Energy Tidbits

Vitol's Mike Muller's Oil Outlook – "So We Are Pushing Towards This Triple Top of the Market and Possibly New Highs"

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January 16, 2022

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Independent Statistics & Analysis

U.S. Energy Information Administration

January 2022

Short-Term Energy Outlook

Forecast highlights

- This edition of the *Short-Term Energy Outlook* (STEO) is the first to include forecasts for 2023.

- The STEO continues to reflect heightened levels of uncertainty as a result of the ongoing COVID-19 pandemic. Notably, the Omicron variant of COVID-19 raises questions about global energy consumption. U.S. real GDP declined by 3.4% in 2020 from 2019 levels. Based on forecasts that use the IHS Markit macroeconomic model, we estimate U.S. GDP increased 5.7% in 2021 and that it will rise by 4.3% in 2022 and by 2.8% in 2023. In addition to macroeconomic uncertainties, uncertainty about winter weather and consumer energy demand also present a wide range of potential outcomes for energy consumption. Supply uncertainty in the forecast stems from uncertainty about OPEC+ production decisions and the rate at which U.S. oil and natural gas producers will increase drilling.

- Brent crude oil spot prices averaged $71 per barrel (b) in 2021, and we forecast Brent prices will average $75/b in 2022 and $68/b in 2023.

- We estimate global liquid fuels inventories fell by an average of 1.4 million barrels per day (b/d) in 2021 compared with inventory growth of 2.1 million b/d in 2020. Global oil inventories rise in the forecast, increasing at a rate of 0.5 million b/d in 2022 and 0.6 million b/d in 2023.

- Global consumption of petroleum and liquid fuels averaged 96.9 million b/d in 2021, up by 5.0 million b/d from 2020, when consumption fell significantly because of the pandemic. We expect global liquid fuels consumption will grow by 3.6 million b/d in 2022 and 1.8 million b/d in 2023.

- Crude oil production from OPEC member countries averaged 26.3 million b/d in 2021, up from 25.6 million b/d in 2020. We forecast that average OPEC crude oil production will rise by 2.5 million b/d to average 28.8 million b/d in 2022 and average 28.9 in 2023.

- U.S. crude oil production averaged 11.2 million b/d in 2021. We expect production to average 11.8 million b/d in 2022 and to rise to 12.4 million b/d in 2023, which would be the highest annual average U.S. crude oil production on record. The current record is 12.3 million b/d, set in 2019.

Note: EIA completed modeling and analysis for this report on Thursday January 6, 2022

- U.S. regular gasoline retail prices averaged $3.02 per gallon (gal) in 2021, compared with an average of $2.18/gal in 2020. We forecast gasoline prices will average $3.06/gal in 2022 and $2.81/gal in 2023. U.S. diesel fuel prices averaged $3.29/gal in 2021, compared with $2.56/gal in 2020, and we forecast diesel prices will average $3.33/gal in 2022 and $3.27/gal in 2023.

- The natural gas spot price at Henry Hub averaged $3.91 per million British thermal units (MMBtu) in 2021. Monthly average prices reached $5.51/MMBtu in October, but they declined in November and December as mild weather prevailed across much of the country, resulting in less natural gas used for space heating. We expect Henry Hub spot prices will average $3.82/MMBtu in the first quarter of 2022 and average $3.79/MMBtu for all of 2022 and $3.63/MMBtu in 2023.

- We estimate that U.S. liquefied natural gas (LNG) exports averaged 9.8 billion cubic feet per day (Bcf/d) in 2021, compared with 6.5 Bcf/d in 2020. We expect U.S. LNG export capacity increases will contribute to LNG exports averaging 11.5 Bcf/d in 2022 and 12.1 Bcf/d in 2023.

- U.S. dry natural gas production averaged 93.5 Bcf/d in 2021, up 2.0 Bcf/d from 2020. Natural gas production in the forecast averages 96.0 Bcf/d for all of 2022 and then rises to 97.6 Bcf/d in 2023.

- U.S. natural gas inventories ended December 2021 at 3.2 trillion cubic feet (Tcf), 3% more than the 2016–20 average. We forecast inventories will end March 2022 at 1.8 Tcf, which would be 8% more than the 2017–21 average for the end of March.

- U.S. coal production totaled 579 million short tons (MMst) in 2021, up 8% from 2020. We expect coal production will increase by 6% in 2022 and then rise 1% to a total of 619 MMst in 2023.

- U.S. coal consumption was 545 MMst in 2021, a 14% increase from 2020. The increase reflected more use of coal-fired electricity generation amid high natural gas prices. We expect coal consumption will fall by 2% in 2022 and then be relatively unchanged in 2023 at a total of 532 MMst in 2023.

- Total U.S. retail sales of electricity remain relatively unchanged in our forecast for 2022 after increasing by 2.2% in 2021. Forecast increases in sales to the commercial and industrial sectors in 2022 offset lower sales to the residential sector. We forecast total U.S. retail sales of electricity across all sectors will grow by 1.4% in 2023.

- The share of U.S. electric power generation produced by natural gas averaged 37% in 2021, and we expect it will average 35% in 2022 and 34% in 2023. Our forecast for the natural gas share as a generation fuel declines primarily as a result of increased generation from new renewable energy generating capacity. Coal's average generation share rose to 23% in 2021 as a result of higher natural gas prices, but we expect it to decline slightly over the next two years, averaging near 22% in 2022 and 2023. We expect the nuclear share of generation will remain near 20% over the next two years.

- We expect electricity-generating capacity from renewable energy sources to continue to grow in 2022 and 2023. Our forecast includes both wind and solar capacity growth, with solar capacity growing at a faster rate. The extreme drought conditions in the West may moderate somewhat in the next year, and we forecast that the share of U.S. generation from hydropower will rise from 6% in 2021 to 7% in 2022 and 2023.

- The U.S. retail electricity price for the residential sector in our forecast averages 14.2 cents per kilowatthour in 2022, which is 4% higher than the average retail price in 2021. Forecast residential prices remain relatively the same in 2023.

- Total energy-related carbon dioxide (CO_2) emissions increased by 6.2% in 2021 as the U.S. economy started to recover from the impacts of the COVID-19 pandemic. We forecast that emissions will rise by 1.8% in 2022 and by 0.5% in 2023. Even with growth over the next two years, forecast CO_2 emissions in 2023 are 3.4% lower than 2019 levels. Energy-related CO_2 emissions are sensitive to changes in weather, economic growth, energy prices, and fuel mix.

Global liquid fuels

The COVID-19 pandemic continued to affect global oil markets in 2021. Oil consumption and oil production fell sharply in early 2020 in response to the pandemic. During the second half of 2020 (2H20), however, rising economic activity and the easing of pandemic-related restrictions on other activities caused oil consumption to increase. This trend continued into 2021 with rollouts of COVID-19 vaccinations. In much of the world, vaccines contributed to increased personal travel and business activity, resulting in global oil consumption rising by 5.5% in 2021 from 2020. However, global consumption in 2021 remained 3% below 2019 levels.

For more than a year now, oil consumption has outpaced oil production. Production has remained restrained as a result of crude oil production curtailments by OPEC+ members, investment restraint from U.S. oil producers, and other supply disruptions. Oil consumption outpacing oil production has led to persistent withdrawals from global oil inventories and significant increases in oil prices. We estimate that global oil inventories have fallen for six consecutive quarters going back to the third quarter of 2020 (3Q20), declining at an average rate of 2.1 million barrels per day (b/d) in 2H20 and at an average rate of 1.4 million b/d in 2021. Brent crude oil spot prices increased from an average of $43 per barrel (b) in 3Q20 to an average of $79/b in 4Q21.

Uncertainty in global oil markets has increased heading into 2022. The way in which the Omicron variant of COVID-19 will affect economic activity and oil consumption this year is still unknown. In late 2021, some restrictions to mitigate the spread of COVID-19 began to return in many regions, notably Europe, even before the Omicron variant surfaced. These restrictions, in combination with increased measures to combat the Omicron variant, raised the possibility that global oil consumption could decline in the coming months and added downward pressure to oil prices.

We forecast that global oil production will outpace global oil consumption during both 2022 and 2023, resulting in rising global oil inventories. We expect global oil inventories will rise by an average of 0.5 million b/d in 2022 and by 0.6 million b/d in 2023 and that these inventory builds will generally put downward pressure on crude oil prices. Brent prices average $75/b in 2022 and $68/b in 2023 in our forecast. However, oil market balances are subject to significant uncertainties during the forecast period, notably, the way in which the ongoing pandemic affects economic growth, oil demand, and the production decisions of OPEC+ members. These factors, among others, could keep oil prices volatile.

Global petroleum and other liquid fuels consumption**.** Based on preliminary data and estimates, global consumption of petroleum and other liquid fuels grew by 5.0 million b/d in 2021. This growth followed a decline of 8.4 million b/d in 2020. We forecast global oil consumption will grow by 3.6 million b/d in 2022 and by 1.8 million b/d in 2023, reaching 100.5 million b/d in 2022 and 102.3 million b/d in 2023. If realized, the 2022 global liquid fuels consumption level would surpass the pre-pandemic 2019 level and represent a new record for world liquid fuels consumption.

Slowing growth in global oil demand in our forecast mostly reflects slowing economic growth. Our global economic growth assumptions come from Oxford Economics, which forecasts global GDP will increase by 4.5% in 2022 and by 3.9% in 2023, compared with an increase of 5.8% in 2021. In addition, oil demand in early 2021 was still significantly affected by pandemic-mitigation measures. As business activity and personal mobility increased through much of 2021, air travel remained the most affected segment of liquid fuels demand in 2021. Our forecast assumes air travel will increase throughout 2022 and into 2023, but it will continue to remain below pre-pandemic levels. With air travel and jet fuel consumption below pre-pandemic levels, we expect economic growth will be the main driver of oil consumption growth, as demand increases for fuels such as gasoline, diesel, and hydrocarbon gas liquids (HGLs).

We expect non-OECD countries, where economic growth tends to be more oil-intensive than in OECD countries, to lead the growth in demand for oil in 2022 and 2023. In our forecast, non-OECD oil consumption grows by 2.2 million b/d during 2022 and by 1.4 million b/d in 2023. Oil consumption in OECD countries grows by 1.4 million b/d in 2022 and by 0.3 million b/d in 2023.

Governments in non-OECD countries in the Asia-Pacific and Latin American regions eased mobility and business activity restrictions during 2021 as an increasing share of the population was vaccinated. However, outbreaks of the Omicron variant in some Asia-Pacific countries have led their governments to delay reopening plans or to extend current restrictions. The Middle East and African regions have been relatively slower to ease mobility restrictions than Europe and the United States. Outbreaks of COVID-19 infections and renewed restrictions on mobility and business activity still pose a significant downside risk in these regions.

Strict mobility restrictions imposed by many of the European OECD countries in 1Q21 gradually eased in 2Q21 as a result of increasing vaccination levels. As a result, Europe experienced a significant jump in economic activity, as capacity limits and restrictions on mobility and nonessential business activity were either reduced or eliminated. However, the spread of the Omicron variant led to a sharp increase in new infections in 4Q21. Some governments have responded by renewing some measures that limit mobility and business activity. Overall, we expect relatively milder movement and business activity restrictions than in 2020 because significant portions of the populations in European countries are fully vaccinated and because some of the new government restrictions have targeted unvaccinated segments of the population.

If currently available vaccines provide insufficient protection against future variants, countries may decide to increase mobility and activity restrictions. This strategy would lead to a longer, more drawn-out recovery in global oil consumption. In addition, the pace of economic growth will drive oil consumption in 2022 and 2023. However, if supply chain issues or central bank measures to limit inflation contribute to GDP growth rates that are lower than those from Oxford Economics that are assumed in this forecast, oil consumption will likely also be lower than forecast.

Non-OPEC production of petroleum and other liquid fuels. We estimate that in 2021, non-OPEC production increased by 0.7 million b/d compared with 2020. Most of this increase came from the three largest non-OPEC producers: the United States, Russia, and Canada. We expect non-OPEC production to increase by 2.8 million b/d in 2022 and by an additional 1.6 million b/d in 2023. The United States and Russia lead production growth among non-OPEC countries in our forecast during both 2022 and 2023. Brazil, Norway, and Canada also contribute significantly to growth in the forecast.

After the United States, Russia is the world’s second-largest producer of liquid fuels. Its liquid fuels production averaged 10.8 million b/d in 2021, 0.3 million b/d more than in 2020. We forecast Russia’s liquid fuels production will continue to grow in 2022 and 2023 but at a slower rate. From December 2020 to December 2021, Russia’s liquid fuels production grew by 0.9 million b/d. However, most of the growth in 2021 occurred during the second half of the year as OPEC+, in which Russia participates, consistently raised its production targets. This growth used up most of Russia’s available spare capacity. We forecast that annual growth in oil production in Russia will average almost 0.8 million b/d during 2022 and 0.3 million b/d in 2023.

Canada’s liquid fuels production increased by 0.3 million b/d in 2021 to reach a record high annual average of 5.6 million b/d. Production growth in Canada followed increased refinery demand for crude oil in the United States, the removal of production curtailments set by Alberta’s provincial government, and the restart of oil sands expansion projects deferred during the COVID-19 pandemic. In our forecast, we assume that no new upstream projects come online in Canada during 2022 or 2023. We expect oil sands output will continue to grow at smaller increments. Canada's oil sands producers have adjusted the scale and pace of upstream development and investment. These producers have increasingly moved toward smaller incremental expansions or optimizations of existing projects rather than toward larger expansions or greenfield projects. Some growth will also come from removing the bottlenecks from pipeline capacity.

We forecast Canada's production of petroleum and other liquid fuels will increase by 0.2 million b/d in 2022. Some increase in our forecast of Canada's 2022 production follows the expansion of the Enbridge Line 3 crude oil pipeline (0.37 million b/d), which became operational in October 2021. The TransMountain pipeline expansion project (0.59 million b/d) is slated to enter service at the end of 2022. Additional Enbridge expansions and optimizations to its existing pipeline system, if completed, will add more than 0.4 million b/d of export capacity over the forecast period. With this new pipeline capacity from Enbridge and other expansions, oil export constraints will be eliminated by the end of 2023. In 2023, we expect Canada's production of petroleum and other liquid fuels to grow by less than 0.1 million b/d.

Brazil's production of petroleum and other liquid fuels fell slightly in 2021. This decline reflects pandemic-related supply chain disruptions and difficulties Petrobras experienced last year when it restarted the fields that had undergone heavy maintenance in 4Q20. We expect Brazil's production to increase by 0.3 million b/d in 2022, reaching 4.0 million b/d for the first time as production facilities return to normal operation. Our forecast assumes six new floating production storage and offloading (FPSO) units will ramp up through 2023 and continue to drive growth, notably at the Sepia, Mero, and Buzios fields. Once they reach full capacity, these FPSOs will each produce between 70,000 b/d and 180,000 b/d. We expect Brazil's production of petroleum and other liquid fuels to grow by 0.1 million b/d during 2023.

Norway's production of petroleum and other liquid fuels grew by less than 0.1 million b/d in 2021, and we expect output to grow by 0.1 million b/d in 2022 and by 0.2 million b/d in 2023. Most of the growth in 2022 comes from the ramp-up in production at the Martin Linge field, which came online in July 2021. The Johan Sverdrup field, which was the main driver of growth in 2021, again is the main source of our forecast growth in 2023. Production from Phase 1 of the project averaged over 0.5 million b/d in 2021, almost 0.1 million b/d more than the peak production of 0.44 million b/d originally expected by the project developers. Phase 2 of the project, with an expected peak production of 0.22 million b/d, will start in 4Q22.

Some of the largest production declines in our forecast occur in Mexico. Mexico's crude oil and other liquid fuels production averaged 1.9 million b/d in 2021, almost unchanged from 2020 and 2019. Last year, the ramp-up of output from the Ixachi, Pokoch, and Hokchi fields stemmed Mexico's long-term production declines. Production in Mexico of petroleum and other liquids falls slightly in 2022 in our forecast. We expect Mexico's oil production to fall faster in 2023, with a decline of 0.1 million b/d. These decreases reflect financial constraints at Mexico's national oil company, PEMEX, and continued large declines in mature fields. New growth in foreign-operated fields in 2021 and beyond will not 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 2022 and 2023, notably in Indonesia and Colombia.

OPEC production of petroleum and other liquid fuels. At the January 2022 OPEC+ meeting, participants reaffirmed their decision to continue to increase production by 0.4 million b/d monthly, with future adjustments possible depending on market conditions. Our forecast assumes that OPEC member countries will not fully increase production in accordance with their targets in 2022. Some countries will be unable to meet their new targets because of wide-ranging challenges to bring idled capacity back online, and other countries will limit increases to avoid large global imbalances between oil production and oil demand.

OPEC crude oil production averaged 26.3 million b/d in 2021, up 0.7 million b/d from 2020. We forecast that average OPEC crude oil production will increase by an additional 2.5 million b/d to average 28.8 million b/d in 2022 and then average 28.9 million b/d in 2023. Our OPEC crude oil production forecast is subject to considerable uncertainty, driven both by country compliance with existing production targets and uncertain future global demand growth.

OPEC+ has instituted monthly meetings to assess global oil market conditions, and the group's production targets are subject to regular adjustments. OPEC+ has indicated that it will adjust production targets in response to changes in global oil demand, but the path of global oil demand in the coming months remains uncertain.

Even with increased OPEC crude oil production, remaining surplus production capacity will be more than sufficient to meet additional demand even if consumption exceeds our expectations. We expect that OPEC surplus crude oil production capacity will decline from 6.0 million b/d in 2021 to average 3.9 million b/d in both 2022 and 2023, compared with an average surplus capacity of 2.2 million b/d from 2010–19. These estimates do not include additional capacity in Iran that is offline because of U.S. sanctions.

Among the OPEC countries, Iran, Libya, and Venezuela are not subject to production targets in the OPEC+ agreement. The STEO forecast assumes current U.S. sanctions remain in place for Iran and Venezuela for the entire forecast period. We also expect that OPEC+ will not implement further production cuts to accommodate any potential increases in oil output from Iran or Venezuela.

After five years of declines, Venezuela's crude oil production rose from 0.5 million b/d in 2020 to almost 0.6 million b/d in 2021, driven by increased service company activity and increased access to condensate and other diluents for blending with Venezuela's heavy crude oil. Despite increases in 2021, we expect Venezuela's crude oil production to decline as a result of ongoing operational difficulties, lack of field and facility maintenance, and continuing sanctions.

Libya's crude oil production rose by 0.8 million b/d to an average of almost 1.2 million b/d in 2021 compared with 2020 after the eastern and western security forces signed a ceasefire agreement in October 2020. The newly formed unified government provided stability among the various factions in Libya in March 2021. Our forecast assumes generally stable production in Libya in 2022 and 2023. However, our forecast of Libya's crude oil production is subject to heightened uncertainty as a result of the tentative political and security situation in Libya and the lack of a budget to support oil and natural gas infrastructure maintenance and repair. Presidential and parliamentary elections set for December 2021 were delayed. Additionally, a blockade at four oil fields disrupted 0.3 million b/d of crude oil production in Libya in late December.

OPEC non-crude oil liquids. OPEC production of non-crude oil liquids increased from 5.1 million b/d on average in 2020 to 5.3 million b/d in 2021. The 2021 production level reflects increases in production of associated liquids as a result of relaxed OPEC production cuts. We expect production of non-crude oil liquids will increase further in 2022 to 5.5 million b/d and stay at that level in 2023.

Global oil inventories. We estimate that global oil inventories decreased by an average of 1.4 million b/d in 2021, after increasing by 2.1 million b/d in 2020. In our forecast, global oil inventories increase by 0.5 million b/d in 2022 and by 0.6 million b/d in 2023. This inventory growth in largely reflects growth in global oil production paired with slowing growth in oil consumption. Global oil supply increases in the forecast, in part, because of easing production cuts from OPEC+ producers and the effects of higher 2021 oil prices on U.S. tight oil production.

Total oil inventories in the OECD fell from 3.0 billion barrels at the end of 2020 to 2.7 billion barrels at the end of 2021. We expect oil inventories in the OECD to rise to 2.8 billion barrels at the end of 2022 and to 2.9 billion barrels at the end of 2021.

Crude oil prices. Oil prices rose during much of 2021, with Brent crude oil spot prices averaging $71/b for the year compared with $42/b in 2020. Rising prices reflected growth in global oil demand that outpaced near-term growth in oil production, resulting in falling global oil inventories. During 2021, Brent prices reached their highest monthly average of $84/b during October. Brent prices fell to an average of $74/b in December, which largely reflected concerns about how the Omicron variant and potential mitigation efforts may affect near-term oil demand. In addition, increases in crude oil supply from OPEC+ members have likely also contributed to lower oil prices. However, crude oil prices ended December at $77/b as concerns that Omicron would lead to significant declines in oil consumption eased and as some crude oil production went offline in Libya.

We expect Brent crude oil spot prices will average $75/b in 2022. Forecast prices remain near current levels in 1Q22, averaging $79/b for the quarter. Oil markets are generally balanced in 1Q22 in our forecast. After 1Q22, we expect inventory builds through the end of 2022, averaging 0.7 million b/d from 2Q22 through 4Q22. We expect some downward oil price pressures during this period, with Brent crude oil prices falling to an average of $71/b by 4Q22. Although inventories build in our forecast, inventory levels are currently lower than in 2019, which may dampen some of the downward price pressures associated with rising inventories. Forecast inventory builds accelerate in 2023, and we expect that Brent crude oil prices will average $68/b for the year.

Global economic developments and numerous uncertainties surrounding the pandemic in the coming months could push oil prices higher or lower than our current price forecast. Our current price path reflects global oil consumption that increases by 4% from 2021 in 2022 and by an additional 2% in 2023. However, this forecast depends on how any potential new COVID-19 variants develop and how oil consumption behavior changes as the pandemic evolves. Global supply chain disruptions have also likely exacerbated inflationary price effects across all sectors in recent months. How central banks respond to inflation may affect economic growth and oil demand during the forecast period. The duration of, and compliance with, the latest OPEC+ production targets also remains uncertain. Our forecast includes the assumption that OPEC+ will limit production increase to less than the current target of 0.4 million b/d per month. However, this assumption leaves more spare OPEC crude oil production capacity than seen during much of the 2010–19 period. If OPEC countries choose to produce from this capacity rather than hold it as spare, prices would likely be lower than our forecast. In addition, the degree to which the U.S. shale industry responds to the recent relatively high 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 the first half of 2022 before widening to a discount of $4/b less than Brent prices through 2023. This price discount is based on our assumption that the recent discount of WTI to Brent, which averaged less than $3/b in 2021, reflected low global demand for oil exports and relatively low levels of U.S. crude oil production. As global refinery demand for crude oil and U.S. crude oil supply increases, we expect the WTI discount to return to $4/b by 2H22. This discount reflects the relative cost of exporting crude oil from the distribution hub in Cushing, Oklahoma, to Asia, compared with the cost of exporting Brent crude oil from the North Sea to Asia.

U.S. liquid fuels

U.S. Consumption. We forecast that petroleum and liquid fuels consumption in the United States will average 20.6 million barrels per day (b/d) in 2022, which would slightly surpass consumption from 2019. In 2023, we forecast that consumption will surpass 2019 levels and reach 20.9 million b/d. The forecast growth in petroleum and liquid fuels consumption is led by increases in gasoline consumption in 2022 and by hydrocarbon gas liquids (HGLs) in 2023.

We forecast that U.S. consumption of HGLs will increase by 0.2 million b/d in 2022 and by 0.1 million b/d in 2023, to reach annual averages of 3.6 million b/d in 2022 and 3.7 million b/d in 2023. We expect all of the HGL consumption growth in 2022 and nearly all of the growth in 2023 to be from increased use of ethane as a petrochemical feedstock. We expect two additional petrochemical crackers to come online in the United States during the next two years, both of which will exclusively use ethane as a feedstock. As a result, our forecast of ethane consumption rises by 0.3 million b/d in 2022 and by 0.1 million b/d in 2023.

In this STEO, we expect that continuing effects from the COVID-19 pandemic will limit U.S. gasoline consumption and that consumption through 2023 will remain below levels seen before the pandemic in 2019. We forecast that gasoline consumption will increase by almost 0.3 million b/d (3.1%) from 2021 levels to an average approaching 9.1 million b/d in 2022. In 2023, we expect that consumption growth will slow to 0.1 million b/d (1.0%) and that annual consumption will average more than 9.1 million b/d, below the 2019 consumption level of 9.3 million b/d.

Although we expect U.S. gasoline consumption will remain below 2019 levels, we forecast that vehicle miles traveled (VMT) will exceed 2019 levels in 2022 and 2023. In the first half of 2022 (1H22), we expect VMT will be below 1H19 levels. We expect that people’s responses to the COVID-19 pandemic will continue to limit driving activity, particularly in 1Q22. We assume the effects of the COVID-19 pandemic on gasoline demand will decrease after 1Q22, and driving activity will increase over the summer season, with personal travel and employment growth bringing VMT above 2019 levels in 2H22. Annual VMT in our forecast for 2022 is about equal to 2019 levels. We expect that VMT growth will continue in 2023 and that VMT will increase by 2.2% compared with 2022.

We expect increasing vehicle fuel efficiency, measured in miles per gallon, to offset some of the increased VMT. In 2022 and 2023, vehicle efficiency will likely increase 1%–2% each year. On December 20, the Biden administration released a final rule for greenhouse gas emissions from cars and trucks for model years 2023–26. The final rule increases the stringency of emissions standards by 5%–10% for each model year and replaces the previous standard that increased 1.5% annually. Because the new rule only applies to new cars and because car manufactures have a great deal of flexibility of when they announce a new model year, we expect that the new rule will have limited effects on fleet-wide vehicle efficiency during 2023.

U.S. distillate consumption increased by almost 0.2 million b/d (4.3%) in 2021. We expect that distillate consumption will increase by more than 0.1 million b/d (3.1%) in 2022 and by less than 0.1 million b/d (1.4%) in 2023, largely because of slowing U.S. GDP growth. Based on forecasts from IHS Markit, annual GDP growth in 2021 averaged 5.7% and is expected to fall to 4.3% in 2022 and 2.8% in 2023. The decreasing rate of GDP growth in our forecast largely slows demand growth for distillate fuel, which includes diesel fuel. Distillate demand, particularly diesel fuel, is closely tied with economic activity and freight movement (such as trucking and rail). We assume that the effects of supply chain bottlenecks on distillate demand will generally decrease compared with 2021, contributing to annual distillate demand growth. If supply chain bottlenecks worsen, however, actual distillate fuel consumption may be less than forecast. Conversely, if supply chain bottlenecks improve, distillate demand could rise above the current forecast.

U.S. jet fuel consumption in the forecast rises from 1.4 million b/d in 2021 to 1.6 million b/d in 2022 and 1.7 million b/d in 2023. We expect responses to the COVID-19 pandemic will have decreasing effects on jet fuel consumption moving further into the forecast period. Jet fuel demand, however, has been the most affected by the pandemic, decreasing from 1.7 million b/d in 2019 to 1.1 million b/d in 2020. Variants of COVID-19 (such as Omicron) could deter people from flying, which may lead to jet fuel consumption being less than forecast.

U.S. Crude oil supply. U.S. crude oil production averaged 11.2 million b/d in 2021, down 0.1 million b/d from 2020 as a result of well freeze-offs during extreme cold in February and well shut-ins during Hurricane Ida in late August and early September. Production in 2021 was 1.1 million b/d lower than the annual record of 12.3 million b/d set in 2019. We expect annual average U.S crude oil production to increase to 11.8 million b/d in 2022 and to 12.4 million b/d in 2023, which would set a new record. Despite our forecast of record annual average crude oil production in 2023, we do not expect production in any month in the forecast will surpass the monthly record of 12.97 million b/d set in November 2019. Production growth reflects oil prices that we expect will be sufficient to lead to continued increases in upstream development activity, which we forecast will proceed at a pace that will more than offset decline rates.

Annual average production numbers can conceal important monthly trends in oil production. For example, in February 2021, monthly average crude oil production from the Lower 48 states (L48) fell by 14% from January, from 8.8 million b/d to 7.6 million b/d, as a result of extreme cold. This event disrupted production operations across the country, particularly in Texas, which experienced widespread well freeze-offs. L48 production increased to 8.9 million b/d in March, as normal operations resumed. Because most L48 production is unconventional tight oil, we expect drilling activity and decline rate dynamics to mainly drive L48 production going forward. Tight oil wells have steep declines in the early years of their production, requiring continuous drilling of new wells to maintain unchanging production rates.

We expect production to increase for most of 2022, as more new wells come online to offset decline rates. For U.S. tight oil production, our models include a four-to-six-month lag between a change in oil price and change in production. We expect that WTI crude oil prices above $70/b during most of 2H21 and 1H22 increase the number of active drilling rigs and contribute to L48 production growth. We expect annual average L48 production of 9.6 million b/d for 2022.

We expect the WTI crude oil price to average $71/b in 2022. This price is up $3/b from the 2021 average and is sufficient for producers to realize positive cash flows in many areas, particularly the more productive areas of the Permian Basin. Producers saw increased cash flow in 2021, having held back on capital investments and cut costs, as crude oil prices rose significantly. Restrained investment led to fewer rig additions than what we have observed at similar crude oil price levels in previous years. With financial conditions among operators improved, we expect development to proceed at a modest pace. We expect average month-over-month L48 production growth to be 50,000 b/d in 2022. Most of L48 growth in the forecast comes from the Permian Basin. We expect L48 production growth to slow to a monthly average of 40,000 b/d in

2023, as a decline in oil prices in our forecast slows rig additions. Annual average L48 crude oil production for 2023 is 10.2 million b/d.

From 2020 to 2021, annual average production in the U.S. Federal Gulf of Mexico (GOM) increased from 1.6 million b/d to 1.7 million b/d. This increase occurred despite Hurricane Ida, which affected the GOM in late August 2021, causing monthly average crude oil production from the region to decline from 1.9 million b/d in July 2021 to 1.1 million b/d in September 2021. At the peak of the hurricane-related disruptions, 96% of GOM crude oil production was shut in, according to estimates by the U.S. Department of Interior's Bureau of Safety and Environmental Enforcement. We expect annual average GOM production of 1.8 million b/d in 2022 and remain near that level in 2023, still below the record 1.9 million b/d of 2019.

Alaska's crude oil production in the forecast stays near the 2021 level of 0.4 million b/d in both 2022 and 2023.

Hydrocarbon gas liquids supply. We forecast U.S. production of hydrocarbon gas liquids (HGLs) to increase by 0.5 million b/d in 2022 to an average of 5.9 million b/d and then increase to an average of 6.1 million b/d in 2023. HGL production will increase as a result of rising production of natural gas in 2022 and 2023, higher rates of natural gas processing plant utilization, and continuing efficiency improvements in the U.S. natural gas processing plant fleet. Ethane production will rise to meet growing demand from the domestic industry and global importers for ethane as a petrochemical feedstock. We expect U.S. ethane production to increase by 0.3 million b/d and by 0.2 million b/d in 2022 and 2023, respectively, reaching an average of 2.6 million b/d in 2023. We expect net ethane exports to grow by 40,000 b/d in 2022 and by 20,000 2023 as a result of rising global petrochemical demand and additional capacity to ship U.S. ethane overseas. We forecast propane production will rise by almost 0.1 million b/d in both 2022 and 2023.

Liquid biofuels. After COVID-19-related responses reduced demand for transportation fuels in 2020, U.S. biofuels consumption returned near to pre-pandemic levels in 2021. We forecast biofuels consumption will increase further in 2022, based on our expectation of increased demand for transportation fuels and the current targets in the Renewable Fuel Standard (RFS) program. Based on the current RFS targets, we forecast increases in biomass-based diesel production, consumption, and net imports.

U.S. biodiesel production increases in 2022 and 2023 in our forecast. U.S. biodiesel production decreased by 10% from 2020 to 2021, averaging an estimated 107,000 b/d in 2021. We expect biodiesel production will increase by 7% to average 114,000 b/d in 2022 and increase to 115,000 b/d in 2023. These production increases follow our expectation of growing U.S diesel consumption, along with higher RFS targets and the continuation of the $1/gal biodiesel and renewable diesel tax credit through December 2022.

Net U.S. imports of biomass-based diesel increased by 31% to 28,000 b/d in 2021, and we expect net imports to increase to an average of 46,000 b/d in both 2022 and 2023. 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 the federal RFS targets.

U.S. ethanol production increased in 2021 from 2020 but remained lower than 2019 levels. U.S. ethanol production in 2021 averaged 980,000 b/d, an increase of 8% from 2020. Ethanol production in our forecast rises to an average of 1.02 million b/d in both 2022 and 2023.

U.S. ethanol consumption averaged 910,000 b/d in 2021, an increase of 10% from 2020. We forecast ethanol consumption will average 930,000 b/d in 2022 and almost 950,000 b/d in 2023. The increase in ethanol consumption reflects our expectation of increasing gasoline demand. At the forecast levels for 2022 and 2023, the ethanol share of gasoline consumption would be near 2020 and 2021 levels of 10.3%.

Product prices. Reduced demand for liquid fuels in the United States during 2020 led to low prices for gasoline and diesel fuel during the same period. In 2021, increases in economic activity and personal mobility contributed to increasing prices for crude oil, gasoline, and diesel fuel compared with 2020. U.S. retail prices for regular-grade gasoline averaged $3.02/gal during 2021, and retail diesel prices averaged $3.29/gal, up 84 cents/gal and 73 cents/gal, respectively, from their 2020 averages.

Higher retail prices for gasoline and diesel in the United States reflect an increase in demand for petroleum fuels as well as increasing crude oil prices. After decreasing significantly in 2020, refinery margins (the difference between the wholesale price of gasoline and the price of Brent crude oil) reached their highest levels since 2014 for both gasoline and diesel in 2021. Refinery margins increased significantly beyond their recent five-year averages, driven primarily by rising fuel demand amid still restrained refinery production. Significant increases in renewable identification number (RIN) prices, which are embedded in wholesale product prices, also raised refinery margins.

Supply disruptions also contributed to increased refinery margins for those facilities that continued operations during several instances in 2021. In February, a severe cold weather system in Texas resulted in a reduction in refinery operations along the U.S. Gulf Coast. In May, a cyberattack on the Colonial Pipeline put upward pressure on retail fuel prices because of related logistical constraints. In August, hurricanes along the U.S. Gulf Coast (particularly in Louisiana) caused flooding and temporary refinery shutdowns, which also contributed to lower refinery production at that time.

Wholesale U.S. refinery gasoline margins started 2021 at a monthly average of 27 cents/gal in January, before increasing to 62 cents/gal in August. We estimate margins averaged 49 cents/gal in December, resulting in an average of 48 cents/gal for 2021, up from 31 cents/gal in

2020 and 32 cents/gal in 2019. As forecast refinery runs continue to increase and inventories grow, we estimate gasoline refinery margins will decrease over the forecast period, averaging 42 cents/gal in 2022 and 38 cents/gal in 2023.

Ongoing uncertainty and volatility related to the COVID-19 pandemic, the Omicron variant, and potential future variants all present additional downside risks for refinery margins and wholesale product prices. However, potential short-term disruptions related to inclement weather, like those that took place in February and August 2021, present upside risks for product prices throughout the forecast.

We expect U.S. regular retail gasoline prices will average $3.20/gal in 1Q22, 64 cents/gal higher than at the same time last year, but down 13 cents/gal compared with 4Q21. We expect the U.S. regular retail gasoline price will average $3.28/gal in January 2022 before decreasing through the year as crude oil prices and refinery margins fall, eventually averaging $2.77/gal in December 2022. We forecast the U.S. regular gasoline retail price, which averaged $3.02/gal in 2021, will average $3.06/gal in 2022 and $2.81/gal in 2023.

Regional annual average forecast prices for 2022 range from a low of $2.71/gal in the Gulf Coast region (PADD 3) to a high of $3.86/gal in the West Coast region (PADD 5). Reduced refinery capacity on the West Coast compared with 2019 pre-pandemic levels is likely to contribute to higher refinery margins, wholesale prices, and resale margins in that region in the future.

The retail price of diesel fuel in the United States averaged $3.29/gal in 2021, which was 73 cents/gal higher than in 2020. We forecast the diesel price will average $3.33/gal in 2022 and $3.27/gal in 2023. We expect that global economic activity returning to pre-pandemic levels will help drive diesel refinery margins higher than their multiyear lows in 2020 during the forecast period. Diesel refinery margins averaged 42 cents/gal in 2021, which was 4 cent/gal higher than the 2016–20 average and 12 cents/gal higher than levels seen in 2020. We forecast that diesel refinery margins will average 47 cents/gal in 2022 and 45 cents/gal in 2023.

Natural gas

Natural gas consumption. Consumption of natural gas in the United States averaged 83.0 billion cubic feet per day (Bcf/d) in 2021, almost unchanged from 2020. We expect U.S. natural gas consumption will remain at nearly the same level in both 2022 and 2023.

The largest natural gas-consuming sector in the United States is the electric power sector. We forecast that the electric power sector will consume an average 28.8 Bcf/d in 2022, which is 6% less than in 2021. This decline is a result of rising electricity-generating capacity from renewable energy. We expect that the consumption of natural gas by the electric power sector will decline by 0.5 Bcf/d (2%) in 2023.

Industrial sector consumption of natural gas in our forecast increases by 3% during 2022, averaging 23.2 Bcf/d, and grows to 23.5 Bcf/d in 2023, as demand for industrial goods and economic activity increases.

We expect combined U.S. residential and commercial natural gas consumption will average 22.6 Bcf/d in 2022, up 4% from 2021. Based on National Oceanic and Atmospheric Administration forecasts, this STEO assumes colder temperatures this year, with 6% more heating degree days (HDDs) across the United States in 2022 compared with 2021. We expect natural gas consumption in the U.S. residential and commercial sectors to increase by 1% to 22.8 Bcf/d in 2023, driven by the assumption of slightly colder weather than 2022.

Natural gas production. U.S. production of dry natural gas averaged an estimated 93.5 Bcf/d in 2021, up 2.0 Bcf/d (2%) from 2020. Natural gas production fell in 2020 as a result of low natural gas and oil prices that reduced drilling activity. Production grew in 2021 as drilling activity came back online, especially in the Permian Basin, where associated gas production in that region contributed to the overall growth in natural gas production. We forecast dry natural gas production will increase by 2.5 Bcf/d (3%) in 2022. Recent increases in oil and domestic natural gas prices contribute to an overall increase in drilling activity in 2022 that will lead to production growth from 2Q22 onward. Growth in dry natural gas production in 2022 is led by the Haynesville region, where production tends to be sensitive to change in U.S. benchmark Henry Hub natural gas prices, and by the Permian Basin, where production tends to be more sensitive to oil prices. In 2023, we expect dry natural gas production to increase by 1.5 Bcf/d (2%) to reach 97.6 Bcf/d.

Natural gas trade. We forecast natural gas exports will reach record highs in 2022 and continue to grow in 2023. Net natural gas exports averaged 10.7 Bcf/d in 2021 and we forecast that they will increase to 13.4 Bcf/d in 2022 and 14.3 Bcf/d in 2023. A combination of both rising liquefied natural gas (LNG) exports and increases in pipeline exports to Mexico will drive this increase.

The United States exported an estimated 11.2 Bcf/d of LNG in December 2021, an increase of 0.7 Bcf/d over the previous record set in November. LNG export growth in 2021 was driven by rising natural gas demand and high LNG prices in Europe and Asia, reductions in global supply because of several unplanned outages at LNG export facilities worldwide, and cold weather in key LNG consumption markets, particularly in Asia.

Rising demand for LNG imports in Europe and Asia and the completion of planned projects that will bring new U.S. LNG export capacity online in 2022 supports growth in LNG exports in the forecast. We forecast that U.S. LNG exports will average 11.5 Bcf/d in 2022, up from 9.8 Bcf/d in 2021. In 2023, we forecast that U.S. LNG exports will average 12.1 Bcf/d. The completion of Train 6 at Sabine Pass, the optimization of operations at Sabine Pass and Corpus Christi LNG terminals, and the completion of a new LNG export facility—Calcasieu Pass LNG—are all expected in 2022; these expansions will increase total U.S. LNG export capacity in 2022 to become the world's largest.

As of December 2021, existing U.S. LNG baseload liquefaction capacity was 10.1 Bcf/d, and peak capacity was 12.2 Bcf/d (including uprates to LNG production capacity at Sabine Pass and Corpus Christi). By the end of 2022, U.S. baseload capacity will increase to 11.4 Bcf/d, and peak capacity will increase to 13.8 Bcf/d, across seven LNG export facilities and 44 liquefaction trains, including 16 full-scale, 18 mid-scale, and 10 small-scale trains at Sabine Pass, Cove Point, Corpus Christi, Cameron, Elba Island, Freeport, and Calcasieu Pass.

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 and as more natural gas-fired power plants come online in Mexico. Gross U.S. pipeline exports to Mexico and Canada in the forecast average 8.9 Bcf/d in 2022, up 0.4 Bcf/d (5.0%) from 2021, and 9.2 Bcf/d in 2023.

U.S. natural gas pipeline imports, almost all of which come from Canada, increased by 0.7 Bcf/d in 2021. We forecast natural gas pipeline imports to decrease 0.7 Bcf/d in 2022 because the United States will import less natural gas in response to increases in domestic production. Pipeline imports in the forecast remain relatively unchanged in 2023.

Natural gas inventories. U.S. working natural gas inventories ended December at 3,221 Bcf, 4% less than one year ago, but 3% more than the five-year (2016–20) average. We forecast close-to-average storage withdrawals in 1Q22, resulting in inventories that total 1,822 Bcf at the end of March, which would be 8% more than the five-year (2017–21) average for that time of year. For the 2022 April–October storage injection season, injections in our forecast do not keep pace with the five-year average rate. The lower-than-average injections reflect demand growth in the industrial sector and rising demand for U.S. exports. We expect that inventories will reach 3,668 Bcf at the end of October 2022, which would be within 1% of the five-year average for the end of October and nearly identical to inventory at the end of October 2021.

Natural gas prices. Henry Hub spot prices averaged $3.91/MMBtu in 2021. Natural gas prices were volatile throughout 2021. Early in 2021, volatility resulted from near record-high spot prices during the extreme winter weather in February. During the rest of the year, Henry Hub prices rose from $2.62/MMBtu in March to $5.51/MMBtu in October, before falling back to $3.76/MMBtu in December, amid a warmer-than-normal start to the heating season across most of the country.

We forecast the Henry Hub spot price will average $3.79/MMBtu in 2022. In 1Q22, we forecast the average Henry Hub spot price of natural gas will be $3.82/MMBtu. We expect prices will stay near current levels as natural gas inventory levels remain near the five-year average levels. Prices average $3.78/MMBtu for the remaining three quarters of 2022. We expect the Henry Hub spot price of natural gas to average $3.63/MMBtu in 2023.

Although we expect natural prices to decline in 2022 and 2023 compared with 2021, prices in the forecast stay relatively high compared with recent years. This dynamic is partly the result of reductions in coal-fired electricity-generating capacity and ongoing constraints in the coal market, which make increases in coal generation (and associated decreases in natural gas generation) less sensitive to rising natural gas prices than they have been in recent years. In addition, natural gas price volatility could result from weather-related increases or decreases in demand and uncertainties about the way in which rising levels of natural gas exports could affect the U.S. market.

Coal

Coal production. U.S. coal production totaled 579 million short tons (MMst) in 2021, up 44 MMst (8%) from 2020. The 2021 increase primarily reflected more consumption of coal in the electric power sector amid an increase in natural gas spot prices, which made coal more economically competitive relative to natural gas for electricity generation dispatch.

In 2022, we expect U.S. coal production to increase by 33 MMst (6%) to 612 MMst. Our forecast coal production increases by 27 MMst (8%) in the Western Region, 3 MMst (3%) in the Interior Region, and 2 MMst (2%) in Appalachia.

In 2023, we expect coal production to increase by 8 MMst (1%) to 619 MMst. Coal production rises by 8 MMst (2%) in the Western Region and by 3 MMst (3%) in the Interior Region. Forecast production declines by 2 MMst (1%) in Appalachia.

Despite less demand from the electric power sector, we expect coal production will grow in 2022 and 2023. The expected increased production reflects demand to replenish depleted coal stocks. Electric power sector inventories saw significant draws in 2021, and we expect stocks to increase by the end of 2023. In our forecast, inventories reach 85 MMst at the end of 2022 and 91 MMst at the end of 2023. In addition, we expect rising demand for coking coal—used for steelmaking—both domestically and for export.

Much of the decrease in coal mine capacity that occurred in 2020 appears to be permanent. Coal producers have experienced labor and capital shortages, which we expect will continue to limit supply in the forecast. Despite these limitations, we forecast more coal production in 2022 and 2023 than in 2021 as utilization at existing mines rises.

Coal consumption. In this forecast, we expect the retirement of approximately 19 gigawatts (GW) of coal-fired power plant capacity through 2023, a decline of 9%. As a result, we forecast electric power sector demand for coal will decrease by 14 MMst in 2022 and by 2 MMst in 2023. Rising natural gas prices led to increased demand for coal-fired power generation in 2H21. We expect that natural gas prices will remain relatively high compared with past years, keeping coal consumption in the electric power sector above 2020 levels but below 2021 levels. The expected decline in electric power sector consumption leads to a decline in overall coal consumption in our forecast. We forecast total U.S. coal consumption for all sectors to decrease by 11 MMst (2%) in 2022 to 534 MMst and by a further 3 MMst (<1%) in 2023 to 532 MMst.

Coal is an essential component of the steel-making process. Demand for coal to make steel increases by 16% in 2022 and by 3% in 2023, particularly for infrastructure-related materials. As a result, we expect demand for coking coal to rise by more than 3 MMst from 2021 to 2023, offsetting some of the decline in electric power sector coal consumption.

Coal trade. Annual U.S. coal exports increased by an estimated 26% in 2021 to reach 87 MMst. Metallurgical coal exports were 47 MMst in 2021, 12% more than the previous year, and steam coal exports were 40 MMst, 47% more than in 2020.

A majority of the 25 leading U.S. coal export destinations increased their imports of U.S. coal in 2021 through October, which is our most recent data. The ongoing trade dispute between Australia and China has continued to increase opportunities for swing coal suppliers, such as the United States, to gain market share and increase overall exports of coal. Between January and October 2021, China imported almost 11 MMst of U.S. coal, more than in the previous four years combined. Metallurgical coal accounts for a large share of China's imports, representing about 90% of China's imports of U.S. coal in 2021.

We expect U.S. coal exports will rise by 1 MMst in 2022 and by 3 MMst in 2023. The increase reflects our assumption that the seaborne coal market in 2022 and 2023 will experience slightly higher demand for U.S. coal. Metallurgical coal will drive the increase in coal exports. We assume global steel production, which increased moderately 2021, will grow further during the forecast period and increase U.S. metallurgical coal exports to 50 MMst in 2022 and 55 MMst in 2023. Forecast U.S. steam coal exports total 38 MMst in 2022 and 37 MMst in 2023, largely unchanged from 2021.

Coal prices. The delivered coal price to U.S. electricity generators averaged an estimated $1.98/MMBtu in 2021. Coal prices increased throughout the year as a result of coal market constraints, averaging $1.92/MMBtu in 1H21 and $2.03/MMBtu in 2H21. We forecast that coal prices will fall to $1.94/MMBtu in 2022 and to $1.81/MMBtu in 2023.

Electricity

Electricity consumption. We forecast that consumption of electricity in the United States, including retail sales and direct use of electricity, will increase by 0.6% in 2022 and 1.4% in 2023. Preliminary data indicate that electricity consumption grew by 2.0% in 2021, and year-over-year growth was fastest in the first half of last year when the economy began to return to pre-pandemic patterns.

Year-to-year changes in residential electricity consumption are most related to changes in temperature, often measured using heating degree days (HDDs) and cooling degree days (CDDs). In 2021, retail sales of electricity to the residential sector grew by 1.2%. Most of this growth last year occurred in 1Q21 when residential electricity consumption grew by 11% from the same quarter in 2020 in response to colder weather. Part of this increased residential consumption during the first quarter may also have reflected changing patterns of electricity use as more people work from home compared with the months in 1Q20 before the pandemic. Residential electricity sales during the last three quarters of 2021 averaged about 1.8% less than the same period in 2020.

In 2022, our forecast include 6.5% more HDDs for the United States than last year, with most of that increase occurring in 4Q22 compared to a mild start to this winter. The increase is less in the southern area of the country where heating with electricity is more prevalent. Cooler temperatures during the summer months of 2022 throughout most of the country (6.4% fewer CDDs) than in 2021 would lead to less use of air-conditioning. The effect of cooler forecast summer temperatures offsets the effect of a colder forecasted 4Q22, leading to an overall 2.2% decline in annual residential retail sales of electricity in our forecast during 2022. We expect residential electricity sales to grow by 2.1% in 2023.

The colder winter weather early in 2021 led to more electricity consumption in the commercial sector, but economic activity and growth in private-sector jobs were still limited at that time. The number of people employed during 1Q21 was 5.6% lower than during the same period in 2020; however, employment during the last three quarters of 2021 returned to an average of 5.8% year-over-year growth. As a result, retail sales of electricity to the commercial sector grew by an estimated 2.7% in 2021. For 2022, we forecast commercial sector electricity use to grow by 1.7%, reflecting the effect of continued economic growth offset somewhat by expected milder summer temperatures this year. We expect commercial sector electricity consumption to grow by 0.4% in 2023.

The U.S. industrial production index for electricity-intensive industries increased by 5.9% in 2021 after declining by 6.4% in 2020. This increase helped to raise U.S. retail electricity sales to the industrial sector by an estimated 2.9% last year. We expect the electricity-weighted industrial production index to grow by 4.1% and 2.5% in 2022 and 2023, respectively, leading to forecast growth in U.S. industrial sector electricity use of 2.8% in 2022 and 1.7% in 2023.

Electricity generation. Electricity generation by the U.S. electric power sector grew by an estimated 2.9% in 2021 after having fallen 2.9% in 2020, which was the largest decline in generation since 2009. We expect the U.S. electric power sector will generate about the same amount of electricity in 2022 as in 2021. Total electric power sector generation in the forecast grows by 1.3% in 2023.

Up until 2021, U.S. coal-fired electricity generation had fallen every year since 2014. However, we estimate that coal generation in 2021 grew by 17%. Some of this increase was a result of the overall increase in U.S. electricity demand last year after the pandemic-related decline in 2020, but most of the increase in coal generation last year was in response to natural gas prices that have been much higher than in past years. We estimate that the cost of natural gas delivered to

U.S. electric generators in 2021 averaged $4.88/MMBtu, twice the average cost in 2020. Higher fuel costs also contributed to an estimated 3% decline in U.S. natural gas generation in 2021.

We expect the delivered cost of natural gas for electricity generation will fall to an average of $4.10/MMBtu in 2022. However, that price remains higher than the average price in recent years. Despite a forecast of lower fuel costs, U.S. natural gas generation is likely to decline in 2022 as rapidly growing renewable energy sources produce more generation. We forecast the share of total U.S. generation from natural gas will average 35% in 2022, down from 37% in 2021. The decline in natural gas generation is especially pronounced in Texas, where a large amount of solar and wind capacity is scheduled to come online.

Lower natural gas prices also tend to discourage generation from coal, and we forecast the U.S. coal generation share to average 22% in 2022, which is slightly below last year. This forecast decline in coal generation is largest in the Northeast and western areas of the country.

We expect the share of generation from renewable sources will increase from 20% in 2021 to 23% in 2022 and to 24% in 2023. We expect most of the increase in renewables generation will come from new solar and wind capacity expansions in the electric power sector. We forecast that hydropower will fuel about 7% of generation in both 2022 and 2023. In 2021, the drought affecting the West restrained electricity generation by hydropower. U.S. hydropower generation contributed about 6% of the total in 2021, which is the lowest share since 2015. In the forecast, the share of total generation for renewables other than hydropower, which was 13% in 2021, rises to 16% in 2022 and to 17% in 2023.

In April 2021, New York's Indian Point nuclear power plant retired. This retirement contributed to the reduction in the nuclear share of U.S. total generation from 21% in 2020 to 20% last year. The Palisades nuclear power plant in Michigan is scheduled to retire in the summer of 2022. However, we expect the amount of U.S. nuclear generation will remain relatively steady in the forecast as two reactors at the Vogtle plant in Georgia are scheduled to come online in 2022 and 2023.

Over the next two years, our forecast of the U.S. electricity generating capacity from renewable sources continues to grow. Growth in wind capacity begins to moderate, but growth in solar capacity remains strong. Since 2019, more non-hydropower renewables capacity has been added to the U.S. generation fleet than natural gas capacity. This trend continues during the forecast period; operators report 29 gigawatts (GW) of planned utility-scale solar and wind capacity additions in 2022 and 28 GW in 2023. Preliminary data indicate that operators plan to add 5 GW of battery storage capacity in 2022 and 5 GW in 2023, annual increases of 84% in 2022 and 47% in 2023. Most planned battery storage additions will be paired with solar capacity.

We forecast that in 2022 additions of utility-scale solar capacity in GW will exceed wind additions for the first time. We expect that 21 GW of solar photovoltaic (PV) capacity will be added by the electric power sector in 2022. We forecast an additional 25 GW for 2023. We forecast small-scale solar PV capacity will increase by about 5 GW in 2022 and by a similar amount in 2023. Residential PV accounts for 70% of this additional small-scale solar PV capacity for 2022 and 64% for 2023.

Preliminary data indicate that solar PV capacity additions continued in 2021 despite tariff and supply chain issues. Forecast solar capacity growth reflects various state and federal policies to support renewable energy. We expect growth to continue over the forecast period, supported by the solar investment tax credit (ITC) under the Consolidated Appropriations Act. Under the ITC, projects that start in 2022 are eligible for a 26% tax credit. The credit drops to 22% for projects that start in 2023. States such as Texas and Florida are set to add significant solar PV in the next two years.

Wind capacity in the electric power sector grows by 7 GW in 2022 in our forecast and by an additional 4 GW in 2023. This growth in forecast wind capacity for 2022 and 2023 marks a decline from the record of 17 GW added in 2021, which surpassed the previous record of 14 GW set in 2020. This slowing growth in wind can be partly attributed to the phasedown of the production tax credit (PTC) and supply chain issues. The PTC, which at the end of 2020 was extended through the 2021 calendar year, provides a 2.5 cents per kilowatthour (kWh) benefit for facilities entering service or securing 5% safe harboring (spending at least 5% of total estimated project cost). Producers of safe harbored projects are able to claim the PTC four years after they qualify.

Because wind capacity is often added at the end of the calendar year, increases in generation frequently lag behind increases in capacity for the year they occur in, and they are reflected in the generation for the next year.

Electricity prices. Wholesale electricity prices throughout the country trended higher in 2021, reflecting the increasing cost of natural gas for power generation. Last year, average annual wholesale prices ranged from $38 per megawatthour (MWh) in Florida to $190/MWh in Texas, though the Texas average would be $43/MWh excluding February when severely cold temperatures caused hourly prices to surge in excess of $6,000/MWh. We expect 2022 average wholesale electricity prices at trading hubs in the eastern part of the country will generally be higher than in 2021, with the exception of PJM, where we expect prices will be mostly unchanged. In the central and western areas, we expect wholesale prices will be lower at most hubs in 2021, with the exception of California where we expect slightly higher prices.

We forecast the U.S. retail electricity price for the residential sector will average 14.2 cents/kWh in 2022, which is 3.8% higher than the average retail price in 2021. Forecast residential prices remain relatively constant in 2023.

U.S. economic assumptions and energy-related carbon dioxide emissions

U.S. economy. We incorporate IHS Markit's macroeconomic forecast model for the United States with our own energy price forecasts to create STEO forecasts.

Based on this model, we estimate that U.S. real GDP grew by 5.7% in 2021. In 2022, U.S. real GDP will grow by 4.3% and by 2.8% in 2023. In comparison, real U.S. GDP fell by 3.4% in 2020. Total industrial production mirrors this pattern. Following a decline of 7.2% in 2020, we estimate it grew by 5.6% in 2021 and will increase by 4.6% in 2022 and 2.8% in 2023. The unemployment rate fell to an estimated 4.2% in December 2021 and our forecast assumes it will fall to an average 3.6% in 2022 and to 3.4% in 2023. This follows an unemployment rate of 8.1% in 2020. Nonfarm payroll employment increased by a total of 3.9 million persons in 2021 (2.7%), and our forecast assumes it will rise by 5.6 million in 2022 (3.8%) and 2.4 million in 2023 (1.6%). Price levels were notably elevated in 2021 when the Consumer Price Index (CPI) rose 4.6%. However, CPI growth in our forecast slows to 3.4% in 2022 and to 2.1% in 2023.

Energy-related carbon dioxide emissions. Energy-related carbon dioxide (CO_2) emissions rose by 6.2% in 2021 relative to 2020, and we estimate that they will rise by 1.8% in 2022 and by 0.5% in 2023. Energy-related CO_2 emissions are sensitive to changes in weather, economic growth, energy prices, and fuel mix. Forecast petroleum-related CO_2 emissions increase by 4.8% in 2022 and by 1.1% in 2023 as economic and mobility activity return to pre-pandemic patterns. We forecast a decrease in coal CO_2 emissions and a modest increase in natural gas CO_2 emissions over the next two years. We forecast CO_2 emissions from coal to fall by 3.0% in 2022 and by 0.3% in 2023 as coal-fired electricity generation is displaced, primarily by renewable sources. We expect CO_2 emissions from natural gas to rise by 0.7% in 2022 and by 0.1% in 2023 as demand for space heating rises.

Notable forecast changes

- For more information, see the detailed table of forecast changes.

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

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

	2021				2022				2023				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2021	2022	2023
Production (million barrels per day) (a)															
OECD	30.08	30.75	31.12	32.13	32.17	32.34	32.49	33.02	33.35	33.51	33.53	33.84	31.02	32.51	33.56
U.S. (50 States)	17.62	19.05	18.93	19.66	19.57	19.86	20.16	20.42	20.55	20.76	20.89	21.04	18.82	20.01	20.81
Canada	5.62	5.37	5.55	5.78	5.81	5.79	5.81	5.84	5.86	5.83	5.85	5.88	5.58	5.81	5.85
Mexico	1.93	1.95	1.90	1.93	1.96	1.93	1.90	1.86	1.90	1.86	1.83	1.79	1.92	1.91	1.85
Other OECD	4.91	4.38	4.74	4.76	4.82	4.76	4.62	4.91	5.04	5.06	4.96	5.13	4.70	4.78	5.05
Non-OECD	62.59	63.86	65.49	66.03	67.26	68.44	69.37	69.08	68.79	69.32	69.68	69.33	64.51	68.55	69.28
OPEC	30.36	30.76	32.19	33.05	33.97	34.15	34.49	34.52	34.54	34.40	34.39	34.38	31.60	34.28	34.42
Crude Oil Portion	25.08	25.49	26.84	27.63	28.39	28.69	28.98	28.98	28.98	28.96	28.90	28.85	26.27	28.76	28.92
Other Liquids (b)	5.28	5.27	5.35	5.42	5.58	5.46	5.50	5.54	5.56	5.44	5.49	5.52	5.33	5.52	5.50
Eurasia	13.38	13.61	13.58	14.23	14.36	14.54	14.74	14.90	14.97	14.90	14.94	15.05	13.70	14.64	14.96
China	4.99	5.03	5.01	4.97	4.99	5.02	5.02	5.06	5.04	5.07	5.06	5.10	5.00	5.02	5.07
Other Non-OECD	13.86	14.46	14.71	13.77	13.95	14.73	15.13	14.60	14.24	14.96	15.30	14.80	14.20	14.61	14.83
Total World Production	92.66	94.61	96.62	98.15	99.43	100.78	101.87	102.10	102.14	102.83	103.22	103.17	95.53	101.05	102.84
Non-OPEC Production	62.30	63.85	64.43	65.10	65.47	66.64	67.38	67.57	67.60	68.44	68.83	68.79	63.93	66.77	68.42
Consumption (million barrels per day) (c)															
OECD	42.25	43.94	45.61	45.66	45.46	45.23	46.10	46.22	45.76	45.59	46.39	46.58	44.38	45.76	46.08
U.S. (50 States)	18.45	20.03	20.21	20.30	20.01	20.58	20.88	20.89	20.46	20.97	21.14	21.11	19.75	20.59	20.92
U.S. Territories	0.15	0.14	0.14	0.14	0.16	0.14	0.15	0.15	0.14	0.13	0.13	0.14	0.14	0.15	0.14
Canada	2.12	2.16	2.38	2.40	2.33	2.28	2.40	2.38	2.38	2.33	2.43	2.41	2.27	2.35	2.39
Europe	11.91	12.61	13.83	13.45	13.14	13.23	13.52	13.17	13.04	13.19	13.59	13.36	12.96	13.26	13.30
Japan	3.73	3.08	3.18	3.33	3.69	3.01	3.13	3.45	3.60	2.99	3.09	3.41	3.33	3.32	3.27
Other OECD	5.89	5.91	5.86	6.05	6.14	5.99	6.03	6.18	6.14	5.98	6.00	6.15	5.93	6.09	6.07
Non-OECD	51.77	52.19	52.50	53.61	53.99	54.91	55.02	55.11	56.01	56.74	56.22	55.79	52.52	54.76	56.19
Eurasia	4.65	4.72	5.08	4.93	4.83	4.88	5.25	5.12	4.82	4.98	5.32	5.23	4.84	5.02	5.09
Europe	0.74	0.74	0.74	0.76	0.76	0.77	0.77	0.78	0.76	0.78	0.78	0.79	0.75	0.77	0.78
China	15.26	15.46	14.98	15.33	15.80	15.95	15.67	15.93	16.68	16.58	15.94	15.86	15.26	15.84	16.26
Other Asia	13.60	13.15	13.01	13.92	14.23	14.32	13.91	14.29	14.99	14.96	14.36	14.67	13.42	14.19	14.74
Other Non-OECD	17.53	18.11	18.70	18.67	18.37	18.99	19.42	18.98	18.77	19.44	19.81	19.25	18.26	18.94	19.32
Total World Consumption	94.03	96.13	98.10	99.27	99.45	100.15	101.12	101.33	101.77	102.32	102.60	102.37	96.90	100.52	102.27
Total Crude Oil and Other Liquids Inventory Net Withdrawals (million barrels per day)															
U.S. (50 States)	0.47	0.51	0.37	0.73	0.03	-0.78	-0.11	0.37	0.09	-0.53	-0.24	0.59	0.52	-0.12	-0.02
Other OECD	0.81	0.13	0.98	0.12	0.00	0.04	-0.20	-0.36	-0.14	0.01	-0.12	-0.44	0.51	-0.13	-0.17
Other Stock Draws and Balance	0.09	0.87	0.14	0.26	-0.01	0.10	-0.44	-0.78	-0.32	0.01	-0.26	-0.96	0.34	-0.29	-0.38
Total Stock Draw	1.36	1.52	1.49	1.11	0.02	-0.63	-0.75	-0.77	-0.37	-0.51	-0.61	-0.80	1.37	-0.54	-0.57
End-of-period Commercial Crude Oil and Other Liquids Inventories (million barrels)															
U.S. Commercial Inventory	1,302	1,271	1,241	1,198	1,214	1,281	1,291	1,265	1,265	1,321	1,340	1,296	1,198	1,265	1,296
OECD Commercial Inventory	2,911	2,868	2,748	2,694	2,710	2,773	2,802	2,809	2,821	2,876	2,907	2,903	2,694	2,809	2,903

(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 January 6, 2022.

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

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

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

Forecasts: EIA Short-Term Integrated Forecasting System.

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

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

	2021				2022				2023				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2021	2022	2023
Supply (million barrels per day)															
Crude Oil Supply															
Domestic Production (a)	10.69	11.28	11.12	11.54	11.58	11.70	11.88	12.05	12.26	12.33	12.46	12.58	11.16	11.80	12.41
Alaska	0.46	0.44	0.41	0.43	0.42	0.35	0.38	0.40	0.41	0.35	0.39	0.41	0.43	0.39	0.39
Federal Gulf of Mexico (b)	1.80	1.79	1.49	1.81	1.80	1.78	1.78	1.78	1.89	1.88	1.81	1.80	1.72	1.79	1.84
Lower 48 States (excl GOM)	8.44	9.05	9.23	9.30	9.36	9.56	9.72	9.87	9.96	10.10	10.26	10.38	9.01	9.63	10.18
Crude Oil Net Imports (c)	2.87	2.96	3.60	3.33	3.92	4.62	4.64	3.83	3.08	4.35	4.43	3.12	3.19	4.25	3.75
SPR Net Withdrawals	0.00	0.18	0.04	0.26	0.21	-0.04	0.00	0.08	0.09	0.09	-0.02	0.11	0.12	0.06	0.07
Commercial Inventory Net Withdrawals	-0.18	0.59	0.30	0.03	-0.37	-0.07	0.24	-0.04	-0.35	-0.09	0.07	0.07	0.19	-0.06	-0.07
Crude Oil Adjustment (d)	0.42	0.63	0.55	0.30	0.22	0.22	0.23	0.16	0.22	0.22	0.23	0.16	0.48	0.21	0.21
Total Crude Oil Input to Refineries	13.81	15.65	15.60	15.47	15.55	16.43	16.98	16.08	15.31	16.90	17.16	16.05	15.14	16.26	16.36
Other Supply															
Refinery Processing Gain	0.84	0.97	0.97	1.05	1.08	1.05	1.08	1.10	1.04	1.02	1.03	1.02	0.96	1.08	1.03
Natural Gas Plant Liquids Production	4.86	5.46	5.52	5.68	5.71	5.85	5.93	5.99	6.03	6.14	6.14	6.17	5.38	5.87	6.12
Renewables and Oxygenate Production (e)	1.03	1.13	1.10	1.17	1.07	1.12	1.14	1.14	1.09	1.12	1.12	1.13	1.11	1.12	1.12
Fuel Ethanol Production	0.90	0.99	0.96	1.05	0.99	1.02	1.03	1.04	1.00	1.03	1.02	1.03	0.98	1.02	1.02
Petroleum Products Adjustment (f)	0.19	0.22	0.22	0.22	0.13	0.14	0.14	0.14	0.13	0.14	0.14	0.14	0.21	0.14	0.14
Product Net Imports (c)	-2.94	-3.13	-3.24	-3.72	-3.74	-3.34	-4.04	-3.89	-3.48	-3.83	-4.17	-3.80	-3.26	-3.75	-3.82
Hydrocarbon Gas Liquids	-2.02	-2.23	-2.16	-2.19	-2.28	-2.30	-2.32	-2.25	-2.43	-2.47	-2.54	-2.41	-2.15	-2.29	-2.46
Unfinished Oils	0.14	0.25	0.22	0.20	0.20	0.25	0.30	0.20	0.19	0.22	0.29	0.21	0.20	0.24	0.23
Other HC/Oxygenates	-0.08	-0.04	-0.03	-0.11	-0.05	-0.04	-0.03	-0.03	-0.04	-0.03	-0.01	-0.02	-0.06	-0.04	-0.03
Motor Gasoline Blend Comp.	0.55	0.79	0.66	0.39	0.53	0.72	0.40	0.21	0.38	0.60	0.38	0.41	0.60	0.46	0.44
Finished Motor Gasoline	-0.66	-0.66	-0.68	-0.81	-0.91	-0.48	-0.54	-0.58	-0.53	-0.49	-0.50	-0.71	-0.70	-0.63	-0.56
Jet Fuel	0.03	0.09	0.09	0.00	0.05	0.03	0.00	0.06	0.00	0.03	0.05	0.11	0.05	0.04	0.05
Distillate Fuel Oil	-0.49	-0.90	-0.94	-0.86	-0.75	-1.05	-1.23	-0.97	-0.65	-1.12	-1.23	-0.93	-0.80	-1.00	-0.98
Residual Fuel Oil	0.08	0.05	0.08	0.14	0.02	0.07	0.02	0.09	0.00	0.02	-0.02	0.09	0.09	0.05	0.02
Other Oils (g)	-0.49	-0.49	-0.50	-0.49	-0.54	-0.56	-0.63	-0.60	-0.40	-0.59	-0.59	-0.53	-0.49	-0.58	-0.53
Product Inventory Net Withdrawals	0.65	-0.26	0.03	0.44	0.19	-0.66	-0.35	0.32	0.35	-0.53	-0.28	0.41	0.21	-0.13	-0.01
Total Supply	18.43	20.03	20.21	20.30	20.01	20.58	20.88	20.89	20.46	20.97	21.14	21.11	19.75	20.59	20.92
Consumption (million barrels per day)															
Hydrocarbon Gas Liquids	3.40	3.33	3.31	3.52	3.82	3.35	3.37	3.86	3.97	3.51	3.45	3.91	3.39	3.60	3.71
Unfinished Oils	0.05	0.03	-0.05	0.05	0.00	0.00	0.00	0.00	0.00	-0.03	-0.01	0.01	0.02	0.00	-0.01
Motor Gasoline	8.00	9.07	9.13	8.94	8.49	9.30	9.39	9.04	8.67	9.38	9.44	9.09	8.79	9.06	9.15
Fuel Ethanol blended into Motor Gasoline	0.82	0.93	0.94	0.95	0.87	0.96	0.96	0.95	0.89	0.97	0.97	0.95	0.91	0.93	0.95
Jet Fuel	1.13	1.34	1.52	1.49	1.47	1.59	1.67	1.69	1.53	1.68	1.73	1.72	1.37	1.61	1.67
Distillate Fuel Oil	3.97	3.93	3.87	4.01	4.15	4.03	3.98	4.12	4.21	4.09	4.05	4.17	3.95	4.07	4.13
Residual Fuel Oil	0.26	0.25	0.33	0.40	0.28	0.27	0.31	0.30	0.26	0.28	0.29	0.31	0.31	0.29	0.28
Other Oils (g)	1.63	2.08	2.10	1.89	1.79	2.04	2.16	1.88	1.82	2.07	2.19	1.92	1.93	1.97	2.00
Total Consumption	18.45	20.03	20.21	20.30	20.01	20.58	20.88	20.89	20.46	20.97	21.14	21.11	19.75	20.59	20.92
Total Petroleum and Other Liquids Net Imports	-0.07	-0.16	0.35	-0.39	0.18	1.28	0.60	-0.06	-0.40	0.52	0.26	-0.68	-0.07	0.50	-0.07
End-of-period Inventories (million barrels)															
Commercial Inventory															
Crude Oil (excluding SPR)	501.9	448.0	420.4	417.6	451.0	457.5	435.5	438.9	470.3	478.1	471.7	465.1	417.6	438.9	465.1
Hydrocarbon Gas Liquids	168.6	195.8	225.6	196.1	154.3	205.6	251.4	211.3	171.4	218.7	255.5	211.5	196.1	211.3	211.5
Unfinished Oils	93.3	93.0	90.2	82.8	93.3	91.1	90.0	83.2	93.3	91.0	89.9	82.8	82.8	83.2	82.8
Other HC/Oxygenates	29.1	27.5	25.4	26.5	28.5	27.3	27.0	27.3	29.3	28.1	27.8	28.1	26.5	27.3	28.1
Total Motor Gasoline	237.6	237.2	227.0	233.2	241.4	246.3	233.8	249.0	247.7	247.1	238.6	250.5	233.2	249.0	250.5
Finished Motor Gasoline	20.3	18.6	18.5	17.1	18.1	21.6	23.5	26.8	23.4	24.4	25.4	27.9	17.1	26.8	27.9
Motor Gasoline Blend Comp.	217.4	218.6	208.5	216.1	223.3	224.8	210.4	222.1	224.3	222.7	213.2	222.6	216.1	222.1	222.6
Jet Fuel	39.0	44.7	42.0	35.0	35.6	37.3	40.4	37.8	37.4	38.5	41.2	38.1	35.0	37.8	38.1
Distillate Fuel Oil	145.5	140.1	131.7	127.1	118.5	124.8	132.9	134.6	123.6	128.6	135.5	137.3	127.1	134.6	137.3
Residual Fuel Oil	30.9	31.1	28.0	25.9	28.4	30.4	29.4	30.8	30.4	31.2	29.9	31.2	25.9	30.8	31.2
Other Oils (g)	55.8	54.1	50.5	53.8	62.7	60.4	51.0	52.4	61.5	59.4	50.1	51.4	53.8	52.4	51.4
Total Commercial Inventory	1301.7	1271.5	1240.7	1197.9	1213.8	1280.8	1291.3	1265.1	1264.9	1320.7	1340.1	1295.9	1197.9	1265.1	1295.9
Crude Oil in SPR	637.8	621.3	617.8	593.6	574.9	578.5	578.5	570.7	562.9	555.1	557.3	546.8	593.6	570.7	546.8

(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 January 6, 2022.

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

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

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

Forecasts: EIA Short-Term Integrated Forecasting System.

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

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

	2021				2022				2023				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2021	2022	2023
Supply (billion cubic feet per day)															
Total Marketed Production	**97.65**	**101.12**	**101.92**	**104.64**	*104.21*	*103.79*	*104.23*	*105.03*	*105.19*	*105.63*	*106.45*	*107.05*	**101.35**	*104.32*	*106.09*
Alaska	**1.02**	**0.95**	**0.90**	**0.94**	*0.90*	*0.75*	*0.70*	*0.85*	*0.90*	*0.75*	*0.71*	*0.86*	**0.95**	*0.80*	*0.80*
Federal GOM (a)	**2.26**	**2.25**	**1.82**	**2.21**	*2.31*	*2.25*	*2.14*	*2.11*	*2.16*	*2.11*	*1.99*	*1.95*	**2.14**	*2.20*	*2.05*
Lower 48 States (excl GOM)	**94.37**	**97.92**	**99.20**	**101.49**	*101.00*	*100.79*	*101.39*	*102.07*	*102.13*	*102.78*	*103.75*	*104.25*	**98.27**	*101.31*	*103.23*
Total Dry Gas Production	**90.59**	**93.15**	**93.89**	**96.33**	*95.94*	*95.55*	*95.96*	*96.69*	*96.71*	*97.13*	*97.89*	*98.45*	**93.51**	*96.04*	*97.55*
LNG Gross Imports	**0.15**	**0.02**	**0.03**	**0.17**	*0.32*	*0.18*	*0.18*	*0.20*	*0.32*	*0.18*	*0.18*	*0.20*	**0.09**	*0.22*	*0.22*
LNG Gross Exports	**9.27**	**9.81**	**9.60**	**10.42**	*11.18*	*11.09*	*11.58*	*12.29*	*12.73*	*11.86*	*11.73*	*12.23*	**9.78**	*11.54*	*12.13*
Pipeline Gross Imports	**8.68**	**6.81**	**7.24**	**7.33**	*7.77*	*6.43*	*6.39*	*6.72*	*7.76*	*6.46*	*6.33*	*6.51*	**7.51**	*6.82*	*6.76*
Pipeline Gross Exports	**8.31**	**8.67**	**8.50**	**8.44**	*8.81*	*8.39*	*9.24*	*9.20*	*9.12*	*9.02*	*9.33*	*9.24*	**8.48**	*8.91*	*9.18*
Supplemental Gaseous Fuels	**0.18**	**0.15**	**0.15**	**0.17**	*0.17*	*0.17*	*0.17*	*0.17*	*0.17*	*0.17*	*0.17*	*0.17*	**0.16**	*0.17*	*0.17*
Net Inventory Withdrawals	**17.19**	**-9.12**	**-7.87**	**0.89**	*15.55*	*-9.96*	*-7.33*	*5.06*	*15.22*	*-11.39*	*-9.21*	*2.94*	**0.21**	*0.78*	*-0.67*
Total Supply	**99.19**	**72.52**	**75.34**	**86.03**	*99.75*	*72.88*	*74.55*	*87.35*	*98.33*	*71.66*	*74.30*	*86.80*	**83.21**	*83.57*	*82.72*
Balancing Item (b)	**0.20**	**-0.60**	**-0.26**	**-0.35**	*-0.70*	*-1.97*	*-0.11*	*-0.44*	*-0.08*	*0.04*	*0.44*	*0.09*	**-0.25**	*-0.80*	*0.12*
Total Primary Supply	**99.40**	**71.92**	**75.08**	**85.68**	*99.05*	*70.91*	*74.44*	*86.91*	*98.25*	*71.70*	*74.73*	*86.88*	**82.96**	*82.77*	*82.84*
Consumption (billion cubic feet per day)															
Residential	**25.67**	**7.49**	**3.62**	**14.79**	*24.81*	*7.81*	*3.78*	*17.13*	*25.08*	*7.91*	*3.87*	*17.17*	**12.84**	*13.34*	*13.46*
Commercial	**14.87**	**6.23**	**4.69**	**9.94**	*14.94*	*6.42*	*4.83*	*10.90*	*15.01*	*6.47*	*4.85*	*10.94*	**8.91**	*9.25*	*9.29*
Industrial	**23.81**	**21.46**	**21.13**	**23.70**	*24.48*	*21.93*	*21.88*	*24.60*	*24.68*	*22.16*	*22.09*	*25.05*	**22.52**	*23.22*	*23.49*
Electric Power (c)	**26.75**	**29.17**	**37.93**	**29.03**	*26.13*	*27.07*	*36.11*	*25.96*	*24.77*	*27.35*	*35.97*	*25.32*	**30.75**	*28.84*	*28.38*
Lease and Plant Fuel	**4.87**	**5.04**	**5.08**	**5.22**	*5.20*	*5.17*	*5.20*	*5.24*	*5.24*	*5.27*	*5.31*	*5.34*	**5.05**	*5.20*	*5.29*
Pipeline and Distribution Use	**3.29**	**2.38**	**2.48**	**2.86**	*3.33*	*2.35*	*2.47*	*2.91*	*3.31*	*2.38*	*2.48*	*2.91*	**2.75**	*2.76*	*2.77*
Vehicle Use	**0.14**	**0.15**	**0.15**	**0.15**	*0.16*	*0.16*	*0.16*	*0.16*	*0.16*	*0.16*	*0.16*	*0.16*	**0.15**	*0.16*	*0.16*
Total Consumption	**99.40**	**71.92**	**75.08**	**85.68**	*99.05*	*70.91*	*74.44*	*86.91*	*98.25*	*71.70*	*74.73*	*86.88*	**82.96**	*82.77*	*82.84*
End-of-period Inventories (billion cubic feet)															
Working Gas Inventory	**1,801**	**2,583**	**3,305**	**3,221**	*1,822*	*2,729*	*3,403*	*2,938*	*1,568*	*2,604*	*3,452*	*3,182*	**3,221**	*2,938*	*3,182*
East Region (d)	**313**	**515**	**804**	**767**	*307*	*555*	*804*	*609*	*237*	*558*	*854*	*755*	**767**	*609*	*755*
Midwest Region (d)	**395**	**630**	**966**	**893**	*376*	*602*	*932*	*813*	*340*	*609*	*955*	*845*	**893**	*813*	*845*
South Central Region (d)	**760**	**991**	**1,051**	**1,143**	*870*	*1,122*	*1,157*	*1,059*	*698*	*995*	*1,103*	*1,094*	**1,143**	*1,059*	*1,094*
Mountain Region (d)	**113**	**175**	**205**	**172**	*93*	*142*	*191*	*176*	*106*	*148*	*210*	*189*	**172**	*176*	*189*
Pacific Region (d)	**197**	**246**	**248**	**219**	*148*	*281*	*291*	*254*	*160*	*267*	*303*	*271*	**219**	*254*	*271*
Alaska	**23**	**27**	**30**	**27**	*27*	*27*	*27*	*27*	*27*	*27*	*27*	*27*	**27**	*27*	*27*

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

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

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

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

- = no data available

LNG: liquefied natural gas.

Notes: EIA completed modeling and analysis for this report on January 6, 2022.

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

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

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

Forecasts: EIA Short-Term Integrated Forecasting System.

https://rbnenergy.com/higher-and-higher-us-lng-feedgas-demand-looks-primed-to-build-on-record-highs

Higher And Higher - U.S. LNG Feedgas Demand Looks Primed To Build On Record Highs

Sunday, 01/09/2022

Published by: Lindsay Schneider

Global natural gas prices went through the roof in December, and while prices are back down from those highs, they remain incredibly strong compared to years past and the economics for U.S. LNG exports are riding high. LNG exports have been in the money for quite some time, but feedgas deliveries to U.S. export terminals throughout the spring and summer of 2021 were somewhat lackluster as maintenance and operational issues at terminals and nearby pipelines kept feedgas from hitting its full potential. Gas deliveries to those terminals began climbing in the fall, first back to full utilization levels, and then beyond. Much of the record feedgas demand has been from commissioning activity at Sabine Pass Train 6, which produced its first LNG in December and is on track to begin full service early this year. But beyond that, operators have been pushing the existing fleet of terminals to operate at peak levels and produce additional cargoes, likely for sale in the spot market or on short-term contract, an extremely profitable endeavor given the prices in Europe, where most if not all destination-flexible cargoes have headed. In today's RBN blog, we look at what's driving LNG feedgas demand to its recent highs and how much higher it could go.

Although prices in Europe and Asia are down from their recent highs in late December (see Baby, It's Cold Outside), they remain very strong. Global gas prices repeatedly set new records throughout the past six months, with the Japan Korea Marker (JKM), representing Asia, and the Dutch Title Transfer Facility (TTF), representing Europe, both averaging nearly $40/MMBtu in December, with TTF spiking to near $60/MMBtu last month. Prior to last summer the highest single-day settlement of either market was just $19.70/MMBtu, which JKM hit in January 2021. Even after a massive fall-off to end the year, prices are still well above that year-ago level. All of that is to say that the economics for exporting LNG from the U.S. look phenomenal and have for some time.

Our LNG Voyager report tracks U.S. exports weekly and Figure 1 summarizes those economics for the past year and in the mid-term, based on the current forward curves. Specifically, the graphs show the JKM and TTF price indices vs. RBN's estimate of marginal and fixed costs to deliver to Asia (left graph) and Europe (right graph). We discussed the various components that make up these costs and how they are calculated at great length in our Sultans of Swing blog series and in Wild Thing. When we show this graph, we typically include just the marginal cost ranges (shown in light blue for deliveries to Asia and light orange for deliveries to Europe), because as long as JKM and TTF (black lines) are above those ranges, contracted U.S. exports from existing terminals are profitable and economic cancellations are unlikely. But global gas prices are so high right now that it makes sense to layer in the fixed costs (dark blue for Asia, dark orange for Europe) because the price spread between the U.S. and the end regions easily clears the full-cycle cost for producing LNG. Looking at this over the past year gives a clear picture as to why the U.S. is likely to see multiple new LNG projects reach a final investment decision (FID) in 2022 (see The Race is On) and why many of the existing U.S. terminals are producing above their contracted capacity, driving feedgas demand above typical full utilization rates.

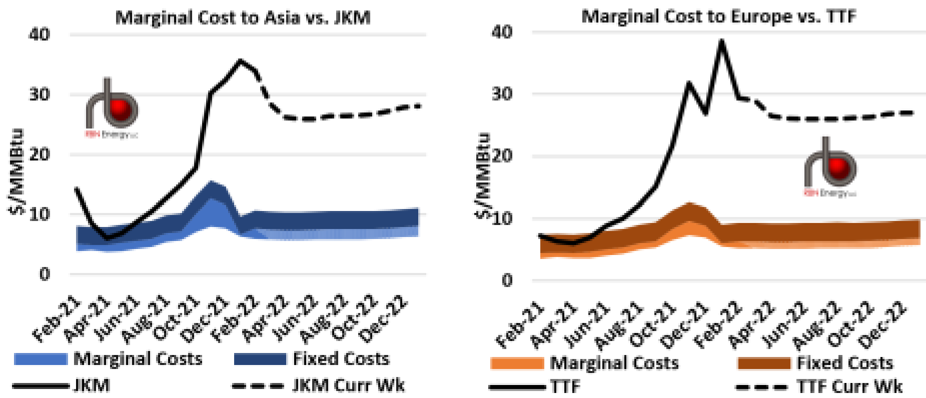

Figure 1. JKM and TTF Prices and Cost to Export from U.S. to Asia or Europe. Source: RBN LNG Voyager

First, let's take a look at the largest driver of the record feedgas levels, the commissioning of Sabine Pass Train 6. This has little to do with the economics right now and more to do with the construction timing of the final train at the U.S's largest export facility, which Cheniere has pushed to bring on very early. It's more than a year ahead of its original schedule and the cargoes produced at Train 6 are a big profit center for the company. Cheniere received Federal Energy Regulatory Commission (FERC) approval to begin introducing feedgas to Train 6 in late September (see Hear My Train A Coming, Part 2). At that time feedgas to the terminal briefly jumped above 4 Bcf/d, but then fell back. Feedgas to Sabine Pass (blue layer in Figure 2) was lower than typical full utilization levels for much of October as Train 3 was offline because of mechanical issues for about half the month, more than offsetting any feedgas increases from Train 6's commissioning. Feedgas began increasing in November and the newest train began producing first LNG late that month ahead of exporting its first commissioning cargo on December 6. Flows to Sabine Pass dipped briefly after that, as is typical after a train's first LNG export, before hitting new highs to close out the year as Train 6 resumed taking feedgas. The train likely exported a second commissioning cargo in late December and feedgas has since dropped again, but will likely rebound soon. Expected feedgas demand at full utilization for the entire six-train terminal, once the final train is completely online, is expected to be around 4.7 Bcf/d. It's already come close to that for a few days but has not been consistent at that level. We expect feedgas to rise even further this year and maintain that higher level as Train 6 comes online, which is expected in the first quarter.

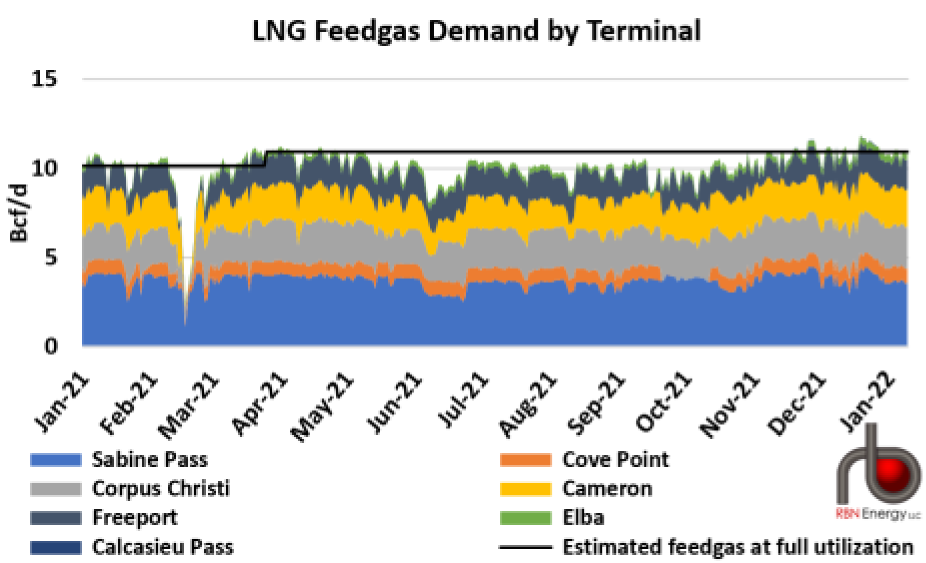

Figure 2. U.S. Feedgas Demand by Terminal. Source: RBN

Beyond Sabine Pass, several other U.S. terminals saw record feedgas intake last month as operators pushed for more LNG output to capitalize on high global gas prices. Because of Department of Energy (DOE) rule changes related to LNG cargo activity reporting, LNG cargoes sold in the global spot market are no longer distinguished from regular cargoes sold under long-term contracts, so it's impossible to know for sure how many cargoes the U.S. is producing for short-term or spot-market sales. Based on feedgas intake, Cove Point (orange area, Figure 2) and Cameron (yellow area) are most likely producing additional cargoes above their long-term contracted levels. Cove Point, in particular, took in feedgas at a record level in December, averaging around 850 MMcf/d over the month, about 15% more than needed to fulfill its long-term contracts but also about 8% above the terminal's previous peak production. Cove Point exported 73 total cargoes last year, a record for the terminal, three more than in 2020 and six more than in 2019. (Cove Point was one of the only U.S. terminals that was not impacted by economic cargo cancellations in 2020.) Flows to the terminal, on Chesapeake Bay in Maryland, have dropped to just over 800 MMcf/d in January, but this is still above the terminal's typical feedgas intake. Not only is Cove Point likely producing for the spot market, but the terminal appears to have accelerated the speed at which it can produce an additional LNG cargo.

Feedgas deliveries to Elba Liquefaction (green layer in Figure 2) are also at a record level, as flows to the Georgia terminal hit full utilization last month for the first time. One of the terminal's 10 mini-trains, Unit 2, went offline after a fire in May 2020 — before the terminal was completed — and had been offline since, so Elba had never operated at full capacity. Kinder Morgan, the terminal's operator, said last spring that it hoped to have Unit 2 back online in the fourth quarter of 2021, and although the company has not commented on the status of Unit 2, feedgas levels at the terminal indicate that it is back online.

Looking ahead, feedgas demand seems very likely to climb higher this year. Global natural gas prices are still providing strong support for LNG export demand, which will keep existing terminals operating at or even above full contracted capacity whenever physically possible, and there is more commissioning activity still to come. As we said recently in Three's (Not Always) a Crowd, the U.S. is expected to surpass Qatar and Australia next year and become the world's largest LNG exporter. The U.S. exported more than 1,000 LNG cargoes in 2021, up 46% from 2020 (though part of that was due to the fact that we were coming off of a baseline year that suffered from massive economic cargo cancellations because of COVID-19). 2021 was a record year for exports, and more growth is still in store. Deliveries to Sabine Pass will continue to climb, then stabilize, as Train 6 finishes commissioning and comes online, likely in the next few months. After that, feedgas demand will get another boost from Calcasieu Pass. Work on that new Louisiana terminal is slightly behind schedule, but it is progressing and will bring an additional 1.5 Bcf/d of feedgas demand by the end of the year. At that time, U.S. feedgas demand will be above 13 Bcf/d, and still expected to grow from there as Golden Pass eyes a mid-decade start, potentially along with several projects that could achieve FID this year. LNG feedgas demand may be higher than ever before, but the top just keeps getting higher.

"(Your Love Keeps Lifting Me) Higher and Higher" was written by Gary Jackson and Carl Smith. It was recorded at Columbia Studio in Chicago in June 1967, with Jackie Wilson's vocals being recorded in a single take. The Carl Davis produced record was released as a single by Wilson in August 1967 and went to #1 on the Billboard R&B and #6 on the Hot 100 charts. The song was inducted into the Grammy Hall of Fame in 1999. It has been covered by several artists, with Rita Coolidge scoring a #2 on the Hot 100 in 1977. Bruce Springsteen and the E Street Band frequently use it in their live shows. A Jackie Wilson album titled *Higher and Higher* was released in November 1967 featuring the hit song. The album went to #26 on the Billboard R&B chart and #163 on the Billboard Top 200 Albums chart. Personnel on the record were: Jackie Wilson (lead vocals), James Jamerson (bass), Richard Allen, Maurice White (drums), Robert White (guitar), Johnny Griffith (keyboards), and The Andantes and Pat Lewis (background vocals).

Jackie Wilson (Jack Leroy Wilson Jr.) was an American soul singer and showman from Detroit. He was a tenor with a four-octave range. His voice and wild stage moves earned him the nickname "Mr. Excitement." He released 25 studio albums, one live album, 10 compilation albums, and 78 singles. Wilson is a member of the Rock and Roll Hall of Fame, R&B Music Hall of Fame, and Michigan Rock and Roll Legends Hall of Fame. In September 1975, Wilson suffered a major heart attack on stage while singing his hit "Lonely Teardrops" at a Dick Clark rock and roll revue show. Lack of oxygen to the brain left him incapacitated and put in full-time care at the Medford Leas Retirement Center in Medford, NJ. Wilson died there in January 1984 at the age of 49. Motown founder Barry Gordy has stated that Wilson was “the greatest singer I've ever heard.”

https://www.agenciapetrobras.com.br/Materia/ExibirMateria?p_materia=984065

Petrobras reaches record LNG imports in 2021

Posted on: 01/12/2022 16:39:20

LNG represents about 30% of the company's total gas supply

In 2021, Petrobras reached the all-time record for imports of liquefied natural gas (LNG), with the purchase of about 23 million cubic meters per day of the input. The daily record took place on 10/1/21, with the import of more than 40 million cubic meters. In the same year, LNG represented around 30% of Petrobras' total portfolio of natural gas supply, being essential to meet the demands contracted by its customers.

The brand represents a volume around 200% higher than the amount acquired in 2020, of 7.5 million m³/day. Previously, the year with the highest volume of LNG imports was 2014, with 20 million m³/day. The 2021 record is the result of the initiatives adopted by the company to expand the supply of natural gas to the market, such as, for example, increasing the capacity of the regasification terminal in Rio de Janeiro.

Petrobras imports LNG from countries such as the United States, Trinidad & Tobago and Qatar, through special ships, which transport the gas in liquid form. The input returns to a gaseous state at the regasification terminals and is then sent to customers who have natural gas commercialization contracts signed with Petrobras. The importation of LNG to meet the demands of the national gas market can also be carried out by other suppliers.

Southern African Bloc Extends Mozambique Deployment Again (1)
2022-01-13 07:03:43.212 GMT

By Matthew Hill
(Bloomberg) -- Southern African nations agreed to extend a military deployment in Mozambique to help put down an Islamic State-affiliated insurgency that's killed thousands of people and delayed a $20 billion natural-gas project.

Southern African Development Community soldiers will continue their mission in Mozambique, the 16-member grouping said in a statement Wednesday following a heads-of-state meeting in the Malawian capital, Lilongwe. SADC had, in October, extended the mission by three months to mid-January.

The heads of state extended the mission's mandate "with associated budgetary implications" and will "continue to monitor the situation going forwards," according to a communique issued by the bloc after the meeting ended. It didn't say how long the latest extension would last, though Mozambique's state-owned Jornal Noticias reported it would be for another three months, citing Mozambican President Filipe Nyusi.

Mozambique has made meaningful progress in containing the insurgency since the arrival in July of soldiers from Rwanda -- which isn't a SADC member -- followed by the bloc's troops. The joint forces have dislodged the insurgents from the towns they'd held for a year, helping the government to regain relative control over large swathes of territory in Cabo Delgado province. Still, the rebels have continued guerrilla-style attacks and the violence has spread to neighboring Niassa province.

Nyusi's government is eager to convince TotalEnergies SE that it's safe for the company to resume construction on the Mozambique LNG project, which is Africa's biggest private investment. One of the world's poorest nations, Mozambique has been counting on revenue from the megaproject to transform its economy and help pay down debt that the International Monetary Fund said reached an estimated 134% of gross domestic product by the end of 2020.

TotalEnergies has said it needs to resume work on the project early this year, or face further delays. The development is already two-years behind schedule, with first output expected in 2026.

Rwandan forces totaling about 1,000 moved quickly after arriving about six months ago, symbolically joining the war before SADC's troops, which had been held up by the bloc's failure to agree with Nyusi over the deployment.

READ: Next Africa: What Does Rwanda Stand to Gain in Mozambique?

The Rwandan deployment, which President Paul Kagame in October said increased to nearly 2,000, is mainly responsible for protecting a coastal area surrounding the natural gas project. SADC soldiers, who are fewer in number, are spread over a much bigger inland area, where they have destroyed a number of insurgent bases. SADC leaders on Wednesday agreed to a $29.5 million budget for the mission, Noticias said.

Mozambique and Rwanda earlier this week signed an agreement to expand their cooperation, “in terms of capacity building of the Mozambique security forces as well as improving the modus operandi of the joint forces,” the Rwandan government said in a statement Monday.

The insurgency is unlikely to be militarily defeated in the next 12 months, even with help from SADC and Rwanda, said Alexandre Raymakers, an Africa analyst at risk intelligence company Verisk Maplecroft. TotalEnergies will likely resume work in the next six months, he said in an emailed note Wednesday.

--With assistance from Borges Nhamire, Frank Jomo and Taonga Clifford Mitimingi.

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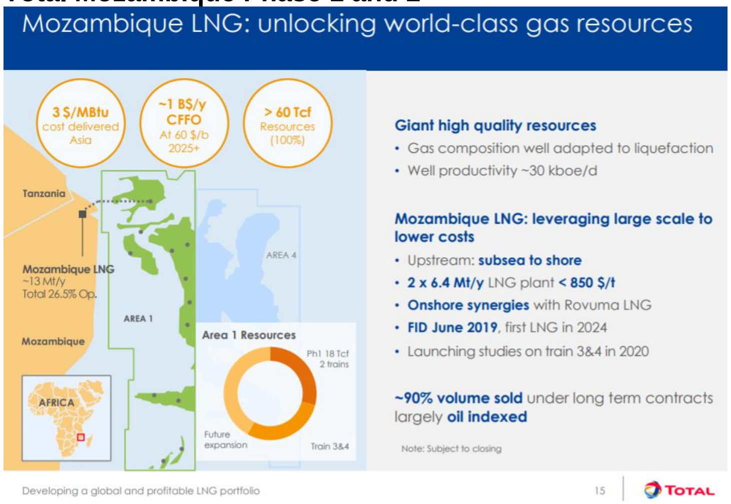
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

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



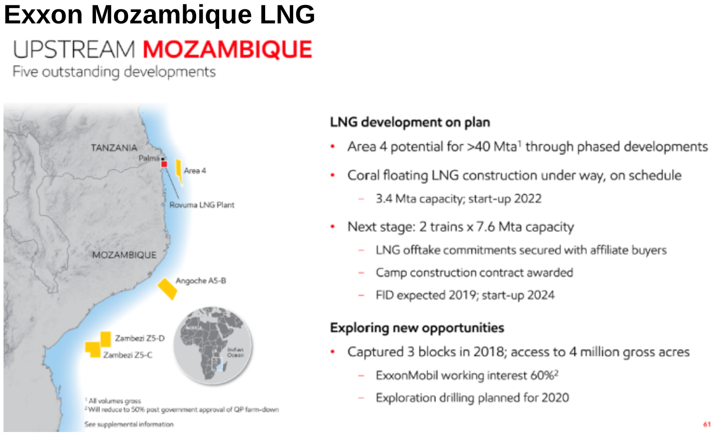
Source: Total Investor Day September 24, 2019

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

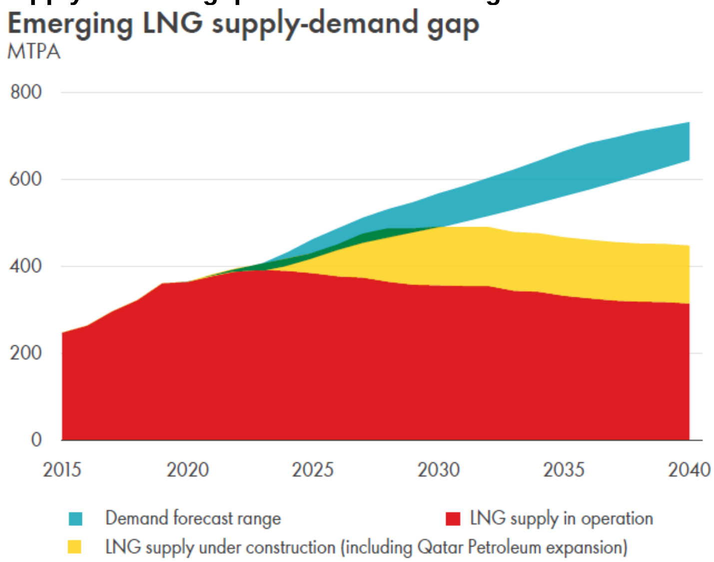
On Track   More Efforts Needed   Not on Track

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

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.. 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.

And does this bigger, nearer supply gap force LNG players to look at what brownfield LNG projects they could advance? A greenfield LNG project would likely take at least until 2027 to be in operations. Its why we believe the Mozambique delays will effectively force major LNG players to look to see if there are brownfield LNG projects they should look to advance. Prior to the just passed winter, no one would think Shell or other major LNG players would be considering any new LNG FIDs in 2021. All the big companies are in capital reduction mode and debt reduction mode. But Brent oil is now solidly over $60 and LNG prices hit record levels in Jan and the world's economic and oil and gas demand outlook are increasing with vaccinations. And we are starting to see companies move to increasing capex with the higher cash flows. We would not expect any major LNG players to move to FID right away. But we see them watching to see if 2021 plays out to still support this increasing LNG supply gap. And unless new mutations prevent vaccinations from returning the world to normal, we suspect that major LNG players, like other oil and gas companies, will be looking to increase capex as they approve 2022 budgets. The outlook for the future has changed dramatically in the last 5 months. The question facing Shell and others, should they look to FID new LNG brownfield projects in the face of an increasing LNG supply gap that is going to hit faster and harder than expected a few months ago. We expect these decisions to be looked at before the end of 2021. LNG prices will be stronger, but we expect the limiting cap in Asia will be that thermal coal will be used to mitigate some LNG price pressure.

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

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

Google Translate of
https://www.enecho.meti.go.jp/category/electricity_and_gas/electricity_measures/pdf/denryoku_LNG_stock_220112.pdf

Inventory status of LNG for power generation

January 12th, 3rd year of Reiwa Electric board maintenance section

 As one of the efforts to secure a stable supply in the winter of 2021, the inventory of LNG for power generation
By monitoring the situation (weekend inventory), the inventory of LNG for power generation is large nationwide.
It is important to detect the sign of a wide decline as soon as possible (signaling effect).

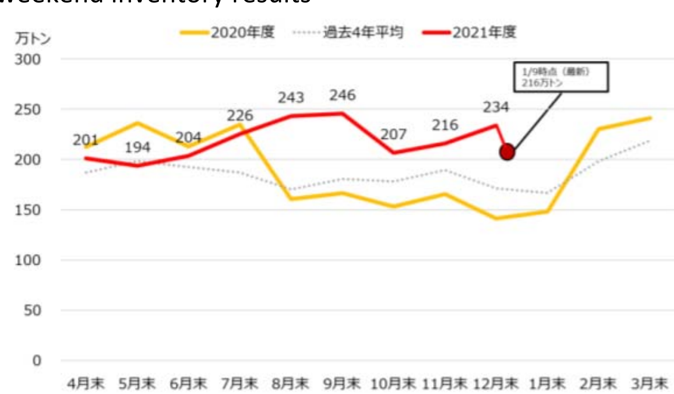
 Therefore, at the Agency for Natural Resources and Energy, the LNG inventory for power generation used by major electric power companies
And monitor. For the time being, the total value of each company is calculated weekly by the Agency for Natural Resources and Energy.
Published on HP.

○ Inventory transition of LNG for power generation
(Unit: 10,000 tons)
Weekend inventory at the end of the same period of the previous year * Average for the past 4 years *

	週末在庫量	前年同月末※		過去４年平均※
11/28 時点	223※	11 月末	166	189
12/5 時点	218	12 月末	142	171
12/12 時点	237			
12/19 時点	227			
12/23 時点	242			
1/2 時点	233	1 月末	149	167
1/9 時点	216			
1/16 時点				
1/23 時点				
1/30 時点				
以降、需給状況に応じ更新				

After that, it will be updated according to the supply and demand situation.
 We did not conduct a weekly survey before the previous year, but as a reference for comparison, the same month of the previous year and the end of the past four years
Describe the amount of stock.
 The amount of stock is the quantity excluding dead (the remaining amount that cannot be physically pumped).

<Reference> LNG for power generation by major electric power companies Month-end inventory trends and latest weekend inventory results



https://www.novatek.ru/en/press/releases/index.php?id_4=4826

NOVATEK and ENN Natural Gas Sign Sales and Purchase Agreement on Long-Term LNG Supply

Moscow, 11 January 2022. PAO NOVATEK ("NOVATEK" and/or the "Company") announced today that its wholly owned subsidiary, NOVATEK Gas & Power Asia Pte. Ltd., and ENN LNG (Singapore) Pte. Ltd., a subsidiary of ENN Natural Gas Co., Ltd. ("ENN Natural Gas") signed a long-term LNG sale and purchase agreement ("SPA") for the LNG produced from the Arctic LNG 2 project.

The SPA stipulates the supply of approximately 0.6 million tons of LNG per annum from the Arctic LNG 2 project for a term of 11 years. The LNG will be delivered on a DES basis to ENN's Zhoushan LNG Receiving Terminal in China.

"We have reached another milestone in successful marketing of NOVATEK's share of LNG to be produced by our Arctic LNG 2 project," noted Leonid Mikhelson, NOVATEK's Chairman of the Management Board. "This is another LNG SPA for delivery to the Chinese market, which is in line with our LNG strategy to expand sales to the Asia-Pacific region with its growing demand for clean-burning natural gas."

https://www.novatek.ru/en/press/releases/index.php?id_4=4825

NOVATEK and Zhejiang Energy Sign Sales and Purchase Agreement on Long-Term LNG Supply

Moscow, 11 January 2022. PAO NOVATEK ("NOVATEK" and/or the "Company") announced today that its wholly owned subsidiary, NOVATEK Gas & Power Asia Pte. Ltd., and Zhejiang Energy Gas Group Co., Ltd, a subsidiary of the Zhejiang Provincial Energy Group ("Zhejiang Energy") signed a long-term LNG sale and purchase agreement ("SPA") for the LNG produced from the Arctic LNG 2 project.

The SPA follows on from the Heads of Agreement signed by parties on 2 June 2021 during the Saint-Petersburg International Economic Forum, and stipulates the supply of up to one (1) million tons of LNG per annum from the Arctic LNG 2 project for a term of 15 years. The LNG will be delivered on a DES basis to Zhejiang Energy's LNG terminals in China.

Note:

Arctic LNG 2 envisages constructing three LNG liquefaction trains of 6.6 million tons per annum each for the total LNG capacity of 19.8 million tons, as well as cumulative gas condensate production capacity of 1.6 million tons per annum. The Project will utilize an innovative construction concept of gravity-based structure (GBS) platforms to reduce overall capital cost and minimize the Project's environmental footprint in the Arctic zone of Russia. As of 31 December 2020, the Utrenneye field's

2P reserves under PRMS totaled 1,434 billion cubic meters of natural gas and 90 million tons of liquids.

The Project's participants include: NOVATEK (60%), TotalEnergies (10%), CNPC (10%), CNOOC (10%) and Japan Arctic LNG, a consortium of Mitsui & Co, Ltd. and JOGMEC (10%).

Asian LNG Buyers Abruptly Change and Lock in Long Term Supply – Validates Supply Gap, Provides Support For Brownfield LNG FIDs

Posted 11am on July 14, 2021

The last 7 days has shown there is a sea change as Asian LNG buyers have made an abrupt change in their LNG contracting and are moving to lock in long term LNG supply. This is the complete opposite of what they were doing pre-Covid when they were trying to renegotiate Qatar LNG long term deals lower and moving away from long term deals to spot/short term sales. Why? We think they did the same math we did in our April 28 blog "*Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?*" and saw a much bigger and sooner LNG supply gap driven by the delay of 5 bcf/d of Mozambique LNG that was built into most, if not all LNG supply forecasts. Asian LNG buyers are committing real dollars to long term LNG deals, which we believe is the best validation for the LNG supply gap. Another validation, Shell, Total and others are aggressively competing to invest long term capital to partner in Qatar Petroleum's massive 4.3 bcf/d LNG expansion despite plans to reduce fossil fuels production in the 2020s. And even more importantly to LNG suppliers, the return to long term LNG contracts provides the financing capacity to commit to brownfield LNG FIDs. The abrupt change by Asian LNG buyers to long term contracts is a game changer for LNG markets and sets the stage for brownfield LNG FIDs likely as soon as before year end 2021. It has to be brownfield LNG FIDs if the gap is coming bigger and sooner. And we return to our April 28 blog point, if brownfield LNG is needed, what about Shell looking at 1.8 bcf/d brownfield LNG Canada Phase 2? LNG Canada Phase 1 at 1.8 bcf/d capacity is already a material positive for Cdn natural gas producers. A FID on LNG Canada Phase 2 would be huge, meaning 3.6 bcf/d of Cdn natural gas will be tied to Asian LNG markets and not competing in the US against Henry Hub. And with a much shorter distance to Asian LNG markets. This is why we focus on global LNG markets for our views on the future value of Canadian natural gas.

<u>Sea change in Asian LNG buyers is also the best validation of the LNG supply gap and big to LNG supply FIDs.</u> Has the data changed or have the market participants changed in how they react to the data? We can't recall exactly who said that on CNBC on July 12, it's a question we always ask ourselves. In the LNG case, the data has changed with Mozambique LNG delays and that has directly resulted in market participants changing and entering into long term contracts. We can't stress enough how important it is to see Asian LNG buyers move to long term LNG deals. (i) Validates the sooner and bigger LNG supply gap. We believe LNG markets should look at the last two weeks of new long term deals for Asian LNG buyers as being the validation of the LNG supply gap that clearly emerged post Total declaring force majeure on its 1.7 bcf/d Mozambique LNG Phase 1 that was under construction and on track for first LNG delivery in 2024. Since then, markets have started to realize the Mozambique delays are much more than 1.7 bcf/d. They have seen major LNG suppliers change their outlook to a more bullish LNG outlook and, most importantly, are now seeing Asian LNG buyers changing from trying to renegotiate long term LNG deals lower to entering into long term LNG deals to have security of supply. Asian LNG buyers are cozying up to Qatar in a prelude to the next wave of Asian buyer long term deals. What better validation is there than companies/countries putting their money where their mouth is. (ii) Provides financial commitment to help push LNG suppliers to FID. We believe these Asian LNG buyers are doing much more than validating a LNG supply gap to markets. The big LNG suppliers can move to FID based on adding more LNG supply to their portfolio, but having more long term deals provides the financial anchor/visibility to long term capital commitment from the buyers. Long term contracts will only help LNG suppliers get to FID.

<u>It was always clear that the Mozambique LNG supply delay was 5.0 bcf/d, not just 1.7 bcf/d from Total Phase 1.</u> LNG markets didn't really react to Total's April 26 declaration of force majeure on its 1.7 bcf/d Mozambique LNG Phase 1. This was an under construction project that was on time to deliver first LNG in 2024. It was in all LNG supply forecasts. There was no timeline given but, on the Apr 29 Q1 call, Total said that it expected any restart decision would be least a year away. If so, we believe that puts any actual construction at least 18 months away. There will be work to do just to get back to where they were when they were forced to stop development work on Phase 1. Surprisingly, markets didn't look the broader implications, which is why we posted our 7-pg Apr 28 blog "*Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?*" [LINK] We highlighted that Mozambique LNG delays were actually 5 bcf/d, not 1.7 bcf/d. And this 5 bcf/d of Mozambique LNG supply was built into most, if not all, LNG supply forecasts. The delay in Total Phase 1 would lead to a commensurate delay in its Mozambique LNG Phase 2 of 1.3 bcf/d. Total Phase 2 was to add 1.3 bcf/d. There was no firm in service date, but it was expected to

follow closely behind Phase 1 to maintain services. That would have put it originally in the 2026/2027 period. But if Phase 1 is pushed back at least 2 years, so will the follow on Phase 2, so more likely, it will be at least 2028/2029. The assumption for most, if not all, LNG forecasts was that Phase 2 would follow Phase 1. Exxon Rozuma Phase 1 of 2.0 bcf/d continues to be pushed back in timeline especially following Total Phase 1. Exxon's Mozambique Rozuma Phase 1 LNG will add 2.0 bcf/d and, pre-Covid, was originally expected to be in service in 2025. The project was being delayed and Total's force majeure has added to the delays. Rozuma onshore LNG facilities are right by Total. On June 20, we tweeted [LINK] on the Reuters report "*Exclusive: Galp says it won't invest in Rovuma until Mozambique ensures security*" [LINK]. Galp is one of Exxon's partners in Rozuma. Reuters reported that Galp said they won't invest in Exxon's Rozuma LNG project until the government ensures security, that this may take a while, they won't be considering the project until after Total has reliably resumed work on its Phase 1, which likely puts any Rozuma decision until at least end of 2022 at the earliest. Galp has taken any Rozuma Phase 1 capex out of their new capex plans thru 2025 and will have to take out projects in their capex plan if Rozuma does come back to work. This puts Rozuma more likely 2028 at the earliest as opposed to before the original expectations of before 2025. Pre-pandemic, Exxon's March 6, 2019 Investor Day noted their operated Mozambique Rovuma LNG Phase 1 was to be 2 trains each with 1.0 bcf/d capacity for total initial capacity of 2.0 bf/d with FID expected in 2019 and first LNG deliveries sometime before 2025. LNG forecasts had been assuming Exxon Rozuma would be onstream around 2025. The 2019 FID expectation was later pushed to be expected just before the March 2020 investor day. But the pandemic hit, and on March 21, 2020, we tweeted [LINK] on the Reuters story "*Exclusive: Coronavirus, gas slump put brakes on Exxon's giant Mozambique LNG plan*" [LINK] that noted Exxon was expected to delay the Rovuma FID. There was no timeline, but now, any FID is not expected until late 2022 at the earliest, that would push first LNG likely to at least 2028. What this means is that the Mozambique LNG delays are not 1.7 bcf/d but 5.0 bcf/d of projects that were in all, if not most, LNG supply forecasts. There is much more in our 7-pg blog. But Mozambique is what is driving a much bigger and sooner LNG supply gap starting ~2025 and stronger outlook for LNG prices

<u>One of the reasons why it went under the radar is that major LNG suppliers played stupid on the Mozambique impact.</u> It makes it harder for markets to see a big deal when the major LNG suppliers weren't making a big deal of Mozambique or playing stupid in the case of Cheniere in their May 4 Q1 call. In our May 9, 2021 Energy Tidbits memo, we said we had to chuckle when we saw Cheniere's response in the Q&A to its Q1 call on May 4 that they only know what we know from reading the Total releases on Mozambique and its impact on LNG markets. It's why we tweeted [LINK] "*Hmm! $LNG says only know what we read on #LNG market impact from $TOT $XOM MZ LNG delays*. *Surely #TohokuElectric & other offtake buyers are reaching out to #Cheniere. MZ LNG delays is a game changer to LNG in 2020s, see SAF Group blog. Thx @olympe_mattei @TheTerminal #NatGas".* How could they not be talking to LNG buyers for Total and /or Exxon Mozambique LNG projects. In the Q1 Q&A, mgmt was asked about Mozambique and didn't know any more than what you or I have read. Surely, they were speaking to Asian LNG buyers who had planned to get LNG supply from Total Mozambique or Exxon Rozuma Mozambique or both. Mgmt is asked "*wanted to just kind of touch on the color use talking about for these supply curve. And are you able to kind of provide any thoughts on the Mozambique and a deferral with the project of that size on 13 and TPA being deferred by we see you have you noticed any impact to the market has is there any impact for stage 3 with that capacity? Thanks*." Mgmt replies "*No. Look, I only know about the Mozambique delay with what I read as well as what you read that from total and an Exxon. And it's a sad situation and I hope everybody is safe and healthy that were there to experience that unrest but no I don't think it's, again it's a different business paradigm than what we offer. So, we offer a full value product, the customer doesn't have to invest in equity, customer doesn't have to worry about the E&P side of the business because, we've been able to both the by at our peak almost 7 Dee's a day of US NAT gas from almost a 100 different producers on 26 different pipelines and deliver it to our to facilities. So we take care of a lot of what the customer needs".*

<u>There are other LNG supply delays/interruptions beyond Mozambique.</u> There have been a number of other smaller LNG delay or existing supply interruptions that add to Asian LNG buyers feeling less secure about the reliability of mid to long term LNG supply. Here are just a few examples. (i) Total Papua LNG 0.74 bcf/d. On June 8, we tweeted [LINK] *"Timing update Papua #LNG project. $OSH June 8 update "2022 FEED, 2023 FID targeting 2027 first gas". $TOT May 5 update didn't forecast 1st gas date. Papua is 2 trains w/ total capacity 0.74 bcf/d."* We followed the tweet saying [LINK] *"Bigger #LNG supply gap being created >2025. Papua #LNG originally expected FID in 2020 so 1st LNG is 2 years delayed.*

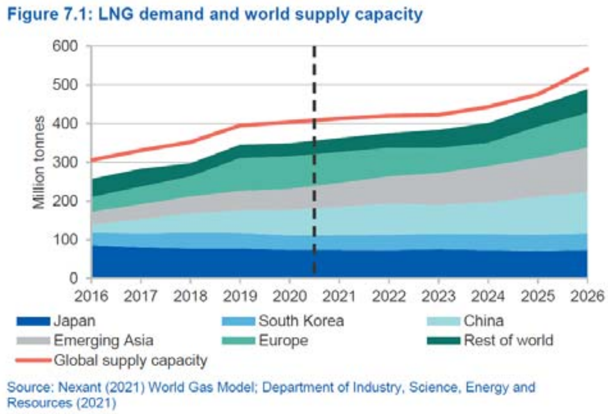
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required additional downtime for repair. Train 2 was shut on May 23 with an original restart of July 11, but the repairs to the weld quality issues meant it didn't restart until late Nov. The same issue was found in Train 1 but repairs were completed. However extended downtime for the trains led to lower LNG volumes. Gorgon produced ~2.3 bcf/d in 2019 but was down to 2.0 bcf/d in 2020. (iii) Equinor's Melkoeya 0.63 bcf/d shut down for 18 months due to a fire. A massive fire led to the Sept 28, 2020 shutdown of the 0.63 bcf/d Melkoeya LNG facility in Norway. On April 26, Equinor released "*Revised start-up date for Hammerfest LNG*" [LINK] with regard to the 0.63 bcf/d Melkoeya LNG facility. The original restart date was Oct 1, 2021 (ie. a 12 month shut down), but Equinor said "*Due to the comprehensive scope of work and Covid-19 restrictions, the revised estimated start-up date is set to 31 March 2022*". When we read the release, it seemed like Equinor was almost setting the stage for another potential delay in the restart date. Equinor had two qualifiers to this March 31, 2022 restart date. Equinor said "*there is still some uncertainty related to the scope of the work*" and "*Operational measures to handle the Covid-19 situation have affected the follow-up progress after the fire. The project for planning and carrying out repairs of the Hammerfest LNG plant must always comply with applicable guidelines for handling the infection situation in society. The project has already introduced several measures that allow us to have fewer workers on site at the same time than previously expected. There is still uncertainty related to how the Covid-19 development will impact the project progress."*

Cheniere stopped the game playing the game on June 30. Our July 4, 2021 Energy Tidbits memo noted that it looks like Cheniere has stopped playing stupid with respect to the strengthening LNG market in 2021. We can't believe they thought they were fooling anyone, especially their competitors. Bu that week, they came out talking about how commercial discussions have picked up in 2021 and it's boosted their hope for a Texas (Corpus Christi) LNG expansion. On Wednesday, Platts reported "*Pickup in commercial talks boosts Cheniere's hopes on mid-scale LNG project*" [LINK] Platts wrote "*Cheniere Energy expects to make a "substantial dent" by the end of 2022 in building sufficient buyer support for a proposed mid-scale expansion at the site of its Texas liquefaction facility, Chief Commercial Officer Anatol Feygin said June 30 in an interview." " As a result, he said, " The commercial engagement, I think it is very fair to say, has really picked up steam, and we are quite optimistic over the coming 12-18 months to make a substantial dent in that Stage 3 commercialization."* Platts also reported that Cheniere noted this has been a tightening market all year (ie would have been known by the May 4 Q1 call). Platts wrote "*We obviously find ourselves at the beginning of this year and throughout in a very tight market where prices today into Asia and into Europe are at levels that we frankly haven't seen in a decade-plus," Feygin said. "We've surpassed the economics that the industry saw post the Fukushima tragedy in March 2011, and that's happened in the shoulder period."* It's a public stance as to a more bullish LNG outlook

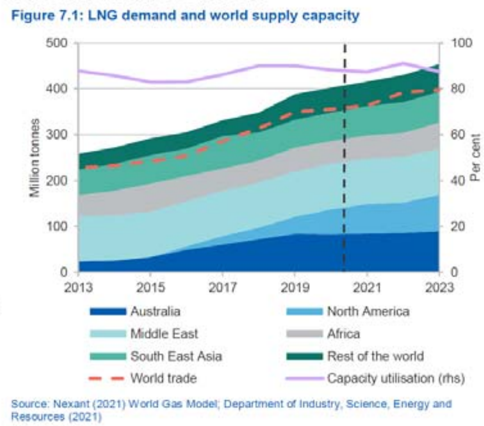
But we still see major LNG suppliers like Australia hinting but not outright saying that LNG supply gap is coming sooner. We have to believe Australia will be unveiling a sooner LNG supply gap in their September forecast. On June 28, we tweeted [LINK] on Australia's Resources and Energy Quarterly released on Monday [LINK] because there was a major change to their LNG outlook versus their March forecast. We tweeted "*#LNGSupplyGap. AU June fcast now sees #LNG mkt tighten post 2023 vs Mar fcast excess supply thru 2026. Why? $TOT Mozambique delays. See below SAF Apr 28 blog. Means brownfield LNG FID needed ie. like #LNGCanada Phase 2. #OOTT #NatGas"*. Australia no longer sees supply exceeding demand thru 2026. In their March forecast, Australia said "*Nonetheless, given the large scale expansion of global LNG capacity in recent years, demand is expected to remain short of total supply throughout the projection period."* Note this is thru 2026 ie. a LNG supply surplus thru 2026. But on June 28, Australia changed that LNG outlook and now says the LNG market may tighten beyond 2023. Interestingly, the June forecast only goes to 2023 and not to 2026 as in March. Hmmm! On Monday, they said "*Given the large scale expansion of global LNG capacity in recent years, import demand is expected to remain short of export capacity throughout the outlook period. Beyond 2023, the global LNG market may tighten, due to the April 2021 decision to indefinitely suspend the Mozambique LNG project, in response to rising security issues. This project has an annual nameplate capacity of 13 million tonnes, and was previously expected to start exporting LNG in 2024*." 13 million tonnes is 1.7 bcf/d so they are only referring to Total Mozambique LNG Phase 1. So no surprise the change is Mozambique LNG driven but we have to believe the reason why they cut their forecast off this time at 2023 is that they are looking at trying to figure out what to forecast beyond 2023 in addition to Total Phase 1. And, importantly, we believe they will be changing their LNG forecast for more than Mozambique ie. India demand that we highlight later in the blog. They didn't say anything else specific on Mozambique but, surely they have to also be delaying the follow on Total Phase 2 of 1.3 bcf/d and Exxon Rozuma Phase 1 of 2.0 bcf/d.

Australia's LNG Outlook: March 2021 vs June 2021 Forecasts

March 2021 LNG Outlook



June 2021 LNG Outlook

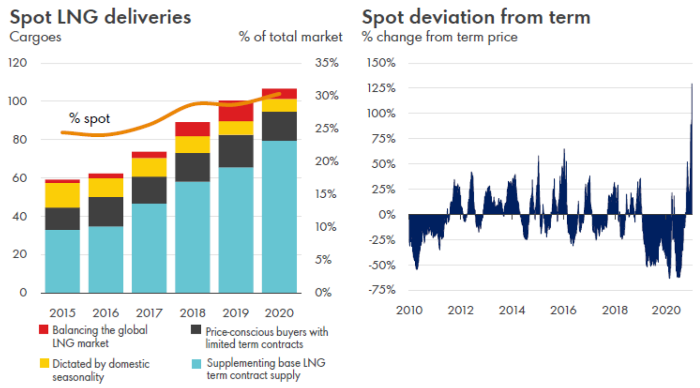


Source: Australia Resources and Energy Quarterly

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

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

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

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

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

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

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

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

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

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

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

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

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

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

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

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

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

North Dakota | Mineral Resources
Be Legendary.

Release Date: 1/14/2022
Director Lynn Helms

Director's Cut
November 2021 Production

Oil Production

October 34,438,214 barrels = 1,110,910 barrels/day (final)
November 34,793,353 barrels = 1,159,778 barrels/day **(+4.4%)**

1,116,909 barrels/day or 96% from Bakken and Three Forks
42,869 barrels/day or 4% from legacy pools
Oct 1,288,953 barrels/day New Mexico
1,519,037 all-time North Dakota high Nov 2019

Revised Revenue Forecast **= 1,200,000→1,100,000→1,000,000 barrels/day** **(+5.4%)**

Crude Price[1] ($/barrel)

	North Dakota Light Sweet	WTI	ND Market estimate
October	74.35	81.22	75.10
November	72.03	79.18	73.70 RF +47%
Today	74.25	82.12	78.19 Est. RF +56%
All-time high (6/2008)	$125.62	$134.02	$126.75

Revised Revenue Forecast **= $50.00**

Gas Production & Capture

October Production 92,977,713 MCF = 2,999,281 MCF/day
Gas Captured: 94% 87,510,345 MCF = 2,822,914 MCF/day

November Production 92,169,175 MCF = 3,072,306 MCF/day **+2.4%**
Gas Captured: 94% 86,853,557 MCF = 2,895,119 MCF/day
3,145,172 MCF/day all-time high production Nov 2019
2,915,667 MCF/day all-time high capture Oct 2021

Rig Count

October	29
November	33
December	32
Today	*32 NM 95*
Federal Surface	0
All-time high	*218 (5/29/2012)*

[1] Pricing References: WTI: EIA and CME Group; ND Light Sweet: Flint Hills Resources

Wells

	October	November	December	Revised Revenue Forecast
Permitted	37 drilling 0 seismic	50 drilling 2 seismic	45 drilling 0 seismic (All-time high was 370 – Oct. 2012)	-
Completed	41 (Final)	60 (Revised)	81 (Preliminary)	**30→<u>40</u>→50→60**
Inactive[2]	1,881	1,957	-	-
Waiting on Completion[3]	457	416	-	-
Producing	17,164	17,238 (Preliminary) NEW All-time high *14,940 (87%) from unconventional Bakken – Three Forks* *2,298 (13%) from legacy conventional pools*	-	-

Fort Berthold Reservation Activity

	Total	Fee Land	Trust Land
Oil Production (barrels/day)	251,997	118,288	147,117
Drilling Rigs	4	1	3
Active Wells	2,621	659	1,962
Waiting on completion	TBD		
Approved Drilling Permits	TBD	TBD	TBD
Potential Future Wells	3,931	1,105	2,826

Drilling and Completions Activity & Crude Oil Markets

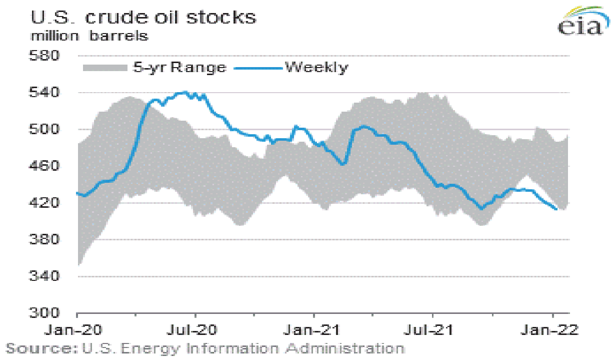
The drilling rig count was stable in the mid 50's second half of 2019 through May 2020. Drilling rig count fell 40% from January 2020 to November 2021, but is slowly increasing.

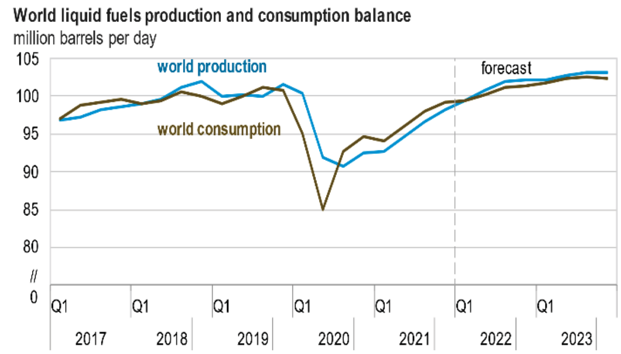
The number of well completions has been low and volatile since 2Q 2020 as the number of active completion crews dropped from 25 to 1 then increased to 8 this week.

OPEC+ continues to phase out oil production cuts by the end of 3Q 2022. Coordinated increases in oil supply from the group known as OPEC+ began in September 2021. At their January 2022 meeting OPEC+ decided to stick with their plan to increase production 400,000 barrels per day each month going forward. The International Energy Agency estimates a tight market despite the gradual OPEC supply boost.

[2] Includes all well types on IA and AB statuses: **IA** = Inactive shut in >3 months and <12 months;
AB = Abandoned (Shut in >12 months)

[3] The number of wells waiting on completions is an estimate on the part of the director based on idle well count and a typical five-year average. Neither the State of North Dakota, nor any agency officer, or employee of the State of North Dakota warrants the accuracy or reliability of this product and shall not be held responsible for any losses caused by this product. Portions of the information may be incorrect or out of date. Any person or entity that relies on any information obtained from this product does so at his or her own risk.





Crude oil transportation capacity including rail deliveries to coastal refineries is adequate, but could be disrupted due to:

- US Appeals Court for the ninth circuit upholding of a lower court ruling protecting the Swinomish Indian Tribal Community's right to sue to enforce an agreement that restricts the number of trains that can cross its reservation in northwest Washington state.
- DAPL Civil Action No. 16-1534 continues, but the courts have now ruled that DAPL can continue normal operations through March 2022.

Drilling activity is slowly increasing and operators continue to maintain a permit inventory of approximately 12 months.

Gas Capture

US natural gas storage is now 2.4% above the five-year average. Crude oil inventories are far below normal in the US, but world storage remains in the upper range of the five-year average.

The price of natural gas delivered to Northern Border at Watford City increased to $23.42/MCF February 17, 2021 but has returned to a slightly higher than normal level of $3.72/MCF today. This results in a current oil to gas price ratio of 21 to 1. The state wide gas flared volume from October to November increased 820 MCFD to 177,187 MCF per day, and the statewide percent flared decreased to 5.8% while Bakken capture percentage increased to 95%.

The historical high flared percent was 36% in 09/2011.

Gas capture details are as follows:

Statewide	94%	
Statewide Bakken	95%	
Non-FBIR Bakken	95%	
FBIR Bakken	93%	
Trust FBIR Bakken	96%	
Fee FBIR	76%	Big Bend Field 61%

The Commission established the following gas capture goals:

74%	October 1, 2014 - December 31, 2014
77%	January 1, 2015 - March 31, 2016
80%	April 1, 2016 - October 31, 2016
85%	November 1, 2016 - October 31, 2018
88%	November 1, 2018 - October 31, 2020
91%	November 1, 2020

Seismic

There is currently no seismic activity for oil and gas.

Active Surveys	Recording	NDIC Reclamation Projects	Remediating	Suspended	Permitted (Oil and Gas)	Permitted (CCS)
2 (Both CCS)	0	0	0	4	0	0

Agency Updates

BIA has published a new final rule to update the process for obtaining rights of way on Indian land. The rule was published 11/19/15 and became effective 12/21/15. The final rule can be found at https://www.federalregister.gov/articles/2015/11/19/2015-28548/rights-of-way-on-indian-land. On 3/11/16, the Western Energy Alliance filed a complaint and motion for a temporary restraining order and/or a preliminary injunction. On 04/19/16, the US District court for the District of North Dakota issued an order denying the motion for a preliminary injunction. The new valuation requirements were resulting in increased delays so BIA provided a waiver that expires 04/05/2020. On 03/09/2020 the NDIC submitted comments supporting an extension of that waiver through 04/05/2021 to allow infrastructure development to continue while BIA develops and implements the new process. NDIC comments can be found at http://www.nd.gov/ndic/ic-press/Sweeney%20letter%20200309.pdf

BLM on 1/20/21 DOI issued order 3395 implementing a 60 day suspension of Federal Register publications; issuing, revising, or amending Resource Management Plans; granting rights of way and easements; approving or amending plans of operation; appointing, hiring or promoting personnel; leasing; and permits to drill. On 1/27/21 President Biden issued an executive order that mandates a “pause” on new oil and gas leasing on federal lands, onshore and offshore, “to the extent consistent with applicable law,” while a comprehensive review of oil and gas permitting and leasing is conducted by the Interior Department. There is no time limit on the review, which means the president’s moratorium on new leasing is indefinite. The order does not restrict energy activities on lands the government holds in trust for Native American tribes.

What is the percentage of federal lands in ND?

Mineral ownership in ND is 85% private, 9% federal (4% Indian lands and 5% federal public lands), and 6% state. 66% of ND spacing units contain no federal public or Indian minerals, 24% contain federal public minerals, 9% contain Indian minerals,1% contain both.

How many potential wells could be delayed or not drilled by a Biden administration ban on drilling permits and hydraulic fracturing on federal lands?

A spatial query found 3,443 undrilled wells in spacing units that would penetrate federal minerals, 2,902 undrilled wells in spacing units would penetrate BIA Trust minerals (700 tribal minerals and 2,202 allotted minerals), and the total number of wells potentially impacted is 6,345. The minimum number of future Bakken wells is 24,000 so the 3,443 wells on federal public lands = 14%, and the 2,902 wells on trust lands = 12%.

What is the potential federal royalty loss from a Biden administration ban on drilling permits and hydraulic fracturing on federal lands?

A recent study from University of Wyoming estimated the ND loss as follows: 2021-2025 $76 million, 2026-2030 $113 million, 2031-2035 $160 million, and 2036-2040 $221 million for a total of $570 million over 15 years. Please note that 50% of the royalties on federal public lands go to the state and 50% of the state share goes to the county where the oil was produced.

The U.S. Interior Department launched its review of the federal oil and gas leasing program on 3/25/21, a key step that will determine whether the Biden administration will permanently halt new leases on federal land and water. The review kicked off with a public forum on oil and gas leasing on federal land and water, with participants representing industry, environmental conservation and justice groups, labor and others, and commence an online comment period. This input will inform an interim report to be released in early summer outlining next steps and recommendations on the future of the program and what can be done to reform how leases are managed and how much revenue should go to taxpayers and other issues.

On 7/7/21 North Dakota sued the Department of Interior (DOI), Secretary of Interior Debra Haaland, Bureau of Land Management (BLM), Director of the BLM Nada Culver, and Director of the Montana-Dakotas BLM John Mehlhoff in US District Court for the District of North Dakota. The lawsuit requests the court:

https://bismarcktribune.com/news/state-and-regional/bakken-oil-patch-weathers-bitterly-cold-temperatures/article_1d0f0ee7-8896-5e4f-8b6f-bb3db44cab4b.html

Bakken oil patch weathers bitterly cold temperatures

AMY R.SISK

Jan 14, 2022

The bitterly cold weather of the past few weeks means the oil patch is moving a little slower than usual.

But the frigid temperatures were not a factor in the latest oil production data released Friday, which accounts for November 2021's output. North Dakota produced 1.16 million barrels per day of oil that month, a 4% increase from October. That's the most significant uptick in oil production the state has seen in over a year, State Mineral Resources Director Lynn Helms said at his monthly press briefing.

Twelve frack crews operated in North Dakota during November, bringing online 60 new wells. Some were newly drilled and others had sat idle for a while after they were drilled.

Bitterly cold temperatures hit the state in late December, however, and lasted until this past week. The below-freezing conditions have affected the rate at which natural gas can be produced and gathered in the oil fields. Oil companies do not want to wastefully flare off the gas at well sites because that could prompt the state to restrict their activities, so they are instead looking to scale back oil and gas production from wells where freezing is an issue, Helms said. That in turn could mean lower oil production figures for December and early this year, he said.

"It's all about the cold weather," Helms said.

It's not unusual for the oil industry to experience a slowdown at the start of the year amid the winter, said Barrett Withers, chief operating officer of Beaver Creek LLC, an oil field service provider on the Fort Berthold Indian Reservation. He told reporters at the monthly oil briefing that his company is optimistic because more frack crews and drilling rigs are operating in the state, a sign of the industry's continued recovery from the coronavirus pandemic.

"We think it's going to be a great 2022 year, similar to what we've seen in pre-pandemic levels," he said.

His expectations for this year are a far cry from where the company found itself after the pandemic hit.

"We looked at sending trucks all the way down to Texas just to keep people working," Withers said.

North Dakota's daily gas production rose 2% to 3.042 billion cubic feet in November. The oil and gas industry is capturing 94% of all gas produced statewide and is meeting the 91% target for the Bakken set by regulators, though a few problematic spots remain on Fort Berthold where there is inadequate gas gathering infrastructure, Helms said.

Well plugging

The state has identified 94 more abandoned oil wells to plug in a continuation of the program it began in 2020 using federal virus aid

Helms said the Oil and Gas Division is looking to finish reclamation work on another 119 well sites that have already been plugged. The state plans to apply for more aid made available under the federal infrastructure bill signed into law last year.

"Twenty-six states filed notices of intent to participate in that program," Helms said. "What we invented here in North Dakota is now going to expand across 26 oil- and gas-producing states nationwide."

Well plugging has helped keep afloat oil field businesses such as Beaver Creek and Ham's Well Service, both of whom had representatives speak at Friday's briefing.

"It kept up to 40 of my guys working and off unemployment," said Shane Bryans of Ham's. "It was very important to me as an employer because it kept my employees around."

MONTHLY UPDATE

JANUARY 2022 PRODUCTION & TRANSPORTATION

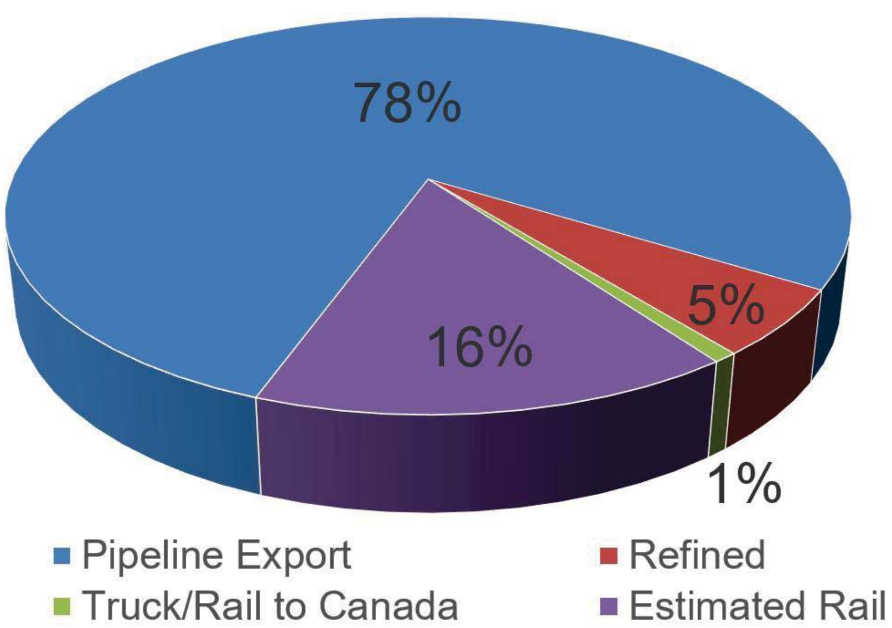
North Dakota Oil Production

Month	Monthly Total, BBL	Average, BOPD
Oct. 2021 - Final	34,438,213	1,110,910
Nov. 2021 - Prelim.	34,791,530	1,159,718

North Dakota Natural Gas Production

Month	Monthly Total, MCF	Average, MCFD
Oct. 2021 - Final	92,977,713	2,999,281
Nov. 2021 - Prelim.	92,169,175	3,072,306

Estimated Williston Basin Oil Transportation, Nov. 2021



CURRENT DRILLING ACTIVITY:

NORTH DAKOTA[1]

32 Rigs

EASTERN MONTANA[2]

0 Rigs

SOUTH DAKOTA[2]

0 Rigs

SOURCE (JAN 13, 2022):

1. ND Oil & Gas Division
2. Baker Hughes

PRICES:

Crude (WTI): $82.85

Crude (Brent): $85.36

NYMEX Gas: $4.22

SOURCE: BLOOMBERG (JAN 14, 2022 9AM CST)

GAS STATS*

94% CAPTURED & SOLD

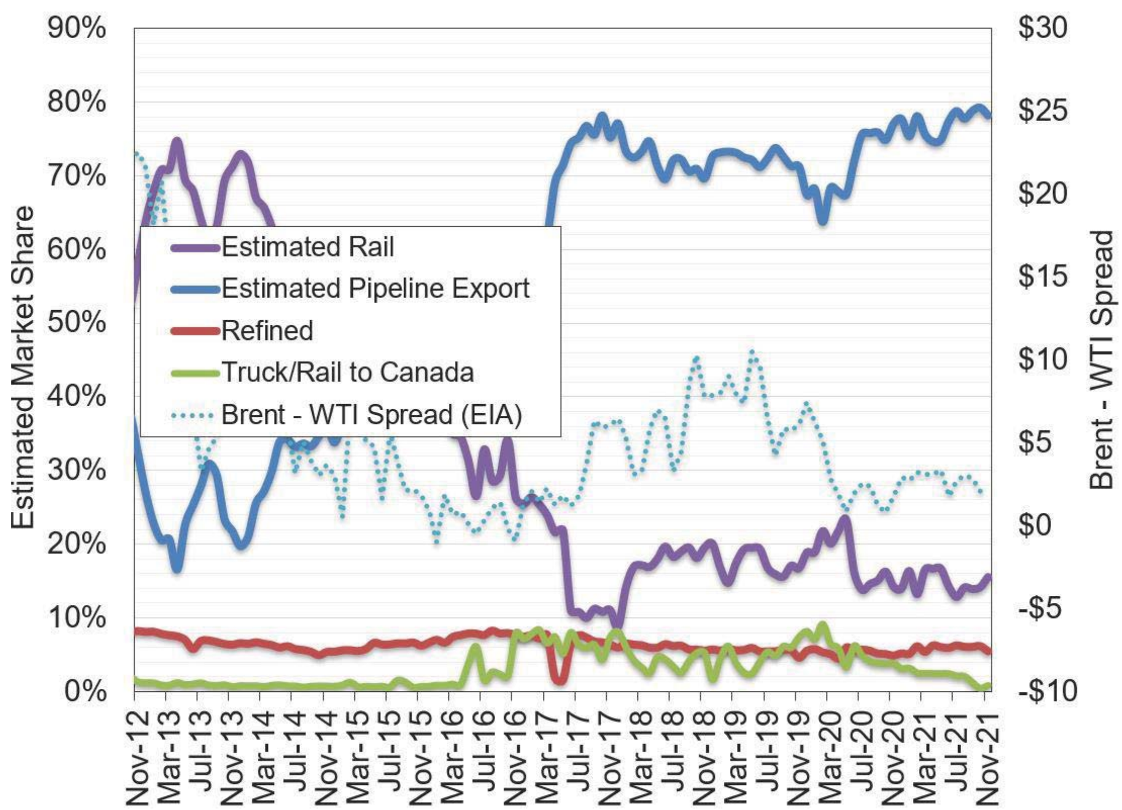
4% FLARED DUE TO CHALLENGES OR CONSTRAINTS ON EXISTING GATHERING SYSTEMS

2% FLARED FROM WELL WITH ZERO SALES

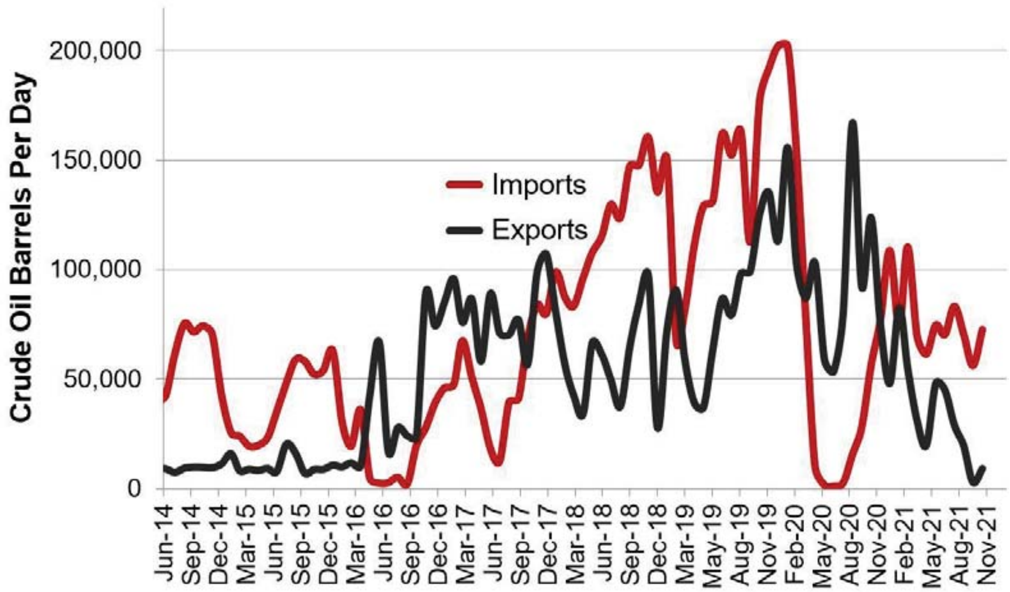
NOV. 2021 NON-CONF DATA

Estimated North Dakota Rail Export Volumes

Estimated Williston Basin Oil Transportation

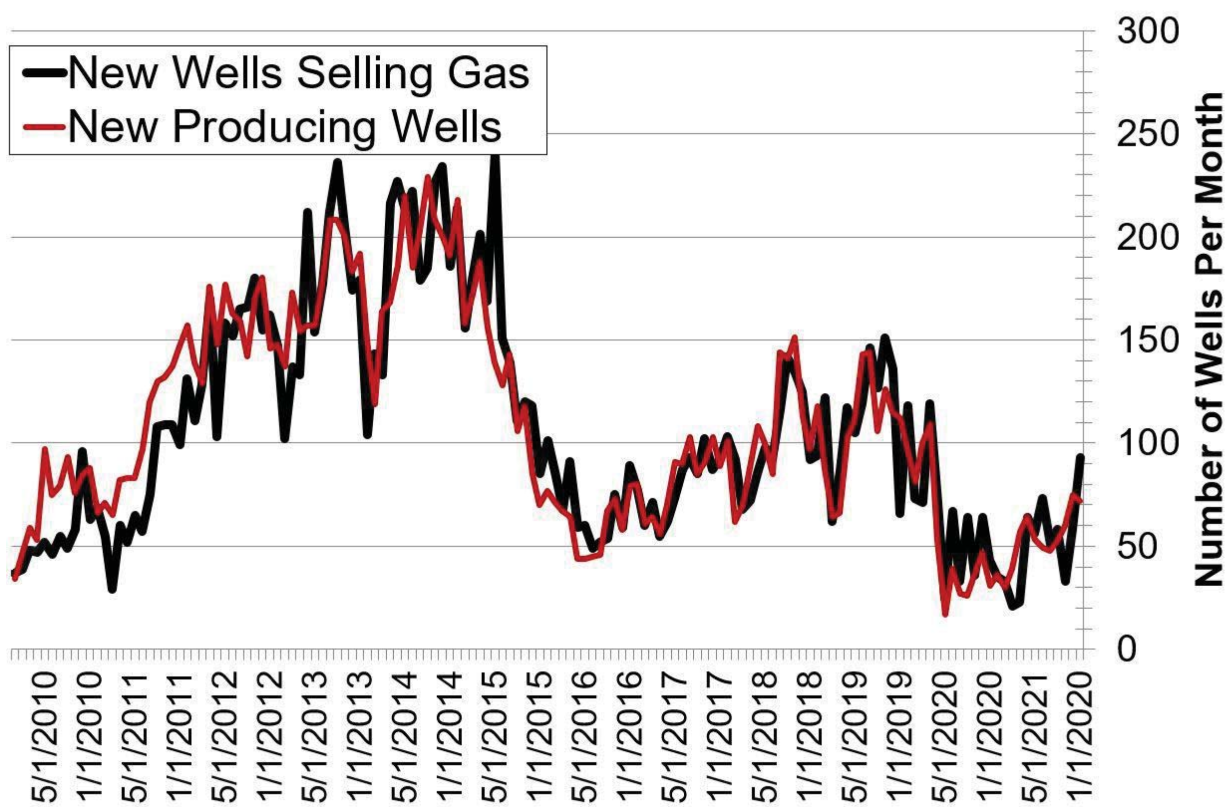


Williston Basin Truck/Rail Imports and Exports with Canada



Data for imports/exports chart is provided by the US International Trade Commission and represents traffic across US/Canada border in the Williston Basin area.

New Gas Sales Wells per Month



US Williston Basin Oil Production, BOPD

2020

MONTH	ND	EASTERN MT*	SD	TOTAL
January	1,431,679	57,460	3,091	1,492,230
February	1,507,069	55,425	3,070	1,565,563
March	1,435,200	57,725	2,946	1,495,870
April	1,225,476	49,042	2,610	1,277,128
May	862,254	37,066	2,466	901,786
June	895,208	42,847	2,680	940,735
July	1,043,089	48,668	3,435	1,095,192
August	1,166,242	47,212	2,807	1,216,260
September	1,224,008	47,522	2,837	1,274,366
October	1,244,056	46,899	2,749	1,293,703
November	1,226,409	45,444	2,798	1,274,650
December	1,191,429	44,814	2,827	1,239,070

2021

MONTH	ND	EASTERN MT*	SD	TOTAL
January	1,147,718	50,417	2,874	1,201,009
February	1,083,819	48,251	2,828	1,134,898
March	1,108,984	49,525	2,744	1,161,254
April	1,121,754	48,439	2,644	1,172,837
May	1,129,777	46,905	2,640	1,179,322
June	1,134,756	43,767	3,103	1,181,626
July	1,078,877	43,413	2,884	1,125,174
August	1,108,131	46,879	2,892	1,157,902
September	1,114,020	49,585	2,847	1,166,452
October	1,110,910	48,179	2,853	1,161,942
November	1,159,718			
December				

* Eastern Montana production composed of the following Counties: Carter, Daniels, Dawson, Fallon, McCone, Powder River, Prairie, Richland, Roosevelt, Sheridan, Valley, Wibaux

2022 Capital Budget
Thermal In Situ – Mid-, & Long-Term Growth

Thermal In Situ *(mid- & long-term growth)*	($ million)	Targeted Opportunity
Base Capital	~$340	✓ Sustains safe & reliable base production
Strategic Growth Capital Opportunities[1]	~$385	✓ Adds ~22,000 bbl/d in 2024, increasing to ~49,000 bbl/d in 2025

- Primrose → average capital efficiency of ~$10,000/bbl/d[2]
  - Targeting 1 SAGD pad and 2 CSS pads → on stream in mid-2023
- SAGD → average capital efficiency of ~$8,000/bbl/d[2]
  - Targeting 3 pads in Kirby and 2 pads in Jackfish → on stream starting mid-2023
- Leveraging technology and innovation → investing ~$25 million in 2022B
  - Progressing commercial scale solvent SAGD at Kirby North, targeting first solvent injection in early 2024
  - Developing and executing GHG reduction projects

(1) 2022B capital only; reflects portion of multi-year capital program.
(2) Additional production growth from 2022 targeted volumes and reflects 12 month average production.

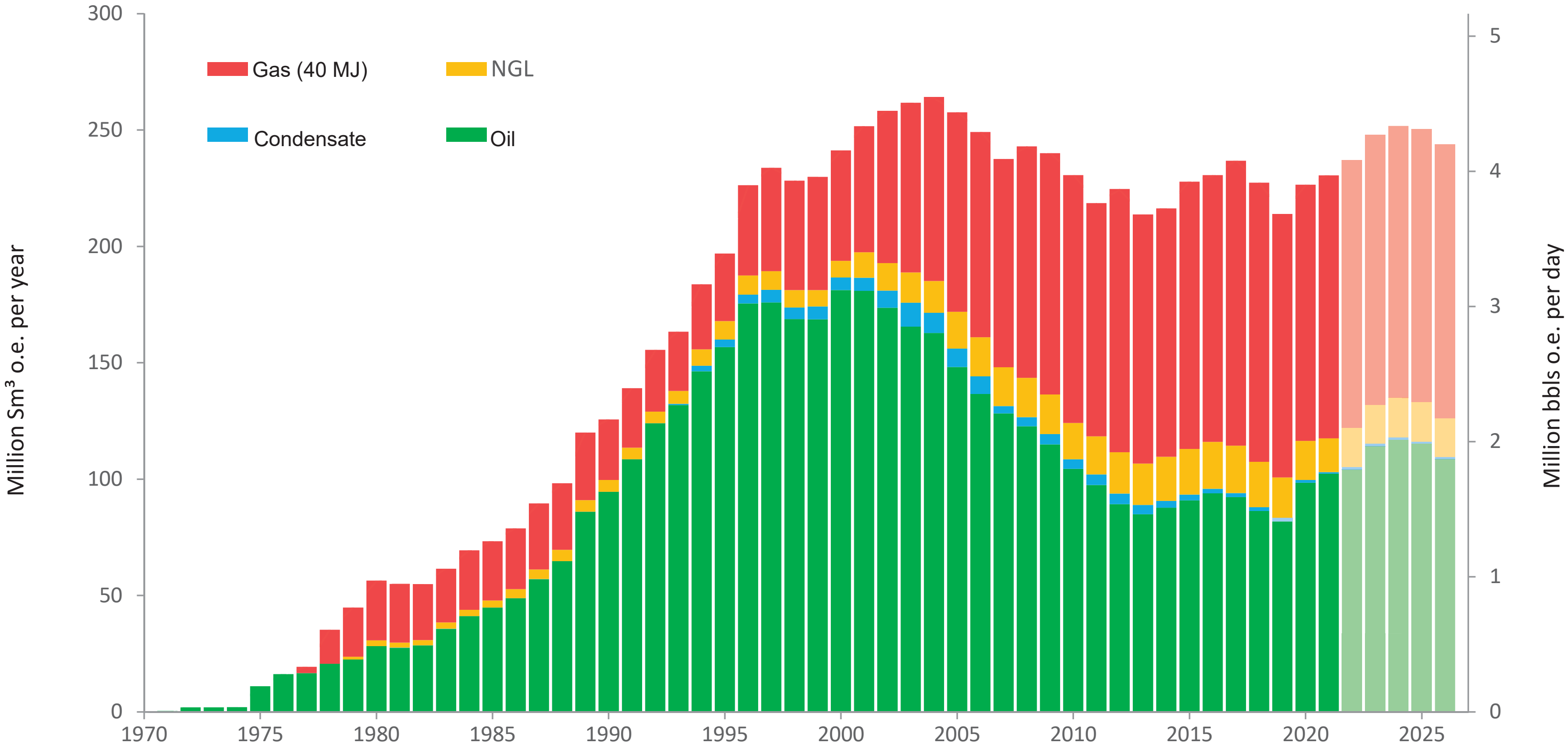
2022 Capital Budget
Oil Sands Mining & Upgrading – Mid- & Long-Term Growth

Oil Sands Mining *(mid- & long-term growth)*	($ million)	Targeted Opportunity
Base Capital	~$1,430	✓ Sustains safe & reliable base production
Strategic Growth Capital Opportunities[1]	~$315	✓ Adds ~5,000 bbl/d of capacity in 2023 increasing to ~14,000 bbl/d of capacity in 2025

- Horizon 2022B targeted activities
  - Planned turnaround – full plant outage targeted for ~32 days beginning in May 2022
    - Targeted ~23,000 bbl/d impact to full year production
  - Advancing reliability enhancement project
    - Targeting to extended major maintenance cycle → reduce from once per year to once every second year
- AOSP 2022B targeted activities
  - Planned turnaround at the Scotford Upgraded → targeted for ~65 days beginning in March 2022
    - Targeted ~12,000 bbl/d, net impact to full year production
- Leveraging technology and innovation → In-Pit Extraction Plant (IPEP) pilot was successful
  - Next Step: front end engineering for a demonstration plant → ~$10 million in 2022B

(1) 2022B capital only; reflects portion of multi-year capital program.

Continued high production



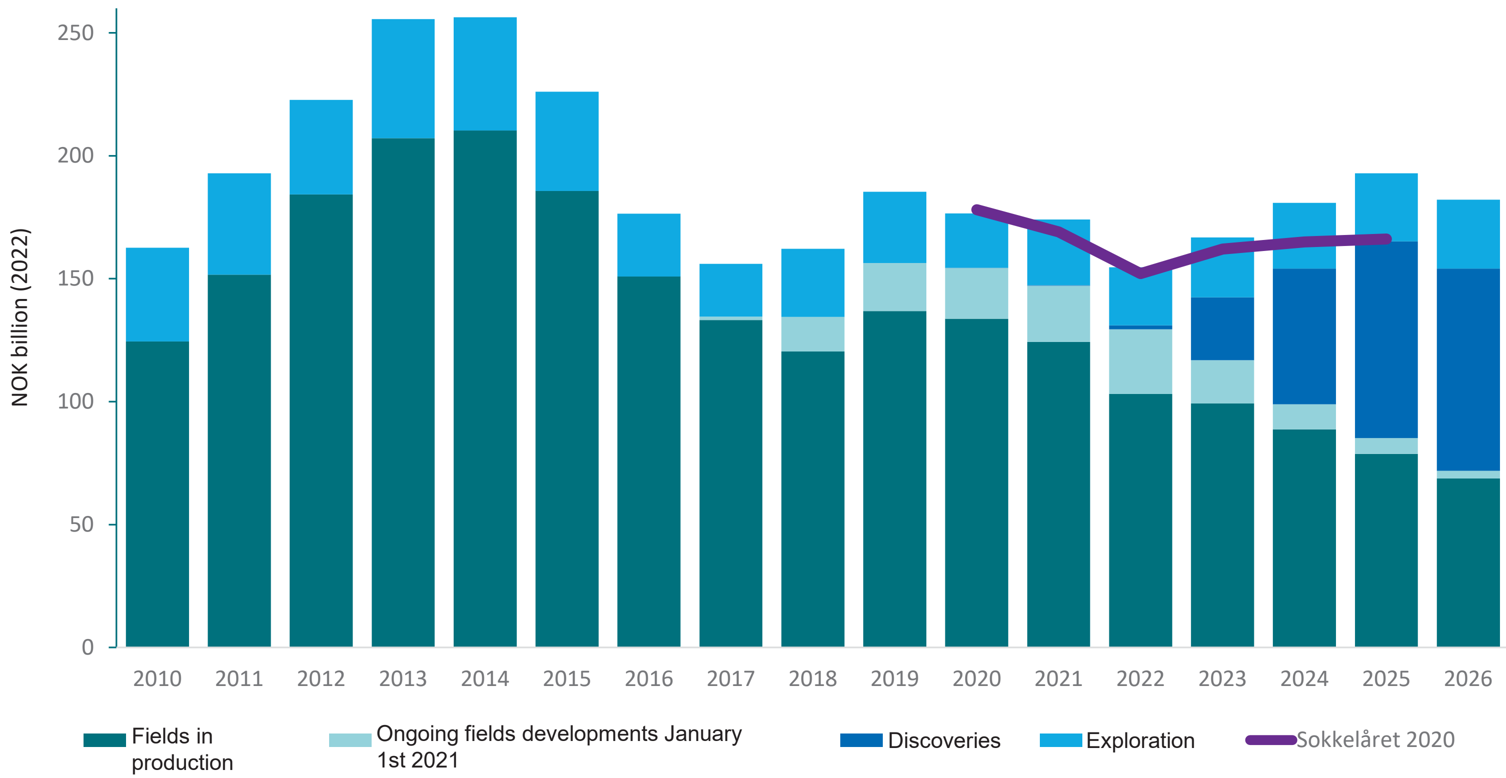
94 Producing fields

230 million Sm³ o.e.

4 million barrels o.e. per day

Stable level of investment on the shelf

NPD

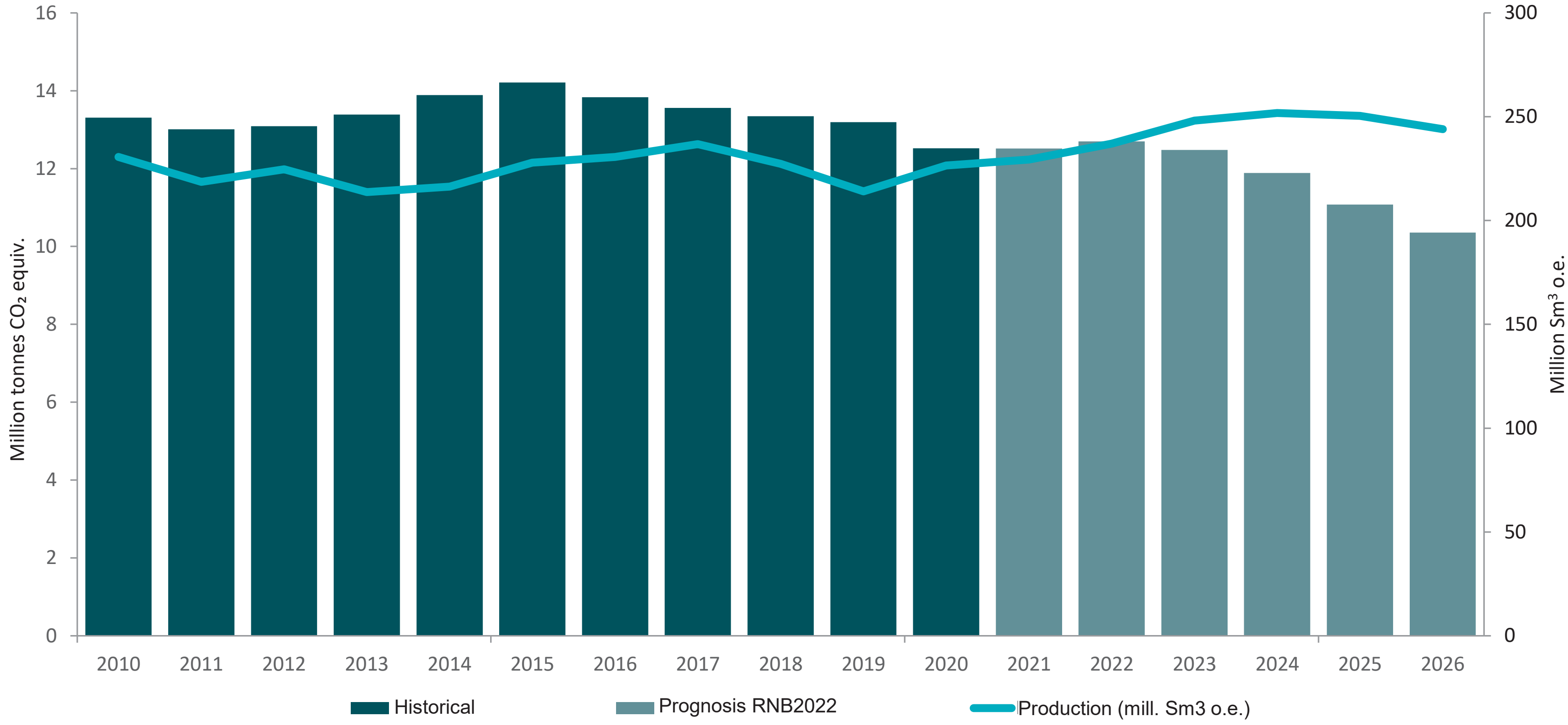


94 Producing fields

27 NOK billion exploration investments

147 NOK billion investments

Production increases, emissions decrease



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Saudi Arabia turns to Gulf states to replenish depleted air defences

Missile and drone strikes against kingdom by Iran-backed Houthi rebels in Yemen increase as relations with US falter

A test firing of a US-made Patriot missile. Saudi ability to procure weapons from Washington has been complicated by bipartisan criticism of the conduct of its war in Yemen © AP

Andrew England in London, Samer Al-Atrush in Dubai and James Politi in Washington JANUARY 8 2022

Saudi Arabia has appealed to regional countries for help to replenish the depleted stock of interceptor missiles for its US-made Patriot air-defence system as Yemeni rebels ramp up rocket and drone strikes on the kingdom.

A senior US official said the Biden administration supported the moves to source missiles from the Gulf amid concerns that Riyadh's Patriot stocks could run out in "months" given the current rate of attacks on the kingdom by Houthi rebels. The US has to greenlight transfers of the interceptors.

"It's an urgent situation," the official told the Financial Times. "There are other places in the Gulf they can get them from, and we are trying work on that. It may be the faster alternative [to US arms sales]."

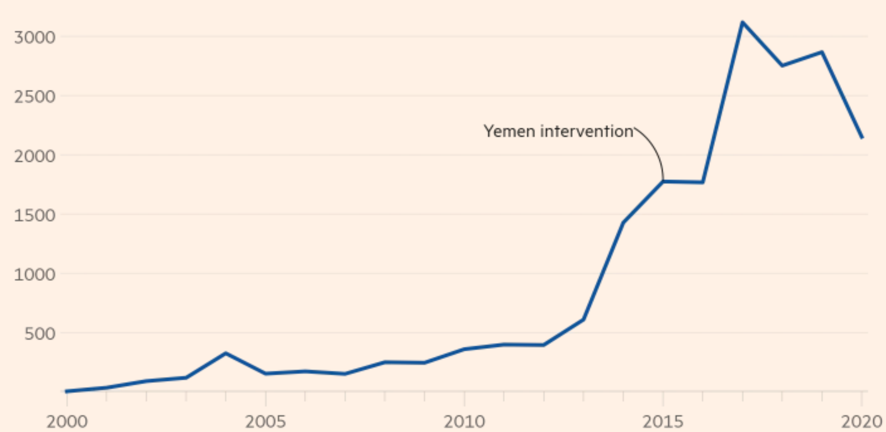
Two people briefed on talks between Saudi Arabia and its neighbours confirmed that Riyadh had made such requests. "There is an interceptor shortage. Saudi Arabia has asked its friends for loans, but there are not many to be had," said one of the people.

A second person said Saudi Crown Prince Mohammed bin Salman hinted at the issue during a Gulf Cooperation Council summit in Riyadh in December and the kingdom subsequently contacted nations in the region directly.

It is not clear if Saudi Arabia's neighbours have been able to supply it with munitions yet.

US arms exported to Saudi Arabia

Military capability of arms exported, SIPRI Trend Indicator Value (millions)



TIV is an index score measuring the capability of weapons transferred, rather than actual volume or sales
Source: SIPRI Arms Transfers Database
© FT

Experts said it would only be a short-term measure to help cover the time it takes for the kingdom to secure US approval for arms sales. Saudi Arabia sources most of its arms from the US but its ability to procure weapons from Washington has been complicated by bipartisan criticism of the conduct of its war in Yemen, as well as concerns about human rights abuses under Prince Mohammed's leadership.

Another senior administration official said Washington was “working closely with the Saudis and other partner countries to ensure there is no gap in coverage”.

A third US official said the Houthi rebels, who are aligned to Iran and control northern Yemen, ramped up their assaults on the kingdom last year, launching 375 cross-border attacks against Saudi Arabia, many of which targeted oil infrastructure, airports and cities.

“Responding to those attacks using those kind of interceptors means that they’re going to have a burn rate that is faster than they may have anticipated before,” the official said. “That is something that we have to deal with and the answer to that is not only more interceptors, but the answer to that is ultimately a diplomatic solution to the crisis in Yemen.”

Saudi defence systems take out the majority of projectiles. But 59 civilians have been killed since Riyadh launched its war against the Houthis seven years ago, according to Brigadier General Turki al-Malki, the Saudi defence spokesman.

He said the kingdom valued “its strong and solid partnership with the United States”. “Our military co-operation is ongoing and we will continue to work closely with our US partners in facing the threat of cross-border ballistic missiles, rockets, and UAVs [drones],” he said.

US President Joe Biden froze the sale of offensive weapons to Saudi Arabia shortly after he entered the White House and ended support for the Saudi-led coalition fighting the Houthis.

He pledged to reassess relations with Riyadh and has criticised the kingdom over the 2018 murder of Jamal Khashoggi by Saudi agents and progressive Democrats are resistant to supporting the kingdom.

Last year, Washington redeployed some Patriot systems out of Saudi Arabia. Biden administration officials insist they are committed to the defence of the kingdom, and the state department has recently approved the sale of 280 air-to-air missiles. In December, the Senate rejected a bipartisan bid to block the $680m deal.

The senior US official said the 280 air-to-air missiles would be a “big help”. But he said the armaments would take time to arrive in the kingdom, adding that Riyadh needed the Patriot interceptors “in addition to that to help them tide them over”.

“This town is hard for the Saudis,” he said. “Even saying we are committed to the defence of the Saudis is a risky statement in this environment.”

Lloyd Austin, the US defence secretary, told a Middle East conference in November that Washington was “significantly enhancing Saudi Arabia’s ability to defend itself”.

Saudi Arabia has been fighting the Houthis since leading an Arab coalition that intervened in Yemen’s civil war in 2015 after the rebels ousted the Yemeni government and seized Sana’a, the capital.

Riyadh’s intervention was backed by the US and UK, but its conduct of the war drew widespread criticism and stoked pressure on governments to halt arms sales to the kingdom as thousands of Yemeni civilians were killed in coalition air strikes, including hundreds of children.

Seth G Jones, director of the international security programme at the Center for Strategic and International Studies, said that there was growing recognition in Washington of the Houthi threat to Saudi Arabia, and concern that if the US did not support the kingdom, Riyadh would turn to China. More centrists elements of the Democratic party are pushing back against progressives, arguing “we need to defend them [Saudi Arabia] from adversaries and pre-empt the Chinese moving in”, he said.

https://www.wsj.com/articles/u-s-businesses-sour-on-saudi-arabia-in-blow-to-crown-princes-growth-plans-11642242604?mod=hp_lead_pos3

U.S. Businesses Sour on Saudi Arabia in Blow to Crown Prince's Growth Plans

Surprise tax hits, unpaid bills and stolen intellectual property undo government's effort to shift economy away from oil

Contractors on Riyadh's new metro system sent some staff home last year amid a more than $1 billion payment dispute. FAYEZ NURELDINE/AGENCE FRANCE-PRESSE/GETTY IMAGES

By Stephen Kalin Follow *and* Justin Scheck Follow

Jan. 15, 2022 5:30 am ET

RIYADH—Saudi Arabia courted the world's top companies to modernize its economy. Instead, the business environment has grown more hostile and investors are souring on the oil-rich kingdom.

Uber Technologies Inc., UBER -3.17% General Electric Co. and other foreign firms were hit by surprise tax assessments often totaling tens of millions of dollars.

Construction company Bechtel Corp. sent some contractors home while it tried to collect on more than $1 billion in unpaid bills.

Bristol-Myers Squibb Co. BMY 0.51% , Gilead Sciences Inc. GILD -0.15% and other drugmakers have complained unsuccessfully for years that their intellectual property was being stolen.

The result is foreign investment in Saudi Arabia has remained stubbornly low and some companies are scaling back their operations or delaying promised expansion plans.

That is a blow to Crown Prince Mohammed bin Salman, the country's de facto leader. He vowed in 2016 to build new industries unrelated to oil by improving the business climate and creating a global hub for innovation. Since then, reducing Saudi Arabia's dependence on oil has grown increasingly urgent as the global economy moves away from fossil fuels.

Foreign direct investment into Saudi Arabia was $5.4 billion in 2020, less than half the level of a decade ago and well below the $19 billion that the country had targeted. It was on track to top $6 billion in 2021 based on data through the third quarter. That excludes the $12.4 billion sale of a stake in a Saudi pipeline company to foreign investors.

One reason the number has stayed low is planned projects that didn't happen. Apple Inc.'s plans to open a flagship store in central Riyadh several years ago have languished. Triple Five Group, the developer of the Mall of America, pulled back from building a multibillion-dollar complex. And movie-theater company AMC Entertainment Holdings is ceding greater control to its Saudi government partner as it lags behind local rivals. AMC says it is pleased with its progress in the kingdom. Apple and Triple Five didn't respond to requests for comment.

Businesses are attracted to Saudi Arabia's potential, "but economic practicalities are still being hammered out," said Robert Mogielnicki, resident scholar at the Arab Gulf States Institute think tank in Washington, D.C.

The Saudi investment ministry said interest in the country remains high, pointing to a 250% annual increase in new investor licenses in 2021.

Saudi Arabia has long been a tough place to do business, with a sluggish bureaucracy, outmoded legal system and poor human-rights record. Prince Mohammed sought to change that, promising big reforms, holding lavish investment conferences in Riyadh and hobnobbing with Silicon Valley executives.

His efforts have borne some fruit. The easing of strict social norms led to new tourism and entertainment industries, and improved the quality of life for expatriate workers. The government rolled out a bankruptcy law, allowed full foreign ownership in certain sectors and streamlined some business services.

The investment ministry said it takes investors' concerns seriously and is constantly reviewing and evolving as needed. "Whether it was a small business or a big corporation, we continue to strive towards creating the best possible environment to do business," it said.

The prince's agenda stumbled in 2018 when men working for him killed journalist Jamal Khashoggi.

That scuttled big deals including with Amazon.com Inc., Richard Branson's space tourism venture and Hollywood superagent Ari Emanuel.

Prince Mohammed failed to change many of the old deterrents to investment. Then Saudi Arabia added new ones.

The country tried to address a cash crunch by levying retroactive taxes on dozens of large foreign firms. In the past year-and-a-half, companies including Uber, its regional subsidiary Careem, and GE have faced huge tax liabilities and sometimes additional fines when their appeals were rejected.

Tax authorities offered the companies little recourse, prompting the State Department late last year to appeal unsuccessfully to the Saudi government for relief.

General Electric, Uber and Careem declined to comment.

The Saudi tax authority said the kingdom aspires to fair and efficient tax policy in line with international standards. It said it maintains full communication with taxpayers undergoing audits and gives them ample time to comply with requests.

The tax change came on top of an overnight tripling of the value-added tax rate in 2020. Such surprises have become commonplace, with new policies often undercutting previously stated objectives.

The government further rattled foreign companies when it ordered them to move their regional headquarters to Riyadh from Dubai or lose government contracts. Companies also were forced to hire more Saudis. And a requirement to boost local content in their products made some goods uncompetitive compared with imports.

Investors are also increasingly concerned about their physical safety. While most of the people arrested in Prince Mohammed's crackdowns on criticism or alleged corruption have been Saudis, some have been foreigners. One foreign businessman said he was detained and tortured after saying publicly that some business laws were unfair.

Another, an American, recently authorized the State Department to disclose relevant information to the media should the person be detained in Saudi Arabia. A second American, seeking to expand his Ohio-based nursing-home operation, was detained on arrival last year in a cramped airport holding cell for three days and deported without explanation.

The investment ministry declined to comment on specific allegations of mistreatment but said most investors have positive experiences.

Saudi Arabia’s long-running dispute with drugmakers over intellectual property has contributed to wariness among the innovative companies the country is courting. Since 2016, Saudi regulators have authorized domestic companies to manufacture generic versions of nearly a dozen pharmaceuticals still under patent or regulatory data protections.

The dispute is one reason Saudi Arabia remains on the U.S. Trade Representative’s priority watch list for intellectual-property violations alongside well-known offenders including China and Russia. Bristol-Myers Squibb and Gilead declined to comment.

As in the tax dispute, contesting the generic-drug policy has proved fruitless despite protests by the State Department and White House. The companies were advised that pursuing claims in Saudi courts is time-consuming and uncertain.

“There are ways to solve this, but the Saudis decided not to,” said one of the people close to those efforts. “Saudi wants the best, but their laws are deterrents to drawing the best.”

The investment ministry said it is studying the issue “to enable a workable balance between a thriving generics and an R&D-based innovation industry.”

Some companies that have worked in Saudi Arabia for decades have downsized their presence amid disputes over payment from government clients, a perennial gripe in the kingdom. Contractors on Riyadh’s new metro system, including Bechtel, sent some staff home last year amid a more than $1 billion payment dispute. Northrop Grumman Corp. , which has sold billions of dollars of military equipment to the kingdom, reduced its footprint about two years ago after the military failed to pay for products it provided.

Bechtel and Northrop declined to comment.

The Saudi government said it has reformed public procurement laws to eliminate the problem and cleared the backlog of cases.

The situation is often worse for smaller companies and solo entrepreneurs, for whom minor issues can turn into painful ordeals.

Suleiman Salehiya, 67 years old, owned a small business that landscaped Saudi universities and royal palaces. After the government reversed a previous round of widely touted business reforms to favor local competitors, the Palestinian investor petitioned investment officials and then sued them. In court, he was given less than two minutes to plead his case, before a judge ruled against him, he said.

Barred from working or leaving the country without paying hundreds of thousands of dollars in disputed fees, Mr. Salehiya remains mired in red tape and stranded in Riyadh with his wife and children, who haven't been able to complete their education or start their own careers.

After Mr. Salehiya, already facing the consequences of the court ruling, spoke with a Wall Street Journal reporter in 2018, police raided his home in the middle of the night, bound his hands and feet and covered his head with a bag. They stuffed him into an SUV and drove him to a small cell where he remained for 18 days with the air conditioner running full blast and two spotlights keeping him awake. Interrogators asked about his business, the lawsuits and his meeting with a foreign journalist.

"They shouted in my face, pounded on the table and gave me electric shocks," he said. "My crime is that I respected the law and followed it."

—*Summer Said, Benoit Faucon and Rory Jones contributed to this article.*

Write to Stephen Kalin at stephen.kalin@wsj.com and Justin Scheck at justin.scheck@wsj.com

https://tass.ru/politika/13428873
THE SITUATION AROUND IRAN'S NUCLEAR PROGRAM
JAN 14, 03:01Updated by Jan 14, 03:35

Lavrov reported on real progress in negotiations on Iranian nuclear deal

Iran must think realistically to reach agreement on nuclear deal, Foreign Minister said

MOSCOW, January 14. / TASS /. Real progress has been made in negotiations on the Iranian nuclear deal, Russian Foreign Minister Sergei Lavrov said at a press conference on the results of the activities of Russian diplomacy in 2021.

"There is real progress on the Iranian nuclear program <...>, there is a real desire, primarily between Iran and the United States, to understand specific concerns and understand how these concerns can be taken into account in the general package," the minister said.

Lavrov stressed that "it can only be a package solution," like the Iranian deal itself. "The joint overarching plan of action was a package solution," he said.

According to the minister, experienced negotiators in Vienna "have already penetrated into the very details of this negotiating matter" and "are making good progress now." "I am knocking on wood, but we expect that an agreement will be reached," he concluded.

According to Lavrov, Iran must think realistically to reach an agreement on a nuclear deal. “We hope that an agreement will be reached. For this it is important that the Iranian partners are as realistic as possible, cooperate with the IAEA,” the minister said. “Secondly, it is important that the Western participants in this negotiation process do not try to create some kind of psychological tension. , periodically throwing into the media public space initiatives criticizing Iran and demanding it. "

According to the head of the Russian Foreign Ministry, "quiet diplomacy" is needed here. “I will repeat it once again, it works,” he stressed. Lavrov also noted with satisfaction that it was possible to overcome the situation when the West began to put forward conditions for the resumption of the Iranian nuclear program, which related to the imposition of restrictions on Iran's missile program, not fixed in the JCPOA, and conditions concerning the "behavior" of the state in the region. The minister stressed that Russia was categorically against such a dishonest approach, "because it was about the JCPOA, which was approved by the UN Security Council in the form in which it was signed." "The point was that after the Trump administration withdrew from this agreement, restore it in full, as agreed, without exceptions and without any appendages," https://www.aljazeera.com/news/2022/1/14/us-blinken-says-only-few-weeks-left-to-save-iran-nuclear-deal

Antony Blinken says ‘a few weeks left’ to save Iran nuclear deal

US officials report modest gains during talks in Vienna, but warn nuclear advances will soon become irreversible.

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United States Secretary of State Antony Blinken says there are only “a few weeks left” to save the 2015 Iran nuclear deal before Tehran’s advancements will become too difficult to reverse.

Blinken spoke on Thursday as negotiations in Vienna between Tehran and the other signatories of the 2015 deal, from which former US President Donald Trump unilaterally withdrew in 2018, continued.

The US has been participating in the talks indirectly, with Washington and Tehran, despite trading charged rhetoric, recently reporting modest gains after months of near-total deadlock. The newest round of talks resumed in November.

“We have, I think, a few weeks left to see if we can get back to mutual compliance,” Blinken said in an interview with US public radio station NPR.

“We’re very, very short on time,” because “Iran is getting closer and closer to the point where they could produce on very, very short order enough fissile material for a nuclear weapon,” he said.

Blinken added that Tehran has made nuclear advances that “will become increasingly hard to reverse because they’re learning things, they’re doing new things as a result of having broken out of their constraints under the agreement”.

The nuclear deal offered direly needed international sanctions relief to Iran in exchange for curbs on its nuclear programme.

Trump reimposed a “maximum pressure” sanctions campaign after withdrawing from the agreement, and Tehran has since increasingly flouted the restrictions in the deal, arguing it is no longer beholden to the agreement following the US withdrawal.

US President Joe Biden has made returning to the deal a top priority, while newly elected Iranian President Ibrahim Raisi, despite holding more hardline positions than his predecessor, is eager to find relief from crushing sanctions.

In an interview with Al Jazeera in early January, Iranian Foreign Minister Hossein Amir-Abdollahian said a return to the deal could be reached if “all forms of sanctions stipulated in the nuclear agreement” were lifted – an apparent softening of the government’s previous calls for a complete lifting of all sanctions, even those imposed on human rights grounds.

On Thursday, Blinken said reviving the accord “would be the best result for America’s security”.

“But if we can’t, we are looking at other steps, other options” with allies including in Europe and the Middle East, he added.

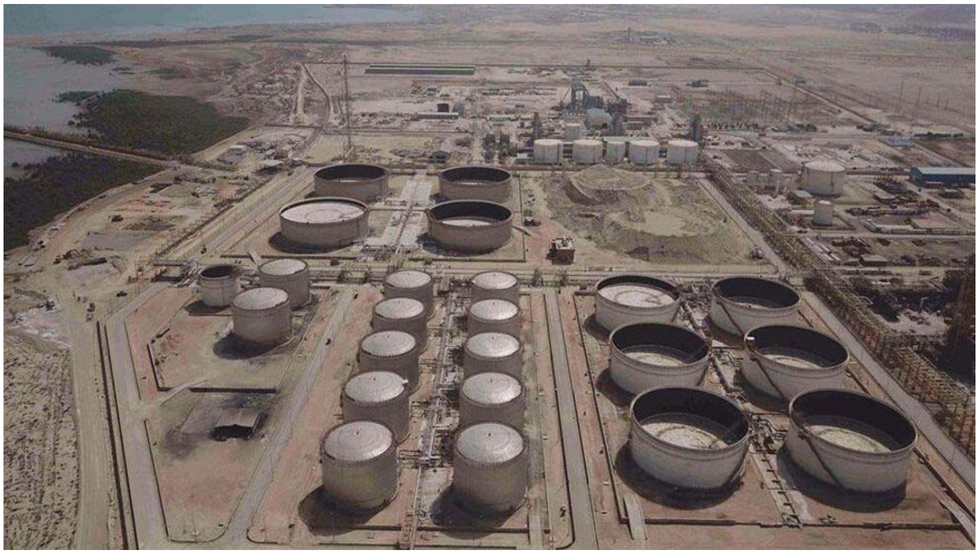
Those “other options” – often seen as an implicit threat of military actions – have been “the subject of intense work as well in the past weeks and months”, Blinken said.

“We’re prepared for either course.”

https://www.presstv.ir/Detail/2022/01/13/674693/Iran-super-heavy-oil-refinery-Qeshm-launch

Iran opens its first super heavy oil refinery in Qeshm

Thursday, 13 January 2022 6:34 PM **[Last Update: Thursday, 13 January 2022 6:34 PM]**



Iranian president is to officially inaugurate the super heavy oil refinery in the southern Qeshm Island.

Iranian President Ebrahim Raeisi is to officially inaugurate a first super heavy oil refinery in Iran on Friday as the country moves ahead with plans to develop its massive petroleum sector despite sanctions imposed by the United States.

The official IRNA news agency said in a Thursday report that Raeisi will open the Qeshm Heavy Oil Refinery on the second day of his provincial tour to the southern Hormozgan region.

It said the refinery had been working on a pilot basis and using a half of its refining capacity in recent years, adding that the facility has now reached its full capacity for processing 70,000 barrels per day of crude.

Iran's Oil Minister Javad Owji said during a visit to the refinery on Thursday that the facility will fed on super heavy oil from Soroush and Nowruz oilfields in the Persian Gulf.

Owji said private owners of the Qeshm Refinery had provided around $220 million in investment for construction of the refinery and for the supply of machinery and equipment to the facility.

He said the refinery could reach a refining capacity of 100,000 barrels per day within the next three years.

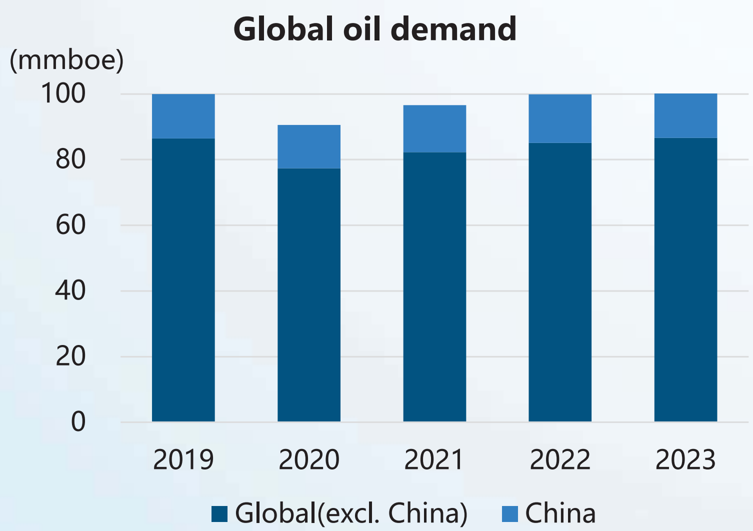
Qeshm in one of the world's largest islands that is located in the Persian Gulf just few kilometers off the southern Iranian coast.

The area is one of major special economic zones of Iran where regulations are more lax compared to the mainland to encourage more investment in trade and manufacturing activities in the region.

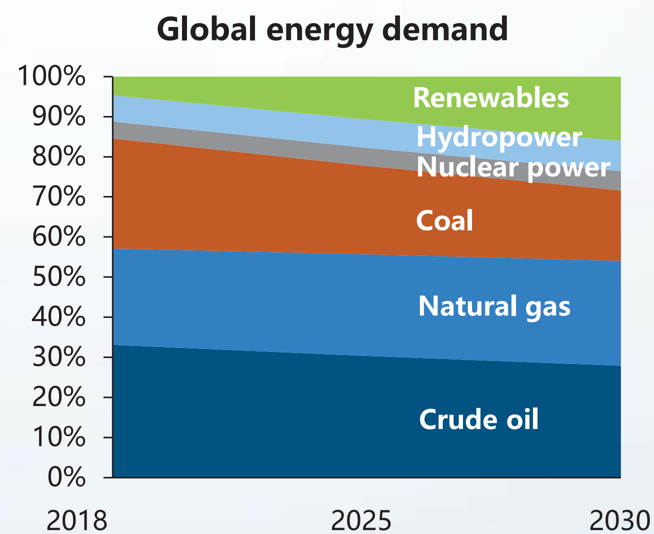
Qeshm Heavy Oil Refinery will become a major supplier of bitumen in Iran as local authorities said the facility will be responsible for one fifth of Iran's total bitumen exports in the near future.

Oil Demand

- **Global and China oil demands are gradually recovering and will continue to grow**
- **Major economies have actively made Net Zero commitments, while oil and gas will continue to account for over 50% of world's future primary energy consumption**



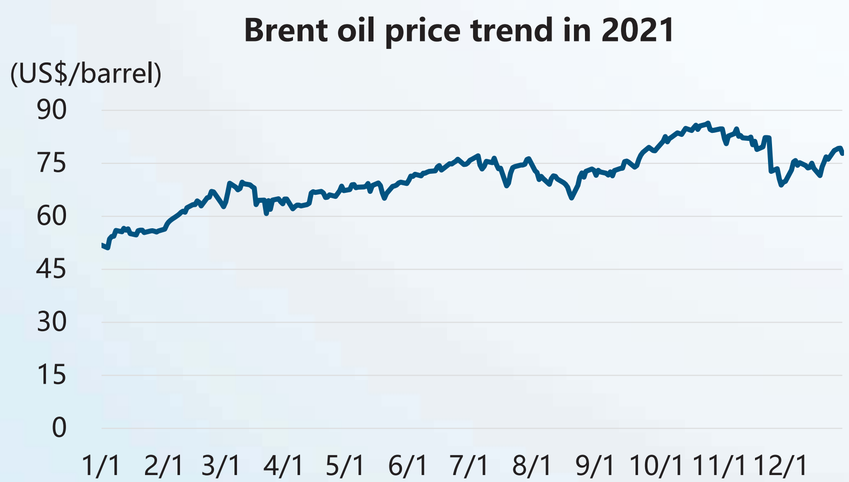
Source: OPEC's World Oil Outlook, 2021



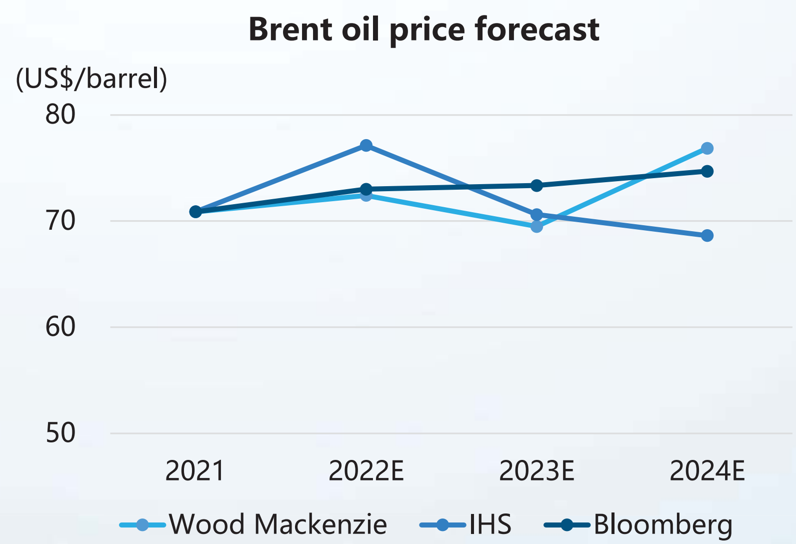
Source: BP World Energy Outlook, 2020

International Oil Price

- International oil prices showed a general upward trend amid fluctuations in 2021, with a slight fall at year end due to recurring pandemic and other factors
- Oil prices in the next three years are expected to remain above US$70/barrel



Source: Bloomberg



Three-year Rolling Production Target

China's Oil Imports Drop for First Time Since 2005 as Costs Soar
2022-01-14 04:10:18.22 GMT

By Bloomberg News
(Bloomberg) -- China's annual crude imports fell for the first time since at least 2005 on the back of rising prices and lower stockpiling activity following an earlier buying spree.
The nation imported about 513 million metric tons of crude in 2021, or 10.3 million barrels a day, according to data released Friday by the General Administration of Customs. That's about 580,000 barrels per day lower than 2020 and the first decline since 2005 when yearly data was made available. December inflows rose from the previous month to 46.14 million tons.
Inbound shipments to the world's biggest oil importer dipped last year as global benchmark Brent crude soared, prompting buyers to stay on the sidelines after building up inventories during 2020's Covid-related price crash. Crude purchases are likely to recover this year as new refineries start up, although independent processors are facing some headwinds.
The ramping up of new plants such as Shenghong Group's 320,000 barrel-a-day integrated refinery and PetroChina's 400,000 barrel-a-day Guangdong complex will lift crude demand, according to Energy Aspects Ltd. The industry consultant predicts a 4% rise in refining throughput in 2022 from the previous year.
Consultant FGE sees potential run rate cuts causing limited upside for imports in the early months of 2022 as China strives to curb pollution ahead of key events such as the Winter Olympics in Beijing. Additionally, the reduction in crude-import quotas for independent refiners may also cap daily imports, which it forecasts at about 11 million barrels in January and February.

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Sarah Chen in Beijing at schen514@bloomberg.net

China Orders Cut to Some Oil Refining Ahead of Olympics: JLC
2022-01-12 08:16:18.426 GMT

By Alfred Cang
(Bloomberg) -- China ordered some independent oil refiners to reduce crude processing ahead of the Winter Olympics, according to industry consultant JLC, as authorities seek to ensure blue skies for the games.
Some processors in the eastern province of Shandong received notices to curb operating rates by about 20% from Jan. 30 to Feb. 20, according to a note from JLC on its WeChat account, citing people it didn't identify. A combined refining capacity of 20 million to 35 million tons a year could be affected, JLC said.
Beijing is ramping up pollution controls ahead of the Olympics starting on Feb. 4, which could curtail the supply of commodities from chemicals to fertilizers. A handful of refiners in Dongying, Shandong, -- which is about 400 kilometers (248 miles) southeast of Beijing -- have already completely halted operations due to strict environmental requirements for the games, JLC said.
Industrial activity typically slows around the Lunar New Year holiday, which starts Feb. 1 in China, while independent processors usually start maintenance work from the second half of March. The buying of crude cargoes for delivery in February and March is likely to remain sluggish due to the curbs, JLC said.

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To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R5L4G5T1UM0W

SAF Group created transcript of excerpts of comments from Mike Muller (Heat, Vitol Asia) on Gulf Intelligence Daily Energy Markets Jan 16 podcast, hosted by Sean Evers (Managing Partner, Gulf Intelligence). Podcast at [LINK]

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

At 1:20 min mark: Evers re prices are back to $86, "*.. are you surprised to see prices back at these levels given the sort of general outlook of supply and demand?"* Muller "*let's just repeat the numbers. $86.50 brent is pretty much the highs of move in October last year, and to go back to when we are at or above that level, there was an $86.70 print in October 18, but then any higher than that, you have to go back to 2014 when prices fell of that plateau they had established to about 4 or 5 years of $100 to $115 per barrel. So we are pushing towards this triple top of the market and possibly new highs. But WTI is close to $84 a barrel, that's come along even faster. And of course, given you have a much more responsive upstream scene with investment prospects in the Permian Basin there. That's incentivizing drilling and so forth. And the other one we need to start to mentioning breath is European gas, which has been making all the headlines while you've had your recess here on these sessions. which had gone as high as 180 something Euros per megawatt hour and that's now sitting at 83 as well. So those markets have definitely been extremely active and volatile. So am I surprised was your question. If you look at global inventories of oil and you look at the success of the OPEC+ concerted action to take inventories down to pre-pandemic levels. OPEC succeeded many months ago but continue to forge on with their policy so much so that many of their producers can't really put their share of the 400,000 b/d monthly increase into the market any longer. Which has been a theme for many months already on these calls. The prices are very much in the hands of core GCC and you could argue Russia. But global inventories are below pre-pandemic levels and in many cases, there are pockets of tightness which would have you say that a front end backwardation and a strong market is very much justified. In fact to put it very generically, there is really one part of the world that has spare capacity in terms of refining capacity and inventories and that is the part of the world where data is a little bit less readily available on a real time basis, namely China. But in the rest of the world, you have a phenomenon in Europe that despite the fact that the piece of the global demand picture that is still missing is jet fuel. You have the regrade as we call it, the differential between jet fuel and diesel, trading positive in Europe for the first time in a very long time. it's still inverted, still negative in Asia. But that tells you there's not enough jet fuel around in a market that's still missing a huge piece of aviation demand. 0.5% very sulfur fuel, which propels ships is tight, the inventories on that product are back down to the sort of levels we had pre IMO when the world was panicking about whether we could make and blend enough of that. and I could go on and on. There are some pockets of the energy complex that are less tight. I mean margins for olefins, petrochemicals are less stellar so that has naptha being one of the weaker products out there. but I could go on and on and on and our half hour would be up if we're not careful. So it is a very tight fundamental market, which underpins the backwardation we are seeing at the front of the market which is 50, 70 cents at the very prompt, but then 80, 90 cents per barrel per month going into the back months. I think Yes, these prices are justified and I think the fact that we've had a lot of risk-off mindset at the end of the year, there's a lot of managed money sitting on the sidelines that might say, hang on oil is looking to about to pop towards 90 and maybe even through that level, let's not miss out. And if that money, which is currently on the sidelines comes back into oil, there is a very real prospect of us making [he was cut off from finishing the sentence]"*

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

Jan 11, 2022 11:40:43

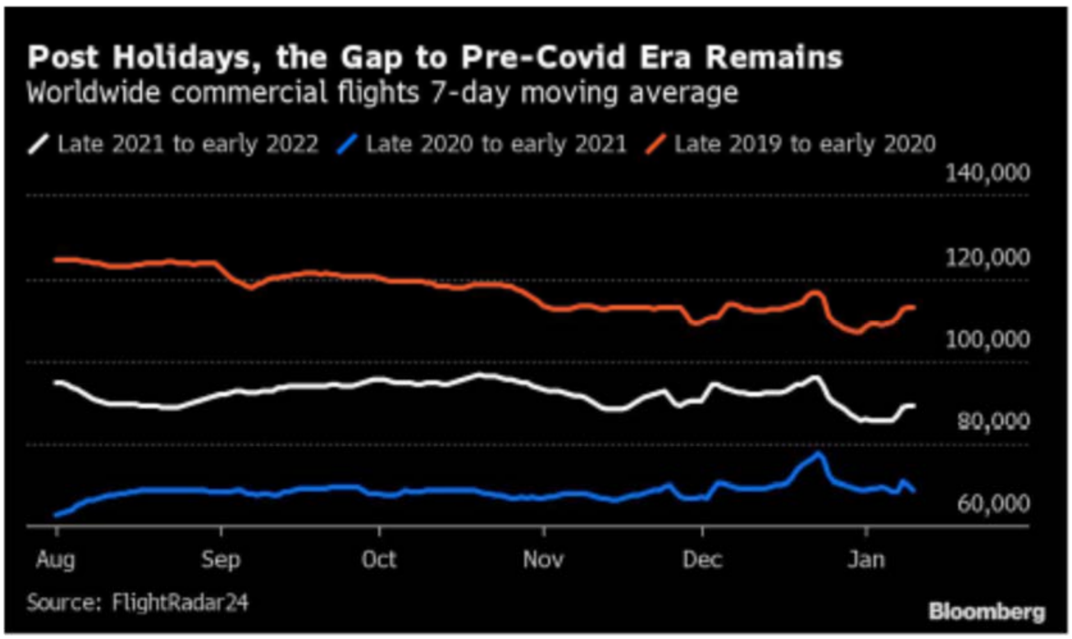
OIL DEMAND MONITOR: Gasoline Sales Resilient to Omicron, for Now

- City traffic building up again after the year-end holidays
- Flights trail pre-Covid period and omicron remains a worry

By Stephen Voss

(Bloomberg) -- Gasoline sales largely remained resilient over the past month in countries including India, the U.S. and Spain and city traffic is growing again around the world after holidays that have made it hard to tell whether the omicron variant of coronavirus is impeding demand for oil-based fuels.

Flight data, which is more easily monitored day to day, shows that despite the usual year-end dip, there hasn't yet been an overly dramatic fall-off in activity. Worldwide commercial flights over the seven days ended Jan. 9 were about 17% and 21% below the same periods of 2019 and 2020, respectively, according to FlightRadar24, which is very similar to percentages seen during the past three months.



With the holiday season over, inner city road traffic picked up during the past week in most locations, particularly in Europe, though congestion is still lower than early-December readings, data from TomTom NV showed. And all world cities regularly tracked in this monitor showed congestion levels at 8 a.m. on Monday morning that were lower than typical levels seen in 2019. The closest was London, which trailed the pre-pandemic average by 3%. New York was 40% down.

Coronavirus case numbers are surging around the globe as the easy-transmissible omicron variant spreads, with records reached in the past few days in New York, the Philippines, Australia and parts of Japan. Some locations are further along that timeline than others, and London "may well be past the peak" of its omicron wave, Kevin Fenton, the city's regional director for public health, said on Sunday. While road congestion information is updated daily, actual sales data take longer to be published. The latest numbers for the U.K. are for the week ended Jan. 2, showing total road fuel sales 40% below the pre-lockdown baseline of the first week of February 2020. While those sales numbers appear weak, the period straddles the New Year holiday so isn't a good indicator of how omicron is affecting driving habits.

A broader nationwide measure of traffic in the U.S. -- vehicle miles on interstate highways in the week ended Jan. 2 -- was 0.5% above the same week of 2019. That reading, which includes cars and trucks, was little different from the prior week when it was 1% above.

Resilient demand and stubbornly high oil prices appear to be justifying, at least for now, the OPEC+ oil producer alliance's decision last week to press ahead with planned production increases, adding another 400,000 barrels a day in February.

Gasoline Demand

Gasoline demand has generally been trending a few percentage points above 2019 levels in many major consuming countries. That's true for monthly November data in Italy, Portugal and Brazil and also for Spain and India, where more timely December data is available. The U.S. provides an estimate each week, with the latest reading for the week ended Dec. 31 some 0.5% higher than the pre-pandemic year. Among those same countries, estimates of distillate or diesel consumption are also higher than 2019 in the U.S., Italy and Brazil and are slightly below in India, Spain and Portugal.

Jet fuel demand remains lower than the pre-pandemic levels in all of the countries previously mentioned, as travel restrictions continue to hobble airlines, though the margin varies considerably. The latest weekly estimate from the Energy Information Administration shows a deficit of just 8.9% in the U.S. while December estimates for India and Spain show consumption down by about 25% versus two years earlier.

Airline Seat Capacity Reductions

The most recent data may nevertheless be troubling for airlines. The number of seats offered by airlines for the week starting Jan. 10 fell in almost all major markets except China, when compared with figures for the week starting Jan. 3, according to OAG Aviation. The number of seats has also been revised down for the full month and later this quarter.

"This week has seen a considerable adjustment in January capacity with 8.7 million seats taken out in the last week for the full month, a reduction of 2.4%," OAG said in a note. "Capacity has also been reduced through February and March, with a further 8.3m seats removed over these two months."

Much of the most recent capacity reduction is in Europe, where omicron is affecting international travel, OAG said.

Heathrow Airport Ltd., which operates the U.K.'s biggest airport, said there's still significant doubt over the speed at which demand will recover.

"At least 600,000 passengers cancelled travel plans from Heathrow in December due to omicron and the uncertainty caused by swiftly imposed government travel restrictions," the company said Tuesday.

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

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

Demand Measure	Location	% y/y	% vs 2019	% m/m	Freq	Latest Date	Latest Value	Source
Gasoline	U.S.	+9.8	+0.5	-8.8	w	Dec. 31	8.17m b/d	EIA
Distillates	U.S.	+27	+11	+4.5	w	Dec. 31	3.74m b/d	EIA
Jet fuel	U.S.	+60	-8.9	+20	w	Dec. 31	1.47m b/d	EIA
Total oil products	U.S.	+15	+1.5	-0.9	w	Dec. 31	19.67m b/d	EIA
All vehicles miles traveled	U.S.		+0.5		w	Jan. 2	16.2b miles	DoT
Passenger car VMT	U.S.		-1.2		w	Jan. 2	n/a	DoT
Truck VMT	U.S.		+7.4		w	Jan. 2	n/a	DoT
All motor vehicle use index	U.K.	+26	-23	-16	d	Jan. 4	77	DfT
Car use	U.K.	+34	-25	-14	d	Jan. 4	75	DfT
Heavy goods vehicle use	U.K.	-13	-24	-31	d	Jan. 4	76	DfT
Gasoline (petrol) avg sales per filling station	U.K.	+30	-28	-25	w	Dec. 27-Jan. 2	5,240 liters/d	BEIS
Diesel avg sales per station	U.K.	+13	-47	-45	w	Dec. 27-Jan. 2	5,490 liters/d	BEIS
Total road fuels sales per station	U.K.	+20	-40	-37	w	Dec. 27-Jan. 2	10,730 liters/d	BEIS
Gasoline	India	+4.3	+13	+6.7	2/m	Dec. 1-31	2.54m tons	Bberg
Diesel	India	+1.5	-1.6	+12	2/m	Dec. 1-31	6.45m tons	Bberg
LPG	India	-1.2	+6.3	+5.3	2/m	Dec. 1-31	2.5m tons	Bberg
Jet fuel	India	+25	-27	+10	2/m	Dec. 1-31	504k tons	Bberg
Total Products	India	-11	-7.5	-4.1	m	November	17.1m tons	PPAC
Toll roads volume	Italy	+102	+3.7		w	Dec. 20-26	n/a	Atlantia
Toll roads volume	Spain	+39	-9		w	Dec. 20-26	n/a	Atlantia
Toll roads volume	France	+28	-5.3		w	Dec. 20-26	n/a	Atlantia
Toll roads volume	Brazil	+7.9	+0.5		w	Dec. 20-26	n/a	Atlantia
Toll roads volume	Chile	+51	+27		w	Dec. 20-26	n/a	Atlantia
Toll roads volume	Mexico	+20	+11		w	Dec. 20-26	n/a	Atlantia
Gasoline	Spain	+23	+1.4	+6.3	m	December	477k m3	Exolum
Diesel	Spain	+7.6	-0.7	+2.7	m	December	2466k m3	Exolum

Jet fuel	Spain	+142	-24	+8	m	December	377k m3	Exolum
Road fuel sales	France	+40	+2.9	-4.9	m	November	4.09m m3	UFIP
Total fuel sales	Italy	+15	-0.2	-4.7	m	November	4.25m tons	Ministry
Gasoline	Italy	+47	+6.5	-6.7	m	November	586k tons	Ministry
Diesel /gasoil	Italy	+18	+2.8	-5.9	m	November	2.23m tons	Ministry
Jet fuel	Italy	+72	-34	-8.6	m	November	222k tons	Ministry
All vehicles traffic	Italy	+38		-6	m	November	n/a	Anas
Heavy vehicle traffic	Italy	+4.8		+1	m	November	n/a	Anas
Gasoline	Portugal	+19	+6.9	-13	m	November	81k tons	ENSE
Diesel	Portugal	+8.1	-3.8	-4.5	m	November	402k tons	ENSE
Jet fuel	Portugal	+177	-5.6	+2.3	m	November	105k tons	ENSE
Gasoline	Brazil	+6.7	+6.7	-0.9	m	November	720k b/d	ANP
Diesel	Brazil	+4.2	+6.2	-6.2	m	November	1.07m b/d	ANP
Jet fuel	Brazil	+40	-21	+10	m	November	94k b/d	ANP

Note: Click here for a PDF with more information on sources, methods. The frequency column shows d for data updated daily, w for weekly, 2/m for twice a month and m for monthly.
* In Dfr 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, which is only released once per month, 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.

City congestion:

Measure	Location	% chg vs avg 2019	% chg m/m	Jan. 10	Jan. 3	Dec. 27	Dec. 20	Dec. 13	Dec 6	Nov 29	Nov 22	Nov 15
		(Jan. 10)			Congestion minutes added to 1 hr trip at 8am local time							
Congestion	Tokyo	-85	-85	5	1	31	38	37	33	35	30	38
Congestion	Taipei	-10	-24	32	32	43	31	42	41			
Congestion	Jakarta	-18	+6	32	26	20	28	30	28			
Congestion	Mumbai	-98	-89	1	2	2	4	5	6	6	8	6
Congestion	New York	-40	-28	19	11	5	20	26	32	28	34	33
Congestion	Los Angeles	-63	-51	13	10	6	16	27	29	29	18	32
Congestion	London	-3	+2	37	1	1	13	36	41	43	43	46
Congestion	Rome	-43	-45	28	7	10	44	50	46	53	49	56
Congestion	Madrid	-66	-47	12	2	3	13	23	0	24	41	28
Congestion	Paris	-19	-22	36	19	10	18	46	52	46	53	51
Congestion	Berlin	-14	-21	29	20	9	22	37	32	31	32	31
Congestion	Mexico City	-60	-37	20	13	11	20	31	34	31	32	1
Congestion	Sao Paulo	-58	-35	18	10	10	22	28	28	29	27	3

Source: TomTom. Click here for a PDF with more information on sources, methods.
NOTE: m/m comparisons are Jan. 10 vs Dec. 13. TomTom has been unable to provide Chinese data since late April. Taipei and Jakarta were added to the table in early December. It was a public holiday in Tokyo on Jan. 3 and Jan. 10 and in London on Jan. 3.

Air Travel:

Measure	Location	y/y	vs 2 yrs ago	vs 2019	m/m	w/w	Freq.	Latest Date	Latest Value	Source
		changes shown as %								
Airline passenger throughput	U.S.	+91	+0.1	-24	-17	-16	d	Jan. 9	1.69m	TSA
Commercial flights	Worldwide	+27	-21	-17	-3.4	+2.6	d	Jan. 9	89,244	FlightRadar24
Air traffic (flights)	Europe			-22	+3.2	-7	d	Jan. 9	20,640	Eurocontrol
Seat capacity	Worldwide	+41	-27			-7.2	w	Jan. 10	77.9m	OAG
Seat cap.	U.S.	+61	-11			-3.4	w	Jan. 10	18.3m	OAG
Seat cap.	China	-1.9	-17			+1.5	w	Jan. 10	14.4m	OAG
Seat cap.	India	+25	-16			-6	w	Jan. 10	3.67m	OAG
Seat cap.	Japan	+31	-34			-4	w	Jan. 10	2.70m	OAG
Seat cap.	Brazil	+30	-15			-1.8	w	Jan. 10	2.44m	OAG
Seat cap.	Spain	+158	-26			-27	w	Jan. 10	1.64m	OAG
Seat cap.	U.K.	+197	-49			-31	w	Jan. 10	1.37m	OAG
Seat cap.	Mexico	+37	+1.5			-5.5	w	Jan. 10	1.94m	OAG
Seat cap.	France	+82	-38			-19	w	Jan. 10	1.14m	OAG
Seat cap.	Germany	+173	-51			-22	w	Jan. 10	1.23m	OAG
Seat cap.	Australia	+34	-39			-15	w	Jan. 10	1.25m	OAG
Seat cap.	S. Africa	+11	-45			-7	w	Jan. 10	331k	OAG
Seat cap.	Singapore	+120	-72			-0.7	w	Jan. 10	237k	OAG

NOTE: Comparisons versus 2019 or versus the early weeks of 2020 are a better measure of a return to normal for most nations, rather than y/y comparisons.
FlightRadar24 data shown above, and comparisons thereof, all use 7-day moving averages, except for w/w which uses single day data.

Refineries:

Measure	Location/area	chg vs 2020 (y/y)	chg vs 2019	m/m chg	Latest as of Date	Latest Value	Source
		Changes are in ppt unless noted					
Crude intake	U.S.	+10%	-6.1%	+0.5%	Dec. 31	15.9m b/d	EIA
Apparent Oil Demand	China	+4.7%		+5.9%	November 2021	14.18m b/d	NBS
Utilization	U.S.	+9.1	-3.2	unch	Dec. 31	89.8 %	EIA
Utilization	U.S. Gulf	+9	-6.9	+1.8	Dec. 31	90.7 %	EIA
Utilization	U.S. East	+24	+24	-1.2	Dec. 31	91.2 %	EIA
Utilization	U.S. Midwest	+6.6	-0.8	-1.6	Dec. 31	93 %	EIA

NOTE: All of the refinery data is weekly, except NBS apparent demand, which is usually monthly. Changes are shown in percentages for the rows on crude intake and Chinese apparent oil demand, while refinery utilization changes are shown in percentage points. SCI99 data on Chinese refinery run rates was discontinued in late 2021.

Air Passenger Market Analysis

November 2021

Air travel improved in November, but Omicron raises concerns

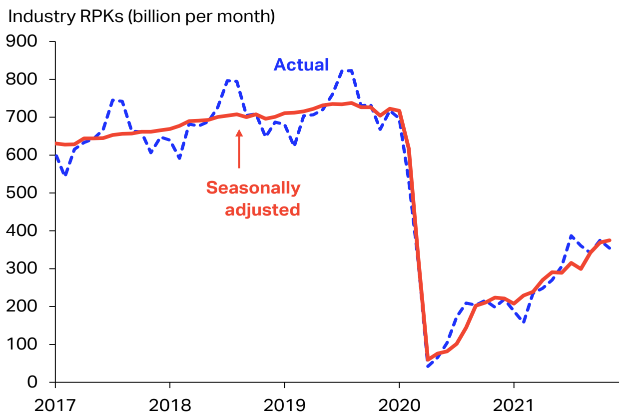
- Global air travel recovery continued ahead of the Omicron outbreak but was slower than in the previous months. Industry-wide revenue passenger-kilometres (RPKs) fell by 47.0% versus November 2019.
- International RPKs maintained their upward trend with improvements recorded across all regions. In contrast, domestic air travel deteriorated amidst new lockdowns in China.
- Passenger numbers might remain resilient in December as people traveled to see their friends and relatives. However, the emergence of the Omicron variant has led to a fall in international ticket sales in recent weeks, which increased uncertainty around further substantial RPKs improvement in early-2022.

The momentum in air travel recovery has slowed…

Air travel recovery continued in November ahead of the Omicron outbreak, but the traffic improvement was smaller than in the previous months. The industry-wide revenue passenger-kilometres (RPKs) fell by 47.0% versus November 2019, compared with a 48.9% contraction in October. Month-on-month growth eased from 7.9% to 1.7% (**Chart 1**).

Global international air travel sustained its steady upward trend as more markets reopened prior to the spread of Omicron. However, domestic traffic weakened, largely due to developments in China. Taken together, all regions but Asia Pacific reported smaller rate od RPK decline versus October, notably North America.

Chart 1 – Global air passenger volumes (RPKs)



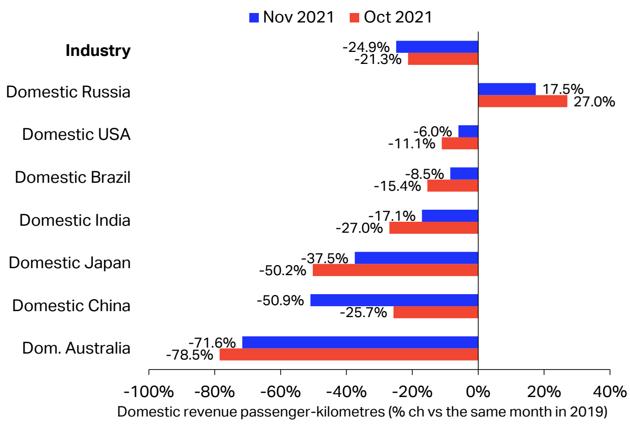
Sources: IATA Economics, IATA Monthly Statistics

The emergence of the Omicron variant in late November and the related travel restrictions have resulted in flight and trip cancellations, which negatively impacted RPKs on some routes at the end of the month. However, we will need to wait for December and January data to understand better the full impact of the new strain on air traffic.

Domestic RPKs fell amidst lockdowns in China

Domestic air travel deteriorated slightly in November after two consecutive monthly improvements. Global domestic RPKs fell by 24.9% versus 2019 compared with a 21.3% decline in October (**Chart 2**).

Chart 2 – Domestic RPK growth versus the same month in 2019, region of registration basis



Sources: IATA Economics, IATA Monthly Statistics

This month's weakness was largely driven by China where the annual RPK contraction nearly doubled to 50.9% after several cities, including the capital, introduced stricter travel restrictions to contain small COVID outbreaks. That said, the bookings data indicate that the traffic should improve slightly in

Air passenger market overview - November 2021

	World share in 2020[1]	November 2021 (% ch vs the same month in 2019)				November 2021 (% year-on-year)			
		RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]	RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]
TOTAL MARKET	***100.0%***	**-47.0%**	**-39.7%**	**-9.7%**	**71.3%**	**78.8%**	**46.1%**	**13.0%**	**71.3%**
International	*45.8%*	-60.5%	-52.5%	-13.4%	66.8%	234.0%	110.9%	24.6%	66.8%
Domestic	*54.2%*	-24.9%	-18.3%	-6.6%	75.6%	27.8%	12.5%	9.1%	75.6%

[1]% of RPKs [2]Change in load factor vs same month in 2019 [3]Load factor level

December since new infections were limited to fewer provinces that month. Russia's domestic market also showed weaker performance versus October, but the traffic growth remained robust compared with pre-crisis standards, at 17% versus November 2019. The slowing growth momentum can be attributed to easing domestic tourism demand with the start of the winter season and the effects of a strong COVID wave.

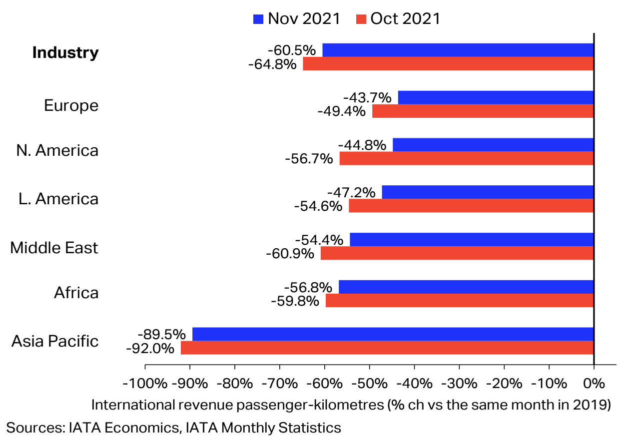
All the remaining key domestic markets showed smaller annual contractions compared with October. The US' domestic RPKs reached 94% of pre-crisis levels, supported by high demand around the Thanksgiving holidays. However, a new spike in COVID cases, staff shortages and bad weather conditions mean that any significant RPK improvement in traffic is unlikely in December.

Brazil' market was the third-best performer among key domestic markets (RPKs down 8.5% versus November 2019), benefitting from falling infections and progress on vaccinations in the country. Positive pandemic developments also contributed to better outcomes in India and Japan, where RPKs fell by 17.1% and 37.5% versus 2019, respectively. Australia remained at the bottom of the domestic RPK chart for the fifth consecutive month with RPKs 71.6% below 2019. The reopening of some internal borders, including that between the populous states of NSW and Victoria nevertheless increased traffic on some routes.

International RPKs sustained the upward trend

Global international RPKs continued to recover in November ahead of the Omicron outbreak, showing a 4.3 percentage points improvement in the rate of decline versus October, at -60.5%. The improvement was widespread across all regions (**Chart 3**).

Chart 3 – International RPK growth versus the same month in 2019 (airline region of registration basis)



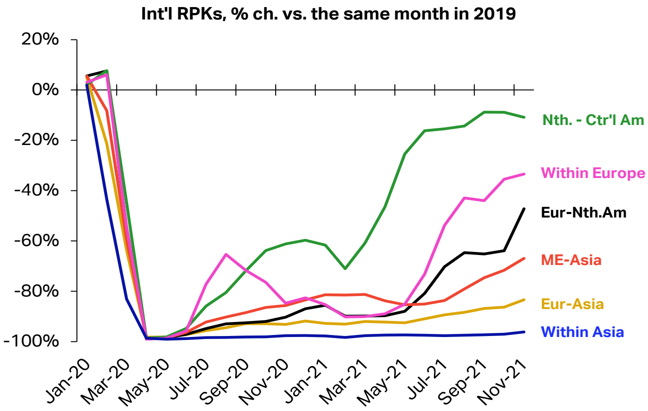
Sources: IATA Economics, IATA Monthly Statistics

European airlines posted the most resilient international air travel outcome in the industry in November, reporting a 43.7% RPK drop from 2019. The airlines' traffic remained supported by robust demand on intra-European routes (RPKs down 33.4% versus 2019), despite the resurgence of COVID-19 in the region. An additional volume boost came from the North Atlantic corridor (**Chart 4**) after the US opened to vaccinated travellers from Europe on 8 November.

Airlines based in North America saw international RPKs 44.8% below the November 2019 level. Same as their European counterparts, they benefitted from the reopening of the North Atlantic market in November.

Latin American carriers flew 47.2% fewer international RPKs than in November 2019 but their international load factor was nearly at its pre-crisis level, at 81.3%. Robust travel demand on North-Central America routes continued to support the region's recovery.

Chart 4: Percentage change in international RPKs, selected routes (segment based)



Source: IATA Monthly Statistics

African and Middle Eastern airlines posted another month of similar RPK declines, at 54.4% and 56.8% vs. 2019, respectively. The recovery in both regions had remained slow but gradual in November. The Omicron discovery led to a sharp fall in bookings from South Africa in late-November but the full impact on the Africa region will be better understood in December.

The Asia Pacific region remains a laggard in terms of the international air travel recovery, with RPKs only at 10.5% of pre-crisis levels in November. Among the key regional markets, Asia-Middle East had been the most resilient whilst nevertheless falling by 67% compared with 2019.

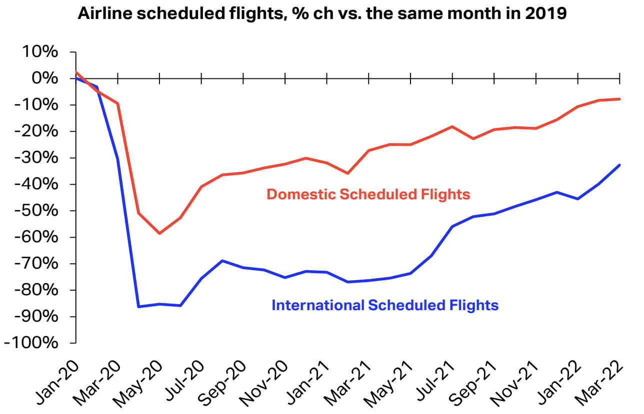
Flight schedules on the rise despite Omicron

Global air passenger capacity continued its slow recovery for the third consecutive month. Industry-wide available seat-kilometers (ASKs) fell by 39.7% in November 2021 versus November 2019, following a 40.8% decline in October.

At the regional level, North America showed the smallest capacity decline from November 2019 (15.4%). In contrast, Asia Pacific airlines reported the largest drop in ASKs, 58.9%, due to lasting international travel restrictions.

There are indications that passenger capacity should improve further in the coming months despite the cancellations related to the Omicron variant. The number of scheduled flights is trending upwards across domestic and, in particular, international routes in Q1 2022 **(Chart 5)**.

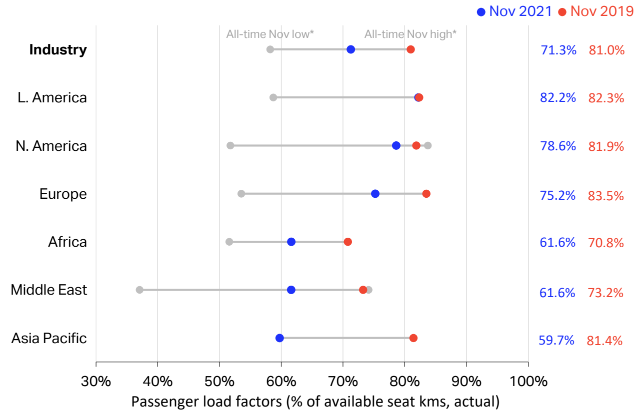
Chart 5: Global airline flight schedules, %ch vs. 2019



Source: OAG

Passenger load factors (PLF) continued to recover in November – albeit slowly – as airlines improved their capacity management despite the pandemic uncertainty. Industry-wide PLF stood at 71.3% in November, down 9.7 percentage points versus November 2019 **(Chart 6)**. That said, the global picture masks some regional differences. While the PLFs of Latin American and North American airlines hovered close to pre-crisis levels, Asia Pacific carriers posted their lowest loads for any month of November in the history of our time series since 1990.

Chart 6 – Passenger load factor by region

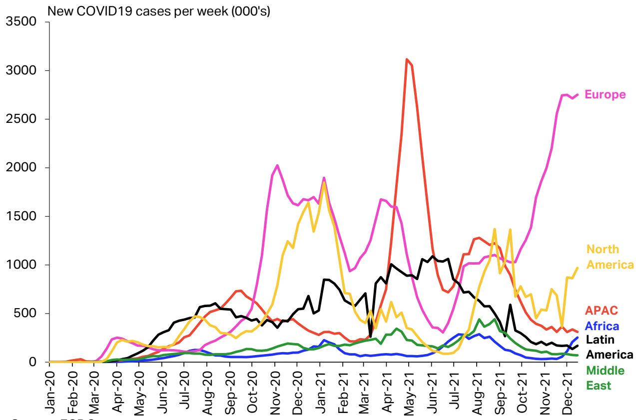


Sources: IATA Economics, IATA Monthly Statistics *Data from 1990 onwards

Challenges on the horizon…

Although air travel volumes trended upwards in November, uncertainties around further RPKs recovery through the northern hemisphere winter have increased. The outbreak of the new and more contagious Omicron variant exacerbated an already deteriorating pandemic situation in Europe and has also led to the resurgence of the virus in North America and Africa **(Chart 7)**.

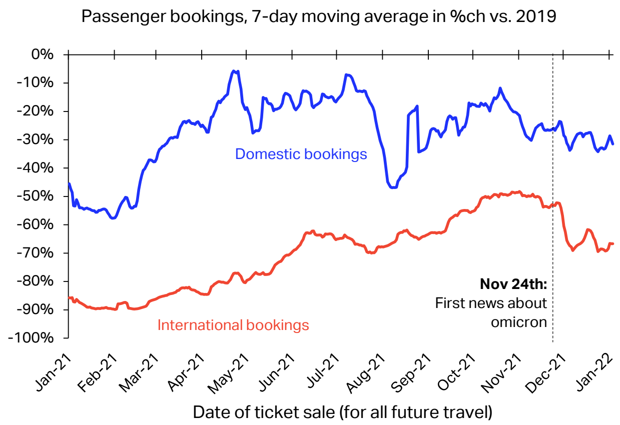
Chart 7: COVID-19 cases by region, thousands



Source: ECDC

The new strain resulted in enhanced travel restrictions around the world just at the time when countries had started to relax travel measures and international travel was gaining momentum. December traffic might remain resilient amidst strong demand over holiday season as people still wanted to see their friends and relatives. However, the number of tickets purchased in December and early-January suggests no improvement in domestic travel and a deterioration in international travel at the start of 2022 **(Chart 8)**.

Chart 8: Trends in passenger bookings (dom. vs. int'l)



Source: IATA Economics using DDS ticket sales

More generally, the fact that Omicron seems to produce milder symptoms than previous variants, might suggest that the pandemic is becoming endemic. Hence, its impact on human activities may start to diminish. Furthermore, it is worthy of note that the UK eased Omicron travel restrictions despite that country's strong COVID wave. This could point to a growing appreciation among governments of the limited impact of travel rules on COVID spread.

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12 January 2022

Air passenger market in detail - November 2021

	World share in 2020[1]	November 2021 (% ch vs the same month in 2019) RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]	November 2021 (% year-on-year, 2020) RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]
TOTAL MARKET	*100.0%*	**-47.0%**	**-39.7%**	**-9.7%**	**71.3%**	**78.8%**	**46.1%**	**13.0%**	**71.3%**
Africa	*2.0%*	-55.1%	-48.4%	-9.2%	61.6%	77.2%	48.3%	10.0%	61.6%
Asia Pacific	*38.5%*	-69.8%	-58.9%	-21.7%	59.7%	-21.1%	-12.5%	-6.5%	59.7%
Europe	*23.8%*	-39.4%	-32.7%	-8.3%	75.2%	239.3%	141.4%	21.7%	75.2%
Latin America	*5.6%*	-27.5%	-27.4%	-0.1%	82.2%	83.6%	66.2%	7.8%	82.2%
Middle East	*7.4%*	-52.6%	-43.6%	-11.6%	61.6%	203.4%	82.5%	24.5%	61.6%
North America	*22.7%*	-18.8%	-15.4%	-3.3%	78.6%	149.2%	64.1%	26.8%	78.6%
International	*45.8%*	**-60.5%**	**-52.5%**	**-13.4%**	**66.8%**	**234.0%**	**110.9%**	**24.6%**	**66.8%**
Africa	*1.6%*	-56.8%	-49.6%	-10.1%	60.3%	81.2%	44.8%	12.1%	60.3%
Asia Pacific	*10.9%*	-89.5%	-80.0%	-37.8%	42.2%	106.2%	56.8%	10.1%	42.2%
Europe	*18.8%*	-43.7%	-36.3%	-9.7%	74.3%	326.9%	175.1%	26.4%	74.3%
Latin America	*2.2%*	-47.2%	-46.6%	-0.9%	81.3%	147.3%	93.7%	17.6%	81.3%
Middle East	*6.9%*	-54.4%	-45.5%	-11.9%	61.3%	227.8%	87.9%	26.1%	61.3%
North America	*5.5%*	-44.8%	-35.6%	-11.6%	69.6%	220.8%	89.0%	28.6%	69.6%
Domestic	*54.2%*	**-24.9%**	**-18.3%**	**-6.6%**	**75.6%**	**27.8%**	**12.5%**	**9.1%**	**75.6%**
Dom. Australia[4]	*0.8%*	-71.6%	-57.4%	-27.9%	55.6%	37.9%	49.6%	-4.7%	55.6%
Domestic Brazil[4]	*1.6%*	-8.5%	-8.1%	-0.4%	82.3%	38.4%	41.9%	-2.1%	82.3%
Dom. China P.R.[4]	*19.8%*	-50.9%	-33.2%	-22.1%	61.1%	-47.6%	-37.1%	-12.2%	61.1%
Domestic India[4]	*2.1%*	-17.1%	-7.1%	-9.6%	80.2%	64.5%	49.0%	7.5%	80.2%
Domestic Japan[4]	*1.4%*	-37.5%	-23.6%	-14.3%	64.5%	6.0%	7.4%	-0.8%	64.5%
Dom. Russian Fed.[4]	*3.4%*	17.5%	12.6%	3.5%	83.5%	48.9%	32.2%	9.4%	83.5%
Domestic US[4]	*16.6%*	-6.0%	-5.1%	-0.8%	81.4%	133.7%	57.1%	26.7%	81.4%

[1]% of RPKs [2]Change in load factor vs same month in 2019 [3]Load factor level

[4] Note: the seven domestic passenger markets for which broken-down data are available account for approximately 46% of global total RPKs and 84% of total domestic RPKs

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

Year-to-date developments (Jan. - Nov. 2021 vs. Jan. - Nov. 2019)

	Year-to-date (% ch vs the same period in 2019) RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]
TOTAL MARKET	**-59.6%**	**-49.9%**	**-16.0%**	**66.6%**
Africa	-63.5%	-55.5%	-12.9%	58.8%
Asia Pacific	-67.0%	-56.9%	-19.3%	62.6%
Europe	-63.2%	-53.7%	-17.5%	67.9%
Latin America	-49.8%	-46.0%	-5.8%	76.7%
Middle East	-71.8%	-56.8%	-26.5%	49.6%
North America	-40.4%	-31.1%	-11.5%	73.2%

[1]% of industry RPKs in 2020 [2]Change in load factor vs same period in 2019 [3]Load factor level

	Year-to-date (% ch vs the same period in 2019) RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]
International	**-77.0%**	**-66.6%**	**-25.5%**	**56.5%**
Africa	-65.8%	-56.9%	-14.6%	56.6%
Asia Pacific	-93.7%	-85.3%	-46.1%	34.7%
Europe	-69.7%	-59.3%	-21.9%	63.9%
Latin America	-69.3%	-64.3%	-11.7%	71.2%
Middle East	-73.6%	-59.1%	-27.0%	49.1%
North America	-67.7%	-53.8%	-25.3%	58.6%

[1]% of industry RPKs in 2020 [2]Change in load factor vs same period in 2019 [3]Load factor level

	Year-to-date (% ch vs the same period in 2019) RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]
Domestic	**-28.7%**	**-19.6%**	**-9.5%**	**74.2%**
Dom. Australia	-62.6%	-51.7%	-18.2%	62.4%
Domestic Brazil	-29.6%	-27.4%	-2.5%	80.1%
Dom. China P.R.	-23.0%	-7.7%	-14.1%	70.8%
Domestic India	-44.6%	-31.2%	-17.0%	70.3%
Domestic Japan	-60.7%	-40.5%	-25.2%	49.0%
Dom. Russian Fed.	24.3%	20.2%	2.8%	86.5%
Domestic US	-24.8%	-17.5%	-7.6%	77.6%

[1]% of industry RPKs in 2020 [2]Change in load factor vs same period in 2019 [3]Load factor level

Statistics compiled by IATA Economics used direct airline reporting complemented by estimates, including the use of FlightRadar24 data provided under license.

Headlines

- **16,281 flights** (63% of 2019 levels) on Wed 12 January 2022, decreasing over 2 weeks (-19%).
- Over the first weeks of 2022, European traffic is recording major flight reductions as the Omicron wave expands, slackening the expected recovery.
- In 2021, number of flights in Europe was 56% of 2019 levels, totalling 6.2 million.
- Yesterday, Ryanair was the busiest Aircraft Operator with 905 flights, followed by Turkish Airlines (888), Lufthansa (669), Air France (658) and KLM (521).
- Domestic traffic vs 2019: Europe (-39%), USA (-21%), China (-24%,) and Middle-East (-13%).
- Flights to/from Europe (intercontinental flows) are at -31% vs 2019 on 12 January.
- Jet fuel prices recorded an 11% rise to 233 cts/gallon between 24 Dec 2021 and 7 Jan 2022.
- Charter (+35%), All-cargo (+3%) and Business Aviation (+9%) are above 2019 levels. The two other segments still below 2019 levels with: Traditional at -33% vs 2019 and Low-cost at -34%.

Traffic Situation

EUROCONTROL

Daily flights (including overflights)

Traffic over the last 7 days is

↓26%

Compared to equivalent days in 2019

Top 10 Aircraft Operators

on Wed 12 January 2022 (daily flights)

1. Ryanair Group — Operated 905 flights — ↓49% of same day in 2019 — ↓55% over 2 weeks

2. Turkish Airlines — Operated 888 flights — ↓27% of same day in 2019 — ↓8% over 2 weeks

3. Lufthansa Airlines — Operated 669 flights — ↓53% of same day in 2019 — ↓20% over 2 weeks

4. Air France Group — Operated 658 flights — ↓42% of same day in 2019 — ↓17% over 2 weeks

5. KLM Group — Operated 521 flights — ↓28% of same day in 2019 — ↓20% over 2 weeks

6. Wizz Air Group — Operated 372 flights — ↓17% of same day in 2019 — ↓46% over 2 weeks

7. SAS Group — Operated 342 flights — ↓53% of same day in 2019 — ↓17% over 2 weeks

8. British Airways Grp — Operated 332 flights — ↓59% of same day in 2019 — ↓24% over 2 weeks

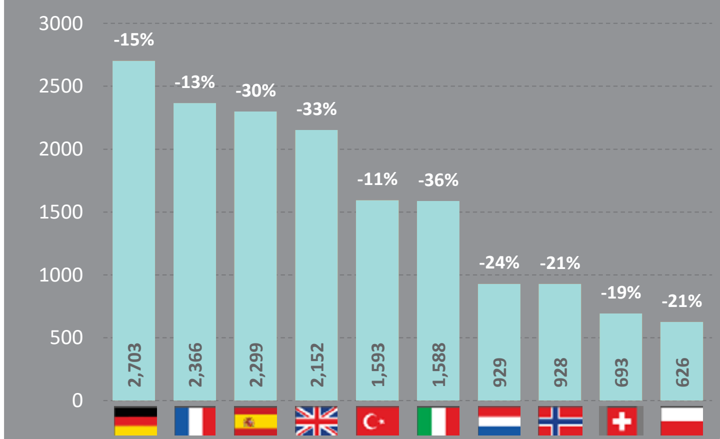
9. DHL Group — Operated 324 flights — ↑19% of same day in 2019 — ↑13% over 2 weeks

10. Wideroe — Operated 322 flights — ↓11% of same day in 2019 — ↓11% over 2 weeks

Top 10 Busiest States

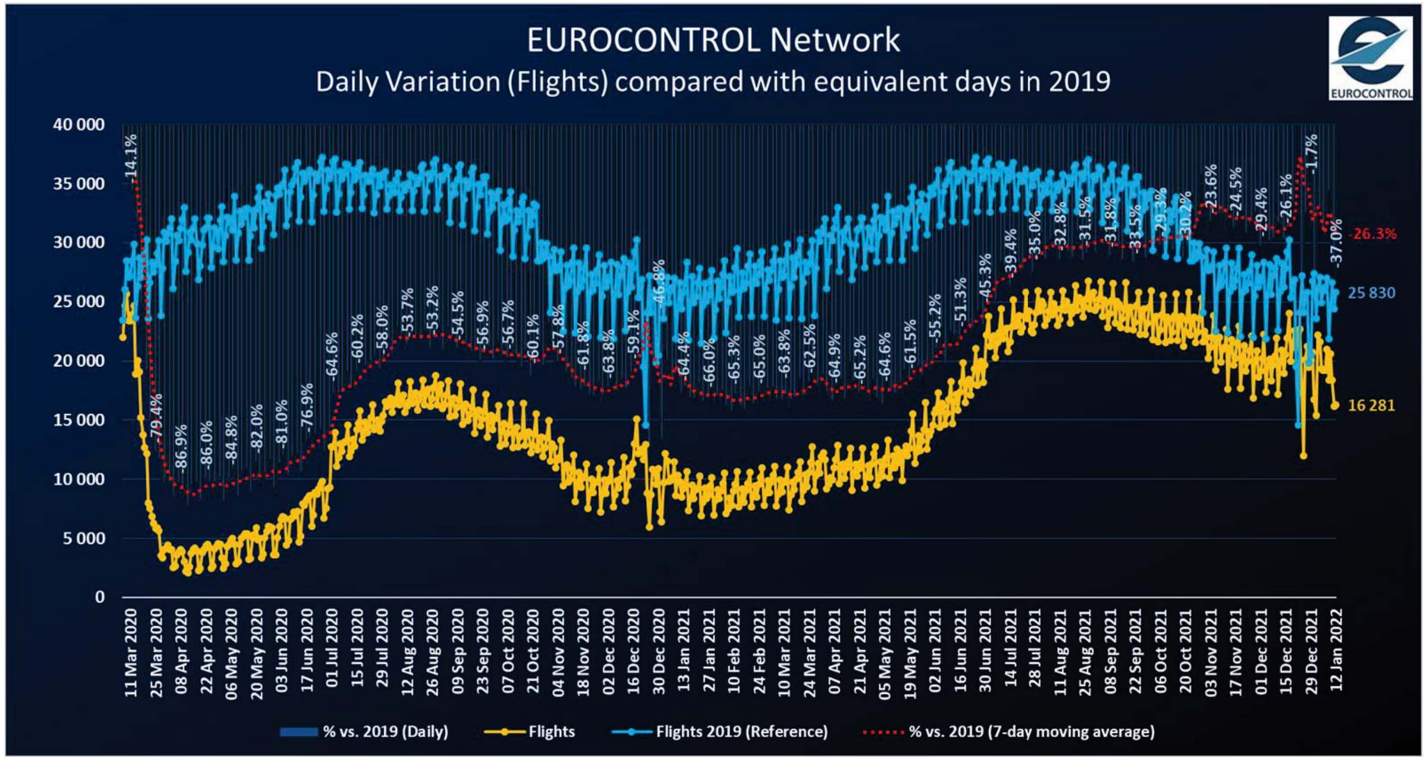
on Wed 12 January 2022

(Dep/Arr flights and variation over 2 weeks)

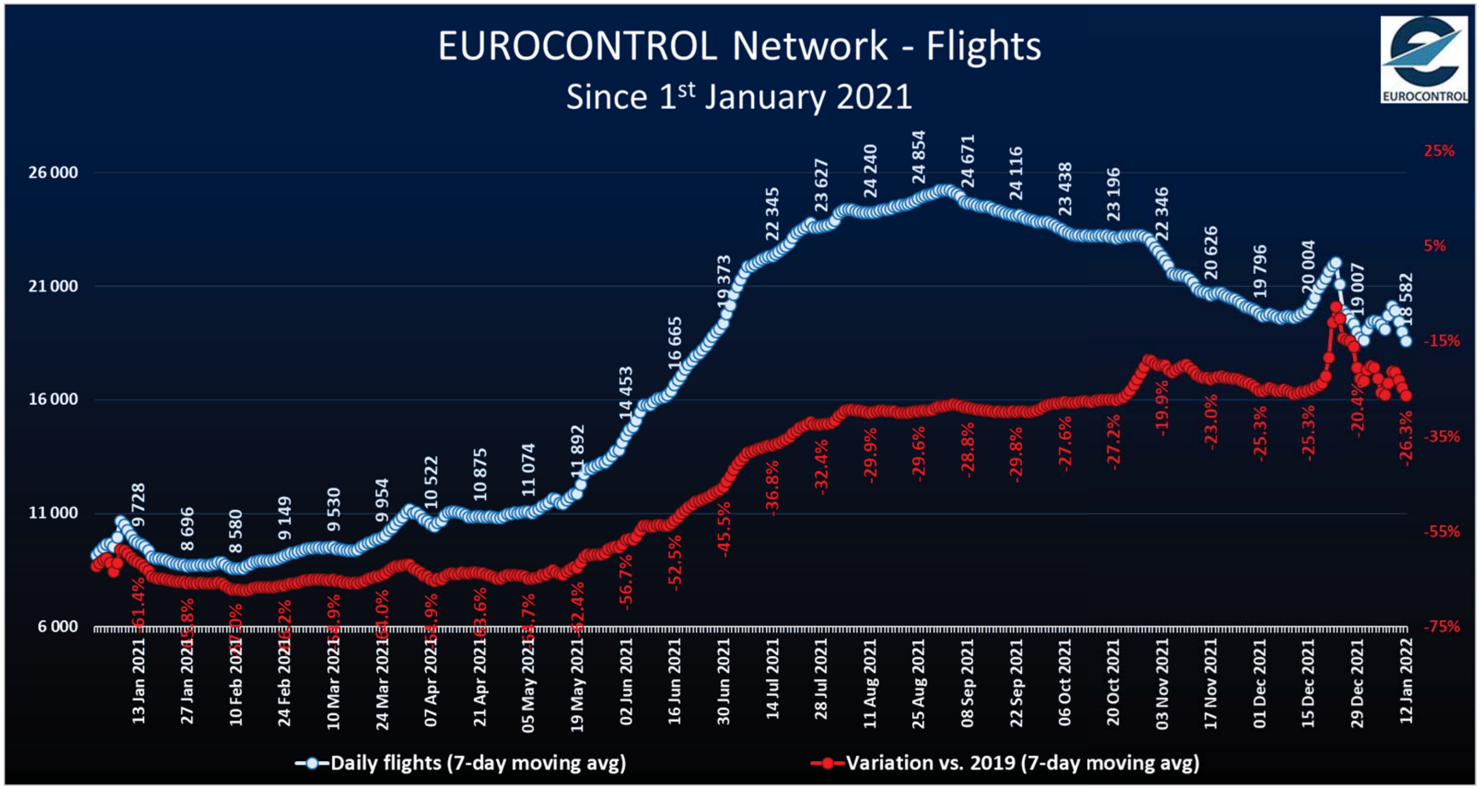


Overall traffic situation at network level

- **16,281 flights** on Wednesday 12 January.
- **-19%** with **-3,833 flights** over 2 weeks (from Wednesday 29 December).
- **-15%** with **-2,932 flights** over 1 week (from Wednesday 5 January).
- **63%** of 2019 traffic levels on Wednesday 12 January.



Current traffic evolution

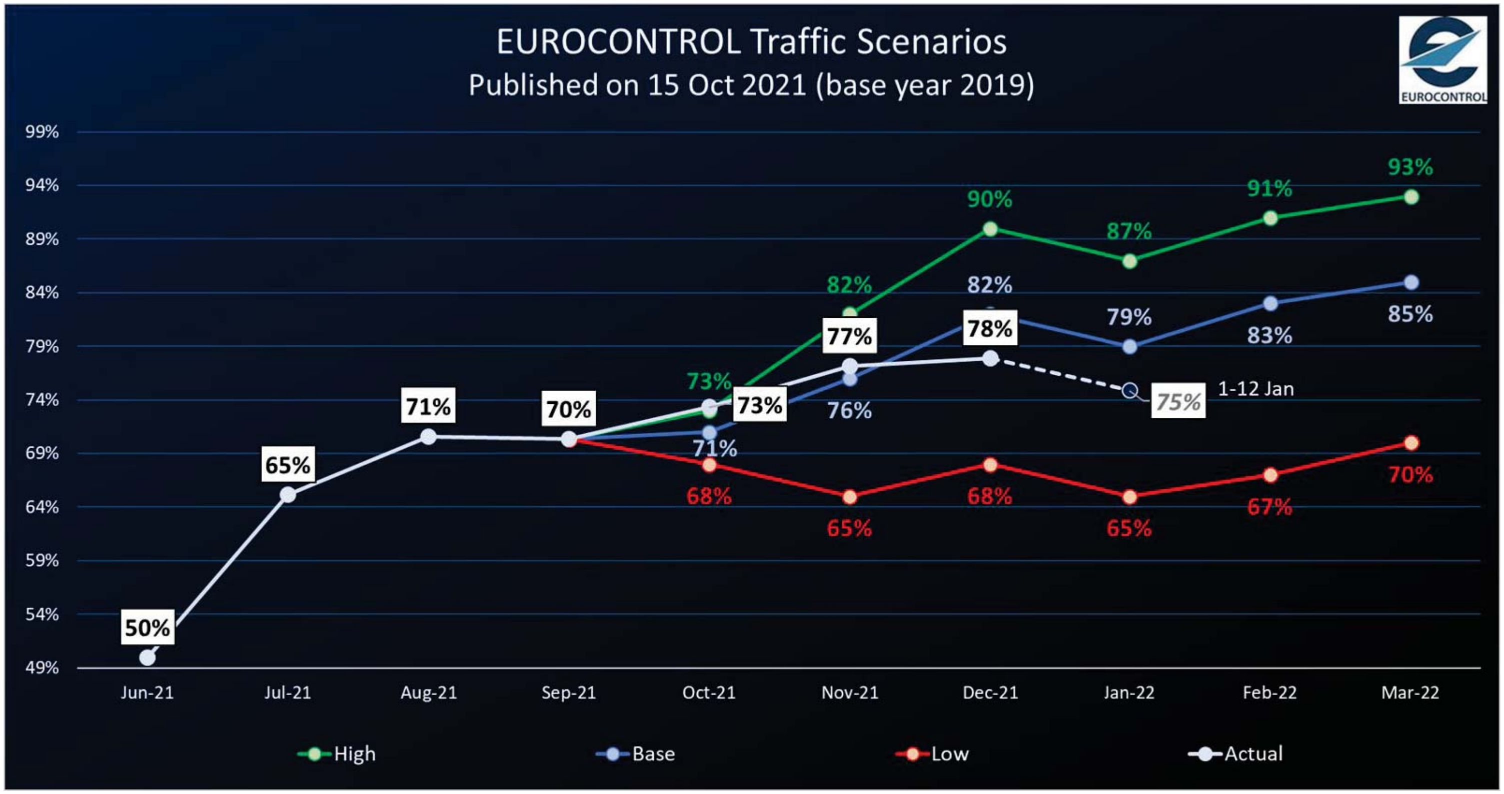


- Since early September, number of daily flights has slowly decreased, except at the start of the Christmas break (increased demand related to holidays).
- Since the beginning of the year 2022, the number of flights continued to decrease due to the tightened travel restrictions to fight the Omicron wave.
- The traffic at network level reached its maximum on Friday 27 August 2021 with 26,773 flights (-27.7% vs 2019).

Current situation compared to the latest EUROCONTROL traffic scenarios

- For the first 12 days of January 2022, **network traffic** was at **75%** compared to same period in 2019.

- Network traffic is between the low and the base scenarios of the EUROCONTROL traffic scenarios published on 15 October 2021.



Aircraft operators
Latest news
European airlines

- **Air France-KLM** signs MoU with Airbus for the firm order of 100 A320neos with options for an additional 60 with deliveries commencing in late 2023; KLM announces that it will add 0.5% SAF to all services departing Amsterdam.
- **Austrian Airlines** mandate FFP2 masks for services to and from Austria; reportedly plan to introduce mandatory vaccination for flight crew on long haul services.
- **easyJet** partners with Cranfield Aerospace on the development of zero emission aircraft, such as those using hydrogen propulsion.
- **IAG** and **Globalia** terminate the acquisition agreement for Air Europa, with IAG paying a total of €75 million; they are looking for another structure to allow the deal to happen; European Commission confirms that the competition concerns had not been adequately addressed; IAG aiming for around 90% of capacity in summer 2022.
- **Lufthansa** planning over 160 destinations in summer 2022 from Frankfurt and Munich with intra-European flights "almost reaching the 2019 level with around 5,000 weekly flights"; Lufthansa Group cancelling 33,000 (~10%) of its flights in January/February as a result of weak demand.
- **Finnair** reports 2.9 million passengers in 2021, 80.5% fewer than in 2019 (domestic -70%, Europe -79%, North Atlantic -79%, Asia -95%).
- **Royal Air Maroc** cancels all international services until the end of January.
- **Ryanair** announces that it expects a net loss for the financial year to end March 2022 of €250m - €450m, worse than pre-Omicron, and cuts its planned January schedule by 33%; reports 9.5 million passengers in December, 8% fewer than in 2019 and with a load factor of 81%; plans to close its Frankfurt am Main base at the end of May.
- **SAS** reports 9.2 million passengers in 2021, 69.2% fewer than in 2019, with a load factor of 52.4%.
- **TAP Portugal** restructuring aid of €2.55 billion and additional aid of €71.4 million approved by European Commission; Portugal's Minister of Infrastructure welcomes this but says the group will have to join a larger group in the sector.
- **Turkish Airlines** expect to receive 8 new narrowbodies and 10 new widebodies in 2022 (its fleet expanded in 2021 by 21 to a total of 373); report 44.8 million passengers in 2021, 39.7% fewer than in 2019 and with a load factor of 67.9% (December 4.3 million, -21.3%, 71.1%).
- **Wizz Air** acquires 15 daily slot pairs from **Norwegian Air Shuttle** at London Gatwick and announces new routes from March/April.

Worldwide airlines

- **Qantas** international cabin crew reject a new agreement imposing a two year pay freeze and changed rostering conditions with 97.5% voting against.
- **Etihad** to transfer several aviation support service businesses to ADQ in order to focus on its Airline business.
- **Cathay Pacific** announces cancellations of passenger flights to/from Hong Kong with only a skeleton passenger flight schedule' in January.
- **Air New Zealand** providing onboard snacks on domestic services when passengers disembark, rather than during the flight.
- **ANA** report 1.2 million domestic passengers over Christmas/New Year, 30% fewer than in 2019 (international -91.3%).

Continued Airworthiness Notification to the International Community

To: Civil Aviation Authorities Date: January 14, 2022

From: Federal Aviation Administration
Aircraft Certification Service
Compliance & Airworthiness Division

Subject: This message is to advise you of the FAA's ongoing continued operational safety activities related to 5G C-Band interference with airplane systems using radio (also known as radar) altimeter data during landing on Boeing Model 787-8, 787-9, and 787-10 airplanes.

Situation description: The FAA issued airworthiness directive (AD) 2021-23-12 on December 9, 2021, for all transport and commuter category airplanes equipped with a radio altimeter. AD 2021-23-12 requires revising the limitations section of the existing airplane flight manual (AFM) to incorporate limitations prohibiting certain operations, which require radio altimeter data to land in low visibility conditions, when in the presence of 5G C-Band interference as identified by Notices to Air Missions (NOTAMs).

Since the FAA issued AD 2021-23-12, Boeing issued Boeing Multi Operator Message (MOM) MOM-22-0001-01B, dated January 3, 2022, and Boeing Flight Crew Operations Manual Bulletin TBC-119, "Radio Altimeter Anomalies due to 5G C-Band Wireless Broadband Interference in the United States," dated January 5, 2022.

The FAA determined anomalies on Boeing Model 787-8, 787-9, and 787-10 airplanes due to 5G C-Band interference which may affect multiple airplane systems using radio altimeter data, regardless of the approach type or weather. These anomalies may not be evident until the airplane is at low altitude during approach. Impacted systems include, but are not limited to: autopilot flight director system; autothrottle system; engines; thrust reversers; flight controls; flight instruments; traffic alert and collision avoidance system (TCAS); ground proximity warning system (GPWS); and configuration warnings.

During landing, this interference could prevent proper transition from AIR to GROUND mode, which may have multiple effects. As a result, lack of thrust reverser and speedbrake deployment and increased idle thrust may occur; and brakes may be the only means to slow the airplane. Therefore, the presence of 5G C-Band interference can result in degraded deceleration performance, increased landing distance, and runway excursion.

Aircraft/engine make, model, and series: The Boeing Company Model 787-8, 787-9, and 787-10 airplanes

U.S.-registered fleet: 137 airplanes; **Worldwide fleet:** 1,010 airplanes

Operators: See attached list

Ongoing activities: The FAA intends to issue an immediately adopted rule (IAR) to address the unsafe condition on the affected airplanes. The FAA is analyzing data from other Boeing model airplanes to determine if a similar unsafe condition exists, and will consider additional rulemaking if warranted.

FAA contact: Paul Bernado, Acting Seattle ACO Branch Manager
Compliance & Airworthiness Division, Telephone: (206) 231-3500

0B0: ZIPAIR	KLM: KLM ROYAL DUTCH AIRLINES
A0B: ATLANTIS AVIATION CORPORATION	LAN: LATAM AIRLINES GROUP
AAL: AMERICAN AIRLINES	LOT: LOT POLISH AIRLINES
ABD: PRESIDENTIAL FLIGHT	MA5: MERX AVIATION SERVICING LIMITED
ACN: AIR CANADA	MXG: GOVERNMENT OF MEXICO
AFA: AIR FRANCE	NBE: ARCTIC AVIATION ASSETS DAC
AHY: AZERBAIJAN AIRLINES	NE2: NEXUS FLIGHT OPERATIONS SERVICES
AIN: AIR INDIA	NEO: NEOS AIR
AMX: AEROMEXICO	NKA: MG AVIATION LIMITED
ANA: ALL NIPPON AIRWAYS CO., LTD.	NLH: NORWEGIAN AIR INTERNATIONAL
ANZ: AIR NEW ZEALAND	NPD: SCOOT TIGERAIR PTE LTD
AP2: AIR PREMIA	NUI: AIR TAHITI NUI
ARE: AIR EUROPA	OAV: COMLUX ARUBA NV
AUX: AIR AUSTRAL	OMR: OMAN AIR (SAOC)
AVI: AVIANCA	OXA: ORIX AVIATION
BAB: BRITISH AIRWAYS	QAN: QANTAS AIRWAYS
BEJ: AIR CHINA	QTR: QATAR AIRWAYS
BMO: BAMBOO AIRWAYS	RAM: ROYAL AIR MAROC
BNG: BIMAN BANGLADESH AIRLINES	RBA: ROYAL BRUNEI AIRLINES
BRI: TUI AIRWAYS	RJA: ROYAL JORDANIAN
BWN: HIS MAJESTY THE SULTAN'S FLIGHT	RJT: ROYAL JET, LLC
CEA: CHINA EASTERN AIRLINES	SHA: SHANGHAI AIRLINES
CKE: CRYSTAL AIR LLC	SIA: SINGAPORE AIRLINES
DBF: DREAM AIRCRAFT LIMITED	SIL: BOC AVIATION LIMITED
DEA: AERCAP	SIQ: GLOBAL JET LUXEMBOURG
DVB: DVB BANK	SQT: VISTARA
EEX: JUNEYAO AIR CO., LTD.	SRF: SAUDIA ROYAL FLEET
EGP: EGYPTAIR	SVA: SAUDI ARABIAN AIRLINES
ELA: EL AL ISRAEL AIRLINES	THY: TURKISH AIRLINES
ETH: ETHIOPIAN AIRLINES GROUP	TII: THAI AIRWAYS INTERNATIONAL
ETI: ETIHAD AIRWAYS	TLB: TUI FLY BELGIUM
EVA: EVA AIR	TNS: TUI FLY NORDIC
GEF: GECAS	TNZ: AIR TANZANIA
GUL: GULF AIR	TPR: LATAM AIRLINES BRASIL
GUN: CHINA SOUTHERN AIRLINES	UAL: UNITED AIRLINES
HNA: HAINAN AIRLINES HOLDING	UZB: UZBEKISTAN AIRWAYS
HXL: TUI FLY NETHERLANDS	VAA: VIRGIN ATLANTIC AIRWAYS
JAL: JAPAN AIRLINES	VIE: VIETNAM AIRLINES
JQS: JETSTAR AIRWAYS	WJI: WESTJET
JT2: JET AVIATION 125 SERVICES, LLC.	XIA: XIAMEN AIRLINES
KAL: KOREAN AIR	YTH: SUPARNA AIRLINES
KEN: KENYA AIRWAYS	

Air Cargo Market Analysis

November 2021

Air cargo growth slows due to supply chain issues

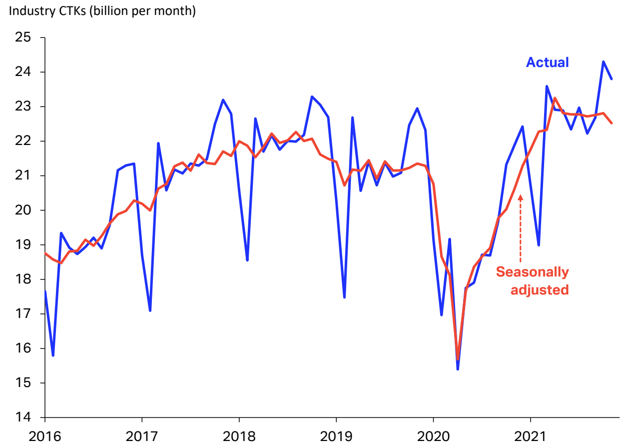
- Growth in industry-wide cargo tonne-kilometres (CTKs) slowed in November after a prolonged period of strong performance. CTKs were 3.7% above their November 2019 levels, after rising 8.2% in October versus October 2019.
- The softening is somewhat unexpected, as many drivers of demand, such as consumption and new export orders, are performing well. However, air cargo is increasingly impacted by supply chain issues, notably with congestion at airports and a lack of capacity where it is most needed.
- The deceleration in growth was widespread across the main regions, though not homogeneous. International CTKs in North America, for instance, grew 11.4% compared to November 2021, while they fell by 13.6% in Latin America.

Air cargo growth slowed in November…

November 2021 was a relatively soft month for air cargo, as industry-wide cargo tonne-kilometres (CTKs) grew by 3.7% compared to the same month in 2019. This is down from 8.2% in October on the same basis and the lowest rate since January 2021. The deterioration is somewhat unexpected, as there are signs that demand remains strong during the peak cargo season. Most of the slowdown in the volumes carried in November can be explained by supply chain issues.

After removing seasonal patterns from the data, CTKs dropped by 1.3% month-on-month in November 2021, nevertheless leaving the actual level slightly higher than the pre-crisis August 2018 peak (**Chart 1**).

Chart 1: CTK levels, actual and seasonally adjusted



Sources: IATA Economics, IATA Monthly Statistics

All the main regions we track registered slower air cargo growth in November versus 2019. Asia Pacific was relatively resilient, with total seasonally adjusted (SA) CTKs rising by 0.4% month-on-month, the only region with an increase in this metric.

… due to the impact of supply chain congestion…

November saw significant difficulties in moving cargo at several key airports, such as New York's JFK, Los Angeles and Amsterdam. This was caused by labour shortages – partly related to workers placed in quarantine – insufficient storage space at airports, and a large backlog of shipments to process.

While it is difficult to quantify the impact this had on air cargo volumes carried, congestion is likely to have intensified in November amid the rush to deliver goods for key consumer events at the end of the year. The lack of cargo capacity on some key trade lanes such as within Asia further prevented all the demand from being met. While there is capacity globally, it is sometimes not available at the right place.

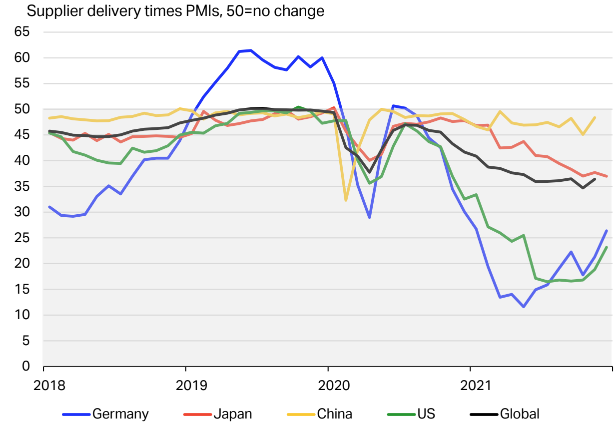
This is captured by the exceptionally low levels of the supplier delivery times PMIs. At the global level, the PMI was at an all-time low of 34.7 in October. It edged up to 36.4 in November; still well below the 50 mark which indicates worsening conditions (more negative responses in the PMI survey than positive). Although longer delivery times usually provide incentives for businesses to turn to air freight to benefit from its speed, in the current conditions point instead more directly to delivery times lengthening because of supply bottlenecks (**Chart 2, overleaf**).

Air cargo market overview - November 2021

	World share [1]	November 2021 (% ch vs the same month in 2019)				November 2021 (% year-on-year)			
		CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]	CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]
TOTAL MARKET	***100.0%***	**3.7%**	**-7.6%**	**6.1%**	**55.9%**	**8.8%**	**10.7%**	**-1.0%**	**55.9%**
International	*85.4%*	4.2%	-7.9%	7.3%	63.2%	10.7%	12.5%	-1.0%	63.2%

[1]% of industry CTKs in 2020 [2]Change in load factor vs same month in 2019 [3]Load factor level

Chart 2: Supplier delivery times component of the manufacturing PMI



Source: Markit

... and despite mostly supportive drivers of demand

There are signs that goods consumption remains well supported. In the US, total SA retail sales rose by 0.2% month-on-month in November, while actual retail sales were 23.5% above November 2019 levels. In the same country, online spending during the five days between Thanksgiving and Cyber Monday rose by 19% in 2021 versus 2019 – although it fell short of the record reached in 2020. In China, online sales for Singles' Day were 60.8% above their 2019 levels.

In October, global goods trade rose by 4.6% compared to October 2019, the best rate of growth since June. Global industrial production was up 2.9% over the same period.

Some indicators suggest demand for air cargo should remain strong in the near term, although whether this will really translate into stronger CTKs growth remains uncertain. Firstly, new export orders – typically a leading indicator of CTKs growth – also improved in November, contrasting with the drop in CTKs growth (**Chart 3**).

Chart 3: CTK growth versus global new export orders Year-on-year growth (capital Y in subtitle), then semi-colon

Sources: IATA Economics, IATA Monthly Statistics, Markit

Moreover, the recent surge in COVID-19 cases in many advanced economies has created strong demand for PPE shipments, which are usually carried by air. Finally, the US inventory-to-sales ratio has been flat at low levels since July, suggesting the inventory restocking cycle still has some ground to cover, as businesses need to refill depleted stocks.

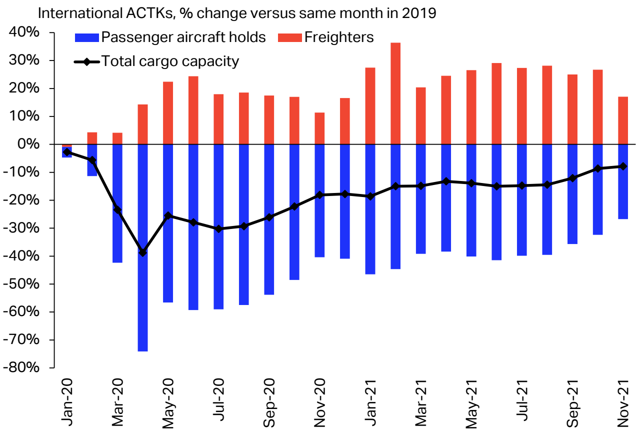
Global cargo capacity stagnates below 2019 levels

Industry-wide available cargo tonne-kilometres (ACTKs) were 7.6% below 2019 levels in November, in line with the October outcome (a 7.4% fall). Although there have been improvements, capacity shortages continue to impact the industry. Total ACTKs are up 5.9% compared to pre-crisis levels in North America, but this is an exception, as many other key trade lanes are congested. For example, in November, total ACTKs declined by 15.7% compared to November 2019 in Asia Pacific.

The recent gains in international passenger traffic have supported capacity in the bellyhold of passenger aircraft. Overall passenger aircraft ACTKs – which include passenger-freighters – were down 26.7% in November, an improvement from the 32.4% decline seen in the previous month.

In November, dedicated freighter capacity growth slowed to 17.1% versus November 2019. Besides, load factors on freighters are currently roughly 12 percentage points higher than those on belly cargo, suggesting that the improvements in passenger traffic do not fully translate into stronger belly air cargo growth. Indeed, dedicated CTKs drove the deceleration in growth seen in November (**Chart 4**).

Chart 4: Int'l belly cargo and freighter capacity growth

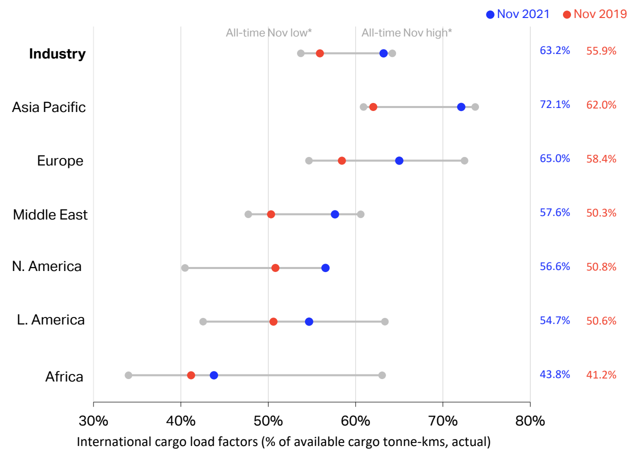


Source: IATA Economics using data from IATA Monthly Statistics

Global load factors eased, but yields are climbing

The fall in CTKs combined with broadly unchanged ACTKs means that the industry-wide cargo load factor (CLF) became less tight in November. It rose by 6.1 percentage points versus November 2019, the smallest gain since March 2021 (**Chart 5, overleaf**).

Chart 5: Cargo load factors by region of registration



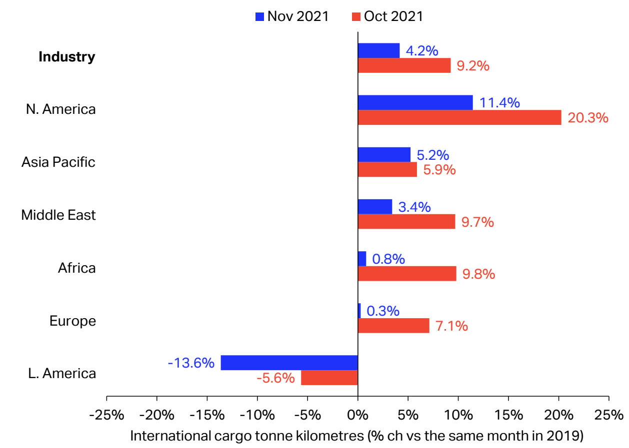
Sources: IATA Economics, IATA Monthly Statistics

That said, this is not necessarily a positive sign for CTKs growth, as capacity is often not at the right place. Indeed, air cargo rates continued to climb at a robust pace in November. In seasonally adjusted terms, they are around 12% above the May 2020 peak, highlighting ongoing tensions in global supply chains.

International CTKs deteriorate in all the main regions

International air cargo volumes followed the same pattern as industry-wide CTKs in November. International CTKs grew by 4.2% versus November 2019, down from 9.2% the month before. Growth softened in all the regions, with North America being the strongest performer (**Chart 6**).

Chart 6: Int'l CTK growth versus the same month in 2019 (airline region of registration)



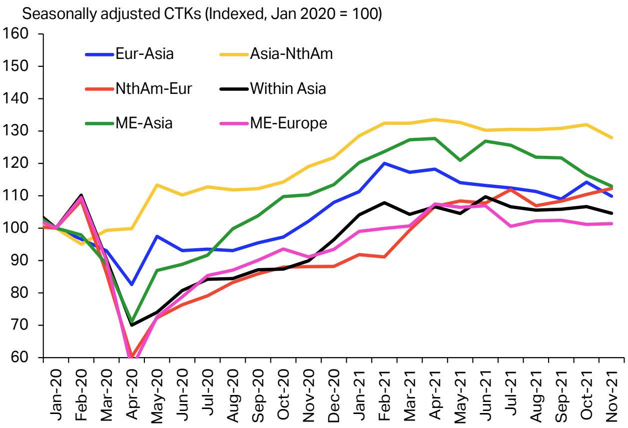
Sources: IATA Economics, IATA Monthly Statistics

In November, carriers based in North America posted an 11.4% increase in international CTKs versus the same month in 2019, down from 20.3% in October. However, seasonally adjusted CTKs declined by 3.3% month-on-month, and a downward trend in volumes is starting to emerge. Inflation, which reached 6.8% year-on-year in the US in November, is hurting consumers, and congestion issues at several key gateways have added to headwinds for cargo volume.

Asia Pacific performed relatively well in November, as airlines based in the region posted a 5.2% rise in their international CTKs versus November 2019. This was only marginally below the outcome of October (5.9%), and the region is the only one with seasonally adjusted cargo volumes currently moving up (0.9% month-on-month in November).

Carriers in the Middle East also faced a significant deterioration in their international CTKs, with growth versus pre-crisis levels diminishing from 9.7% in October to 3.4% in November. A downward trend may be starting to emerge in SA volumes, partly driven by the large Middle East-Asia trade route (**Chart 7**).

Chart 7: SA int'l CTKs by route (segment-based)



Source: IATA Economics, IATA Monthly Statistics by Route

In both Africa and Europe, airlines posted marginally positive rates of growth in their international CTKs compared to November 2019, at respectively 0.8% and 0.3%. In the former, traffic has stabilised after a period of strong growth earlier in the year – in the year-to October, CTKs in Africa were up a downwardly revised 12.9% against 2019.

Europe was also impacted by supply chain congestion and localised capacity constraints, as illustrated by long supplier delivery times and deteriorating capacity on the key Europe-Asia market (down 7.3% versus 2019 in November).

There was a 13.6% decline in international CTKs carried by Latin American airlines in November, compared to the same month in 2019. Rates of decline have seesawed for most of the year, partly due to the restructuring process at some of the largest airlines in the region. Those carriers are now progressively emerging from bankruptcy protection, which may reduce volatility moving into 2022.

IATA Economics
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11 January 2022

Air cargo market in detail - November 2021

	World share [1]	November 2021 (% ch vs the same month in 2019)				November 2021 (% year-on-year)			
		CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]	CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]
TOTAL MARKET	***100.0%***	**3.7%**	**-7.6%**	**6.1%**	**55.9%**	**8.8%**	**10.7%**	**-1.0%**	**55.9%**
Africa	*1.7%*	-0.1%	-6.9%	3.0%	43.4%	16.9%	20.6%	-1.3%	43.4%
Asia Pacific	*32.7%*	1.1%	-15.7%	10.9%	65.4%	11.4%	3.7%	4.6%	65.4%
Europe	*22.1%*	0.3%	-9.7%	6.3%	63.1%	12.9%	17.6%	-2.7%	63.1%
Latin America	*2.4%*	-12.8%	-24.4%	6.0%	44.6%	7.2%	15.9%	-3.6%	44.6%
Middle East	*13.0%*	3.4%	-9.6%	7.2%	57.2%	5.9%	10.4%	-2.4%	57.2%
North America	*28.1%*	13.3%	5.9%	2.9%	44.4%	3.4%	12.1%	-3.8%	44.4%
International	***85.4%***	**4.2%**	**-7.9%**	**7.3%**	**63.2%**	**10.7%**	**12.5%**	**-1.0%**	**63.2%**
Africa	*1.7%*	0.8%	-5.2%	2.6%	43.8%	17.0%	20.8%	-1.4%	43.8%
Asia Pacific	*29.0%*	5.2%	-9.5%	10.1%	72.1%	16.1%	17.0%	-0.6%	72.1%
Europe	*21.7%*	0.3%	-9.9%	6.6%	65.0%	13.0%	17.7%	-2.7%	65.0%
Latin America	*2.1%*	-13.6%	-20.1%	4.1%	54.7%	4.1%	10.7%	-3.4%	54.7%
Middle East	*13.0%*	3.4%	-9.7%	7.3%	57.6%	5.8%	10.3%	-2.4%	57.6%
North America	*17.9%*	11.4%	0.1%	5.7%	56.6%	3.2%	2.5%	0.4%	56.6%

[1]% of industry CTKs in 2020 [2]Change in load factor vs same month in 2019 [3]Load factor level

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

Air cargo year-to-date developments (Jan-November 2021)

	Year-to-date (% ch vs the same period in 2019)			
	CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]
TOTAL MARKET	**6.7%**	**-11.5%**	**9.6%**	**56.3%**
Africa	10.5%	-15.9%	11.3%	47.4%
Asia Pacific	-0.1%	-18.5%	11.8%	64.1%
Europe	3.5%	-17.5%	13.1%	64.6%
Latin America	-16.6%	-33.2%	8.9%	44.4%
Middle East	11.0%	-10.2%	11.0%	57.6%
North America	19.5%	3.2%	6.2%	45.8%

[1]% of industry CTKs in 2020 [2]Change in load factor vs same period in 2019 [3]Load factor level

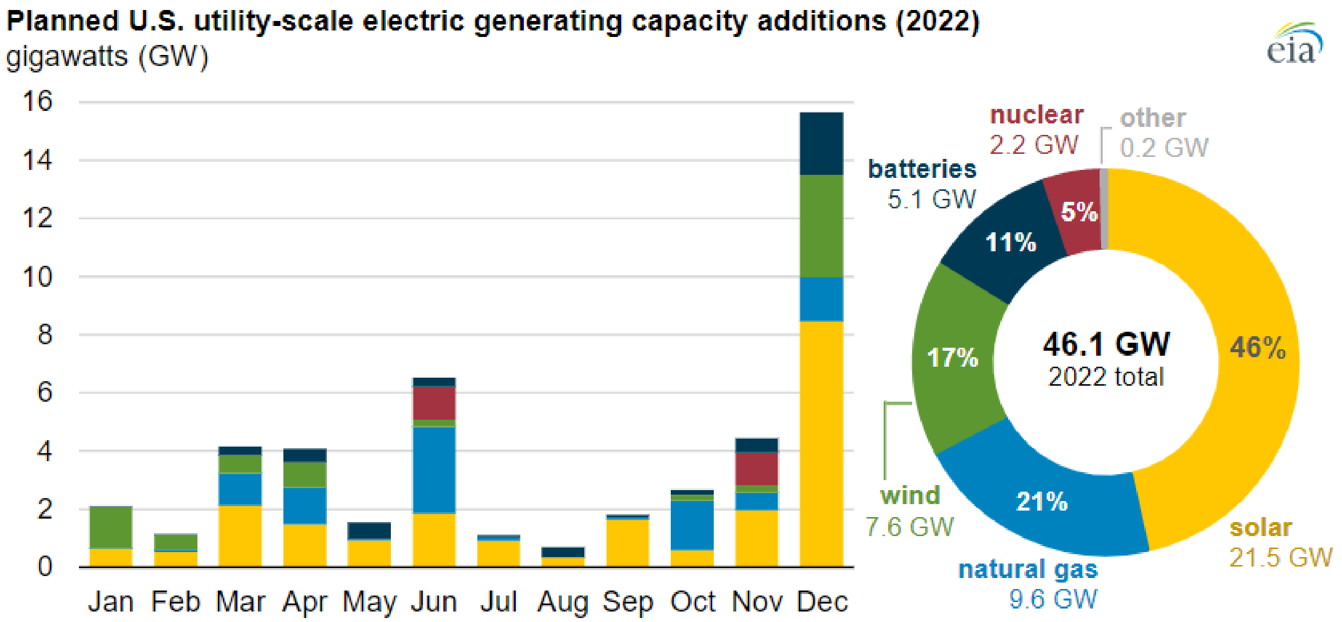
Air cargo year-to-date developments (Jan-November 2021)

	Year-to-date (% ch vs the same period in 2019)			
	CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]
International	**7.1%**	**-13.4%**	**12.3%**	**64.1%**
Africa	11.6%	-14.4%	11.2%	48.1%
Asia Pacific	3.1%	-17.8%	15.0%	73.9%
Europe	3.4%	-18.4%	14.2%	67.5%
Latin America	-16.3%	-30.6%	9.0%	52.7%
Middle East	11.0%	-10.2%	11.1%	58.1%
North America	20.0%	-0.5%	9.6%	56.0%

[1]% of industry CTKs in 2020 [2]Change in load factor vs same period in 2019 [3]Load factor level

https://www.eia.gov/todayinenergy/detail.php?id=50818
JANUARY 10, 2022

Solar power will account for nearly half of new U.S. electric generating capacity in 2022



Source: U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory*, October 2021

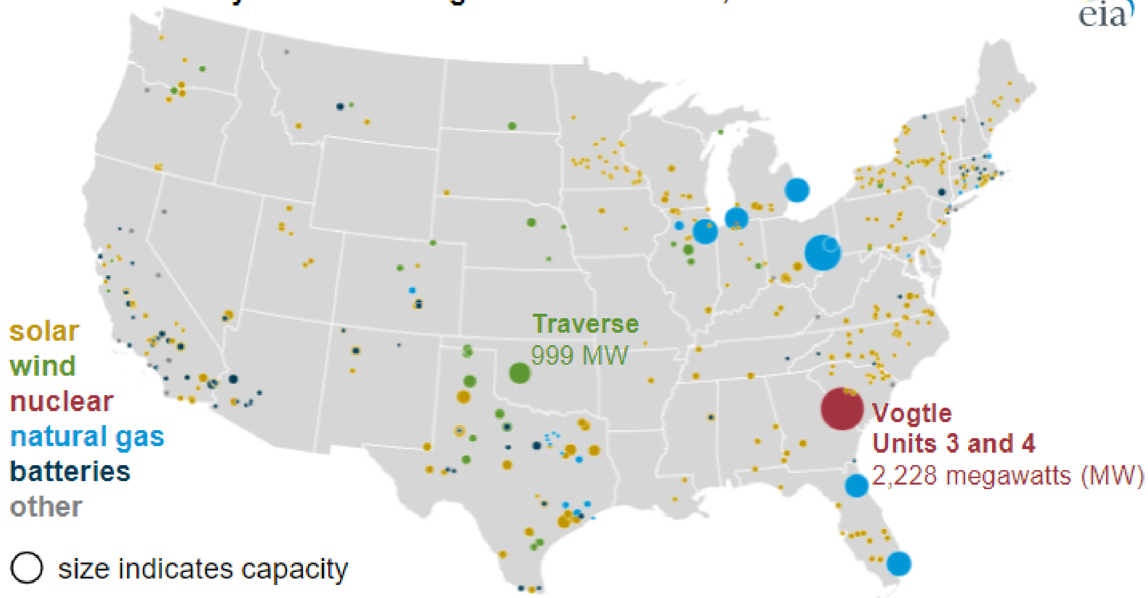
In 2022, we expect 46.1 gigawatts (GW) of new utility-scale electric generating capacity to be added to the U.S. power grid, according to our *Preliminary Monthly Electric Generator Inventory*. Almost half of the planned 2022 capacity additions are solar, followed by natural gas at 21% and wind at 17%.

Developers and power plant owners report planned additions to us in our annual and monthly electric generator surveys. In the annual survey, we ask respondents to provide planned online dates for generators coming online in the next five years. The monthly survey tracks the status of generators coming online based on reported in-service dates.

Solar. We expect U.S. utility-scale solar generating capacity to grow by 21.5 GW in 2022. This planned new capacity would surpass last year's 15.5 GW of solar capacity additions, an estimate based on reported additions through October (8.7 GW) and additions scheduled for the last two months of 2021 (6.9 GW). Most planned solar additions in 2022 will be in Texas (6.1 GW, or 28% of the national total), followed by California (4.0 GW).

Natural gas. In 2022, we expect 9.6 GW of new natural gas-fired capacity to come online. Combined-cycle plants account for 8.1 GW of the planned capacity additions (over 84%), and combustion-turbine plants account for 1.4 GW. Almost all (88%) of the planned natural gas capacity is located in Ohio, Florida, Michigan, and Illinois.

Planned U.S. utility-scale electric generator additions, 2022



Source: U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory*, October 2021

Wind. In 2021, a record-high 17.1 GW of wind capacity came online in the United States. We based this estimate on reported additions through October (9.9 GW) and planned additions in November and December (7.2 GW). Another 7.6 GW of wind capacity is scheduled to come online in 2022. About half (51%) of the 2022 wind capacity additions are located in Texas. The 999 MW Traverse Wind Energy Center in Oklahoma, the largest wind project expected to come online in 2022, is scheduled to begin commercial operations in April.

Battery storage. We expect U.S. utility-scale battery storage capacity to grow by 5.1 GW, or 84%, in 2022. Several factors have helped expand U.S. battery storage, including declining costs of battery storage, deploying battery storage with renewable generation, and adding value through regional transmission organization (RTO) markets.

Nuclear. Another 5% of the country's planned electric capacity additions in 2022 will come from two new reactors at the Vogtle nuclear power plant in Georgia. One of these reactors, Unit 3, was expected to come online in 2021, but the unit's planned start date was delayed until June 2022 to allow additional time for construction and testing.

Principal contributors: Elesia Fasching, Suparna Ray

Tags: generation, electricity, natural gas, wind, solar, capacity, map

Table 6.07.B. Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels

Year/Month	Geothermal		Hydroelectric		Nuclear		Other Biomass		Other Gas		Solar				Wind		Wood	
											Photovoltaic		Thermal					
	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor
Annual Data																		
2011	2,407.9	71.5%	78,564.7	45.8%	101,265.1	89.1%	4,469.8	64.2%	1,902.7	54.1%	537.0	19.0%	485.3	23.9%	42,019.2	32.1%	7,000.3	59.6%
2012	2,531.8	68.3%	78,296.6	39.6%	101,166.0	86.6%	4,639.7	63.3%	1,802.8	59.6%	1,527.1	20.4%	476.0	23.6%	49,458.0	31.8%	7,089.1	61.3%
2013	2,509.5	71.8%	78,873.5	38.8%	99,006.8	90.8%	4,949.7	62.3%	2,171.6	55.9%	3,525.2	24.5%	552.1	17.4%	59,175.6	32.4%	7,887.9	59.0%
2014	2,513.3	72.0%	79,582.8	37.2%	98,569.3	91.7%	5,114.6	62.7%	1,994.0	54.0%	6,555.6	25.6%	1,445.3	18.3%	60,587.8	34.0%	8,319.7	60.0%
2015	2,523.0	71.9%	79,650.8	35.7%	98,614.6	92.3%	5,104.5	62.6%	2,527.7	60.8%	9,521.6	25.5%	1,697.3	21.7%	67,106.2	32.2%	9,024.5	59.3%
2016	2,516.6	71.6%	79,806.0	38.2%	99,364.8	92.3%	5,099.5	62.7%	2,458.8	64.8%	14,161.4	25.0%	1,757.9	22.1%	74,162.7	34.5%	8,979.8	58.3%
2017	2,460.4	73.2%	79,698.8	43.0%	99,619.5	92.3%	5,125.6	61.8%	2,375.8	62.8%	21,940.9	25.6%	1,757.9	21.8%	83,355.6	34.6%	8,807.5	60.2%
2018	2,391.5	76.0%	79,771.9	41.9%	99,605.2	92.5%	5,059.0	61.8%	2,543.9	65.4%	27,143.3	25.1%	1,757.9	23.6%	89,228.5	34.6%	8,760.2	60.6%
2019	2,535.2	69.6%	79,838.0	41.2%	98,836.7	93.4%	4,786.5	62.5%	2,504.1	67.4%	31,840.8	24.3%	1,758.1	21.2%	97,564.8	34.4%	8,485.0	59.0%
2020	2,561.5	69.1%	79,810.4	40.7%	97,238.3	92.4%	4,653.8	62.5%	2,275.2	64.6%	39,458.1	24.2%	1,747.9	20.6%	107,387.7	35.3%	8,327.2	57.8%
Year 2019																		
January	2,527.5	73.9%	79,881.1	41.7%	99,440.4	99.6%	4,894.7	63.2%	2,509.0	68.2%	30,238.8	15.2%	1,758.1	8.4%	94,361.8	34.4%	8,716.6	62.0%
February	2,527.5	76.1%	79,883.6	42.6%	99,440.4	96.8%	4,894.7	62.3%	2,509.0	64.8%	30,911.4	17.7%	1,758.1	10.9%	95,284.6	35.3%	8,716.6	60.7%
March	2,527.5	75.6%	79,897.2	44.3%	99,440.4	88.0%	4,796.3	61.4%	2,509.0	61.6%	31,124.1	24.1%	1,758.1	19.8%	95,776.4	36.0%	8,565.9	57.6%
April	2,535.4	68.7%	79,897.2	48.4%	99,595.4	84.5%	4,785.1	59.9%	2,514.0	62.1%	31,355.0	28.4%	1,758.1	25.5%	96,608.9	41.6%	8,553.5	52.8%
May	2,535.4	71.1%	79,874.5	53.8%	98,921.8	90.8%	4,783.7	61.5%	2,514.0	67.6%	31,466.6	29.1%	1,758.1	25.7%	96,610.5	35.7%	8,538.5	54.1%
June	2,535.4	72.8%	79,878.4	48.8%	98,921.8	96.6%	4,764.2	64.2%	2,499.2	67.5%	31,528.4	32.9%	1,758.1	35.5%	96,840.0	31.9%	8,469.0	58.2%
July	2,535.4	72.9%	79,879.9	41.9%	98,921.8	98.1%	4,765.8	63.8%	2,499.2	68.5%	31,803.5	32.4%	1,758.1	31.4%	98,084.1	30.1%	8,498.4	61.4%
August	2,535.4	73.9%	79,776.1	38.0%	98,921.8	97.7%	4,765.9	64.4%	2,499.2	68.0%	32,079.8	31.0%	1,758.1	32.0%	98,359.7	27.1%	8,498.4	62.7%
Sept	2,535.4	74.9%	79,775.9	32.3%	98,119.0	93.1%	4,754.4	62.6%	2,499.2	72.4%	32,302.5	27.4%	1,758.1	24.3%	98,668.1	34.1%	8,409.1	59.2%
October	2,535.4	60.5%	79,772.0	30.8%	98,119.0	85.0%	4,754.4	61.5%	2,499.2	64.4%	32,556.1	23.3%	1,758.1	23.0%	99,662.8	37.2%	8,305.5	57.0%
November	2,535.4	53.3%	79,772.0	35.2%	98,119.0	90.8%	4,751.2	61.5%	2,499.2	71.6%	33,001.5	17.4%	1,758.1	11.3%	99,618.3	34.9%	8,305.5	60.2%
December	2,555.4	61.5%	79,772.0	36.2%	98,119.0	100.1%	4,735.4	63.7%	2,499.2	72.2%	33,658.4	12.8%	1,758.1	5.4%	100,729.8	34.9%	8,258.5	62.7%
Year 2020																		
January	2,554.7	59.0%	79,765.8	41.3%	98,093.5	101.6%	4,700.3	64.5%	2,275.2	69.7%	35,875.0	15.7%	1,747.9	8.2%	103,858.1	36.2%	8,351.2	62.6%
February	2,554.7	67.7%	79,765.8	46.6%	98,093.5	96.5%	4,700.9	62.6%	2,275.2	67.2%	37,077.5	20.6%	1,747.9	14.6%	104,551.4	39.9%	8,321.7	63.0%
March	2,554.7	75.5%	79,765.8	40.1%	98,093.5	87.7%	4,700.0	65.0%	2,275.2	57.9%	37,500.2	21.8%	1,747.9	14.7%	104,636.5	37.5%	8,321.7	59.2%
April	2,540.1	72.8%	79,765.8	40.4%	97,082.0	83.9%	4,700.0	63.4%	2,275.2	60.6%	37,735.2	27.5%	1,747.9	24.3%	106,196.7	38.6%	8,321.7	56.2%
May	2,550.8	69.9%	79,769.8	50.5%	97,082.0	89.1%	4,698.0	62.9%	2,275.2	62.6%	38,408.7	31.4%	1,747.9	31.7%	106,475.5	35.4%	8,321.7	54.7%
June	2,550.8	67.6%	79,769.8	48.8%	97,082.0	96.2%	4,622.3	60.0%	2,275.2	64.1%	38,802.8	32.1%	1,747.9	29.9%	107,334.9	38.7%	8,308.0	55.2%
July	2,571.9	68.3%	79,771.8	45.1%	97,082.0	96.1%	4,619.2	63.0%	2,275.2	65.7%	39,865.9	33.3%	1,747.9	33.3%	107,951.1	28.2%	8,308.0	56.0%
August	2,571.9	68.0%	79,793.0	39.2%	97,082.0	95.5%	4,619.2	63.7%	2,275.2	66.9%	40,454.3	29.0%	1,747.9	28.2%	108,153.1	28.4%	8,308.0	58.5%
Sept	2,571.9	68.3%	79,793.0	32.5%	97,082.0	94.0%	4,618.4	61.6%	2,275.2	68.3%	41,058.4	24.8%	1,747.9	22.5%	108,677.1	29.3%	8,346.0	56.4%
October	2,571.9	65.9%	79,919.7	31.6%	97,102.0	82.2%	4,617.1	59.5%	2,275.2	60.5%	41,672.4	21.7%	1,747.9	20.0%	109,470.5	34.9%	8,346.0	54.3%
November	2,571.9	74.0%	79,919.7	36.3%	96,500.6	88.9%	4,629.9	60.7%	2,275.2	64.4%	42,042.0	17.9%	1,747.9	13.0%	109,794.4	41.1%	8,346.0	57.5%
December	2,571.9	71.8%	79,921.7	36.2%	96,500.6	97.3%	4,621.9	63.5%	2,275.2	67.9%	42,910.0	14.9%	1,747.9	7.1%	111,449.8	36.5%	8,326.5	60.5%
Year 2021																		
January	2,571.9	71.1%	79,921.2	43.4%	96,500.6	100.0%	4,619.2	64.8%	2,275.2	71.0%	46,350.7	16.2%	1,747.9	6.3%	118,384.7	34.1%	8,326.5	61.7%
February	2,571.9	75.4%	79,926.2	40.3%	96,500.6	97.1%	4,619.2	63.1%	2,275.2	68.0%	46,734.5	19.7%	1,747.9	11.4%	119,490.8	33.1%	8,326.5	61.1%
March	2,571.9	64.6%	79,925.0	36.3%	96,500.6	88.7%	4,619.2	64.5%	2,275.2	64.5%	47,417.4	25.1%	1,747.9	19.8%	120,457.6	44.0%	8,183.5	60.9%
April	2,571.9	68.6%	79,925.8	33.4%	95,464.3	82.2%	4,619.2	63.5%	2,275.2	57.4%	49,025.0	29.4%	1,739.9	26.7%	121,357.2	40.9%	8,183.5	53.9%
May	2,596.7	70.2%	79,931.0	38.3%	95,464.3	89.3%	4,617.8	63.1%	2,275.2	59.8%	49,555.3	31.9%	1,739.9	30.2%	121,870.8	36.4%	8,183.5	57.6%
June	2,596.7	75.2%	79,967.9	41.8%	95,464.3	96.1%	4,617.8	63.6%	2,275.2	64.5%	50,204.8	31.3%	1,739.9	25.8%	123,234.4	29.4%	8,183.5	62.1%
July	2,596.7	71.8%	79,995.4	37.2%	95,464.3	96.9%	4,621.2	62.8%	2,275.2	66.1%	50,993.9	30.2%	1,559.9	22.3%	124,882.8	22.9%	8,183.5	60.7%
August	2,596.7	70.1%	79,993.0	35.3%	95,464.3	97.8%	4,621.2	71.6%	2,275.2	64.6%	51,944.9	28.9%	1,559.9	29.6%	126,150.6	28.4%	8,183.5	62.6%
Sept	2,596.7	72.2%	79,993.0	31.2%	95,464.3	93.8%	4,617.9	62.0%	2,275.2	63.6%	53,220.6	27.6%	1,559.9	26.8%	126,489.0	31.4%	8,183.5	60.4%
October	2,596.7	67.3%	79,995.5	30.4%	95,464.3	82.2%	4,625.9	60.8%	2,275.2	62.6%	54,214.5	21.9%	1,479.9	19.9%	126,837.2	34.1%	8,188.5	57.1%

Values for 2020 and prior years are final. Values for 2021 are preliminary.
Time adjusted capacity for month rows is the summer capacity of generators in operation for the entire month; units that began operation during the month or that retired during the month are excluded. Time adjusted capacity for year rows is a time weighted average of the month rows.
Capacity factors are a comparison of net generation with available capacity. See the technical note for an explanation of how capacity factors are calculated.
Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Excerpt IEA Canada 2022: Energy Policy Review https://iea.blob.core.windows.net/assets/7ec2467c-78b4-4c0c-a966-a42b8861ec5a/Canada2022.pdf

Foreword

The twin crises of climate change and biodiversity loss pose enormous threats to long-term global security and economic well-being around the world. Canada, alongside others in the international community, must rapidly reduce carbon emissions to fight climate change and seize the significant economic opportunities presented for businesses, communities and workers.

As Canada's Minister of Natural Resources, I am very pleased to welcome the International Energy Agency's (IEA) review of Canada's approach to building a clean energy future. This report acknowledges our ambitious efforts and historic investments to develop pathways to achieve net-zero emissions by 2050 and ensure a transition that aligns with our objective of limiting global warming to 1.5 degrees Celsius. These pathways will drive inclusive economic prosperity for our workers while yielding technology, products and know-how that can be exported and applied around the world.

Canada is blessed with an abundance of natural resources that position us to be a global leader in clean energy. We also have a skilled workforce and innovative organizations at the helm of the transition, with 12 Canadian companies featured in the 2020 Global Cleantech 100 and Indigenous leaders across the country building and operating renewable energy projects for their communities.

The key to Canada's clean energy future will be empowering our workers to harness Canada's vast resources in ways that make sense environmentally and economically for their region — and that's exactly what our government is doing.

We have committed more than $100 billion toward climate action and clean growth since 2015, including major investments in clean power, energy efficiency, industrial decarbonization, clean technology and transportation. We also have a world-leading price on pollution and action plans for promising technologies like hydrogen and small modular reactors.

All of this is intended to ensure that emissions go down at a pace and on a scale aligned with our 1.5 degree Celsius targets — but more must be done.

That's why our government recently committed to new measures to accelerate the clean energy transition, including:

- requiring the oil and gas sector to be net-zero by 2050 and setting interim five-year targets;
- requiring oil and gas companies to reduce methane emissions by at least 75 percent below 2012 levels by 2030;
- creating a 100-percent net-zero electricity system by 2035; and
- providing support for domestic procurement of Canadian clean technology.

As this report recognizes, Canada's energy policies, programs and investments align with our ambitious climate goals. We believe that we can achieve our targets while creating good jobs, a stronger economy and a more inclusive future for all regions of the country.

Of course, for any nation to succeed in the fight against climate change, we must all succeed. Canada is working with our partners to support a truly global transition and build on the momentum from COP26.

I am proud of the progress that Canada has made in the last six years, and I believe the future is bright. I thank the IEA for the work it does to help governments build a clean energy future and, specifically, for this report.

The Honourable Jonathan Wilkinson

Canada's Minister of Natural Resources

https://www.canada.ca/en/environment-climate-change/news/2021/12/canada-to-launch-consultations-on-new-climate-commitments-this-month-establish-emissions-reduction-plan-by-the-end-of-march-2022.html

Canada to launch consultations on new climate commitments this month, establish Emissions Reduction Plan by the end of March 2022

From: Environment and Climate Change Canada

News release

December 3, 2021 – Calgary, Alberta

Climate change is the biggest threat facing our generation, and ambitious action to fight it presents significant economic opportunities for Canadians in all parts of the country. Over the past five years, an intensive national effort was undertaken to develop and implement the measures needed to put Canada on a path to significantly reduce emissions. The latest science shows—and Canadians are demanding—that we must do even more to fight climate change, and on a faster timeline. That is why Canada increased its 2030 climate target to a 40 to 45 percent emissions reduction below 2005 levels earlier this year, and has worked with Canadians to develop and implement ambitious measures that put us on track to exceed our previous 2030 target of 30 percent.

Recognizing the urgency of the crisis and the need to involve all economic sectors and all regions of Canada, the Minister of Environment and Climate Change, the Honourable Steven Guilbeault, announced today that the Government is launching a series of early consultations on key, new emissions reductions measures before the end of the year.

The Minister also confirmed that he will table the 2030 Emissions Reduction Plan (ERP)—as required by the new *Canadian Net-Zero Emissions Accountability Act*—by the end of March 2022. The ERP will be informed by early consultations on these new commitments.

The *Canadian Net-Zero Emissions Accountability Act* requires the Minister of Environment and Climate Change, the Honourable Steven Guilbeault, to establish the 2030 Emissions Reduction Plan (ERP) within six months of royal assent, with the authority to extend this deadline by ninety days. Today, the Minister confirmed that the 2030 ERP would be established by the end of March 2022. This time will enable the Government to engage with provinces, territories, Indigenous Peoples, the Net-Zero Advisory Body, and interested Canadians on what is needed to reach Canada's climate objectives. Written submissions will be welcomed.

In addition, early consultations, supported by a series of discussion papers, will be launched before the end of 2021 on the following new commitments:

- Mandating the sale of zero-emission vehicles so that 100 percent of new light-duty vehicles (cars, pickups, etc.) sold in Canada are zero emission by 2035 and at least 50 percent by 2030;
- Developing emissions standards for heavy-duty vehicles that are aligned with the most ambitious standards in North America, and requiring that 100 percent of selected categories of medium- and heavy-duty vehicles be zero emission by 2040;
- Capping emissions from the oil and gas sector at current levels and requiring that they decline at the pace and scale needed to get to net zero by 2050;
- Developing a plan to reduce methane emissions across the broader Canadian economy in support of the Global Methane Pledge and the goals in Canada's climate plan, reducing oil and gas methane emissions by at least 75 percent below 2012 levels by 2030 through an approach that includes regulations, as well as regulating methane landfill emissions and reducing agricultural methane emissions;
- Transitioning to a net-zero emitting electricity grid by 2035.

The Government will work closely with provinces, territories, cities, Indigenous peoples, industry, and civil society on the design of these new commitments in order to ensure that relevant considerations are identified and joint priorities are addressed.

Canada’s 2030 Emissions Reduction Plan is the first of many requirements under the *Canadian Net-Zero Emissions Accountability Act*. The Government of Canada is considering more formal, ongoing, and consistent engagement processes for the establishment of future emissions reduction targets, plans, and reports.

Climate change impacts Canadians in all parts of the country and the Government of Canada is committed to taking a whole-of-government, whole-of-society approach to address it. Full participation from Canadians in all parts of the country and all sectors of the economy is essential for building an effective path forward to achieve Canada’s climate goals for 2030 and 2050 and a prosperous economy.

Quotes

“Through the efforts of millions of Canadians from coast to coast to coast, Canada has successfully flattened its emissions curve. But as we are seeing from the immediate, devastating impacts of a changing climate, we need to do more, on a faster timeline. The health of our citizens, the health of our economy, the safety of our communities, and the conservation of our natural world depends on us working together to reduce Canada’s GHG emissions by 40 to 45 percent by 2030. The debate over whether we need to act is long over. Now we must determine how we can get where we need to go, together.”
– The Honourable Steven Guilbeault, Minister of Environment and Climate Change

“Collaboration and consultation with our natural resource sectors is essential in establishing the ways in which we will achieve net-zero emissions by 2050, while promoting the development of good jobs and a prosperous clean economy. Our Government is committed to doing just that, in order to ensure we chart a pathway that works for every region across the country.”
– The Honourable Jonathan Wilkinson, Minister of Natural Resources

“Our Government believes that only bold climate policies lead to bold results. With the sector representing a quarter of total greenhouse gas emissions, we recognize the urgency to eliminate pollution from transportation. That is why we launched the Incentives for Zero-Emission Vehicles program and will be implementing additional measures to accelerate the transition to 100 percent zero-emission vehicles sales. We will continue building a cleaner and more resilient economy, while also creating good jobs and opportunities for all Canadians.”
– The Honourable Omar Alghabra, Minister of Transport

“We will continue to create economic opportunities in ways that will help us meet our ambitious climate targets. By turning climate action into economic opportunities for Canadian companies and workers, we will continue to grow Canada’s competitive advantage in the low-carbon economy. This will mean good jobs for Canadian workers and real progress towards reducing emissions.”
– The Honourable François-Philippe Champagne, Minister of Innovation, Science and Industry

Quick facts

- The Government of Canada is committed to achieving net-zero emissions no later than 2050. It developed and passed the Canadian Net-Zero Emissions Accountability Act earlier this year. This Act enshrines Canada’s climate goals for 2030 and 2050 into law and requires the Government to establish an emissions reduction plan to achieve Canada’s 2030 target. The 2030 plan will be the first emissions reduction plan established under the Act and is a key milestone on the pathway to net zero by 2050.

- Many of our cities and several provinces have also made their own net-zero commitments, including Quebec, Newfoundland and Labrador, Vancouver, Hamilton, Toronto, Montreal, Charlottetown, and Halifax.

- Many of Canada’s oil and gas producers have made their own net-zero commitments. Canadian Natural Resources, Cenovus Energy, Imperial, MEG Energy, and Suncor Energy—collectively accounting for around 90 percent of Canada’s oil sands production—have each committed to achieving net-zero emissions from their oil sands operations by 2050.

- Emissions from the transportation sector and oil and gas sector account for 25 and 26 percent of Canada's overall emissions respectively.

- In November 2021, the independent Net-Zero Advisory Body was asked by the Minister of Environment and Climate Change and the Minister of Natural Resources to provide advice on guiding principles to inform the development of quantitative five-year targets for caps on emissions from the oil and gas sector to support the achievement of the Government's commitment to capping and cutting emissions from the sector at the pace and scale needed to get to net zero by 2050.

- In October 2021, Minister Wilkinson announced Canada's support for the Global Methane Pledge, which aims to reduce methane emissions around the world by 30 percent below 2020 levels by 2030 and committed to reducing methane emissions across the broader Canadian economy for 2030, and to developing regulations to reduce oil and gas methane emissions by 75 percent below 2012 levels by 2030.

- At COP26 in Glasgow in November 2021, Prime Minister Trudeau announced on the world stage Canada's commitment to cap and cut emissions from the oil and gas sector and to achieve net-zero emitting electricity in Canada by 2035.

- In June 2021, the Government joined major economies by announcing its commitment to require that 100 percent of cars sold in Canada be zero emission by 2035.

- In December 2020's strengthened climate plan, the Government committed to aligning with the most ambitious fuel efficiency standards for light-duty vehicles in North America and to develop ambitious uel-efficiency standards for heavy-duty vehicles.

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Date modified:

2021-12-03

2022 Deloitte Global Automotive Consumer Study

From September through October 2021, Deloitte surveyed more than 26,000 consumers in 25 countries to explore opinions regarding a variety of critical issues impacting the automotive sector, including the development of advanced technologies. The overall goal of this annual study is to answer important questions that can help companies prioritize and better position their business strategies and investments.

Willingness to pay for advanced tech remains limited

A majority of consumers are unwilling to pay more for advanced technologies in most global markets as they have been trained to expect new vehicle features as a cost of doing business for brands looking to differentiate themselves from their competitors.

Interest in EVs driven by lower running costs and better experience

Consumer interest in electrified vehicles (EVs) centers on the perception of lower fuel costs, environmental consciousness, and a better driving experience. However, driving range and lack of available charging infrastructure remain barriers to adoption.

In-person purchase experience still preferred by many

Most consumers would still prefer to purchase a vehicle at an authorized dealership. However, a perception of increased convenience and ease of use will likely support continued growth of virtual purchase processes.

Personal vehicles continue as the preferred mode of transportation

Shared mobility services like ride-hailing and car sharing have been slow to return to their prepandemic pace of growth as people prefer using personal vehicles to satisfy their transportation requirements.

Advanced technologies and vehicle connectivity

Consumer willingness to pay for advanced technologies, including alternative powertrains and vehicle connectivity, is limited in most global markets.

Percentage of consumers that are unwilling to pay more than ~US$500[1] for a vehicle with advanced technologies (including people that would not pay any more)

Advanced technology category	US	Germany	Japan	Rep. of Korea	China	India	Southeast Asia†
Safety	56%	70%	66%	58%	31%	48%	59%
Connectivity	65%	77%	83%	72%	39%	48%	65%
Infotainment	69%	82%	86%	78%	39%	57%	72%
Autonomy	61%	69%	56%	42%	31%	37%	48%
Alternative engine solutions	53%	56%	57%	41%	31%	35%	46%
Unwilling to pay more than...	$500	€400	¥50,000	₩500,000	¥2,500	₹25,000	Local currencies‡

Note: Did not consider "don't know" responses.

† Southeast Asia region comprises Indonesia, Malaysia, Philippines, Singapore, Thailand, and Vietnam markets.

‡ IDR 5 million/MYR 2,000/25,000 Php/SGD 500/15,000 Thai baht/10 million VND.

[1] Calculated for each country in local market currency (roughly equivalent to $US500).

Q3. How much more would you be willing to pay for a vehicle that had each of the technologies listed below?

Sample size: China=1,016; Germany=1,401; India=989; Japan=880; Republic of Korea=961; Southeast Asia=5,070; US=960

Depending on the market, consumers will share personal data in exchange for less congested and safer routes, and vehicle health reporting/lower maintenance costs.

Interest (somewhat/very interested) in a connected vehicle if it provides benefits related to...

	US	Germany	Japan	Rep. of Korea	China	India	Southeast Asia
Updates regarding traffic congestion and suggested alternate routes	58%	55%	70%	79%	81%	83%	78%
Suggestions regarding safer routes (i.e., avoid unpaved roads)	58%	41%	69%	69%	80%	82%	76%
Updates to improve road safety and prevent potential collisions	56%	51%	72%	76%	81%	83%	81%
Customized/optimized vehicle insurance plan	48%	38%	51%	59%	75%	82%	72%
Maintenance updates and vehicle health reporting	59%	54%	63%	69%	79%	84%	80%
Maintenance cost forecasts based on your driving habits	51%	44%	54%	61%	79%	81%	74%
Customized suggestions regarding ways to minimize service expenses	51%	45%	63%	76%	81%	82%	75%
Over-the-air vehicle software updates	50%	53%	51%	66%	73%	77%	65%
Access to nearby parking (i.e., availability, booking, and payment)	47%	46%	56%	64%	79%	80%	72%
Special offers regarding non-automotive products and services related to your journey or destination	40%	29%	43%	55%	77%	75%	62%
Receiving a discount for access to a Wi-Fi connection in your vehicle	46%	35%	55%	62%	75%	77%	69%

Top three interests

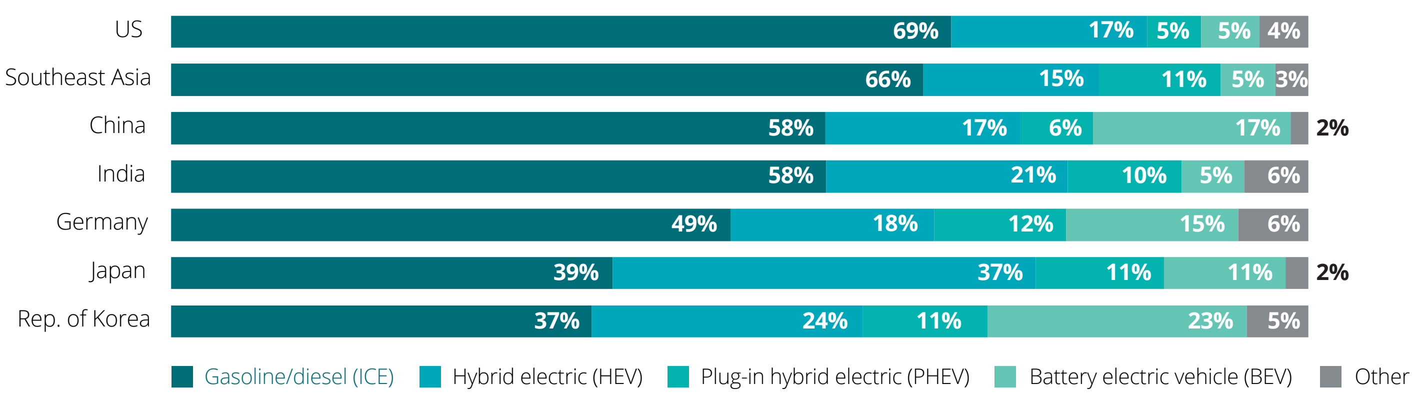
Q34. How interested are you in the following benefits of a connected vehicle if it meant sharing your own personal data and vehicle/operational data with the manufacturer or a third party?

Sample size: China=888; Germany=1,303; India=910; Japan=695; Republic of Korea=899; Southeast Asia=5,249; US=974

Vehicle electrification

Consumer interest in BEVs is highest in South Korea, China, and Germany while Japanese consumers prefer HEVs. ICE still dominates future intentions in the US.

Consumer powertrain preferences for their next vehicle



Note: "Other" includes engine types such as compressed natural gas, ethanol, and hydrogen fuel cells; did not consider "don't know" responses.
Q25. What type of engine would you prefer in your next vehicle?
Sample size: China=881; Germany=1,150; India=895; Japan=608; Republic of Korea=843; Southeast Asia=5,070; US=918

For the most part, people are drawn to an EV because of an expectation of lower fuel costs, or they are concerned about climate change and want to reduce emissions.

Factors that impact the decision to acquire an electrified vehicle

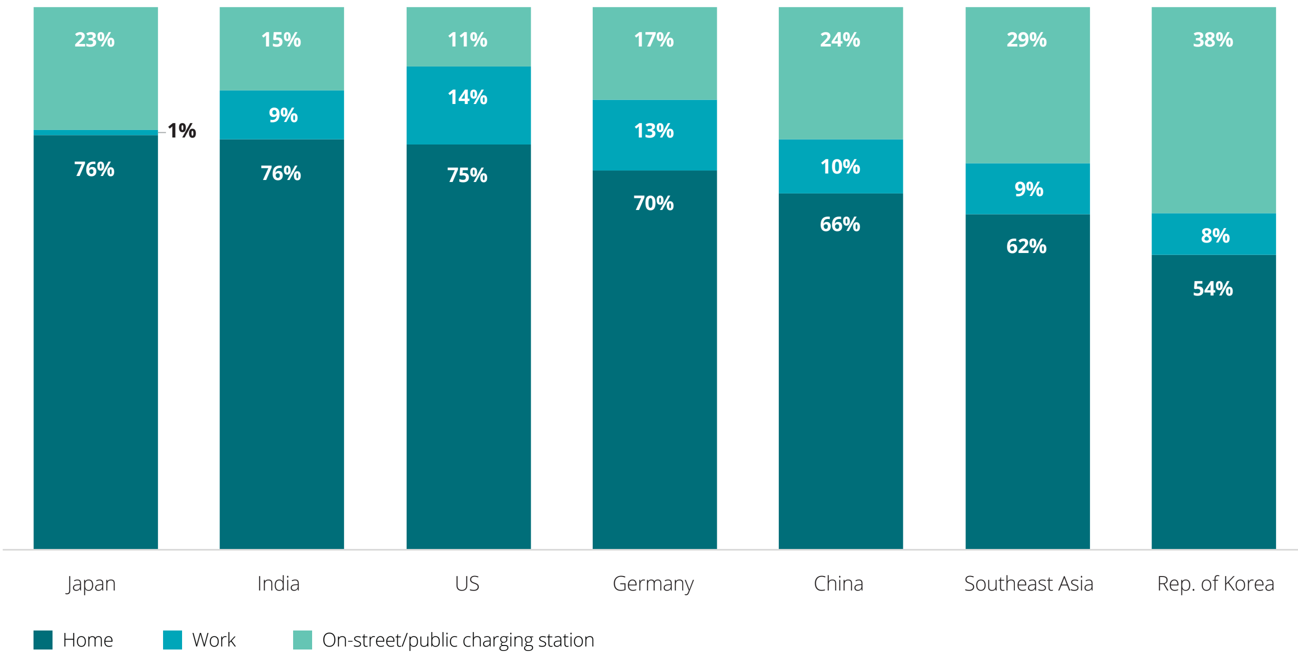
Factors	US	Germany	Japan	Rep. of Korea	China	India	Southeast Asia
Concern about climate change/ reduced emissions	2	1	2	2	1	1	2
Concern about personal health	6	4	5	7	3	4	5
Lower fuel costs	1	2	1	1	4	2	1
Less maintenance	4	7	7	3	6	5	4
Better driving experience	3	5	3	4	2	3	3
Government incentives/ stimulus programs	5	3	4	5	7	6	6
Potential for extra taxes/ levies applied to internal combustion vehicles	7	6	6	6	5	7	7

Top concern

Q26. Please rank the following factors in terms of their impact on your decision to acquire an electrified vehicle (highest to lowest).
Sample size: China=360; India=331; Germany=513; Japan=361; Republic of Korea=482; Southeast Asia=1,568; US=250

Most people in Japan, India, and the US plan to charge their PHEV/BEVs at home, while demand for public charging is high in South Korea and the SEA region.

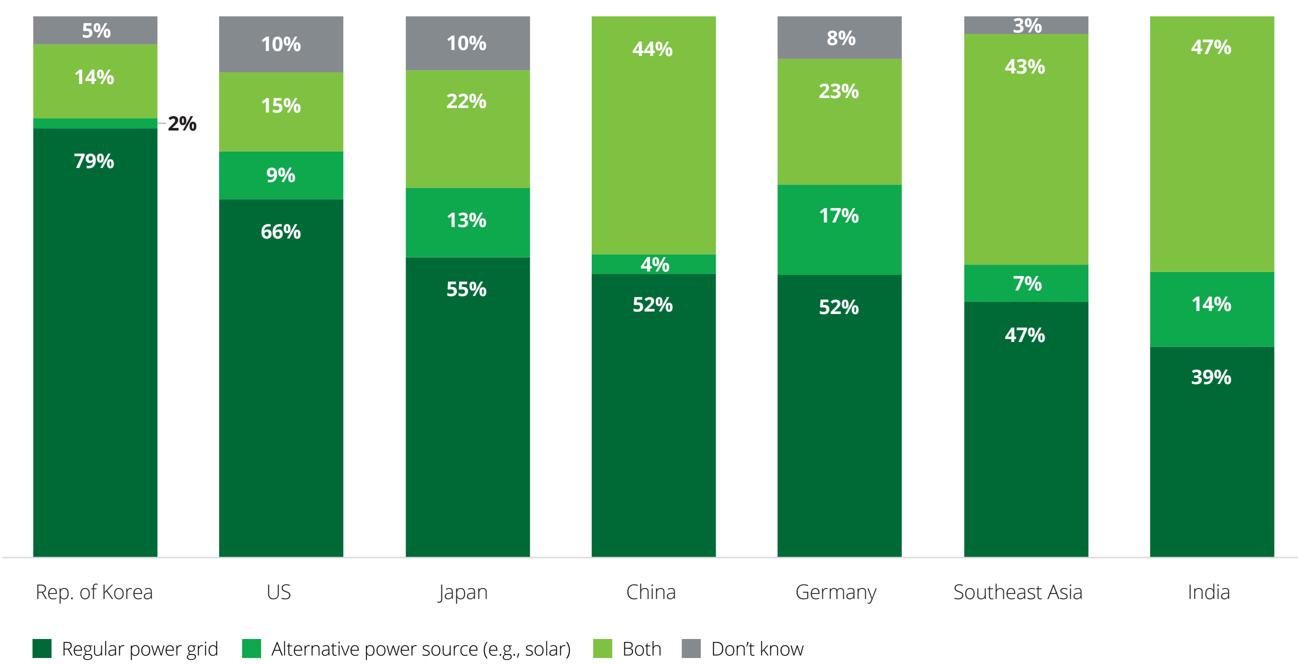
Location people expect to charge their electrified vehicle most often



Q27. Where do you expect to charge your electrified vehicle most often?
Sample size: China=209; Germany=307; India=143; Japan=133; Republic of Korea=284; Southeast Asia=784; US=91

Among those who plan to charge their PHEV/BEV at home, consumers in India, China, and the SEA region plan to use both regular grid and renewable power.

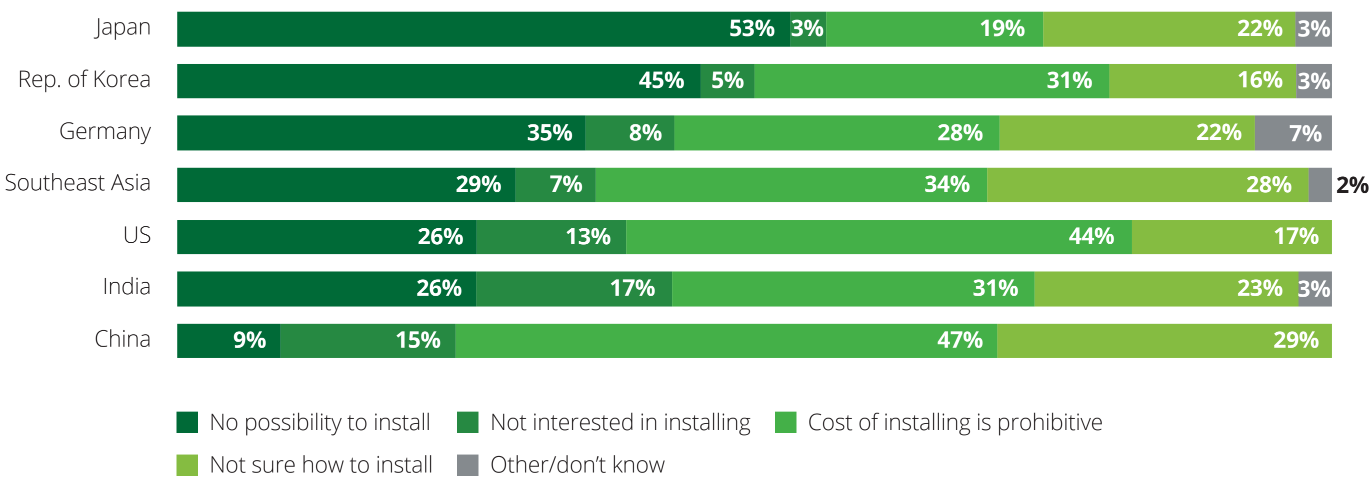
Source of power consumers intend to use to charge electric vehicles



Q28. How do you intend to charge your electrified vehicle at home?
Sample size: China=137; Germany=216; India=108; Japan=101; Republic of Korea=154; Southeast Asia=482; US=68

Consumers not planning to charge a PHEV/BEV at home say they either can't install a charger or the cost of installing a charger is prohibitive.

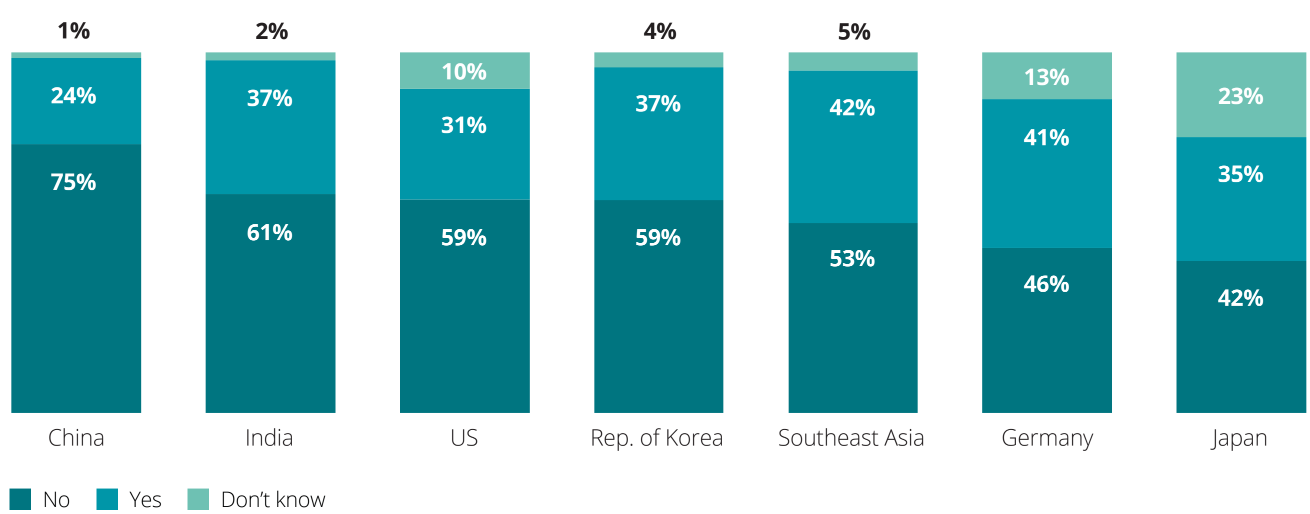
Reasons for not charging the electrified vehicle at home



Q29. What is the main reason you do not intend to charge your electrified vehicle at home?
Sample size: China=72; Germany=91; India=35; Japan=32; Republic of Korea=130; Southeast Asia=302; US=23

Potential increases in the price of electricity may sway a significant number of consumers away from a PHEV/BEV purchase in most global markets.

How many consumers would alter their decision to purchase an electrified vehicle if the electricity used for mobility was priced similar to current fossil fuels?



Q30. Would your decision to purchase an electrified vehicle change if the electricity used for mobility was priced similar to current fossil fuels?
Sample size: China=209; Germany=307; India=143; Japan=133; Republic of Korea=284; Southeast Asia=784; US=91

Consumers who said they are not considering an EV as their next vehicle cited range anxiety and a lack of public charging infrastructure as their biggest concerns.

Greatest concern regarding all battery-powered electric vehicles

Concern	US	Germany	Japan	Rep. of Korea	China	India	Southeast Asia
Driving range	20%	24%	15%	10%	22%	10%	13%
Cost/price premium	13%	12%	16%	9%	6%	12%	11%
Uncertain resale value	2%	2%	2%	1%	4%	4%	3%
Potential for extra taxes/levies associated with BEVs	4%	2%	1%	2%	6%	5%	4%
Time required to charge	10%	9%	8%	15%	11%	11%	11%
Lack of public electric vehicle charging infrastructure	14%	14%	19%	26%	12%	23%	28%
Lack of charger at home	8%	10%	19%	7%	5%	4%	6%
Lack of alternate power source (e.g., solar) at home	5%	4%	4%	3%	4%	6%	5%
Safety concerns with battery technology	9%	8%	6%	19%	16%	14%	11%
Lack of sustainability (i.e., battery manufacturing/recycling)	6%	10%	4%	4%	12%	8%	6%
Lack of choice	3%	3%	1%	1%	3%	3%	2%

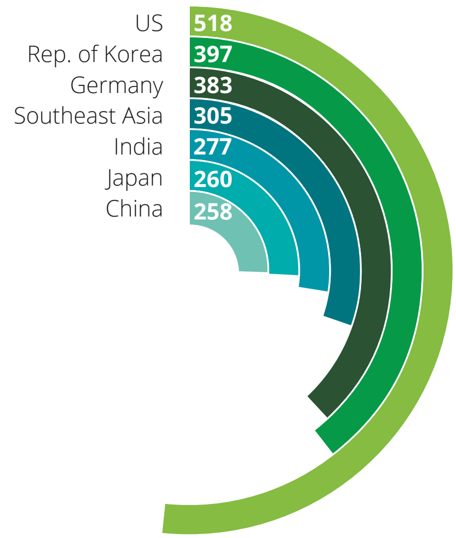
Greatest concern

Note: Sum of "concerns" for a market may not add up to 100% as "Other" and "Don't know" percentages are not shown.
Q31. What is your greatest concern regarding all battery-powered electric vehicles?
Sample size: China=888; Germany=1,303; India=910; Japan=695; Republic of Korea=899; Southeast Asia=5,249; US=974

US consumers expect fully charged BEV driving range to be north of 500 miles, while those in China, Japan, and India are content with a range of around 250 miles.

Consumer expectation of driving range from a fully charged all-battery electric vehicle

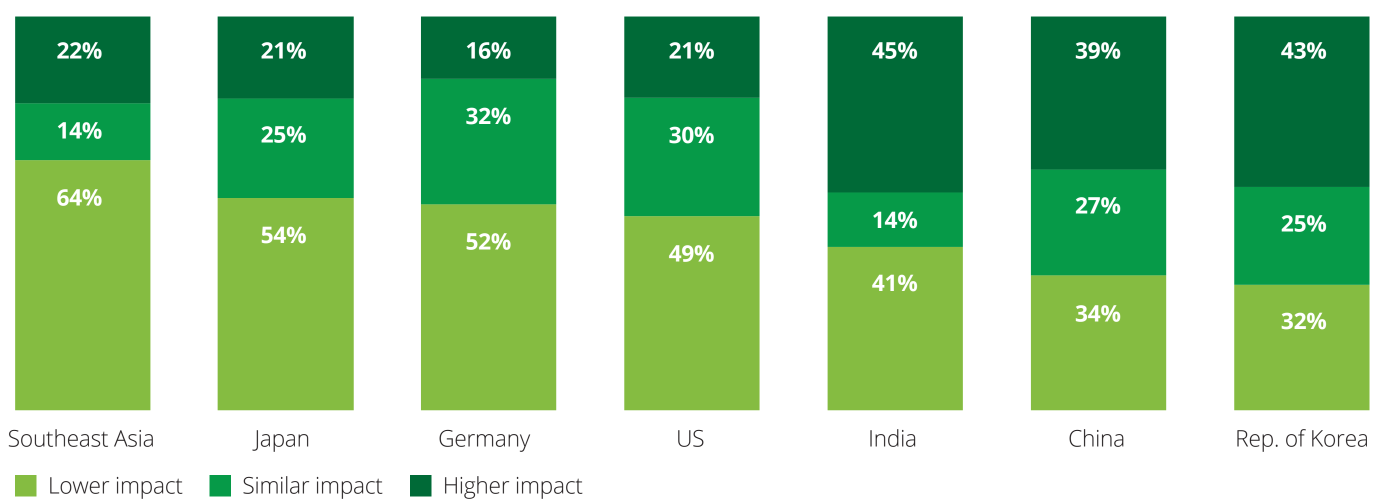
Driving range (in miles)



Q32. How much driving range would a fully charged all-battery electric vehicle need to have in order for you to consider acquiring one?
Sample size: China=735; Germany=1,129; India=861; Japan=630; Republic of Korea=709; Southeast Asia=5,004; US=927

Twice as many consumers in the SEA region see BEVs as having a lower environmental impact than ICE vehicles as compared to South Korea.

Comparison of all-battery electric vehicles with internal combustion vehicles from an environmental impact point of view



Note: Did not consider "Don't know" responses.
Q33. In your opinion, how do all-battery electric vehicles compare to internal combustion vehicles from an environmental impact point of view?
Sample size: China=878; Germany=1,194; India=894; Japan=605; Republic of Korea=838; Southeast Asia=4,952; US=831

https://www.rystadenergy.com/newsevents/news/press-releases/electric-car-makers-brace-for-cost-headache-as-battery-grade-lithium-price-set-to-rise-50pct-within-a-year/

Electric car makers brace for cost headache as battery-grade lithium price set to rise 50% within a year

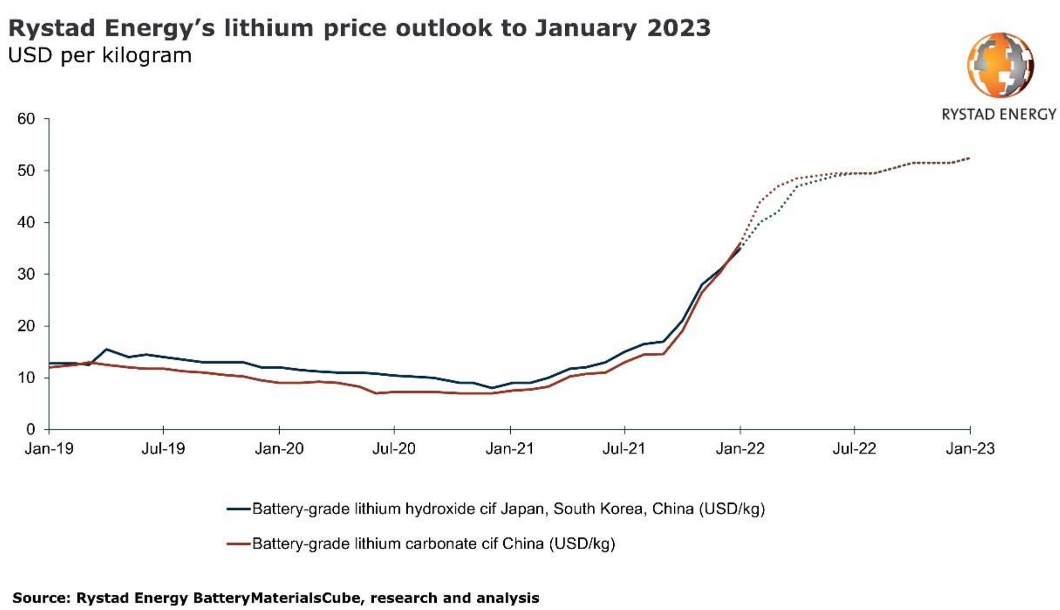
January 13, 2022

Electric vehicle (EV) producers and suppliers could be facing a major cost headache starting this year as prices for battery-grade lithium are poised to skyrocket. Prices for the metal are already trading at a record high of $35 per kilogram in Asia, and are likely to keep climbing to $50 per kilogram in the second half of 2022 and trade at around $52.5 per kilogram in January 2023, a Rystad Energy analysis shows.

Interest in lithium iron phosphate (LFP) batteries has taken off among manufacturers since early 2021. Rystad Energy therefore expects the supply of lithium salts to remain tight through the first half of 2022 at least, due to lagging production in China and South America. Producers appear reluctant to sell significant volumes on the spot market, as supply constraints and the ongoing logistical issues caused by the pandemic create bottlenecks in the trading market for lithium salts.

Chinese producers are hesitant to sell lithium salts on the spot market due to constraints caused by a slowdown in lithium carbonate production in Qinghai province in recent months. Similarly, suppliers in South America's lithium triangle are reluctant to allocate volumes outside long-term contracts despite their planned ramp-up in 2022, taking a cautious stance because of the ongoing logistical challenges.

This supply tightness for lithium salts, combined with the optimistic demand outlook for LFP batteries that typically feed on lithium carbonate, is expected to keep lithium carbonate prices high and support a notable premium over the price for lithium hydroxide in early 2022. However, Rystad Energy estimates this premium will gradually narrow after seasonal supply bottlenecks ease in China and a ramp-up plan in South America materializes.



"A fresh new driver for China's lithium market are lithium contract prices on the Changzhou Zhonglianjin exchange platform. Launched some six months ago, the futures contracts have driven sentiment in the market to some extent, especially over the past two months. This has contributed significantly to the current momentum in lithium prices in China and made trader-suppliers who have attempted to destock in January hold back from selling for now," says Susan Zou, senior analyst on Rystad Energy's battery materials team.

Changzhou’s lithium contract price for February 2022 hit an intraday high of CNY 418,500 per tonne on 10 January, up 14.34% from CNY 366,000/tonne at the close on 31 December 2021. The contract price then dropped to CNY 345,500/tonne at close on 12 January. However, it is still too early to say whether Changzhou’s lithium contract price will repeat the success of the cobalt contract on Wuxi, which has long dictated cobalt prices in China’s physical market, Zou said.

Rystad Energy’s monthly price index suggests that prices for battery-grade lithium carbonate ex-works China rose to CNY 300,000/tonne in early January 2022, up nearly 43% from CNY 210,000/tonne a month earlier. The price for battery-grade lithium hydroxide ex-works China rose to CNY 290,000/tonne in early January from CNY 192,000/tonne in early December.

For more analysis, insights and reports, clients and non-clients can apply for access to Rystad Energy’s Free Solutions and get a taste of our data and analytics universe.

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Maersk Orders Four More Ships to Run on Methanol
2022-01-10 11:17:14.60 GMT

By Jack Wittels
(Bloomberg) -- Maersk will take delivery of four large container vessels from Hyundai Heavy Industries, the firm said in a statement.
* Ships will be able to run on carbon-neutral methanol and will be delivered in 2025
** Four ships are in addition to eight similar vessels the firm had already ordered
* Once fully phased in, the total 12 new ships will generate total annual CO2 emissions savings of 1.5m tons, equivalent to 4.5% of total Maersk fleet emissions
* A statement from HHI showed an order for four container ships from a European shipping company, for 839.7 billion South Korean won (about $700 million)
* READ: Maersk's New Lower-Carbon Ships Will Also Carry More Stuff
* READ: Shipping Has an Emissions Problem. Can It Be Fixed?: QuickTake

--With assistance from Alaric Nightingale.

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https://www.maersk.com/news/articles/2021/08/24/maersk-accelerates-fleet-decarbonisation

A.P. Moller - Maersk accelerates fleet decarbonisation with 8 large ocean-going vessels to operate on carbon neutral methanol

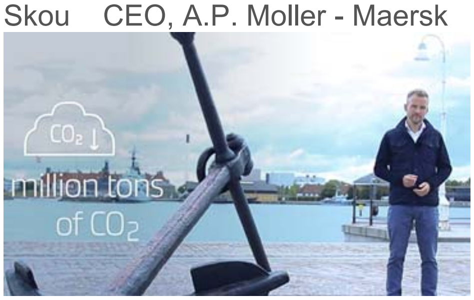
24 August 2021

Copenhagen – In the first quarter of 2024, A.P. Moller - Maersk will introduce the first in a groundbreaking series of 8 large ocean-going container vessels capable of being operated on carbon neutral methanol. The vessels will be built by Hyundai Heavy Industries (HHI) and have a nominal capacity of approx. 16,000 containers (Twenty Foot Equivalent - TEU). The agreement with HHI includes an option for 4 additional vessels in 2025. The series will replace older vessels, generating annual CO2 emissions savings of around 1 million tonnes. As an industry first, the vessels will offer Maersk customers truly carbon neutral transportation at scale on the high seas.

More than half of Maersk's 200 largest customers have set – or are in the process of setting – ambitious science-based or zero carbon targets for their supply chains. As part of Maersk's ongoing collaboration with customers, corporate sustainability leaders including Amazon, Disney, H&M Group, HP Inc., Levi Strauss & Co., Microsoft, Novo Nordisk, The Procter and Gamble Company, PUMA, Schneider Electric, Signify, Syngenta and Unilever have committed to actively use and scale zero carbon solutions for their ocean transport, with many more expected to follow.

The vessels come with a dual fuel engine setup. Additional capital expenditure (CAPEX) for the dual fuel capability, which enables operation on methanol as well as conventional low Sulphur fuel, will be in the range of 10-15% of the total price, enabling Maersk to take a significant leap forward in its commitment to scale carbon neutral solutions and lead the decarbonisation of container logistics.

"*The time to act is now, if we are to solve shipping's climate challenge. This order proves that carbon neutral solutions are available today across container vessel segments and that Maersk stands committed to the growing number of our customers who look to decarbonise their supply chains. Further, this is a firm signal to fuel producers that sizable market demand for the green fuels of the future is emerging at speed*." Soren Skou CEO, A.P. Moller - Maersk



Maersk will operate the vessels on carbon neutral e-methanol or sustainable bio-methanol as soon as possible. Sourcing an adequate amount of carbon neutral methanol from day one in service will be challenging, as it requires a significant production ramp up of proper carbon neutral methanol production, for which Maersk continues to engage in partnerships and collaborations with relevant players.

The vessels will be designed to have a flexible operational profile, enabling them to perform efficiently across many trades, and add flexibility regarding customer needs. They will feature a methanol propulsion configuration developed in collaboration with makers including MAN ES, Hyundai (Himsen) and Alfa Laval which represents a significant scale-up of the technology from the previous size limit of around 2,000 TEU. The vessels will be classed by the American Bureau of Shipping and sail under Danish flags.

"We are very excited about this addition to our fleet, which will offer our customers unique access to carbon neutral transport on the high seas while balancing their needs for competitive slot costs and flexible operations. To us, this is the ideal large vessel type to enable sustainable, global trade on the high seas in the coming decades and from our dialogue with potential suppliers, we are confident we will manage to source the carbon neutral methanol needed." Henriette Hallberg Thygesen CEO, Fleet & Strategic Brands, A.P. Moller - Maersk

Replacing Maersk tonnage reaching end-of-life
The new vessels come as part of Maersk's ongoing fleet renewal program and will replace tonnage of more than 150,000 TEU which is reaching end-of-life and leaving the Maersk managed fleet between 2020 and Q1 2024.

CAPEX for the announced vessels is included in current guidance for 2021-2022 of USD 7bn. Maersk further reiterates its strategy of maintaining a fleet capacity in the 4.0 to 4.3 million TEU range, as a combination of Maersk managed and time-chartered vessels.

Customer quotes

H&M Group "*As an industry leader, H&M Group has a responsibility to fight climate change. We have the ambition to become climate neutral by 2030 and climate positive by 2040. We truly believe that our climate actions should be co-created with our partners. Maersk's investment in large vessels operating on green methanol is an important innovative step supporting H&M Group's climate goals within International Freight and we are proud to take part in this pioneer journey*." Leyla Ertur Head of Sustainability - H&M Group

HP Inc "*Sustainability is embedded across our business and remains a core value at HP. We recently announced some of the most ambitious climate action goals in our industry and to achieve them we are implementing more sustainable transportation solutions within our supply chain, including this green fuels collaboration with Maersk. It's an important step for all companies involved to make the greatest impact possible and help combat the climate crisis."* Antoine Simonnet chief supply chain officer - HP Inc

Signify "*Today, the world is finally waking up to the climate crisis. The next decade has to be one of 'climate action.' With Brighter Lives, Better World 2025 – our five-year sustainability program – we've set a new goal to go beyond carbon neutrality and to double the pace at which we will meet the 1.5°C scenario set out by the Paris Agreement. The pledge is to meet this ambitious target across our entire value chain and do this six years early. Our renewed partnership with Maersk will help us to scale zero carbon solutions in our supply chain and logistical operations, providing rich pickings for emission reductions*." Maurice Loosschilder Head of Sustainability – Signify

Unilever "*Unilever is committed to accelerating the transition to clean transport solutions, not just in our own operations but along global value chains as we work to achieve net zero emissions by 2039. With logistics and distribution accounting for around 15% of our greenhouse gas emissions footprint, it's important that we work with partners shifting to lower carbon fuels. We are proud to partner with Maersk as they pioneer carbon neutral transportation on the high seas*." Michelle Grose Head of Logistics and Fulfilment – Unilever

About A.P. Moller - Maersk
A.P. Moller - Maersk is an integrated container logistics company working to connect and simplify its customers' supply chains. As the global leader in shipping services, the company operates in 130 countries and employs around 80,000 people. For more information check here.

Office market posts first quarter of rebound activity since onset of pandemic

▲ 15.8%
Vacancy Rate

▲ 1.7M
SF Net Absorption

▼ 14.9M
SF Under Construction

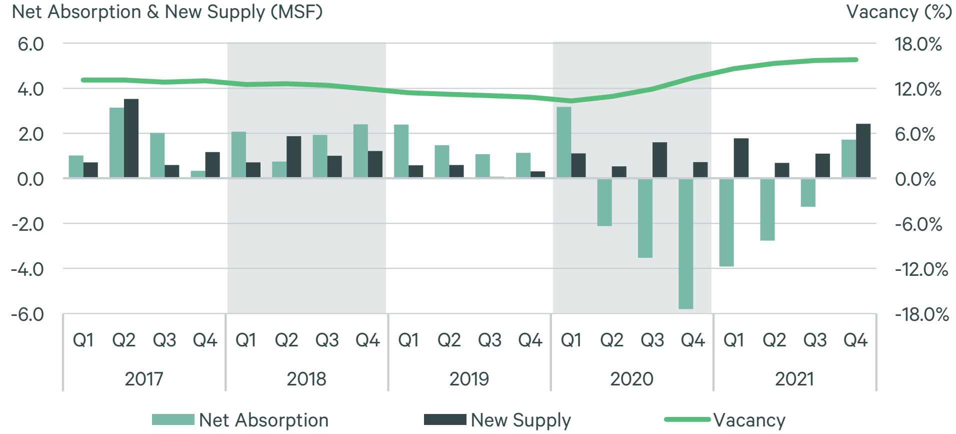
▲ $21.28
PSF Class A Net Asking Lease Rate

Note: Arrows indicate change from previous quarter.

Executive Summary

- In stark contrast to the fourth quarter of 2020, net absorption totaled a positive 1.7 million sq. ft. in Q4 2021. These gains even outpace 2019's quarterly average of 1.5 million sq. ft. when global tech occupiers flocked to Canadian gateway cities.
- Sublease levels continue to retreat, primarily in downtown cores which have declined 18% from their peak in Q1 2021. Vacant sublets now represent 3.0% of total inventory nationally.
- Vacancy experienced a minor uptick of just 10 basis points (bps) this quarter, ending the year at 15.8%. This is the smallest quarterly increase on record since the onset of the pandemic, signaling a likely turn in the market as three markets reported declining vacancy at year-end: Toronto, Vancouver and Ottawa.
- 2.4 million sq. ft. of new supply was delivered in the fourth quarter. With over 70% pre-leased upon completion, these projects helped push absorption into positive territory for the first time since Q1 2020.

FIGURE 1: National Office Supply & Demand



Source: CBRE Research, Q4 2021.

Canada's first quarter of positive net absorption since onset of the pandemic

- In stark contrast to the fourth quarter of 2020, Canada's office market ended 2021 on a high note, recording positive net absorption for the first time since Q1 2020. Leasing momentum is building, and fourth quarter touring levels reached their highest point in two years.

- Taking a retrospective look, Canada recorded a cumulative total loss of 19.4 million sq. ft. in leased office space between Q2 2020 and Q3 2021. This quarter's 1.7 million sq. ft. represents a strong start in the recovery, making up 8.7% of these losses.

- Net absorption was highest in the Toronto, Vancouver and Ottawa markets, where the delivery of new office towers with high levels of pre-leasing played a key role in boosting occupancy gains. In all, Canada recorded 2.4 million sq. ft. of new supply in the fourth quarter, of which 70.0% was pre-leased upon completion.

FIGURE 2: Historical Change in Occupied Space, National Net Absorption (MSF)

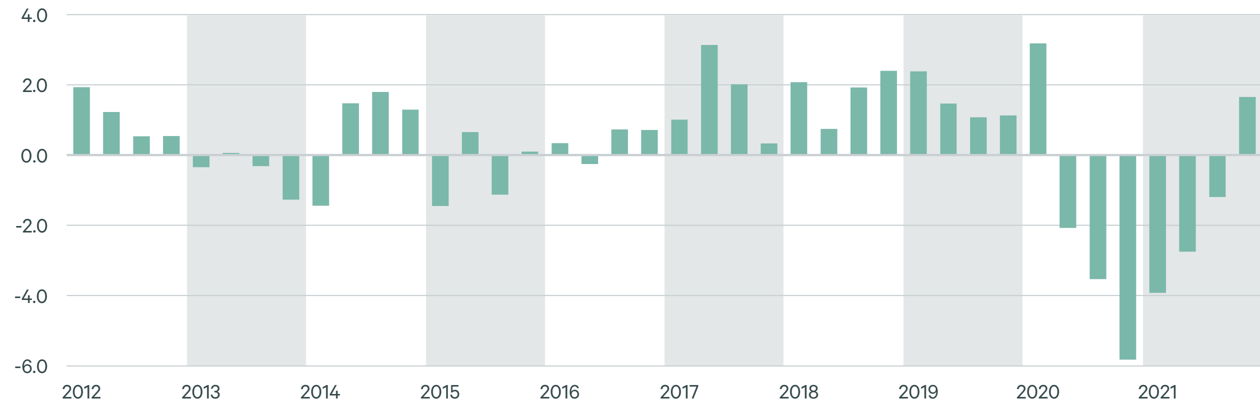
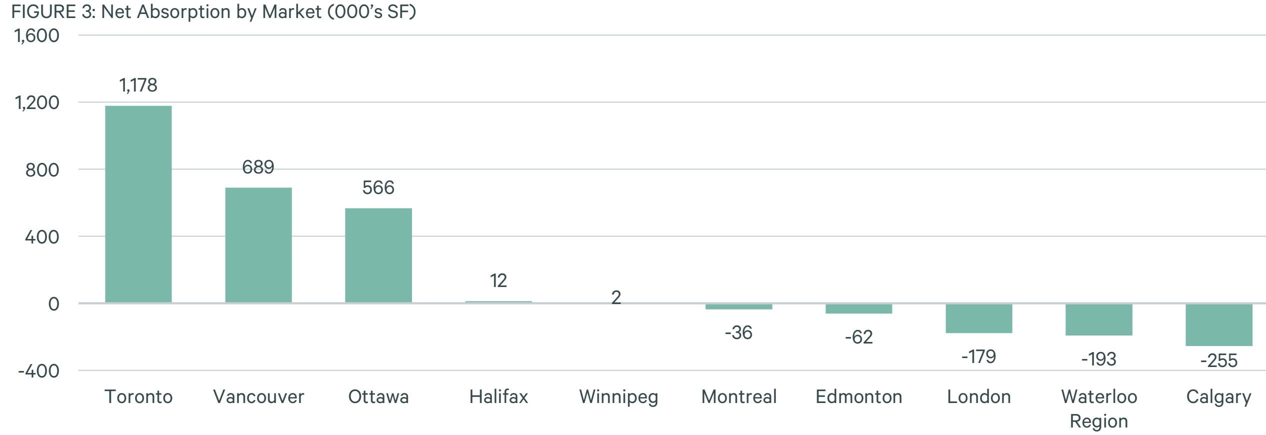
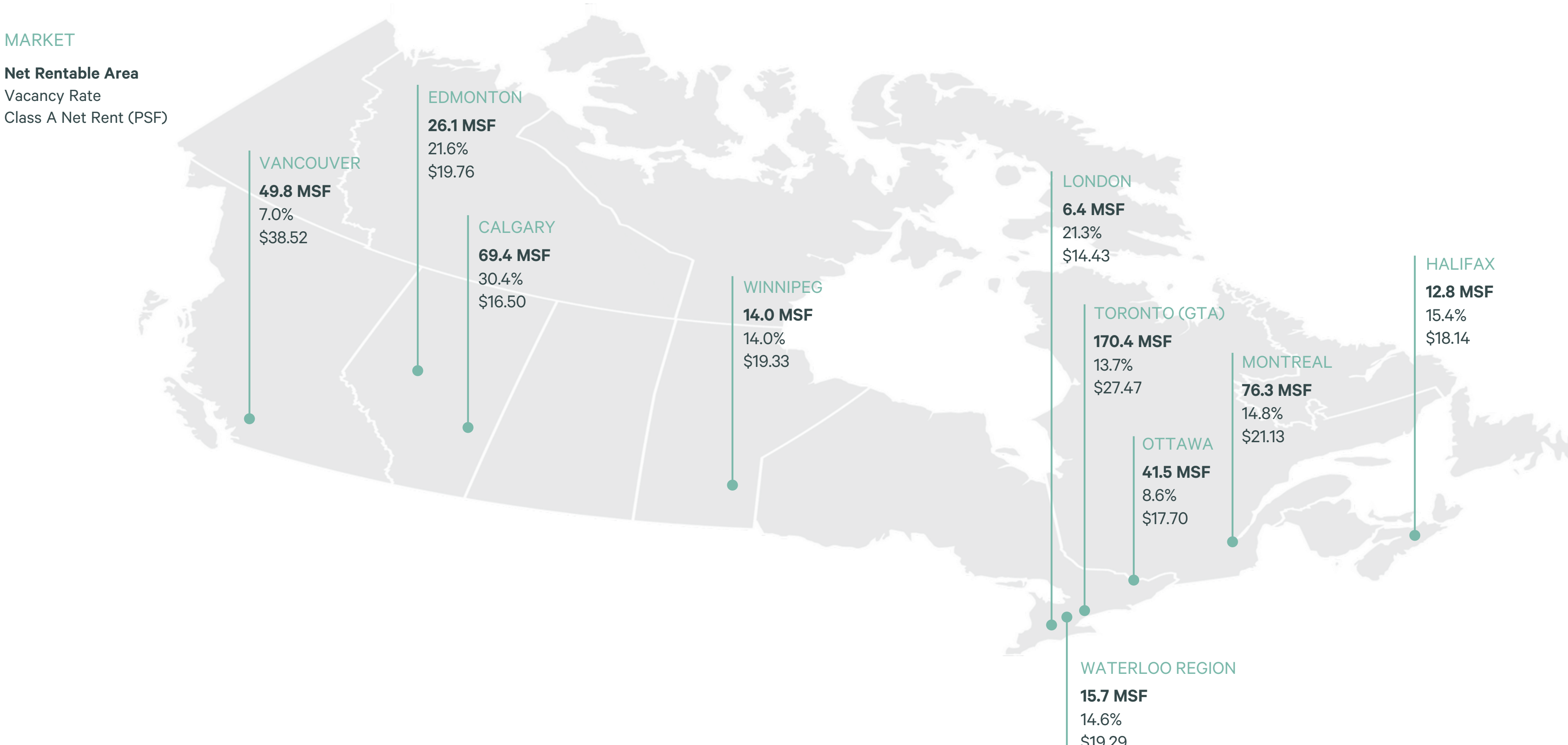


FIGURE 3: Net Absorption by Market (000's SF)



Source: CBRE Research, Q4 2021.

FIGURE 10: Canadian Office Markets At A Glance



Source: CBRE Research, Q4 2021.

FIGURE 11: Canadian Office Markets Statistics, Q4 2021

DOWNTOWN	VANCOUVER	CALGARY	EDMONTON	WINNIPEG	LONDON	WATERLOO	TORONTO	OTTAWA	MONTREAL	HALIFAX	NATIONAL
Net Rentable Area	24,921,293	43,217,521	16,045,040	9,950,827	4,766,661	4,941,027	92,508,192	18,909,918	45,425,372	5,331,061	266,016,912
Overall Vacancy Rate	7.2%	33.2%	21.1%	15.3%	26.1%	27.1%	9.7%	9.9%	13.7%	20.3%	15.7%
Direct Space	1,429,692	10,975,320	2,966,146	1,485,147	1,182,821	1,295,613	6,652,037	1,539,616	5,301,363	1,069,219	33,896,974
Sublet Space	373,329	3,357,287	422,812	41,779	60,970	43,888	2,305,850	329,205	912,100	13,503	7,860,723
Sublet of Vacant Space	20.7%	23.4%	12.5%	2.7%	4.9%	3.3%	25.7%	17.6%	14.7%	1.2%	18.8%
Class A Vacancy Rate	7.2%	27.7%	19.2%	14.4%	11.2%	27.0%	8.0%	6.4%	10.1%	27.1%	13.0%
Average Class A Net Rent (PSF)	$46.79	$15.48	$20.48	$19.33	$14.43	$26.17	$34.18	$22.64	$24.82	$19.37	$23.96
Quarter Net Absorption	404,444	-169,584	-82,905	-72,593	-179,220	-243,045	1,354,926	260,375	-227,511	-6,254	1,038,633
Year-to-Date Net Absorption	364,333	-1,760,701	-161,485	-377,157	-311,033	-474,298	718,899	77,628	-1,606,511	-43,314	-3,573,639
Quarter New Supply	345,846	0	0	0	0	0	1,314,345	167,953	0	0	1,828,144
Year-to-Date New Supply	766,319	0	0	0	0	192,168	3,212,345	167,953	0	0	4,338,785
Under Construction	2,916,547	0	0	300,000	0	0	7,519,259	34,384	624,577	0	11,394,767
SUBURBAN											
Net Rentable Area	24,910,594	26,157,039	10,037,106	4,083,333	1,605,465	10,798,866	77,879,737	22,591,987	30,825,012	7,425,788	216,314,927
Overall Vacancy Rate	6.8%	25.9%	22.4%	10.6%	7.2%	8.9%	18.5%	7.5%	16.6%	12.0%	15.8%
Direct Space	1,212,294	5,577,951	1,871,121	416,719	114,839	699,217	11,168,726	1,541,051	4,243,402	848,568	27,693,888
Sublet Space	469,278	1,185,635	376,171	18,089	0	262,837	3,209,180	149,895	866,110	39,201	6,576,396
Sublet of Vacant Space	27.9%	17.5%	16.7%	4.2%	0.0%	27.3%	22.3%	8.9%	17.0%	4.4%	19.2%
Class A Vacancy Rate	7.4%	22.4%	19.9%	N/A	N/A	8.5%	20.4%	7.9%	15.3%	17.8%	16.2%
Average Class A Net Rent (PSF)	$28.61	$18.75	$17.72	N/A	N/A	$17.29	$18.05	$15.49	$16.45	$15.88	$18.18
Quarter Net Absorption	284,340	-85,819	20,535	75,040	667	50,246	-176,849	305,712	191,587	18,689	684,148
Year-to-Date Net Absorption	652,538	-677,342	-90,275	53,044	-13,107	-409,431	-2,476,997	106,976	139,713	59,821	-2,655,060
Quarter New Supply	197,313	63,141	0	53,750	0	0	0	153,000	133,067	0	600,271
Year-to-Date New Supply	748,936	77,918	0	53,750	0	22,754	103,590	153,000	492,611	0	1,652,559
Under Construction	786,890	0	0	0	0	69,963	593,848	0	1,870,262	200,000	3,520,963
TOTAL											
Net Rentable Area	49,831,887	69,374,560	26,082,146	14,034,160	6,372,126	15,739,893	170,387,929	41,501,905	76,250,384	12,756,849	482,331,839
Overall Vacancy Rate	7.0%	30.4%	21.6%	14.0%	21.3%	14.6%	13.7%	8.6%	14.8%	15.4%	15.8%
Direct Space	2,641,986	16,553,271	4,837,267	1,901,866	1,297,660	1,994,830	17,820,763	3,080,667	9,544,765	1,917,787	61,590,862
Sublet Space	842,607	4,542,922	798,983	59,868	60,970	306,725	5,515,030	479,100	1,778,210	52,704	14,437,119
Sublet of Vacant Space	24.2%	21.5%	14.2%	3.1%	4.5%	13.3%	23.6%	13.5%	15.7%	2.7%	19.0%
Class A Vacancy Rate	7.3%	26.0%	19.4%	14.4%	11.2%	13.2%	13.1%	7.3%	12.0%	22.9%	14.3%
Average Class A Net Rent (PSF)	$38.52	$16.50	$19.76	$19.33	$14.43	$19.29	$27.47	$17.70	$21.13	$18.14	$21.28
Quarter Net Absorption	688,784	-255,403	-62,370	2,447	-178,553	-192,799	1,178,077	566,087	-35,924	12,435	1,722,781
Year-to-Date Net Absorption	1,016,871	-2,438,043	-251,760	-324,113	-324,140	-883,729	-1,758,098	184,604	-1,466,798	16,507	-6,228,699
Quarter New Supply	543,159	63,141	0	53,750	0	0	1,314,345	320,953	133,067	0	2,428,415
Year-to-Date New Supply	1,515,255	77,918	0	53,750	0	214,922	3,315,935	320,953	492,611	0	5,991,344
Under Construction	3,703,437	0	0	300,000	0	69,963	8,113,107	34,384	2,494,839	200,000	14,915,730

Source: CBRE Research, Q4 2021.

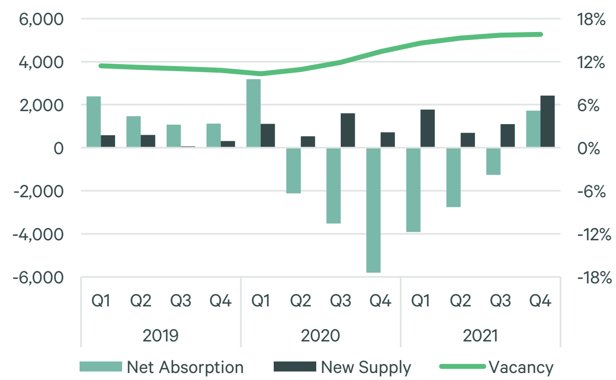
Canada

Vacancy experienced a minor uptick of just 10 bps this quarter, ending the year at 15.8%. This is the smallest quarterly increase on record since the onset of the pandemic, signaling a likely turn in the market as three markets reported declining vacancy at year-end.

MARKET STATS	DOWNTOWN	SUBURBAN	TOTAL	Q/Q
Net Rentable Area	266,016,912	216,314,927	482,331,839	↑
Overall Vacancy Rate	15.7%	15.8%	15.8%	↑
Direct Space	33,896,974	27,693,888	61,590,862	↑
Sublet Space	7,860,723	6,576,396	14,437,119	↓
Sublet % of Vacant	18.8%	19.2%	19.0%	↓
Class A Vacancy Rate	13.0%	16.2%	14.3%	↔
Avg. Class A Net Rent (PSF)	$23.96	$18.18	$21.28	↑
Quarter Net Absorption	1,038,633	684,148	1,722,781	↑
Quarter New Supply	1,828,144	600,271	2,428,415	↑
Under Construction	11,394,767	3,520,963	14,915,730	↓

METRO SUPPLY & DEMAND

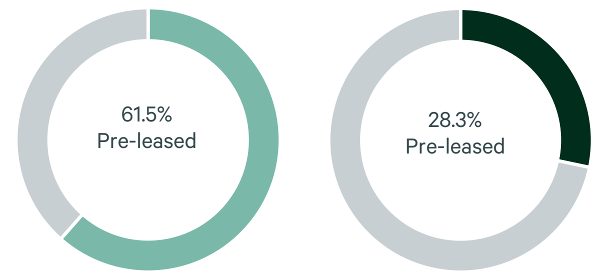
Net Absorption & New Supply (000's SF)　　Vacancy (%)



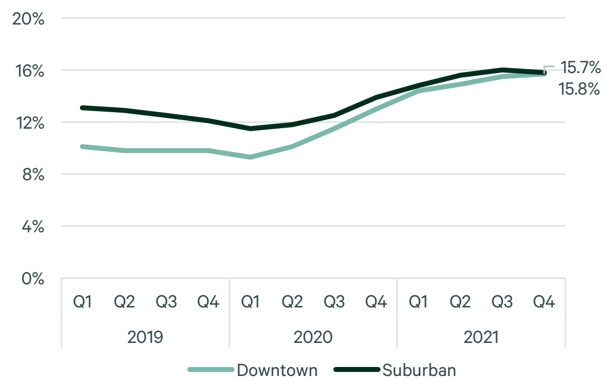
UNDER CONSTRUCTION

Downtown
11.4 MSF
4.3% of Inventory

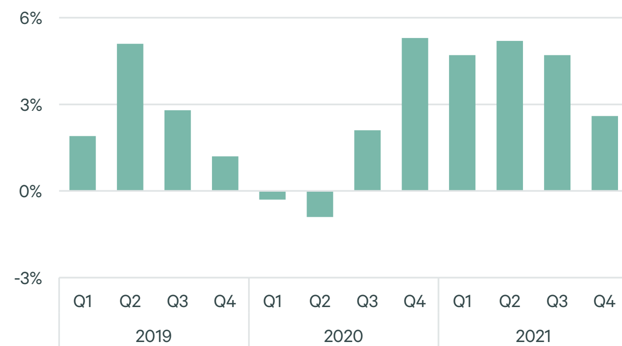
Suburban
3.5 MSF
1.6% of Inventory



DOWNTOWN VS SUBURBAN VACANCY



METRO CLASS A RENT, Y-o-Y GROWTH

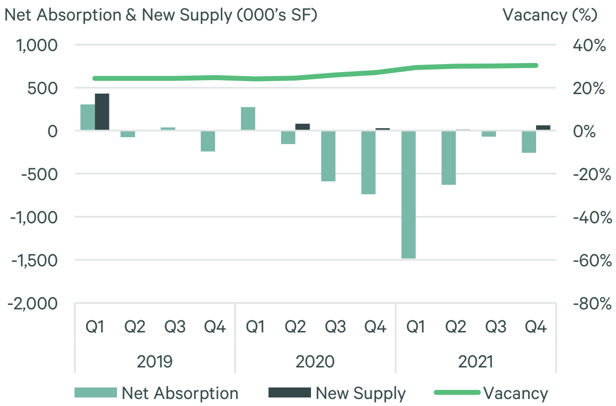


Calgary

Further M&A activity in the energy sector is expected as we exit the downturn and commodity prices stabilize. An uptick in asset sales by major oil and gas firms is expected as foreign companies looking to exit Canada capitalize on improved pricing.

MARKET STATS	DOWNTOWN	SUBURBAN	TOTAL	Q/Q
Net Rentable Area	43,217,521	26,157,039	69,374,560	↑
Overall Vacancy Rate	33.2%	25.9%	30.4%	↑
Direct Space	10,975,320	5,577,951	16,553,271	↑
Sublet Space	3,357,287	1,185,635	4,542,922	↓
Sublet % of Vacant	23.4%	17.5%	21.5%	↓
Class A Vacancy Rate	27.7%	22.4%	26.0%	↑
Avg. Class A Net Rent (PSF)	$15.48	$18.75	$16.50	↓
Quarter Net Absorption	-169,584	-85,819	-255,403	↓
Quarter New Supply	0	63,141	63,141	↑
Under Construction	0	0	0	↓

METRO SUPPLY & DEMAND

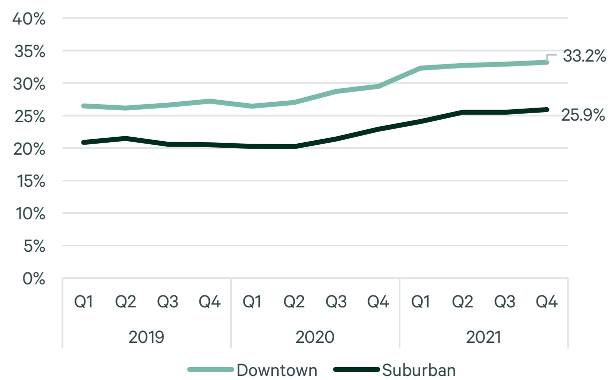


UNDER CONSTRUCTION

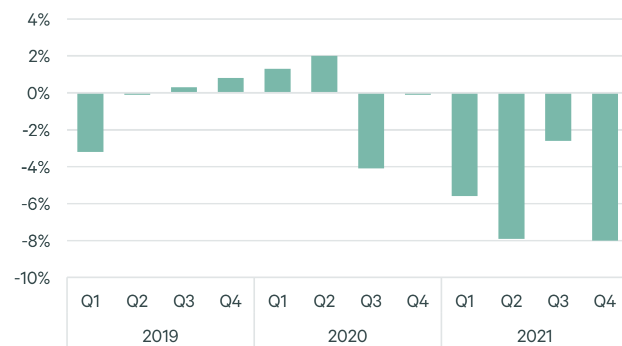
Downtown
0 MSF
0% of Inventory

Suburban
0 MSF
0% of Inventory

DOWNTOWN VS SUBURBAN VACANCY



METRO CLASS A RENT, Y-o-Y GROWTH



Executive Summary

On September 15, 2021, Senator Rosa Galvez requested that the PBO update the High-net-worth Family Database (HFD) with the most recent data from the Survey of Financial Security (SFS) for the year 2019 and that the methodology be applied to the SFS of previous years in order to study the trends in Canadian net wealth distribution. This report addresses the request, using the methodology laid out in PBO's June 2020 report titled "Estimating the top tail of the family wealth distribution in Canada."[1]

Consistent with the June 2020 report, we use the SFS Public Use Microdata File (PUMF) and the National Balance Sheet Accounts (NBSA) as data sources to construct the HFD for 2019. However, the Canadian Business (CB) magazine's Richest People List used in the 2020 report is no longer published and unavailable for the year 2019. As such, this updated version uses World's Real Time Billionaires lists published by Forbes as a complementary source of information to the SFS.

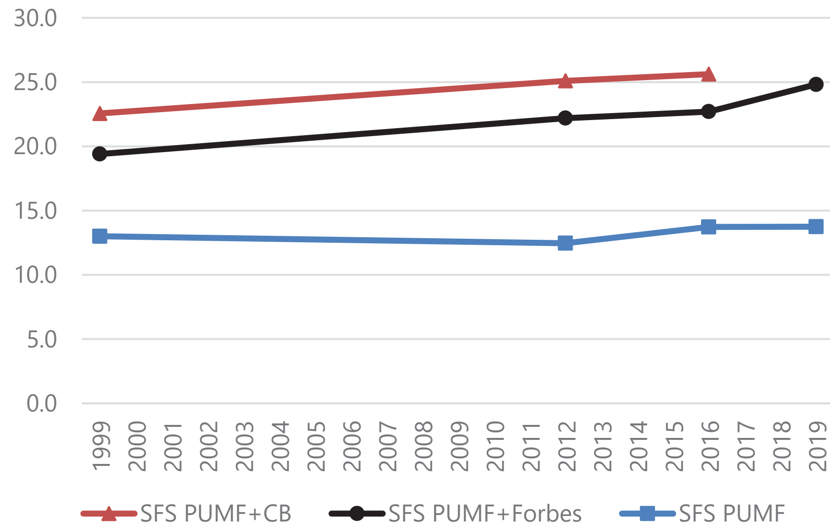
The updated HFD shows that the top one percent of high-net-worth families in Canada hold 24.8 percent of the country's total net wealth. Furthermore, using the SFS PUMF for the years 1999, 2012, 2016, and 2019, along with the Forbes billionaire lists in the corresponding years, PBO finds that the top one percent's share of net wealth in Canada has increased by approximately 5 percentage points over the period of 1999-2019. The increase is corroborated by similar estimates made with the Canadian Business Lists for the years 1999-2016.

Table ES-1 Family net wealth distribution in Canada, 2019

Percentile of family net wealth	Statistics Canada's SFS PUMF Share of total net wealth (per cent)	PBO'S HFD Share of total net wealth (per cent)
Top 0.01%	0.4	5.0
Top 0.1%	2.8	11.2
Top 0.5%	8.9	19.5
Top 1%	13.7	24.8
Top 5%	33.1	43.5
Top 10%	47.8	56.9
Top 20%	66.9	73.9
Middle 40%	30.4	25.1
Bottom 40%	2.7	1.1

Sources: PBO calculations of the SFS PUMF; PBO High-net-worth Family Database

Figure ES-1 Share of wealth of top 1%, 1999-2019



Source: PBO calculations for 1999, 2012, 2016, and 2019.

1. Introduction

Senator Galvez requested that the PBO update the High-net-worth Family Database (HFD) with the most recent data from the Survey of Financial Security (SFS) for the year 2019 and that the methodology be applied to create the HFD with the SFS of previous years to study the wealth distribution in Canada over time.

This report uses the modelling approach laid out in PBO's June 2020 report titled "Estimating the top tail of the family wealth distribution in Canada." Briefly, the approach consists of a Pareto interpolation which creates a synthetic dataset bridging microdata on wealth from the SFS PUMF and the Forbes Billionaires list. This resulting dataset is constrained to produce aggregates that match those found in the NBSA.

The report proceeds as follows. First, the HFD is updated to reflect the latest information available from the SFS, the NBSA and the World's Real Time Billionaires lists published by Forbes. These results are then grown to the second quarter of 2021. Next, using the 1999, 2012, 2016, and 2019 SFS PUMF, along with previously published rich lists, the top tail of the distribution is estimated for the corresponding years. This latter step gives a glimpse at the evolution of wealth concentration in Canada from 1999 to 2019 using a consistent approach.

2. Estimating the HFD with the 2019 SFS

2.1. Method for constructing the 2019 HFD

As in PBO's previous estimation report, the HFD is created using both the SFS PUMF and a rich people list. Forbes Real Time World's Billionaires list from November 1st, 2019 is used for the 2019 HFD, to match the SFS collection period of 2019 Q4.[2] The Forbes values of net wealth were converted from USD to CAD.[3] As before, the rich list is adjusted to take into account economic families; as a result, all split entries that fall below the lowest individual entry on the list are dropped.

The bottom threshold value for the interpolation used for the estimation of the 2016 HFD is adjusted to reflect the increase in the Consumer Price Index (CPI) between 2016 and 2019. Using the newly constructed dataset, we iteratively estimate the HFD, such that aggregate asset, liabilities, and net worth values align with those published in the NBSA by Statistics Canada.[4]

2.2. Results

The 2019 HFD shows that the top one percent of high-net-wealth families in Canada hold 24.8 percent of the country's total net wealth. Table 2-1 provides the share of total net wealth by various percentiles. Similar to the 2016 HFD, the 2019 HFD adds 11.1 percentage points to the share of total net wealth held by the top 1 percent of families, compared to the 2019 SFS PUMF.

Table 2-1 Family net wealth distribution in Canada, 2019

Percentile of family net wealth	Statistics Canada's SFS PUMF Share of total net wealth (per cent)	PBO'S HFD Share of total net wealth (per cent)
Top 0.01%	0.4	5.0
Top 0.1%	2.8	11.2
Top 0.5%	8.9	19.5
Top 1%	13.7	24.8
Top 5%	33.1	43.5
Top 10%	47.8	56.9
Top 20%	66.9	73.9
Middle 40%	30.4	25.1
Bottom 40%	2.7	1.1

Sources: PBO calculations of the SFS PUMF; PBO High-net-worth Family Database

Table 2-2 summarizes the total net wealth and share of total net wealth held by selected percentiles of net wealth distribution. The threshold for being in the given percentile, along with the number of families in each percentile, is included. The cut-off for the top one percent of family net wealth is $6.3 million. There are currently 160,600 families in Canada in that group, compared to 159,300 in the 2016 HFD.

Table 2-2 Net wealth distribution, by selected percentiles, Canada, 2019

Percentile of family net wealth	Net wealth threshold ($ millions)	Number of families (thousands)	Total net wealth ($ billions)	Share of total net wealth (per cent)
Top 0.01%	129.5	1.6	583	5.0
Top 0.1%	28.8	16.0	1,309	11.2
Top 0.5%	9.9	80.2	2,285	19.5
Top 1%	6.3	160.6	2,903	24.8
Top 5%	2.4	800.4	5,088	43.5
Top 10%	1.6	1,591.7	6,653	56.9
Top 20%	1.0	3,183.7	8,643	73.9
Middle 40%	0.1-1.0	6,365.6	2,931	25.1
Bottom 40%	under 0.1	6,365.7	123	1.1

Source: PBO High-net-worth Family Database

Additional summary statistics from the 2019 HFD are provided in Table 2-3. There are approximately 3 million families in Canada with net wealth above one million dollars. Collectively, these families hold 73 percent of the total wealth in Canada.

Table 2-3 Net wealth distribution, by selected net wealth thresholds, Canada, 2019

Family net wealth threshold Families with net worth above:	Number of families (thousands)	Total net wealth ($ billions)	Share of total net wealth (per cent)
$1 billion	0.1	185	1.6
$500 million	0.2	277	2.4
$250 million	0.6	407	3.5
$100 million	2.4	668	5.7
$50 million	6.8	968	8.3
$25 million	19.5	1,390	11.9
$10 million	78.4	2,261	19.3
$5 million	225.2	3,254	27.8
$2.5 million	722.4	4,904	41.9
$1 million	3,078.2	8,534	73.0

Source: PBO High-net-worth Family Database

As illustrated in previous reports, the 2019 HFD can be projected forward to answer questions regarding the amount of wealth held by families and potential tax revenues from a wealth tax. Table 2-4 summarizes the results of projecting the 2019 HFD to the second quarter of 2021. The approach and assumptions made in the report are consistent with PBO's 2020 report and the subsequent report titled "Revenue Estimates of M-68: One-time Tax on Extreme wealth."[5]

Table 2-4 **Net wealth distribution, by selected percentiles, Canada, Q2 2021**

Percentile of family net wealth	Net wealth threshold ($ millions)	Number of families (thousands)	Total net wealth ($ billions)	Share of total net wealth (per cent)
Top 0.01%	153.2	1.6	720	5.1
Top 0.1%	33.8	16.1	1,578	11.1
Top 0.5%	11.7	80.8	2,733	19.2
Top 1%	7.3	161.7	3,464	24.3
Top 5%	2.8	802.3	6,055	42.5
Top 10%	1.9	1,602.4	7,924	55.7
Top 20%	1.2	3,207.6	10,328	72.6
Middle 40%	0.2-1.2	6,407.3	3,664	25.7
Bottom 40%	Under 0.2	6,408.6	239	1.7

Source: PBO High-net-worth Family Database

3. Estimating the top of the wealth distribution using past SFS

3.1. Data and methodology

In this section, we discuss how past SFSs and our interpolation methodology are used to investigate the concentration in net wealth over the last twenty-year period.

The SFS has been conducted in the years 1999, 2005, 2012, 2016, and 2019. The available Public Use Microdata Files (PUMF) for the latest three editions of the survey are relatively comparable in methodology and format. However, the 1999 and 2005 editions both have issues that need to be taken into consideration. First, the 2005 SFS has a significantly smaller sample size compared to the other years and is therefore not considered as reliable for

SAF

Dan Tsubouchi @Energy_Tidbits · 1h

great sunrise in #Canmore in the Canadian Rockies. looking east over the Bow River.

1 14

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Dan Tsubouchi @Energy_Tidbits · 2h

Note @michaelwmuller quote "you have to go back to 2014 when prices fell of that plateau they had established to about 4 or 5 years of $100 to $115 per barrel. So we are pushing towards this triple top of the market and possibly new highs" for #Oil. Great call @sean_evers #OOTT

Dan Tsubouchi @Energy_Tidbits · 2h

"#Oil is looking to pop towards 90 & maybe through that level". see below SAF Group transcript, many more oil insights in just this one @michaelwmuller reply to @sean_evers. worth listening to his other comments in 30 min @gulf_intel podcast. #OOTT soundcloud.com/user-846530307...

SAF Group created transcript of excerpts of comments from Mike Muller (Heat, Vitol Asia) on Gulf Intelligence Daily Energy Markets Jan 16 podcast, hosted by Sean Evers (Managing Partner, Gulf Intelligence). Podcast at [LINK]

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

At 1:20 min mark: Evers re prices are back to $86, "*... are you surprised to see prices back at these levels given the sort of general outlook of supply and demand?*" Muller "*let's just repeat the numbers. $86.50 brent is pretty much the highs of move in October last year, and to go back to when we are at or above that level, there was an $86.70 print in October 18, but then any higher than that, you have to go back to 2014 when prices fell of that plateau they had established to about 4 or 5 years of $100 to $115 per barrel. So we are pushing towards this triple top of the market and possibly new highs. But WTI is close to $84 a barrel, that's come along even faster. And of course, given you have a much more responsive upstream scene with investment prospects in the Permian Basin there. That's incentivizing drilling and so forth. And the other one we need to start to mentioning breath is European gas, which has been making all the headlines while you've had your recess here on these sessions. which had gone as high as 180 something Euros per megawatt hour and that's now sitting at 83 as well. So those markets have definitely been extremely active and volatile. So am I surprised was your question. If you look at global inventories of oil and you look at the success of the OPEC+ concerted action to take inventories down to pre-pandemic levels. OPEC succeeded many months ago but continue to forge on with their policy so much so that many of their producers can't really put their share of the 400,000 b/d monthly increase into the market any longer. Which has been a theme for many months already on these calls. The prices are very much in the hands of core GCC and you could argue Russia. But global inventories are below pre-pandemic levels and in many cases, there are pockets of tightness which would have you say that a front end backwardation and a strong market is very much justified. In fact to put it very generically, there is really one part of the world that has spare capacity in terms of refining capacity and inventories and that is the part of the world where data is a little bit less readily available on a real time basis, namely China. But in the rest of the world, you have a phenomenon in Europe that despite the fact that the piece of the global demand picture that is still missing is jet fuel. You have the regrade as we call it, the differential between jet fuel and diesel, trading positive in Europe for the first time in a very long time. it's still inverted, still negative in Asia. But that tells you there's not enough jet fuel around in a market that's still missing a huge piece of aviation demand. 0.5% very sulfur fuel, which propels ships is tight, the inventories on that product are back down to the sort of levels we had pre IMO when the world was panicking about whether we could make and blend enough of that. and I could go on and on. There are some pockets of the energy complex that are less tight. I mean margins for olefins, petrochemicals are less stellar so that has naptha being one of the weaker products out there. but I could go on and on and on and our half hour would be up if we're not careful. So it is a very tight fundamental market, which underpins the backwardation we are seeing at the front of the market which is 50, 70 cents at the very prompt, but then 80, 90 cents per barrel per month going into the back months. I think Yes, these prices are justified and I think the fact that we've had a lot of risk-off mindset at the end of the year, there's a lot of managed money sitting on the sidelines that might say, hang on oil is looking to about to pop towards 90 and maybe even through that level, let's not miss out. And if that money, which is currently on the sidelines comes back into oil, there is a very real prospect of us making [he was cut off from finishing the sentence]*"

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

2 5

Dan Tsubouchi @Energy_Tidbits · 2h ···

SAF

"#Oil is looking to pop towards 90 & maybe through that level". see below SAF Group transcript, many more oil insights in just this one @michaelwmuller reply to @sean_evers. worth listening to his other comments in 30 min @gulf_intel podcast. #OOTT soundcloud.com/user-846530307...

SAF Group created transcript of excerpts of comments from Mike Muller (Head, Vitol Asia) on Gulf Intelligence Daily Energy Markets Jan 16 podcast, hosted by Sean Evers (Managing Partner, Gulf Intelligence). Podcast at [LINK]

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

1 · 7 · 19

Dan Tsubouchi @Energy_Tidbits · 4h ···

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Libya #Oil production restored. "output is around 1.2 million barrels a day, Mohammed Oun said in response to questions from Bloomberg on Sunday" reports @S_Elwardany. #OOTT

1 · 4

Dan Tsubouchi @Energy_Tidbits · 12h

"Canada must focus on significantly
decarbonising its oil and gas sectors while at the same time ensuring competitiveness in
increasingly well-supplied world markets" warns @IEA. Doubt #Macron & others see increasingly well supplied #Oil #NatGas markets. #OOTT

Excerpt IEA Canada 2022: Energy Policy Review
https://www.iea.org/reports/canada-2022

Though notable gains have been made in improving efficiency and lowering emissions from upstream production to date, sizeable additional gains will be needed in a net zero future. Canada's plans for hydrogen production from natural gas, coupled with CCUS technology, could help reduce the carbon footprint of this and other sectors. Biofuels can also play an important role. Moreover, Canada should pay close attention to shifting demand for oil and gas globally, as countries around the world undertake their own energy transitions and put in place net zero targets. Canada must focus on significantly decarbonising its oil and gas sectors while at the same time ensuring competitiveness in increasingly well-supplied world markets. While Canada scores well on overall ESG indicators relative to many other oil and gas producers, the environmental profile of oil sands production, in particular, will become a greater focus for importing countries and warrants action. In addition, Canada is leveraging its strong ESG performance to position itself to become a global leader in the production and export of clean LNG to help countries transition away from higher emitting fuels, such as coal.

Dan Tsubouchi @Energy_Tidbits · Oct 30, 2021

Oops, #Macron on #EnergyTransition "ironic, because we are building a system where in the medium & long term fossil energy will cost more & more, that's what we want to [to fight climate change]". 2020s will be very good for #Oil #NatGas prices. Great report ...

1 3 1

Dan Tsubouchi @Energy_Tidbits · 12h

#JCPOA positive. @AJEnglish, Iran's FM @HAabdollahian said a return to the deal could be reached if "all forms of sanctions stipulated in the nuclear agreement" were lifted – an apparent softening of the government's previous calls for a complete lifting of all sanctions. #OOTT

https://www.aljazeera.com/news/2022/1/14/us-blinken-says-only-few-weeks-left-to-save-iran-nuclear-deal

Antony Blinken says 'a few weeks left' to save Iran nuclear deal

US officials report modest gains during talks in Vienna, but warn nuclear advances will soon become irreversible.

Published On 14 Jan 202214 Jan 2022

United States Secretary of State Antony Blinken says there are only "a few weeks left" to save the 2015 Iran nuclear deal before Tehran's advancements will become too difficult to reverse.

Blinken spoke on Thursday as negotiations in Vienna between Tehran and the other signatories of the 2015 deal, from which former US President Donald Trump unilaterally withdrew in 2018, continued.

The US has been participating in the talks indirectly, with Washington and Tehran, despite trading charged rhetoric, recently reporting modest gains after months of near-total deadlock. The newest round of talks resumed in November.

"We have, I think, a few weeks left to see if we can get back to mutual compliance," Blinken said in an interview with US public radio station NPR.

"We're very, very short on time," because "Iran is getting closer and closer to the point where they could produce on very, very short order enough fissile material for a nuclear weapon," he said.

Blinken added that Tehran has made nuclear advances that "will become increasingly hard to reverse because they're learning things, they're doing new things as a result of having broken out of their constraints under the agreement".

The nuclear deal offered direly needed international sanctions relief to Iran in exchange for curbs on its nuclear programme.

Trump reimposed a "maximum pressure" sanctions campaign after withdrawing from the agreement, and Tehran has since increasingly flouted the restrictions in the deal, arguing it is no longer beholden to the agreement following the US withdrawal.

US President Joe Biden has made returning to the deal a top priority, while newly elected Iranian President Ibrahim Raisi, despite holding more hardline positions than his predecessor, is eager to find relief from crushing sanctions.

In an interview with Al Jazeera in early January, Iranian Foreign Minister Hossein Amir-Abdollahian said a return to the deal could be reached if "all forms of sanctions stipulated in the nuclear agreement" were lifted – an apparent softening of the government's previous calls for a complete lifting of all sanctions, even those imposed on human rights grounds.

On Thursday, Blinken said reviving the accord "would be the best result for America's security".

"But if we can't, we are looking at other steps, other options" with allies including in Europe and the Middle East, he added.

Those "other options" – often seen as an implicit threat of military actions – have been "the subject of intense work as well in the past weeks and months", Blinken said.

"We're prepared for either course."

3 3 3

Dan Tsubouchi @Energy_Tidbits · 17h

#Vortexa crude #Oil floating storage for 01/14 est 72.72 mmb, hugely down 27.42 mmb WoW vs revised up 01/07 100.14 mmb. Should wait to see next week data as upward revisions were made to each of 10 prior weeks. Thx @Vortexa @TheTerminal #OOTT

Source: Bloomberg, Vortexa

Jan 15, 1pm MT Estimate

FZWWFST VTXA Index 01/13/2020 - 01/14/2022

	Date	FZWWFST VT... Mid Px
Fr	01/14/2022	72720
Fr	01/07/2022	100.139k
Fr	12/31/2021	101.377k
Fr	12/24/2021	99808
Fr	12/17/2021	94753
Fr	12/10/2021	93011
Fr	12/03/2021	90672
Fr	11/26/2021	100.755k
Fr	11/19/2021	113.539k
Fr	11/12/2021	110.236k
Fr	11/05/2021	111.433k

Jan 8, 3pm MT Estimate

FZWWFST VTXA Index 01/06/2020 - 01/07/2022

	Date	FZWWFST VT... Mid Px
Fr	01/07/2022	93780
Fr	12/31/2021	100.715k
Fr	12/24/2021	95632
Fr	12/17/2021	91527
Fr	12/10/2021	85689
Fr	12/03/2021	83841
Fr	11/26/2021	90115
Fr	11/19/2021	100.833k
Fr	11/12/2021	100.522k
Fr	11/05/2021	104.878k
Fr	10/29/2021	91462

Source: Bloomberg, Vortexa

2 5 28

Dan Tsubouchi @Energy_Tidbits · Jan 14

Positive for E&P stocks. Generalist interest in E&Ps has completely flipped on its head. Pre-Covid, 6 or 7 to 1 ratio hedge funds to long only interest. This yr, it's 7 or 8 to 1 ratio long only generalists vs hedge funds. Thx @RaymondJames John.Freeman@RaymondJames.com #OOTT

Re pick up in generalist institutional investor interest in E&P stocks.

Items in "*italics*" are SAF Group created transcript of Q&A from RJ Energy Market Outlook.

Question was on inbound interests from generalists. RJ's John Freeman replies "*on the E&P side, it's been a pretty dramatic change. Pre-Covid, probably like a 6 to 1, 7 to 1 ratio hedge fund to long only interest in my sector. That's completely flipped on its head, this year it's probably 7 or 8 to 1 ratio, long only generalists money vs hedge fund incoming calls that I get. The majority of those incoming calls on the long only side are value investors.*"

RAYMOND JAMES

RJ Energy Market Outlook

The Stocks Worked in 2021; What's in Store for 2022?

January 2022

9 15

Dan Tsubouchi @Energy_Tidbits · Jan 14

Will still be #Israel wildcard even if return to #JCPOA. TASS Lavrov also noted with satisfaction that was possible to overcome situation when West tried to impose restrictions on Iran's missile program, not fixed in the JCPOA & conditions on Iran's behavior in region. #OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Jan 14
>
> #JCPOA. "knocking on wood, but we expect an agreement will be reached" "there is real progress" "real desire primarily between Iran & the US to understand specific concerns & undertand how these concerns can be taken into account in the general package" says RUS Lavrov. #OOTT
>
> **Lavrov reported on real progress in negotiations on Iranian nuclear deal**
>
> Iran must think realistically to reach agreement on nuclear deal, Foreign Minister said
>
> MOSCOW, January 14. /TASS/. Real progress has been made in negotiations on the Iranian nuclear deal, Russian Foreign Minister Sergei Lavrov said at a press conference on the results of the activities of Russian diplomacy in 2021.
>
> Lavrov stressed that "it can only be a package solution," like the Iranian deal itself. "The joint overarching plan of action was a package solution," he said.
>
> The minister stressed that Russia was categorically against such a dishonest approach, "because it was about the JCPOA, which was approved by the UN Security Council in the form in which it was signed." "The point was that after the Trump administration withdrew from this agreement, restore it in full, as agreed, without exceptions and without any appendages."

1 · 2

Dan Tsubouchi @Energy_Tidbits · Jan 14

Asking a direct question works. "when I look at different indicators around the world, I would say that the oil demand dynamics now are significantly stronger than it was a few weeks ago" says @fbirol to @SullyCNBC ask for sneak peak @IEA Jan OMR. See SAF Group transcript. #OOTT

> F Group created transcript of excerpts from CNBC World Wide Exchange, Brian Sullivan, interview with IEA Executiv
> ector, Faith Birol on Jan 14, 2022. https://www.cnbc.com/video/2022/01/14/iea-executive-director-fatih-birol-on-
> bal-oil-demand-and-what-is-behind-the-european-energy-crisis.html?&qsearchterm=birol
>
> ms in "*italics*" are SAF Group created transcript.
>
> 7:45 min mark. Brian Sullivan "*I know you've got your latest estimates coming out on Wednesday, maybe you can k give us a sneak peak. Do you think the world, not Europe or the US necessarily, but the world is underestimating ne m demand growth for oil, because the market seems to be saying it is?*" Faith Birol "*As you rightly mention, our essment of the markets, oil markets, we are going to release it in a few days of time. But, when I look at different icators around the world, I would say that the oil demand dynamics now are significantly stronger than it was a few eks ago. And this is driven, among other things, mainly the Omicron impacts are considered softer than many of the alysts thought before. But at the same time, I wouldn't be surprised, the production increase, strong increase comin m US and elsewhere. What is of course is not good news is there is a lot of outages in Nigeria, in Libya, Ecuador, the all hurting on the supply side.*"
>
> pared by SAF Group https://safgroup.ca/news-insights/

> **Dan Tsubouchi** @Energy_Tidbits · Jan 14
>
> Look for @IEA to increase #Oil demand fcast in OMR on Wed. @SullyCNBC just tweeted "I would say oil demand dynamics are higher than they were a few weeks ago" - IEA head Dr. Fatih Birol to CNBC just now .. Oil back to pre-SPR release levels" #OOTT twitter.com/SullyCNBC/stat...

1 · 1 · 3

Dan Tsubouchi @Energy_Tidbits · Jan 14

#JCPOA. "knocking on wood, but we expect an agreement will be reached" "there is real progress" "real desire primarily between Iran & the US to understand specific concerns & undertand how these concerns can be taken into account in the general package" says RUS Lavrov. #OOTT

Lavrov reported on real progress in negotiations on Iranian nuclear deal

Iran must think realistically to reach agreement on nuclear deal, Foreign Minister said

MOSCOW, January 14. /TASS/. Real progress has been made in negotiations on the Iranian nuclear deal, Russian Foreign Minister Sergei Lavrov said at a press conference on the results of the activities of Russian diplomacy in 2021.

"There is real progress on the Iranian nuclear program <...>, there is a real desire, primarily between Iran and the United States, to understand specific concerns and understand how these concerns can be taken into account in the general package," the minister said.

Lavrov stressed that "it can only be a package solution," like the Iranian deal itself. "The joint overarching plan of action was a package solution," he said.

According to the minister, experienced negotiators in Vienna "have already penetrated into the very details of this negotiating matter" and "are making good progress now." "I am knocking on wood, but we expect that an agreement will be reached," he concluded.

According to Lavrov, Iran must think realistically to reach an agreement on a nuclear deal. "We hope that an agreement will be reached. For this it is important that the Iranian partners are as realistic as possible, cooperate with the IAEA," the minister said. "Secondly, it is important that the Western participants in this negotiation process do not try to create some kind of psychological tension, periodically throwing into the media public space initiatives criticizing Iran and demanding it."

According to the head of the Russian Foreign Ministry, "quiet diplomacy" is needed here. "I will repeat it once again, it works," he stressed. Lavrov also noted with satisfaction that it was possible to overcome the situation when the West began to put forward conditions for the resumption of the Iranian nuclear program, which related to the imposition of restrictions on Iran's missile program, not fixed in the JCPOA, and conditions concerning the "behavior" of the state in the region. The minister stressed that Russia was categorically against such a dishonest approach, "because it was about the JCPOA, which was approved by the UN Security Council in the form in which it was signed." "The point was that after the Trump administration withdrew from this agreement, restore it in full, as agreed, without exceptions and without any appendages,"

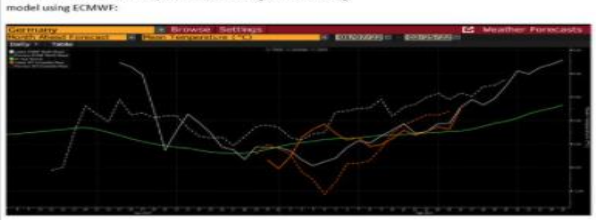
1 2 3

Dan Tsubouchi @Energy_Tidbits · Jan 14

Europe storage now 49% full (5-yr ave ~65%). Good thing for EU that its been a warmer than normal winter. Probably would have been #NatGas shortages by now if a normal winter. will it be relief or false sense of security for winter 22/23? Thx @JesperStarn. #OOTT

Mild German Winter Weather Set to Last Into February: DWD
2022-01-14 07:48:05.419 GMT

By Jesper Starn
(Bloomberg) -- Temperatures throughout Germany will remain around or above the seasonal average until the middle of February, national forecaster Deutscher Wetterdienst said in a month-ahead outlook.
* Warmer-than-normal temperatures seen in the north and mostly around average levels expected in the south during Jan. 17 to Feb. 13 forecast period
* Very windy outlook for northern Germany next week and for southeast region during last week of January
* For Bloomberg's weather functions, see WFOR
* German month-ahead temperatures, according to a Bloomberg model using ECMWF:



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To contact the editors responsible for this story:
Isis Almeida at ialmeida3@bloomberg.net
Dylan Griffiths

Dan Tsubouchi @Energy_Tidbits · Jan 1

Record warm temps across Europe for last week. No wonder Europe #NatGas prices down huge in last 10 days ie. UK 12/31/21 are 0closed down 62% since 12/21. But UK 12/31/21 are still at 3x vs year ago 12/31/20. #OOTT twitter.com/mccstudy/statu...

2 1

Dan Tsubouchi @Energy_Tidbits · Jan 14

Look for @IEA to increase #Oil demand fcast in OMR on Wed. @SullyCNBC just tweeted "I would say oil demand dynamics are higher than they were a few weeks ago" - IEA head Dr. Fatih Birol to CNBC just now .. Oil back to pre-SPR release levels" #OOTT twitter.com/SullyCNBC/stat...

> Dan Tsubouchi @Energy_Tidbits · Jan 12
>
> #Oil "demand dynamics are stronger than many of the market observers had thought, mainly due to the milder Omicron expectations" says @fbirol. Reported by @isiscarol14 gsmith52@bloomberg.net #OOTT

1 2

Dan Tsubouchi @Energy_Tidbits · Jan 13

53% of US won't pay >$500 for alternative engine solutions (#EVs), 69% prefer ICE vs 5% EVs for next vehicle. It's why EVs are still mostly for higher income & need even bigger subsidies. Much more in @Deloitte 2022 Global Automative Consumer Study. Thx @KarenBowman #OOTT

8 18

SAF

Dan Tsubouchi @Energy_Tidbits · Jan 13

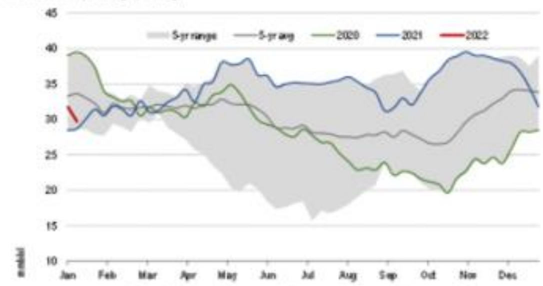
"latest Genscape/Wood Mackenzie data shows a steep drop off in Alberta crude inventories. Over the last month, Alberta storage has dropped by 8 mmb to under 30 mmb with added egress (from L3R) seemingly outpacing incremental production volumes" NBF Energy Sales Josh Ochman #OOTT.

Excerpt National Bank of Canada: Energy Sales Institutional Equities

NBF Energy Sales note from Josh Ochman. Jan 13, 2021

The latest Genscape/Wood Mackenzie data shows a steep drop off in Alberta crude inventories. Over the last month, Alberta storage has dropped by 8 mmb to under 30 mmb with added egress (from L3R) seemingly outpacing incremental production volumes

Alberta Genscape Storage (Working)



as of 7-Jan-22	Last	1W	1M	1Y	5Yavg
Storage	29.7	31.8	37.9	28.7	33.6
Δ Change	-	-2.1	-8.2	1.0	-3.9
% Change	-	-6.5%	-21.6%	3.6%	-11.6%

Source: Genscape, NBC

6 · 5 · 34

SAF

Dan Tsubouchi @Energy_Tidbits · Jan 13

the "saskatchewan screamer" is a good name for sharing our cold/snow with our neighbours & means support for #NatGas prices. a more descriptive warning than a nice sounding alberta clipper. how about alberta ambush or alberta assault to warn US cold/snow is coming

Breaking Weather by AccuWeather @breakingweather · Jan 12

Winter storm watches have been issued from North Dakota through Iowa ahead of a type of snowstorm sometimes called a "Saskatchewan screamer": bit.ly/3tv8wMG

4

SAF

Dan Tsubouchi @Energy_Tidbits · Jan 13

Not a good sign for CAN #Oil #NatGas sector ahead of emissions reduction hard 2025 target coming in March. @JonathanWNV message to the world in @IEA Canada 2022 Energy Policy Review. Don't even acknowledge #OilSands pathways to #NetZero, just their requiring actions.#OOTT

Excerpt IEA Canada 2022: Energy Policy Review https://iea.blob.core.windows.net/assets/7ec2467c-78b4-4c0c-a966-a42b8861ec5a/Canada2022.pdf

Foreword

The twin crises of climate change and biodiversity loss pose enormous threats to long-term global security and economic well-being around the world. Canada, alongside others in the international community, must rapidly reduce carbon emissions to fight climate change and seize the significant economic opportunities presented for businesses, communities and workers.

As Canada's Minister of Natural Resources, I am very pleased to welcome the International Energy Agency's (IEA) review of Canada's approach to building a clean energy future. This report acknowledges our ambitious efforts and historic investments to develop pathways to achieve net-zero emissions by 2050 and ensure a transition that aligns with our objective of limiting global warming to 1.5 degrees Celsius. These pathways will drive inclusive economic prosperity for our workers while yielding technology, products and know-how that can be exported and applied around the world.

Canada is blessed with an abundance of natural resources that position us to be a global leader in clean energy. We also have a skilled workforce and innovative organizations at the helm of the transition, with 12 Canadian companies featured in the 2020 Global Cleantech 100 and Indigenous leaders across the country building and operating renewable energy projects for their communities.

The key to Canada's clean energy future will be empowering our workers to harness Canada's vast resources in ways that make sense environmentally and economically for their region — and that's exactly what our government is doing.

We have committed more than $100 billion toward climate action and clean growth since 2015, including major investments in clean power, energy efficiency, industrial decarbonization, clean technology and transportation. We also have a world-leading price on pollution and action plans for promising technologies like hydrogen and small modular reactors.

All of this is intended to ensure that emissions go down at a pace and on a scale aligned with our 1.5 degree Celsius targets — but more must be done.

That's why our government recently committed to new measures to accelerate the clean energy transition, including:

- requiring the oil and gas sector to be net-zero by 2050 and setting interim five-year targets;
- requiring oil and gas companies to reduce methane emissions by at least 75 percent below 2012 levels by 2030;
- creating a 100-percent net-zero electricity system by 2035; and
- providing support for domestic procurement of Canadian clean technology.

As this report recognizes, Canada's energy policies, programs and investments align with our ambitious climate goals. We believe that we can achieve our targets while creating good jobs, a stronger economy and a more inclusive future for all regions of the country.

Of course, for any nation to succeed in the fight against climate change, we must all succeed. Canada is working with our partners to support a truly global transition and build on the momentum from COP26.

I am proud of the progress that Canada has made in the last six years, and I believe the future is bright. I thank the IEA for the work it does to help governments build a clean energy future and, specifically, for this report.

The Honourable Jonathan Wilkinson

Canada's Minister of Natural Resources

4

Dan Tsubouchi @Energy_Tidbits · Jun 13, 2021

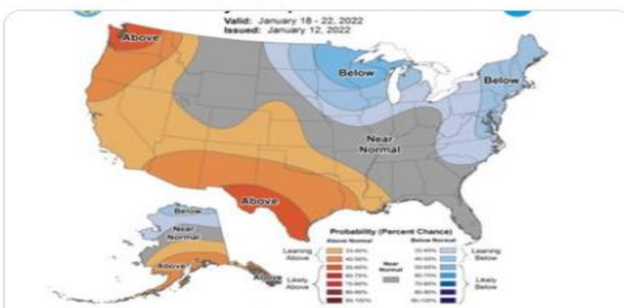
#OilSands. Note #Trudeau wouldn't even acknowledge the oil sands pathways to net zero, or say positive move but need to do more or move faster. not a good sign. have to worry it links to prior tweet #G7 May 21 warning re stranded assets risk. #OOTT...

4 6 8

SAF

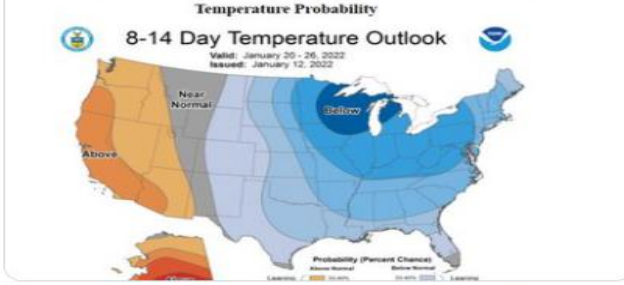
Dan Tsubouchi @Energy_Tidbits · Jan 12

Looks like today's @NOAA update for middle of Jan temperature probability forecast is supportive of #NatGas. #OOTT



https://www.cpc.ncep.noaa.gov/products/predictions/814day/index.php

Temperature Probability



2 1 5

Dan Tsubouchi @Energy_Tidbits · Jan 12

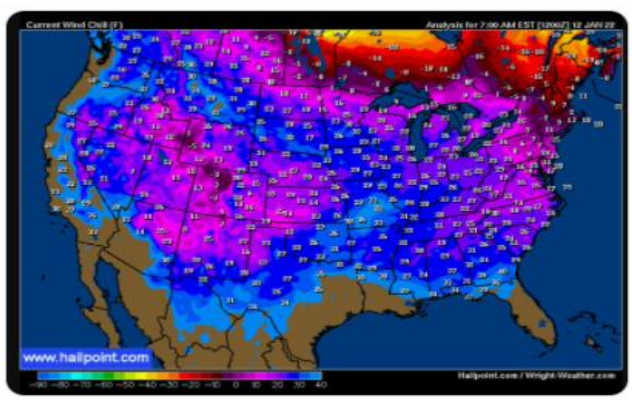
#Oil "demand dynamics are stronger than many of the market observers had thought, mainly due to the milder Omicron expectations" says @fbirol. Reported by @isiscarol14 gsmith52@bloomberg.net #OOTT

4 5

Dan Tsubouchi @Energy_Tidbits · Jan 12

Nice to see, from a #NatGas perspective, its a cold start to the day across most of the US. Current wind chill map from Wright-Weather, LLC. Note this is wind chill, not straight temps. #OOTT

hp2.wright-weather.com/icons/us_chill...



Dan Tsubouchi @Energy_Tidbits · Jan 11

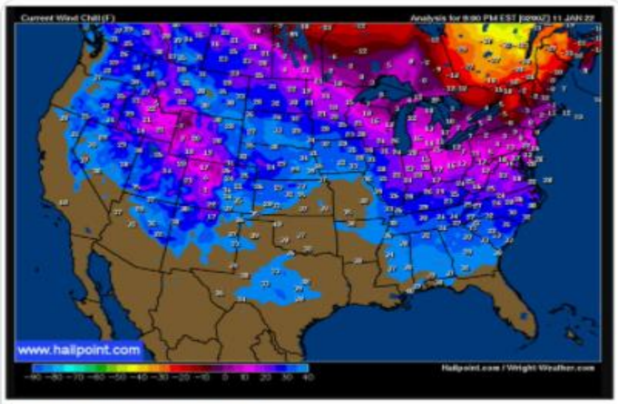
Finally, most of the US is below freezing tonight. Wind chill map from Wright-Weather, LLC. Dec was record warmth so need a decent Jan/Feb. #NatGas #OOTT twitter.com/Energy_Tidbits...

6

SAF

Dan Tsubouchi @Energy_Tidbits · Jan 11

Finally, most of the US is below freezing tonight. Wind chill map from Wright-Weather, LLC. Dec was record warmth so need a decent Jan/Feb. #NatGas #OOTT



http://hp2.wright-weather.com/icons/us_chill.gif

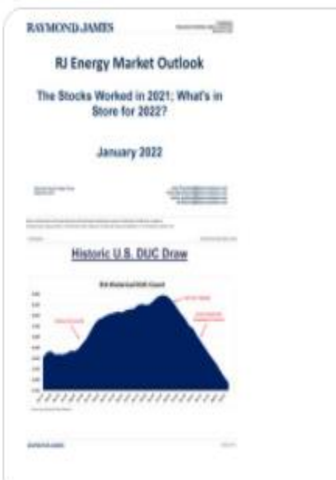
> **Dan Tsubouchi** @Energy_Tidbits · Jan 10
>
> 
>
> Hottest Dec on record. Pre #LNG days, record warmth in 1 of 3 key winter demand months would have crashed HH #NatGas prices. But with US LNG exports currently #1 and ~11 bcf/d (~4 tcf/yr), HH is still above $4. #OOTT twitter.com/SStapczynski/s...

4 · 7

SAF

Dan Tsubouchi @Energy_Tidbits · Jan 11

Biggest mistake in US #Oil growth fcast is correlation of rig count vs prod. Oil growth in 21/22 driven by historic DUC drawdown. Excess DUCs gone, higher rigs needed to replenish DUCs. It's why higher rigs in 23 = lower growth rate. one of many insights from @RaymondJames #OOTT



6 · 15 · 79

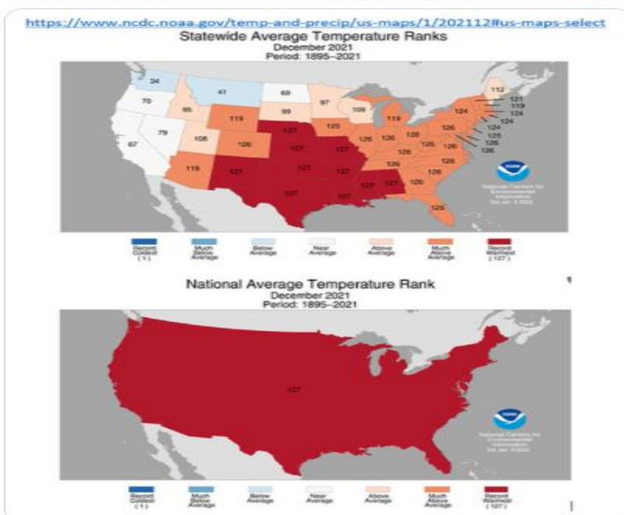
Dan Tsubouchi @Energy_Tidbits · Jan 11

Two more Asian LNG Buyers now locked up 3.5 bcf/d long term LNG supply since 07/01, 16 & 17th Asian deals, China's ENN 11 yr & Zheijiang 15 yr deals with #Novatek #ArcticLNG2 project. #LNG #NatGas looks good thru 2030s. See SAF Group 07/14 blog. #OOTT

3 · 8

Dan Tsubouchi @Energy_Tidbits · Jan 10

Hottest Dec on record. Pre #LNG days, record warmth in 1 of 3 key winter demand months would have crashed HH #NatGas prices. But with US LNG exports currently #1 and ~11 bcf/d (~4 tcf/yr), HH is still above $4. #OOTT

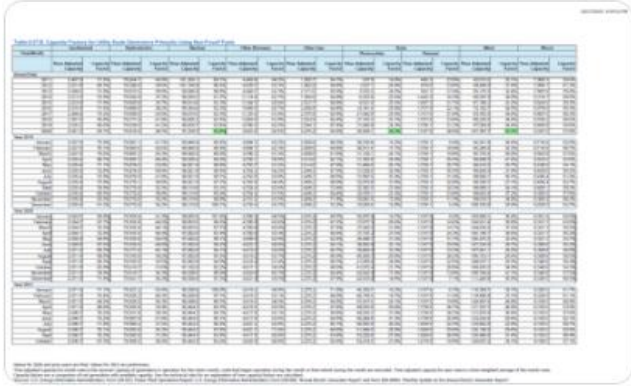


> **Stephen Stapczynski** @SStapczynski · Jan 3
>
> 
>
> The US was the world's biggest exporter of liquefied natural gas last month for the first time ever 🇺🇸 🚢
>
> American output edged slightly above Qatar in ...
>
> Show this thread

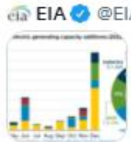
1 · 4 · 12

Dan Tsubouchi @Energy_Tidbits · Jan 10

Reminder renewable is intermittent so need multiples more capacity to replace equivalent #Coal, #NatGas or nuclear. @EIAgov data, #Solarpower generates at ~25% of capacity, #Windpower at 35% of capacity. US #Nuclearpower is ~92%. #OOTT



EIA @EIAgov · Jan 10



#TodayInEnergy - #Solarpower will account for nearly half of new U.S. electric generating capacity in 2022 #PV #electricity go.usa.gov/xt4V3

3 9

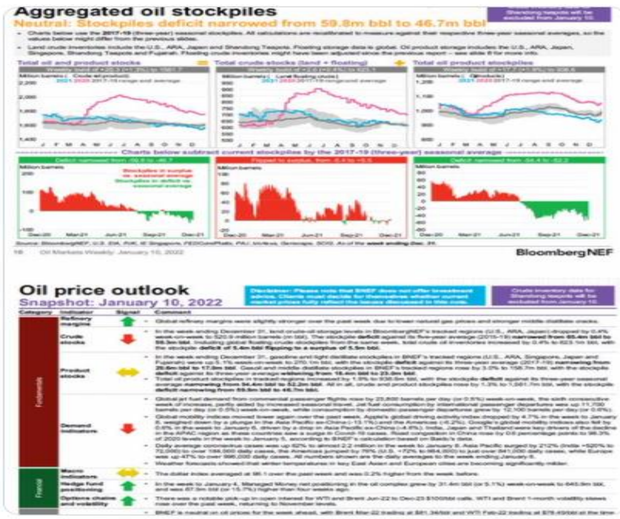
Dan Tsubouchi @Energy_Tidbits · Jan 10

can see the clear blue sky from the #ChinookArch coming in. it's now 6c in #Calgary vs -22c ar this time yesterday

1

Dan Tsubouchi @Energy_Tidbits · Jan 10

"Aggregated oil stockpiles. Neutral: Stockpiles deficit narrowed from 59.8m bbl to 46.7m bbl" as of Dec 31. As seen in @Vortexa floating storage, feels like a creep up in #Oil stocks, let's watch in Jan/Feb. Thx @WayneTanMing @BloombergNEF Oil Price Indicators Weekly. #OOTT



> **Dan Tsubouchi** @Energy_Tidbits · Jan 8
>
> 
>
> #Vortexa crude #Oil floating storage for 01/07 est 93.78 mmb, -6.94 WoW vs revised up 12/31 100.72 mmb. 01/07 is +10 mmb to 06/30 when #OPEC+ started big production increases. Feels like a bit of creep up, will want to watch in Jan/Feb. Thx @Vortex...

1 4

Dan Tsubouchi @Energy_Tidbits · Jan 10

#Maersk orders 4 more dual fuel (#Methanol & fuel oil) ships reports @JWittels. Remember why dual fuel? note 08/24 below release - sourcing enough "proper carbon neutral methanol" from day 1 will be "challenging". #Oil will be needed for longer than #NetZero aspirations. #OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Aug 24, 2021
>
> #Maersk orders 8 container vessels "capable" of operating on #Carboneutral #methanol. however vessels have "dual fuel engine setup" so can run on conventional low sulphur fuel oil as sourcing enough "proper carbon neutral methanol" from day 1 will be "challenging" #OOTT
>
> 

2 2

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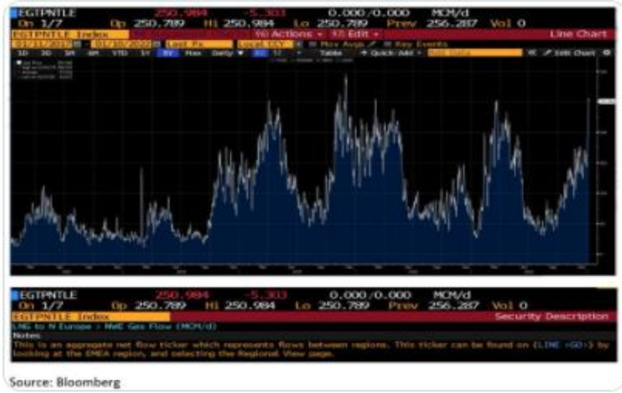
Dan Tsubouchi @Energy_Tidbits · Jan 10

Looks like the rush of #LNG tankers to Europe is arriving. LNG into NW Europe now right at all time record highs of ~8.9 bcf/d. Data courtesy of @TheTerminal #OOTT #NatGas



Source: Bloomberg

Sergio Chapa @SergioChapa · Dec 29, 2021

U.S. LNG Update: 20 cargoes with undeclared destinations on a path to Europe

Another 24 with declared destinations:

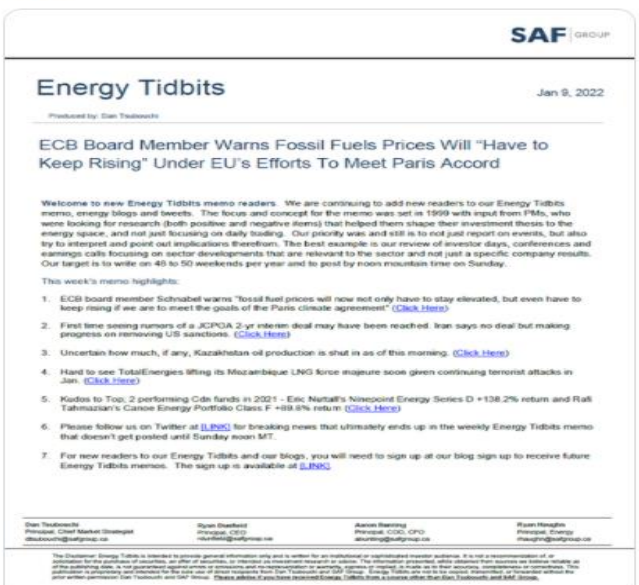
...

3 · 7

SAF GROUP

Dan Tsubouchi @Energy_Tidbits · Jan 9

Our weekly SAF Jan 9, 2022 Energy Tidbits memo is posted on our SAF Group website. This 51-pg energy research memo expands upon & covers more items than tweeted this week. See news/insights section of SAF website #Oil #OOTT #LNG #NatGas #EnergyTransition safgroup.ca/news-insights/



SAF GROUP

Energy Tidbits

Jan 9, 2022

Produced by: Dan Tsubouchi

ECB Board Member Warns Fossil Fuels Prices Will "Have to Keep Rising" Under EU's Efforts To Meet Paris Accord

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. ECB board member Schnabel warns "fossil fuel prices will now not only have to stay elevated, but even have to keep rising if we are to meet the goals of the Paris climate agreement" (Click Here)
2. First time seeing rumors of a JCPOA 2-yr interim deal may have been reached. Iran says no deal but making progress on removing US sanctions. (Click Here)
3. Uncertain how much, if any, Kazakhstan oil production is shut in as of this morning. (Click Here)
4. Hard to see TotalEnergies lifting its Mozambique LNG force majeure soon given continuing terrorist attacks in Jan. (Click Here)
5. Kudos to Top; 2 performing Cdn funds in 2021 - Eric Nuttall's Ninepoint Energy Series D +138.2% return and Rafi Tahmazian's Canoe Energy Portfolio Class F +89.8% return (Click Here)
6. Please follow us on Twitter at [LINK] for breaking news that ultimately ends up in the weekly Energy Tidbits memo that doesn't get posted until Sunday noon MT.
7. For new readers to our Energy Tidbits and our blogs, you will need to sign up at our blog sign up to receive future Energy Tidbits memos. The sign up is available at [LINK].

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