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BP expects output growth in 2023 despite delays to African LNG project

- Greater Tortue LNG startup pushed to Q1 2024
- Confirms longer-term capex, output targets
- Reports weaker-than-expected Q2 earnings

BP expects to grow its oil and gas production this year supported by four major project start-ups despite further delays to its Greater Tortue Ahmeyim (GTA) LNG project in Mauritania and Senegal, the energy major said Aug. 1.

Reporting weaker-than-expected second-quarter earnings, BP said it now expects GTA Phase 1 to start up during the first quarter of 2024, up to six months later than previously expected. GTA is one of nine major projects that BP hopes will together boost its production by 200,000 b/d of oil equivalent by 2025. The initial phase of the offshore project is expected to deliver 2.3 million mt/year of LNG. The project will eventually produce up to 10 million mt of LNG a year.

In its main upstream segment, BP reported Q2 production of 1.37 million boe/d for the quarter, 7.5% higher than the second quarter of 2022. It reported a further 903,000 boe/d of production from its gas-focused segment, which was 2.2% lower than the same period in 2022.

During the second quarter, BP started up its Mad Dog Phase 2 project in the Gulf of Mexico and the Reliance-operated KG D6-MJ project in India, which together are expected to add around 90,000 boe/d of net production by 2025. In the second half of the year, BP expects to bring online Tangguh Phase 3 in Indonesia and Seagull in the North Sea.

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Upstream oil and gas operators contract deepwater rigs for 2025-2026, as market tightens

- Rig deals now being signed for 2025-2026 work
- Contract durations are up 60% year on year
- Q2 deal inked at $500,000/d, a sum not seen in years

Deepwater driller Transocean is seeing upstream oil and natural gas operators signing up to lease its most capable rigs "well in advance" of planned drilling program start dates, indicating customer recognition of the high demand for top-tier equipment amid tightening market supply, its top executive said Aug. 1.

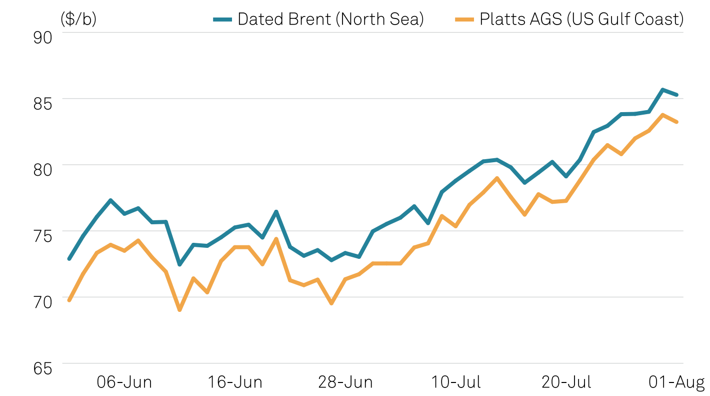
Start dates for some work now being contracted extends into late 2025 and 2026 – notably an ultradeepwater rig in the Mexican Gulf of Mexico for 1,080 days at a rate of $480,000, the driller's CEO Jeremy Thigpen said during a company second-quarter earnings conference call.

"We're undoubtedly in what appears to be a multiyear up-cycle," Thigpen said. "Our customers are both demonstrating their confidence and commitment to their projects and acknowledging the tightness of supply of high-specification floaters by securing rigs well in advance of their programs and locking them up for multiple years."

"We believe this signals our customers' recognition of the scarcity of capable high-specification assets and clearly demonstrates the strength of commitment to offshore projects, further validating that we're in an upcycle that will be of significant longevity," he said.

(continued on page 11)

Benchmark S&P Global Platts spot crude prices



Source: S&P Global Commodity Insights

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Asia Pacific

India middle distillates output slips 3% on month in June

- Production over January-June up 3.99% on year
- Gasoil output falls below 10 million mt

Indian refiners produced 11.22 million mt of middle distillates in June, down 3.36% month on month but up 3.48% on the year, latest preliminary data from the Petroleum Planning and Analysis Cell showed, with production volumes of gasoil, jet fuel and kerosene all posting month-on-month declines.

Combined gasoil, jet fuel and kerosene output totaled 67.98 million mt over January-June, rising 3.99% compared to the same period last year.

Gasoil production fell 3.2% on the month to 9.76 million mt in June, while jet fuel/kerosene output was 4.38% lower at 1.46 million mt.

Over January-June, gasoil output inched up 1.58% to 59.15 million mt, while jet fuel/kerosene production was 23.65% higher at 8.82 million mt.

The decline in June output came despite a rise in gasoil and jet fuel crack spreads that typically incentivize refiners to increase production, but market sources said this could have been offset by refinery maintenance scheduled during the month.

In its Global Refining Outlook report released late-June, S&P Global Commodity Insights said India and the rest of South Asia are expected to see crude distillation unit outages and run cuts totaling 144,000b/d in June.

“Outages in June are higher by 11,000 b/d compared to last month as refineries in India continue with their planned shutdowns,” the report said, adding that “South Asia refinery outages are expected to increase by 113,000 b/d in July, to 257,000 b/d.”

“Outages in India are higher during the July-September period as this is the typical turnaround season in India following the low demand period owing to monsoons,” the report said.

The Platts FOB Singapore 10 ppm sulfur gasoil derivatives crack against front-month Dubai swap averaged $16.93/b in June, rising $1.98/b or 13.4% from May when it averaged $14.95/b, , S&P Global data showed. The FOB Singapore jet fuel/kerosene swap crack spread averaged $15.79/b in June, up from an average of $14.11/b in May, gaining $1.68/b, or 11.91%.

— Clarice Chiam, Amy Tan, Ernest Puey

Europe, Middle East and Africa

Sanctions deal fresh blow to coup-hit Niger’s emerging oil sector

- Ecowas measures ban transactions, freeze assets
- Niger-Benin pipeline construction could halt: expert
- Oil-rich country looking to quintuple crude output

Severe sanctions imposed on post-coup Niger by West African bloc Ecowas could halt construction of the Niger-Benin pipeline and activities by state energy company Sonidep, just as the emerging oil producer looks to quintuple crude output.

At an emergency summit in neighboring Nigeria on July 30, West African nations imposed sanctions on Niger and threatened the use of force if military leaders fail to reinstate ousted president Mohamed Bazoum within a week.

It came days after the presidential guard detained Bazoum in his residence July 26 and announced his ouster on state television, claiming the government’s lack of progress in battling a yearslong Islamist insurgency had compelled them to act.

Abdourahamane Tchiani, head of Niger’s presidential guard, says he is now the country’s leader.

However, amid fears that chaos in Niger – a longstanding Western ally and security partner – could further destabilize the wider region, which has seen seven coups in three years, the West African Economic and Monetary Union said that with immediate effect borders with Niger would be closed, commercial flights banned, business halted, national assets frozen and aid ended.

Aneliese Bernard — director of Strategic Stabilization Advisors, a Washington DC-based consultancy focused on security issues, and a former State Department official — said the economic measures, in particular suspension of commercial and financial transactions, freezing of assets of public companies and suspension of bank operations would impact the country’s emerging oil sector.

“Especially the Niger-Benin pipeline and Sonidep operations, this could halt all of that,” she told S&P Global Commodity Insights.

Output boost

Niger – which is also the world’s seventh-largest uranium producer – is on the cusp of an oil production boost, with the 110,000 b/d Niger-Benin pipeline 75% complete, according to Bazoum’s government.

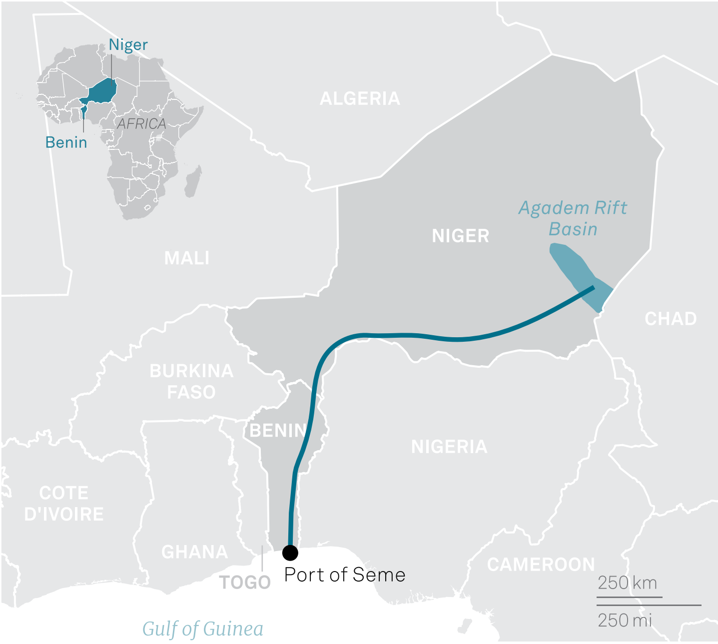
The country has an estimated one billion barrels of crude reserves and currently produces around 20,000 b/d, most of it from China National Petroleum Corp projects in the Agadem Rift Basin. However, with no export route, Niger’s oil is used locally or transported by road to Nigeria.

The CNPC-built pipeline, which will link Koulele in Niger to the Benin port of Seme, should therefore transform the country into a significant regional oil producer and exporter. A concerned industry source said last week that the pipeline would be a “game changer” for Niger, which is one of the world’s poorest countries.

London-listed Savannah Energy, the only Western oil company in Niger, is also planning to add crude production at its R3 East development in the coming quarters, starting with 1,500 b/d and ramping up to 5,000 b/d. The company, which declined to comment, has identified 163 exploration targets in its acreage.

“The companies invested in oil and Uranium might face increasing obstacles to preserving their operations, but these businesses have also weathered coups in Niger in the past, as this was the 5th coup since Niger's independence in 1960; the last coup was in 2010," Bernard told S&P Global July 28.

Niger-Benin pipeline to overhaul Niger oil sector



Source: Savannah Energy, S&P Global Commodity Insights

As well as Ecowas, the coup has been criticized by the African Union, EU, US and colonial power France.

However, Yevgeny Progozhin, the head of Russia's Wagner mercenary group, which deployed operatives in Mali following that country's coup in 2020, cheered the Niger rebellion and offered his fighters' services. There is no evidence of Russian involvement in Bazoum's overthrow.

— Charlie Mitchell

INTERVIEW: Afentra CEO eyes 'conveyor belt of deals' as majors retreat from mature African basins

- Company buying assets for responsible energy transition
- Net production to hit 6,000 b/d after Angola acquisitions
- Africa, North Sea experience Afentra's 'selling point'

Afentra, the West Africa-focused independent, is looking to sign a "conveyor belt of deals" in multiple countries to ensure a "responsible" African energy transition, CEO Paul McDade told S&P Global Commodity Insights after penning a complex multi-party agreement to establish a foothold in Angola.

McDade, who previously ran Tullow Oil, led a takeover of Sterling Energy in 2021 and rebranded it Afentra — short for Africa Energy Transition — to support the exit strategies of majors like ExxonMobil and TotalEnergies and guide African countries through the transition.

Recent trends in Angola, Equatorial Guinea and Nigeria mirror activity in the North Sea two decades ago, when smaller companies bought assets from retreating majors, McDade argues. As majors look to scale back carbon emissions, the social and governance aspects of ESG risk being overlooked, he claims.

"We're chasing production assets in West Africa, really the mantra being operated [and] non-operated mature assets, and us bringing our African experience, combined with having been through this industrial phase in the North Sea," he said in a wide-ranging interview. "We're really very cognizant of the energy transition. Africa needs to produce this oil and gas, in my view, therefore they need to produce it cleanly."

Afentra finds itself in a strong position in the aftermath of the Ukraine war, with discussions around the energy transition now "more pragmatic and sensible," McDade said. "I was trying to convince investors in May 2021, oil and gas is around to stay for a long time, this transition is going to take a long time. And if it's going to take a long time then better get responsible at producing oil and gas," he said. "Post Ukraine those principles became normal."

Conveyor belt

To that end, Afentra's core missions include rapidly building a portfolio of producing assets and proven resources, building on a strong track record in Africa, and facilitating a responsible energy transition.

"This is a medium-term game, it's not one deal and that's it. It's about a conveyor belt of deals — and we've got to be selective," McDade said. "We're looking at lots of things... We might miss some things, we might choose not to do them because the value is not right, but there will be plenty."

The company's "selling point" is merging technical and operating experience acquired over decades at Tullow and in the North Sea, and the ability "to navigate the above-ground and the ministries and the national companies and build relationships and leverage those," he said.

Underinvestment has hit Angolan oil output in recent years

Source: Platts OPEC Survey

In addition to Angola, the company has a stake in a wildcat play in Somaliland, the breakaway region of Somalia, which is operated by Genel. Drilling is ongoing in a nearby block and that will dictate whether Afentra retains its position or decides "at some point [to] farm down our interest," since the company is not interested in spending exploration dollars, McDade said.

Afentra is also keen to stop flaring, including in Angola by potentially exporting LNG from its gassy Punja discovery. "If we can stop flaring… then actually we're having a positive incremental benefit from an emissions and energy transition point of view," McDade said, summarizing his pitch to shareholders.

Accretive deal

Blocks 3/05 and 3/05A in the Lower Congo Basin offshore Angola, the company's first major acquisitions, "fitted in really well" to the strategy, McDade said. "Big fields, 2 billion barrels in place, mature. Production has declined but there's a lot of untapped potential." State-owned Sonangol took over 3/05 from TotalEnergies a decade ago but has not developed the asset. 3/05A meanwhile has production potential close to infrastructure.

Following completion, expected in Q4 2023, Afentra's interest acquisitions from Croatia's INA, BP-Eni venture Azule and Sonangol will give it an operating interest of 30% in 3/05 and 21.33% in 3/05A, equivalent to roughly 6,000 b/d of production, with the blocks producing 19,100 b/d and 1,200 b/d respectively at the moment.

The deals were "a bit tricky to coordinate," McDade said, but offer a "balanced equity position for all parties", are very accretive, did not require raising any equity, come with over a year of cashflow from the assets, and have contingencies, with Afentra protected in case of low oil prices — although McDade said he is "quite bullish" on prices in the medium term.

"We see opportunities for ESPs [electric submersible pumps], infill drilling, water injections really improving. Just all the classic things you'd be doing with an old mature field to offset decline and boost production," he said. "We think this asset with the fullness of time, between 3/05 and 3/05A has got the potential to go up to even as high as 30,000 b/d."

Angola's government, he added, is "using Afentra as an example [that] you can be a small, medium-sized company and you're now very welcome." The West African country, which is struggling to reverse a sharp production decline in recent years due partly to underinvestment, accepts that it needs to be open to smaller companies and make its blocks commercially attractive, McDade said. "My view is that they are doing both."

According to estimates, some 15 billion barrels of Angola's reserves are still to be produced, while majors like ExxonMobil and TotalEnergies are shifting towards wildcat plays in Namibia and Guyana, and less carbon intensive projects. Afentra is keen to rapidly build its portfolio, although McDade concedes it is starting from a modest base. "I'm impatient, I want to push on," he said. "People tell me you're only two years in and that's not a bad start, but we will grow."

— Charlie Mitchell

Norway to introduce 6% biofuel mandate for domestic shipping

- Nordic country's new mandate to take effect from October
- RED-compliant HVO, FAME deemed as compliant fuels
- Norway has been pushing for green shipping regulations

Norway will require bunker suppliers to have at least 6% of their sales in domestic shipping from advanced biofuels from October, the government said Aug. 1 as it continues its push for a greener ship fuel.

In an emailed statement to S&P Global Commodity Insights, the Norwegian Environment Agency said suppliers need to use hydrotreated vegetable oil and fatty acid methyl ester that meet the EU Renewable Energy Directive's sustainability criteria to stay compliant.

Each supplier can determine its own blending ratio in fuel deliveries as long as it can ensure 6% from its total sales are attributed to HVO or FAME, according to the government agency. Bio-methane is not covered by the upcoming regulation.

Norway's biofuel mandate is expected to affect the bunker mix of passenger ships, coastal cargo carriers and offshore supply vessels in the Norwegian Continental Shelf.

Total deliveries of petroleum products to the Norwegian water transportation sector, including bio-blends, rose to 442 million liters in 2022 from 422 million liters in the previous year, according to government data from Statistics Norway. Marine gasoil and diesel deliveries rose to 384 million liters from 349 million liters.

For pure biofuels, total deliveries jumped to 3.11 million liters in 2022 from 1.16 million liters in 2021.

Biofuels have become a popular choice among shipowners looking to decarbonize their operations in recent quarters, providing a "drop-in" solution that requires little to no retrofitting of vessels.

In its reference case, S&P Global expects biofuels to account for 6.2% of global low-carbon bunker supplies in 2030.

Aside from the biofuel regulation, the Norwegian government has said it is studying a new Emissions Control Area to promote green shipping.

The existing North Sea ECA, where sulfur limits for marine fuels are 0.1%, covers part of Norwegian waters and the world heritage fjords in western Norway. The government separately plans to ban ships emitting greenhouse gas emissions from the fjords from 2026.

— Max Lin

The Americas

US' Enterprise Products maintains bullish crude oil outlook for balance of 2023

- Demand to tighten supply in H2 2023
- July crude exports to exceed 30 million barrels
- SPOT to see final investment decision in Q3

Enterprise anticipates a bullish remainder of the year as their demand outlook called for a tight H2 2023 and expanded their export capacity as a result, meanwhile drilling and completions activity in the Permian and gassy Haynesville Shale remained efficient, executives said Aug. 1.

"Even though industrial demand continues to lag, consumer demand is strong, especially in developed nations," co-CEO Jim Teague said in the earnings call. "Crude oil demand fundamentals continue to indicate that we're in store for much tighter balances in 2024."

Enterprise's net income of $1.3 billion in Q2 2023 was just shy of the year-ago period during the second quarter of 2022 at $1.4 billion, driven by the impact of a low price and lower margin environment for crude and natural gas.

"Oil and gas has faced commodity price headwinds, especially compared to the premiums of last year when crude averaged over $100 a barrel," Teague said.

Despite the decline, the company saw a record 11.9 million barrels of oil equivalent of total pipeline volumes during the quarter led by growth on the expanded Midland-to-ECHO (Enterprise crude Houston) pipeline system.

Of that, total crude oil pipeline transportation volumes increased 8% to 2.4 million b/d for Q2 2023 compared to Q2 2022, while total marine volumes were 814,000 b/d for Q2 2023 compared to 777,000 b/d for the same quarter last year.

As for exports, Enterprise expects July crude exports to exceed 30 million barrels with demand expected to increase over a tight supply environment.

Expanding export capacity remains a priority ahead of the third quarter, with the company's planned deepwater crude-exporting terminal offshore of the Houston Ship Channel, the Seaport Oil Terminal, expected to see a final investment decision as soon as September or October, Teague said.

Production efficiency

Looking to the Permian basin and Haynesville shale, the company maintained a bullish outlook regarding growth.

Several producers, including Chevron, ExxonMobil, and Ovintiv, have said they also see Permian Basin production rising down the road.

Meanwhile, the Haynesville Shale will also see expansion projects going forward as the extension is full and gas is continuing to be produced, Natalie Gayden, senior vice president of natural gas said.

Enterprise executives also noted that producers were continuing to see significant drilling and completions efficiencies.

The resulting cost mitigations led producers to foresee some amount of deflation on costs, adding that longer laterals were key.

However, top executives of US land drillers Patterson-UTI and Helmerich & Payne said in separate earnings calls July 27 they see the domestic rig count reversing toward year-end as activity picks up from expectations of a clearer macro-outlook.

The company also shared greater interest in transporting energy products to Houston as the Corpus Christi, Texas pipelines were full.

— Binish Azhar

Canada's Gibson to add two 435,000-barrel crude storage tanks at Edmonton

- To add over 1.5 million of new storage at Texas crude terminal
- New Edmonton tanks to be commissioned Q4 2023

Gibson Energy has signed an agreement with Cenovus Energy to build two crude oil storage tanks at Edmonton — each of capacity 435,000 barrels — to facilitate the producer's target to ship more barrels on the Trans Mountain Expansion pipeline in Western Canada, a senior official of the midstream company said Aug. 1.

"Additional storage has been contracted at our Edmonton terminal, and they underpinned by 15-year take or pay contracts," CEO Steve Spaulding said during Gibson's earnings call.

In service in late 2024

The two tanks are expected to be placed into service in late 2024 and will come on the back of Gibson commissioning in the fourth quarter of 2023 another tank of capacity 435,000 barrels at Edmonton, Spaulding said without identifying the customer.

TMX is due for startup in early 2024 and will move 590,000 b/d from Edmonton to the marine terminal at Burnaby in British Columbia on the Canadian Pacific coast.

Gibson has crude oil capacity of 13.5 million barrels at Hardisty and 1.7 million barrels at Edmonton, according to information on the company website.

Alberta's crude oil storage capacity is estimated to be 75 million to 78 million barrels, Vijay Muralidharan, director of R-Cube Economic Consulting, said separately Aug. 1, adding that the facilities are at Edmonton, Hardisty, Kerrobert and the Alberta industrial heartland area.

The building of additional midstream infrastructure, particularly storage tanks, in Western Canada comes with the changes in the WTI and Western Canadian Select price differentials in the last quarter compared with Q1 2023.

WCS at Nederland, Texas, was assessed by Platts at a $4.60/b discount to WTI July 31, narrowing from a $5.85/b discount July 26. Platts is part of S&P Global Commodity Insights.

Adding facilities at Texas terminal

In Texas, where Gibson unveiled in June a $1.1 billion acquisition of the South Texas Gateway Terminal, the company is putting together a plan for organic growth that could see capital being deployed early next year, Spaulding said.

"STGT is in Ingleside at the Port of Corpus Christi and enhances our existing infrastructure position across North America including Hardisty and Edmonton and provides us with a new platform for growth that is connected to the prolific Permian Basin," he said. "The terminal is strategically advantaged as one of the only two terminals in Texas with the ability to load VLCC."

The other terminal is the Enbridge Ingleside Energy Center.

Permian Basin oil production has swelled more than 1 million b/d since 2020 to a current 5.5 million b/d, according to S&P Global Commodity Insights data, although the pace of growth has slowed a bit recently. For example, the Permian added about 500,000 b/d in 2022 compared with the previous year, averaging 5.215 million b/d. In 2023, it is expected to average 5.783 million b/d.

STGT is underpinned by take or pay contracts with investment grade shippers and Gibson's target is to add additional tankage and pipeline connectivity, he said,.

With a permitted throughput capacity of 1 million b/d, the terminal is tied to the Gray Oak, Cactus II and the EPIC pipelines that run from the Permian Basin and the Harvest pipeline that connects to the Eagle Ford Basin. The pipelines in total provide a connectivity of up to 2.7 million b/d of Texas crude, he said.

The crude export terminal was officially placed into service and loaded its first vessel in July 2020. It has a total crude storage capacity of 8.6 million barrels in 20 tanks with two deep-water docks that enable the simultaneous loading of two VLCCs, according to information on Gibson's website.

Less congestion

The Port of Corpus Christi is also less congested compared with other US ports and offers the flexibility of Aframax and VLCC loadings, Spaulding said.

"We expect the acquisition of STGT to close in the very, very near term," Spaulding said without setting a deadline.

Gibson is the second Canadian midstream player to acquire a USGC crude export terminal in Texas. In October 2021, Enbridge acquired the Ingleside Energy Center, also at the Port of Corpus Christi.

— Ashok Dutta

BRAZIL DATA: June oil, gas production jumps to fresh record high

- Reaches 4.324 mil boe/d
- Tops record set in Feb
- New FPSOs at Buzios, Marlim

Brazil's crude oil and natural gas production set a fresh record high in June, jumping 18.0% year on year to more than 4.3 million b/d of oil equivalent for the first time ever as production ramped up at recently installed offshore floating production units, the country's National Petroleum Agency, or ANP, said Aug. 1.

Oil companies operating in Brazil pumped 4.324 million boe/d in June, up from 3.664 million boe/d in June 2022, the ANP said in its latest production report. That topped the previous record of 4.183 million boe/d set in February. June's production also advanced 1.8% from 4.11 million boe/d in May.

The latest surge in production came after state-led oil company Petrobras and its partners pumped first oil from two new floating production, storage and offloading vessels, or FPSOs, installed at the Marlim and Buzios fields in May. The FPSO P-71 also pumped first oil from the Itapu subsalt field in December. The vessels were expected to increase output as onboard operations were ramped up to full capacity through the remainder of 2023, according to Petrobras.

The FPSO Anna Nery, which was the first of two vessels that will be installed at the Marlim complex of heavy oil fields in 2023 as part of a revitalization campaign, pumped first oil from Marlim on May 7, according to Petrobras. The FPSO has installed capacity of 70,000 b/d and 4 million cu m/d.

The FPSO Anita Garibaldi, which is already anchored at the offshore complex, will pump first oil in the second half of 2023, according to Petrobras. The FPSO has installed capacity of 80,000 b/d and 3 million cu m/d.

Petrobras also installed the FPSO Almirante Barroso at the Buzios subsalt field on May 31. The FPSO, which was the fifth installed at the field, has installed capacity to produce 150,000 b/d and 6 million cu m/d.

Crude oil production also rose to a record 3.367 million barrels in June, from 2.829 million barrels in June 2022, the ANP said. That topped the previous record for oil output of 3.274 million b/d set in January. June's oil output also climbed 5.2% from May's 3.201 million b/d.

Subsalt fields continued to dominate Brazil's production profile, accounting for 75% of total output in June, the ANP said. Subsalt fields produced 2.553 million b/d and 109.8 million cu m/d, or about 3.243 million boe/d, from 142 wells in June. That was up from 2.51 million b/d and 109.2 million cu m/d, or 3.196 million boe/d, from 144 wells in May.

The Tupi field, which was formerly known as Lula, remained the country's top oil and gas producer in June, the ANP said. Tupi produced 790,005 b/d and 37.8 million cu m/d. The FPSO Guanabara, which is installed at the Mero field, was the top production platform in June, pumping 177,029 b/d and 11.4 million cu m/d.

In addition to the FPSO Anita Garibaldi, Petrobras also plans to install a second floating production unit at the Mero field in the Libra production sharing area in the second half of 2023. The FPSO Sepetiba will be one of Brazil's largest floating production units, capable of producing 180,000 b/d and processing up to 12 million cu m/d, according to Petrobras.

Gas production record

Natural gas production also reached a fresh record high on the end of maintenance work and new FPSOs, according to the ANP. Gas output is expected to soar to greater heights in 2024, when the long-delayed Route 3 pipeline and GasLub Itaborai natural gas processing facility are expected to enter operations.

The Route 3 pipeline will boost offshore gas-export capacity, especially from subsalt fields in the Campos and Santos basins, by 21 million cu m/d.

Brazil produced 152.3 million cu m/d in June, a 14.6% increase from 132.9 million cu m/d in June 2022, the ANP said. That topped the previous record of 148.8 million cu m/d set in October 2022. June's gas output also rose 5.5% from May's 144.4 million cu m/d.

Oil companies injected 77.9 million cu m/d in June, with 54.7 million cu m/d available for commercial sale, the ANP said. Oil companies also flared, or burned off, 4.6 million cu m/d in June.

Petrobras was the country's largest oil and gas producer by concession stakes in June, pumping 2.119 million b/d and 98.7 million cu m/d, the ANP said. Shell was second at 381,811 b/d and 17.3 million cu m/d, while TotalEnergies was third at 141,674 b/d and 4.4 million cu m/d.

— Jeff Fick

BRAZIL DATA: June crude oil exports climb 8.6% on latest production record

- June oil output at record high
- 9.2% export tax ended June 30
- Product exports, imports lower

Brazilian oil exports advanced 8.6% year on year in June on record output from Latin America's biggest producer and the pending end of a temporary tax on overseas oil shipments, the country's National Petroleum Agency, or ANP, said Aug. 1.

Brazil shipped 44.020 million barrels of crude overseas in June, up from 40.546 million barrels in June 2022, the ANP said. June's oil exports, however, retreated 15.9% from 52.351 million barrels.

In the first half of 2023, Brazil boosted oil exports 23.8% year on year to 270.4 million barrels, the ANP said.

The upswing in oil exports came as Brazil once again set a fresh production record for oil in June, with recently installed floating production units ramping up output during the month, according to the ANP. Oil companies operating in Brazil pumped a record 3.367 million b/d in June, topping the previous record of 3.274 million b/d set in January.

State-led oil company Petrobras and its development partners started operations onboard the FPSO P-71 installed at the Itapu field in December 2022, while the first oil was pumped in May from the FPSO Anna Nery installed at the Marlim complex of heavy oil fields and the FPSO Almirante Barroso installed at the Buzios subsalt field.

The export surge also came ahead of the expiration of a temporary, 9.2% tariff on oil exports that was implemented March 1. The export tax, which was retired as expected on June 30, was aimed at making up for a revenue shortfall after Brazil partially restored federal fuel taxes earlier in 2023.

The tax, however, has had little impact on oil exports amid strong global demand for Brazil light and heavy grades, which are prized by global refiners for low sulfur content, according to industry officials.

The latest jump in crude exports, however, came amid a recent strategy shift at Petrobras that could undermine shipments through the remainder of 2023, industry officials say. In May, Petrobras ended its use of import-parity pricing and increased its focus on supplying the domestic market.

Petrobras also has dramatically increased domestic crude oil processing in 2023, with refineries operating at 93% of installed capacity in the second quarter. That was up from 89% in the year-ago period and 85% in the first quarter. The government wants Petrobras to increase domestic crude processing and pass along the savings to consumers at the pump.

Crude oil imports, meanwhile, broadly retreated in June, the ANP data showed. Oil imports have recently turned upward after trending lower since 2013, when growing output of high-quality light oil from the subsalt reduced Brazil's need for blending grades. Brazil typically imports light grades and condensates used for blending and lubricants production.

Brazil imported 6.197 million barrels of crude in June, down 25.9% from 8.36 million barrels in June 2022, the ANP said. June's oil imports also fell 30.8% from 8.954 million barrels in May.

Oil imports, however, remained 35.2% higher year on year in the first six months of 2023 at 55.4 million barrels, the ANP said.

Product exports retreat

Refined product exports also retreated broadly in June amid the renewed focus on domestic markets, although overseas shipments continued to be led by exports of low-sulfur fuel oil and bunker fuel, the ANP data showed.

Brazil exported 8.709 million barrels of refined products in June, down 9.5% from 9.621 million barrels in June 2022, the ANP said. June's refined product exports also fell 51.2% from May's 17.847 million barrels. Bunker fuel and fuel oil shipments led the decline, falling 24.6% year on year to 5.907 million barrels in June. June's bunker fuel and fuel oil exports also sank 59.6% from May's 14.615 million barrels.

Refined product imports, meanwhile, were mixed in June, the ANP data showed. Imports advanced 19.6% in June to 16.842 million barrels, up from 14.083 million barrels in June 2022, the ANP said. June's refined product imports, however, fell 16.6% from May's 20.183 million barrels.

— Jeff Fick

Markets and Data

US plays down need for Russian oil price cap revision as Urals crude tops $60/b

- Priority is still to hurt Moscow's oil revenues: official
- Urals FOB Primorsk last assessed at $69.78/b
- No formal agreement to regularly amend oil price cap

The US-led G7 coalition is in no rush to revise its $60/b price cap on Russian crude exports even as the value of Moscow's key export crude continues to climb above circling helped by a growing fleet of gray market tankers to move the oil, a senior US administration official said Aug.1.

Russia's flagship crude export grade, Urals, began selling above $60/b for the first time since the G7 + EU coalition rolled out its price cap on Moscow's oil on July 12.

Designed to keep Russian oil flowing into global markets while curbing Moscow's ability to fund its war in Ukraine, G7 restrictions on shipping Russian crude bought for more than $60/b came into effect on Dec. 5, 2022. The price cap targets the provision of shipping insurance and other maritime services for cargoes of Russian crude acquired at the port of loading (FOB) at values over $60/b.

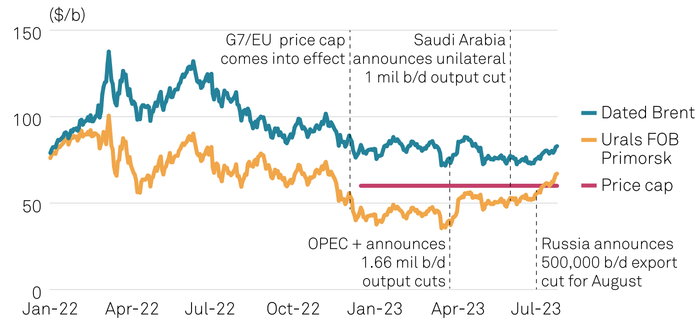
"The way we set the price cap is really focused on maintaining an incentive for Putin to produce while continuing to limit his revenue relative to the market," the US official told reporters in a London briefing. "We do not view the cap as something that's supposed to move in lockstep with market prices... so we're going to be hesitant to change that in response to market fluctuations generally but the intersection of global markets and this trade is something we're paying close attention to in the coalition."

The price of Russia's medium sour Urals crude averaged $64.37/b in July, up $9.09/b on the month but down from $78.41/b in July 2022, Russian finance ministry data released Aug. 1 showed. Pulled up by rising global oil prices, Platts last assessed Urals FOB Primorsk at $69.78/b on July 31, the highest since November 2022. Platts is part of S&P Global Commodity Insights.

But Urals has also recovered in value relative to Dated Brent as Russia continues to find willing buyers for its oil in China, India and Turkey. The current Urals price marks a significant shrinking of the discount to Dated Brent from up to $40/b in mid-2022 to $15.70/b, the lowest since March, 2022 in the weeks after Moscow's invasion of Ukraine.

"When the non-G7 shipping capacity expands, as it has over the last seven months, we would expect the discount to narrow and that has absolutely occurred," the official said. "The structure of the market is such that the capacity is not there for Putin do to all his oil trade outside the G7. Even if that share of G7 services narrows, there's going to be sufficient market power and influence there to keep prices lower for the buyers wherever they are."

Urals rises above $60/b price cap



Source: S&P Global Commodity Insights

Revision mechanism

According to the initial price cap agreement, the cap levels can be amended by the G7's Price Cap Coalition every two months to respond to developments in the market. It will be set at least 5% below the average market price for Russian oil and petroleum products, calculated on the basis of data provided by the International Energy Agency. Where a price cap level is amended, there is wind-down period of ninety days for the maritime-related services and the maritime transport of Russian crude oil and petroleum products.

The US official played down the scheduled amendment mechanism for the cap, however, saying "We never formally agreed to a periodic mechanism of every couple of months. There was an initial agreement for a formal review a few months after implementation."

The EU did not respond to requests for comment on whether the European Council has been discussing a revision to the existing price cap.

The US official said the conversations within the Price Cap Coalition are "ongoing regularly over whether the cap is at the appropriate level."

The focus, however. remains whether Moscow's oil revenues are continuing to suffer from the mechanism compared to the open oil market prices, he said.

"The average price cap has been overplayed in the market," he said. "Even if there is some non-G7 Urals oil trade above $60/b/ that means that the average will be above $60/b...just the fact that the average Urals price has passed above $60/b we don't think is a particularly important milestone. I think that's kind of what we expect when global oil prices do that."

Urals values have been lifted along with other medium sour crude grades after Saudi Arabia and Russia pledged to slash their crude output by 1 million b/d and exports by 500,000 b/d respectively in August. An ongoing impasse between Turkey and Iraq blocking some 450,000 b/d of sour Kurdish crude flow via Ceyhan is supporting sour crude values.

Discounts for Russian Urals crude delivered to the West Coast of India have also been narrowing in recent weeks. The margin between Urals crude delivered to the West Coast of India and Dated Brent narrowed to $6.98/b on Aug 3, according to Platts assessments, down from a peak of $18.80/b soon after Platts began assessing the value in mid-January.

— Robert Perkins

BP's Looney sees case for 'strong' oil prices in coming years

- Expects higher price volatility to be bullish for trading results
- Demand growth, OPEC+ discipline supportive of oil prices
- S&P Global sees Dated Brent averaging $83/b in mid-2024

Global oil prices will likely be supported by growing demand, greater OPEC+ discipline, and slowing US output growth in the short and medium term, BP CEO Bernard Looney said Aug. 1.

Despite lingering concerns about the speed of China's economic rebound from COVID-19 and risks to global growth from high interest rates, Looney said he expects to see oil demand growth of more than 2 million b/d this year with well over 1 million b/d of demand growth in 2024.

Looney also noted that US rig counts have fallen from year-ago levels, while OPEC+ appears to be set on supporting oil prices, with unilateral production cuts by Saudi Arabia and Russia.

"I can create a very strong case for oil," Looney told analysts on a quarterly earnings call. "OPEC+ remains exceptionally disciplined if not increasingly disciplined and shows no sign of changing that. You also look at the US where I think the rig count has fallen to the lowest level now since February of last year... so I can create there a situation where you describe the outlook for oil prices to be strong over the coming months and years."

His comments come a day after Goldman Sachs said it continues to forecast that Brent crude futures will rise further to hit $93/b by mid-2024, as supply deficits from record oil demand and Saudi supply cuts are tempered by high OPEC capacity and expected US shale growth.

Brent crude futures were trading at $84.96/b at 1215 GMT Aug. 1, up about $13, or 18%, since the end of June. Analysts at S&P Global Commodity Insights currently forecast Dated Brent to average $83/b in July 2024. Platts, part of S&P Global, assessed Dated Brent at an average of $85.655/b July 31.

Price volatility

Over the coming months, BP also expects to see continued high historical volatility in oil and gas prices, Looney said. He pointed specifically to the potential for European natural gas demand to recover this winter from the 20% hit in the wake of Russia's invasion of Ukraine even though regional gas stocks are currently higher than seasonal norms.

"I think the one thing that you can expect through all of these product streams is probably a lot of volatility, probably more so than we have experienced in history," he said.

Looking ahead, Looney was upbeat that higher expected price volatility for its key energy commodities will lift earnings from its trading divisions.

"I think the one thing that you can say as you look forward in the world... is that the energy transition is complex and therefore complexity will likely lead to volatility. As everybody knows, volatility is constructive for a trading business," he said.

Despite expecting a more supportive oil price environment in the medium term, Loney said BP will continue to plan financially based on much more prudent expectations for price realizations.

"We know that there are numerous uncertainties and we therefore don't plan on that basis and that is why we run the

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company on the basis of a $40/b oil price, a $3/MMBtu Henry Hub price and we have no intention of moving away from running the company on that basis," he said.

— Robert Perkins

Distillates lead crude futures prices as supply remains tight

- ULSD crack spread soars $4 midday
- Distillate prices high despite weak trucking
- European diesel market remains tight

Crude oil futures settled mixed Aug. 1 as distillates led the complex over a persistent tight supply situation in the US and Europe, leading crack spreads to soar nearly $4 during the day before settling slightly up on the day.

NYMEX front-month ULSD settled at $3.0234/gal, up 3.79 cents, while NYMEX front-month RBOB fell 2.25 cents to settle at $2.8730/gal.

NYMEX front-month crude fell 43 cents to settle at $81.37/b, while ICE front-month Brent settled at $84.91/b, down 52 cents.

"The diesel crack spread is [also] hitting the highest level since October of 2022 as global supply tightness is causing a major run-up in price," Phil Flynn, analyst at PRICE Futures Group, said.

US gasoline cracks settled higher on the year amid peak seasonal demand, as margins were strong and refinery runs were heightened due to minimal outages.

The NYMEX August ULSD crack spread against WTI was at $45.61/b Aug. 1, up $2.02 on the day and up from roughly $41.34/b in August 2022.

The NYMEX August RBOB crack against WTI settled at $39.30/b, down 51 cents on the day and but still up from roughly $22.72/b a year ago.

Supply in the US was forecast to remain tight, as analysts polled by S&P Global Commodity Insights on average expected US gasoline stocks to decline by 1 million barrels in the week ended July 28 and expected distillate stocks to fall by 400,000 barrels.

US gasoline imports have also slipped, with S&P Global Commodities at Sea data showing 600,000 b/d imported the week ended July 28, down from more than 1 million b/d in early June. With the bulk of gasoline imports arriving on the US Atlantic Coast, the slowdown could be bullish for the New York-delivered NYMEX RBOB futures contract.

Refiners are forecast to have increased net crude inputs as well in the week ended July 28. Net crude inputs at 16.5 million b/d in the week ended July 21 had fallen 180,000 b/d from two weeks prior on several refinery glitches, US Energy Information Administration data showed.

Tightening supplies were also expected to strengthen prices amid mounting expectations that Saudi Arabia and Russia would extend their voluntary output cuts into September, analysts said.

Although diesel demand in 2023 has mostly recovered from 2020 lows, trends have been uneven across the country, according to a report by S&P Global.

"While the strong oil sector and agricultural activity have supported diesel demand in the Midwest and Gulf Coast in 2022 and 2023, demand in PADDs 1 and 5 is now suffering from shifting consumer demand from goods to services and layoffs in the tech sector," S&P Global analysts said.

Additionally, weakness in the truck tonnage index resulted in a fourth consecutive decline, according to the American Trucking Associations. Even so, demand was still climbing as the supply situation remained uncertain.

However, following a month of rises for crude prices, elevated costs could lead to demand destruction, CMC Markets' Chief Market Analyst Michael Hewson said Aug. 1, highlighting the example of gasoline demand — a key driver of oil product consumption in the US.

"This rise in prices over the last four weeks is already feeding into higher prices at the fuel pumps, which if sustained could impact consumer demand in the coming weeks," Hewson said.

In Europe, the market was "currently grappling with ongoing distillate shortages, causing sales prices, cracks, and spreads to surge in the last week," James Noel-Beswick, analyst at Sparta, said in a Aug. 1 note.

Noel-Beswick pointed to multiple factors contributing to the situation, including "Shell Pernis CDU issues, Shell Wesseling slowdowns, Donges hydrotreater problems, a fire at Repsol's Bilbao refinery, and ARA stocks hitting a six-month low last week." He also said there were rumors in the market that Europe-wide distillate stocks were around 7% below their seasonal average.

Meanwhile, a Europe-based market source said that front-month gasoil futures were jumping due to the lack of resupply in Europe. Now that Russian supply was excluded from European flows, volatility had been more pronounced in 2023, as supply was further away from the pricing center, according to the source.

The ICE low sulfur gasoil front-month contract broke above $900/mt for the first time in six months in mid-morning European trading Aug. 1, despite crude futures moving slightly lower during the session, with traders citing concerns over diesel supply into Europe for the move higher. Platts, part of S&P Global Commodity Insights, last assessed the ICE LSGO front-month contract higher than $900/mt on Jan. 31.

— Binish Azhar

BP expects output growth in 2023 despite delays to African LNG project ...from page 1

BP had previously guided towards flat output growth this year but the more upbeat growth forecast still comes as part of BP's longer-term, managed oil and gas output decline as it transitions to low-carbon energy. BP expects its oil and gas production in 2030 to be around 2 million boe/d, about 25% lower than in 2019. BP sees its oil and gas production at around 2.3 million boe/d in 2025, compared with 2.25 million boe/d in 2022.

Looking to Q3, BP said it expects to report upstream production broadly flat compared with Q2. Within this, BP expects production from oil production and operations to be lower and gas and low carbon energy to be higher, including the effects of seasonal maintenance in higher margin regions offset by major project delivery.

Refining outlook

For Q2, BP's reported adjusted earnings of $2.59 billion were down from $8.45 billion in the year-prior period on lower oil and gas prices and weaker refining margins. The result was below analysts' expectations of around $3.5 billion largely on the back of weaker refining margins and lower results from oil trading in the quarter.

Despite the result, BP remained upbeat over its underlying cash flow and raised its dividend by 10%, as well as announcing a further $1.5 billion of share buybacks. BP also confirmed its capital expenditure target of $16-18 billion in 2023 including inorganic spending.

"Our underlying performance was resilient with good cash delivery during a period of significant turnaround activity and weaker margins in our refining business," CEO Bernard Looney said in a statement.

Like its energy major peers, BP saw its refining margins collapse on the year after Russia's invasion of Ukraine pushed its margin to $45.5/b in Q2, 2022. BP's refining marker margin declined less steeply than some of its peers between the first and second quarters, however, from $28.1/b to $24.9/b, reflecting its greater US footprint. For the US Midwest, BP's refining marker margin was unchanged quarter on quarter at $28.8/b.

For Q3, BP said it expects industry refining margins to remain above historical average levels, supported by low product inventories and seasonal demand in the US. BP also expects a lower level of turnaround and maintenance activity compared with Q2.

On costs, Looney said BP is continuing to drive down the company's unit production costs helped by deflation in some of its key supply markets.

"Across the world, we're seeing things like steel costs coming down some of the raw material costs coming down," Looney said in an earnings call. "Labor is an area where we do see inflation right across the world and that is unchanged and we do our best to offset that with some productivity improvements."

Looney said BP is currently seeing costs come down by around 20% on the year in its US shale unit bpx.

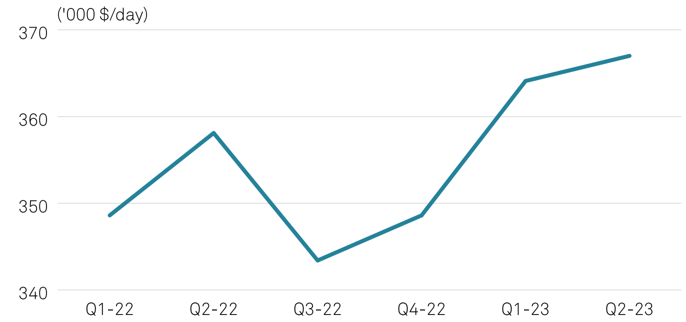
— Robert Perkins

Upstream oil and gas operators contract deepwater rigs for 2025-2026, as market tightens ...from page 1

A limited supply of top-tier rigs in the face of increasing demand has pushed up day rates higher than they have been in recent years. Thigpen said during Q2 2023, Transocean's fleet average day rate was $363,000 compared to $312,000 in Q2 2022.

And, based on the driller's existing $9.2 billion backlog, which expanded by $1.2 billion in Q2 2023, "by second-quarter 2024, we expect the average to be to be about $433,000 a day," he said.

Transocean's revenues soar as rig market tightens



Source: Transocean

Contract durations 'materially' longer

In addition, contract durations are lengthening "materially," Thigpen said.

Year to date, the average length of contract drillship awards has increased to 495 days, compared to 310 days in 2022 for the same period, up 60% year on year. And, the average duration of semi-submersible fixtures increased 18% over the same time period in 2022, and nearly 150% from 2020.

Also, nearly 15,000 drillship days have been awarded to date in 2023, a 134% increase when compared to the same period in 2022. Similarly, nearly 8,500 harsh-environment semisubmersible contract days have been awarded this year, a 72% increase versus the same period in 2022.

Globally, Thigpen predicted about 81 rig-years of work likely to be awarded near-term across 80 deepwater drilling programs, suggesting an average duration per program of about a year – up from seven to eight months in early 2022.

And, more than a quarter of these programs involve exploration and appraisal wells – suggesting more work is occurring for projects that may replenish future oil and gas production.

Moreover, not only has Transocean increased average dayrates for its ultradeepwater fleet, but it has seen a "rapid tightening" of the high-specification harsh-environment semisubmersible market, Thigpen said.

"As recently confirmed by Westwood Energy group, this asset class is effectively sold out with committed utilization at 100% for first time since 2014," he said.

As further evidence of market strength, a number of operators are evaluating and increasingly pursuing longer-term rig contracts that are not yet tied to specific projects or may not have approval from one or more partners, he added.

"We have not seen this type of market behavior in some time, and it's one of the more exciting and encouraging developments to date," he said.

Rig market seen remaining tight

The rig market is expected to remain tight, especially for the highest-specification ultradeepwater drillships and harsh-environment semisubmersibles, Thigpen said.

He cited an analysis by Wood Mckenzie, which oilfield service provider SLB quoted during its recent Q2 conference call in July, that estimated $500 billion of investment in oil and gas is expected between 2022 and 2025, of which $200 billion should be in deepwater projects.

Around 85% of those sums should generate favorable returns at oil prices below $50/b, while oil prices have remained "comfortably" above that threshold for more than two years "and remain stable in the mid-$70s to mid-$80s range," he noted.

"As the majority of offshore project breakevens are significantly below this threshold, and many are below $50 [/b], we expect customers' programs will receive approval to move ahead," Thigpen said.

In addition, Transocean recently became the first deepwater driller to ink at least one contract at the landmark day rate of $500,000 – for a semisubmersible to work on a project in Australia although the operator was not disclosed.

Day rates topped that amount during the boom cycle of 2011-2014, but rates have not been that high since that time.

— Starr Spencer

Platts pricescore

Week ending		28-Jul	21-Jul
Crude oil			
Dated Brent	($/b)	83.41	79.55
Dubai (First month)	($/b)	83.97	80.57
WTI (Cushing) (First month)	($/b)	79.70	75.68
ANS (California)	($/b)	85.21	81.62
Mars (MOC)	($/b)	80.46	77.04
Products			
NWE (CIF cargoes)			
Naphtha (physical)	($/mt)	613.80	576.10
Diesel 10PPM NWE	($/mt)	855.55	785.65
Diesel 10ppm UK	($/mt)	856.80	786.45
Fuel Oil 3.5%	($/mt)	484.55	452.10
Jet Kerosene	($/mt)	895.45	828.65
Singapore (FOB cargoes)			
Kerosene (physical)	($/b)	106.09	98.60
Kerosene (paper)	($/b)	105.48	98.33
Gasoil 0.5%	($/b)	109.41	101.24
HSFO 180cst	($/mt)	500.93	472.09
C&F Japan			
Naphtha (physical)	($/mt)	618.00	585.80
US Atlantic Coast (Barge)			
RBOB 87	(¢/gal)	291.54	272.95
No. 6 1.0% (Cargo)	($/b)	79.38	74.36
US Gulf (Pipeline)			
Unleaded 87	(¢/gal)	289.04	267.03
No. 2	(¢/gal)	254.35	233.16
US Gulf (Waterborne)			
USGC HSFO	($/b)	75.24	70.21
Average settlement prices			
NY Mercantile Exchange			
Light Sweet Crude	($/b)	79.15	75.57
No. 2 oil	(¢/gal)	283.14	263.31
RBOB	(¢/gal)	289.95	270.24
Natural Gas	($/MMBtu)	26.57	26.36
IntercontinentalExchange			
Gasoil	($/mt)	831.78	766.70
Brent	($/b)	83.18	79.70

The averages in this table are the mean of Platts low and high daily quotations, or exchange settlements, calculated on a 5-day week basis, Monday through Friday. Saturdays and Sundays are excluded.

US degree days indicator through July 30

The degree days indicator for US heating oil demand so far this heating season (through July 30) was 2.49% less then the corresponding period of the last season and 51.28% less then normal.

The indicator is comprised of the average degree days for 18 geographically representative US cities, weighted to reflect the cities' relative consumption of home heating oil.

The degree days data were compiled by Platts from reports by CustomWeather.

	September 1 - July 30			
	Sep-22 Jul-23	Sep-21 Jul-22	Normal	Week Ended 30-Jul
East Coast				
Boston	2,601	2,686	5,431	0
New York City	2,152	2,295	4,541	0
Philadelphia	2,084	2,065	4,375	0
Washington DC	2,113	2,136	4,553	0
Average	2,237	2,295	4,725	0
Great Lakes				
Buffalo	3,194	3,128	6,387	0
Chicago	2,998	3,074	6,112	0
Cleveland	2,753	2,868	5,716	0
Detroit	2,723	3,044	5,937	0
Average	2,917	3,029	6,038	0
Midwest				
Denver	3,367	2,837	5,802	0
Minneapolis	3,972	4,033	7,354	0
Omaha	3,225	2,842	5,905	0
St. Louis	2,124	2,131	4,335	0
Average	3,172	2,961	5,849	0
Southeast				
Birmingham	1,077	1,095	2,480	0
Charleston, SC	697	871	1,738	0
Nashville	1,498	1,571	3,373	0
Raleigh	1,347	1,420	3,144	0
Average	1,154	1,239	2,684	0
West Coast				
Portland, OR	2,255	2,201	4,147	0
San Francisco	1,453	1,196	2,453	5
Average	1,854	1,698	3,300	2
Simple Average for all groups				
	2,267	2,244	4,519	0
Heating oil demand indicator*				
	2,359	2,420	4,843	0

* This is the average of each group's simple average weighted to reflect each group's percentage of past home heating oil demand, totaled for the 18 cities.

June milder in Europe, Canada, and Japan

June was milder in Europe, Canada, and Japan than a year ago, according to data obtained from CustomWeather and gathered by Platts.

A total of 19 cities geographically representative of Europe had 30.3% fewer heating degree days in June than in June 2022. The total for the September-June period was 2.4% fewer degree days than the similar period last year and 6.2% fewer than normal.

Eight cities geographically representative of Canada had 21.2% fewer degree days in June than in June 2022. The total for the September-June period was 3.2% fewer than the similar period last year and 6.6% fewer than normal.

Four cities geographically representative of Japan had 34.7% fewer degree days in June than in June 2022. The total for the September-June period was 6.7% fewer than the similar period last year and 10.8% fewer than normal.

	Sep-Jun 2022-2023	Sep-Jun 2021-2022	Sep-Jun Normal	June 2023	June 2022
Canada					
Based on 65 deg. F					
Edmonton	9,531	9,731	10,009	119	205
Halifax	6,701	6,799	7,501	172	138
Montreal	6,641	7,273	7,659	46	30
Regina	10,122	9,988	10,091	34	123
St. John's	7,365	7,569	8,253	242	206
Toronto	5,954	6,283	6,773	28	33
Vancouver	5,066	5,307	5,030	111	143
Winnipeg	9,832	10,308	10,219	19	99
TOTAL	61,212	63,259	65,535	770	977
Europe					
Based on 65 deg. F					
Amsterdam	4,597	4,544	5,020	49	107
Brussels	4,568	4,566	4,891	43	99
Copenhagen	5,399	5,495	5,967	65	133
Dublin	4,909	4,977	5,111	172	257
Essen	4,596	4,654	4,945	23	67
Frankfurt	4,748	4,769	4,983	6	34
Geneva	4,342	4,830	4,999	0	23
Hamburg	5,183	5,192	5,652	57	125
Helsinki	7,994	8,255	7,935	191	154
Klagenfurt	5,550	5,952	5,930	21	7
London	4,059	3,937	4,544	45	71
Marseilles	2,504	2,769	2,766	0	0
Milan	3,680	4,150	4,312	0	0
Munich	5,626	5,878	6,012	58	40
Oslo	7,986	7,624	8,101	85	150
Paris	3,894	4,074	4,266	9	21
Rome	2,328	2,638	2,605	0	0
Stockholm	7,109	7,018	6,971	123	112
Vienna	5,019	5,050	5,294	33	4
TOTAL	94,092	96,371	100,302	979	1,405
Japan					
Based on 65 deg. F					
Nagasaki	2,145	2,390	2,392	0	0
Osaka	2,794	2,901	3,015	2	0
Sapporo	6,800	7,079	7,582	93	142
Tokyo	2,333	2,706	2,779	0	5
TOTAL	14,072	15,076	15,768	96	147

US degree days for June

The degree days indicator for US heating oil demand for June was 214.06% greater than for June 2022 and 34.34% less then normal.

The indicator is comprised of the average degree days for 18 geographically representative US cities, weighted to reflect the cities relative consumption of home heating oil.

The degree days data were compiled by Platts from reports by CustomWeather.

	June 2023	June 2022	June Normal
East Coast			
Boston	43	16	38
New York City	7	0	8
Philadelphia	2	0	3
Washington DC	3	0	5
Average	14	4	14
Great Lakes			
Buffalo	25	20	40
Chicago	14	1	26
Cleveland	19	5	24
Detroit	4	2	19
Average	16	7	27
Midwest			
Denver	44	17	33
Minneapolis	3	4	20
Omaha	4	1	5
St. Louis	0	0	1
Average	13	6	15
Southeast			
Birmingham	0	0	0
Charleston, SC	0	0	0
Nashville	0	0	0
Raleigh	0	0	0
Average	0	0	0
West Coast			
Portland, OR	27	30	75
San Francisco	50	27	93
Average	38	29	84
Simple Average for all groups			
	16	9	28
***Heating oil demand indicator**			
	12	4	18

* This is the average of each group's simple average but weighted to reflect each group's percentage of past home heating oil demand, totaled for the 18 cities.

