 (**Chart 3**). Nevertheless, the latest policy development is accommodative to the strong willingness to travel demonstrated by passengers.

Air passenger market overview - January 2023

	World share [1]	January 2023 (% year-on-year)				January 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%***	**67.0%**	**35.5%**	**14.7%**	**77.7%**	**-15.8%**	**-13.5%**	**-2.1%**	**77.7%**
International	*57.9%*	104.0%	53.7%	19.4%	78.6%	-23.0%	-21.7%	-1.3%	78.6%
Domestic	*42.1%*	32.7%	16.3%	9.5%	76.4%	-2.6%	1.2%	-3.0%	76.4%

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

Chart 3 – Domestic markets, RPK share (%) of the same month in 2019



Source: IATA Economics, IATA Monthly Statistics

Given the size of China's domestic market – accounting for 9.8% of total industry RPKs and 27.1% of total domestic RPKs in 2019 – its recent growth in traffic had a substantial impact on global RPKs. Total domestic RPKs recovered to 97.4% of their 2019 levels in January. In YoY terms, domestic RPKs and ASKs increased 67.0% and 35.5%, respectively.

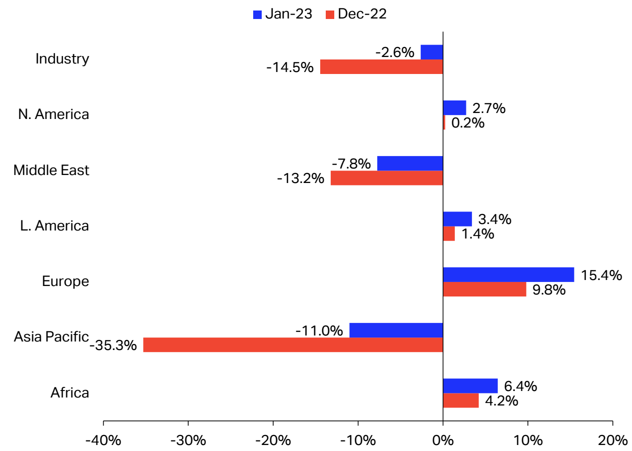
Other monitored markets of the Asia Pacific region sustained their past year's recovery momentum in Januray, and continued to approach pre-pandemic domestic traffic levels. In India, domestic RPKs were 1.3% below January 2019 levels and grew 92.0% YoY. Japan and Australia saw 63.3% and 107.3% YoY domestic traffic growth in January, respectively, recovering their RPKs to 89.7% and 88.8% of 2019 levels. Overall, domestic RPKs carried by airlines of the Asia Pacific region grew 47.8% YoY in January, and currently sit 11.0% under 2019 levels.

The US domestic market continued its robust recovery in January. Domestic RPKs climbed 26.8% YoY and stood 3.1% above levels achieved in January 2019 (**Chart 2**). In Brazil, traffic grew 3.0% YoY to bring January passenger levels only 3.2% below their pre-pandemic levels. These developments are consistent with performance improvements for airlines in the broader region. Domestic RPKs in January increased 3.4% and 2.7% above pre-pandemic levels for Latin America and North America regions, respectively (**Chart 4**).

In Europe, domestic passenger traffic continued to rise above pre-pandemic levels. Compared to January 2019 performance, domestic traffic transported by European airlines rose 15.4%, while growing 19.2% over January 2022 levels. Due to data constraints, we are unable to report on specific developments in Russia's domestic market.

Although domestic RPKs contracted 1.3% YoY for the Middle East airlines in January, the region's airlines sustained 92.2% of their pre-pandemic domestic traffic.

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

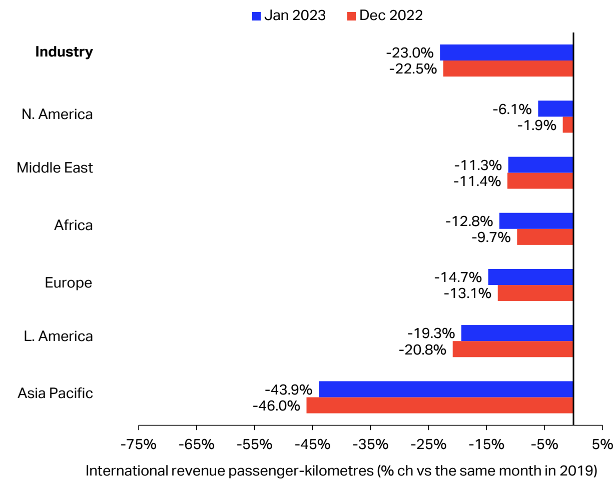


Source: IATA Economics, IATA Monthly Statistics

International traffic continues to grow steadily

In January, total international RPKs more than doubled compared with the previous year's traffic (104.0% YoY) and recovered to 77.0% of pre-pandemic levels. The annual growth in international ASKs in January was 53.7%, roughly half the pace of passenger demand growth over the same period. As a result, the passenger load factor for this market segment increased 19.4 ppts from the previous year to reach 78.4%, which is only 1.3 ppts less than the January 2019 load factor. (**Chart 5**).

Chart 5 – International RPK growth by airline region of registration, YoY% change versus 2019



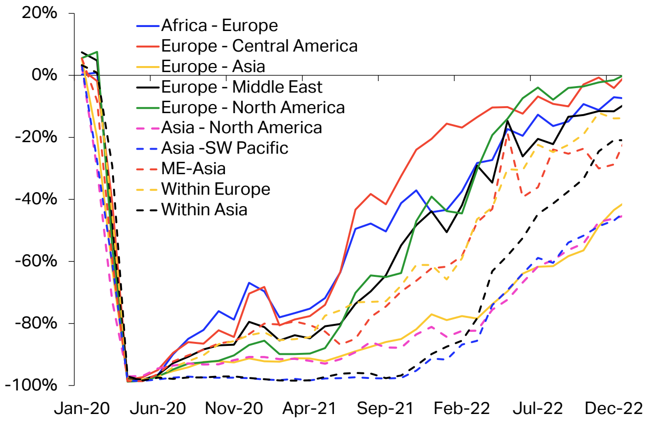
Sources: IATA Economics, IATA Monthly Statistics

The reopening of China's borders for international travel on 8 January 2023 had an immediate effect on ticket sales for inbound travel to the country. The relaxation of the Covid-19 restrictions led to an uptick in the number of people flying to China, including those visiting friends and relatives for the Chinese New Year. The increase in purchased tickets is also expected to be reflected in the reported RPKs for the upcoming

February travel period. Airlines registered in the broader Asia Pacific region continued to display the strongest annual growth rates in international passenger traffic. In January, the region's international RPKs increased 376.3% YoY, reaching 56.1% of January 2019 levels (**Chart 5**). This growth also reflects recovery from a very low traffic base last year when much of the region was still closed to travel.

Within the Asia Pacific region, international traffic continued to show positive developments, and reached 79.0% of pre-pandemic levels in January. Although demand between the Asia Pacific region and the rest of the world lags in terms of recovery rate, the most recent developments support a positive outlook for the region (**Chart 6**).

Chart 6 – International RPKs, YoY% change versus 2019 – Top 10 route areas in 2019, ranked by performed traffic level



Source: IATA Economics, IATA Monthly Statistics

International RPKs performed by European airlines increased 60.6% YoY. The intra-European international air passenger market continued to recover in line with previously gained momentum, and RPKs in January recovered to 86.2% of their 2019 levels. The Europe – North America and Europe – Central America route areas surpassed 2019 demand levels in January for the first time since 2020, with 0.9% and 1.2% growth, respectively.

Airlines from North America and Latin America grew their January international RPKs 82.4% and 46.8% YoY, respectively. Recent developments show encouraging trends for both regions, with their respective January traffic levels sitting 6.1% and 19.3% below pre-pandemic levels. International traffic within South America recovered to 2019 levels, achieving 3.2% annual growth in January.

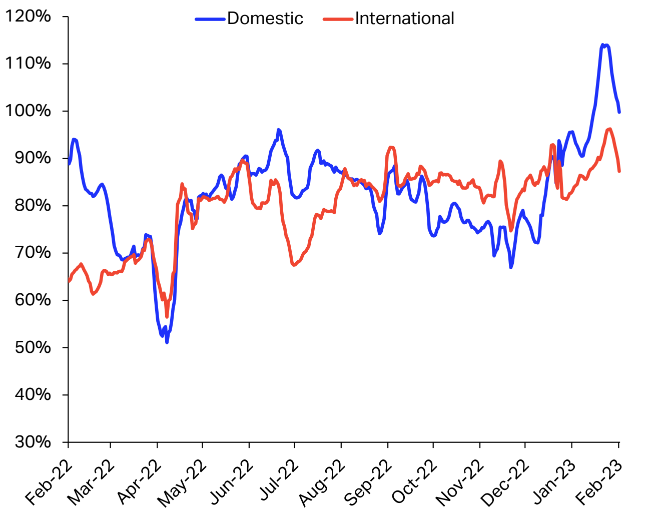
As air connectivity between the Americas and other regions continues to recover, two route areas have achieved pre-pandemic levels since April 2022: Middle East – North America and North America – Central America. In January, passenger flows on these route areas exceeded their pre-pandemic levels by 12.0% and 9.6%, respectively (**Chart 6**).

Middle Eastern carriers grew international RPKs by 97.7% YoY in January, reaching 88.7% of pre-pandemic demand. African airlines achieved 124.8% YoY growth in international RPKs, with traffic levels only 12.8% under those of January 2019.

Ticket sales on international and domestic markets align

Domestic ticket sales in 2022 have roughly followed a sideways trend while international ticket sales began to rise over 2022 levels (**Chart 7**). The most recent data show an uptick in ticket sales in January, mainly attributed to China's travel markets reopening. Meanwhile international ticket sales have caught up to, and maintained their recovery with, domestic ticket sales.

Chart 7 – Passenger ticket sales by purchase date, YoY% change versus 2019



Source: IATA Economics, DDS

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Air passenger market in detail - January 2023

	World share[1]	January 2023 (% year-on-year)				January 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%***	**67.0%**	**35.5%**	**14.7%**	**77.7%**	**-15.8%**	**-13.5%**	**-2.1%**	**77.7%**
Africa	*2.1%*	113.8%	76.9%	12.8%	74.2%	-10.1%	-14.3%	3.5%	74.2%
Asia Pacific	*22.1%*	114.9%	58.8%	20.2%	77.4%	-29.7%	-26.1%	-4.0%	77.4%
Europe	*30.7%*	53.2%	27.1%	13.0%	76.2%	-11.5%	-7.2%	-3.7%	76.2%
Latin America	*6.4%*	24.3%	20.0%	2.8%	81.3%	-8.5%	-7.4%	-1.0%	81.3%
Middle East	*9.8%*	91.1%	42.5%	20.1%	79.1%	-11.1%	-16.2%	4.5%	79.1%
North America	*28.9%*	42.2%	19.6%	12.5%	78.4%	-0.4%	1.1%	-1.2%	78.4%
International	***57.9%***	**104.0%**	**53.7%**	**19.4%**	**78.6%**	**-23.0%**	**-21.7%**	**-1.3%**	**78.6%**
Africa	*1.8%*	124.8%	82.5%	13.9%	73.7%	-12.8%	-16.3%	2.9%	73.7%
Asia Pacific	*8.9%*	376.3%	167.1%	36.6%	83.3%	-43.9%	-44.8%	1.3%	83.3%
Europe	*26.3%*	60.6%	30.1%	14.2%	75.0%	-14.7%	-8.4%	-5.5%	75.0%
Latin America	*2.9%*	46.8%	34.3%	7.1%	82.7%	-19.3%	-19.5%	0.2%	82.7%
Middle East	*9.4%*	97.7%	45.9%	20.8%	79.2%	-11.3%	-16.3%	4.5%	79.2%
North America	*8.7%*	82.4%	37.3%	19.7%	79.6%	-6.1%	-4.8%	-1.1%	79.6%
Domestic	***42.1%***	**32.7%**	**16.3%**	**9.5%**	**76.4%**	**-2.6%**	**1.2%**	**-3.0%**	**76.4%**
Dom. Australia[4]	*1.0%*	107.3%	50.0%	22.0%	79.7%	-11.2%	-13.1%	1.6%	79.7%
Domestic Brazil[4]	*1.5%*	3.0%	5.5%	-2.0%	81.5%	-3.2%	-0.3%	-2.5%	81.5%
Dom. China P.R.[4]	*6.4%*	37.2%	19.0%	9.4%	70.6%	-13.7%	0.5%	-11.6%	70.6%
Domestic India[4]	*2.0%*	92.0%	47.2%	19.9%	85.2%	-1.3%	-0.3%	-0.8%	85.2%
Domestic Japan[4]	*1.2%*	63.3%	3.0%	25.3%	68.6%	-10.3%	-12.6%	1.8%	68.6%
Domestic US[4]	*19.3%*	26.8%	12.0%	9.0%	77.5%	3.1%	5.3%	-1.6%	77.5%

[1]% of industry RPKs in 2022 [2]Change in load factor vs same month in 2019 [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 74.5% 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 registrated; it should not be considered as regional traffic.

IATA Economics
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08 March 2023

Air Cargo Market Analysis

January 2023

Air cargo demand started the year on a weak note

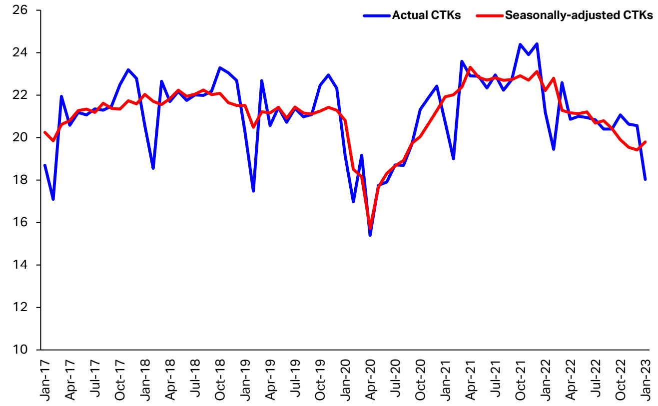
- Industry-wide cargo tonne-kilometers (CTKs) continued to decline in January, falling 14.9% year-on-year (YoY) and marking the 11th month of consecutive annual declines. Compared with pre-pandemic levels, air cargo demand was also down 11%.
- Cargo capacity – measured by available cargo tonne-kilometers (ACTKs) – picked up 3.9% YoY in January, reflecting the strong recovery of belly cargo capacity in passenger airline markets. Cargo load factors stood at 44.8%, after falling 9.9 percentage points below load factors in January 2022.
- The economic outlook for the air cargo industry in 2023 is expected to be a challenging one. Multiple macroeconomic headwinds stemming from the global pandemic persist and the on-going war in Ukraine has disrupted important trade flows and economic activity across various regions.

Air cargo demand contracted further in January

Industry-wide cargo tonne-kilometers (CTKs) fell 14.9% YoY in January, marking the 11th month of consecutive annual declines in global air cargo demand **(Chart 1)**. Compared with January 2019 cargo traffic, industry CTKs also contracted by 11%.

Seasonally adjusted (SA) air cargo traffic decreased by 10.9% YoY, albeit with a 2% increase from December 2022 levels.

Chart 1 Global Industry CTKs (billions per month)



Sources: IATA Economics, IATA Monthly Statistics

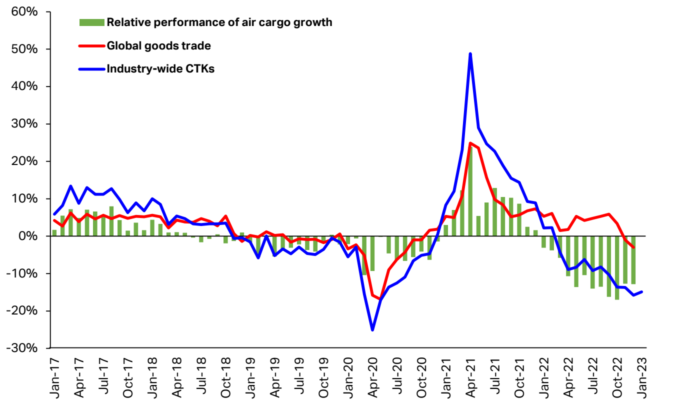
International CTKs declined slightly faster than industry-wide cargo traffic, registering a 16.2% YoY contraction in January.

The challenging economic environment for air cargo is expected to persist this year. Global economic growth is forecast to remain weak, and a slowdown of economic activity is unavoidable in major economies. High inflation will continue curtailing purchasing power, dampening consumption and global trade. These impacts are worsened by currency depreciations relative to the US dollar, which increase the local currency price of commodities invoiced in US dollars. Oil price volatility will likely remain in 2023, owing to the EU ban on maritime transportation of Russian crude oil and petroleum products. Finally, the ongoing war in Ukraine remains the greatest geopolitical risk to the global economy.

Global goods trade continued to decline while relative air cargo performance stabilized

Global trade decreased by 3.0% YoY in December, the second monthly decline in a row **(Chart 2)**.

Chart 2 Growth in global goods trade and CTKs (YoY)



Sources: IATA Statistics, Netherlands CPB

Although trade continued to benefit maritime transportation more than air cargo, the relative growth

Air cargo market overview - January 2023

	World share [1]	January 2023 (% year-on-year)				January 2023 (% ch vs the same month in 2019)			
		CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]	CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]
TOTAL MARKET	***100.0%***	**-14.9%**	**3.9%**	**-9.9%**	**44.8%**	**-11.0%**	**-6.7%**	**-2.2%**	**44.8%**
International	*86.8%*	-16.2%	1.4%	-10.4%	49.4%	-11.4%	-10.1%	-0.7%	49.4%

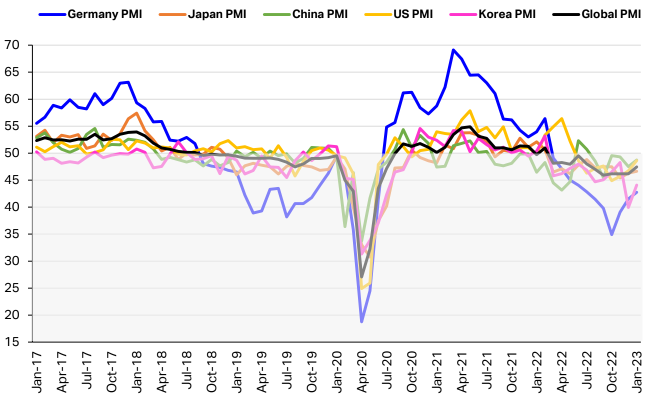
[1]% of industry CTKs in 2022 [2]Change in load factor [3]Load factor level

performance of air cargo stabilized at -12.8% in December.

Global new export orders in the manufacturing Purchasing Managers' Index (PMI) – historically a leading indicator for air cargo demand – slightly increased across all major economies in January, despite still being below the critical 50 (no-change) line **(Chart 3)**.

Germany continued to catch up with other major economies since its first uptick in export orders in November 2022. China and the US approached the critical 50 line, a promising sign that demand for manufactured goods from the world's two largest economies is stabilizing. South Korea saw a strong rebound from its weak performance in December, and Japan also had a slight increase in its new export order PMIs. As a result, the global new export orders index increased, month-on-month, for the first time since October 2022.

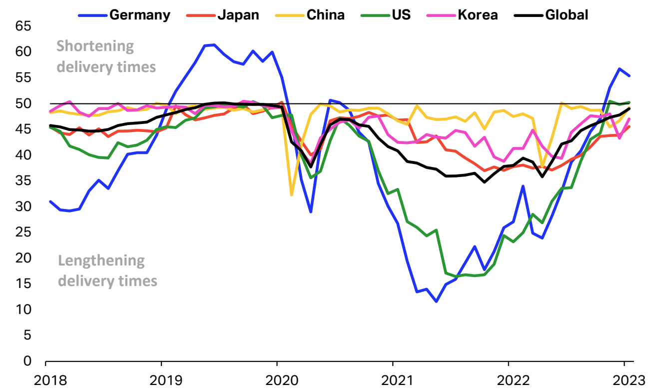
Chart 3 Global new export orders, component of the manufacturing PMI (50 = no change, SA)



Sources: Markit

Compared with the previous year, new export orders fell by 4.5% YoY in January. This is a significant improvement compared with the annual declines that were in the 9%-range for the previous five months. A key factor behind this improvement is the recovery of global supply chains, where supplier delivery times have been shortened significantly, particularly in the US and Germany (**Chart 4**).

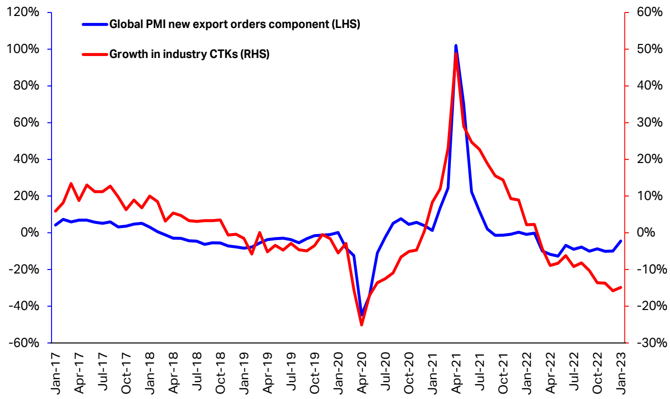
Chart 4 Supplier delivery times PMIs (50 = no change)



Source: Markit

Owing to the historical relationship between global manufacturing PMIs and industry-wide CTKs, the recent increase in new export orders could also point to growth in air cargo demand going forward (**Chart 5**).

Chart 5 CTK growth and global new export orders (YoY)

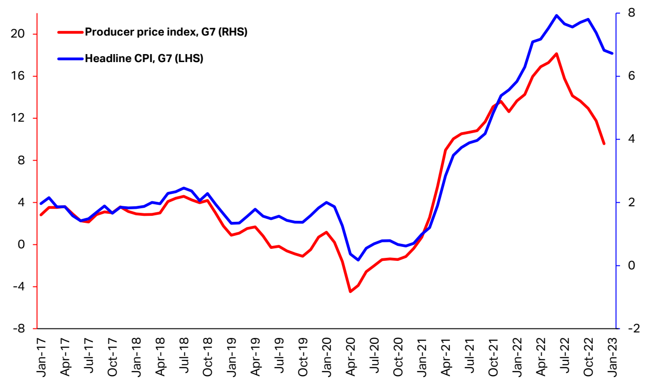


Sources: IATA Economics, IATA Monthly Statistics, Markit

Inflation continued to slow in January

Year-on-year inflation – as measured by the headline Consumer Price Index (CPI) for the G7 countries – was down to 6.7% in January from its peak of 7.9% in June 2022. Producer (input) prices, as measured by the Producer Price Index (PPI), also continued to retreat by 2.2 percentage points (ppts) from the previous month to 9.6% in December (**Chart 6Chart 6**).

Chart 6 G7 headline CPI and PPI inflation (% ch YoY)



Source: Refinitiv Eikon

The slowing pace of increase in the cost of goods and services points to possible improvements in the purchasing power of consumers and in air cargo demand. However, although the annual rate of inflation is expected to cool further in 2023, the general price level has already increased, and continues to climb on a monthly basis. Thus, price inflation, even after stripping out volatile food and energy prices, will remain a challenge for global air cargo demand in the year ahead.

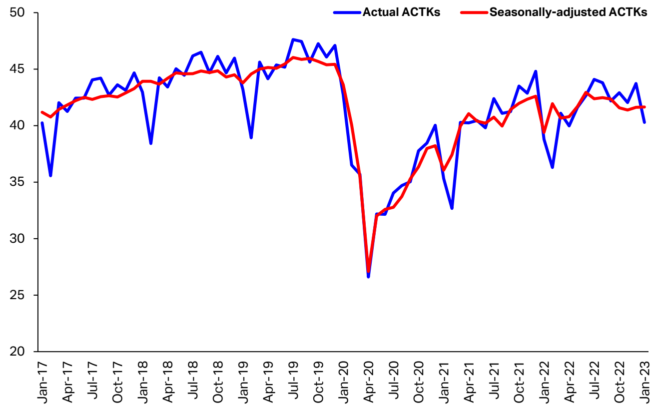
Although global oil prices have been declining since June 2022, they increased slightly in January. The average Brent crude oil price climbed to USD 83.9 per barrel (bbl) from USD 82.1 per bbl in December. Additionally, the jet crack spread expanded to USD 51.4

per bbl on average in January, which is an USD 13.2 per bbl increase from the December spread. The elevated crack spread in the start of the year is an expected feature of the market in 2023 due to strong demand amidst limited global refining capacity.

Cargo capacity increased despite demand slowdown

Global air cargo capacity, measured by available cargo tonne-kilometers (ACTKs), picked up by 3.9% YoY. This was also the first YoY growth in ACTKs since October 2022 (**Chart 7**).

Chart 7 Global ACTKs (billions per month)



Sources: IATA Economics, IATA Monthly Statistics

The increase in industry ACTKs was driven by the strong recovery of belly cargo capacity in international passenger airline markets, which accounted for 77.5% of the industry total ACTKS in 2022. In January 2023, international ACTKs for belly cargo grew 50% over 2022 capacity and reached 71% of their 2019 level. In contrast, dedicated cargo international capacity declined by 11% YoY. With increased total capacity, industry cargo load factors stood at 44.8% in January, 9.9 ppts below load factors from the previous year.

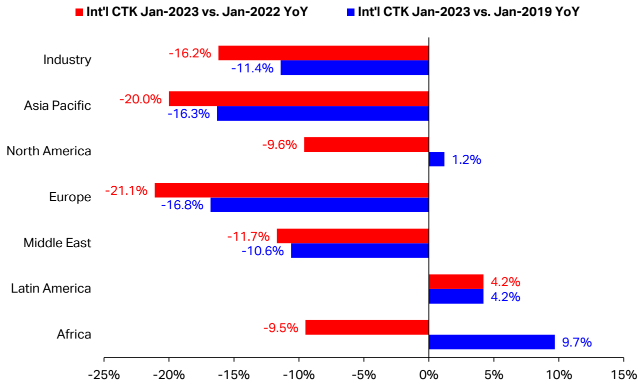
International CTKs declined across all regions except in Latin America

International CTKs accounted for 87% of the global air cargo market demand in 2022. They contracted by 16.2% YoY in January, declining across all regions except in Latin America. Compared with January 2019 levels, international air cargo demand decreased by 11.4% YoY. Carriers in North America, Latin America, and Africa, however, have managed to keep international CTKs above 2019 levels (**Chart 8**).

Airlines in North America and Latin America regions grew their CTKs over 2019 levels by 1.2% and 4.2%, respectively. Latin American carriers had the strongest traffic growth compared with other regions in January, and a significant improvement in performance compared to the previous month.

Airlines registered in the Asia Pacific region, which account for the largest share of international CTKs globally, continued to endure disruptions to trade, manufacturing, and supply chains due to the residual effects of restrictions imposed in China. Additionally, the Lunar New Year national holiday in China, which has traditionally led to lower cargo activities in China and within the APAC region, was in January this year, compared to February in 2019 and in 2022. As a result, International CTKs for the region's airlines declined 20.0% YoY in January and were 16.3% below 2019 levels. China's recent reopening of international markets, however, is expected to gradually benefit global trade and the growth of air cargo demand in the region as capacity picks up.

Chart 8 YoY growth in international CTKs by region

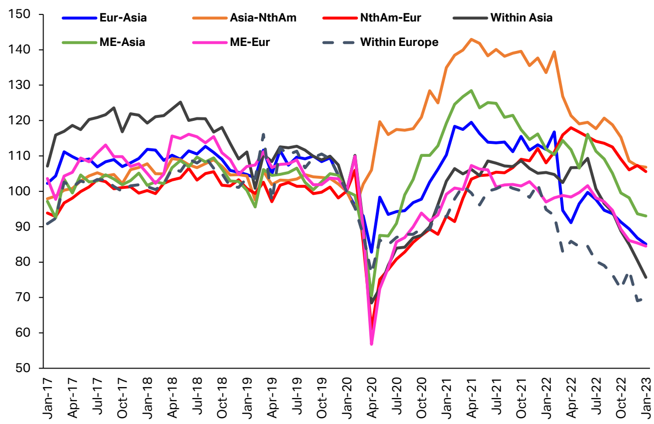


Sources: IATA Economics, IATA Monthly Statistics

International air cargo demand in Europe and the Middle East also contracted significantly from 2022 and 2019 levels (-21.1% and -16.8%, respectively). For Europe's cargo markets, the war in Ukraine has distorted important trade corridors and supply chains. African carriers saw their international CTKs drop 9.5% compared to 2022 traffic, but demand for the region's airlines remained 9.7% higher than pre-pandemic levels.

Air cargo demand between region areas maintained similar trends compared with previous months (**Error! Reference source not found.**).

Chart 9 Seasonally adjusted CTKs by route area (indexed, Jan 2020 = 100)



Source: IATA Economics, IATA Monthly Statistics by Route

Despite slight declines from December, Asia-North America and North America-Europe remained the only two route areas that kept CTKs above their pre-pandemic levels. The growth in CTKs within Europe was still the slowest among the comparison route areas, reaching only 70% of their January 2020 traffic.

All route areas saw a slight decrease in their CTKs compared to the previous month.

Air cargo market in detail - January 2023

	World share [1]	January 2023 (% year-on-year)				January 2023 (% ch vs the same month in 2019)			
		CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]	CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]
TOTAL MARKET	***100.0%***	**-14.9%**	**3.9%**	**-9.9%**	**44.8%**	**-11.0%**	**-6.7%**	**-2.2%**	**44.8%**
Africa	*2.0%*	-9.5%	-1.8%	-3.8%	43.9%	8.6%	-12.5%	8.5%	43.9%
Asia Pacific	*32.4%*	-19.0%	8.8%	-15.5%	45.2%	-18.9%	-9.6%	-5.2%	45.2%
Europe	*21.8%*	-20.4%	-9.3%	-7.5%	54.1%	-16.0%	-21.6%	3.6%	54.1%
Latin America	*2.7%*	4.6%	34.4%	-9.3%	32.5%	-1.5%	-4.7%	1.0%	32.5%
Middle East	*13.0%*	-11.8%	9.6%	-10.0%	41.1%	-10.7%	-3.5%	-3.3%	41.1%
North America	*28.1%*	-8.7%	2.3%	-5.1%	42.3%	2.4%	7.6%	-2.2%	42.3%
International	***86.8%***	**-16.2%**	**1.4%**	**-10.4%**	**49.4%**	**-11.4%**	**-10.1%**	**-0.7%**	**49.4%**
Africa	*2.0%*	-9.5%	-2.7%	-3.4%	45.3%	9.7%	-11.9%	8.9%	45.3%
Asia Pacific	*29.7%*	-20.0%	2.0%	-14.8%	53.9%	-16.3%	-13.4%	-1.9%	53.9%
Europe	*21.4%*	-21.1%	-10.6%	-7.5%	56.1%	-16.8%	-22.8%	4.0%	56.1%
Latin America	*2.3%*	4.2%	42.3%	-13.7%	37.3%	4.2%	2.8%	-1.9%	37.3%
Middle East	*13.0%*	-11.7%	9.8%	-10.1%	41.3%	-10.6%	-3.4%	-3.3%	41.3%
North America	*18.4%*	-9.6%	2.5%	-6.2%	46.2%	1.2%	3.5%	-1.0%	46.2%

[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.

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07 March 2023

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Independent Statistics and Analysis
U.S. Energy Information Administration

Country Analysis Brief: Algeria

Last Updated: March 2, 2023
Next update: March 2024

Overview

Map of Algeria

Data source: U.S. Central Intelligence Agency, [*CIA World Factbook*–Algeria]

Table 1. Algeria's energy overview, 2021

	Crude oil and other petroleum liquids	Natural gas	Coal	Nuclear	Hydro	Other renewables	Total
Primary energy consumption (quad Btu)	0.8	1.6	0.0	0.0	0.0	0.0	2.3
Primary energy consumption (%)	32%	67%	1%	0%	0%	0%	100%
Primary energy production (quad Btu)	2.8	3.8	0.0	0.0	0.0	0.0	6.7
Primary energy production (%)	42%	58%	0%	0%	0%	0%	100%
Electricity generation (TWh)		76.6		0.0	0.1	0.8	77.5
Electricity generation (%)		99%		0%	0%	1%	100%

Data source: BP 2022 Statistical Review of World Energy, U.S. EIA International Energy Statistics database
Note: BP data is used for primary energy consumption. Primary energy production and electricity generation data are from EIA's International Energy Statistics database. EIA aggregates crude oil and other petroleum liquids, natural gas, and coal fuel sources as fossil fuel derived fuel sources for electricity generation.

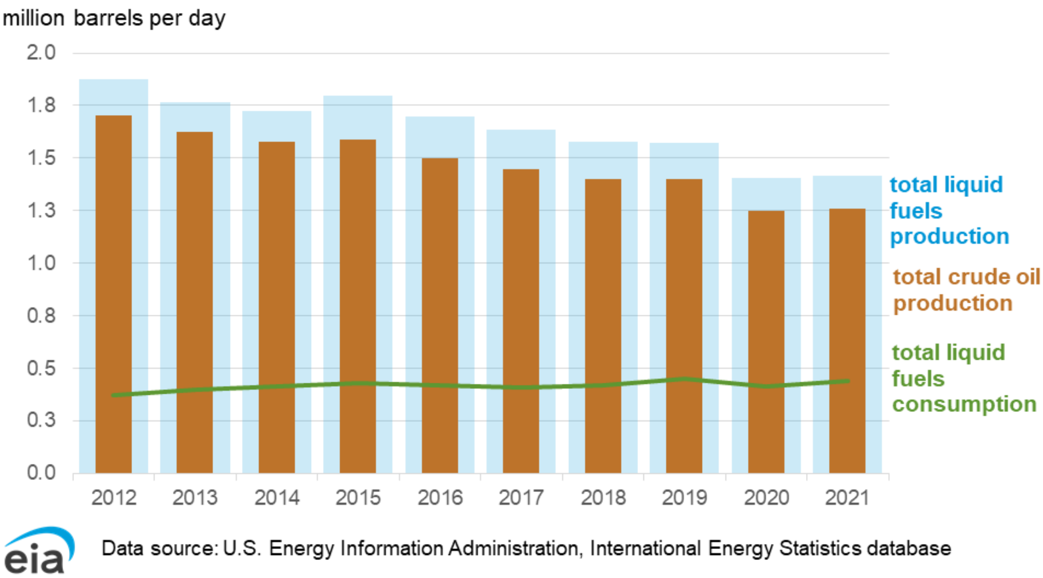
- Algeria is a major crude oil and natural gas producer in Africa and has been a member of the Organization of the Petroleum Exporting Countries (OPEC) since 1969, about 10 years after Algeria first began producing crude oil. Algeria is also a participant in the OPEC+ agreement.
- Algeria imports very little energy as its domestic consumption is met by its own oil and natural gas production, which is heavily subsidized. Natural gas and oil account for almost all of Algeria's total primary energy consumption.
- In the first quarter of 2023, the Algerian government plans to offer at least 10 exploration blocks in an upstream bidding round, its first since 2014.[1]

Petroleum and other liquids

- Algeria held an estimated 12.2 billion barrels of proved crude oil reserves at the beginning of 2023.[2]
- Algeria's oil fields produce high quality, light, sweet crude oil with a very low sulfur content. The country's main crude oil grade is the Sahara blend (API gravity of 46.0° and a sulfur content of 0.10%), which is a blend of crude oils produced at fields in the Hassi Messaoud region.[3]
- Algeria's largest oil fields are mature. Algeria has struggled to attract new investment in its upstream segment and been unable to prevent production declines (Figure 1).
- In December 2019, the Algerian government introduced a new hydrocarbons law meant to attract international investment in the upstream sector. The law reduces taxes across a number of upstream activities and simplifies the contractual agreement structure and other legal procedures for international investors.[4]
- Sonatrach, Algeria's state-owned oil company, solely owns and operates Algeria's refineries, which were built between 1960's and 1980's. Most recently, the Adrar refinery (2007) and the

condensate splitter at the Skikda refinery (2009) were built.[5] A number of proposals were made in 2012 to construct new refineries and to expand existing ones, but progress was repeatedly delayed. Eventually construction started on three of the proposed refineries, the Hassi Messaoud, Bishkra, and Tiaret refineries, and they are set to begin commercial operations within the next five years. Sonatrach is planning to upgrade the Skikda refinery by building a fuel cracker and naphtha processing unit to produce gasoline and diesel, but a final investment decision has not yet been reached (Tables 2 and 3).[6]

Figure 1. Total annual liquid fuels production and consumption in Algeria, 2012–2021



Data source: U.S. Energy Information Administration, International Energy Statistics database

Table 2. Refineries in Algeria

Refinery name	Nameplate capacity (thousand barrels per day)	Status	Ownership and operator
Adrar	13	Operating	JV between China National Petroleum Company and Sonatrach
Algiers (Sidi Rezine)	77	Operating	Sonatrach
Arzew	81	Operating	Sonatrach
Hassi Messaoud	23	Operating	Sonatrach
Skikda I	355	Operating	Sonatrach
Skikda II (natural gas condensate splitter)	122	Operating	JV between China National Petroleum Company and Sonatrach
Total	**671**		

Data source: *Middle East Economic Survey* as of January 2020, Refining & Petrochemicals

Table 3. Proposed upgrades or expansions of existing refineries or new refineries in Algeria

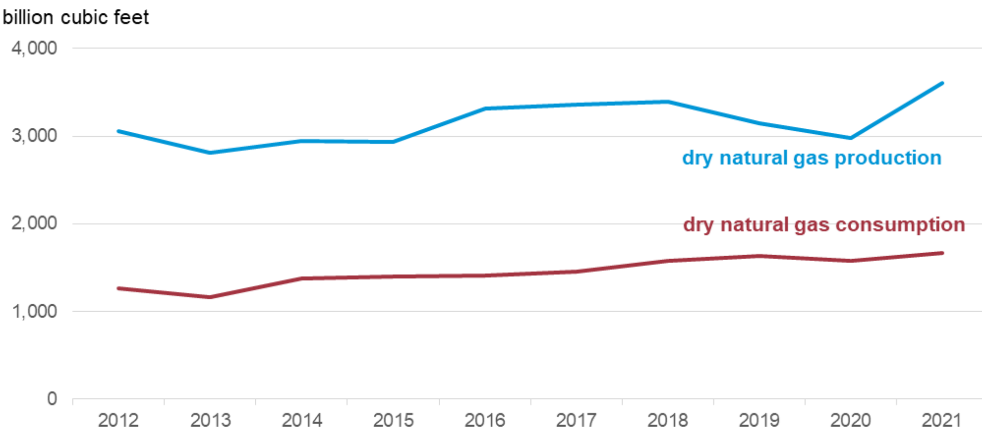
Refinery name	Target completion date	Notes
Hassi Messaoud	2024	When completed, the refinery will have the capacity to produce 5 million tons of oil products and 120,900 tons of natural gas. Planned refinery capacity is about 112,000 barrels per day (b/d).
Skikda	NA	This expansion will enable the refinery to produce diesel and gasoline.
Tiaret	NA	Initial launch date of 2022 is delayed; final investment decision is not likely until after 2025. Once completed, refinery capacity will be 100,000 b/d.
Biskra	NA	Initial launch date of 2022 is delayed; final investment decision is not likely until after 2025.

Data source: NS Energy Business, Energy Capital & Power, Middle East Economic Survey, government press releases, Africa News, S&P Global Platts

Natural gas

- Algeria held an estimated 159 trillion cubic feet (Tcf) of proved natural gas reserves at the beginning of 2023.[7]
- Dry natural gas production averaged about 3.2 Tcf between 2012 and 2021, while dry natural gas consumption averaged 1.5 Tcf over the same time period. In 2020, natural gas production fell as a result of the impact of the COVID-19 pandemic on economic activity and thus lower crude oil consumption, but it quickly rose again in 2021, reaching a record high of 3.6 Tcf (Figure 2).[8]
- According to the *Middle East Economic Survey*, the increased production in 2021 is attributed to upstream investment that brought online a number of new project startups and expansions, especially at its largest field, Hassi R'Mel, as well as a reduced need for natural gas reinjection at its oil fields as a result of lower crude oil production levels, thus freeing up more natural gas for domestic consumption and export (Table 4).[9]

Figure 2. Total dry annual natural gas production and consumption in Algeria, 2012–2021



Data source: U.S. Energy Information Administration, International Energy Statistics database

Table 4. Selected natural gas projects in Algeria

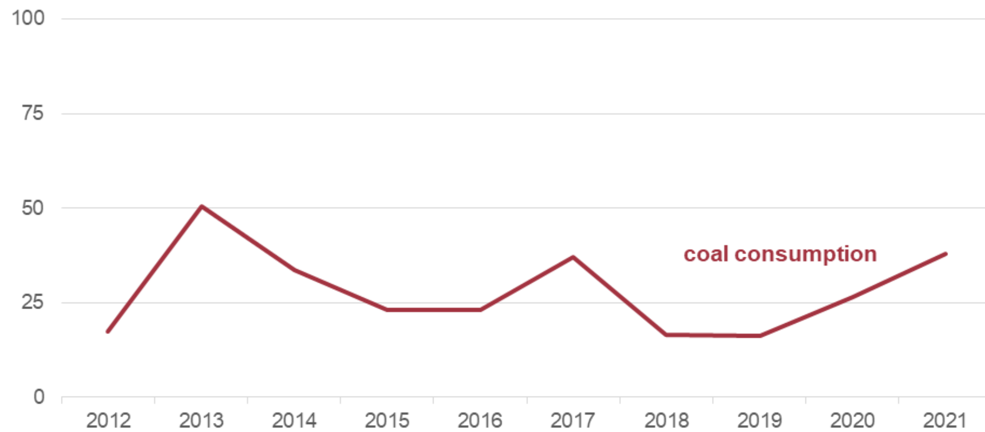
Project name	Location	Status	Operator and ownership	Estimated startup year
Touat	Southwest	operating	Neptune (operator) 35%, Engie 30%, Sonatrach 35%	2019
El Hamra (boosting project)	Illizi Basin	operating	Sonatrach	2020
North Berkine	Berkine Basin	operating	Eni, Sonatrach	2020
Menzel Ledjmet SE satellites	Berkine Basin	operating	Sonatrach	2020
Gassi Touil (peripheral fields)	Berkine Basin	operating	Sonatrach	2020
Hassi R'Mel (boosting project)	Hassi R'Mel Dome	operating	Sonatrach	2021
Tinhert phase 1 expansion (Ohanet tie-in)	Illizi Basin	operating	Sonatrach	2022
Isarene (Ain Tsila)	Illizi Basin	under development	Sunny Hill (operator) 38%, Sonatrach 62%	2023
Hassi Bahamou/Reg Mouaded (SW Gas Project phase 2)	Southwest	under development	Sonatrach	2024
Hassi Tidjerane (SW Gas Project phase 2)	Southwest	under development	Sonatrach	2024
Tinerkouk (SW Gas Project phase 2)	Southwest	under development	Sonatrach	2024
Touat Phase 2	Southwest	planned	Neptune (operator) 35%, Engie 30%, Sonatrach 35%	2026
Timimoun (ramp up project)	Southwest	under development	Total (operator) 38%, Cepsa 11%, Sonatrach 51%	unknown
South Berkine	Berkine Basin	under development	Eni 49%, Sonatrach 51%	unknown
Tinher phase 2 expansion (Alrar tie-in)	Illizi Basin	under development	Sonatrach	unknown
Tin Fouye Tabankort	Illizi Basin	planned	Total 26.4%, Repsol 22.4%, Sonatrach 51%	unknown
Tin Fouye Tabankort Sud	Illizi Basin	planned	Total 49%, Sonatrach 51%	unknown

Data source: *Middle East Economic Survey*
Note: boosting projects are development projects that aim to maintain output levels at the El Hamra and Hassi R'Mel fields. Ramp up projects are development projects that aim to increase total output at an existing field

Coal

- Algeria does not hold any reserves of coal and, as a result, produces no coal. Algeria consumes very small amounts of coal, averaging 28,000 short tons per year from 2012 to 2021 (Figure 3).[10]

Figure 3. Total coal consumption in Algeria, 2012–2021
thousand short tons



eia Data source: U.S. Energy Information Administration, International Energy Statistics database

Electricity

- Algeria has renewable energy potential as a result of its geographic features that are conducive to renewable power generation, such as its relatively long coastline on the Mediterranean Sea suitable for wind and desert regions that could provide high levels of solar.[11]
- Algeria has 13 hydropower plants, mainly located in the northern parts of the country where rainfall is relatively plentiful.[12] Although the share of renewable energy in the generation mix remains limited, it is growing. Algeria's electric power sector primarily uses fossil fuel-derived sources for generation, comprising about 97% of total power capacity in Algeria (Figures 4 and 5).
- Algeria's total electricity capacity nearly doubled between 2011 and 2020. Additions of natural gas-fired or combined-cycle natural gas turbine (CCGT) power plants, which generate electricity more efficiently relative to Algeria's older power plants, propelled most of this growth.[13] Sonelgaz had planned to bring an additional 4 gigawatts (GW) of CCGT capacity online by the end of 2021, but it only achieved the partial startup of the 1.4 GW Bellara CCGT plant and a 1.2 GW unit at the Naama CCGT plant. Although the growth of electricity capacity was significant, construction of many of the CCGT plants have reportedly faced considerable delays.[14]
- The Algerian government's renewable energy targets call for 15 GW of power capacity at a rate of 1 GW per year by 2035.[15] To achieve these ambitious targets given the relatively short timeframe and low capacity of renewable energy-derived power capacity (of less than 1 GW in 2020), the government seeks to attract foreign investment in power projects. In December 2021, Algeria launched a call for bids to install 1 GW of solar photovoltaic capacity, split into 11 projects ranging in size from 50 megawatts (MW) to 300 MW. However, the deadline to submit bids was postponed, and the estimated project start dates for these contracts, once awarded, is around the end-2023 or early 2024.[16]

Figure 4. Algeria's electricity capacity by fuel type, 2011–2020
gigawatts

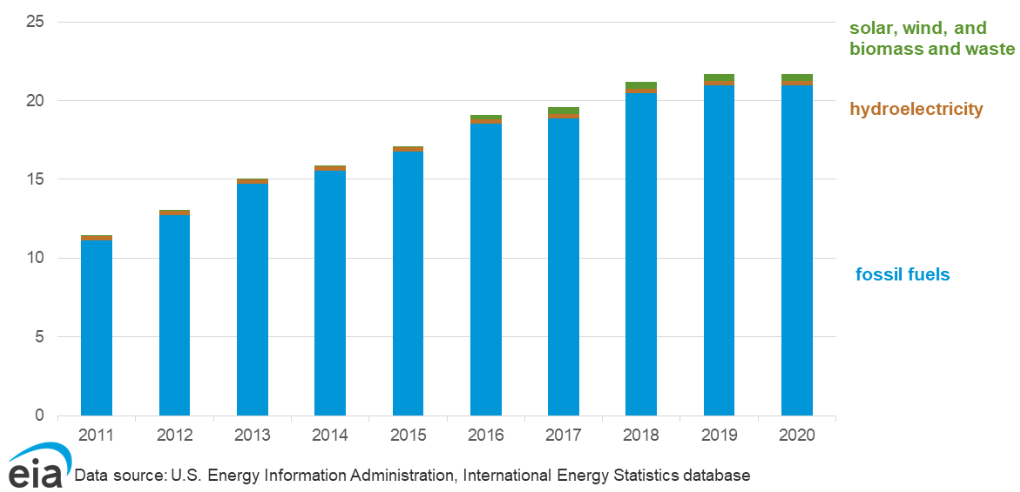
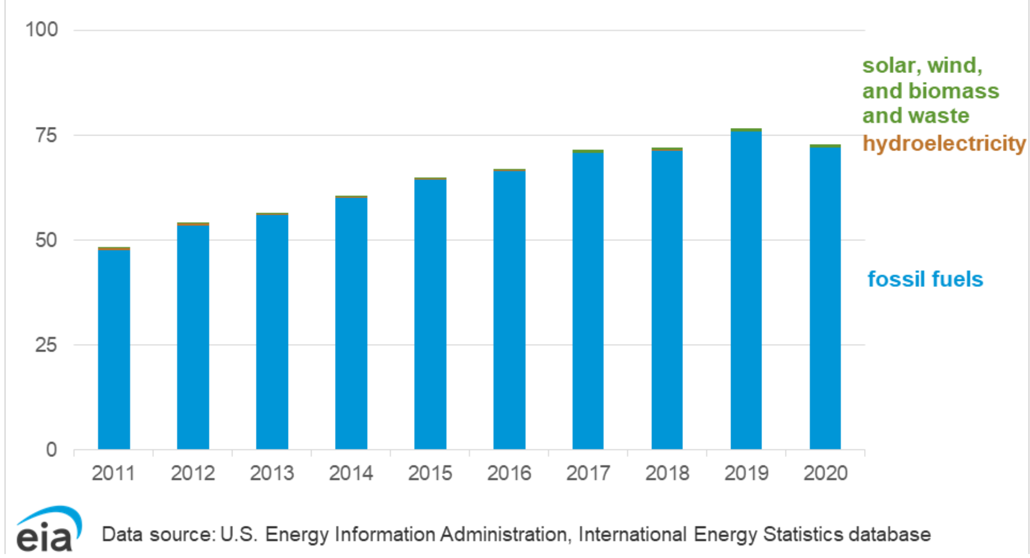


Figure 5. Algeria's net electricity generation by fuel type, 2011–2020
gigawatthours



Energy trade

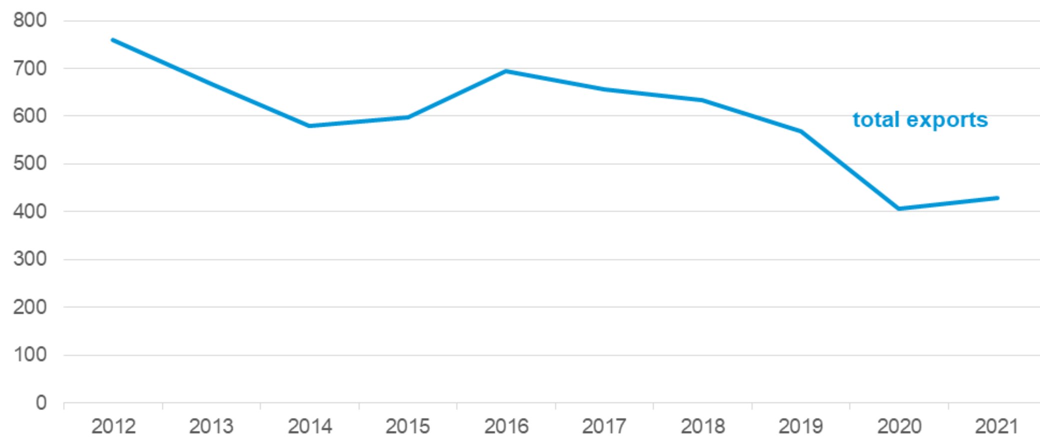
- According to our estimates and Kpler's estimates, Algeria imports virtually no crude oil. Crude oil exports from Algeria averaged about 599,000 barrels per day (b/d) between 2012 and 2021, including a decrease in 2020 because of the COVID-19 pandemic's impact on global petroleum consumption. In 2021, Algeria exported about 428,000 b/d of crude oil and condensate, and a majority of the exports went to Europe (289,000 b/d). France (80,000 b/d) and Spain (49,000 b/d) received most of these exports. Relatively smaller volumes were exported to the Asia-Pacific and Western Hemisphere (Figures 6 and 7).[17]
- According to estimates by Kpler, Algeria exported an average of 115,000 b/d of liquefied petroleum gas (LPG) between 2017 and 2021 (Figure 8). Algeria exported butane and propane

from its refineries to Europe and Africa, which were its top two primary regional destinations in 2017–2021. Europe accounted for an average of 76% of total LPG exports, and Africa accounted for an average of 14% over that time period.[18]

- Given the abundance of natural gas relative to its domestic needs, Algeria does not import any natural gas, and it exports the natural gas it does not use for domestic consumption. Algeria exported an average of about 1.7 Tcf of natural gas between 2011 and 2020 (Figure 9).[19]
- According to BP's 2022 *Statistical Review of World Energy,* Algeria exported about 1.9 Tcf of natural gas in 2021, most of which went to Europe. About 567 billion cubic feet (Bcf) of natural gas was exported as LNG, and the remaining 1.4 Tcf was shipped via pipeline (Figure 10 and Figure 11).[20]
- Algeria is among the top African LNG exporters and primarily exports its LNG to Europe.[21] Algeria has four LNG terminals currently in operation, all owned and operated by Sonatrach.[22] Between June 2020 and July 2021, the Skikda LNG terminal was shut down as a result of a sudden failure of a turbine control mechanism at the terminal. The incident did not affect LNG deliveries because Sonatrach had spare liquefaction capacity at its other terminals at Arzew.[23] In February 2022, Sonatrach signed a contract with Sinopec to expand and upgrade the Skikda LNG terminal by increasing its storage capacity and modernizing its port facilities to accommodate larger vessels (Table 5).[24]
- Algeria has three major intercontinental pipelines that export natural gas to Europe: the Enrico Mattei (Transmed) pipeline, the Medgaz pipeline, and the Maghreb-Europe (MEG) pipeline. The capacity of the Medgaz pipeline, which delivers natural gas to Spain, increased from 283 Bcf per year to 378 Bcf per year at the end of 2021 after a third turbo compressor was put into service.[25]
- Algeria suspended delivery of natural gas exports via the MEG pipeline to Spain in October 2021 as a result of increased political tensions between Algeria and Morocco, which is a destination as well as a transit country for Algeria's natural gas exports.[26] However, in June 2022, deliveries of natural gas through the MEG pipeline resumed, albeit in the opposite direction, when Spain began exporting natural gas to Morocco. Spain is reportedly using LNG imports (not from Algeria) sourced on the international market, which are then re-gasified and transported to Morocco.[27]
- The construction of two major regional pipelines, the Gasdotto-Algeria Sardegna-Italia (GALSI) pipeline and the Trans-Saharan Gas pipeline (TSGP), has been proposed but no final investment decision has been announced. In June 2022, the energy ministers from Niger, Nigeria, and Algeria signed a memorandum of understanding to set up a task force for the Trans-Saharan Gas pipeline that aimed to update the existing feasibility study. If built, the Trans-Saharan Gas pipeline could transport piped natural gas from Nigeria to Algeria's Hassi R'Mel field, where natural gas could be transported to Europe via Algeria's intercontinental pipelines.[28] Talks regarding the development of the GALSI pipeline project, which originally aimed to deliver natural gas to Italy, have reportedly restarted, and the pipeline could potentially transport green hydrogen instead. No concrete plans have been announced (Table 6).[29]
- Algeria imports all the coal it consumes, nearly all of which was metallurgical coal. Algeria imports small quantities of bituminous coal (Figure 12).[30]

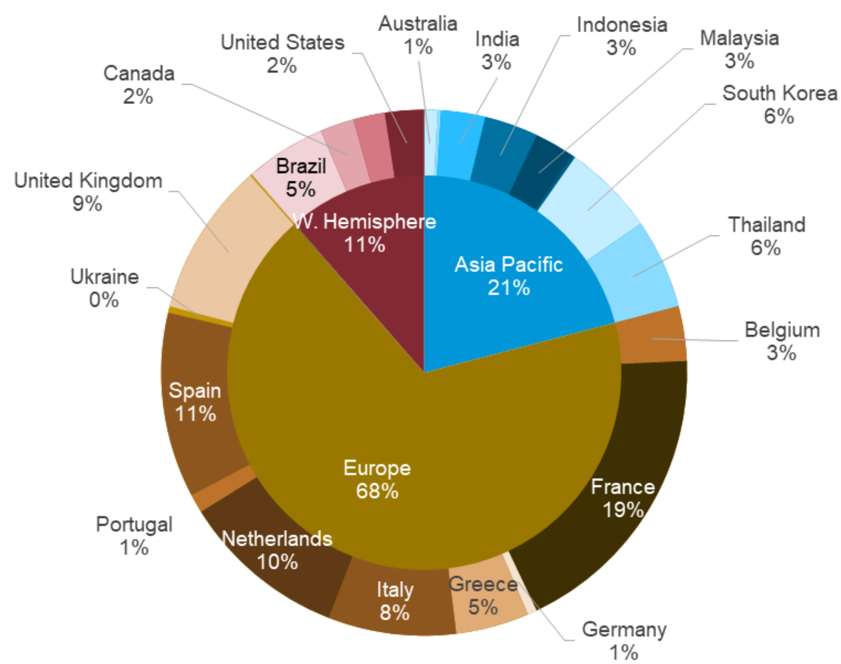
Figure 6. Algeria's total annual exports and imports of crude oil and condensate, 2012–2021

thousand barrels per day



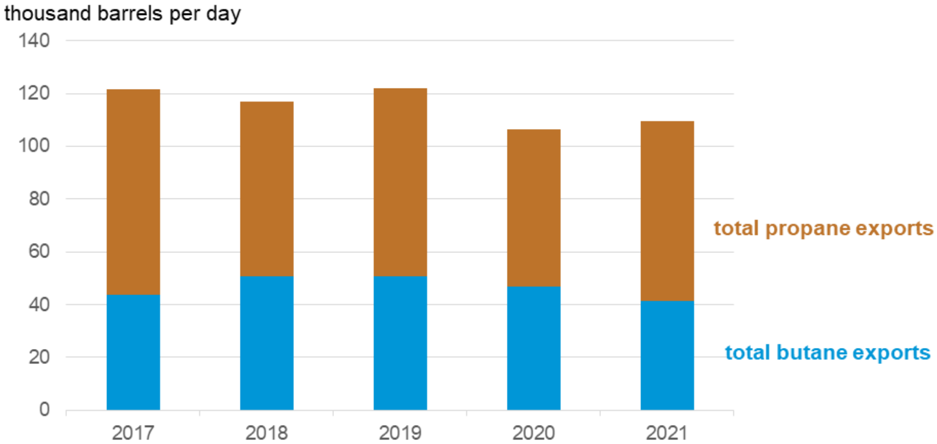
Data source: U.S. Energy Information Administration International Energy Statistics database and Kpler crude oil flows database

Figure 7. Algeria's crude oil and condensate exports by destination, 2021



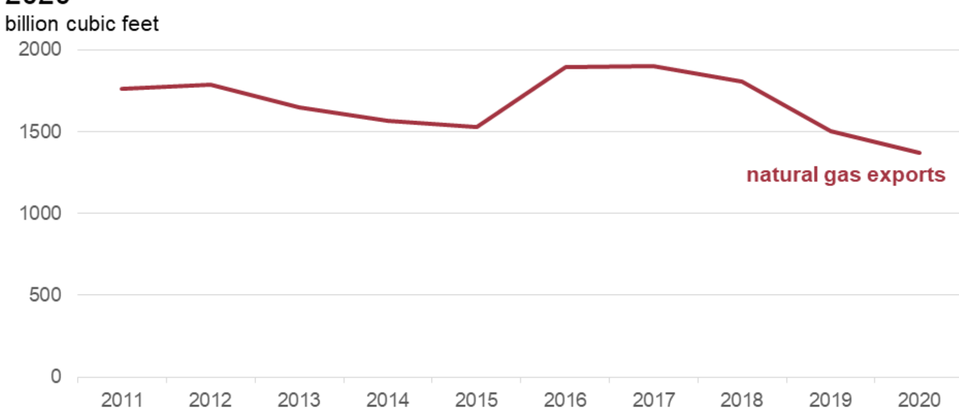
Data source: Kpler crude oil flows database

Figure 8. Algeria's total annual liquefied petroleum gas exports, 2017–2021



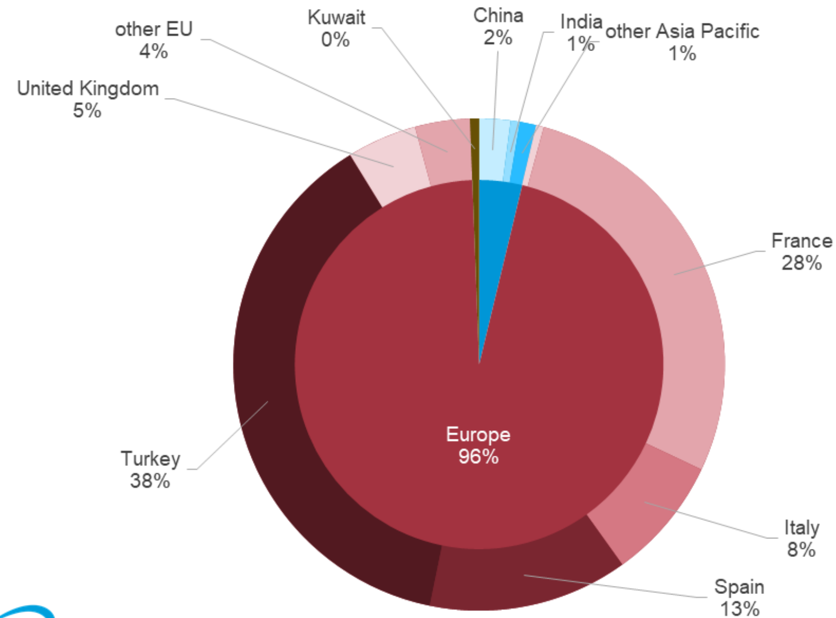
Data source: Kpler Liquefied Petroleum Gas Products data

Figure 9. Algeria's total annual natural gas imports and exports, 2011–2020



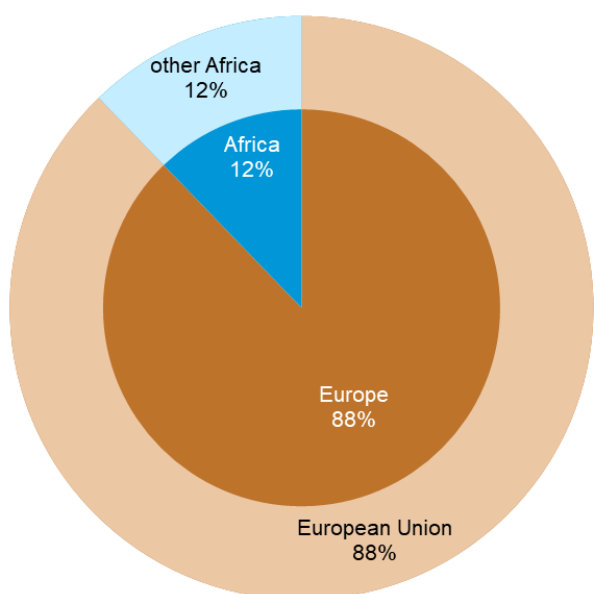
Data source: U.S. Energy Information Administration, International Energy Statistics database

Figure 10. Algeria's liquefied natural gas exports by destination, 2021



Data source: BP's *2022* Statistical Review of World Energy

Figure 11. Algeria's piped natural gas exports by destination, 2021



Data source: BP's 2022 Statistical Review of World Energy

Table 5. Algeria's LNG terminals

Project name	Ownership	Start date	Number of trains	Number of storage tanks	Nominal liquefaction capacity (billion cubic feet per year)	Storage capacity (million cubic feet)
Arzew GL1Z	Sonatrach	1978	6	3	379	11
Arzew GL2Z	Sonatrach	1981	6	3	394	11
Arzew GL3Z	Sonatrach	2014	1	2	226	11
Skikda GL1K	Sonatrach	2013	1	1	216	5
Total					**1,215**	**38**

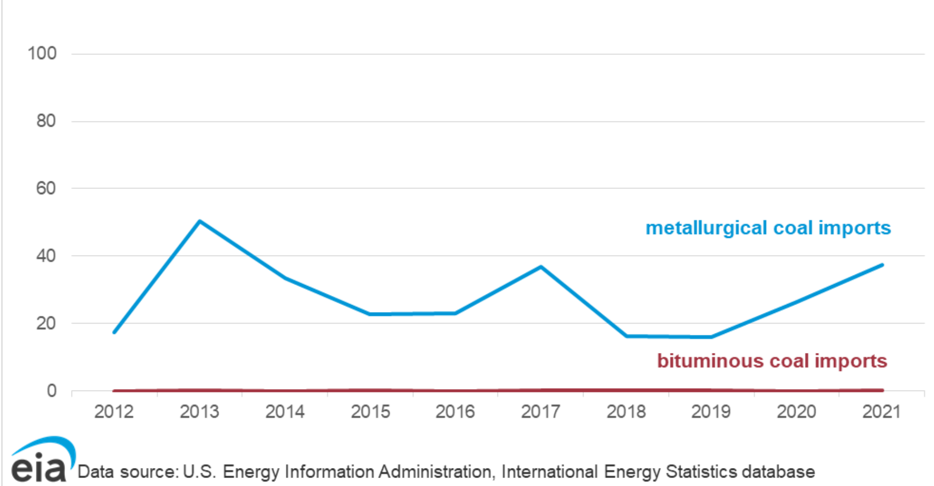
Data source: GIIGNL 2022 Annual Report
Note: LNG=liquefied natural gas

Table 6. Algeria's transcontinental natural gas pipelines

Pipeline name	Status	Ownership	Route	Start date	Length of pipeline (miles)	Pipeline capacity (billion cubic feet per year)
Enrico Mattei (TransMed) pipeline	operational	Sonatrach, Eni	Algeria to Italy via Tunisia	1983	1547	1183
Maghreb-Europe Gas pipeline (MEG)	operational[1]	Sonatrach, Naturgy, Enagas, Galp Energia	Algeria to Spain/Portugal via Morocco	1996	844	424
Medgaz pipeline	operational	Sonatrach, Naturgy	Algeria to Spain via the Mediterranean Sea	2011	473	378
Gasdott Algeria - Sardegna Italia (GALSI) pipeline	shelved	Sonatrach, Edison, Enel, Hera Group	Algeria to Italy	unknown	538	283
Trans-Saharan Gas pipeline (TSGP)	proposed	Sonatrach, Nigerian National Petroleum Corporation, Niger Ministry of Petroleum, Energy, and Renewable Energies	Nigeria to Algeria via Niger	unknown	2580	1059

Data source: Hydrocarbons Technology, Global Energy Monitor
[1] Deliveries of natural gas from Algeria to Morocco and Spain/Portugal via the MEG pipeline were suspended in October 2021. The pipeline resumed transportation of natural gas, but in the opposite direction, with Spain exporting natural gas to Morocco.

Figure 12. Algeria's total annual coal imports, 2012–2021
thousand short tons



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Excerpts from Australia govt posted transcript of Australia PM Albanese Q&A today.

https://www.pm.gov.au/media/afr-business-summit-0

TRANSCRIPT

07 Mar 2023

Prime Minister

Energy transition; Industrial relations; Business and unions working together; Economic outlook; Super reform; India trip; China relationship

E&OE

PHIL COOREY, HOST: Thanks, Prime Minister. My name is Phil Coorey, I'm the political editor of the AFR. And we've got time for a quick Q and A with the PM before he has to get back to Parliament. So, again, appreciate your time. This is the first time the summit has overlapped with a sitting day.

ANTHONY ALBANESE, PRIME MINISTER: I can give you a lift back.

COOREY: I've got to stay for Peter Dutton.

PRIME MINISTER: The offer stands.

COOREY: So this is your fourth business summit, PM, but your first as Prime Minister, you've done three, I think, as Opposition Leader. So if I could just begin with the speech.

PRIME MINISTER: I think I might have done some as Infrastructure Minister too.

COOREY: You can interview yourself. If I could just go to the speech before we get into the broader issues, you sort of talk about the challenges and the exposures of COVID in the economy, the things that have been laid bare and need to be fixed. You talk about energy security and the volatile energy market, and in doing so you go out of your way to mention the role of gas in the transition. That's a big topic in Parliament at the moment, with you trying to get the legislation for the safeguard mechanism through. The Greens, some independent Senators are railing against the ongoing use of gas and want you to pretty much rule out and ban any new gas projects. Is your message today sort of deliberately aimed at that as much as the engineering reality of energy?

PRIME MINISTER: It's just aimed at where we're coming from, being straight. And being straight, gas will play a role in renewables. A company, I don't know if they're here or not, but I assume they are somewhere, like Rio, what they want to do in Gladstone with their aluminium refinery and other activity. They want to move towards hydrogen, they want to move towards renewables and to power that, they need the firming capacity of gas. And that is the case for so many companies as they move towards net zero where they want to be. So I think my concern as well, I guess my message is twofold, that a message to the Greens and others that for all of the rhetoric, if it doesn't stack up, if it has a negative impact, then you're not actually helping the transition of what you say your objectives are, and to the Opposition as well, I mean for goodness sake, this is a safeguard mechanism that was put in place by Tony Abbott. How the Coalition can say they are a credible organisation concerned with business and oppose something that business is crying out for, that certainty. I believe in markets. Government has a role though in setting frameworks to facilitate private sector activity. And this is the perfect example. The safeguard mechanism is supported universally. I don't know an opponent in the business community, in the resources sector, in any of these areas that require that certainty going forward. If you have that certainty, you will see the investment flow in, but you need that framework, and gas is a part of that.

COOREY: Well, following on from that, principally, would you be opposed, to ensure the transition to a new gas field or an expanded gas field if that was what was required over the next few decades?

PRIME MINISTER: I firmly believe that those decisions should be based upon the return on capital that private sector make. The Government's role is to set a framework but also to obviously have proper environmental assessment based upon the merits of projects. Governments have a role to do that, but we will need, in coming years, we will need additional supply. And for all of the rhetoric of my predecessors, nothing happened in that decade. Nothing. There wasn't a project.

COOREY: Ok, thanks PM. As my editor Michael Stutchbury mentioned in the opening speech, you were here last year. There was a wariness in the business community about a Labor government among some sections. You've spoken about your willingness to work with business. You mentioned the spirit of Hawke-Keating, and that was sort of the broader theme of your speech today. And you harked back to the Jobs and Skills Summit. One of the big, I guess, developments from that was the industrial relations changes. A lot of business leaders at that summit, some of them felt like that was already locked in before the summit, felt a little bit ambushed. You've got another big IR agenda coming up for the second half of this year, we're looking at labour hire, the gig economy, wage theft, things like that. There's a lot of nervousness, I know in the mining sector, in the airlines, in retail about labour hire, how do you envisage nuancing that through with business and getting the balance right?

https://www.pm.gov.au/media/afr-business-summit

SPEECH
07 Mar 2023
Sydney
Prime Minister
Check against delivery

I begin by acknowledging the traditional owners of the land on which we meet and I pay my respects to elders past, present and emerging.
I am proud to lead a government committed to the Uluru Statement from the Heart, in full.
Later today, I'll be on my way to India.
I'll be joined on that trip by 25 CEOs and business leaders – in transport, resources, finance, higher education, architecture and energy – one of the biggest and most significant Australian business delegations to ever visit any of our trading partners.
Australia and India are Indo-Pacific partners through the Quad – and I'm looking forward to hosting the Quad Leaders Summit in the middle of the year.
Our two nations share a rich history - bound by our democratic values and enlivened by genuine friendship and fierce sporting rivalry.
By any measure, Australia is a better place because of our large, diverse and aspirational Indian-Australian community.
Yet for all of this, in 2021-22, India was only Australia's sixth largest goods and services trading partner.
We can elevate that - and not just by volume.
Our government is seeking to deepen and diversify Australia's trade links.
Greater diversity in who we trade with - and greater variety in what we trade.
Meaning our economy is more resilient and more secure.
1 in 4 Australian jobs are related to international trade.
I am determined to create more jobs in export industries and broaden our export base…
…so that more Australian businesses – big and small – can find markets for their products and services overseas.
If you look at India, they have set ambitious goals for 50 per cent renewable energy by 2030 - and 30 per cent Electric Vehicles by the same year.
Australia can help realise those goals - and not just as a supplier of critical minerals.
But as a provider of technology and services, mining equipment, software and systems expertise, training and skills.
And value-added products, made in Australia: batteries and storage and charging technology, the next generation of solar panels, electrolysers and zero carbon fertilisers through green ammonia.
And in resources too – green steel and green aluminium and green iron.
The point that is always worth making here is that this is not a zero-sum game.
We can do all these things as well as remaining a trusted and reliable supplier of energy to key trading partners such as Japan and the Republic of Korea…
…as well as supporting their transition to cleaner sources such as green hydrogen.
Australia has the natural advantages to make this happen.
We can be a global provider of choice in the resources, research and expertise that will drive the world to net zero.
But – as every business person in this audience understands – natural advantages are no guarantee of success.
Securing the next generation of Australian prosperity depends on making the right investments in our workforce, our infrastructure, our productivity and innovation.
Because the world isn't waiting for us.
And doing things the way we've always done them before, just because that's the way they've always been done, doesn't ensure stability – it only guarantees decline.
In the last few years, global shocks have presented us with a series of national wake-up calls.
We've seen we are vulnerable, when we are the last link in a global supply chain.
We've seen our national energy grid is out of date and our energy market more exposed than it should be, to movements in international prices.

We've seen that our cyber security systems – in government and in corporate Australia – are not at the level they need to be.
And we've seen the flaws and weaknesses in our national skills base, the over-reliance on temporary migration exposed by closed borders.
All of this has come at a cost.
It's driven up inflation, hurting family budgets and business costs.
And it's shown us the extraordinary pressures on our public hospitals and aged care sector.

The worst thing Australia could do, the most expensive mistake our nation could make would be to ignore these warnings.
To dismiss what's happened as a once-in-a-century event and assume that things will gently return to normal.
We have before us a window of opportunity, a chance for genuine renewal and reform:

- To deliver greater economic security, by investing in our sovereignty, our capacity to stand on our two feet
- To build lasting energy security, by upgrading our energy grid, reducing our emissions and reducing our energy costs
- And to create stronger job security for people, by investing in the skills and training and innovation that drive productivity.

But we have to move fast – because other countries have seen the same signs.
Economies around the world are embarked on a new wave of investment in their own advanced manufacturing capacity.
And they're seeking new productivity gains through investment in research and development and skills and science and technology.
Governments – and businesses – here in Australia, have to do the same.
That's the idea at the heart of our National Reconstruction Fund.
Based on the proven success of the Clean Energy Finance Corporation, this is a model for enhancing private sector capital investment and delivering a return on taxpayer dollars.
Boosting our nation's capacity to make things here again – and enabling businesses to add more value here.
We are determined to legislate our Safeguard Mechanism: to provide business and industry with a clear, stable and long-term framework for reducing emissions.
Everyone recognises that the global transition to net zero will take time.
Equally, we understand there is no time to waste.
The work of transition will require massive investment in building new physical assets and modifying existing ones.
This is where gas in particular has a key role to play, as a flexible source of energy – providing peaking power today and continuing to provide firming power.
Helping to smooth the transition to renewables, while guaranteeing energy security both for Australia and for our partners in the region.
And when businesses have to make capital decisions over five and ten and twenty year timeframes, it is so important they can look to government for the confidence and certainty of a stable foundation and a long-term vision.
Not the sort of chopping and changing that saw the Liberals and Nationals announce 22 different energy policies without delivering a single one.
Including, I might add, the very Safeguard Mechanism that they are now seeking to oppose.
We're acting to upgrade Australia's energy security – and we're also acting on cyber security.
Cyber security is as essential and as important for business as a lock on the door.
It's vital to protecting your intellectual property, your clients' privacy and your customers' confidence.
Threats like cybercriminal activity are fast-moving and rapidly-evolving – but for too long the capacity of government and business has been off the pace.
We are determined to change that.
That's why, last week, we brought together business and civil society and intelligence agencies and the public service to inform a comprehensive and co-ordinated Cyber Security Strategy.
And with this same focus on greater long-term security, we are reforming our migration program, returning the emphasis to permanent residency and citizenship.
We are making Infrastructure Australia a serious, rigorous body again.
Moving away from the partisanship and short-termism, so we can get Commonwealth investment flowing into a pipeline of productivity-enhancing projects that create jobs and train apprentices.
And – last month – we tasked the Productivity Commission to map out the path to universal, affordable child care.
Universal, affordable child care is an investment in early education, in the next generation, that the world is making.
Importantly, it's an economic reform which will boost workforce participation, productivity and population – the three Ps of economic growth - while taking pressure off family budgets.
I've said before that business has been ahead of government in so many areas over the last decade.
More engaged, in more parts of our region.
More alive to the global challenge of climate change – and the global opportunity of renewables and clean energy technology.
And I have no doubt, there are leaders in this room who have driven company-wide, even sector-wide initiatives that our government can take lessons from.

My colleagues and I didn't come to office with a sense of entitlement, we don't imagine we hold a monopoly on good ideas.
We want to work with business, to get things done, for the good of the nation.
Last year's Jobs and Skills Summit - which many of you made a valuable contribution to – stands as proof of that.
Those two days of discussions produced agreement on 36 immediate outcomes, which we acted quickly to deliver:

- Increasing the Permanent Migration Intake to 195,000
- Additional investment in visa processing, to tackle the extraordinary backlog we inherited.
- The creation of Jobs and Skills Australia, to identify and anticipate workforce demand – now and into the future.
- Industrial relations reform, to encourage employers and employees being able to sit down and negotiate improvements in productivity and pay.
- Expanding Paid Parental Leave – and making it more flexible.
- And a national skills agreement, signed by every state and territory to create 180,000 fee-free TAFE places this year.

There are Australians enrolled in new courses, training for good jobs in areas of national priority, right now, as a result of that agreement.
And work is well underway in other areas: including creating new digital apprenticeships in the public service and improving workforce participation opportunities for people with disability.
Not all of these ideas came from within government.
Not all of these were policies we took to the election.
Neither was the Energy Price Relief plan we agreed with every state and territory and government, to shield Australian business and Australian households from the worst of global price spikes.
But what these things have in common is they recognise and meet an urgent national need – and they set us up for a more secure future, over the long term.
Through a wasted decade, the previous government ignored every wake-up call and warning.
And they shot down every alternative, because it suited their pathology of political conflict.
We are determined to leave that pattern of neglect and crisis and hurried announcement behind.
We've put a priority on orderly process, on debate informed by evidence and experts.
Because we understand that to deliver reform, people need to know where you are coming from – as well as where you want to go.
So when my colleagues come to you, as business leaders, seeking your input, be assured it is not for the sake of it, or the look of it. It's not to pad out a report to put on the shelf.
We want you involved and engaged in the work of change and reform.
Of course, that doesn't mean I expect us to agree on every element of every initiative - no reform worth doing is wholly uncontested.
But I think we all come to this conversation with the understanding that turning away from this window of opportunity…
…hitting snooze on this wake-up call, settling for a slow decline as the world forges ahead, is simply not good enough.
Our government has every confidence Australia can rise to this moment.
And we are determined to continue working with business and unions, with civil society, policy experts - and a reinvigorated public service, to seize the opportunities ahead of our nation.
Deepening and diversifying our international investment and trade links.
Taking our place as a clean energy superpower.
Revitalising advanced manufacturing in our regions.
Training Australians to lead in cyber capability and technology.
And building an economy that embraces innovation and flexibility and equality for women to draw on the talent of our whole population.
In all of this, business has a vital role to play - and I look forward to engaging with you in the years ahead.

https://www.ft.com/content/8385f5d8-b045-46a7-a822-47a9ba09e219

Macron warns of threat to global economy from energy crisis

French president urges world leaders to act on climate change with more financial pledges ahead of COP26 summit

Leila Abboud in Paris and Leslie Hook in London YESTERDAY

President Emmanuel Macron has warned that an energy crisis threatens the world's post-pandemic recovery, calling for leaders at a G20 summit in Rome this weekend to work together to stabilise supplies.

In an interview, the French president also urged bigger financial commitments towards the fight against global warming on the eve of the COP26 climate summit in Scotland, and for particular attention to be paid to a deal to phase out coal power.

The G20 needed to co-ordinate between energy producers and consuming countries to prevent a supply breakdown this winter, which risked "extreme tensions both economically and socially", Macron said.

"In the coming weeks and months, we need to get better visibility and stability on prices so tension on the energy prices doesn't generate uncertainties, and undermine the global economic recovery, " he told the Financial Times in the Elysée Palace. "What we expect is to have co-ordination to avoid soaring prices."

Global energy costs have surged this year, disrupting industry and hitting consumers with higher prices. Eurozone inflation surged in October to a 13-year-high of 4.1 per cent, according to a flash estimate published by the EU's statistics arm on Friday.

"I don't think we're going to be able to lower prices given tensions on the demand side," Macron said. "But what we need to avoid is to have a break in supply [and further] increases in prices, particularly as we're moving into the winter period for the northern hemisphere."

Emmanuel Macron: 'I don't think we're going to be able to lower [gas] prices given tensions on the demand side' © Magali Delporte/FT

Rapid economic recovery from the pandemic has pushed up energy prices "almost too rapidly" which risked "weighing on economic growth and putting a burden on households", Macron said.

France and a number of other EU governments have sought to protect consumers and businesses with billions in aid and price freezes.

Concerns have mounted that Russia's state-backed gas producer Gazprom has kept storage levels unusually low in western Europe, exacerbating fears over supplies and driving up prices.

Asked whether he blamed high European energy prices on Russia, Macron said: "I have no evidence that there's been manipulation of prices and I'm not accusing anybody. These are trading relations. They shouldn't be used for geopolitical reasons."

Asked about Gazprom's power over Europe, Macron said: "It's not a matter of whether we're too dependent on a company or not, it's how do we create alternatives. And the only alternatives are to have European renewables and of course, European nuclear."

France is the EU's biggest user of nuclear power, contrasting with a move away from atomic power by Germany and some other countries.

Macron called for Europe to develop a more diverse gas supply but also to speed up a transition away from fossil fuels, which will be necessary to slow rising temperatures and tame the climate disruptions caused by global warming.

“What is happening now is ironic, because we are building a system where in the medium and long term fossil energy will cost more and more, that’s what we want [to fight climate change],” he said. “The problem is that industries and households will need to be accompanied in this transition . . . or it won’t be sustainable.”

The French president, who is facing national elections in April, has been a vocal advocate of multilateralism. He has pushed for more co-operation globally and at EU level to reach deals on issues including international taxation and global warming.

“The first subject for the G20 is to accelerate the exit from coal power” Emmanuel Macron

Against a backdrop of global tensions, a supply chain crisis and the Covid-19 pandemic, Macron said the G20 had a responsibility to work together, especially to help low-income countries. He urged leaders at the Rome summit to agree a plan for faster vaccine delivery to developing countries.

“France has always stressed the importance of maintaining multilateralism, but we have to get concrete results from it,” he said.

The leaders of China, Russia and Japan will not attend the summit in Rome in person this weekend because of Covid-19 concerns and an election in Japan.

Macron said the G20 meeting, which is being hosted by Italian leader Mario Draghi on the eve of COP26, would also give countries a chance to hammer out more ambitious plans to fight climate change.

“When we’ll be meeting in Rome, the major challenge is to ensure that members of G20 can usefully contribute in Glasgow, to making this COP26 a success,” he said. “Nothing can be taken for granted before a COP,” he added.

“The first subject for the G20 is to accelerate the exit from coal power,” he said. G20 leaders expect a heated debate this weekend over including a pledge to end international coal financing.

“We need the G20 to go right through to the eradication of all international financing of coal-fired power plants,” Macron said.

Macron also called for rich countries, particularly the US, to commit more financially to help developing countries meet their climate goals. And he called on China to bring forward the date at which it will peak emissions, from 2030, to 2025.

“So as not to lose more time, we have to do as much as is absolutely possible in terms of financing, and encourage the US administration so that they can convince Congress to front-load its financing.”

Another issue will be to hold countries to their emissions targets for 2030 and 2050. “Our objective is to get maximum results from all countries,” he said. “This pathway is possible, even if it’s a challenge, especially for emerging countries which at the same time are trying to recover from the Covid crisis.”

Macron also urged the G20 leaders to do more to help vaccinate the world against Covid-19. The group should end vaccine export bans, increase its donations of vaccine doses, and support vaccine production in Africa, he said.

“Every French person has given one vaccine to somebody else in the world,” he said, referring to the roughly 60m doses that were on the way to Covax, the World Health Organisation’s procurement scheme for low-income countries. “If everybody in the G20 could do that we would get to the 20 per cent of the population vaccinated. This is vital,” he said.

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https://www.energy.gov/articles/secretary-granholm-ceraweek-luncheon-keynote-address

Secretary Granholm CERAWeek Luncheon & Keynote Address

MARCH 8, 2023

Energy.gov Secretary Granholm CERAWeek Luncheon & Keynote Address

Remarks as Prepared for Delivery by U.S. Secretary of Energy Jennifer M. Granholm at 2023 CERAWeek Luncheon & Keynote Address

March 8, 2023, Houston, Texas

Thank you so much, Dan, for the introduction—so gracious, as always.

And hello, everyone. What a pleasure to be back in Houston for CERAWeek. And my, what a different world I see from this stage today, compared to a year ago.

A year ago, we stood at the very outset of Vladimir Putin's horrific, barbaric invasion of Ukraine. No one could question the ferocious bravery of the Ukrainian people. But plenty doubted their chances.

Yet today, we know that their guts and heart and resolve forced Russia into retreat and proved those doubters wrong.

A year ago, fears abounded that Putin's weaponization of energy would plunge the global economy into a recession and leave European citizens suffering in the dark of winter.

Today … today the world is moving quickly to shift away from Russian energy sources, and Europe is poised to reach the spring without major outages or shortages.

That's thanks in no small part to the many in this room working with the US and allies. Indeed, the US has become an indispensable partner to our allies, and a global energy powerhouse.

A year ago, it was an open question what this conflict would do to energy markets. Whether the resulting supply disruptions would push countries away from clean energy ambition.

And today, the answer is indisputable.

Thanks again to many in this room, global investments in clean energy matched those in fossil fuel production for the very first time in 2022. New clean energy installations reached a new record, as the EU added more wind and solar capacity than any year prior.

In spite of—and partially because of—the geopolitics of the day, the clean energy transition is firmly underway.

So. What lies ahead?

Make no mistake. Enormous challenges remain across global energy markets.

We have not yet vanquished the volatility that characterized so much of the last 12 months.

The risks to energy security, and the vulnerabilities they leave for our national and economic security—those have not disappeared.

The costs of climate change keep piling up.

And the imperative every country faces to meet the energy needs of its citizens will heighten as demand rises in the years ahead.

It will take partnership between governments and private sectors to meet those challenges. A willingness to work together, even amid differing views.

And here's where we need to start: by acknowledging the clean energy transition is happening, and that we are growing the energy pie.

Which offers a powerful solution to those challenges of volatility, security, and demand:

Energy diversity.

We can make our country more energy independent. We can make our allies more energy secure. We can make our world and our future safer in the face of climate change, all by growing the pie, for all to share.

Now, look. We know that oil and gas will remain part of our energy mix for years to come.

And we know that even the boldest projections for clean energy deployment suggest that, in the middle of this century, we'll be using abated fossil fuels.

We need to advance the technologies for abating fossil emissions, and we need to advance the technologies for clean sources.

We need both traditional and new energy.

As this transition progresses, our energy mix will change.

And that means we all have to play a part to make sure this is a managed transition.

One that keeps us ready and able to meet consumer energy demand today, while expanding into more and more diverse sources for tomorrow.

And one where we're able to send energy from where it's generated to where it needs to go.

It should not take over a decade to get permitting for a transmission project on federal lands. John Podesta was on this stage just two days ago noting that the President has directed DOE, with the federal permitting agencies, to use our full authorities within the Federal Power Act to significantly speed those permitting timelines.

This is not about closing doors. It's about opening new windows of opportunity.

Let me tell you: President Biden has spent the last two years making sure those windows are wide open. And under his watch, the United States will be the global leader of this transition.

When I visited CERAWeek last year, I spoke of the $62 billion that the Department of Energy is overseeing, as part of the Bipartisan Infrastructure Law, for grid upgrades, supply chains, demonstration projects for high-potential technologies, and more.

And since then, we've added to that pot with the Inflation Reduction Act.

Between all the President's signature legislative achievements, the U.S. government has made hundreds of billions of dollars available to the private sector for American clean energy development.

There's that direct, competitive funding from the Infrastructure Law—a lot of that to clean up fossil emissions.

There's 10 years of investment and production tax credits, offering unparalleled levels of certainty for a wide range of clean energy sources—including geothermal, clean hydrogen, sustainable aviation fuels, and offshore wind.

There's loans and loan guarantees to support large-scale, made-in-America deployment projects.

Put it all together, and you'll see that the Biden-Harris administration has made the United States the world's most attractive investment landscape for new energy and decarbonization technologies.

In many cases, it makes the U.S. irresistible.

Granted, we know there are issues with permitting, workforce, and supply chains ahead. Believe me, the administration is concerned that these challenges are holding much-needed development back.

We have welcomed and continue to encourage your input on how to detangle these issues using what tools we have.

Because we want American workers making these technologies here.

We want them supplying American families and businesses with affordable, reliable, resilient power.

We want people using these technologies stamped Made in America all over the world.

And we make no apologies for this.

The level of investment we're tapping into will unlock technological leaps forward, leading to lower costs and faster deployment.

I don't just mean lower costs in the United States. I mean worldwide—from Europe to Australia, Asia to Africa, and all across the Americas.

Just as we saw with solar and wind and EVs in the last decade, innovation anywhere leads to progress everywhere.

We want to recapture that innovation effect, and punch through obstacles to adoption of the next generation of clean energy and decarbonization technologies.

That's why, today, two announcements.

First, DOE is soft launching our Pathways to Commercial Liftoff.

Over the last two years, we've engaged businesses in conversations on what it will take for key technologies to reach commercial liftoff.

Some of your companies contributed to those conversations.

We've synthesized those views alongside market analysis to lay out the technological, commercial, and regulatory barriers holding back large-scale deployment of four technologies:

Clean hydrogen, advanced nuclear, carbon management, and long duration storage.

And as these reports make clear—there is a path to liftoff for these essential technologies, leading to a generational economic opportunity.

We will start releasing them next week, at liftoff.energy.gov.

We are eager to hear your feedback—on what we got right, what we got wrong, what we're missing, and what's changing over time—so we can keep on guiding these technologies along a steady path to market competitiveness.

Of course, beyond studies and analysis, we at DOE are also working each and every day to get money from the President's agenda out the door.

And to that end, today, I'm thrilled to make this second announcement:

We are releasing a $6 billion funding opportunity for industrial decarbonization projects.

The Department has been investing in methods to minimize carbon pollution from heavy industry for years. The amount of funding we're pouring in now is unprecedented.

This is an opportunity to accelerate transformational projects for the industrial sector. Taking concepts that might have required decades—plural—to prove out and scale, and shrinking that timeline down to this decade.

It's an opportunity to make important progress on our climate goals, slashing pollution from a sector that contributes roughly a third of the country's carbon emissions.

And it's an opportunity to give the United States a competitive edge. An edge in developing technologies that every country's industrial sector will look to adopt in the years ahead. And in producing the world's least carbon-intensive iron and steel, aluminum, cement, concrete, glass, pulp and paper, industrial ceramics, and chemicals.

That's really what this is all about. Our competitive edge. Our innovative advantage. Our ability to build and lead new markets.

The US is the indispensable nation. Our companies producing irresistible products.

And this administration has gone all in.

We have passed the policies. Secured the resources.

We are working around the clock to implement.

But government is only part of the equation here.

To make this all work, we need the private sector stepping up—we often say these investments are private sector led, government enabled.

So perhaps most of all, we need the energy sector stepping up. And that certainly includes the oil and gas industry.

You have the skillsets and knowledge to build some critical technologies at scale.

Your expertise in offshore drilling gives you a leg up on offshore wind.

Your breakthroughs in fracking give you a massive advantage in geothermal.

Your practices around natural gas transport and infrastructure development could lend themselves to clean hydrogen.

And, of course, few are better positioned to crack open cost-effective carbon management.

We know some of you are already moving in these directions—we've heard your plans on your earnings calls.

And we know that others are still hesitant, citing uncertainty.

You now have 10 years of IRA carrots you can take to the bank.

That's certainty.

There has never been a better time to invest in the future—to invest in that great, necessary solution of energy diversity and security than right now.

What an amazing time to be in the energy sector.

We are in the middle of history. There is a geopolitical realignment around energy. The tectonic plates are moving.

The world looks very different today than it did one year ago. So imagine what it will look like one year from now. Imagine what it will look like one decade from now.

Leaders in traditional energy will be leaders in new energy. Businesses in fossil energy will have enlarged their territory into clean energy.

Someone is going to write this chapter of history.

Well, ok, Dan Yergin will be chronicling it.

But who will he be writing about? What courageous visionaries in this room will be shaping this chapter?

I tell you what—he won't be writing about the ones who covered their eyes and ears and hunkered down in a defensive crouch.

He'll be writing about the ones who saw this moment and chose to boldly lead in this diverse energy future.

So I expect he'll be writing about some of y'all.

Let's not let this moment pass us by.

Thank you.

https://www.whitehouse.gov/briefing-room/statements-releases/2023/03/09/fact-sheet-the-presidents-budget-cuts-the-deficit-by-nearly-3-trillion-over-10-years/

MARCH 09, 2023

FACT SHEET: The President's Budget Cuts the Deficit by Nearly $3 Trillion Over 10 Years

President Biden believes that investing in America, growing the economy from the bottom up and middle out, lowering costs for families, and reforming our tax code to reward work and not wealth are economic and fiscal imperatives. Strong and shared growth that benefits all Americans isn't just good for the economy; it will also lead to better fiscal outcomes. At the same time, President Biden believes that long-term investments in our Nation and its people should be paid for. And his Budgets have consistently paid for all of his investments and improved the Nation's fiscal outlook.

The President took office after his predecessor signed into law a reckless and unpaid for tax cut that was skewed to the wealthy and large corporations, adding nearly $2 trillion to the deficit. He also inherited a poorly managed pandemic response. The President has taken a different, responsible approach. He enacted a bold agenda to rescue the economy and get the American people vaccinated. Because of the strength of the recovery and responsible winding down of emergency programs, the deficit fell by $1.7 trillion in the first two years of the Biden-Harris Administration compared to the year before the President took office. And the Inflation Reduction Act that the President signed into law last year will reduce the deficit by more than $200 billion over the next decade, relative to deficit projections without that law.

Building on that record of fiscal responsibility, the President's Budget improves the fiscal outlook by reducing the deficit by nearly $3 trillion over the next decade. The Budget achieves this deficit reduction while lowering costs for families, investing in our economy and our future, and protecting the most vulnerable Americans because it proposes tax reforms to ensure the wealthy and large corporations pay their fair share and tackles wasteful special interest giveaways.

Improving the Nation's Fiscal Outlook

The President's Budget improves the Nation's fiscal outlook and reduces long-term fiscal risks by reducing the deficit, stabilizing deficits as a share of the economy, and keeping the economic burden of debt within historical norms. Specifically, the Budget reduces the deficit by nearly $3 trillion over the next decade, compared to deficits without the President’s policies. The deficit reduction in the Budget increases over time, with $500 billion of deficit reduction in 2033.

The Budget also reduces the deficit, as a share of the economy, from current levels. Under the Budget policies, the deficit would decline over the next several years, stabilizing at around five percent of the economy throughout the remainder of the 10-year window. This compares to deficits increasing to around 6 percent without the President’s policies.

Finally, under the President’s Budget, the economic burden of debt would remain in line with historical norms over the next decade. Real net interest as a share of the economy directly measures the cost of servicing the debt: resources that must go towards paying off old debt rather than investing in the future or providing services to Americans now. The Budget forecast takes into account recent increases in interest rates and projected future increases in line with private-sector forecasters. Nonetheless, the Budget keeps real net interest payments as a share of the economy at or below the average for the last several decades, around 1 percent of GDP, and well below the 2 percent level of the 1990s.

Reducing the Deficit by Making the Tax System Fairer and Ending Special Interest Giveaways

The President believes that the best way to reduce the deficit is to reform our tax code to reward work and not wealth, ensure that the largest corporations pay their fair share, and end giveaways to special interests. For example, the Inflation Reduction Act he signed into law cracked down on wealthy tax cheats and took critical steps forward in ensuring that large corporations pay their fair share, including a 15% corporate minimum tax and a surcharge on large, publicly-traded corporations that buy back their own stock. The Inflation Reduction Act will save taxpayers more than $150 billion through reforms that cut what Medicare pays to Big Pharma.

The Budget builds on this progress and reflects the President’s ironclad belief that we need to reward work, not wealth—and ensure the wealthiest Americans and biggest corporations don’t pay lower tax rates than teachers or firefighters.

To date, Republicans in Congress have put forward a much different approach, calling for more than $3 trillion in tax giveaways to the rich and large corporations and handouts to special interests. While they haven’t said how they would pay for those giveaways and also reduce the deficit, their past proposals have cut Social Security and Medicare, repealed the Affordable Care Act, slashed Medicaid, and made deep cuts to other programs that drive economic growth and that seniors, people with disabilities, and families count on.

Instead of making reckless cuts to programs that millions of Americans count on, the President's Budget takes the following steps to reduce the deficit.

Making the Wealthy Pay Their Fair Share

- Proposing a Minimum Tax on Billionaires. The tax code currently offers special treatment for the types of income that wealthy people enjoy. Whereas the wages and salaries that everyday Americans earn are taxed as ordinary income, billionaires make their money in ways that are taxed at lower rates, and sometimes not taxed at all. This special treatment, combined with sophisticated tax planning and giant loopholes, allows many of the wealthiest Americans to pay an average tax rate of just 8 percent on their full incomes, less than many middle-class households pay. To finally address this glaring problem, the Budget includes a 25 percent minimum tax on the wealthiest 0.01 percent.
- Raising Taxes on the Wealthiest Americans to Improve Medicare Hospital Insurance (HI) Trust Fund Solvency by At Least 25 Years. The Budget includes key reforms to the tax code to ensure high-income individuals pay their fair share into the Medicare HI trust fund. Specifically, it closes the loophole that allows some wealthy investors with passthrough businesses to avoid paying the tax on their investments that everyone else pays, and it directs that tax into the HI trust fund as was originally intended. It also raises the tax rate that households earning more than $400,000 per year pay into the Medicare trust fund – by just 1.2 percentage points. These reforms will extend the life of the trust fund without cutting any benefits, or raising costs for beneficiaries.
- Repealing the Trump Tax Cuts for the Wealthy and Reforms Capital Gains Tax to Ensure the Wealthy Pay Their Fair Share. The 2017 tax law lowered tax rates for the wealthiest Americans, delivering an average tax cut of more than $50,000 for the top 1% and more than $190,000 for the top 0.1%. The Budget repeals those cuts, restoring the top tax rate of 39.6 percent for those making more than $400,000 a year. It also proposes taxing capital gains at the same rate as wage income for those with more than $1 million in income, closing the capital gains loophole that allows the wealthy to avoid ever paying tax on their appreciated investments, and finally closing the carried interest loophole that allows some wealthy investment fund managers to pay tax at lower rates than their secretaries.

Making Large Corporations Pay Their Fair Share

- Reversing the Trump Tax Giveaway to Large Corporations. The Budget includes an increase to the rate that corporations pay in taxes on their profits. Corporations received an enormous tax break in 2017, cutting effective tax rates for corporations to an average of 7.8 percent in 2018, compared to 16 percent in 2016. While their profits have soared, their investment in the economy did not. Their shareholders and top executives reaped the benefits, without the promised trickle down to workers, consumers, or communities. The Budget would set the corporate tax rate at 28 percent, still well below the 35 percent rate that prevailed prior to the 2017 tax law. This tax rate change is complemented by other proposals to incentivize job creation and investment in the United States and ensure large corporations pay their fair share.
- Stopping the Race to the Bottom in International Corporate Tax and Ending Tax Breaks for Offshoring. For decades, countries have competed for multinational business by slashing tax rates, at the expense of having adequate revenues to finance core services. Thanks in part to the Administration's leadership, more than 130 nations signed on to a global tax framework to finally address this race to the bottom. Building on that framework, the Budget proposes to reform the international tax system to reduce the incentives to book profits in low-tax jurisdictions, stop corporate inversions to tax havens, and raise the tax rate on U.S. multinationals' foreign earnings from 10.5% to 21%. These reforms will ensure that profitable multinational corporations pay their fair share.

Ending Wasteful Spending to Special Interests

- Expand Medicare's Ability to Negotiate Drug Prices. The IRA finally gave Medicare the power to negotiate with drug companies on the high prices they charge for prescription drugs, and the Budget builds on that progress. The Budget cuts Federal spending by $160 billion: increasing the number of drugs Medicare can select for negotiation and bringing more drugs into the negotiation process sooner. (All estimates are for savings over 10 years.) These reforms will not only cut costs for the Federal government; they will also save billions of dollars for seniors.
- Expand the IRA's Requirement that Drug Companies Pay Rebates When They Increase Prices Faster than Inflation. Thanks to the IRA, drug manufacturers must now pay rebates to Medicare if their price increases for certain drugs exceed inflation. The Budget builds on the IRA by requiring rebates for commercial drug sales, as well as sales to Medicare. That will save the Federal Government $40 billion, further curb prescription drug price inflation, and reduce health insurance premiums for people with private health insurance coverage.
- Eliminating Tax Subsidies for Oil and Gas. The President is committed to ending tens of billions of dollars of Federal subsidies for oil and gas companies, leveling the playing field for clean energy. Oil

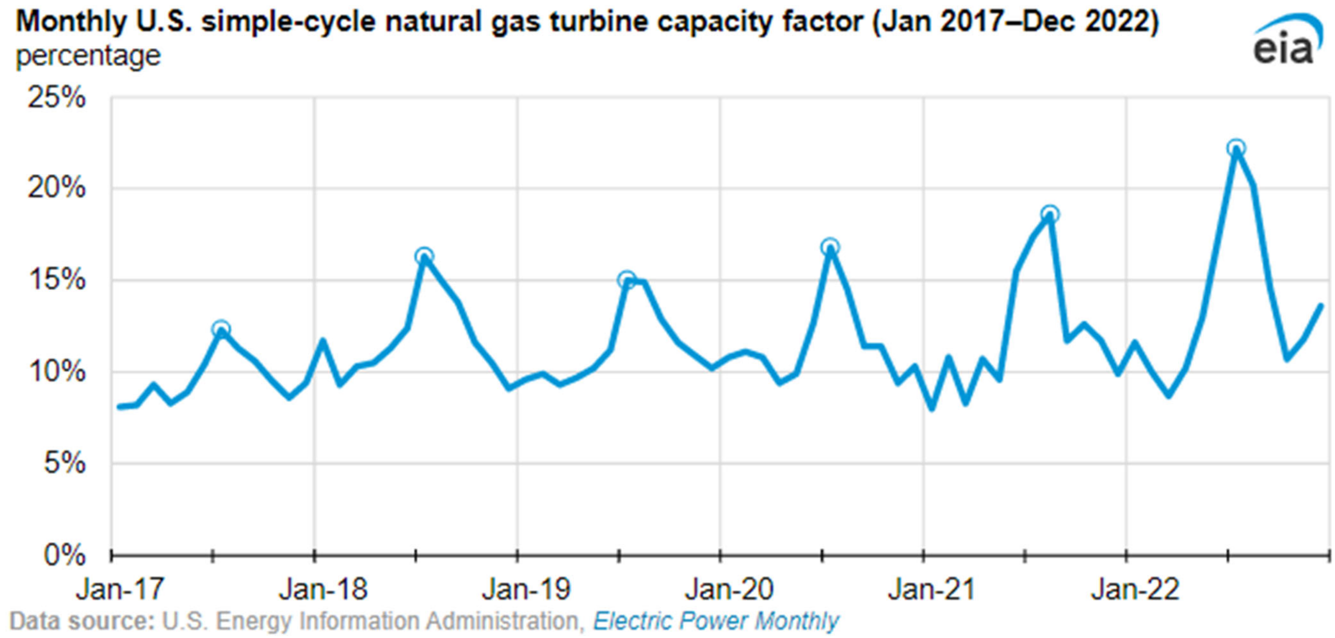
companies had record profits in 2022 and undertook record stock buybacks that benefited executives and wealthy shareholders, all while continuing to benefit from tax subsidies worth billions of dollars. The Budget eliminates special treatment for oil and gas company investments, as well as other tax preferences.

- Lower Medicaid Spending by Addressing Excessive Payments to Medicaid Managed Care Organizations. The Budget will lower Medicaid costs by over $20 billion by requiring that insurance companies that are charging Medicaid far more than they actually spend on patient care pay back some of the excess. Currently, only about half of states require private insurance companies that provide Medicaid coverage to pay money back when they realize outsize profits. Without this requirement, insurance companies are keeping millions of dollars each year in excessive payments. The Budget would apply this requirement nationwide, consistent with similar requirements in Medicare Advantage and Affordable Care Act plans. With it, insurance companies will no longer be able to charge for unnecessary administrative expenses or sacrifice quality care to increase their profit margins, and if they charge too much, they will have to pay it back to the Medicaid program rather than keeping the profits and, in some cases, making larger payments to shareholders.
- Eliminate Tax Subsidies for Real Estate. The Budget saves $19 billion by closing the “like-kind exchange” loophole, a special tax subsidy for real estate. This loophole lets real estate investors put off paying tax on profits from real estate deals indefinitely as long as they keep investing in real estate. This amounts to an indefinite interest free loan from the government. Real estate is the only asset that gets this sweetheart deal.
- Eliminate Tax Subsidies for Cryptocurrency Transactions. The Budget saves $24 billion by eliminating a special tax subsidy for crypto currency and certain other transactions. Right now, crypto investors aren’t subject to the same rules of the road that investors in stocks or other securities have to follow, allowing them to report excessive losses. For example, a crypto investor – unlike an investor in stocks or bonds – can sell a cryptocurrency at a loss, take a substantial tax loss to reduce their tax burden, and then buy back that same cryptocurrency the very next day. The Budget eliminates this tax subsidy for crypto currencies by modernizing the tax code’s anti-abuse rules to apply to crypto assets just like they apply to stocks and other securities.

https://www.eia.gov/todayinenergy/detail.php?id=55680

MARCH 1, 2023

U.S. simple-cycle natural gas turbines operated at record highs in summer 2022



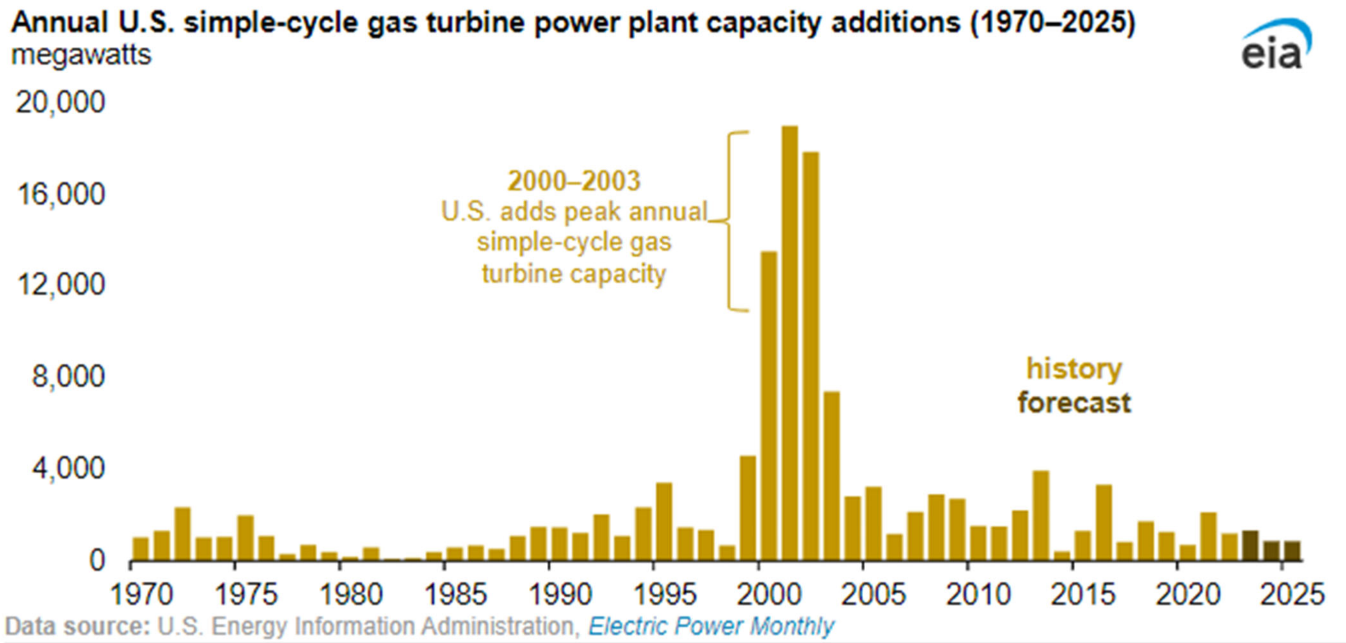
The average monthly capacity factor for simple-cycle, natural gas turbine (SCGT) power plants in the United States has grown annually since 2020. Average capacity factors surpassed 20% for two consecutive summer months in 2022—the first time on record—to meet peak electricity demand, based on data from our *Electric Power Monthly*.

SCGT power plants typically operate year-round but are most active during the summer when electricity demand reaches its peak and varies the most. For the past five summers, SCGT power plants operated at a 17% average capacity factor from June through August. The average monthly capacity factor during the rest of the year fell to around 10% as a result of less electricity demand and more consistent wind-powered electricity generation.

SCGT power plants burn natural gas in a single turbine to produce electricity. They are the second-largest source of U.S. natural gas-fired power generation, after combined-cycle natural gas turbine (CCGT) power plants. SCGT power plants are less efficient and require more fuel per unit of output compared with CCGT power plants because CCGT plants capture excess heat from the combustion process and deliver that heat to a steam turbine to produce additional electricity.

Electric grid operators can use SCGT power plants to respond quickly to fluctuating demand for electricity. The need for more electric grid support during the day is growing as the share of electricity generation from intermittent renewables grows. SCGT power plants can meet demand if there is a lull in wind or solar output. SCGT power plants can best provide grid support because they can produce electricity quickly to immediately fill gaps in electricity output on the grid, and they can ramp down just as quickly. Other natural gas-fired electricity generators, such as CCGT or steam boiler plants, can take two to three times longer than SCGT power plants to start and ramp up to full load.

An estimated 2,121 megawatts (MW) of new SCGT capacity entered service in 2021, and we expect another 1,196 MW entered service in 2022. Texas accounted for nearly half of the 2021 and 2022 capacity additions because of its need for more fast-starting generating capacity. Texas is experiencing both rising power demand and greater variability in supply.



Total U.S. SCGT operating capacity was 132,274 MW in December 2022, based on our latest *Electric Power Monthly*.

Principal contributor: Mark Morey

Tags: generation, electricity, natural gas, capacity factor, power plants

RystadEnergy

https://www.rystadenergy.com/news/ev-sales-collapse-as-subsidies-and-tax-credits-come-to-an-abrupt-halt

Press release

01. March 2023

EV sales collapse as subsidies and tax credits come to an abrupt halt

The global electric vehicle (EV) market is reeling from one of the most dramatic collapses in monthly sales to date, with Rystad Energy research showing that only 672,000 units were sold in January, almost half of December 2022 sales and a mere 3% year-on-year increase over January 2022. The EV market share among all passenger car sales also tumbled to 14% in January, well down on the 23% seen in December.

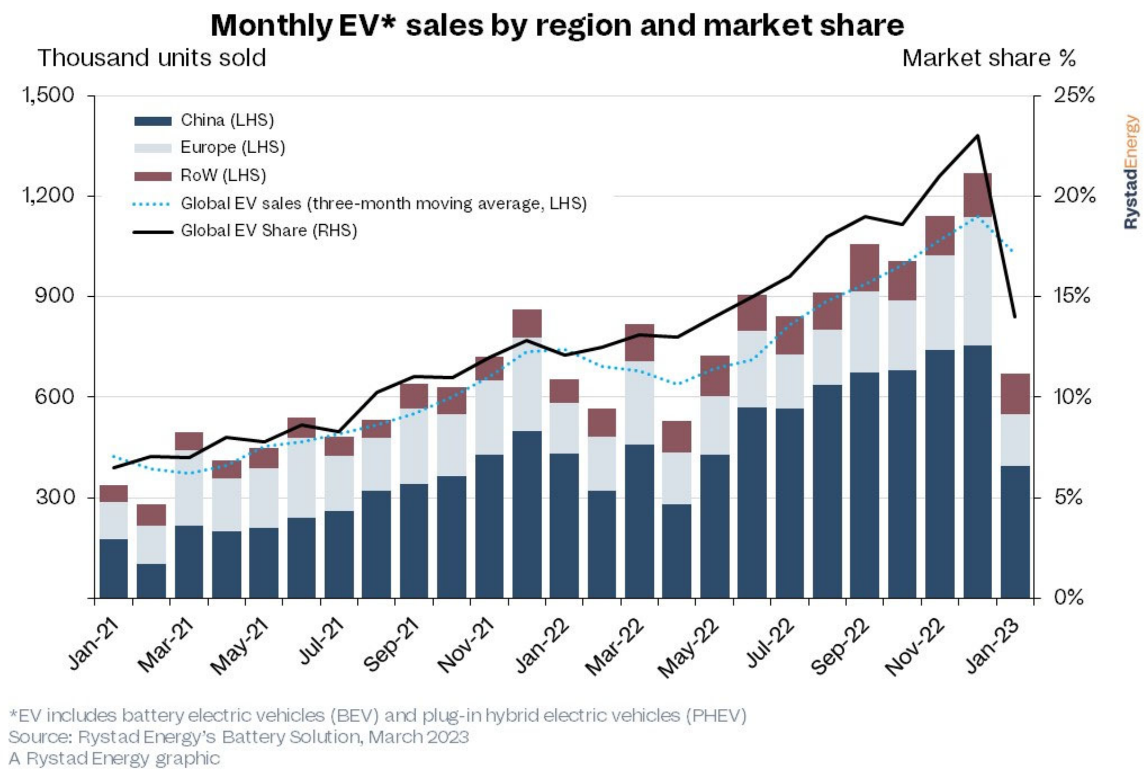
EV sales have been on a relatively consistent upward trajectory in recent years – aside from periods impacted by Covid-19 pandemic-related supply chain issues – and a significant collapse in sales is worrying news for the industry. Tax credits and government subsidies have propped up the EV market to date as countries identify passenger car fleet electrification as a core tactic for meeting net-zero emissions goals, but the reduction or removal of these subsidies this year has dampened consumer sentiment. Automakers are now scrambling to reverse the downward spiral and salvage the market in 2023.

The automotive market is usually cyclical, with sales taking a hit after new subsidy rules come into effect at the start of each year, followed by a gradual recovery. However, the cuts in January this year hit harder than normal, triggering this dramatic collapse. The ramifications of this will be long-lasting and will impact sales through the first quarter of the year and potentially the rest of 2023.

EV subsidies in many European countries and mainland China were sliced at the start of the year, and a return of any significance is highly unlikely in the immediate future. One ray of hope for the global outlook is the US market, which is just beginning its electrification journey and rolling out tax credits thanks to the Inflation Reduction Act. The US was the only major market that saw an increase in both EV sales and market share year-on-year, although its contribution to the global total is still relatively minimal.

The sands are shifting for the global EV market. Consumer appetite for electric cars remains strong, but it's clear that tax credits and subsidies still play a significant role in convincing consumers to make the switch. Carmakers may have no option but to respond with reduced prices.

Abhishek Murali, clean tech analyst, Rystad Energy



Learn more with Rystad Energy's low-carbon solutions.

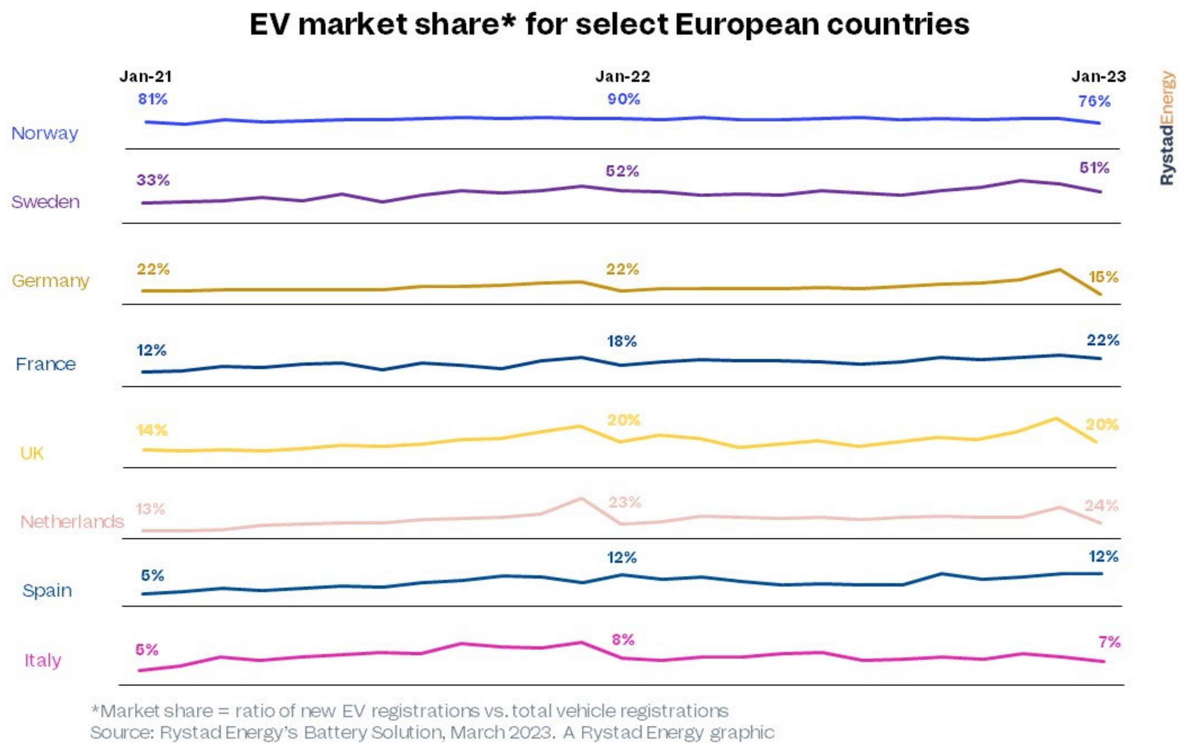
China, the largest EV market globally, experienced a near 50% cut in EV sales in January 2023 compared to the prior month, but the year-over-year change was relatively flat due to the affinity of consumers for cheaper domestic-made models. The Chinese Association of Automotive Manufacturers forecasts a slowing of sales momentum this year, predicting around 8 million EV sales this year. We expect slow sales to continue through the first quarter, but CATL's announcement of a price cut in battery cells for automotive offtakers will help boost sales again.

Although there was a marginal year-on-year growth in EV sales in Europe last month, market performance has been grim, with many countries showing a steep drop in EV sales from December 2022. With EV subsidies coming to an end, many consumers brought forward their purchases from the first quarter of 2023 to December 2022, leading to a massive spike in purchases before the end of the year. Widespread subsidy reductions will have a lasting impact on sales activity, but automakers will not tolerate this weakening for long – Tesla is already testing their pricing limits, offering a massive discount, triggering a large volume of pre-orders.

Germany have seen a steep falloff in sales and market share. Sales in Germany dropped about a third in January compared to 2022, totaling only 27,000 for the month. Market share in the country also fell off a cliff – after EVs accounted for 55% of all car sales in December 2022, the market share fell to just 15%. Elsewhere in Europe, the EV market share in the UK halved from about 40% to 20% month-to-month and from 50% to 24% in the Netherlands. This downward trend is replicated across much of Europe and will be giving automakers sleepless nights.

Norway experienced the worst monthly passenger car sales in over 60 years, with just 1,860 vehicles sold, including EVs. Electric cars accounted for 76.3% of those sales, totaling 1,419 units. That market share was also the lowest and dipped below 80% for the first time in two years. A slew of new taxes have contributed to this, and battery electric vehicles are now impacted by two new taxes that will negatively impact sales.

Across the Atlantic, the US anticipated falling EV sales and was one of the only markets to implement fresh incentives through federal tax credits. Around 80,000 EVs were sold in January – a 7.8% market share. However, there was no sales surge from these credits as automakers made the prudent decision to offer EV discounts in December to avoid an unmanageable influx of orders. US automakers are also grappling to make smart pricing decisions for their EV models. Tesla, for instance, is slowly increasing vehicle prices to gauge consumer price ceilings after previously offering sizeable discounts. The US market outlook for 2023 is strong, and the country is expected to break the 10% adoption mark this year.



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https://www.eia.gov/energyexplained/nuclear/where-our-uranium-comes-from.php

Nuclear explained

Where our uranium comes from

BASICS

The United States imports most of the uranium it uses as fuel

Uranium is the fuel most widely used by nuclear power plants for nuclear fission. Uranium is a common metal found in rocks all over the world. Uranium occurs in combination with small amounts of other elements. There are economically recoverable uranium deposits in the western United States, Australia, Canada, Central Asia, Africa, and South America.

Owners and operators of U.S. nuclear power reactors purchased the equivalent of about 46.74 million pounds of uranium in 2021.

Sources and percentage shares of total U.S. purchases of uranium in 2021 were:

35% **Kazakhstan**

15% **Canada**

14% **Australia**

14% **Russia**

7% **Namibia**

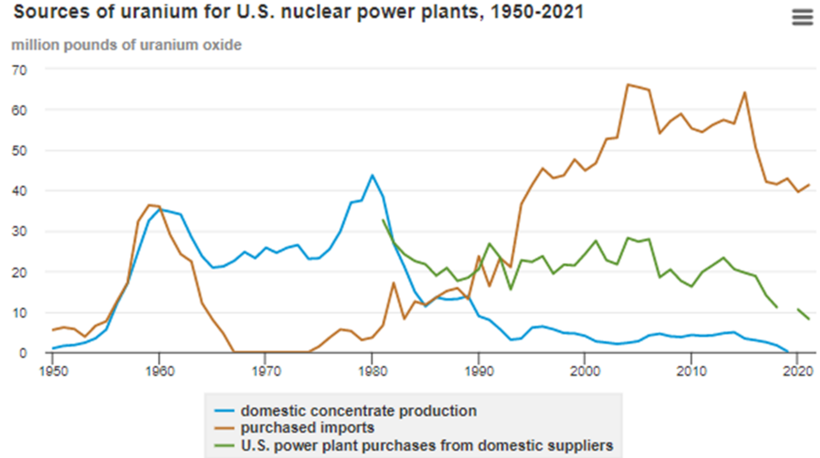
5% **United States**

10% **Five countries combined (W)**

Data source: *Uranium Marketing Annual Report*, Table 3, May 2022
Note: W = data withheld; sum of shares may not equal 100% because of independent rounding.

The chart below shows annual U.S. uranium production and the sources of uranium purchased by U.S. nuclear power plant operators from 1950 through 2021.

Sources of uranium for U.S. nuclear power plants, 1950-2021



Data source: U.S. Energy Information Administration, *Monthly Energy Review*, Table 8.2, June 2022
Note: Data withheld for U.S. power plant purchases from domestic suppliers in 2019 and for domestic production in 2020 to avoid disclosure of individual company data.

Click to enlarge

Last updated: July 7, 2022, with most recent data available at the time of update.

World Food Situation

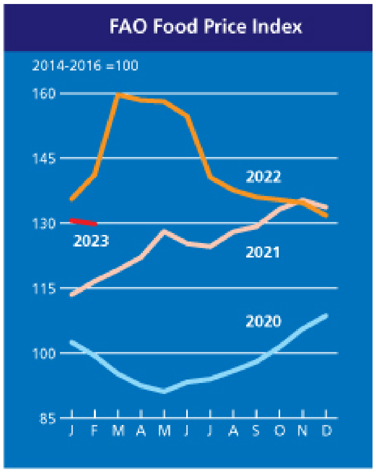
FAO Food Price Index

The FAO Food Price Index (FFPI) is a measure of the monthly change in international prices of a basket of food commodities. It consists of the average of five commodity group price indices weighted by the average export shares of each of the groups over 2014-2016. A feature article published in the June 2020 edition of the Food Outlook presents the revision of the base period for the calculation of the FFPI and the expansion of its price coverage, to be introduced from July 2020. A November 2013 article contains technical background on the previous construction of the FFPI.

Monthly release dates for 2023: 6 January, 3 February, 3 March, 7 April, 5 May, 2 June, 7 July, 4 August, 8 September, 6 October, 3 November, 8 December.

The FAO Food Price Index drops again in February, albeit only marginally

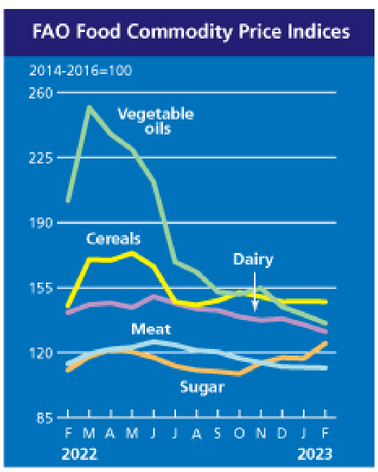
Release date: 03/03/2023



» The **FAO Food Price Index*** (FFPI) averaged 129.8 points in February 2023, marginally down (0.6 percent) from January, continuing the downward trend for the eleventh consecutive month. With the latest decline, the index has fallen 29.9 points (18.7 percent) from the peak it reached in March 2022. The marginal decline of the FFPI in February reflected significant drops in the price indices of vegetable oils and dairy, together with fractionally lower cereals and meat indices, more than offsetting a steep rise in the sugar price index.

» The **FAO Cereal Price Index** averaged 147.3 points in February, down fractionally (0.1 percent) from January and 2.0 points (1.4 percent) above its level one year ago. After falling for three consecutive months, international wheat prices rose marginally (0.3 percent) in February. The slightly firmer tone mostly reflected ongoing concerns over dry conditions in key production areas of Hard Red Winter wheat in the United States of America, and robust demand for supplies from Australia, while strong competition among exporters helped to cap price gains. World maize prices changed little, up just 0.1 percent month-on-month. Support stemmed from worsening conditions in Argentina, and planting delays for the second maize crop along with a strong export pace in Brazil, while low demand for supplies from the United States of America weighed on maize export prices. By contrast, among other coarse grains, world prices of sorghum were down fractionally (0.2 percent), while barley prices declined slightly (0.9 percent) in February, mostly attributed to higher seasonal availability in the southern hemisphere. On the other hand, international rice prices eased by 1.0 percent in February, as trading activities in most major Asian exporters slowed, while their national currencies depreciated against the United States dollar. This was especially the case in Thailand, where the baht weakened from the ten-month highs it reached in January, contributing to the reversal of most of the price increases registered in January.

» The **FAO Vegetable Oil Price Index** averaged 135.9 points in February, down 4.5 points (3.2 percent) from January and marking the lowest level since the beginning of 2021. The continued weakness of the index was driven by lower world prices across palm, soy, sunflowerseed and rapeseed oils. International palm oil prices dropped for the third consecutive month in February, chiefly weighed by lingering sluggish global import demand, despite seasonally lower production from major growing regions in Southeast Asia. Meanwhile, world soyoil prices also continued to decline, underpinned by softened purchases from key importing countries and prospects of rising outputs from South America. As for sunflower and rapeseed oils, world quotations remained on a downward trajectory, depressed by their abundant global exportable availabilities.



» The **FAO Dairy Price Index** averaged 131.3 points in February, down 3.6 points (2.7 percent) from January and standing 10.2 points (7.2 percent) below the corresponding month last year. In February, the decline in the index was driven by lower prices across all dairy products, with the steepest falls in butter and skim milk powder (SMP). The continued weakness in global import demand, especially for near-term deliveries underpinned the price declines, despite a noticeable increase in purchases in recent weeks by North Asia. In addition, increased exportable supplies, including inventories of butter, cheese and SMP, in Western Europe, where seasonal milk deliveries in recent months have tracked above their corresponding monthly averages, also weighed on global export prices.

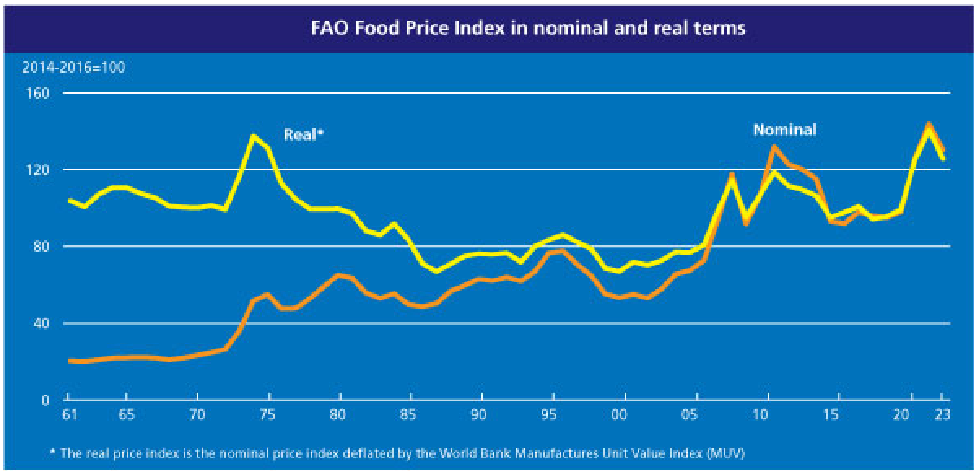
» The **FAO Meat Price Index*** averaged 112.0 points in February, fractionally lower (0.1 points and 0.1 percent) from January and standing 1.9 points (1.7 percent) below its value a year ago. In February, international poultry meat prices fell for the eighth consecutive month, reflecting abundant global supplies compared to softer import demand, notwithstanding avian influenza outbreaks in several leading producer countries. By contrast, international pig meat prices increased, underpinned by market concerns over the low availability of slaughter-ready hogs amid rising internal demand in Europe. Meanwhile, bovine meat prices were stable, following continuous declines since June 2022, as improved import purchases, especially from North Asia, led global demand to balance relatively well with current supplies. International ovine meat prices also remained broadly unchanged, as global demand was adequate to absorb elevated supplies from Australia.

» The **FAO Sugar Price Index** averaged 124.9 points in February, up 8.1 points (6.9 percent) from January, reaching the highest level since February 2017. The February rebound was mostly related to the downward revision to the 2022/23 sugar production forecast in India, which dampened export prospects for the current season. Concerns over lower export availabilities from India amid strong global import demand lent additional support to world sugar prices. However, the good harvest progress in Thailand and abundant precipitation in the key growing areas of Brazil prevented a larger monthly price increase. The decline in international crude oil price quotations and ethanol prices in Brazil also contributed to limit the upward pressure on world sugar prices.

** Unlike for other commodity groups, most prices utilized in the calculation of the FAO Meat Price Index are not available when the FAO Food Price Index is computed and published; therefore, the value of the Meat Price Index for the most recent months is derived from a mixture of projected and observed prices. This can, at times, require significant revisions in the final value of the FAO Meat Price Index which could in turn influence the value of the FAO Food Price Index.*

To access benchmark export quotations of various foodstuffs and national retail/wholesale prices of foods please visit FAO's Food Price Monitoring and Analysis (FPMA) Tool

Download full dataset: Excel, CSV | For more information contact us.



Download full dataset: Excel

FAO food price index

		Food Price Index [1]	Meat [2]	Dairy [3]	Cereals [4]	Vegetables Oils [5]	Sugar [6]
2005		**67.4**	**71.8**	**77.2**	**60.8**	**64.4**	61.2
2006		**72.6**	**70.5**	**73.1**	**71.2**	**70.5**	91.4
2007		**94.3**	**76.9**	**122.4**	**100.9**	**107.3**	62.4
2008		**117.5**	**90.2**	**132.3**	**137.6**	**141.1**	79.2
2009		**91.7**	**81.2**	**91.4**	**97.2**	**94.4**	112.2
2010		**106.7**	**91.0**	**111.9**	**107.5**	**122.0**	131.7
2011		**131.9**	**105.3**	**129.9**	**142.2**	**156.5**	160.9
2012		**122.8**	**105.0**	**111.7**	**137.4**	**138.3**	133.3
2013		**120.1**	**106.2**	**140.9**	**129.1**	**119.5**	109.5
2014		**115.0**	**112.2**	**130.2**	**115.8**	**110.6**	105.2
2015		**93.0**	**96.7**	**87.1**	**95.9**	**89.9**	83.2
2016		**91.9**	**91.0**	**82.6**	**88.3**	**99.4**	111.6
2017		**98.0**	**97.7**	**108.0**	**91.0**	**101.9**	99.1
2018		**95.9**	**94.9**	**107.3**	**100.8**	**87.8**	77.4
2019		**95.1**	**100.0**	**102.8**	**96.6**	**83.2**	78.6
2020		**98.1**	**95.5**	**101.8**	**103.1**	**99.4**	79.5
2021		**125.7**	**107.7**	**119.1**	**131.2**	**164.9**	109.3
2022		**143.7**	**118.8**	**142.4**	**154.7**	**187.8**	114.5
2022	February	**141.2**	113.9	141.5	145.3	201.7	110.5
	March	**159.7**	119.3	145.8	170.1	251.8	117.9
	April	**158.4**	121.9	146.7	169.7	237.5	121.5
	May	**158.1**	122.9	144.2	173.5	229.2	120.4
	June	**154.7**	125.9	150.2	166.3	211.8	117.3
	July	**140.6**	124.1	146.5	147.3	168.8	112.8
	August	**137.6**	121.1	143.4	145.6	163.3	110.5
	September	**136.0**	120.3	142.7	147.9	152.6	109.7
	October	**135.4**	116.8	139.3	152.3	151.3	108.6
	November	**134.7**	114.6	137.4	150.1	154.7	114.4
	December	**131.8**	112.4	138.2	147.3	144.6	117.2
2023	January	**130.6**	112.1	135.0	147.5	140.4	116.8
	February	**129.8**	112.0	131.3	147.3	135.9	124.9

1 Food Price Index: Consists of the average of 5 commodity group price indices mentioned above, weighted with the average export shares of each of the groups for 2014-2016: in total 95 price quotations considered by FAO commodity specialists as representing the international prices of the food commodities are included in the overall index. Each sub-index is a weighted average of the price relatives of the commodities included in the group, with the base period price consisting of the averages for the years 2014-2016.

2 Meat Price Index: Based on 35 average export unit values/market prices of four meat types (bovine, pig, poultry and ovine) from 10 representative markets. Within each meat type, export unit values/prices are weighted by the trade shares of their respective markets, while the meat types are weighted by their average global export trade shares for 2014-2016. Quotations for the two most recent months may consist of estimates and be subject to revision.

3 Dairy Price Index: Computed using 8 price quotations of four dairy products (butter, cheese, SMP and WMP) from two representative markets. Within each dairy product, prices are weighted by the trade shares of their respective markets, while the dairy products are weighted by their average export shares for 2014-2016.

4 Cereals Price Index: Compiled using the International Grains Council (IGC) wheat price index (an average of 10 different wheat price quotations), the IGC maize price index (an average of 4 different maize price quotations), the IGC barley price index (an average of 5 different barley price quotations), 1 sorghum export quotation and the FAO All Rice Price Index. The FAO All Rice Price Index is based on 21 rice export quotations, combined into four groups consisting of Indica, Aromatic, Japonica and Glutinous rice varieties. Within each varietal group, a simple average of the relative prices of appropriate quotations is calculated; then the average relative prices of each of the four rice varieties are combined by weighting them with their (fixed) trade shares for 2014-2016. The Cereal Price Index combines the relative prices of sorghum, the IGC wheat, maize and barley price indices (re-based to 2014-2016) and the FAO All Rice Price Index by weighing each commodity with its average export trade share for 2014-2016.

5 Vegetable Oil Price Index: Consists of an average of 10 different oils weighted with average export trade shares of each oil product for 2014-2016.

6 Sugar Price Index: Index form of the International Sugar Agreement prices with 2014-2016 as base.

https://www.businessinsider.com/millennials-parents-debt-jobs-wages-homeownership-social-security-retirement-economy-2023-3

Millennials in their 30s are sitting in an economic quagmire that could stick with them through retirement

Yam G-Jun / Getty Images

- **Millennials in their 30s are in a tough economic spot.**
- **They're struggling to get back to work and are accruing debt faster than other age groups.**
- **In the long run, this generation may also be hit by cuts in Social Security benefits.**

Millennials in their 30s are living in a perfect storm of economic factors right now.

Pandemic-specific circumstances, such as the cost of childcare when schools closed, are still adversely affecting young parents. In the long run, millennials' retirement may also be affected if Social Security benefits are cut. Plus, they're accruing debt at the fastest rate since the 2008 financial crisis, according to a recent Wall Street Journal analysis of New York Fed data.

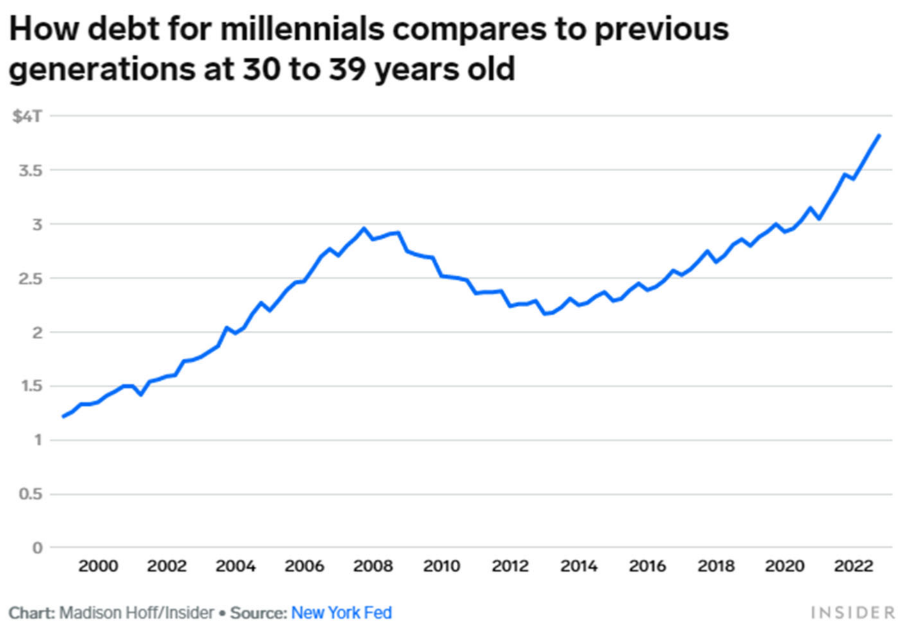
Below are some of the ways millennials are struggling in this economy.

Millennials in their 30s are accruing debt faster than their peers

While research from Experian and Credit Karma shows that Gen X has the highest average debt of any age group, millennials still hold a lot of debt too — and are accumulating it faster than anyone else.

According to The Journal's analysis, people who are 30 to 39 years old — currently the bulk of the millennial generation — have about $3.8 trillion in debt as of the fourth quarter of 2022, or about a $140 billion increase from the third quarter of 2022. As the Wall Street Journal article noted, that's 27% higher than in the fourth quarter of 2019, and the last time debt owed by 30-somethings grew this quickly was between 2005 and 2008.

A major part of that story is the way that student debt has hampered millennials' finances — more than a third of them report that their loans have kept them from buying a home, for instance, according to a survey from Legal & General.



As seen in the above chart, millennials are holding a lot more total debt than previous generations in that age group.

Millennials are missing credit card and auto loan payments

The debt burdens racked up by millennials are starting to stress their finances, and many have begun defaulting on those burdens.

Research published on the New York Fed's Liberty Street Economics blog showed that "millennials are missing credit card and auto loan payments at rising rates" as they take on more debt, as reported by Insider's Jacob Zinkula.

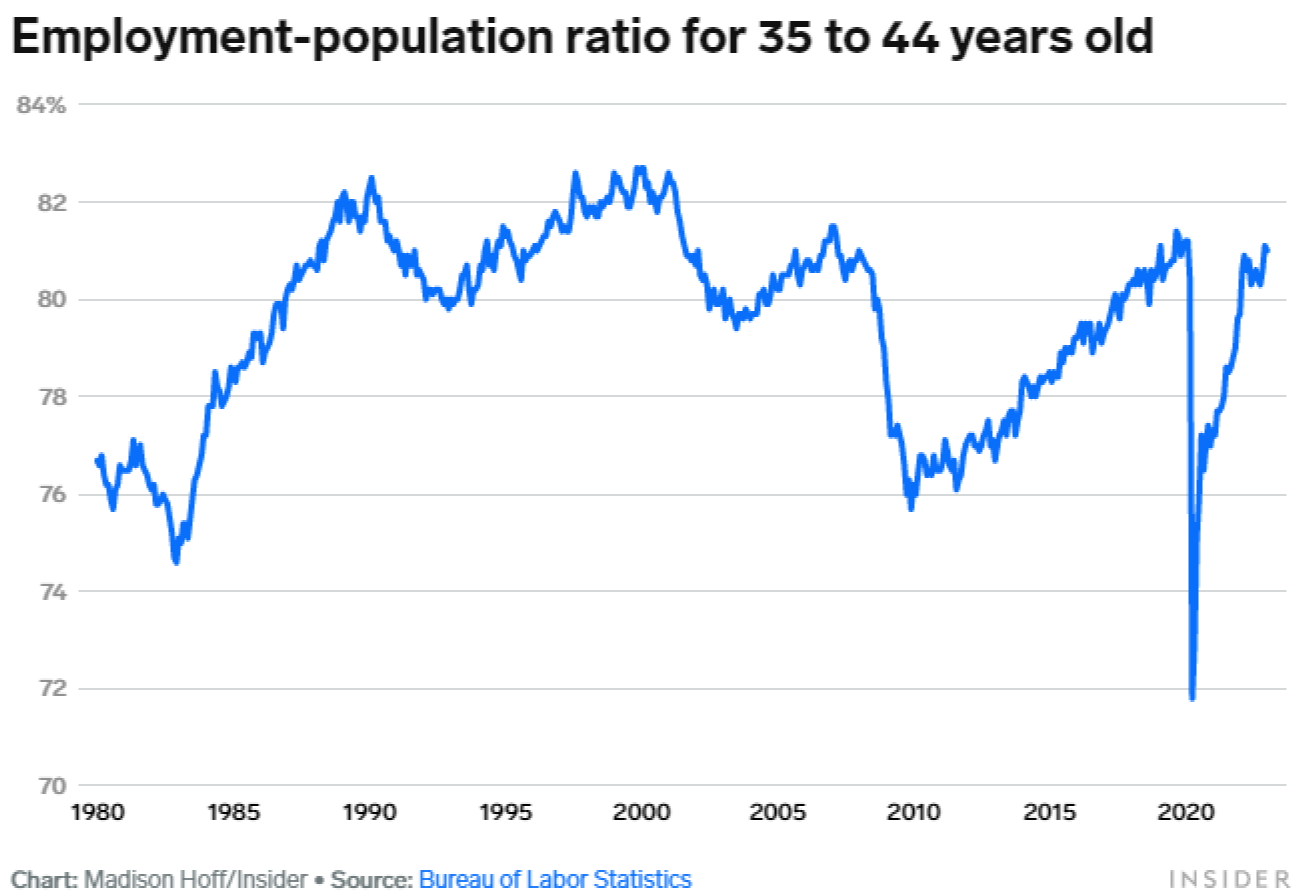
The data also underscores how inflation and the rising cost of living has hurt millennials in particular.

"We are seeing a 'credit gap' emerge in the sense that younger, less-affluent borrowers are coming under financial pressure from higher living costs and inflation outpacing their income gains," Silvio Tavares, chief executive of VantageScore, told The Journal. "We aren't seeing that among older and more-affluent borrowers."

Working millennials are still recovering from the pandemic

Millennials have also had trouble getting back to work.

Based on employment-population ratio data from the Bureau of Labor Statistics, the share of 35- to 44-year-olds with a job saw a severe drop during the pandemic. The ratio dropped from 81.2% in February 2020 to 71.8% in April 2020. The ratio in January 2023 of 81.0% falls short of that in the late '90s and early 2000s, when baby boomers were the same age. The highest ratio for this age group was in November 1999 as well as in January and February in 2000, when this ratio was 82.7%.



Millennials, who are in their prime parenting years, were affected by childcare issues during the pandemic and the childcare shortage. During the pandemic, some parents left the labor force as they handled issues like closed childcare centers.

Childcare issues aren't over though. The sector is still below its pre-pandemic level of employment and childcare costs can be expensive. According to a 2022 survey of mothers from Motherly, almost half of millennial or Gen Z unemployed respondents who ended up leaving the workforce in 2021 said they left because of childcare issues.

Additionally, more than half of families with young children — up to the age of five — saw their household income decline when childcare was unavailable, according to a study at The Century Foundation last year.

Millennials are still behind on homeownership

The fraught nature of homeownership for millennials is also a factor. They're the generation that waited the longest to own their first homes, contending with multiple recessions and being locked out of the housing market for years. Over the last few years, millennials have powered forward, however, propelling the pandemic-homebuying boom.

According to Census Bureau data, the homeownership rate among 35 to 44-year-olds was 62.2% in the fourth quarter of 2022. In 1999 when the youngest baby boomers fell in this age group, the homeownership rate was 67.0% in the first quarter of the year and 67.9% in the fourth quarter.

Millennials' determination to own homes has persisted, even as the market became impenetrable. It's only started to cool over the last few months.

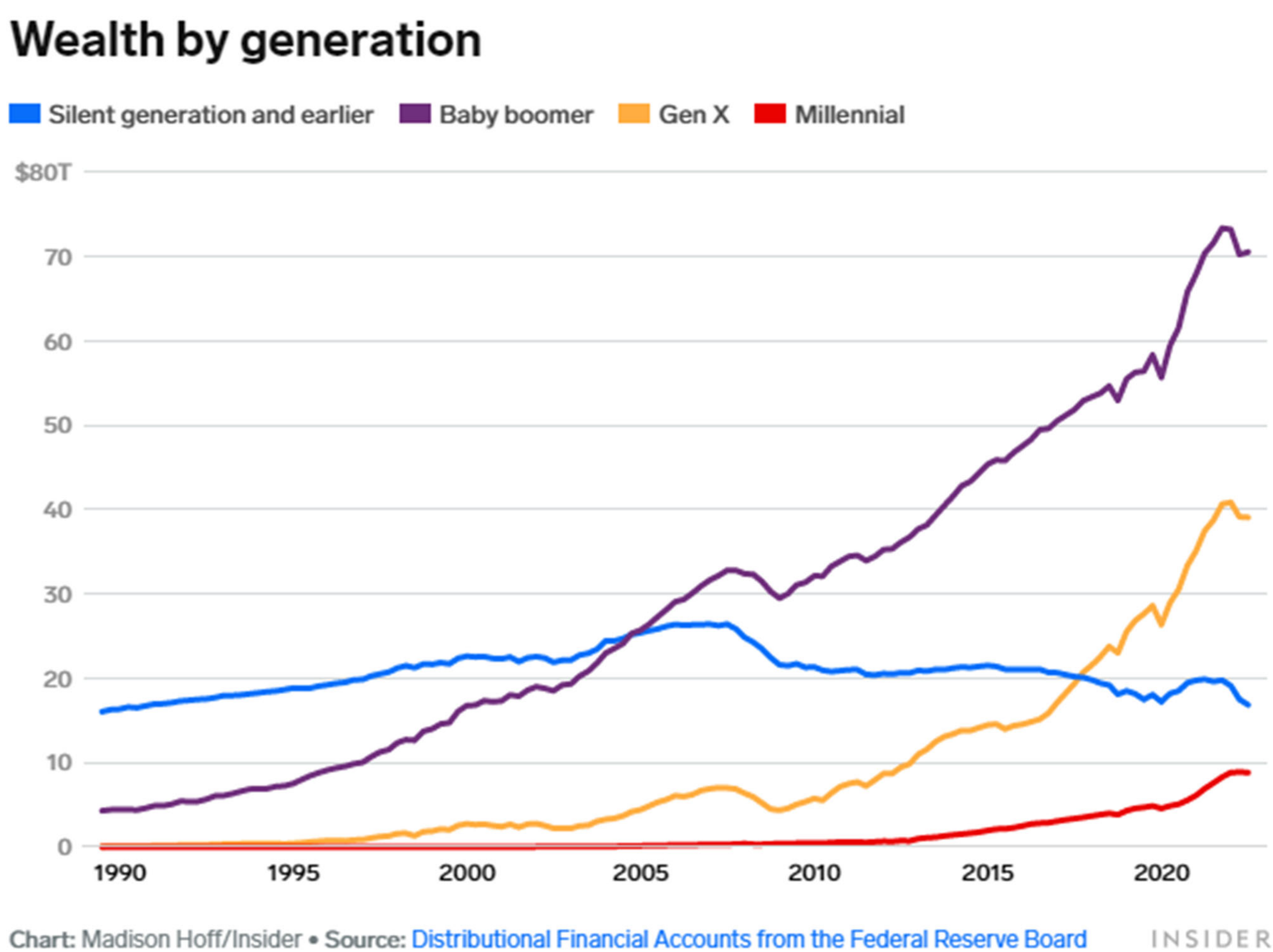
According to a Bankrate survey, about 4 in 10 millennials who don't own a home said that's because homes are too expensive and 4 in 10 also said that they don't have sufficient income.

Millennials face looming retirement insecurity

If all of that wasn't enough, millennials' retirement situation in the future could be different from Gen X and baby boomers. The authors of a 2021 brief from the Center for Retirement Research at Boston College said that while millennials "are catching up in the labor market and they are getting married and buying houses," they are falling behind earlier generations in savings.

"One place Millennials have not caught up, however, is wealth accumulation," the authors added. "They are saving for retirement at the rate of earlier generations, but student debt is a constant drag on their balance sheet."

The below chart shows just how much wealth millennials hold compared to other generations as of the third quarter of 2022.



Additionally, millennials' retirement safety nets are likely to be affected if they can't get full Social Security benefits. A report from HealthView Services said that "If benefits are reduced by 20% (in accordance with the

SSA's projections), an average 35-year-old Millennial earning $50,000 in 2022 will receive $13,500 less in annual Social Security income in the first year of retirement, and $365,000 less in lifetime benefits."

While a 35-year-old making that much in 2022 would see a lifetime benefit drop of about $365,000, the report showed that those earning six figures would see larger declines in lifetime benefits. Those that age making $100,000 would see a decline of about $563,000 and a decline of about $677,000 for a 35-year-old making $150,000.