SAF GROUP

Energy Tidbits

Tight/Short Oil/Gas Supply for 2020s? SLB's "Distinctive" New Phase in Upcycle, "It's Multi-Pronged. It Moves Multiple Engines, Short and Long, Oil and Gas, Offshore and Onshore"

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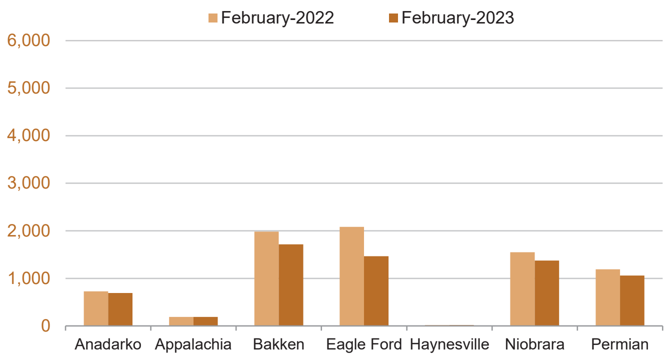
Year-over-year summary

Drilling Productivity Report

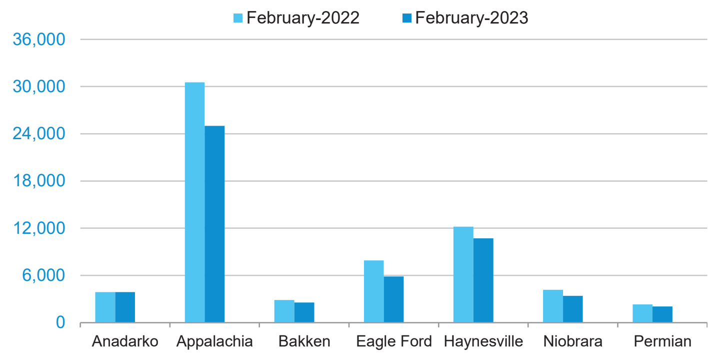
January 2023

drilling data through December
projected production through February

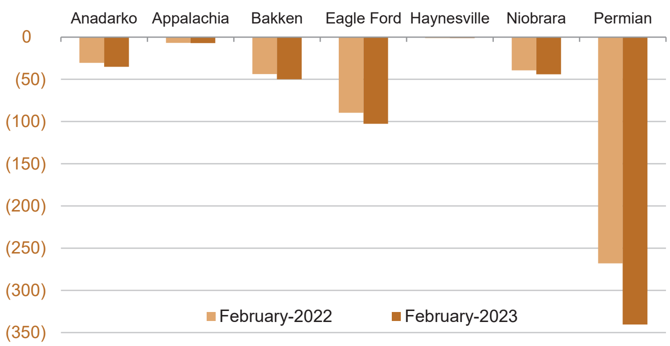
New-well oil production per rig
barrels/day



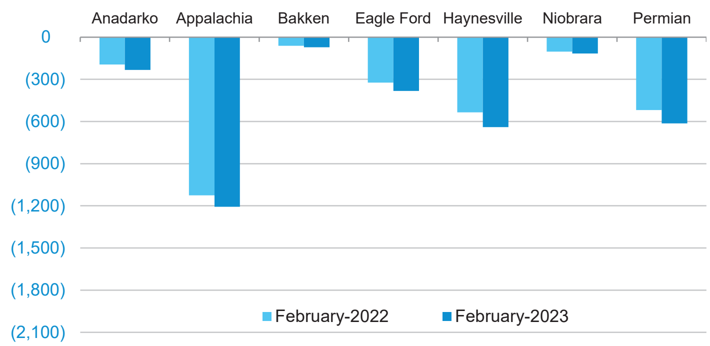
New-well gas production per rig
thousand cubic feet/day



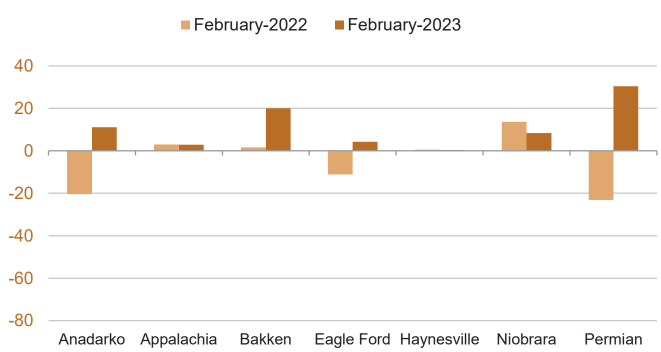
Legacy oil production change
thousand barrels/day



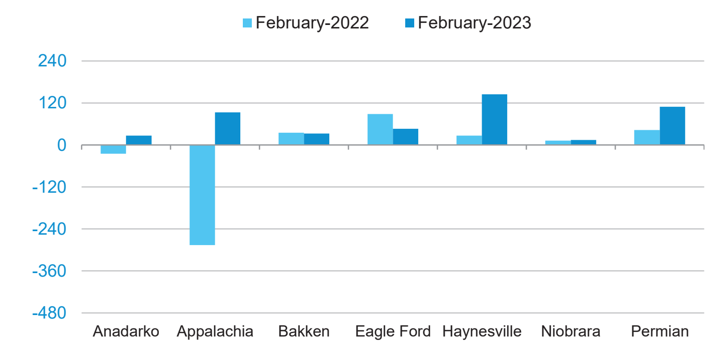
Legacy gas production change
million cubic feet/day



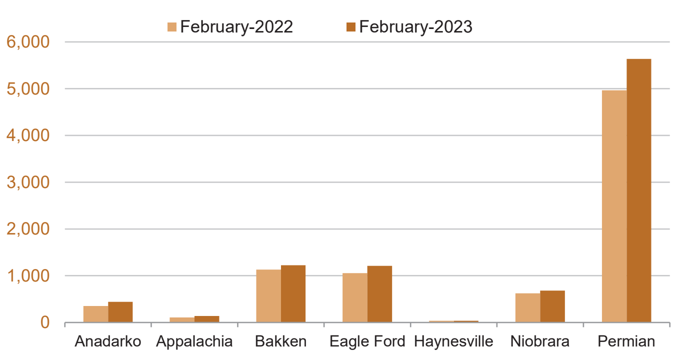
Indicated monthly change in oil production (Feb vs. Jan)
thousand barrels/day



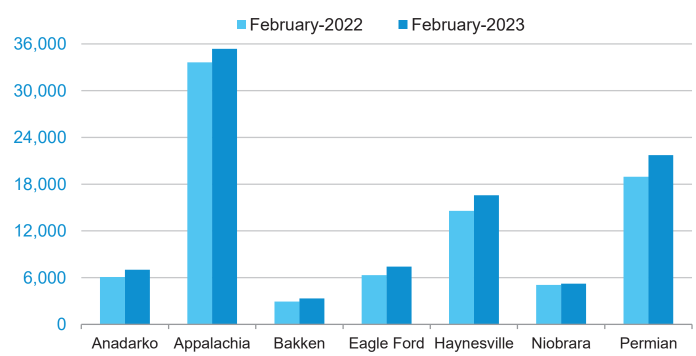
Indicated monthly change in gas production (Feb vs. Jan)
million cubic feet/day



Oil production
thousand barrels/day



Natural gas production
million cubic feet/day



Anadarko Region

Drilling Productivity Report

January 2023

drilling data through December
projected production through February

Oil +1
barrels/day
month over month

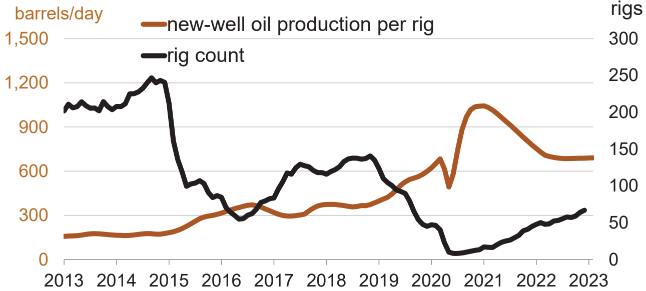
690 *February*
689 *January*
barrels/day

Monthly additions from one average rig

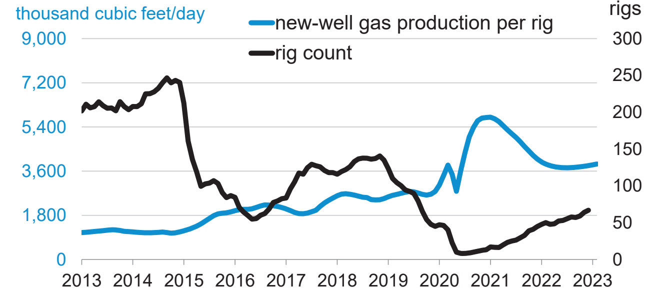
February **3,892**
January **3,857**
thousand cubic feet/day

Gas +35
thousand cubic feet/day
month over month

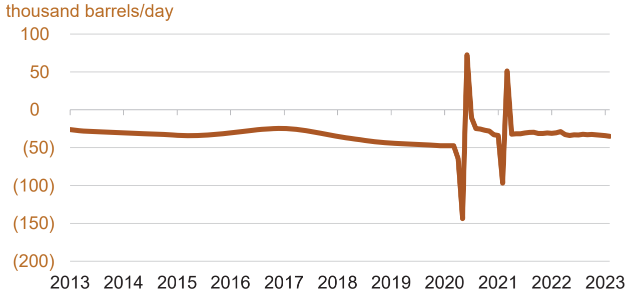
Anadarko Region
New-well oil production per rig
barrels/day
Rig count
rigs



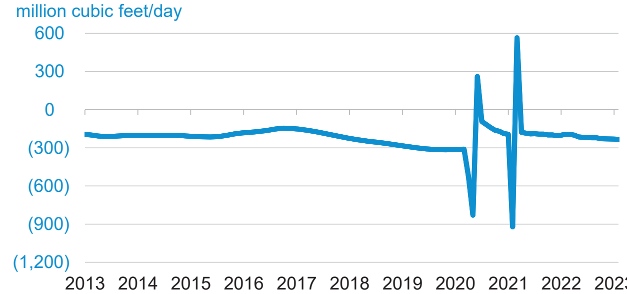
Anadarko Region
New-well gas production per rig
thousand cubic feet/day
Rig count
rigs



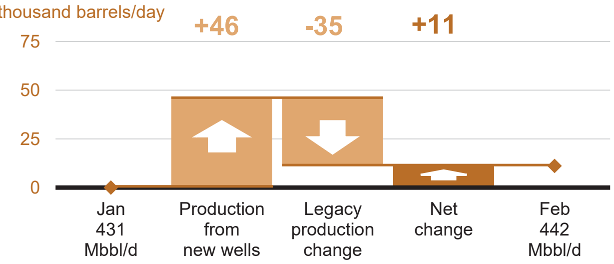
Anadarko Region
Legacy oil production change
thousand barrels/day



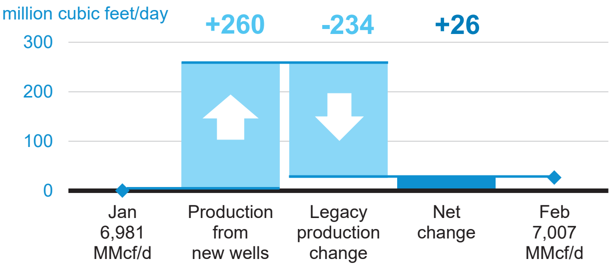
Anadarko Region
Legacy gas production change
million cubic feet/day



Anadarko Region
Indicated change in oil production (Feb vs. Jan)
thousand barrels/day

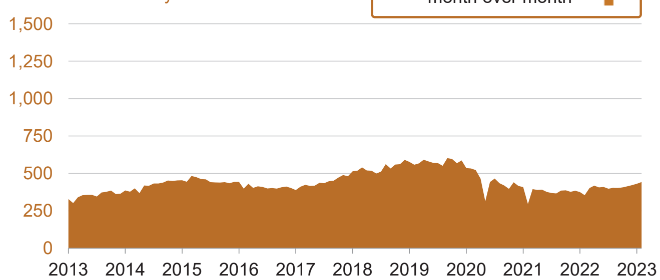


Anadarko Region
Indicated change in natural gas production (Feb vs. Jan)
million cubic feet/day



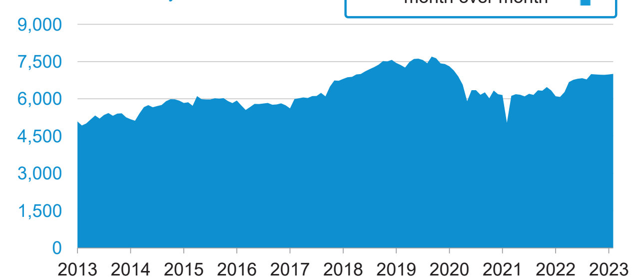
Anadarko Region
Oil production
thousand barrels/day

Oil +11
thousand barrels/day
month over month



Anadarko Region
Natural gas production
million cubic feet/day

Gas +26
million cubic feet/day
month over month



Appalachia Region

Drilling Productivity Report

January 2023

drilling data through December
projected production through February

Oil
0
barrels/day
month over month

191 *February*
191 *January*
barrels/day

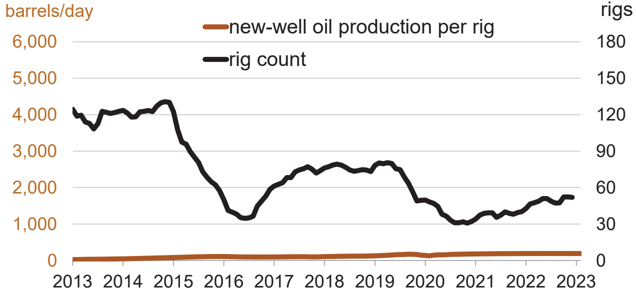
Monthly additions from one average rig

February **25,004**
January **25,436**
thousand cubic feet/day

Gas
-432
thousand cubic feet/day
month over month

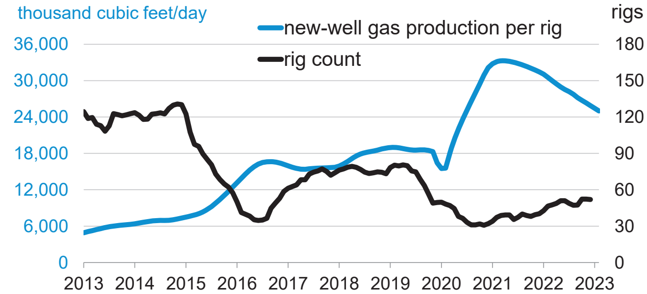
Appalachia Region
New-well oil production per rig
barrels/day

Rig count
rigs

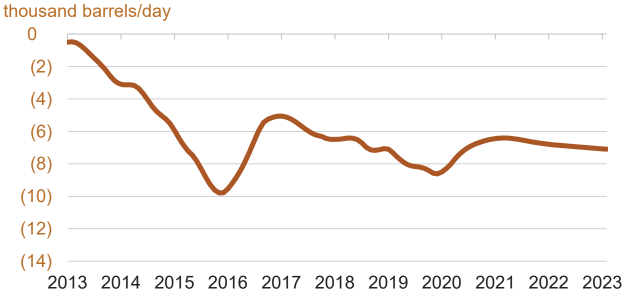


Appalachia Region
New-well gas production per rig
thousand cubic feet/day

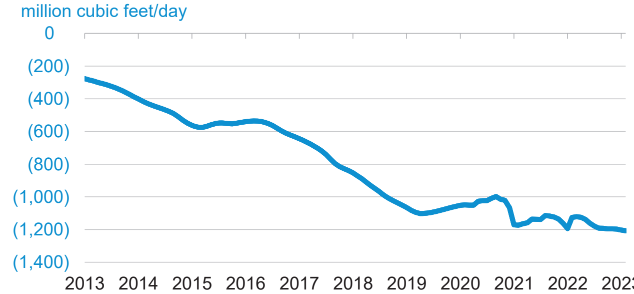
Rig count
rigs



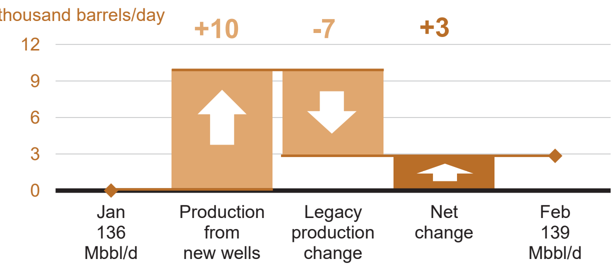
Appalachia Region
Legacy oil production change
thousand barrels/day



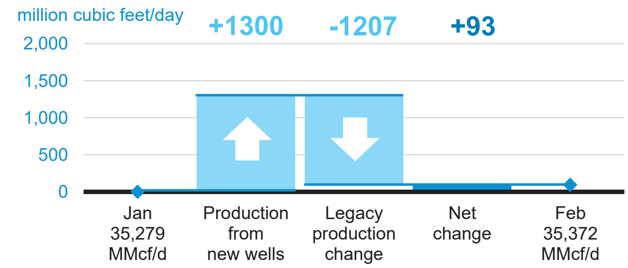
Appalachia Region
Legacy gas production change
million cubic feet/day



Appalachia Region
Indicated change in oil production (Feb vs. Jan)
thousand barrels/day

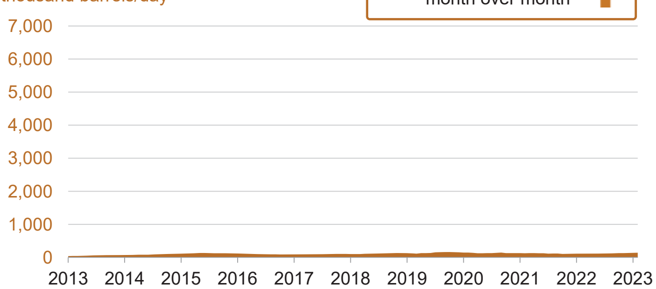


Appalachia Region
Indicated change in natural gas production (Feb vs. Jan)
million cubic feet/day



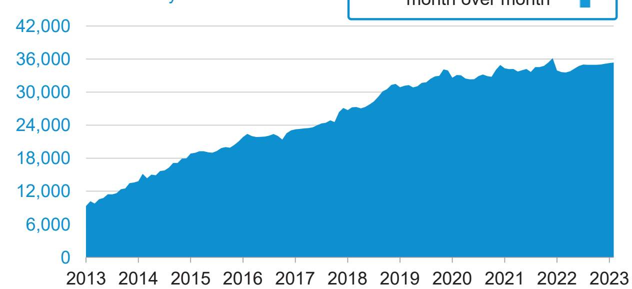
Appalachia Region
Oil production
thousand barrels/day

Oil +3
thousand barrels/day
month over month



Appalachia Region
Natural gas production
million cubic feet/day

Gas +93
million cubic feet/day
month over month



Bakken Region

Drilling Productivity Report

January 2023

drilling data through December
projected production through February

Oil +9
barrels/day
month over month

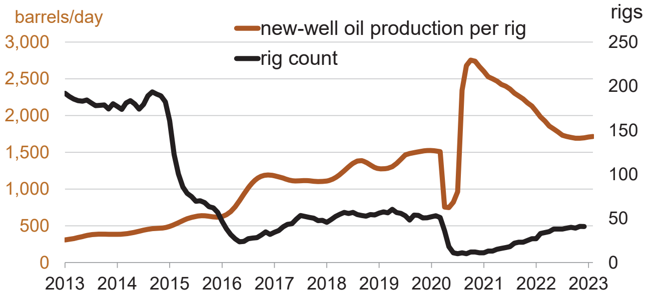
1,716 *February*
1,707 *January*
barrels/day

Monthly additions from one average rig

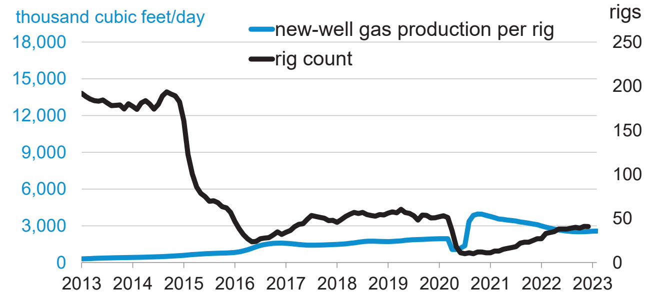
February **2,573**
January **2,555**
thousand cubic feet/day

Gas +18
thousand cubic feet/day
month over month

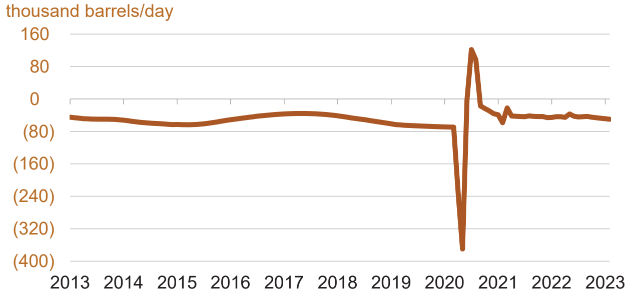
Bakken Region
New-well oil production per rig — **Rig count**



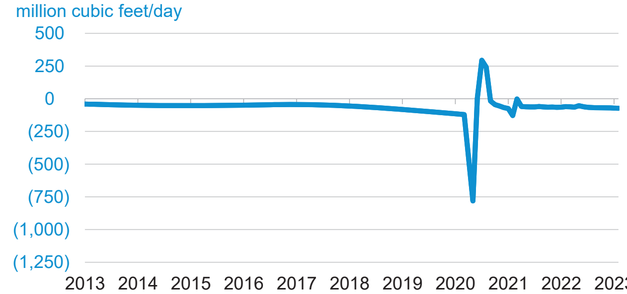
Bakken Region
New-well gas production per rig — **Rig count**



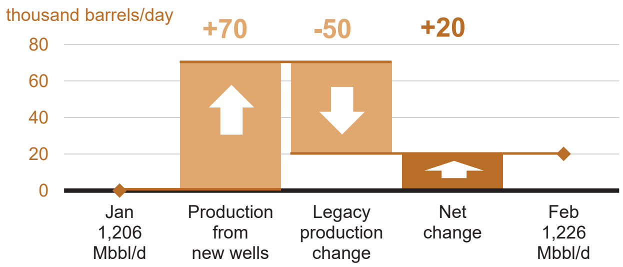
Bakken Region
Legacy oil production change



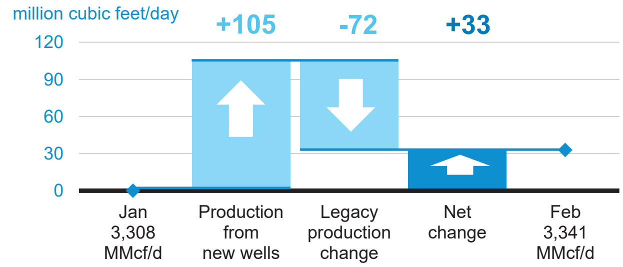
Bakken Region
Legacy gas production change



Bakken Region
Indicated change in oil production (Feb vs. Jan)

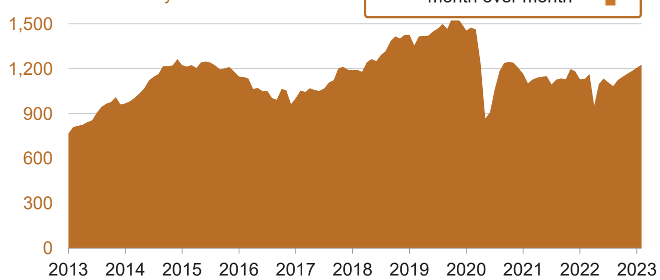


Bakken Region
Indicated change in natural gas production (Feb vs. Jan)



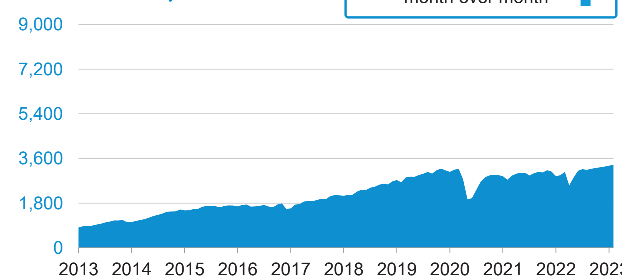
Bakken Region
Oil production

Oil +20
thousand barrels/day
month over month



Bakken Region
Natural gas production

Gas +33
million cubic feet/day
month over month



Eagle Ford Region

Drilling Productivity Report

January 2023

drilling data through December
projected production through February

Oil -16 barrels/day month over month

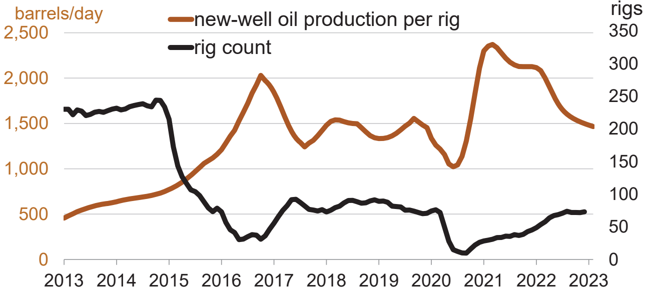
1,465 *February*
1,481 *January*
barrels/day

Monthly additions from one average rig

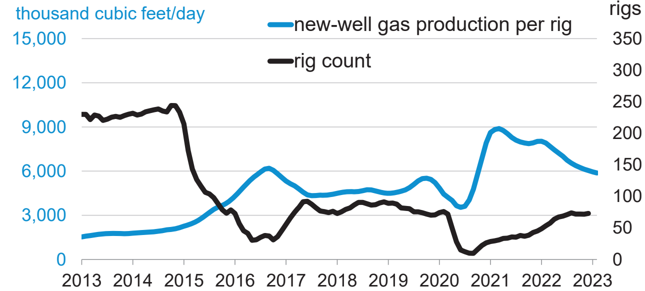
February **5,875**
January **5,952**
thousand cubic feet/day

Gas -77 thousand cubic feet/day month over month

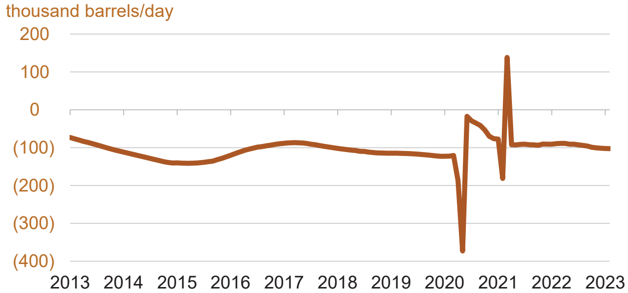
Eagle Ford Region
New-well oil production per rig — **Rig count**



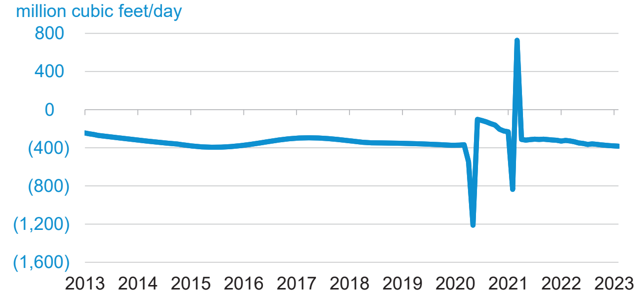
Eagle Ford Region
New-well gas production per rig — **Rig count**



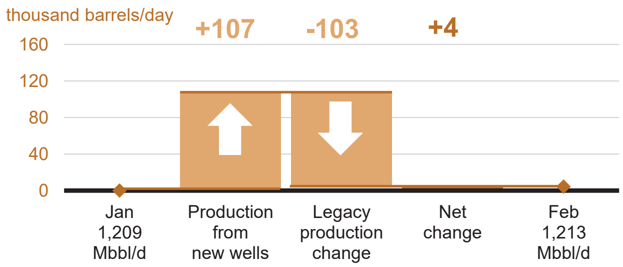
Eagle Ford Region
Legacy oil production change



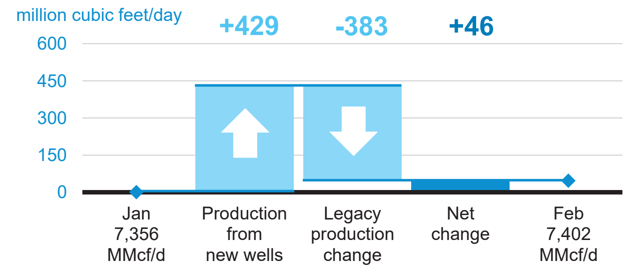
Eagle Ford Region
Legacy gas production change



Eagle Ford Region
Indicated change in oil production (Feb vs. Jan)

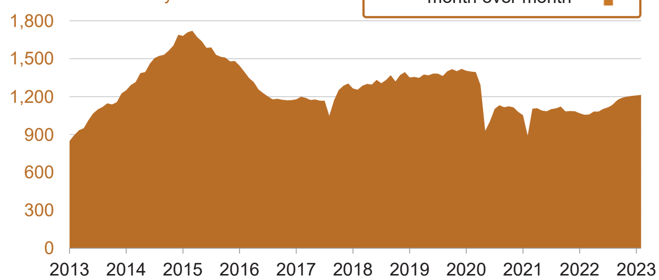


Eagle Ford Region
Indicated change in natural gas production (Feb vs. Jan)



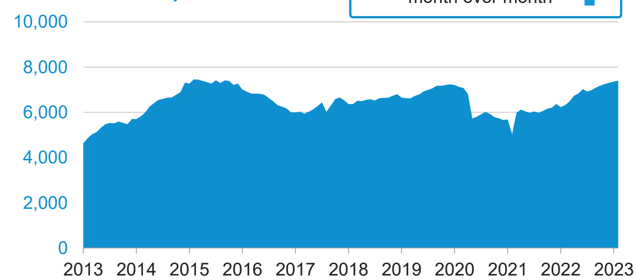
Eagle Ford Region
Oil production

Oil +4 thousand barrels/day month over month



Eagle Ford Region
Natural gas production

Gas +46 million cubic feet/day month over month



Haynesville Region

Drilling Productivity Report

January 2023

drilling data through December
projected production through February

Oil **0** barrels/day month over month

19 *February*
19 *January*
barrels/day

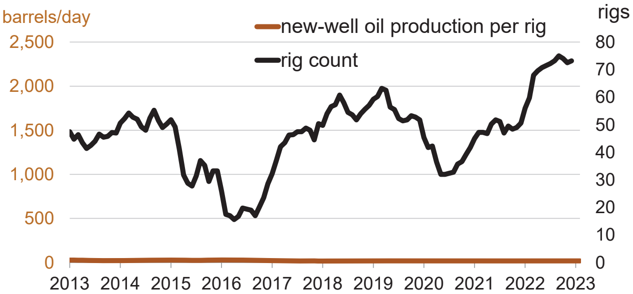
Monthly additions from one average rig

February **10,728**
January **10,739**
thousand cubic feet/day

Gas **-11** thousand cubic feet/day month over month

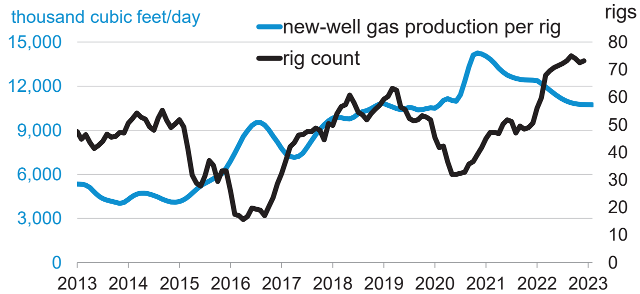
Haynesville Region
New-well oil production per rig **Rig count**

barrels/day



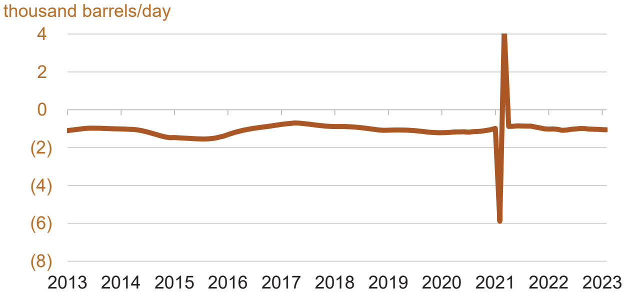
Haynesville Region
New-well gas production per rig **Rig count**

thousand cubic feet/day



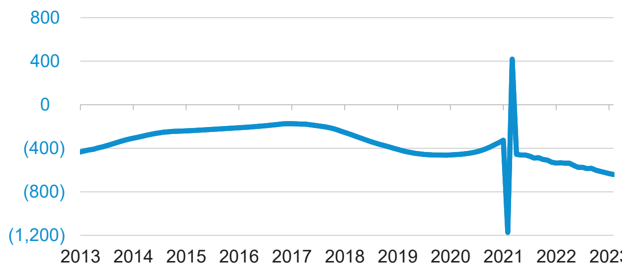
Haynesville Region
Legacy oil production change

thousand barrels/day



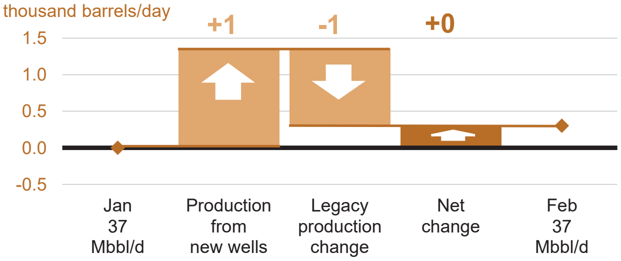
Haynesville Region
Legacy gas production change

million cubic feet/day



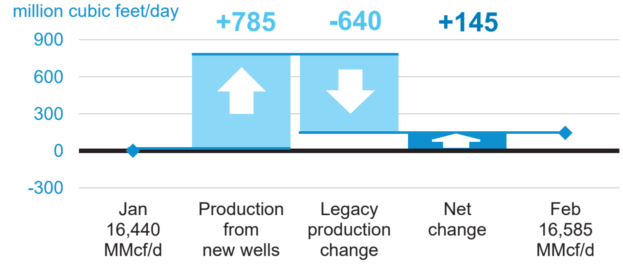
Haynesville Region
Indicated change in oil production (Feb vs. Jan)

thousand barrels/day



Haynesville Region
Indicated change in natural gas production (Feb vs. Jan)

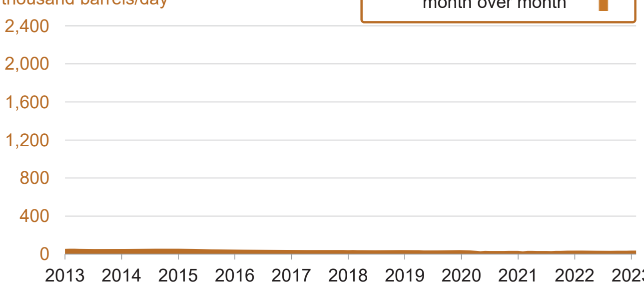
million cubic feet/day



Haynesville Region
Oil production

thousand barrels/day

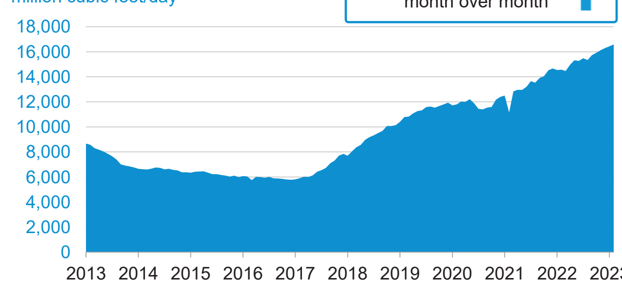
Oil +0 thousand barrels/day month over month



Haynesville Region
Natural gas production

million cubic feet/day

Gas +145 million cubic feet/day month over month



Niobrara Region

Drilling Productivity Report

January 2023

drilling data through December
projected production through February

Oil -6 barrels/day month over month

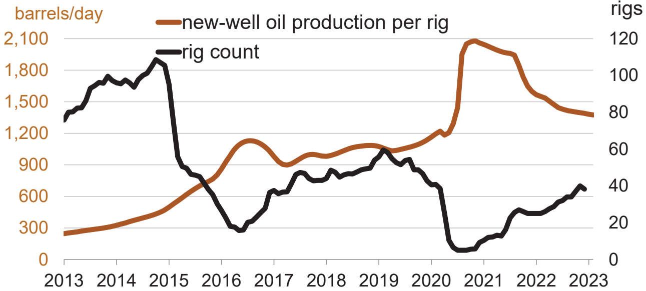
1,375 *February*
1,381 *January*
barrels/day

Monthly additions from one average rig

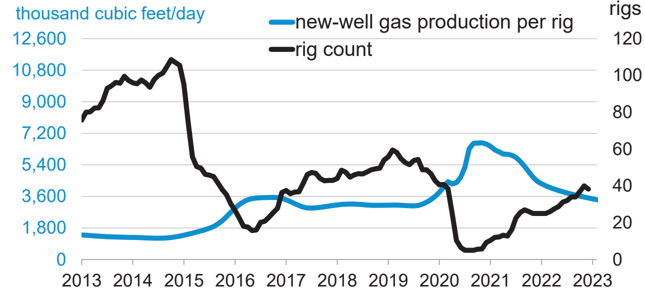
February **3,408**
January **3,453**
thousand cubic feet/day

Gas -45 thousand cubic feet/day month over month

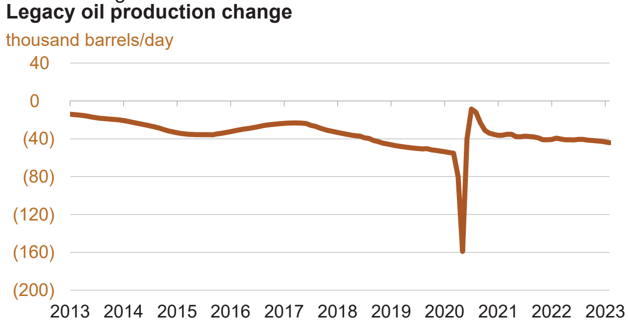
Niobrara Region
New-well oil production per rig **Rig count**



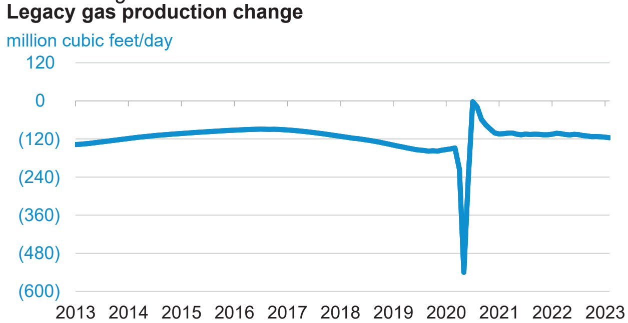
Niobrara Region
New-well gas production per rig **Rig count**



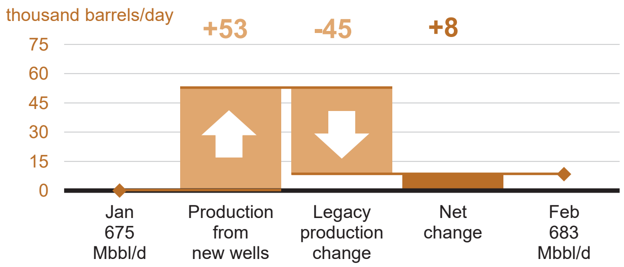
Niobrara Region
Legacy oil production change



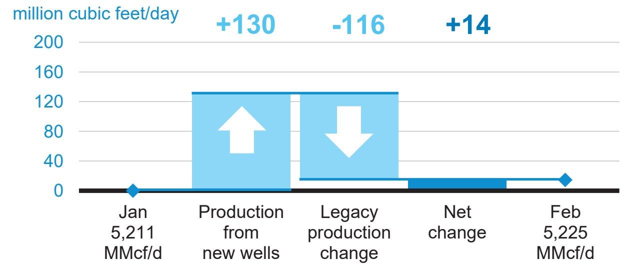
Niobrara Region
Legacy gas production change



Niobrara Region
Indicated change in oil production (Feb vs. Jan)

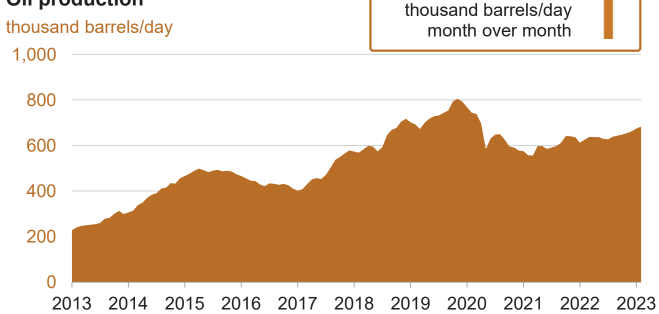


Niobrara Region
Indicated change in natural gas production (Feb vs. Jan)



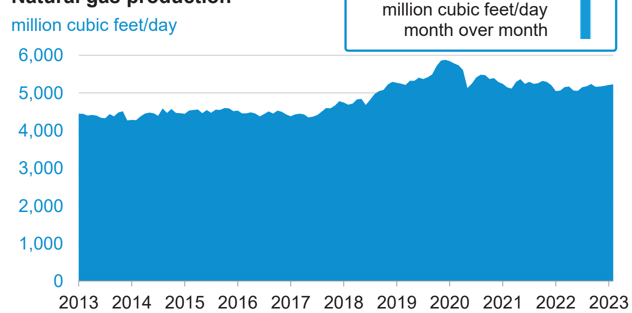
Niobrara Region
Oil production

Oil +8 thousand barrels/day month over month



Niobrara Region
Natural gas production

Gas +14 million cubic feet/day month over month



Permian Region

Drilling Productivity Report

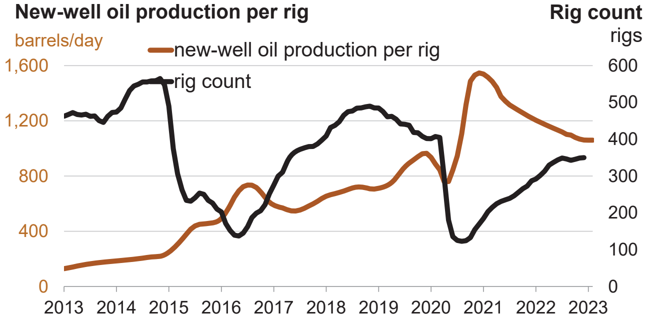
January 2023

drilling data through December
projected production through February

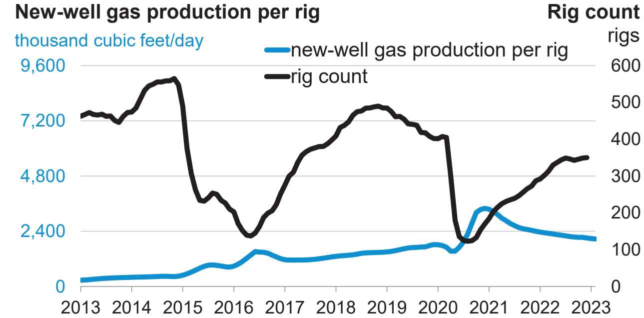
Oil			Gas
Oil -1 barrels/day month over month	**1,060** *February* **1,061** *January* barrels/day	*February* **2,065** *January* **2,086** thousand cubic feet/day	**Gas -21** thousand cubic feet/day month over month

Monthly additions from one average rig

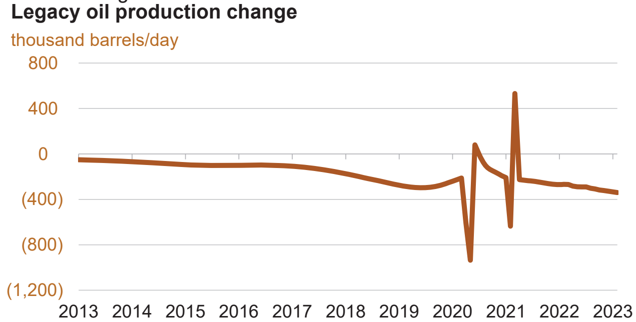
Permian Region
New-well oil production per rig



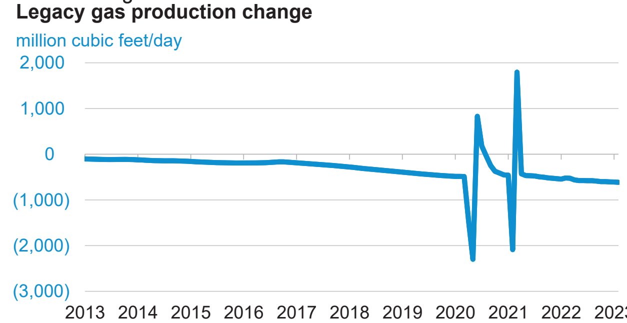
Permian Region
New-well gas production per rig



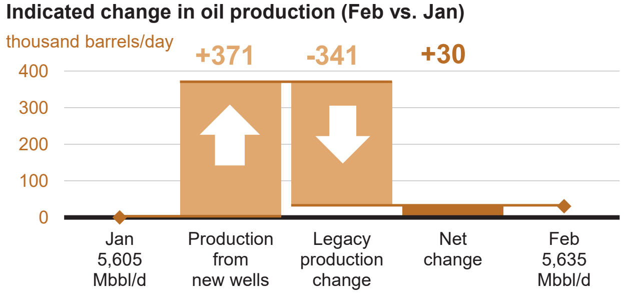
Permian Region
Legacy oil production change



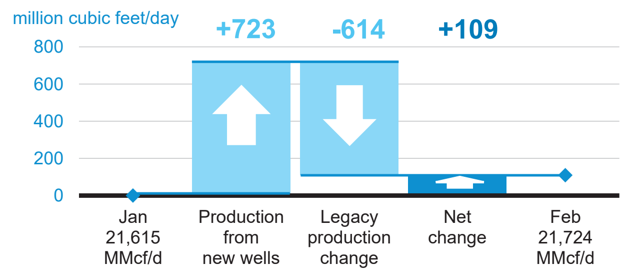
Permian Region
Legacy gas production change



Permian Region
Indicated change in oil production (Feb vs. Jan)

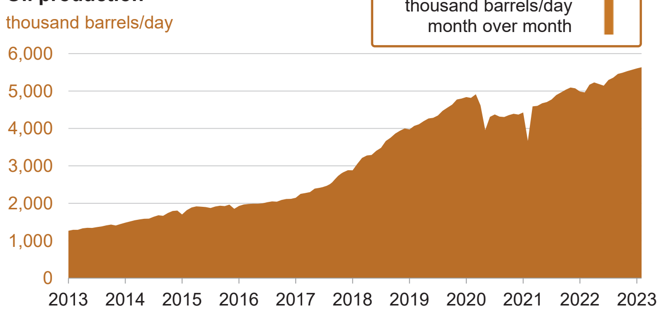


Permian Region
Indicated change in natural gas production (Feb vs. Jan)



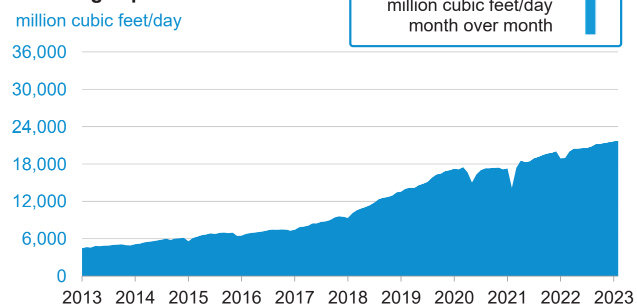
Permian Region
Oil production

Oil +30 thousand barrels/day month over month



Permian Region
Natural gas production

Gas +109 million cubic feet/day month over month



The Drilling Productivity Report uses recent data on the total number of drilling rigs in operation along with estimates of drilling productivity and estimated changes in production from existing oil and natural gas wells to provide estimated changes in oil[1] and natural gas[2] production for seven key regions. EIA's approach does not distinguish between oil-directed rigs and gas-directed rigs because once a well is completed it may produce both oil and gas; more than half of the wells do that.

Monthly additions from one average rig

Monthly additions from one average rig represent EIA's estimate of an average rig's[3] contribution to production of oil and natural gas from new wells.[4] The estimation of new-well production per rig uses several months of recent historical data on total production from new wells for each field divided by the region's monthly rig count, lagged by two months.[5] Current- and next-month values are listed on the top header. The month-over-month change is listed alongside, with +/- signs and color-coded arrows to highlight the growth or decline in oil (brown) or natural gas (blue).

New-well oil/gas production per rig

Charts present historical estimated monthly additions from one average rig coupled with the number of total drilling rigs as reported by Baker Hughes.

Legacy oil and natural gas production change

Charts present EIA's estimates of total oil and gas production changes from all the wells other than the new wells. The trend is dominated by the well depletion rates, but other circumstances can influence the direction of the change. For example, well freeze-offs or hurricanes can cause production to significantly decline in any given month, resulting in a production increase the next month when production simply returns to normal levels.

Projected change in monthly oil/gas production

Charts present the combined effects of new-well production and changes to legacy production. Total new-well production is offset by the anticipated change in legacy production to derive the net change in production. The estimated change in production does not reflect external circumstances that can affect the actual rates, such as infrastructure constraints, bad weather, or shut-ins based on environmental or economic issues.

Oil/gas production

Charts present all oil and natural gas production from both new and legacy wells since 2007. This production is based on all wells reported to the state oil and gas agencies. Where state data are not immediately available, EIA estimates the production based on estimated changes in new-well oil/gas production and the corresponding legacy change.

Footnotes:

1. Oil production represents both crude and condensate production from all formations in the region. Production is not limited to tight formations. The regions are defined by all selected counties, which include areas outside of tight oil formations.
2. Gas production represents gross (before processing) gas production from all formations in the region. Production is not limited to shale formations. The regions are defined by all selected counties, which include areas outside of shale formations.
3. The monthly average rig count used in this report is calculated from weekly data on total oil and gas rigs reported by Baker Hughes.
4. A new well is defined as one that began producing for the first time in the previous month. Each well belongs to the new-well category for only one month. Reworked and recompleted wells are excluded from the calculation.
5. Rig count data lag production data because EIA has observed that the best predictor of the number of new wells beginning production in a given month is the count of rigs in operation two months earlier.

The data used in the preparation of this report come from the following sources. EIA is solely responsible for the analysis, calculations, and conclusions.

Drilling Info (http://www.drillinginfo.com) Source of production, permit, and spud data for counties associated with this report. Source of real-time rig location to estimate new wells spudded and completed throughout the United States.

Baker Hughes (http://www.bakerhughes.com) Source of rig and well counts by county, state, and basin.

North Dakota Oil and Gas Division (https://www.dmr.nd.gov/oilgas) Source of well production, permit, and completion data in the counties associated with this report in North Dakota

Railroad Commission of Texas (http://www.rrc.state.tx.us) Source of well production, permit, and completion data in the counties associated with this report in Texas

Pennsylvania Department of Environmental Protection (https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Welcome.aspx) Source of well production, permit, and completion data in the counties associated with this report in Pennsylvania

West Virginia Department of Environmental Protection (http://www.dep.wv.gov/oil-and-gas/Pages/default.aspx) Source of well production, permit, and completion data in the counties associated with this report in West Virginia

Colorado Oil and Gas Conservation Commission (http://cogcc.state.co.us) Source of well production, permit, and completion data in the counties associated with this report in Colorado

Wyoming Oil and Conservation Commission (http://wogcc.state.wy.us) Source of well production, permit, and completion data in the counties associated with this report in Wyoming

Louisiana Department of Natural Resources (http://dnr.louisiana.gov) Source of well production, permit, and completion data in the counties associated with this report in Louisiana

Ohio Department of Natural Resources (http://oilandgas.ohiodnr.gov) Source of well production, permit, and completion data in the counties associated with this report in Ohio

Oklahoma Corporation Commission (http://www.occeweb.com/og/oghome.htm) Source of well production, permit, and completion data in the counties associated with this report in Oklahoma

Summary

Overview of Activity for November 2022

- **Top five countries of destination, representing 69.3% of total U.S. LNG exports in November 2022**
  - United Kingdom (82.8 Bcf), France (50.7 Bcf), Turkey (31.4 Bcf), Japan (24.4 Bcf), and Netherlands (20.6 Bcf)
- **302.3 Bcf of exports in November 2022**
  - 2.3% decrease from October 2022
  - 1.2% less than November 2021
- **94 cargos shipped in November 2022**
  - Sabine Pass (35), Cameron (33), Corpus Christi (16), Elba (4), Cove Point (6), and Freeport (0)
  - 96 cargos in October 2022
  - 99 cargos in November 2021

1a. Table of Exports of Domestically-Produced LNG Delivered by Region (Cumulative from February 2016 through November 2022)

Region	Number of Countries Receiving Per Region	Volume Exported (Bcf)	Percentage Receipts of Total Volume Exported (%)	Number of Cargos*
East Asia and Pacific	8	4,409.4	33.3%	1298
Europe and Central Asia	14	5,536.7	41.8%	1738
Latin America and the Caribbean**	13	2,128.3	16.0%	757
Middle East and North Africa	5	376.6	2.8%	110
South Asia	3	809.3	6.1%	241
Sub-Saharan Africa	0	0.0	0.0%	0
Total LNG Exports	**43**	**13,260.3**	**100.0%**	**4,145**

*Split cargos counted as both individual cargos and countries

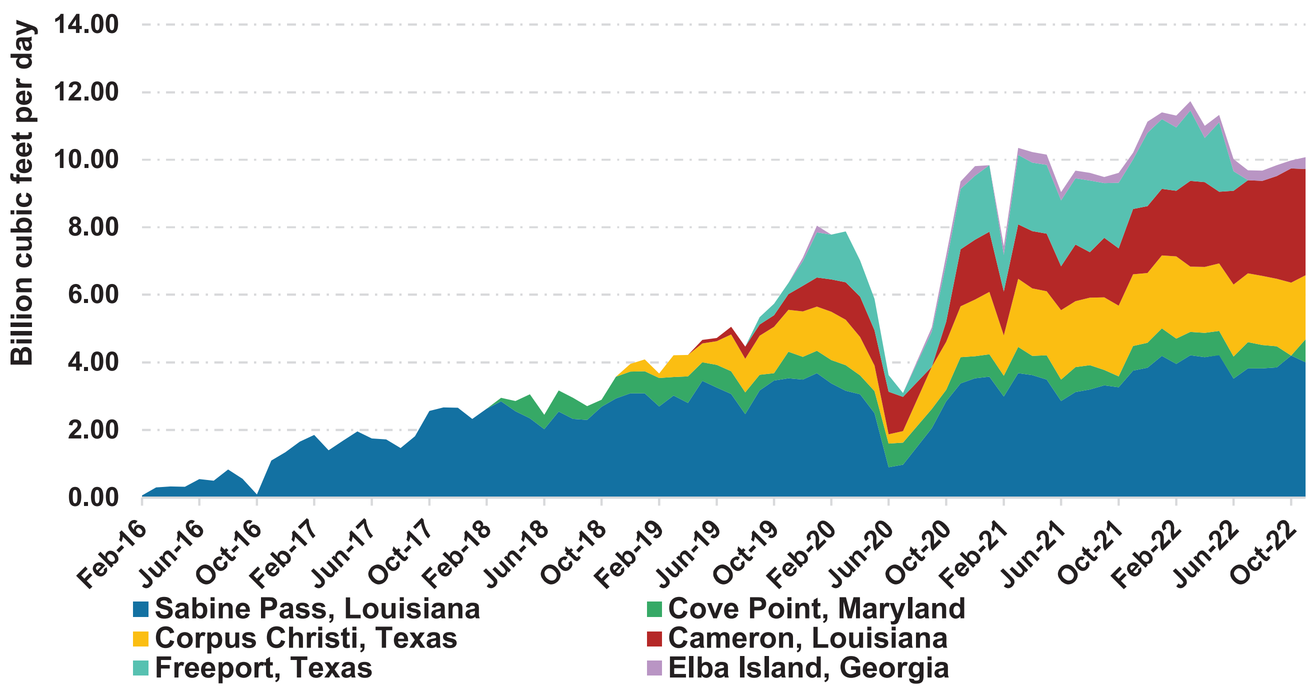
**Number of cargos does not include the shipments by ISO container

1b. Shipments of Domestically-Produced LNG Delivered – by Country (Cumulative from February 2016 through November 2022)

	Country of Destination	Region	Number of Cargos	Volume (Bcf of Natural Gas)	Percentage of Total U.S LNG Exports (%)
1.	South Korea*	East Asia and Pacific	487	1,692.9	12.8%
2.	Japan*	East Asia and Pacific	354	1,222.1	9.2%
3.	Spain*	Europe and Central Asia	322	1,010.9	7.6%
4.	China*	East Asia and Pacific	287	979.6	7.4%
5.	France*	Europe and Central Asia	287	933.4	7.0%
6.	United Kingdom*	Europe and Central Asia	279	926.1	7.0%
7.	Netherlands*	Europe and Central Asia	209	694.9	5.2%
8.	India*	South Asia	182	615.9	4.6%
9.	Brazil*	Latin America and the Caribbean	217	608.3	4.6%
10.	Turkey*	Europe and Central Asia	179	574.3	4.3%
11.	Mexico*	Latin America and the Caribbean	163	546.3	4.1%
12.	Chile*	Latin America and the Caribbean	132	419.3	3.2%
13.	Taiwan*	East Asia and Pacific	99	314.4	2.4%
14.	Italy*	Europe and Central Asia	97	307.6	2.3%
15.	Argentina*	Latin America and the Caribbean	110	265.2	2.0%
16.	Poland*	Europe and Central Asia	76	254.9	1.9%
17.	Portugal*	Europe and Central Asia	79	251.4	1.9%
18.	Greece*	Europe and Central Asia	73	172.6	1.3%
19.	Kuwait	Middle East and North Africa	45	156.4	1.2%
20.	Dominican Republic*	Latin America and the Caribbean	63	151.1	1.1%
21.	Lithuania	Europe and Central Asia	47	144.0	1.1%
22.	Belgium*	Europe and Central Asia	43	138.4	1.0%
23.	Pakistan*	South Asia	40	128.9	1.0%
24.	Jordan*	Middle East and North Africa	36	124.2	0.9%
25.	Croatia	Europe and Central Asia	37	110.5	0.8%
26.	Singapore*	East Asia and Pacific	33	107.3	0.8%
27.	Thailand*	East Asia and Pacific	24	82.9	0.6%
28.	Bangladesh*	South Asia	19	64.5	0.5%
29.	Jamaica*	Latin America and the Caribbean	26	57.4	0.4%
30.	Panama*	Latin America and the Caribbean	28	51.7	0.4%
31.	United Arab Emirates	Middle East and North Africa	15	51.1	0.4%
32.	Israel*	Middle East and North Africa	9	28.0	0.2%
33.	Colombia*	Latin America and the Caribbean	18	24.2	0.2%
34.	Malta*	Europe and Central Asia	10	17.6	0.1%
35.	Egypt*	Middle East and North Africa	5	16.9	0.1%
36.	Indonesia*	East Asia and Pacific	13	6.6	0.0%
37.	Malaysia	East Asia and Pacific	1	3.7	0.0%
	Total Exports by Vessel		**4,144**	**13,255.7**	
38.	Antigua and Barbuda	Latin America and the Caribbean	33	0.0	0.0%
39.	Nicaragua	Latin America and the Caribbean	1	0.0	0.0%
40	Germany	Europe and Central Asia	1	0.0	0.0%
41	Haiti	Latin America and the Caribbean	128	0.4	0.0%
42	Barbados	Latin America and the Caribbean	305	1.3	0.0%
	Jamaica	Latin America and the Caribbean	131	1.5	0.0%
43	Bahamas	Latin America and the Caribbean	647	1.5	0.0%
	Total Exports by ISO		**1246**	**4.7**	
	Total Exports by Vessel and ISO		**5,390**	**13,260.3**	

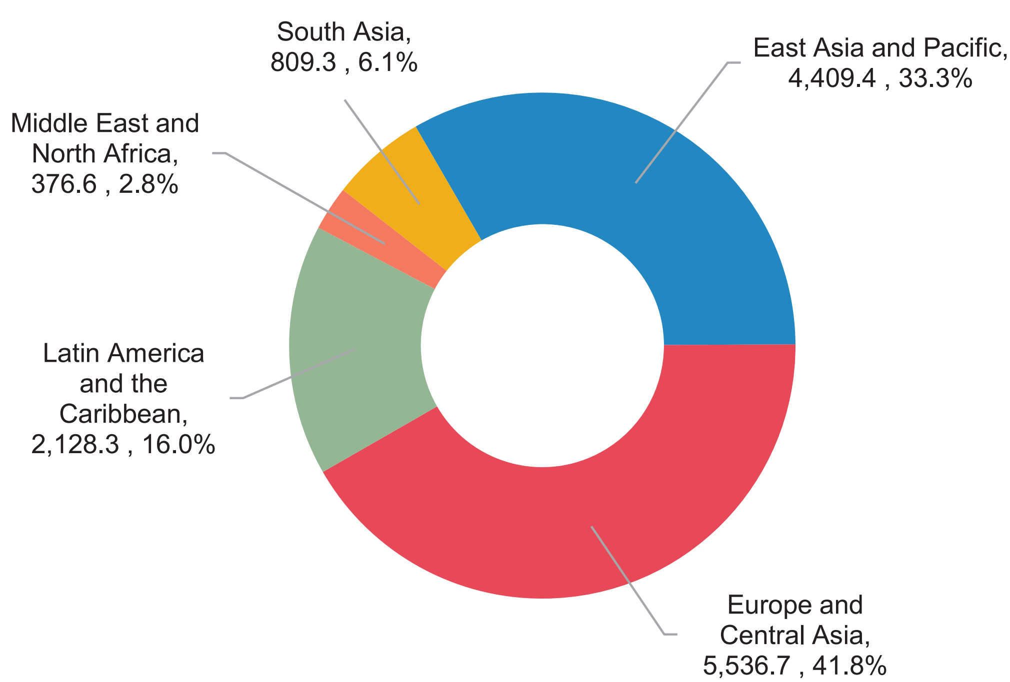
Note:
Volume and Number of Cargos are the cumulative totals of each individual Country of Destination by Region starting from February 2016.
Jamaica has received U.S. LNG exports by both vessel and ISO container. The volumes are totaled separately
* Split cargos counted as both individual cargos and countries.
Vessel = LNG Exports by Vessel and ISO container = LNG Exports by Vessel in ISO Containers.
Does not include re-exports of previously-imported LNG. See table 2c for re-exports data.
Totals may not equal sum of components because of independent rounding.

1c. Domestically-Produced LNG Exported by Point of Exit
(February 2016 through November 2022)



The Cameron, LA point of exit includes exports from Cameron LNG and Venture Global Calcasieu Pass.

1d. Domestically-Produced LNG Exported by Region
(Cumulative from February 2016 through November 2022)
(Bcf, %)



https://news.gov.bc.ca/releases/2023WLRS0004-000043?utm_source=dlvr.it&utm_medium=twitter

Province, Blueberry River First Nations reach agreement

Prince George
Wednesday, January 18, 2023 2:39 PM

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The B.C. government and Blueberry River First Nations have reached a historic agreement that will guide them forward in a partnership approach to land, water and resource stewardship that ensures Blueberry River members can meaningfully exercise their Treaty 8 rights, and provide stability and predictability for industry in the region.

"This agreement provides a clear pathway to get the hard work started on healing and restoring the land, and start on the joint planning with strong criteria to protect ecosystems, wildlife habitat and old forests," said Chief Judy Desjarlais of the Blueberry River First Nations. "With the knowledge and guidance of our Elders, this new agreement will ensure there will be healthy land and resources for current and future generations to carry on our people's way of life."

The Blueberry River First Nations Implementation Agreement responds to a B.C. Supreme Court decision on June 29, 2021, that found the Province had infringed upon Blueberry River's Treaty 8 rights due to the cumulative impacts of decades of industrial development. The court prohibited the provincial government from authorizing further activities, which unjustifiably infringe Blueberry River's rights and directed the parties to negotiate a collaborative approach to land management and natural resource development that protects the Nations' treaty rights.

"I've always believed that negotiation, rather than litigation, is the way forward for achieving reconciliation and strengthening vital government-to-government relationships," said Premier David Eby. "This historic agreement between British Columbia and Blueberry River First Nations not only brings more predictability for the region and local economy but it helps ensure that we are operating on the land in partnership to ensure sustainability for future generations."

The agreement will transform how the Province and First Nations steward land, water and resources together, and address cumulative effects in Blueberry River's Claim Area through restoration to heal the land, new areas protected from industrial development, and constraint on development activities while a long-term cumulative effects management regime is implemented. In addition, it supports and advances the Province's climate change strategy. The work of achieving these goals will be carried out through a series of measures, including:

- a $200-million restoration fund by June 2025, which supports healing of the land from decades of legacy industrial disturbance;
- an ecosystem-based management approach for future land-use planning in Blueberry River's most culturally important areas, with ambitious timelines to complete new local and watershed level, land use plans;
- limits on new petroleum and natural gas (PNG) development and a new planning regime for future oil and gas activities;
- protections for old forest and traplines during and through planning;

- land protections in Blueberry River's high-value areas, which includes more than 650,000 hectares of protection from new PNG and forestry activities and will advance B.C.'s 30% land protections goal by 2030; and
- wildlife co-management efforts, including moose management through licensed hunter restrictions to support population recovery.

Blueberry River First Nations will receive $87.5 million as a financial package over three years, with an opportunity for increased benefits based on PNG revenue-sharing and provincial royalty revenues in the next two fiscal years.

Quotes:

Josie Osborne, Minister of Energy, Mines and Low Carbon Innovation –

"This agreement supports progress on responsible resource development in British Columbia in a way that recognizes and respects Treaty 8 rights and promotes a new approach to stewarding the land, water and resources together. This is important work for all of us; it's about honouring a century-old treaty and leaving the land in a good way for future generations."

Murray Rankin, Minister of Indigenous Relations and Reconciliation –

"Our government is committed to upholding our obligations under Treaty 8. Following a thorough process of negotiations, we have found a sustainable, long-term solution with Blueberry River First Nations that will reset the balance promised in Treaty 8, ensuring environmental sustainability, protection of Indigenous culture, and stable economic activity and employment. I commend the leadership of Blueberry River First Nations, leaders in industry, and local community who have helped us on the path to achieving this landmark agreement."

Nathan Cullen, Minister of Water, Land and Resource Stewardship –

"This historic agreement will help all of us achieve that crucial balance between protecting our environment, respecting and honouring the treaty rights of Blueberry River First Nations, and providing stability and predictability for industry, workers, and communities in the northeast. I want to thank the negotiators on all sides for their hard work in developing this agreement, which will help us heal the land from decades of industrial development."

Bruce Ralston, Minister of Forests –

"This agreement recognizes the significant opportunities of moving forward in partnership with Blueberry River First Nations to co-manage our forests and create a stronger, more sustainable future. It aligns with our government's work to better manage our forests for long-term ecosystem health and community resiliency."

George Heyman, Minister of Environment and Climate Change Strategy –

"The agreement sets a new course to assist Blueberry River First Nations to heal, conserve and develop their lands in accordance with their rights, title and culture. It will change how resource activities are administered in Blueberry River's claim area by building a new and critical framework that accounts for and addresses cumulative impacts. This agreement will result in significant positive effect on local ecosystems and climate impacts, and will ensure our path forward is based on environmental sustainability as a core principle guiding economic activity."

Quick Facts:

- The agreement is focused in Blueberry River's civil claim area, which includes areas that are important to Blueberry, and other Treaty 8 Nations, for practising their treaty rights.
- The agreement provides for annual reviews of implementation progress and effectiveness, and includes a formal three-year review.
- The Province and Blueberry River have agreed to expeditiously begin implementation, and in order to support the local economy, this agreement provides for a series of timber harvesting and oil and gas activities to proceed throughout Blueberry River's claim area.
- In October 2021, the B.C. government and Blueberry River First Nations signed an initial agreement that provided the Nations with $65 million for land restoration, wildlife stewardship, and cultural and capacity investments.
- That agreement provided added security for many existing authorized activities to continue in Blueberry River's claim area as negotiations ensued.

Learn More:

To read the Supreme Court of B.C. decision, visit: https://www.bccourts.ca/jdb-txt/sc/21/12/2021BCSC1287.htm

Blueberry River First Nations, where happiness dwells: https://blueberryfn.com/where-happiness-dwells/

Three backgrounders follow.

Backgrounders

What people are saying about the Blueberry River First Nations Implementation Agreement

Michael Rose, president and CEO, Tourmaline Oil Corp. –

"I am pleased with this new framework for oil and gas development that will create significant prosperity for the people and the Province, for Blueberry River First Nations and all the Treaty 8 First Nations of B.C., and for industry. Providing low-emission Canadian natural gas to the world is one of the best things we can do for the global atmosphere and the overall Canadian economy."

Izwan Ismail, president and CEO, Petronas Energy Canada Ltd. –

"Petronas Canada is encouraged that an agreement has been reached between the Government of British Columbia and Blueberry River First Nations, in an important step toward reconciliation and the management of cumulative impacts. As a global energy leader, we look to B.C.'s world-class North Montney basin and LNG Canada as cornerstones of both our global portfolio and B.C.'s important economic and environmental opportunity to deliver the world's lowest-emission LNG. With this important agreement in place, our collaborative relationship with Blueberry River First Nations as well as other Treaty 8 Nations, and our commitment to sustainable development, including land restoration continues. It is our expectation that the necessary work can now proceed to ensure that the gas PETRONAS Canada delivers to the LNG Canada project is responsibly produced right here in B.C., benefiting the entire province and country."

Lisa Baiton, president and CEO, Canadian Association of Petroleum Producers (CAPP) –

"Indigenous partnerships and participation are integral to the success of the natural gas and oil industry in British Columbia. CAPP and our members appreciate the diligent efforts of the Province of B.C. and the Blueberry River First Nations to reach this detailed agreement, and we acknowledge all the other Nations in our areas of operations. This agreement is a positive step forward and we are focused on gaining an understanding of the details within the agreement to chart a path forward, which enables the responsible development of B.C.'s rich natural resources in a way that ensures mutual benefits for industry, Indigenous Nations and British Columbians across the province."

Tristan Goodman, president and CEO, The Explorers and Producers Association of Canada –

"The agreement between the British Columbia government and Indigenous communities in northeast B.C. provides much-needed clarity to move forward with natural gas development. These historic agreements demonstrate a commitment from all parties to reconciliation and the environmentally conscious development of B.C.'s natural resources. British Columbia's clean and responsibly produced natural gas can support Canada's climate goals and supply the world with lower carbon, reliable and affordable energy. The agreement offers opportunities for economic prosperity for Indigenous communities and contributes revenues to support provincial priorities, such as health care and affordable housing."

Linda Coady, president and CEO, BC Council of Forest Industries (COFI) –

"As this agreement is implemented and more details made known, COFI will work with our members to support a path forward that reflects our recognition of Indigenous rights and our commitment to supporting sustainable forestry, people and communities. More broadly, and as important conversations about the future of forestry continue to take place across the province, we will keep collaborating with partners to further maximize the role a strong and sustainable forest industry can play in advancing reconciliation, fighting climate change and delivering good jobs for British Columbians today, and into the future."

Mike Blosser, senior vice-president, Louisiana Pacific, Manufacturing Services –

"LP Building Solutions is pleased to see Blueberry River First Nations and the Province of B.C. finalize this agreement to ensure a successful balance between ecological, social and economic values and the long-term prosperity of northeast B.C. We look forward to working with all the Treaty 8 Nations and the Province of B.C. in the years to come."

Greg D'Avignon, president and CEO, Business Council of British Columbia –

"The business council and our members have long advocated for meaningful reconciliation with Indigenous Nations that enable sustainable development in British Columbia. This agreement takes necessary steps toward advancing those shared goals and opportunities. Efficient, predictable and thorough decision-making processes are essential to urgently advancing our low-carbon natural resource and energy products to markets to reduce global GHG emissions, while enabling investment conditions for innovation and infrastructure to reduce domestic emissions. Acting in collaboration with purpose, globally and locally, will create sustainable economic prosperity for Nations, communities, businesses and all British Columbians."

Leonard Hiebert, chair, Peace River Regional District –

"We are pleased that Blueberry River First Nations and the B.C. government have taken a thorough and collaborative approach to reach this significant milestone. This agreement is a step forward that will guide decision-making in the spirit of reconciliation, stewardship and partnership."

Dale Bumstead, former mayor of Dawson Creek –
"The Yahey v. British Columbia decision is an incredible and iconic opportunity for all of us to recognize the importance of balancing resource development and respect for the land. The opportunity is to move forward as a region and a province together, toward a strong and prosperous future."
Tim Burkhart, B.C. manager, strategic engagement, Yellowstone to Yukon Conservation Initiative (Y2Y) –
"Blueberry River First Nations have been stewarding their traditional territories since time immemorial, protecting both nature and way of life in the face of cumulative industrial disturbance. Y2Y celebrates the leadership of Blueberry River First Nations and the Province for reaching this agreement that invests back into Indigenous governments and communities to conserve ecosystems and biodiversity, advances B.C.'s 30% by 2030 land protection goals, and takes an important step to uphold the promises made in Treaty 8."
Meaghen McCord, executive director, Canadian Parks and Wilderness Society (CPAWS), B.C. chapter –
"CPAWS-BC celebrates the agreement between the Province and Blueberry River First Nations as a much-needed step toward facilitating Indigenous land stewardship, recognizing Indigenous rights, and increasing land protection in B.C. Northeastern British Columbia has been significantly impacted by resource extraction and we are optimistic this agreement will help prevent and reverse biodiversity loss through improved land-use planning and restoration."

Implementation agreement key highlights

Wildlife management

The ability to access wildlife that is important to Blueberry River's culture and way of life was a critical component of the B.C. government's court case, and a key topic of discussion and consultation between the parties for many years. The Province and Blueberry River will work toward wildlife co-management. Measures include:

- improving information on wildlife populations, bringing together Indigenous knowledge and western science;
- cultural burning to improve wildlife habitat;
- increased focus on moose management, including future opportunities to revise licenced hunter restrictions to support population recovery;
- continued support for caribou recovery; and
- support to launch a community stewardship, monitoring and guardian program.

Land-use plans

Collaborative land-use planning is an important way that the Province and Blueberry River can ensure the Nations' Treaty rights are protected and natural resource development activities can occur, for the benefit of local communities, the Province and First Nations. Through land-use planning, B.C. and Blueberry River will determine together where certain activities can occur, and under what expectations or requirements, and where they will be avoided in the future. Highlights from the agreement include:

- a commitment to advance multiple watershed-level land use plans within the next three years. These plans will improve clarity about the natural-resource activities that are available and how ecosystem-based management will be implemented; and
- as these 'Watershed Management Basin Plans' are developed, a series of operational level plans focused on land restoration, and petroleum and natural gas (PNG) sector activities will also be developed. The initial set of these high-value plans is targeted for completion within 15 months.

Petroleum and natural gas (PNG)

Through the agreement, the Province and Blueberry River will bring a more collaborative approach to oil and natural gas development planning and projects. Companies, the Province, Blueberry River and other Nations will sit together to discuss, design and agree to development plans. Measures include:

- establishing areas for permanent protection from new development;
- focusing disturbance from PNG wherever possible in areas already developed;
- reducing new disturbance from PNG by approximately 50% from pre-court decision years;
- introducing operational and strategic planning expectations for the sector, applicable to all new proposed activities; and
- a limit on overall new disturbance from PNG activities in Blueberry River's claim area, designated at 750 hectares, as further detailed planning and restoration activities can be developed and agreed to.

Forestry

Through the agreement, the Province will protect old forest and reduce timber harvesting in the defined High Value 1 (HV1) areas and traplines, to promote the return of healthy mature forests for the meaningful exercise of treaty rights. This includes an approximate reduction of 350,000 cubic metres per year in the Fort St. John Timber Supply Area, with the exception of a handful of small, locally held woodlot tenures. Impacted tenure holders will be compensated.

Other key elements of the agreement applicable to forestry include:

- a cessation to aerial herbicide use, and ground-based herbicide use only in exceptional circumstances;
- a commitment to implementing ecosystem-based management, applicable to the forest sector and other sectors as the Watershed Management Basin plans are complete; and
- a two-year harvest schedule outside the Nations' important forestry areas, while land-use planning activities are initiated.

Honouring Treaty 8

The parties have agreed to work together on measures to honour Treaty 8, including improving the awareness of and education on Treaty 8. Honouring the treaty will include sustained communications, shared training and awareness building, and providing support for communications with other Treaty 8 First Nations and local elected leaders.

B.C. Supreme Court decision summary

On June 29, 2021, the B.C. Supreme Court released its decision in Yahey v. British Columbia. The court found that the Province had breached its treaty commitment to Blueberry River First Nations (BRFN) and infringed the Nations' rights to carry out their traditional ways of life. The court determined that decades of provincial development authorizations had left Blueberry River with no meaningful ability to exercise their Treaty 8 rights to hunt, fish and trap on their traditional territory. The court ruled that the Province could no longer authorize further activities that unjustifiably infringe Blueberry River's treaty rights, or breach the Province's honourable and fiduciary obligations. The court issued four declarations which among them include the requirement for the Province to work with Blueberry River on a new approach to natural resource development that protects the Nations' Treaty rights and addresses cumulative impacts.

In handing down her decision, Justice Emily M. Burke issued four declarations:

1. In causing and/or permitting the cumulative impacts of industrial development on BRFN's Treaty Rights, the Province has breached its obligation to BRFN under Treaty 8, including its honourable and fiduciary obligations. The Province's mechanisms for assessing and taking into account cumulative effects are lacking and have contributed to the breach of its obligations under Treaty 8;
2. The Province has taken up lands to such an extent that there are not sufficient and appropriate lands in the Claim Area to allow for BRFN's meaningful exercise of their Treaty Rights. The Province has therefore unjustifiably infringed BRFN's Treaty Rights in permitting the cumulative impacts of industrial development to meaningfully diminish BRFN's exercise of its Treaty Rights in the Claim Area;
3. The Province may not continue to authorize activities that breach the promises included in Treaty 8, including the Province's honourable and fiduciary obligations associated with Treaty 8 or that unjustifiably infringe BRFN's exercise of its Treaty Rights; and
4. The Parties must act with diligence to consult and negotiate for the purpose of establishing timely enforceable mechanisms to assess and manage the cumulative impact of industrial development on BRFN's Treaty Rights, and to ensure these constitutional rights are respected.

On July 28, 2021, David Eby, then Attorney General and Minister Responsible for Housing, released a public statement, announcing the Province would not appeal the court's decision.

To read the full court decision, see the B.C. court's online portal: https://www.bccourts.ca/jdb-txt/sc/21/12/2021BCSC1287.htm

SAF Group created transcript of BC Premier David Eby from the Q&A at the press conference announcing the BC deal with Blueberry First Nations on Jan 18, 2023

Items in "italics" are SAF Group created transcript

Question: "can you talk a little bit about the message this sends to industry, particularly the oil and gas industry. We heard there that LNG Canada project is ready to go ahead. There have been concerns about how BC will, or could possibly expand LNG and still meet its climate goals. Can you talk about the messaging here?

Premier Eby "*this agreement does have an impact on oil and gas development in the NE. It has very specific provisions about the amount of land disturbance that is permitted related to oil and gas. And this is one of the major concerns that caused Blueberry, as I understand it, to bring the court challenge and it was also a key discussion around the table. Industry is going to have to be more innovative. The oil and gas industry is going to have to find ways to work with less land disturbance. The agreement is not a cap on production, it is a cap on land . And we expect that, we expect high standards in British Columbia. And it is certainly very good to see Petronas here today at the announcement . And agreement across broad industries about the importance of this agreement from a couple of perspectives – predictability, certainty, understanding what's allowed and what's not. and also that they need to innovate and find ways to work on the lands in different ways. So it's a very significant agreement in that way. And it's my firm belief that is agreements like this providing certainty, providing that predictability, providing those boundaries will ensure innovation and partnership that is going to put us in a much better economic position going forward than continued court battles and uncertainty and all the unpredictability that that brings with it*."

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

https://investors.next-decade.com/news-releases/news-release-details/nextdecade-and-itochu-corporation-execute-10-mtpa-lng-sale-and

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JANUARY 19, 2023

NextDecade and Itochu Corporation Execute 1.0 MTPA LNG Sale and Purchase Agreement

BACK TO NEWS & EVENTS

HOUSTON--(BUSINESS WIRE)--Jan. 19, 2023-- NextDecade Corporation (NextDecade) (NASDAQ: NEXT) announced today the execution of a 15-year sale and purchase agreement (SPA) with Itochu Corporation (Itochu) for the supply of liquefied natural gas (LNG) from NextDecade's Rio Grande LNG (RGLNG) export project in Brownsville, Texas.

Under the SPA, ITOCHU will purchase 1.0 million tonnes per annum of LNG indexed to Henry Hub on a free-on-board basis.

"We are honored to have Itochu Corporation as our first Japanese customer," said Matt Schatzman, NextDecade's Chairman and Chief Executive Officer. "We look forward to providing Itochu and their customers with LNG, and we are actively working to reduce the carbon footprint of the Rio Grande LNG facility through our proposed carbon capture and storage project."

NextDecade is currently targeting a positive Final Investment Decision (FID) on the first three trains of the RGLNG export project during the first quarter of 2023, with FIDs of its remaining trains to follow thereafter.

About NextDecade Corporation

NextDecade Corporation is an energy company accelerating the path to a net-zero future. Leading innovation in more sustainable LNG and carbon capture solutions, NextDecade is committed to providing the world access to cleaner energy. Through our wholly owned subsidiaries Rio Grande LNG and NEXT Carbon Solutions, we are developing a 27 MTPA LNG export facility in South Texas along with one of the largest carbon capture and storage projects in North America. We are also working with third-party customers around the world to deploy our proprietary processes to lower the cost of carbon capture and storage and reduce CO_2 emissions at their industrial-scale facilities. NextDecade's common stock is listed on the Nasdaq Stock Market under the symbol "NEXT." NextDecade is headquartered in Houston, Texas. For more information, please visit www.next-decade.com.

Forward-Looking Statements

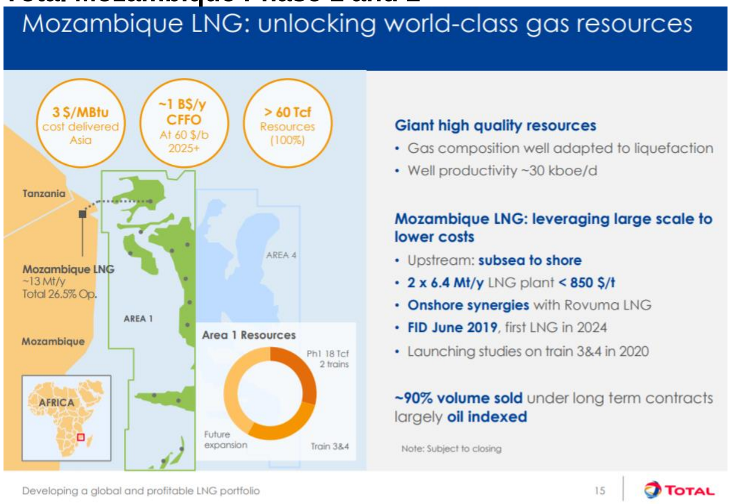
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

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



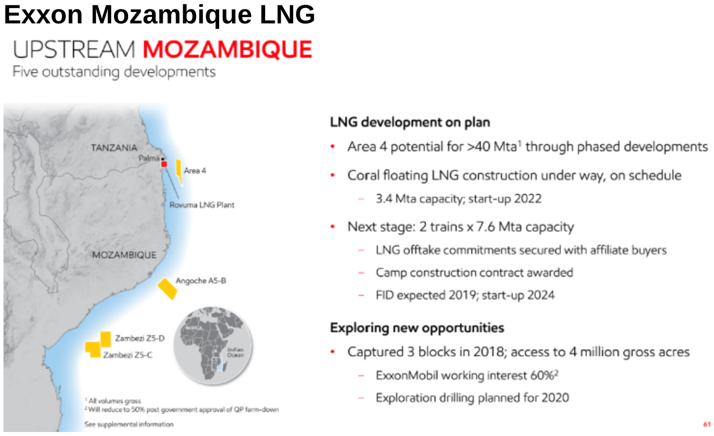
Source: Total Investor Day September 24, 2019

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

Source: IEA

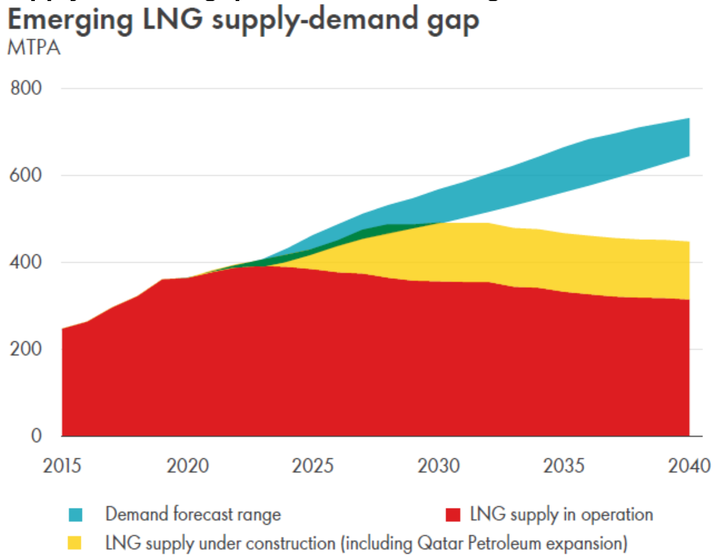
🟢 On Track 🟡 More Efforts Needed 🔴 Not on Track

Source: IEA Tracking Clean Energy Progress, June 2020

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

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

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



Source: Shell LNG Outlook 2021, Feb 25, 2021

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

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

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

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

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

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".*

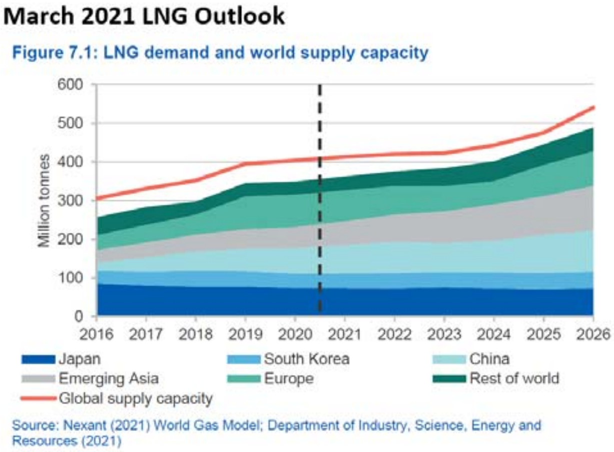
<u>There are other LNG supply delays/interruptions beyond Mozambique.</u> There have been a number of other smaller LNG delay or existing supply interruptions that add to Asian LNG buyers feeling less secure about the reliability of mid to long term LNG supply. Here are just a few examples. (i) Total 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.*

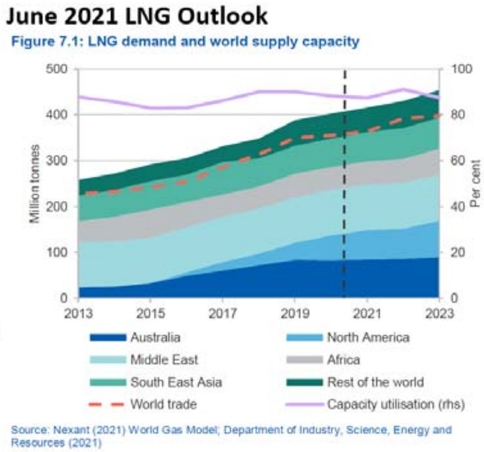
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required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



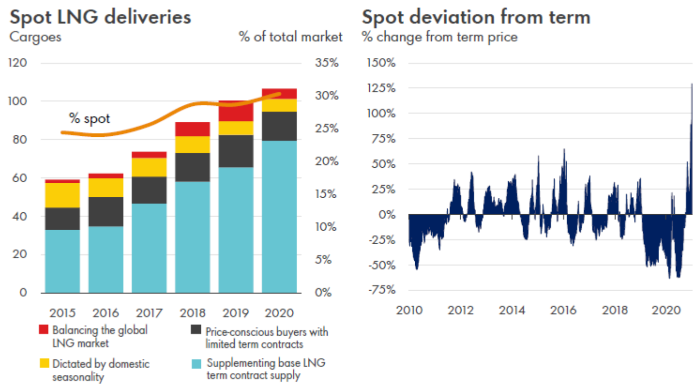


Source: Australia Resources and Energy Quarterly

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

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

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Highlights for the month

- Indigenous crude oil and condensate production during December 2022 was down by 1.1 % than that of December 2021 as compared to a de-growth of 1.1 % during November 2022. OIL registered a growth of 7.0 % and ONGC registered a de - growth of 0.237 % during December 2022 as compared to December 2021. PSC registered de-growth of 7.1 % during December 2022 as compared to December 2021. De-growth of 1.3 % was registered in the total crude oil and condensate production during April - December 2022 over the corresponding period of the previous year.
- Crude oil processed during December 2022 was 22.3 MMT, which was 3.7 % higher than December 2021 as compared to a de-growth of 8.9 % during November 2022. Growth of 6.4 % was registered in the total crude oil processing during April-December 2022 over the corresponding period of the previous year.
- Crude oil imports decreased by 3.0% and increased by 9.9% during December 2022 and April-December 2022 respectively as compared to the corresponding period of the previous year. The net import bill for Oil & Gas was $11.2 billion in December 2022 compared to $10.7 billion in December 2021. In this the crude oil imports constitutes $11.9 billion, LNG imports $1.6 billion and the exports were $4.6 billion during December 2022.
- The price of Brent Crude averaged $81.82/bbl during December 2022 as against $91.67/bbl during November 2022 and $74.10/bbl during December 2021. The Indian basket crude price averaged $78.10/bbl during December 2022 as against $87.55/bbl during November 2022 and $73.30 /bbl during December 2021.
- Production of petroleum products saw a growth of 3.7 % during December 2022 over December 2021 as compared to a de-growth of 9.3 % during November 2022. Growth of 5.4 % was registered in the total POL production during April- December 2022 over the corresponding period of the previous year.
- POL products imports decreased by 13.6% and increased by 5.6% during December 2022 and April-December 2022 respectively as compared to the corresponding period of the previous year. Increase in POL products imports during April-December 2022 were mainly due to increase in imports of all products except aviation turbine fuel (ATF), superior kerosene oil (SKO), lubes/LOBS and fuel oil (FO).

•	Exports of POL products decreased by 17.2% and 2.8% during December 2022 and April- December 2022 respectively as compared to the corresponding period of the previous year. Decrease in POL products exports during April- December 2022 were mainly due to decrease in exports of motor spirit (MS), naphtha, superior kerosene oil (SKO), high speed diesel (HSD), light diesel oil (LDO) and bitumen.
•	The consumption of petroleum products during April-Dec 2022 with a volume of 164.87 MMT reported a growth of 10.5% compared to the volume of 149.16 MMT during the same period of the previous year. This growth was led by 14.6% growth in MS, 14% in HSD & 50% in ATF consumption besides FO/LSHS, Petcoke, Bitument, Lubes & Greases, LPG and others during the period. The consumption of petroleum products during Dec 2022 recorded a growth of 3.1% with a volume of 19.6 MMT compared to the same period of the previous year.
•	Ethanol Blending with Petrol during December 2022, the first month of the Ethanol Supply Year(ESY) 2022-23, achieved 10.43% as compared to 10.02% during the ESY December 2021- November 2022
•	Total Natural Gas Consumption (including internal consumption) for the month of December 2022 was 5154 MMSCM which was 4.1% lower than the corresponding month of the previous year. The cumulative consumption of 45661 MMSCM for the current year till December 2022 was lower by 6.9 % compared with the corresponding period of the previous year.
•	Gross production of natural gas for the month of December 2022 (P) was 2951 MMSCM which was higher by 1.9% compared with the corresponding month of the previous year. The cumulative gross production of natural gas of 25868 MMSCM for the current financial year till December 2022 was higher by 0.8% compared with the corresponding period of the previous year.
•	LNG import for the month of December 2022 (P) was 2266 MMSCM which was 11.5% lower than the corresponding month of the previous year. The cumulative import of 20394 (P) MMSCM for the current year till December 2022 was lower by 15.1% compared with the corresponding period of the previous year.

1. Selected indicators of the Indian economy

	Economic indicators	Unit/ Base	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
1	Population (basis RGI projections)	Billion	1.309	1.323	1.337	1.351	1.365	1.377
2	GDP at constant (2011-12 Prices)	Growth %	6.8 3rd RE	6.5 2nd RE	4.0 1st RE	-6.6 1st RE	8.7 PE (2021-22)	7.0 1st AE
3	Agricultural Production (Food grains)	MMT	285.0	285.2	297.5	310.7	315.7 4th AE	149.9 1st AE (Kharif)
		Growth %	3.6	0.1	4.3	4.5	1.6	-
4	Gross Fiscal Deficit (as percent of GDP)	%	3.5	3.4	4.6	9.5 RE	6.8 BE	6.4 BE

	Economic indicators	Unit/ Base	2020-21	2021-22 (P)	Dec		April-Dec	
					2021-22	2022-23 (P)	2021-22	2022-23 (P)
5	Index of Industrial Production (Base: 2011-12)	Growth %	-8.4	11.4	1.0*	7.1* QE	17.6#	5.5#
6	Imports^	$ Billion	394.4	611.9	53.0	55.9	381.2	493.6
7	Exports^	$ Billion	291.8	419.7	31.8	32.0	265.8	295.3
8	Trade Balance	$ Billion	-102.6	-192.2	-21.2	-23.9	-115.4	-198.4
9	Foreign Exchange Reserves @	$ Billion	579.3	617.6	633.6	562.9	-	-

Population projection by RGI is taken as on 1st July for the year. IIP is for the month of *Nov and #April-Nov; @2020-21-as on March 26, 2021, 2021-22 - as on March 26, 2022, Dec 2021 as on Dec 31, 2021 and Dec 2022-as on Dec 30, 2022; ^Imports & Exports are for Merchandise for the month of November 22; E: Estimates; PE: Provisional Estimates; AE-Advanced Estimates; RE-Revised Estimates; QE-Quick Estimates.

Source: Registrar General India**,** Ministry of Commerce & Industry, Ministry of Statistics and Programme Implementation, Ministry of Agriculture & Farmer's Welfare, Ministry of Finance, Reserve Bank of India

2. Crude oil, LNG and petroleum products at a glance

	Details	Unit/ Base	2020-21	2021-22 (P)	Dec 2021-22 (P)	Dec 2022-23 (P)	April-Dec 2021-22 (P)	April-Dec 2022-23 (P)
1	Crude oil production in India#	MMT	30.5	29.7	2.5	2.5	22.4	22.1
2	Consumption of petroleum products*	MMT	194.3	204.2	19.0	19.6	149.2	164.9
3	Production of petroleum products	MMT	233.5	254.3	22.8	23.6	186.0	196.1
4	Gross natural gas production	MMSCM	28,672	34,024	2,897	2,951	25,674	25,868
5	Natural gas consumption	MMSCM	60,815	63,907	5,375	5,154	49,069	45,661
6	Imports & exports:							
	Crude oil imports	MMT	196.5	212.4	19.6	19.1	156.5	171.9
		$ Billion	62.2	120.7	10.9	11.9	82.6	125.5
	Petroleum products (POL) imports*	MMT	43.2	42.1	4.4	3.8	30.9	32.6
		$ Billion	14.8	25.2	2.5	2.4	18.0	20.9
	Gross petroleum imports (Crude + POL)	MMT	239.7	254.4	24.1	22.9	187.4	204.5
		$ Billion	77.0	145.9	13.4	14.3	100.7	146.5
	Petroleum products (POL) export	MMT	56.8	62.8	6.0	5.0	46.1	44.8
		$ Billion	21.4	44.4	4.1	4.6	29.6	45.3
	LNG imports*	MMSCM	33,031	30,776	2,561	2,266	24,033	20,394
		$ Billion	7.9	13.4	1.3	1.6	9.5	14.3
	Net oil & gas imports	$ Billion	63.5	114.9	10.7	11.2	80.6	115.5
7	Petroleum imports as percentage of India's gross imports (in value terms)	%	19.5	23.8	25.3	25.6	26.4	29.7
8	Petroleum exports as percentage of India's gross exports (in value terms)	%	7.3	10.6	12.8	14.5	11.1	15.3
9	Import dependency of crude oil (on POL consumption basis)	%	84.4	85.7	86.9	87.2	85.2	87.0

#Includes condensate; *RIL data prorated for Dec'22. Private direct imports are prorated for the period April'22 to Dec'22 for POL. LNG Imports figures from DGCIS are prorated for Oct-Dec 2022. Total may not tally due to rounding off.

3. Indigenous crude oil production (Million Metric Tonnes)

Details	2020-21	2021-22	Dec			April-Dec		
			2021-22	2022-23 Target*	2022-23 (P)	2021-22	2022-23 Target*	2022-23 (P)
ONGC	19.1	18.5	1.6	1.6	1.6	13.9	14.4	14.0
Oil India Limited (OIL)	2.9	3.0	0.3	0.3	0.3	2.2	2.6	2.4
Private / Joint Ventures (JVs)	7.1	7.0	0.6	0.8	0.5	5.3	6.7	4.8
Total Crude Oil	**29.1**	**28.4**	**2.4**	**2.7**	**2.4**	**21.4**	**23.6**	**21.1**
ONGC condensate	1.1	0.9	0.08	0.0	0.1	0.7	0.0	0.8
PSC condensate	0.3	0.30	0.02	0.0	0.03	0.23	0.0	0.22
Total condensate	**1.4**	**1.2**	**0.10**	**0.0**	**0.1**	**0.9**	**0.0**	**1.0**
Total (Crude + Condensate) (MMT)	**30.5**	**29.7**	**2.5**	**2.7**	**2.5**	**22.4**	**23.6**	**22.1**
Total (Crude + Condensate) (Million Bbl/Day)	0.61	0.60	0.59	0.64	0.59	0.60	0.63	0.59

*Provisional targets inclusive of condensate.

4. Domestic and overseas oil & gas production (by Indian Companies)

Details	2020-21	2021-22 (P)	Dec		April-Dec	
			2021-22 (P)	2022-23 (P)	2021-22 (P)	2022-23 (P)
Total domestic production (MMTOE)	59.2	63.7	5.4	5.4	48.1	47.9
Overseas production (MMTOE)	21.9	21.8	1.9	1.5	16.5	14.2

Source: ONGC Videsh, GAIL, OIL , IOCL, HPCL & BPRL

5. High Sulphur (HS) & Low Sulphur (LS) crude oil processing (MMT)

Details		2020-21	2021-22	Dec		April-Dec	
				2021-22	2022-23 (P)	2021-22	2022-23 (P)
1	High Sulphur crude	161.4	185.0	17.1	17.0	134.8	145.7
2	Low Sulphur crude	60.3	56.7	4.4	5.3	42.4	42.9
Total crude processed (MMT)		**221.8**	**241.7**	**21.5**	**22.3**	**177.2**	**188.6**
Total crude processed (Million Bbl/Day)		4.45	4.85	5.08	5.27	4.72	5.03
Percentage share of HS crude in total crude oil processing		**72.8%**	**76.6%**	**79.5%**	**76.4%**	**76.1%**	**77.3%**

6. Quantity and value of crude oil imports

Year	Quantity (MMT)	$ Million	Rs. Crore
2020-21	196.5	62,248	4,59,779
2021-22 (P)	212.4	120,675	9,01,262
April-Dec 2022(P)	171.9	125,524	9,96,799

7. Self-sufficiency in petroleum products (Million Metric Tonnes)

Particulars		2020-21	2021-22 (P)	Dec		April-Dec	
				2021-22 (P)	2022-23 (P)	2021-22 (P)	2022-23 (P)
1	Indigenous crude oil processing	28.0	27.0	2.3	2.4	20.3	20.2
2	Products from indigenous crude (93.3% of crude oil processed)	26.1	25.2	2.2	2.2	19.0	18.8
3	Products from fractionators (Including LPG and Gas)	4.2	4.1	0.3	0.3	3.1	2.7
4	Total production from indigenous crude & condensate **(2 + 3)**	30.3	29.3	2.5	2.5	22.1	21.5
5	Total domestic consumption	194.3	204.2	19.0	19.6	149.2	164.9
% Self-sufficiency (4 / 5)		**15.6%**	**14.3%**	**13.1%**	**12.8%**	**14.8%**	**13.0%**

8. Refineries: Installed capacity and crude oil processing (MMTPA / MMT)											
Sl. no.	Refinery	Installed capacity (01.01.2022) MMTPA	Crude oil processing (MMT)								
			2020-21	2021-22	Dec			April-Dec		
					2021-22	2022-23 (Target)	2022-23 (P)	2021-22	2022-23 (Target)	2022-23 (P)
1	Barauni (1964)	6.0	5.5	5.6	0.6	0.6	0.5	3.9	4.8	5.1
2	Koyali (1965)	13.7	11.6	13.5	1.3	1.2	1.3	9.7	10.7	11.7
3	Haldia (1975)	8.0	6.8	7.3	0.3	0.7	0.7	5.6	6.3	6.4
4	Mathura (1982)	8.0	8.9	9.1	0.8	0.8	0.9	6.7	6.9	7.1
5	Panipat (1998)	15.0	13.2	14.8	1.3	1.4	0.9	11.2	10.6	10.0
6	Guwahati (1962)	1.0	0.8	0.7	0.08	0.1	0.1	0.46	0.8	0.8
7	Digboi (1901)	0.65	0.6	0.7	0.06	0.06	0.06	0.5	0.5	0.5
8	Bongaigaon(1979)	2.70	2.5	2.6	0.2	0.2	0.3	2.0	1.9	2.0
9	Paradip (2016)	15.0	12.5	13.2	1.3	1.3	1.417	9.3	9.8	9.6
	IOCL-TOTAL	**70.1**	**62.4**	**67.7**	**5.9**	**6.4**	**6.2**	**49.4**	**52.2**	**53.2**
10	Manali (1969)	10.5	8.2	9.0	0.8	0.9	1.0	6.1	7.6	8.4
11	CBR (1993)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CPCL-TOTAL	**10.5**	**8.2**	**9.0**	**0.8**	**0.9**	**1.0**	**6.1**	**7.6**	**8.4**
12	Mumbai (1955)	12.0	12.9	14.4	1.3	1.3	1.3	10.6	10.3	10.5
13	Kochi (1966)	15.5	13.3	15.4	1.4	1.4	1.5	11.0	11.4	11.5
14	Bina (2011)	7.8	6.2	7.4	0.7	0.7	0.7	5.4	5.6	5.8
	BPCL-TOTAL	**35.3**	**32.4**	**37.2**	**3.3**	**3.3**	**3.6**	**27.1**	**27.4**	**27.8**
15	Numaligarh (1999)	3.0	2.7	2.6	0.1	0.2	0.3	1.9	2.2	2.4

Sl. no.	Refinery	Installed capacity (1.01.2022) (MMTPA)	Crude oil processing (MMT)							
			2020-21	2021-22	Dec			April-Dec		
					2021-22	2022-23 (Target)	2022-23 (P)	2021-22	2022-23 (Target)	2022-23 (P)
16	Tatipaka (2001)	0.066	0.081	0.075	0.007	0.006	0.006	0.055	0.047	0.056
17	MRPL-Mangalore (1996)	15.0	11.5	14.9	1.4	1.5	1.5	10.5	11.7	12.7
	ONGC-TOTAL	**15.1**	**11.6**	**14.9**	**1.4**	**1.5**	**1.5**	**10.6**	**11.7**	**12.8**
18	Mumbai (1954)	9.5	7.4	5.6	0.7	0.6	0.9	3.2	6.3	7.3
19	Visakh (1957)	8.3	9.1	8.4	0.8	1.1	0.8	6.0	7.1	6.8
20	HMEL-Bathinda (2012)	11.3	10.1	13.0	1.1	1.0	1.1	9.8	8.6	9.5
	HPCL- TOTAL	**29.1**	**26.5**	**27.0**	**2.6**	**2.6**	**2.8**	**19.1**	**22.0**	**23.6**
21	RIL-Jamnagar (DTA) (1999)	33.0	34.1	34.8	3.0	3.0	2.8	25.9	25.9	26.2
22	RIL-Jamnagar (SEZ) (2008)	35.2	26.8	28.3	2.5	2.5	2.5	21.9	21.9	20.5
23	NEL-Vadinar (2006)	20.0	17.1	20.2	1.7	1.7	1.7	15.2	15.2	13.7
All India (MMT)		**251.2**	**221.8**	**241.7**	**21.5**	**22.2**	**22.3**	**177.2**	**186.1**	**188.6**
All India (Million Bbl/Day)		**5.02**	**4.45**	**4.85**	**5.08**	**5.25**	**5.27**	**4.72**	**4.96**	**5.03**

Note: Provisional Targets; Some sub-totals/ totals may not add up due to rounding off at individual levels.

9. Major crude oil and product pipeline network (as on 01.01.2023)

Details		ONGC	OIL	Cairn	HMEL	IOCL	BPCL	HPCL	Others*	Total
Crude Oil	Length (KM)	1,284	1,193	688	1,017	5,301	937			**10,420**
	Cap (MMTPA)	60.6	9.0	10.7	11.3	48.6	7.8			**147.9**
Products	Length (KM)		654			11,214	2,596	3,775	2,386	**20,625**
	Cap (MMTPA)		1.7			59.4	23.0	34.1	9.4	**127.6**

*Others include GAIL and Petronet India. HPCL and BPCL lubes pipeline included in products pipeline data

11. Production and consumption of petroleum products (Million Metric Tonnes)

Products	2020-21		2021-22 (P)		Dec 2021		Dec 2022 (P)		Apr-Dec 2021		Apr-Dec 2022 (P)	
	Prod	Cons	Prod	Cons	Prod	Cons	Prod	Cons	Prod	Cons	Prod	Cons
LPG	12.1	27.6	12.2	28.3	1.1	2.5	1.1	2.6	9.0	20.9	9.6	21.3
MS	35.8	28.0	40.2	30.8	3.7	2.8	3.7	3.0	29.4	22.9	31.4	26.3
NAPHTHA	19.4	14.1	20.0	14.3	1.7	1.1	1.4	1.1	14.9	10.6	12.7	9.5
ATF	7.1	3.7	10.3	5.0	1.1	0.6	1.3	0.7	7.3	3.6	10.9	5.4
SKO	2.4	1.8	1.9	1.5	0.2	0.1	0.0	0.0	1.4	1.1	0.7	0.4
HSD	100.4	72.7	107.2	76.7	9.4	7.3	10.0	7.8	78.4	56.1	83.9	63.9
LDO	0.7	0.9	0.8	1.0	0.06	0.09	0.04	0.07	0.6	0.8	0.4	0.5
LUBES	1.1	4.1	1.2	4.6	0.1	0.5	0.1	0.4	0.8	3.3	0.9	3.4
FO/LSHS	7.4	5.6	8.9	6.3	0.9	0.6	0.7	0.6	6.6	4.6	7.6	5.1
BITUMEN	4.9	7.5	5.1	7.9	0.5	0.8	0.4	0.7	3.4	5.2	3.4	5.5
PET COKE	12.0	15.6	15.5	15.8	1.5	1.7	1.4	1.3	11.2	10.6	11.3	11.5
OTHERS	30.2	12.8	30.9	12.1	2.6	1.0	3.4	1.4	23.0	9.4	23.3	12.1
ALL INDIA	**233.5**	**194.3**	**254.3**	**204.2**	**22.8**	**19.0**	**23.6**	**19.6**	**186.0**	**149.2**	**196.1**	**164.9**
Growth (%)	**-11.0%**	**-8.9%**	**8.9%**	**5.1%**	**5.9%**	**3.5%**	**3.7%**	**3.1%**	**9.4%**	**5.5%**	**5.4%**	**10.5%**

Note: Prod - Production; Cons - Consumption

15. LPG consumption (Thousand Metric Tonne)

LPG category	2020-21	2021-22	Dec			April-Dec		
			2021-22	2022-23 (P)	Growth (%)	2021-22	2022-23 (P)	Growth (%)
1. PSU Sales :								
LPG-Packed Domestic	25,128.1	25,501.6	2,235.3	2,253.9	0.8%	18,839.5	18,891.4	0.3%
LPG-Packed Non-Domestic	1,886.0	2,238.8	196.6	266.4	35.5%	1,624.1	1,922.2	18.4%
LPG-Bulk	361.9	390.9	26.4	40.3	52.7%	270.6	302.9	11.9%
Auto LPG	118.4	122.0	11.1	9.0	-18.5%	91.2	82.4	-9.7%
Sub-Total (PSU Sales)	27,494.3	28,253.3	**2,469.3**	**2,569.6**	**4.1%**	**20,825.4**	**21,198.9**	**1.8%**
2. Direct Private Imports*	64.2	82.0	9.99	6.4	-36.4%	65.0	57.2	-12.0%
Total (1+2)	27,558.4	28,335.3	**2,479.3**	**2,575.9**	**3.9%**	**20,890.4**	**21,256.1**	**1.8%**

*Apr -Dec 2022 DGCIS data is prorated

16. LPG marketing at a glance

Particulars (As on 1st of April)	Unit	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	1.01.23 (P)
LPG Active Domestic Customers	(Lakh)					1486	1663	1988	2243	2654	2787	2895	3053	3137
	Growth						11.9%	19.6%	12.8%	18.3%	5.0%	3.9%	5.5%	2.8%
LPG Coverage (Estimated)	(Percent)					56.2	61.9	72.8	80.9	94.3	97.5	99.8	-	-
	Growth						10.1%	17.6%	11.1%	16.5%	3.4%	2.3%	-	-
PMUY Beneficiaries	(Lakh)							200	356	719	802	800.4	899.0	958.7
	Growth								77.7%	101.9%	11.5%	-0.2%	12.2%	7.0%
LPG Distributors	(No.)	10541	11489	12610	13896	15930	17916	18786	20146	23737	24670	25083	25269	25341
	Growth	8.8%	9.0%	9.8%	10.2%	14.6%	12.5%	4.9%	7.2%	17.8%	3.9%	1.7%	0.7%	0.6%
Auto LPG Dispensing Stations	(No.)	604	652	667	678	681	676	675	672	661	657	651	601	567
	Growth	12.7%	7.9%	2.3%	1.6%	0.4%	-0.7%	-0.1%	-0.4%	-1.6%	-0.6%	-0.9%	-8.5%	-10.6%
Bottling Plants	(No.)	183	184	185	187	187	188	189	190	192	196	200	202	206
	Growth	0.5%	0.5%	0.5%	1.1%	0.0%	0.5%	0.5%	0.5%	1.1%	2.1%	2.0%	1.0%	3.5%

Source: PSU OMCs (IOCL,BPCL and HPCL)

1.Growth rates as on 01.01.2023 are with respect to figs as on 01.01.2022. Growth rates as on 1 April of any year are with respect to figs as on 1 April of previous year.

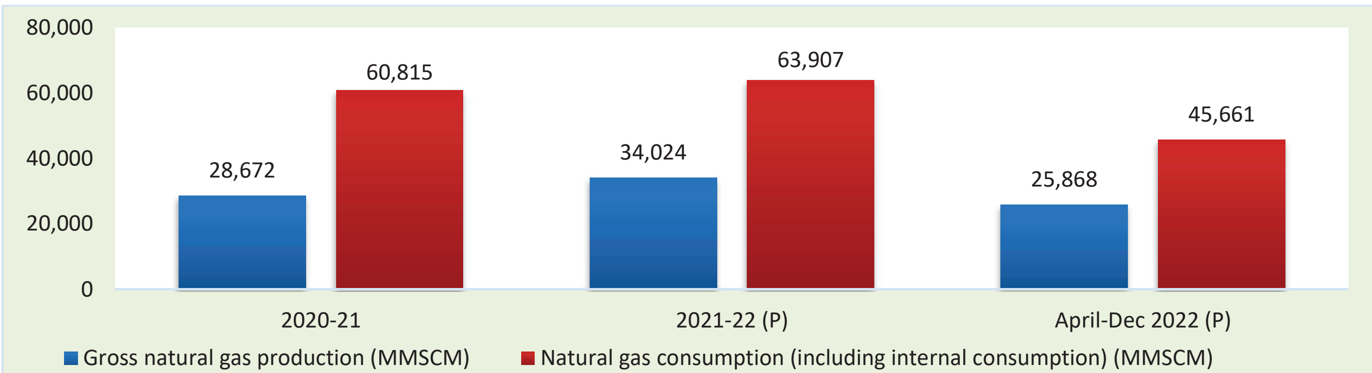
2. The LPG coverage is calculated by PSU OMCs based upon the active LPG domestic connections and the estimated number of households. The number of households has been projected by PSU OMCs based on 2011 census data. Factors like increasing nuclearization of families, migration of individuals/ families due to urbanization and reduction in average size of households etc. impact the growth of number of households. Due to these factors, the estimated no. of households through projection of 2011 census data may slightly differ from the actual no. of households in a State/UT. Further, this methodology does not include PNG (domestic) connections.

18. Natural gas at a glance

(MMSCM)

Details	2020-21 (P)	2021-22 (P)	Dec			April-Dec		
			2021-22 (P)	2022-23 (Target)	2022-23 (P)	2021-22 (P)	2022-23 (Target)	2022-23 (P)
(a) Gross production	28,672	34,024	2,897	3,032	2,951	25,674	26,724	25,868
- ONGC	21,872	20,629	1,757	1,693	1,680	15,542	15,305	15,057
- Oil India Limited (OIL)	2,480	2,893	240	315	257	2,190	2,799	2,295
- Private / Joint Ventures (JVs)	4,321	10,502	899	1,024	1,014	7,942	8,620	8,516
(b) Net production (excluding flare gas and loss)	27,784	33,131	2,814		2,888	25,036		25,267
(c) LNG import#	33,031	30,776	2,561		2,266	24,033		20,394
(d) Total consumption including internal consumption (b+c)	60,815	63,907	5,375		5,154	49,069		45,661
(e) Total consumption **(in BCM)**	60.8	63.9	5.4		5.2	49.1		45.7
(f) Import dependency based on consumption (%), {c/d*100}	54.3	48.2	47.6		44.0	49.0		44.7

Oct - Dec 2022 DGCIS data prorated.



19. Coal Bed Methane (CBM) gas development in India

Prognosticated CBM resources		91.8	TCF
Established CBM resources		10.4	TCF
CBM Resources (33 Blocks)		62.8	TCF
Total available coal bearing areas (India)		32760	Sq. KM
Total available coal bearing areas with MoPNG/DGH		17652	Sq. KM
Area awarded		20460	Sq. KM
Blocks awarded*		36	Nos.
Exploration initiated (Area considered if any boreholes were drilled in the awarded block)		10670***	Sq. KM
Production of CBM gas	April-Dec 2022 (P)	511.50	MMSCM
Production of CBM gas	Dec 2022 (P)	56.18	MMSCM

*ST CBM Block awarded & relinquished twice- in CBM Round II and Round IV -Area considered if any boreholes were drilled in the awarded block. **MoPNG awarded 04 new CBM Blocks (Area 3862 sq. km) under Special CBM Bid Round 2021 in September 2022. ***Area considered if any boreholes were drilled in the awarded block.

19a. Status of Compressed Bio Gas (CBG) projects under SATAT (as on 01.01.2023) (Provisional)

Particulars	Units	IOCL	HPCL	BPCL	GAIL	IGL	Total
LOIs issued	No. of plants	2756	474	318	275	50	**3823**
Expected CBG production against LOI issued	Tons per day	19414	2575	1412	1567	247	**24968**
No. of CBG plants commissioned/ Sale initiated	No. of plants	18	4	1	8	2	**31**
Start of CBG sale from retail outlet(s)	Nos.	39*	20**	37***	1	1	**98**
Injection/Supply of CBG in CGD network	GA Nos.	-	-	-	11	1	**12**
Total Sale of CBG (since Sep'2019)	Tons	9472*	1349**	1617***	2923****	468	**468**

*All 39 IOCL ROs. Sales include sale through RO & Industrial consumers. *2 HPCL ROs sourcing CBG from HPCL LOI holder plants, 18 HPCL ROs sourcing CBG from other than HPCL LOI holder plants. ** BPCL CBG sales from 37 ROS. Out of 37 ROS, for 1 RO sourcing CBG from own LOI holder & other ROs CBG is being sourced from other OMC's LOI holder(s). ****Sale of CBG by GAIL includes sales through its own channels as well as through other CGDs for CBG sourced under synchronization scheme from other Oil & Gas Company's LOI holders.

20. Common Carrier Natural Gas pipeline network as on 30.09.2022

Nature of pipeline		GAIL	GSPL	PIL	IOCL	AGCL	RGPL	GGL	DFPCL	ONGC	GIGL	GITL	Others*	Total
Operational	Length	9,577	2,695	1,459	143	107	304	73	42	24				**14,424**
	Capacity	167.2	43.0	85.0	20.0	2.4	3.5	5.1	0.7	6.0				**-**
Partially commissioned#	Length	4,777			282						1,254	365		**6,678**
	Capacity				-						-	-		**-**
Total operational length		**14,354**	**2,695**	**1,459**	**425**	**107**	**304**	**73**	**42**	**24**	**1,254**	**365**	**0**	**21,102**
Under construction	Length	5,097	100		1,149						1,078	1,666	2,915	**12,005**
	Capacity	-	3.0		-						-	-	-	**-**
Total length		**19,451**	**2,795**	**1,459**	**1,574**	**107**	**304**	**73**	**42**	**24**	**2,332**	**2,031**	**2,915**	**33,107**

Source: PNGRB; Length in KMs ; Authorized Capacity in MMSCMD; *Others-APGDC, HEPL, IGGL, IMC, Consortium of H-Energy. Total authorized Natural Gas pipelines including Tie-in connectivity, dedicated & STPL is 35335 Kms (P)

21. Existing LNG terminals

Location	Promoters	Capacity as on 01.01.2023	% Capacity utilisation (April-Nov 2022)
Dahej	Petronet LNG Ltd (PLL)	17.5 MMTPA	79.3
Hazira	Shell Energy India Pvt. Ltd.	5.2 MMTPA	43.9
Dabhol	Konkan LNG Limited	*5 MMTPA	27.2
Kochi	Petronet LNG Ltd (PLL)	5 MMTPA	17.5
Ennore	Indian Oil LNG Pvt Ltd	5 MMTPA	13.0
Mundra	GSPC LNG Limited	5 MMTPA	17.7
Total Capacity		**42.7 MMTPA**	

* To increase to 5 MMTPA with breakwater. Only HP stream of capacity of 2.9 MMTPA is commissioned

22. Status of PNG connections and CNG stations across India (Nos.), as on 31.10.2022(P)

State/UT (State/UTs are clubbed based on the GAs authorised by PNGRB)	CNG Stations	PNG connections		
		Domestic	Commercial	Industrial
Andhra Pradesh	151	241,884	411	32
Andhra Pradesh, Karnataka & Tamil Nadu	29	170	0	2
Assam	1	47,193	1,319	439
Bihar	70	85,153	56	2
Bihar & Jharkhand	1	5,560	0	0
Chandigarh (UT), Haryana, Punjab & Himachal Pradesh	24	24,471	109	19
Dadra & Nagar Haveli (UT)	7	9,992	54	54
Daman & Diu (UT)	4	5,134	46	42
Daman and Diu & Gujarat	14	1,580	3	0
Goa	11	10,367	15	27
Gujarat	969	2,858,013	21,899	5,742
Haryana	291	285,652	765	1,399
Haryana & Himachal Pradesh	9	0	0	0
Haryana & Punjab	17	0	0	0
Himachal Pradesh	7	3,677	0	0
Jharkhand	64	94,675	2	0
Karnataka	236	362,470	485	272
Kerala	94	28,948	19	14
Kerala & Puducherry	9	118	0	0
Madhya Pradesh	194	183,656	309	398
Madhya Pradesh and Chhattisgrah	3	0	0	0
Madhya Pradesh and Rajasthan	24	152	0	0
Madhya Pradesh and Uttar Pradesh	16	0	0	0
Maharashtra	620	2,582,816	4,548	808
Maharashtra & Gujarat	52	131,181	3	13
National Capital Territory of Delhi (UT)	466	1,329,722	3,353	1,774
Odisha	44	75,905	5	0
Puducherry & Tamil Nadu	8	107	0	0
Punjab	177	55,928	252	220
Rajasthan	195	173,377	61	219
Tamil Nadu	152	18	0	6
Telangana	134	180,820	71	90
Telangana and Karnataka	1	0	0	0
Tripura	18	57,598	506	62
Uttar Pradesh	681	1,278,299	2,089	2,451
Uttar Pradesh & Rajasthan	38	18,958	36	340
Uttar Pradesh and Uttrakhand	16	6,263	0	0
Uttrakhand	29	63,922	51	78
West Bengal	42	0	0	0
Total	**4,918**	**10,203,779**	**36,467**	**14,503**

Source: PNGRB

Note: 1. All the GAs where PNG connections/CNG Stations have been established are considered as Operational, 2. Under normal conditions. Operation of any particular GA commences within around one year of authorization. 3. State/UTs wherever clubbed are based on the GAs authorised by PNGRB.

23. Domestic natural gas price and gas price ceiling (GCV basis)

Period	Domestic Natural Gas price in US$/MMBTU	Gas price ceiling in US$/MMBTU
November 2014 - March 2015	5.05	-
April 2015 - September 2015	4.66	-
October 2015 - March 2016	3.82	-
April 2016 - September 2016	3.06	6.61
October 2016 - March 2017	2.50	5.30
April 2017 - September 2017	2.48	5.56
October 2017 - March 2018	2.89	6.30
April 2018 - September 2018	3.06	6.78
October 2018 - March 2019	3.36	7.67
April 2019 - September 2019	3.69	9.32
October 2019 - March 2020	3.23	8.43
April 2020 - September 2020	2.39	5.61
October 2020 - March 2021	1.79	4.06
April 2021 - September 2021	1.79	3.62
October 2021 - March 2022	2.90	6.13
April 2022 - September 2022	6.10	9.92
October 2022 - March 2023	8.57	12.46

24. CNG/PNG prices

City	CNG (Rs/Kg)	PNG (Rs/SCM)	Source
Delhi	79.56	53.59	IGL website (13.01.2023)
Mumbai	89.50	54.00	MGL website (13.01.2023)

Indian Natural Gas Spot Price for Physical Delivery

IGX Price Index Month	Avg. Price		Volume (MMSCM)	Source
	INR/MMBtu	$/MMBtu		
Dec 2022	1294	15.69	87.80	As per IGX website: www.igxindia.com

*Prices are weighted average prices | $1=INR 82.46| 1 MMBtu=25.2 SCM

For Immediate Release
January 17, 2023
Lynn Helms, Ph.D., Director ND Department of Mineral Resources

NORTH Dakota | Mineral Resources
Be Legendary.™

North Dakota Department of Mineral Resources January Director's Cut November 2022 Production Numbers

Oil Production Numbers

October	34,774,367 barrels	= 1,121,754 barrels/day (final)
New Mexico	48,616,372 barrels	= 1,568,270 barrels/day **-3.4%**
November	32,931,469 barrels	= 1,097,716 barrels/day **-2.1%** **RF +9.8%**
	1,519,037	all-time high Nov 2019
	1,058,025 barrels/day	= 96% from Bakken and Three Forks
	39,691 barrels/day	= 4% from Legacy Pools
Revised Revenue Forecast	**1,000,000 barrels/day**	

Crude Price ($barrel)

Crude Price ($barrel)	ND Light Sweet	WTI	ND Market	
September	83.93	87.03	83.65	**RF+67%**
October	82.18	84.39	82.07	**RF+64%**
Today	74.50	79.86	77.18	**Est. RF+54%**
All-time high (6/2008)	125.62	134.02	126.75	
Revised Revenue Forecast			**50.00**	

Gas Production and Capture

October	97,531,984 MCF	=	3,146,193 MCF/Day	
94% Capture	92,895,776 MCF	=	2,996,638 MCF/Day	
November	90,870,989 MCF	=	3,029,033 MCF/Day	**-4%**
95% Capture	92,807,966 MCF	=	2,842,285 MCF/Day	
			3,175,779 all-time high 9/2022	
			3,021,655,384 all-time high capture 9/2022	

Wells Permitted

Wells Permitted	Drilling	Seismic
September	65	0
October	77	1
November	86	0
		All time high 370 in 10/2012

Rig Count

October	43	
November	40	
December	44	
Today	43	All time high 218 in 5/29/2012
Federal Surface	2	
New Mexico	100	

Waiting on Completions

October	489
November	447

Inactive

October	1,886
November	2,271

Completed

October	54 (Preliminary)	
November	58 (Preliminary)	
December	104 (Preliminary)	**RF+100%**
Revised Rev Forecast	30-40-<u>50</u>-60	

Producing

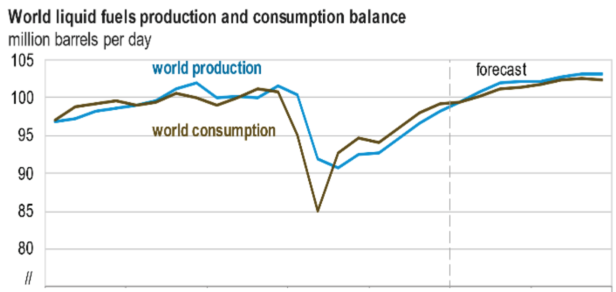
October	17,791	
November	17,563 (Preliminary)	NEW all-time high 17,791 10/2022
	15,411 wells	88% are now unconventional Bakken/Three Forks Wells
	2,152 wells	12% produce from legacy conventional pools

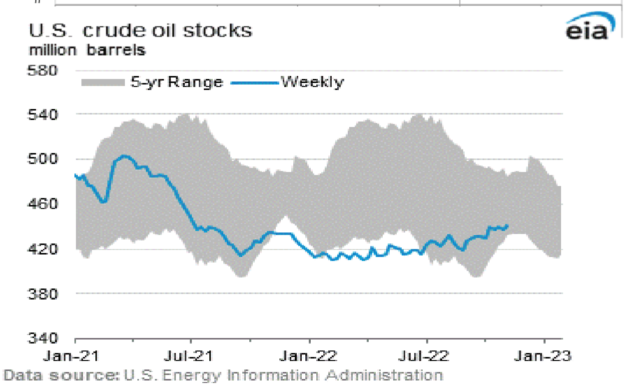
Fort Berthold Reservation Activity

	Total	Fee Land	Trust Land
Oil Production (barrels/day)	169,455	70,735	116,418
Drilling Rigs	5	3	2
Active Wells	2,638	646	1,992
Waiting on Completion	16		
Approved Drilling Permits	235 ↑	33	202
Potential Future Wells	3,914	1,118	2,796

Comments:

The drilling rig count has stalled in the low to mid-forties with a gradual increase expected over the next 2 years.





The number of active completion crews increased to 20 before the blizzard, no completion activity the last week of December, there are now 19 active crews.

OPEC+ is managing production month to month. Russia sanctions, China COVID lockdowns, and looming recessions have created significant price volatility in an already volatile market.

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 until the USACOE EIS is completed.

Potential railroad worker strike – reported that a tentative deal has been reached.

Drilling activity is expected to slowly increase with operators maintaining a permit inventory of approximately 12 months.

A survey of operators by JPT revealed the following:

“The surge in the cost of services and supplies pushed the average oil price needed to justify drilling a new oil well in the Mid-Continent to $65/bbl, according to a survey of industry experts by the Federal Reserve Bank of Kansas City released on 8 July.

When they were asked what it would take to get them to substantially increase drilling, they put the number at $98/bbl, which was higher than the closing price for the WTI price in futures trading on 14 July.”

There is 0 survey active, 1 recording, 0 NDIC reclamation projects, 0 remediating, 0 permitted, 6 suspended.

US natural gas storage is less than 1.4% below the five-year average. Both US and world crude oil inventories are approaching normal. US strategic petroleum reserve is at the lowest level since 1984.

The price of natural gas delivered to Northern Border at Watford City has risen sharply to $6.76/MCF today due to much colder winter weather and LNG exports to Europe. Current oil to gas price ratio is 11 to 1. The state-wide gas flared volume from September to October decreased 7.8 MMCFD to 149,814 MCF per day, the statewide percent flared remained at 5% while Bakken gas capture percentage remained 96%. The historical high flared percent was 36% in 09/2011.

Gas capture details are as follows:

Statewide	94%
Statewide Bakken	94%
Non-FBIR Bakken	95%
FBIR Bakken	94%
Trust FBIR Bakken	95%
Fee FBIR	85%
Big Bend	78%
Deep Water Creek Bay	76%
Twin Buttes	59%
Charlson	84%

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

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.

https://bismarcktribune.com/news/state-and-regional/august-oil-production-flat-in-north-dakota-natural-gas-production-drops-slightly/article_e9518c14-4b35-11ed-8d00-2fbcea270ea1.html

August oil production flat in North Dakota

- By Jackie Jahfetson The Bismarck Tribune
- Oct 14, 2022 Updated 2 hrs ago

North Dakota oil production in August remained flat, while natural gas production dropped by 1%, the state Department of Mineral Resources reported Thursday.

August oil production was 1.073 million barrels per day. That was up 746 barrels daily from July — "almost dead flat," state Mineral Resources Director Lynn Helms said. The state's oil figures lag two months as officials collect and analyze data from energy companies.

"It's a preliminary number, and it may go up or down a little bit. But it isn't even a 1% change," Helms said, adding that the good news is that oil tax revenue is exceeding the state's forecast by a little more than 7%.

August's average oil price for North Dakota crude was $90.34 per barrel, Helms said, explaining that exceeded the revenue forecast price by 81%.

"All the buckets are full. And so if you know how North Dakota plans to use oil and gas revenue, we learned from the boom and bust of the 1980s not to count on oil and gas revenue for ongoing bill payments, but to put the money in buckets (funds) and then spend it out of those buckets usually late in the biennium or the following biennium," he said, referring to the state's two-year budget cycle.

August natural gas production in North Dakota totaled 3.09 billion cubic feet per day, down from 3.1 billion cubic feet per day the previous month. The drop in production from July may be due to some plant outages, Helms said.

There was a “steady stream” of oil and gas drilling permit applications in August, he said. The drilling rig count continues to stall out in the mid-forties and is expected to do so for the rest of the year.

There is a steady stream of newly completed wells, with a projection that September’s numbers will continue to increase.

“So we would seriously anticipate we’re going to see an increase in production for the September report,” he said. “... We’re at a record number of producing wells (in August) but not a record production.”

Producers maintained 94% gas capture in August, the same as July, and exceeded the state’s 91% target. The rest was burned off at well sites in a wasteful process known as flaring, due to a lack of access to pipelines and processing plants.

MONTHLY UPDATE

JANUARY 2023 PRODUCTION & TRANSPORTATION

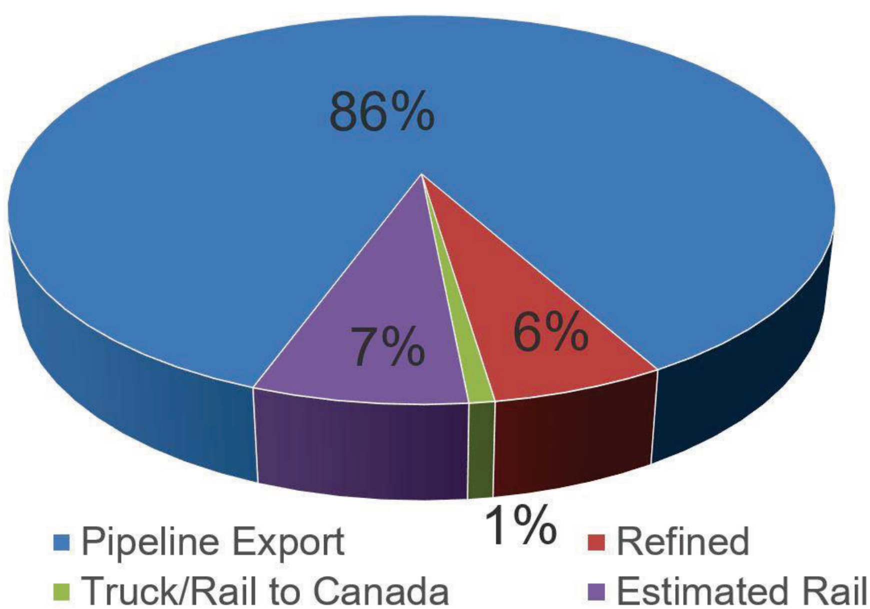
North Dakota Oil Production

Month	Monthly Total, BBL	Average, BOPD
Oct. 2022 - Final	34,774,367	1,121,754
Nov. 2022 - Prelim.	32,931,469	1,097,716

North Dakota Natural Gas Production

Month	Monthly Total, MCF	Average, MCFD
Oct. 2022 - Final	97,531,984	3,146,193
Nov. 2022 - Prelim.	90,870,989	3,029,033

Estimated Williston Basin Oil Transportation, Nov. 2022



CURRENT DRILLING ACTIVITY:

NORTH DAKOTA[1]

43 Rigs

EASTERN MONTANA[2]

3 Rigs

SOUTH DAKOTA[2]

0 Rigs

SOURCE (JAN 17, 2023):

1. ND Oil & Gas Division
2. Baker Hughes

PRICES:

Crude (WTI): $80.27

Crude (Brent): $85.87

NYMEX Gas: $3.65

SOURCE: BLOOMBERG (JAN 17 2023 11AM CST)

GAS STATS*

94% CAPTURED & SOLD

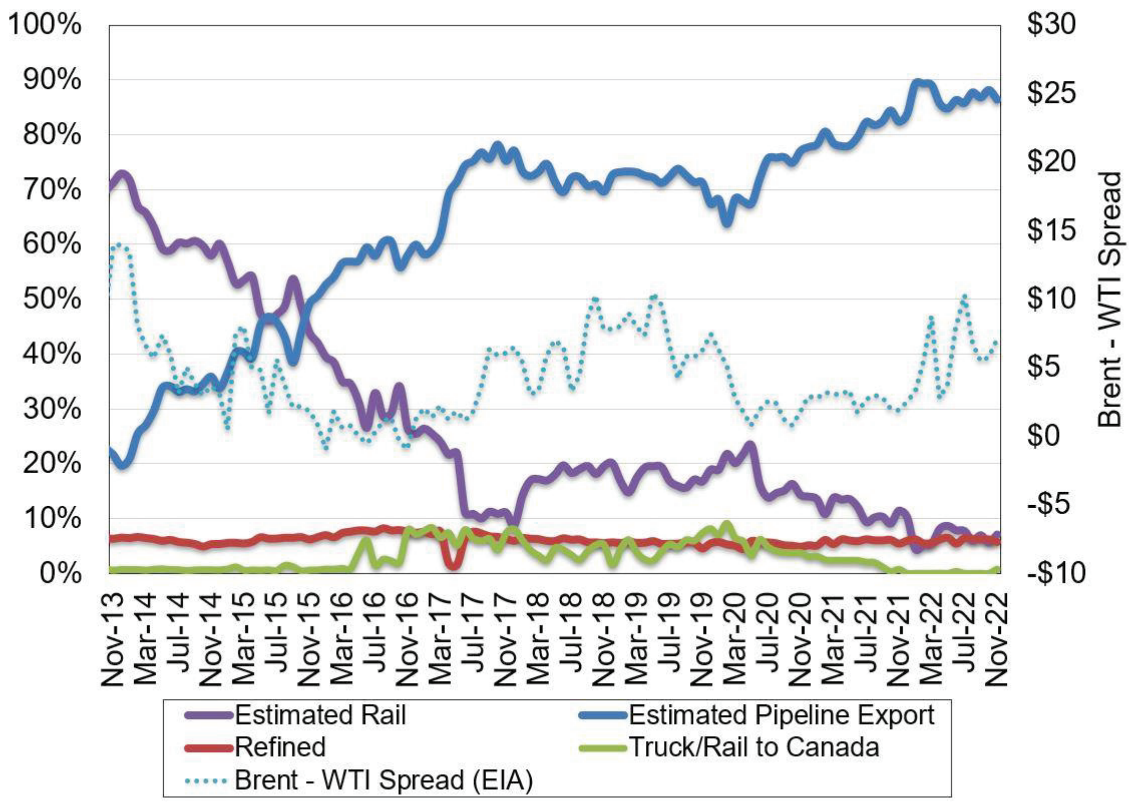
5% FLARED DUE TO CHALLENGES OR CONSTRAINTS ON EXISTING GATHERING SYSTEMS

1% FLARED FROM WELL WITH ZERO SALES

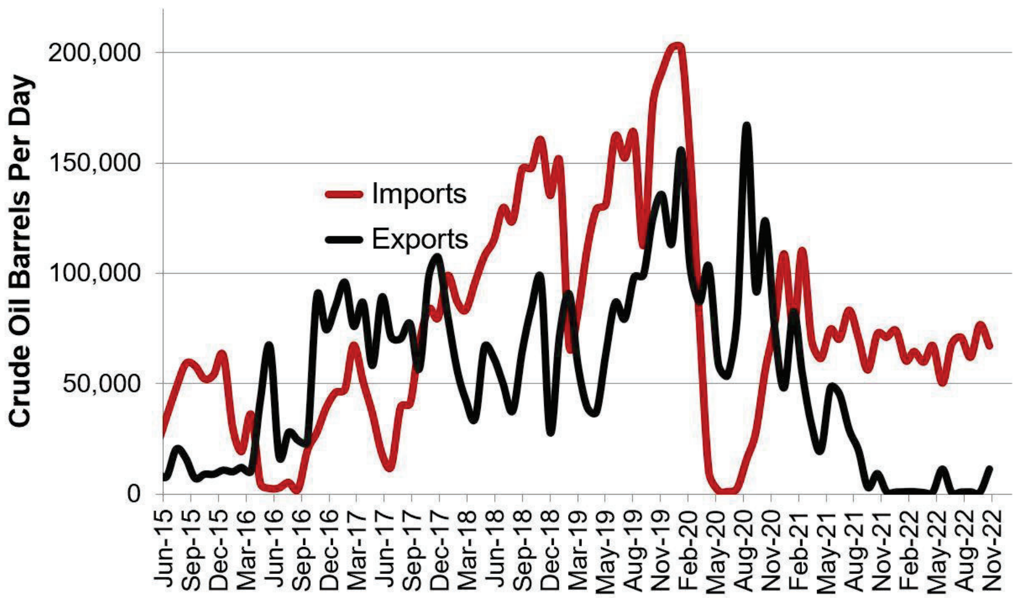
NOV. 2022 NON-CONF DATA

Estimated North Dakota Rail Export Volumes

Estimated Williston Basin Oil Transportation

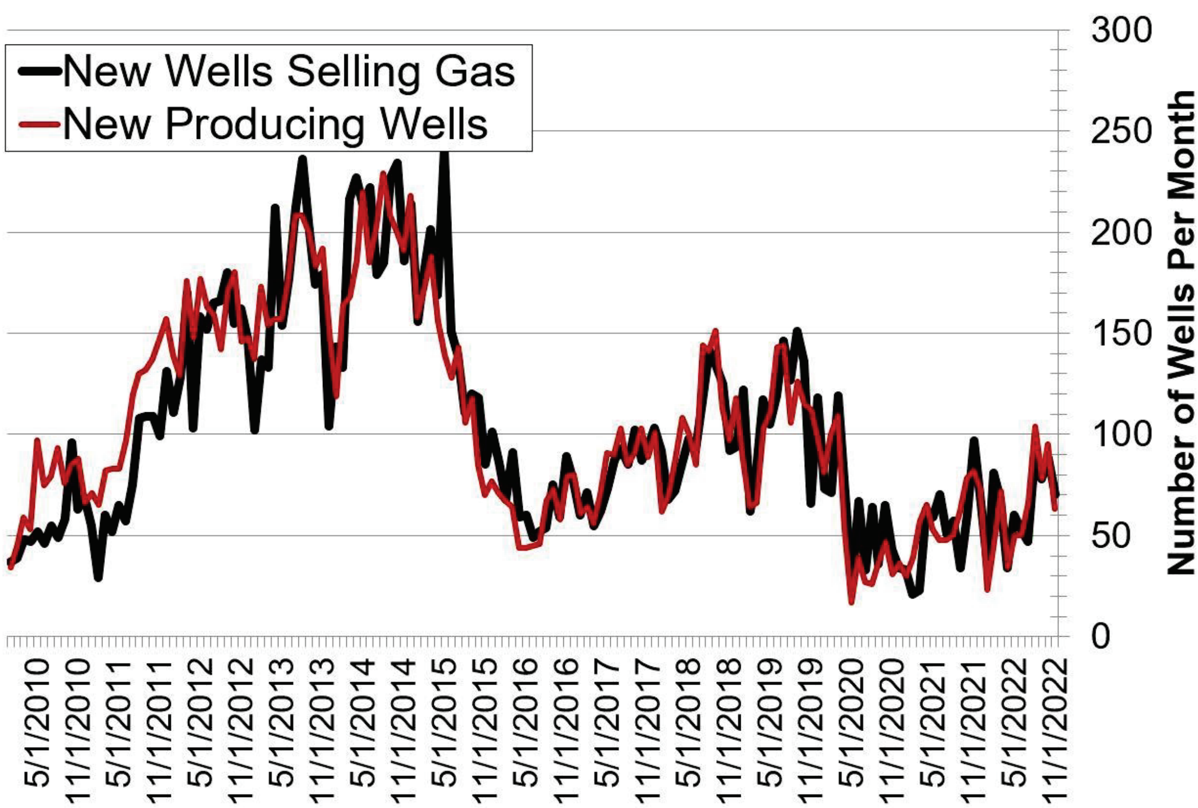


Williston Basin Truck/Rail Imports and Exports with Canada



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

2021

MONTH	ND	EASTERN MT*	SD	TOTAL
January	1,147,724	50,433	2,874	1,201,031
February	1,083,820	48,246	2,828	1,134,894
March	1,109,005	49,523	2,744	1,161,273
April	1,121,776	48,440	2,644	1,172,860
May	1,129,785	47,273	2,640	1,179,698
June	1,134,758	44,101	3,103	1,181,962
July	1,078,883	43,758	2,884	1,125,525
August	1,108,084	47,285	2,892	1,158,261
September	1,113,963	50,412	2,847	1,167,222
October	1,110,828	48,953	2,853	1,162,634
November	1,158,553	48,585	2,780	1,209,918
December	1,144,999	47,957	2,717	1,195,673

2022

MONTH	ND	EASTERN MT*	SD	TOTAL
January	1,091,932	47,598	2,709	1,142,239
February	1,095,458	46,947	2,742	1,145,147
March	1,129,880	50,498	2,709	1,183,087
April	908,339	49,825	2,338	960,502
May	1,062,157	49,159	2,648	1,113,964
June	1,099,408	58,901	2,764	1,161,073
July	1,073,610	54,729	2,774	1,131,113
August	1,075,289	55,823	2,756	1,133,868
September	1,121,063		2,679	
October	1,121,754		2,621	
November	1,097,716			
December				

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

Oil Market Highlights

Crude Oil Price Movements

The OPEC Reference Basket (ORB) averaged $79.68/b in December, a drop of $10.05 m-o-m, or 11.2%. The ICE Brent front-month fell $9.51, or 10.5%, to average $81.34/b, and NYMEX WTI dropped by $7.87, or 9.3%, to average $76.52/b. The Brent/WTI futures spread narrowed further m-o-m, contracting by $1.64 to average $4.82/b. The market structure of ICE Brent and NYMEX WTI weakened again as the first-to-third month spreads moved into contango in December. The combined futures and options net long positions of hedge funds and other money managers rose slightly in December compared to late-November's low levels for both ICE Brent and NYMEX WTI.

World Economy

The world economic growth forecast for 2022 is revised up slightly to 3%, given better-than-anticipated 2H22 economic performance in various key economies. The 2023 global economic growth forecast remained unchanged at 2.5%. For the US, the economic growth forecast is revised up to 2% for 2022 and 1% for 2023. Similarly, the Euro-zone economic growth forecast is revised up to 3.2% for 2022 and 0.4% for 2023. Japan's economic growth forecast is revised down to 1.2% for 2022, but remained at 1% for 2023. China's economic growth forecasts remained unchanged at 3.1% for 2022 and 4.8% for 2023. India's economic growth forecast is revised up to 6.8% for 2022 but remained at 5.6% for 2023. Brazil's economic growth forecast is revised up to 2.8% for 2022, but remained unchanged at 1% for 2023. The 2022 economic growth forecast for Russia is revised up to a contraction of 4%, followed by a small contraction of 0.5% in 2023. Although growth momentum is expected to carry over into 2023, the world economy will continue navigating through many challenges, amid high inflation, monetary tightening by major central banks, and high sovereign debt levels in many regions. Moreover, geopolitical and COVID-19 related risks and uncertainties may add to the downside risk in a few selected economies.

World Oil Demand

The world oil demand forecast for 2022 is unchanged at 2.5 mb/d. Oil demand is adjusted downward in the 3Q22, amid data showing a demand decline in the OECD and China, but non-OECD countries outside of China are revised higher. Similarly, world oil demand growth for 2023 is also unchanged at 2.2 mb/d, with the OECD growing by 0.3 mb/d and non-OECD at 1.9 mb/d. This forecast remains surrounded by uncertainties including global economic developments, shifts in COVID-19 containment policies, and geopolitical tensions.

World Oil Supply

Non-OPEC liquids supply is estimated to expand by 1.9 mb/d in 2022, unchanged from last month's assessment. Upward adjustments to liquids production in Russia and OECD Americas were largely offset by downward revisions to OECD Europe and OECD Asia Pacific. The main drivers of liquids supply growth for 2022 are the US, Russia, Canada, Guyana, China and Brazil, while production is expected to see the largest declines in Norway and Thailand. For 2023, non-OPEC liquids production growth remains unchanged from last month's assessment at 1.5 mb/d. The main drivers of liquids supply growth are expected to be the US, Norway, Brazil, Canada, Kazakhstan and Guyana, while declines are forecast in Russia and Mexico. Nonetheless, large uncertainties remain over the impact of geopolitical developments, as well as expectations for US shale output in 2023. OPEC NGLs and non-conventional liquids are set to grow by 0.1 mb/d in 2022 to average 5.4 mb/d and by 50 tb/d in 2023 to average 5.4 mb/d. OPEC-13 crude oil production in December increased by 91 tb/d m-o-m to average 28.97 mb/d, according to available secondary sources.

Product Markets and Refining Operations

Refinery margins weakened in all main trading hubs in December, as product availability continued to rise. The largest losses were in the Atlantic Basin, particularly from transport fuels, reflecting the easing tightness, especially in the middle section of the barrel. Similarly, in Asia, margins were pressured by elevated refinery runs and fuel supplies. This weighed on regional gasoil and jet/kero markets, despite the relaxation of China's zero COVID-19 policy and positive regional gasoline and residual fuel performance. Global refinery processing rates continued to rise in December, gaining nearly 700 tb/d as refineries ramped up in line with seasonal trends. In the coming month, refinery intakes are expected to remain strong, as returning US capacity from the recent winter storm will likely offset the slight rise in offline capacity elsewhere.

Tanker Market

Dirty freight rates in December fell from elevated levels as activities slowed ahead of seasonal holidays, with losses on almost all monitored routes. VLCCs on average showed the biggest decline, with spot freight rates on the Middle East-to-East route falling 31% m-o-m. In the Suezmax class, dirty spot freight rates dropped 22% on the US Gulf Coast to Europe route. Aframax rates saw the smallest decline, slipping around 3% on the inter-Mediterranean route. In contrast, clean rates remained robust, up 50% on the Middle East-to-East route and around 27% higher in the Mediterranean. Continued tonnage demand amid ongoing trade dislocations kept clean tanker availability relatively tight.

Crude and Refined Products Trade

US crude imports followed seasonal trends, falling to an eight-month low of 6.2 mb/d in December. US crude exports remained above 4 mb/d for the third-consecutive month. US product flows were broadly steady, despite a cold wave that shut-in US refineries and disrupted travel. Preliminary figures show crude imports into OECD Europe remaining at healthy levels through the end of the year, despite imports of Russian crude falling to near zero excluding flows to Turkey. OECD Europe product imports are also seen to be higher in anticipation of the impending February sanctions on Russian oil product imports. Japan's crude imports fell to a five-month low in November, averaging 2.6 mb/d and marking the first y-o-y decline in 15-months. China's crude imports continued to recover in November, averaging 11.4 mb/d, and preliminary data shows December flows remaining at similarly high levels. China's product exports jumped to the highest since June 2020, with diesel and gasoline outflows rising sharply. India's crude imports continued to recover from the 11-month low reached in September, averaging of 4.6 mb/d in November. India's product imports rose to a seven-month high, driven by LPG flows which were the highest on record. Product exports picked up from a two-year low in the previous month, with gasoline leading gains.

Commercial Stock Movements

Preliminary November data sees total OECD commercial oil stocks up 2.7 mb from the previous month. At 2,768 mb, inventories were 26 mb higher than the same month a year ago, 137 mb lower than the latest five-year average and 173 mb below the 2015–2019 average. Within the components, crude stocks fell by 25.8 mb, while product stocks rose m-o-m by 28.5 mb. At 1,343 mb, OECD crude stocks were 22 mb higher than the same time a year ago, but 73 mb lower than the latest five-year average and 108 mb lower than the 2015–2019 average. OECD product stocks stood at 1,425 mb, representing a surplus of 4 mb from the same time a year ago, but 63 mb lower than the latest five-year average and 65 mb below the 2015–2019 average. In terms of days of forward cover, OECD commercial stocks rose m-o-m by 0.1 day in November to stand at 59.5 days. This is 0.3 days above levels seen in the same month last year, but 3.5 days less than the latest five-year average and 2.6 days lower than the 2015–2019 average.

Balance of Supply and Demand

Demand for OPEC crude in 2022 remains broadly unchanged from the previous month's assessment to stand at 28.5 mb/d. This is around 0.5 mb/d higher than in 2021. Demand for OPEC crude in 2023 remained also unchanged from the previous assessment to stand at 29.2 mb/d, which is 0.6 mb/d higher than in 2022.

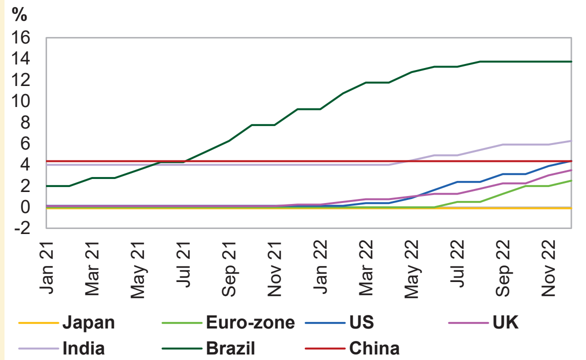
Feature Article

Monetary policies and their impact on the oil market

In early 2022, major central banks stepped up their monetary tightening measures in an effort to reign in increasing levels of inflation and recalibrate their overheating economies amid continued strong global economic growth. These tightening measures, in combination with the COVID-19 situation in China and the geopolitical developments in Eastern Europe, contributed to oil market volatility over the course of the year.

By the end of 1Q22, inflationary pressures forced many major central banks to become even more hawkish, most notably the US Fed, which had a considerable impact on oil markets as well. However, the trend in, and pace of, policies were not uniform in all countries.

Graph 1: Official/policy interest rate, 2021-2022



Sources: BoJ, ECB, FRB, BoE, RBI, BCB, CSIC and Haver Analytics.

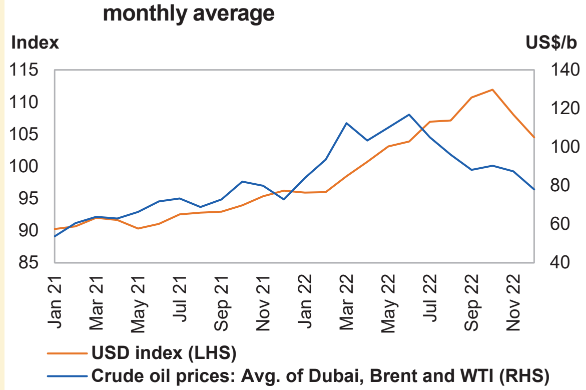
The Bank of England raised rates by late 4Q21 and the US Federal Reserve (Fed) followed suit with an initial announcement to increase their policy rate beginning in 1Q22 and continued with more hikes until the year's end. Meanwhile, the European Central Bank (ECB) and the Bank of Japan maintained their accommodative rates for a longer period of time, in an effort to support markets and keep capitalization rates low.

These divergent monetary policies had three major results, namely, they: (1) strengthened the US dollar, (2) raised the average cost of capital and (3) inverted the yield curve for short-to-long- term US bonds.

With regard to the first point, as most commodities are priced in US dollars, the appreciation of the US dollar, relative to other currencies, led to an increase in commodity prices, including oil. Additionally, the safe-haven appeal of the US dollar rose relative to other currencies amid the strong and rapid rise in US interest rates.

Additionally, the strengthening of the US dollar, along with the rapid monetary tightening by the US Fed, put upward pressure on non-US government bonds and increased bond market sell-offs outside the US, leading to some fragility in the global economy. Furthermore, the rise in US interest rates increased the cost of capital, hindering capital investment, notably in the oil industry. Moreover, high-interest rates weighed on investors' risk appetite and contributed to a decline in liquidity, which also affected the oil futures markets.

Graph 2: US dollar index and crude oil prices, monthly average



Sources: Thomson Reuters and World Bank.

With regard to the third point, the rapid monetary tightening created an inverted yield curve in the US, with the consequence that short-term interest rates are higher than long-term interest rates. This is generally regarded as a warning sign that the US economy is likely to head into a recession in the coming months.

Emerging market economies also saw monetary policy divergences. China maintained its accommodative policy rates to sustain its economy. However, its economy continued to be challenged by the zero COVID-19 policy and the ongoing issues in the property and construction markets, which contributed to a y-o-y decline in oil demand for the country in 2022. Brazil raised interest rates early on, at a time when its economy received support from rising commodity prices. India resisted raising rates earlier in the year, providing a base for relatively strong economic growth in 2022, but then decided to lift rates by 2Q22. While oil demand in the country remained strong, inflation had a limited impact, as India benefited from discounted Russian crude oil imports.

By the end of 3Q22, monetary tightening policies were largely aligned across major central banks, with the exception of China and Japan. However, by year-end, Japan's central bank also became more hawkish in tightening its yield curve control measures. The extent to which monetary tightening will slow economic growth, particularly in advanced economies, and subsequently drag on oil demand in 2023 remains to be seen. In light of the ongoing challenges, OPEC and non-OPEC countries participating in the Declaration of Cooperation will continue to coordinate their efforts to sustain a balanced and stable oil market in order to support healthy global economic growth.

World Oil Demand

The forecast for 2022 world oil demand growth remains unchanged from last month at 2.5 mb/d. Oil demand was adjusted downward mostly in 3Q22, amid data showing a drop in China's oil demand, due to reduced mobility and manufacturing activity as a result of the zero COVID-19 policy restrictions as well as some slight slowdown in OECD countries towards the end of the year. In contrast, non-OECD countries outside of China were revised higher, due to improvements in economic activity in some countries. Total world oil demand is expected to average 99.6 mb/d in 2022.

For 2023, the forecast for world oil demand growth is also the same as in the previous month's assessment at 2.2 mb/d, with the OECD increasing by 0.3 mb/d and non-OECD growth at 1.9 mb/d. Minor upward adjustments were made due to the expected better performance in China's economy on the back of its reopening from COVID-19 restrictions, while other regions are expected to see slight declines, due to economic challenges that are likely to weigh on oil demand. Accordingly, in 1Q23, oil demand is expected to rise by 1.7 mb/d y-o-y. Total world oil demand is anticipated to reach 101.8 mb/d in 2023. However, this forecast is subject to many uncertainties, including global economic developments, shifts in COVID-19 policies, and ongoing geopolitical tensions.

Table 4 - 1: World oil demand in 2022*, mb/d

							Change 2022/21	
World oil demand	**2021**	**1Q22**	**2Q22**	**3Q22**	**4Q22**	**2022**	**Growth**	**%**
Americas	24.32	24.77	24.98	25.34	25.19	25.07	0.76	3.12
of which US	*20.03*	*20.38*	*20.41*	*20.62*	*20.64*	*20.51*	*0.48*	*2.38*
Europe	13.13	13.19	13.42	14.07	13.90	13.65	0.52	3.96
Asia Pacific	7.38	7.85	6.99	7.22	7.81	7.47	0.08	1.15
Total OECD	**44.83**	**45.81**	**45.39**	**46.63**	**46.91**	**46.19**	**1.36**	**3.04**
China	14.97	14.74	14.42	14.64	15.24	14.76	-0.21	-1.39
India	4.77	5.18	5.16	4.95	5.35	5.16	0.39	8.11
Other Asia	8.63	9.09	9.27	8.73	8.85	8.98	0.36	4.12
Latin America	6.23	6.32	6.36	6.55	6.45	6.42	0.19	3.11
Middle East	7.79	8.06	8.13	8.50	8.22	8.23	0.44	5.60
Africa	4.22	4.51	4.15	4.25	4.58	4.37	0.15	3.54
Russia	3.61	3.67	3.42	3.45	3.59	3.53	-0.08	-2.32
Other Eurasia	1.21	1.22	1.16	1.00	1.21	1.15	-0.06	-5.07
Other Europe	0.75	0.79	0.75	0.73	0.80	0.77	0.01	1.62
Total Non-OECD	**52.18**	**53.58**	**52.81**	**52.79**	**54.27**	**53.36**	**1.18**	**2.26**
Total World	**97.01**	**99.38**	**98.20**	**99.43**	**101.18**	**99.55**	**2.54**	**2.62**
Previous Estimate	97.01	99.35	98.21	99.54	101.11	99.56	2.55	2.62
Revision	0.00	0.04	-0.01	-0.11	0.07	0.00	0.00	0.00

*Note: * 2022 = Estimate. Totals may not add up due to independent rounding. Source: OPEC.*

Table 4 - 2: World oil demand in 2023*, mb/d

World oil demand	2022	1Q23	2Q23	3Q23	4Q23	2023	Change 2023/22 Growth	%
Americas	25.07	24.95	25.26	25.68	25.45	25.34	0.26	1.05
of which US	*20.51*	*20.46*	*20.54*	*20.88*	*20.77*	*20.66*	*0.15*	*0.74*
Europe	13.65	13.22	13.45	14.10	13.95	13.68	0.03	0.24
Asia Pacific	7.47	7.88	7.04	7.27	7.83	7.50	0.04	0.49
Total OECD	**46.19**	**46.06**	**45.74**	**47.04**	**47.23**	**46.52**	**0.33**	**0.72**
China	14.76	14.90	15.20	15.20	15.78	15.27	0.51	3.48
India	5.16	5.41	5.44	5.21	5.59	5.41	0.25	4.94
Other Asia	8.98	9.42	9.61	9.10	9.20	9.33	0.35	3.85
Latin America	6.42	6.44	6.49	6.71	6.61	6.57	0.15	2.29
Middle East	8.23	8.45	8.46	8.84	8.51	8.56	0.33	4.05
Africa	4.37	4.71	4.34	4.43	4.77	4.56	0.19	4.35
Russia	3.53	3.63	3.45	3.59	3.75	3.61	0.08	2.17
Other Eurasia	1.15	1.21	1.16	1.02	1.22	1.15	0.01	0.51
Other Europe	0.77	0.80	0.76	0.75	0.82	0.78	0.02	2.32
Total Non-OECD	**53.36**	**54.98**	**54.90**	**54.86**	**56.24**	**55.25**	**1.89**	**3.53**
Total World	**99.55**	**101.04**	**100.65**	**101.90**	**103.47**	**101.77**	**2.22**	**2.23**
Previous Estimate	99.56	100.87	100.74	102.04	103.41	101.77	2.22	2.23
Revision	0.00	0.16	-0.10	-0.14	0.06	0.00	0.00	0.00

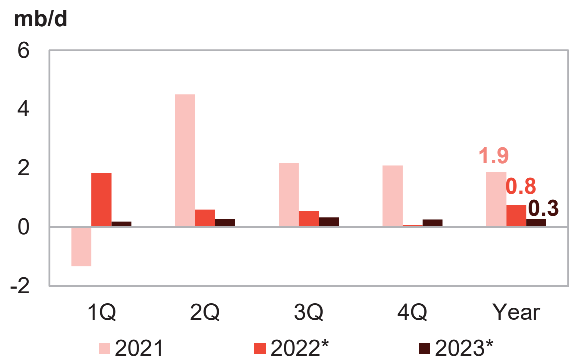
*Note: * 2022 = Estimate and 2023 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

OECD

OECD Americas

Update on the latest developments

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



*Note: * 2022 = Estimate and 2023 = Forecast.*
Source: OPEC.

Oil demand in OECD Americas posted y-o-y growth of 0.2 mb/d in October, driven by increased requirements in Mexico, and following strong y-o-y growth of 0.7 mb/d in September. Diesel posted growth of 0.2 mb/d. Jet fuel remained firm, with y-o-y growth of 90 tb/d. On the negative side, gasoline declined by 0.1 mb/d, while naphtha fell y-o-y by 10 tb/d, residual fuels were down by 20 tb/d and the “other products” category was down by 0.1 mb/d y-o-y.

US oil demand weakened to growth of 40 tb/d y-o-y in October, from 0.3 mb/d y-o-y growth in September. The US economy has been facing headwinds from rising inflation and other macroeconomic challenges weighing on October oil demand. US CPI inflation in October was at 7.8%, much higher than the Fed’s 2% target. The manufacturing PMI was at 50.2, down from 50.9 in September, according to ISM, while the services PMI was at 54.4, down from 56.7 in September. Further, data from the US Federal Highways Administration shows that October traffic volume trends remained below pre-pandemic levels. However, IATA Air Passenger Market Analysis indicates that US airline activity has stayed resilient, with October at about 90% of pre-crisis levels.

LPG took the lead in October’s oil demand growth at 0.2 mb/d y-o-y, up from 0.1 mb/d growth in September. Diesel recovered from a y-o-y decline of 10 tb/d in September to slight growth of 0.1 mb/d in October. Jet fuel increased by 51 tb/d y-o-y in October, from growth of 61 tb/d in September. The uptick in jet fuel demand was due to the continued air travel recovery.

With Americans making fewer car journeys, gasoline weakened further y-o-y in October by 0.2 mb/d, from an annual decline of 0.1 mb/d in September. Residual fuels recorded a y-o-y decline of 75 tb/d in October, and naphtha remained weak due to low demand from the petrochemical sector.

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

By product	Oct 21	Oct 22	*Change Oct 22/Oct 21* Growth	%
LPG	3.41	3.60	0.19	5.5
Naphtha	0.15	0.12	-0.03	-20.9
Gasoline	9.03	8.83	-0.20	-2.2
Jet/kerosene	1.48	1.53	0.05	3.4
Diesel	3.97	4.10	0.13	3.3
Fuel oil	0.36	0.28	-0.08	-21.0
Other products	2.28	2.25	-0.03	-1.2
Total	**20.67**	**20.71**	**0.04**	**0.2**

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

Near-term expectations

In 1Q23, **US GDP** is set to remain positive, albeit marginally. Ongoing elevated inflation levels in addition to seasonal softening of mobility in winter months is expected to dampen demand for transportation fuels. Accordingly, in 1Q23, US oil demand is projected to grow y-o-y by 80 tb/d. The 1Q23 oil demand growth is expected to come mostly from jet fuel and diesel, with slight improvements in petrochemical feedstock demand as well. Gasoline demand is anticipated to be relatively weak.

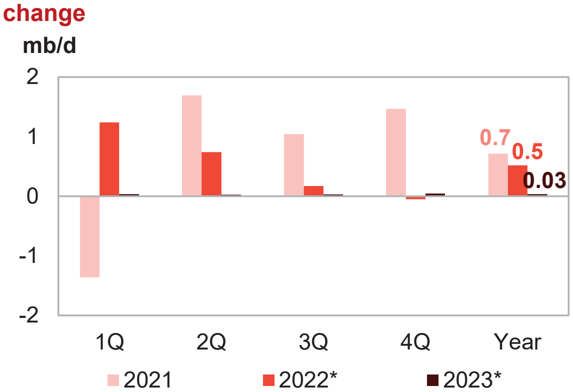
In 2Q23, US GDP is projected to improve slightly and inflation is expected to continue to decline in response to US monetary tightening. Furthermore, improving airline activity, combined with an uptick in road mobility, will likely support oil demand in the quarter. Accordingly, US oil demand is set to expand by 0.13 mb/d y-o-y in 2Q23.

OECD Europe

Update on the latest developments

Oil demand in OECD Europe remained depressed in October 2022. It posted a further y-o-y decline of 0.1 mb/d, compared to a drop of 90 tb/d y-o-y in September. The demand decline was due to rising inflation, as well as slowing economic and industrial activity in the region. According to data from Haver Analytics and the Statistical Office of European Communities, the Euro area's annual inflation was 10.7% in October, up from 9.9% in September. Additionally, the services PMI was down to 48.6 in October, compared to 48.8 in September, and the manufacturing PMI was down from 48.4 points in September to 46.4 points in October. However, airline activity showed some signs of improvement, with a report from IATA Air Passenger Market Analysis indicating that air traffic within the region in October 2022 stood at 80.9% of October 2019 levels.

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



*Note: * 2022 = Estimate and 2023 = Forecast.*
Source: OPEC.

In terms of specific oil products, jet/kerosene remained strong at 0.3 mb/d y-o-y growth, supported by air travel activity in the region. Residual fuels grew by 0.16 mb/d y-o-y in October, compared to 90 tb/d expansion in September, supported by gas-to-oil switching. LPG also remained in the positive, at slight 10 tb/d y-o-y growth.

On the negative side, naphtha softened by 0.25 mb/d y-o-y, mostly affected by slow demand from blending activities due to weak gasoline and other petrochemical feedstock markets in Europe. Similarly, diesel softened by 0.24 mb/d y-o-y, mostly due to weaker manufacturing activity and a slowdown in trucking activity. Gasoline weakened by 30 tb/d y-o-y, mostly due to lower driving activity in the region.

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

By product	Oct 21	Oct 22	*Change Oct 22/Oct 21* Growth	%
LPG	0.38	0.33	-0.05	-12.9
Naphtha	0.61	0.45	-0.16	-26.2
Gasoline	1.17	1.14	-0.03	-2.5
Jet/kerosene	0.56	0.74	0.18	32.8
Diesel	3.41	3.11	-0.30	-8.7
Fuel oil	0.16	0.22	0.06	40.1
Other products	0.50	0.47	-0.03	-6.0
Total	**6.79**	**6.47**	**-0.32**	**-4.7**

*Note: * Germany, France, Italy and the UK. Totals may not add up due to independent rounding.*

Sources: JODI, UK Department for Business, Energy & Industrial Strategy, Unione Petrolifera and OPEC.

Near-term expectations

The region's GDP is projected to soften in 1Q23. In addition, persistent inflationary pressures raise the risk of recession in the region, and supply chain bottlenecks due to ongoing geopolitical developments continue to be a challenge. The region's petrochemical industry has also been relatively weak. Nevertheless, sustained growth in air travel activity and ongoing gas-to-oil switching are expected to support oil demand in the near future. Accordingly, in 1Q23, oil demand in OECD Europe is projected to rise marginally y-o-y by 30 tb/d. Demand is expected to be supported by jet fuel, fuel oil and diesel.

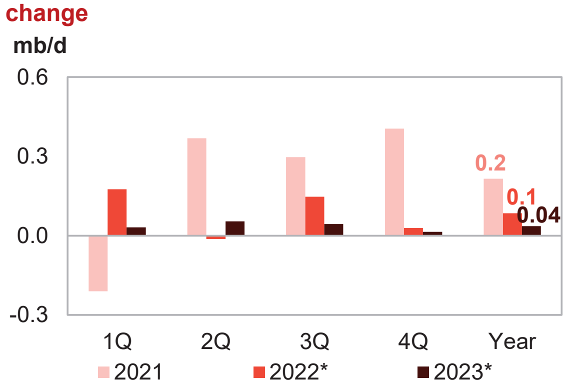
In 2Q23, oil demand growth is projected to also grow by a marginal 30 tb/d y-o-y. Second quarter oil demand is expected to be backed by rising demand for air travel, as well as anticipated improvements in road mobility. Accordingly, jet fuel and gasoline are set to be the main oil demand drivers in the second quarter.

OECD Asia Pacific

Update on the latest developments

Oil demand in OECD Asia Pacific recovered by 0.1 mb/d y-o-y in October from a decline of 0.1 mb/d in September. Most of the oil demand growth came from Australia. From the perspective of products, gasoline was the main driver in October, expanding y-o-y by 0.15 mb/d, compared to 63 tb/d growth in September. Airlines based in Asia Pacific continued to see y-o-y activity improvements, standing at 69.8% of pre-pandemic levels at the end of October, with jet/kerosene demand growing by 0.1 mb/d y-o-y. Rising natural gas prices also led to oil-to-gas switching, enabling the "other products" category to expand by 60 tb/d y-o-y. Residual fuels also benefitted from gas-to-oil switching to grow by 50 tb/d y-o-y. Diesel demand saw a marginal improvement, from a y-o-y decline of 30 tb/d in September to 30 tb/d growth in October.

Graph 4 - 3: OECD Asia Pacific oil demand, y-o-y change



*Note: * 2022 = Estimate and 2023 = Forecast.*
Source: OPEC.

Naphtha posted an annual y-o-y decline of 0.3 mb/d, with the region's naphtha demand slow due to weak margins to produce plastic derivatives. Naphtha demand was also subdued due to China's zero-COVID policy that impacted the petrochemical industry in Japan and South Korea.

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

By product	Nov 21	Nov 22	*Change Nov 22/Nov 21* Growth	%
LPG	0.40	0.37	-0.03	-6.8
Naphtha	0.75	0.67	-0.09	-11.5
Gasoline	0.70	0.71	0.01	2.1
Jet/kerosene	0.40	0.41	0.01	3.4
Diesel	0.75	0.75	0.00	-0.4
Fuel oil	0.26	0.27	0.00	0.8
Other products	0.24	0.25	0.01	3.8
Total	**3.51**	**3.43**	**-0.08**	**-2.2**

Note: Totals may not add up due to independent rounding. Sources: JODI, METI and OPEC.

Near-term expectations

The region's GDP is projected to grow in 2023. However, the economies of the two major oil consuming countries in the region, Japan and South Korea, have witnessed some slowing momentum and inflation levels in both are on a rising trend. At the same time, air travel activity remains on a recovery path. Accordingly, the region's oil demand is projected to grow y-o-y by a slight 30 tb/d in 1Q23. By 2Q23, oil demand growth is projected to marginally improve further at 50 tb/d y-o-y.

Non-OECD

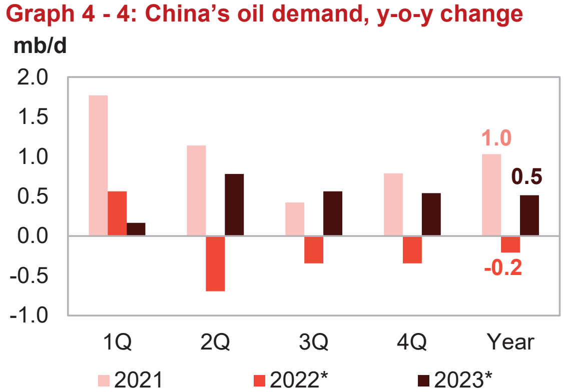
China

Update on the latest developments

COVID-19 lockdowns in **China** continued to constrain economic activity and oil demand. The latter decelerated further from a y-o-y decline of 0.2 mb/d in October to a drop of 0.25 mb/d in November.

On the positive side, China's petrochemical industry remained resilient as demand for feedstock from independent refineries in China's Shandong region was firm in November, supporting naphtha growth of 0.3 mb/d, y-o-y. Further, demand for diesel remained relatively resilient at 0.2 mb/d y-o-y growth. However, this is lower than 0.7 mb/d y-o-y growth posted in October. Softening demand can be attributed to weak manufacturing activity due to the COVID-19 lockdowns, which is evidenced in China's manufacturing PMI that stood at 49.4 points in November, marking a contraction for the fourth straight month. On the back of household requirements, LPG posted y-o-y growth of 88 tb/d, and there was an improvement in jet/kerosene at 94 tb/d y-o-y, compared to a 0.3 mb/d decline in October.

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



*Note: * 2022 = Estimate and 2023 = Forecast.*
Source: OPEC.

As lockdowns continued to depress mobility in China, gasoline declined by 0.7 mb/d y-o-y in November, from an annual decline of 0.4 mb/d the previous month. The "other fuels" category recorded an improvement from an annual decline of 0.45 mb/d in October to a 0.23 mb/d y-o-y decline in November.

Table 4 - 6: China's oil demand*, mb/d

By product	Nov 21	Nov 22	Change Nov 22/Nov 21 Growth	%
LPG	2.30	2.39	0.09	3.8
Naphtha	1.65	1.94	0.29	17.8
Gasoline	3.30	2.57	-0.73	-22.2
Jet/kerosene	0.65	0.74	0.09	14.4
Diesel	3.70	3.95	0.25	6.6
Fuel oil	0.50	0.49	-0.01	-1.5
Other products	1.75	1.52	-0.23	-13.0
Total	**13.85**	**13.60**	**-0.25**	**-1.8**

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

Near-term expectations

Chinese oil demand is on course to rebound due to the recent relaxation of the country's zero-COVID-19 measures, with the country's GDP projected to grow by 4.8% in 2023. In addition, China's plans to expand fiscal spending to aid the economic recovery is likely to support oil demand in manufacturing, construction and mobility. The manufacturing sector is expected to start recovering relatively quickly, and the aviation sector is expected to see significant increases in both local and international travel given pent-up demand. Furthermore, the performance of the resilient petrochemical sector is also projected to improve further.

China's 1Q23 oil demand is set to rebound from an annual decline of 0.3 mb/d y-o-y in 4Q22 to modest 0.2 mb/d y-o-y growth. The quarter also sees the Lunar New Year holiday, traditionally a time when Chinese people head home for family reunions, with many traveling from cities to rural areas, accelerating demand for mobility and air travel. In addition, manufacturing and construction activity are expected to pick up, and feedstock consumption from independent refineries in China's Shandong region may find some support. However, there are a number of uncertainties regarding the impacts of the spread of COVID-19 after the opening up, particularly, in the first quarter.

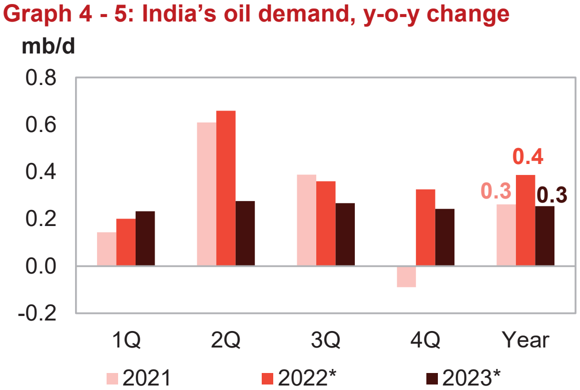
In 2Q23, manufacturing and construction activity are set to accelerate further, and it is envisaged there will be expanding requirements for the petrochemical industry. This would boost demand and output for middle and light distillate products. Accordingly, China's oil demand is projected to accelerate further to reach y-o-y growth of 0.8 mb/d.

India

Update on the latest developments

India recorded bullish y-o-y **oil demand** growth of 0.43 mb/d in November, up from 0.1 mb/d growth in October. The November oil demand expansion was driven by diesel, which posted y-o-y growth of 0.3 mb/d. Diesel consumption surpassed a three-year high, rising 19% y-o-y in November. Demand for diesel was supported by strong manufacturing activity as indicated by November's Manufacturing PMI that rose to 55.7 points from 55.3 points in October. In addition, the Services PMI also increased from 55.1 points in October to 56.4 points in November. India's inflation rate is also on a declining trend, dropping from 6.8% in October to 5.7% in November. It is now trending towards the pre-pandemic level of 5.4% in 2019. These factors provide evidence of healthy economic activity in India.

Graph 4 - 5: India's oil demand, y-o-y change



*Note: * 2022 = Estimate and 2023 = Forecast.*
Source: OPEC.

Requirements for irrigation and transportation activities in the farm sector, combined with progress in construction activity, supported demand for diesel. The "other products" category posted growth of 70 tb/d y-o-y, with bitumen consumption providing strong support with the continued significant expansion in road construction projects in India.

Further, on the back of increased economic activity as well as travel on occasion of seasonal festivities, gasoline posted y-o-y growth of 60 tb/d. LPG recovered with y-o-y growth of 47 tb/d, compared with an annual decline of 30 tb/d in October. Indian airline activity continues to steadily recover from the pandemic. Air Passenger Market Analysis reports that October's revenue passenger-kilometres (RPKs) are now only 12.2% short of 2019 levels. In November, jet/kerosene showed a slight 7 tb/d y-o-y growth, from roughly the same growth seen in October. However, naphtha remained weak, declining by 63 tb/d, y-o-y. In India, naphtha is mostly used for gasoline blending and its by-products are channelled into the domestic petrochemical sector as feedstock for naphtha-fed steam crackers.

Table 4 - 7: India's oil demand, mb/d

By product	Nov 21	Nov 22	*Change Nov 22/Nov 21* Growth	%
LPG	0.91	0.96	0.05	5.1
Naphtha	0.35	0.29	-0.06	-18.2
Gasoline	0.75	0.81	0.06	8.1
Jet/kerosene	0.16	0.17	0.01	4.6
Diesel	1.59	1.88	0.30	18.8
Fuel oil	0.11	0.12	0.01	8.3
Other products	0.66	0.73	0.07	10.1
Total	**4.53**	**4.96**	**0.43**	**9.4**

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

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

Near-term expectations

Looking forward, India's GDP growth is expected to continue healthy in 2023. Furthermore, India's manufacturing and service PMIs have been on rising trends, while inflation is on the decline. Accordingly, economic and social activity is expected to continue to accelerate. India's oil demand is projected to rise by 0.2 mb/d y-o-y in 1Q23. India's gasoline demand is expected to expand due to rising vehicle sales and overall steady economic growth. Similarly, middle distillates (diesel and jet/kerosene) are also set to show healthy growth due to economic development and ongoing strong airline travel activities. Demand for transportation fuel is anticipated to lead product demand.

With projected continued healthy GDP growth, India's oil demand is forecast to expand y-o-y by 0.3 mb/d in 2Q23.

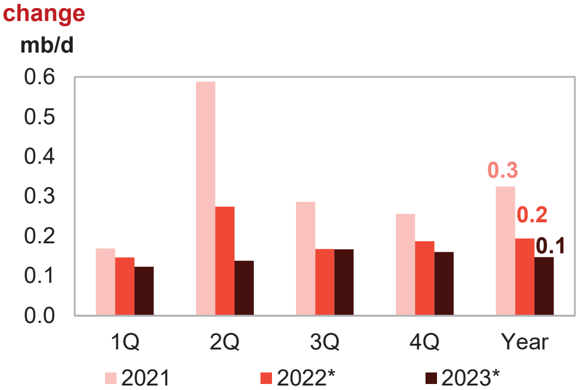
Latin America

Update on the latest developments

In October, **oil demand in Latin America** remained firm at 0.2 mb/d y-o-y growth. This was the same as posted in September. Oil demand growth was driven by demand from Brazil and Venezuela. Economic activity in the region is currently positive, reflecting improvements in the services sector and employment. The services PMI in Brazil was at 50.8 in October. Airline activity in the region also continued to improve in October, and is now at 84.9% of pre-pandemic levels.

Oil demand in Latin America was supported by y-o-y growth of 77 tb/d in gasoline, up from y-o-y growth of 69 tb/d in September. On the back of healthy aviation sector activity, jet fuel posted y-o-y growth of 50 tb/d.

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



*Note: * 2022 = Estimate and 2023 = Forecast.*
Source: OPEC.

Similarly, "other fuels" grew y-o-y by 50 tb/d. Residual fuels posted a y-o-y gain of 30 tb/d in October, against a decline of 35 tb/d in September. However, weak petrochemical activity weighed on naphtha, which softened by 10 tb/d y-o-y.

Near-term expectations

GDP growth for the region in 2023 is projected to slow, albeit remaining positive at 1.5%. Oil demand is projected to grow y-o-y by 0.1 mb/d in 1Q23. Mobility and manufacturing activity should support demand for gasoline and distillates. Similarly, further air travel recovery is expected to aid jet/ kerosene demand.

In 2Q23, oil demand is projected to remain steady at 0.1 mb/d y-o-y growth. The outlook for oil demand growth sees Brazil in the lead, followed by Argentina. In terms of product demand, transportation fuels are expected to grow the most, supported by the continuing recovery in mobility and air travel.

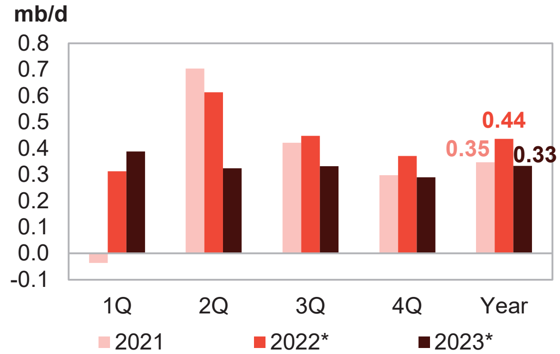
Middle East

Update on the latest developments

Oil demand in the Middle East continued strong at 0.5 mb/d growth y-o-y in October, slightly up from 0.4 mb/d growth in September. The economies of Middle East countries remain robust and supportive of oil demand. Saudi Arabia posted a composite PMI of 57 points in October while inflation seems to be on a declining trend. The UAE recorded a composite PMI of 56.6 points in October, according to S&P Global and also saw low inflation in October.

Oil demand in the Middle East was mostly supported by strong requirements for the "other products" category, with y-o-y growth of 0.25 mb/d, driven by requirements for electricity generation, particularly in Iraq and Saudi Arabia. Diesel grew by 0.2 mb/d y-o-y, from 0.1 mb/d growth in September.

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



*Note: * 2022 = Estimate and 2023 = Forecast.*
Source: OPEC.

Gasoline posted y-o-y growth of 50 tb/d, up from 30 tb/d growth in September. The petrochemical industry and household requirements boosted LPG, which expanded by 30 tb/d y-o-y, compared to 20 tb/d y-o-y growth in September. Further, healthy airline activity supported jet/kerosene demand that grew y-o-y by 30 tb/d, as Middle East carriers saw growth in international traffic. Nevertheless, airline activity was 20.3% below pre-COVID-19 levels in October. However, residual fuels and naphtha saw y-o-y declines of 90 tb/d and 10 tb/d, respectively.

Table 4 - 8: Saudi Arabia's oil demand, mb/d

			Change	*Nov 22/Nov 21*
By product	**Nov 21**	**Nov 22**	**Growth**	**%**
LPG	0.05	0.05	0.00	9.1
Gasoline	0.48	0.51	0.03	5.3
Jet/kerosene	0.04	0.07	0.03	68.2
Diesel	0.50	0.59	0.09	18.2
Fuel oil	0.64	0.64	0.00	0.6
Other products	0.42	0.52	0.10	23.0
Total	**2.13**	**2.38**	**0.25**	**11.8**

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

Near-term expectations

Strong economic activity in the region is set to continue to support oil demand in the near future.The region's healthy economic growth outlook is expected to support consumer spending and accelerate mobility and construction activity. These factors should support demand for both gasoline and diesel. Moreover, infrastructure project developments and an uptick in power generation requirements should also support the upside oil demand momentum. Hence, demand for residual and fuel oil is expected to continue to accelerate. Similarly, as air travel recovery persists, jet/kerosene demand will further support oil demand growth. Accordingly, in 1Q23, oil demand in the Middle East is projected to expand y-o-y by 0.4 mb/d.

In 2Q23, oil demand growth momentum is set to continue, albeit at an anticipated slightly slower pace. Oil demand in the second quarter is projected to grow y-o-y by 0.3 mb/d. Gasoline, transportation diesel and jet/kerosene are expected to lead oil demand growth, with fuel oil demand further supporting the expansion.

World Oil Supply

Non-OPEC liquids supply in 2022 (including processing gains) is estimated to grow by 1.9 mb/d to average 65.6 mb/d, broadly unchanged from the previous month's assessment. Upward revisions to liquids production in Russia and OECD Americas were largely offset by downward revisions to OECD Europe and OECD Asia Pacific.

In the US, oil drilling activity has recovered to near pre-pandemic levels. However, producers are still challenged by high cost inflation and supply chain issues, with many operators experiencing longer-than-usual wait times for supplies and equipment in the oil patch. US liquids production rose in October on the back of higher crude and biofuel production, with steady growth expected in November, while output is projected to slump in December due to winter blizzards and freezing weather across the northern US. Accordingly, the US liquids supply growth forecast for 2022 has been revised up slightly to average 1.2 mb/d. The production forecast for Canada was revised down, due to unplanned maintenance and lower-than-anticipated output in 2H22. Extended maintenance on UK offshore platforms, along with output underperformance in Norway, reduced 4Q22 projections in the North Sea region. On the other hand, Russian production was higher than expected in December. The main drivers of liquids supply growth for 2022 are expected to be the US, Russia, Canada, Guyana, China and Brazil, while production is expected to see the largest declines in Norway and Thailand.

Non-OPEC liquids production growth in 2023 is forecast to grow by 1.5 mb/d to average 67.2 mb/d, unchanged from last month. The liquids supply in OECD countries is forecast to increase by 1.6 mb/d, while the non-OECD region is expected to show a decline of 0.2 mb/d. The main growth drivers are expected to be the US, Norway, Brazil, Canada, Kazakhstan and Guyana, whereas oil production is forecast to see declines in Russia and Mexico. Nonetheless, large uncertainties remain over the impact of ongoing geopolitical developments in Eastern Europe, and US shale output prospects in 2023.

OPEC NGLs and non-conventional liquids production in 2022 is forecast to grow by 0.1 mb/d to average 5.4 mb/d and increase by 50 tb/d to average 5.4 mb/d in 2023. OPEC-13 crude oil production in December increased by 91 tb/d m-o-m to average 28.97 mb/d, according to available secondary sources.

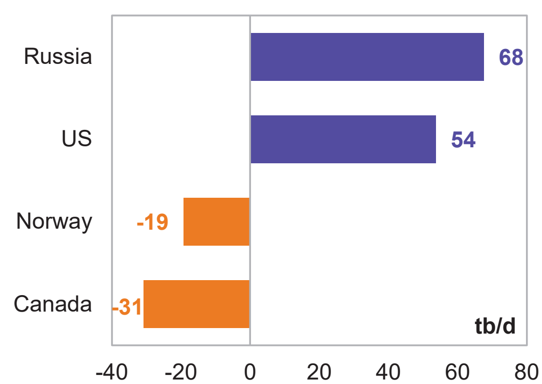
Non-OPEC liquids production in December, including OPEC NGLs, is estimated to have increased m-o-m by 0.2 mb/d to average 72.8 mb/d, up by 2.8 mb/d y-o-y. As a result, preliminary data indicates that December's global oil supply increased by 0.3 mb/d m-o-m to average 101.7 mb/d, up by 3.8 mb/d y-o-y.

The **non-OPEC liquids supply forecast for 2022** was revised slightly up by 43 tb/d to average 65.6 mb/d. Y-o-y growth averaged 1.9 mb/d, revised up slightly by 42 tb/d compared with the previous month.

The overall **OECD** supply growth estimate for 2022 has remained quite steady. While OECD Europe and OECD Asia Pacific saw downward revisions, OECD Americas was revised up from the previous month's assessment.

The **non-OECD** supply growth forecast for 2022 was revised up by 48 tb/d. Minor downward revisions to Other Asia and Africa were more than offset by upward revisions to Russia.

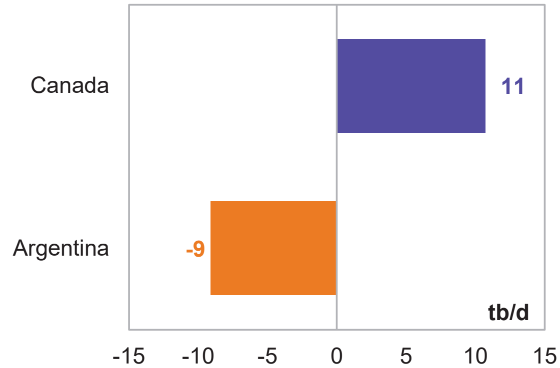
Graph 5 - 1: Major revisions to annual supply change forecast in 2022*, MOMR Jan 23/Dec 22



*Note: * 2022 = Estimate. Source: OPEC.*

Non-OPEC liquids production growth in 2023 is forecast to remain unchanged compared with the previous month's assessment, despite some minor up and down revisions for some countries.

Graph 5 - 2: Major revisions to annual supply change forecast in 2023*, MOMR Jan 23/Dec 22

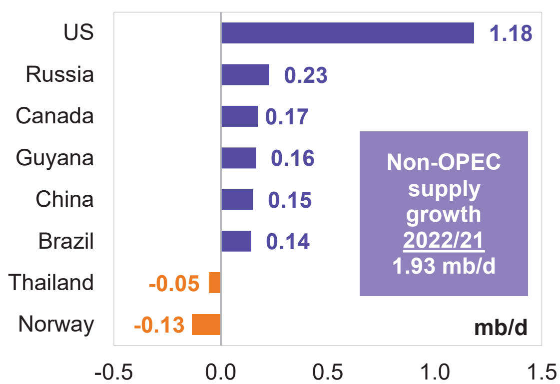


*Note: * 2023 = Forecast. Source: OPEC.*

Key drivers of growth and decline

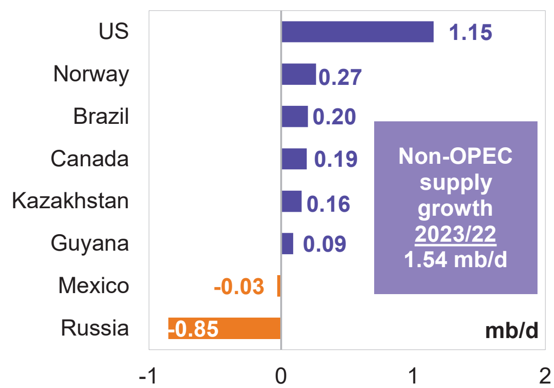
The **key drivers of non-OPEC liquids supply growth in 2022** are projected to be the US, Russia, Canada, Guyana, China and Brazil, while oil production is expected to see the largest declines in Norway and Thailand.

Graph 5 - 3: Annual liquids production changes for selected countries in 2022*



*Note: * 2022 = Estimate. Source: OPEC.*

Graph 5 - 4: Annual liquids production changes for selected countries in 2023*



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

For **2023**, the key drivers of non-OPEC supply growth are forecast to be the US, Norway, Brazil, Canada, Kazakhstan and Guyana, while oil production is projected to see the largest declines in Russia and Mexico.

Non-OPEC liquids production in 2022 and 2023

Table 5 - 1: Non-OPEC liquids production in 2022*, mb/d

Non-OPEC liquids production	2021	1Q22	2Q22	3Q22	4Q22	2022	Change 2022/21 Growth	%
Americas	25.25	25.86	26.27	27.01	27.49	26.66	1.41	5.59
of which US	*17.85*	*18.27*	*18.83*	*19.32*	*19.69*	*19.03*	*1.18*	*6.63*
Europe	3.76	3.73	3.43	3.49	3.65	3.57	-0.18	-4.82
Asia Pacific	0.51	0.49	0.51	0.43	0.51	0.48	-0.03	-5.29
Total OECD	**29.52**	**30.08**	**30.22**	**30.94**	**31.64**	**30.72**	**1.20**	**4.08**
China	4.31	4.51	4.52	4.38	4.43	4.46	0.15	3.51
India	0.78	0.78	0.77	0.76	0.76	0.77	-0.01	-1.44
Other Asia	2.41	2.35	2.30	2.24	2.31	2.30	-0.11	-4.44
Latin America	5.95	6.11	6.18	6.45	6.62	6.34	0.39	6.49
Middle East	3.24	3.29	3.33	3.36	3.35	3.33	0.09	2.89
Africa	1.35	1.33	1.31	1.32	1.30	1.32	-0.03	-2.34
Russia	10.80	11.33	10.63	11.01	11.15	11.03	0.23	2.10
Other Eurasia	2.93	3.05	2.77	2.61	2.95	2.84	-0.08	-2.83
Other Europe	0.11	0.11	0.11	0.10	0.10	0.11	-0.01	-6.36
Total Non-OECD	**31.87**	**32.85**	**31.92**	**32.23**	**32.96**	**32.49**	**0.62**	**1.94**
Total Non-OPEC production	61.39	62.93	62.14	63.17	64.60	63.21	1.82	2.97
Processing gains	2.29	2.40	2.40	2.40	2.40	2.40	0.11	4.90
Total Non-OPEC liquids production	**63.68**	**65.33**	**64.54**	**65.57**	**67.00**	**65.61**	**1.93**	**3.04**
Previous estimate	63.68	65.33	64.54	65.61	66.79	65.57	1.89	2.97
Revision	0.00	0.00	0.00	-0.04	0.21	0.04	0.04	0.07

*Note: * 2022 = Estimate. Totals may not add up due to independent rounding. Source: OPEC.*

Table 5 - 2: Non-OPEC liquids production in 2023*, mb/d

Non-OPEC liquids production	2022	1Q23	2Q23	3Q23	4Q23	2023	Change 2023/22 Growth	%
Americas	26.66	27.64	27.73	28.09	28.46	27.98	1.32	4.95
of which US	*19.03*	*19.80*	*20.10*	*20.30*	*20.53*	*20.19*	*1.15*	*6.06*
Europe	3.57	3.93	3.91	3.80	3.93	3.89	0.32	8.90
Asia Pacific	0.48	0.50	0.48	0.50	0.48	0.49	0.00	0.99
Total OECD	**30.72**	**32.07**	**32.12**	**32.39**	**32.88**	**32.37**	**1.64**	**5.34**
China	4.46	4.51	4.50	4.47	4.47	4.49	0.03	0.64
India	0.77	0.79	0.78	0.77	0.76	0.78	0.01	1.15
Other Asia	2.30	2.37	2.36	2.33	2.35	2.35	0.05	2.37
Latin America	6.34	6.49	6.67	6.71	6.78	6.67	0.32	5.10
Middle East	3.33	3.34	3.36	3.39	3.39	3.37	0.04	1.08
Africa	1.32	1.32	1.33	1.35	1.34	1.33	0.02	1.42
Russia	11.03	10.21	10.08	10.18	10.23	10.18	-0.85	-7.71
Other Eurasia	2.84	3.09	3.05	3.02	3.06	3.06	0.21	7.44
Other Europe	0.11	0.10	0.10	0.10	0.10	0.10	0.00	-2.83
Total Non-OECD	**32.49**	**32.21**	**32.25**	**32.32**	**32.50**	**32.32**	**-0.17**	**-0.53**
Total Non-OPEC production	63.21	64.28	64.36	64.71	65.37	64.69	1.47	2.33
Processing gains	2.40	2.47	2.47	2.47	2.47	2.47	0.07	2.96
Total Non-OPEC liquids production	**65.61**	**66.75**	**66.83**	**67.18**	**67.84**	**67.16**	**1.54**	**2.35**
Previous estimate	65.57	66.50	66.86	67.19	67.88	67.11	1.54	2.35
Revision	0.04	0.25	-0.02	-0.01	-0.04	0.04	0.00	0.00

*Note: * 2022 = Estimate and 2023 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

OECD

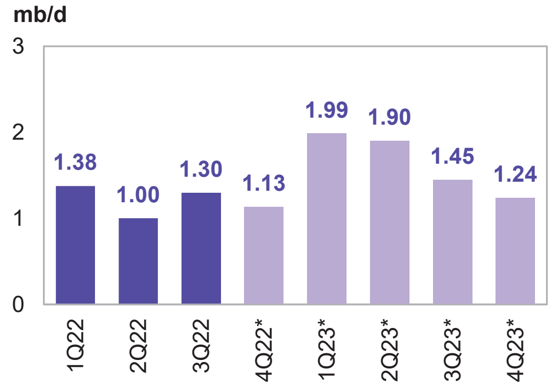
OECD liquids production in 2022 is estimated to increase y-o-y by 1.2 mb/d to average 30.7 mb/d. This remains broadly unchanged compared with a month earlier, as upward revisions for OECD America were offset by downward revisions in OECD Europe.

OECD Americas was revised up by 25 tb/d compared with last month's assessment. It is now expected to grow by 1.4 mb/d to average 26.7 mb/d.

OECD Europe is anticipated to decline y-o-y by 0.2 mb/d to average 3.6 mb/d.

OECD Asia Pacific is forecast to drop by 27 tb/d y-o-y to average 0.5 mb/d.

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



*Note: * 4Q22-4Q23 = Forecast. Source: OPEC.*

For **2023**, oil production in the OECD is forecast to grow by 1.6 mb/d to average 32.4 mb/d. Growth is led by OECD Americas with 1.3 mb/d to average 28.0 mb/d. Yearly liquids production in OECD Europe is anticipated to grow by 0.3 mb/d to average 3.9 mb/d, while OECD Asia Pacific is expected to remain broadly unchanged to average 0.5 mb/d.

OECD Americas

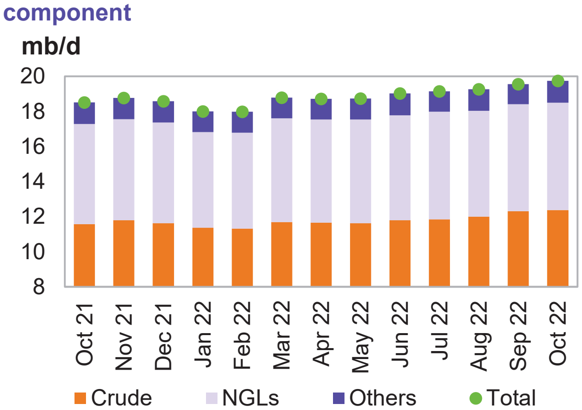
US

US liquids production increased m-o-m by 182 tb/d in **October 2022** to average 19.7 mb/d. This was up by 1.2 mb/d compared with October 2021.

Crude oil and condensate production rose m-o-m by 69 tb/d in **October 2022** to average 12.4 mb/d, up by 0.8 mb/d y-o-y.

In terms of **crude and condensate production breakdown by region (PADDs)**, production increased mainly in the US Gulf Coast (USGC), where it was up by 53 tb/d to average 8.9 mb/d. Production in the Rocky Mountain and West Coast regions rose by a minor 6 tb/d, while the Midwest and East Coast remained broadly unchanged m-o-m. Production growth in the main regions was primarily driven by higher completion and fracking activities and normal production levels in the Gulf of Mexico (GoM).

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



Source: OPEC.

NGLs production was up by 22 tb/d m-o-m to average 6.1 mb/d in October. This was higher y-o-y by 0.4 mb/d. Production of **non-conventional liquids** (mainly ethanol) jumped by 91 tb/d m-o-m to average 1.2 mb/d in October, according to the US Department of Energy (DoE). Preliminary estimates see non-conventional liquids averaging 1.3 mb/d in November 2022, up by 23 tb/d compared with the previous month.

GoM production declined m-o-m by a minor 5 tb/d in October to average 1.8 mb/d, with quite stable production seen on Gulf Coast offshore platforms. In the **onshore Lower 48**, crude and condensate production increased m-o-m by 69 tb/d to average 10.1 mb/d in October.

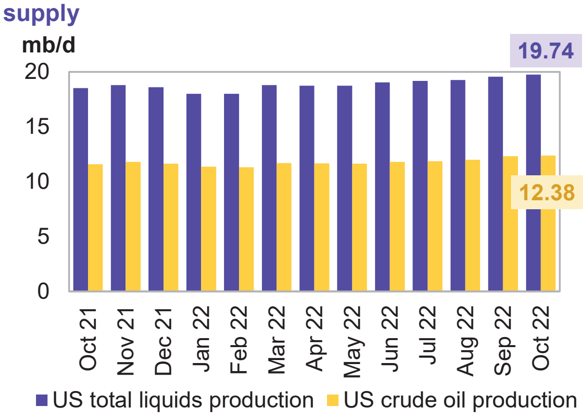
Looking at **individual states**, New Mexico's oil production increased m-o-m by 41 tb/d to average 1.7 mb/d, which is 347 tb/d higher than a year ago. Texas production was up by 11 tb/d to average 5.2 mb/d, which is 229 tb/d higher than a year ago. In the Midwest, North Dakota's production decreased m-o-m by a minor 5 tb/d to average 1.1 mb/d, remaining steady y-o-y, while Oklahoma's production was broadly unchanged at an average of 0.4 mb/d. Alaska's output was up by a minor 5 tb/d m-o-m, and in Colorado, production declined slightly by 7 tb/d.

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

State	Oct 21	Sep 22	Oct 22	Change m-o-m	Change y-o-y
Texas	4,967	5,185	5,196	*11*	*229*
Gulf of Mexico (GOM)	1,678	1,847	1,842	*-5*	*164*
New Mexico	1,380	1,686	1,727	*41*	*347*
North Dakota	1,101	1,108	1,103	*-5*	*2*
Alaska	437	430	435	*5*	*-2*
Colorado	460	434	427	*-7*	*-33*
Oklahoma	403	416	420	*4*	*17*
Total	**11,569**	**12,312**	**12,381**	***69***	***812***

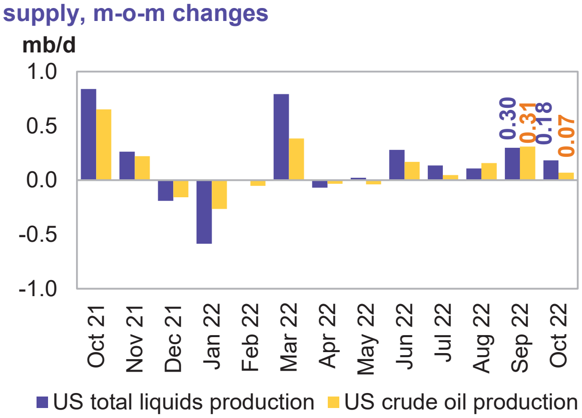
Sources: EIA and OPEC.

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



Sources: EIA and OPEC.

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



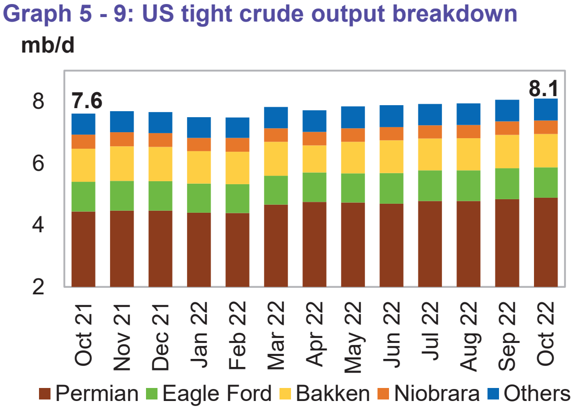
Sources: EIA and OPEC.

US tight crude output in **October 2022** is estimated to have risen by 37 tb/d m-o-m to average 8.1 mb/d, according to the latest estimation by the US Energy Information Administration (EIA). This was 0.5 mb/d higher than in the same month last year.

The m-o-m increase from shale and tight formations using horizontal wells came mainly from the Permian, which increased output by 46 tb/d to average 4.9 mb/d. This was up by 0.4 mb/d y-o-y.

In the Williston Basin, Bakken shale production remained chiefly unchanged, averaging 1.1 mb/d. This is up by a minor 8 tb/d y-o-y. Tight crude output at Eagle Ford in Texas fell by 15 tb/d to average 0.9 mb/d. This is up by 22 tb/d y-o-y. Production in Niobrara-Codell in Colorado and Wyoming was unchanged at an average of 0.4 mb/d.

Graph 5 - 9: US tight crude output breakdown



Sources: EIA, Rystad Energy and OPEC.

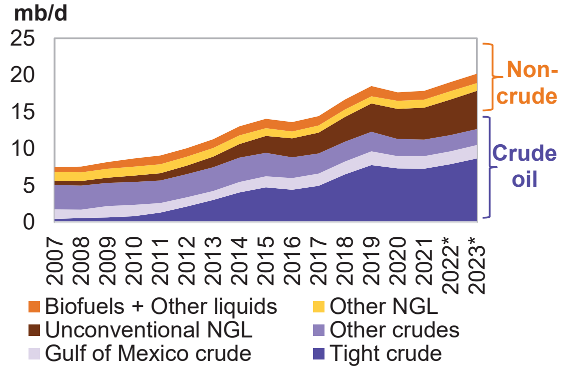
US liquids production in 2022, excluding processing gains, is forecast to expand y-o-y by 1.2 mb/d to average 19.0 mb/d. This is an upward revision of 54 tb/d compared with the previous assessment due to higher-than-expected output in September and October reported by the EIA and an upward revision to 4Q22. Tight crude is forecast to grow by 0.6 mb/d in 2022 to average 7.9 mb/d. In addition, NGLs (mainly from unconventional basins) are projected to grow by 0.5 mb/d to average 5.9 mb/d, and production in the GoM is anticipated to increase by a minor 30 tb/d. Non-conventional liquids are projected to expand by 40 tb/d to average 1.2 mb/d. However, the expected growth is likely to be partially offset by y-o-y natural declines of 25 tb/d in conventional onshore fields.

Given the current pace of oil field drilling and well completions, **crude oil and condensate production** is forecast to grow by 0.6 mb/d y-o-y to average 11.9 mb/d in 2022. This forecast assumes continuing capital discipline, inflation rate pressure, ongoing supply chain issues and oil field service constraints (labour and equipment). Tightness in the hydraulic fracking market has been one of the biggest issues for US producers in recent months, and this is expected to remain a challenge.

US liquids production in 2023, excluding processing gains, is forecast to grow y-o-y by 1.2 mb/d to average 20.2 mb/d, unchanged from the previous assessment. Greater drilling activity and fewer supply chain/logistical issues in the prolific Permian, Eagle Ford and Bakken shale sites are assumed for 2023. Crude oil output is anticipated to increase by 0.8 mb/d y-o-y to average 12.7 mb/d. Average tight crude output in 2023 is forecast at 8.7 mb/d, up by 0.8 mb/d y-o-y.

At the same time, NGLs production and non-conventional liquids, particularly ethanol, are forecast to increase y-o-y by 0.33 mb/d and 40 tb/d, to average 6.3 mb/d and 1.3 mb/d, respectively.

Graph 5 - 10: US liquids supply developments by component



*Note: * 2022 = Estimate and 2023 = Forecast.*
Source: OPEC.

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

US liquids	2021	Change 2021/20	2022*	Change 2022/21	2023*	Change 2023/22
Tight crude	7.28	-0.03	7.90	0.62	8.68	0.78
Gulf of Mexico crude	1.71	0.04	1.74	0.03	1.82	0.09
Conventional crude oil	2.27	-0.07	2.24	-0.03	2.15	-0.09
Total crude	**11.25**	**-0.06**	**11.87**	**0.62**	**12.65**	**0.78**
Unconventional NGLs	4.31	0.23	4.81	0.50	5.20	0.39
Conventional NGLs	1.12	0.02	1.15	0.03	1.09	-0.06
Total NGLs	**5.42**	**0.25**	**5.95**	**0.53**	**6.29**	**0.33**
Biofuels + Other liquids	1.17	0.02	1.21	0.04	1.25	0.04
US total supply	**17.85**	**0.21**	**19.03**	**1.18**	**20.18**	**1.15**

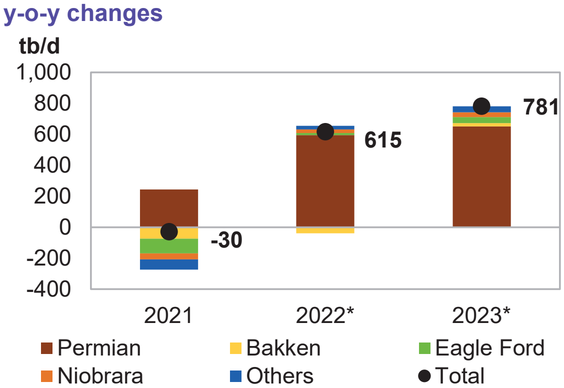
*Note: * 2022 = Estimate and 2023 = Forecast. Sources: EIA, OPEC and Rystad Energy.*

US tight crude production in the **Permian** in 2022 is estimated to increase y-o-y by 0.6 mb/d to 4.7 mb/d. It is then forecast to grow by 0.6 mb/d y-o-y to average 5.4 mb/d in 2023.

The **Bakken** shale production decline that occurred in 2020 and 2021 is expected to continue in 2022. Tight crude production in the Bakken is estimated to drop by 39 tb/d in 2022 to average 1.0 mb/d. This is lower than the pre-pandemic average output of 1.4 mb/d. Drilling activity in North Dakota and available DUC wells are lower than the levels required to revive output. In 2023, growth is forecast to resume at 21 tb/d to average 1.1 mb/d.

The **Eagle Ford** in Texas saw an output of 1.2 mb/d in 2019, which declined in 2020 and 2021. It is estimated to rise by 13 tb/d in 2022 to average 1.0 mb/d. Growth of 40 tb/d is then forecast for 2023, to average just over 1.0 mb/d.

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



*Note: * 2022 = Estimate and 2023 = Forecast.*
Sources: EIA, Rystad Energy and OPEC.

Niobrara production is estimated to grow y-o-y by 24 tb/d in 2022 and then forecast to increase by 30 tb/d in 2023 to average 437 tb/d and 467 tb/d, respectively. Other shale plays are expected to show marginal increases totalling 22 tb/d and 40 tb/d in 2022 and 2023, given current drilling and completion activities.

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

US tight oil	2021	Change 2021/20	2022*	Change 2022/21	2023*	Change 2023/22
Permian tight	4.15	0.24	4.75	0.59	5.40	0.65
Bakken shale	1.08	-0.07	1.04	-0.04	1.06	0.02
Eagle Ford shale	0.96	-0.09	0.97	0.01	1.01	0.04
Niobrara shale	0.41	-0.04	0.44	0.02	0.47	0.03
Other tight plays	0.67	-0.07	0.70	0.02	0.74	0.04
Total	**7.28**	**-0.03**	**7.90**	**0.62**	**8.68**	**0.78**

*Note: * 2022 = Estimate and 2023 = Forecast. Source: OPEC.*

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

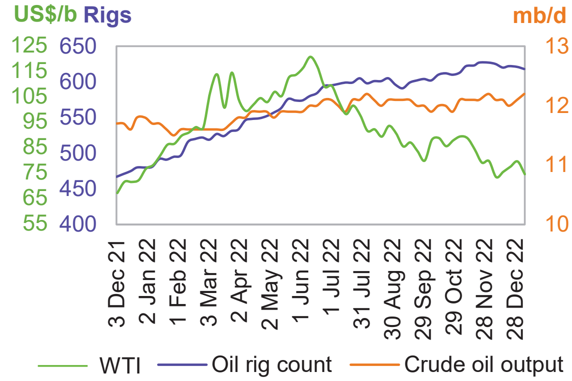
Total **active US drilling rigs** decreased by seven to 772 in the week ending January 6, 2023. This was up by 184 rigs compared with a year ago. The number of active offshore rigs rose w-o-w to 16, an increase of one. This is unchanged from the same month a year earlier. Onshore oil and gas rigs decreased by eight w-o-w to stand at 754 rigs, up by 184 rigs y-o-y, with two rigs in inland waters.

The **US horizontal rig count** fell by six w-o-w to 700, compared with 532 horizontal rigs a year ago. The number of drilling rigs for oil fell by three w-o-w to 618. At the same time, gas-drilling rig counts were down by four to 152.

The Permian's rig count remained unchanged w-o-w at 353 rigs. At the same time, rig counts remained steady in Eagle Ford, Williston and DJ-Niobrara at 71, 42 and 17, respectively. The rig count also stayed unaffected w-o-w in Cana Woodford at 26.

Three operating oil rigs remained in the Barnett basin, unchanged w-o-w.

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



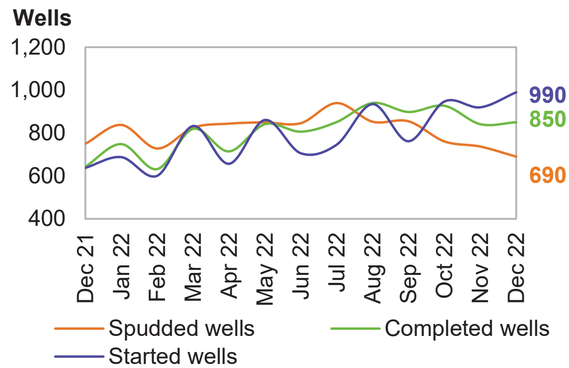
Sources: Baker Hughes, EIA and OPEC.

Drilling and completion (D&C) activities for spudded, completed and started oil-producing wells in all US shale plays, based on EIA-DPR regions, included 737 horizontal wells spudded in November 2022 (as per preliminary data). This is down by 24 m-o-m, and 5% lower than in November 2021.

November 2022 preliminary data indicates a lower number of completed wells at 841. However, this is up 24% y-o-y. Moreover, the number of started wells was estimated at 920, which is 37% higher than a year earlier.

Preliminary data for December 2022 estimates 690 spudded, 850 completed and 990 started wells, according to Rystad Energy.

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

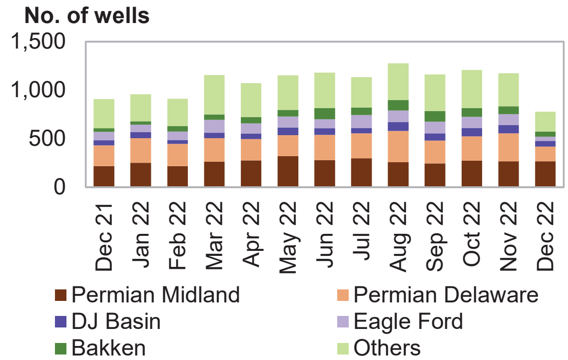


Note: Nov 22-Dec 22 = Preliminary data.
Sources: Rystad Energy and OPEC.

In terms of identified **US oil and gas fracking operations by region**, Rystad Energy reported that 1,207 wells were fracked in October 2022. In November and December, it stated that 1,173 and 780 wells started fracking, respectively. Preliminary numbers are based on analysis of high-frequency satellite data.

Preliminary November data showed that 266 and 289 wells were fracked in the Permian Midland and Permian Delaware, respectively. Compared with October, there was a jump of 38 in Delaware and a decline of eight wells fracked in the Midland, according to preliminary data. Data also indicated that 86 wells were fracked in the DJ Basin, 113 in Eagle Ford and 78 in Bakken during November.

Graph 5 - 14: Fracked wells count per month



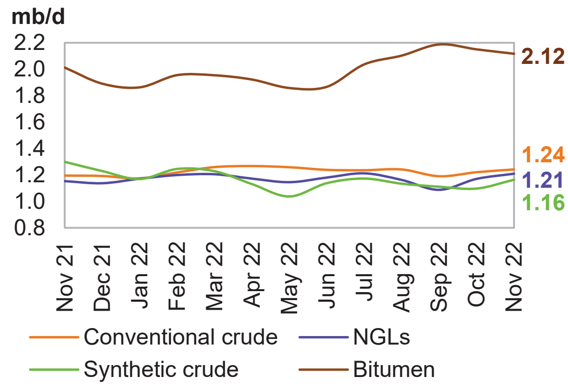
Note: Nov 22-Dec 22 = Preliminary data.
Sources: Rystad Energy Shale Well Cube and OPEC.

Canada

Canada's liquids production in **November** is estimated to have increased m-o-m by 94 tb/d to average 5.8 mb/d, largely as the Hibernia field came back online after October maintenance and gains were seen in upgraded crude. It represents the highest Canadian production on record.

Conventional crude production increased m-o-m by 21 tb/d to average 1.2 mb/d and NGLs output rose m-o-m by 39 tb/d to average 1.2 mb/d. At the same time, crude bitumen production output fell m-o-m by 33 tb/d in November, while synthetic crude rose by 67 tb/d. Taken together, crude bitumen and synthetic crude production increased by 34 tb/d to 3.3 mb/d.

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

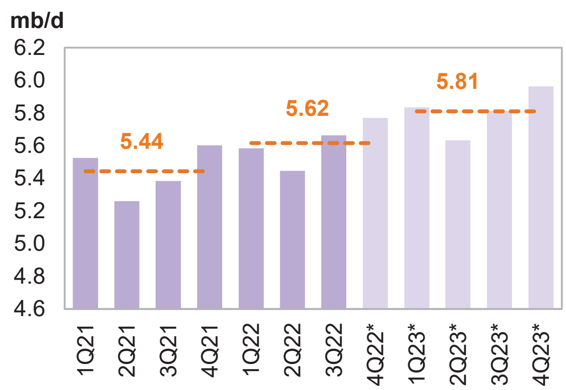


Sources: National Energy Board and OPEC.

Canada's liquids supply in **2022** is estimated to grow by 0.2 mb/d to average 5.6 mb/d, down by 31 tb/d from the previous assessment due to national source downward revisions in 3Q22 and lower-than-anticipated output in 4Q22. Oil sands output, mainly from Alberta's projects, saw an average of 3.1 mb/d from January to November 2022.

Canada's production is estimated to grow in 4Q22 by 0.1 mb/d q-o-q, as upgraders returned from maintenance. However, disruptions related to a short closure of the Canada-to-US Keystone crude pipeline and maintenance provide downside risks to the 4Q22 forecast.

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



*Note: * 4Q22-4Q23 = Forecast. Source: OPEC.*

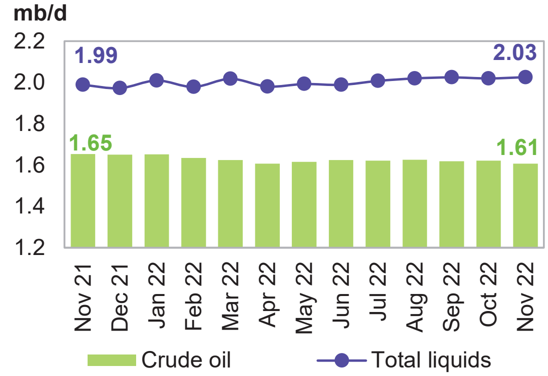
For **2023**, Canada's liquids production is forecast to increase at a pace similar to 2022, rising by 0.2 mb/d to average 5.8 mb/d. Incremental production will come through oil sand project ramp-ups and debottlenecks, alongside conventional growth. Moreover, the Terra Nova Floating Production Storage and Offloading (FPSO) platform is expected to resume production in 1Q23.

Mexico

Mexico's crude output decreased by 14 tb/d m-o-m in **November** to average 1.6 mb/d, while NGLs output rose by 20 tb/d, driven by the ramp-up of the Quesqui condensate field. This saw Mexico's total November liquids output remain broadly unchanged m-o-m at an average of 2.0 mb/d, according to Pemex.

For **2022**, Mexico's liquids production is estimated to average 2.0 mb/d, broadly unchanged from the previous month's assessment. Growth of 50 tb/d in 2022 is expected to be driven by foreign-operated fields, while minor growth is also anticipated in Pemex-operated assets. High decline rates in Pemex's mature and heavy oil fields are set to mostly offset its other grades.

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



Sources: PEMEX and OPEC.

For **2023**, liquids production is forecast to decline by 29 tb/d to average 1.98 mb/d, which is similar to the previous assessment. The total crude production decline in Pemex's mature fields is projected to outweigh production ramp-ups, mainly from Mexico's foreign-operated fields.

OECD Europe

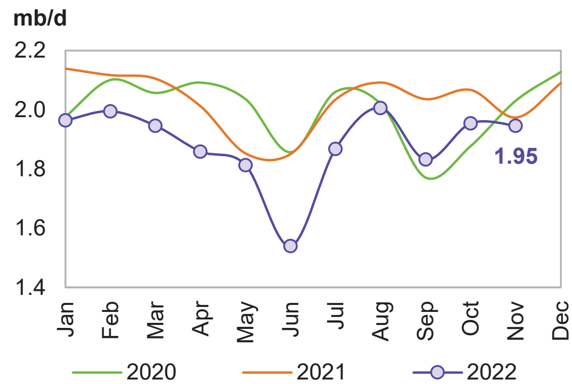
Norway

Norwegian liquids production in **November** decreased by a minor 8 tb/d m-o-m to average 1.9 mb/d. This reflects ongoing underperformance in Norwegian fields.

Norway's crude production declined by 10 tb/d m-o-m in November to average 1.7 mb/d, broadly unchanged y-o-y. Monthly oil production was 8.7% lower than the Norwegian Petroleum Directorate's (NPD) forecast.

At the same time, the production of NGLs and condensates remained chiefly unchanged m-o-m, averaging 0.2 mb/d, according to NPD data.

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



Sources: NPD and OPEC.

For **2022**, production growth has been revised down by 19 tb/d y-o-y to average 1.9 mb/d. This is mainly due to downward revisions in 4Q22 output on the back of lower-than-anticipated November production.

According to Equinor, the start-up of giant Johan Sverdrup's Phase 2 took place on December 15. The two phases now account for around one-third of the country's oil production and add a heavier, sour crude to the North Sea's predominantly light sweet flows. It is expected that the field's total export will be stepped up gradually as further commissioning and testing of systems are ongoing. In addition, the Njord field is back online after a multi-year modification process and has been upgraded for future tie-back developments by the Fenja and Bauge fields.

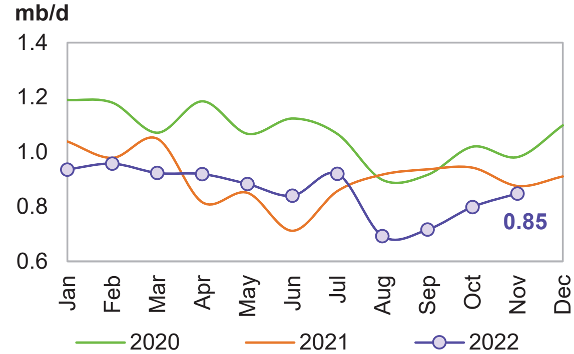
For **2023**, Norwegian liquids production is forecast to grow by 0.3 mb/d, broadly unchanged compared with the previous month, to average 2.2 mb/d. A number of small-to-large projects are scheduled to ramp up in 2023. The continuing Johan Sverdrup Phase 2 ramp-up is projected to be the main source of growth for this year.

UK

UK liquids production increased m-o-m in **November** by 49 tb/d to average 0.8 mb/d. Crude oil output increased by 47 tb/d m-o-m to average 0.7 mb/d, according to official data, though this was lower by 28 tb/d y-o-y. NGLs output remained broadly unchanged at an average of 90 tb/d. UK liquids output in November was down by 3% from the same month a year earlier, mainly due to extended maintenance and natural declines.

For **2022**, UK liquids production is forecast to decline by 47 tb/d to average 0.9 mb/d. This is a downward revision by a minor 5 tb/d from the previous assessment, owing to lower-than-expected November production.

Graph 5 - 19: UK monthly liquids production development



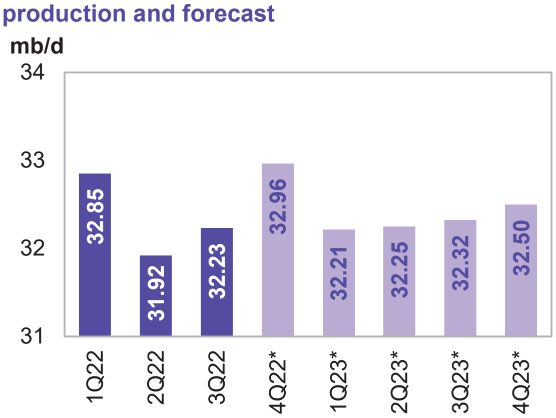
Sources: Department of Energy & Climate Change and OPEC.

For **2023**, UK liquids production is forecast to increase by 48 tb/d to average 0.9 mb/d. The Shell Penguins FPSO set off for its UK North Sea destination on December 5. Penguins is the redevelopment of a former tie-back field to the Brent Charlie hub and is expected to reach 45 tboe/d at peak.

Project sanctioning will be essential to maintain future oil and gas output, as UK output has been in long-term decline. It should be noted that UK authorities announced plans to raise the Energy Profits Levy (EPL) on oil and gas companies by ten percentage points to 35%, yielding a total tax rate of 75%, one of the highest in the world, effective from January 2023.

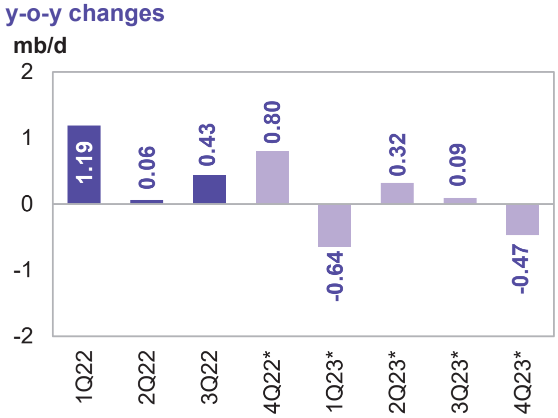
Non-OECD

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



*Note: * 4Q22-4Q23 = Forecast. Source: OPEC.*

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

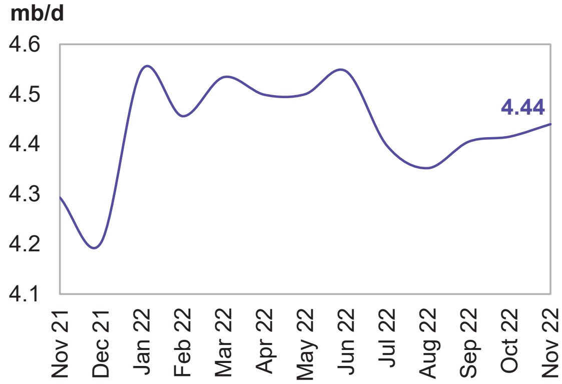


*Note: * 4Q22-4Q23 = Forecast. Source: OPEC.*

China

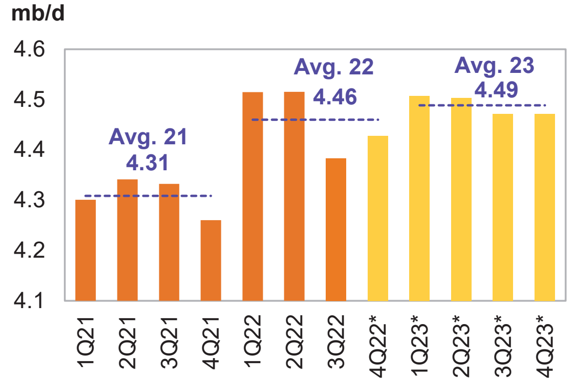
China's liquids production increased m-o-m in **November** by 25 tb/d to average 4.4 mb/d, which is a rise of 147 tb/d y-o-y, according to official data. Crude oil output in November averaged 4.0 mb/d, up by 27 tb/d compared with the previous month, and higher y-o-y by 114 tb/d. Liquids production over January–November 2022 averaged 4.5 mb/d, higher by 3.3% compared with the same period the previous year.

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



Sources: CNPC and OPEC.

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



Note: * 4Q22-4Q23 = Forecast. Sources: CNPC and OPEC.

For **2022**, growth of 151 tb/d is estimated for an average of 4.5 mb/d. This is unchanged from the previous assessment. Natural decline rates are expected to be offset by additional growth through more infill wells and enhanced oil recovery projects amid efforts by state-owned oil companies to ensure energy supply security. China National Offshore Oil Corporation (CNOOC) has started production from the Kenli 6-1 oilfield, part of the block's development project in the southern Bohai Sea offshore eastern China. The development covers the main area of Kenli 6-1, China's first large-scale shallow oilfield project, according to Offshore Magazine.

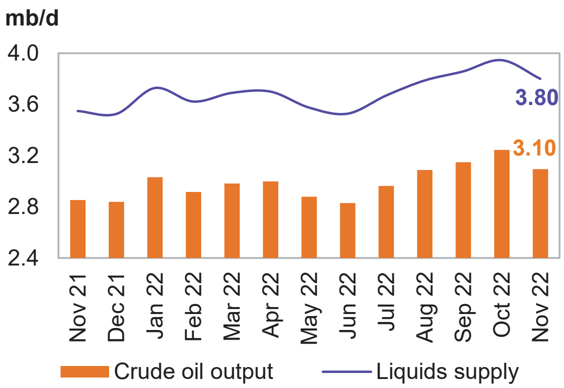
For **2023**, y-o-y growth of 30 tb/d is forecast for an average of 4.5 m/d, unchanged from last month's assessment. New offshore discoveries, the development of remote onshore basins and more investment in advanced enhanced oil recovery projects are expected to offset the declining output of mature fields.

Latin America

Brazil

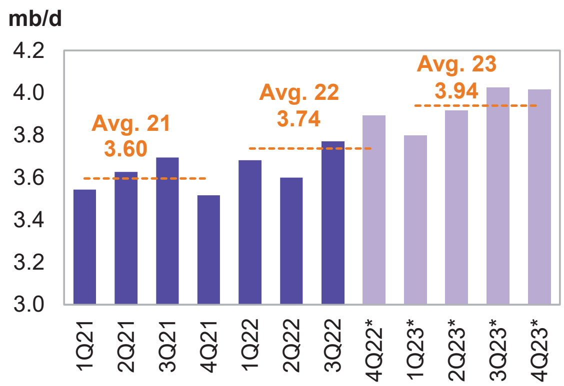
Brazil's crude output in **November** decreased m-o-m by 149 tb/d to average 3.1 mb/d. NGLs production was largely unchanged at an average of 93 tb/d and is expected to remain flat in December. Biofuels output (mainly ethanol) was flat in November at an average of 612 tb/d, with preliminary data also showing a flat trend in December. Total liquids production decreased by 147 tb/d in November to average 3.8 mb/d, after the highest production rate on record of 3.9 mb/d was seen in October. However, this is a rise of 0.3 mb/d y-o-y. The output reduction was mainly due to some issues at Tupi field installations.

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



Sources: ANP, Petrobras and OPEC.

Graph 5 - 25: Brazil's quarterly liquids production



Note: * 4Q22-4Q23 = Forecast. Sources: ANP and OPEC.

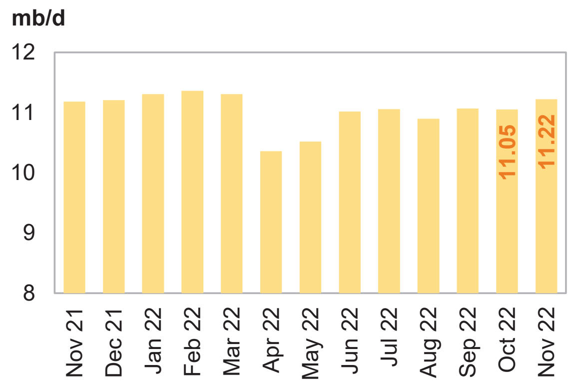
For **2022,** Brazil's liquids supply, including biofuels, is forecast to increase by 0.1 mb/d y-o-y to average 3.7 mb/d. This is down by a minor 7 tb/d from the previous month's assessment due to lower-than-expected production in November. Equinor's Peregrino Phase 2 (Platform C) started production in October and is ramping up volumes in 4Q22 and into 2023. Growth in 2022 is being driven by the continued ramp-up of the Sepia field and the start-up of Mero 1 in the pre-salt Santos basin, as well as Peregrino (Phases 1 and 2) in the Campos basin.

For **2023**, Brazil's liquids supply, including biofuels, is forecast to increase by 0.2 mb/d y-o-y to average 3.9 mb/d, broadly unchanged from the previous forecast. Crude oil output is set to increase through production ramp-ups in the Mero (Libra NW), Buzios (Franco), Tupi (Lula), Peregrino, Sepia, Marlim and Itapu (Florim) fields. However, offshore maintenance is expected to cause interruptions in major fields. Petrobras has started operations at the FPSO P-71 on the Itapu Field in the presalt Santos Basin. The vessel is designed to process up to 150 tb/d of oil and 6 MMcm/d of gas, and can store up to 1.6 MMbbl of oil. The startup was ahead of the original schedule, according to Petrobras.

Russia

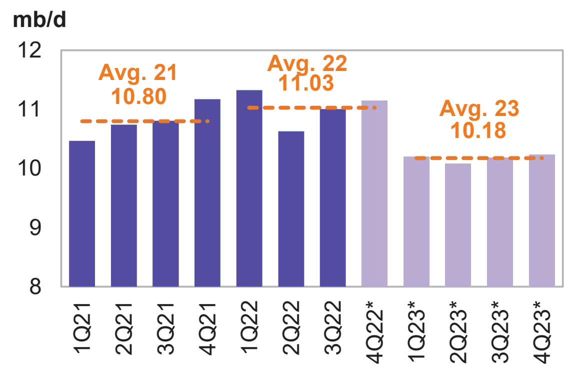
Russia's liquids production in November jumped m-o-m by 173 tb/d to average 11.2 mb/d. This includes 9.8 mb/d of crude oil and 1.4 mb/d of NGLs and condensate. A preliminary estimate of Russia's crude production in December 2022 shows a m-o-m decrease of 53 tb/d to average 9.8 mb/d, while stable output is seen for NGLs and condensate.

Graph 5 - 26: Russia's monthly liquids production



Sources: Nefte Compass and OPEC.

Graph 5 - 27: Russia's quarterly liquids production



Note: * 4Q22-4Q23 = Forecast.
Sources: Nefte Compass and OPEC.

Russian liquids output in **2022** is forecast to increase y-o-y by 0.2 mb/d to average 11.0 mb/d. This is revised up by 68 tb/d from the previous month's assessment, mainly due to higher November output and higher-than-expected preliminary production data in December.

For **2023**, Russian liquids production is forecast to drop by 0.85 mb/d to average 10.2 mb/d. The annual growth is unchanged from the previous assessment. It should be noted that Russia's oil forecast remains subject to high uncertainty.

Caspian

Kazakhstan & Azerbaijan

Liquids output in Kazakhstan rose by 372 tb/d to average 2.0 mb/d in **November**. Crude production was up by 233 tb/d m-o-m to average 1.7 mb/d, and NGLs increased by 139 tb/d to average 0.4 mb/d. Higher oil output was due to the gradual ramp-up of the Kashagan oil field, as well as the completion of planned maintenance at the Karachaganak gas condensate field.

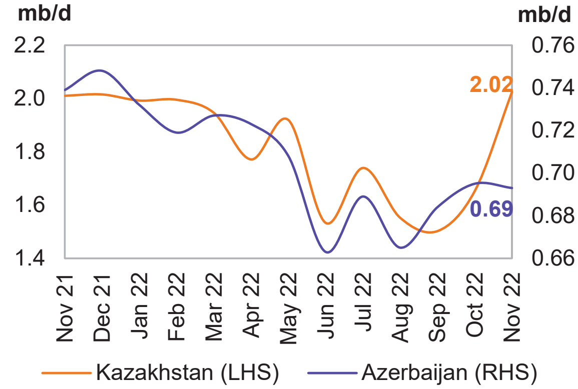
Kazakhstan's liquids supply for **2022** is now forecast to decline by 35 tb/d y-o-y to average 1.8 mb/d. This is broadly unchanged compared with the previous month's assessment. Crude production at the Kashagan field recovered to a nominal capacity of around 400 tb/d in the second week of November. At the same time, the two required Single Point Moorings (SPM) have been operational at a crude terminal on Russia's Black Sea coast since November.

For **2023**, the liquids supply is forecast to increase by 157 tb/d, unchanged compared with the previous forecast. In addition to the production ramp-up at the Kashagan oil field, oil output in the Tengiz field and gas condensate production in the Karachaganak field are also expected to rise marginally.

Azerbaijan's liquids production in November remained unchanged m-o-m, averaging 0.7 mb/d, although this is a drop of 46 tb/d y-o-y. Crude production averaged 553 tb/d, with NGLs output at 140 tb/d, according to official sources.

For **2022**, the liquids supply in Azerbaijan is estimated to decline y-o-y by 34 tb/d to average 0.7 mb/d. This is a downward revision by a minor 7 tb/d due to lower-than-expected production in major oil fields in November. The main declines in legacy fields are expected to be offset by ramp-ups in other fields, such as the BP-led consortium's Shah Deniz gas condensate field, which has increased gas production capacity in the Azeri sector of the Caspian Sea.

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



Sources: Nefte Compass and OPEC.

Azerbaijan's liquids supply for **2023** is forecast to rise by 60 tb/d to average 0.8 mb/d, according to voluntary production adjustments agreed on at the 33rd OPEC and non-OPEC Ministerial Meeting. Growth is forecast to come from the Shah Deniz and Absheron condensate projects. Production could rise further after output starts up at the Azeri Central East flank project in 2023.

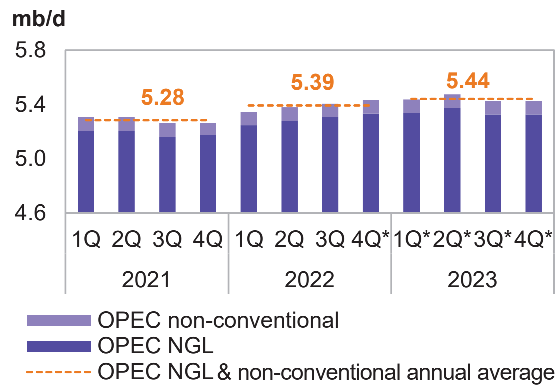
OPEC NGLs and non-conventional oils

OPEC NGLs and non-conventional liquids in 2022 are estimated to grow by 0.1 mb/d to average 5.4 mb/d, unchanged from the previous assessment.

NGLs output in 3Q22 is estimated to have averaged 5.31 mb/d, while OPEC non-conventional output remained steady at 0.1 mb/d. Taken together, 5.4 mb/d is expected for November, according to preliminary data.

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

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



*Note: * 4Q22-4Q23 = Forecast. Source: OPEC.*

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

OPEC NGL and non-coventional oils	2021	Change 21/20	2022	Change 22/21	1Q23	2Q23	3Q23	4Q23	2023	Change 23/22
OPEC NGL	**5.18**	*0.12*	**5.29**	*0.11*	5.34	5.37	5.33	5.33	**5.34**	*0.05*
OPEC non-conventional	**0.10**	*0.00*	**0.10**	*0.00*	0.10	0.10	0.10	0.10	**0.10**	*0.00*
Total	**5.28**	***0.12***	**5.39**	***0.11***	**5.44**	**5.47**	**5.43**	**5.43**	**5.44**	***0.05***

Note: 2022 = Estimate and 2023 = Forecast. Source: OPEC.

OPEC crude oil production

According to secondary sources, total **OPEC-13 crude oil production** averaged 28.97 mb/d in December 2022, higher by 91 tb/d m-o-m. Crude oil output increased mainly in Nigeria, Angola, Libya and Venezuela, while production in Kuwait, Congo and Algeria declined.

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

Secondary sources	2021	2022	2Q22	3Q22	4Q22	Oct 22	Nov 22	Dec 22	*Change* Dec/Nov
Algeria	913	1,017	1,015	1,040	1,030	1,050	1,026	1,015	*-11*
Angola	1,117	1,142	1,171	1,151	1,093	1,054	1,092	1,134	*42*
Congo	265	263	268	266	255	261	261	243	*-18*
Equatorial Guinea	97	84	90	90	66	70	65	64	*-1*
Gabon	182	197	190	201	199	205	199	193	*-6*
IR Iran	2,392	2,554	2,555	2,565	2,565	2,557	2,565	2,574	*9*
Iraq	4,049	4,448	4,440	4,542	4,519	4,593	4,484	4,480	*-4*
Kuwait	2,419	2,705	2,690	2,801	2,713	2,806	2,684	2,649	*-35*
Libya	1,143	991	751	992	1,156	1,166	1,142	1,159	*17*
Nigeria	1,372	1,203	1,209	1,063	1,169	1,066	1,175	1,267	*91*
Saudi Arabia	9,114	10,531	10,450	10,894	10,606	10,861	10,474	10,478	*4*
UAE	2,727	3,065	3,045	3,168	3,091	3,187	3,047	3,039	*-9*
Venezuela	553	685	714	667	674	681	664	676	*13*
Total OPEC	**26,343**	**28,885**	**28,587**	**29,440**	**29,139**	**29,558**	**28,879**	**28,971**	***91***

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

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

Direct communication	2021	2022	2Q22	3Q22	4Q22	Oct 22	Nov 22	Dec 22	*Change* Dec/Nov
Algeria	911	1,020	1,016	1,050	1,030	1,060	1,021	1,009	*-12*
Angola	1,124	1,140	1,173	1,151	1,076	1,051	1,088	1,088	*0*
Congo	267	262	258	261	261	267	260	257	*-3*
Equatorial Guinea	93	81	91	83	56	57	56	54	*-1*
Gabon	181	191	184	198	183	170	191	189	*-2*
IR Iran	..	..	..	..	..	..	..	..	*..*
Iraq	3,971	4,450	4,472	4,632	4,505	4,651	4,430	4,431	*1*
Kuwait	2,415	2,707	2,694	2,799	2,721	2,811	2,676	2,676	*0*
Libya	1,207	..	..	..	..	..	..	..	*..*
Nigeria	1,323	1,143	1,133	999	1,145	1,014	1,186	1,235	*50*
Saudi Arabia	9,125	10,591	10,542	10,968	10,622	10,957	10,468	10,435	*-32*
UAE	2,718	3,064	3,042	3,170	3,093	3,188	3,047	3,043	*-4*
Venezuela	636	716	745	673	693	717	693	669	*-23*
Total OPEC	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	***..***

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

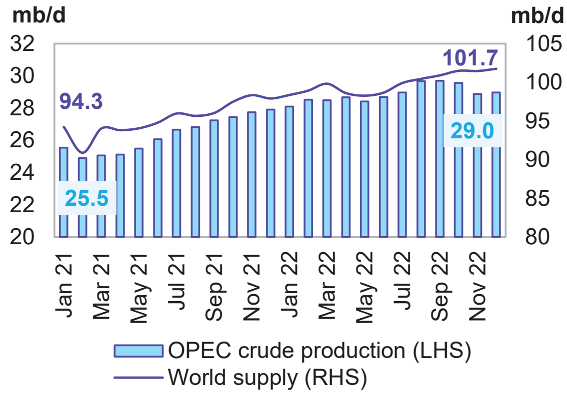
World oil supply

Preliminary data indicates that **global liquids production in December** increased by 0.3 mb/d to average 101.7 mb/d compared with the previous month.

Non-OPEC liquids production (including OPEC NGLs) is estimated to have increased m-o-m in December by 0.2 mb/d to average 72.8 mb/d. This was higher by 2.8 mb/d y-o-y. Preliminary estimated production increases in December were mainly driven by OECD Europe, Latin America and Other Eurasia and partially offset by declines in the US and Russia.

The **share of OPEC crude oil in total global production** remained unchanged at 28.5% in December, compared with the previous month. Estimates are based on preliminary data for non-OPEC supply, OPEC NGLs and non-conventional oil, while assessments for OPEC crude production are based on secondary sources.

Graph 5 - 30: OPEC crude production and world oil supply development



Source: OPEC.

Commercial Stock Movements

Preliminary November data sees total OECD commercial oil stocks up m-o-m by 2.7 mb. At 2,768 mb, they were 26 mb higher than the same time one year ago, 137 mb lower than the latest five-year average and 173 mb below the 2015–2019 average. Within the components, crude stocks fell by 25.8 mb, while product stocks rose m-o-m by 28.5 mb.

At 1,343 mb, OECD crude stocks were 22 mb higher than the same time a year ago, but 73 mb lower than the latest five-year average and 108 mb lower than the 2015–2019 average.

OECD product stocks stood at 1,425 mb, representing a surplus of 4 mb from the same time a year ago, but 63 mb lower than the latest five-year average and 65 mb below the 2015–2019 average.

In terms of days of forward cover, OECD commercial stocks rose m-o-m by 0.1 day in November to stand at 59.5 days. This is 0.3 days above November 2021 levels, but 3.5 days less than the latest five-year average and 2.6 days lower than the 2015–2019 average.

Preliminary data for December showed that total US commercial oil stocks fell by 11.9 mb m-o-m to stand at 1,205 mb. This is 6.6 mb lower than the same month in 2021 but 57.1 mb below the latest five-year average. Crude stocks rose by 6.7 mb, while product stocks fell by 18.7 mb.

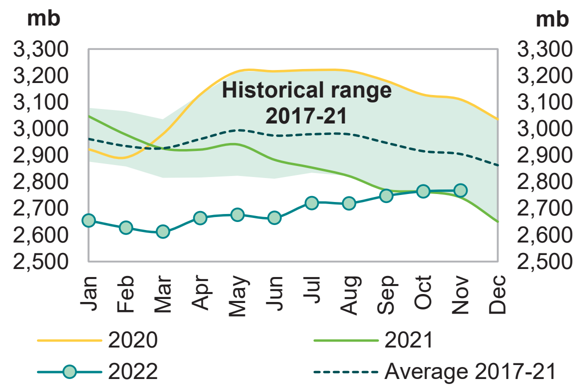
OECD

Preliminary **November** data sees **total OECD commercial oil stocks** up m-o-m by 2.7 mb. At 2,768 mb, they were 26 mb higer than the same time one year ago, but 137 mb lower than the latest five-year average and 173 mb below the 2015–2019 average.

Within the components, crude stocks fell by 25.8 mb, while product stocks rose m-o-m by 28.5 mb. Total commercial oil stocks in November rose in OECD Europe, while they fell in OECD Americas and OECD Asia Pacific.

OECD commercial **crude stocks** stood at 1,343 mb in November. This is 22 mb higher than the same time a year ago, but 73 mb lower than the latest five-year average and 108 mb lower than the 2015–2019 average.

Graph 9 - 1: OECD commercial oil stocks



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

Compared with the previous month, OECD Americas saw a stock draw of 25.5 mb, OECD Asia Pacific stocks fell by 4.4 mb, while stocks in OECD Europe increased by 4.2 mb.

Total product inventories stood at 1,425 mb in November. This is 4.3 mb above the same time a year ago; 63 mb lower than the latest five-year average and 65 mb below the 2015–2019 average. Product stocks rose in all OECD regions.

Table 9 - 1: OECD's commercial stocks, mb

OECD stocks	Nov 21	Sep 22	Oct 22	Nov 22	Change Nov 22/Oct 22
Crude oil	1,321	1,348	1,368	1,343	-25.8
Products	1,421	1,400	1,397	1,425	28.5
Total	**2,742**	**2,748**	**2,765**	**2,768**	**2.7**
Days of forward cover	**59.2**	**58.6**	**59.4**	**59.5**	***0.1***

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

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

In terms of **days of forward cover**, OECD commercial stocks rose m-o-m by 0.1 days in November to stand at 59.5 days. This is 0.3 days above November 2021 levels, but 3.5 days less than the latest five-year average and 2.6 days lower than the 2015–2019 average.

All three OECD regions were below the latest five-year average: the Americas by 4.5 days at 58.8 days; Asia Pacific by 2.2 days at 45.5 days; and Europe by 2.9 days at 69.3 days.

OECD Americas

OECD Americas total commercial stocks fell by 4.3 mb m-o-m in November to settle at 1,469 mb. This is 40 mb less than the same month in 2021 and 79 mb lower than the latest five-year average.

Commercial **crude oil stocks** in OECD Americas fell m-o-m by 25.5 mb in November to stand at 725 mb, which is 39 mb lower than in November 2021 and 52 mb less than the latest five-year average. The monthly drop in crude oil stocks can be attributed to higher US crude runs, which rose by 0.65 mb/d to 16.92 mb/d.

By contrast, **total product stocks** in OECD Americas rose m-o-m by 21.2 mb in November to stand at 744 mb. Nevertheless, this was 0.9 mb lower than the same month in 2021 and 27 mb below the latest five-year average. Lower consumption in the region was behind the product stock build.

OECD Europe

OECD Europe total commercial stocks rose m-o-m by 7.6 mb in November to settle at 929 mb. This is 42 mb higher than the same month in 2021, but 30 mb below the latest five-year average.

OECD Europe's **commercial crude stocks** rose by 4.2 mb m-o-m to end the month of November at 428 mb, which is 42 mb higher than one year ago and 6 mb above the latest five-year average. The build in crude oil inventories came despite higher m-o-m refinery throughput in the EU-14, plus the UK and Norway, which increased by 550 tb/d to 9.79 mb/d.

Europe's **product stocks** also rose m-o-m by 3.4 mb to end November at 501 mb. This is 0.1 mb less than a year ago and 36 mb below the latest five-year average.

OECD Asia Pacific

OECD Asia Pacific's total commercial oil stocks fell m-o-m by 0.6 mb in November to stand at 370 mb. This is 25 mb higher than a year ago, but 27 mb below the latest five-year average.

OECD Asia Pacific's **crude inventories** dropped by 4.4 mb m-o-m to end November at 190 mb, which is 20 mb higher than one year ago, but 27 mb below the latest five-year average.

By contrast, OECD Asia Pacific's **total product inventories** rose m-o-m by 3.9 mb to end November at 180 mb. This is 5 mb higher than the same time a year ago but 0.1 mb below the latest five-year average.

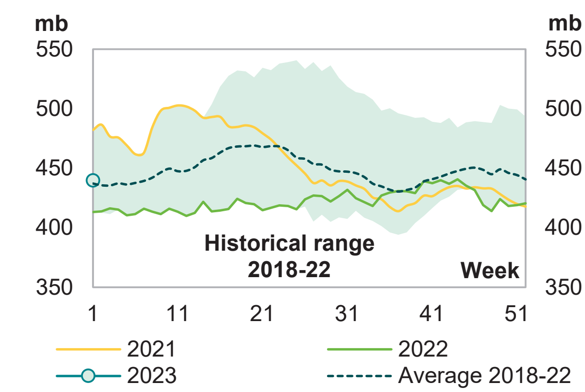
US

Preliminary data for December showed that **total US commercial oil stocks** fell by 11.9 mb m-o-m to stand at 1,205 mb. This is 6.6 mb, or 0.6%, higher than the same month in 2021 but 57.1 mb, or 4.5%, below the latest five-year average. Crude stocks rose by 6.7 mb, while product stocks fell by 18.7 mb.

US commercial crude stocks in November stood at 420.6 mb. This is 0.5 mb, or 0.1%, below the same month of the previous year, and 20.1 mb, or 4.6%, below the latest five-year average. The monthly build in crude oil stocks can be attributed to lower crude runs, which dropped by around 300 tb/d to 16.62 mb/d.

In contrast, **total product stocks** fell in December to stand at 784.6 mb. This is 7.2 mb, or 0.9%, higher than December 2021 levels but 37.1 mb, or 4.5%, lower than the latest five-year average. The stock drop could be attributed to higher product consumption.

Graph 9 - 2: US weekly commercial crude oil inventories



Sources: EIA and OPEC.

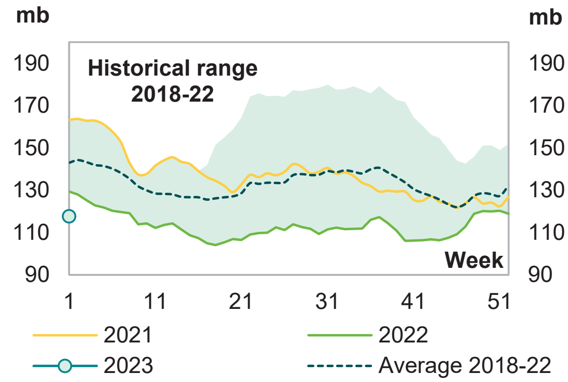
Gasoline stocks rose m-o-m by 3.6 mb to settle at 222.7 mb. This is 9.5 mb, or 4.1% lower than in the same month in 2021 and 19.9 mb, or 8.2%, lower than the latest five-year average.

Residual fuel oil stocks also rose by 1.0 mb m-o-m in December. At 30.0 mb, this was 4.3 mb, or 16.5%, higher than a year earlier, and 1.2 mb, or 4.2%, above the latest five-year average.

By contrast, **jet fuel stocks** fell m-o-m by 3.8 mb, ending December at 34.1 mb. This is 1.7 mb, or 4.7%, lower than the same month in 2021, and 5.4 mb, or 13.7%, below the latest five-year average.

Meanwhile, **distillate stocks** remained unchanged m-o-m in December to stand at 118.8 mb. This is 11.3 mb, or 8.7%, lower than the same month of the previous year and 24.6 mb, or 17.2%, below the latest five-year average.

Graph 9 - 3: US weekly distillate inventories



Sources: EIA and OPEC.

Table 9 - 2: US commercial petroleum stocks, mb

US stocks	Dec 21	Oct 22	Nov 22	Dec 22	*Change* Dec 22/Nov 22
Crude oil	**421.2**	**439.4**	**413.9**	**420.6**	***6.7***
Gasoline	232.2	211.0	219.1	222.7	*3.6*
Distillate fuel	130.0	110.5	118.8	118.8	*0.0*
Residual fuel oil	25.8	29.8	29.0	30.0	*1.0*
Jet fuel	35.8	36.6	38.0	34.1	*-3.8*
Total products	**777.4**	**791.3**	**803.3**	**784.6**	***-18.7***
Total	**1,198.6**	**1,230.7**	**1,217.2**	**1,205.2**	***-11.9***
SPR	**593.7**	**398.6**	**387.0**	**372.4**	***-14.6***

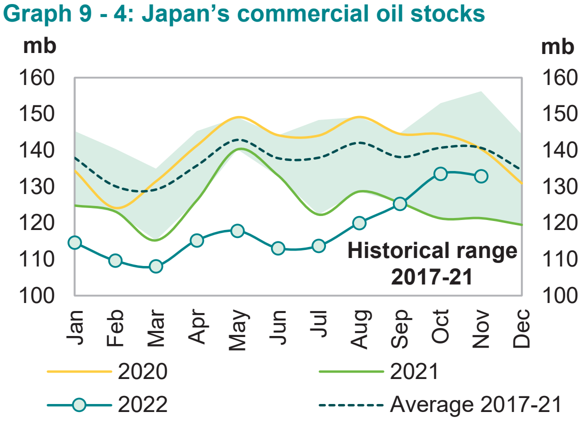
Sources: EIA and OPEC.

Japan

In **Japan**, **total commercial oil stocks** in November fell m-o-m by 0.6 mb to settle at 132.9 mb. This is 11.6 mb, or 9.5%, higher than the same month in 2021 but 7.7 mb, or 5.5%, below the latest five-year average. Crude stocks fell by 4.4 mb, while product stocks rose m-o-m by 3.9 mb.

Japanese **commercial crude oil stocks** fell in November to stand at 67.1 mb. This is 8.4 mb, or 14.4% higher than the same month of the previous year, but 7.6 mb, or 10.1%, lower than the latest five-year average. This stock draw came on the back of lower crude imports, which declined m-o-m by 144 tb/d, or 5.3%, to stand at 2.58 mb/d.

Graph 9 - 4: Japan's commercial oil stocks



Sources: METI and OPEC.

In contrast, Japan's **total product inventories** rose m-o-m by 3.9 mb to end November at 65.8 mb. This is 3.1 mb, or 5.0%, higher than the same month in 2021, but 0.1 mb, or 0.2%, below the latest five-year average.

Gasoline stocks rose m-o-m by 1.3 mb to stand at 11.1 mb in November. This was 0.7 mb, or 6.3% higher than a year earlier and in line with the latest five-year average. The build came on higher gasoline production, amounting to 3.1% m-o-m. Lower domestic sales, which declined by 6.0 % also supported the build in gasoline stocks.

Distillate stocks also rose m-o-m by 2.3 mb to end November at 32.1 mb. This is in line with the same month in 2021 and 0.5 mb, or 1.4%, below the latest five-year average. Within distillate components, kerosene, jet fuel and gasoil stocks went up by 11.3%, 6.1% and 2.2%, respectively.

Total residual fuel oil stocks rose m-o-m by 0.2 mb to end November at 12.6 mb. This is 0.9 mb, or 7.7%, higher than in the same month of the previous year but 0.4 mb, or 3.1%, below the latest five-year average. Within the components, fuel oil A stocks rose by 5.2 %, while fuel oil B.C stocks fell by 0.5 % m-o-m.

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

Japan's stocks	Nov 21	Sep 22	Oct 22	Nov 22	*Change* Nov 22/Oct 22
Crude oil	**58.7**	**67.5**	**71.6**	**67.1**	***-4.4***
Gasoline	10.5	9.8	9.8	11.1	*1.3*
Naphtha	8.5	9.5	9.9	10.0	*0.1*
Middle distillates	32.1	27.0	29.8	32.1	*2.3*
Residual fuel oil	11.7	11.5	12.4	12.6	*0.2*
Total products	**62.7**	**57.8**	**61.9**	**65.8**	***3.9***
Total**	**121.4**	**125.3**	**133.5**	**132.9**	***-0.6***

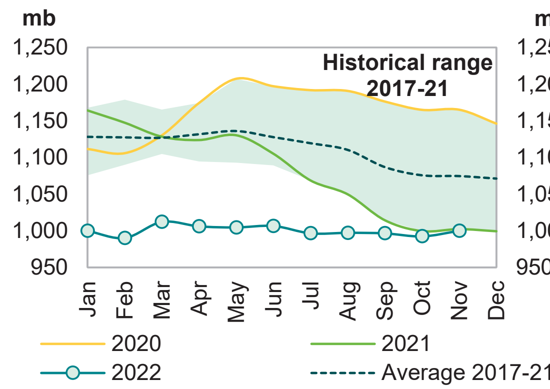
*Note: * At the end of the month. ** Includes crude oil and main products only.*
Sources: METI and OPEC.

EU-14 plus UK and Norway

Preliminary data for November showed that **total European commercial oil stocks** rose m-o-m by 7.6 mb to stand at 1000.1 mb. At this level, they were 2.2 mb, or 0.2%, below the same month a year earlier and 74.3 mb, or 6.9% lower than the latest five-year average. Crude and product stocks rose m-o-m by 4.2 mb and 3.4 mb, respectively.

European **crude inventories** rose in November to stand at 439.7 mb. This is 14.7 mb, or 3.4%, higher than the same month in 2021 but 28.1 mb, or 6.0%, below the latest five-year average. The build in crude oil inventories came despite higher m-o-m refinery throughput in the EU-14, plus the UK and Norway, which increased by 550 tb/d to 9.79 mb/d.

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



Sources: Argus, Euroilstock and OPEC.

Total European product stocks also rose m-o-m by 3.4 mb to end November at 560.4 mb. This is 16.8 mb, or 2.9%, lower than the same month of the previous year and 46.2 mb, or 7.6%, below the latest five-year average.

Gasoline stocks rose m-o-m by 0.3 mb in November to stand at 105.4 mb. At this level, they were 3.1 mb, or 2.8%, lower than the same time a year earlier, and 7.3 mb/d, or 6.5%, below the latest five-year average.

Distillate stocks also rose m-o-m by 2.4 mb in November to stand at 361.9 mb. This is 24.0 mb, or 6.2%, below the same month in 2021 and 42.2 mb, or 10.4%, less than the latest five-year average.

Residual fuel stocks rose m-o-m by 0.3 mb in November to stand at 61.9 mb. This is 3.9 mb, or 6.7%, higher than the same month in 2021, but 0.8 mb, or 1.3%, below the latest five-year average.

Naphtha stocks also rose by 0.4 mb in November, ending the month at 31.2 mb. This is 6.4 mb, or 25.8%, higher than November 2021 levels and 4.1 mb, or 15.3%, higher than the latest five-year average.

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

EU stocks	Nov 21	Sep 22	Oct 22	Nov 22	Change Nov 22/Oct 22
Crude oil	**425.0**	**431.9**	**435.5**	**439.7**	***4.2***
Gasoline	108.5	106.0	105.1	105.4	*0.3*
Naphtha	24.8	30.6	30.8	31.2	*0.4*
Middle distillates	385.9	368.3	359.5	361.9	*2.4*
Fuel oils	58.0	59.7	61.6	61.9	*0.3*
Total products	**577.2**	**564.6**	**557.0**	**560.4**	***3.4***
Total	**1,002.2**	**996.6**	**992.5**	**1,000.1**	***7.6***

Sources: Argus, Euroilstock and OPEC.

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

Singapore

In November, **total product stocks in Singapore** rose m-o-m by 1.1 mb to 42.3 mb. This is 1.9 mb, or 4.6%, higher than the same month in 2021, but 3.3 mb or 7.2% below the latest five-year average.

Light distillate stocks fell m-o-m by 0.1 mb in November to stand at 14.6 mb. This is 2.5 mb, or 21.1%, higher than the same month of the previous year and 2.3 mb or 18.8% above the latest five-year average.

In contrast, **middle distillate stocks** rose m-o-m by 0.9 mb in November, to stand at 7.8 mb. This is 0.3 mb, or 3.9%, lower than a year earlier and 3.5 mb or 31.4% lower than the latest five-year average.

Residual fuel oil stocks also rose m-o-m by 0.3 mb, ending November at 19.9 mb. This is 0.4 mb, or 1.8%, lower than November 2021 and 2.1 mb or 9.4% below the latest five-year average.

ARA

Total product stocks in ARA rose m-o-m in November by 1.1 mb. At 40.7 mb, they were 3.6 mb, or 9.7%, higher than the same month in 2021 and 1.5 mb or 3.9% higher than the latest five-year average.

Gasoline stocks in November rose by 1.0 mb m-o-m to stand at 11.5 mb, which is 4.3 mb, or 59.3%, higher than the same month of the previous year and 3.4 mb or 41.4% above the latest five-year average.

Jet oil stocks also rose by 0.3 mb m-o-m to stand at 6.9 mb. This is 0.6 mb, or 8.9%, higher than levels seen in November 2021 and 1.0 mb or 15.9% above the latest five-year average. .

In contrast, **gasoil stocks** dropped by 0.1 mb m-o-m, ending November at 12.9 mb. This is 0.5 mb, or 3.4%, lower than November 2021 and 3.1 mb or 19.3 % below the latest five-year average.

Fuel oil stocks also fell by 0.5 mb m-o-m in November to stand at 6.6 mb, which is 1.4 mb, or 17.2%, less than in November 2021 and 0.4 mb or 5.4% below the latest five-year average.

Fujairah

During the week ending 2 January 2023, **total oil product stocks in Fujairah** fell w-o-w by 0.32 mb to stand at 20.35 mb, according to data from Fed Com and S&P Global Platts. At this level, total oil stocks were 3.83 mb higher than at the same time a year ago.

Light distillate stocks fell by 0.64 mb to stand at 6.83 mb, which is 2.08 mb higher than a year ago. By contrast, **middle distillate stocks** rose w-o-w by 0.03 mb to stand at 3.12 mb, which is 1.47 mb higher than the same time last year. **Heavy distillate stocks** also rose by 0.29 mb w-o-w to stand at 10.40 mb in the week to 2 January 2023, which is 0.28 mb higher than the same period a year ago.

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

World oil demand and supply balance	2019	2020	2021	1Q22	2Q22	3Q22	4Q22	2022	1Q23	2Q23	3Q23	4Q23	2023
World demand													
Americas	25.40	22.45	24.32	24.77	24.98	25.34	25.19	25.07	24.95	25.26	25.68	25.45	25.34
of which US	*20.58*	*18.35*	*20.03*	*20.38*	*20.41*	*20.62*	*20.64*	*20.51*	*20.46*	*20.54*	*20.88*	*20.77*	*20.66*
Europe	14.31	12.41	13.13	13.19	13.42	14.07	13.90	13.65	13.22	13.45	14.10	13.95	13.68
Asia Pacific	7.95	7.17	7.38	7.85	6.99	7.22	7.81	7.47	7.88	7.04	7.27	7.83	7.50
Total OECD	**47.66**	**42.03**	**44.83**	**45.81**	**45.39**	**46.63**	**46.91**	**46.19**	**46.06**	**45.74**	**47.04**	**47.23**	**46.52**
China	13.81	13.94	14.97	14.74	14.42	14.64	15.24	14.76	14.90	15.20	15.20	15.78	15.27
India	4.99	4.51	4.77	5.18	5.16	4.95	5.35	5.16	5.41	5.44	5.21	5.59	5.41
Other Asia	9.06	8.13	8.63	9.09	9.27	8.73	8.85	8.98	9.42	9.61	9.10	9.20	9.33
Latin America	6.59	5.90	6.23	6.32	6.36	6.55	6.45	6.42	6.44	6.49	6.71	6.61	6.57
Middle East	8.20	7.45	7.79	8.06	8.13	8.50	8.22	8.23	8.45	8.46	8.84	8.51	8.56
Africa	4.44	4.08	4.22	4.51	4.15	4.25	4.58	4.37	4.71	4.34	4.43	4.77	4.56
Russia	3.57	3.39	3.61	3.67	3.42	3.45	3.59	3.53	3.63	3.45	3.59	3.75	3.61
Other Eurasia	1.19	1.07	1.21	1.22	1.16	1.00	1.21	1.15	1.21	1.16	1.02	1.22	1.15
Other Europe	0.76	0.70	0.75	0.79	0.75	0.73	0.80	0.77	0.80	0.76	0.75	0.82	0.78
Total Non-OECD	**52.62**	**49.16**	**52.18**	**53.58**	**52.81**	**52.79**	**54.27**	**53.36**	**54.98**	**54.90**	**54.86**	**56.24**	**55.25**
(a) Total world demand	**100.27**	**91.19**	**97.01**	**99.38**	**98.20**	**99.43**	**101.18**	**99.55**	**101.04**	**100.65**	**101.90**	**103.47**	**101.77**
Y-o-y change	***1.08***	***-9.09***	***5.82***	***5.18***	***2.55***	***1.77***	***0.74***	***2.54***	***1.65***	***2.44***	***2.47***	***2.29***	***2.22***
Non-OPEC liquids production													
Americas	25.84	24.75	25.25	25.86	26.27	27.01	27.49	26.66	27.64	27.73	28.09	28.46	27.98
of which US	*18.49*	*17.64*	*17.85*	*18.27*	*18.83*	*19.32*	*19.69*	*19.03*	*19.80*	*20.10*	*20.30*	*20.53*	*20.19*
Europe	3.70	3.89	3.76	3.73	3.43	3.49	3.65	3.57	3.93	3.91	3.80	3.93	3.89
Asia Pacific	0.52	0.52	0.51	0.49	0.51	0.43	0.51	0.48	0.50	0.48	0.50	0.48	0.49
Total OECD	**30.07**	**29.16**	**29.52**	**30.08**	**30.22**	**30.94**	**31.64**	**30.72**	**32.07**	**32.12**	**32.39**	**32.88**	**32.37**
China	4.05	4.15	4.31	4.51	4.52	4.38	4.43	4.46	4.51	4.50	4.47	4.47	4.49
India	0.83	0.78	0.78	0.78	0.77	0.76	0.76	0.77	0.79	0.78	0.77	0.76	0.78
Other Asia	2.72	2.51	2.41	2.35	2.30	2.24	2.31	2.30	2.37	2.36	2.33	2.35	2.35
Latin America	6.08	6.03	5.95	6.11	6.18	6.45	6.62	6.34	6.49	6.67	6.71	6.78	6.67
Middle East	3.19	3.19	3.24	3.29	3.33	3.36	3.35	3.33	3.34	3.36	3.39	3.39	3.37
Africa	1.51	1.41	1.35	1.33	1.31	1.32	1.30	1.32	1.32	1.33	1.35	1.34	1.33
Russia	11.51	10.54	10.80	11.33	10.63	11.01	11.15	11.03	10.21	10.08	10.18	10.23	10.18
Other Eurasia	3.07	2.91	2.93	3.05	2.77	2.61	2.95	2.84	3.09	3.05	3.02	3.06	3.06
Other Europe	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10
Total Non-OECD	**33.09**	**31.67**	**31.87**	**32.85**	**31.92**	**32.23**	**32.96**	**32.49**	**32.21**	**32.25**	**32.32**	**32.50**	**32.32**
Total Non-OPEC production	63.16	60.83	61.39	62.93	62.14	63.17	64.60	63.21	64.28	64.36	64.71	65.37	64.69
Processing gains	2.37	2.16	2.29	2.40	2.40	2.40	2.40	2.40	2.47	2.47	2.47	2.47	2.47
Total Non-OPEC liquids production	**65.53**	**62.98**	**63.68**	**65.33**	**64.54**	**65.57**	**67.00**	**65.61**	**66.75**	**66.83**	**67.18**	**67.84**	**67.16**
OPEC NGL + non-conventional oils	5.21	5.17	5.28	5.35	5.38	5.41	5.43	5.39	5.44	5.47	5.43	5.43	5.44
(b) Total non-OPEC liquids production and OPEC NGLs	**70.74**	**68.15**	**68.96**	**70.68**	**69.92**	**70.97**	**72.43**	**71.01**	**72.19**	**72.31**	**72.61**	**73.27**	**72.60**
Y-o-y change	***2.18***	***-2.60***	***0.82***	***2.72***	***1.25***	***1.99***	***2.22***	***2.04***	***1.51***	***2.39***	***1.63***	***0.84***	***1.59***
OPEC crude oil production (secondary sources)	29.36	25.71	26.34	28.36	28.59	29.44	29.14	28.88					
Total liquids production	100.11	93.86	95.31	99.04	98.51	100.41	101.57	99.89					
Balance (stock change and miscellaneous)	-0.17	2.67	-1.70	-0.35	0.30	0.98	0.39	0.34					
OECD closing stock levels, *mb*													
Commercial	2,894	3,037	2,651	2,613	2,666	2,748							
SPR	1,535	1,541	1,484	1,442	1,343	1,245							
Total	**4,429**	**4,578**	**4,134**	**4,055**	**4,009**	**3,993**							
Oil-on-water	1,033	1,148	1,202	1,222	1,290	1,386							
Days of forward consumption in OECD, *days*													
Commercial onland stocks	69	68	57	58	57	59							
SPR	37	34	32	32	29	27							
Total	**105**	**102**	**90**	**89**	**86**	**85**							
Memo items													
(a) - (b)	**29.53**	**23.04**	**28.05**	**28.70**	**28.28**	**28.46**	**28.75**	**28.55**	**28.85**	**28.34**	**29.30**	**30.20**	**29.17**

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

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

Oil Market Report - January 2023

About this report

The IEA Oil Market Report (OMR) is one of the world's most authoritative and timely sources of data, forecasts and analysis on the global oil market – including detailed statistics and commentary on oil supply, demand, inventories, prices and refining activity, as well as oil trade for IEA and selected non-IEA countries.

Highlights

- Global oil demand is set to rise by 1.9 mb/d in 2023, to a record 101.7 mb/d, with nearly half the gain from China following the lifting of its Covid restrictions. Jet fuel remains the largest source of growth, up 840 kb/d. OECD oil demand slumped by 900 kb/d in 4Q22 as weak industrial activity and weather effects lowered use, while non-OECD demand was 500 kb/d higher.
- World oil supply growth in 2023 is set to slow to 1 mb/d following last year's OPEC+ led growth of 4.7 mb/d. An overall non-OPEC+ rise of 1.9 mb/d will be tempered by an OPEC+ drop of 870 kb/d due to expected declines in Russia. The US ranks as the world's leading source of supply growth and, along with Canada, Brazil and Guyana, hits an annual production record for a second straight year.
- Global refinery activity was steady in December as US runs plunged 910 kb/d due to weather-related outages, but higher runs in Europe and Asia offset the fall. After an increase of 2.1 mb/d in 2022, refinery throughputs are set to grow by 1.5 mb/d in 2023, helped by 2.2 mb/d of capacity additions between 4Q22 and end-2023.
- Russian oil exports fell by 200 kb/d m-o-m in December to 7.8 mb/d, as crude shipments to the EU declined after the EU crude embargo and G7 price cap came into effect. Russian diesel exports surged to a multi-year high of 1.2 mb/d, of which 720 kb/d was destined for the EU. Record discounts for Russian benchmark Urals grade saw Russian revenues slip by $3 bn m-o-m to $12.6 bn.
- Global observed oil inventories surged by 79.1 mb m-o-m in November, hitting their highest levels since October 2021. The increase was led by non-OECD stocks (+43.9 mb) and oil on water (+38.1 mb). In the OECD, the release of government reserves offset a small increase in industry holdings. At 2 779 mb, OECD industry stocks were 37.1 mb above a year ago but 125.9 mb below their five-year average.
- Benchmark crude oil futures extended their rout in December, with ICE Brent falling $9.51/bbl to $81.34/bbl. The lifting of China's Covid-restrictions did little to boost sentiment while Russian oil exports remained resilient. Refinery outages in the US lifted product cracks. Freight rates eased for large crude carriers but rose on product routes ahead of the EU embargo on Russian oil products.

Risk management

Two wild cards dominate the 2023 oil market outlook: Russia and China. This year could see oil demand rise by 1.9 mb/d to reach 101.7 mb/d, the highest ever, tightening the balances as

Russian supply slows under the full impact of sanctions. China will drive nearly half this global demand growth even as the shape and speed of its reopening remains uncertain.

Energy efficiency gains **and** booming sales of electrical vehicles will curb global 2023 demand growth by close to 900 kb/d this year. Measures like these are especially vital in a supply-constrained oil market.

A slow demand recovery expected in 1H23 suggests continued inventory builds like those that started to emerge in 3Q22. In the last quarter of 2022, supply outpaced demand by over 1 mb/d despite a cut in OPEC+ production targets and disruptions to US supply due to winter storms. Mild weather combined with weak industrial activity to cut oil demand use in Europe. Demand was also restrained by China's Covid lockdowns and winter blizzards that disrupted holiday travel in the US and Canada. As a result, 4Q22 oil demand contracted by a massive 910 kb/d year-on-year in the OECD and exceptionally by 130 kb/d y-o-y in China.

Much of the surplus oil appears to have ended up in emerging markets, including China, and on tankers at sea. By end-November, observed non-OECD inventories had risen by 75 mb y-o-y compared to a 233 mb decline in the OECD where 270 mb of government reserves were released. Oil on water increased by a massive 181 mb because tankers now have to sail significantly longer distances due to the reallocation of Russian flows.

Following an initial collapse in Russian loadings after the EU crude embargo and a G7 price cap came into effect on 5 December, exports have partially rebounded - underscoring the high degree of uncertainty for the outlook. For December as a whole, loadings of Russian oil fell 200 kb/d on average to 7.8 mb/d, while total oil supply held steady at 11.2 mb/d. Nevertheless, record price discounts on Russian benchmark export grades of up to $40/bbl compared with North Sea Dated shrunk revenues by $3 bn to $12.6 bn last month – their lowest since February 2021. At the time of writing the North Sea benchmark was trading at around $83/bbl, down $18/bbl from a November peak and largely unchanged from a year ago.

The well-supplied oil balance at the start of 2023 could quickly tighten however as western sanctions impact Russian exports. Product markets, especially diesel, are most at risk just as demand growth recovers. In December, Russia exported a record 1.2 mb/d of diesel, with 60% destined for the EU. Fresh supplies from new plants in the Middle East and from China will provide welcome relief. Chinese diesel is already arriving in Europe after Beijing raised export quotas late last year.

Oil use savings and government stocks have proved their worth for managing market risks during the energy crisis triggered by Russia's invasion of Ukraine. Moving forward, accelerating efficiency gains, supporting EV uptake and prudent handling of government stocks will be more crucial than ever.

OPEC+ crude oil production[1]
million barrels per day

	Nov 2022 Supply	Dec 2022 Supply	Dec Prod vs Target	Dec-2022 Target	Sustainable Capacity[2]	Eff Spare Cap vs Dec[3]
Algeria	1.02	1.01	0.0	1.01	1.02	0.01
Angola	1.09	1.09	-0.36	1.46	1.17	0.08
Congo	0.26	0.25	-0.06	0.31	0.28	0.03
Equatorial Guinea	0.06	0.06	-0.06	0.12	0.09	0.03
Gabon	0.19	0.18	0.0	0.18	0.2	0.02
Iraq	4.46	4.45	0.02	4.43	4.7	0.25
Kuwait	2.68	2.66	-0.02	2.68	2.8	0.14
Nigeria	1.15	1.23	-0.51	1.74	1.37	0.14
Saudi Arabia	10.48	10.48	0.0	10.48	12.22	1.74
UAE	3.29	3.23	0.21	3.02	4.12	0.89
Total OPEC-10	**24.68**	**24.64**	**-0.78**	**25.42**	**27.98**	**3.34**
Iran[4]	2.72	2.72			3.8	
Libya[4]	1.15	1.17			1.2	0.03
Venezuela[4]	0.68	0.66			0.76	0.1
Total OPEC	**29.23**	**29.19**			**33.75**	**3.48**
Azerbaijan	0.55	0.55	-0.14	0.68	0.58	0.03
Kazakhstan	1.68	1.68	0.06	1.63	1.65	-0.03
Mexico[5]	1.61	1.65		1.75	1.66	0.01
Oman	0.84	0.84	0	0.84	0.86	0.02
Russia	9.8	9.77	-0.71	10.48	10.2	
Others [6]	0.84	0.85	-0.2	1.06	0.93	0.09
Total Non-OPEC	**15.31**	**15.34**	**-0.99**	**16.44**	**15.88**	**0.15**
OPEC+ 19 in cut deal[4]	**38.38**	**38.33**	**-1.77**	**40.1**	**42.2**	**3.48**
Total OPEC+	**44.54**	**44.53**			**49.63**	**3.63**

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

IEA World Oil Supply and Demand Forecasts: Summary (Table)
2023-01-18 09:00:00.7 GMT
By Kristian Siedenburg
(Bloomberg) -- Following is a summary of world oil supply and demand forecasts from the International Energy Agency in Paris:

	4Q 2023	3Q 2023	2Q 2023	1Q 2023	4Q 2022	3Q 2022	2Q 2022	1Q 2022	2023	2022
					Demand					
Total Demand	103.5	102.9	100.8	99.6	100.5	100.7	98.7	99.5	101.7	99.9
Total OECD	46.8	46.9	45.9	46.1	46.0	46.6	45.4	45.8	46.4	46.0
Americas	25.1	25.5	25.2	24.9	24.9	25.3	25.0	24.8	25.1	25.0
Europe	13.8	14.1	13.6	13.3	13.5	14.1	13.4	13.2	13.7	13.6
Asia Oceania	7.9	7.4	7.1	7.9	7.6	7.2	7.0	7.9	7.6	7.4
Non-OECD countries	56.7	55.9	54.9	53.6	54.5	54.1	53.3	53.7	55.3	53.9
FSU	4.9	4.9	4.7	4.6	4.9	5.1	4.7	4.7	4.8	4.9
Europe	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
China	16.8	16.1	15.6	15.0	15.5	14.8	14.4	15.4	15.9	15.0
Other Asia	14.8	14.0	14.3	14.4	14.0	13.4	14.0	14.1	14.4	13.9
Americas	6.2	6.3	6.1	6.0	6.2	6.3	6.1	5.9	6.1	6.1
Middle East	8.9	9.8	9.3	8.7	8.9	9.6	9.2	8.5	9.2	9.0
Africa	4.2	4.1	4.1	4.2	4.3	4.1	4.1	4.2	4.2	4.2
					Supply					
Total Supply	n/a	n/a	n/a	n/a	101.6	101.1	98.8	98.8	n/a	100.1
Non-OPEC	66.7	66.6	66.2	66.1	66.8	66.2	64.8	65.0	66.4	65.7
Total OECD	31.2	30.8	30.5	30.4	30.2	29.7	28.9	28.8	30.7	29.4
Americas	27.3	27.1	26.8	26.5	26.5	26.2	25.4	25.0	26.9	25.8
Europe	3.4	3.3	3.3	3.4	3.2	3.1	3.0	3.3	3.3	3.2
Asia Oceania	0.5	0.5	0.5	0.5	0.5	0.4	0.5	0.5	0.5	0.5
Non-OECD	30.1	30.0	30.1	30.8	31.4	30.9	30.5	31.4	30.2	31.0
FSU	12.4	12.4	12.6	13.4	14.1	13.7	13.4	14.4	12.7	13.9
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	4.2	4.2	4.2	4.3	4.1	4.1	4.2	4.2	4.2	4.2
Other Asia	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.6	2.7
Americas	6.3	6.2	6.1	5.9	5.9	5.8	5.5	5.4	6.1	5.6
Middle East	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.1	3.2	3.2
Africa	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Processing Gains	2.4	2.4	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.3
Total OPEC	n/a	n/a	n/a	n/a	34.8	34.9	34.1	33.8	n/a	34.4
Crude	n/a	n/a	n/a	n/a	29.4	29.6	28.7	28.5	n/a	29.1
Natural gas liquids NGLs	5.4	5.4	5.4	5.4	5.3	5.4	5.4	5.3	5.4	5.3
Call on OPEC crude and stock change *	31.4	30.8	29.2	28.2	28.3	29.1	28.6	29.2	29.9	28.8

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

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IEA: December Crude Oil Production in OPEC Countries (Table)
2023-01-18 09:00:00.5 GMT
By Kristian Siedenburg
(Bloomberg) -- Following is a summary of oil production in OPEC countries from the International Energy Agency in Paris:

	Dec. 2022	Nov. 2022	Dec. MoM
Total OPEC	29.19	29.23	-0.04
Total OPEC10	24.64	24.68	-0.04
Algeria	1.01	1.02	-0.01
Angola	1.09	1.09	0.00
Congo	0.25	0.26	-0.01
Equatorial Guinea	0.06	0.06	0.00
Gabon	0.18	0.19	-0.01
Iraq	4.45	4.46	-0.01
Kuwait	2.66	2.68	-0.02
Nigeria	1.23	1.15	0.08
Saudi Arabia	10.48	10.48	0.00
UAE	3.23	3.29	-0.06
Iran	2.72	2.72	0.00
Libya	1.17	1.15	0.02
Venezuela	0.66	0.68	-0.02

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

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IEA REPORT WRAP: Oil Surplus Revised Up With Demand Constrained
2023-01-18 10:41:07.885 GMT
By Jack Wittels
(Bloomberg) -- Summary of stories from IEA's monthly Oil Market Report on Wednesday:
* Global oil markets face a bigger surplus this quarter than previously expected
** Demand still constrained despite China's bid to reopen its economy from Covid lockdowns

** Supplies also swelling as Russia defies prediction that sanctions would crush exports
** That said, the IEA continues to expect a plunge in Russia's output later this quarter
** And global oil demand to add 1.9m b/d this year, hitting a record 101.7m b/d
** IEA predicts global oil markets will tighten in 2H 2023
* See summary of key IEA world oil supply demand forecasts
** Click here for detailed quarterly forecast table
* OPEC+ oil supply to fall 870k b/d this year on Russian cutback
** OPEC-13 group crude oil production -0.04m b/d m/m in December
** See full table for the 13 members
** Non-OPEC+ oil supply to grow 1.9m b/d this year
** OPEC crude output slid 40k b/d in December as UAE cut back
* Oil Stockpiles of OECD governments seen lowest since 1994
* Russia Oil revenues drop to 2022 low in December
* New oil refineries to more than offset loss of Russia
* IEA cuts forecast for global gas-to-oil switching this winter
* Electric vehicles stymie demand for road fuels
* Russian oil exports resilient in December despite EU embargo
* China refinery runs to rise to record in 2023

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IEA World Oil Supply/Demand Key Forecasts
2023-01-18 09:00:00.8 GMT
By Kristian Siedenburg
(Bloomberg) -- World oil demand 2023 forecast was revised to 101.7m b/d from 101.6m b/d in Paris-based Intl Energy Agency's latest monthly report.
* 2022 world demand was unrevised at 99.9m b/d
* Demand change in 2023 est. 1.9% y/y or 1.9m b/d
* Non-OPEC supply 2023 was revised to 66.4m b/d from 66.3m b/d
* Call on OPEC crude 2023 was unrevised at 29.9m b/d
* Call on OPEC crude 2022 was revised to 28.8 m b/d from 28.9m b/d
** OPEC crude production in Dec. fell by 40k b/d on the month to 29.19m b/d
* Detailed table: FIFW NSN ROOA2CGFR4SG <GO>
* NOTE: Fcasts based off IEA's table providing one decimal point

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Oil Market Faces Bigger Surplus Even as China Reopens, IEA Says
2023-01-18 09:00:00.10 GMT
By Grant Smith
(Bloomberg) -- Global oil markets face a bigger surplus this quarter than previously expected, with demand still constrained despite China's bid to reopen its economy from Covid lockdowns.
World supplies will exceed consumption by roughly 1 million barrels a day in the first three months of the year, the International Energy Agency said in a monthly report. While the organization made a modest upgrade to its outlook for China after the easing of restrictions, it doesn't expect to see annual demand growth there until the second quarter.
"As China faces a challenging winter, its exit path will unquestionably be bumpy and drawn-out," the Paris-based adviser said. "Hardship and disruptions therefore look set to prevail in the near-term" in the country.
READ: China Tells Davos That Growth Will Rebound, Covid Has Peaked (1)
Oil prices have had a rocky start to the year as Beijing's lifting of restrictions triggered a new surge of virus infections that threatens to derail efforts to restart the economy. Brent futures traded near $86 a barrel on Wednesday.
Supplies are also swelling as Russia manages to defy predictions that international sanctions would crush its exports. Output from the country was steady near 11 million barrels a day in December even as a European Union ban took effect, though the IEA continues to expect a plunge later this quarter.
"A slow demand recovery expected in the first half of 2023 suggests continued inventory builds like those that started to emerge" last year, the agency said.
OPEC Secretary-General Haitham Al-Ghais also gave a conservative outlook at the World Economic Forum in Davos on Tuesday, saying that he was "cautiously optimistic" on the global economy. Led by Saudi Arabia, the producer group and its allies have been constraining supply to keep world markets in equilibrium.
READ: Aramco Sees Oil Demand Picking Up on China and Aviation Recovery
The IEA predicted that global oil markets will tighten in

the second half of the year as Chinese consumption accelerates and sanctions targeting Moscow have a greater effect. Russia's output may drop a further 1.5 million barrels a day by the end of March, it said.
"The well-supplied oil balance at the start of 2023 could quickly tighten," said the agency.
That accords with sentiment in many parts of the market, with Goldman Sachs Group Inc. seeing a "bullish concoction" for commodities, and hedge fund manager Pierre Andurand predicting prices of up to $140 a barrel.
World consumption remains on track to expand by 1.9 million barrels a day this year, to reach a record average of 101.7 million a day, according to the IEA. About half of the growth will come from China.

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OPEC Crude Output Slid 40k B/D in December as UAE Cut Back: IEA
2023-01-18 09:00:00.0 GMT
By Amanda Jordan
(Bloomberg) -- OPEC's December crude output slipped 40k b/d from a month earlier to 29.19m b/d as UAE production dropped, the IEA said in its monthly market report.
* UAE volumes fell 60k b/d to 3.23m b/d, still above its OPEC+ target
* Saudi production held steady at 10.48m b/d, in line with its quota
* Elsewhere in the Middle East, Iraqi output inched down 10k b/d to 4.45m b/d; Kuwaiti supply dipped to 2.66m b/d
* Production in Iran, exempt from quotas, was unchanged at 2.72m b/d
* In Africa, Nigerian crude output jumped 80k b/d to 1.23m b/d, the highest level since April
** Sabotage and oil theft pushed Nigerian supply to 40-year lows in 2022
* Production in Angola was stable m/m at 1.09m b/d
* Libyan output edged up by 20k b/d to 1.17m b/d
* Venezuelan volumes slid 20k b/d to 660k b/d
* NOTE: On Tuesday, OPEC released its own production figures for December, estimating its 13 members pumped 28.97m b/d
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Oil Stockpiles of OECD Governments Seen Lowest Since 1994: IEA
2023-01-18 09:00:00.30 GMT
By Jack Wittels
(Bloomberg) -- OECD government oil stockpiles at the end of 2022 were estimated at ~1.2b bbl, the lowest level since 1994, the IEA said in its monthly Oil Market Report.
* NOTE: Figure includes crude and oil products
* Barrels were offered to the market last year via stockpile releases co-ordinated with the IEA, announced in March and April
** The vast majority of supplies offered in this way were released by the end of October
** The US released 180m bbl of oil from its SPR by December, including volumes independent of IEA collective actions
* Further to the IEA stock-draw decisions, government stocks were made available to the market for various other reasons in 2022, including:
** Refinery accident in Austria
** Low Rhine water levels
** Strikes in France's oil industry
* "IEA collective actions remain active and countries will not be obliged to replenish their stocks until a decision is taken by the IEA's Governing Board"
** Countries can still choose to replenish emergency stocks in advance of such a decision
** "This has been the case for a number of countries, which have begun to rebuild strategic stocks in advance of the Feb. 5 implementation of the embargo on Russia oil products"

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Russia Oil Revenues Drop to 2022 Low in December, IEA Says
2023-01-18 09:00:00.23 GMT

By Bloomberg News
(Bloomberg) -- Russia's oil-export revenues fell to the lowest level in 2022 last month as an embargo cut sales to Europe and a price cap triggered record discounts on the nation's crude, according to the International Energy Agency.
Russia earned about $12.6 billion in December from crude and fuel exports, down nearly a fifth from November, the IEA estimated in its market report on Wednesday. For the whole year, average monthly oil-export revenue jumped to $18.2 billion from $14.7 billion in 2021, helped by a recovery in global prices.

Western nations have targeted energy exports — the single largest source of revenue for the Russian budget — to squeeze the flow of money funding the Kremlin's invasion of Ukraine. From Dec. 5, the European Union and the Group of Seven industrialized countries imposed a $60 a barrel price cap on Russian oil by restricting access to insurance and shipping services for any buyers that don't adhere to the threshold. The cap has led to a widening discount on Urals — Russia's key oil-export blend — which has traded at roughly half the price of international benchmark Brent.
Read: Kremlin Revenue Under Pressure as Crude Price Falls on Sanctions
The EU also stopped most seaborne Russian crude imports from early December and aims to halt seaborne petroleum product purchases from Feb. 5, putting additional pressure on the Kremlin's energy revenues.
Russia has been working to redirect crude and fuel toward Asia, with India receiving record 1.6 million barrels per day from the sanctioned nation last month, compared with just 100,000 barrels before the invasion, according to IEA estimates.
Still, the sanctions may cause a temporary drop of some 500,000 to 700,000 barrels per day in Russia's production at the start of the year, according to Deputy Prime Minister Alexander Novak.
The IEA's outlook is more pessimistic. The agency expects Russia to shut-in around 1.6 million barrels per day of production by the end of this quarter compared with pre-invasion

levels, with the average daily output for the year falling to 9.7 million barrels. The outlook is slightly higher than the one the agency made last month.
Russian producers pumped about 10.9 million barrels in December and early January, according to Bloomberg calculations based on the data from the CDU-TEK unit of the Energy Ministry. The nation's average daily production for 2022 reached around 10.74 million barrels.
The resilience of Russian oil output last year amid mounting sanctions makes the nation "a wildcard" of the global energy market, according to the IEA. "The big question is just how far Russian output will fall," it said.

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New Oil Refineries to More Than Offset Loss of Russia, IEA Says
2023-01-18 09:00:00.11 GMT
By Rachel Graham
(Bloomberg) -- The expansion of refining capacity in the Middle East and China this year will more than offset any loss from Russia, the IEA said in its monthly Oil Market Report.
* "New refineries in Africa and the Middle East, as well as China, are expected to step in to cater for the growth in refined product demand, more than offsetting forecast declines in Russia"
* Timing of start-ups will be critical
** The commercial operations at Oman's Duqm project have been delayed to the second half of the year
** Nigeria's Lekki is expected to start up this summer, but the size and complexity of this single-train refinery could require a slower and later start
** Start of Mexico's Olmeca, also known as Dos Bocas, pushed back to 2024
** Expansion of Exxon Mobil's Beaumont refinery in Texas is due to start in the first half
* In total, capacity is forecast to expand by 1.7m b/d this year
* In the Middle East, throughput is set to reach 9m b/d in 2H of 2023, when Kuwait's Al-Zour is at full capacity and Oman's 230k b/d Duqm refinery starts up

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IEA Cuts Forecast for Global Gas-to-Oil Switching This Winter
2023-01-18 09:00:00.4 GMT
By Rachel Graham
(Bloomberg) -- The IEA cut its forecast for gas-to-oil switching following the drop in the price of natural gas, the agency said in its monthly market report.
* It reduced its forecast for substitution this winter by about 200k b/d, and now expects worldwide additional oil use of about 550k b/d from 4Q of last year into 1Q

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Electric Vehicles Stymie Demand for Road Fuels: IEA
2023-01-18 09:00:00.3 GMT
By Alaric Nightingale
(Bloomberg) -- Oil consumption growth this year to be curtailed by about 870k b/d because of fuel efficiency gains and growth in electric vehicle sales, the IEA says in its monthly oil market report.
* Efficiency accounts for 610k b/d, EVs 260k b/d
* Gasoline demand eroded by 570k b/d; diesel by 300k b/d
* China seeing fastest EV uptake, eliminating about 100k b/d of new fuel use

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Russian Oil Exports Resilient in Dec. Despite EU Embargo: IEA
2023-01-18 09:00:00.2 GMT
By Sherry Su
(Bloomberg) -- Russian oil exports remained resilient, despite an EU embargo, as a drop in crude exports was partly offset by an increase in products, the IEA said in its Oil Market Report.
* Russian oil exports fell 200k b/d m/m in December; a 270k b/d reduction in crude shipments was partly offset by an 80k b/d increase in product volumes
* Loadings to Europe were only down by 140k b/d m/m last month as a 240k b/d fall in seaborne shipments was partly offset by a 100k b/d increase in Druzhba volumes
* Germany has said it will fully stop pipeline deliveries from Russia, which means that Druzhba volumes are set to fall by 330k b/d, to around 360k b/d, according to the report
** Russia's share in EU crude oil imports could fall to just 5%, from pre-war levels of 27-30%
* A record amount of crude oil, about 1.4m b/d, was shipped to India in December, along with a new high of 225k b/d of products: IEA
* Product exports to EU countries were steady m/m at 1.2m b/d, with diesel volumes at a 10-month high of 720k b/d
** Gasoline exports were up by 110k b/d m/m to a record level of 275k b/d, with some of the increase going to the EU
* Oil export revenues in December fell by $3b, the largest monthly drop since April
** Overall, in 2022, Russian oil exports increased by 4% y/y to 7.8m b/d, with all the increase coming from crude oil as products remained flat on average

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China Refinery Runs to Rise to Record in 2023, IEA Forecasts
2023-01-18 09:00:00.1 GMT

By Rachel Graham
(Bloomberg) -- China's refinery throughput is set to rise to a record of 14.4m b/d this year, the IEA said in its monthly report.

* That will follow a slowdown in January and February due to Covid
* "Higher crude import and higher product export quotas indicate the willingness of the government to enable more product exports, but the uncertainty in the refinery throughput forecast remains very high as it also depends on domestic demand prospects"
* China's throughput was choppy last year, rising to its third-highest level ever in November but seeing its first drop on an annual basis in decades
* Global crude throughput is forecast to rise to 81.9m b/d in 2023 from 80.4m b/d last year
* "The expected growth in refined product demand this year, at 1.3m b/d, should be comfortably covered by the cumulative 2.2m b/d additions" between 4Q of 2022 and 4Q of 2023

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https://www.scmp.com/news/china/science/article/3207713/china-unlikely-see-second-wave-covid-cases-any-time-soon-because-most-people-have-already-been?utm_term=Autofeed&utm_medium=Social&utm_content=article&utm_source=Twitter#Echobox=1674377809

China reports thousands of Covid deaths in 1 week, amid estimates 80 per cent of population has been infected

- The country's hospitals reported almost 13,000 deaths in the week from January 13
- Leading expert downplays fears of second wave soon, saying most people have already been infected

Luna Sun **in Beijing**
Published: 4:19pm, 22 Jan, 2023

17

China reported almost 13,000 Covid-19 deaths in one week, while a leading epidemiologist said around 80 per cent of Chinese had already been infected so a second wave was unlikely in the near future.

The Chinese Centre for Disease Control and Prevention said on Sunday that the death toll related to Covid-19 in hospitals reached 12,658 in the seven days between January 13 and 19.

The country had previously reported nearly 60,000 deaths between December 8 and January 12 after the abrupt ending of the zero-Covid policy.

Separately, Wu Zunyou, the CDC's chief epidemiologist, played down concerns about a second wave in the next few months while also calling for caution over the elderly and other vulnerable groups over the Lunar New Year holiday.

"The massive social mobility during Chinese New Year could accelerate the spread of the pandemic to a certain extent, and the number of infected people will increase in some areas," Wu wrote in a post on the social media site Weibo on Saturday.

But because the latest wave had infected about 80 per cent of the people in the country there was little possibility of a large-scale epidemic rebound or a second wave of cases in the next two to three months, Wu said.

China has seen a tsunami of Covid infections since Beijing abruptly dropped its restrictive zero-Covid policies last month without making preparations for the shift.

The official death toll was greeted with scepticism after the authorities narrowed the definition of Covid deaths, with concerns the true numbers are being underestimated.

Several provinces have reported this month that they have reached the peak of infections, and that shortages of medical supplies have eased, but hospitals are still under heavy pressure.

“The country as a whole has passed the peak of the wave. Cities and counties of all sizes are basically seeing infections come down,” Wu wrote.

Billions of trips will be taken by Chinese people during the Lunar New Year, also known as the Spring Festival season, as the country marks the first major holiday after the lifting of travel restrictions.

Lunar New Year’s Eve fell on Saturday this week, starting a week-long statutory holiday that runs until January 27, and many companies also give their employees extra time off.

The mass movement has triggered concerns about the pandemic in rural areas, where the provision of medical services is patchy at best, and the possible emergence of a second wave.

Up to 5 billion journeys are expected to be made during this year’s Spring Festival, including 2.1 billion on the country’s transit system, according to the Ministry of Transport, almost double the number made in the same period last year.

On Saturday, some 800,000 passengers took domestic flights, twice the number seen during Lunar New Year’s Eve in 2022, official data showed.

On Friday, the number of passengers travelling by air nationwide exceeded 1.1 million, a 25 per cent increase compared with a year earlier and 74 per cent of the total from the same period in 2019.

During the Spring Festival holiday period, the number of domestic passenger flights is expected to surge by nearly 70 per cent compared with the same period last year.

While many people have welcomed the opportunity to finally reunite with family members after three years of Covid restrictions, high-risk groups remain vulnerable.

Wu said older people should be closely monitored for symptoms and people who were infected should avoid travelling long distances to visit family and friends.

He added that those who only recently recovered and still had symptoms should take it easy and continue wearing masks in public.

Discussing threats from abroad, Wu said despite cases in China of XBB.1.5, one of the prevailing variants in the United States, those cases were still rare, exclusively imported and unlikely to lead to a fresh wave in China.

Oil price outlook – Snapshot: January 17, 2023

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

Category	Indicator	Signal	Comment
Fundamentals	**Refinery margins**		• Global refinery margins were higher over the past week as oil product cracks across the barrel strengthened.
	Crude stocks		• In the week ending January 6, land crude-oil storage levels in BloombergNEF's tracked regions (the US, ARA and Japan) grew 2.6% to 563.3 million barrels (m bbl). The stockpile **deficit** against the five-year average (2016-19 & 2022) **narrowed from 32.5m bbl to 8.1m bbl.** • Including global floating crude stockpiles from the same week, total crude oil inventories increased 1.0% to 657.0m bbl, while the stockpile **surplus** of **31.7m bbl narrowed to 27.1m bbl.**
	Product stocks		• In the week ending January 6, gasoline and light distillate stockpiles in BNEF's tracked regions (the US, ARA, Singapore, Japan and Fujairah) rose 3.1% week-on-week to 274.7m bbl, with the stockpile **deficit** against the four-year average (2017-19 & 2022) **narrowing from 20.0m bbl to 11.0m bbl.** Gasoil and middle distillate stockpiles in BNEF's tracked regions were up 1.1% to 156.3m bbl, with the stockpile **deficit** against the four-year average **widening from 26.6m bbl to 29.8m bbl.** • Oil product stockpiles in tracked regions grew 1.3% to 968.9m bbl, with the stockpile **deficit** against the four-year seasonal average **narrowing from 32.1m bbl to 11.1m bbl.** Altogether, crude and product stockpiles increased 1.2% to 1,625.9m bbl, with the stockpile **deficit of 0.4m bbl flipping to a surplus of 15.9m bbl.**
	Demand indicators		• In the week to January 24, global jet fuel demand from commercial passenger flights is set to fall 1.2% to 5.48 million barrels per day. Jet fuel consumption by international passenger flight departures is on course to drop 102,200 barrels per day (or -3.2%) week-on-week, while consumption by domestic passenger flight departures will rise 38,400 barrels per day (or +1.7%). In the week to January 14, flights in the Eurocontrol area fell to 85.7% of the equivalent week in 2019, down from 93.4% last week. The four-week moving average, however, inched higher to 91.3%, from 90.6%, and reached a new post-Covid 19 high. Meanwhile, in the same week, US passenger throughput rose to 109.4% of the average week in 2019, up from 104.0% last week. The four-week moving average rose to 100.3%, from 96.0%, hitting a new post-Covid 19 high. • In the week to January 16, peak congestion levels showed strong growth in Europe (+24.5%), Asia Pacific excluding mainland China (+12.9%) and North America (+11.1%). However, on a four-week moving average basis, all three regions were still lower than the previous week. All three regions recorded stronger growth against the same week last year – Europe grew 31.1 percentage points to 144.1% of the same week last year, Asia Pacific ex-mainland China saw a 13.5 percentage points growth to 123.7%, while North America grew 27.3 percentage points to 149.1%. In the week to January 16, road congestion in China's 15 key cities slipped 2.4 percentage points to 131.2% of January 2021 levels, according to BNEF's calculation based on Baidu data. Month-to-date, traffic congestion in China's 15 key cities was 21.6% higher than January 2022 levels. • Weather in several cities across Western Europe and East Asia turned colder over the past week.
Financial	**Macro indicators**		• The dollar index averaged 102.8 in the week to January 13 and was 1.6% lower than the week before.
	Hedge fund positioning		• In the week to January 10, Managed Money net positioning in the oil complex was down 17.3m bbl (or -4.0%) week-on-week to 416.5m bbl, and stood at the ninth percentile of the past five years.
	Options and volatility		• There seems to be a rollover in the open interest of Brent calls from Mar-23 to Apr-23, and as well as a notable increase in open interest for Brent puts from Apr-23 to Dec-23. Brent and WTI 1M volatility skews were largely unchanged over the past week.
Outlook	**Weekly call**		• BNEF is bullish on oil prices for the week ahead, with Brent Mar-23 trading at $84.52/bbl and WTI Mar-23 trading at $79.41/bbl at the time of writing. • Road congestion levels saw strong weekly growth in Asia ex-China, Europe and North America. For all three regions, road congestion growth against the same week last year also accelerated over the past week. In China, weekly congestion in key cities fell slightly by 2 percentage points ahead of the Chinese New Year on January 22, but was still up 77 percentage points on a four-week moving average basis to 131% of January 2021 levels. Month-to-date, congestion levels were 22% higher than January 2022 average levels. Of the 379 cities across 56 countries that BNEF tracks outside mainland China, 329 (87%) recorded weekly growth in congestion levels. Of the 99 cities that BNEF tracks in mainland China, 76 (77%) saw a weekly growth in congestion levels. • Flights in the Eurocontrol area and US air passenger throughputs against the equivalent week in 2019 have both hit a new post-pandemic high on a four-week moving average basis. Global jet fuel demand estimates for the week to January 24 fell slightly from the week before but remain elevated. • Oil inventories saw a net bearish move over the past week, driven by a strong narrowing of oil product stockpile deficit against its four-year seasonal average.

BloombergNEF

Past outlooks

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

Date of report	Refinery margins	Crude stocks	Product stocks	Demand indicators	Commitment of traders	Options chain and volatility	BNEF week ahead call	Brent/WTI price at time of writing ($/bbl)	Web Link
January 17	↑	↔	↑	↑	↓	↔	↑	Brent-Mar: 84.52 WTI-**Mar**: 79.41	
January 9	↓	↓	↑	↔	↓	↔	↔	Brent-Mar: 80.88 WTI-Feb: 76.09	
January 3	↑	↓	↑	↔	↑	↔	↔	Brent-Mar: 85.00 WTI-Feb: 79.39	
December 20	↑	↔	↓	↓	↓	↑	↓	Brent-Feb: 80.56 WTI-Feb: 76.42	
December 13	↓	↑	↔	↔	↓	↑	↔	Brent-Feb: 79.12 WTI-Jan: 74.19	
December 6	↓	↔	↓	↓	↓	↔	↓	Brent-Feb: 81.80 WTI-Jan: 76.04	
November 28	↔	↓	↓	↓	↓	↔	↔	Brent-Feb: 81.42 WTI-Jan: 74.17	
November 21	↑	↔	↓	↓	↓	↔	↓	Brent-Jan: 83.07 WTI-Jan: 76.03	
November 16	↔	↑	↔	↔	↑	↑	↔	Brent-Jan: 93.91 WTI-Dec: 86.81	
November 2	↔	↔	↓	↔	↑	↑	↔	Brent-Jan: 94.43 WTI-Dec: 88.22	
October 26	↔	↓	↔	↓	↓	↔	↔	Brent-Jan: 91.89 WTI-Dec: 85.77	
October 19	↔	↓	↔	↓	↑	↔	↓	Brent-Dec: 90.28 WTI-Dec: 82.78	
October 4	↔	↔	↑	↔	↓	↓	↔	Brent-Dec: 90.71 WTI-Nov: 85.26	
September 27	↔	↓	↓	↓	↓	↓	↔	Brent-Dec: 94.06 WTI-Nov: 87.83	

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

Fundamentals Financial

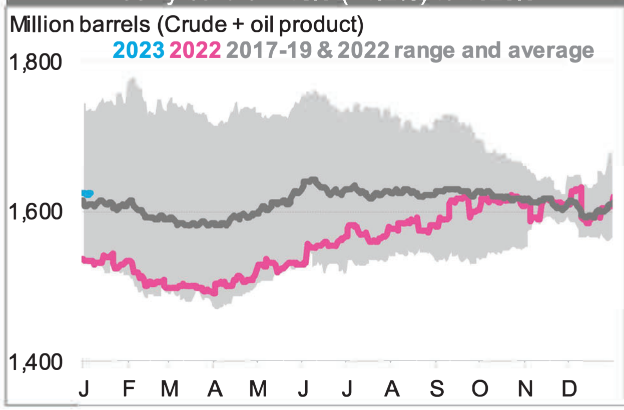
Aggregated oil stockpiles

Bearish: Stockpile flipped from a deficit of 0.4m bbl to a surplus of 15.9m bbl

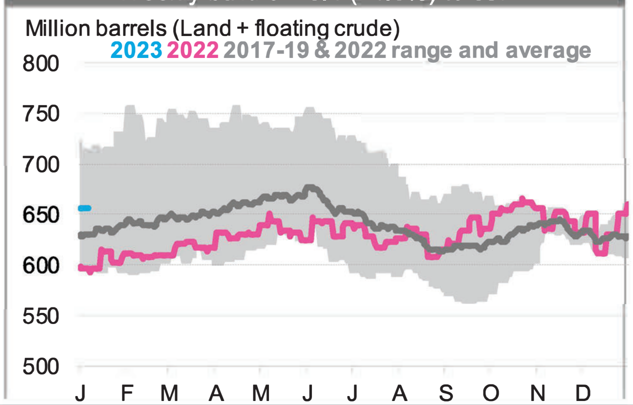
- All inventories in 2023 are compared against the **2017-19 & 2022** (four-year) seasonal stockpiles. Calculations are recalibrated to measure against their respective four-year seasonal averages, so the values below may differ from the subsequent slides.
- Land crude inventories include the US, ARA, and Japan. Floating storage data are global. Oil product storage includes the US, ARA, Japan, Singapore and Fujairah. Floating crude inventories tend to be revised retroactively.

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

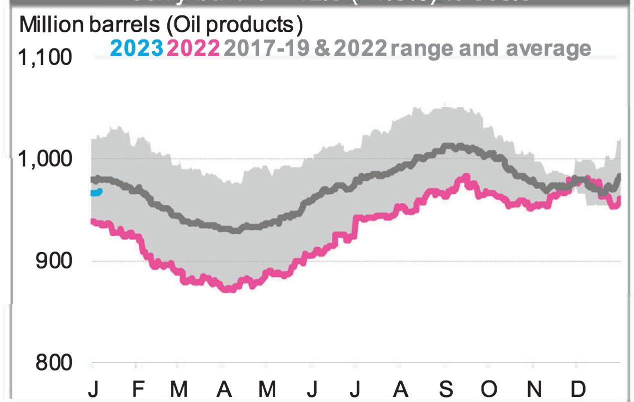
Weekly build of +18.9 (+1.2%) to 1625.9



Weekly build of +6.4 (+1.0%) to 657



Weekly build of +12.5 (+1.3%) to 968.9

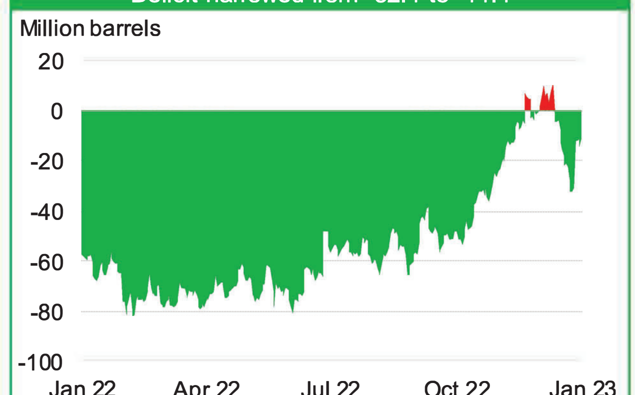


Charts below subtract current stockpiles by the 2017-19 & 2022 (four-year) seasonal average

Flipped to surplus, from -0.4 to +15.9

Surplus narrowed from +31.7 to +27.1

Deficit narrowed from -32.1 to -11.1



Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ ,Vortexa, Genscape. Note: As of the ***week ending January 6, 2023.***

BloombergNEF

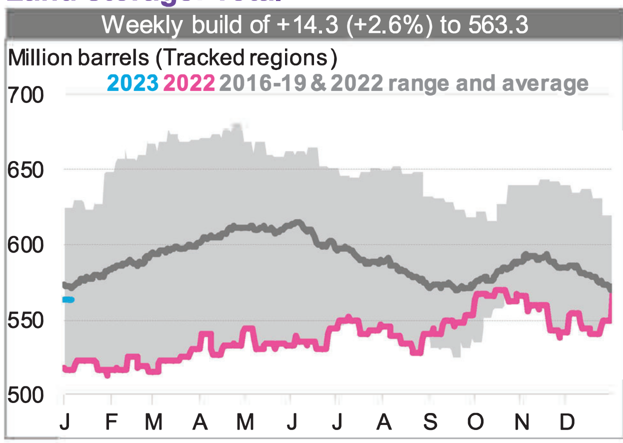
Fundamentals | Financial

Crude stocks: Land

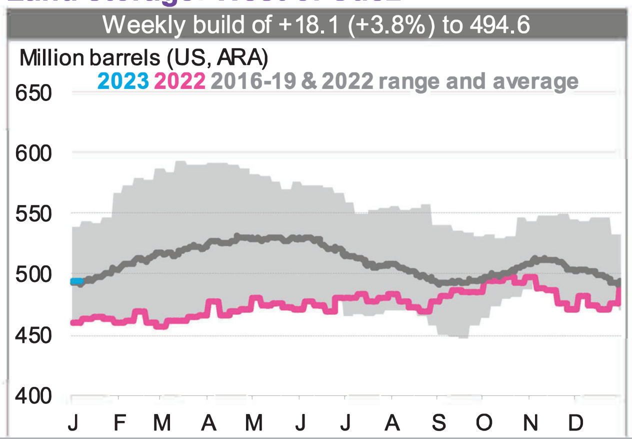
Bearish: Stockpile deficit narrowed from 32.5m bbl to 8.1m bbl

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

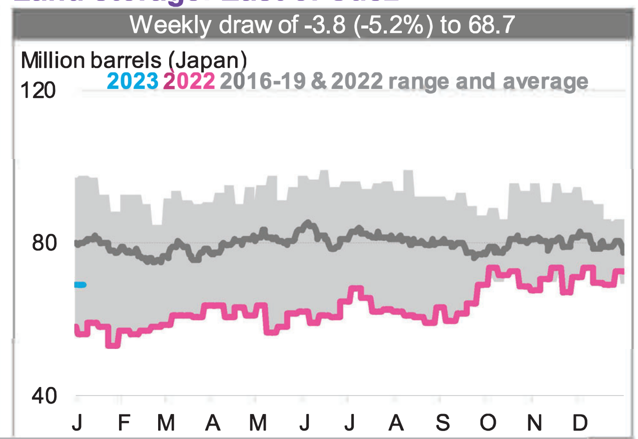
Land storage: Total



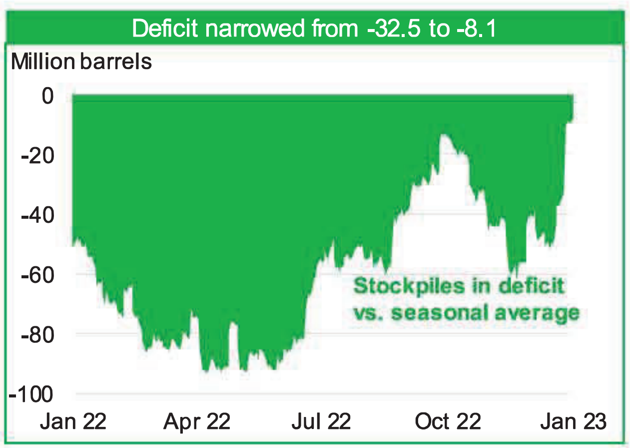
Land storage: West of Suez

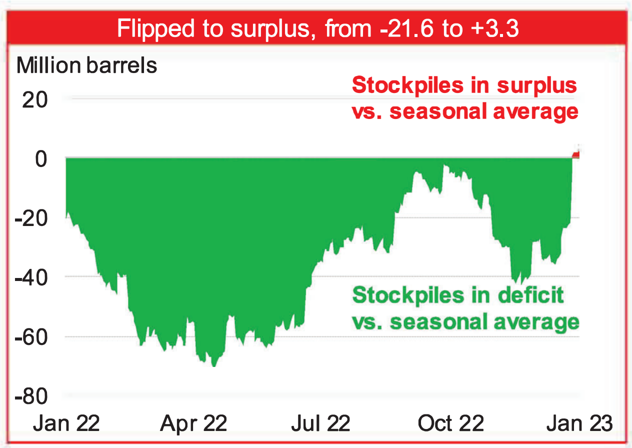


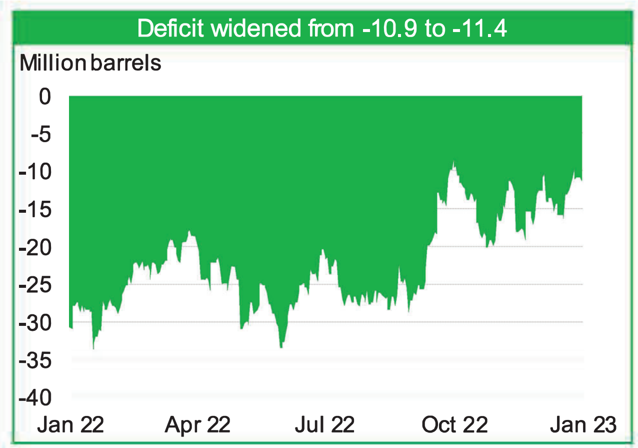
Land storage: East of Suez



Charts below subtract current stockpiles by the 2016-19 & 2022 (five-year) seasonal average







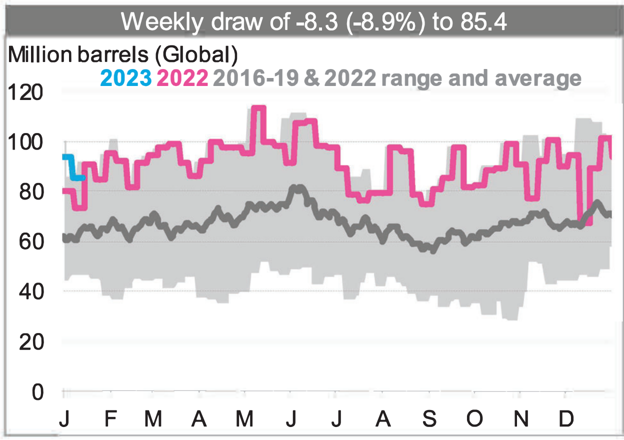
*Source: BloombergNEF, US EIA, Genscape, PAJ. Note: As of the **week ending January 6, 2023.***

Crude stocks: Floating

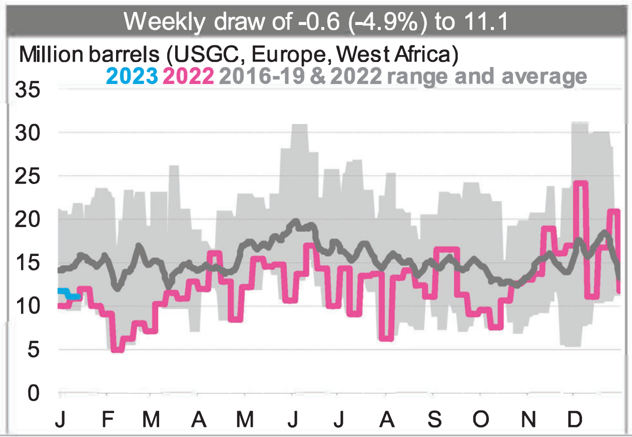
Bullish: Stockpile surplus narrowed from 31.4m bbl to 24.1m bbl

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

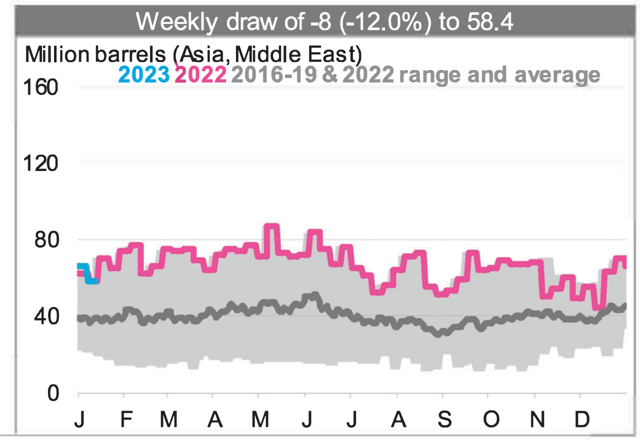
Floating storage: Total



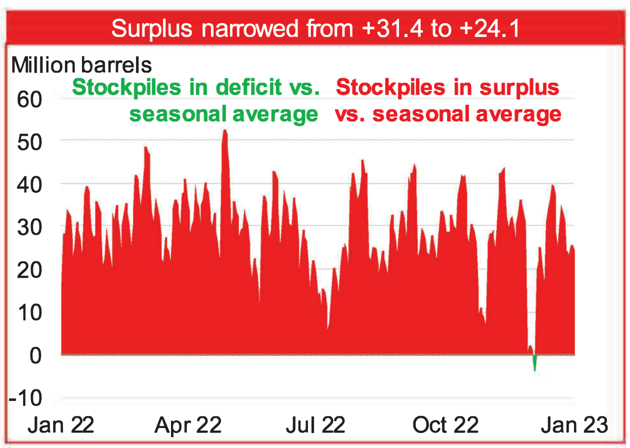
Floating storage: West of Suez

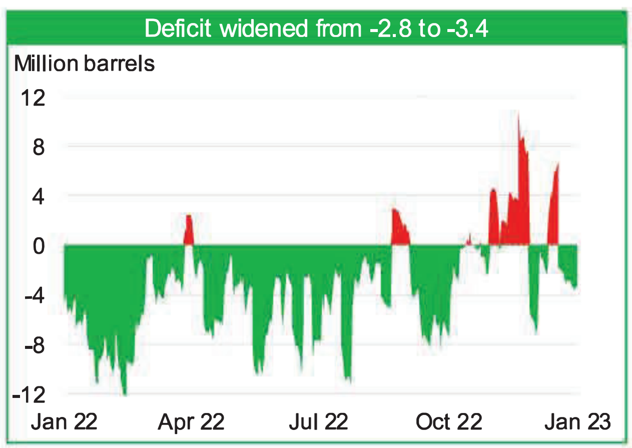


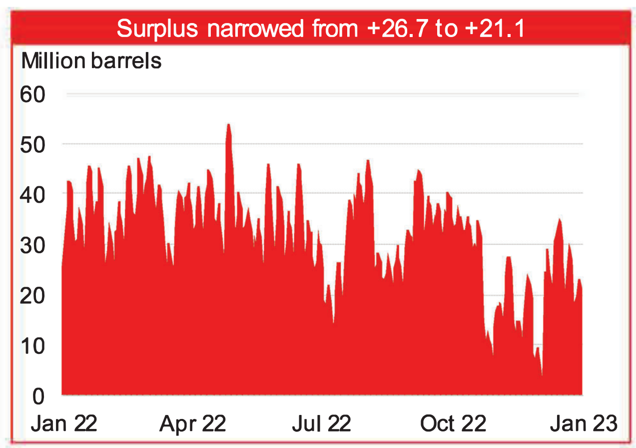
Floating storage: East of Suez



Charts below subtract current stockpiles by the 2016-19 & 2022 (five-year) seasonal average







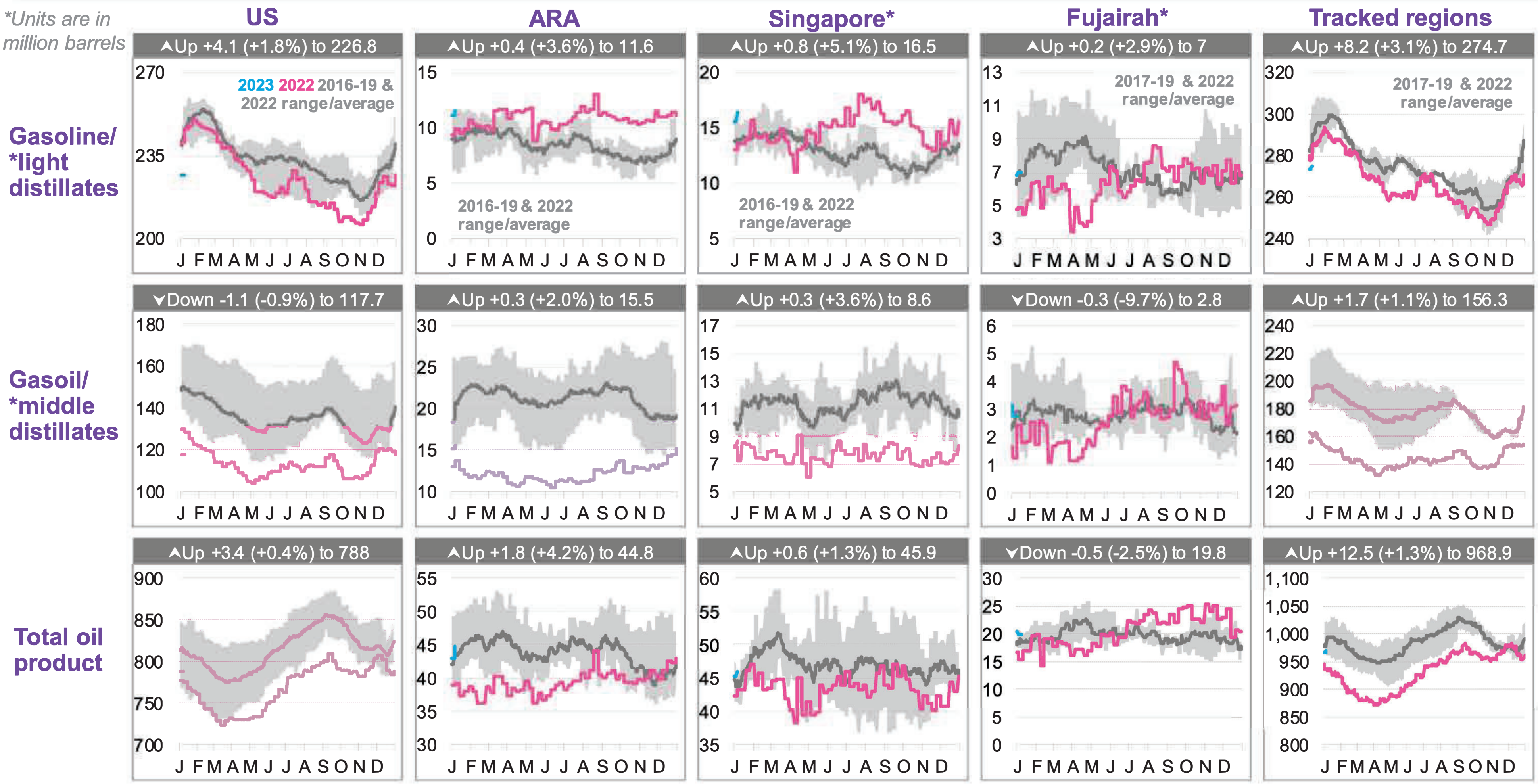
*Source: BloombergNEF, Vortexa. Note: As of the **week ending January 13, 2023**. ***Data from Vortexa are revised frequently, so the data in this report might change week-to-week.***

Fundamentals | Financial

Product stocks: Current versus seasonal average

Bearish: Oil product stockpiles in tracked regions rose 1.3% over the past week

- Chart legend are as follows: 2023, 2022 and the 2016-19 and 2022 (five-year) range and average (except for Fujairah and tracked regions).
- For Fujairah and tracked regions, the 2017-19 and 2022 (four-year) seasonal range and average are shown. Tracked regions include US, ARA, Singapore, Japan and Fujairah.

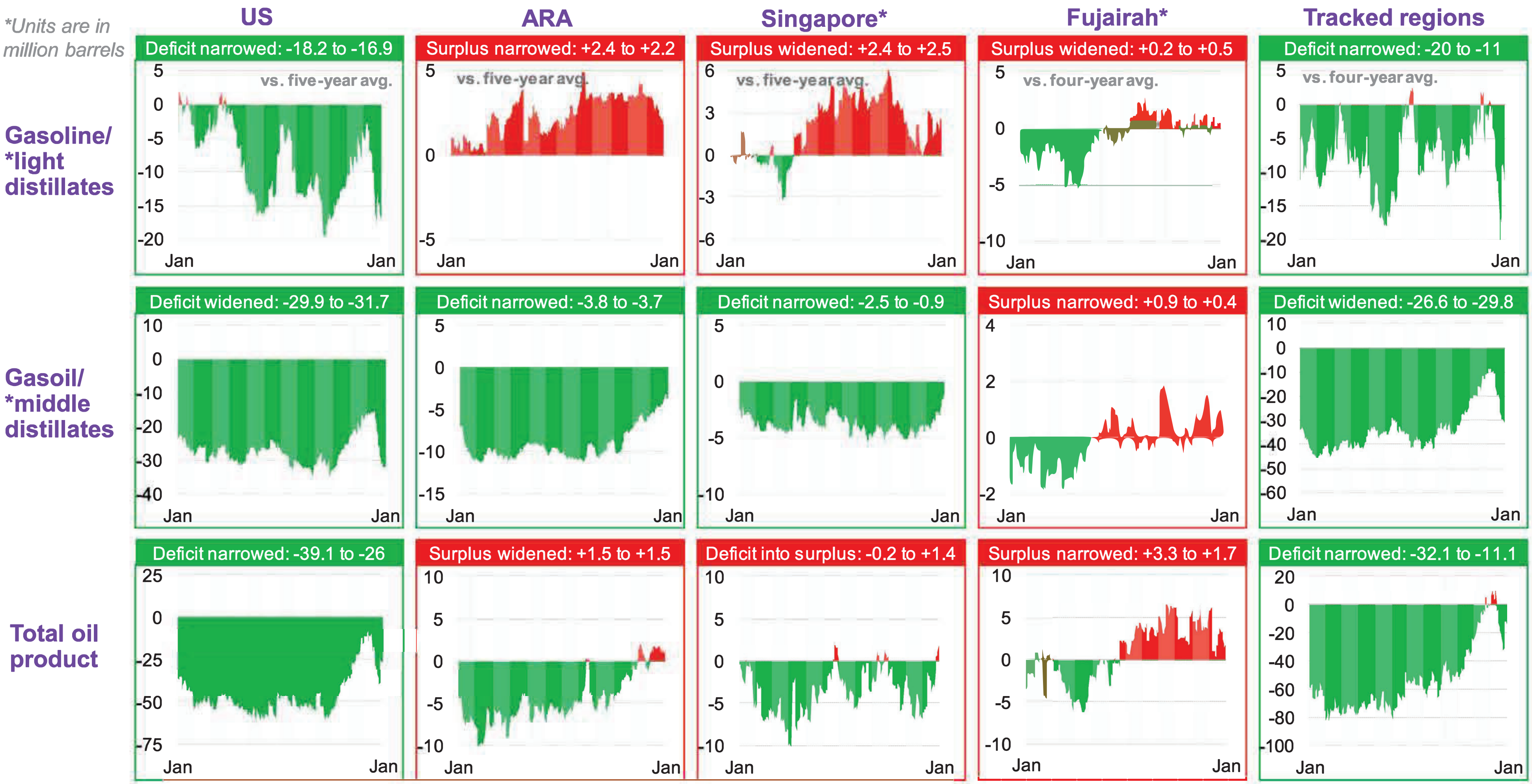


Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ. Note: As of the ***week ending January 6, 2023.***

Product stocks: Current versus seasonal average

Bullish: Oil product stockpile deficit narrowed from 21.1m bbl to 11.1m bbl

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



Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ. Note: As of the **week ending January 6, 2023.**

Excerpt https://www.businesswire.com/news/home/20230118006018/en/

SLB Announces Fourth-Quarter and Full-Year 2022 Results

Primed for Strong Growth and Returns—A Distinctive New Phase in the Upcycle

Le Peuch said, "The fourth quarter affirmed a distinctive new phase in the upcycle. In the Middle East, revenue increased by double digits sequentially, with growth in Saudi Arabia, Iraq, and the United Arab Emirates in the solid teens, affirming the much-anticipated acceleration of activity in the region. Offshore activity continued to strengthen, partially offset by seasonality in the Northern Hemisphere. In North America, US land rig count remains at robust levels, although the pace of growth is moderating. Additionally, pricing continues to trend favorably, extending beyond North America and into the international regions, supported by new technology and very tight equipment and service capacity in certain markets.

"These activity dynamics, improved pricing, and our commercial success—particularly in the Middle East, offshore, and North American markets—combine to set a very strong foundation for outperformance in 2023.

"Looking ahead, we believe the macro backdrop and market fundamentals that underpin a strong multi-year upcycle for energy remain very compelling in oil and gas and in low-carbon energy resources. First, oil and gas demand is forecast by the International Energy Agency (IEA) to grow by 1.9 million barrels per day in 2023 despite concerns for a potential economic slowdown in certain regions. In parallel, markets remain very tightly supplied. Second, energy security is prompting a sense of urgency to make further investments to ensure capacity expansion and diversity of supply. And third, the secular trends of digital and decarbonization are set to accelerate with significant digital technology advancements, favorable government policy support, and increased spending on low-carbon initiatives and resources.

"Based on these factors, global upstream spending projections continue to trend positively. Activity growth is expected to be broad-based, marked by an acceleration in international basins. These positive activity dynamics will be amplified by higher service pricing and tighter service sector capacity. The impact of loosening COVID-19 restrictions and an earlier than expected reopening of China could support further upside potential over 2023.

"Overall, the combination of these effects will result in a very favorable mix for SLB with significant growth opportunities in our Core, Digital, and New Energy. We expect another year of very strong growth and margin expansion. We have a clear strategy, an advantaged portfolio, and the right team in place to drive our business forward. I look forward to another successful year for our customers and our shareholders."

Excerpt https://seekingalpha.com/article/4571289-schlumberger-limited-slb-q4-2022-earnings-call-transcript

Schlumberger Limited (SLB) Q4 2022 Earnings Call Transcript

Jan. 20, 2023 2:34 PM ET**Schlumberger Limited (SLB)**
Play Earnings Call

Schlumberger Limited (NYSE:SLB) Q4 2022 Earnings Conference Call January 20, 2023 9:30 AM ET

Company Participants

ND Maduemezia - Vice President, Investor Relations

Olivier Le Peuch - Chief Executive Officer

Stephane Biguet - Chief Financial Officer

Olivier Le Peuch

As we see today, the combination of offshore Middle East and broad gas investments internationally will continue to support a very solid growth internationally. We are seeing -- as we have seen in the fourth quarter an uptick into the rate of growth for Middle East and that's driven by a commitment to oil capacity increase and further gas development.

And this, as I commented briefly in my prepared remarks will lead Middle East investment to be on record ever as we anticipated in this year or next year. And as a result, we generate significant pull for our revenue going forward.

But I think what I will say is that, what is characterizing international as we see it, is that it has a lot of resilience, because it's multi-pronged. It moves multiple engines, short and long, oil and gas, offshore and onshore.

And I believe that the -- with our commitment for capacity expansion and gas development in Middle East is combining with offshore long-cycle, a return of deepwater, which is the operating environment I will see the most activity increase this year and also the return or the acceleration of exploration and appraisal offshore, which would be one of the defining characteristics of the quarters to come.

So when you combine all of this, you are getting a very resilient multi-pronged and multiyear sustained growth pattern for international market. And I think that's what we see and it will indeed support not only growth this year, but it will support your growth next year and the years to come and it will be multi-pronged and fairly broad and with multiple geographic impact.

https://www.tipro.org/newsroom/tipro-news/tipro-highlights-continued-upstream-employment-growth-in-december

TIPRO NEWS RELEASES AND STATEMENTS

JANUARY 20, 2023

TIPRO HIGHLIGHTS CONTINUED UPSTREAM EMPLOYMENT GROWTH IN DECEMBER

Austin, Texas - Citing the latest Current Employment Statistics (CES) report from the U.S. Bureau of Labor Statistics (BLS), the Texas Independent Producers and Royalty Owners Association (TIPRO) today highlighted new employment figures showing continued growth in monthly employment for the Texas upstream sector and strong demand for available talent throughout the industry.

According to TIPRO's analysis, direct Texas upstream employment for December 2022 totaled 211,200, an increase of 1,300 jobs from November employment numbers, subject to revisions. Texas upstream employment in December 2022 represented the addition of 36,100 positions compared to December 2021, including an increase of 7,000 jobs in oil and natural gas extraction and 29,100 jobs in the services sector. The average monthly gain in Texas upstream employment last year was 3,127.

TIPRO's new employment data also indicated a significant rise in job postings for the upstream, midstream and downstream industries for the month of December. According to the association, there were 14,482 active unique jobs postings for the Texas oil and natural gas industry in December, including 6,953 new job postings added in the month by companies.

Among the 14 specific industry sectors TIPRO uses to define the Texas oil and natural gas industry, Support Activities for Oil and Gas Operations continued to lead in the rankings for unique job listings in December with 4,526 postings, followed by Crude Petroleum Extraction (1,982), and Petroleum Refineries (1,418). The leading three cities by total unique oil and natural gas job postings were Houston (5,688), Midland (1,217) and Odessa (677), said TIPRO.

The top three companies ranked by unique job postings in December were John Wood Group with 820 positions, Baker Hughes (816) and KBR (576), according to TIPRO. Of the top ten companies listed by unique job postings last month, six companies were in the services sector, followed by two companies in oil and natural gas extraction and two midstream companies.

Top posted industry occupations for December included heavy tractor-trailer truck drivers (604), managers (414) and maintenance and repair workers (334). Top qualifications for unique job postings included Commercial Driver's License (CDL) (492), CDL Class A License (427) and Master of Business Administration (230). TIPRO reports that 44 percent of unique job postings required a bachelor's degree, 34 percent a high school diploma or GED, and 23 percent had no education requirement listed as part of the criteria.

There were 1,758 advertised salary observations, or 12 percent of total oil and natural gas job postings, with a median salary of $52,200. Based on TIPRO's new full year analysis for 2022, the average annual wage for the Texas oil and natural gas industry was $139,000, with average wages for the Texas upstream sector exceeding $145,000 last year.

When further examining the economic impact of the sector, TIPRO says direct Gross Regional Product (GRP), which is essentially Gross Domestic Product (GDP) for a region of study, for the Texas oil and natural gas industry was $315 billion in 2022, representing 14 percent of the state economy. Texas upstream industry direct GRP exceeded $157 billion last year. TIPRO says indirect employment tied to the Texas oil and natural gas industry also increased in 2022. When calculating direct, indirect, and induced employment for the upstream sector, for every position in Crude Petroleum Extraction, eight jobs are created in other industries, followed by Natural Gas Extraction (seven jobs), Drilling Oil and Gas Wells (two jobs) and Support Activities for Oil and Gas Operations (two jobs).

TIPRO also highlights recent data released from the Texas comptroller's office showing production taxes paid by the oil and natural gas industry to the state of Texas generated $887 million in tax revenue in December. According to the comptroller's data, in December, Texas oil producers paid $516 million in production taxes, up 15 percent from December 2021. Natural gas producers, meanwhile, last month also paid $371 million in state taxes.

Additionally, TIPRO reports that oil and gas production is on track to continue to rise in the months to come. Oil output in the Permian Basin is forecasted to grow by 30,000 barrels per day (bpd) to hit a record 5.635 million bpd in February, according to the U.S. Energy Information Administration (EIA). In the Eagle Ford Shale in South Texas, oil output will also go up next month to total 1.213 million bpd. Overall, U.S. crude oil production is expected to go up by 76,000 bpd and will top 9.375 million bpd in February, projects the EIA. Natural gas production in the Permian Basin will also rise by 109 million cubic feet per day (Mmcf/D) and will hit record highs in January at 21.72 billion cubic feet per day (bcf/d). Natural gas output in the Eagle Ford Shale is also forecasted to reach 7.4 bcf/d in February, up 46 Mmcf/d from projected January levels. Altogether, EIA forecasts natural gas production in the United States to grow to 96.656 bcf/d in February.

"The oil and natural gas industry continues to have a tremendous impact on our state economy, providing high paying jobs and billions of dollars annually in taxes to support infrastructure investments, education and other essential services," said Ed Longanecker, president of TIPRO. "We look forward to working with policymakers during the 88th Texas Legislative Session to fund programs that will help drive further growth in our sector for the benefit of our state, including road repair and maintenance in energy producing areas, seismicity research and produced water pilot projects," concluded Longanecker.

Independent Statistics and Analysis
U.S. Energy Information Administration

Country Analysis Brief: Russia

Last Updated: January 17, 2023
Next Update: January 2024

Overview

Table 1. Russia's energy overview, 2021

	Crude oil and other petroleum liquids	Natural gas	Coal	Nuclear	Hydro	Other renewables	Total
Primary energy production (quadrillion British thermal units)	22.7	26.6	10.5	2.4	--	2.0	64.1
Primary energy production (percentage)	35.4%	41.5%	16.4%	3.7%	--	3.1%	100.0%
Primary energy consumption (quadrillion British thermal units)	7.2	18.1	4.8	2.4	--	1.8	34.2
Primary energy consumption (percentage)	20.9%	52.8%	14.0%	6.9%	--	5.4%	100.0%
Electricity generation (terawatthours)	7.9	464.0	191.2	222.4	214.3	10.0	1109.7
Electricity generation (percentage)	0.7%	41.8%	17.2%	20.0%	19.3%	0.9%	100.0%

Data source: U.S. Energy Information Administration, International Energy Statistics, and BP, *Statistical Review of World Energy 2022*
Note: *Other renewables* includes hydro for primary energy production and primary energy consumption.

- In 2021, Russia was the third-largest energy producer and energy consumer in the world (Table 1).
- On February 24, 2022, Russia launched a full-scale invasion of Ukraine. Following the invasion, the United States enacted a range of sanctions targeting Russian trade, broad economic sectors, and specific entities.[1]
- The European Union (EU), Russia's main market for its energy exports and source for export-based revenues, also implemented several rounds of increasingly punitive sanctions and restrictive measures in response to the February 2022 invasion. Notably, initial rounds of EU sanctions disconnected 10 leading Russian financial institutions from SWIFT and banned coal imports from Russia.[2]
- In early June 2022, the European Union (EU) passed its sixth sanctions package against Russia, which included a complete ban on all seaborne crude oil and petroleum product imports from Russia into the EU. The sixth sanctions package also banned EU-based

companies from providing any maritime transport services for petroleum cargoes from Russia.[3]

- Because companies in the EU, the United Kingdom, and Norway have significant market share in the global maritime insurance and shipping industry, the sixth sanctions package prompted concerns that those sanctions could severely restrict oil flows from Russia and cause global oil prices to increase.[4] As a result, in late June 2022, the Group of Seven (G7) countries announced they would explore a global price cap on crude oil and refined products from Russia. The price cap would allow all members of the G7 to impose their own maritime services ban on oil flows from Russia, unless those cargoes are sold at or below a pre-determined price. The goal for this initiative was to prevent potential oil price increases by providing a way for Russia's oil to continue flowing on the market while limiting the amount Russia could earn for its oil exports.
- In early October 2022, the EU passed its eighth sanctions package, which codified the price cap initiative, and the G7 officially agreed to an initial crude oil price cap of $60/barrel in early December 2022.[5] The price cap for Russia's crude oil came into force on December 5, 2022, and the price cap for Russia's refined products will become effective on February 5, 2023.[6]
- A number of international energy companies have withdrawn or curtailed their Russia-based operations as well. BP, Equinor, Shell, Eni, and ExxonMobil have initiated total divestment from Russian assets. Total Energies, OMV, and Wintershall Dea have paused new investments in Russia.
- Energy flows from Russia to Europe decreased starting in February 2022, but Russia increased trade with countries where it can sell and ship, mostly to China and India.

Petroleum and Other Liquids

- Russia's proved oil reserves were 80 billion barrels as of December 2022.[7] Russian firms Rosneft, Lukoil, Surgutneftegas, Gazprom, and Tatneft account for a majority of total crude oil production (Table 2).

Table 2. Russia's crude oil and condensate production by company, 2021
thousand barrels per day

Company	Total crude oil and condensate production
Rosneft	3,476
Gazprom	1,634
Lukoil	1,473
Surgutneftegas	1,171
Tatneft	557
Others	2,217

Data source: Rystad Energy

- The Russian government released its *Energy Strategy to 2035* in June 2020. The strategy seeks to diversify energy exports, modernize energy infrastructure, increase national competitiveness, and accelerate innovation and digitalization within its energy system, particularly in the Arctic region. Russia is prioritizing exports and revenue.[8]

- Further, Rosneft established the Vostok Oil project to focus on the northern territories, related infrastructure, and transportation via Russia's Northern Sea Route. As part of the Vostok Oil project, Rosneft began constructing an Arctic oil terminal at the Bukhta Sever port in 2022.[9]
- As of December 2022, Russia had 5.4 million barrels per day (b/d) of crude oil refining capacity from more than 25 refineries (Table 3).[10] Rosneft, the largest refinery operator, owns more than 2.0 million b/d of crude oil refining capacity.

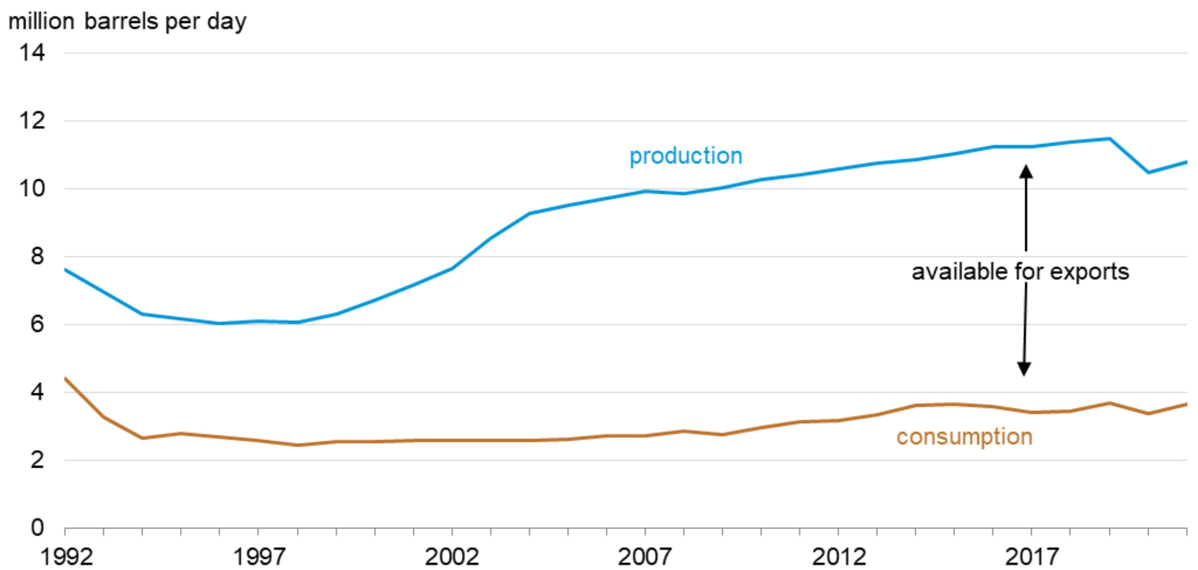
Table 3. Russia's crude oil refining capacity by operator, 2022
thousand barrels per day

Operator	Crude oil refining capacity
Rosneft	2,189
Lukoil	985
Gazprom	831
Tatneft	210
Others	1,195

Data source: *Oil and Gas Journal*

- In 2022, Gazprom Neft upgraded its Omsk Refinery (which supplies petroleum products to Siberia, the Urals, and Kazakhstan) to produce internationally compliant jet fuel and low-sulfur marine fuel that meets more stringent emission standards.[11] Upgrades to Forte Invest's Orsk Refinery (which delivers petroleum products to neighboring Kazakhstan, Tajikistan, Uzbekistan, Belarus, and Kyrgyzstan as well as to Turkey and Malta) will be completed in 2023, increasing its yield of light oil products to 98%.[12]
- In 2021, 34% of Russia's domestic petroleum and other liquid fuels production was consumed domestically (Figure 1).

Figure 1. Russia petroleum and other liquid fuels production and consumption, 1992–2021



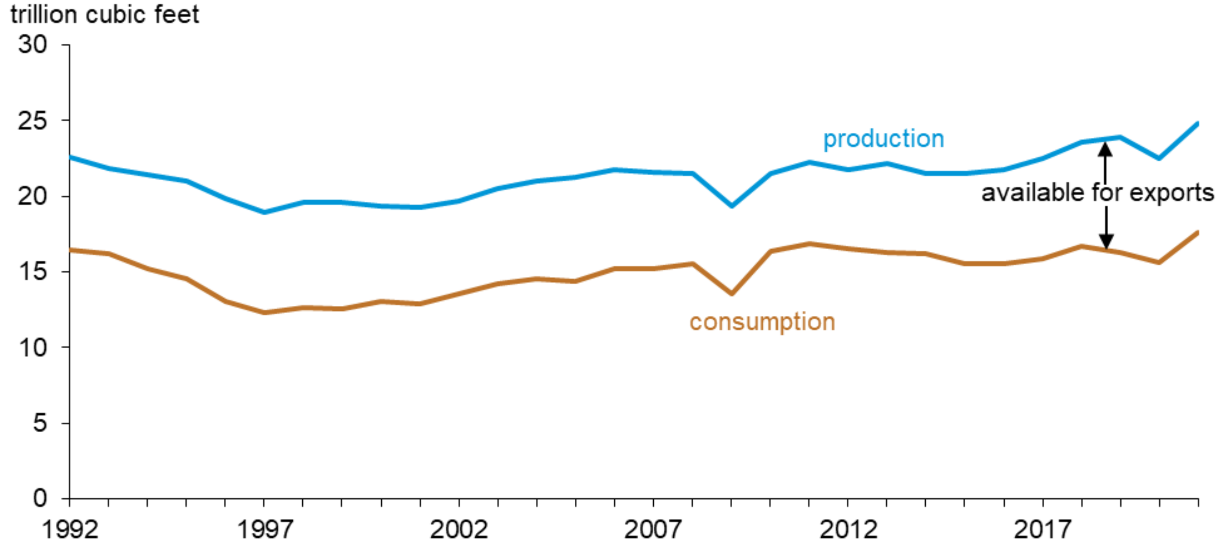
Data source: U.S. Energy Information Administration, International Energy Statistics

- The Caspian Pipeline Consortium's (CPC) de-bottlenecking program is nearly complete. Beginning in 2023, the upgraded pipeline, which transports crude oil produced in Kazakhstan and Russia to the Russian Black Sea port of Novorossiysk, will be able to transport nearly 1.5 million b/d of oil from Kazakhstan. Pipeline capacity will rise to 1.7 million b/d as it passes through Russia.[13]
- Russia may delay the launch of new hydrocarbon gas liquid (HGL) facilities following the full-scale invasion of Ukraine. Sibur's Amur Gas Chemical Complex (with a planned production capacity of 2.7 million tons per year), is a joint venture with China's Sinopec, and is co-located with Gazprom's Amur Gas Processing Plant in Svobodny and was originally scheduled to start production in 2024. The facility will produce polyethylene and polypropylene and consume ethane as well as smaller quantities of propane as feedstock. Irkutsk Oil's Ust-Kut polymer plant (with a planned production capacity of 650 thousand tons per year), located in East Siberia, will produce ethylene and polyethylene and consume approximately 45,000 b/d of ethane feedstock, and was also scheduled to launch in 2024.[14] Revised launch schedules for either facilities have not been published.

Natural Gas

- Russia held the world's largest natural gas reserves, at 1,688 trillion cubic feet (Tcf), as of January 1, 2023.[15]
- Natural gas discoveries in Russia's Arctic region, particularly in the Yamal Peninsula and Ob Bay, could facilitate Russia's plans to increase liquefied natural gas (LNG) exports to approximately 4.5 Tcf−4.9 Tcf per year by 2024 and to about 8.3 Tcf−9.6 Tcf per year by 2035, according to industry publications.[16,17,18,19]
- In 2021, Russia flared more than 883 Tcf of natural gas, accounting for the largest share of the 5.1 Tcf flared globally.[20]
- In 2021, 71% of Russia's natural gas was consumed domestically (Figure 2).

Figure 2. Russia dry natural gas production and consumption, 1992–2021



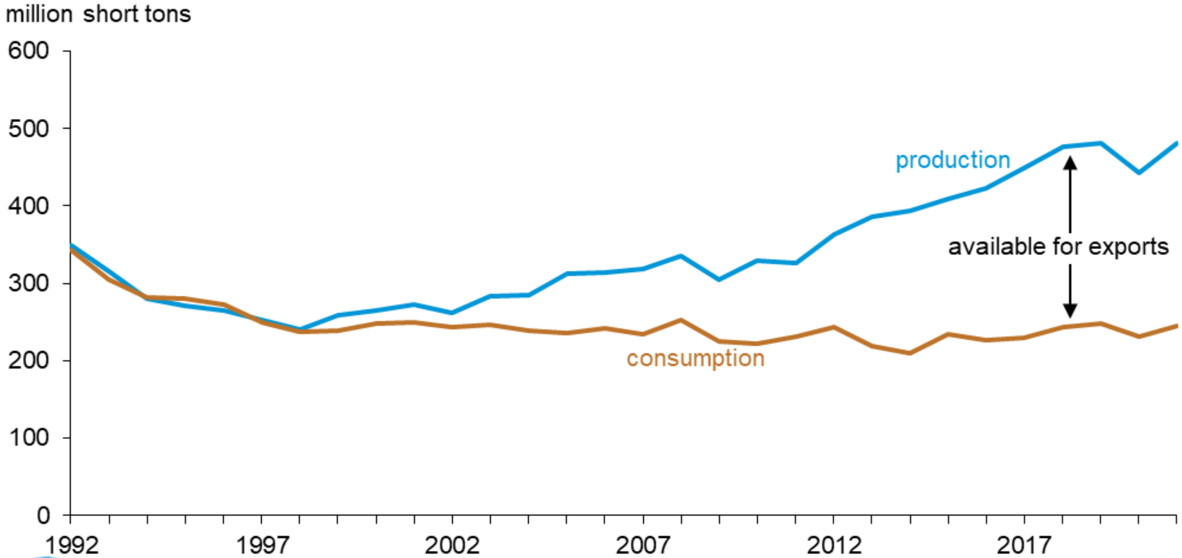
Data source: U.S. Energy Information Administration, International Energy Statistics

- Russia continues to increase its LNG export capacity. The first train of Gazprom's Baltic LNG at Ust-Luga port, a two-train LNG export facility with a total capacity of 624 billion cubic feet (Bcf) per year, is scheduled to begin commercial operations in 2023. The second train will come on stream in 2024.[21] Novatek's Arctic LNG-2 project on the Gydan Peninsula, a three-train liquefaction export facility with a total capacity of 951 Bcf per year, is scheduled to export its first LNG cargo in 2023. Arctic LNG-2's second and third trains will begin operation in 2024 and 2026, respectively.[22] However, these dates were announced by operating companies prior to Russia's full-scale invasion of Ukraine and have not been revised since then.

Coal

- Russia's coal reserves were approximately 179 billion short tons at the end of 2021, making it the second-largest holder of recoverable coal reserves in the world after the United States.
- Russia is ranked the sixth-largest coal producer in the world behind China, India, Indonesia, the United States, and Australia. The Kuznetsk Basin, located equidistant to the main Baltic and Black Sea ports in the west and the Far East ports on the Pacific, accounts for over half the coal produced in Russia.[23] Other key basins include the long-mined Donetsk Basin, the Yakutia Basin, and the Pechora Basin, which is close to the north coast.
- Bituminous coal, used for thermal generation, and metallurgical coal, an important input for iron and steel production, cumulatively accounted for nearly two-thirds of the 481 million short tons of coal produced in 2021.
- In 2021, 51% of Russia's coal production was consumed domestically (Figure 3).

Figure 3. Russia coal production and consumption, 1992–2021



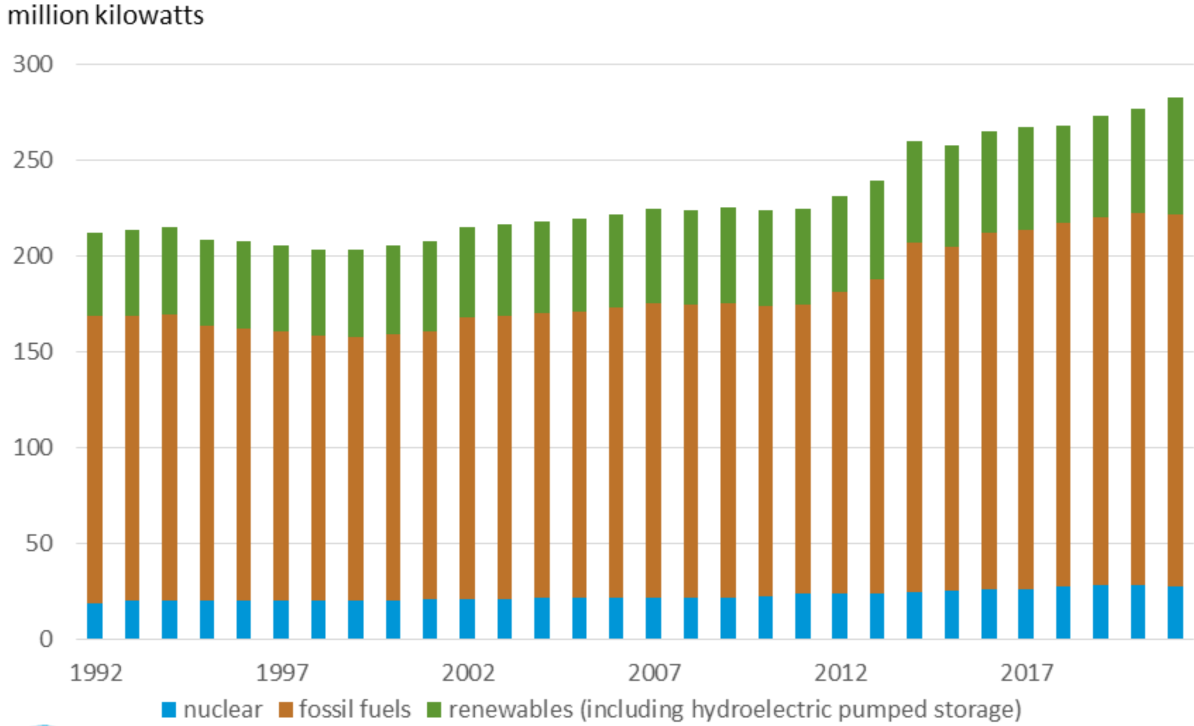
Data source: U.S. Energy Information Administration, International Energy Statistics

- Russia is investing in its coal infrastructure. In June 2020, Russia adopted a long-term program for developing its coal industry by 2035. With the 2035 Coal Program, Russia plans to expand the eastern ends of the Baikal-Amur Mainline (BAM) and Trans-Siberian railways, removing a bottleneck for coal flows to its eastern seaports; create new coal extraction hubs; and implement high global standards on efficiencies and capacities for domestic coal producers.[24,25]

Electricity

- Russia's installed electricity generation capacity increased to 283 gigawatts (GW) at the end of 2021. Although the country added 7 GW of renewable (hydro, solar, and wind) capacity last year, renewable capacity, as a share of total capacity, has averaged 21% since 1992 (Figure 4).

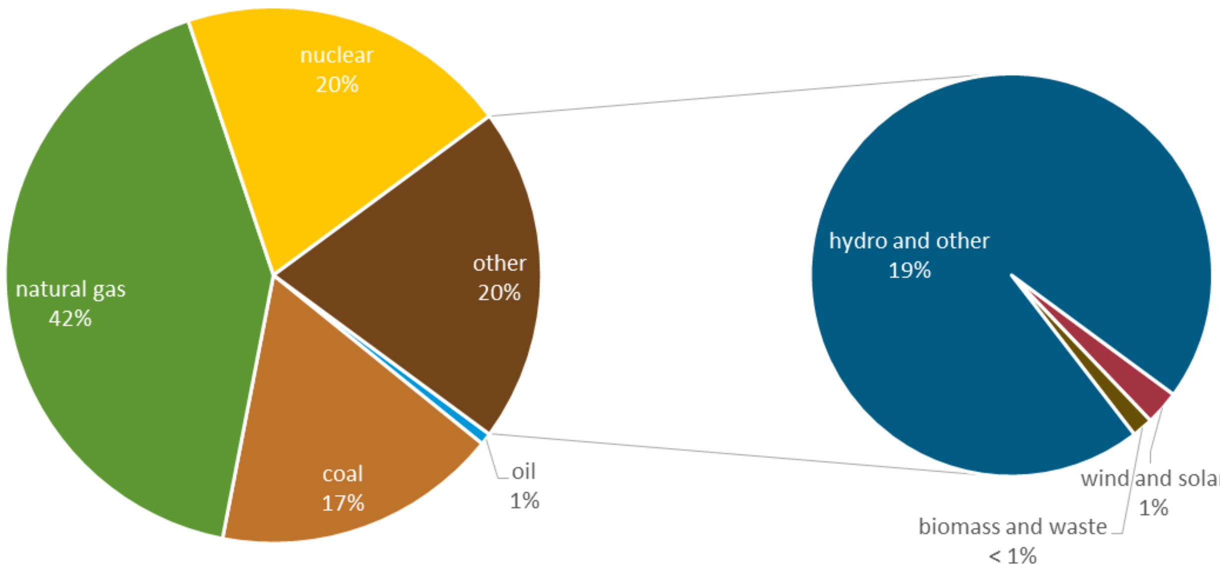
Figure 4. Russia electricity capacity share by source, 1992–2021



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

- Russia's electric power generation was 1,110 billion kilowatthours (kWh) in 2021. About 60% of Russia's electric power generation came from fossil fuel-derived sources, and the remainder came mostly from nuclear and hydroelectric sources (Figure 5).

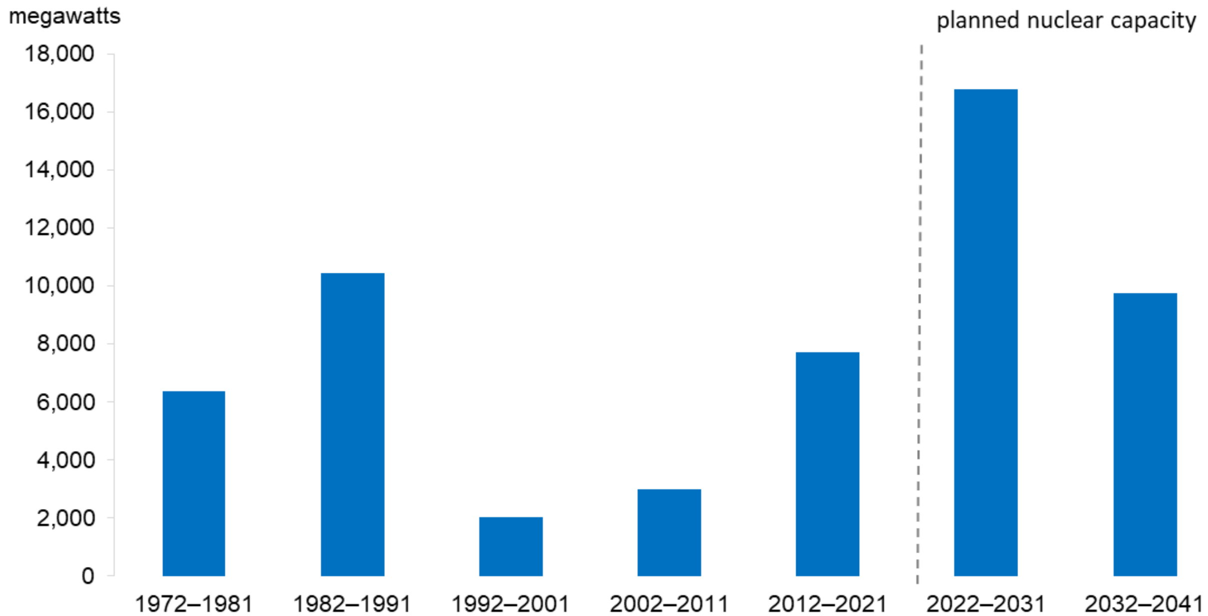
Figure 5. Russia electricity generation by source, 2021



Data source: U.S. Energy Information Administration, International Energy Statistics, and BP, Statistical Review of World Energy 2022

- Russia is planning to expand the role of nuclear energy. Based on the most recent information available, three nuclear power reactors (Kursk II-1, Kursk II-2, and BREST-OD-300), with a total gross generation capacity of 2.8 GW, are under construction.[26] In addition, Rosenergoatom, Russia's sole utility company operating the country's nuclear plants, anticipates building 26 additional nuclear reactors that would potentially provide approximately 24 GW of additional capacity over the next 15 years (Figure 6).[27]

Figure 6. Operating and planned nuclear capacity in Russia, as of December 2022



Data source: International Atomic Energy Association, Power Reactor Information System
Note: According to the World Nuclear Association (WNA), construction of Baltic I was suspended in July 2013, and the reactor pressure vessel (RPV) made for Baltic I was sent to be used in Ostrovets 2 in Belarus. The unit was removed from the WNA's database in November 2020 and is not part of the data for the graph above.

- Russia has the world’s first floating cogeneration nuclear power plant, the *Academician Lomonosov*. Located at the Artic port of Pevek, 600 miles from the Bering Strait, the Academician Lomonosov is based on technology used for nuclear icebreaker ships and consists of two 35 megawatts reactors that provide heat and power to the town.

Energy Trade

Petroleum and other liquids

- In 2022, four ports (Primorsk, Nakhodka, Novorossiysk, and Ust-Luga) accounted for 82% of Russia’s crude oil and condensate exports (Table 4). Similarly, three ports (Ust Luga, Novorossiysk, and Primorsk) accounted for more than half of Russia’s refined petroleum product exports (Table 5).

Table 4. Russia's seaborne crude oil and condensate exports by port terminal, 2022
thousand barrels per day

Port terminal	Crude oil and condensate exports
Primorsk	826
Nakhodka	795
Novorossiysk	640
Ust-Luga	554
Murmansk	314
Sokol Sakhalin	99
Varandey	101
Others	114

Data source: Kpler
Note: Novorossiysk includes CPC loadings where the seller is Lukoil, excludes all other CPC loadings. Murmansk includes volumes that are originally loaded in Arctic ports, and transshipped through Murmansk, in order to optimize shipping.

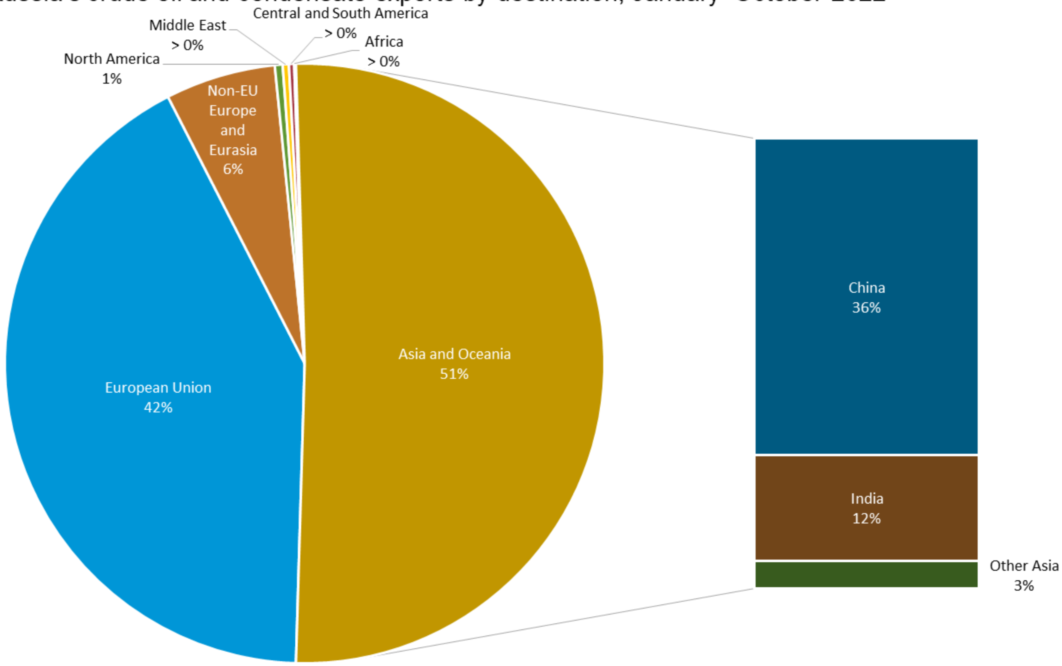
Table 5. Russia's seaborne refined petroleum product exports by port terminal, 2022
thousand barrels per day

Port terminal	Refined petroleum product exports
Ust Luga	701
Novorossiysk	372
Primorsk	350
Tuapse	251
Vysotsk	239
St Petersburg	192
Taman	139
Others	362

Data source: Kpler

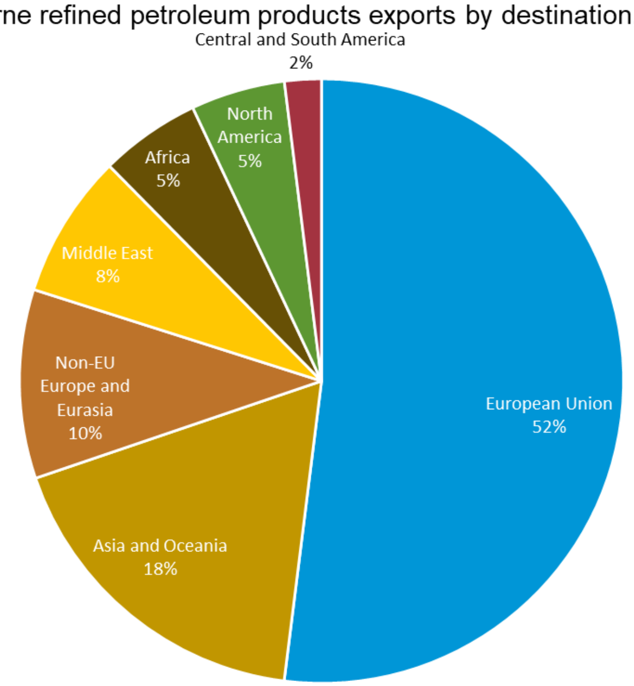
- Russia exports crude oil and condensates to Europe via the Druzhba pipeline system, which was briefly interrupted in mid-November 2022.[28] Russia exports crude oil and condensates to China via the ESPO and the Kazakhstan-China (KC) pipelines. The KC pipeline is under a swap arrangement between Russia and Kazakhstan. A small portion of the Caspian Pipeline Consortium (CPC) pipeline, which primarily carries Kazakh crude oil, is also used to export crude oil and condensates.
- Between January and October 2022, Russia's seaborne and piped exports of crude oil and condensate totaled about 5 million barrels per day (b/d) (Figure 7). China received the largest share, at 36%, of Russia's total crude oil and condensate exports. During the first 10 months of 2022, seaborne deliveries of refined petroleum products were 2.5 million b/d, and EU markets received 52% of these deliveries (Figure 8). Diesel, fuel oil, and naphtha, cumulatively, accounted for 86% of total seaborne refined petroleum products exports. Data are limited for other methods of transportation.[29]

Figure 7. Russia's crude oil and condensate exports by destination, January–October 2022



Data source: Kpler and International Energy Agency, *Oil Market Report*

Figure 8. Russia's seaborne refined petroleum products exports by destination, January–October 2022



Data source: Kpler

Natural gas

- Six major pipelines connect Russia's natural gas infrastructure to European markets, and two pipelines transport Russia's natural gas to Asian markets (Table 6). Russia's western pipelines have also been affected by Russia's full-scale invasion of Ukraine last year. For example, the German government suspended certification of the Nord Stream 2 following the full-scale invasion of Ukraine.[30] In May 2022, Ukraine suspended operations at the Sokhranivka measuring station and the Novopskov compressor station, which are part of the Soyuz and Brotherhood pipeline system, because of interference by Russian forces.[31] In early-September 2022, Nord Stream was shut down following explosions that damaged the pipeline.[32] Russia plans to increase deliveries of natural gas to China via Mongolia with the proposed Power of Siberia 2 pipeline, which would expand its export options beyond Europe.

Table 6. Russia's major natural gas export pipelines

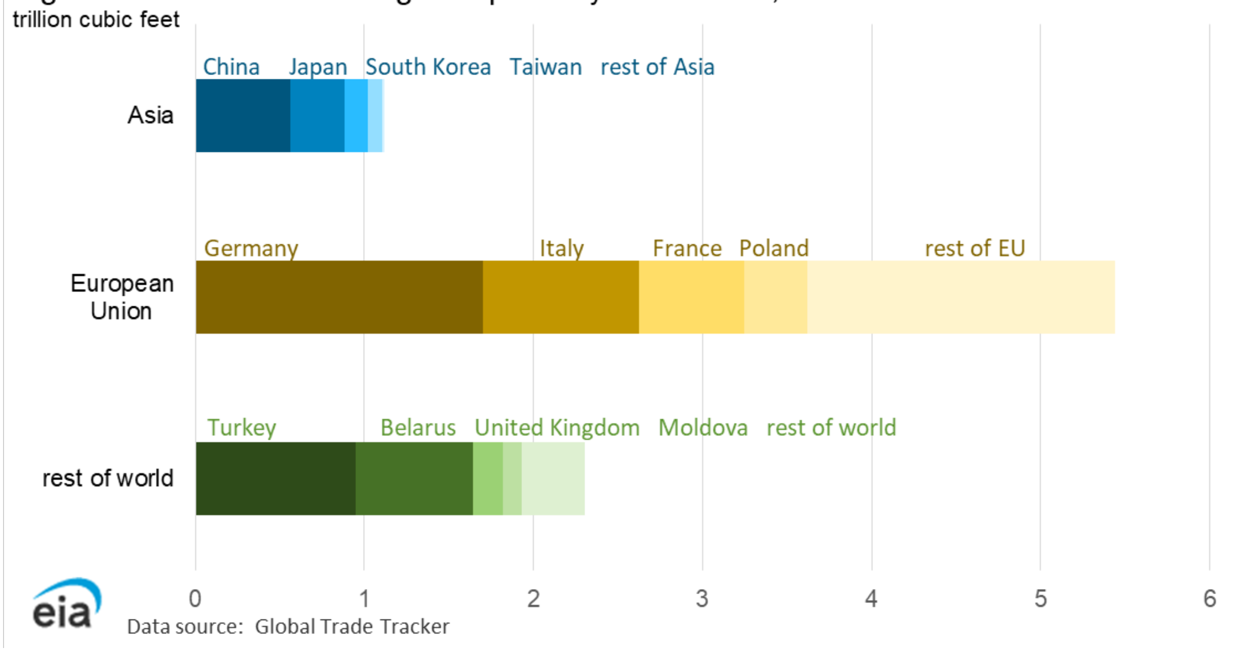
Pipeline	Annual capacity (trillion cubic feet)	Total length (miles)	Supply regions	Markets
Western pipelines				
Yamal-Europe	1.2	2,552	West Siberian fields including Urengoy area	Poland, Germany, and northern Europe via Belarus
Blue Stream	0.6	754	West Siberian fields including Urengoy area	Turkey via the Black Sea
Nord Stream	1.9	761	West Siberian fields including Urengoy area	Germany and northern Europe via the Baltic Sea
Nord Stream 2	1.9	761	West Siberian fields including Urengoy area	Germany and northern Europe via the Baltic Sea
Soyuz and Brotherhood (Urengoy-Pomary-Uzhhorod)	1.1	2,800	West Siberian fields including Urengoy area, Russian Urals fields, and Central Asia	Western Russia and Europe via Ukraine
TurkStream	1.1	580	West Siberian fields including Urengoy area	Turkey and southeastern Europe via the Black Sea
Eastern pipelines				
Sakhalin-Khabarovsk-Vladivostok	0.2	1,118	Sakhalin fields (offshore northern Sakhalin)	Eastern Russia with potential exports to Asia via Vladivostok LNG or new pipelines
Power of Siberia	Mainline: 2.2 China spur: - 1.3	5,040	East Siberian fields including Chayadinskoye in Yakutia region and Kovytka in Irkutsk region	Northeast China with a connection to the Sakhalin-Khabarovsk-Vladivostok pipeline

Data source: Enerdata, Reuters, British Petroleum, Gazprom, Sakhalin Energy, TurkStream, World Gas Intelligence, Nefte Compass, and Argus FSU

- Between January and October 2022, Russia delivered 1.4 trillion cubic feet (Tcf) of natural gas via various pipelines to Europe, a large decrease compared with the 2.9 Tcf delivered during the same period in 2021. However, Russia increased natural gas exports to China via the Power of Siberia pipeline between January and October 2022.[33] During the first 10 months of 2022, Russia also exported 2.1 Bcf of liquefied natural gas (LNG).[34] Japan, China, and [France](#) were the top three destinations for Russia's LNG exports. Data are limited for other methods of transportation.

- In 2021, Russia exported 8.9 Tcf of liquefied and piped natural gas. Nearly 85% of Russia's exported natural gas arrived at its destination country via pipeline, and the rest was shipped as LNG. The EU received more than 60% of Russia's natural gas exports (Figure 9). Within the EU, Germany was the largest importer of Russia's natural gas exports, receiving 1.7 Tcf.

Figure 9. Russia's natural gas exports by destination, 2021



Coal

- Historically, Russia's coal exports accounted for most of the European coal import market because of Russia's proximity to Europe. Now, they compete with Indonesia to supply coal to the Asian and Far Eastern markets. Russia is increasing coal sales in new markets by offering price discounts.
- Following the EU ban on importing coal from Russia, Russia began marketing its coal to buyers in Asia. Between January and October 2022, Russia's seaborne coal exports were nearly 200 million short tons (MMst), a slight decrease compared with the 218 MMst during the same period in 2021.[35,36] Despite rising rail costs and railway bottlenecks domestically, Russia continued to deliver both thermal and metallurgical coal to China and India, the primary benefactors of Russia's price discounts. Together, seaborne coal exports to China and India, which previously accounted for 27% of Russia's total seaborne coal exports in 2021, grew to over 40% from January through October 2022. Data are limited for other methods of transportation.
- In 2021, Russia exported 262 million short tons (MMst), or more than half of the coal the country produced. Thermal coal exports, often used for power generation, accounted for 86% of Russia's coal exports. The EU received 24% of all Russia's thermal coal exports and 11% of all Russia's metallurgical coal exports (Figures 10 and 11).

Figure 10. Russia's thermal coal exports by destination, 2021

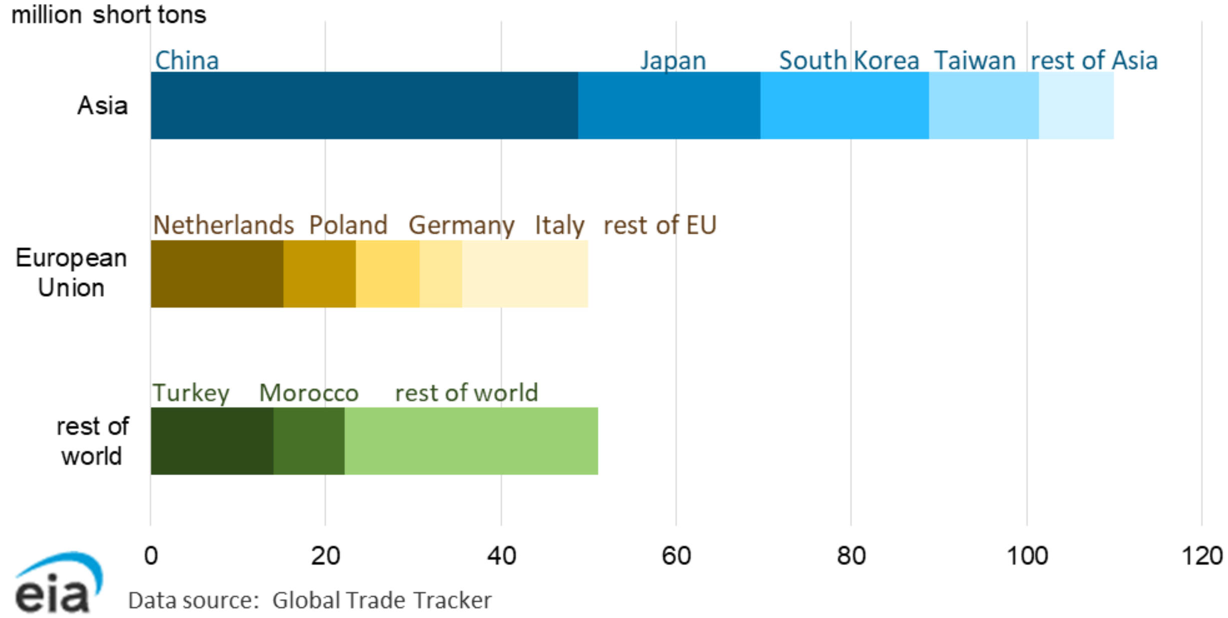
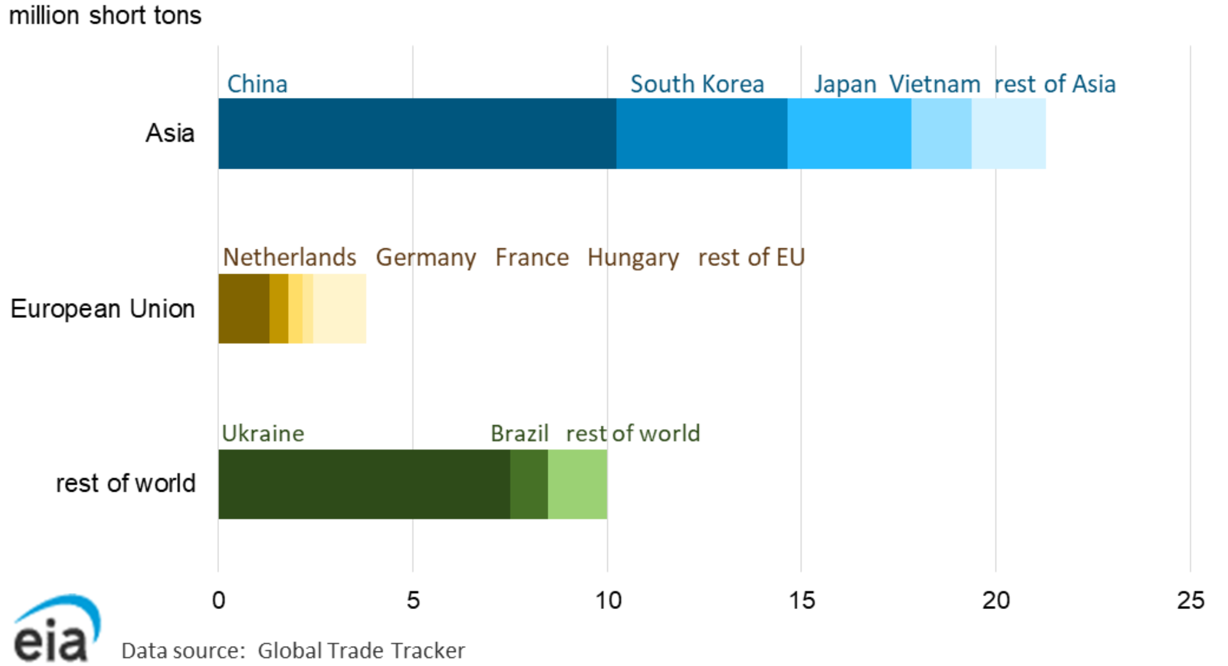


Figure 11. Russia's metallurgical coal exports by destination, 2021



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Ownership and climate risk in the GPFG - on the instruments for managing climate risk in the GPFG

Speech by Deputy Governor Øystein Børsum, 21 December 2021.

Actual performance may differ from published text

Introduction

Climate challenges are an engaging theme.

Figure: Emissions must be reduced

The world economy, as it operates today, is not sustainable. It must be, and then emissions must go down. It concerns us all - and not least our common fund. With a broadly diversified, global portfolio and a long horizon, we are in many ways burdened with the world economy.

Norges Bank is a financial investor. We will secure and create financial value for future generations. It is our task as manager of the fund. But how the assignment is carried out can also have an impact beyond the purely financial. Among other things, in the transition to a low-emission society. What our role should be - what our work should consist of - is what I want to talk about today.

This summer, an expert group submitted a report to the Ministry of Finance with recommendations on how climate risk should be managed in the fund. During the autumn, we at Norges Bank worked to assess the proposals and look at how they can be implemented.

A couple of days ago, the Executive Board sent its response to the Ministry of Finance. In the bank's management of climate risk, a lot is already being done, and we are outlining even more ambitious plans for the future. As a long-term and global investor with ownership interests in several thousand companies, we have a financial interest in the companies adapting to the risk and opportunities that climate change entails in a good way.

We propose that Norges Bank be a driving force for the companies we are invested in to adjust to net zero emissions over time - that the companies we invest in reflect the restructuring that the world has to go through.

The fund as an investor

Our characteristics as an investor

The climate risk in the fund is related to who we are as an investor and our overall investment strategy. In short: The fund is large, broadly diversified, long-term and close to the index.

Chart: Large, broadly diversified, long-term and index-linked

Of the fund's more than 12,000 billion, 70 per cent is invested in shares. With that, we are one of the world's largest shareholders. We are owners of 9000 companies in 70 countries.

And we are long-term. By using only the real return, the fund can in principle be perpetual.

The strategy is based somewhat simply on the following: If we are to achieve the best balance between expected return and risk, we must spread the investments widely and own a little of everything in the market. There is a solid professional basis for this approach.

How climate risk is relevant to the fund

What does this way of managing the fund have to say for the fund's climate risk? By spreading the investments widely, we are protected against incidents that only affect individual companies or special sectors. But we can not protect ourselves from events or developments that affect everyone.

The fund is exposed to two types of climate risk - physical risk and transition risk.

Transition risk is about whether the *companies* we own will manage the transition to a low-emission economy. Here the challenge is very different across sectors and companies.

Chart: Transition risk and the fund

The fund's equity investments can be categorized according to transition risk as assessed by the research company MSCI today. The blue bars in the figure show shares of the fund's portfolio. The white bars show the emissions in the companies. The companies that have ended up in the category «restructuring» have high emissions and must therefore restructure significantly. They make up 14 percent of the equity portfolio. The rest are companies that are either considered to be neutrally positioned or are considered to make a positive contribution to a green transition. The latter are thus part of the solution. [1]

Physical risk is more directly linked to climate change. The easiest to think about are acute events such as extreme weather, but also more gradual changes such as warmer climates, droughts and increased sea levels can affect individual investments in both negative and positive directions.

In a scenario where the world does not succeed in the transition to a low-emission economy, the risk increases, also for the fund, because the consequences of major climate change will be felt everywhere. As owners of shares, bonds and real assets, we are invested in everything from real estate and infrastructure, forestry and the food industry to all kinds of production capital. All of these are investments that can be affected by changes in the environment, including heat waves, floods and fires. We own a little of everything.

For a large, long-term, global fund, there will be nowhere to hide.

Climate risk is a long-term and important risk that the fund must deal with.

What does a long-term goal of net zero emissions mean for the fund?

A key recommendation from the expert group is that Norges Bank's responsible management be given a long-term goal of working towards net zero emissions from the companies in which the fund is invested. Norges Bank supports this recommendation.

Some may interpret this as a plan to sell shares in companies with large emissions.

But that is not our approach, nor is it the expert group's proposal. Instead of selling ourselves out, we will through active ownership be a *driving force* for the companies to adapt. In order to influence, we must actually be owners.

And we believe that ownership work works.

It works because we are big. Norges Bank is among the ten largest owners in about half of the companies we are invested in, and we have experienced that the companies listen when we talk.

Responsible management - a chain of instruments

Figure: Responsible management - a chain of instruments

Responsible management is our foremost tool in the work with climate risk and climate-related investment opportunities. I will now consider some important parts of this work. We are already doing a lot, and now we want to do even more.

The work can be grouped into three: The work we do towards the markets, towards the companies and with the portfolio. Together, this constitutes a coherent chain of instruments. I can not take a full review of the work here, but will highlight some points.

Default setting

The first point, standard setting, is about standards for reporting and measuring companies' climate risk.

Good common standards are important. This enables us as managers to assess the companies' prospects, prioritize ownership work and make good investment decisions.

But not just us. Better reporting will make the financial markets more well-functioning and better able to allocate capital. International standards provide equal conditions across markets and set the list for all companies. We, and other major investors, have an important role to play in contributing to the development of these standards.

Among the particularly important initiatives we have supported are climate reporting from the Task Force on Climate-Related Financial Disclosures (TCFD). Such reporting has been voluntary, but we believe that it must now become a requirement. Another issue we are working on is a comprehensive standard for sustainability reporting in line with the recently launched International Sustainability Standards Board (ISSB).

We will also work for good standards for reporting on companies' indirect emissions in the value chain, so-called "framework 3". In many sectors, this is crucial for understanding the companies' climate risk. We will also work with other climate-related issues where international standards may be appropriate. The use of various forms of climate quotas can be an example of this.

Our work with the companies starts with setting clear expectations.

We have formulated our expectations in our own expectations documents. In the climate area, we already expect companies to have a climate strategy, set emission targets, report on developments and stress test their business models against different climate scenarios. Going forward, it is natural for us to emphasize the horizon towards zero emissions. This will provide a clearer direction for the exercise of ownership.

Exercise of ownership

The exercise of ownership will be central to the work to manage the fund's climate risk. Not least, the dialogue with the companies is important.

Figure: Climate is more often a theme in the dialogue

The dialogue with the companies follows our expectations. Last year we had about 3,000 meetings with the companies, and as you can see from this figure, sustainability is increasingly on the agenda.

Going forward, we will increase ownership activity on climate, both in scope and depth.

We will give particular priority to ownership activity towards the companies that have the largest emissions, towards those that have not published their own climate plans or have inadequate climate reporting. We will also strengthen the ownership activity aimed at the financial sector, which is indirectly exposed to climate risk through lending and investments.

The dialogue is adapted to the sector and situation. Steel and cement are an example. These companies currently have large emissions, but are also manufacturers of products we also need in a low-emission society. Therefore, the dialogue is precisely about transition plans, much about the technological measures and investments needed for change. We also address the need for industry standards and lobbying, which is a significant challenge.

Figure: Companies report better on climate

We see signs that the work is working. For example, when we analyze the reporting from 1,500 companies, we see that the companies we have been actively involved in have made greater progress in reporting on climate strategy than the other companies. Of course, we should not take all the credit for these advances. But there is progress.

In the future, we will report more about the dialogue with the companies, what they are about and changes we see. That it is visible is a tool in itself.

Reporting and voting

The dialogue with the companies will not succeed in all cases. We can then hold the boards responsible for their decisions through our voting. This year, we have, among other things, in six cases voted against renewed confidence in board members due to inadequate management of climate risk. This sounds small, but in the future we will work to use this tool to a greater extent than today.

We have started by announcing our voting five days before the actual voting. What we do is noticed.

Another alternative is to promote shareholder proposals, alone or together with others. In the past year, we have supported 19 shareholder proposals on climate. One of those who gained a majority led to a large international company initiating work on reporting on emissions in the value chain ("Box 3"). Going forward, we will also consider promoting our own shareholder proposals.

Risk-based divestments

A last resort, when the exercise of ownership does not succeed, is the sale. It will not be the case that we automatically sell out if the ownership work does not succeed. But in some cases it can be the result.

Norges Bank can sell out of a company on a financial basis. This is what we call risk-based divestments. These are companies that we believe handle climate risk in a very deficient way - and thus provide an increased financial risk. This is about avoiding companies that we believe do not have sustainable business models.

Figure: More than half of the sales are related to climate

Risk-based divestments are active decisions made by Norges Bank, which draw on the fund's framework for deviations from the benchmark index. In the period 2012-2020, we have made more than 300 such sales, and more than half have been linked to climate change.

We are ready to do more of this in the future.

As a continuation of risk-based divestments, we have also begun to systematically assess companies' sustainability risk before entering the fund's benchmark index.

The fund is managed close to the index. Risk-based divestments will therefore mainly be relevant for smaller companies. For larger companies, we have more limited room for maneuver, as such sales will to a greater extent draw on the framework for deviations from the benchmark index.

The behavioral criterion

Figure - Responsible management - a chain of instruments

This takes me over to the second form of divestiture, namely exclusion on ethical grounds. The fund's ethical guidelines contain both a product-based coal criterion and a behavior-based climate criterion.

The latter includes companies that are linked to serious environmental damage or to an unacceptable degree lead to greenhouse gas emissions.

The Council on Ethics advises observing or excluding a company based on this criterion. Based on their recommendations, the Executive Board of Norges Bank makes the final decision based on these recommendations. A decision on exclusion means that the company is excluded from both the portfolio and the benchmark index. It therefore does not draw on our framework for deviations.

It is our experience that the practice of this criterion is complex and that it requires broad insight and detailed information about companies' activities and plans.

Norges Bank expects that we will - in light of the work I have talked about today - gather further detailed information about the companies' climate risk and climate plans. We will share this information with the Council on Ethics.

Downsizing or exclusion is the last link in the chain of instruments, but far from the most important. We plan for Norges Bank to be a driving force for the companies in the portfolio to adjust to net zero emissions over time. Active ownership is the key tool.

End

Before I conclude, I would like to mention that we invest in companies that can contribute to solutions to the climate challenges, both through the environmental mandates and in the rest of equity management. We are now also in the process of building up a portfolio of high-quality wind and solar power plants.

The first environmental mandates were established in December 2009, and have had positive learning effects for several parts of the organization. As we write in the letter to the ministry, we will in future draw more on the competence of the managers of the environmental mandates in other parts of the administration.

Overall: Our ambition is for us to be a leader in responsible management. In collaboration with other large investors, we will contribute to the development of standards and methods for reporting. We will strengthen our dialogue with companies about climate both in scope and depth, and utilize the entire toolbox we have as an investor. We will influence companies to take the restructuring seriously. We expect concrete plans, not empty words or greenwashing! And not least - we must have a clear voice in our ownership work.

Footnote

[1] The calculations are based on the analysis company MSCI's classification of companies' transition risk. 80 per cent of the market value of the fund's equity portfolio ends up in the group of companies that are neutrally exposed to transition risk.

PUBLISHED December 21, 2021 9:00 AM

https://www.cppinvestments.com/public-media/headlines/2021/cpp-investments-highlights-importance-of-decarbonizing-hard-to-abate-sectors-in-addressing-climate-change

CPP Investments highlights importance of decarbonizing hard-to-abate sectors in addressing climate change

• CPP Investments releases position outlining investors' role in enabling an economy-wide evolution to a low-carbon future
• Introduces new investment approach that will identify, fund and support companies in their effort to decarbonize

Toronto, CANADA (December 15, 2021) – Helping essential, high-emitting businesses decarbonize is critical to addressing climate change, according to a recent perspective published by Canada Pension Plan Investment Board (CPP Investments). The perspective, "Investing to enable an economy-wide evolution to a low-carbon future," highlights the opportunity decarbonization presents for long-term investors, noting the need to address a particularly serious obstacle to decarbonization: strategic sectors that are essential, high-emitting and hard-to-abate.

The perspective also outlines CPP Investments' new investment approach which aims to identify, fund and support companies that are committed to creating value by lowering their emissions over time, consistent with CPP Investments' time horizon advantage.

"High-emitting companies that successfully navigate the economy-wide evolution to a low-carbon future will preserve and deliver embedded value for patient long-term investors like CPP Investments," said Deb Orida, Global Head of Real Assets & Chief Sustainability Officer. "This new investment approach complements the Fund's ongoing commitment to investing in companies that have the potential to develop innovative climate technologies around the world and furthers our existing capabilities in technologies that enable the energy evolution."

Strategic sectors that are essential, high emitting and hard-to-abate within this investment approach include agriculture, chemicals, cement, conventional power, oil and gas, steel and heavy transportation. The successful decarbonization of these sectors is not only essential to meet wider net-zero ambitions, but also to sustain economic growth, stability and a responsible transition. CPP Investments plans to work in partnership with like-minded companies, industry leaders, investors, and other interested parties to build out a dedicated investment approach to support current and future portfolio companies in their evolution.

CPP Investments also released a related perspective today focusing on an additional key element of sustainable investing, "Financing a greener future," highlighting green bonds as part of the Fund's approach to deploying capital for projects with environmental benefits. The paper outlines how for green bonds to go from a fast-growing niche to a mainstream offering, standards will have to grow out of a mix of evolving draft rules into something closer to the bond market's extant framework for governing how debt is rated, issued and evaluated for performance. The imperative is to improve green bond standards and practices quickly. Doing so can help the financial sector realize its enormous potential for guiding capital toward investments that support the transition to a low-carbon economy while also boosting returns. In 2018, CPP Investments was the world's first pension fund to issue green bonds and has floated six more issuances since.

For more information, the "*Investing to enable an economy-wide evolution to a low-carbon future*" perspective can be found on the CPP Investments website here. The "*Financing a greener future*" paper can be found here.

About CPP Investments

Canada Pension Plan Investment Board (CPP Investments™) is a professional investment management organization that manages the Fund in the best interest of the more than 20 million contributors and beneficiaries of the Canada Pension Plan. In order to build diversified portfolios of assets, investments are made around the world in public equities, private equities, real estate, infrastructure and fixed income.

Headquartered in Toronto, with offices in Hong Kong, London, Luxembourg, Mumbai, New York City, San Francisco, São Paulo and Sydney, CPP Investments is governed and managed independently of the Canada Pension Plan and at arm's length from governments. At September 30, 2021, the Fund totalled $541.5 billion. For more information, please visit www.cppinvestments.com or follow us on LinkedIn, Facebook or Twitter.

Dan Tsubouchi @Energy_Tidbits · 1h

Hmmm!

Bullish indicators #Oil #NatGas for 2020s

$SLB "distinctive" new phase in upcycle

"it's multi-pronged. It moves multiple engines, short and long, oil and gas, offshore and onshore"

Points to tight/lack #Oil #NatGas #LNG supply for 2020s!

#OOTT

Excerpt https://www.businesswire.com/news/home/20230118006018/en/

SLB Announces Fourth-Quarter and Full-Year 2022 Results

Primed for Strong Growth and Returns—A Distinctive New Phase in the Upcycle

Le Peuch said, "The fourth quarter affirmed a distinctive new phase in the upcycle. In the Middle East, revenue increased by double digits sequentially, with growth in Saudi Arabia, Iraq, and the United Arab Emirates in the solid teens, affirming the much-anticipated acceleration of activity in the region. Offshore activity continued to strengthen, partially offset by seasonality in the Northern Hemisphere. In North America, US land rig count remains at robust levels, although the pace of growth is moderating. Additionally, pricing continues to trend favorably, extending beyond North America and into the international regions, supported by new technology and very tight equipment and service capacity in certain markets.

"These activity dynamics, improved pricing, and our commercial success—particularly in the Middle East, offshore, and North American markets—combine to set a very strong foundation for outperformance in 2023.

"Looking ahead, we believe the macro backdrop and market fundamentals that underpin a strong multi-year upcycle for energy remain very compelling in oil and gas and in low-carbon energy resources. First, oil and gas demand is forecast by the International Energy Agency (IEA) to grow by 1.9 million barrels per day in 2023 despite concerns for a potential economic slowdown in certain regions. In parallel, markets remain very tightly supplied. Second, energy security is prompting a sense of urgency to make further investments to ensure capacity expansion and diversity of supply. And third, the secular trends of digital and decarbonization are set to accelerate with significant digital technology advancements, favorable government policy support, and increased spending on low-carbon initiatives and resources.

"Based on these factors, global upstream spending projections continue to trend positively. Activity growth is expected to be broad-based, marked by an acceleration in international basins. These positive activity dynamics will be amplified by higher service pricing and tighter service sector capacity. The impact of loosening COVID-19 restrictions and an earlier than expected reopening of China could support further upside potential over 2023.

"Overall, the combination of these effects will result in a very favorable mix for SLB with significant growth opportunities in our Core, Digital, and New Energy. We expect another year of very strong growth and margin expansion. We have a clear strategy, an advantaged portfolio, and the right team in place to drive our business forward. I look forward to another successful year for our customers and our shareholders."

Excerpt https://seekingalpha.com/article/4571289-schlumberger-limited-slb-q4-2022-earnings-call-transcript

Schlumberger Limited (SLB) Q4 2022 Earnings Call Transcript

Jan. 20, 2023 2:34 PM ETSchlumberger Limited (SLB)
Play Earnings Call

Schlumberger Limited (NYSE:SLB) Q4 2022 Earnings Conference Call January 20, 2023 9:30 AM ET

Company Participants

ND Maduemezia - Vice President, Investor Relations

Olivier Le Peuch - Chief Executive Officer

Stephane Biguet - Chief Financial Officer

Olivier Le Peuch

As we see today, the combination of offshore Middle East and broad gas investments internationally will continue to support a very solid growth internationally. We are seeing – as we have seen in the fourth quarter an uptick into the rate of growth for Middle East and that's driven by a commitment to oil capacity increase and further gas development.

And this, as I commented briefly in my prepared remarks will lead Middle East investment to be on record ever as we anticipated in this year or next year. And as a result, we generate significant pull for our revenue going forward.

But I think what I will say is that, what is characterizing international as we see it, is that it has a lot of resilience, because it's multi-pronged. It moves multiple engines, short and long, oil and gas, offshore and onshore.

And I believe that the – with our commitment for capacity expansion and gas development in Middle East is combining with offshore long-cycle, a return of deepwater, which is the operating environment I will see the most activity increase this year and also the return or the acceleration of exploration and appraisal offshore, which would be one of the defining characteristics of the quarters to come.

So when you combine all of this, you are getting a very resilient multi-pronged and multiyear sustained growth pattern for international market. And I think that's what we see and it will indeed support not only growth this year, but it will support your growth next year and the years to come and it will be multi-pronged and fairly broad and with multiple geographic impact.

2 · 9 · 1,575

Dan Tsubouchi @Energy_Tidbits · 3h

Set up for sustained Q2 #oil demand rebound, herd immunity in China.

#SCMP reports china CDC today: tsunami of infections post reopening, ~80% already infected so little possibility of large-scale epidemic rebound.

see @Pfizer 👇 what is herd immunity

Thx @sunyue_luna

#OOTT

's "What is herd immunity?"
s Pfizer's explanation. [LINK]

is herd immunity?
mmunity occurs when the majority of a population is immune to a disease or virus. Otherwise known as community immur to slow the spread of infectious diseases in two ways: People contract the disease and develop an immune response. Pec ated. When enough people are vaccinated, everyone—including those who are too young or too sick to be immunized—r protection from the spread of diseases. An infectious disease is less likely to spread from person to person because there germs around to infect others. And if a person does get sick, the likelihood of an outbreak is low because more people are ne.

is herd immunity most effective?
ists estimate that in order for herd immunity to be effective, about 70 - 90 percent of a population need to be immune to a by contracting the disease and recovering or getting a protective vaccine. This reaches what the World Health Organizatic) calls the herd immunity threshold. Although, there are factors to consider. For instance, if a disease is considered highly ious, a higher percentage of immunity is needed. Measles, an extremely contagious disease that is preventable through ation, needs 93-95 percent of a population to be immune in order to reach herd immunity threshold and for measles to be ated. Herd immunity works best when there is a vaccine to provide protection. For example, diseases like polio and smallp once very common in the United States, however due to widespread vaccination, these diseases have become extremely e United States has been polio-free since 1979. The vaccines for these diseases have helped establish herd immunity.

South China Morning Post @SCMPNews · 7h
China unlikely to see second wave of Covid cases any time soon because most people have already been infected, says disease expert
scmp.com/news/china/sci...

2 · 10 · 1,589

Dan Tsubouchi @Energy_Tidbits · 12h

must be doing three nights of fireworks at the One and Only Palmilla for chinese new year. even bigger fireworks tonight, tomorrow will be huge. someone was flying a drone with a green light recording.

1 1,015

Dan Tsubouchi @Energy_Tidbits · 13h

Looks like Bakken will be challenged for near term #Oil growth.

"migration of drilling activity out of the core and into the Tier 2 & Tier 3 areas" "i think it's probably approaching half of our drilling rigs now that are outside the core" says North Dakota.

#OOTT

SAF Group created transcript of comments by North Dakota Director of Mineral Resources, Lynn Helms at the monthly press conference to discuss the NDIC Director's Cut and November Production Numbers on Jan 17, 2023 Replay is at https://www.dmr.nd.gov/dmr/oilgas/directorscut.

Items in "italics" are SAF Group created transcript

At 1:35 min mark, Helms ""... *I don't think it changes the long term trend, but we have seen a migration of drilling activity out of the core and into the Tier 2 and Tier 3 areas as the advent of three-mile laterals and drilling, more drilling by some of our independent oil and gas companies out on those Tier 2 and Tier 3 areas has picked up. I think it's probably approaching half of our drilling rigs now that are outside the core".*

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

2 4 18 3,238

SAF GROUP

Dan Tsubouchi @Energy_Tidbits · 19h

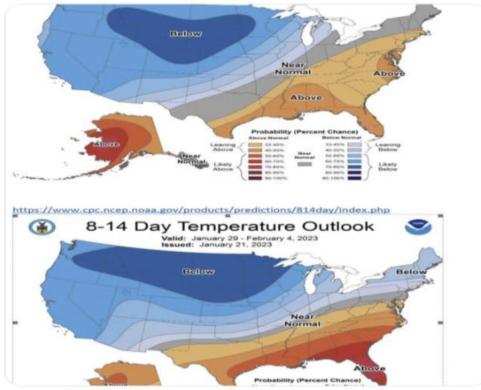
Reminder weather forecasts >1 week out regularly change.

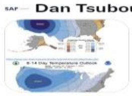
Wed 👎 @NOAA expected colder than normal across all of US for last week of Jan.

Today, @NOAA calls for normal to colder than normal for 2/3 of US for last week of Jan.

Need some sustained cold to boost #NatGas.

#OOTT



> **Dan Tsubouchi** @Energy_Tidbits · Jan 18
>
> 
>
> Finally!
>
> @NOAA calling for colder than normal temps across all of US for last week of Jan'
> ...

2 · 2 · 2,749

SAF GROUP

Dan Tsubouchi @Energy_Tidbits · 22h

#Vortexa crude #Oil floating storage at 01/20 est 84.94 mmb, -3.62 mmb WoW vs revised up big by +10.2 mmb 01/13 of 88.59 mmb. Last several weeks average 89.9 mmb (was 87.5 mmb). Thx @Vortexa @business. #OOTT

Vortexa Crude Oil Floating Storage Estimate Posted Jan 21 at 10am MT

Source: Bloomberg, Vortexa

Posted Jan 21, 10am MT

FZWWFST VTXA Index — 01/19/2020 - 01/20/2023

	Date	FZWWFST VT... Last Px
Fr	01/20/2023	84938
Fr	01/13/2023	88586
Fr	01/06/2023	98477
Fr	12/30/2022	102.061k
Fr	12/23/2022	91396
Fr	12/16/2022	68496
Fr	12/09/2022	95073
Fr	12/02/2022	89287
Fr	11/25/2022	100.762k
Fr	11/18/2022	92227
Fr	11/11/2022	77731

jan 14, 10am MT

FZWWFST VTXA Index — 01/12/2020 - 01/13/2023

	Date	FZWWFST VT... Last Px
Fr	01/13/2023	78385
Fr	01/06/2023	92192
Fr	12/30/2022	99136
Fr	12/23/2022	89209
Fr	12/16/2022	67245
Fr	12/09/2022	95973
Fr	12/02/2022	90272
Fr	11/25/2022	100.872k
Fr	11/18/2022	92509
Fr	11/11/2022	77508
Fr	11/04/2022	90999

Jan 7, 10am MT

FZWWFST VTXA Index — 01/05/2020 - 01/06/2023

	Date	FZWWFST VT... Last Px
Fr	01/06/2023	86473
Fr	12/30/2022	98010
Fr	12/23/2022	88620
Fr	12/16/2022	65993
Fr	12/09/2022	94265
Fr	12/02/2022	90887
Fr	11/25/2022	100.867k
Fr	11/18/2022	92113
Fr	11/11/2022	76062
Fr	11/04/2022	89658
Fr	10/28/2022	98148

Source: Bloomberg, Vortexa

2 · 7 · 1,797

Dan Tsubouchi @Energy_Tidbits · Jan 20

big fireworks at The One and Only Palmilla. went on for at least a couple minutes but expect an even bigger display to be celebrate chinese new year on sunday!

5 1,154

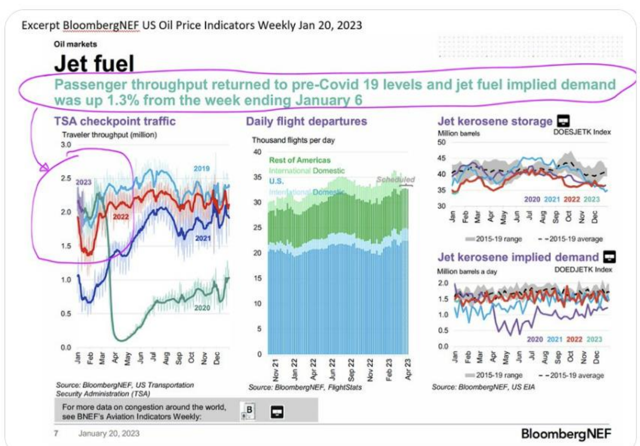
Dan Tsubouchi @Energy_Tidbits · Jan 20

US air passengers throughput back to pre-Covid levels.

Positive for #JetFuel, but still need Rest of World to get back to 2019 levels.

Thx @BloombergNEF.

#OOTT



9 23 22.9K

Dan Tsubouchi @Energy_Tidbits · Jan 20

"the macro backdrop and market fundamentals that underpin a strong multi-year upcycle for energy remain VERY COMPELLING in oil and gas" "energy security is prompting a sense of urgency to make further investments to ensure capacity expansion and diversity of supply" $SLB. #OOTT

Excerpt
https://www.businesswire.com/news/home/20230118006018/en/

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"Looking ahead, we believe the macro backdrop and market fundamentals that underpin a strong multi-year upcycle for energy remain very compelling in oil and gas and in low-carbon energy resources. First, oil and gas demand is forecast by the International Energy Agency (IEA) to grow by 1.9 million barrels per day in 2023 despite concerns for a potential economic slowdown in certain regions. In parallel, markets remain very tightly supplied. Second, energy security is prompting a sense of urgency to make further investments to ensure capacity expansion and diversity of supply. And third, the secular trends of digital and decarbonization are set to accelerate with significant digital technology advancements, favorable government policy support, and increased spending on low-carbon initiatives and resources.

"Based on these factors, global upstream spending projections continue to trend positively. Activity growth is expected to be broad-based, marked by an acceleration in international basins. These positive activity dynamics will be amplified by higher service pricing and tighter service sector capacity. The impact of loosening COVID-19 restrictions and an earlier than expected reopening of China could support further upside potential over 2023.

"Overall, the combination of these effects will result in a very favorable mix for SLB with significant growth opportunities in our Core, Digital, and New Energy. We expect another year of very strong growth and margin expansion. We have a clear strategy, an advantaged portfolio, and the right team in place to drive our business forward. I look forward to another successful year for our customers and our shareholders."

11 14 5,215

Dan Tsubouchi @Energy_Tidbits · Jan 19

US #LNG exports Nov/22 were 10.0 bcf/d, -1.2% YoY, +2.3% MoM

Continued impact of #FreeportLNG 2.2 bcf/d June 8 shut.

Nov/22 top 5 export countries: UK, France, Turkey, Japan, Dutch

Nov/21 top 5 export countries: China, Turkey, Japan, Korea, UK.

@ENERGY data.

#OOTT

US Dept of Energy LNG Monthly Jan 2023

Summary

Overview of Activity for November 2022

- **Top five countries of destination, representing 69.3% of total U.S. LNG exports in November 2022**
  - United Kingdom (82.8 Bcf), France (50.7 Bcf), Turkey (31.4 Bcf), Japan (24.4 Bcf), and Netherlands (20.6 Bcf)
- **302.3 Bcf of exports in November 2022**
  - 2.3% decrease from October 2022
  - 1.2% less than November 2021
- **94 cargos shipped in November 2022**
  - Sabine Pass (35), Cameron (33), Corpus Christi (16), Elba (4), Cove Point (6), and Freeport (0)
  - 96 cargos in October 2022
  - 99 cargos in November 2021

1a. Table of Exports of Domestically-Produced LNG Delivered by Region (Cumulative from February 2016 through November 2022)

Region	Number of Countries Receiving Per Region	Volume Exported (Bcf)	Percentage Receipts of Total Volume Exported (%)	Number of Cargos*
East Asia and Pacific	8	4,409.4	33.3%	1298
Europe and Central Asia	14	5,536.7	41.6%	1738
Latin America and the Caribbean**	13	2,128.3	16.0%	757
Middle East and North Africa	5	376.6	2.8%	110
South Asia	3	809.3	6.1%	241
Sub-Saharan Africa	0	0.0	0.0%	0
Total LNG Exports	**43**	**13,260.3**	**100.0%**	**4,145**

*Split cargos counted as both individual cargos and countries
**Number of cargos does not include the shipments by ISO container

US Dept of Energy LNG Monthly Jan 2022

Summary

Overview of Activity for November 2021

- **Top five countries of destination, representing 63.0% of total U.S. LNG exports in November 2021**
  - China (50.2 Bcf), Turkey (47.3 Bcf), Japan (33.9 Bcf), South Korea (30.8 Bcf), and United Kingdom (30.6 Bcf)
- **306.1 Bcf of exports in November 2021**
  - 2.8% increase from October 2021
  - 9.1% more than November 2020
- **99 cargos shipped in November 2021**
  - Sabine Pass (35), Corpus Christi (21), Cameron (17), Freeport (16), Cove Point (8), Elba Island (2)
  - 94 cargos in October 2021
  - 87 cargos in November 2020

1a. Table of Exports of Domestically-Produced LNG Delivered by Region (Cumulative from February 2016 through November 2021)

Region	Number of Countries Receiving Per Region	Volume Exported (Bcf)	Percentage Receipts of Total Volume Exported (%)	Number of Cargos*
East Asia and Pacific	8	3,623.6	38.6%	1057
Europe and Central Asia	13	2,910.6	31.0%	908
Latin America and the Caribbean**	13	1,855.1	19.8%	652
Middle East and North Africa	5	319.6	3.4%	94
South Asia	3	682.0	7.3%	203
Sub-Saharan Africa	0	0.0	0.0%	0
Total LNG Exports	**42**	**9,390.9**	**100.0%**	**2,914**

*Split cargos counted as both individual cargos and countries
**Number of cargos does not include the shipments by ISO container

3 6 2,804

Dan Tsubouchi @Energy_Tidbits · Jan 19

Great map showing Blueberry River First Nations lands vs Montney producer lands included in @JeremyMcCreaCFA's comment gives excellent perspective and also insight into who might be a target! #OOTT

> **Raymond James (Canada)** @RaymondJamesCDN · Jan 19
>
> raymondjames.bluematrix.com/docs/html/f727...
> RJL Analyst @JeremyMcCreaCFA talks about the implications of the Blueberry Agreement. One key conclusion: 18 months of uncertainty has now ended which should drive new international investors - see map inside for companies impacted. $ARX $CR $TOU $KEL $VET

4 · 1,668

Dan Tsubouchi @Energy_Tidbits · Jan 19

Reminds why there are really good Cdn E&P trading at low multiples. And why there will be continued push to buy back stock.

"That [multiple expansion] isn't happening any more because there is nobody to notice what actually happens at these companies."

Thx @BurggrabenH! #OOTT

> **Bloomberg TV** @BloombergTV
>
> David Einhorn, the founder of Greenlight Capital, who was among hedge fund managers wagering on Twitter, speaks to Bloomberg's @SonaliBasak at the Robin Hood Investors Conference about his stake in the social media company trib.al/q4qQrmd

11:30 AM · Oct 12, 2022

SAF Group created transcript of comments by David Einhorn (Greenlight Capital) with Bloomberg's Sonali Basak on Oct 12, 2022 https://twitter.com/BloombergTV/status/1580249493395582976

Items in "italics" are SAF Group created transcript

At 1:10 min mark, Einhorn "*.... the world has moved passive and so there is a lot less competition for what we do.*" Basak "*Well what does it mean for you as you operate as an investor if you're saying so much of the world has turned passive or quantitative, has that made your job fundamentally different as someone who picks specific securities?*" Einhorn "*It absolutely does. It used to be that we could buy at a reasonably low multiple, whatever we thought that was, think that the company would do somewhat benefit, benefit from it being somewhat better and realize other investors would see what we saw, six months later, a year later and would rerate he shares. So you could buy something you could buy something at 11 times earnings, and maybe they would earn 10% more but you get another three points on the multiple. And you'd make 50% over 2 or 3 years. That isn't happening any more because there is nobody to notice what actually happens at these companies.*"

> **Bloomberg TV** @BloombergTV · Oct 12, 2022
>
> 
>
>
> David Einhorn, the founder of Greenlight Capital, who was among hedge fund managers wagering on Twitter, speaks to Bloomberg's @SonaliBasak at the Robin Hood Investors Conference about his stake in the social media company trib.al/q4qQrmd

1 · 6 · 2,378

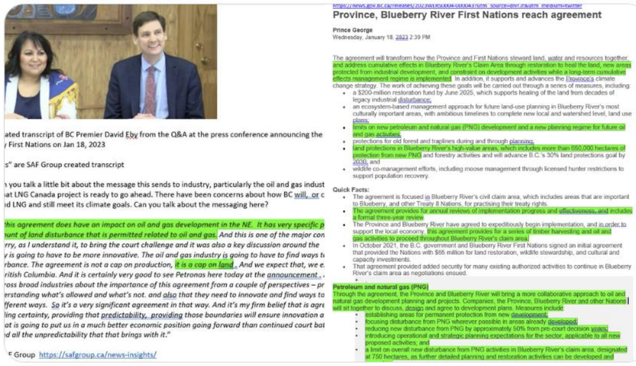
Dan Tsubouchi @Energy_Tidbits · Jan 19

BC/BRFN deal

"this agreement does have an impact on oil and gas development in the NE""not a cap on production, it is a cap on land" @Dave_Eby

Less land = less #Natgas growth. 2,500 sq miles protected from new E&P activity

Hard to see #LNGCanada 1.8 bcfd Phase 2 FID!
#OOTT



ated transcript of BC Premier David Eby from the Q&A at the press conference announcing the
First Nations on Jan 18, 2023

s" are SAF Group created transcript

you talk a little bit about the message this sends to industry, particularly the oil and gas indust
at LNG Canada project is ready to go ahead. There have been concerns about how BC will, or c
d LNG and still meet its climate goals. Can you talk about the messaging here?

*this agreement does have an impact on oil and gas development in the NE. It has very specific p
unt of land disturbance that is permitted related to oil and gas. And this is one of the major con
rry, as I understand it, to bring the court challenge and it was also a key discussion around the
is going to have to be more innovative. The oil and gas industry is going to have to find ways t
rbance. The agreement is not a cap on production, it is a cap on land. And we expect that, we e
ritish Columbia. And it is certainly very good to see Petronas here today at the announcement .
oss broad industries about the importance of this agreement from a couple of perspectives – pr
erstanding what's allowed and what's not. and also that they need to innovate and find ways to
fferent ways. So it's a very significant agreement in that way. And it's my firm belief that is agre
ing certainty, providing that predictability, providing those boundaries will ensure innovation a
at is going to put us in a much better economic position going forward than continued court bat
d all the unpredictability that that brings with it."*

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

Province, Blueberry River First Nations reach agreement

Prince George
Wednesday, January 18, 2023 2:39 PM

The agreement will transform how the Province and First Nations steward land, water and resources together and address cumulative effects in Blueberry River's Claim Area through restoration to heal the land, new areas protected from industrial development, and constraint on development activities while a long-term cumulative effects management regime is implemented. In addition, it supports and advances the Province's climate change strategy. The work of achieving these goals will be carried out through a series of measures, including:

- a $200-million restoration fund by June 2025, which supports healing of the land from decades of legacy industrial disturbance;
- an ecosystem-based management approach for future land-use planning in Blueberry River's most culturally important areas, with ambitious timelines to complete new local and watershed level, land use plans;
- limits on new petroleum and natural gas (PNG) development and a new planning regime for future oil and gas activities;
- protections for old forest and traplines during and through planning;
- land protections in Blueberry River's high-value areas, which includes more than 650,000 hectares of protection from new PNG and forestry activities and will advance B.C.'s 30% land protections goal by 2030; and
- wildlife co-management efforts, including moose management through licensed hunter restrictions to support population recovery.

Quick Facts:

- The agreement is focused in Blueberry River's civil claim area, which includes areas that are important to Blueberry, and other Treaty 8 Nations, for practising their treaty rights.
- The agreement provides for annual reviews of implementation progress and effectiveness, and includes a formal three-year review.
- The Province and Blueberry River have agreed to expeditiously begin implementation, and in order to support the local economy, this agreement provides for a series of timber harvesting and oil and gas activities to proceed throughout Blueberry River's claim area.
- In October 2021, the B.C. government and Blueberry River First Nations signed an initial agreement that provided the Nations with $65 million for land restoration, wildlife stewardship, and cultural and capacity investments.
- That agreement provided added security for many existing authorized activities to continue in Blueberry River's claim area as negotiations ensued.

Petroleum and natural gas (PNG)
Through the agreement, the Province and Blueberry River will bring a more collaborative approach to oil and natural gas development planning and projects. Companies, the Province, Blueberry River and other Nations will sit together to discuss, design and agree to development plans. Measures include:

- establishing areas for permanent protection from new development;
- focusing disturbance from PNG wherever possible in areas already developed;
- reducing new disturbance from PNG by approximately 50% from pre-court decision years;
- introducing operational and strategic planning expectations for the sector, applicable to all new proposed activities; and
- a limit on overall new disturbance from PNG activities in Blueberry River's claim area, designated at 750 hectares, as further detailed planning and restoration activities can be developed and

1 · 4 · 1,733

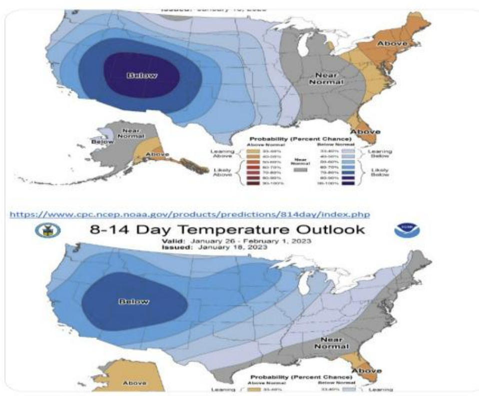
Dan Tsubouchi @Energy_Tidbits · Jan 18

Finally!

@NOAA calling for colder than normal temps across all of US for last week of Jan'

See 👇 01/08 tweet, shows huge swings in res/com #NatGas consumption in cold vs warm temps.

Should help put a floor on HH price with upside if Feb can be normal or colder.
#OOTT



Dan Tsubouchi @Energy_Tidbits · Jan 8

See 👇 excerpt from SAF Group Jan 8, 2023 Energy Tidbits memo on the table with data showing the huge swings in residential/commercial #NatGas consumption in hot vs cold winters. #OOTT twitter.com/Energy_Tidbits...

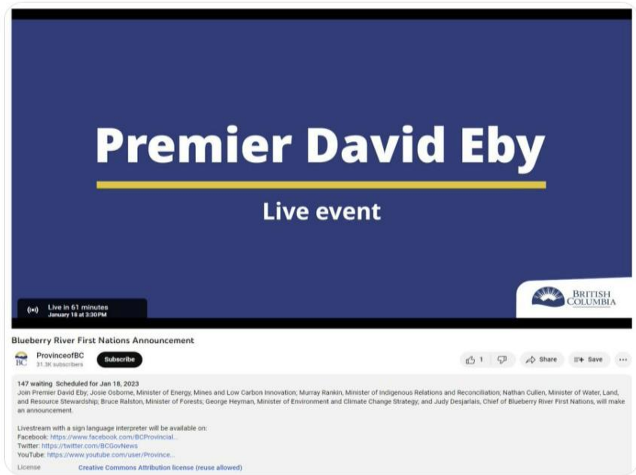
2 · 4 · 13 · 6,154

Dan Tsubouchi @Energy_Tidbits · Jan 18

BC deal with Blueberry River First Nations, presser at 2:30pm PT.

May not save this winter drilling, BUT deal was needed to give Shell the chance to FID #LNGCanada 1.8 bcf/d Phase 2. Hope the deal works for Shell as LNG Canada is material to BC/AB #NatGas.

#OOTT



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Dan Tsubouchi @Energy_Tidbits · Jan 18

"what we do do is to invest in the integrated energy companies. I think that's a good place to be. They play a very, very important role in the energy transition" Norway wealth fund CEO

See 👇 12/21/26 tweet on their #Oil #NatGas investing shift.

Thx @lisaabramowicz1. #OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Dec 26, 2021
>
> Our weekly SAF Dec 26, 2021 Energy Tidbits memo is posted on our SAF Group website. This 44-pg energy research memo expands upon & covers more items than tweeted this week. See news/insights section of SAF website #Oil #OOTT #LNG #NatGas ...

1 1 8 6,732

Dan Tsubouchi @Energy_Tidbits · Jan 18

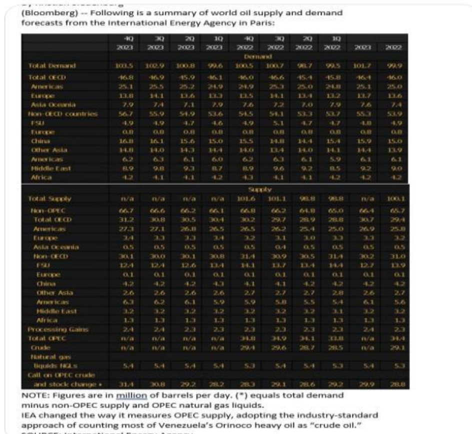
Prescription for higher #Oil prices in H2/23?

@IEA OMR. call on #OPEC
Q1/23 - 28.2 mbd
Q2/23 - 29.2 mbd
Q3/23 - 30.8 mbd
Q4/23 - 31.4 mbd

Especially if US doesn't release another 180 mb from SPR.

Thx @business Kristian Siedenburg for table.

#OOTT



(Bloomberg) -- Following is a summary of world oil supply and demand forecasts from the International Energy Agency in Paris:

	4Q 2023	3Q 2023	2Q 2023	1Q 2023	4Q 2022	3Q 2022	2Q 2022	1Q 2022	2023	2022
					Demand					
Total Demand	103.5	102.9	100.8	99.6	100.5	100.7	98.7	99.5	101.7	99.9
Total OECD	46.8	46.9	45.9	46.1	46.0	46.6	45.4	45.8	46.4	46.0
Americas	25.1	25.5	25.2	24.9	24.9	25.3	25.0	24.8	25.1	25.0
Europe	13.8	14.1	13.6	13.3	13.5	14.1	13.4	13.2	13.7	13.6
Asia Oceania	7.9	7.4	7.1	7.9	7.6	7.2	7.0	7.9	7.6	7.4
Non-OECD countries	56.7	55.9	54.9	53.6	54.5	54.1	53.3	53.7	55.3	53.9
FSU	4.9	4.9	4.7	4.6	4.9	5.1	4.7	4.7	4.8	4.9
Europe	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
China	16.8	16.1	15.6	15.0	15.5	14.8	14.4	15.4	15.9	15.0
Other Asia	14.8	14.0	14.3	14.4	14.0	13.4	14.0	14.1	14.4	13.9
Americas	6.2	6.3	6.1	6.0	6.2	6.3	6.1	5.9	6.1	6.1
Middle East	8.9	9.8	9.3	8.7	8.9	9.6	9.2	8.5	9.2	9.0
Africa	4.2	4.1	4.1	4.2	4.3	4.1	4.1	4.2	4.2	4.2
					Supply					
Total Supply	n/a	n/a	n/a	n/a	101.6	101.1	98.8	98.8	n/a	100.1
Non-OPEC	66.7	66.6	66.2	66.1	66.8	66.2	64.8	65.0	66.4	65.7
Total OECD	31.2	30.8	30.5	30.4	30.2	29.7	28.9	28.8	30.7	29.4
Americas	27.3	27.1	26.8	26.5	26.5	26.2	25.4	25.0	26.9	25.8
Europe	3.4	3.3	3.3	3.4	3.2	3.1	3.0	3.3	3.3	3.2
Asia Oceania	0.5	0.5	0.5	0.5	0.5	0.4	0.5	0.5	0.5	0.5
Non-OECD	30.1	30.0	30.1	30.8	31.4	30.9	30.5	31.4	30.2	31.0
FSU	12.4	12.4	12.6	13.4	14.1	13.7	13.4	14.4	12.7	13.9
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	4.2	4.2	4.2	4.3	4.1	4.1	4.2	4.2	4.2	4.2
Other Asia	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.6	2.7
Americas	6.3	6.2	6.1	5.9	5.9	5.8	5.5	5.4	6.1	5.6
Middle East	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.1	3.2	3.2
Africa	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Processing Gains	2.4	2.4	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.3
Total OPEC	n/a	n/a	n/a	n/a	34.8	34.9	34.1	33.8	n/a	34.4
Crude	n/a	n/a	n/a	n/a	29.4	29.6	28.7	28.5	n/a	29.1
Natural gas liquids NGLs	5.4	5.4	5.4	5.4	5.3	5.4	5.4	5.3	5.4	5.3
Call on OPEC crude and stock change *	31.4	30.8	29.2	28.2	28.3	29.1	28.6	29.2	29.9	28.8

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

5 13 3,905

Dan Tsubouchi @Energy_Tidbits · Jan 18

Hmm! Overlooked China extra stimulus?

US economy "quite good shape": #Blackstone Schwarzman $2.5T in excess savings during Covid, spent half, "an extra stimulus"

China $2T in EXCESS savings to be spent on reopening. see 👇 @aguzin tweet last night.

Thx @DavidWestin

#OOTT

1:11 | 840 views

> **Dan Tsubouchi** @Energy_Tidbits · Jan 17
>
> 1/2. $2 Trillion in EXCESS savings in China to be allocated in the reopening.
>
> @HKEXGroup CEO @aguzin "Something important around Covid also that I want to make sure people know. Over the last 2 yr, savings in ...
>
> Show this thread

3 11 3,925

Dan Tsubouchi @Energy_Tidbits · Jan 17

2/2 .. It is very very high. But over the last 2 yr, that jumped to >30% so there's ~$2 trillion EXCESS savings in the system in China. $2 trillion. Now with the reopening that will have to be reallocated somewhere. Thx @haslindatv @aguzin #OOTT

2 2 9 2,311

Show this thread

Dan Tsubouchi @Energy_Tidbits · Jan 17

1/2. $2 Trillion in EXCESS savings in China to be allocated in the reopening.

@HKEXGroup CEO @aguzin "Something important around Covid also that I want to make sure people know. Over the last 2 yr, savings in China which traditionally size ~20% of disposable income... #OOTT

3 6 15 10.2K

Dan Tsubouchi @Energy_Tidbits · Jan 17

WOW!

Headline "the post-Covid reopening of China is going to be the most consequential, positive catalyst to global markets in 2023"

@aguzin made other bullish comments on China reopening not in posted clips. will send next.

Thx @haslindatv.

#Oil #OOTT

> **Bloomberg Live** @BloombergLive · Jan 17
>
> "The post-covid reopening of China is going to be the most consequential, positive catalyst to global markets." @HKEXGroup CEO Nicolas @aguzin tells @BloombergTV's @haslindatv #TheYearAhead #WEF23

2 1 11 2,727

Dan Tsubouchi @Energy_Tidbits · Jan 17

.@honeywell CEO on Direct Air Carbon Capture "they're energy intensive. & obviously you're using energy that's not clean, you're really not. it sort of throwing the bucket at one end & emptying it at the other"

Like 👇 01/15 on hydrogen - the math doesn't work

@SquawkCNBC #OOTT

SAF Group created transcript of Honeywell CEO Darius Adamczyk on CNBC Squawk Box on Jan 17, 2023.

Items in "italics" are SAF Group created transcript

CNBC's Andrew Ross Sorkin *"what do you think the chances are that carbon capture, not just at the point of, but more broadly literally out of the air is a real technology five, ten years from now?"*

Honeywell CEO Darius Adamczyk *"I think it's very possible. And the longer we wait to become carbon neutral, direct carbon capture is going to be a broader part of the answer. Because, at some point, you get down the line, it's the only solution you have. Some of the challenges those technologies that I saw is that they're energy intensive. And obviously if you're using energy that's not clean, you're really not, it's sort of throwing the bucket at one end and emptying it at the other"*

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

Dan Tsubouchi @Energy_Tidbits · Jan 15

Note 👇 Moe's common sense approach why #Hydrogen is "light years away from being justifiable or reasonable". Moe "And we must have a proven relationship with simple factors such as resource efficiency and effectiveness".

...

1 3 1,436

Dan Tsubouchi @Energy_Tidbits · Jan 17

can the war end if putin "loses" or he isn't overthrown?
how many more massive x22 bomb hits can ukraine take?
is there a case for a deal later in 2023 and RUS #NatGas to play a role on some sort of compensation? thx @andrewrsorkin @PalentieTech alex karl. #OOTT

Squawk Box @SquawkCNBC · Jan 17

"I don't think the war is likely to end in Ukraine," says @PalantirTech CEO Alex Karp. "If Putin goes home and says we lost, he will lose life, his friends, and all his money."

1,519

Dan Tsubouchi @Energy_Tidbits · Jan 17

great to look out and see all the canada geese. not the norm for the Elbow River to have open water in mid Jan.

1 1 7 3,326

Dan Tsubouchi @Energy_Tidbits · Jan 17

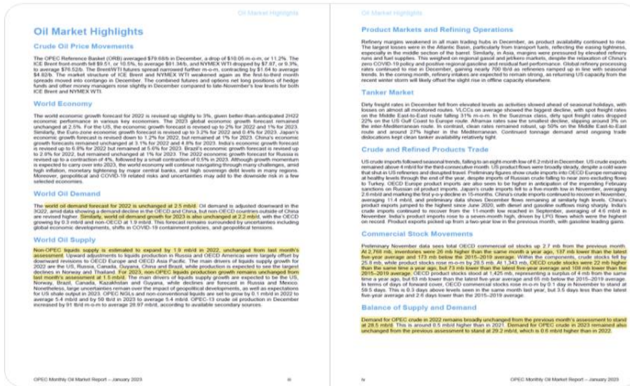
#OPEC MOMR Jan just out.

Looks Neutral

No change to #Oil demand and non-OPEC supply forecasts for both 2022 & 2023.

Minor narrowing of OECD commercial "crude" stocks. MOMR Jan est Nov 30 at 108 mmb below 2015-19 ave. vs MOMR Dec est Oct 31 at 118 mmb below 2015-19 ave.

#OOTT



5 21 1,918

Dan Tsubouchi @Energy_Tidbits · Jan 16

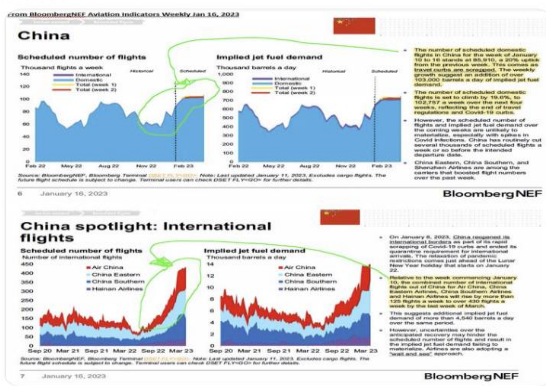
China reopening!

China domestic flights +20% WoW for Jan 10-16 week.

Peak Covid cases + rush to herd immunity = people out driving and now flying domestically especially with 1st Spring Festival without Covid restictions.

Thx @BloombergNEF Claudio Lubis.

#OOTT



Dan Tsubouchi @Energy_Tidbits · Jan 12

China reopening.

Run up to 1st New Year without restrictions with all major cities past peak Covid

...

1 7 17 15.7K

Dan Tsubouchi @Energy_Tidbits · Jan 16

.@BlackRock Vice Chair: "I don't see any chances, frankly, of easing this year. I think the market has that wrong." easy from 9 to 4%, tough is 4 to 2%, Fed may back off from 2% depending on how damaging that fight is to real economy. Thx @flacqua. #OOTT

bloomberg.com
BlackRock's Hildebrand on Central Bank Actions, I...
BlackRock Vice Chair Philipp Hildebrand says central banks are facing 'a new world' getting ...

1 1 5 1,696

Dan Tsubouchi @Energy_Tidbits · Jan 16

China population shrinks by 850,000 to 1.4118 b, 1st decline in 60 yrs.

Seems Covid impact with deaths and also lower birth rates.

But reminds of long-term challenge for China - an aging population ie. a Japan demographic problem in 10 or 20 years.

Thx @sunyue_luna

#OOTT

> **luna sun** @sunyue_luna · Jan 16
> China's population declined in 2022 for the first time in 60 years sc.mp/5ays?utm_sourc... via @scmpnews

2 1 2,491

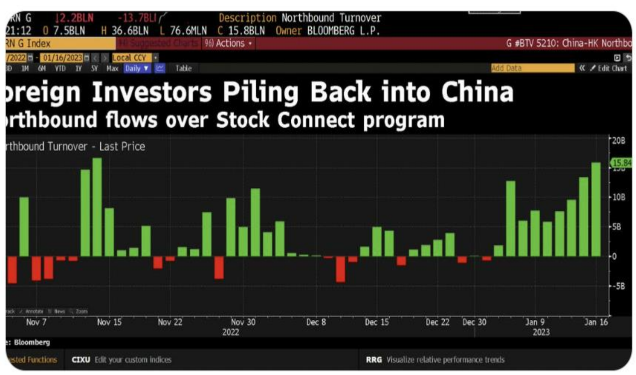
Dan Tsubouchi @Energy_Tidbits · Jan 16

China reopening.

May not necessarily be smooth, but foreign investors are increasingly believing it will happen.

"Foreign investors piling back into China" graph an hour ago from @YvonneManTV on @markets China Open.

#OOTT



1 5 1,572

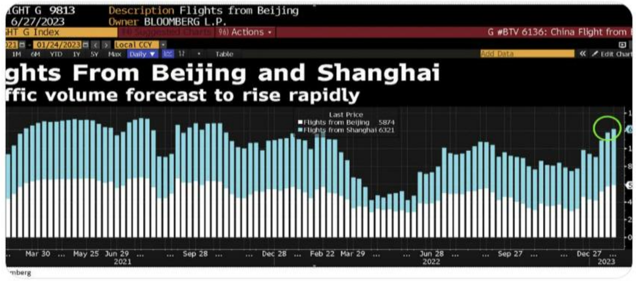
Dan Tsubouchi @Energy_Tidbits · Jan 15

China reopening!

All major cities have seen peak Covid & moving to herd immunity, which means people are getting out and driving and now flying domestically.

Flights from Beijing and Shanghai to rise rapidly. chart just now on Bloomberg Markets Asia.

#OOTT #Oil



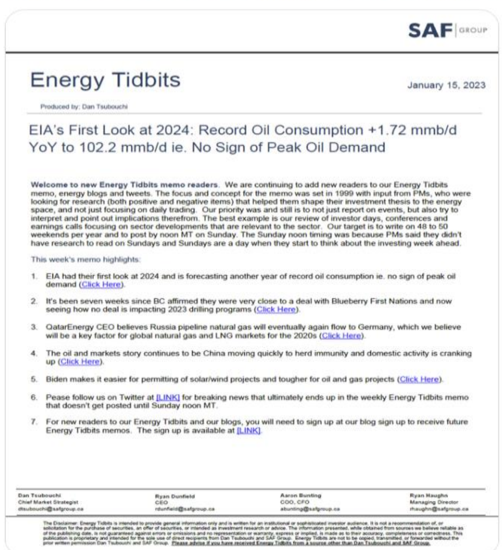
Dan Tsubouchi @Energy_Tidbits · Jan 9

china speeding to herd immunity.
@AmChamSh Eric Zheng just now. no official stats but in Shanghai, based on anecdotal evidence at least 70% of people have already got the Covid infection.
set up for sustained #Oil demand recovery on Q2....

7 37 118 63.9K

Dan Tsubouchi @Energy_Tidbits · Jan 15

SAF Group Jan 15, 2022 Energy Tidbits memo is posted on SAF Group website. this 54-pg energy research memo expands upon & covers more items than tweeted this week. See news/insights section of SAF website #Oil #OOTT #LNG #NatGas #EnergyTransition safgroup.ca/news-insights/



SAF | GROUP

Energy Tidbits

January 15, 2023

Produced by: Dan Tsubouchi

EIA's First Look at 2024: Record Oil Consumption +1.72 mmb/d YoY to 102.2 mmb/d ie. No Sign of Peak Oil Demand

Welcome to new Energy Tidbits memo readers. We are continuing to add new readers to our Energy Tidbits memo, energy blogs and tweets. The focus and concept for the memo was set in 1999 with input from PMs, who were looking for research (both positive and negative items) that helped them shape their investment thesis to the energy space, and not just focusing on daily trading. Our priority was and still is to not just report on events, but also try to interpret and point out implications therefrom. The best example is our review of investor days, conferences and earnings calls focusing on sector developments that are relevant to the sector. Our target is to write on 48 to 50 weekends per year and to post by noon MT on Sunday. The Sunday noon timing was because PMs said they didn't have research to read on Sundays and Sundays are a day when they start to think about the investing week ahead.

This week's memo highlights:

1. EIA had their first look at 2024 and is forecasting another year of record oil consumption ie. no sign of peak oil demand (Click Here).
2. It's been seven weeks since BC affirmed they were very close to a deal with Blueberry First Nations and now seeing how no deal is impacting 2023 drilling programs (Click Here).
3. QatarEnergy CEO believes Russia pipeline natural gas will eventually again flow to Germany, which we believe will be a key factor for global natural gas and LNG markets for the 2020s (Click Here).
4. The oil and markets story continues to be China moving quickly to herd immunity and domestic activity is cranking up (Click Here).
5. Biden makes it easier for permitting of solar/wind projects and tougher for oil and gas projects (Click Here).
6. Pease 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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5 5 4,499