Energy Tidbits

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Short-Term Energy Outlook

Forecast highlights

- The July *Short-Term Energy Outlook* (STEO) remains subject to heightened levels of uncertainty related to the ongoing economic recovery from the COVID-19 pandemic. U.S. economic activity continues to rise after reaching multiyear lows in the second quarter of 2020 (2Q20). The increase in economic activity and easing of the COVID-19 pandemic have contributed to rising energy use. U.S. gross domestic product (GDP) declined by 3.5% in 2020 from 2019 levels. This STEO assumes U.S. GDP will grow by 7.4% in 2021 and by 5.0% in 2022. We based the U.S. macroeconomic assumptions in this outlook on forecasts by IHS Markit.

- Brent crude oil spot prices averaged $73 per barrel (b) in June, up $5/b from May and $33/b higher than in June of last year. In the coming months, we expect that global oil production, largely from OPEC+ members (OPEC and partner nonmember countries), will increase by more than global oil consumption. We expect rising production will reduce the persistent global oil inventory draws that have occurred for much of the past year and keep prices similar to current levels, averaging $72/b during the second half of 2021 (2H21). However, in 2022, we expect that continuing growth in production from OPEC+ and accelerating growth in U.S. tight oil production, along with other supply growth, will outpace growth in global oil consumption and contribute to declining oil prices. Based on these factors, we expect Brent to average $67/b in 2022.

- We estimate that global consumption of petroleum and liquid fuels averaged 92.3 million barrels per day (b/d) for all of 2020, down by 8.6 million b/d from 2019. We expect that global liquid fuels consumption will grow by 5.3 million b/d in 2021. In our forecast, global consumption of liquid fuels rises by an additional 3.7 million b/d in 2022 to 101.4 million b/d, which would surpass 2019 levels.

- Based on our estimates, global liquid fuels inventories rose by 6.3 million b/d in 1H20 before declining at an average rate of 2.1 million b/d in 2H20 and 1H21. We forecast global inventories will continue to fall in the near term but at a slower rate, with global inventories falling by 0.2 million b/d in 2H21. We then expect inventories to rise by almost 0.5 million b/d in 2022.

- U.S. regular gasoline retail prices averaged $2.78 per gallon (gal) in 1H21, compared with an average of $2.20/gal in 1H20. In June, monthly retail gasoline prices averaged $3.06/gal, the first time the monthly average was more than $3.00/gal since October

Note: EIA completed modeling and analysis for this report on Thursday July 1, 2021

2014 (in nominal terms). We forecast regular-grade gasoline prices to average $2.92/gal in 2H21 and $2.74/gal for all of 2022.

- U.S. liquid fuels consumption in 2020 averaged 18.1 million b/d, down 2.4 million b/d (12%) from 2019 consumption. We forecast U.S. liquid fuels consumption will rise to 19.6 million b/d in 2021 and then to 20.7 million b/d in 2022, which would surpass the 2019 level.

- Henry Hub natural gas spot prices averaged $2.03 per million British thermal units (MMBtu) in 2020. We expect Henry Hub prices will rise to an annual average of $3.22/MMBtu in 2021, and we forecast prices will then fall to an average of $3.00/MMBtu in 2022.

- We expect U.S. dry natural gas production to average 92.6 billion cubic feet per day (Bcf/d) in 2021, up by 1.3% from 2020, and then rise to 94.7 Bcf/d in 2022.

- U.S. natural gas consumption averaged 83.3 Bcf/d in 2020, down 2.2% from 2019. We expect that natural gas consumption will decline by 1.1% in 2021 and then grow by 0.7% in 2022. Most of the forecast decline in natural gas consumption this year is the result of less natural gas use in the electric power sector, which we expect to continue to decline because of rising natural gas prices.

- U.S. working natural gas in storage ended the winter withdrawal season in March 2021 at 1.8 trillion cubic feet (Tcf), slightly less than the five-year (2016–20) average. We forecast that flat U.S. natural gas production this summer combined with record U.S. natural gas exports will contribute to slightly lower-than-average inventory builds during the remainder of the summer build season, which ends in October. Forecast natural gas inventories end October 2021 at 3.6 Tcf, which is 3% lower than the five-year average.

- We forecast that U.S. retail sales of electricity will increase by 2.8% in 2021 after falling by 3.9% in 2020. The largest forecast increase in electricity consumption occurs in the industrial sector, driven by rising levels of economic output. We forecast U.S. retail sales of electricity to the industrial sector will grow by 5.1% this year. Retail sales of electricity to the commercial sector also grow in the forecast, but they grow at the slightly slower pace of 2.1% in 2021 as some workers continue working from home instead of in office buildings. We forecast U.S. residential electricity sales will grow by 1.9% in 2021, as a result of colder temperatures in 1Q21 compared with 1Q20 and a hot start to the summer.

- We expect the share of electric power generation produced by natural gas in the United States will average 36% in both 2021 and 2022, down from 39% in 2020. Our forecast for the natural gas share as a generation fuel declines because we expect a higher delivered natural gas price for electricity generators. Because we expect higher natural gas prices, we forecast coal's generation share to rise from 20% in 2020 to 24% this year but to fall to 22% next year. New additions of solar and wind generating capacity support our expectation that the share of U.S. generation from these two energy sources will rise from 11% in 2020 to 15% by 2022. Extreme drought conditions in the West drive our expectation that the share of U.S. generation from hydropower will fall from 8% in 2020 to 6% in 2021 and 7% in 2022. The nuclear share of U.S. electricity generation declines from 21% in 2020 to 20% in 2021 and to 19% in 2022 as a result of retiring capacity at some nuclear power plants.

- The U.S. retail electricity price for the residential sector in our forecast averages 13.6 cents per kilowatthour in 2021, which is 2.8% higher than the average retail price in 2020. Forecast residential prices increase by an additional 1.8% in 2022.

- During the next 18 months, we expect electricity generation capacity from renewable energy sources to continue growing. Our forecast includes both wind and solar capacity growth, and solar capacity grows at a faster rate. Based on our survey data, large-scale solar capacity growth in gigawatts (GW) will exceed wind growth for the first time in 2022.

- We expect U.S. coal production to total 617 million short tons (MMst) in 2021, which is 78 MMst (15%) more than in 2020. Rising electricity demand for coal amid higher natural gas prices is driving this production increase. In 2022, we expect coal production to fall by 7 MMst (1%).

- We forecast that total energy-related carbon dioxide (CO_2) emissions will increase by 7.1% in 2021 and by 1.5% in 2022 after declining by 11.1% in 2020. Even with growth over the next two years, forecast emissions in 2022 remain 3.3% lower than in 2019.

Global Liquid Fuels

***Global Petroleum and Other Liquid Fuels Consumption*.** Based on preliminary data and estimates from 1Q21, as well as our assumptions of continued economic recovery, we forecast consumption of global petroleum and other liquid fuels will grow by 5.3 million b/d in 2021. This growth follows a decline of 8.6 million b/d in 2020. Forecast growth in global oil consumption of 3.7 million b/d in 2022 would bring global oil consumption to 101.4 million b/d, which would be 0.4 million b/d higher than in 2019. Our global economic growth forecasts come from Oxford Economics, which forecasts GDP in 2021 will increase by 6.3% and by 4.8% in 2022, compared with a decline of 3.4% in 2020.

We expect oil demand growth in 2021 to be fairly evenly split between the OECD and non-OECD. OECD oil demand grows by 2.5 million b/d, and non-OECD demand grows by 2.8 million b/d. Our forecast assumes that business activity and travel will continue to increase throughout 2021 and into 2022. For 2021, in addition to rising economic activity, oil consumption growth is driven by reopening economies and a return to travel patterns more similar to pre-pandemic norms. In 2022, economic growth alone becomes the main driver of oil consumption growth.

We expect U.S. liquid fuels consumption in 2021 to rise by 1.5 million b/d from 2020, making it the largest contributor to global consumption growth in the forecast. Since the beginning of 2021, some of the most significant increases in our expectations for oil demand have been for Europe. Strict travel restrictions imposed by many of the European OECD countries in 1Q21 gradually eased in the second quarter as a result of successful large-scale vaccination campaigns. As a result, Europe has experienced a significant increase in economic activity in 2Q21 as capacity limits and restrictions on mobility and non-essential business activity have either been reduced or eliminated. We estimate that 2Q21 liquid fuels consumption in OECD Europe was up 1.8 million b/d from the same period in 2020, contributing to our expectation that liquids consumption in OECD Europe will be up 0.5 million b/d for all 2021 compared with 2020.

Oil consumption growth in many of the non-OECD regions remains more uncertain. Large-scale vaccination campaigns in Asia, Latin America, the Middle East, and Africa have been relatively slower—with some exceptions—than in Europe and the United States. Outbreaks of COVID-19 infections and the re-imposition of restrictions on mobility and business activity still pose a significant downside risk in these regions. In 1H21, Malaysia, Thailand, and Vietnam, where a majority of the populations remain unvaccinated, imposed mobility and business activity restrictions after experiencing large outbreaks of COVID-19 infections.

In addition, the spread of COVID-19 variants and the effectiveness of the vaccines against these variants are significant risk factors to a full and sustained global recovery. India experienced its worst outbreak of COVID-19 infections in 2Q21 when the Delta variant spread, which is reportedly more virulent and contagious than other variants, and the outbreak led to a sharp reduction in economic activity from which the country is now slowly recovering. If the vaccines currently available are not effective against the Delta or other variants, countries will have to continue to rely on mobility and activity restrictions to mitigate the spread, which will lead to a longer, more drawn-out return in global oil demand.

For 2021, we forecast liquid fuels consumption in India to grow by 0.3 million b/d (6%), consumption in China to grow by 0.9 million b/d (6%), and consumption in the rest of non-OECD to grow by 1.7 million b/d (5%).

Non-OPEC Production of Petroleum and Other Liquid Fuels. Following a 2.5 million b/d decrease in 2020, with declines extending into 1Q21, we estimate that non-OPEC liquid fuels production increased by 2.6 million b/d in 2Q21 from 2Q20. Almost three quarters of this increase came from two non-OPEC producers: the United States and Russia. We expect non-OPEC production to rise by 1.1 million b/d in 2021 and by 3.1 million b/d in 2022. We expect Canada and Brazil to lead non-OPEC production growth in 2021 and the United States and Russia to lead growth in 2022.

We expect Canada's production of petroleum and other liquid fuels to increase by more than 0.3 million b/d in 2021, which would make it the leading source of non-OPEC liquid fuels supply growth this year. Despite heavier-than-normal turnarounds at a number of oil sands projects in 1H21, we forecast Canada's production to reach new record highs in 2H21. Output growth in 2021 is driven by increasing refinery demand for crude oil in the United States, the end of Canadian government-ordered curtailments, and the restart of oil sands expansion projects that were deferred during 2020. We do not expect any new upstream projects to come online in Canada during the forecast period. Forecast crude oil production growth comes from expansions or debottlenecking of existing projects.

In January 2021, President Biden revoked the presidential permit authorizing the construction of the Keystone XL pipeline, and in June 2021, owner TC Energy officially canceled the project. The pipeline would have expanded Canada's crude oil export capacity to the United States by 830,000 b/d. The cancellation of the Keystone XL does not materially affect our production outlook for Canada, and we expect Canada's pipeline export capacity will be adequate through the end of the forecast period. Enbridge's Line 3 replacement (370,000 b/d) will come online at the end of 2021, the TransMountain expansion project (590,000 b/d) in 2022, and additional Enbridge expansion and optimizations to its existing pipeline system can bring more than 400,000 b/d of increased export capacity over the forecast period. Forecast production in Canada grows by 0.2 million b/d in 2022.

Even as production in most non-OPEC producers declined in 2020, Brazil's liquid fuels supply grew by 0.1 million b/d during 2020. We expect Brazil's production to grow by more than 0.2 million b/d in 2021. However, our current forecast is 0.1 million b/d lower on average compared with the January 2021 STEO and reflects the difficulties Brazil's national oil company, Petrobras, experienced at the beginning of 2021 with restarting fields that had undergone heavy maintenance in 4Q20. Growth in 2021 is further limited as a result of delayed startups. Petrobras has postponed the start-up of the first phase of the Mero oil field development, the floating production storage and offloading vessel (FPSO) Guanabara, from 4Q21 to 1H22. The restart of the Equinor-operated Peregrino field has also been delayed to 2022. The current operational asset in the Peregrino field has been offline since 2019 because of technical issues and was delayed again in 2020 because of COVID-19 safety protocols. The startup of its second phase of development has also been delayed to 2022 because of work disruptions caused by the pandemic. Forecast production in Brazil will grow by 0.3 million b/d in 2022. We expect that five new FPSO units will ramp up through the forecast period and continue to drive growth, notably at the Sepia, Mero, and Buzios fields. Each of these FPSOs has a production capacity of 180,000 b/d.

Russia is the second-largest producer of liquid fuels among non-OPEC countries after the United States. Production in Russia grew by 0.5 million b/d in 1H21 from 2H20, as OPEC+ participants eased crude oil production cuts. We expect Russia's liquid fuels production to increase by 0.2 million b/d for all of 2021 and by 0.8 million b/d in 2022. After the OPEC+ agreement ends in early 2022, we expect Russia's production to rise above 11.5 million b/d during 2H22, with annual average production in 2022 equal to 2019 levels.

China’s liquid fuels production in our forecast increases by more than 0.1 million b/d in 2021. China’s government outlined its goals for national oil companies to increase upstream crude oil and natural gas production during the next few years to help meet its outlined energy security goals. We expect slight declines in crude oil production in 2022 will be offset by both increasing production of other liquids and by increasing refinery gains, resulting in a small increase in China’s overall production.

Norway’s liquid fuels production rises in our forecast by about 0.1 million b/d in both 2021 and 2022. Norway’s Ministry of Petroleum and Energy enacted unilateral production limits on the Norwegian continental shelf from June 2020 to December 2020. When production limits expired, Norway’s liquid fuels production was up slightly in 1H21 compared with 1H20. We expect liquid fuels production to continue to grow in 2H21 and in 2022 as new fields come online and ramp up production, including the much-delayed Martin Linge field. The Johan Sverdrup field, which was the main driver of growth in Norway’s liquid fuels production in 2020, will also contribute to growth in 2021 and 2022.

Mexico’s forecast liquid fuels production averages 1.9 million b/d in 2021, almost unchanged from 2019 and 2020. We have revised our 2021 production forecast upwards from its January 2021 STEO estimate of 1.8 million b/d because private operators have surpassed our expectations regarding their ability to ramp up the Ixachi, Pokoch, and Hokchi fields. We expect Mexico’s oil production to fall to 1.8 million b/d on average in 2022, reflecting financial constraints at Mexico’s national oil company, PEMEX, and continued large declines in mature fields. New growth in foreign-operated fields in 2021 is insufficient to offset declines from PEMEX’s older fields, in particular the Maloob field.

We forecast that output across a number of other non-OPEC producers will decline in 2021 and 2022, notably Indonesia, the United Kingdom, and Colombia.

OPEC Production of Petroleum and Other Liquid Fuels. At the April 2021 OPEC+ meeting, the OPEC+ countries agreed to incrementally raise their production from May through July 2021, including a full reversal of Saudi Arabia’s voluntary production cut of 1 million b/d. They reaffirmed this agreement at their June meeting. This forecast was completed on July 1, prior to OPEC+ calling off its most recent meeting on July 5. However, we forecast that OPEC and its OPEC+ partners will continue to increase crude oil production beyond July in response to rising global oil consumption.

Although our forecast assumes current U.S. sanctions remain in place for Iran and Venezuela for the entire forecast period, we expect Iran will increase crude oil supply somewhat in the coming months. We also expect that OPEC+ will not implement further production cuts to accommodate any potential increases in oil output from Iran or Venezuela.

After holding crude oil production near 25 million b/d during the first four months of 2021, OPEC began increasing production in May based on its agreement with OPEC+ partners. We expect OPEC will increase production by 2.4 million b/d from May through August, raising production in response to rising global oil consumption. In our forecast OPEC crude oil production averages 28.2 million b/d in 2H21, up 2.9 million b/d from 1H21 and up 4.0 million b/d from 2H20. For all of 2021, we forecast that OPEC crude oil production will average 26.8 million b/d, up 1.2 million b/d from 2020. We forecast OPEC will raise crude oil production by an additional 1.8 million b/d in 2022 to 28.6 million b/d.

Our OPEC crude oil production forecast is subject to considerable uncertainty. OPEC+ implemented monthly meetings to assess global oil market conditions, and the group's production targets are potentially subject to regular adjustments. OPEC+ has indicated it will adjust production targets in response to changes in global oil demand, but the path of global oil demand in the comings months remains highly uncertain. Also, the manner in which OPEC+ would change production targets in response to higher production from Iran, or other changes in the oil market, is not clear. Finally, country compliance with existing production targets as the oil price rises is uncertain.

Even with increased OPEC crude oil production, remaining surplus production capacity will be more than sufficient to meet additional demand should consumption exceed our expectations. We expect that OPEC surplus crude oil production capacity, which averaged 6.2 million b/d in 2020, will average 6.7 million b/d in 2021 and 4.8 million b/d in 2022, compared with average surplus capacity of 2.2 million b/d from 2010–19. These estimates do not include additional capacity that may be available in Iran that is offline because of U.S. sanctions on Iran's oil sales. All else equal, elevated levels of OPEC surplus production capacity tend to have a moderating effect on crude oil price increases.

Venezuela is not subject to the current OPEC+ production target, and in contrast to the rest of OPEC, we expect Venezuela's crude oil production to continue to decline as a result of ongoing operational difficulties, lack of field and facility maintenance, and continuing sanctions. Venezuela's production declines accelerated in 2020 after the United States government imposed new sanctions on its main oil trader, Rosneft Trading, in mid-February 2021. In addition, the decline in global oil demand following the onset of the COVID-19 pandemic further reduced the demand for Venezuela's oil.

OPEC Non-Crude Oil Liquids. We estimate that OPEC production of other liquids declined to 5.1 million b/d on average in 2020, down from 5.4 million b/d in 2019. The 2020 production decrease was driven by reduced output of associated condensate stemming from reduced crude oil production. In the forecast, associated liquids production rises as OPEC relaxes its crude oil production cuts. We expect OPEC non-crude oil liquids production will rise to 5.3 million b/d in 2021 and to 5.5 million b/d in 2022.

Global Oil Inventories. We estimate global oil inventories increased by 1.2 billion barrels during the first five months of 2020. Inventories subsequently fell by 0.8 billion barrels from June 2020 through June 2021. However, we expect that markets will be much more balanced during 2H21 and in 2022. Although global oil demand continues to rise, relaxed OPEC+ production targets during the second half of the year, rising oil supplies in Iran, and rising non-OPEC production will result in global oil inventory draws of 0.2 million b/d during 2H21, compared with our estimate that inventory draws were 1.7 million b/d in 1H21. We expect inventories to build at a rate of nearly 0.5 million b/d in 2022 as OPEC continues to raise production in response to rising demand and as non-OPEC production growth, particularly in the United States, accelerates.

Crude Oil Prices. Brent crude oil prices averaged $73/b in June 2021, up $5/b from May. June was the first month when Brent crude oil prices averaged more than $70/b since May 2019. The increase likely reflected market expectations of continuing near-term tightness in global oil markets, which were evident in ongoing declines in global oil inventories. As vaccination rollouts have continued to ramp up in parts of the world, personal travel and mobility have been rising during much of 2021. Increasing oil consumption combined with production restraint from OPEC+ and relatively flat crude oil output in the United States have kept global oil consumption above global oil supply, draining inventories. Although global oil inventories during May and June fell at a slower rate than earlier in the year, the inventory draws of 1.2 million b/d over the past two months indicate the oil market was still in a structural deficit. Crude oil prices received additional support from increasing global economic activity and decreasing global COVID-19 cases. These factors have also contributed to rising prices across a wide range of assets including equities and other commodities.

We expect that recent increases in crude oil prices along with the OPEC+ decision to raise production will help meet the expected increase in global oil demand and lead to relatively balanced global oil markets for the remainder of the forecast period. Despite strength in oil prices during 1H21, we expect moderate downward oil price pressures to emerge beginning in 2H21, when we forecast global oil production to rise and cause inventories to draw at a slower pace. We expect global oil inventories will fall by 0.2 million b/d in 2H21, compared with an average draw of 1.7 million b/d in 1H21. We forecast Brent spot prices to average $71/b during 4Q21 compared with the average of $73/b in June.

Although we expect oil markets to be fairly balanced in 2022, in our forecast, global oil production begins to outpace global oil demand in 2022, which we expect will continue to put moderate downward pressure on oil prices. Higher oil price levels realized in 2021 drive increases in U.S. tight oil production in 2022. In addition, we expect more barrels from OPEC+ members to reach the market. We expect U.S. crude oil production to increase by 0.8 million b/d in 2022 and OPEC crude oil production to increase by 1.8 million b/d in 2022. Paired with a forecast deceleration in global oil demand growth to 3.7 million b/d in 2022—compared with 5.3 million b/d in 2021—rising oil production contributes to our forecast that Brent crude oil spot prices will average $67/b next year.

Global economic developments and numerous uncertainties surrounding the ongoing COVID-19 pandemic in the coming months could push oil prices higher or lower than our current price forecast. The current forecast price path reflects global oil consumption increasing by 6% from 2020 levels in 2021 and by an additional 4% in 2022. However, this forecast depends on the rate at which current vaccinations continue and the way oil consumption behavior changes once populations are widely vaccinated. The duration of, and compliance with, the latest OPEC+ production targets also remains uncertain. Lastly, the degree to which the U.S. shale industry responds to the recent relative strength in oil prices will affect the oil price path in the coming quarters.

We forecast West Texas Intermediate (WTI) crude oil prices will average about $3/b less than Brent prices in 2021 and $4/b less than Brent prices in 2022. This price discount is based on our assumption that the recent discount of WTI to Brent, which averaged less than $3/b in 2Q21, reflected low global demand for oil exports and relatively low levels of U.S. crude oil production. As global refinery demand for crude oil increase and U.S. crude oil supply also increases, we expect the WTI discount to return to $4/b by 2H22. This discount reflects the relative cost of exporting U.S. crude oil from the Cushing distribution hub to Asia, compared with the cost of exporting Brent crude oil from the North Sea to Asia.

U.S. Liquid Fuels

Consumption. Although U.S. liquid fuels consumption has increased since reaching a recent low in 2Q20, lingering effects from COVID-19 continue to limit consumption. We estimate that in 1H21, U.S. consumption of liquids fuels averaged 19.1 million b/d, down 1.3 million b/d (6%) from 1H19. We expect the effects of the COVID-19 pandemic on liquid fuels consumption will continue to abate and liquids consumption will increase through the forecast period. Although we expect the direct effects from the pandemic on U.S. petroleum consumption to decrease, some consumption patterns may be more lasting, including increased working from home and changes in travel behavior, which could limit growth in gasoline and jet fuel consumption.

In 2021, we forecast that total U.S. liquids consumption will average 19.6 million b/d, down from 20.5 million b/d in 2019. Although we expect consumption of distillate fuel to be approximately equal to 2019 levels, we expect consumption of gasoline and jet fuel to remain below 2019 levels. We expect consumption of hydrocarbon gas liquids (HGL) to remain above 2019 levels in 2021, offsetting some of the declines in gasoline and jet fuel consumption.

In 2022, we expect distillate and HGL consumption to rise above 2019 levels, while gasoline and jet consumption will remain below 2019 levels. In the forecast, distillate and HGL consumption drive 2022 total liquids consumption to an average of 20.7 million b/d, surpassing 2019 consumption by about 0.1 million b/d.

In 1H21, we estimate U.S. gasoline consumption averaged 8.5 million b/d, down from 9.3 million b/d in 1H19 and the lowest level for the first half of a year since 2001 (except in 2020). Consumption in 1Q21 averaged 8.0 million b/d and increased to an estimated 9.0 million b/d in 2Q21 as the effects of COVID-19 decreased (driven by falling COVID-19 infections and increased vaccinations) and seasonal driving increased. We expect the effects of COVID-19 will continue to decrease and gasoline consumption will increase to an average of 8.9 million b/d in 2H21, up from 8.3 million b/d from 2H20, but still lower than the 9.3 million b/d consumed in the same period during 2019. For all of 2021, we forecast U.S. gasoline consumption to average 8.7 million b/d and increase to 9.0 million b/d in 2022, compared with 9.3 million b/d in 2019.

We do not expect U.S. gasoline consumption to exceed 2019 levels in the forecast period. In 2021, we forecast that U.S. vehicle miles traveled (VMT) will average 8.6 million miles per day, up from 7.7 million miles per day in 2020 but below the average of 8.9 million miles per day in 2019. In 2022, however, we expect VMT to average 9.0 million miles per day, slightly above the level seen in 2019. Increased vehicle efficiency, however, partly offsets the increases in VMT, keeping gasoline consumption below 2019 levels. We assume that work-from-home options in the future will remain more available than before the pandemic, limiting gasoline demand growth.

Responses to the COVID-19 pandemic affected distillate consumption in the United States in 2020 less than gasoline and jet fuel because it is driven more by economic activity and freight movement and less by reduced travel. In weekly data, distillate consumption recently returned to 2019 levels, and we estimate that distillate consumption in June 2021 surpassed distillate consumption in June 2019 by 70,000 b/d. For 1H21, distillate consumption averaged an estimated 4.0 million b/d, which is below the 1H19 average of 4.2 million b/d. However, we forecast distillate consumption to average 4.2 million b/d in 4Q21, surpassing the 4Q19 average by 0.1 million b/d. We forecast distillate consumption to average almost 4.3 million b/d in 2022, the highest level on record in our data, which dates back to 1945.

In 1H21, jet fuel consumption averaged 1.2 million b/d, up from 1.1 million b/d in 2020 but below 2019 consumption of 1.7 million b/d. We expect jet fuel consumption will average 1.4 million b/d in 2021, down from 1.7 million b/d in 2019. In 2022, forecast jet fuel consumption almost returns to 2019 levels, averaging 1.7 million b/d.

U.S. consumption of HGLs in our forecast increases by 0.1 million b/d to an average 3.3 million b/d in 2021 and then increase by 0.3 million b/d to 3.6 million b/d in 2022. The growth in HGL consumption in 2021 and 2022 reflects more demand for ethane as a petrochemical feedstock in the United States. We forecast ethane consumption will increase by 30,000 b/d in 2021 and by a further 300,000 b/d in 2022 with new demand coming from additional ethylene cracking capacity.

***Crude Oil Supply*.** We forecast that annual U.S. crude oil production will average 11.1 million b/d in 2021, which is a 0.2 million b/d decrease from 2020 levels. However, annual average numbers somewhat obscure production trends. Production in 1Q21 was down by more than 2.0 million b/d from 1Q20, the quarter before 2Q20 when production fell sharply in response to falling oil prices. However, from 2Q21 through 4Q21, we forecast U.S. crude oil production will be up 0.4 million b/d on average year over year. We forecast U.S. crude oil production will rise to an average of 11.9 million b/d in 2022.

Most crude oil production in the Lower 48 (L48) states, excluding the Federal Offshore Gulf of Mexico (GOM), is tight oil production, and we expect trends in L48 production to drive overall U.S. crude oil production levels. Our forecast crude oil production growth is based on WTI prices that indicate a favorable environment for drilling activity. In June, WTI prices averaged more than $70/b for the first time since October 2018, and we expect that through the end of 2022, WTI prices will remain above $60/b—a price that has signaled robust activity among U.S. operators in the past. Because changes in rig counts typically lag changes in the WTI price by three to six months and production changes typically occur about two months after rig deployment, current crude oil price levels will not likely affect production until late 2021. We forecast U.S. crude oil production to average about 11.2 million b/d in both 2Q21 and 3Q21 before beginning to rise more steadily. Forecast U.S. crude oil production reaches 11.3 million b/d in 4Q21 and increases to 12.2 million b/d by 4Q22.

Assuming that other factors remain constant, recent and forecast crude oil price levels will likely continue to drive rig deployments through the end of 2022. However, this forecast depends on the capital decisions of operators. The recent pace of rig deployment indicates that operators are adding rigs more slowly than during past periods when prices reached similar levels. If operators take a more cautious approach to rig deployment than we are expecting, crude oil production could be lower than in our forecast.

In the GOM, we expect crude oil production to average 1.8 million b/d in both 2021 and 2022. Ten new projects that will likely begin operations during the forecast period will help offset declines at existing GOM projects.

We expect little change in Alaska’s crude oil production, which will average more than 0.4 million b/d in both 2021 and 2022, down slightly from 2020 levels. We do not expect the U.S. federal moratorium on new federal oil and natural gas leases that occurred earlier this year to affect the short-term outlook for the GOM or Alaska.

Hydrocarbon Gas Liquids Supply. We forecast natural gas plant production of HGLs to increase by 0.1 million b/d in 2021 and by almost 0.5 million b/d in 2022. Rising HGL production in the forecast is mostly driven by increased ethane production. Higher rates of ethane recovery at natural gas processing plants occur in the forecast to meet growing demand for ethane as a petrochemical feedstock in the United States and abroad during both 2021 and 2022.

Liquid Biofuels. COVID-19-related reductions in economic activity in general, and decreased demand for liquid fuels in particular, significantly affected U.S. biofuels markets in 2020, and we expect some of these impacts to persist through the forecast period. The current forecast reflects the most recent 2020 targets in the Renewable Fuel Standard (RFS) program, and given the delays in finalizing 2021 RFS targets, we assume those 2020 target levels to remain unchanged throughout the forecast period. In the forecast, these RFS targets primarily affect biomass-based diesel production and net imports, which help meet multiple RFS targets for biomass-based diesel, advanced biofuel, and total renewable fuel.

Because of sharp reductions in motor gasoline demand resulting from responses to COVID-19, U.S. fuel ethanol production was significantly lower in 2020 than in previous years. U.S. fuel ethanol production fell by 12% from 2019 to an average of 0.91 million b/d in 2020. As a result, we forecast that persistent reductions in domestic gasoline demand and limited higher-blend fuel ethanol growth potential will result in fuel ethanol production remaining lower than 2019 levels throughout the STEO forecast. We expect fuel ethanol production to average 0.97 million b/d in 2021, 7% more than in 2020, and to average 1.00 million b/d in 2022, 4% more than 2021, but still slightly below the 2019 level.

U.S. fuel ethanol consumption averaged 949,000 b/d in 2019, and we estimate fuel ethanol consumption fell by 13% to an average of 822,000 b/d in 2020. We forecast that fuel ethanol consumption will gradually rise during the forecast period, largely following the growth in domestic motor gasoline consumption with limited growth in any higher blending levels. In our forecast, U.S. fuel ethanol consumption averages 896,000 b/d in 2021 and 917,000 b/d in 2022. This level of consumption results in the fuel ethanol share of total gasoline, which was an estimated 10.2% in both 2019 and 2020, remaining near this level during 2021 and 2022. This stable fuel ethanol share assumes that growth in higher-level fuel ethanol blends is limited by a lack in consumer demand for higher levels of fuel ethanol blending beyond 10% of gasoline (E10) despite significantly elevated renewable identification number (RIN) prices which could incentivize increased fuel ethanol blending by some gasoline blenders and retailers.

We estimate that U.S. biodiesel production increased in 2020 and was less affected by COVID-19-related restrictions than many other fuels, despite production capacity that declined slightly. U.S. biodiesel production increased by an estimated 5% from 2019 to 2020, averaging an estimated 118,000 b/d last year. We expect biodiesel production will fall slightly to 117,000 b/d in 2021 before increasing by 10% to 129,000 b/d in 2022, driven largely by biodiesel's role in meeting multiple RFS targets and the existence of the biodiesel production tax credit through 2022. Despite RIN prices that have recently been at all-time highs, record-high feedstock costs are expected to limit biodiesel production growth over the forecast period.

U.S. net imports of biomass-based diesel increased by an estimated 6% to an average of 22,000 b/d in 2020, and we expect net imports to increase to an average of 29,000 b/d in 2021 and 44,000 b/d in 2022. Increased net imports of biomass-based diesel primarily reflect increased volumes of renewable diesel imported to meet both California Low Carbon Fuel Standard requirements and RFS targets for biomass-based diesel and advanced biofuels.

Product Prices. Changes in travel patterns in response to COVID-19 resulted in significant reductions in crude oil prices and demand for liquid fuels in the United States during 2020, which significantly reduced prices for gasoline and diesel fuel during the same period. In 2021, as vaccination levels have increased and general economic activity has begun to recover, personal mobility and seasonal driving demand has grown sharply year-over-year, leading to increasing prices for crude oil, gasoline, and diesel fuel compared with the same time last year.

Although much of the increase in U.S. gasoline and diesel prices so far in 2021 reflects rising crude oil prices, higher refinery margins have also contributed. Refinery margins (the difference between the wholesale price of gasoline and the price of Brent crude oil), which fell significantly along with gasoline and diesel demand in March and April 2020, returned to levels within their seasonal ranges in 4Q20. Since then, margins have increased significantly beyond their recent five-year averages, driven in part by significant increases in RIN prices, which are embedded to some degree in wholesale product prices. So, although refinery margins have increased beyond seasonal averages for both gasoline and diesel fuel, RIN costs have likely limited actual refinery profitability to some degree. This dynamic is reflected in refinery production of gasoline, which has not increased in line with growing gasoline demand, resulting in U.S. gasoline inventories that have been lower than in recent years and in upward pressure on prices.

The U.S. refinery wholesale gasoline margin averaged 30 cents/gal in February 2021. It then increased to an average of 52 cents/gal in June, which was 17 cents/gal higher than at the same time last year and 11 cents/gal higher than the recent five-year average. We expect the U.S. refinery wholesale gasoline margin will average 42 cents/gal in 2021 and 36 cents/gal in 2022, compared with a five-year (2016–20) average of 35 cents/gal. Because some of the strength in margins is attributable to elevated RIN costs, the margins remain uncertain throughout the year because RIN markets can be highly volatile and are currently driven by both agricultural commodity markets as well as uncertainty around future RFS rulemakings. Our forecast assumes current elevated agricultural commodity prices will not persist to the same degree, and future RFS rulemakings will add clarity and reduce some tightness in RIN markets.

In addition to elevated refinery margins, supply disruptions as a result of the Colonial Pipeline Cyberattack added upward retail gasoline price pressure in May, when the U.S. weekly average gasoline retail prices surpassed $3.00/gal for the first time since late 2014. Since then, U.S. regular gasoline retail prices have remained above $3.00/gal, averaging $3.06/gal in June. We expect that gradual reductions in U.S. refinery margins, driven partially by increased refinery output along with falling crude oil prices, will result in lower retail gasoline prices for the remainder of the year. We forecast the retail price of regular gasoline in the United States will average $3.04/gal during 3Q21, 85 cents/gal higher than at the same time last year. We expect the U.S. monthly regular retail gasoline price will fall from an average of $3.11/gal in July 2021 to $2.93/gal in September before falling to $2.76/gal in December 2021. We forecast the U.S. regular gasoline retail price, which averaged $2.18/gal in 2020, to average $2.85/gal in 2021 and $2.74/gal in 2022.

Regional annual average forecast prices for 2021 range from a low of $2.56/gal in the Gulf Coast region (PADD 3) to a high of $3.51/gal in the West Coast region (PADD 5).

The retail price of diesel fuel in the United States averaged $2.55/gal in 2020, which was 50 cents/gal lower than in 2019. We forecast that the diesel price will average $3.16/gal in 2021 and $3.09/gal in 2022. We expect that global economic activity returning to pre-pandemic levels will help drive diesel refinery margins higher during the forecast period than their multiyear lows in 2020. Diesel refinery margins based on the Brent crude oil price averaged 30 cents/gal in 2020, which was 11 cents/gal lower than the 2015–19 average and the lowest annual average since 2009. We expect diesel refinery margins will average 40 cents/gal in 2021 and 44 cents/gal in 2022.

Natural Gas

Natural Gas Consumption. U.S. consumption of natural gas averaged 83.3 billion cubic feet per day (Bcf/d) in 2020, and we expect consumption will decrease by 0.9 Bcf/d (1.1%) in 2021 and then increase by 0.6 Bcf/d (0.7%) 2022 to average 82.9 Bcf/d for the year.

The largest natural gas-consuming sector in the United States is the electric power sector. We estimate that the electric power sector will consume an average of 29.3 Bcf/d in 2021, which is 7.7% less than in 2020. We forecast that higher prices for natural gas (compared with coal prices) for power generation and rising electricity generation capacity from renewable energy will likely cause natural gas consumption in the electric power sector to decline in 2021. We forecast electric power sector consumption of natural gas will increase by 1.3% in 2022, based on an expected decline in natural gas prices next year.

We expect combined U.S. residential and commercial natural gas consumption will average 22.6 Bcf/d in 2021, up 6.0% from 2020. Compared with 1Q20, colder temperatures and people spending more time at home because of the COVID-19 pandemic led to increases in heating demand in 1Q21. Based on forecasts by the National Oceanic and Atmospheric Administration (NOAA), we assume colder temperatures with 7.0% more heating degree days (HDD) across the United States in 2021 compared with 2020. We expect natural gas consumption in the U.S. residential and commercial sectors to decline by 0.4% in 2022.

We forecast U.S. consumption of natural gas in the industrial sector will increase 1.2% in 2021 to 22.8 Bcf/d and an additional 0.9% to 23.0 Bcf/d in 2022. Our natural gas-weighted manufacturing index, based on forecasts from IHS Markit, has steadily increased after falling in 2Q20, and our forecast assumes that the natural gas-weighted manufacturing index will reach 2019 levels in 2H21.

Natural Gas Production. We forecast that U.S. dry natural gas production will average 92.6 Bcf/d in 2021, which would be up 1.3% from 2020. Natural gas production rises in response to higher crude oil and natural gas prices. We forecast Henry Hub spot prices in 2021 will average more than $1 per million British thermal units (MMBtu), or 58%, higher than the average in 2020. In addition, we expect associated natural gas production from oil directed rigs in the Permian Basin to increase in 2021 as WTI prices average almost $27/b (68%) more than in 2020.

In 2022, we expect dry natural gas production to average 94.7 Bcf/d, which would be up 2.3% from 2021.

Natural Gas Trade. We forecast U.S. liquefied natural gas (LNG) exports to average 9.6 Bcf/d in 2021 and 10.2 Bcf/d in 2022, surpassing pipeline exports for the first time on an annual basis in both years. Several factors support this forecast: gradual recovery in global LNG demand, high winter LNG demand, particularly in Asia, and expansions in global LNG regasification capacity in both existing and new markets in the next two years. U.S. LNG exports are projected to increase in 2022 because of commissioning of additional LNG trains at Sabine Pass and Calcasieu Pass.

U.S. LNG exports have reached record high levels this spring, averaging 10.3 Bcf/d from March through May, supported by high spot LNG prices in Asia and Europe, and a continuous recovery in global LNG demand. We estimate that U.S. LNG exports declined to 9.0 Bcf/d in June, likely because of planned and unplanned outages at several U.S. liquefaction facilities.

Pipeline exports of U.S. natural gas have also increased as more infrastructure has been built to transport natural gas both to and within Mexico. U.S. pipeline exports averaged 7.9 Bcf/d in 2020, an increase of 1.7% compared with 2019. We expect pipeline exports to increase as more natural gas-fired power plants come online in Mexico and more pipeline infrastructure is built within Mexico and the United States. We expect gross U.S. pipeline exports to Mexico and Canada to average 9.0 Bcf/d in 2021 and 9.2 Bcf/d in 2022.

U.S. natural gas pipeline imports (almost all of which come from Canada) decreased from 2019 to 2020, continuing a trend that began in 2008. We forecast natural gas pipeline imports to increase 5.7% in 2021 because the United States will import more natural gas amid relatively flat U.S. natural gas production along with record U.S. exports of natural gas. However, pipeline imports will likely decline in 2022 in response to an increase in U.S. natural gas production in 2022.

Natural Gas Inventories. Storage withdrawals in 1Q21 were 14% higher than the five-year average because severely cold temperatures in February caused near-record storage withdrawals and because of declines in natural gas production. Total inventories were 1.8 trillion cubic feet (Tcf) at the end of March, about 2% lower than the five-year average for that time of year. For the 2021 April–October storage injection season, we expect injections will be 5% below the five-year average rate because record exports outpace increases in natural gas production. We expect that inventories will reach more than 3.6 Tcf at the end of October 2021, which would be 3% lower than the previous five-year average for the end of October and 8% lower than at the end of October 2020.

Natural Gas Prices. The Henry Hub spot price averaged $2.03/MMBtu in 2020. Natural gas prices fell through much of 2020 as U.S. natural gas consumption outside of the electric power sector declined and LNG exports also dropped. These declines outpaced declines in production and contributed to inventories building at a faster rate than the five-year average.

The Henry Hub spot price rose to an average of $3.25/MMBtu in 1H21, somewhat elevated by the February monthly average price of $5.35/MMBtu, which was strongly influenced by cold weather. More recently, the daily spot price reached $3.79/MMBtu on June 30. U.S. natural gas prices rose in 1H21 as growth in demand for natural gas outpaced supply. The combination of U.S. consumption of natural gas outside of the power sector and exports together were up almost 6 Bcf/d in 1H21 compared with the same period in 2020. At the same time, domestic dry natural gas production plus imports were almost unchanged in 1H21 compared in 1H20.

We expect the Henry Hub spot price to fall from recent highs and average $3.22/MMBtu in 3Q21 and also average $3.22/MMBtu for all of 2021. For the remaining months in 2021, we expect prices to remain more than $3.00/MMBtu, driven by continuing record natural gas exports and rising demand for natural gas outside of the electric power sector amid relatively flat natural gas production. We expect downward price pressure to emerge in 2022 as U.S. natural gas production increases and export growth slows. We forecast the Henry Hub spot price to average $3.00/MMBtu in 2022.

Coal

Coal Production. We forecast U.S. coal production will increase by 78 million short tons (MMst) (15%) in 2021 to total 617 MMst for the year. The expected increase in production reflects greater electric power sector demand for coal. Higher natural gas prices make coal more economically competitive relative to natural gas for electricity generation dispatch. In the forecast, coal production increases by 13 MMst (9%) in the Appalachia region, 14 MMst (16%) in the Interior region, and 51 MMst (17%) in the Western region.

Coal production in the forecast falls by 7 MMst (1%) in 2022 to 610 MMst. The decline is in response to falling natural gas prices in our forecast, which tends to reduce coal use for power generation. Western region production is expected to decline by 6% in 2022, offsetting gains in the Interior (7%) and Appalachia (5%) regions.

Overall production capacity decreased in 2020, and the lost capacity is unlikely to come back online. We expect an increased draw on electric power sector coal inventories in 2021 (25 MMst) and 2022 (23 MMst).

Coal Consumption. We expect a 92 MMst (19%) increase in U.S. coal consumption in 2021. Rising consumption is largely driven by an increase in demand from the electric power sector, which is expected to consume 522 MMst of coal in 2021, 20% more than 2020. We forecast total U.S. coal consumption to decrease 32 MMst (6%), in 2022 to 537 MMst.

Coal Trade. Annual U.S. coal exports dropped 26% between 2019 and 2020, from 94 MMst to 69 MMst. Metallurgical coal exports were 42 MMst in 2020, 20% lower than the previous year, and steam coal exports were 27 MMst, 34% lower than in 2019.

Four of the top 10 U.S. coal export destinations—Brazil, Turkey, the Dominican Republic, and China—increased their imports of U.S. coal in 2020. Exports to the Dominican Republic increased by 1.3 MMst, more than double its 2019 imports of U.S. coal. In particular, an ongoing trade dispute between Australia and China has opened up opportunities for swing suppliers, such as the United States, to gain market share and increase overall exports especially for steam coal.

In our forecast, we assume the seaborne steam coal market in 2021 will be more robust with higher demand for U.S. coal. Forecast U.S. steam coal exports reach 37 MMst in 2021, which is a 37% increase from 2020. Rising U.S. exports in the forecast reflect smaller export volumes from other global suppliers and seaborne coal prices that are supportive of U.S. exports. We expect total U.S. coal exports to increase by 15 MMst (21%) in 2021 as a result of economic growth for major coal importers that are emerging from a lower demand market because of the pandemic in 2020. Steel production, which was limited by pandemic shutdowns, is expected to return to average levels during the remainder of 2021 and bring U.S. metallurgical coal exports to 47 MMst. We expect coal exports to increase by 15 MMst (18%) in 2022 as overall seaborne supply comes back into line with 2019 levels. We expect that U.S. coal exports will total 99 MMst in 2022.

Coal Prices. The delivered coal price to U.S. electricity generators averaged $1.92/MMBtu in 2020, which was 10 cents/MMBtu lower than the 2019 price. We forecast that coal prices will decrease to $1.88/MMBtu in 2021 and $1.85/MMBtu in 2022.

Electricity

Electricity Consumption. We forecast total retail sales of electricity by U.S. utilities and electricity suppliers will increase by 2.8% in 2021 and by 1.0% in 2022. So far this year, estimated U.S. retail electricity sales during 1H21 were 4.5% more than for the same period of 2020. We forecast that electricity sales during 2H21 will grow by 1.2% compared with 2H20.

The relaxing of social distancing guidelines and growing COVID-19 vaccinations have led to increased economic activity compared with last year, especially in restaurants and retail stores, which were most affected by pandemic-related restrictions in 2020. Residential electricity consumption in 2020 noticeably increased because people were staying at home for longer periods during the day and because many were working from home. Residential electricity use is likely to remain elevated as work-from-home arrangements continue for some workers.

Year-to-year changes in residential electricity consumption are most related to changes in temperature, often measured using heating degree days (HDD) and cooling degree days (CDD). We estimate residential electricity sales during 1H21 to be 5.7% more than during the same period in 2020. Much of this increase reflected colder winter temperatures compared with last year's mild winter and a hot June across much of the country. HDDs in the United States during 1H21 were 6.9% more than in 2020. Based on forecasts from NOAA, our forecast assumes U.S.

HDDs to be higher than last year during 2H21, but the effect on electricity consumption is offset by CDDs in the forecast that are 9.7% lower than in 2H20. We forecast residential electricity sales during 2H21 will be 1.4% lower than residential sales in 2020. Forecast annual residential electricity use grows by 1.9% in 2021 and falls by 0.5% in 2022.

Weather and overall economic activity affect electricity consumption in the commercial sector. Although the colder winter weather earlier this year supported electricity consumption in the commercial sector, economic activity and growth in private-sector jobs were still restrained, especially during 1Q21 compared with the same period in 2020, before the pandemic-related lockdowns began. Nonfarm employment during 1Q21 was 5.6% lower during the same period in 2020, while retail electricity sales to the commercial sector were 2.9% lower. For 2H21, we forecast commercial sector retail electricity sales will grow by 1.7% compared with last year, driven in part by an expected 4.8% increase in nonfarm employment. For 2022, forecast commercial sector electricity use grows by 1.4% on an annual basis.

Improving economic conditions will also likely increase electricity demand in the industrial sector. The U.S. industrial production index for electricity-intensive industries in the forecast increases by 6.5% in 2021 after declining by a similar percentage in 2020. This expected increase in industrial production contributes to our forecast that retail sales of electricity to the industrial sector will rise by 5.1% in 2021. In 2022, we forecast retail sales of electricity to the industrial sector will increase by 2.6%.

Electricity Generation. We expect the U.S. electric power sector will generate 2.1% more power during 2021 than in 2020. Electric power sector generation in the forecast grows by an additional 0.7% in 2022.

One of the largest shifts in fuels for electricity generation in recent years has been the industry's reduced use of coal and increased use of natural gas. Coal-fired electricity generation in the United States has declined almost every year over the past decade. The amount of U.S. coal generation in 2020 was 62% below its high in 2007. In contrast, natural gas generation grew by 86% between 2007 and 2020.

Both regulatory and economic factors are driving this trend of declining coal use and rising natural gas use. One of the most important drivers has been the sustained low cost of natural gas, which reached the lowest level in decades last year. In 2020, the price of natural gas delivered to electric generators averaged $2.39/MMBtu. However, natural gas prices have been rising in recent months now that the economy is beginning to recover from the effects of the pandemic, but U.S. production of natural gas is growing at a slower pace. In April 2021, the most recent available history, the delivered natural gas price to electricity generators averaged $3.04/MMBtu. Expected natural gas costs remain relatively elevated through the forecast and delivered prices average $3.44/MMBtu in 2H21.

These expected changes in the costs of fuels used for generating power will likely reverse some of the recent trends in the use of coal and natural gas for electricity generation, at least temporarily. We forecast that the natural gas-fired share of total U.S. generation will decline from 39% in 2020 to 36% in both 2021 and 2022, which would be close to what the natural gas share was in 2019. The expected rise in natural gas costs make coal more economical for electricity generation. The forecast share of generation from coal-fired power plants rises from 20% last year to 24% in 2021 and 22% in 2022.

We forecast the share of generation from renewable sources will increase from 20% in 2020 to 21% in 2021 and to 23% in 2022. Most of this increase will come from new solar and wind generating capacity expansions in the electric power sector. The current drought in the West has restrained electricity generation by hydropower. U.S. hydropower generation contributes about 6.5% of total generation in the 2021 forecast, which would be the lowest share since 2015. In 2022, the forecast hydropower share rises to 6.8% but is still below the 7.5% share last year.

The forecast nuclear share of total electricity generation, which averaged nearly 21% in 2020 will fall to 20% by 2021 and to 19% in 2022. The declining share partly reflects retirements of nuclear capacity. In April, New York's Indian Point nuclear power plant retired. Reactors at three other nuclear plants in the Midwest are scheduled to retire in either 2021 or 2022. The retirements are partly offset by two reactors at the Vogtle plant in Georgia that are scheduled to come online next year.

Renewable Capacity. We expect that generating capacity from renewable energy sources will continue to grow through the STEO forecast horizon. By the end of 2022, electric power sector total renewables capacity increases by 81 gigawatts (GW) from 2019. An additional 15 GW in all other sectors brings the total to 96 GW.

We forecast that in 2022 large-scale solar capacity growth will exceed wind growth for the first time. We forecast that 16 GW of solar photovoltaic (PV) generating capacity in the electric power sector will be added in 2021 and an additional 17 GW is forecast for 2022. We forecast small-scale solar PV capacity to increase by about 5 GW per year through the STEO forecast period. Residential PV accounts for most of this additional small-scale generating capacity for both 2021 and 2022. Solar capacity growth in the forecast reflects various state and federal policies that support renewable energy.

We forecast generating capacity from wind turbines in the electric power sector to grow by 17 GW in 2021 and by 6 GW in 2022. Because wind capacity is often added at the end of the calendar year, increases in wind generation frequently lag behind increases in capacity for the year they occur in, and they are reflected in the generation for the next year.

Much of this slowing growth in wind capacity can be attributed to the expiration of the production tax credit. The credit, which at the end of 2019 was extended through 2020, provided a 2.5 cents per kilowatthour (kWh) benefit for facilities entering service or securing 5% safe harbor (spending at least 5% of total estimated project cost) through the 2020 calendar year. The effect of the tax credit extension included in the Consolidated Appropriation Act 2021, enacted in late-December 2020, is now reflected in this forecast. This extension caused capacity additions to move from 2020 to 2021 and the slowing wind growth in 2022.

Electricity Prices. Wholesale electricity prices throughout the country so far in 2021 have been higher than last year, reflecting the increased cost of natural gas for power generation. During 2Q21, wholesale prices ranged from $31 per megawatthour (MWh) in the Central region, which is 58% higher than 2Q20, to $52/MWh in the Northwest region, which is 256% higher than in 2020. Wholesale prices are likely to remain relatively volatile over the next few months. Forecast prices during 2H21 average from a low of $24/MWh in Texas to a high of $46/MWh in California.

We forecast the U.S. retail electricity price for the residential sector will average 13.6 cents/kWh in 2021, which is 2.8% higher than the average retail price in 2020. Forecast residential prices increase by an additional 1.8% in 2022.

U.S. Economic Assumptions and Energy-Related Carbon Dioxide Emissions

U.S. Economy. We base the STEO on macroeconomic forecasts for the United States by IHS Markit. We used the June 2021 version of the IHS Markit macroeconomic model with our own energy price forecasts as model assumptions to develop the economic forecasts in the STEO.

Using the IHS Markit model, we assume U.S. real GDP will grow by 7.4% in 2021 and by 5.0% in 2022. These rates compare with a 3.5% decline in annual GDP growth in 2020. We assume that total U.S. industrial production will increase 6.5% in 2021 and 4.8% in 2022. This growth contrasts with the 7.2% decline in annual growth in 2020. In the forecast, U.S. nonfarm employment, which decreased by 5.7% in 2020, will increase by 2.9% in 2021 and 3.8% in 2022.

Energy-Related Carbon Dioxide Emissions. Energy-related carbon dioxide (CO_2) emissions in the United States fell by 11.1% in 2020 relative to 2019. We expect CO_2 emissions to rise by 7.1% in 2021 and by 1.5% in 2022. We forecast an increase in coal CO_2 emissions and a decrease in natural gas CO_2 emissions because higher natural gas prices make coal more economically competitive for electric power generation. We expect CO_2 emissions from coal to rise by 18.5% in 2021 and to decline by 4.9% in 2022. We expect CO_2 emissions from natural gas to fall by 1.3% from 2020 to 2021 and then increase by less than 1% in 2022. Petroleum-related CO_2 emissions increase 9.0% in 2021 and 5.2% in 2022 as transportation patterns begin to return to normal. Energy-related CO_2 emissions are sensitive to changes in weather, economic growth, energy prices, and fuel mix.

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

U.S. Energy Information Administration | Short-Term Energy Outlook - July 2021

	2020				2021				2022				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2020	2021	2022
Supply (million barrels per day) (a)															
OECD	32.94	29.42	29.97	30.68	30.17	30.93	31.47	31.94	32.22	32.50	32.84	33.36	30.75	31.13	32.74
U.S. (50 States)	20.22	17.58	18.30	18.31	17.63	18.99	18.94	19.15	19.44	19.85	20.27	20.58	18.60	18.68	20.04
Canada	5.64	4.91	4.94	5.55	5.63	5.29	5.66	5.76	5.79	5.76	5.79	5.81	5.26	5.59	5.79
Mexico	2.00	1.94	1.91	1.90	1.93	1.95	1.93	1.90	1.84	1.80	1.77	1.74	1.94	1.93	1.79
Other OECD	5.08	4.99	4.81	4.93	4.99	4.70	4.94	5.14	5.15	5.08	5.01	5.24	4.95	4.94	5.12
Non-OECD	67.68	63.02	61.06	62.09	62.55	64.15	67.36	68.01	67.77	69.09	69.77	69.64	63.45	65.54	69.07
OPEC	33.50	30.72	28.65	30.00	30.35	30.81	33.17	34.07	34.22	34.09	34.12	34.16	30.71	32.11	34.15
Crude Oil Portion	28.28	25.65	23.63	24.88	25.08	25.53	27.82	28.67	28.63	28.63	28.63	28.63	25.60	26.79	28.63
Other Liquids (b)	5.22	5.07	5.02	5.12	5.27	5.28	5.35	5.40	5.59	5.46	5.49	5.53	5.11	5.32	5.52
Eurasia	14.73	13.18	12.72	13.13	13.39	13.63	13.71	13.88	14.04	14.63	14.78	14.92	13.44	13.65	14.59
China	4.96	4.91	4.95	4.90	5.05	5.06	5.01	5.06	5.05	5.08	5.08	5.13	4.93	5.05	5.08
Other Non-OECD	14.49	14.21	14.74	14.06	13.77	14.64	15.46	15.00	14.46	15.30	15.78	15.43	14.38	14.72	15.25
Total World Supply	100.63	92.44	91.02	92.78	92.73	95.08	98.82	99.95	99.99	101.59	102.61	103.00	94.20	96.67	101.81
Non-OPEC Supply	67.13	61.72	62.37	62.77	62.38	64.27	65.65	65.88	65.77	67.51	68.49	68.84	63.49	64.56	67.66
Consumption (million barrels per day) (c)															
OECD	45.26	37.40	42.12	42.79	42.23	43.95	45.35	45.97	45.61	45.41	46.37	46.53	41.90	44.39	45.98
U.S. (50 States)	19.33	16.08	18.36	18.71	18.45	19.78	20.09	20.23	20.10	20.62	21.00	21.00	18.12	19.64	20.68
U.S. Territories	0.17	0.15	0.16	0.17	0.20	0.18	0.18	0.19	0.20	0.18	0.19	0.20	0.16	0.19	0.19
Canada	2.33	1.88	2.16	2.05	2.01	2.16	2.30	2.30	2.26	2.21	2.31	2.30	2.10	2.19	2.27
Europe	13.33	11.01	12.87	12.51	11.88	12.79	13.56	13.48	13.13	13.29	13.64	13.32	12.43	12.93	13.35
Japan	3.69	2.89	3.03	3.50	3.69	2.95	3.06	3.40	3.63	2.97	3.05	3.37	3.27	3.27	3.25
Other OECD	6.41	5.41	5.55	5.87	6.01	6.09	6.16	6.36	6.29	6.14	6.18	6.34	5.81	6.16	6.24
Non-OECD	50.33	47.45	51.21	52.59	52.27	52.79	53.68	54.19	54.19	55.61	55.76	55.88	50.40	53.24	55.37
Eurasia	4.86	4.48	5.28	5.17	4.92	5.00	5.39	5.23	5.04	5.13	5.53	5.38	4.95	5.14	5.27
Europe	0.71	0.69	0.71	0.72	0.73	0.74	0.74	0.74	0.73	0.75	0.76	0.76	0.71	0.74	0.75
China	13.89	14.08	14.65	15.11	15.03	15.48	15.21	15.53	15.83	16.07	15.76	16.02	14.43	15.31	15.92
Other Asia	13.35	11.63	12.60	13.61	13.83	13.45	13.50	14.06	14.44	14.69	14.28	14.71	12.80	13.71	14.53
Other Non-OECD	17.53	16.55	17.98	17.99	17.76	18.13	18.84	18.62	18.15	18.98	19.43	19.01	17.51	18.34	18.90
Total World Consumption	95.59	84.85	93.33	95.39	94.50	96.74	99.03	100.15	99.81	101.02	102.13	102.41	92.30	97.63	101.35
Total Crude Oil and Other Liquids Inventory Net Withdrawals (million barrels per day)															
U.S. (50 States)	-0.43	-1.68	0.49	0.89	0.48	0.33	-0.09	0.48	0.05	-0.55	0.02	0.43	-0.18	0.30	-0.01
Other OECD	-0.51	-1.16	0.04	0.69	0.76	0.42	0.10	-0.09	-0.07	-0.01	-0.16	-0.32	-0.23	0.29	-0.14
Other Stock Draws and Balance	-4.10	-4.75	1.79	1.04	0.54	0.91	0.21	-0.18	-0.16	-0.02	-0.35	-0.70	-1.49	0.37	-0.31
Total Stock Draw	-5.03	-7.59	2.31	2.61	1.77	1.66	0.21	0.21	-0.18	-0.58	-0.49	-0.59	-1.90	0.96	-0.46
End-of-period Commercial Crude Oil and Other Liquids Inventories (million barrels)															
U.S. Commercial Inventory	1,321	1,453	1,422	1,344	1,302	1,288	1,297	1,257	1,257	1,312	1,313	1,283	1,344	1,257	1,283
OECD Commercial Inventory	2,964	3,201	3,167	3,026	2,915	2,864	2,863	2,832	2,838	2,894	2,909	2,908	3,026	2,832	2,908

(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 Thursday July 1, 2021.

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 - July 2021

	2020				2021				2022				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2020	2021	2022
Supply (million barrels per day)															
Crude Oil Supply															
Domestic Production (a)	12.75	10.81	10.81	10.90	10.70	11.20	11.17	11.34	11.54	11.72	11.95	12.20	11.31	11.10	11.85
Alaska	0.48	0.41	0.44	0.46	0.46	0.43	0.40	0.44	0.43	0.41	0.39	0.43	0.45	0.43	0.42
Federal Gulf of Mexico (b)	1.96	1.69	1.45	1.52	1.80	1.77	1.74	1.73	1.77	1.74	1.75	1.78	1.66	1.76	1.76
Lower 48 States (excl GOM)	10.31	8.71	8.92	8.91	8.44	9.00	9.03	9.17	9.34	9.56	9.81	9.99	9.21	8.91	9.68
Crude Oil Net Imports (c)	2.90	3.08	2.31	2.51	2.87	2.99	4.50	3.73	3.77	4.77	4.82	3.96	2.70	3.53	4.33
SPR Net Withdrawals	0.00	-0.23	0.15	0.04	0.00	0.18	0.00	0.05	0.05	0.05	0.03	0.11	-0.01	0.06	0.06
Commercial Inventory Net Withdrawals	-0.55	-0.54	0.38	0.13	-0.18	0.58	0.15	-0.06	-0.29	-0.02	0.27	-0.02	-0.14	0.12	-0.01
Crude Oil Adjustment (d)	0.67	0.03	0.38	0.32	0.42	0.58	0.23	0.16	0.22	0.22	0.23	0.16	0.35	0.35	0.21
Total Crude Oil Input to Refineries	15.77	13.16	14.03	13.90	13.81	15.54	16.04	15.22	15.28	16.74	17.30	16.41	14.21	15.16	16.44
Other Supply															
Refinery Processing Gain	1.02	0.82	0.94	0.92	0.84	1.06	1.08	1.05	1.07	1.10	1.15	1.15	0.92	1.01	1.12
Natural Gas Plant Liquids Production	5.12	4.96	5.33	5.23	4.86	5.41	5.37	5.46	5.54	5.70	5.82	5.87	5.16	5.28	5.73
Renewables and Oxygenate Production (e)	1.11	0.80	1.03	1.07	1.03	1.11	1.10	1.09	1.08	1.11	1.13	1.13	1.01	1.08	1.11
Fuel Ethanol Production	1.02	0.70	0.92	0.97	0.90	1.00	1.00	0.98	0.98	1.01	1.02	1.02	0.91	0.97	1.00
Petroleum Products Adjustment (f)	0.22	0.19	0.20	0.19	0.19	0.21	0.21	0.21	0.21	0.22	0.23	0.23	0.20	0.21	0.22
Product Net Imports (c)	-4.03	-2.94	-3.12	-3.32	-2.94	-3.12	-3.48	-3.29	-3.38	-3.67	-4.34	-4.14	-3.35	-3.21	-3.88
Hydrocarbon Gas Liquids	-1.99	-1.86	-1.86	-2.03	-2.02	-2.21	-2.26	-2.07	-2.11	-2.25	-2.33	-2.18	-1.94	-2.14	-2.22
Unfinished Oils	0.31	0.25	0.34	0.19	0.14	0.36	0.42	0.29	0.21	0.25	0.30	0.20	0.27	0.30	0.24
Other HC/Oxygenates	-0.10	-0.05	-0.04	-0.04	-0.08	-0.06	-0.07	-0.08	-0.09	-0.08	-0.08	-0.09	-0.06	-0.07	-0.08
Motor Gasoline Blend Comp.	0.39	0.36	0.48	0.43	0.55	0.68	0.42	0.14	0.53	0.76	0.43	0.21	0.42	0.45	0.48
Finished Motor Gasoline	-0.72	-0.40	-0.58	-0.78	-0.66	-0.59	-0.61	-0.63	-0.82	-0.68	-0.74	-0.76	-0.62	-0.62	-0.75
Jet Fuel	-0.07	0.09	0.12	0.07	0.03	0.09	0.11	0.13	0.00	0.03	0.12	0.19	0.05	0.09	0.09
Distillate Fuel Oil	-1.19	-0.86	-1.15	-0.74	-0.49	-0.85	-0.91	-0.50	-0.53	-0.97	-1.28	-1.09	-0.98	-0.69	-0.97
Residual Fuel Oil	-0.02	0.02	0.05	0.05	0.08	0.04	0.00	0.05	-0.03	-0.08	-0.06	0.04	0.02	0.04	-0.03
Other Oils (g)	-0.65	-0.49	-0.49	-0.48	-0.49	-0.59	-0.59	-0.62	-0.53	-0.67	-0.70	-0.65	-0.52	-0.57	-0.64
Product Inventory Net Withdrawals	0.12	-0.91	-0.04	0.71	0.66	-0.43	-0.24	0.49	0.30	-0.59	-0.28	0.35	-0.03	0.12	-0.06
Total Supply	19.33	16.08	18.36	18.71	18.45	19.78	20.09	20.23	20.10	20.62	21.00	21.00	18.12	19.64	20.68
Consumption (million barrels per day)															
Hydrocarbon Gas Liquids	3.31	2.83	2.95	3.70	3.40	3.10	2.97	3.64	3.84	3.29	3.30	3.84	3.20	3.28	3.57
Unfinished Oils	0.14	0.11	0.01	0.03	0.05	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.03	0.00
Motor Gasoline	8.49	7.11	8.50	8.02	8.00	9.02	9.13	8.74	8.45	9.22	9.29	8.92	8.03	8.73	8.97
Fuel Ethanol blended into Motor Gasoline	0.85	0.72	0.87	0.84	0.82	0.94	0.93	0.89	0.86	0.94	0.94	0.93	0.82	0.90	0.92
Jet Fuel	1.56	0.69	0.97	1.09	1.13	1.33	1.55	1.55	1.53	1.66	1.81	1.82	1.08	1.39	1.71
Distillate Fuel Oil	3.97	3.51	3.70	3.92	3.97	4.01	4.06	4.24	4.30	4.25	4.19	4.28	3.78	4.07	4.26
Residual Fuel Oil	0.17	0.15	0.32	0.23	0.26	0.24	0.28	0.24	0.23	0.21	0.26	0.26	0.22	0.25	0.24
Other Oils (g)	1.68	1.68	1.91	1.71	1.63	1.98	2.11	1.82	1.74	1.99	2.15	1.88	1.75	1.89	1.94
Total Consumption	19.33	16.08	18.36	18.71	18.45	19.78	20.09	20.23	20.10	20.62	21.00	21.00	18.12	19.64	20.68
Total Petroleum and Other Liquids Net Imports	-1.13	0.14	-0.81	-0.81	-0.07	-0.12	1.02	0.44	0.39	1.11	0.48	-0.17	-0.65	0.32	0.45
End-of-period Inventories (million barrels)															
Commercial Inventory															
Crude Oil (excluding SPR)	482.5	531.9	497.3	485.3	501.9	449.3	435.5	441.0	467.6	469.1	443.9	445.9	485.3	441.0	445.9
Hydrocarbon Gas Liquids	180.8	233.9	299.1	229.2	168.6	209.1	248.4	201.8	158.9	207.4	248.5	206.7	229.2	201.8	206.7
Unfinished Oils	100.1	91.9	81.4	78.2	93.3	91.3	90.2	83.1	93.1	90.8	90.0	83.2	78.2	83.1	83.2
Other HC/Oxygenates	33.6	26.2	25.2	29.9	29.1	27.6	27.5	27.7	29.8	28.6	28.3	28.6	29.9	27.7	28.6
Total Motor Gasoline	260.8	253.3	226.5	243.2	237.6	241.2	228.3	234.7	241.8	246.5	234.3	249.8	243.2	234.7	249.8
Finished Motor Gasoline	22.6	23.5	22.4	25.3	20.3	22.4	22.4	24.5	24.1	23.9	23.2	26.2	25.3	24.5	26.2
Motor Gasoline Blend Comp.	238.3	229.8	204.1	217.9	217.4	218.8	205.9	210.2	217.7	222.6	211.2	223.6	217.9	210.2	223.6
Jet Fuel	39.9	41.5	40.1	38.6	39.0	44.6	45.9	42.2	41.2	41.7	43.9	40.7	38.6	42.2	40.7
Distillate Fuel Oil	126.7	175.4	171.7	160.4	145.5	137.6	139.8	141.8	131.0	135.6	142.6	143.6	160.4	141.8	143.6
Residual Fuel Oil	34.4	39.6	32.1	30.2	30.9	31.1	30.1	31.7	31.5	32.4	30.5	32.0	30.2	31.7	32.0
Other Oils (g)	62.0	59.2	48.6	49.3	55.8	56.6	51.0	53.2	62.2	60.0	50.7	52.1	49.3	53.2	52.1
Total Commercial Inventory	1320.8	1452.8	1422.0	1344.3	1301.7	1288.4	1296.7	1257.3	1257.2	1312.0	1312.7	1282.5	1344.3	1257.3	1282.5
Crude Oil in SPR	635.0	656.0	642.2	638.1	637.8	620.9	620.9	616.7	612.4	608.1	605.4	595.8	638.1	616.7	595.8

(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) For net imports and inventories “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; for consumption “Other Oils” also includes renewable fuels except fuel ethanol.

- = no data available

SPR: Strategic Petroleum Reserve

HC: Hydrocarbons

Notes: EIA completed modeling and analysis for this report on Thursday July 1, 2021.

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 - July 2021

	2020				2021				2022				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2020	2021	2022
Supply (billion cubic feet per day)															
Total Marketed Production	**102.27**	**96.83**	**97.55**	**98.70**	**97.33**	**100.49**	*100.76*	*101.43*	*101.26*	*101.75*	*102.89*	*103.61*	**98.83**	*100.01*	*102.39*
Alaska	**0.96**	**0.88**	**0.88**	**0.98**	**1.02**	**0.85**	*0.73*	*0.88*	*0.92*	*0.80*	*0.73*	*0.87*	**0.92**	*0.87*	*0.83*
Federal GOM (a)	**2.72**	**2.22**	**1.72**	**1.73**	**2.26**	**2.23**	*2.10*	*2.03*	*2.04*	*1.97*	*1.87*	*1.84*	**2.09**	*2.16*	*1.93*
Lower 48 States (excl GOM)	**98.58**	**93.74**	**94.95**	**95.99**	**94.05**	**97.41**	*97.92*	*98.51*	*98.30*	*98.98*	*100.29*	*100.90*	**95.81**	*96.99*	*99.63*
Total Dry Gas Production	**94.79**	**89.68**	**89.83**	**91.15**	**90.31**	**92.88**	*93.17*	*93.80*	*93.65*	*94.10*	*95.16*	*95.82*	**91.35**	*92.55*	*94.69*
LNG Gross Imports	**0.24**	**0.12**	**0.09**	**0.09**	**0.15**	**0.12**	*0.18*	*0.20*	*0.32*	*0.18*	*0.18*	*0.20*	**0.13**	*0.16*	*0.22*
LNG Gross Exports	**7.92**	**5.52**	**3.91**	**8.78**	**9.27**	**9.89**	*9.24*	*9.83*	*10.47*	*9.73*	*9.41*	*11.00*	**6.53**	*9.56*	*10.15*
Pipeline Gross Imports	**7.60**	**6.08**	**6.39**	**7.27**	**8.68**	**6.68**	*6.71*	*6.84*	*7.38*	*6.36*	*6.38*	*6.71*	**6.84**	*7.22*	*6.70*
Pipeline Gross Exports	**8.15**	**7.17**	**8.09**	**8.21**	**8.31**	**8.70**	*9.45*	*9.56*	*9.36*	*8.67*	*9.39*	*9.38*	**7.91**	*9.01*	*9.20*
Supplemental Gaseous Fuels	**0.19**	**0.17**	**0.15**	**0.18**	**0.18**	**0.18**	*0.18*	*0.18*	*0.18*	*0.18*	*0.18*	*0.18*	**0.17**	*0.18*	*0.18*
Net Inventory Withdrawals	**12.74**	**-12.24**	**-7.68**	**5.36**	**17.19**	**-9.09**	*-8.14*	*5.69*	*17.35*	*-11.01*	*-9.13*	*4.98*	**-0.46**	*1.35*	*0.49*
Total Supply	**99.49**	**71.12**	**76.78**	**87.06**	**98.92**	**72.18**	*73.41*	*87.31*	*99.05*	*71.40*	*73.97*	*87.51*	**83.61**	*82.90*	*82.93*
Balancing Item (b)	**-0.18**	**-0.29**	**0.05**	**-0.98**	**0.25**	**-0.14**	*-1.25*	*-1.15*	*-1.15*	*0.69*	*0.41*	*-0.18*	**-0.35**	*-0.58*	*-0.05*
Total Primary Supply	**99.31**	**70.84**	**76.83**	**86.08**	**99.17**	**72.04**	*72.16*	*86.16*	*97.90*	*72.10*	*74.38*	*87.33*	**83.25**	*82.32*	*82.87*
Consumption (billion cubic feet per day)															
Residential	**22.83**	**8.20**	**3.82**	**16.00**	**25.59**	**7.45**	*3.73*	*16.86*	*25.06*	*7.90*	*3.69*	*16.92*	**12.70**	*13.35*	*13.34*
Commercial	**13.93**	**5.82**	**4.36**	**10.31**	**14.81**	**6.49**	*4.76*	*10.95*	*14.84*	*6.27*	*4.71*	*10.85*	**8.60**	*9.23*	*9.14*
Industrial	**24.65**	**20.62**	**21.15**	**23.83**	**24.05**	**21.83**	*21.26*	*24.24*	*24.72*	*22.08*	*21.49*	*23.92*	**22.56**	*22.84*	*23.05*
Electric Power (c)	**29.55**	**29.05**	**40.10**	**28.19**	**26.65**	**28.85**	*35.09*	*26.56*	*25.52*	*28.37*	*37.00*	*27.75*	**31.74**	*29.30*	*29.69*
Lease and Plant Fuel	**5.17**	**4.90**	**4.93**	**4.99**	**4.92**	**5.08**	*5.09*	*5.13*	*5.12*	*5.14*	*5.20*	*5.24*	**5.00**	*5.06*	*5.18*
Pipeline and Distribution Use	**3.02**	**2.15**	**2.33**	**2.61**	**3.01**	**2.19**	*2.08*	*2.28*	*2.47*	*2.16*	*2.12*	*2.49*	**2.53**	*2.39*	*2.31*
Vehicle Use	**0.16**	**0.10**	**0.13**	**0.13**	**0.14**	**0.15**	*0.15*	*0.15*	*0.16*	*0.16*	*0.16*	*0.16*	**0.13**	*0.15*	*0.16*
Total Consumption	**99.31**	**70.84**	**76.83**	**86.08**	**99.17**	**72.04**	*72.16*	*86.16*	*97.90*	*72.10*	*74.38*	*87.33*	**83.25**	*82.32*	*82.87*
End-of-period Inventories (billion cubic feet)															
Working Gas Inventory	**2,030**	**3,133**	**3,840**	**3,341**	**1,801**	**2,628**	*3,377*	*2,853*	*1,291*	*2,294*	*3,134*	*2,675*	**3,341**	*2,853*	*2,675*
East Region (d)	**385**	**655**	**890**	**763**	**313**	**528**	*826*	*623*	*115*	*399*	*659*	*448*	**763**	*623*	*448*
Midwest Region (d)	**472**	**747**	**1,053**	**918**	**395**	**639**	*972*	*787*	*202*	*484*	*863*	*732*	**918**	*787*	*732*
South Central Region (d)	**857**	**1,221**	**1,313**	**1,155**	**760**	**1,010**	*1,068*	*1,005*	*660*	*921*	*1,011*	*941*	**1,155**	*1,005*	*941*
Mountain Region (d)	**92**	**177**	**235**	**195**	**113**	**177**	*216*	*175*	*117*	*166*	*230*	*210*	**195**	*175*	*210*
Pacific Region (d)	**200**	**308**	**318**	**282**	**197**	**248**	*269*	*238*	*172*	*298*	*344*	*319*	**282**	*238*	*319*
Alaska	**23**	**25**	**31**	**28**	**23**	**26**	*26*	*26*	*26*	*26*	*26*	*26*	**28**	*26*	*26*

(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 Thursday July 1, 2021.
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.dailysabah.com/business/energy/gas-up-hydropower-down-drought-changes-power-dynamics-in-turkey

Gas up, hydropower down: Drought changes power dynamics in Turkey

BY DAILY SABAH WITH AA

#STANBUL#ENERGY##

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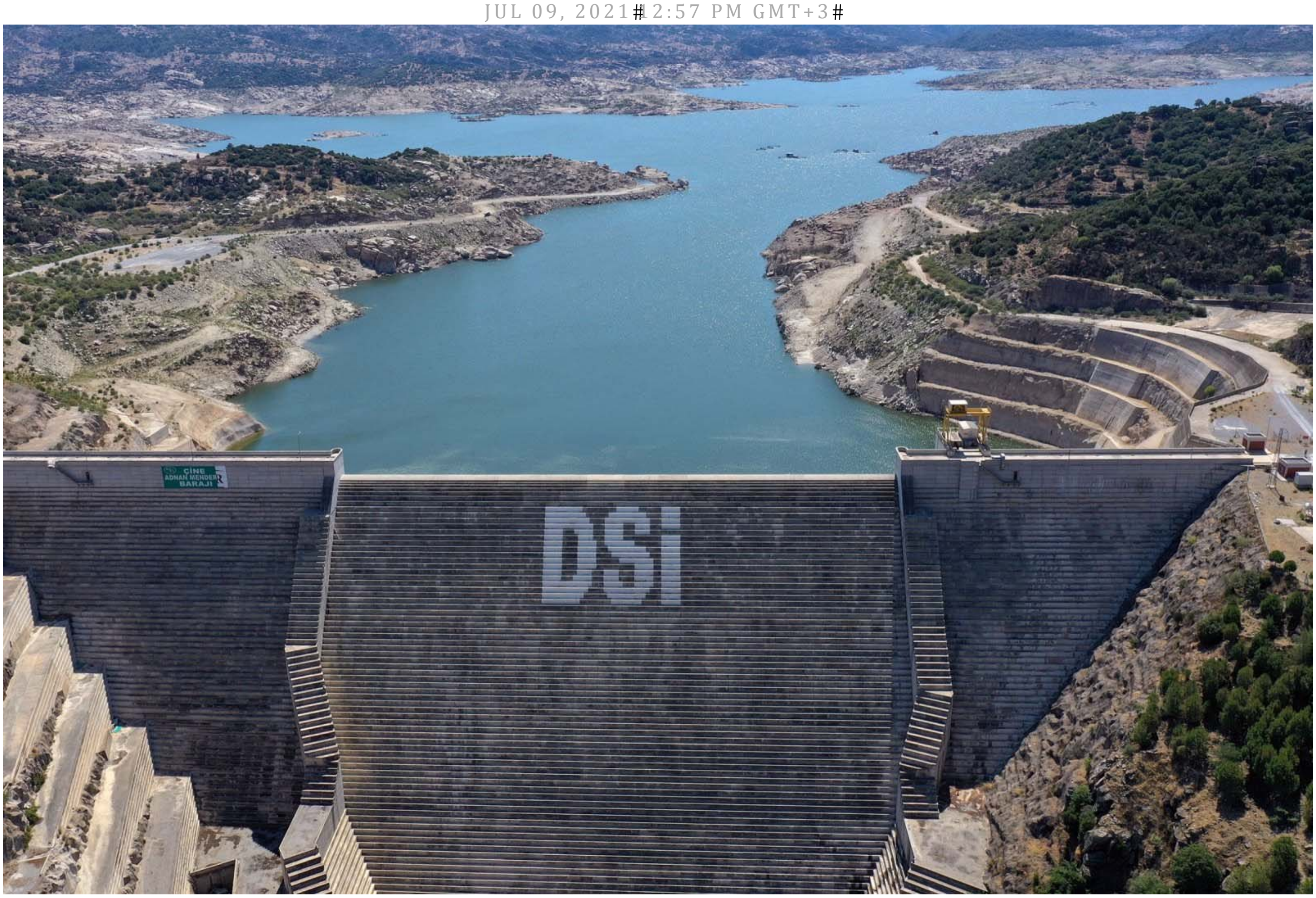


A view of Adnan Menderes Dam in the western Aydın province, Turkey, July 8, 2021. (AA Photo)

#

Atangible drought in Turkey, particularly since the end of last year, has changed power generation dynamics as natural gas plants boosted their share to replace falling output from hydropower plants.

Hydropower capacity in Turkey has shown an increase of 80% over the last 10 years, representing the largest capacity among clean energy sources at over 31,000 megawatts, and accounting for almost one-third of the country's total installed capacity.

However, as the share of hydropower out of total electricity generation varies depending on rainfall, the average share of hydropower plants over the last 10 years has been 23.2%.

A hard drought in 2014 saw the water level reach the lowest at 29.6 billion cubic meters (bcm), in contrast to the highest in 2019 at 81.6 bcm, according to data of the Hydroelectric Power Plants Industry Businessmen's Association.

The share of hydropower plants of total electricity generation in 2014 amounted to 16% and in 2019 jumped to 29.2%, data from investment and consultancy company APLUS Energy showed.

In 2014, natural gas plants compensated for lower output from hydropower plants, generating 48% out of the total, but with heavy rainfall in 2019 when hydropower generation was at its highest, this share dropped to 18%.

Volkan Yiğit, a partner at APLUS Energy, told Anadolu Agency (AA) that the average share of coal plants in Turkey's total electricity generation was 31.9% in the last decade, with natural gas plants reaching 35.2%, hydropower plants at 23.2% and other renewables generating 9.7%.

He noted that the continuous increase in renewables capacity has ensured a drop in the share of natural gas plants in electricity generation.

This has been evident in wind power, which has seen the biggest increase in electricity generation in the past 10 years, he said.

"Wind accounted for 2% of total electricity generation in 2011 and reached 9% last year. Solar, which has no share in electricity generation 10 years ago, made up 3.7% of the total electricity output in 2020," Yiğit said.

"The share of renewables, except for hydropower, climbed over 16.8% to 42.4% together with hydropower plants in 2020," Yiğit said.

Gas replacing hydropower

The amount of water in Turkey's main dams fell by 27% in 2020 compared to the previous year.

The share of hydropower plants in total electricity generation stood at 25.6%, while the share for natural gas power plants was 22.7%, marking a 26.1% increase from the lows of 18% for natural gas in 2019.

Imported coal and lignite power plants accounted for 34.8% of total generation last year.

In the first five months of this year, the amount of water in the main dams dropped by 50% to 24.3 bcm compared to the same period of last year.

The share of hydropower plants during this period was 21.7%, while natural gas power plants generated 27.3% of the total electricity output. Imported coal and lignite plants had a share of 31.9% in the January-May 2021 period.

Drought lifts electricity prices

Yiğit explained that despite renewables lowering electricity prices, natural gas is still an important factor in determining prices.

This was evident during the drought when greater gas plant output had more impact on electricity market prices.

"Just as electricity market prices fell in 2019 during the rainy season, prices climbed during the times of drought. This year, we have seen the impact of drought on electricity prices since April but we should also keep in mind the lower demand in the same month of last year due to the pandemic," Yiğit said.

The average rate price for one megawatt-hour of electricity in Turkey's day-ahead spot market was TL 260.30 in 2019 but surged to TL 278.70 last year.

The average price for one megawatt-hour in the first five months of this year was TL 314.30 ($36.22).

The monthly average price in April was up by 72.3% to TL 312 and by 77% in May to TL 360 compared to the same months of last year.

However, due to lockdown measures, both demand and prices were relatively lower during these months.

Turkey's electricity demand dropped by 15% and 16.7% in April and May 2020, respectively.

"However, since the second half of last month, a number of factors combined with drought and growing demand because of increasing temperatures triggered price increases," Yiğit said.

He said among these factors are natural gas power plants that are currently down, lower stock of imported coal plants, some technical constraints at lignite plants and lower wind power output.

The monthly average price for one megawatt-hour in June 2021 increased by 38% compared to the same month of last year to TL 402.

The average price for one megawatt-hour climbed to TL 571 in the first week of this month.

Meanwhile, Turkey hiked consumer electricity prices by 15% and natural gas prices by up to 20% as of July 1.

"With the return of natural gas plants, increases in wind generation and lower temperatures, electricity demand will fall and the system will find its balance," Yiğit concluded.

Overview and key findings

Global natural gas demand dropped by 1.9%, or 75 bcm, in 2020 because of an exceptionally mild winter in the northern hemisphere and the impact of the Covid-19 pandemic. We forecast global demand to rebound by 3.6% in 2021. And unless major policy changes to curb global gas consumption are introduced, demand is set to keep growing in the coming years, albeit at a slower pace, to reach nearly 4 300 bcm by 2024, a 7% rise from pre-Covid levels.

Gas demand growth is set to slow despite coal-to-gas switching, but more ambitious policies are needed to shift to a net zero path

Almost half of the increase in gas demand to 2024 is expected to come from the Asia Pacific region, driven by China and India as well as by emerging markets in South and Southeast Asia. The industrial sector plays a pivotal role in medium-term gas demand growth, accounting for about 40% of the total increase between 2020 and 2024 in our forecast. This includes the use of gas for industrial processes and as a feedstock for chemicals and fertilisers.

Natural gas demand is set to grow by 350 bcm between 2020 and 2024. This would have been 80 bcm higher were it not for energy efficiency improvements and measures to replace gas with other fuels. Of the 430 bcm increase that can be considered as "gross gas demand additions" over the period, growth driven by higher economic activity can explain almost two-thirds (270 bcm), while the substitution of coal (and oil to a lesser extent) explains the rest (160 bcm). Strong natural gas demand growth in 2021 is mostly the result of the global economic recovery from the Covid-19 crisis. Growth in 2022-2024 is driven in equal proportions by economic activity and fuel substitution.

In spite of this limited medium-term growth, our forecast for global gas demand in 2024 is above what is called for in the IEA's climate-driven scenarios, notably in the recent special report *Net Zero by 2050: A Roadmap for the Global Energy Sector*. To get on track for the emissions pathway set out in the *Roadmap*, stronger policies would need to be introduced within our forecast period to underpin further fuel substitution and efficiency gains. This is especially the case in more mature markets, where much of the potential for switching from coal and oil to gas has already been tapped. Strong and early policy actions and investment are required, with impacts on gas demand that would commence during our forecast period and intensify significantly over the course of the 2020s. Switching from oil and coal to gas, particularly in emerging and developing economies, can reduce emissions and improve air quality, and already explains half of gas consumption growth in these markets in the 2022-2024 period.

Projects already under development meet most supply needs, and the focus on cleaner gas supply is growing

Global gas production in 2024 is expected to be 6% higher than 2019's pre-Covid levels. This additional supply comes almost exclusively from large conventional assets already under development, mainly in Russia and the Middle East. It is supplemented by new investment in US shale gas production to keep pace with expanding LNG export capacity. However, without strong policy measures to curb longer-term gas demand growth, market volatility and concerns over security of supply may arise in the last years of our forecast.

To reduce its emissions footprint and align with net-zero emissions objectives, the gas industry needs to continue reducing the intensity of its greenhouse gas emissions along the value chain, support the development of low-carbon gases and develop carbon management solutions to minimise emissions from combustion. Reducing methane emissions is an efficient way – in terms of both time and cost – of narrowing the industry's footprint. Analysis from the IEA Methane Tracker shows as much as 40% of current methane emissions could be avoided at no net cost. The transition to low-carbon sources of gas supply – such as biomethane, hydrogen and synthetic methane – requires the adjustment of regulations and infrastructure to ensure their cost-competitive integration into future energy systems. This report reviews recent market and policy developments supporting such a transition to cleaner gases.

LNG markets tighten; new sources of flexibility reinforce security of supply

Global LNG trade volumes in 2024 are expected to be 17% above the pre-Covid levels seen in 2019, driven by continued demand growth in Asia and in the absence of strong policy initiatives in major gas markets. At an annual average growth rate of 3.3% through 2024, this is much slower than the double-digit increases observed between 2016 and 2019. The wave of final investment decisions on LNG projects taken before 2020 should therefore prove sufficient to satisfy additional LNG demand in the coming years. The global liquefaction utilisation rate is expected to return progressively to its pre-2020 level by 2024. In the absence of major project delays or unplanned outages, the risk of a structurally tight market appears limited before 2024 with the possible exception of short seasonal episodes.

Further flexibility would help ensure security of supply in an increasingly interdependent global gas market, even if it is well supplied. The growth of long-term contracts without a destination clause for LNG exported from the United States is contributing to flexibility. US projects account for the large majority of additional LNG supply capacity to be commissioned over the next three years. Robust growth of the LNG carrier fleet is another contributor, with current order books for deliveries in the next two to three years representing a 25% increase in the vessel count. Underground storage capacity, another pivotal source of flexibility, is set to increase by 7% over the forecast period.

Main assumptions behind the forecast

2020 saw the worst economic downturn since World War II, with a 3.3% decline in global GDP. This forecast is based on the assumption of a strong economic rebound of up to 6% in 2021. Global GDP growth is then expected to slow, increasing by 4.6% in 2022 and about 3% on average per year in the following years.

The strong short-term recovery is underpinned by the assumption of a prompt rollout of Covid-19 vaccination in mature economies, and continuous efforts to deploy vaccines and protect the most vulnerable in emerging economies. Recovery packages, public investment and fiscal relief policies have been the primary engine of economic rebound. They are expected to remain the principal driver of growth in the short term as funds committed under stimulus packages keep pouring into the economy.

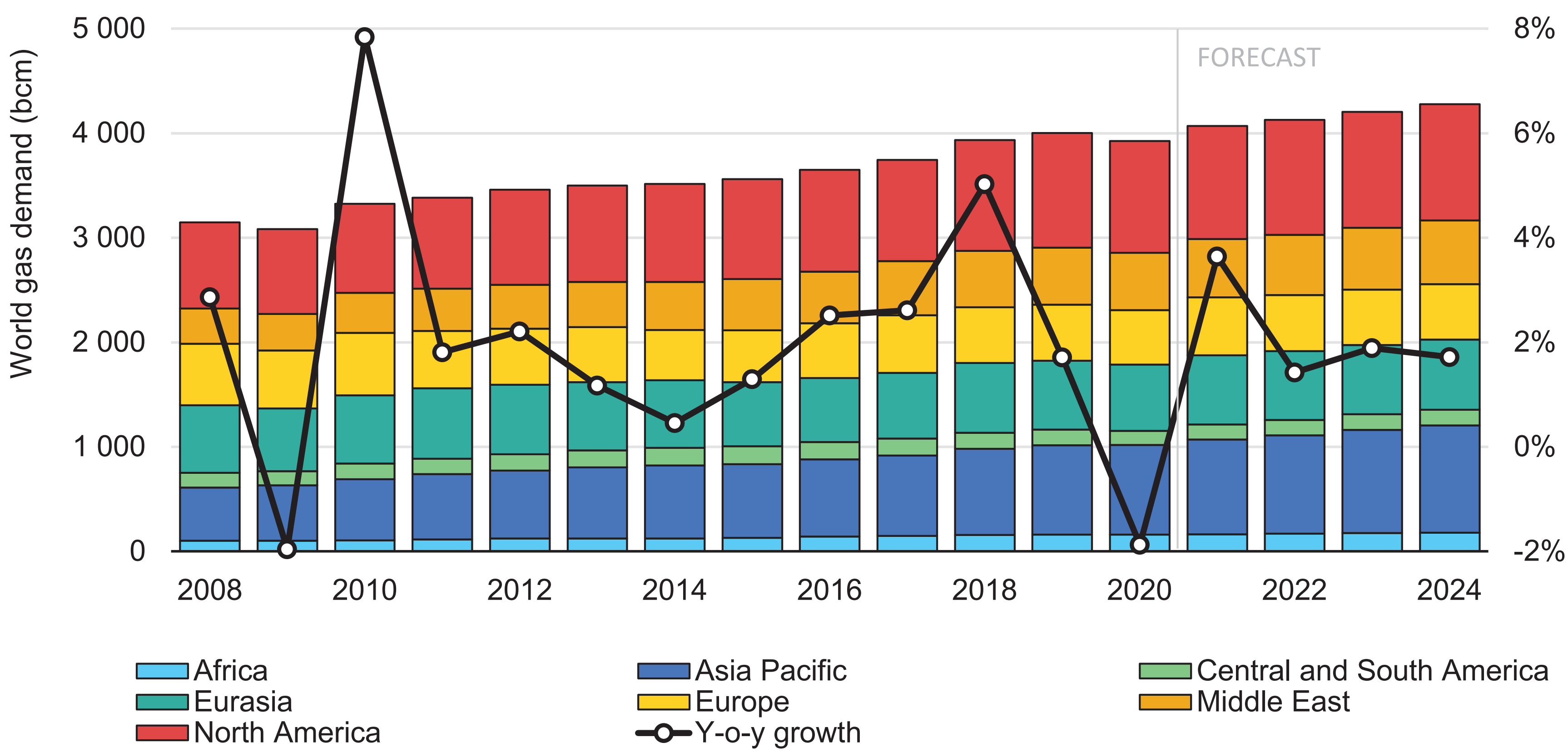
However, levels of uncertainty remain high for the course of the global health recovery. The main short-term risk is the appearance and spread of new Covid-19 variants, potentially more contagious and more resistant to current vaccines. Although the repetition of 2020's hard lockdowns looks less likely, further waves of infection are possible. They would delay the global recovery and increase disparities among economies in their individual growth paths.

In spite of the unprecedented policy action to support the economy, some longer-lasting impacts are likely due to investment delays and cancellations, bankruptcies and slower growth, especially in services. Emerging markets, which account for the bulk of natural gas demand growth, have been strongly affected by both the health and economic crises, which have led to rising debt and fiscal imbalances that could hamper medium-term growth.

Natural gas demand is also particularly sensitive to temperature. After an exceptionally mild heating season in the northern hemisphere in 2020, 2021 saw more average – and even colder than usual – temperatures. This forecast assumes average winter conditions for the forthcoming heating seasons, and the report uses the average of futures prices during April 2021 as price indicators. When futures price curves do not extend to the full forecast horizon, we extend them to converge with medium-term fuel price assumptions contained in the *World Energy Outlook 2020* to provide an indication of assumed longer-term price evolution.

Gas demand is expected to fully recover in 2021 from its drop in 2020, although the recovery remains modest compared to the rebound after the 2008-2009 crisis

Global natural gas demand by region, 2008-2024



Gas demand bounces back at lower average growth rates, but still too high to be compatible with net zero in the longer term

Natural gas demand is expected to reach close to 4 300 bcm by 2024, adding 350 bcm or 9% compared to its 2020 low point.

Short-term recovery plays a major role in the forecast period, with the demand gains expected in 2021 accounting for about 40% of the total increase. The global gas consumption growth rate stands at 3.6% in 2021, then declines progressively over the following years to 1.7% in 2024. Compared with 2019, natural gas increases by only 275 bcm over the forecast period – or about 7%.

The industrial sector, which provides the largest contribution to the 2021 recovery in global gas demand, maintains a leading role in the following years. The growing demand for natural gas, both for industrial processes and as a feedstock, is expected to account for a dominant 40% share of the total increase in gas consumption over the 2020-2024 period.

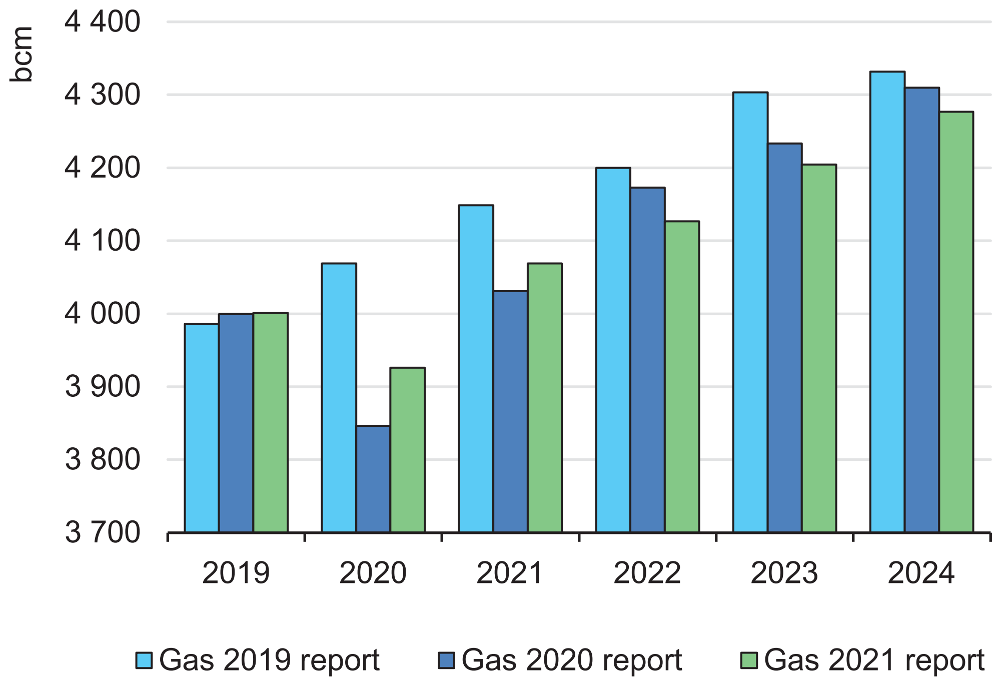
The Asia Pacific region alone is responsible for almost half of total gas demand growth, with a 47% share of the global increase. The Middle East, the second-largest contributor to growth, stands far behind at less than 20%. For most other regions, and especially mature markets, the bulk of the increase comes in the initial years as demand recovers from the 2020 downturn.

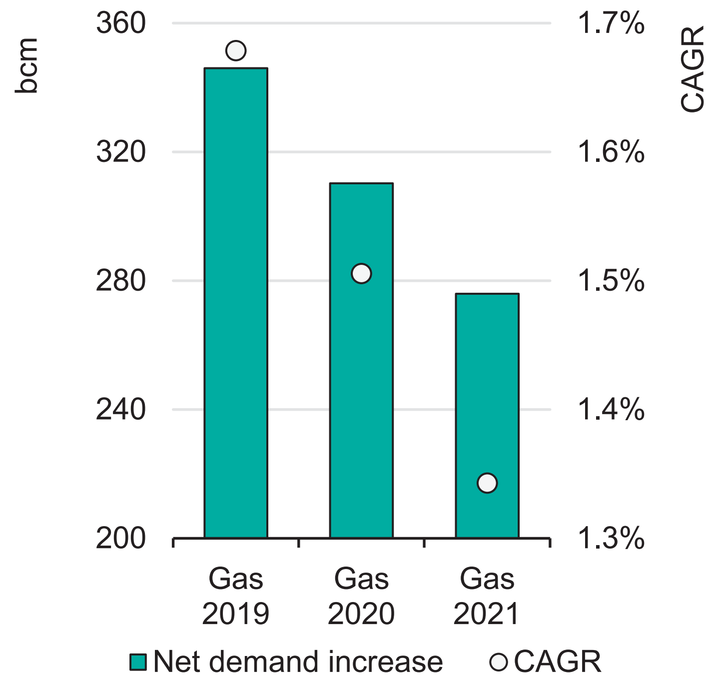
From 2020 to 2024, the substitution of gas and efficiency gains reduce natural gas demand by 80 bcm, mostly in power generation, moderating a gross demand increase of 430 bcm to a net increase of 350 bcm. The return to economic growth – driven by the industrial sector and led by Asia's fast-growing markets – remains the principal driver of rising gas consumption, accounting for almost two-thirds of the gross demand increase to 2024. Fuel substitution in favour of gas and at the expense of coal and oil, principally (but not only) in the power generation sector, covers the remaining third.

In spite of relatively modest demand growth in the coming years, projected gas demand in 2024 is already about 2% above the 2025 level of the World Energy Outlook 2020 Sustainable Development Scenario. This scenario maps out a trajectory consistent with global net-zero emissions by 2070. A faster decarbonisation path, as described in the IEA Net Zero by 2050 report, would require even slower growth.

While the downturn in 2020 was less than expected, medium-term growth – following the rebound – loses speed in this latest forecast update

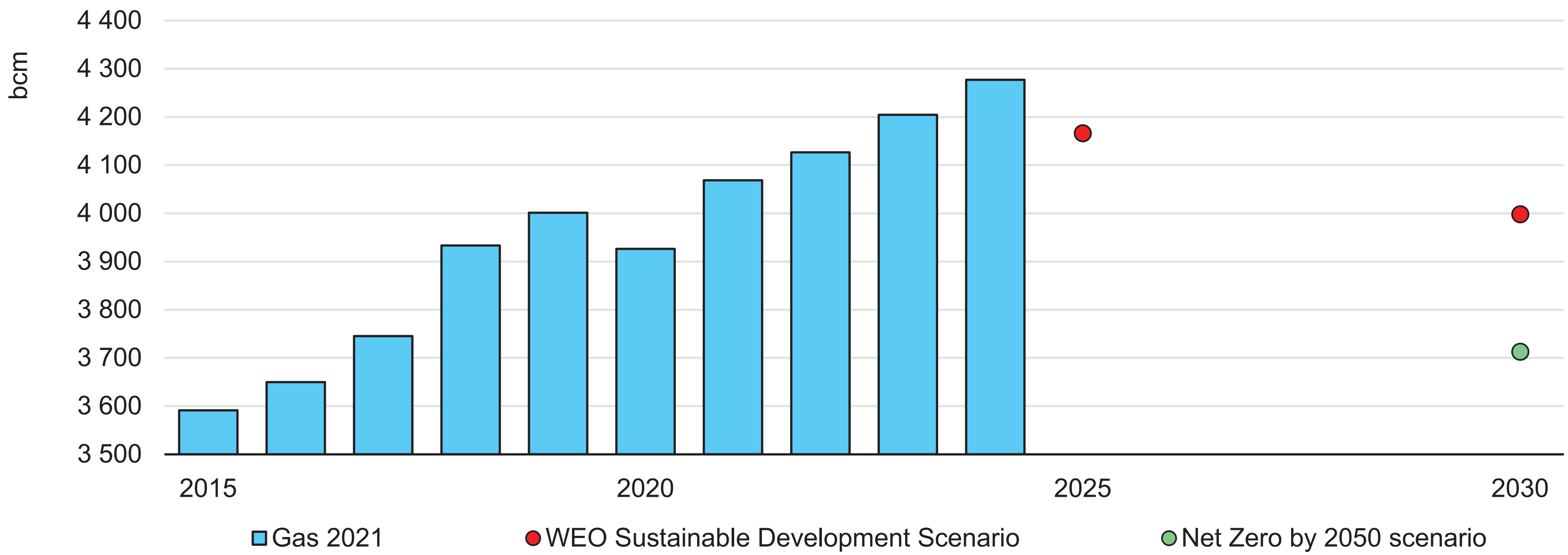
Evolution of global gas demand forecasts in the three latest issues of the IEA medium-term gas report, 2019-2024





Despite its moderate growth rate, global gas demand by 2024 would already be 2% above the 2025 level in the Sustainable Development Scenario

Evolution of global gas demand compared to the WEO Sustainable Development Scenario and Net Zero by 2050 scenario



Sources: IEA (2020), World Energy Outlook 2020; (2021), Net Zero by 2050.

LNG remains the main driver of global gas trade after 2021, though growth is slower than before

Global gas trade – including both LNG and long-distance pipeline – is expected to expand more quickly than demand growth over the forecast period, principally driven by LNG expansion.

Global LNG trade is expected to expand by 16% between 2020 and 2024, driven by continued growth in Asia. The annual average growth rate of 3.8% over the forecast period is a far cry from the double-digit rates observed between 2016 and 2019, but represents a recovery from 2020's low rate of 1.4%. Investment in new liquefaction projects stalled in 2020 due to the Covid-19 pandemic, but the growth in gas demand is also slower compared to pre-Covid levels. In the 2021-2024 period incremental LNG demand growth only marginally exceeds liquefaction capacity additions, which limits the risk of a structurally tight LNG market in the next three years. China, India and emerging Asian markets account for most of the future growth in LNG imports. Europe remains the main importing market after Asia, keeping its role as the balancing market for LNG. On the supply side, North America accounts for more than 70% of the growth as the primary engine of export development.

Long-distance pipeline trade[3] is expected to expand by over one-fifth between 2020 and 2024, driven by a strong recovery in 2021 and by the rising import requirements of Europe and China through the rest of the forecast period. Following a steep drop of 10% in 2020, **European pipeline imports** are set to recover to close to their 2019 levels in 2021, and increase at an average growth rate of 2% between 2021 and 2024, largely driven by the region's rapidly declining domestic production. This will be met by a combination of higher Norwegian deliveries, the ramp-up of Azerbaijani flows via the TAP pipeline to 10 bcm/y and higher Russian pipeline exports.

Similarly, **China's pipeline imports** are expected to expand by more than two-thirds between 2020 and 2024. This growth will be largely dominated by the ramp-up of Russian export flows via the Power of Siberia pipeline, which are set to reach 30 bcm/y by the end of our forecast. In North America, US net imports from Canada are expected to oscillate in the range of 50-55 bcm/y during the forecast period, and play a critical role in meeting seasonal demand swings. Additional pipeline capacity between the United States and Mexico will allow US exports to Mexico to expand by close to 10% between 2020 and 2024.

[3] For the purpose of this analysis, long-distance pipeline trade includes Europe's pipeline imports (including deliveries from Norway), North American net pipeline trade and China's pipeline imports.

LNG import growth is dominated by Asia; LNG supply growth is led by North America and Russia

Global LNG trade is expected to reach 561 bcm by 2024, an increase of 16% compared to 2020.

LNG import growth is predominantly driven by the Asia Pacific region, where demand for LNG is set to rise by 26% (89 bcm) between 2020 and 2024. The region's share of global LNG imports is projected to increase from 71% in 2020 to 77% in 2024. China alone is expected to account for nearly 30% of global LNG demand growth in the 2020-2024 period, and is on track to become the world's largest importer of LNG on a yearly basis in 2021 or 2022. India is responsible for more than 20% of the net increase globally; import growth is expected to re-accelerate from 2022 as the post-Covid gas demand recovery coincides with a slowdown in production growth. Emerging Asian countries are projected to double their LNG imports between 2020 and 2024, driven by strong demand growth and the decline of domestic production. Japan's LNG imports are expected to gradually decrease, while Korea's LNG demand continues to expand over the forecast period.

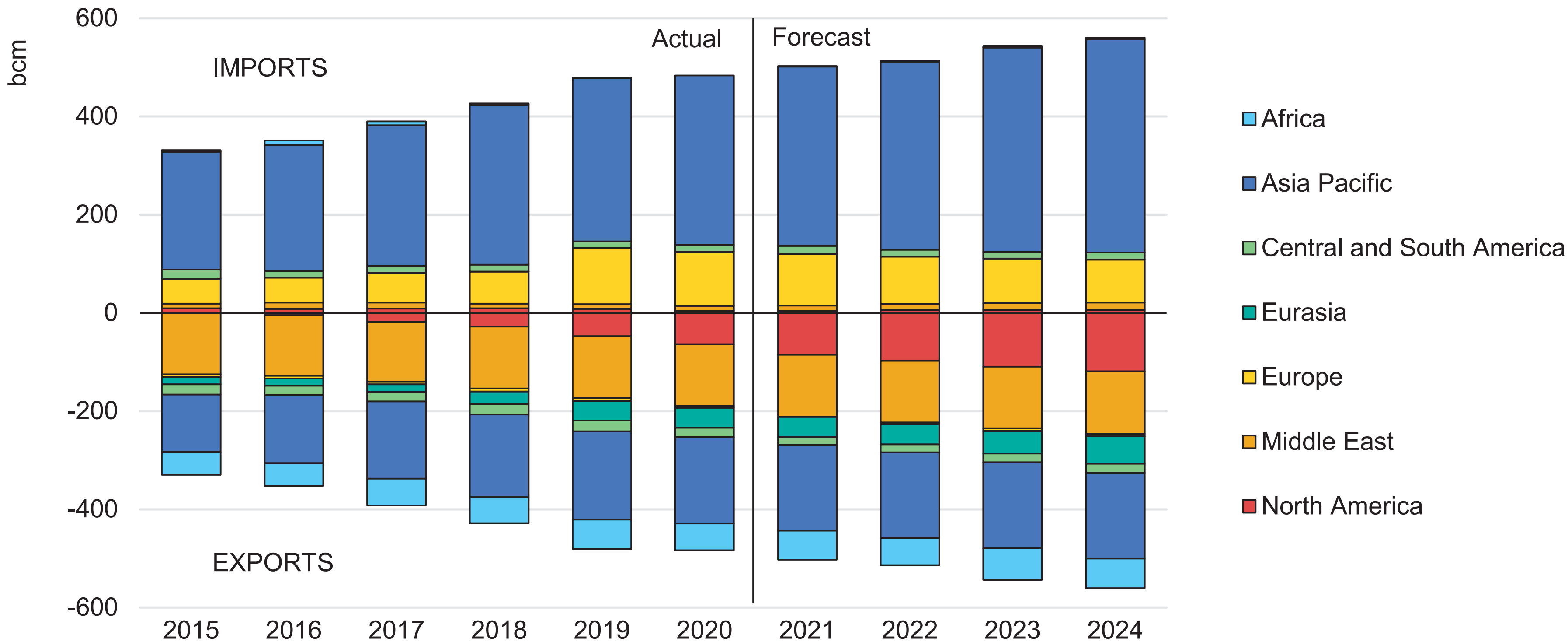
European LNG imports reached record levels in 2019 and 2020, and are expected to decrease and oscillate around 90 bcm in the 2021-2024 period as the region continues to play the role of swing consumer to balance the market. Europe's share of total LNG imports is expected to decrease from 23% in 2020 to 16% in 2024. LNG imports into Africa (led by Ghana, Senegal and South Africa) and the Middle East (driven by Kuwait) also register small increases throughout the forecast period.

LNG export growth is led by North America, which is projected to boost production by 86% (55 bcm) between 2020 and 2024. This strong growth is driven by already sanctioned liquefaction projects, albeit some of these will not start production (or reach full capacity) within the forecast period. Russia is the second-biggest source of LNG supply growth, with a 38% increase between 2020 and 2024. Export growth from Africa is limited due to the delay of the Mozambique LNG project. Output from the Middle East remains stable through to 2024, as Qatar's expansion project is not expected to ramp up before 2025. Exports from Asia Pacific and South America are on course for a slight decline between 2020 and 2024.

The utilisation of available liquefaction capacity is expected to gradually recover from the low point of 88% in 2020, but remains slightly below the 2019 level of 93% at the end of the forecast period. Therefore, the risk of persistent supply shortfalls and a structurally tight LNG market remains limited throughout the forecast period. However, periods of temporary tightness may occur – and lead to dramatic price swings – as was illustrated by the Northeast Asian energy crisis in January 2021, when a combination of surging demand, supply constraints and a lack of storage pushed spot LNG prices to record-high levels for a brief period.

Global LNG trade reaches more than 560 bcm by 2024

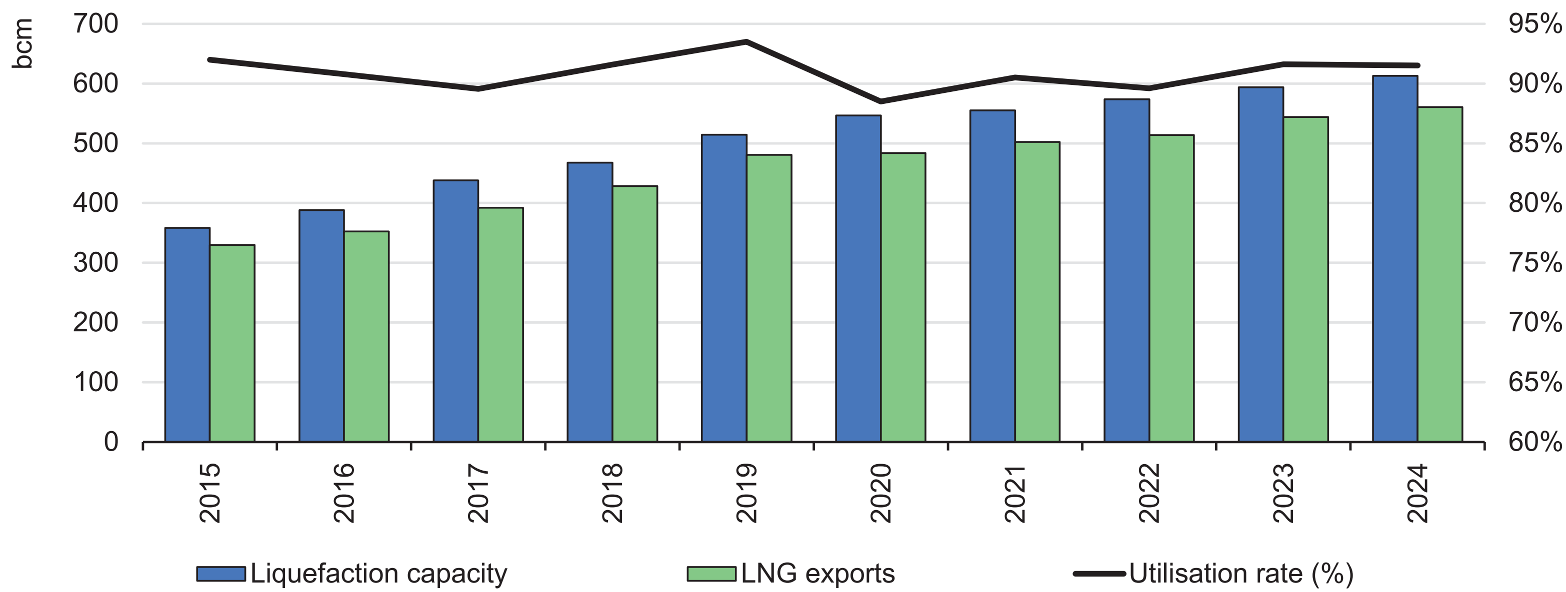
World LNG imports and exports by region, 2015-2024



Source: IEA analysis based on ICIS (2021), ICIS LNG Edge.

LNG trade growth only marginally exceeds capacity expansions, leading to a slow increase in utilisation rates

Global LNG trade and liquefaction utilisation rate, 2015-2024



Note: Liquefaction capacity and utilisation rate are based on assessed available capacity – adjusted to take into account the assumption that several liquefaction plants will remain offline or run below their nameplate capacity because of technical issues, lack of feed gas, weather-related issues or security risks.
Source: IEA analysis based on ICIS (2021), ICIS LNG Edge.

LNG investment: Tentative post-Covid recovery underway

True to the cyclical nature of the LNG business, the pace of FIDs on new LNG capacity have fluctuated wildly in recent years. In 2019 developers approved nearly 100 bcm of new capacity (worth USD 65 billion), an all-time high far exceeding any previous records. This was followed by a near collapse of activity in 2020, with only one project (the 4 bcm Energía Costa Azul plant in Mexico) taking FID as the Covid-19 crisis brought new investments to a standstill. 2021 has seen a sharp rebound of sanctioned capacity, but so far this has been solely driven by Qatar's 45 bcm expansion project, the largest FID in the history of LNG. Notwithstanding the wide fluctuations in project approvals in recent years, the spending profile associated with already sanctioned projects is expected to recover steadily from a low point of USD 14 billion in 2020 to USD 30 billion in 2024. Annual spend on liquefaction projects is expected to average USD 24 billion in the 2020-2024 period, 13% lower than in the preceding five years.

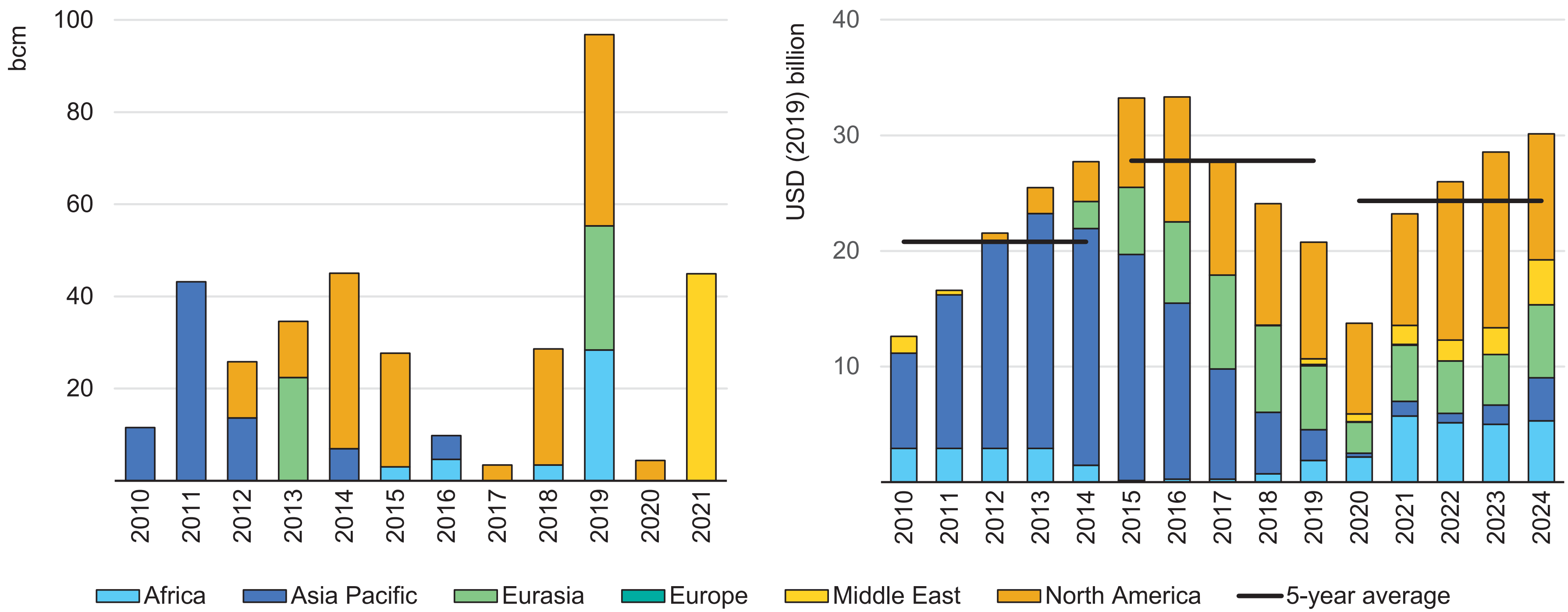
The previous wave of LNG FIDs in 2018-2019 was led by the major portfolio players, which participated as offtakers, equity partners or developers in all of the liquefaction projects sanctioned in that period. Confidence in long-term market growth – combined with the widespread use of the equity-lifting structure – enabled projects to reach FID without having to secure end-use demand for equity LNG volumes in advance. This trend is unlikely to be repeated on the scale seen in 2018-2019. The appetite for additional uncommitted LNG among portfolio players could be limited by the overhang of such volumes from the previous cycle, which will be compounded by the expiry of nearly 200 bcm of long-term LNG contracts between 2021 and 2025. Capex cuts and write-downs on LNG-related assets – combined with greater uncertainty about future LNG demand and investor pressure to limit fossil fuel investment – could present further headwinds to another investment wave led by international oil companies in the foreseeable future. Independent developer-led projects (especially in North America) also suffered setbacks, saw their FID target dates pushed back and in some cases were outright cancelled in the past 18 months as buyer appetite for new long-term LNG contracts dried up during the pandemic.

Nonetheless, market developments in H1 2021 indicate that there may well be room for further investments in 2021 and beyond. In the month of May 2021 alone, North American pre-FID projects secured two binding long-term sales purchase agreements with offtakers, more than in 2020 as a whole. Qatar Petroleum announced that it is planning to approve the second 22 bcm phase of its expansion project by early 2022, and that the company is evaluating additional capacity increases beyond the six-train development envisaged by 2027.

LNG investment: 2018-2019 wave and 2021 recovery drives sustained capex growth to 2024

FIDs for new LNG liquefaction capacity, 2010-2021

Investment in new LNG liquefaction capacity, 2010-2024



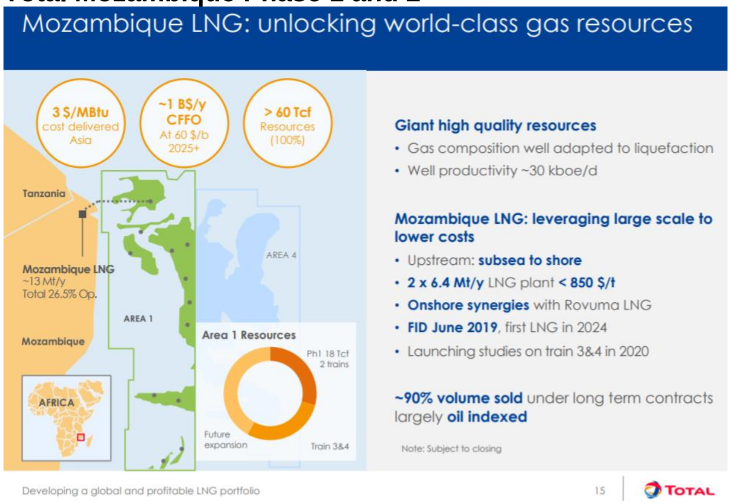
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

Posted Wednesday April 28, 2021. 9:00 MT

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

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

Total Mozambique Phase 1 and 2



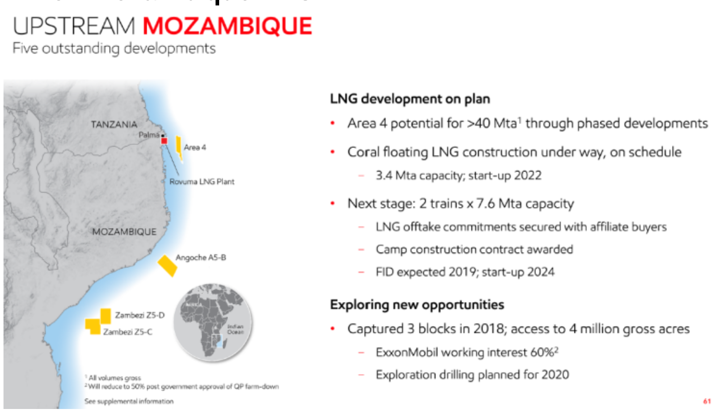
Source: Total Investor Day September 24, 2019

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

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

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

Exxon Mozambique LNG



Source: Exxon Investor Day March 6, 2019

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

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

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

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

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

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

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

Source: IEA

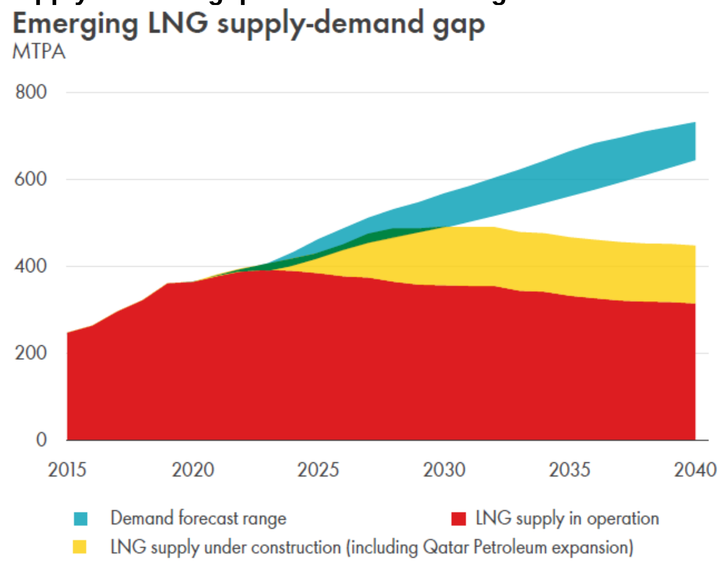
On Track   More Efforts Needed   Not on Track

Source: IEA Tracking Clean Energy Progress, June 2020

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

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

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



Source: Shell LNG Outlook 2021, Feb 25, 2021

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

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

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

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

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

https://www.petronas.com/media/press-release/petronas-and-cnooc-sign-10-year-lng-supply-agreement

7 · Jul · 2021

PETRONAS and CNOOC Sign 10-Year LNG Supply Agreement

Media Releases

Kuala Lumpur, 7 July 2021 – PETRONAS LNG Ltd. (PLL), a subsidiary of PETRONAS, has secured a 10-year term deal to supply liquefied natural gas (LNG) to CNOOC Gas and Power Trading & Marketing Limited, a subsidiary of China National Offshore Oil Corporation (CNOOC).

This long-term supply agreement also includes supply from LNG Canada when the facility commences its operations by middle of the decade.

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.

"PETRONAS is proud to strengthen our decade long relationship with CNOOC through this term LNG supply. Importantly, it reflects the markets' receptiveness and recognition of AECO indexed LNG into the world's largest LNG market; as we seek to grow the use of LNG as a cleaner and cost effective form of energy," said PETRONAS Vice President of LNG Marketing & Trading, Shamsairi M. Ibrahim.

The AECO index, housed on the ICE NGX commodity exchange platform, is one of the most liquid spot and forward energy markets in North America. It is the leading price marker for natural gas in Canada similar to the United States' Henry Hub, which is the benchmark for natural gas prices used as an indexation to LNG prices. PETRONAS introduced the AECO index to its customers in May this year following the sale of a spot cargo from Bintulu, Malaysia, to a buyer in the Far East.

The agreement with CNOOC, China's largest LNG importer, reflects PETRONAS' commitment to ensure security of supply through an established transparent and stable price index such as AECO in the LNG market, while providing additional pricing options for its customers. 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.

The deal also further strengthens the ongoing relationship established since 2006 and reflects PETRONAS' commitment in supporting the endeavor of CNOOC and its associated companies to meet the fast-growing demand for cleaner energy and support China's national aspiration of peak emissions and carbon neutrality.

Issued by
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Group Strategic Communications
PETRONAS

https://www.lngcanada.ca/news/living-up-to-climate-promises/

NEWSMar 23, 2020

Living up to climate promises

Susannah Pierce
Director of Corporate Affairs, LNG Canada

From the air, things can seem different. Perspectives can change. In B.C., we enjoy blue skies, clean air and low carbon emissions. In other parts of the world, flying over a city that relies on coal-fired power for electricity or industrial and residential heating offers another experience.

Many of the world's fastest growing, most populous and carbon-intensive urban centres struggle with severe air pollution. That's why countries such as China are transitioning from coal to cleaner natural gas.

China's shift from coal is being driven primarily by its air pollution crisis. Researchers estimate that 1.6 million people die each year in China from heart, lung and stroke problems due to air pollution. It should come as no surprise, then, that the International Energy Agency (IEA) forecasts that renewable energy demand in that country will more than quadruple.

Meanwhile, natural gas demand will triple by 2040. Natural gas is already being used to complement China's emerging renewable energy sector, and is increasingly being used in Chinese factories and for district heating. It's far cleaner burning than coal, and ideal in the transition to a lower carbon future.

According to the IEA's latest World Energy Outlook, 80 per cent more natural gas will be required over the next 20 years in China, India and Southeast Asia in order to displace higher carbon-producing coal.

Research conducted for LNG Canada demonstrates that our own liquified natural gas exports to China will emit approximately 35 per cent to 55 per cent fewer greenhouse gas (GHG) emissions than China's prevailing energy source – domestic coal. The largest GHG reductions realized in China from Canadian LNG will come from displacing coal in residential heating (56 per cent), followed by electricity generation (52 per cent), and industrial heat generation (36 per cent).

While LNG Canada won't satisfy all of the world's growing demand for natural gas, it will supply the cleanest. But reducing emissions overseas is not enough. LNG Canada must also live up to climate promises at home. That means working with our Joint Venture Partners to ensure our natural gas supply chain – from well-head to tidewater – has the smallest amount of greenhouse gas emissions possible.

GHG emissions from LNG Canada's Kitimat operation will be lower than any facility currently operating anywhere in the world today: 35 per cent lower than the world's best performing facilities and 60 per cent lower than the global weighted average. LNG Canada will use B.C. natural gas that's produced and compressed using renewable electricity from the BC Hydro grid. Energy-efficient gas turbines and the latest methane mitigation technologies will also help us reach our low-emissions standards.

It’s also important that our governments develop policies to further incentivize decarbonization through new technologies, such as carbon capture, utilization and storage, and nature-based solutions including forest management and tidal wetlands restoration. These solutions both provide new opportunities for Indigenous communities and businesses.

At LNG Canada, we understand we must think globally and act locally. We’ve worked hard with our stakeholders, including our Indigenous partners and our northern communities, to get to where we are in our development, and we continue to look for new opportunities to make a positive difference. We are excited about the opportunity to develop the cleanest LNG in the world, and deliver economic opportunities for British Columbia and Canada – all while working together to meet our provincial and federal climate goals.

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

News

Back

Qatar Petroleum signs a 15-year SPA to supply 1.25 MTPA of LNG to CPC Corporation, Taiwan

Qatar Petroleum today entered into a 15-year LNG Sale and Purchase Agreement (SPA) with CPC Corporation, Taiwan (CPC) for the supply of 1.25 million tons per annum (MTPA) of LNG.

The SPA was signed by His Excellency Mr. Saad Sherida Al-Kaabi, the Minister of State for Energy Affairs, the President and CEO of Qatar Petroleum, and Mr. Shun-Chin Lee, the President and Acting Chairman of CPC, during a virtual ceremony attended by Sheikh Khalid bin Khalifa Al Thani, CEO of Qatargas and senior officials from both sides.

Pursuant to the agreement, LNG deliveries will commence in January 2022, and will be delivered to CPC's receiving LNG terminals. This SPA further demonstrates the State of Qatar's continued commitment to meeting the growing energy requirements of its customers around the world in the form of reliable long-term LNG supplies.

Commenting on this occasion, His Excellency Mr. Saad Sherida Al-Kaabi, the Minister of State for Energy Affairs, the President and CEO of Qatar Petroleum, 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."

H.E. Minister Al-Kaabi concluded his remarks by saying, "We are grateful to CPC and all our customers around the world for selecting us as their trusted LNG supplier of choice. I would like to take this opportunity to thank the management of CPC and the negotiating teams from both sides for their efforts in concluding this SPA. I also would like to offer my thanks and gratitude to Sheikh Khalid bin Khalifa Al Thani, CEO of Qatargas, for his valuable contribution, to achieve this important milestone."

Since the first LNG delivery in March 2006 to date, CPC has received more than 63 million tons of LNG from Qatar.

BP signs LNG supply deal with Guangzhou Gas

Published date: 07 July 2021

BP has signed a 650,000 t/yr LNG supply agreement with southern Chinese city gas firm Guangzhou Gas.

The agreement will start in 2022 and run until 2034, Guangzhou Gas said, with contract prices linked to an index of international crude prices.

Guangzhou Gas typically procures LNG on the spot market for prompt requirements, although it did issue a tender in late April for around 1mn t/yr over 10 years starting from August 2022. The tender, which closed on 9 June, was intended to secure deliveries to the firm's planned Xiaohudao import terminal in Guangdong province, which is expected to become operational in August 2022.

The buyer had signed a preliminary deal to buy 1mn t/yr from Canada's planned 2.1mn t/yr Woodfibre LNG project, which had expected to start up in 2020, but it opted not to finalise the agreement in late August 2019 amid delays to the project's start-up.

BP already has a number of supply agreements with northeast Asian firms, including Japan's Jera, Kansai Electric and China's CNOOC. But the seller's 750,000 t/yr des agreement with Taiwan's state-owned CPC is set to expire this year.

By Samuel Good

https://www.spglobal.com/platts/en/market-insights/topics/hydrogen

- ATURAL GAS

- 30 Jun 2021 | 08:38 UTC

Algeria has taken 'necessary measures' to offset non-renewal of Morocco gas deal

HIGHLIGHTS

Contract for key gas export line expires at end-October

Reports that Morocco has decided to halt talks

GME pipeline transited 3.67 Bcm in 2020: Platts Analytics

- Natural Gas

Author Lies Sahar with Stuart Elliott

Algeria has taken all the "necessary measures" to ensure stable gas exports to Spain even if Morocco fails to renew a key gas transit agreement for supplies via the GME pipeline, which expires at the end of October, the CEO of state-owned Sonatrach said June 29.

Cited by the state-owned APS news agency, Toufik Hakkar said no decision had been taken regarding the renewal of the transit deal, but that regardless of the outcome there would be no impact on Algerian gas exports to Spain.

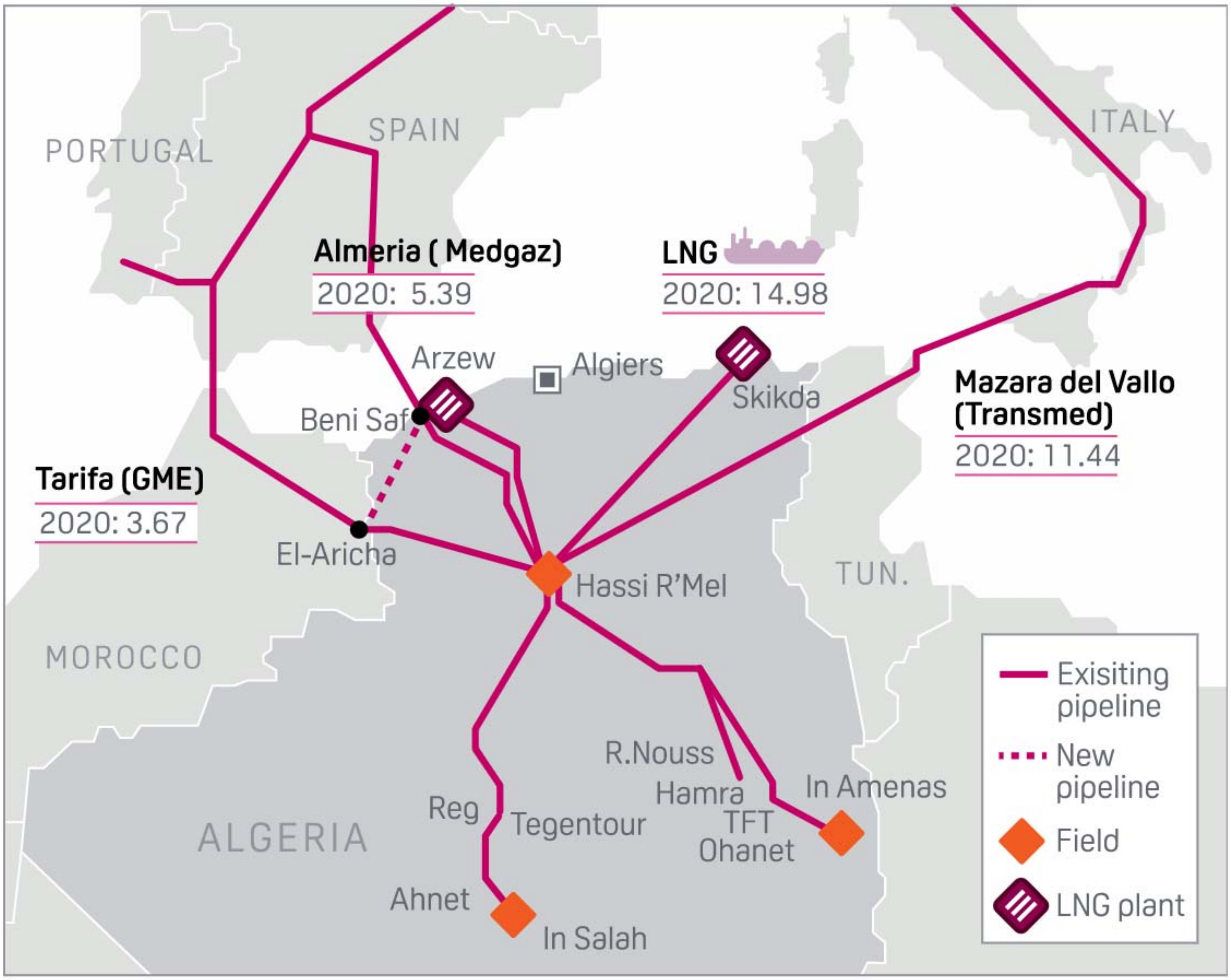
"Even if the contract is not renewed, Algeria can supply Spain without any problems and even respond to any additional demand from the Spanish market," Hakkar said.

Morocco has reportedly opted to halt talks on the renewal of the transit deal due to worsening relations with both Algeria and Spain.

Algeria sends gas to Spain via two pipelines -- the GME pipeline via Morocco and the direct Medgaz link -- with volumes totaling 9.06 Bcm in 2020, according to S&P Global Platts Analytics data.

More gas was sent via the Medgaz line to Almeria (5.39 Bcm) than via the GME line to Tarifa (3.67 Bcm).

ALGERIA COMMISSIONS NEW GME DIVERSION PIPELINE (Bcm)



Source: S&P Global Platts Analytics

Relations have worsened in recent months between Algeria and Morocco, primarily over the sovereignty of Western Sahara, and there has been no indication of a breakthrough in talks for a renewal of the transit deal.

There have been signs that Algeria might be happy to stop using the GME pipeline, which enters Spain at the Tarifa interconnection point, and instead focus flows on the shorter, and cheaper, Medgaz line.

For Morocco, the stakes are high as it relies on Algerian gas to help meet its own demand, taking gas in kind for the transit service it provides under a 25-year agreement that came into effect in November 1996.

Rabat is also due to take over ownership of the line from current owners -- Spain's Naturgy and Portugal's Galp -- later this year.

Industry sources have also said that some of the delivery of Algerian gas to Spain has already been contractually moved away from the GME to the Medgaz pipeline.

Mitigation actions

Hakkar said discussions between all parties involved in the GME pipeline were ongoing, but that Sonatrach had already taken action to mitigate the potential loss of the GME pipeline.

"We were already prepared for all scenarios in 2018-2019," Hakkar said, referring to a new loop pipeline that can divert gas from the GME link into Medgaz.

Energy minister Mohamed Arkab on May 6 formally inaugurated the 197 km pipeline from El-Aricha on the border between Algeria and Morocco to Beni Saf, the starting point of the Medgaz pipeline.

The new El-Aricha-Beni Saf pipeline was designed as a tool for Algeria to be able to maintain exports to Spain should there be issues in future with supplies via the GME line.

Sonatrach began construction work on the new pipeline in 2018 to create the new "loop" between the export lines.

In order to be able to move gas in that direction, the capacity of Medgaz was expanded to 10.5 Bcm/year and could be expanded further to 16 Bcm/year.

"If there is a new demand from the Spanish market for Algerian gas, there will be discussions between the Algerian and Spanish parties," Hakkar said, adding that Algeria had the means to supply more gas to Spain.

"We have the Medgaz with a capacity of 10.5 Bcm/year," he said. "We have the gas liquefaction units whose capacities are available. We will deliver on any Spanish requests for more gas without any problems."

China Gas Monthly: More LNG Needed Despite Higher Prices

July 2021 edition

Lujia Cao

Daniela Li

*The **BNEF China Gas Monthly** report series will become a **quarterly publication** moving forward. The next edition will be published in October.*

July 6, 2021

BloombergNEF

Executive summary

China's LNG imports in June fell month-on-month for the first time since February, driven by lower gas demand and potentially higher import prices. July gas demand may increase from June due to warm weather in eastern and southern China, which is likely to boost LNG imports in order to meet continued growth in power demand. Gas consumption is expected to grow in August too, but decline into September when temperatures start to cool.

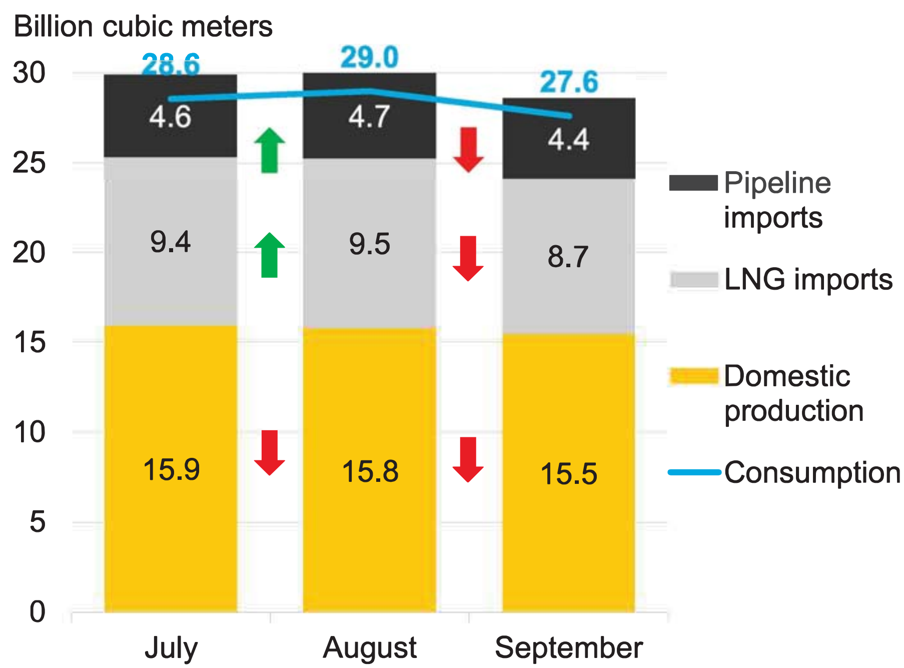
- **Market updates:** A deadly gas explosion in Hubei Province led to a nationwide investigation of safety risks, which could potentially impact industrial and commercial gas demand in some way. Hubei Province accounts for less than 3% of total gas consumption in China.
- **Gas power updates:** Several provinces in China are facing power shortages as the global economic recovery and hot summer weather boost gas demand. Jiangsu needs to import more LNG over the summer to meet rising gas demand, while power outages in Guangdong have been alleviated since early June.
- **PipeChina updates:** PipeChina signed an agreement with Gansu's government to take over the provincial natural gas grid. China segregates PipeChina's trunk pipelines into four regions, each having its own uniform rate, down from 19 rates before the establishment of PipeChina. The streamlining of gas pricing paves the way for end-users to negotiate power prices directly with suppliers.
- **Terminal updates:** The FSRU Cape Ann has docked at Tianjin terminal after its last cargo delivery to Jiangsu terminal on June 4. The Hoegh Esperanza has since left Tianjin and is heading to Corpus Christi, U.S.
- **Gas outlook:** BloombergNEF estimates China's gas demand in July will increase 16% year-on-year to 28.6 billion cubic meters and further increase to 29.0Bcm in August. July LNG imports may increase 4% from June to 6.7 million tons. Pipeline imports are estimated to reach 4.6Bcm in July and grow to 4.7Bcm in August.

26% China's June LNG imports growth year-on-year

90% LNG terminal average utilization rate from January to June

28.6Bcm Estimated July total gas demand

Estimated China gas demand-supply

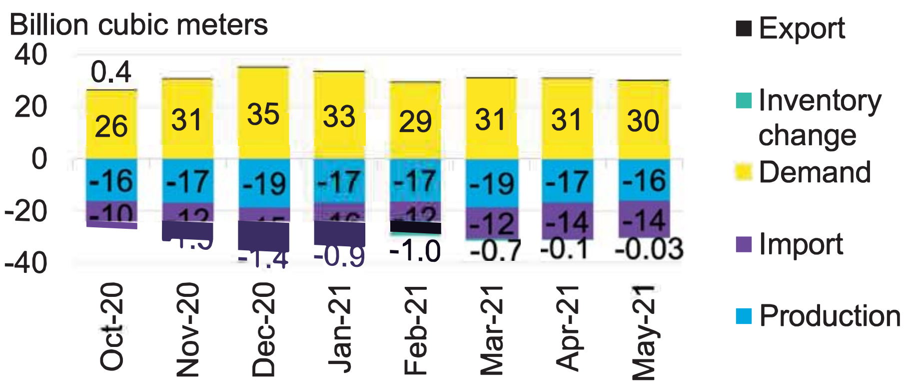


Source: BloombergNEF. Note: Arrows are for month-on-month change.

China monthly data

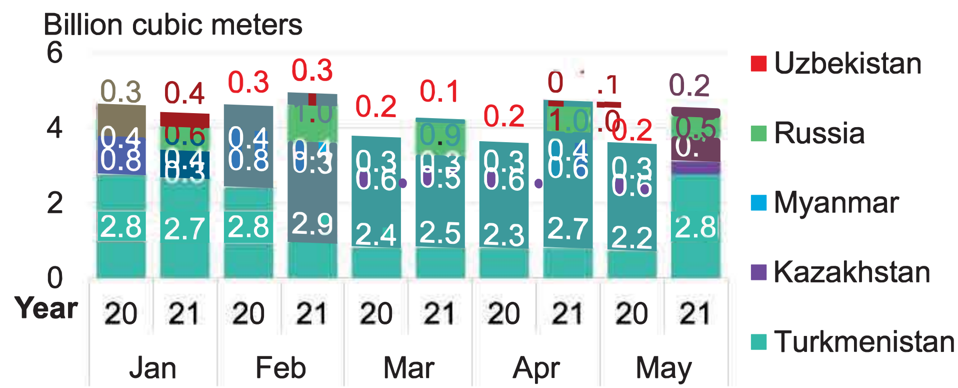
Gas dashboard: May production level drops, while pipeline gas and LNG prices rise

Monthly supply demand balance



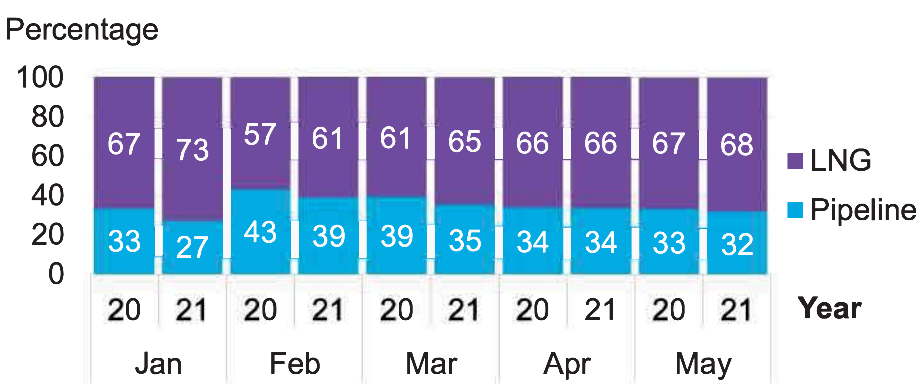
Source: JLC, BloombergNEF. Note: Export figures not shown.

Pipeline gas imports by country breakdown



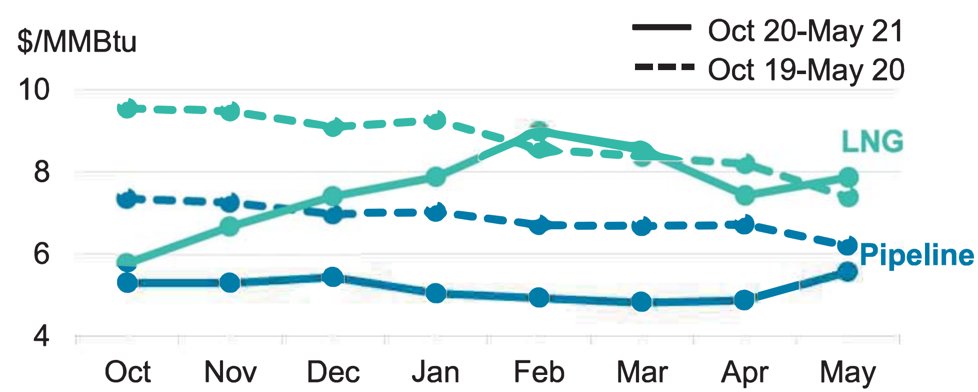
Source: China customs, BloombergNEF.

Pipeline imports versus LNG imports share



Source: China customs, BloombergNEF.

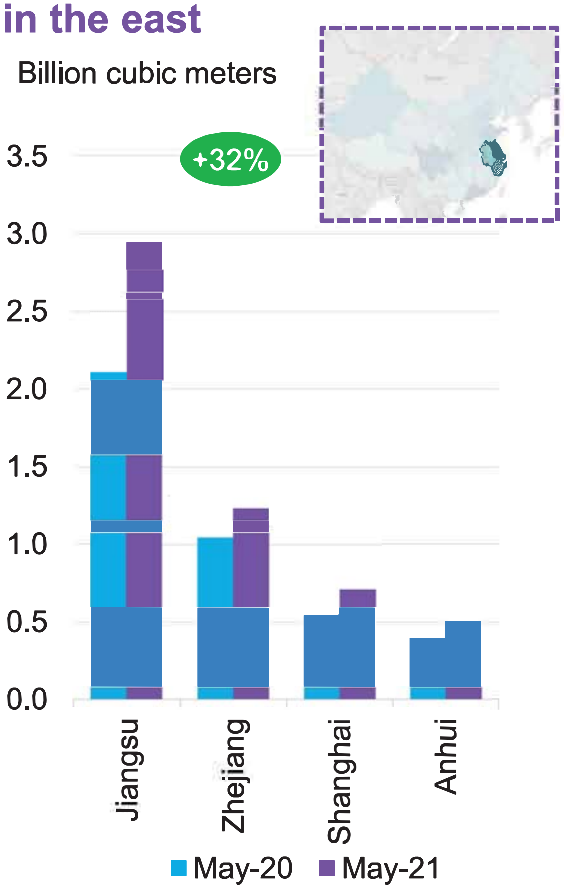
Gas import prices



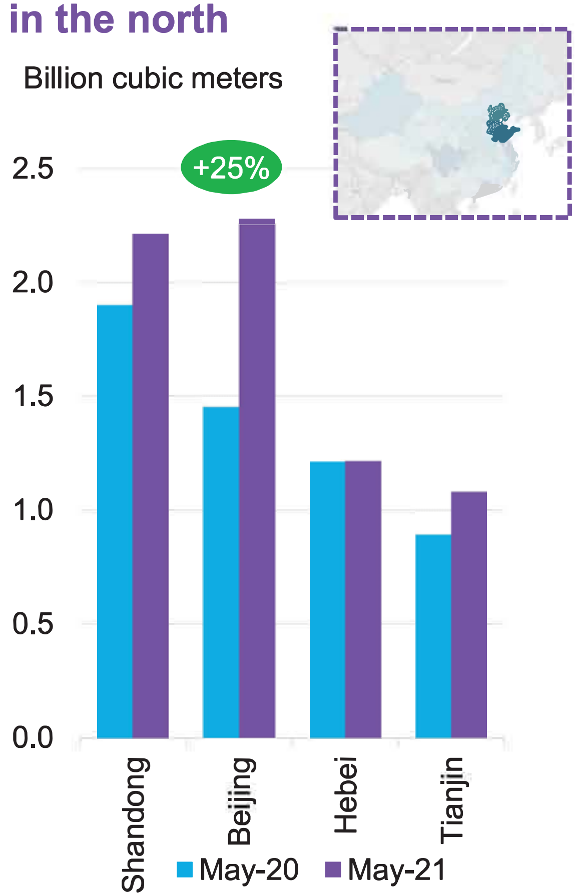
Source: China customs, BloombergNEF.

Regions: Demand in the east region jumps, potentially driven by the power sector

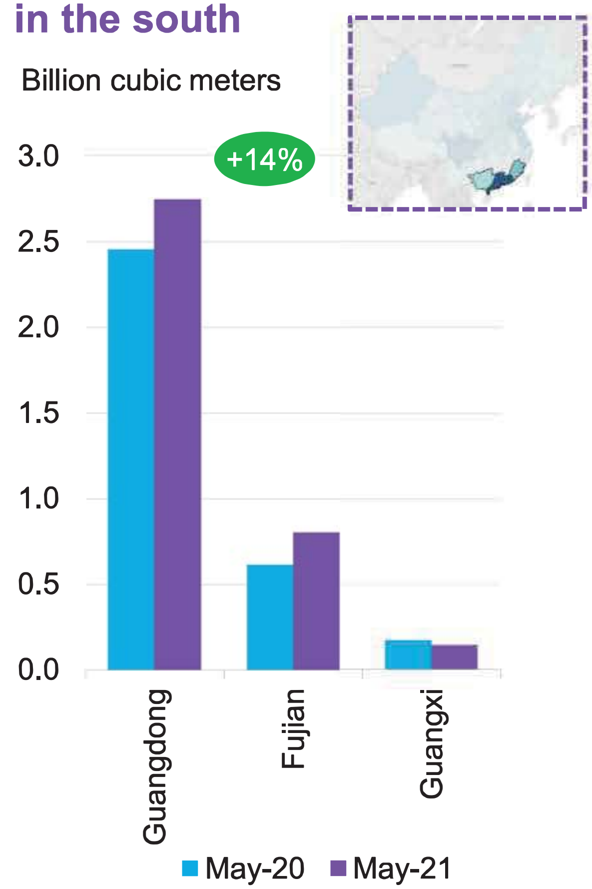
Major gas demand provinces in the east



Major gas demand provinces in the north



Major gas demand provinces in the south

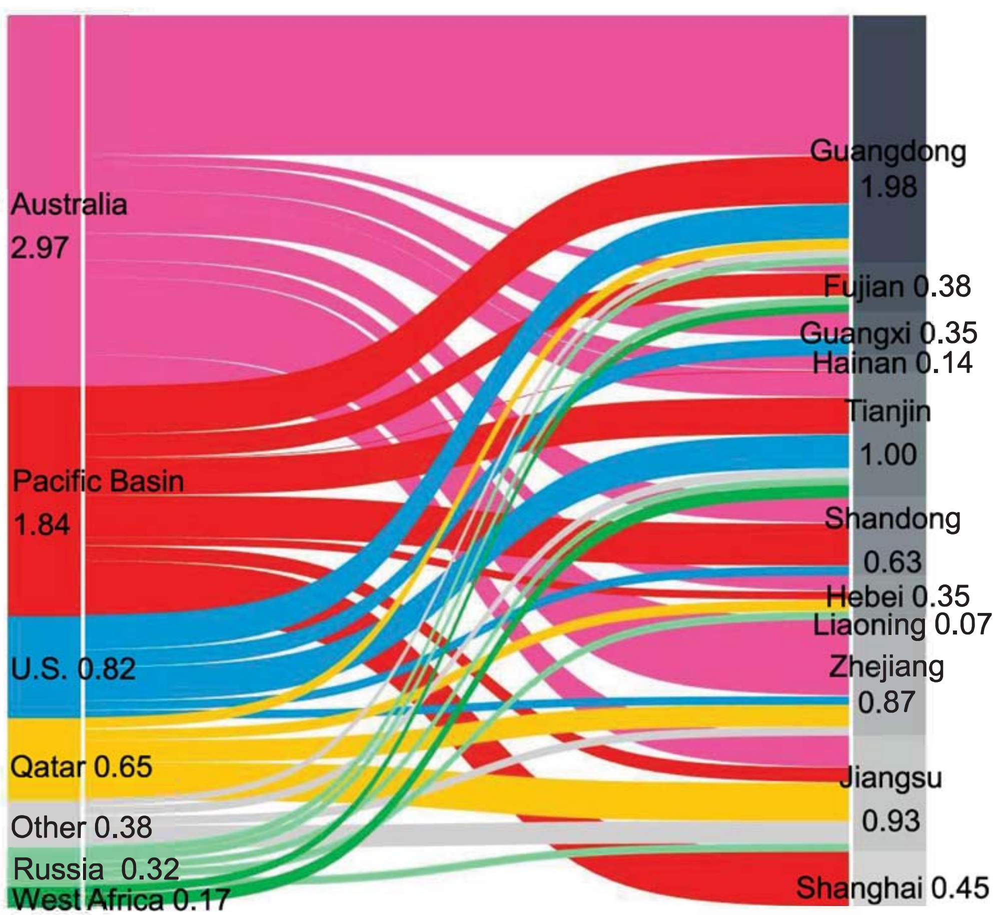


Source: JLC, BloombergNEF. Note: Not all provinces are included in the regions.

China monthly data

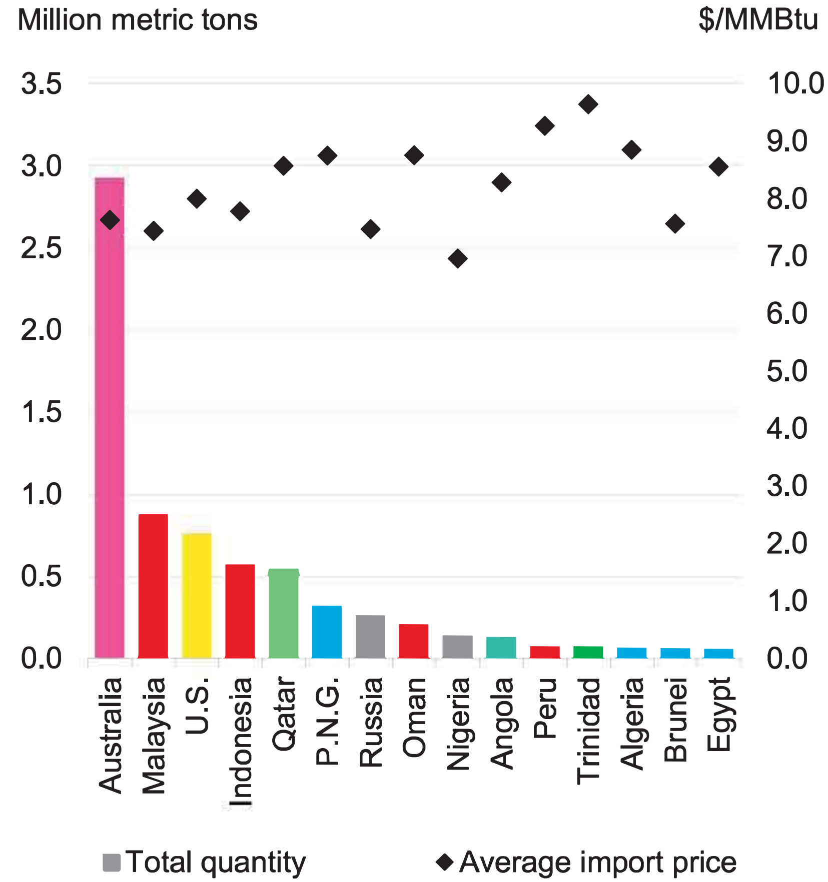
Import LNG flows: Nigerian cargoes appear to be the cheapest, while Trinidadian is most expensive

May LNG supply to destination provinces



Source: Bloomberg Terminal's AHOY JOURNEY <GO>, BloombergNEF.

May average LNG import price by supply source

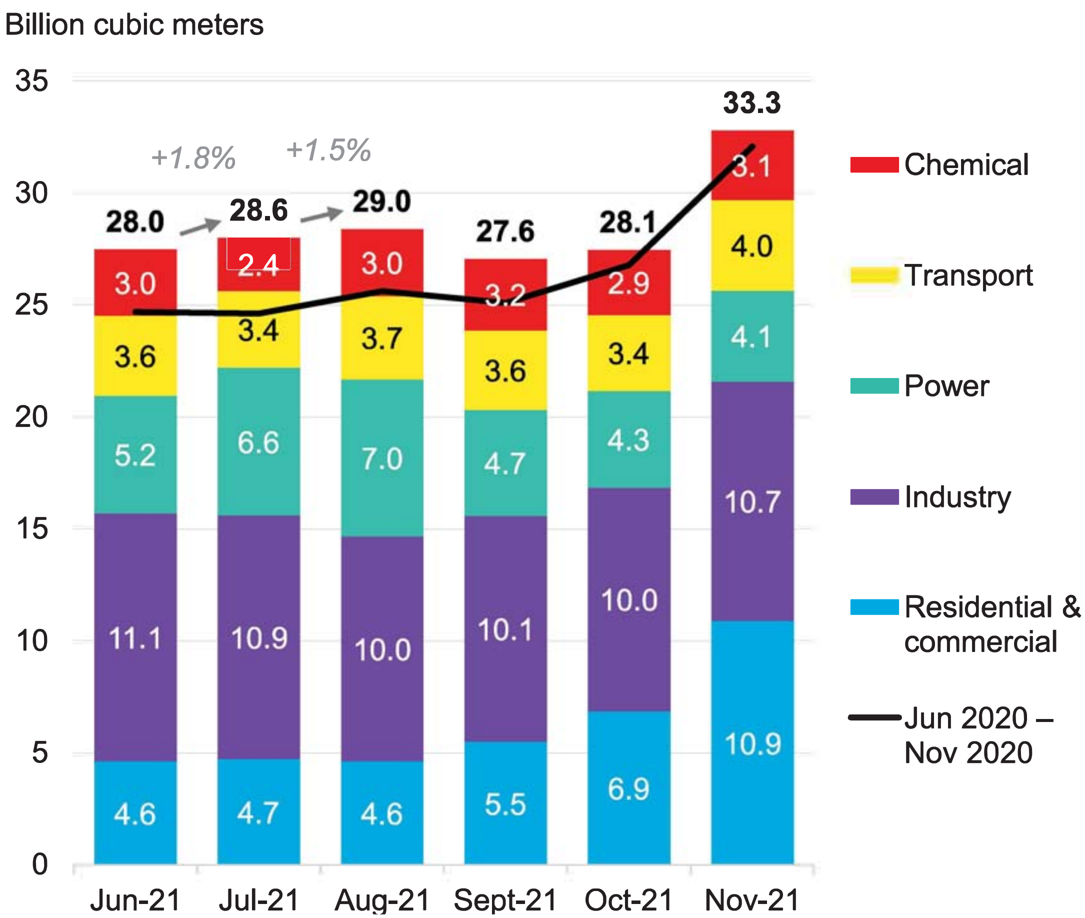


Source: China Customs, BloombergNEF. P.N.G. is Papua New Guinea.

BloombergNEF

Gas demand: 3Q consumption to remain strong with industrial and power demand

China gas demand forecast and annual change

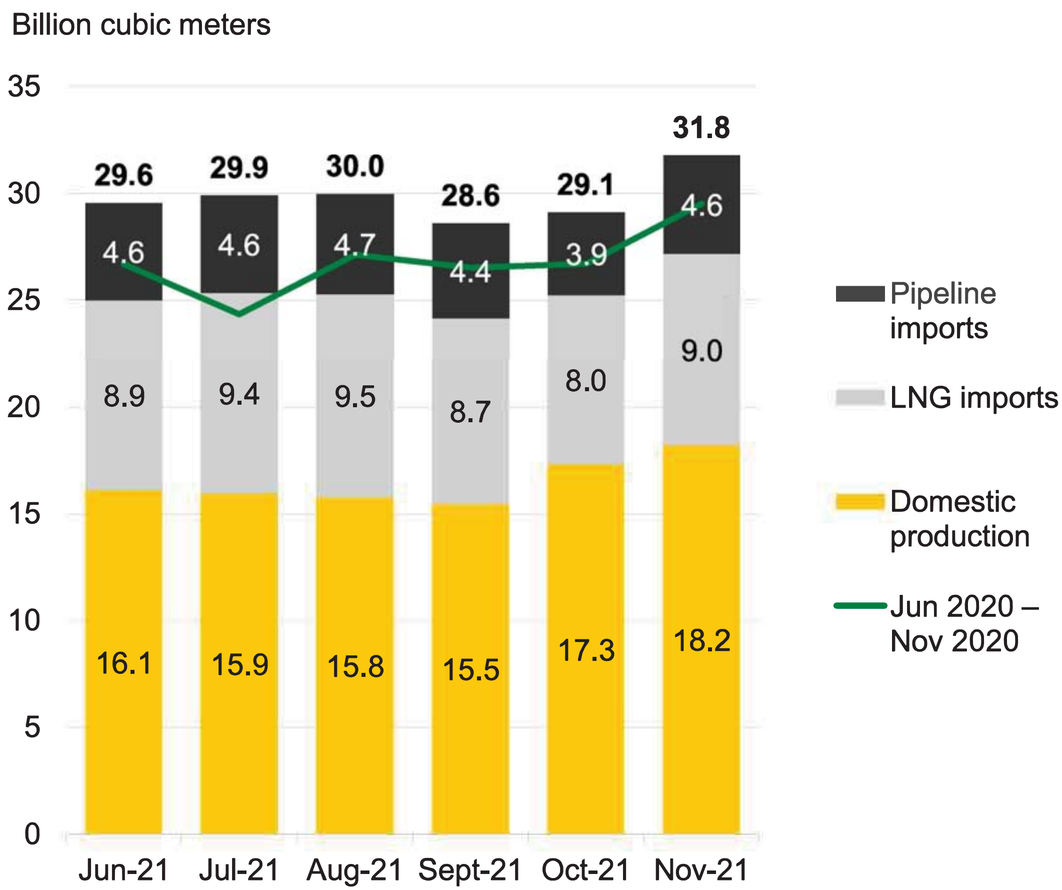


- Apparent gas consumption during July to August is likely to increase steadily by 14.5% year-on-year to 57.5 billion cubic meters. Strong demand growth, especially from the industry and power sectors, is expected to boost gas consumption.
- BNEF estimates June gas demand to be 28.0Bcm, up 13.6% year-on-year. June gas demand is estimated to have dropped from May as Guangdong's gas power demand reduced and the country prepared to celebrate the 100th anniversary of China's Communist Party, which ordered some shut-down of polluting factories.
- Power shortages in Guangdong have been alleviated since early June. The province removed a price cap for utility-scale gas power units with an annual utilization hour higher than 3,500hr to encourage more gas power generation – see BNEF analysis. At the same time, Yunnan also exported more electricity to Guangdong with more rainfall. Therefore, gas for power demand is expected to remain fairly level at 5.2Bcm.
- Anticipated July gas demand could increase 1.8% from June to 28.6Bcm, 16.0% higher year-on-year. August gas consumption is likely to further increase 1.5% from July to 29.0Bcm, 13.1% higher on a yearly basis.
- Gas demand in the third quarter is expected to reach 85.1Bcm, up 13.0% compared to the same period last year.

Source: BloombergNEF. Note: Figures are rounded.

Gas supply: LNG imports to grow in July and August but high prices add pressure

China natural gas supply forecast and annual change



Source: BloombergNEF. Note: Gas inventory changes are not included. Therefore, supply change is different from demand change. Figures are rounded.

- June domestic gas production is expected to increase 6% year-on-year to 16.1 billion cubic meters, down 5% from May. July and August gas output is forecast to rise 11% on a yearly basis to 31.7Bcm. Domestic gas production in the third quarter is likely to grow 10% yearly to 47Bcm.
- LNG imports surged 25.9% year-on-year in June, reaching 6.5 million tons – according to Bloomberg's AHOY JOURNEY <GO>. LNG imports were high in June compared to the same period last year due to industrial and power gas consumption. But this was still 10% lower than May, possibly due to higher LNG prices. Average June JKM front-month futures prices reached $11.6/MMBtu, 21% higher than May. July LNG imports could increase 6% from June, due to higher gas power demand with warmer temperatures in eastern and southern China. LNG imports in the third quarter could increase 19.6% year-on-year to 20 million tons.
- Pipeline gas imports in June and July are estimated to be 4.6Bcm, maintaining a similar level to May. Russian gas deliveries are estimated to resume normal levels. Third quarter pipeline imports are estimated to total 13.7Bcm, growing at 14.8% year-on-year.
- Total gas supply in 3Q may increase 13% to 88.3Bcm to meet growing gas demand and refill storage before the heating season.

https://www.gazprom.com/about/marketing/europe/

Gazprom – Europe

The main goals of Gazprom in the European market are retaining its leadership position, ensuring reliable gas supplies, and improving the efficiency of its marketing activities.

European countries have been among the key consumers of Russian gas for over 50 years.

Gazprom is the largest exporter of natural gas to the European market.

Over the course of 2020, the Gazprom Group sold 219 billion cubic meters of gas to countries outside the former Soviet Union (including both exports from Russia and sales of gas purchased by the Group abroad). The net revenue from gas sales (net of excise tax and customs duties) totaled RUB 1,811.6 billion.

In 2020, Russian gas exports to Europe (under contracts of Gazprom Export) amounted to 174.9 billion cubic meters.

Gazprom's activities in the European gas market are underpinned by long-term contracts with take-or-pay clauses. The Company also uses new forms of trade based on short- and medium-term sales, swap operations, and spot contracts.

Unified export channel

The unified export channel is the backbone of Gazprom's export strategy. Pursuant to the Russian law on gas export, Gazprom has an exclusive right to export gas via gas pipelines. The law allows the Company to pursue a coordinated production and marketing policy and serves as an additional legal guarantee of reliable gas exports from Russia.

Long-term contract system

Gazprom exports gas to Central, Western and southeastern Europe mostly under long-term contracts.

Long-term contracts with take-or-pay clauses are fundamental to stable and sustainable gas supplies. No other contract can guarantee that producers and exporters will get returns on multibillion investments in major gas export projects and that importers will enjoy secure and uninterrupted gas supplies in the long term.

The main features of the long-term contracts are as follows:

- price formula taking into account changes in the prices of the basket of reference goods in the previous six to nine months;
- clauses forbidding the unilateral termination of contracts unless caused by prolonged force majeure events;
- take-or-pay clause for significant contracted volumes, stipulating that buyers should pay for all contracted gas, whether offtaken or not, but may later withdraw the unconsumed volumes at a surcharge upon receiving the minimum annual volumes contracted for the specified year.

In essence, the long-term contracts are service contracts that allow buyers to exercise flexibility with regard to both daily and annual volumes supplied, while the seller has an obligation to deliver the pre-paid take-or-pay volumes. Moreover, long-term contracts provide a guarantee of gas deliveries over a substantial period of time. Spot gas, meanwhile, is a fundamentally different product, which makes direct comparisons between contract and spot prices unjustified.

Contracts which are partially oil-indexed, however, continue to be relevant. Oil indexation is a long-term business planning tool that provides for investment continuity and stability in the gas sector.

Average gas selling price beyond FSU (net of VAT, including excise tax and customs duties)

	Year ended December 31				
	2016	2017	2018	2019	2020
RUB/1,000 m^3	11,763.3	11,670.5	15,499.5	13,613.0	10,355.9
USD*/1,000 m^3	176.0	200.2	246.4	210.6	143.0
EUR*/1,000 m^3	159.0	176.8	209.1	188.2	124.9

* The data were not derived from financial statements and were calculated based on exchange rates as of the end of the relevant period.

European gas market

The dynamics of Russian gas supplies to Europe depend on a number of factors, including rates of economic growth and indigenous gas production, prices for other energy sources – particularly in the power industry – and gas prices in other international markets.

Natural gas sales by Gazprom Group in Europe beyond FSU in 2020, billion cubic meters

Country	Volumes
Austria	10.6
Belgium	1.3
Bosnia and Herzegovina	0.2
Bulgaria	2.3
Croatia	1.8
Czech Republic	4
Denmark	1.8
Finland	1.6
France	14
Germany	41.6
Greece	3.1
Hungary	8.6
Italy	20.9
Netherlands	48.1
North Macedonia	0.3
Poland	9.7
Romania	1
Serbia	1.4
Slovakia	7.6
Slovenia	0.4
Spain	0.8
Switzerland	0.4
Turkey	16.4
United Kingdom	8.9

Enhancing reliability of gas supplies to Europe

Gazprom implements a set of measures to enhance the reliability of its gas supplies to European consumers, including systematic efforts for contracting gas transmission capacities, optimizing and redistributing the contracted capacities, executing swap deals, and mitigating flow interruptions and other emergencies.

With a view to further improve supply reliability, Gazprom initiated the Nord Stream, Nord Stream 2 and TurkStream gas transmission projects.

Nord Stream, the first gas pipeline in history to establish a direct connection between the Russian and European gas transmission systems, reached its design capacity in 2012.

Nord Stream 2 is a new export gas pipeline to Europe across the Baltic Sea. The construction project is ongoing.

TurkStream is a new export gas pipeline stretching from Russia to Turkey across the Black Sea. The first string of the gas pipeline is intended for Turkish consumers, while the second string is meant to deliver gas to southern and southeastern Europe. Construction of TurkStream started in 2017. Gas supplies via the pipeline began in January 2020.

https://www.ft.com/content/0d60da9b-54ad-4027-b054-2ff25261e506?shareType=nongift

Opec 'gets a pass to lift oil prices' as hedging losses hobble US shale

American producers lose billions of dollars after locking in sales at lower prices

Many of the hedges agreed by US operators were signed during the worst months of last year's crude price crash © Callaghan O'Hare/Bloomberg

Derek Brower and David Sheppard YESTERDAY

Some of America's biggest oil groups are racking up tens of billions of dollars in hedging losses despite soaring crude prices, as contracts signed during last year's crash leave them selling their output at deeply discounted prices.

Oil is trading near six-year highs of around $75 a barrel, but almost a third of the US's 11m barrels a day of production is being sold for just $55 a barrel, according to IHS Markit, a consultancy.

The figures will offer comfort to the Opec cartel that rallying prices are not about to spark another market-busting surge in American shale production.

"Opec gets a pass to keep lifting prices right now if it wants to, without fearing much of a US supply response," said Bill Farren-Price, an analyst at Enverus. "Shale producers are locked into selling their oil cheaply this year."

IHS Markit said US oil hedging losses in the first half of 2021 had already hit $7.5bn, but would rise by another $12bn if crude remained at $75 a barrel until the end of the year. Many Wall Street forecasts suggest it could go higher.

"They missed the boat this year" Raoul LeBlanc, IHS Markit

Last week a political spat between Saudi Arabia and the United Arab Emirates left the Opec cartel unable to agree on a plan to restore oil production, which it cut last year in an effort to prop up global crude prices.

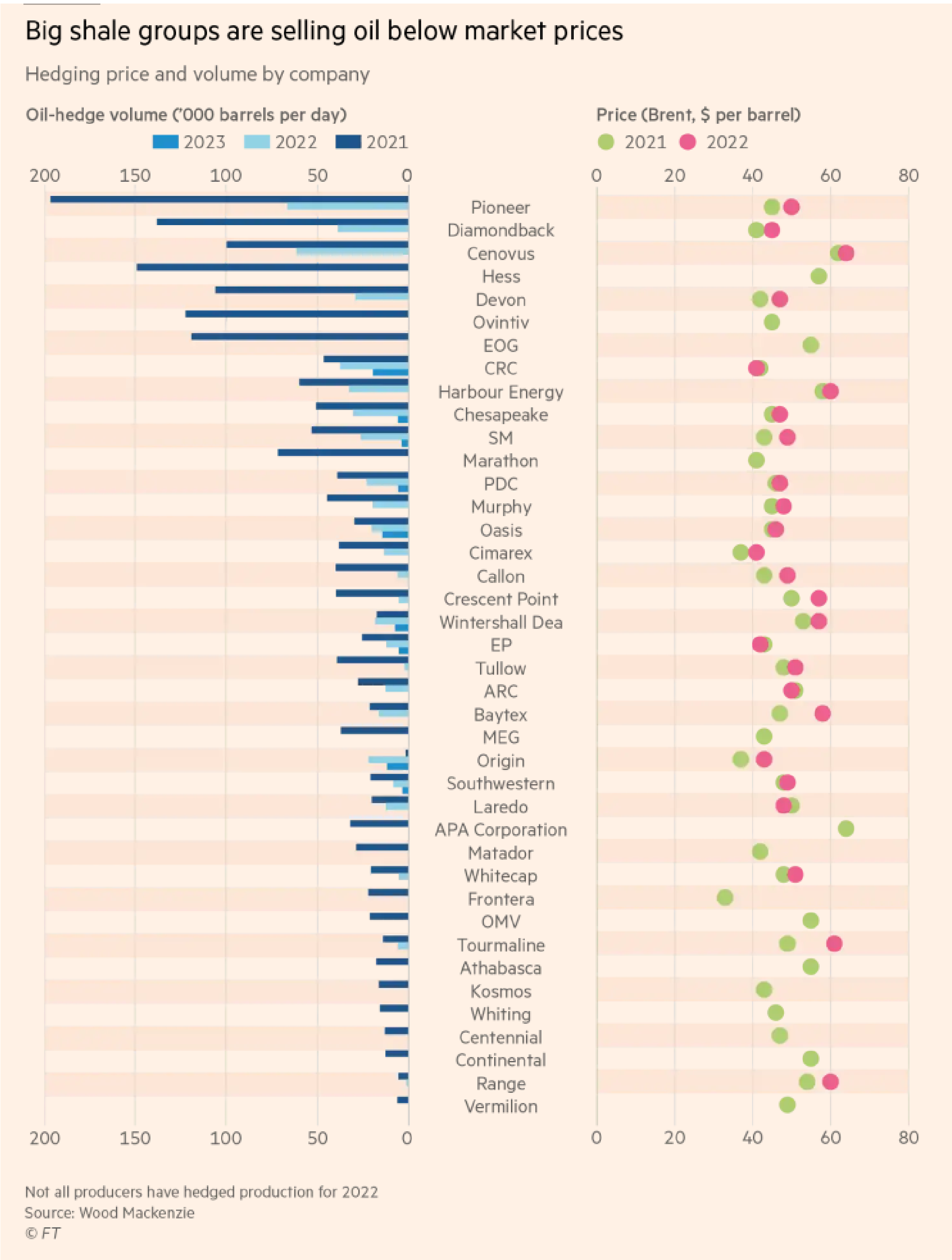
The initial reaction of the market was to fear a growing supply shortage, sending prices higher. They have since pulled back, as some traders speculated the cartel could fray and countries such as Saudi Arabia and Russia could start producing at a much higher level.

Many of the hedges agreed by operators were signed during the worst months of last year's crash, when creditors demanded that companies buy insurance against further price drops.

In the wake of vaccination breakthroughs and Opec's output cuts since then, those hedges now look far too pessimistic.

"If you get hedging right, people don't give you credit for it. If you get it wrong, you get hammered," said Raoul LeBlanc, a vice-president in IHS Markit's unconventionals team. "They missed the boat this year."

Analysts at JPMorgan said that surging US oil prices in recent months now left almost all the hedges made by the companies it covers underwater.



Among exceptions in the shale patch are Occidental Petroleum and Hess, said Goldman Sachs, as well as Continental Resources, mostly owned by the billionaire shale pioneer Harold Hamm.

“These are bets — people should know that about hedges,” Hamm told the Financial Times. “When everyone’s urging everyone to hedge, that’s a good time not to.”

Continental’s income has risen as the company has taken almost full advantage of the oil price increases in recent months, with cash flow from operations more than doubling between the fourth quarter of last year and the first quarter of 2021.

“With an 82 or 83 per cent ownership position you can afford to have the courage to take the heat from the market and go with your gut,” said Hamm, who recently increased his stake in Continental.

Among producers stuck selling oil beneath market prices is Pioneer Natural Resources, the largest producer in the prolific Permian Basin field of Texas and New Mexico, with most of its output priced at less than $50 a barrel, according to IHS Markit.

Pioneer faces hedging losses of almost $900m this year, JPMorgan said. Rival Permian operators Devon Energy and Diamondback Energy would accrue hedging losses of $657m and $608m respectively at a US oil price of $60, the bank calculated.

The hedging losses among some big US producers far exceed those among independent international operators, according to data from Wood Mackenzie, a consultancy. Among companies it follows, Germany's Wintershall Dea was by far the biggest loser, on the hook for $345m in a base-case price scenario, it said.

Shale's revival as oil prices have recovered has been much slower than after previous downturns, with the US onshore rig count still well below its range before last year's pandemic sparked a brutal price crash.

Pledges to rein in spending and eschew new production growth in favour of balance sheet repair and shareholder payouts are one reason. But the hedging losses are hampering companies, said Alex Beeker, principal corporate analyst at Wood Mackenzie.

"I think it is weighing on the decision at least a little bit to add to activity right now," he said.

https://www.detroitnews.com/story/news/local/michigan/2021/07/09/state-enbridge-aim-complete-line-5-mediation-end-august/7913099002/

State, Enbridge aim to complete Line 5 mediation by end of August

Published 11:33 a.m. ET Jul. 9, 2021 Updated 11:50 a.m. ET Jul. 9, 2021
Beth LeBlanc
The Detroit News
View Comments

The state of Michigan and Enbridge expect to complete mediation over the future of Line 5 in the Straits of Mackinac by the end of August, the parties told a federal judge Thursday.

The parties are expected to meet with their mediator, former Detroit U.S. District Judge Gerald Rosen, on Aug. 11. They began meeting with Rosen in April about the ongoing dispute over the future of the 68-year-old pipeline.

Enbridge wants to "work cooperatively to reconcile interests, resolve disputes and move forward" through the mediation process, spokesman Ryan Duffy said Friday.

"We understand the stakes in this matter are important not only for Enbridge and the state, but for many others throughout the region that have strong interest in its outcome," Duffy said in a statement. "Meanwhile, we will continue to safely and responsibly deliver the energy the region relies upon from the Line 5 system. "

Attorney General Dana Nessel's office declined comment due to the confidential nature of the court-ordered mediation.

Gov. Gretchen Whitmer in November revoked Enbridge's easement through the Straits of Mackinac and ordered the company by May 12 to shut down the dual pipeline carrying up to 540,000 barrels of oil and natural gas liquids a day through the Straits.

Whitmer filed in Ingham County Circuit Court at the same time, seeking a court order to uphold her actions.

She argued that Enbridge had "persistent and incurable violations" of the easement as well as violations of the public trust document.

Enbridge has argued it cured whatever violations cropped up during the lifetime of the pipeline

The company refused to close the line absent a court order and filed its own suit in federal district court, where the Canadian oil giant argued federal regulators, not state, had the final say over the operation of the line.

The company also removed Michigan's suit from state court to federal on similar grounds. The state continues to fight the removal of the case to the conservative-leaning federal court.

Amid the litigation, Enbridge continues moving forward with plans to build an estimated $500 million tunnel beneath the Straits to house a new segment of the pipeline.

Enbridge has secured permits from the state for the project but still lacks authorization from the Michigan Public Service Commission and federal permits from the U.S. Army Corps of Engineers.

Both agencies have ordered environmental reviews of the project that could delay construction.

eleblanc@detroitnews.com

https://www.transmountain.com/news/2021/summer-construction-look-ahead

Summer Construction Look Ahead

Jul 8, 2021

This summer, construction continues along the pipeline route and at facilities throughout Alberta and BC. Many steps are involved in building a pipeline and it's not unusual to see the same types of work at different phases of completion across the Project corridor. This year, we'll see peak construction for the Project with thousands of people working at hundreds of worksites. We've highlighted a few of the construction activities below that will be taking place this summer.

Pipeline Construction

In Alberta, Trans Mountain has begun construction of the Expansion Project in the Yellowhead region between Highway 60 in Parkland County and west of Hinton, AB. Construction is taking place in a series of phased activities along the pipeline right-of-way through Spruce Grove, Stony Plain, Yellowhead County, Edson and Hinton, AB and will be underway through December 2022. While construction in the Yellowhead region continues, work in the Greater Edmonton Area is nearly complete, with minimal work remaining, including the final few steps of conventional pipeline construction and the Whitemud Drive crossing.

In the North Thompson region, crews will focus on stripping, grading and stringing pipe.

This June, we marked one year of work in the Kamloops Urban Area (KUA). Throughout the summer, work will continue in the KUA, however, work in the BC Interior will begin in other areas and crews will mobilize in Merritt to start on access and stripping.

With extreme heat and active wildfires in several BC locations, Trans Mountain is taking extra precautions at our operations and construction sites to ensure we are doing our part to mitigate fire risks this summer. Trans Mountain's first priority is the health and safety of our workforce, their families and our communities. We are constantly monitoring the active wildfires in British Columbia and assessing their impact on our existing operations and construction of the Expansion Project.

We have access to fire suppression equipment at all of our operations and worksites, which includes structural protection units and mobile wildfire gel trailers equipped with water tanks, hoses, pumps, foam and gel.

In BC, the Kiewit Bonatti TMEP Partnership is mobilizing in the Coquihalla-Hope region and will be active this summer. In the area, progress continues with surveys, sweeps, ROW access and stringing of pipe. Similar right-of-way preparation activities will be ongoing in the North Thompson this summer as well.

In the Lower Mainland, construction will continue in Coquitlam through the summer months.

Trenchless Crossings

In July, construction of the Sundance Creek crossing near Marlboro, AB and the Lobstick River crossing near Niton Junction, AB will continue. The Raft River crossing in the North Thompson region will also continue. In August, preparatory work will begin for the first of three trenchless crossings of the North Thompson River.

Work at the Coquihalla River, approximately 10 kilometres northwest of Hope, BC will also be underway this summer. Alongside Trans Mountain Expansion Project installation, Trans Mountain is replacing a segment of the existing pipeline beneath the Coquihalla River for safe continued operation of the Trans Mountain system. A new pipeline will be installed and the existing line will be decommissioned in compliance with Canada Energy Regulator (CER) authorizations. Trans Mountain has chosen to undertake both installations simultaneously and alongside each other to limit environmental impact to the Coquihalla River.

In Coquitlam, a guided horizontal auger bore, which is a form of trenchless crossing used to reduce construction impacts in the area, will be used in the United Boulevard area and preparation work for this crossing is currently underway.

Terminals and Pump Stations

The Gainford, Hinton, Edson and Wolf pump stations in Alberta will continue to see work throughout the summer, as will the Hargreaves, Blue River, Blackpool and McMurphy pump stations in the North Thompson.

Work at the Edmonton Terminal is also steadily progressing and will continue throughout the summer. Of the four new tanks being installed at the terminal, Tank 1 is complete while work continues at various stages on tanks 2 – 4.

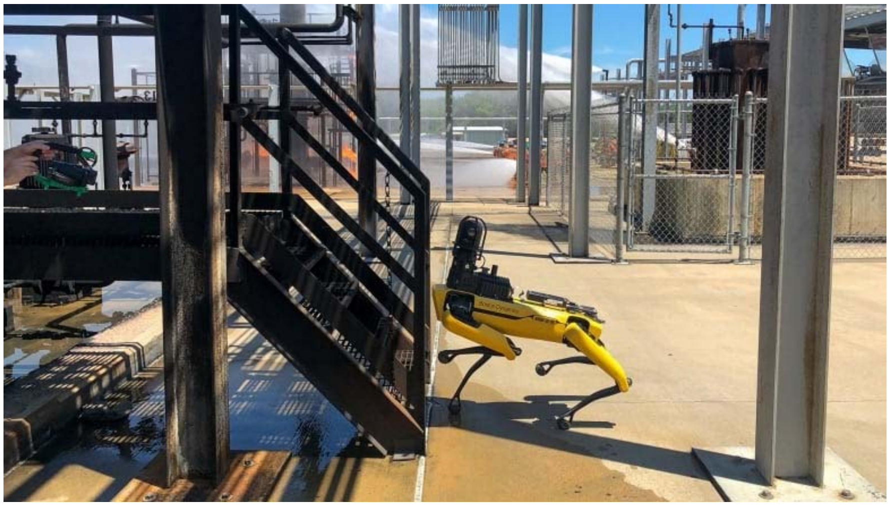
Over the next few months, a number of maintenance and Expansion Project activities will take place at Burnaby Terminal, including tank construction, in-line inspections of existing pipe segments and relocation of existing infrastructure where required. While over at Westridge Marine Terminal, construction will continue during regular work hours with low-impact work overnight. Work that takes place overnight includes construction of a derailment wall, ground improvements on the foreshore and access road widening. Tunnel boring at Westridge Marine Terminal is continuing this summer to construct the 2.6-kilometre tunnel that will connect Burnaby Terminal to Westridge Marine Terminal.

https://www.cbc.ca/news/canada/edmonton/shell-scotford-robodogs-1.5934940

Unleashing the future: Shell adds a team of robodogs to its Scotford operations

Bolt, Gadget and their human handlers are all currently in training

CBC News · Posted: Mar 03, 2021 11:58 AM MT | Last Updated: March 3



The four-legged Spot robots have cameras or arm attachments where the head would be. (Supplied by Boston Dynamics)

A dog training academy is teaching new tricks to a pair of very special dogs and their human handlers at Shell's Scotford Complex.

But with their abilities to open doors and take photos, the four-legged robots named Bolt and Gadget are clearly a cut above the average canine.

"The intent is to use them for some basic maintenance inspections," Conal MacMillan, the company's external relations manager, told CBC Radio's *Edmonton AM* on Wednesday.

"We'll be able to program them to their own custom routes to test our plant conditions, to help us out with some security tasks and if needed — hopefully not — perform autonomous emergency response missions on our site, too."

The robots are part of the bright yellow Spot line of quadruped robots made by Boston Dynamics, a company that was spun out of MIT in 1992 and is now owned by Hyundai. The Spot robots became commercially available in June, priced at $74,500 US.

Boston Dynamics is known for creating robots with advanced mobility and dexterity. Spot's smooth moves are featured in a viral YouTube video released in December that features a chorus line of the company's robots dancing to The Contours' hit *Do You Love Me*.

The robots, while headless, have doglike attributes that become more pronounced when they start moving. "Once it starts moving around," MacMillan said, "it would look 100 per cent like a dog."

MacMillan said one robot has 360-degree visual and scanning capabilities, with a camera mounted where its head would be. The second has attachments that give it the ability to manipulate items and perform tasks.

They have heat detection capabilities and can do 3D scans of equipment that could be digitally mapped using computer software, he said.

One of the new Spot robots and a controller are shown in this photo, taken at Shell Scotford's Innovation Hub. (Supplied by Conal MacMillan/Shell Scotford)

"The possibilities right now are endless, in terms of what it could do," he said. "But until we actually know how to manipulate the arm and use that bot more effectively, it'll be small, incremental steps to start out. And will grow it and learn more as we move along.

"So right now, like I said, he can open the door, he could dig a hole and probably hide a bone."

The robots can be operated in two ways. A remote handler can guide its movements with a controller similar, except for the embedded screen, to what you would use for an XBox gaming system. The robots also can be taught to operate autonomously, he said.

Employee safety is the primary reason for adding ground robots to Shell's suite of technological assistants, which also includes drones for aerial inspections and robots that clean the inside of the refinery's massive tanks.

"In the past, we might have had to put somebody in a situation where we had to de-risk it with scaffolding or PPE or different layers of safety barriers," he said.

"(With the robots), we wouldn't have to do that. We wouldn't have to put that person in that situation."

Bolt and Gadget were named through two contests involving young family members of Scotford staff and student suggestions from schools in Fort Saskatchewan, Sherwood Park and Bruderheim.

"It's pretty cool technology and we wanted to create some awareness around the future jobs that some of these kids could have," he said.

MacMillan said Shell is actively bringing more innovative technology into its operations. Scotford is one of two Shell sites — the other being its Pernis refinery in Rotterdam — with robotic dogs.

Much of the training, expected to continue through the first quarter of the year, is geared toward familiarizing the human handlers with the robots, MacMillan said. The plan is to unleash them in Q2.

Training is taking place away from the Scotford's refinery, upgrader and chemical plant in Fort Saskatchewan, which is restricted to essential workers as a pandemic precaution.

But curiosity among employees is still very high, he said.

"There's definitely a general level of excitement and interest in seeing what these dogs can do — and what they're going to look like when they're doing it."

Watch: An end-of-2020 dance party with some Boston Dynamics robots

https://www.cbc.ca/news/canada/edmonton/alberta-takes-50-per-cent-equity-stake-in-sturgeon-refinery-1.6090845

Alberta takes 50 per cent equity stake in Sturgeon Refinery

30-year processing deal extended another decade

Michelle Bellefontaine · CBC News · Posted: Jul 05, 2021 4:18 PM MT | Last Updated: July 5

The Sturgeon Refinery is located 45 kilometres northeast of Edmonton. (CBC)

The Alberta government is buying a 50 per cent stake in the troubled Sturgeon Refinery and extending the current 30-year processing agreement by another decade.

The province will share ownership of the refinery, located 45 kilometres northeast of Edmonton, with Canadian Natural Resources Limited.

The government said in a news release Monday the partnership will save $2 billion over the life of the project. Debt refinancing will free up to $1 billion in cash flow over five years due to better interest rates.

Energy Minister Sonya Savage said the government made this deal to make the best of a bad agreement that had iron-clad provisions that were impossible to escape.

"Under the previous deal, we had all the risk, we took all the risk...and we had no ability to control or mitigate that risk to control costs or to have any say in how the refinery was operated," Savage said in an interview with CBC News.

"With this deal, we save $2 billion and we have a seat at the table."

Under the original agreement reached in 2012, North West Redwater Partnership, which was owned equally by North West Refining Inc. and a subsidiary of Canadian Natural Resources, owned and operated the refinery.

- **OPINION | This 'Bitumen Boondoggle' is costing Alberta taxpayers billions**

The deal announced Monday has North West Refining transferring its ownership stake to the government of Alberta, which gives the province an equal vote in the operations. Officials say taxpayers wouldn't incur additional costs.

The North West Redwater Partnership is paying $425 million to North West Refining and $400 million to CNRL. Under the original agreement, Alberta government had to pay processing fees and profits each month.

Paying this money upfront means the government will no longer have to make these monthly payments, and will save money over the term of the agreement.

Savage compared it to the savings of paying off a credit card balance today instead of incurring interest costs by paying instalments over a longer period of time.

"The owners of the refinery were guaranteed a rate of return by the Alberta government under the previous deal for many, many years," Savage said.

"By paying that out now, it saved a lot of money for the Alberta government. If we didn't pay it out now, we'd be paying it out month-by-month, year-by-year over decades and it would be a lot more."

The Alberta Petroleum Marketing Commission (APMC) has responsibility for supplying 75 per cent of the feedstock for the refinery, which would process raw bitumen into diesel and other products.

The government estimates the refinery will lose $2.5 billion over the life of the project.

The cost of building the refinery was estimated at $5.7 billion when construction started in 2013 and ended up at $10.1 billion last year.

Government intervention 'inevitable'

Richard Masson, the former CEO of APMC and a current executive fellow with the University of Calgary School of Public Policy, said it was inevitable the government would have to step in.

He said North West Refining Inc. didn't have much money and wasn't able to sustain the ongoing losses. He said having one partner go out of business could put the whole project at risk.

"I think APMC probably took the view it would be better to be an owner where you can have some control than potentially have something go wrong, and see North West go under," Masson said.

The continued involvement of an experienced company like CNRL as a partner and operator is good news, he added.

Andrew Leach, an energy and environmental economist at the University of Alberta, has called the Sturgeon Refinery deal a "bitumen boondoggle." He says the government should have become involved once the construction costs started ballooning.

Instead, in 2014, the government of the day changed the terms of the agreement and started loaning the project money, he said.

Leach thinks the province should hold an inquiry or Alberta's auditor general should take a closer look at the government's decisions around the North West Redwater Partnership, the crude-by rail contracts and the lost investment in the cancelled Keystone XL pipeline.

"These are billions and billions and billions of dollars," Leach said. "Risky decisions that are being taken with the taxpayers' guarantee behind it.

"We've lost more on these contracts than we've taken in on royalties in the last couple of years."

With files from Janet French and Paige Parsons

SAF Group Created Transcript

CNBC Brian Sullivan interview with Saudi Energy Minister Abdulaziz bin Salman Post Wed July 7, 2021 5:41am ET https://www.cnbc.com/video/2021/07/07/full-interview-saudi-oil-minister-abdulaziz-bin-salman.html

any items in "*italics*" are SAF Group created transcript

along with Russia, 20 countries agreed to a good agreement to the market

"*still going thru Covid and the movement of Covid is still unknown. There are too many things that are happening with Covid*" …..

"we *still have issue as you know with Iran. how much, when and where and by how much they will come*. *also there is a potential for Venezuela*. *these things makes you wonder what would be the right thing to do with a market that needs guidance with a much more stretch period simply because also we have this 5.8 million that we still need to attend to and make sure that we attend to it properly whereby maybe many of these things may convolute. And if we don't attend to it properly, we may lose sight of what the market requires and how we can continue maintaining sustainability and stability"*

Brian Sullivan "*are there any current negotiations happening right now your Royal Highness?"*. *"not that I know of, but you know we have our monthly meetings "*

Didn't see anyone on Friday not mention their commitment to the existing agreement

"*we have an agreement and it will continue until April. And more important, I think it will be in the interests of everybody that we stretch it more for the rest of 22 to ensure we can download these volumes in a meticulous way to ensure that we would not disturb the market"*.

Brian Sullivan *"is it fair to say that the next time you might address adding barrels to the market is at a meeting in August*". "*well it could be*."

"*yes we have every interest to bring barrels the sooner the better, yes we need to do in a very diligent way, careful way and we worked hard in developing our mechanism, the monthly meeting is a [?}. you were complimentary about it. the adjustment mechanism is a good safety valve for the market because it enabled us and we did exercise it*"

"*we need to have volume now to cope with the current season, and we have to mitigate what we need to do in terms of this particular quarter, yet we have to be careful not to overdo it. not doing it is not being careful. Overdoing it is also not being careful because we still have these things going and we have no certainty about it, especially Iran and Covid. And also because we have a first quarter that demand, inventory get to be a build"*

"*in this one, no, we still have a 9 month period*.

Don't recall any of the other countries did not repeatedly stress the commitment to this agreement

"*There are two different subjects. The extension, it is in the public domain, you can see it that it was mentioned in the agreement, the reason we did it there is that some of our colleagues when we were putting that agreement together in April, had a bit of a difficulty accepting an agreement to go beyond 2 years. and that's* *why we had put that clause in the agreement that by December next, we could review the extension. so it is there, its embedded there. so if it is embedded there, its part of the agreement. the volumes, the 5.8 were not there. actually it was said verbatim that it will remain just until the end of April. Now if you look at the two texts, you would know, somebody, you know we were the original drafters with others, we had to accommodate this concern by saying we can review it in December 21 about we could do with the 5.8. and any person on planet earth would say that agreement has to be stretched to allow for a gradual phased in approach to the 5.8. if we did not put that clause, then the whole world, it would become like a ticking clock, or a ticking bomb when the end of that agreement would come. the world would live with the reality that there is still 5.8 million still to be attended to, attended for. and therefore our original concept was where we go from where we had the agreement was originally [?] to extend that agreement and start earlier the phasing out of this 5.8 million. It will gives us 9 months until the end of that agreement and with the extension it would give us another 8 months. if you take the whole volume, the 5.8 and you put it in a linear way, just a* straightforward *400,000 barrel every month, that will take you to the end of September 2022. Which means if you extend the agreement even until the end of September you will barely finish the 5.8. now how could we even argue that we don't know need that extension. I don't know. But more important, why we stretch it to the end of 2022, simple, we need to have 3 months of space that we can apply the adjustment mechanism. Because there are too many things that could happen next month, the month after, in October, in November, which may bring so many barrels to the market ie. an Iranian return, that sort. So you need to have that mechanism truly available and the market can believe that you can exercise…. You need that 3 months just to make sure so you can honor what you saying to the market"*

Re Biden administration have you heard from them? I haven't yet personally talked to anyone yet. [note stressed "I"]

Re Goldman deficit for oil barrels. I spoke to Jeff Currie today, I honestly don't have an issue of speaking out proudly, 20 countries agreed to that proposal. Check our joint Saudi/Russia proposal and ask what is wrong with that proposal. Aside from the basis issue, what is wrong with that proposal. Need to stretch the agreement. Have to be careful about being too optimistic. All require a longer time line. gives the market more comfort

If we can congregate around these big principles and dash around our individual grievances, that would be good. case in point, why did we do the voluntary cut? I did arithmetic to it. if you take our voluntary cuts total, it means we have done 400,000 barrels all the way a day. nobody compelled us to do it.

If you talk about grievance, check the last 30 years. Saudi Arabia capacity.

"*Luckily we have mechanisms be it within OPEC itself, before even the emergence of OPEC+. And within OPEC+ itself, there are a few precedents where there were grievances and these processes were activated, some of them, all of them were attended to, some of them were accepted, but this is the kind of, in my judgement, professional arrangement that one would need to, there is no point, and I don't want to divert to why I am here for but you cannot pick a month and say this is my capacity, you've got to give it to me now. this is not the way to do it."*

Prepared by SAF Group http://www.safgroup.ca/

Excerpt Bloomberg @TheTerminal transcript

State Department Spokesperson Ned Price holds daily press briefing, sked FINAL
2021-07-07 21:29:14.620 GMT

QUESTION: Follow-up on Iran. You mentioned the talks in Vienna yesterday, the interrupted talks. Are -- are -- are you certain those talks are going to resume, have they hit a snag? You know, you mentioned consultations. What are the consultations about? Is it about the new president-elect, Raisi, or some of Iran's behavior in the region?

Or some of the, you know, political backdrop and concerns that -- that are bubbling up, you know, can we absolutely commit that those talks are going to continue? And when do you think we might -- we might see that?

PRICE: What I would say is I would need to direct you to the Iranians for feedback on their consolations, what's going on in -- in their capitol. I can tell you from our part the team has been back here at the department meeting with officials throughout the building.

Including with Secretary Blinken, updating him on the progress of those talks. Of course, nothing is certain in the world of diplomacy but I think we have every expectation that there will be a seventh round of talks at the appropriate moment, at the right time. And our team looks forward to being engaged in that next round of talks when it does begin.

QUESTION: (Inaudible) consultations with the U.S. team in its capitol, those are finished now?

PRICE: We -- we are -- I think we...

QUESTION: Your just waiting for the -- the Europeans to say OK, come on guys, let's go back to the (inaudible).

PRICE: Well, of course, the team continues to remain here, continues to engage in discussions, continues to do important work from the department but that team will be ready, will be prepared to travel back to Vienna when there's a seventh round of talks. Yes.

Crude Oil in Floating Storage 47% Lower Than Year Ago: Vortexa
2021-06-07 07:00:01.260 GMT

By Bloomberg Automation
(Bloomberg) -- The amount of crude oil held around the world on tankers that have been stationary for at least 7 days rose to 93.04m bbl as of June 4, Vortexa data show.

* That's up 0.3% from 92.73m bbl on May 28
* Asia Pacific down 2% w/w to 59.91m bbl; lowest since February
* Middle East up 21% w/w to 8.30m bbl
* Europe up 61% w/w to 7.25m bbl
* North Sea up 434% w/w to 4.40m bbl
* West Africa down 38% w/w to 1.84m bbl
* U.S. Gulf Coast down 30% w/w to 1.44m bbl
* Company Exposure:
** Asia: Cosco Shipping Energy Transportation Co., HMM Co. Ltd., Mitsui O.S.K. Lines Ltd., Nippon Yusen KK
** Europe: Euronav NV, Frontline, Vopak
** U.S.: DHT Holdings, International Seaways, Nordic American Tankers, Teekay Tankers, Tsakos Energy Navigation
* NOTE:
** Vortexa data exclude FPSO units, oil products and Iranian condensate
** Crude oil transferred by STS isn't included until that volume has been stationary on receiving vessel for 7 days
** Data don't include vessels booked for floating storage until they are actually stationary for the minimum period
** See VTXA or DATA FLOAT for more data, which is subject to revisions, and see NI TANTRA for all tanker-tracking stories
** See SPOT FREIGHT for freight rate assessments using shipbroker data

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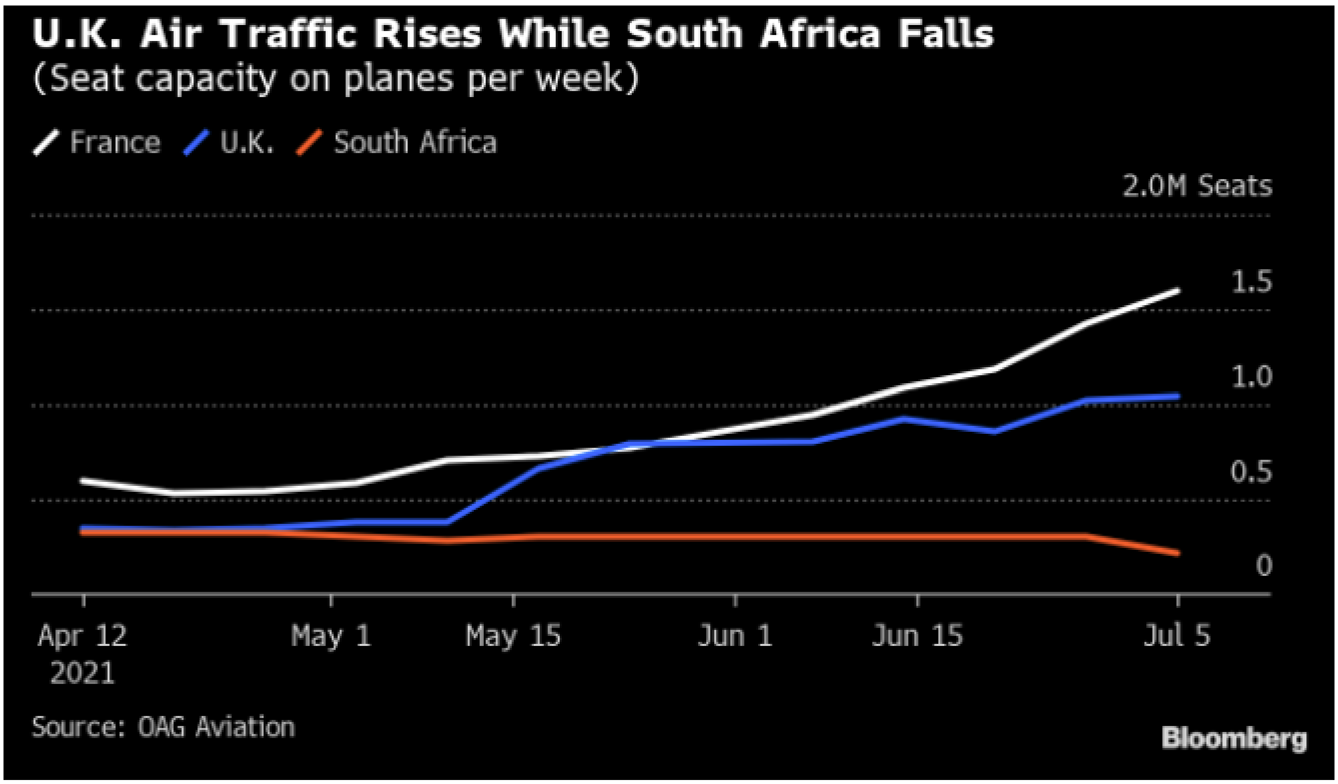
OIL DEMAND MONITOR: Air Traffic Rising for Vaccinated Countries
2021-07-06 08:49:05 GMT

- **South Africa, Australia airline seat capacity falls: OAG**
- **Jet fuel consumption still lags the rebound for road fuels**

By Stephen Voss

(Bloomberg) -- The U.K. and South Africa -- both witnessing a surge in coronavirus infections -- show a marked divergence in air traffic trends as the largely-vaccinated British population benefits from a continued easing of restrictions on mobility and travel.

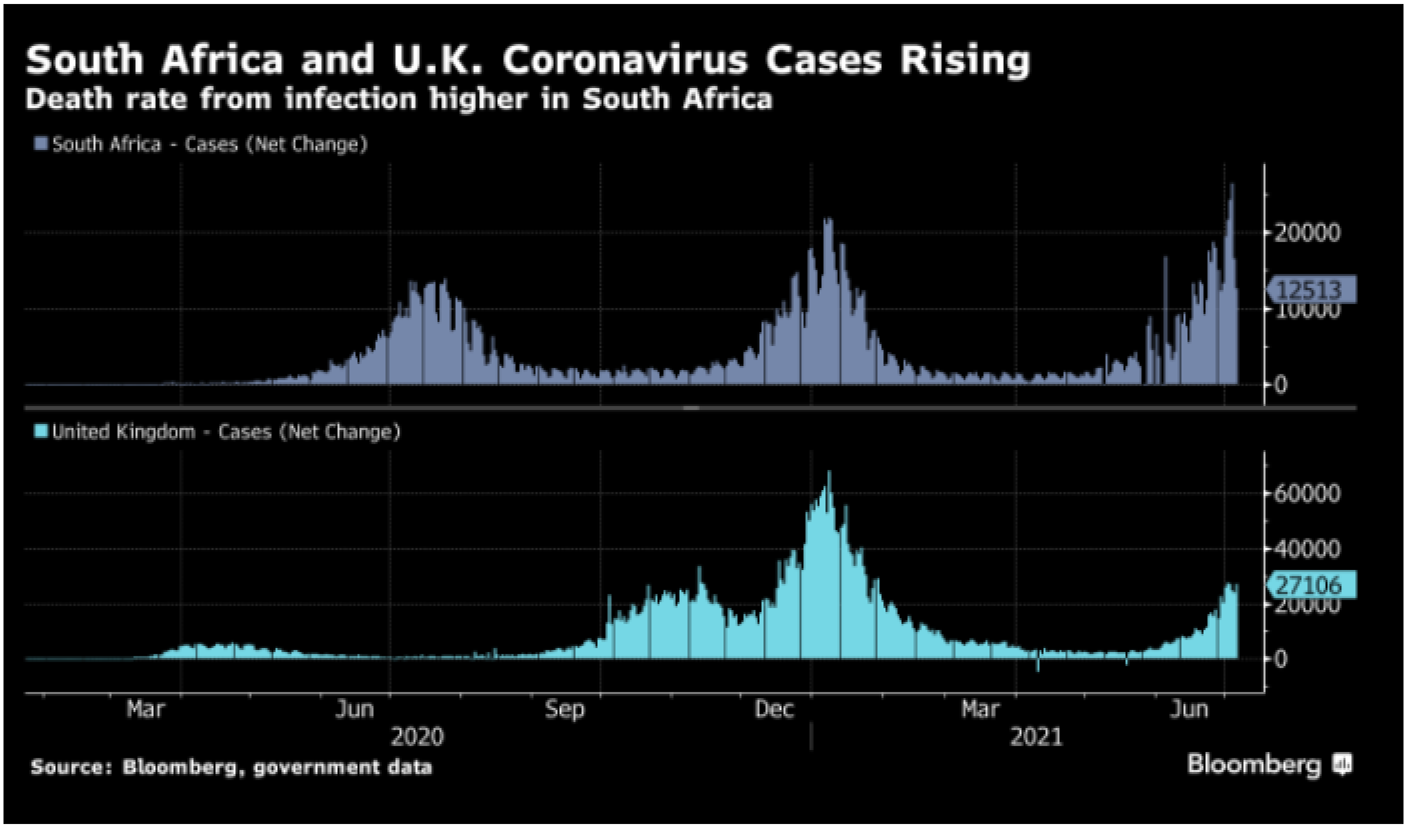
Plane journeys have lagged the recovery seen in road usage across most parts of the world this year as commuters begin to return to offices and restaurants reopen. For instance, jet fuel consumption in Spain last month was 61% less than two years earlier while gasoline demand was 1.1% higher, according to deliveries from the pipeline network operated by Exolum.



Airline seat capacity figures tumbled in Australia and South Africa during the past week, while making large gains in some parts of Europe, notably France, data compiled by OAG Aviation show.

Australia recently imposed new citywide lockdowns and limited commercial flight arrivals to contain outbreaks of the delta variant of coronavirus. The situation is more severe in South Africa, where a third wave of infections has now surpassed the peak of the previous wave in January.

The U.K. is also seeing a significant surge in infections, but with the population largely vaccinated that has not yet translated into a significant increase in deaths and the government is pursuing its plan to remove legal mandates on social distancing in England from July 19.



The clear leader among major airline markets remains China, where seat capacity in the week ended July 5 was 3% higher than the equivalent week of 2019. The next closest was Mexico, some 13% less than two years ago, and the U.S., at 18% below. Both China and the U.S. benefit from large, and thriving domestic markets, which aren't subject to the same restrictions as international travel.

Car movements in Poland and the U.K. increased over the past month, government data show, and as with the U.S., road traffic in those places is pretty much back to levels seen before the pandemic. Toll motorway volumes were more mixed for Italy, Spain and France in the past few weeks after a rapid improvement in May, according to road operator Atlantia Group.

The Bloomberg weekly oil-demand monitor uses a range of high-frequency data series to help identify trends that may become clearer later in more comprehensive monthly figures.

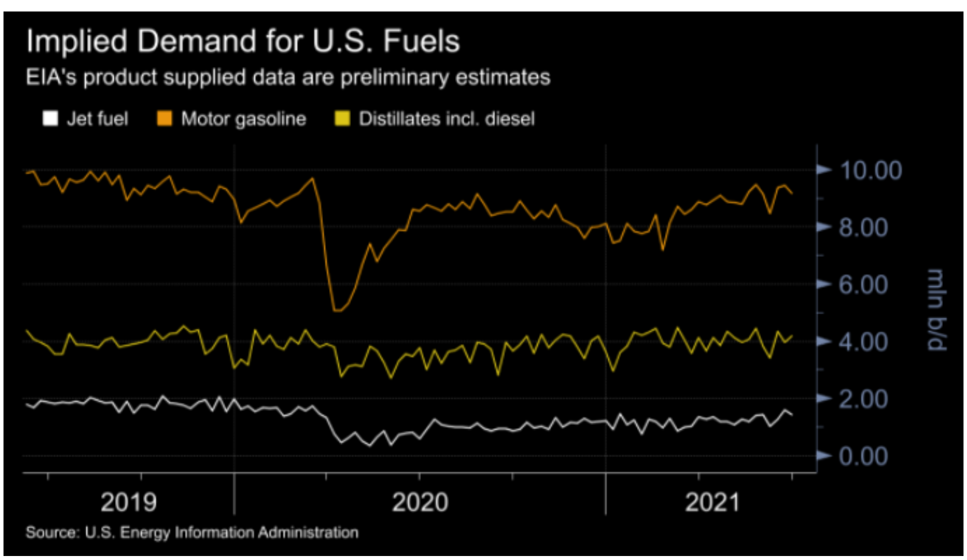
Following are the latest indicators, in the four tables below. The first two show fuel demand and mobility, the next shows air travel globally and the last is refinery activity:

Measure	Location	% y/y	% vs 2019	% m/m	Freq.	Latest as of Date	Latest Value	Source
Gasoline demand	U.S.	+7.1	-3.4	+0.3	w	June 25	9.17m b/d	EIA
Distillates demand	U.S.	+10	+8.9	+9.4	w	June 25	4.17m b/d	EIA
Jet fuel demand	U.S.	+144	-23	-0.4	w	June 25	1.44m b/d	EIA
Total oil products demand	U.S.	+20	+0.7	+9.2	w	June 25	20.9m b/d	EIA
All vehicles miles traveled	U.S.		-2		w	June 27	16.9b miles	DoT
Passenger car VMT	U.S.		-3		w	June 27	n/a	DoT
Truck VMT	U.S.		+7		w	June 27	n/a	DoT
All motor vehicle use index	U.K.	+27	-2	+14	d	June 28	98	DfT
Car use	U.K.	+31	-6	+3	d	June 28	94	DfT
Heavy goods vehicle use	U.K.	+13	+8	+140	d	June 28	108	DfT
Gasoline (petrol) avg sales per filling station	U.K.	+31	-5.7	+1.4	w	June 27	6,845 liters/d	BEIS
Diesel avg sales per station	U.K.	+22	-6.6	-1.5	w	June 27	9,745 liters/d	BEIS
Total road fuels sales per station	U.K.	+26	-6.2	-0.3	w	June 27	16,590 liters/d	BEIS
Gasoline	India	+5.7	-10	n/a	2/m	June 1-30	2.12m tons	Bberg
Diesel	India	-1.8	-19	+13	2/m	June 1-30	5.36m tons	Bberg
Jet fuel	India	+10	-62	n/a	2/m	June 1-30	233k tons	Bberg
Total Products	India	-1.5	-21	-11	m	May 2021	15.11m tons	PPAC
Passenger car traffic	Poland	+13	-0.4	+10	m	June 2020	23,938	GDDKiA
Heavy goods traffic	Poland	+15	+10	-0.4	m	June 2020	4,645	GDDKiA
Toll roads volume	France	+2.5	-14		w	June 27	n/a	Atlantia

Toll roads volume	Italy	+14	-7.3		w	June 27	n/a	Atlantia
Toll roads volume	Spain	+20	-6.4		w	June 27	n/a	Atlantia
Toll roads volume	Brazil	+18	-2.9		w	June 27	n/a	Atlantia
Toll roads volume	Chile	+84	-16		w	June 27	n/a	Atlantia
Toll roads volume	Mexico	+28	+4.3		w	June 27	n/a	Atlantia
All vehicles traffic	Italy	+58		+25	m	May	n/a	Anas
Heavy vehicle traffic	Italy	+23		+1.6	m	May	n/a	Anas
Gasoline	Portugal	+28	-16	+5.1	m	May	79k tons	ENSE
Diesel	Portugal	+12	-12	-0.1	m	May	380k tons	ENSE
Jet fuel	Portugal	+298	-68	+39	m	May	46k tons	ENSE
Gasoline	Spain	+40	+1.1		m	June	500k m3	Exolum
Diesel	Spain	+15	-8		m	June	2199k m3	Exolum
Jet fuel	Spain	+371	-61		m	June	268k m3	Exolum

The frequency column shows d for data updated daily, w for weekly, 2/m for twice a month and m for monthly.

* In DfT U.K. data, the column showing versus 2019 is actually showing the change versus the first week of February 2020, to represent the pre-Covid era.
** In BEIS U.K. data, the column showing versus 2019 is actually showing the change versus the average of Jan. 27-March 22, 2020, to represent the pre-Covid era.
*** Polish GDDKiA weekly data is compared against appropriate prior-year weeks that also contained the Corpus Christi national holiday.

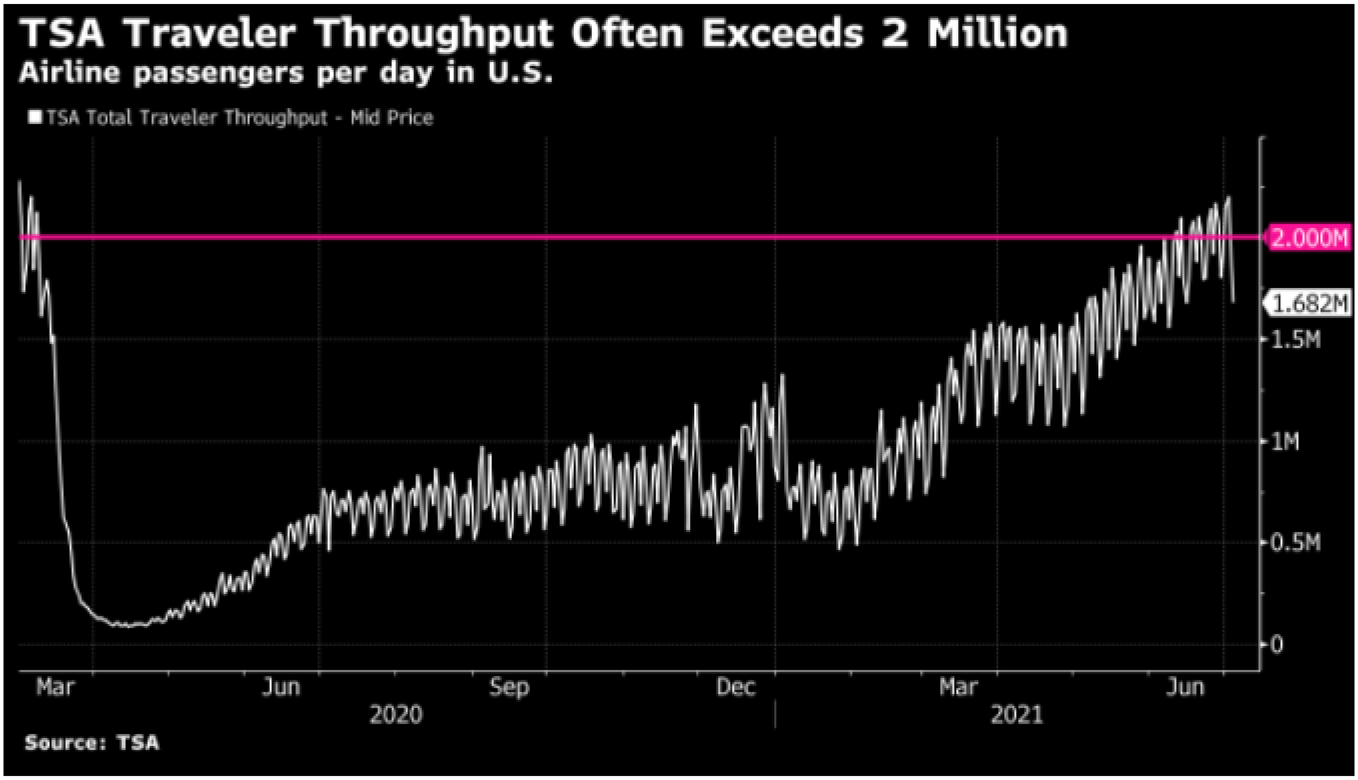


Measure	Location	% chg vs 2019	% chg m/m	July 5	Jun. 28	Jun. 21	Jun. 14	Jun. 7	May 31	May 24	May 17	May 10	May 3
		(July 5)					Minutes of congestion at 8am local time						
Congestion	Tokyo	-3	+33	36	27	28	30	27	26	29	31	28	7
Congestion	Mumbai	-84	+43	6	5	5	4	4	2	2	3	2	1
Congestion	New York	n/a	n/a	0	16	16	22	23	2	20	17	19	20
Congestion	Los Angeles	-92	-85	3	17	16	19	20	3	21	19	19	20
Congestion	London	-11	-16	34	38	37	39	40	3	41	40	41	2
Congestion	Rome	-27	-28	35	13	36	34	49	24	38	34	40	29
Congestion	Madrid	-59	-47	14	16	18	22	27	22	23	19	24	1
Congestion	Paris	-12	-7	39	37	44	42	42	37	3	32	31	29
Congestion	Berlin	-52	-43	16	19	28	28	28	26	3	25	24	23
Congestion	Mexico City	-54	-5	23	24	21	26	24	22	23	23	14	20
Congestion	Sao Paulo	-53	-23	20	23	26	23	26	28	23	22	22	24

Source: TomTom. Note: M/m comparison is July 5 vs June 7. New York and Los Angeles experienced less traffic on July 5 because of the Independence Day public holiday, which also skewed m/m comparisons. TomTom has been unable to provide Chinese data since late April.

Air Travel:

Measure	Location	% chg y/y	% chg vs 2019	% chg m/m	Freq.	Latest as of Date	Latest Value	Source
Airline passenger throughput	U.S.	+130	-33	-15	d	July 4	1.68m people	TSA
Commercial flights	Worldwide	+66	-25	+12	d	July 5	89,771	FlightRadar24
Air traffic (flights)	Europe		-40	+36	d	July 5	22,114	Eurocontrol
Seat capacity	Worldwide	+59	-34		w	July 5	78.64m	OAG
Seat cap.	China	+37	+3		w	July 5	17.32m	OAG
Seat cap.	U.S.	+72	-18		w	July 5	19.39m	OAG
Seat cap.	India	+66	-43		w	July 5	2.26m	OAG
Seat cap.	Japan	-22	-57		w	July 5	1.79m	OAG
Seat cap.	Australia	+188	-49		w	July 5	1.10m	OAG
Seat cap.	Brazil	+218	-36		w	July 5	1.68m	OAG
Seat cap.	France	+93	-39		w	July 5	1.59m	OAG
Seat cap.	Germany	+75	-56		w	July 5	1.52m	OAG
Seat cap.	U.K.	+56	-73		w	July 5	1.05m	OAG
Seat cap.	S. Africa	+380	-64		w	July 5	218k	OAG



Refineries:

Measure	Location	y/y chg	vs 2019 chg	m/m chg	Latest as of Date	Latest Value	Source
Crude intake	U.S.	+16%	-5.7%	+4.5%	June 25	16.3m b/d	EIA
Utilization	U.S.	+17 ppt	-1.3 ppt	+4.2 ppt	June 25	92.9 %	EIA
Utilization	Gulf Coast U.S.	+14 ppt	-3.1 ppt	+3 ppt	June 25	92.7 %	EIA
Utilization	East Coast U.S.	+37 ppt	+14 ppt	-0.3 ppt	June 25	87.6 %	EIA
Utilization	Midwest U.S.	+17 ppt	+0.8 ppt	+6.7 ppt	June 25	98.2 %	EIA
Apparent Oil Demand	China	-0.9%		+4.8%	May 2021	13.58m b/d	NBS
Indep. refs run rate	Shandong province, China	-1.6 ppt	+11 ppt	+5.7 ppt	July 2	73.8 %	SCI99
State refs run rate	East China	-0.6 ppt	+2 ppt	+2.5 ppt	June 30	78.8 %	SCI99
State refs run rate	South China	-4.6 ppt	+0.3 ppt	-4.3 ppt	June 30	82.4 %	SCI99

NOTE: All of the refinery data is weekly, except for SCI99 state refineries, which is twice per month, and the NBS apparent demand, which is usually monthly.

--With assistance from Julian Lee.

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https://calgary.ctvnews.ca/university-of-calgary-suspends-admission-for-oil-and-gas-engineering-program-1.5502133

CALGARY | News

University of Calgary suspends admission for oil and gas engineering program

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Volume 90%

U of C to suspend oil and gas classes

The University of Calgary announced Thursday that it's suspending a formerly popular program that doesn't attract many students these days.

CALGARY -- The University of Calgary has suspended admission for its oil and gas engineering bachelor program amidst a downturn in Canada’s energy sector and a transition towards a more renewable future.

In fact, enrollment for the program has hit an all-time low with only about 10 students registered over the course of the last two years.

Those existing students will still be able to complete their studies, but Prof. Arin Sen, head of the department of chemical and petroleum engineering said the university has no intention to abandon oil and gas studies.

“This wasn’t a decision that we made lightly and we certainly had a lot of engagement, but we had a lot of decline in the demand,” Sen said.

“That’s obviously something that we need to take into consideration and the other is that there's a changing energy landscape that we see here in Alberta, and even beyond Alberta you can see changes globally going on.”

Sen added that the goal is to now focus on how to better train students and give students further access to knowledge, especially in the world of digital technologies.

“We need to give students a chance to learn about what geothermal means, what hydrogen energy means, wind and solar, and then package that together, so when students graduate from here, they are actually stronger and will be able to better perform once they go into whichever segment of the energy industry that they end up.”

The university has plans to allocate further resources to better support students wanting to work in the energy sector, including oil and gas.

NOT A SURPRISE

The news of a suspension does not come as a surprise for Nima Macci, a former chemical engineering student who was chair of the 2021 Alberta Student Energy Conference.

She says energy firms have already rebranded themselves to students over the years and many of her colleagues are noticing a shift in the energy landscape.

“Through the conference, what we saw was a lot of anxiety, kind of being associated with the idea of going back into oil and gas, or being pigeonholed into one career, especially in an industry that had kind of a precarious future,” Macci said.

“For the longest time we've seen oil and gas as the primary source of energy. Nowhere do I see oil and gas ever becoming obsolete in any form, but we do need to diversify and it's shifting the conversation to incorporate companies like clean tech firms, renewable energy sources as well which I think is a great opportunity.”

ENERGY TRANSITION LEADS TO GREATER OPPORTUNITY

Mitch Jacobsen graduated from the University of Calgary’s oil and gas engineering program in 2015, but has since made a drastic shift in his career plans.

He started out as a water strategist in the oil and gas sector, looking for creative ways to conserve water, but realized a new opportunity in the beverage industry.

“When I looked at packaging on beverages I wanted to find the most sustainable packaging, in terms of water usage fossil fuel usage carbon emissions, and that's really how we got into it.”

Jacobsen stepped away from his oil and gas career in January of 2020 and founded Rviita Energy Tea.

He says his background in oil and gas engineering prompted him to create juice products made out of linear low density polyethylene and an environmentally-friendly 100 per cent recyclable aluminum and plastic layer.

“I think the future of the oil and gas industry is really more moving towards those sustainable technologies,” Jacobsen said.

“We produce some of the cleanest oil and gas in the world so I hope this program at UofC comes back in the future because it creates so many new jobs and opportunities and it educates the next generation of engineers that need to take sustainability initiatives.”

Other students like Amanda Quinn, who is currently enrolled in the UofC energy engineering program agree that petroleum engineering is still a very useful degree that her colleagues should have the option to enrol in.

“To take away petroleum engineering means you're taking away the opportunity for people to get their master's in petroleum engineering and potentially their doctorate too,” Quinn said.

“We need the experts on petroleum engineering to be there to help us with the transition of it, because they might know the best way of how, how we attain oil, how we process it, and how we refine it more efficiently.”

Bloomberg @TheTerminal
Canada Greenhouse Gas Emission Cut Bill Becomes Law (1)
2021-06-30 14:39:47.859 GMT

By James Munson
(Bloomberg Law) -- Canada will have to set national greenhouse gas emission reduction targets every five years, under legislation adopted into law.
The bill, known as the Canadian Net-Zero Emissions Accountability Act, passed the Senate, Canada's upper house, without amendment after clearing the House of Commons June 22. It's received Royal Assent, a formal procedure that makes the bill law.
The legislation requires Ottawa to lay out plans for how it will meet reduction targets that begin in 2030 and end in 2050, when the goal is net-zero emissions, according to the legislation. Regulators also must issue progress reports.
The bill is meant to strengthen the transparency and accountability of Canada's plans to reduce greenhouse gas emissions after decades of missing targets set at international climate change conferences.

Reduction Targets

Prime Minister Justin Trudeau during President Joe Biden's summit on climate change April 22 unveiled a reduction target of 40% to 45% below 2005 emission levels by 2030.
The Environment and Climate Change Canada minister must release the targets and plans for how to reach them at least five years before each target year, according to the legislation. The minister must provide a progress report two years before the target year and an assessment report one year later, it says.
The legislation also creates a 15-person advisory body to inform the target plans.
The House of Commons amended the bill to include 2023, 2025 and 2027 progress reports over concerns from left-leaning opposition parties that the targets were too far off in the future to increase accountability.
The Standing Committee on Environment and Sustainable Development also amended the bill to require the environment minister to include a 2026 interim reduction target within the plan to reach the 2030 target.
The committee also added mandatory factors the advisory body must include in its reports to the minister and made it compulsory for the minister to publish their response to the body's recommendations.

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Summary

The Government recently announced changes to its climate change plan to exceed Canada's 2030 Paris Agreement target for reducing greenhouse gas (GHG) emissions:

- In December 2020, the Government announced a series of measures under the rubric of *A Healthy Environment and a Healthy Economy* (HEHE).
- The Government estimated that the HEHE measures would reduce Canada's emissions to 503 megatonnes (Mt) of CO_2 equivalent, or 8 Mt (31 per cent) below Canada's 2030 Paris target.
- Budget 2021 included further measures to reduce Canada's emissions to 468 Mt, or 36 per cent below Canada's 2030 Paris target.

Announcements and projected GHG emissions in 2030

• **Reference Case emissions in 2030**	674 MtCO2e	
		With $120 additional carbon pricing and other policies
• ***Paris target***	511 MtCO2e*	
• **December 2020 HEHE policy scenario emissions**	503 MtCO2e*	
		Additional non-price policies (some unspecified)
• **Budget 2021 announcement**	468 MtCO2e*	

Sources: Environment and Climate Change Canada and Office of the Parliamentary Budget Officer.

Note: (*) Including LULUCF, WCI and NBS, which reduce reported emissions by 39 Mt under HEHE and 29 Mt in the ECCC Reference Case. The ECCC Reference Case includes carbon pricing of $50 per tonne in 2030.

Under HEHE, the federal carbon levy rises from $50 per tonne in 2022 to $170 per tonne in 2030, which is $120 higher compared to the Environment and Climate Change Canada (ECCC) Reference Case.[1] HEHE projections also include an illustrative tightening in the emissions standards for the Output Based Pricing System (OBPS)—the mechanism under which carbon pricing is applied to trade-exposed energy-intensive industry—by 2 per cent per year starting in 2023. PBO has retained that change.

These visible market-based measures are complemented by other policies which are not immediately visible but, like carbon pricing, can raise the costs of firms' production.

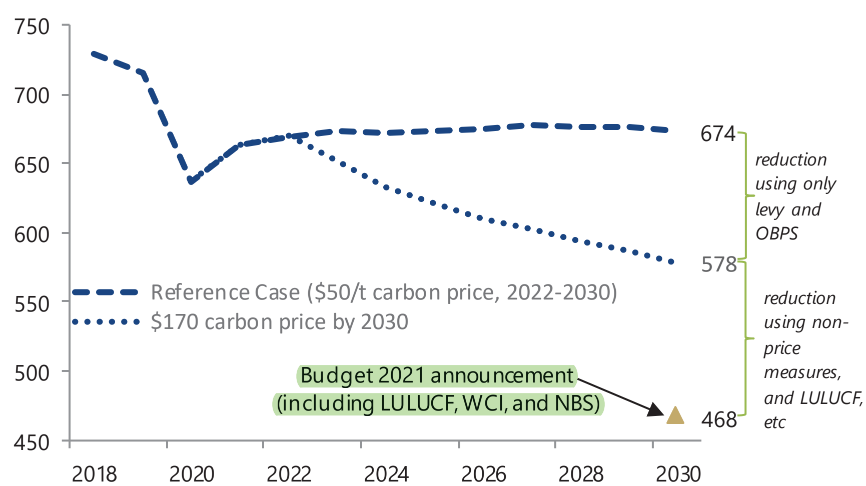
This report's main focus is to estimate the differential impacts on emissions reduction from market-based measures versus less visible regulatory policies. This is within the context of assessing the impacts of the Government's plan to exceed the reduction in Canada's GHG emissions by 2030 under the Paris Agreement.

We estimate that increasing the federal carbon levy by an additional $120 per tonne to $170 in 2030 and tightening OBPS standards will reduce Canada's emissions by 96 Mt: from 674 Mt in 2030 under ECCC's Reference Case to 578 Mt.

Since the Government projected that HEHE and Budget 2021 policies would reduce emissions to 468 Mt in 2030 (including 39 Mt from Land Use, Land Use Change and Forestry (LULUCF), the Western Climate Initiative (WCI) and nature-based solutions (NBS)), we conclude that 71 Mt in emissions reduction is being done through non-price and regulatory measures.

Projected GHG emissions with additional carbon pricing

Megatonnes of CO_2 equivalent



Sources: Environment and Climate Change Canada and Office of the Parliamentary Budget Officer.

Note: The reported reference emissions (674 Mt) and emissions with additional carbon pricing (578 Mt) do not include LULUCF, WCI and NBS, which reduce emissions by an additional 39 Mt.

The non-price measures in HEHE and Budget 2021 are then examined for the "minimum" price equivalent required to achieve the Government's projected emissions level of 468 Mt in 2030.

Since the cost of regulatory policies are not immediately visible, it is imperative to look at their price equivalent, and to anchor them to visible price policies, for example, a carbon levy. This report provides an anchor for the emission cost that non-price measures impose on firms and consumers to reach the projected emissions level of 468 Mt in 2030.

In this case, if the HEHE and Budget 2021 non-price measures are achieved at minimum cost—that is, the actions that firms undertake in response to policy have a minimum cost—we estimate that they would have to be equivalent to an additional $91 per tonne carbon levy to reduce emissions by a further 71 Mt ($72 in 2019 dollars).

We estimate that the HEHE price-based mechanisms that reduce emissions by 96 Mt will lower real GDP by 0.8 per cent in 2030. The non-price measures, if achieved a minimum cost, would further reduce real GDP by 0.6 per cent in 2030. Thus, the combined price- and non-price-based measures in HEHE and Budget 2021 would reduce the projected level of real GDP in 2030 by 1.4 per cent.

These estimates are provided without context. For example, there is no countervailing estimate of the impact that climate change might cause in Canada. We are also not allowing for the possibility of exceptional productivity gains in moving to new technologies. The estimates are, however, useful when looking at base-case projections of growth and government balances under climate policies.

Reducing Canada's GHG emissions to 468 Mt by 2030

	Additional carbon price (per tonne)[a]	Emissions reduction[b]	GDP impact in 2030[c]
HEHE carbon levy and OBPS	$120	96 Mt	-0.8%
Non-price policies (implicit price)[d]	$91	71 Mt	-0.6%
Total impact in 2030	**$211**	**167 Mt**	**-1.4%**

Source: Office of the Parliamentary Budget Officer.

Note: (a) Beyond the $50 per tonne over 2022-2030. Nominal dollars: to convert to 2019 dollars, divide by 1.258.

(b) Not including LULUCF, WCI and NBS.

(c) The impact is measured as the percentage difference between the level of real GDP in 2030 (under the Reference Scenario) and the level of real GDP in 2030 projected under HEHE and Budget 2021 measures.

(d) Minimum cost is achieved by using an equivalent price instrument.

On a sectoral basis, the additional carbon levy and OBPS will have the largest impact on the transportation and oil and gas sectors. By contrast, real GDP in heavy industry is projected to increase as it is sheltered from full carbon pricing under the OBPS system and can substitute its energy and production inputs for relatively lower cost.

Sectoral economic impacts with additional carbon pricing and OBPS

Real GDP, percentage difference from Reference Scenario

	2023	2024-2026	2027-2029	2030
Electricity	0.7	1.3	2.2	2.7
Oil and Gas	-2.6	-5.6	-9.2	-10.8
Heavy Industry	-0.1	0.7	1.5	1.7
Transportation	-3.1	-8.1	-13.5	-16.2
Agriculture and Fishing	0.2	0.7	1.5	2.1
Buildings	-0.1	-0.1	-0.2	-0.2
Waste and others	0.2	0.3	0.3	0.3
Total	**-0.1**	**-0.3**	**-0.6**	**-0.8**

Source: Office of the Parliamentary Budget Officer.

Note: Increasing the carbon levy from $50 per tonne over 2022-2030 to $170 per tonne in 2030 and tightening OBPS standards.

We also estimate that the carbon levy and OBPS alone will reduce economy-wide real labour income by 1.2 per cent, primarily in the oil and gas and transportation sectors. In addition, we project that workers with lower levels of education will see larger income losses than higher educated workers.

This report does not provide detailed analysis of the Government's April announcement to further reduce emissions to between 40 and 45 per cent below 2005 levels (that is, 438 Mt and 402 Mt, respectively). While technologies to achieve this reduction are currently available, the scale and speed of the changes will make it challenging to achieve.

3. Exceeding the Paris Target

Under the Paris Agreement, Canada committed to reduce its GHG emissions to 30 per cent below its 2005 level of 730 Mt by 2030. This translates into a target of 511 Mt in 2030.

Based on measures announced in the HEHE plan and Budget 2021, the Government projects that the reduction in emissions will exceed the Paris target, with emissions falling to 468 Mt in 2030, which would be 36 per cent below the 2005 level.

Relative to the Reference Case in 2030, this represents a reduction of 206 Mt, including 39 Mt in contributions from LULUCF, WCI and NBS. Thus, 167 Mt of the emissions reduction is due to the direct impacts of measures announced in the HEHE plan and Budget 2021.

Included in those measures is an additional $120 carbon pricing – indeed, probably its most important component. To partially disentangle those components, we use a modified version of the ENVISAGE model (van der Mensbrugghe, 2019) and the GTAP database (Aguiar et al., 2019; see Appendix A of PBO, 2020).

We begin by calibrating the model so it reproduces the aggregate profile of emissions in the ECCC 2020 Reference Case, and approximately reproduces the sectoral profile. Some differences between PBO and ECCC exist in the definitions of sectors, and these lead to some minor, but not consequential, effects on the analysis. This calibration is termed our *Reference Scenario* – it includes the $50 carbon levy and some basic OBPS measures (to 2030). Onto this scenario we then introduce the additional carbon levy and OBPS under the Government's HEHE plan.

Once the reduction in emissions from additional carbon pricing and OBPS is identified, we then estimate the (minimum) cost of reducing the remaining emissions to achieve the 2030 GHG level of 468 Mt that the Government projected in Budget 2021.

3.1. Contribution of additional carbon pricing and OBPS

The Government's assumptions regarding OBPS is a change from previous ECCC projections. OBPS is intended to mitigate the impact on international competitiveness of carbon pricing and does that by encouraging firms to reduce emissions while limiting the negative impact on their competitiveness (see Dobson, *et al*, 2017). In previous ECCC projections, the sectors covered by OBPS were expected to face an emission standard that was unchanged, but a carbon levy on part of their emissions that rose to $50 in 2022 and remain unchanged thereafter.

Under the HEHE projections, firms face an increasing carbon levy on emissions above the standard, but that standard decreases by 2 per cent per year to encourage greater efficiency (Table 3-1). We have updated our OBPS modelling to account for this illustrative ECCC change, as well as the special treatment of fossil fuels used for generating electricity.[11]

Table 3-1 OBPS sectors and OBS fractions

Estimated fraction of historical emission intensity that will be exempt from the levy

OBPS sector	OBS fraction	
	2022	2030
Mining, Oil and gas, Pipelines, Food and tobacco, Lumber, Pulp and paper mills, Non-ferrous metals, Miscellaneous manufacturing, Transport equipment manufacturing	80%	66%
Fertiliser, Petrochemicals, Petroleum products	90%	77%
Electricity using solid fuels	74%	46%
Electricity using liquid fuels	95%	63%
Electricity using gaseous fuels	95%	46%
Cement, Gypsum and lime, Iron and steel	95%	81%

Sources: Environment and Climate Change Canada and Office of the Parliamentary Budget Officer.

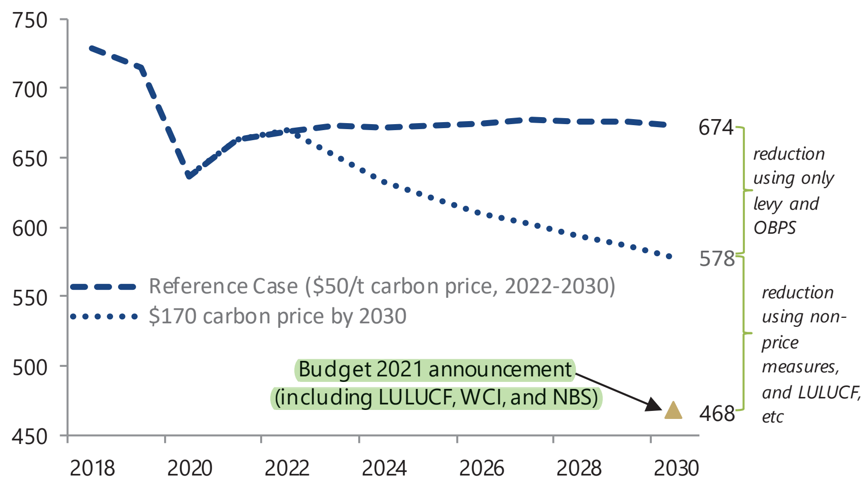
The partial change to the OBPS standard outlined in Table 3-1 places it between two earlier PBO scenarios (PBO, 2020).[12]

We estimate that the additional $120 carbon levy and enhanced OBPS will reduce emissions by 96 Mt by 2030 (Figure 3-1). The effect is weakest in agriculture, and waste and others (Table 3-2). Though the agriculture sector is subject to the levy on some of its activities, such as natural gas heating of buildings, the impact is small. The predominance of non-CO2 sources of emissions in waste and others also means that a carbon levy on fuels has little impact there.

Other sectors therefore have to contribute more to emissions reductions, including oil and gas, as well as transportation, with emissions in each of these two sectors falling by 30 Mt. Relative to our Reference Scenario, the levy would raise nominal gasoline prices in 2030 by about $0.27 per litre (for a total carbon levy of $0.38 per litre).

Figure 3-1 Projected GHG emissions with additional carbon pricing

Megatonnes of CO_2 equivalent



Sources: Environment and Climate Change Canada and Office of the Parliamentary Budget Officer.

Note: The reported reference emissions (674 Mt) and emissions with additional carbon pricing (578 Mt) do not include LULUCF, WCI and NBS, which reduce emissions by an additional 39 Mt.

Table 3-2 Sectoral GHG emissions with $120 additional carbon pricing and OBPS

	Reference Scenario levels in 2030*	Reductions in 2030	
	Mt	Mt	%
Electricity	28	-9	-31
Oil and gas	192	-30	-15
Heavy industry	64	-8	-13
Transportation	177	-30	-17
Agriculture	78	-0	-1
Buildings	75	-17	-23
Waste and others	61	-2	-4
Total	**674**	**-96**	**-14**

Source: Office of the Parliamentary Budget Officer.

Note: * Sectoral emissions in 2030 represent PBO's approximation of ECCC's Reference Case. Totals may not add up due to rounding.

3.2. Contribution of non-price measures

Based on the Government's estimates of reductions from LULUCF, WCI and NBS, non-price-based measures account for 71 Mt of additional abatement to achieve the emissions level of 468 Mt in 2030 projected in Budget 2021. That additional abatement is significant and will require effective measures.[13]

As announced, those measures span a wide range of policies: from building retrofits, to fuel standards, to transportation subsidies and even carbon capture. While it would be informative to outline a detailed description of each of the policies and their impacts, a more limited analysis could nonetheless serve to formulate some general conclusions. This could include, for example, their cost, both for the economy as a whole as well as for the cost (implicit and explicit) that firms and individuals will face for emissions.

Non-price measures impose costs on individuals and firms, for example by making them undertake expenditures, or change their operations to conform to the policy requirement. In principle, a price-based measure could achieve the same objective as a non-price measure. In such a case, the (implicit) cost of the non-price measure would be roughly the same as the price-based measure (though issues such as the treatment of revenues would still need to be dealt with).

This approach assigns an implicit carbon price to achieving a given reduction in GHG emissions. In this report, we assign an optimistic cost to the non-priced-based measures by using a price-based measure that achieves the same emission reduction. It is optimistic because it assumes that the Government has very detailed information concerning the operations of a large number of regulated firms (see Box 1).

However, like all scenarios where a levy is imposed, additional revenues are generated – whose use could engender important secondary effects. Here we deal with this issue by assuming these proceeds are refunded to households. Admittedly, this is itself not a completely neutral solution to the revenue-recycling question, but it engages fewer secondary effects such as the returns to government or private investment – or even the ability of green investments to generate super-normal returns.

Given the widespread nature of the non-price policies, we impose their price equivalent across the entire economy. Because extending the equivalent of a $170 (nominal) carbon price to all sectors is not sufficient to reach the target, we raise the carbon price and its equivalent throughout the economy until the 468 Mt level of emissions is achieved in 2030.

OBPS sectors also face the higher carbon price, but without additional changes to their performance standard. (Table 3-1). This may cause some upward bias in the carbon price since it implies some measure of protection to those sectors.

We thus estimate that the price and non-price policies needed to reach the Government's projection of 468 Mt in 2030 would have to be the equivalent of an additional $91 per tonne across all sources of emissions. This brings the combined measures to the equivalent of a carbon levy of $211 per tonne ($120+$91) (see endnote 5 for conversion of 2019 dollars) above the $50 per tonne in 2022. This price is only a little lower than Melton, et al, (2020) for a similar reduction (about $270 in constant 2019 dollars for a 200 Mt reduction in 2030).

Across sectors, there is now a more even proportional distribution of reductions except for agriculture (Table 3-3). All sectors are impacted, with electricity again showing the biggest proportionate decline relative to the Reference Scenario. The magnitude of these changes, particularly for oil and gas, imply substantial change. Without a more rapid development and implementation of technologies to reduce emissions, the scenario implies that output will have to be lower if exports cannot be increased.

Table 3-3 Sectoral emissions with measures

	Reference Scenario	Additional carbon pricing	Additional price and non-price measures	Total reduction
Electricity	28	19	16	-12
Oil and gas	192	163	139	-54
Heavy industry	64	56	51	-13
Transportation	177	147	132	-45
Agriculture	78	78	77	-1
Buildings	75	58	50	-25
Waste and others	61	59	43	-18
Total	**674**	**540***	**468***	**-168**

Source: Office of the Parliamentary Budget Officer.

Note: PBO's Reference Scenario approximates ECCC's Reference Case but differences persist due to sectoral definitions and other issues. Additional pricing includes increasing the carbon levy by $120/t and increasing OBPS stringency. The total reduction represents the difference between emissions under the additional price and non-price measures scenario relative to the Reference Scenario.

(*) including LULUCF, WCI and NBS.

https://www.shell.com/media/news-and-media-releases/2021/shell-second-quarter-2021-update-note.html

Shell second quarter 2021 update note

Jul 7, 2021

The following is an update to the second quarter 2021 outlook. The impacts presented here may vary from the actual results and are subject to finalisation of the second quarter 2021 results, which will be announced on July 29, 2021. Unless otherwise indicated, all outlook statements exclude identified items.

Strong cash generation supports additional shareholder distributions in the second half of 2021

As a result of strong operational and financial delivery, combined with an improved macro-economic outlook, Shell will move to the next phase of its capital allocation framework and, subject to final Board approval, increase total shareholder distributions to within the range of 20-30% of CFFO, starting at the Q2 results announcement. The level of additional distributions will be determined with full visibility of the Q2 financial results.

In the second quarter, Shell expects to have further reduced its net debt, although the extent of the reduction will be moderated by working capital movements. In conjunction with the increased distributions, Shell will retire its net debt milestone of $65 billion and will continue to target further strengthening of its balance sheet and AA credit metrics. 2021 cash capex will remain below $22 billion.

Integrated Gas

Adjusted EBITDA

- Production is expected to be between 900 and 960 thousand barrels of oil equivalent per day.
- LNG liquefaction volumes are expected to be between 7.1 and 7.7 million tonnes, reflecting additional unplanned maintenance activities, which are expected to impact trading and optimisation results.
- Trading and optimisation results are expected to be significantly below average and similar to the first quarter 2021.
- Underlying opex is expected to be between $400 and $500 million lower than the first quarter 2021, which included higher provisions related to counterparty credit risk.

Adjusted Earnings

- Pre-tax depreciation is expected to be between $1.3 and $1.4 billion.
- Taxation charge is expected to be between $300 and $600 million.

Cash flow from operations

- Tax paid is expected to be between $200 and $400 million.
- CFFO excluding working capital is expected to be positively impacted by cash flows related to variation margin.

Upstream

Adjusted EBITDA

- Production is expected to be between 2,225 and 2,300 thousand barrels of oil equivalent per day.
- Any positive impacts from currency effects are expected to be offset by higher Underlying opex from increased planned maintenance activities compared with the first quarter 2021.

Adjusted Earnings

- Pre-tax depreciation is expected to be between $3.2 and $3.5 billion.
- Taxation charge is expected to be between $500 and $900 million, which includes a one-off release of non-cash tax provision of approximately $600 million.

Cash flow from operations

- Tax paid is expected to be between $750 and $1,100 million.

Oil Products

Adjusted EBITDA

- Marketing margins are expected to be higher than the first quarter 2021, reflecting strong retail unit margins, partly offset by lower lubricant margins due to base oils and additives shortages.
- Refining indicative margin is around $4.17/bbl. Definition and formula are provided at the end of this release.
- Sales volumes are expected to be between 4,000 and 5,000 thousand barrels per day.
- Refinery utilisation is expected to be between 75% and 79%.
- Trading and optimisation results are expected to be average, similar to the first quarter 2021.
- Underlying opex is expected to be between $200 and $400 million higher than the first quarter 2021, mainly due to an increase in marketing volumes.

Adjusted Earnings

- Pre-tax depreciation is expected to be between $800 and $1,000 million.
- Taxation charge is expected to be between $100 and $600 million.

Cash flow from operations

- Tax paid is expected to be between $150 and $350 million.
- CFFO excluding working capital is expected to be positively impacted by the lower cash cost of sales.
- Working capital outflows are expected due to the higher commodity price environment.

Chemicals

Adjusted EBITDA

- Chemicals margins are expected to be in line with the first quarter 2021.
- Chemicals sales volumes are expected to be between 3,500 and 3,800 thousand tonnes.
- Chemicals manufacturing plant utilisation is expected to be between 81% and 85%.
- Underlying opex is expected to be between $100 and $150 million higher than the first quarter 2021.

Adjusted Earnings

- Pre-tax depreciation is expected to be between $250 and $300 million.
- Taxation charge is expected to be between $50 and $200 million.

Cash flow from operations

- Tax paid is expected to be up to $100 million.

- CFFO is expected to be positively impacted by $200 to $300 million due to the timing effect of dividends received from Joint Ventures & Associates.

Corporate

Corporate segment Adjusted Earnings are expected to be a net expense of $300 to $450 million for the second quarter, impacted by favourable movements in deferred tax positions. This excludes the impact of currency exchange effects.

Full-year price and margin sensitivities

The Adjusted Earnings and CFFO price and margin sensitivities are indicative and in relation to the full-year results. These exclude the short-term impacts from working capital movements, cost-of-sales adjustments and derivatives. Sensitivity accuracy is subject to trading and optimisation performance, including short-term opportunities, depending on market conditions.

$ million	**Adjusted Earnings**	**CFFO**
Integrated Gas		
+$10/bbl Brent	1,100	1,200
+$10/bbl Japan Customs-cleared Crude - 3 months	1,100	1,200
Upstream		
+$10/bbl Brent	3,000	4,000
+$1/mmbtu Henry Hub	350	450
+$1/mmbtu EU TTF	150	200
Refining		
+$1/bbl indicative refining margin	500	—

Indicative refining margin

The indicative margin is an approximation of Shell's global net realised refining margin, calculated using price and margin markers from third parties' databases. It is based on an approximation of Shell's crude intake and production from refinery units. The actual margins realised by Shell may vary due to factors including specific local market effects, refinery configuration, crude diet, operating decisions and production.

Q2 2021: $4.17/bbl

Q1 2021: $2.65/bbl

Q4 2020: $1.59/bbl

Q3 2020: $0.84/bbl

The formula provided will be reviewed and updated annually, reflecting any changes in our refining portfolio.

Calculation formula ($/bbl) - note that brackets indicate a negative sign

Brent*(25%) + MSW*(11%) + LLS*(24.5%) + Dubai*(24.5%) + Urals CIF EU*(13%) + NWE Naphtha (RDAM FOB Barge)*8% + NWE Mogas premium unleaded*12.50% + NWE Kero*11.50% + NWE AGO*24.5% + NWE Benzene*1% + Sing Fueloil 380 cst*6.50% + Edmonton ULG Reg*3.50% + Edmonton ULSD*3.50% + USGC Normal Butane*1.50% + USGC LS No 2 Gasoil*7% + USGC Natural Gas*(2%) + USGC CBOB*15% + RINS*(20.50%) + NWE Propylene Platts*0.50% – $1.7/bbl

Consensus

The consensus collection for quarterly Adjusted Earnings and CFFO excluding working capital movements, managed by Vara research, will be published on 22 July 2021.

https://www.bakersfield.com/ap/national/what-shakealert-warning-system-got-wrong-and-right-about-this-weeks-6-0-quake-in/article_3185c037-ea1f-5444-8d0a-a1dc7fdc7727.html

What ShakeAlert warning system got wrong — and right — about this week's 6.0 quake in California

- Lisa M. Krieger The Mercury News (TNS)

15 hrs ago

California's new ShakeAlert earthquake warning system got three big things wrong about this week's Antelope Valley temblor.

But that doesn't mean it won't work for us.

The fledgling system, built to alert people about imminent risk, was tested on Thursday evening in the toughest of places: a hotspot of geologic turbulence in a rural and remote region with very few sensors.

Its performance in the Bay Area and other metropolitan areas is likely to be far better, especially as it gains more experience, said Doug Given, ShakeAlert Program national coordinator at the U.S. Geological Survey.

"We've prioritized the higher population areas in our build-up strategy," he said. "These rural earthquakes gave the system difficulty."

The detection stations "are sparse near the earthquake," he said. "The system is not yet built out for the coverage that we have planned."

A similar problem was created by last May's earthquake in rural north Lake Tahoe. The system sent out a warning of a magnitude 6 quake; in reality, it was 4.7. The rupture happened about 18 miles northwest of the system's original reports.

"The system has to be super fast. There's always this trade off between speed and accuracy," he said.

"And we're making those calculations initially with very, very limited information," he added. "We're trying to characterize an earthquake with, in some cases, less than one second of ground motion data from a single location."

On Thursday evening, ShakeAlert was fast, but not accurate.

The system initially got the earthquake's magnitude wrong: called it a 4.8; later, it was upgraded to a 6.0.

The system thought the rupture happened about 31 miles south of where it actually did. And at first it presumed it was detecting three different small earthquakes, rather than one large one.

Such details didn't matter to some California residents, who welcomed the warning in time to take action.

"It worked. The whole point is to give you a little notice," said a Lodi-based wine industry consultant who asked that his name not be used. He rushed from his office to the safety of a bathroom when the system's app issued a startling emergency alert. "It's really worth it."

"I was just working at my computer and I saw the phone shake and buzz, then a notification popped up. My computer is right next to a window and the glass could have shattered," he said. With his daughter, "we both got down on the floor next to the sink and we started feeling the rolling waves."

After more than a decade in development, the system is finally a reality for tens of millions of West Coast residents. Public use started in October 2019. There are three apps available: the U.S. Geological Survey's ShakeAlert, University of California, Berkeley's MyShake and Early Warning Labs's QuakeAlertUSA. California authorities can also issue alerts via text message, through the Amber Alert-style Wireless Emergency System, which does not require downloading an app or having a smartphone.

The earthquake warnings are possible because when a fault slips, it generates two kinds of waves. The initial waves travel fast but are weak. It's the second set of waves that are so damaging.

When seismic sensors detect the first waves, they quickly send alerts to monitoring centers in Seattle, Menlo Park, Berkeley and Pasadena, California. Within about 5 seconds, computer algorithms analyze the data to rapidly identify the epicenter and strength of the earthquake and decide whether the temblor will be powerful enough to warrant an alert.

The system detects earthquakes as low as magnitude 3.5. Alerts are sent when a magnitude hits 4.5. The Amber Alert-style alarm goes off when a magnitude reaches 5.

When complete, the system will have a network of 1,675 seismic sensors. Currently 773 sensors – about half of the goal – are in place, because of funding constraints.

Thursday's rupture took place in the Antelope Valley, a high and lonesome 15-mile-long valley in the eastern Sierra Nevada stretching from Mono County, California, to Douglas County, Nevada. It's an agricultural region, home to only 1,500 people, flanked on either side by the lofty 10,000-foot Sierra Nevada mountains.

There are few sensors in that region of California, because not many people are threatened. It's a formidable terrain, and sensors aren't allowed in wilderness areas. A reading may be influenced by whether a sensor is sitting on hard rock or soft soil. On Thursday, one of the existing sensors may not have been working right.

"This meant that you don't have stations nearby where the earthquake occurs, then you have to wait for the waves that are propagated to hit the stations that you do have," said Given.

This also created a 25-second delay. "I took quite a while for the system to get enough information to declare an earthquake. In a densely instrumented area, we typically can issue an alert in under 5 seconds," he said.

Because those sensors are clustered down near Mammoth Mountain, and the system triangulates signals, it got the location wrong.

Those stations – whose readings are combined to create an average — skewed the magnitude. "One anomalously high or low station can pull the average in one direction or the other," said Given.

Over the vast distance, the waves propagated across other stations in the state's network. This confused the system and it interpreted the Antelope Valley event as several earthquakes, not one.

"This is a work in progress," said Given. "The station coverage is not complete. The algorithms are still being improved."

"The system worked, but we're not going to be done until it's perfect," he said. "And it's never going to be perfect."

(Correspondent Bailey Bedford contributed to this article.)

https://www.npr.org/sections/money/2021/07/06/1012409112/beware-of-shrinkflation-inflations-devious-cousin

Beware Of 'Shrinkflation,' Inflation's Devious Cousin

July 6, 20216:30 AM ET

GREG ROSALSKY

Don Emmert/AFP via Getty Images

A couple of weeks ago, Edgar Dworsky walked into a Stop & Shop grocery store in Somerville, Mass., like a detective entering a murder scene.

He stepped into the cereal aisle, where he hoped to find the smoking gun. He scanned the shelves. Oh no, he thought. He was too late. The store had already replaced old General Mills cereal boxes — such as Cheerios and Cocoa Puffs — with newer ones. It was as though the suspect's fingerprints had been wiped clean.

Then Dworsky headed toward the back of the store. Sure enough, old boxes of Cocoa Puffs and Apple Cinnamon Cheerios were stacked at the end of one of the aisles. He grabbed an old box of Cocoa Puffs and put it side by side with the new one. Aha! The tip he had received was right on the money. General Mills had downsized the contents of its "family size" boxes from 19.3 ounces to 18.1 ounces.

Dworsky went to the checkout aisle, and both boxes — gasp! — were the same price. It was an open-and-shut case: General Mills is yet another perpetrator of "shrinkflation."

The smoking gun
Edgar Dworsky

Downsizing and shrinkflation mean the same thing

Dworsky is a former Massachusetts assistant attorney general and longtime consumer advocate. He has spent decades tracking instances of companies shrinking products on his website Mouseprint. He refers to it by its original name, downsizing, but economist Pippa Malmgren rechristened it "shrinkflation" about a decade ago, and the term stuck. Downsizing and shrinkflation both refer to the same thing: companies reducing the size or quantity of their products while charging the same price or even more.
"Downsizing is really a sneaky price increase," Dworsky says. "Consumers tend to be price conscious. But they're not net-weight conscious. They can tell instantly if they're used to paying $2.99 for a carton of orange juice and that goes up to $3.19. But if the orange juice container goes from 64 ounces to 59 ounces, they're probably not going to notice."

[Editor's note: This is an excerpt of* Planet Money*'s newsletter. You can sign up here]
If consumers were the rational creatures depicted in classic economic theory, they would notice shrinkflation. They would keep their eyes on the price per Cocoa Puff and not fall for gimmicks in how companies package those Cocoa Puffs. A study by John T. Gourville and Jonathan J. Koehler analyzed data from the market for cereal and other sectors and found that consumers are much more gullible than classic theory predicts. They are more sensitive to changes in price than to changes in quantity. Companies, of course, have known this for years.

The case of the shrinking toilet paper roll

Back in the day, Dworsky says, he remembers buying bigger candy bars and bigger rolls of toilet paper. The original Charmin roll of toilet paper, he says, had 650 sheets. Now you have to pay extra for "Mega Rolls" and "Super Mega Rolls" — and even those have many fewer sheets than the original. To add insult to injury, Charmin recently shrank the size of their toilet sheets. Talk about a crappy deal.
Shrinkflation, or downsizing, is probably as old as mass consumerism. Over the years, Dworsky has documented the downsizing of everything from Doritos to baby shampoo to ranch dressing. "The downsizing tends to happen when manufacturers face some type of pricing pressure," he says. For example, if the price of gasoline or grain goes up.

That is why, when the government began reporting surges in inflation several months ago, Dworsky was on the lookout for its devious, shrinkifying cousin. We're now seeing a wave of shrinkflation, from Tillamook ice cream to Royal Canin cat food. "As we're seeing inflation picking up now, that's why I think you're going to see more items being downsized," Dworksy says. "And maybe it's going to be a double-whammy: We're going to see some products going up in price at the same time that you're actually getting less in the package."

A taller cereal box does not always mean more cereal

Not all consumers are oblivious to shrinkflation.

Jonathan Fitzer is a big fan of Cinnamon Toast Crunch, another cereal made by General Mills. A couple of weeks ago, he went to a local grocery store in Tampa, Fla., to re-up. But on the shelf were two different versions of the product. The old box was the same as always. The new box, however, was taller and skinnier. And it was adorned with a picture advertising *Space Jam*, a new movie reboot starring LeBron James. Fitzer might have been forgiven for assuming a taller cereal box meant more cereal. "And then I looked at the bottom and I saw the numbers were off and I was like, 'oh, come on now. I'm getting ripped off here,'" he says.
Fitzer follows the "r/shrinkflation" thread on Reddit, and he uploaded a picture of the two boxes on the site. "That's crazy shrinkage," said one commenter. Another had words for the makers of Cinnamon Toast Crunch: "Why ya being shady, yo?"

Fitzer's shrunken Cinnamon Toast Crunch
Jonathan Fitzer

Last week, General Mills announced the rising cost of ingredients, packaging, labor, and trucking was forcing it to revamp its business. It said that it was taking "pricing actions" and other steps to grapple with this inflation. We reached out to General Mills about reports that it's downsizing its cereals as part of its strategy.
"General Mills has been working to create consistency and standardization across our cereal products, making it easier for shoppers to distinguish between sizes on shelf. For consumers seeking the best price per ounce, the most value is normally in our larger boxes of cereal," says Kelsey Roemhildt, a General Mills spokesperson. "This change also allows more efficient truck loading leading to fewer trucks on the road and fewer gallons of fuel used, which is important in both reducing global emissions as well as offsetting increased costs associated with inflation."

General Mills' reframing of its shrinkflation seems to be pretty typical of Corporate America. Companies often sell downsizing as a way to help the environment, offer consumers more choice, or improve the quality of their products. When a spokesperson for Charmin, for example, was confronted by reporters at WBUR about shrinking the size of their toilet sheet squares, she suggested it was the result of "innovations" that allow consumers to, basically, wipe their butts more efficiently.
If this keeps up, maybe someday we'll all be living in a Lilliputian dystopia where we're forced to eat miniature candy bars, drink tiny drinks, and wipe our bottoms with teeny-tiny squares of paper. Or maybe consumers will start to notice and voice concern and the power of consumer demand will force companies to listen and right-size their products. Until then, our prayers are with the lovers of Cocoa Puffs.

Did you enjoy this newsletter segment? Well, it looks even better in your inbox! You can sign up here.

Dan Tsubouchi @Energy_Tidbits · 17h

The set up for skilled #Oil #NatGas people shortage if the world, incl 🇨🇦, needs reliable, affordable and available energy from #Oil #NatGas longer than aspirations of #EnergyTransition. No longer a choice at U of C, to enter oil & gas engineering program. #OOTT

> **CTV Calgary** @CTVCalgary · Jul 8
>
> The University of Calgary has suspended admission for its oil and gas engineering bachelor program amidst a downturn in Canada's energy sector and a transition towards a more renewable future. @CTVMarkVillani calgary.ctvnews.ca/university-of-...

5 · 7 · 5

Dan Tsubouchi @Energy_Tidbits · 21h

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 safgroup.ca) & wanting to tie up LNG supply. #OOTT

SAF GROUP

Blog Summary

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

> **Hardeep Singh Puri** @HardeepSPuri · Jul 10
>
> 
>
> 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 ...

1 · 1

Dan Tsubouchi @Energy_Tidbits · Jul 10

#Line5. #Enbridge/Michigan mediator meeting Aug 11 as work to complete mediation by Aug 31. nothing is impossible but, unless someone gives in, how do you find a common ground on a no pipeline vs pipeline?#OOTT

> **Beth LeBlanc** @DNBethLeBlanc · Jul 9
>
> The State of Michigan and Enbridge told a judge Thursday that they hope to complete Line 5 mediation by the end of August detroitnews.com/story/news/loc... via @detroitnews

1 · 2

Dan Tsubouchi @Energy_Tidbits · Jul 9

Note, @PeteMilne4 comment on potentially more widespread is a question on the other 4 trains at #NorthWestShelfLNG. Total capacity at NWS is ~2.2 bcf/d. Waiting to hear when @Woodside says Train 4 will be back in service. #LNG #OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Jul 9
>
> 1/2. Must read. @PeteMilne4 reports #Woodside investigating corrosion on #NorthWestShelfLNG Train 4 (~0.6 bcf/d) "there are concerns the problem could be more widespread". Positive for 2021 #LNG prices and US LNG exports, but if more widespread ...
> boilingcold.com.au/concern-over-c...
>
> Show this thread

3 3

Dan Tsubouchi @Energy_Tidbits · Jul 9

2/2. More widespread would add to the 2021 changing view on LNG supply in 2020s. 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?" #LNG #NatGas #AECO #OOTT safgroup.ca

SAF GROUP

Blog Summary

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

1 3

Dan Tsubouchi @Energy_Tidbits · Jul 9

1/2. Must read. @PeteMilne4 reports #Woodside investigating corrosion on #NorthWestShelfLNG Train 4 (~0.6 bcf/d) "there are concerns the problem could be more widespread". Positive for 2021 #LNG prices and US LNG exports, but if more widespread ...

Concern over corrosion at Woodside's North West Shelf LNG

Woodside has found corrosion during a shutdown of the North West Shelf's LNG Train 4 that potentially is a serious concern.

boilingcold.com.au

2 2 1

Show this thread

Dan Tsubouchi @Energy_Tidbits · Jul 8

US State Dept also confirms no date yet set for #JCPOA 7th round negotiations. Remind absent a major shift in positions, no one expects 7th round to be the last. Positive for #Oil, continues to point to Iran oil not coming back to maybe Nov? #OOTT

Including with Secretary Blinken, updating him on the progress of those talks. Of course, nothing is certain in the world of diplomacy but I think we have every expectation that there will be a seventh round of talks at the appropriate moment, at the right time. And our team looks forward to being engaged in that next round of talks when it does begin.

QUESTION: (Inaudible) consultations with the U.S. team in its capitol, those are finished now?

PRICE: We -- we are -- I think we...

QUESTION: Your just waiting for the -- the Europeans to say OK, come on guys, let's go back to the (inaudible).

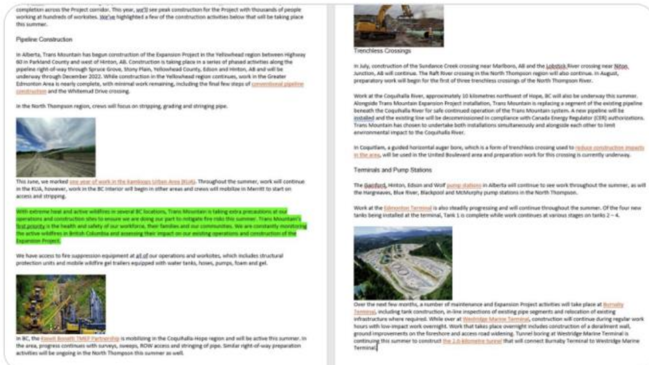
Dan Tsubouchi @Energy_Tidbits · Jul 8

Positive for #Oil. No date for 7th round of #JCPOA discussions, and would need a major shift in someone's position for a 7th round to be the last. looks like pointing to Iran oil return to market to at least Nov? #OOTT twitter.com/Amb_Ulyanov/st...

5 6

Dan Tsubouchi @Energy_Tidbits · Jul 8

#TMX understandable that extreme heat/active wildfires are having an impact. but "assessing the impact" on "construction of the Expansion Project". need to see what impact on expansion construction time & costs. #OOTT transmountain.com/news/2021/summ...



completion across the Project corridor. This year, we'll see peak construction for the Project with thousands of people working at hundreds of worksites. We've highlighted a few of the construction activities below that will be taking place this summer.

Pipeline Construction

In Alberta, Trans Mountain has begun construction of the Expansion Project in the Yellowhead region between Highway 60 in Parkland County and west of Hinton, AB. Construction is taking place in a series of phased activities along the pipeline right-of-way through Spruce Grove, Stony Plain, Yellowhead County, Edson and Hinton, AB and will be underway through December 2022. While construction in the Yellowhead region continues, work in the Greater Edmonton Area is nearly complete, with minimal work remaining, including the final few steps of conventional pipeline construction and the Whitemud Drive crossing.

In the North Thompson region, crews will focus on stripping, grading and stringing pipe.

This June, we marked one year of work in the Kamloops Urban Area (KUA). Throughout the summer, work will continue in the KUA, however, work in the BC interior will begin in other areas and crews will mobilize in Merritt to start on access and stripping.

With extreme heat and active wildfires in several BC locations, Trans Mountain is taking extra precautions at our operations and construction sites to ensure we are doing our part to mitigate fire risks this summer. Trans Mountain's first priority is the health and safety of our workforce, their families and our communities. We are constantly monitoring the active wildfires in British Columbia and assessing their impact on our existing operations and construction of the Expansion Project.

We have access to fire suppression equipment at all of our operations and worksites, which includes structural protection units and mobile wildfire gel trailers equipped with water tanks, hoses, pumps, foam and gel.

In BC, the Kiewit Bonatti TMEP Partnership is mobilizing in the Coquihalla-Hope region and will be active this summer. In the area, progress continues with surveys, sweeps, ROW access and stringing of pipe. Similar right-of-way preparation activities will be ongoing in the North Thompson this summer as well.

Trenchless Crossings

In July, construction of the Sundance Creek crossing near Marlboro, AB and the Lobstick River crossing near Niton Junction, AB will continue. The Raft River crossing in the North Thompson region will also continue. In August, preparatory work will begin for the first of three trenchless crossings of the North Thompson River.

Work at the Coquihalla River, approximately 10 kilometres northwest of Hope, BC will also be underway this summer. Alongside Trans Mountain Expansion Project installation, Trans Mountain is replacing a segment of the existing pipeline beneath the Coquihalla River for safe continued operation of the Trans Mountain system. A new pipeline will be installed and the existing line will be decommissioned in compliance with Canada Energy Regulator (CER) authorizations. Trans Mountain has chosen to undertake both installations simultaneously and alongside each other to limit environmental impact to the Coquihalla River.

In Coquitlam, a guided horizontal auger bore, which is a form of trenchless crossing used to reduce construction impacts in the area, will be used in the United Boulevard area and preparation work for this crossing is currently underway.

Terminals and Pump Stations

The Gainford, Hinton, Edson and Wolf pump stations in Alberta will continue to see work throughout the summer, as will the Hargreaves, Blue River, Blackpool and McMurphy pump stations in the North Thompson.

Work at the Edmonton Terminal is also steadily progressing and will continue throughout the summer. Of the four new tanks being installed at the terminal, Tank 1 is complete while work continues at various stages on tanks 2 – 4.

Over the next few months, a number of maintenance and Expansion Project activities will take place at Burnaby Terminal, including tank construction, in-line inspections of existing pipe segments and relocation of existing infrastructure where required. While over at Westridge Marine Terminal, construction will continue during regular work hours with low-impact work overnight. Work that takes place overnight includes construction of a derailment wall, ground improvements on the foreshore and access road widening. Tunnel boring at Westridge Marine Terminal is continuing this summer to construct the 2.6-kilometre tunnel that will connect Burnaby Terminal to Westridge Marine Terminal.

2

Dan Tsubouchi @Energy_Tidbits · Jul 8

For those not near their laptop, EIA weekly #Oil #Gasoline #Distilliates inventory data for July 2 just out. Prior to release, WTI was $71.79. #OOTT

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

Oil/Products Inventory July 2: EIA, Bloomberg Survey Expectations, API

(million barrels)	EIA	Expectations	API
Oil	-6.87	-4.00	-7.98
Gasoline	-6.08	-1.75	-2.74
Distillates	1.62	0.15	1.09
	-11.33	-5.60	-9.63
Note:In addition, SPR draw of 1.2 mmb for July 2-week			
Note: Cushing had a draw of 0.61 mmb for July 2 week			
Source EIA, Bloomberg			
Prepared by SAF Group			

1 3 21

Dan Tsubouchi @Energy_Tidbits · Jul 8

great sunrise in san jose del cabo. be back for the EIA oil inventory data to see if a big draw does anything to help oil prices looking over 1st tee on Ocean nine at @PalmillaGolf

1 1 6

Dan Tsubouchi @Energy_Tidbits · Jul 8

Positive for #Oil. No date for 7th round of #JCPOA discussions, and would need a major shift in someone's position for a 7th round to be the last. looks like pointing to Iran oil return to market to at least Nov? #OOTT

> **Mikhail Ulyanov** @Amb_Ulyanov · Jul 8
>
> The date of the beginning of the seventh round of the #ViennaTalks on #JCPOA isn't set yet. After Presidential elections #Iran needs more time for preparations. It's normal. However today's uncertainties do not meet any country's interests. The sooner the talks resume the better.

3 4

Dan Tsubouchi @Energy_Tidbits · Jul 7

2/2. @MoEnergy_Saudi Abdulaziz reminds #OPEC+ DOC provided for Dec 2022 reviews. "The agreement will be valid until 30 April 2022, however, the extension of this agreement will be reviewed during December 2021." #OOTT

cooperation in ensuring the resilience of energy systems.

In view of the current fundamentals and the consensus market perspectives, and in line with the decision taken at the 9th (Extraordinary) OPEC and non-OPEC Ministerial Meeting, all Participating Countries agreed to:

1. Reaffirm the Framework of the DoC, signed on 10 December 2016 and further endorsed in subsequent meetings; as well as the Charter of Cooperation, signed on 2 July 2019.
2. Adjust downwards their overall crude oil production by 9.7 mb/d, starting on 1 May 2020, for an initial period of two months that concludes on 30 June 2020. For the subsequent period of 6 months, from 1 July 2020 to 31 December 2020, the total adjustment agreed will be 7.7 mb/d. It will be followed by a 5.8 mb/d adjustment for a period of 16 months, from 1 January 2021 to 30 April 2022. The baseline for the calculation of the adjustments is the oil production of October 2018, except for the Kingdom of Saudi Arabia and The Russian Federation, both with the same baseline level of 11.0 mb/d. The agreement will be valid until 30 April 2022, however, the extension of this agreement will be reviewed during December 2021.
3. Call upon all major producers to provide commensurate and timely contributions to the efforts aimed at stabilizing the oil market.
4. Reaffirm and extend the mandate of the Joint Ministerial Monitoring Committee and its membership, to closely review general market conditions, oil production levels and the level of conformity with the DoC and this Statement, assisted by the Joint Technical Committee and the OPEC Secretariat.
5. Reaffirm that the DoC conformity is to be monitored considering crude oil production, based on the information from secondary sources, according to the methodology applied for OPEC Member Countries.
6. Meet on 10 June 2020 via videoconference, to determine further actions, as needed to balance the market.

1 4

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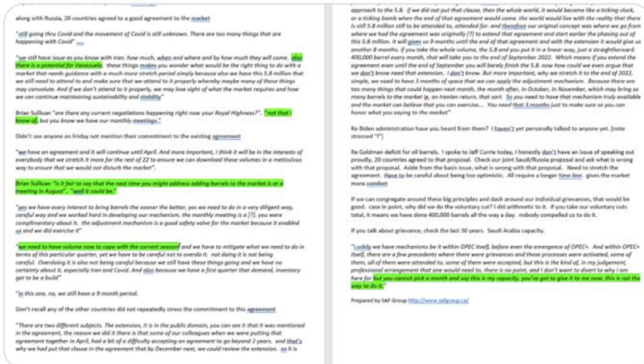
Dan Tsubouchi @Energy_Tidbits · Jul 7

1/2. #Oil markets should hope @MoEnergy_Saudi Abdulaziz carries the day. how do you disagree with his logic tor why extend to Dec 2022? Interesting warning for potential of more Venezuela oil barrels coming back. See below SAF Group transcript. Great @SullyCNBC interview. #OOTT



along with Russia, 20 countries agreed to a good agreement to the market

"still going thru Covid and the movement of Covid is still unknown. There are too many things that are happening with Covid" ...

"we still have issue as you know with Iran. how much, when and where and by how much they will come. also there is a potential for Venezuela. these things makes you wonder what would be the right thing to do with a market that needs guidance with a much more stretch period simply because also we have this 5.8 million that we still need to attend to and make sure that we attend to it properly whereby maybe many of these things may convolute. And if we don't attend to it properly, we may lose sight of what the market requires and how we can continue maintaining sustainability and stability"

Brian Sullivan "are there any current negotiations happening right now your Royal Highness?". "not that I know of, but you know we have our monthly meetings."

Didn't see anyone on Friday not mention their commitment to the existing agreement

"we have an agreement and it will continue until April. And more important, I think it will be in the interests of everybody that we stretch it more for the rest of 22 to ensure we can download these volumes in a meticulous way to ensure that we would not disturb the market".

Brian Sullivan "is it fair to say that the next time you might address adding barrels to the market is at a meeting in August". "well it could be."

"yes we have every interest to bring barrels the sooner the better, yes we need to do in a very diligent way, careful way and we worked hard in developing our mechanism. the monthly meeting is a [?]. you were complimentary about it. the adjustment mechanism is a good safety valve for the market because it enabled us and we did exercise it"

"we need to have volume now to cope with the current season and we have to mitigate what we need to do in terms of this particular quarter, yet we have to be careful not to overdo it. not doing it is not being careful. Overdoing it is also not being careful because we still have these things going and we have no certainty about it, especially Iran and Covid. And also because we have a first quarter that demand, inventory get to be a build"

"in this one, no, we still have a 9 month period.

Don't recall any of the other countries did not repeatedly stress the commitment to this agreement

"There are two different subjects. The extension, it is in the public domain, you can see it that it was mentioned in the agreement, the reason we did it there is that some of our colleagues when we were putting that agreement together in April, had a bit of a difficulty accepting an agreement to go beyond 2 years. and that's why we had put that clause in the agreement that by December next, we could review the extension. so it is

approach to the 5.8. if we did not put that clause, then the whole world, it would become like a ticking clock, or a ticking bomb when the end of that agreement would come. the world would live with the reality that there is still 5.8 million still to be attended to, attended for. and therefore our original concept was where we go from where we had the agreement was originally [?] to extend that agreement and start earlier the phasing out of this 5.8 million. it will gives us 9 months until the end of that agreement and with the extension it would give us another 8 months. if you take the whole volume, the 5.8 and you put it in a linear way, just a straightforward 400,000 barrel every month, that will take you to the end of September 2022. Which means if you extend the agreement even until the end of September you will barely finish the 5.8. now how could we even argue that we don't know need that extension. I don't know. But more important, why we stretch it to the end of 2022, simple, we need to have 3 months of space that we can apply the adjustment mechanism. Because there are too many things that could happen next month, the month after, in October, in November, which may bring so many barrels to the market ie, an Iranian return, that sort. So you need to have that mechanism truly available and the market can believe that you can exercise... You need that 3 months just to make sure so you can honor what you saying to the market"

Re Biden administration have you heard from them? I haven't yet personally talked to anyone yet. [note stressed "I"]

Re Goldman deficit for oil barrels. I spoke to Jeff Currie today, I honestly don't have an issue of speaking out proudly, 20 countries agreed to that proposal. Check our joint Saudi/Russia proposal and ask what is wrong with that proposal. Aside from the basis issue, what is wrong with that proposal. Need to stretch the agreement. Have to be careful about being too optimistic. All require a longer time line. gives the market more comfort

If we can congregate around these big principles and dash around our individual grievances, that would be good. case in point, why did we do the voluntary cut? I did arithmetic to it. If you take our voluntary cuts total, it means we have done 400,000 barrels all the way a day. nobody compelled us to do it.

If you talk about grievance, check the last 30 years. Saudi Arabia capacity.

"Luckily we have mechanisms be it within OPEC itself, before even the emergence of OPEC+. And within OPEC+ itself, there are a few precedents where there were grievances and these processes were activated, some of them, all of them were attended to, some of them were accepted, but this is the kind of, in my judgement, professional arrangement that one would need to, there is no point, and I don't want to divert to why I am here for but you cannot pick a month and say this is my capacity, you've got to give it to me now. this is not the way to do it."

Prepared by SAF Group http://www.safgroup.ca/

> **Dan Tsubouchi** @Energy_Tidbits · Jul 7
>
> No doubting @MoEnergy_Saudi Abdulaziz view on UAE position "you cannot pick a month and say this is my capacity, you've got to give it to me now. this is not the way to do it." Much more in this great @SullyCNBC interview. #OOTT cnbc.com/video/2021/07/...

1 2 5

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Dan Tsubouchi @Energy_Tidbits · Jul 7

🇨🇦Canadian sports fans should be watching @Wimbledon men quarter finals. @felixtennis just evened it up 1 set each. can't imagine how great it would be if he joined fellow 🇨🇦 @denis_shapo in the semi finals!

Quarter-final · Court 1 Live

🇮🇹 7	M. Berrettini	6	5	0	0	•
🇨🇦 16	F. Auger Aliassime	3	7	0	0	

Dan Tsubouchi @Energy_Tidbits · Jul 7

No doubting @MoEnergy_Saudi Abdulaziz view on UAE position "you cannot pick a month and say this is my capacity, you've got to give it to me now. this is not the way to do it." Much more in this great @SullyCNBC interview. #OOTT cnbc.com/video/2021/07/...

> **Dan Tsubouchi** @Energy_Tidbits · Jul 1
>
> If you could invite 3 people for dinner? #SaudiEnergyMinister Abdulaziz should be on everyone's list, he is on mine! "The Man" who saved the #Oil market and shows he is just a good person with a heartfelt tribute. #OOTT Thx @dan_murphy for video. twitter.com/dan_murphy/sta...

4 7

Dan Tsubouchi @Energy_Tidbits · Jul 7

#BigOil messaging under #EnergyTransition. #Shell debt down, shareholder distributions up. Would it have hurt to say due to high #Oil #NatGas prices? Like it or not, level of shareholder distributions for coming years will be driven by oil & gas, not #RenewableEnergy #OOTT

Excerpt from
https://www.shell.com/media/news-and-media-releases/2021/shell-second-quarter-2021-update-note.html

Shell second quarter 2021 update note

Jul 7, 2021

The following is an update to the second quarter 2021 outlook. The impacts presented here may vary from the actual results and are subject to finalisation of the second quarter 2021 results, which will be announced on July 29, 2021. Unless otherwise indicated, all outlook statements exclude identified items.

Strong cash generation supports additional shareholder distributions in the second half of 2021

As a result of strong operational and financial delivery, combined with an improved macro-economic outlook, Shell will move to the next phase of its capital allocation framework and, subject to final Board approval, increase total shareholder distributions to within the range of 20-30% of CFFO, starting at the Q2 results announcement. The level of additional distributions will be determined with full visibility of the Q2 financial results.

In the second quarter, Shell expects to have further reduced its net debt, although the extent of the reduction will be moderated by working capital movements. In conjunction with the increased distributions, Shell will retire its net debt milestone of $65 billion and will continue to target further strengthening of its balance sheet and AA credit metrics. 2021 cash capex will remain below $22 billion.

Upstream

Adjusted EBITDA

- Production is expected to be between 2,225 and 2,300 thousand barrels of oil equivalent per day.
- Any positive impacts from currency effects are expected to be offset by higher Underlying opex from increased planned maintenance activities compared with the first quarter 2021.

Adjusted Earnings

- Pre-tax depreciation is expected to be between $3.2 and $3.5 billion.
- Taxation charge is expected to be between $500 and $900 million, which includes a one-off release of non-cash tax provision of approximately $600 million.

Cash flow from operations

- Tax paid is expected to be between $750 and $1,100 million.

Full-year price and margin sensitivities

$ million	Adjusted Earnings	CFFO
Integrated Gas		
+$10/bbl Brent	1,100	1,200
+$10/bbl Japan Customs-cleared Crude - 3 months	1,100	1,200
Upstream		
+$10/bbl Brent	[illegible]	[illegible]
+$1/mmBtu Henry Hub	[illegible]	[illegible]
+$1/mmBtu EU TTF	150	200
Refining		
+$1/bbl indicative refining margin	900	—

4 8

Dan Tsubouchi @Energy_Tidbits · Jul 7

Reality reminder, big positive to Cdn #NatGas is coming when #LNGCanada Phase 1 ~1.8 bcf/d starts up in a few yrs moving big Cdn #NatGas volumes to Asia. #Petronas signs 10-yr #CNOOC deal incl LNG Canada supply and 1st ever LNG deal indexed to #AECO prices petronas.com/media/press-re...

https://www.petronas.com/media/press-release/petronas-and-cnooc-sign-10-year-lng-supply-agreement
7 · Jul · 2021
PETRONAS and CNOOC Sign 10-Year LNG Supply Agreement

Media Releases

Kuala Lumpur, 7 July 2021 – PETRONAS LNG Ltd. (PLL), a subsidiary of PETRONAS, has secured a 10-year term deal to supply liquefied natural gas (LNG) to CNOOC Gas and Power Trading & Marketing Limited, a subsidiary of China National Offshore Oil Corporation (CNOOC).

This long-term supply agreement also includes supply from LNG Canada when the facility commences its operations by middle of the decade.

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.

"PETRONAS is proud to strengthen our decade long relationship with CNOOC through this term LNG supply. Importantly, it reflects the markets' receptiveness and recognition of AECO indexed LNG into the world's largest LNG market; as we seek to grow the use of LNG as a cleaner and cost effective form of energy," said PETRONAS Vice President of LNG Marketing & Trading, Shamsairi M. Ibrahim.

The AECO index, housed on the ICE NGX commodity exchange platform, is one of the most liquid spot and forward energy markets in North America. It is the leading price marker for natural gas in Canada similar to the United States' Henry Hub, which is the benchmark for natural gas prices used as an indexation to LNG prices. PETRONAS introduced the AECO index to its customers in May this year following the sale of a spot cargo from Bintulu, Malaysia, to a buyer in the Far East.

2

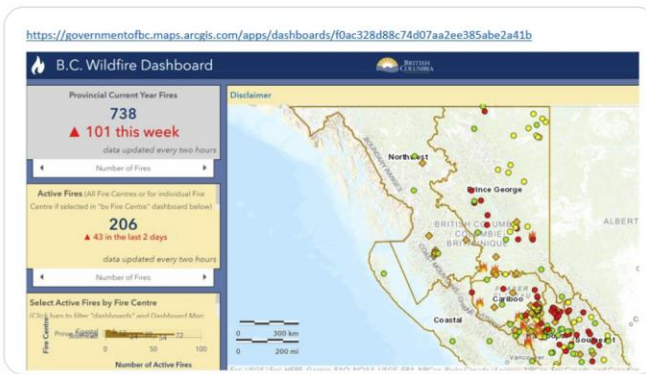
Dan Tsubouchi @Energy_Tidbits · Jul 6

Look at this list of all time great clutch Habs that @joshanderson_77 joined with his OT winner last night. What a great game. Imagine if he gets one more and joins Rocket Richard at the top of the list!

Dan Tsubouchi @Energy_Tidbits · Jul 6

Brutal last 2 weeks for BC #Wildfires. Below are links to BC wildfires. Really hope people stay safe. #NatGas #OOTT

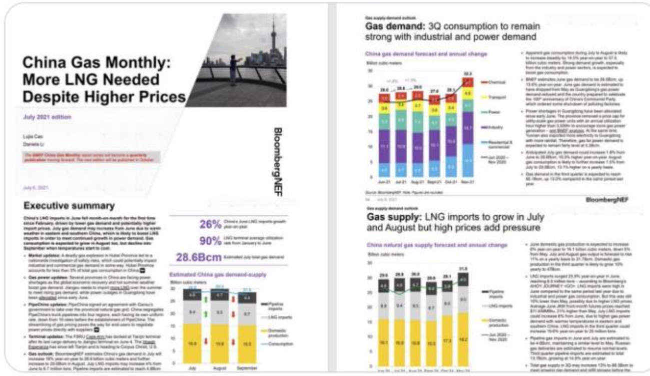
governmentofbc.maps.arcgis.com/apps/dashboard...
wildfire.alberta.ca/wildfire-statu...



1

Dan Tsubouchi @Energy_Tidbits · Jul 6

Continued support for summer #LNG prices from China. @BloombergNEF "China Gas Monthly: More LNG Needed Despite Higher Prices". If #Nordstream2 doesn't start for Q4, there will be a mad scramble for LNG this winter. Thx @BloombergNEF Lujia Cao & Daniela Li. #NatGas



1 4

Dan Tsubouchi @Energy_Tidbits · Jul 5

Crazy chain of events aside, #Pemex repairing affected pneumatic pumping line but not saying if production is impacted. Hmm! 1st update inferred were restoring normal operations. still have trouble believing that a gas line out wouldn't impact ability to produce the oil. #OOTT

https://www.pemex.com/saladeprensa/boletines_nacionales/Paginas/2021-184_nacional.aspx

Electrical storms and the presence of gas on the sea surface caused a fire in the Campeche Sound

07/05/2021 | 184

- **There was no oil spill and immediate action to control the fire on the surface avoided environmental damage**
- **Analysis is performed to identify the root cause of the gas leak in the pipeline**

Petróleos Mexicanos (PEMEX) reports that, according to weather reports, on July 2 an electrical storm with heavy rain occurred in the platform area of the Ku asset, which caused the necessary pneumatic pump gas turbocompression equipment to go out of operation. for the production of wells.

At the same time, a leak was detected in the 12 "pneumatic pumping pipeline that feeds the wells of the Ku-C platform; the gas outside the pipe migrated from the seabed to the surface and due to the electric shocks and heavy rains, the fire broke out on the sea surface.

As a result of these events, and after approximately 5 hours, the fire was completely extinguished by closing the submarine valve and injecting Nitrogen into the gas pipeline.

It should be noted that there was no oil spill and immediate actions to control the fire that occurred on the sea surface avoided environmental damage.

PEMEX has started with the definitive repair program for the affected pneumatic pumping line and is carrying out the analysis to identify the root cause of the gas leak in the pipeline.

> **Dan Tsubouchi** @Energy_Tidbits · Jul 3
>
> #Pemex says "restoring normal operating conditions". does this mean fire out so crisis is over or are they saying, as being inferred, that no interruption or ongoing impact on production other than during the fire? Would have thought losing the gas line would ...

1 2

Dan Tsubouchi @Energy_Tidbits · Jul 5

Russia #TASS says OPEC+ meeting is cancelled, not postponed. #OOTT

https://tass.ru/ekonomika/11828433

JUL 5, 11:17

OPEC promised to announce date of new OPEC + meeting "in due time"

MOSCOW, July 5. / TASS /. The decision to cancel the OPEC + ministerial meeting on July 5 was made after consultations with the Minister of Energy of Saudi Arabia, Prince Abdel Aziz bin Salman and Deputy Prime Minister of the Russian Federation Alexander Novak, who are the chairman and co-chairman of the conference, according to a letter from OPEC Secretary General Mohammad Barkindo to the heads of the OPEC + delegations, with which TASS got acquainted with.

"The date of the new meeting will be announced in due course, and we will inform you accordingly," he said in a statement.

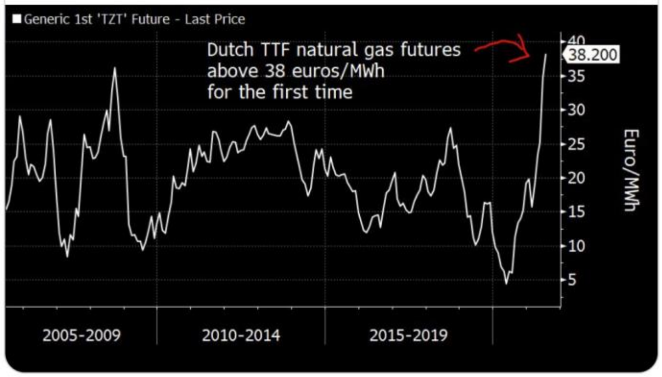
On behalf of the chairman and co-chairman of the ministerial conference, Barkindo apologized for the inconvenience caused by the cancellation of the meeting.

3 7

Dan Tsubouchi @Energy_Tidbits · Jul 5

Positive for summer #LNG prices. Also supports need for US LNG exports to Europe this summer, which is more support for #HenryHub #NatGas price. Europe needs to attract more LNG cargoes to refill tanks prior to winter. Thx @SStapczynski.

> **Stephen Stapczynski** @SStapczynski · Jul 5
>
> Russia decides not to book extra annual natural gas pipeline capacity via the Ukraine and Poland, spooking the market amid supply crunch fears 🇷🇺 🙅
>
> Even though the auctions were for capacity starting from Oct., the front-month Europe gas benchmark jumped to a new record high
>
> Show this thread



1 2

Dan Tsubouchi @Energy_Tidbits · Jul 5

Got to love @Amb_Ulyanov's "attempt to hit 3 birds with 1 stone". "analysts" are 1 thing, but if "officials" means US, then bullish for #Oil markets as this means any #JCPOA return will take even longer. #OOTT

> **Mikhail Ulyanov** @Amb_Ulyanov · Jul 5
>
> In the context of #ViennaTalks some analysts and officials advocate for addressing new topics such as regional security and missiles. An attempt to hit 3 birds with 1 stone. Unrealistic and counterproductive. The agreed goal of the talks is just to restore the original #JCPOA.

1 1 1

Dan Tsubouchi @Energy_Tidbits · Jul 5

Can UAE stay resolute & separate #DOC extension talks for now? RUS #OPEC+ to continue "until a consensus is reached." Only consensus is increase #Oil prod in Aug. Surely no one expects UAE to convince everyone else to flip? like Henry Fonda in 1957 classic #12AngryMen? #OOTT

https://tass.ru/ekonomika/11823409

Peskov said that OPEC + consultations will continue until a consensus is reached

At the same time, the Kremlin spokesman did not comment on the course of the OPEC + consultations.

MOSCOW, July 5. / TASS /. OPEC + consultations will continue until a consensus is reached, press secretary of the Russian President Dmitry Peskov is sure.

On Monday, in an interview with reporters, when asked how long consultations on the deal would take, a Kremlin spokesman replied that this would continue "until a consensus is reached."

At the same time, Peskov did not comment on the very course of the OPEC + consultations. "Work continues there, and, of course, this work cannot be carried out in some kind of public format," the Kremlin spokesman explained.

The ministers of the OPEC + countries for three days, from June 30 to July 2, tried to agree on the levels of oil production from August, as well as the extension of the current agreement after April 2022, when it expires, until the end of next year. An obstacle to reaching an agreement was the position of the UAE, which asked for a revision of the base level of oil production, from which the volume of reduction is calculated. Now it is set for everyone as of October 2018, with the exception of Russia and Saudi Arabia, which are cutting from the level

2 3

Dan Tsubouchi @Energy_Tidbits · Jul 4

3/3. Fits to why on 06/13 #Trudeau wouldn't even acknowledge #OilSands pathways to net zero, or say positive move but need to do more or move faster. He can say Its now the law to stay on track for 2025 and 2030 emissions reduction targets. Negative for Cdn #Oil #NatGas #OOTT

SAF Group created transcript of PM Trudeau post G7 press conference June 13, 2021.

At 49:00 min mark of CBC Rosemary Barton Live [LINK]

Question: "*COP-26 coming up as well, the oil sands/tar sands producers, they've got a plan to Net Zero by 2050, is that good enough, a lot of it is based on technology, which as of yet is unproven on a mass scale, sequestration as well. Do you Sir, does Canada need to be more ambitious?*"

Trudeau: "*Canada has put in place one of the strongest, broad based prices on pollution in the world. We know putting a price on pollution is one of the strongest ways not just to move forward on fighting climate change, but to incentivize business to make investments that decarbonize the workings of our economy. We also at the same time know that transforming our energy mix is going to be extremely important. that's why the energy expertise by workers across this country are going to be put forward in initiatives like a recent agreement we signed on hydrogen for example. Investing in critical minerals that will be essential for zero emissions vehicles of the future. when we talk of critical minerals, we know that china is right now a strong provider to the world of critical minerals. But Canada is a place where we have strong and stable supplies of that as well that could be of use in a reliable supply chain to the world. There are many many conversations we have on strengthening our environment and creating good jobs in the future and that involves being ambitious as we have been in setting not just ambitious targets for 2030 but showing a very clear plan on how we are going to reach those targets as well as being deeply*

2 2 3

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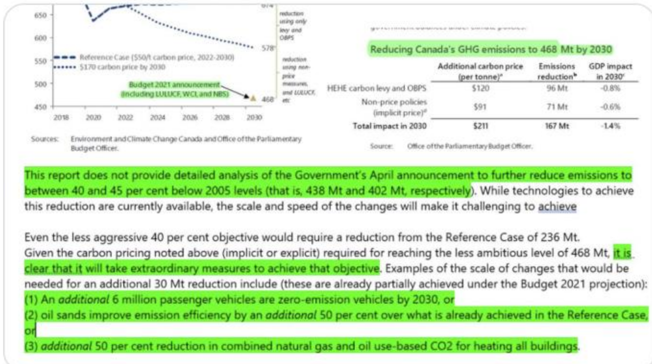
Dan Tsubouchi @Energy_Tidbits · Jul 4

2/3. #Trudeau has to accelerate actions. @PBO_DPB will take extraordinary measures to get to bottom end of #Liberals April announced target for 40-45% reduction vs 2005 emissions levels. can only mean tougher #Oil #OilSands #NatGas actions coming soon #OOTT



Reducing Canada's GHG emissions to 468 Mt by 2030

	Additional carbon price (per tonne)[a]	Emissions reduction[b]	GDP impact in 2030[c]
HEHE carbon levy and OBPS	$120	96 Mt	-0.8%
Non-price policies (implicit price)[d]	$91	71 Mt	-0.6%
Total impact in 2030	**$211**	**167 Mt**	**-1.4%**

Source: Office of the Parliamentary Budget Officer.

This report does not provide detailed analysis of the Government's April announcement to further reduce emissions to between 40 and 45 per cent below 2005 levels (that is, 438 Mt and 402 Mt, respectively). While technologies to achieve this reduction are currently available, the scale and speed of the changes will make it challenging to achieve

Even the less aggressive 40 per cent objective would require a reduction from the Reference Case of 236 Mt.
Given the carbon pricing noted above (implicit or explicit) required for reaching the less ambitious level of 468 Mt, it is clear that it will take extraordinary measures to achieve that objective. Examples of the scale of changes that would be needed for an additional 30 Mt reduction include (these are already partially achieved under the Budget 2021 projection):
(1) An *additional* 6 million passenger vehicles are zero-emission vehicles by 2030, or
(2) oil sands improve emission efficiency by an *additional* 50 per cent over what is already achieved in the Reference Case, or
(3) *additional* 50 per cent reduction in combined natural gas and oil use-based CO2 for heating all buildings.

1 3 1

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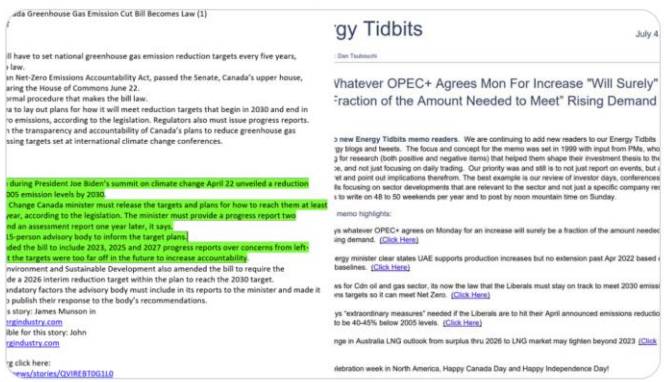
Dan Tsubouchi @Energy_Tidbits · Jul 4

1/3. ICYMI, Negative to Cdn #Oil & #NatGas, #Trudeau can say he has to accelerate actions because its now the law, he has to keep CAN on track to meet 2025 & 2030 emissions targets. See SAF June 4, 2021 Energy Tidbits. Thx @james_munson #OOTT safgroup.ca/insights/trend...


ada Greenhouse Gas Emission Cut Bill Becomes Law (1)

ll have to set national greenhouse gas emission reduction targets every five years,
law.
an Net-Zero Emissions Accountability Act, passed the Senate, Canada's upper house,
aring the House of Commons June 22.
rmal procedure that makes the bill law.
a to lay out plans for how it will meet reduction targets that begin in 2030 and end in
o emissions, according to the legislation. Regulators also must issue progress reports.
the transparency and accountability of Canada's plans to reduce greenhouse gas
ssing targets set at international climate change conferences.

during President Joe Biden's summit on climate change April 22 unveiled a reduction
005 emission levels by 2030.
Change Canada minister must release the targets and plans for how to reach them at least
year, according to the legislation. The minister must provide a progress report two
nd an assessment report one year later, it says.
15-person advisory body to inform the target plans.
ded the bill to include 2023, 2025 and 2027 progress reports over concerns from left-
t the targets were too far off in the future to increase accountability.
nvironment and Sustainable Development also amended the bill to require the
de a 2026 interim reduction target within the plan to reach the 2030 target.
ndatory factors the advisory body must include in its reports to the minister and made it
publish their response to the body's recommendations.
s story: James Munson in
rgindustry.com
ible for this story: John
rgindustry.com

g click here:
ews/stories/QVIREBT0G1L0

gy Tidbits July 4

Dan Tsubouchi

Vhatever OPEC+ Agrees Mon For Increase "Will Surely" Fraction of the Amount Needed to Meet" Rising Demand

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

memo highlights:

ys whatever OPEC+ agrees on Monday for an increase will surely be a fraction of the amount needed ing demand. (Click Here)

ergy minister clear states UAE supports production increases but no extension past Apr 2022 based baselines. (Click Here)

ws for Cdn oil and gas sector, its now the law that the Liberals must stay on track to meet 2030 emiss ns targets so it can meet Net Zero. (Click Here)

ys "extraordinary measures" needed if the Liberals are to hit their April announced emissions reductio to be 40-45% below 2005 levels. (Click Here)

nge in Australia LNG outlook from surplus thru 2026 to LNG market may tighten beyond 2023 (Click

lebration week in North America, Happy Canada Day and Happy Independence Day!

1 3 3

Show this thread

Dan Tsubouchi @Energy_Tidbits · Jul 4

Our weekly SAF July 4, 2021 Energy Tidbits memo was just posted to our SAF Group website. This 42-pg energy research piece expands upon and covers many more items than tweeted this week. See the research section of the SAF website. #Oil #OOTT #OPEC #LNG safgroup.ca/insights/trend...

Energy Tidbits

July 4, 2021

Produced by: Dan Tsubouchi

Vitol: Whatever OPEC+ Agrees Mon For Increase "Will Surely" "Be a Fraction of the Amount Needed to Meet" Rising Demand

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

This week's memo highlights:

1. Vitol says whatever OPEC+ agrees on Monday for an increase will surely be a fraction of the amount needed to meet rising demand. (Click Here)

1 5 7