Energy Tidbits

Russia's Oil Operating Costs +19% YoY to $44/b in 2022, No Wonder There is a "Voluntary" 500,000 b/d Shut-In

Produced by: Dan Tsubouchi

February 26, 2023

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https://www.cpc.ncep.noaa.gov/products/analysis_monitoring/cdus/degree_days/wsahddy.txt

HEATING DEGREE DAY DATA WEEKLY SUMMARY
POPULATION-WEIGHTED STATE,REGIONAL,AND NATIONAL AVERAGES
CLIMATE PREDICTION CENTER-NCEP-NWS-NOAA

LAST DATE OF DATA COLLECTION PERIOD IS FEB 18, 2023
ACCUMULATIONS ARE FROM JUL 1, 2022 TO FEB 18, 2023
-999 = NORMAL LESS THAN 100 OR RATIO INCALCULABLE

STATE	WEEK TOTAL	WEEK DEV FROM NORM	WEEK DEV FROM L YR	CUM TOTAL	CUM DEV FROM NORM	CUM DEV FROM L YR	CUM DEV FROM NORM PRCT	CUM DEV FROM L YR PRCT
ALABAMA	93	-33	-21	1765	-377	-21	-18	-1
ALASKA	339	-10	54	6920	-641	-281	-8	-4
ARIZONA	149	62	70	1958	367	663	23	51
ARKANSAS	122	-29	-13	2417	-230	243	-9	11
CALIFORNIA	135	42	64	1842	139	351	8	24
COLORADO	278	27	29	4773	-178	664	-4	16
CONNECTICUT	160	-91	-62	3386	-706	-256	-17	-7
DELAWARE	130	-80	-53	2825	-460	-94	-14	-3
DISTRCT COLUMBIA	118	-68	-43	2371	-520	-97	-18	-4
FLORIDA	24	-15	-1	368	-184	-24	-33	-6
GEORGIA	99	-29	-8	1909	-245	81	-11	4
HAWAII	0	0	0	0	0	-1	-999	-999
IDAHO	281	46	45	4822	57	329	1	7
ILLINOIS	202	-59	-73	4005	-450	26	-10	1
INDIANA	180	-66	-72	3702	-438	-9	-11	0
IOWA	255	-31	-61	4821	-209	208	-4	5
KANSAS	216	4	3	3730	-4	542	0	17
KENTUCKY	143	-53	-44	2943	-370	49	-11	2
LOUISIANA	83	-1	-5	1414	-3	207	0	17
MAINE	239	-71	-41	4386	-921	-496	-17	-10
MARYLAND	134	-77	-55	2936	-459	-31	-14	-1
MASSACHUSETTS	176	-83	-50	3572	-685	-212	-16	-6
MICHIGAN	219	-64	-79	4116	-575	-100	-12	-2
MINNESOTA	297	-40	-122	5615	-530	-76	-9	-1
MISSISSIPPI	92	-23	-13	1701	-271	65	-14	4
MISSOURI	187	-32	-40	3523	-265	246	-7	8
MONTANA	279	6	34	5421	-231	407	-4	8
NEBRASKA	255	-3	5	4598	-58	752	-1	20
NEVADA	191	53	62	3042	336	535	12	21
NEW HAMPSHIRE	210	-87	-52	4211	-902	-324	-18	-7
NEW JERSEY	141	-90	-71	3168	-548	-128	-15	-4
NEW MEXICO	228	51	38	3591	166	471	5	15
NEW YORK	163	-92	-72	3352	-748	-161	-18	-5
NORTH CAROLINA	104	-51	-24	2343	-228	71	-9	3
NORTH DAKOTA	312	-39	-80	6279	-338	347	-5	6
OHIO	174	-74	-72	3586	-530	-45	-13	-1
OKLAHOMA	161	-1	7	2727	-102	383	-4	16
OREGON	198	37	47	3345	-30	88	-1	3
PENNSYLVANIA	161	-84	-73	3605	-436	-75	-11	-2
RHODE ISLAND	163	-78	-58	3383	-464	-244	-12	-7
SOUTH CAROLINA	87	-40	-12	1823	-281	-11	-13	-1
SOUTH DAKOTA	283	-12	-19	5328	-159	679	-3	15
TENNESSEE	126	-45	-37	2631	-296	25	-10	1
TEXAS	97	6	10	1462	-120	283	-8	24
UTAH	290	52	71	4627	90	417	2	10
VERMONT	225	-96	-74	4780	-674	-306	-12	-6
VIRGINIA	124	-68	-42	2809	-352	71	-11	3
WASHINGTON	200	26	36	3672	-14	67	0	2

WEST VIRGINIA	156	-62	-58	3301	-383	15	-10	0
WISCONSIN	243	-61	-94	4855	-488	-49	-9	-1
WYOMING	310	30	44	5389	-191	733	-3	16
REGION								
NEW ENGLAND	182	-84	-54	3696	-714	-265	-16	-7
MIDDLE ATLANTIC	158	-89	-72	3391	-610	-127	-15	-4
E N CENTRAL	201	-65	-76	3984	-500	-33	-11	-1
W N CENTRAL	244	-25	-55	4543	-268	265	-6	6
SOUTH ATLANTIC	86	-41	-21	1796	-273	21	-13	1
E S CENTRAL	116	-40	-30	2323	-331	25	-12	1
W S CENTRAL	104	1	6	1675	-110	280	-6	20
MOUNTAIN	230	46	52	3704	113	565	3	18
PACIFIC	149	40	59	2211	104	291	5	15
UNITED STATES	153	-30	-22	2866	-281	100	-9	4

GAS HOME HEATING CUSTOMER WEIGHTED

REGION								
NEW ENGLAND	174	-84	-54	3572	-679	-235	-16	-6
MIDDLE ATLANTIC	157	-89	-72	3382	-604	-127	-15	-4
E N CENTRAL	201	-65	-76	3986	-501	-33	-11	-1
W N CENTRAL	244	-25	-55	4548	-265	263	-6	6
SOUTH ATLANTIC	109	-51	-29	2318	-314	34	-12	1
E S CENTRAL	117	-41	-31	2352	-334	26	-12	1
W S CENTRAL	107	1	5	1740	-111	283	-6	19
MOUNTAIN	243	43	49	3983	63	561	2	16
PACIFIC	143	40	61	2063	118	315	6	18
UNITED STATES	168	-31	-25	3131	-288	117	-8	4

OIL HOME HEATING CUSTOMER WEIGHTED

REGION								
NEW ENGLAND	187	-84	-54	3770	-735	-287	-16	-7
MIDDLE ATLANTIC	159	-89	-72	3400	-628	-131	-16	-4
E N CENTRAL	205	-67	-80	4079	-515	-51	-11	-1
W N CENTRAL	283	-34	-89	5377	-396	133	-7	3
SOUTH ATLANTIC	115	-61	-37	2537	-338	25	-12	1
E S CENTRAL	131	-47	-39	2690	-337	34	-11	1
W S CENTRAL	103	-1	3	1700	-103	271	-6	19
MOUNTAIN	259	40	48	4467	57	424	1	10
PACIFIC	190	32	44	3291	2	115	0	4
UNITED STATES	167	-76	-58	3462	-579	-129	-14	-4

ELECTRIC HOME HEATING CUSTOMER WEIGHTED

REGION								
NEW ENGLAND	176	-85	-54	3596	-702	-247	-16	-6
MIDDLE ATLANTIC	158	-88	-72	3434	-568	-116	-14	-3
E N CENTRAL	194	-66	-75	3894	-492	-27	-11	-1
W N CENTRAL	234	-25	-48	4374	-250	296	-5	7
SOUTH ATLANTIC	68	-34	-15	1402	-245	10	-15	1
E S CENTRAL	116	-40	-31	2335	-329	23	-12	1
W S CENTRAL	101	2	6	1605	-108	276	-6	21
MOUNTAIN	198	52	59	3044	218	596	8	24
PACIFIC	162	37	54	2571	72	233	3	10
UNITED STATES	122	-20	-9	2248	-203	119	-8	6

https://lngir.cheniere.com/news-events/press-releases/detail/272/cheniere-initiates-permitting-process-for-significant

Cheniere Initiates Permitting Process for Significant Expansion of LNG Export Capacity at Sabine Pass

FEBRUARY 23, 2023 7:15AM EST

SPL Expansion Project is being designed for approximately 20 million tonnes per annum and is expected to leverage existing infrastructure at Sabine Pass

HOUSTON--(BUSINESS WIRE)-- Cheniere Energy Partners, L.P. ("Cheniere Partners") (NYSE American: CQP), a subsidiary of Cheniere Energy, Inc. ("Cheniere") (NYSE American: LNG), announced today that certain of its subsidiaries have initiated the pre-filing review process under the National Environmental Policy Act with the Federal Energy Regulatory Commission ("FERC") for the proposed Sabine Pass Stage 5 Expansion Project (the "SPL Expansion Project") adjacent to the existing Sabine Pass Liquefaction Project (the "SPL Project"). The SPL Expansion Project is being designed for total production capacity of approximately 20 million tonnes per annum ("mtpa") of liquefied natural gas ("LNG").

The SPL Expansion Project is being designed to include up to three large-scale liquefaction trains, each with a production capacity of approximately 6.5 mtpa of LNG, a boil-off-gas ("BOG") re-liquefaction unit with an approximate production capacity of 0.75 mtpa of LNG, and two 220,000m^3 LNG storage tanks. The SPL Expansion Project is being designed with accommodations for waste heat recovery as well as carbon capture from acid gas removal units.

The SPL Expansion Project is expected to benefit from the significant existing infrastructure at the SPL Project and contemplates various enhancements to its current capabilities, including optimized ship loading at the existing marine facilities. Feed gas related to the SPL Expansion Project is expected to be transported via a combination of new and existing pipelines currently supplying the SPL Project.

Cheniere Partners has engaged Bechtel Energy, Inc. to complete a Front-End Engineering and Design (FEED) study of the SPL Expansion Project.

"As the first and largest LNG export facility in the Lower 48, Sabine Pass has pioneered an industry critical to supplying reliable, flexible, and cleaner burning natural gas to markets and customers around the world, and we look forward to significantly growing those capabilities through the SPL Expansion Project," said Jack Fusco, Chairman, President and CEO of Cheniere Partners. "The SPL Expansion Project is being designed to leverage the infrastructure platform we've built at Sabine Pass to deliver economically advantaged incremental LNG capacity in a safe and environmentally responsible manner. We are committed to developing the SPL Expansion Project utilizing the same rigorous and financially disciplined approach to project development and capital investment that's become synonymous with the Cheniere brand."

The development of the SPL Expansion Project, and any necessary supporting infrastructure, is subject to receipt of all required regulatory approvals and permits, and sufficient commercial and financing arrangements before a final investment decision ("FID") can be reached.

About Cheniere Partners

Cheniere Partners owns the Sabine Pass LNG terminal located in Cameron Parish, Louisiana, which has natural gas liquefaction facilities consisting of six liquefaction Trains with a total production capacity of approximately 30 million tonnes per annum of liquefied natural gas. The Sabine Pass LNG terminal also has operational regasification facilities that include five LNG storage tanks, vaporizers, and three marine berths. Cheniere Partners also owns the Creole Trail Pipeline, which interconnects the Sabine Pass LNG terminal with a number of large interstate and intrastate pipelines.

For additional information, please refer to the Cheniere Partners website at www.cheniere.com and Annual Report on Form 10-K for the year ended December 31, 2022, filed with the Securities and Exchange Commission.

http://freeportlng.newsrouter.com/news_release.asp?intRelease_ID=9759&intAcc_ID=77

Freeport LNG Receives Regulatory Approval for Commercial Operations of its Liquefaction Facility
FINAL Freeport LNG Restart Press Release 022123.pdf
Feb 21st, 2023

FREEPORT LNG RECEIVES REGULTAORY APPROVAL FOR COMMERCIAL OPERATIONS OF ITS LIQUEFACTION FACILITY

Houston, TX, February 21, 2022 – Freeport LNG Development, L.P. (Freeport LNG) today announced that it has received regulatory approval to commence commercial operations of the company's natural gas liquefaction and export facility. Today's authorization provides for the immediate full return to service of one liquefaction train, that has already restarted, and the incremental restart and full return to service of a second train. The restart and return to service of Freeport LNG's third liquefaction train will require subsequent regulatory approval once certain operational conditions are met. A conservative ramp-up profile to establish three-train production of approximately 2.0 billion cubic feet per day is anticipated to occur over the next several weeks as stable operation of each incremental train is established and maintained. Operations are initially utilizing two of Freeport LNG's three LNG storage tanks and one of its two LNG berths. The second LNG berth and third LNG storage tank are expected to return to service in May. First LNG production and ship loading from the facility began on February 11.

"Returning to liquefaction operations is a significant achievement for Freeport LNG," said Michael Smith, Freeport LNG Founder, Chairman and CEO. "Over the past eight months, we have implemented enhancements to our processes, procedures and training to ensure safe and reliable operations, and significantly increased staffing levels with extensive LNG and petrochemical operating experience to reduce overtime, enhance operational excellence, and improve quality assurance and business performance. Eight months of diligence, discipline and dedicated efforts by our teams, working collaboratively alongside the regulatory agencies and local officials, have positioned us to resume LNG production and commence ramp-up to the safe establishment of commercial operations of our liquefaction facility."

ABOUT FREEPORT LNG

Freeport LNG is an LNG export company headquartered in Houston, Texas. The company's three train, 15 MTPA liquefaction facility is the seventh largest in the world and second largest in the U.S. Freeport LNG's liquefaction facility is the largest all-electric drive motor plant of its kind in the world, making it the most environmentally sustainable site of its kind. The facility's electric drive motors reduce carbon emissions by over 90% relative to gas turbine-driven liquefaction facilities. Freeport plans to expand by adding a fourth liquefaction train, which has received all regulatory approvals for construction. Freeport was formed in 2002 to develop, own and operate an LNG terminal on Quintana Island, near Freeport, Texas. The terminal started LNG import operations in June 2008 and began LNG export operations in 2019. Further information can be found on Freeport's website at www.freeportlng.com.

https://venturegloballng.com/press/14343/

FEBRUARY 23, 2023

- PRESS RELEASE

Venture Global and China Gas Sign Two 20-year Long-Term LNG Agreements

Arlington, Virginia– Today, Venture Global LNG and China Gas Holdings Limited (“China Gas” or the “Group”; stock code: 384), a leading natural gas operator in China, announced that the wholly-owned subsidiary China Gas Hongda Energy Trading Co., LTD (“China Gas Hongda”) and Venture Global LNG (“Venture Global”), have signed two 20-year LNG Sales and Purchase Agreements (SPA).

Under the deals, China Gas will buy 1 million tonnes per annum (MTPA) of LNG on a free on board (FOB) basis from Plaquemines LNG and another 1 MTPA from the CP2 LNG export facility, both in Louisiana.

Mr. Liu Minghui, Chairman and President of China Gas Holdings Co. Ltd., said “As a major participant in China’s energy market, we are committed to providing reliable and low-carbon LNG to Chinese customers. These two SPAs increase additional volume for our LNG portfolio and strengthen China Gas’s supply ability. We look forward to working with Venture Global over the coming years to help further reduce greenhouse gas emissions.”

Mike Sabel, Chief Executive Officer of Venture Global LNG said, “Venture Global is pleased to welcome China Gas as a customer both at Plaquemines and CP2. Through relentless execution and innovation, our company will continue to bring much needed new capacity to the global LNG market, supporting energy security and environmental progress both in Asia and Europe. Importantly, low-cost LNG supplied to the region will accelerate fuel switching and lower carbon emissions, contributing meaningfully to China and the world’s existing climate targets.”

About Venture Global

Venture Global is a long-term, low-cost provider of U.S. LNG sourced from resource rich North American natural gas basins. Venture Global’s first facility, Calcasieu Pass, commenced producing LNG in January 2022. The company is also constructing or developing an additional 60 MTPA of production capacity in Louisiana to provide clean, affordable energy to the world. The company is developing Carbon Capture and Sequestration (CCS) projects at each of its LNG facilities.

About China Gas

China Gas Holdings Limited (“China Gas”, HKEX: 00384) is one of China’s largest trans-regional, integrated energy suppliers and service providers. Focusing on China, it is primarily engaged in the investment, construction, and operation of city and township gas pipelines, gas terminals, storage and transport facilities, and logistics systems, delivering natural gas and LPG to residential, industrial, and commercial users. The Group also builds and operates CNG/LNG fueling stations while developing and applying natural gas and LPG technologies. In addition, it has drawn on its extensive gas user base to form a comprehensive business portfolio of value-added services, urban heating, new energy, electricity distribution and sales, and charging stations.

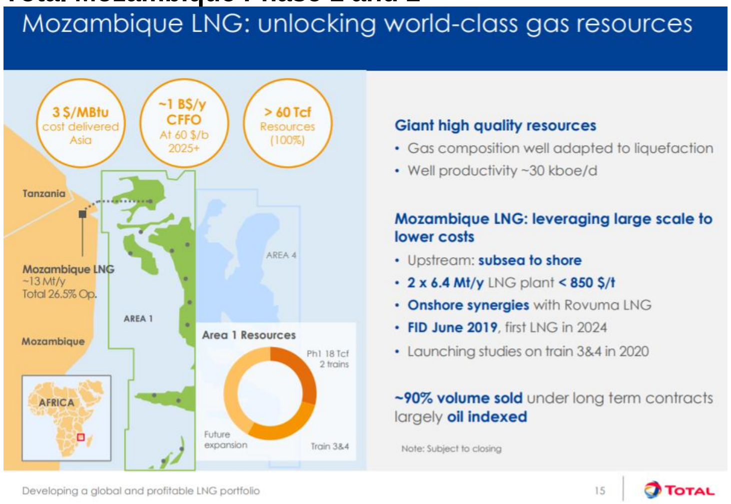
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

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.

<u>Total declares force majeure on Mozambique LNG,</u> 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



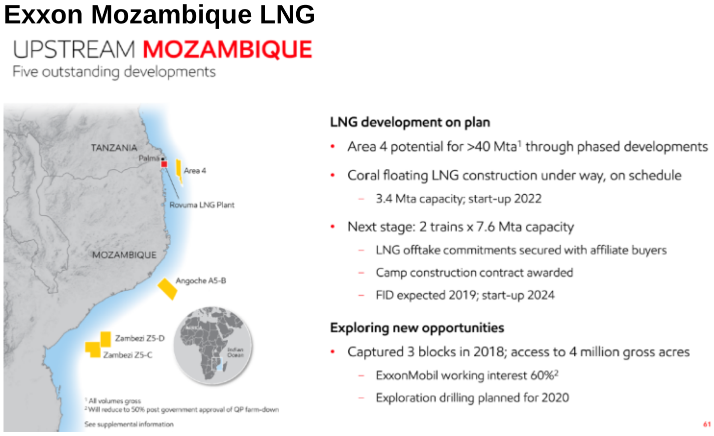
Source: Total Investor Day September 24, 2019

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

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

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

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

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

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

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

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

Source: IEA

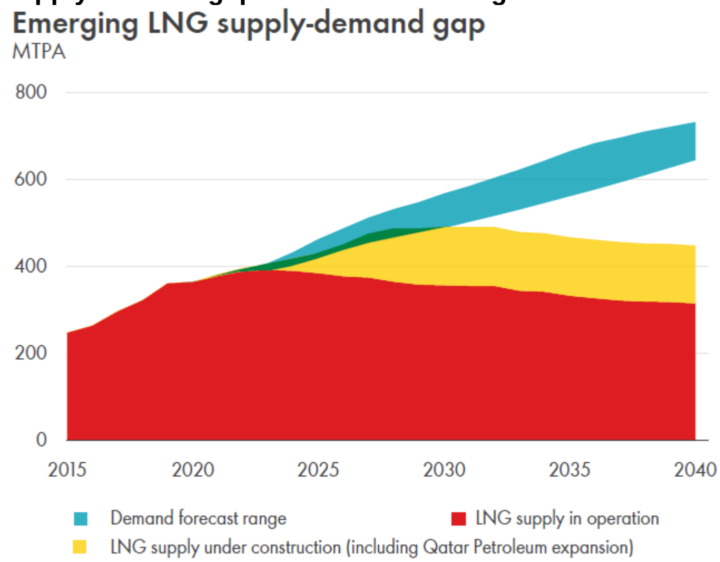
On Track   More Efforts Needed   Not on Track

Source: IEA Tracking Clean Energy Progress, June 2020

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

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

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



Source: Shell LNG Outlook 2021, Feb 25, 2021

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

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

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

<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.*

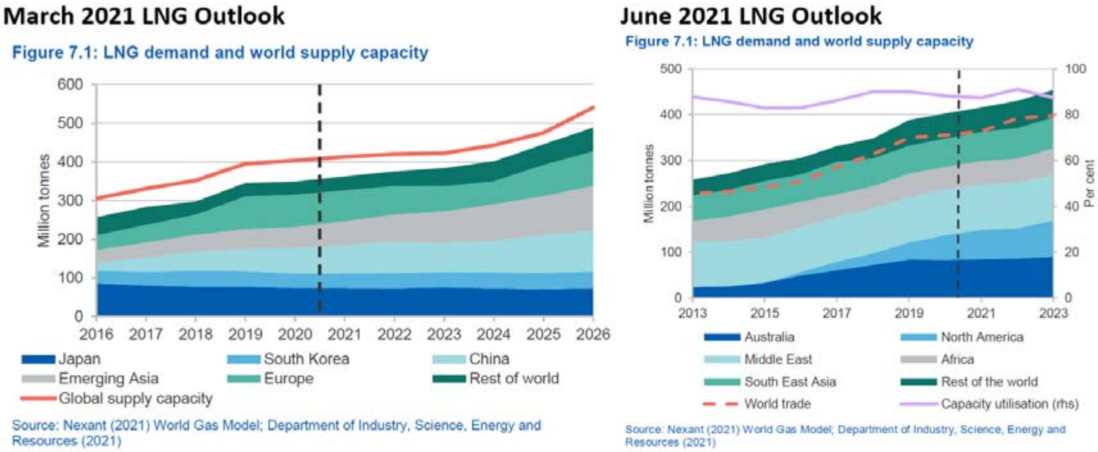
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required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

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

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

demand that we highlight later in the blog. They didn't say anything else specific on Mozambique but, surely they have to also be delaying the follow on Total Phase 2 of 1.3 bcf/d and Exxon Rozuma Phase 1 of 2.0 bcf/d.

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

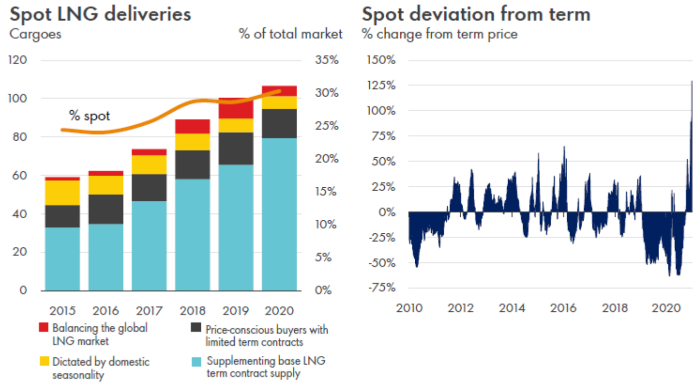


Source: Australia Resources and Energy Quarterly

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 January 2023 was down by 1.1 % than that of January 2022 as compared to a de-growth of 1.1 % during December 2022. OIL registered a growth of 7.0 % and ONGC registered a growth of 0.551 % during January 2023 as compared to January 2022. PSC registered de-growth of 9.0 % during January 2023 as compared to January 2022. De-growth of 1.3 % was registered in the total crude oil and condensate production during April - January 2023 over the corresponding period of the previous year.
•	‘Crude oil processed during January 2023 was 22.8 MMT, which was 5.1 % higher than January 2022 as compared to a growth of 3.7 % during December 2022. Growth of 6.3 % was registered in the total crude oil processing during April-January 2023 over the corresponding period of the previous year.
•	Crude oil imports increased by 3.6% and 9.5% during January 2023 and April-January 2023 respectively as compared to the corresponding period of the previous year. The net import bill for Oil & Gas was $11.1 billion in January 2023 compared to $11.3 billion in January 2022. In this the crude oil imports constitutes $11.2 billion, LNG imports $1.6 billion and the exports were $3.9 billion during January 2023.
•	The price of Brent Crude averaged $82.78/bbl during January 2023 as against $81.12/bbl during Decembet 2022 and $87.22/bbl during January 2022. The Indian basket crude price averaged $80.92/bbl during January 2023 as against $78.10/bbl during December 2022 and $84.67 /bbl during January 2022.
•	Production of petroleum products saw a growth of 4.5 % during January 2023 over January 2022 as compared to a growth of 3.7 % during December 2022. Growth of 5.3 % was registered in the total POL production during April- January 2023 over the corresponding period of the previous year.
•	POL products imports increased by 4.2% and 5.4% during January 2023 and April-January 2023 respectively as compared to the corresponding period of the previous year. Increase in POL products imports during April-January 2023 were mainly due to increase in imports of liquified petroleum gas (LPG), motor spirt (MS), high speed diesel (HSD), fuel oil (FO) and petcoke etc.

•	Exports of POL products decreased by 11.3% and 1.8% during January 2023 and April- January 2023 respectively as compared to the corresponding period of the previous year. Decrease in POL products exports during April- January 2023 were mainly due to decrease in exports of Motor spirit (MS), Naphtha, Superior Kerosene Oil (SKO), High Speed Diesel (HSD) and Bitumen etc.
•	The consumption of petroleum products during April-Jan 2023 with a volume of 183.32 MMT reported a growth of 9.6% compared to the volume of 167.25 MMT during the same period of the previous year. This growth was led by 14.6% growth in MS, 13.8% in HSD & 50.2% in ATF consumption besides FO/LSHS, Petcoke, LPG and others during the period. The consumption of petroleum products during Jan 2023 recorded a growth of 3.6% with a volume of 18.1 MMT compared to the same period of the previous year.
•	Ethanol blending with Petrol was 11.63% during January 2023 and cumulative ethanol blending during December 2022-January 2023 was 11.01%.
•	Total Natural Gas Consumption (including internal consumption) for the month of January 2023 was 5179 MMSCM which was 6.4% higher than the corresponding month of the previous year. The cumulative consumption of 50840 MMSCM for the current financial year till January 2023 was lower by 6.1 % compared with the corresponding period of the previous year.
•	Gross production of natural gas for the month of January 2023 (P) was 2975 MMSCM which was higher by 4.0% compared with the corresponding month of the previous year. The cumulative gross production of natural gas of 28843 MMSCM for the current financial year till January 2023 was higher by 1.1% compared with the corresponding period of the previous year.
•	LNG import for the month of Jnauary 2023 (P) was 2266 MMSCM which was 7.9% higher than the corresponding month of the previous year. The cumulative import of 22660 (P) MMSCM for the current financial year till Januaryr 2023 was lower by 14% compared with the corresponding period of the previous year.

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

	Details	Unit/ Base	2020-21	2021-22 (P)	Jan 2021-22 (P)	Jan 2022-23 (P)	April-Jan 2021-22 (P)	April-Jan 2022-23 (P)
1	Crude oil production in India#	MMT	30.5	29.7	2.5	2.5	24.9	24.6
2	Consumption of petroleum products*	MMT	194.3	204.7	18.1	18.7	167.2	183.3
3	Production of petroleum products	MMT	233.5	254.3	23.0	24.0	209.0	220.2
4	Gross natural gas production	MMSCM	28,672	34,024	2,861	2,975	28,535	28,843
5	Natural gas consumption	MMSCM	60,982	64,159	4,961	5,179	54,164	50,840
6	Imports & exports:							
	Crude oil imports	MMT	196.5	212.4	19.3	20.0	175.8	192.4
		$ Billion	62.2	120.7	11.6	11.2	94.2	136.2
	Petroleum products (POL) imports*	MMT	43.2	42.1	3.9	4.0	34.7	36.6
		$ Billion	14.8	25.2	2.3	2.1	20.3	22.7
	Gross petroleum imports (Crude + POL)	MMT	239.7	254.4	23.1	24.0	210.5	229.0
		$ Billion	77.0	145.9	13.8	13.3	114.5	158.9
	Petroleum products (POL) export	MMT	56.8	62.8	5.1	4.5	51.2	50.2
		$ Billion	21.4	44.4	3.8	3.9	33.4	49.2
	LNG imports*	MMSCM	33,198	31,028	2,100	2,266	26,360	22,660
		$ Billion	7.9	13.5	1.3	1.6	10.9	15.9
	Net oil & gas imports	$ Billion	63.5	114.9	11.3	11.1	92.0	125.6
7	Petroleum imports as percentage of India's gross imports (in value terms)	%	19.5	23.8	22.9	22.9	25.9	28.8
8	Petroleum exports as percentage of India's gross exports (in value terms)	%	7.3	10.6	9.8	11.2	10.9	14.8
9	Import dependency of crude oil (on POL consumption basis)	%	84.4	85.7	85.7	87.3	85.3	87.0

#Includes condensate; *Private direct imports are prorated for the period Nov'22 to Jan'23 for POL. LNG Imports figures from DGCIS are prorated for Dec-Jan 2023. Total may not tally due to rounding off.

3. Indigenous crude oil production (Million Metric Tonnes)

Details	2020-21	2021-22	Jan			April-Jan		
			2021-22	2022-23 Target*	2022-23 (P)	2021-22	2022-23 Target*	2022-23 (P)
ONGC	19.1	18.5	1.6	1.8	1.6	15.5	17.6	15.5
Oil India Limited (OIL)	2.9	3.0	0.3	0.3	0.3	2.5	2.8	2.6
Private / Joint Ventures (JVs)	7.1	7.0	0.6	0.6	0.5	5.9	6.0	5.3
Total Crude Oil	**29.1**	**28.4**	**2.4**	**2.7**	**2.4**	**23.8**	**26.5**	**23.4**
ONGC condensate	1.1	0.9	0.08	0.0	0.1	0.8	0.0	0.9
PSC condensate	0.3	0.30	0.02	0.0	0.03	0.26	0.0	0.25
Total condensate	**1.4**	**1.2**	**0.10**	**0.0**	**0.1**	**1.0**	**0.0**	**1.1**
Total (Crude + Condensate) (MMT)	**30.5**	**29.7**	**2.5**	**2.7**	**2.5**	**24.9**	**26.5**	**24.6**
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)	Jan		April-Jan	
			2021-22 (P)	2022-23 (P)	2021-22 (P)	2022-23 (P)
Total domestic production (MMTOE)	59.2	63.7	5.4	5.5	53.4	53.4
Overseas production (MMTOE)	21.9	21.8	1.8	1.5	18.4	15.7

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

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

Details		2020-21	2021-22	Jan		April-Jan	
				2021-22	2022-23 (P)	2021-22	2022-23 (P)
1	High Sulphur crude	161.4	185.0	17.1	17.6	151.9	163.3
2	Low Sulphur crude	60.3	56.7	4.6	5.3	47.1	48.1
Total crude processed (MMT)		**221.8**	**241.7**	**21.7**	**22.8**	**198.9**	**211.4**
Total crude processed (Million Bbl/Day)		4.45	4.85	5.13	5.39	4.77	5.06
Percentage share of HS crude in total crude oil processing		**72.8%**	**76.6%**	**78.7%**	**77.0%**	**76.3%**	**77.2%**

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-Jan 2022-23(P)	192.4	136,238	10,84,823

7. Self-sufficiency in petroleum products (Million Metric Tonnes)							
Particulars		**2020-21**	**2021-22 (P)**	**Jan**		**April-Jan**	
				2021-22 (P)	**2022-23 (P)**	**2021-22 (P)**	**2022-23 (P)**
1	Indigenous crude oil processing	28.0	27.0	2.4	2.2	22.7	22.4
2	Products from indigenous crude (93.3% of crude oil processed)	26.1	25.2	2.3	2.1	21.2	20.9
3	Products from fractionators (Including LPG and Gas)	4.2	4.1	0.3	0.3	3.4	3.0
4	Total production from indigenous crude & condensate **(2 + 3)**	30.3	29.3	2.6	2.4	24.6	23.8
5	Total domestic consumption	194.3	204.7	18.1	18.7	167.2	183.3
% Self-sufficiency (4 / 5)		**15.6%**	**14.3%**	**14.3%**	**12.7%**	**14.7%**	**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	Jan			April-Jan		
					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	0.6	4.5	5.4	5.7
2	Koyali (1965)	13.7	11.6	13.5	1.3	1.3	1.3	10.9	11.9	13.0
3	Haldia (1975)	8.0	6.8	7.3	0.3	0.5	0.7	5.9	6.9	7.1
4	Mathura (1982)	8.0	8.9	9.1	0.7	0.8	0.8	7.5	8.0	7.9
5	Panipat (1998)	15.0	13.2	14.8	1.2	1.3	1.3	12.4	12.4	11.3
6	Guwahati (1962)	1.0	0.8	0.7	0.09	0.1	0.1	0.55	0.9	0.9
7	Digboi (1901)	0.65	0.6	0.7	0.06	0.06	0.06	0.6	0.5	0.6
8	Bongaigaon(1979)	2.70	2.5	2.6	0.2	0.2	0.3	2.2	2.2	2.3
9	Paradip (2016)	15.0	12.5	13.2	1.3	1.4	1.4	10.6	11.4	11.0
	IOCL-TOTAL	**70.1**	**62.4**	**67.7**	**5.8**	**6.2**	**6.5**	**55.2**	**59.7**	**59.8**
10	Manali (1969)	10.5	8.2	9.0	0.9	0.9	1.0	7.0	9.0	9.4
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**	**0.9**	**0.9**	**1.0**	**7.0**	**9.0**	**9.4**
12	Mumbai (1955)	12.0	12.9	14.4	1.3	1.3	1.4	11.9	11.6	11.9
13	Kochi (1966)	15.5	13.3	15.4	1.5	1.4	1.5	12.5	12.9	13.1
14	Bina (2011)	7.8	6.2	7.4	0.7	0.7	0.7	6.1	6.4	6.4
	BPCL-TOTAL	**35.3**	**32.4**	**37.2**	**3.5**	**3.4**	**3.6**	**30.5**	**30.9**	**31.4**
15	Numaligarh (1999)	3.0	2.7	2.6	0.3	0.3	0.3	2.2	2.6	2.6

Sl. no.	Refinery	Installed capacity (1.01.2022) (MMTPA)	Crude oil processing (MMT)							
			2020-21	2021-22	Jan			April-Jan		
					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	0.004	0.007	0.063	0.054	0.062
17	MRPL-Mangalore (1996)	15.0	11.5	14.9	1.4	1.5	1.5	12.0	14.2	14.2
	ONGC-TOTAL	**15.1**	**11.6**	**14.9**	**1.4**	**1.5**	**1.5**	**12.0**	**14.3**	**14.3**
18	Mumbai (1954)	9.5	7.4	5.6	0.9	0.8	0.8	4.1	7.0	8.1
19	Visakh (1957)	8.3	9.1	8.4	0.8	0.8	0.8	6.8	7.6	7.7
20	HMEL-Bathinda (2012)	11.3	10.1	13.0	1.1	1.0	1.1	10.9	9.6	10.6
	HPCL- TOTAL	**29.1**	**26.5**	**27.0**	**2.7**	**2.5**	**2.8**	**21.8**	**24.2**	**26.4**
21	RIL-Jamnagar (DTA) (1999)	33.0	34.1	34.8	3.0	3.0	2.8	28.9	28.9	29.0
22	RIL-Jamnagar (SEZ) (2008)	35.2	26.8	28.3	2.2	2.2	2.5	24.2	24.2	23.1
23	NEL-Vadinar (2006)	20.0	17.1	20.2	1.7	1.7	1.7	16.9	16.9	15.4
All India (MMT)		**251.2**	**221.8**	**241.7**	**21.7**	**21.8**	**22.8**	**198.9**	**210.7**	**211.4**
All India (Million Bbl/Day)		**5.02**	**4.45**	**4.85**	**5.13**	**5.16**	**5.39**	**4.77**	**5.05**	**5.06**

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 01.02.2023)

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)		Jan 2022		Jan 2023 (P)		Apr-Jan 2022		Apr-Jan 2023 (P)	
	Prod	Cons	Prod	Cons	Prod	Cons	Prod	Cons	Prod	Cons	Prod	Cons
LPG	12.1	27.6	12.2	28.3	1.1	2.6	1.1	2.5	10.1	23.5	10.7	23.7
MS	35.8	28.0	40.2	30.8	3.7	2.5	3.8	2.8	33.1	25.4	35.2	29.1
NAPHTHA	19.4	14.1	20.0	14.3	1.7	1.4	1.5	1.2	16.5	12.0	14.2	10.1
ATF	7.1	3.7	10.3	5.0	1.0	0.5	1.4	0.7	8.3	4.0	12.3	6.1
SKO	2.4	1.8	1.9	1.5	0.2	0.1	0.1	0.0	1.6	1.3	0.7	0.4
HSD	100.4	72.7	107.2	76.7	9.5	6.4	10.2	7.2	87.9	62.5	94.1	71.1
LDO	0.7	0.9	0.8	1.0	0.07	0.09	0.07	0.05	0.6	0.9	0.5	0.6
LUBES	1.1	4.1	1.2	4.6	0.1	0.3	0.1	0.4	0.9	3.7	1.1	3.2
FO/LSHS	7.4	5.6	8.9	6.3	0.8	0.5	0.9	0.6	7.4	5.2	8.8	5.8
BITUMEN	4.9	7.5	5.1	7.9	0.5	0.8	0.4	0.6	3.9	6.0	3.8	5.8
PET COKE	12.0	15.6	15.5	15.8	1.5	1.9	1.4	1.6	12.7	12.5	12.7	14.9
OTHERS	30.2	12.8	30.9	12.5	2.8	1.0	3.0	1.1	25.8	10.4	25.9	12.5
ALL INDIA	**233.5**	**194.3**	**254.3**	**204.7**	**23.0**	**18.1**	**24.0**	**18.7**	**209.0**	**167.2**	**220.2**	**183.3**
Growth (%)	**-11.0%**	**-8.9%**	**8.9%**	**5.4%**	**3.7%**	**2.5%**	**4.5%**	**3.6%**	**9.3%**	**5.2%**	**5.3%**	**9.6%**

Note: Prod - Production; Cons - Consumption

15. LPG consumption (Thousand Metric Tonne)

LPG category	2020-21	2021-22	Jan			April-Jan		
			2021-22	2022-23 (P)	Growth (%)	2021-22	2022-23 (P)	Growth (%)
1. PSU Sales :								
LPG-Packed Domestic	25,128.1	25,501.6	2,312.1	2,224.9	-3.8%	21,151.6	21,116.3	-0.2%
LPG-Packed Non-Domestic	1,886.0	2,238.8	194.4	238.2	22.5%	1,818.5	2,160.4	18.8%
LPG-Bulk	361.9	390.9	46.2	35.0	-24.2%	316.9	338.0	6.7%
Auto LPG	118.4	122.0	9.4	8.3	-10.9%	100.6	90.7	-9.8%
Sub-Total (PSU Sales)	27,494.3	28,253.3	**2,562.2**	**2,506.5**	**-2.2%**	**23,387.6**	**23,705.4**	**1.4%**
2. Direct Private Imports*	64.2	82.0	4.54	2.7	-40.6%	69.5	8.1	-88.3%
Total (1+2)	27,558.4	28,335.3	**2,566.7**	**2,509.2**	**-2.2%**	**23,457.1**	**23,713.5**	**1.1%**

*Nov'22 -Jan'23 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	1.02.23 (P)
LPG Active Domestic Customers	(Lakh)					1486	1663	1988	2243	2654	2787	2895	3053	3139
	Growth						11.9%	19.6%	12.8%	18.3%	5.0%	3.9%	5.5%	3.1%
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%	6.6%
LPG Distributors	(No.)	10541	11489	12610	13896	15930	17916	18786	20146	23737	24670	25083	25269	25355
	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	527
	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%	-16.9%
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 01.02.2023 are with respect to figs as on 01.02.2022. Growth rates as on 1 April of any year are with respect to figs as on 1 April of previous year.

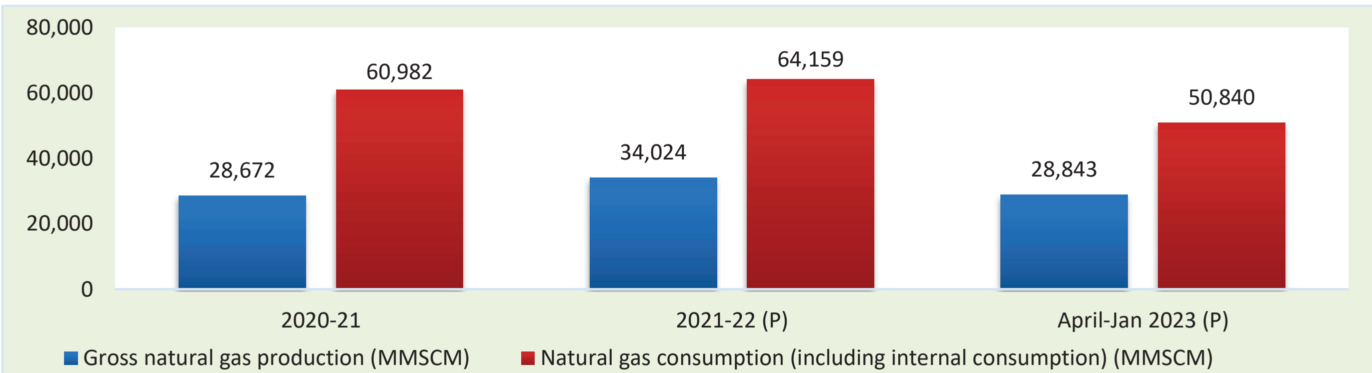
2. The LPG coverage is calculated by PSU OMCs based upon the active LPG domestic connections and the estimated number of households. The number of households has been projected by PSU OMCs based on 2011 census data. Factors like increasing nuclearization of families, migration of individuals/ families 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)	Jan			April-Jan		
			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	2,861	3,197	2,975	28,535	30,420	28,843
- ONGC	21,872	20,629	1,749	1,821	1,704	17,291	17,996	16,761
- Oil India Limited (OIL)	2,480	2,893	233	280	253	2,423	2,708	2,548
- Private / Joint Ventures (JVs)	4,321	10,502	879	1,096	1,018	8,821	9,716	9,534
(b) Net production (excluding flare gas and loss)	27,784	33,131	2,861		2,913	27,803		28,180
(c) LNG import#	33,198	31,028	2,100		2,266	26,360		22,660
(d) Total consumption including internal consumption (b+c)	60,982	64,159	4,961		5,179	54,164		50,840
(e) Total consumption **(in BCM)**	61.0	64.2	5.0		5.2	54.2		50.8
(f) Import dependency based on consumption (%), {c/d*100}	54.4	48.4	42.3		43.8	48.7		44.6

Dec - Jan 2023 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-Jan 2023 (P)	567.41	MMSCM
Production of CBM gas	Jan 2023 (P)	55.91	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 01.02.2023) (Provisional)

Particulars	Units	IOCL	HPCL	BPCL	GAIL	IGL	Total
LOIs issued	No. of plants	2745	474	318	276	,,50	**3863**
Expected CBG production against LOI issued	Tons per day	19386	2576	1412	1568.43	247.2	**25189.63**
No. of CBG plants commissioned/ Sale initiated	No. of plants	20	4	2**	08	3	**37**
Start of CBG sale from retail outlet(s)	Nos.	39	23*	38	01	1	**102**
Injection/Supply of CBG in CGD network	GA Nos.	-	-	-	13	2	**15**
Total Sale of CBG (since Sep'2019)	Tons	9976	1509*	1980	3390#	466.52	**17,322**

*2 HPCL ROs sourcing CBG from HPCL LOI holder plants, 21 HPCL ROs sourcing CBG from other than HPCL LOI holder plants. ** **Total No. of CBG and Bio gas plants commissioned is 8. #Till Dec 2022

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 01.02.2023	% Capacity utilisation (April-Dec 2022)
Dahej	Petronet LNG Ltd (PLL)	17.5 MMTPA	78.4
Hazira	Shell Energy India Pvt. Ltd.	5.2 MMTPA	40.6
Dabhol	Konkan LNG Limited	*5 MMTPA	31.0
Kochi	Petronet LNG Ltd (PLL)	5 MMTPA	18.1
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 31.12.2022(P)				
State/UT (State/UTs are clubbed based on the GAs authorised by PNGRB)	CNG Stations	PNG connections		
		Domestic	Commercial	Industrial
Andhra Pradesh	154	242,338	413	32
Andhra Pradesh, Karnataka & Tamil Nadu	31	170	0	3
Assam	2	47,932	1,323	439
Bihar	73	86,199	63	2
Bihar & Jharkhand	1	5,921	0	0
Chandigarh (UT), Haryana, Punjab & Himachal Pradesh	25	24,896	112	21
Dadra & Nagar Haveli (UT)	7	10,281	54	54
Daman & Diu (UT)	4	5,134	46	42
Daman and Diu & Gujarat	14	1,637	3	0
Goa	11	10,480	15	28
Gujarat	971	2,889,319	21,954	5,777
Haryana	307	292,399	789	1,497
Haryana & Himachal Pradesh	9	0	0	0
Haryana & Punjab	17	0	0	0
Himachal Pradesh	7	4,058	4	0
Jharkhand	64	96,431	2	0
Karnataka	248	366,461	495	280
Kerala	95	32,476	19	14
Kerala & Puducherry	9	164	0	0
Madhya Pradesh	195	191,646	312	404
Madhya Pradesh and Chhattisgrah	5	0	0	0
Madhya Pradesh and Rajasthan	25	173	0	0
Madhya Pradesh and Uttar Pradesh	16	0	0	0
Maharashtra	634	2,667,332	4,568	821
Maharashtra & Gujarat	58	131,181	4	13
National Capital Territory of Delhi (UT)	470	1,343,333	3,396	1,781
Odisha	46	76,602	5	0
Puducherry & Tamil Nadu	8	143	0	0
Punjab	179	61,390	266	225
Rajasthan	208	175,550	71	224
Tamil Nadu	159	32	0	6
Telangana	142	186,218	72	91
Telangana and Karnataka	1	0	0	0
Tripura	18	58,203	506	62
Uttar Pradesh	698	1,294,924	2,104	2,493
Uttar Pradesh & Rajasthan	39	18,958	37	340
Uttar Pradesh and Uttrakhand	16	6,263	0	0
Uttrakhand	28	64,308	52	79
West Bengal	46	0	0	0
Total	**5,040**	**10,392,552**	**36,685**	**14,728**

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 (16.02.2023)
Mumbai	87.00	54.00	MGL website (16.02.2023)

Indian Natural Gas Spot Price for Physical Delivery

IGX Price Index Month	Avg. Price		Volume (MMSCM)	Source
	INR/MMBtu	$/MMBtu		
Jan 2022	1513	18.48	96.59	As per IGX website: www.igxindia.com

*Prices are weighted average prices |$1=INR 81.89| 1 MMBtu=25.2 SCM would add almost 1 million tonnes of production and two full containment LNG storage tanks. You can see the rendering of the project on this slide. We have been hard at work on early-stage development of this project and have back already engaged on front-end engineering and design work and are excited about transforming the engineering drawing on this slide into reality at Sabine Pass.

We will develop the Sabine Pass expansion project, utilizing the same rigorous and financially disciplined approach, the project development and capital investment you've become accustomed to from Cheniere. The SPL expansion project is consistent with the significant growth plans we laid out in our capital allocation presentation in September. We showed a potential 90 million tonne platform across the Sabine Pass in Corpus Christi. Our infrastructure platform is an enormous competitive advantage, which this project is expected to capitalize on in order to deliver brownfield economics.

As the world cost for more LNG capacity, Cheniere is in an economically and environmentally advantaged position to provide that incremental capacity. We look forward to updating you on this large-scale growth project at Sabine Pass as well as the developments at Corpus as we move through this process.

Thank you again for your continued support of Cheniere. I'll now turn the call over to Anatol, who will provide an update on the LNG market.

Anatol Feygin {BIO 1959069 <GO>}

Thanks, Jack, and good morning, everyone. Please turn to Slide 9. An accelerated post-pandemic recovery followed by the curtailment of Russian gas flows into Europe, made for a sharp increase in LNG demand in 2022. With limited new liquefaction capacity in several production outages, the LNG market remained extremely tight throughout the year as we saw prices reach all-time highs and remain elevated.

Despite the supply side challenges, global LNG trade grew by approximately 5% from 2021 or an additional approximately 19 million tonnes. Overall, U.S. exports increased 9% year-on-year, up 6.3 million tonnes to 76.5 mtpa in 2022 despite the Freeport outage during the second half of the year. U.S. LNG represented nearly 40% of the growth in global LNG supply and the early completion of our ninth train meaningfully contributed to that growth.

As Jack noted, our increase in production enabled Cheniere to help answer Europe's call for reliable, flexible natural gas supply. Having lost Russia as a significant supplier Europe became a substantial demand center for LNG, attracting approximately 70% of all U.S. LNG in 2022 as prices reached record levels and redirected destination flexible U.S. LNG volumes to address the deficit.

The TTF monthly settlement prices averaged around $40 per MMBtu in 2022, over 180% higher than the $14 average in 2021. In the fourth quarter, TTF monthly settlement prices averaged $42 per MMBtu or 46% higher year-on-year, but significantly lower than the peak of nearly $100 an MMBtu in late August.

Similarly, the 2022 JKM average settlement price increased by over 125% year-on-year to an average of $34 per MMBtu, with the fourth quarter average price increasing 38% year-on-year to an average of $38, but well below the summer peak of nearly 70. In the U.S., Henry Hub price averaged nearly $7.22 but has moderated considerably since the peak in September and is now trading well below $3 per MMBtu.

This rapid correction driven by North American production growth, again, demonstrates the relative attractiveness of Cheniere's Henry Hub denominated long-term FOB and DES contracts and underpins producers' desire to diversify away from solely domestic indices. Despite the retreat of global gas prices to pre-war levels beginning in the fourth quarter and into 2023 on the back of a mild winter and demand reduction efforts in Europe, the overall market remains volatile, and we expect volatility to remain elevated as Europe sorts out its near and long-term gas supply strategies and the impact of a post-COVID China on the market becomes more apparent.

Let's now turn to Slide 10 to address regional dynamics in some more detail. As noted, much of the flexible LNG in the market was directed to Europe and was able to offset a large part, approximately 84% of the 74 Bcm or 55 million tonne reduction in Russian gas supply. Europe's LNG imports totaled over 120 million tonnes, of which 110 million tonnes went to EU plus U.K., which is a 69% increase year-on-year. U.S. LNG to the block plus the U.K. totaled 48 million tonnes, a 165% increase year-on-year. Clearly, destination flexible U.S. LNG was able to answer Europe's call for natural gas supply in 2022.

Throughout the year, the EU implemented several extraordinary measures to mitigate the potential impact of a complete cutoff of Russian gas and a potentially cold winter amid low nuclear and hydro generation output. As Jack noted, the challenges the European nations faced were significant, but these measures, along with mild weather and demand price response enabled Europe to replenish its inventories and avoid a potentially crippling energy crisis in the near term.

Some of the coordinated initiatives included a regulatory push to immediately increase LNG import infrastructure, diversified supply sources and reduce natural gas demand. To date, five new re-gasification terminals have commenced service in Europe since September, a key enabler of Europe's ability to grow LNG imports to record levels in the fourth quarter.

Demand reduction efforts have also been made across Europe. Residential, commercial and industrial customers were able to reduce aggregate demand by an estimated 12% during the year as power generation resorted to increased coal usage, a trend that we think will reverse in 2023 given elevated gas storage levels and again, a mild weather outlook. At present, it appears the European gas system will make it through this winter without the enforced supply restrictions many had feared.

Amid historically high LNG prices, the global inflationary environment, lower economic activity and lower market liquidity, some of the more price-sensitive Asian buyers withdrew from the spot LNG market. Imports into Asia declined by 20 million tonnes or 7% year-on-year with nearly 16 million tonnes of the drop attributable to China. This was the first substantial annual decline in LNG imports since the country began importing in 2006. China's economy faced extended COVID restrictions, a property sector crisis and severe drought, all of which led to a drop in total gas demand of 4 Bcm in 2022 with the decline led by the industrial and power generation sectors.

Similar to parts of Europe, low hydro output and high gas prices supported increased coal generation in the second half of 2022. However, with JKM and TTF prices moderating, we expect to see price-sensitive Asian LNG demand resume and indications of higher industrial activity in China as COVID restrictions are lifted. The latter, of course, could have a potentially material impact on next winter's global balance.

Let's move to Slide 11. Europe shift away from Russia created an immediate supply gap of approximately 70 Bcm in 2022, which will likely rise to approximately 110 Bcm in 2023. Assuming Russian pipeline supplies are eventually fully curtailed, the gap created of 100 mtpa is equivalent to around 1/4 of the current global LNG market. The magnitude of the supply shock stressed the global LNG market in 2022, resulting in some demand destruction in certain regions during the year.

More important, however, as Jack noted, the market dynamics of '22 highlighted the critical role of LNG in ensuring energy security, underscoring the importance of long-term contracted reliable LNG supply in the global energy mix. While short-term dynamics have dominated headlines and narratives over the last year, the long-term fundamentals are central to our strategic planning and positioning and the need for further investment in LNG capacity was again laid bare last year.

Over the next few decades, both the supply and demand side are supportive of new liquefaction infrastructure. In addition to high project development hurdles, capital intensity and long construction timelines for new LNG facilities, legacy plant utilization rates worldwide continued to decline as a result of outages, feedstock limitations and fleet inefficiencies as well as competing domestic demand in some markets. Since 2010, the volume produced from these legacy projects has declined by 23% or over 25 million tonnes, further contributing to the need for more capacity.

While these facilities produced about 1/4 of all total volume last year, their contribution will likely decline overtime. As feedstock resources deplete, their ability to export declines and their performance potentially degrades. Meanwhile, investment in downstream LNG infrastructure continues to grow not only in Europe, but also in other parts of the world. Over 370 million tonnes of re-gas capacity is under development, which is equivalent to about 80% of global LNG trade today. Furthermore, nine new markets are expected to enter the LNG trade in the next two years, including Vietnam, the Philippines and Ghana, just to name a few.

Investments in new LNG supply are critically needed not only to address the current market imbalance and meet the expected long-term demand growth, but also to offset declining production from certain legacy production facilities.

https://www.dallasfed.org/research/economics/2023/0221

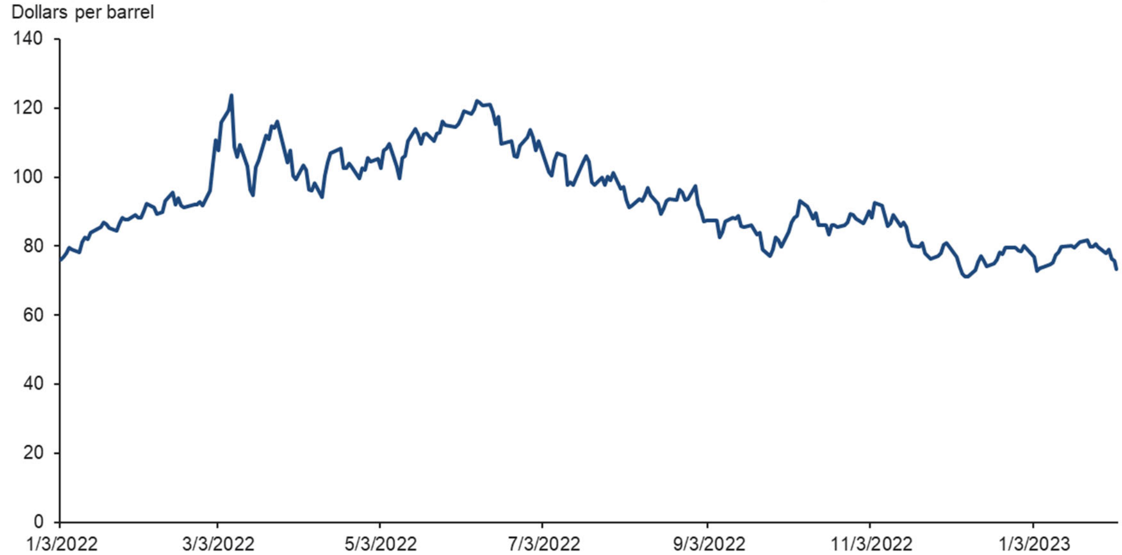
Trade diversion has helped ease the impact of the embargo on Russian oil

Lutz Kilian and Kunal Patel
February 21, 2023

Many observers expected trade sanctions against Russia to substantially raise the price of oil. Tanker traffic data suggest that global oil markets have been more resilient than anticipated. A good portion of the Russian oil destined for export to the West is finding its way to Asia.

Much has been made of the effect of Russia's invasion of Ukraine on the price of oil. However, the price of oil was already drifting upward well before the invasion in late February 2022—driven by growing demand for oil, as the global economy recovered from the COVID downturn. This trend continued into mid-2022 (Chart 1).

Chart 1
Daily price of WTI crude oil rises after Ukraine invasion, trails lower since mid-year 2022



NOTES: WTI is benchmark West Texas Intermediate crude oil. Russia invaded Ukraine on Feb. 24, 2022.
SOURCES: Haver Analytics; Energy Information Administration.
Federal Reserve Bank of Dallas

As global demand growth slowed in the second half of the year, the price of oil began falling, reaching levels by October 2022 not far from where it had started the year. The decision by OPEC to reduce its oil supply in October only temporarily raised the price, as expected demand continued to weaken.

In other words, the price of oil in 2022 was driven first and foremost by global demand. The invasion's only effect was to create volatility, notably in March and April 2022, when the price of oil spiked relative to trend in response to concerns about imminent Russian oil supply disruptions that never materialized.

There is little evidence in Chart 1 to support the narrative that higher oil prices in 2022 were driven by shortfalls of Russian oil that producers in the rest of the world were unable to offset. Nor is there evidence in more-recent data that the onset of the embargo on Russian oil has had much effect in early 2023. This conclusion is consistent with data for Russian oil exports by tanker provided by TankerTrackers.com.

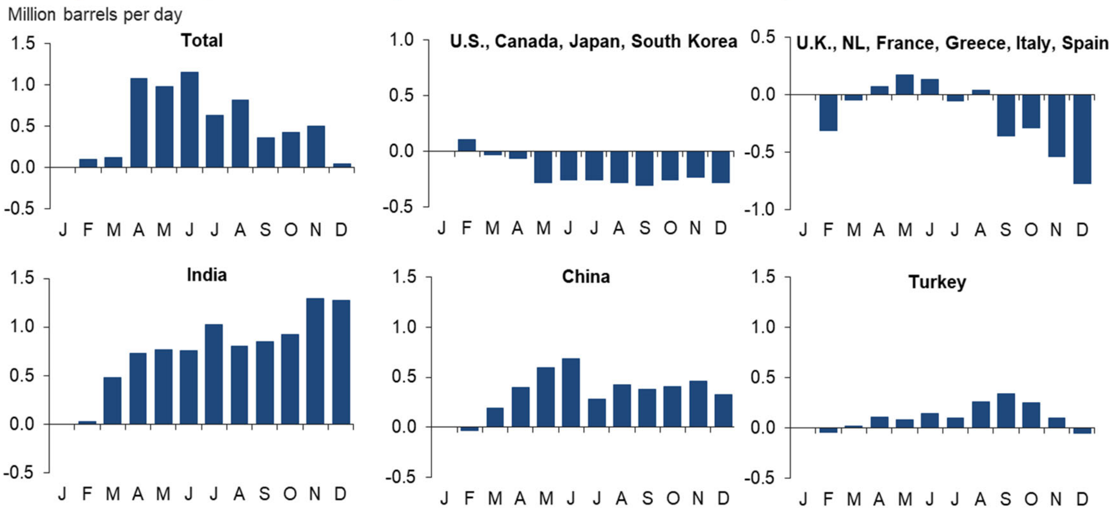
Effects of the oil embargo that started in December 2022

As recently as 2021, Russia exported 4.7 million barrels of crude oil per day (mb/d) to the rest of the world, along with 2.8 mb/d of petroleum products. Some of the crude oil exports to Europe and Asia relied on oil pipelines, which were operating near full capacity before the invasion.

Since the pipeline exports of about 0.8 mb/d to Europe remained stable in 2022 and pipeline exports to Asia could not be increased, much of the adjustment of export flows relied on oil tankers loading Russian oil at Black Sea and Baltic Sea ports as well as ports in the Arctic and East Asia.

Total Russian oil tanker exports during 2022 increased substantially despite reduced deliveries to the West (Chart 2). Russia was not only able to divert crude oil originally destined for Europe and its allies to countries not participating in the embargo but was able to raise its overall oil tanker export volume by as much as 40 percent.

Chart 2
Monthly Russian exports of crude oil by tanker in 2022 relative to their January 2022 level



SOURCES: TankerTrackers.com, Jan. 31, 2023; Federal Reserve Bank of Dallas.

Federal Reserve Bank of Dallas

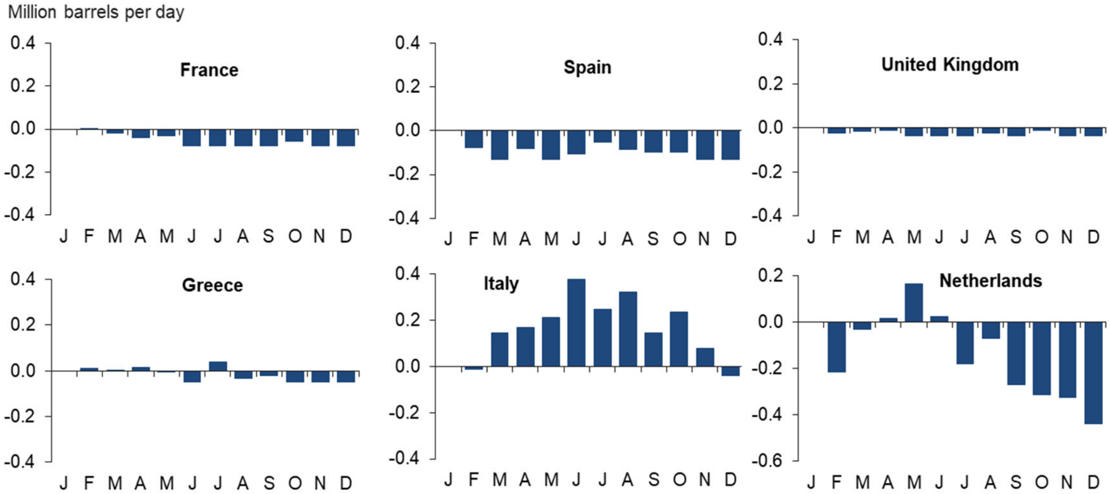
The main beneficiaries of this shift were India, China and Turkey. For example, India's imports of Russian oil in 2021 were not material, but the country took full advantage of heavily discounted imports of Russian crude in 2022, allowing it to cut back on other oil imports and to export low-cost refined products to the West, blunting the impact of oil sanctions on product markets.

In the aggregate, Russia—far from reducing the supply of its crude to the rest of the world after January 2022—increased that supply and did so at prices lower than those available elsewhere. This, if anything, provided a global stimulus while helping finance the Russian war effort. It also helps explain why the West Texas Intermediate price did not remain elevated relative to trend after the initial uncertainty about the impact of the Russian invasion had died down.

What happened in Europe

Oil markets might have been tighter in 2022 had it not been for some European countries continuing to import Russian crude oil and—in some cases—even increasing their imports. Italy, in particular, took the opportunity to stock up on discounted Russian oil, while many other European countries, with varying degrees of success, gradually reduced their imports (Chart 3).

Chart 3
Italy becomes a leading European importer of Russian crude oil delivered via tanker in 2022



NOTE: Oil import volume by tanker is shown for select European counties relative to January 2022 levels.
SOURCES: TankerTrackers.com, Jan. 31, 2023; Federal Reserve Bank of Dallas.

Federal Reserve Bank of Dallas

By January 2023, these flows declined to a trickle with limited exports continuing to reach Italy, the Netherlands and Spain despite the embargo. Meanwhile, pipeline exports of Russian oil to Europe also dropped substantially.

However, preliminary data indicate that total Russian exports by oil tanker in January 2023 recovered to near 4 mb/d, about 1 mb/d higher than in December 2022 when bad weather delayed shipments. This suggests that Russia has been able to divert most of the oil formerly shipped to Europe by pipeline, coupled with only modest oil production cuts.

The outlook for 2023

The tanker traffic data indicate that the impact of the crude oil embargo on oil prices and on the global economy is likely to be fairly benign in 2023, absent a strong surge in demand. The fact that the $60 price cap on Russian crude—imposed in December 2022 as part of the trade sanction regime—was too high to be binding undoubtedly helped reduce the frictions in the tanker market, as did India's decision to proceed without Western insurance and Russia's move to expand its own tanker fleet.

With the European Union product embargo taking effect in February 2023, there is less reason for optimism about product markets. While it appears that the price cap for products has been set above the current market price for Russian products, one key difference is that refined products such as diesel can only be shipped in "clean" tankers that are in shorter supply than the "dirty" tankers used to ship crude oil. If the available product tankers are used for longer runs to Asia rather than to European ports, the effective fleet size shrinks.

Another key difference is that markets for diesel and jet fuel are already stressed, as global transportation demand has recovered. An interesting question is whether Russia will choose to lower its refining output and exports in favor of higher exports of crude oil. That could help Russia deal with the product tanker shortage, while allowing India and China, in particular, to increase their exports of products made from Russian crude—alleviating the global shortage of diesel and jet fuel.

Share this About the Authors

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Energy Trade

https://www.kommersant.ru/doc/5841534

- Business

22.02.2023, 20:17

Rosstat: the cost of oil production in 2022 increased by 19%

The average cost of oil production in Russia in 2022 increased to 24.6 thousand rubles. per ton (rubles / ton), which is 19% more than in 2021 (20.69 thousand rubles), follows from the data (.xls) published on the website of Rosstat. Taking into account the average dollar exchange rate last year (67.46 rubles), the average cost of production per barrel of oil in the Russian Federation was $ 50.

According to statistics provided by the department, during 2022, the cost of oil production decreased. In the first quarter, it was 33.1 thousand rubles / ton, in the second - 25.1 thousand rubles / ton, in the third - 21.4 thousand rubles / ton, in the fourth - 18.6 thousand rubles / ton.

Rosstat also reported that oil production in the Russian Federation, taking into account gas condensate in January of this year, amounted to 46 million tons, which is 1% less than in January 2022, and 0.4% less than in December,

The level of oil production excluding gas condensate decreased more significantly. In January 2023, it amounted to 42 million tons, which is 2.5% and 0.5% lower than in January and December last year, the department added.

Erdni Kagaltynov

https://tass.com/economy/1580649

22 FEB, 11:28

Russia second by average daily oil production in December 2022 — statistics

Russia’s crude oil production was 10.873 mln barrels daily in December 2022, while the US lifted 12.087 mln barrels per day and Saudi Arabia produced 10.435 barrels per day

MOSCOW, February 22. /TASS/. Russia was second in crude oil production after the United States in December 2022, the state statistics service Rosstat reported on Wednesday. Saudi Arabia was third.

Russia’s crude oil production was 10.873 mln barrels daily in December 2022, while the US lifted 12.087 mln barrels per day and Saudi Arabia produced 10.435 barrels per day.

The country produced in total 534 mln metric tons of oil during January - December of the last year, up 2.1% in annual terms. Crude oil production in December had an uptick by 0.1% in annual terms to 46.2 mln metric tons.

https://tass.com/economy/1579341

21 FEB, 02:52

Russia has decided on voluntary reduction of oil output only for March, says Novak

It is noted that companies' output reduction in March will be proportional to production

MOSCOW, February 21. /TASS/. Russia has only made a decision on voluntary reduction of crude production by 500,000 barrels per day for March so far, Deputy Prime Minister Alexander Novak told reporters, adding that the policy would be extended later depending on the situation.

"We will see how the market situation will unfold, and depending on this, decisions will be taken on the market," he said, adding that "the present decision has only been made for March."

Companies' output reduction in March will be proportional to production, Novak noted. "Yes, depending on production," he said.

Earlier, Novak said that Russia planned a voluntary decrease in oil production by 500,000 barrels per day in March.

A representative of the Deputy Prime Minister said later that the reduction in production would affect only oil, without taking gas condensate into consideration. Meanwhile, a TASS source in the industry specified that the reduction in production would be calculated from the real volume of production, and not from Russia's production quota under the OPEC+ deal. According to the deal, from November 2022, Russia is to produce 10.478 mln barrels per day. In January 2023, as Novak said earlier, Russia produced approximately 9.8-9.9 mln barrels per day.

https://tass.ru/ekonomika/12290253

SEP 2, 17:44

Ministry of Energy: production of half of oil reserves in Russia is unprofitable at a price of $ 50 per barrel

Deputy head of the department Pavel Sorokin considers the range of $ 55-60 per barrel as a balanced oil price for 2022

MOSCOW, September 3. / TASS /. The production of about half of the oil reserves in the Russian Federation at a price of $ 50 per barrel is unprofitable. It is worth focusing on working with the current resource base, Deputy Energy Minister Pavel Sorokin said in an interview with the Izvestia newspaper published on Friday.

“Even in our current structure of reserves, a significant part of it is unprofitable at a price of $ 50 - about half there. There is a very large layer of opportunities for working with the current resource base: with small fields, with depleted, with tailing assets, with deeper and more difficult layers. what you need to concentrate on, "Sorokin said.

The Deputy Minister considers the range of $ 55-60 per barrel to be a balanced oil price for next year, but only after the completion of the recovery in the world of production under the OPEC + deal, which under the current terms of the agreement should take place in May 2022.

"In general, after everyone has restored their production to the pre-pandemic level, all other things being equal (and if there are no shocks), the equilibrium price, we think, is in the range of $ 55-60," he said.

Google Translate of TASS Russian story “В Минэнерго сообщили, что рентабельными в России являются только 36% запасов нефти” https://tass.ru/ekonomika/10559021

27 JAN, 04:40

The Ministry of Energy said that only 36% of oil reserves in Russia are profitable

Deputy head of the department Pavel Sorokin noted that the development of deep horizons of Western Siberia will require investments comparable to the cost of drilling in the Arctic

MOSCOW, January 27. / TASS /. Only 36% of 30 billion tons of oil reserves in Russia are profitable, which is associated with the deterioration of development conditions and a drop in the quality of reserves, writes the Deputy Minister of Energy of the Russian Federation Pavel Sorokin in an article for the Energy Policy magazine.

"According to the data of the inventory of the economics of field development, carried out on behalf of the Russian government, out of 30 billion tons of recoverable oil reserves in Russia, only 36% is profitable in the current macroeconomic conditions. This is due to the deterioration of development opportunities: an increase in water cut, the need to permeability and compartmentalization of reservoirs, withdrawal into marginal zones and strata with small thicknesses, and so on, "Sorokin explained.

"All this not only increases the cost of production, but also increases the risks of not confirming the planned development indicators due to the complexity of modeling processes and errors during drilling, for example, the exit from the productive formation during horizontal drilling. As a result, for some assets, the actual profitability of drilling may differ significantly from plans, and reserves are not confirmed, "the deputy minister stressed.

According to him, the quality of reproduction of the resource base is also deteriorating. The average size of new field discoveries in 2015-2019 amounted to 9-14 million tons (excluding several large ones on the shelf and the Payakhskoye field). The increase in reserves in recent years is provided by additional exploration in the operating regions of production, as well as by revaluation of reserves. Basically, in traditional regions, the growth is due to the search for missed deposits or drilling into deep horizons. At the same time, the technological complexity of geological exploration increases significantly.

"It is important to understand that the omission of promising formations when using traditional methods of data interpretation is associated with their small size and complexity. Therefore, it is necessary to apply completely new technologies for exploration and modeling of assets," Sorokin said.

Thus, the question of the future of the Russian oil industry is associated with advanced technological development and increased efficiency. "Only this will allow maintaining the position of one of the lowest producers in terms of cost on the world oil supply curve," the deputy minister sums up.

Investments in the further development of Western Siberia

The development of the deep horizons of Western Siberia will require investments comparable to the costs of drilling in the Arctic, which are traditionally very high, Sorokin also noted.

"The development of deep horizons requires increased investment. For example, for the pre-Jurassic complex of Western Siberia, capital expenditures for exploratory drilling are comparable to the Arctic - from 500 million rubles or more per well. In terms of major discoveries, the most promising region is the Arctic and the shelf. Here Several major discoveries have already been made in recent years - Neptune, Triton, Payakha with total reserves of more than 1.3 billion tons of oil However, these basins are poorly studied and, given the high cost of exploratory drilling, it is necessary to use completely new modeling technologies for effective localization hydrocarbon deposits, "Sorokin noted.

“Thus, the question of the future of the Russian oil industry is associated with advanced technological development and efficiency gains. Only this will allow us to maintain the position of one of the lowest producers in terms of cost on the world oil supply curve,” the deputy minister added.

According to him, the oil and gas industry is currently facing a number of problems that reduce its competitiveness in the world market.

A common problem is the gradual depletion of reserves in developed fields and a drop in oil production in traditional oil-producing regions. The highest rates are observed in the key oil-producing region of Russia - Western Siberia, where production has decreased by 10% over the past ten years - to 288 million tons, Sorokin concludes.

TASS English Posted Story https://tass.com/economy/1249505
27 JAN, 04:26
Only 36% of oil reserves profitable in Russia, energy minister says
This is related to worsening of development opportunities, according to the minister

MOSCOW, January 27. /TASS/. Just 36% of 30 bln tonnes of oil reserves are profitable, Deputy Energy Minister of Russia Pavel Sorokin wrote in his article for the Energy Policy magazine.

"According to data of fields' development economics inventory completed on the instruction of the Russian government, just 36% out of 30 bln tonnes of recoverable reserves of Russian oil are profitable in current macroeconomic environment. This is related to worsening of development opportunities: growing water cut, the need to build costly wells of complex design, low permeability and compartmentalization of reservoirs, the move to marginal areas and beds with low thickness, and so on," the official said.

"All that does not merely increase the lifting costs but also moves upward risks of failure to confirm target development figures because of the complexity of processes modeling and drilling errors, for example, leaving the pay bed in horizontal drilling. The result is the actual profitability of drilling may considerably differ from plans for certain assets and reserves will not be confirmed," Sorokin said.

https://www.globaltimes.cn/page/202302/1285849.shtml

Foreign airlines ramp up international flights to China amid rising demand

By Global Times Published: Feb 20, 2023 10:08 PM

Beijing airport Photo: VCG

A number of foreign airlines that have benefited from the rapid growth of China's outbound travel are working hard to restart flights serving the country as China has lifted the travel ban, bringing a fast recovery of demand.

KLM Royal Dutch Airlines, a subsidiary of the Air France-KLM Group, said it will increase the frequency of flights connecting with China starting from March 26. It also plans to have three flights from Amsterdam to Hong Kong and to start six direct flights per week to Beijing and Shanghai on the same day, and increase service to a daily flight from May.

Air France plans to increase the frequency of flights between Paris and Beijing, Shanghai and Hong Kong to one daily from July.

As a leading European airline group in China, Lufthansa Group has a long history. The first Lufthansa flight arrived in Beijing from Berlin in 1926.

After the reopening of the Chinese mainland, Lufthansa Group further increased its flight frequency. Starting from March, Lufthansa will double its flights to the Chinese mainland from five weekly flights to nine.

China is always a very important intercontinental market of Lufthansa, the company told the Global Times on Monday.

Airlines in Southeast Asia, which are favored by Chinese tourists, are expanding more rapidly. AirAsia restarted the Guangzhou-Kuala Lumpur route on February 11, and it plans to increase service to eight flights per week from March 2.

Emirates will increase flights between Dubai and Shanghai to daily from March, and will restart the Dubai-Beijing route on March 15. Qatar Airways announced that it will resume daily flight services from Doha to Beijing Daxing International Airport from March 26, while increasing services between Doha and Guangzhou to daily flights.

China-UK direct flights, which were interrupted during the COVID-19 epidemic, are set to resume soon.

According to British Airways, the route between London Heathrow Airport and Shanghai Pudong International Airport will be resumed operations on April 23, with seven flights per week, and British Airways will resume London Heathrow to Beijing Daxing International Airport on June 3.

China has maintained a fast recovery of international flights, as resumed weekly fixed passenger flights have increased by more than 60 percent over the week before downgrading management of COVID-19 on January 8.

The number of fixed international passenger flights stood at 795 across 98 carriers from home and abroad from February 6 to 12, covering 58 countries and regions, the Civil Aviation Administration of China said on Thursday.

The number of flights was up 65 percent over the week from January 2 to 8, the week before China prioritized its COVID-19 management.

Although the return of international routes is accelerating overall, market analysts said it is difficult for domestic airports to see a sharp increase in a short time.

By looking at routes longer than 3,000 miles, the number of flights departing from East Asian airports in the first quarter of this year was 41 percent lower than in the first quarter of 2019. The figure was partly influenced by the Chinese region, a report released by industry consultancy Cirium sent to the Global Times on Monday showed.

Due to the reopening of China, there may be significant changes to flight schedules in the region. The China flight schedule for the first quarter of 2023 shows that while inbound and outbound capacity is roughly 82 percent below pre-pandemic levels, it is more than double that of the first quarter of 2022, Cirium said.

Global Times

Oil price outlook – Snapshot: February 20, 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 largely flat over the past week.
Fundamentals	**Crude stocks**	↓	• In the week ending February 10, land crude-oil storage levels in BloombergNEF's tracked regions (the US, Japan and the Amsterdam-Rotterdam-Antwerp oil trading hub [ARA]) grew by 1.7% to 584.3 million barrels (m bbl). The stockpile **deficit** against the five-year average (2016-19 and 2022) **narrowed from 9.8m bbl to 2.7m bbl.** • Including global floating crude stockpiles from the same week, total crude oil inventories increased 1.1% to 662.1m bbl, while the stockpile **surplus of 12.7m bbl widened to 19.6m bbl.**
Fundamentals	**Product stocks**	↓	• In the week ending February 10, gasoline and light distillate stockpiles in BNEF's tracked regions (the US, ARA, Singapore, Japan and Fujairah) grew 1.2% week-on-week to 289.8m bbl, with the stockpile **deficit** against the four-year average (2017-19 and 2022) **narrowing from 9.8m bbl to 6.9m bbl.** Gasoil and middle distillate stockpiles in BNEF's tracked regions were down 0.8% to 155.3m bbl, with the stockpile **deficit** against the four-year average **narrowing from 28.8m bbl to 27.9m bbl.** • Oil product stockpiles in tracked regions grew by 0.1% to 954.1m bbl, with the stockpile **deficit** against the four-year seasonal average **narrowing from 15.0m bbl to 6.6m bbl.** Altogether, crude and product stockpiles increased 0.5% to 1,616.2m bbl, with the stockpile **deficit of 2.3m bbl flipping to a surplus of 12.9m bbl.**
Fundamentals	**Demand indicators**	↓	• In the week to February 27, global jet fuel demand from commercial passenger flights is set to **rise** 0.3% to 5.55m b/d (million barrels per day). Jet fuel consumption by international passenger flight departures is on course to **grow** 32,300 barrels per day (or +1.0%) week-on-week, while consumption by domestic passenger flight departures will **fall** 13,900 barrels per day (or -0.6%). In the week to February 18, flights in the Eurocontrol area were **flat** at 87.6% of the equivalent week in 2019. The four-week moving average **rose** to 86.1%, from 85.3% in the prior week. Meanwhile, in the same week, US TSA passenger throughput **slipped** to 97.0% of the average week in 2019, down from 103.1% last week. The four-week moving average also **fell** to 101.9%, down from 102.4% in the previous week. • In the week to February 18, congestion levels showed **declines** in Asia Pacific excluding mainland China (-5.3%), Europe (-4.8%) and North America (-1.0%). On a four-week moving average basis, APAC ex-China (-1.8%) and Europe (-3.0%) **fell,** while North America (+0.9%) posted a **gain**. Against the same week last year, all three regions registered **declines** - Asia Pacific ex-mainland China **dropped** 12.9 percentage points to 116.4% of the same week last year, Europe **fell** 3.1 percentage points to 95.0%, while North America **slipped** 3.7 percentage points to 109.8%. In the week to February 19, road congestion in China's 15 key cities **rose** by 12 percentage points to 164% 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 43% higher than January 2021 levels. • Weather in several cities across Western Europe and East Asia became warmer over the past week.
Financial	**Macro indicators**	↓	• The dollar index averaged 103.6 in the week to February 17, and was **up** 0.2% from the week prior. The market priced in a more hawkish US Federal Reserve as the CPI report released last week suggest that US inflation is not yet showing clear signs of easing.
Financial	**Commitment of traders**	↔	• The Commodity Futures Trading Commission (CFTC) has delayed the release of the Commitment of Traders report for the third week due to a cyber-related incident.
Financial	**Options and volatility**	↓	• Brent and WTI 1M volatility **fell** over the past week. There was a significant in open interest for Brent May-23 $70-75/bbl puts.
Outlook	**Weekly call**	↓	• BNEF is **bearish** on oil prices for the week ahead, with Brent Apr-23 trading at $83.73/bbl and WTI Apr-23 trading at $77.20/bbl at the time of writing. • Key agencies – OPEC, the IEA (International Energy Agency) and the US EIA (Energy Information administration) – made some adjustments to their 2023 oil balance outlook. OPEC was the only agency to make a net change to its full-year oil balance forecast. ▪ OPEC cut US and Russia oil production forecast by a total 0.09m b/d for 2023, while hiking China's demand projections by 0.13m b/d. Assuming the OPEC+ deal remains unchanged, its oil market balance forecast for 2023 flipped to a supply deficit of 0.2m b/d from its previous forecasted surplus of 0.1m b/d. ▪ The IEA increased its expectations of non-OECD Asia oil demand in 1Q 2023 by 0.3m b/d and in 2Q by 0.2m b/d, but reduced its 3Q and 4Q demand projections by 0.1m b/d. The oil demand forecast for the full-year was revised higher by 0.2m b/d. However, expectations of Russia's oil supply rose as well, offsetting the upward revisions in demand. The IEA projects an oil supply deficit of 0.6m b/d for 2023, which is largely unchanged from its previous forecast. ▪ The US EIA adjusted its demand trajectory for the year ahead but made no change to total oil demand.. The agency decreased its oil demand projections for the first half of the year but hiked demand in second half. The US EIA projects a 0.7m b/d oil supply surplus for 2023, which is largely unchanged from its previous forecast. • The seven-day moving average road traffic levels in China continued to **grow** for the third consecutive week, albeit at a lower pace as compared to the previous two weeks. Of the 99 cities BNEF tracks in China, 69 recorded a weekly growth in traffic levels. • Road mobility outside of China continues to face headwinds, as year-on-year growth in Europe, North America and APAC ex-China **declined** versus the same week last year. Europe is showing signs of weakness as traffic levels have fallen below the same week last year. • Oil inventories saw a net **bearish** move over the past week, as crude stockpile surplus widened while the oil product stockpiles flipped from a deficit to a surplus.

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
February 20	↔	↓	↓	↓	↔	↓	↓	Brent-Apr: 83.73 WTI-**Apr**: 77.20	
February 13	↓	↑	↔	↔	↔	↑	↔	Brent-Apr: 85.65 WTI-Mar: 78.97	
February 6	↓	↑	↔	↑	↔	↑	↑	Brent-Apr: 80.50 WTI-Mar: 73.72	
January 30	↑	↑	↓	↔	↑	↔	↔	Brent-Apr: 86.17 WTI-Mar: 79.41	
January 23	↑	↔	↑	↔	↑	↔	↔	Brent-Mar: 88.25 WTI-Mar: 82.16	
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	

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

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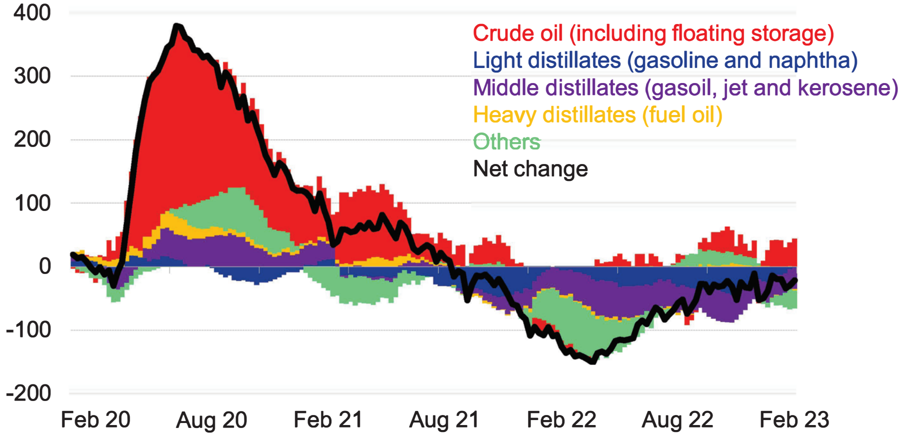
Fundamentals Financial

Weekly oil inventories

Oil inventories grew 0.5% over the past week

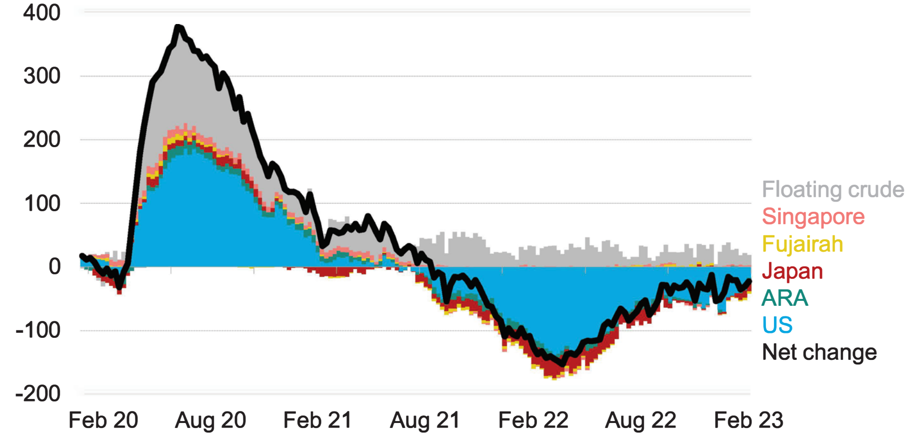
Weekly oil inventories by type

Million barrels (indexed to January 1, 2020)



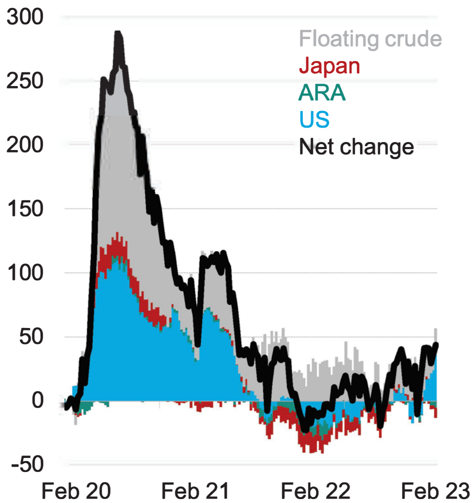
Weekly oil inventories by region

Million barrels (indexed to January 1, 2020)



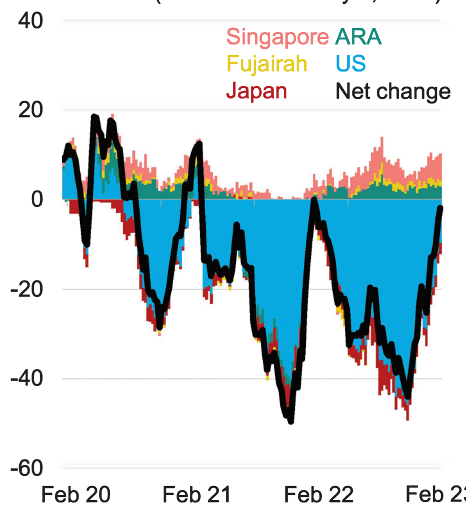
Crude inventories

Million barrels (indexed to January 1, 2020)



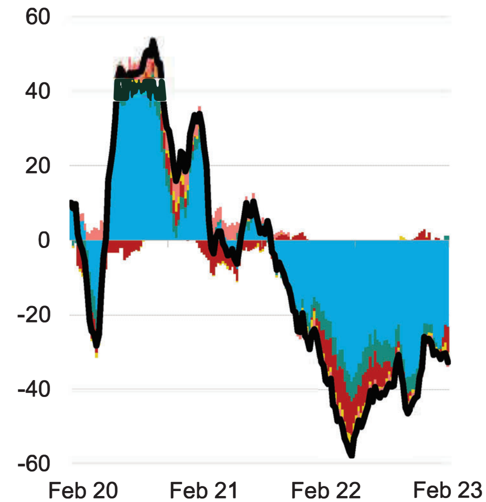
Light distillate inventories

Million barrels (indexed to January 1, 2020)



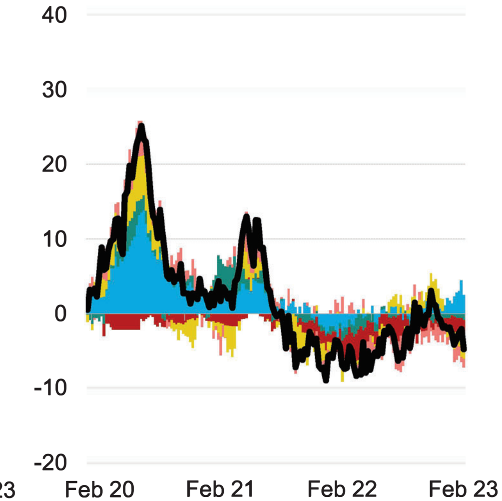
Middle distillate inventories

Million barrels (indexed to January 1, 2020)



Heavy distillate inventories

Million barrels (indexed to January 1, 2020)



*Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ ,Vortexa, Genscape. Note: As of the week ending **February 3, 2023**.*

BloombergNEF

Methodology update: Inventory data

Key changes highlighted in blue *(Changes effective from report dated January 17, 2023)*

	Chart average and range		Seasonal averages for stockpile comparison
	Before change	After change	After change
Aggregated oil stockpiles	2017-19 (three years)	2017-19 and 2022 (four years)	• All inventory data in 2023 will be compared against 2017-19 and 2022 (four years) • All inventory data in 2022 will be compared against 2017-19 (three years)
Crude stocks: Land	2016-19 (four years)	2016-19 and 2022 (five years)	• All inventory data in 2023 will be compared against 2016-19 and 2022 (five years) • All inventory data in 2022 will be compared against 2016-19 (four years)
Crude stocks: Floating	2016-19 (four years)	2016-19 and 2022 (five years)	• All inventory data in 2023 will be compared against 2016-19 and 2022 (five years) • All inventory data in 2022 will be compared against 2015-19 (five years)
Oil product stocks – the US, ARA and Singapore	2015-19 (five years) for the US, ARA and Singapore	2016-19 and 2022 (five years) for the US, ARA and Singapore	• All inventory data in 2023 will be compared against 2016-19 and 2022 (five years) • All inventory data in 2022 will be compared against 2015-19 (five years)
Oil product stocks – Fujairah and all tracked regions	2017-19 (three years) for Fujairah and all tracked regions	2017-19 and 2022 (four years) for Fujairah and all tracked regions	• All inventory data in 2023 will be compared against 2017-19 and 2022 (four years) • All inventory data in 2022 will be compared against 2017-19 (three years)

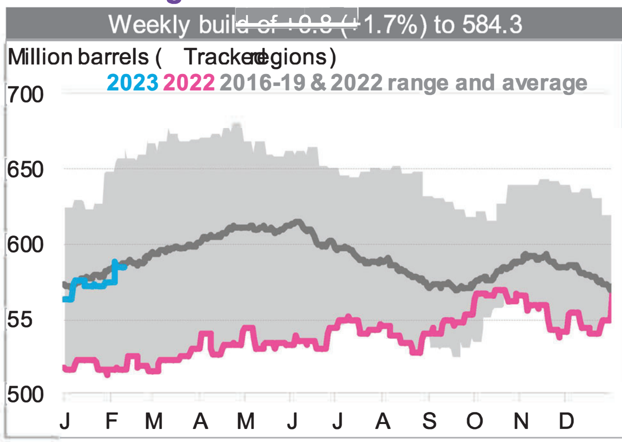
Source: BloombergNEF

Crude stocks: Land

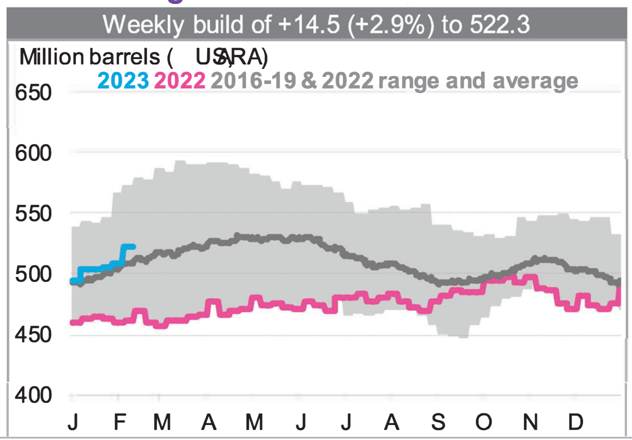
Bearish: Stockpile deficit narrowed from 9.8m bbl to 2.7m bbl

- 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.

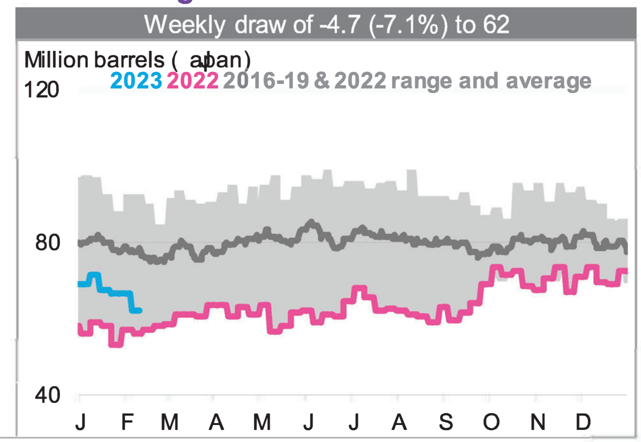
Land storage: Total



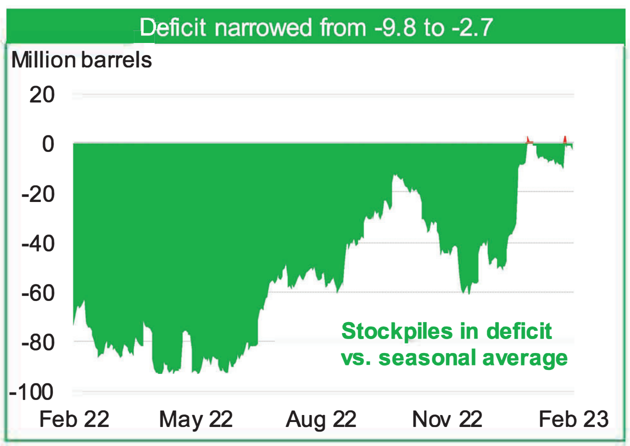
Land storage: West of Suez

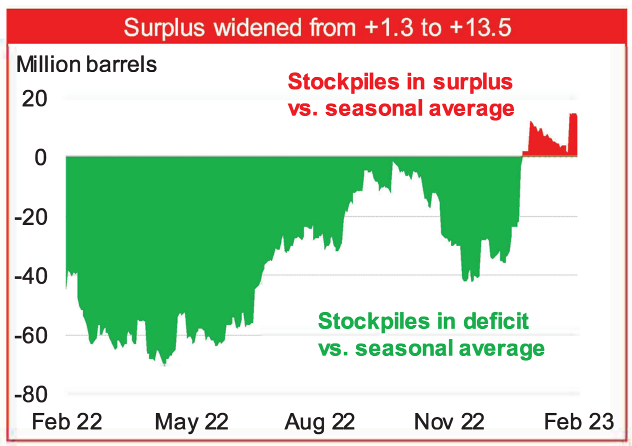


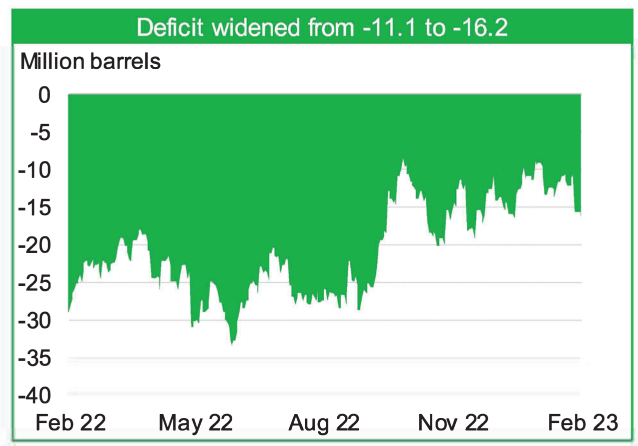
Land storage: East of Suez



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 February 10, 2023.***

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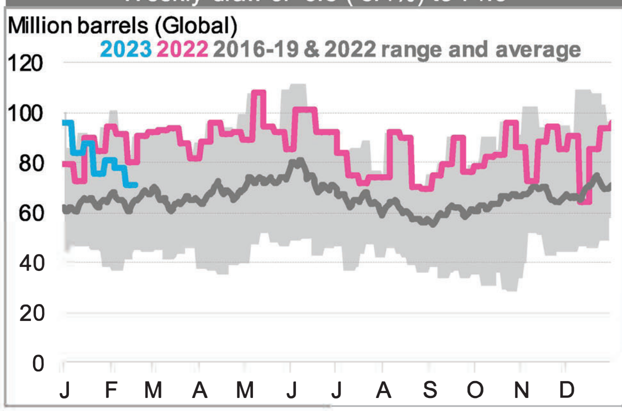
Crude stocks: Floating

Bullish: Stockpile surplus narrowed from 12.0m bbl to 8.0m 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 (which is the week before the latest data shown below).

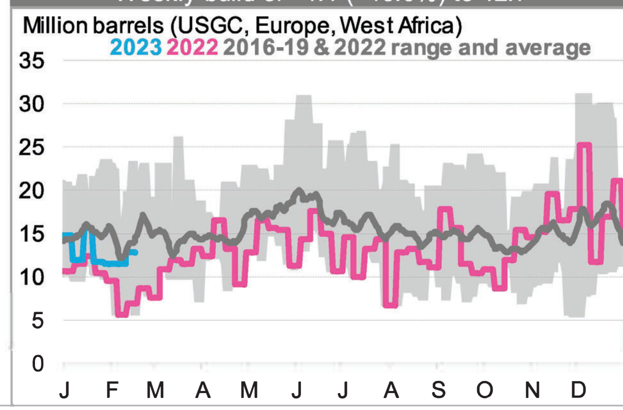
Floating storage: Total

Weekly draw of -6.5 (-8.4%) to 71.3



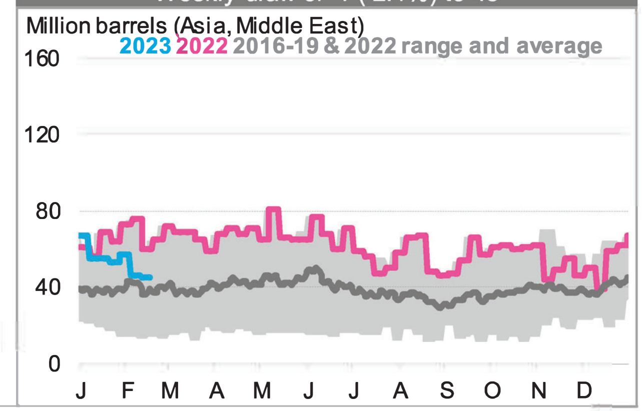
Floating storage: West of Suez

Weekly build of +1.1 (+10.0%) to 12.7



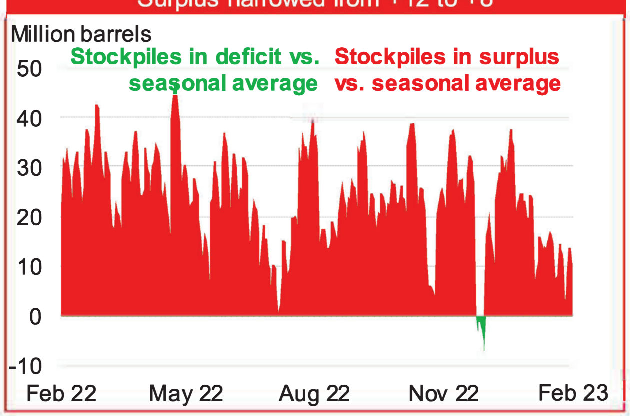
Floating storage: East of Suez

Weekly draw of -1 (-2.1%) to 45

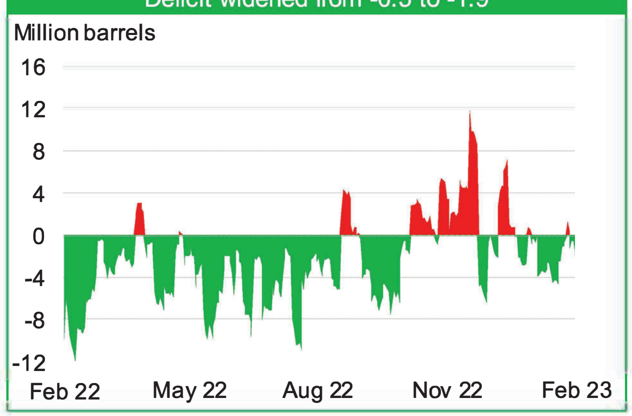


Charts below subtract current stockpiles by the 2016-19 & 2022 (five-year) seasonal average

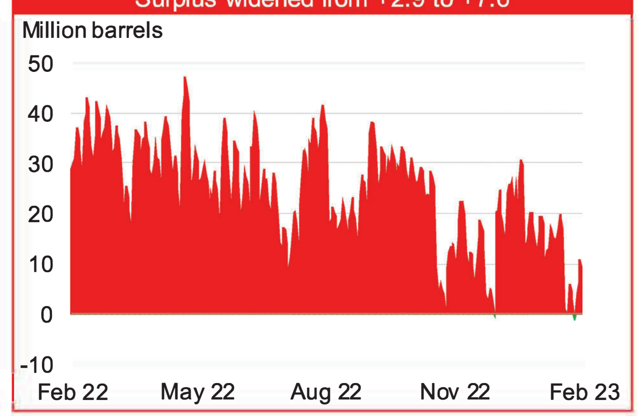
Surplus narrowed from +12 to +8



Deficit widened from -0.3 to -1.9



Surplus widened from +2.9 to +7.6

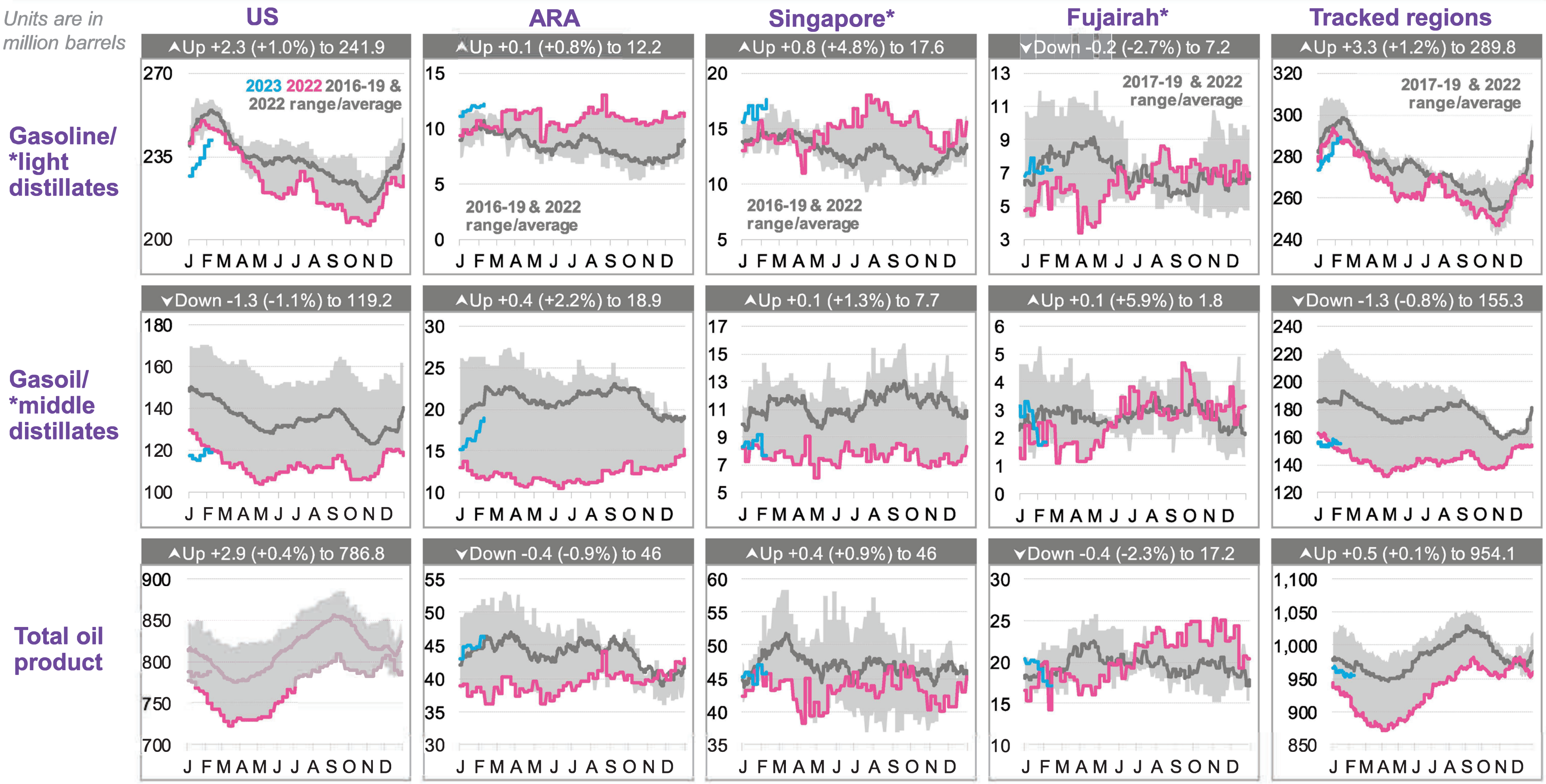


*Source: BloombergNEF, Vortexa. Note: As of the **week ending February 17, 2023**. ***Data from Vortexa are revised frequently, so the data in this report might change week-to-week.***

Product stocks: Current versus seasonal average

Neutral: Oil product stockpiles in tracked regions grew 0.1% 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.



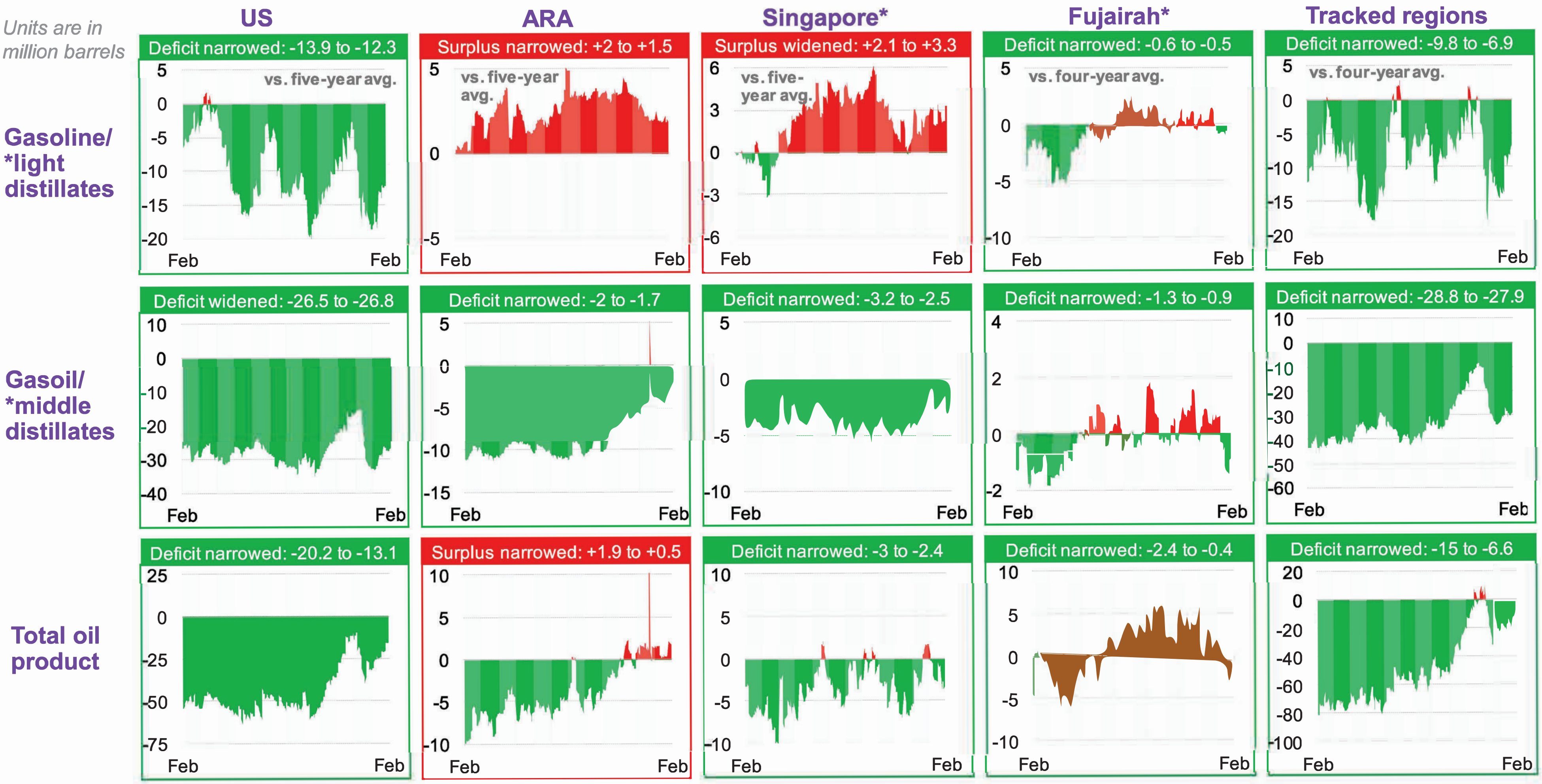
*Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ. Note: As of the week ending **February 10, 2023**. *Inventories for Singapore and Fujairah include light and middle distillates.*

Fundamentals | Financial

Product stocks: Current versus seasonal average

Bearish: Oil product stockpile deficit narrowed from 15.0m bbl to 6.6m 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 **February 10, 2023**. *Inventories for Singapore and Fujairah include light and middle distillates.

BloombergNEF

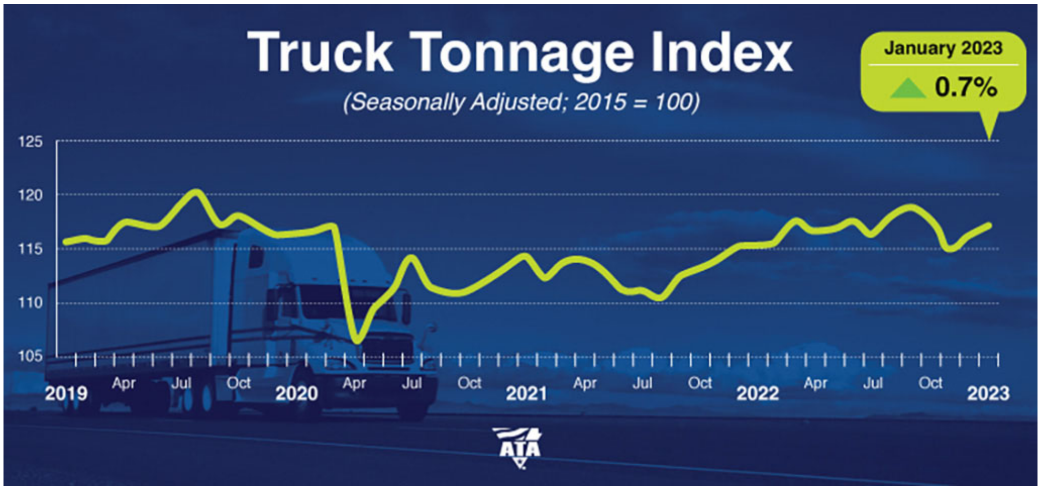
https://www.trucking.org/news-insights/ata-truck-tonnage-index-increased-07-january

ATA Truck Tonnage Index Increased 0.7% in January

Media Contact: Sean McNally

Feb 21, 2023

Washington — American Trucking Associations' advanced seasonally adjusted (SA) For-Hire Truck Tonnage Index rose 0.7% in January after increasing 1% in December. In January, the index equaled 117.1 (2015=100) compared with 116.2 in December.



ATA recently revised the seasonally adjusted index back five years as part of its annual revision.

"Tonnage has increased nicely in the last couple of months," said **ATA Chief Economist Bob Costello**. "I suspect that some of the gain is attributable to capacity coming out of the network, especially those carriers that primarily operate in the spot market and/or bought expensive used equipment in the last couple of years. This would push more freight to contract carriers, which dominate this index.

"It could also be that freight bottomed and is coming up a little too. So, the gain is likely a little higher demand and a little less supply. Despite the increases in December and January, tonnage is still off 1.4% from its recent high in September," Costello said.

Compared with January 2022, the SA index increased 1.5%, which was the seventeenth straight year-over-year gain. In December, the index was up 0.9% from a year earlier. In 2022, compared with the average in 2021, tonnage was up 3.5%.

The not seasonally adjusted index, which represents the change in tonnage actually hauled by the fleets before any seasonal adjustment, equaled 112.7 in January, 0.4% below the December level (113.2). In calculating the index, 100 represents 2015. ATA's For-Hire Truck Tonnage Index is dominated by contract freight as opposed to spot market freight.

Trucking serves as a barometer of the U.S. economy, representing 72.2% of tonnage carried by all modes of domestic freight transportation, including manufactured and retail goods. Trucks hauled 10.93 billion tons of freight in 2021. Motor carriers collected $875.5 billion, or 80.8% of total revenue earned by all transport modes.

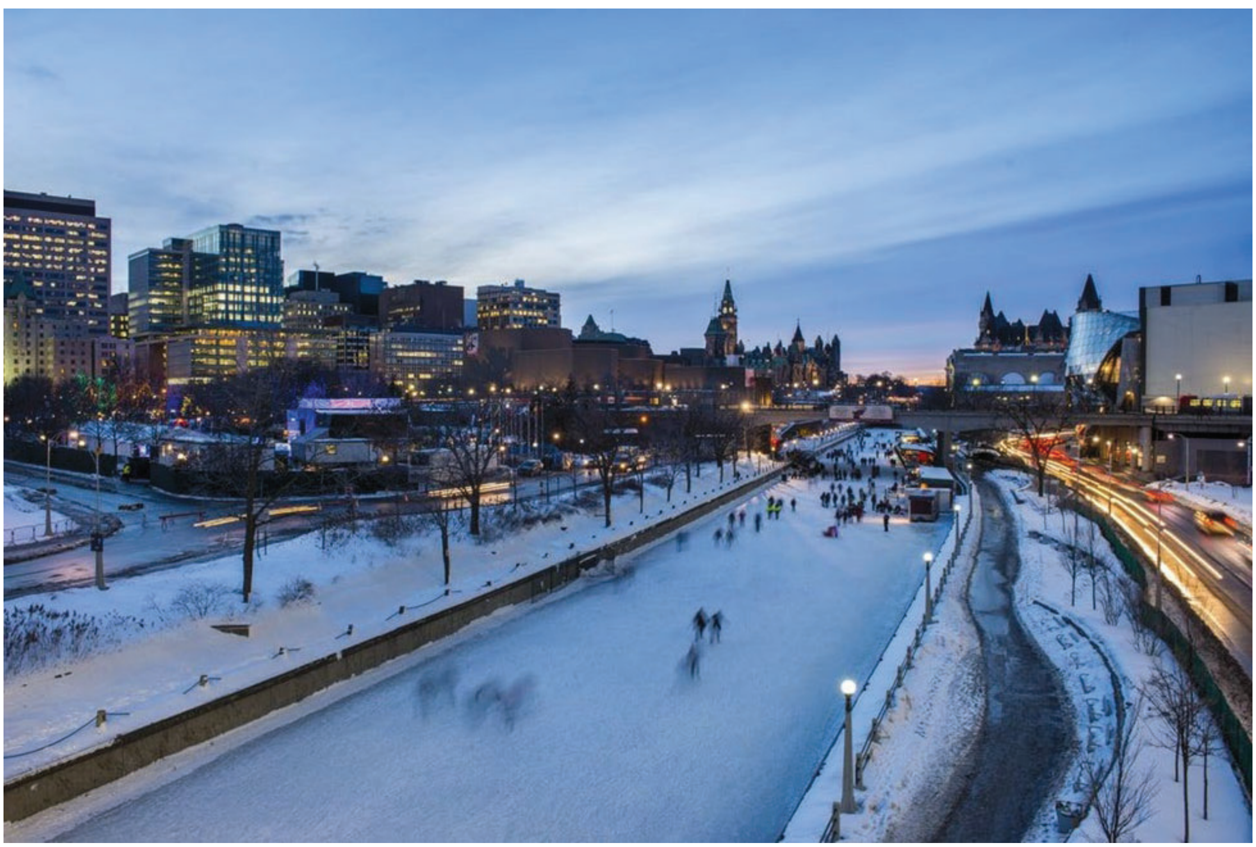
ATA calculates the tonnage index based on surveys from its membership and has been doing so since the 1970s. This is a preliminary figure and subject to change in the final report issued around the 5th day of each month. The report includes month-to-month and year-over-year results, relevant economic comparisons, and key financial indicators.

NATIONAL CAPITAL COMMISSION – STANDARDS COUNCIL OF CANADA
REPORT NUMBER: 201-10298-00

RISK ASSESSMENT OF THE EFFECTS OF CLIMATE CHANGE ON THE RIDEAU CANAL SKATEWAY

ANALYSIS AND RECOMMENDATION OPTIONS

JULY 19, 2021



EXECUTIVE SUMMARY

The Rideau Canal Skateway (the Skateway or RCS) is among one of the longest natural skating rinks in the world and has been maintained by the National Capital Commission (NCC) since 1971. Questions have started to surface regarding the long-term viability of the Rideau Canal Skateway under changing climate conditions. Warming temperatures and increased temperature variability, shorter winter seasons, and changes in winter precipitation patterns will all affect the operations, equipment, and infrastructure needed to maintain a high-quality skating surface for the longest period possible every year.

The NCC and the Standards Council of Canada (SCC) have commissioned WSP to conduct a climate change risk assessment that will define the climate change impacts on the RCS, analyse the severity of consequences and likelihood of these impacts, and propose recommendations to mitigate the greatest climate risks and increase the resilience of the RCS. The scope of this assessment includes impacts to all access, welcoming and decorative features, food and sanitary facilities, health and safety services with a focus on skating surface and ice maintenance operations. This work was involved a qualitative and quantitative desktop risk analysis, supplemented with a literature review and a water temperature and conductivity monitoring program that was conducted in February 2021 to address immediate data gaps. This report summarizes key information about the RCS under future climate conditions, the risk assessment and impact prioritization process, and potential adaptation planning and risk reduction measures.

SKATING SEASON PROJECTIONS

Analysis was conducted to explore the projected changes in skating conditions in the future under two greenhouse gas (GHG) emission scenarios. The selected scenarios were RCP4.5 (decrease in GHG emissions by the 2040s referred to as the “moderate” or stabilization scenario) and RCP8.5 (regular increase in GHG emissions until the end of the century, often referred to as the “business as usual” scenario). The main conclusions from this analysis are:

- In the next decades, under a moderate GHG emission scenario (RCP4.5), the NCC should prepare for seasons with less than 40 days of skating approximately 50% of the time;
- Winters of greater than 60 skating days are unlikely to occur in the future under both RCP scenarios;
- Under both GHG emissions scenarios, the probability of having at least 20 skating days annually is high until the 2050s, although this probability could drop below 50% in the second half of the century under a high GHG emission scenario;
- In the next decades, under a moderate GHG emission scenario, the NCC should expect to open the RCS on average, one to two weeks later than historically;
- Opening of the RCS in December is unlikely to occur in the future;
- Significant changes in the beginning of the skating season are projected to occur in the second half of the century; and
- The date of the end of the skating season is not projected to change as much as the beginning of the season. This is consistent with historical data where there were no significant trends for the last day of the season.

CLIMATE CHANGE RISK ASSESSMENT

A qualitative risk assessment was conducted following the ISO 14091 adaptation to climate change methodology to investigate the social, environmental, and economic consequences associated with the impacts of climate change on the RCS. In summary, the climate risk assessment process includes:

- Identification of relevant climate hazards and potential impacts for the RCS considering each climate hazard; and

IFIC Monthly Investment Fund Statistics – January 2023

Mutual Fund and Exchange-Traded Fund Assets and Sales

February 23, 2023 (Toronto) – The Investment Funds Institute of Canada (IFIC) today announced investment fund net sales and net assets for January 2023.

Mutual fund assets totalled $1.886 trillion at the end of January 2023. Assets increased by $77.0 billion or 4.3% compared to December 2022. Mutual funds recorded net redemptions of $477 million in January 2023.

ETF assets totalled $328.9 billion at the end of January 2023. Assets increased by $15.2 billion or 4.8% compared to December 2022. ETFs recorded net redemptions of $491 million in January 2023.

Mutual Fund Net Sales/Net Redemptions ($ Millions)*

Asset Class	Jan. 2023	Dec. 2022	Jan. 2022
Long-term Funds			
Balanced	(4,384)	(4,969)	3,095
Equity	(668)	(3,083)	2,926
Bond	3,463	(2,253)	356
Specialty	650	(37)	631
Total Long-term Funds	(940)	(10,342)	7,009
Total Money Market Funds	463	1,642	178
Total	(477)	(8,700)	7,186

Mutual Fund Net Assets ($ Billions)*

Asset Class	Jan. 2023	Dec. 2022	Jan. 2022
Long-term Funds			
Balanced	911.8	880.5	997.9
Equity	684.0	649.4	719.1
Bond	232.3	222.7	255.9
Specialty	23.0	22.1	22.4
Total Long-term Funds	1,851.0	1,774.7	1,995.2
Total Money Market Funds	35.0	34.4	26.6
Total	1,886.1	1,809.1	2,021.8

* Please see below for important information regarding this data.

ETF Net Sales/Net Redemptions ($ Millions)*

Asset Class	Jan. 2023	Dec. 2022	Jan. 2022
Long-term Funds			
Balanced	65	125	301
Equity	(383)	1,950	4,297
Bond	(940)	3,524	(269)
Specialty	492	(94)	88
Total Long-term Funds	(766)	5,504	4,417
Total Money Market Funds	275	2,172	161
Total	(491)	7,676	4,579

ETF Net Assets ($ Billions)*

Asset Class	Jan. 2023	Dec. 2022	Jan. 2022
Long-term Funds			
Balanced	12.7	12.0	12.1
Equity	206.6	194.9	206.4
Bond	81.6	80.4	79.6
Specialty	11.4	10.2	12.3
Total Long-term Funds	312.4	297.5	310.4
Total Money Market Funds	16.5	16.3	6.6
Total	328.9	313.7	317.0

* Please see below for important information regarding this data.

IFIC direct survey data (which accounts for approximately 85% of total mutual fund industry assets and approximately 83% of total ETF industry assets) is complemented by estimated data to provide comprehensive industry totals.

IFIC makes every effort to verify the accuracy, currency and completeness of the information; however, IFIC does not guarantee, warrant, represent or undertake that the information provided is correct, accurate or current.

*** Important Information Regarding Investment Fund Data:**

1. Mutual fund data is adjusted to remove double counting arising from mutual funds that invest in other mutual funds.
2. Starting with January 2022 data, ETF data is adjusted to remove double counting arising from Canadian-listed ETFs that invest in units of other Canadian-listed ETFs. Any references to IFIC ETF assets and sales figures prior to 2022 data should indicate that the data has not been adjusted for ETF of ETF double counting.
3. The Balanced Funds category includes funds that invest directly in a mix of stocks and bonds or obtain exposure through investing in other funds.
4. Mutual fund data reflects the investment activity of Canadian retail investors.
5. ETF data reflects the investment activity of Canadian retail and institutional investors.

About IFIC

The Investment Funds Institute of Canada is the voice of Canada's investment funds industry. IFIC brings together 150 organizations, including fund managers, distributors and industry service organizations, to foster a strong, stable investment sector where investors can realize their financial goals. By connecting Canada's savers to Canada's economy, our industry contributes significantly to Canadian economic growth and job creation. To learn more about IFIC, please visit www.ific.ca.

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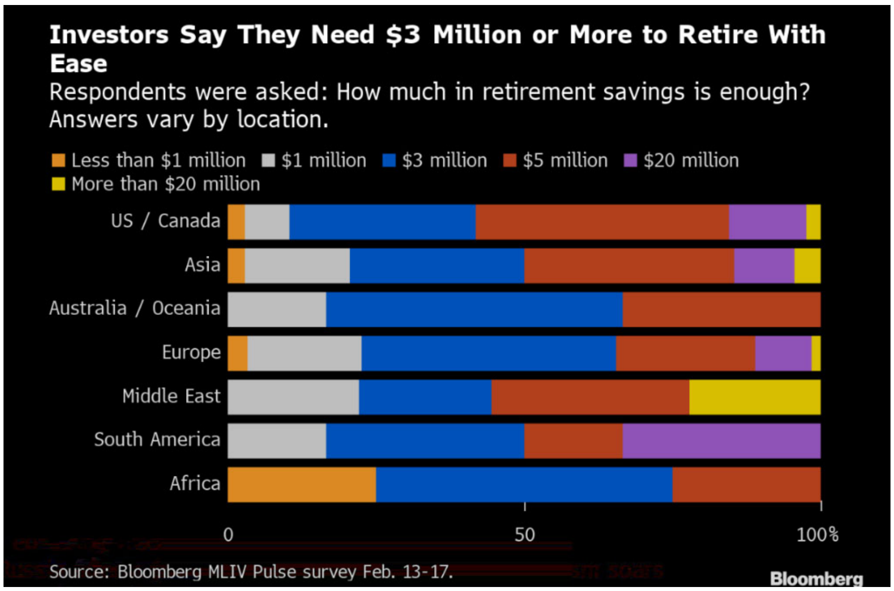
You Want $3 Million in Savings to Retire Comfortably: MLIV Pulse
2023-02-21 14:53:44.615 GMT

By Suzanne Woolley
(Bloomberg) -- It's one of the thorniest financial questions: how much is enough to retire comfortably?
The answer is somewhere between $3 million and $5 million, according to the 553 investors worldwide who shared their views in the latest MLIV Pulse survey. About a third of investors pegged it at $3 million, and roughly another third at $5 million.



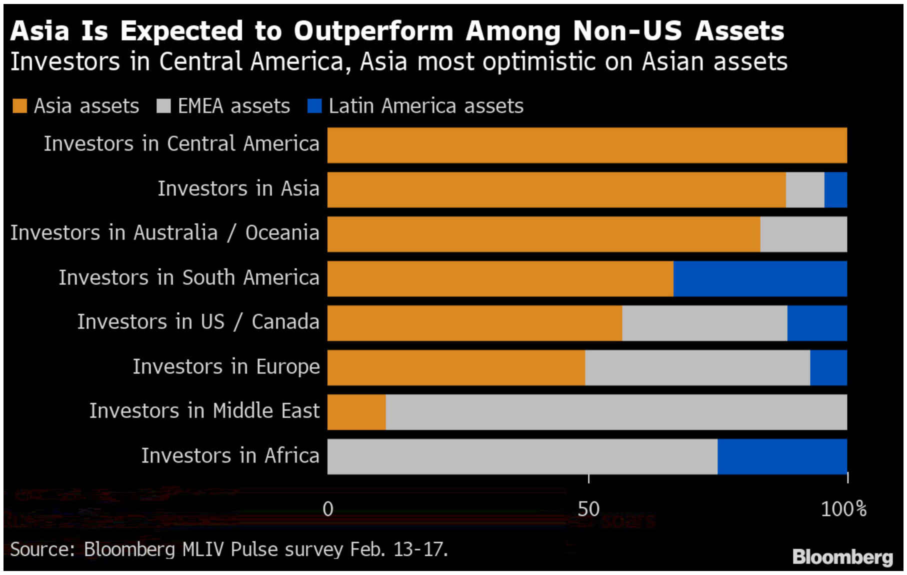
Most respondents are optimistic they'll move closer to their retirement goal by ending 2023 with more in retirement savings than at the end of 2022. Last year, inflation and rising borrowing costs hammered stocks, and since bond prices also plunged, the average US 401(k) retirement account was down 20% at plans where Vanguard Group is a recordkeeper.
This year, both professional and retail investors expect stocks and bonds to resume their traditional relationship by moving in opposite directions, with fixed-income serving as a cushion for any potential losses from riskier assets.
Respondents were not as sure about whether they'd ultimately have enough saved to maintain their lifestyle in retirement. Less than half of investors placed the odds of that at 100%.
"It's no wonder many would-be retirees are doubting the viability of their nest eggs," said Christine Benz, Morningstar's director of personal finance and retirement planning. "While inflation appears to be cooling off, it increases the amount of funds that a person needs to have in retirement."
Of course, building a seven-figure nest egg is an impossibility for many would-be retirees. Only about two-thirds of US private-sector workers had access to a workplace retirement savings plan in 2021, according to the Bureau of

Labor Statistics. The average participant account balance across the 5 million or so plans where Vanguard is a recordkeeper was $112,572 at the end of 2022, and the median balance was just $27,376.
Omny Studio: How Long Will You Have To Wait To Ret...Uncertain Outlook
That uncertainty likely also reflects the economic outlook, with corporate profits shrinking and recession a possibility later this year.
Whether the expected gain in 401(k) balances will come from investments or from contributions is unclear. A lot of retirement savings are invested in index funds that track the S&P 500 and, particularly for older savers, in actively managed equity funds heavily weighted in the benchmark index's top stocks.
During the bull run, mega-cap tech stocks like Apple Inc., Microsoft Corp., Amazon.com Inc., Alphabet Inc. and Meta Platforms Inc. came to dominate the index, leading to very concentrated investment portfolios for many savers. These stocks kicked off the year with a nice rally after a horrible 2022.
Nevertheless, investors expect those market leaders to be supplanted. Asked whether the same general group of giant tech stocks will drive the US stock market performance over the next three years, 58% said they expect new leaders to emerge.
"When five names in the S&P 500 make up more than 20% of the index, those names tend to lag the index over the next three to five years," said Bob Shea, chief investment strategist at Dynasty Financial Partners.

Read more: Where to Invest $1 Million Right Now

Non-US Assets

Shea also expects 2023 to be a year when non-US assets, particularly in Asia, begin to outperform. Asia was chosen by the highest percentage of MLIV survey respondents as the region outside the US most likely to have the best dollar-denominated returns in 2023. China's faster-than-expected reopening helped fuel a rally that started in November, but recent geopolitical tensions and concerns about the country's economic recovery have weighed on the Hang Seng China Enterprises Index, which is down about 11% from a late January peak.



Read more:
Most investors aren't adjusting their retirement plans despite the uncertain economic outlook and recent losses in their accounts. Some 56% of survey respondents said they were sticking with their retirement plans. About 8% said they are thinking about never retiring.
MLIV Pulse is a weekly survey of Bloomberg News readers on the terminal and online, conducted by Bloomberg's Markets Live team, which also runs a 24/7 MLIV blog on the terminal. To subscribe to MLIV Pulse stories, click here.
This week, the MLIV Pulse survey focuses on soft landing, hard landing and Ukraine. Click here to share your views.

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https://www.bignewsnetwork.com/news/273561520/china-single-population-to-reach-400-million

China's single population to reach 400 million

ANI

24th February 2023, 15:03 GMT+11

Beijing [China], February 23 (ANI): In the face of plummeting marriage rates and the soaring divorce rate, Chinese youths risk being unmarried for life.

According to a recent survey, unmarried young people over 30 are widespread in China. Many young men and women in cities choose to be single, while many young men in rural areas are eliminated from the marriage market, reported Sina Weibo, a Chinese microblogging website.

China's population is shrinking for the first time in more than six decades in 2022, which is a serious demographic crisis for the country with significant implications for its slowing economy, CNN Business reported.

According to China's National Bureau of Statistics (NBS), the population fell from the previous year by some 850,000 people as it recorded to 1.411 billion in the year 2022.

According to data surveyed in late January last month show that unmarried youths over the age of 30 are very common among men and women.

The survey conducted by Wuhan University covered 425 cities/counties/districts in China's 34 provincial-level administrative regions.

The survey throws some alarming reality of present-day society. There are significant differences between urban and rural single. In the urban community, it is common for young men and women to marry late; in rural society, it is common for young men to face lifelong singleness, reported Sina Weibo.

Data analysis results show that - in cities, many single young men and women are the result of active choices. An ideology that being "single" is also a good life spreads in urban and rural societies.

In county towns, although a considerable number of women in the system are willing to marry, they are single due to the lack of high-quality male resources and unwillingness to give in.

In rural areas, a considerable number of unmarried young men over 30 have already been eliminated from the marriage market and are likely to face the risk of never marrying for life, added Sina Weibo.

China's single population is to reach 400 million. In recent years, China's marriage rate has continued to decline. The marriage situation of rural youths has attracted the attention of public opinion, and the issue of "difficulty for older rural men and youths to get married" has aroused heated discussions.

According to data from the Ministry of Civil Affairs of China, the single adult population in China reached 240 million in 2018. The number of marriage registrations in 2021 was only 7.636 million, a new low since 1986.

As China's marriage rate has declined in recent years and the divorce rate has continued to rise, it is estimated that China's single population will reach 400 million in the future, reported Sina Weibo.

In the face of the soaring divorce rate, China issued a regulation last year that forces couples who want to break up to go through a 30-day "calm down period" before a final divorce in an attempt to reduce the divorce rate.

Falling marriage rates have led to a sharp drop in the birth rate, a sign of growing concern in a rapidly ageing Chinese society. Many young Chinese say they would rather not get married because jobs are getting harder to find, competition is fiercer, and the cost of living is getting out of hand.

Even if they get married, many Chinese couples prefer not to have children. The reason is that they are worried about the rising cost of education and the fact that there will be a burden on life if there are seniors and younger ones, added Sina Weibo.

Worried about a shrinking population, the Chinese government has for years introduced policies to encourage marriage and having children.

Strict family planning regulations have been revised twice in the past decade. First, it ended the decades-old "one-child" policy in 2015 and later allowed married couples to have three children.

Some cities have even come up with various incentives, such as extra vacation time for newlyweds and better maternity leave and protections for working mothers, to encourage marriage and to have children. However, since 2014, the marriage rate has declined every year. (ANI) https://www.scmp.com/economy/economic-indicators/article/3207047/china-population-2022-marks-first-population-decline-60-years

Breaking | China population: 2022 marks first decline in 60 years

- Mainland China's overall population fell to 1.4118 billion last year, as the growth rate hit negative 0.6 per thousand people
- Official results show how China's demographic crisis continues to deepen, while illustrating how widespread shifts to pronatalist policies are not producing the desired results

Luna Sun in Beijing
Published: 10:00am, 17 Jan, 2023
Why you can trust SCMP

2022 officially marked the year China saw its first population decline in six decades, with the national birth rate falling to a record low. And the deepening demographic crisis threatens far-reaching implications for China's already slowing economic growth.

China's overall population plummeted by 850,000 people – to 1.4118 billion in 2022, from 1.4126 billion a year earlier, the National Bureau of Statistics (NBS) said.

Mothers in China had 9.56 million babies last year, a 9.98 per cent drop from 10.62 million in 2021.

The national birth rate fell to a record low of 6.77 births for every 1,000 people in 2022, down from 7.52 in 2021, and marking the lowest rate since records began in 1949.

The national death rate was 7.37 per thousand last year, putting the national growth rate at negative 0.6 per thousand people.

China's population includes 31 provinces, autonomous regions and municipalities, as well as servicemen, but excludes foreigners. It does not include Hong Kong, Macau or Taiwan.

High child-rearing costs, the new generation's shifting ideologies on family and marriages, as well as the slowing economic growth amid China's draconian coronavirus policies, were all blamed for catalysing the population decline.

Population growth had been slowing since 2016, and although Beijing has resolved to reverse the trend and boost childbirths with a raft of pronatalist policy support measures, both at central and local levels, they largely failed to make a significant difference in raising people's willingness to start families and give birth, with China's population eventually coming to a decline last year.

In 2021, China eased birth restrictions to allow couples to have three children, entitling them to childcare and other benefits. And having more babies was not to be effectively punished.

As world population hits 8 billion, China frets over too few babies

Policies also shifted to pronatalism. Local governments responded by launching a variety of measures to boost birth rates, including doling out cash awards, offering housing and education discounts, giving more parental days off, better social security benefits, and other perks.

Shenzhen is among the latest cities to incentivise childbirth via cash handouts. Couples having one to three children in the city will be eligible for subsidies totalling as much as 19,000 yuan (US$2,800). But how effective these measures will be remains unclear, and maternity surveys across the country have shown that incentives remain insufficient, and that most couples are simply unwilling to have a third child.

With China's population decline, India is projected to overtake China as the world's most populous country this year, according to the United Nations.

The UN also expects China's population to drop to 1.313 billion by 2050 and fall below 800 million by 2100.

The demographic crisis arising from so few newborns, coupled with a rapidly ageing population, will undoubtedly have wide-ranging economic implications.

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