Saudi expects 13mn bpd oil capacity by 2027: Minister

Saudi Arabia expects to ramp up its daily oil production capacity by more than 1mn barrels to exceed 13mn barrels by early 2027, the kingdom's energy minister announced Monday.

"Most likely it will be 13.2 to 13.4 (million barrels per day), but that would be (reached) at the end of 2026, beginning 2027," Prince Abdulaziz bin Salman told an energy conference in Bahrain.

Production at that level would be maintained "if the market allows it", he said.

Energy giant Saudi Aramco announced in March 2020 it had been directed by the energy ministry to increase its maximum sustainable capacity from 12mn bpd to 13mn bpd.

No timeline was given then for the new target.

Monday's announcement came one day after Saudi energy giant Aramco posted an 82% jump in first quarter profits, buoyed by a global surge in oil prices stemming from the Ukraine war.

Those results helped Aramco dethrone Apple last week as the world's most valuable company by market capitalisation.

They continued a string of positive economic news for Saudi

Arabia, which in early May reported that growth in the first quarter had risen 9.6% over the same period in 2021.

Yet Aramco has faced security challenges stemming from the war pitting a Saudi-led military coalition against Yemen's Houthi rebels who have repeatedly targeted the kingdom, including Aramco sites.

Saudi Arabia, the world's biggest oil exporter, has resisted US entreaties to raise output in an attempt to rein in prices that have spiked since the Ukraine war broke out on February 24.

As the war got underway, Saudi Arabia and the United Arab Emirates stressed their commitment to the Opec+ oil alliance, which Riyadh and Moscow lead.

Last year, ahead of the COP26 climate-change summit, Saudi Arabia pledged to achieve net zero carbon emissions by 2060, sparking scepticism from environmental campaign group Greenpeace.

With increasing global urgency to limit global warming, experts warn of the urgent need to reduce fossil fuel use.

But Saudi officials' stated targets indicate "they still believe in oil as a source of energy for the coming decade", Mazen Alsudairi, head of research for Al Rajhi Capital, a financial services firm in Riyadh, told AFP. "They are not following the global trend by reducing exposure to hydrocarbons."

Also at Monday's conference in Bahrain, Iraqi Oil Minister Ihsan Abdul-Jabbar Ismail said his country was accelerating its production capacity goals, targeting 6mn bpd in 2027 and 8mn bpd in 2029.

Iraq's current daily production is just under 3.5mn.

It reported $11bn in oil revenues in March, Iraq's highest in half a century.

Record fuel costs driven by refining crunch, says Saudi energy minister

Bloomberg / Riyadh

Saudi Arabia’s top oil official said that a refining crunch – rather than any shortage of crude – is driving the surge in fuel costs to unprecedented levels.

“The bottleneck has now to do with refining,” Saudi Energy Minister Prince Abdulaziz bin Salman said in an interview. “I did warn this was coming back in October. Many refineries in the world, especially in Europe and the US, have closed over the last few years. The world is running out of energy capacity at all levels.”

The processing crunch – previously outlined by the Prince at the CERAWeek conference in India last October – is buoying prices above $100 a barrel even as markets are well-supplied with crude, he added.

Tumult across fuel markets is widely evident. Gasoline futures climbed to a record of 389.98 cents a gallon on Friday, with prices at the pump already at unprecedented levels, while diesel still commands a premium after spiking in recent months. The surge is compounding inflationary pressures that threaten the economy recovery and worsening the cost-of-living crisis suffered by consumers. Nonetheless, the Organisation of Petroleum Exporting Countries (Opec) and its partners has stuck to schedule of modest supply increases, rubber-stamping another small increment last week, even as flows from coalition member Russia are disrupted by an international boycott.

Their intransigence has caught the attention of US lawmakers. Last week, the Senate Judiciary Committee approved legislation known as NOPEC that, if passed, would subject the group to antitrust laws. The bill has been introduced several times in previous years but never made it into law.

Yet Riyadh and its allies remain adamant that the market still isn’t facing a deficit of crude barrels. United Arab Emirates Energy Minister Suhail al-Mazrouei expressed similar views at a conference on Wednesday, saying that high taxes in consuming nations are responsible for surging costs.

Their perspective is gaining support elsewhere.

The International Energy Agency — which advises consuming nations and has called on Opec+ to raise production faster — shifted its focus to products markets in a report on Thursday. While an “acute supply deficit” of oil isn’t on the horizon, consumers do face more strain from limited fuel supplies. The lack of refining capacity is being aggravated by the disruption in flows from Russia, which used to send significant quantities of diesel fuel to Europe, the IEA said.

Shipments of diesel-type fuel out of Russia’s Baltic and Black sea ports were about half-a-million tonnes, or 14%, lower last month than in February, according to data from Vortexa Ltd.

Gasoline, diesel, jet fuel refining capacity too low in US to meet demand

Bloomberg / New York

From record gasoline prices to higher airfares to fears of diesel rationing ahead, America’s runaway energy market is disquieting both US travellers and the wider economy. But the chief driver isn’t high crude prices or even the rebound in demand: It’s simply too few refineries turning oil into usable fuels.
More than 1mn barrels a day of the country’s oil refining capacity – or about 5% overall – has shut since the beginning of the pandemic. Elsewhere in the world, capacity has shrunk by 2.13mn additional barrels a day, energy consultancy Turner, Mason & Co estimates. And with no plans to bring new US plants online, even though refiners are reaping record profits, the

supply squeeze is only going to get worse.
“We are on the razor’s edge,” said John Auers, executive vice president at Turner, Mason & Co in Dallas. “We’re ripe for a potential supply crisis.”
The dearth of refining capacity has dire implications for both US consumers and global markets. At home, retail gasoline prices continue hitting new records, exacerbating some of the worst inflation American households have ever seen.
Meanwhile, the East Coast is on the brink of a diesel shortage that risks crippling already strained supply chains that have disrupted the flow of everything from grocery staples to construction supplies in the last two years. The factors fuelling the refining shortage won’t surprise anyone: With demand for gasoline and jet fuel practically vanishing during the height of the pandemic, companies closed some of their least profitable crude-processing plants permanently.
Some of those plants had been affected by fires, explosions and hurricanes and were just too expensive to fix, especially because an eventual transition toward cleaner energy makes their long-term business model unprofitable and makes them less likely to attract buyers. By the end of 2023, as much as 1.69mn barrels of US capacity is targeted for closure compared to 2019 levels, according to Turner, Mason & Co.
At the same time American refining shrinks, the war in Ukraine has made the global divergence between supply and demand even more acute. With many countries shunning Russian fuel exports in the wake of the war, the US is now supplying more of the world’s fuel with an ever-shrinking fleet of plants. Europe has been seeking alternatives to Russian diesel since the war began, while fuel demand in Latin America, the largest buyer of US refined products, is strong and growing. Meanwhile, the US is itself gearing up for a spike in consumption this summer.
That’s setting up refiners to reap record profits this year. Valero Energy Corp is seen generating the most cash from operations since its stock started trading in 1997, while top refiner Marathon Petroleum Corp. is expected to post its

highest margins in a decade. The two companies are the second and 10th best performers, respectively, in the S&P 500 index this year as of Friday morning.

Retail prices for both gasoline and diesel climbed to fresh records of $4.432 and $5.56 a gallon respectively, AAA data showed on Friday. US gasoline futures also rose to a new high.

In other kinds of markets, a surge of demand and shortage of supply would trigger more investment, especially with such swelling cash hordes. But the longer-term transition away from fossil fuels dims the outlook for demand, making companies unwilling to put up the billions of dollars needed to build new plants.

Even resurrecting idled plants can be prohibitively costly at a time when construction and labour costs in the US are booming. With California unveiling this week a roadmap to slash oil use by 91% from 2022 levels by 2045 and other places moving to limit fossil-fuel use in the decades ahead, refining companies and their investors can see the writing on the wall.

“Nothing about the current environment is promoting investments in fossil fuels,” said Bloomberg Intelligence analyst Fernando Valle. “It’s a 15 to 20 year payback on most of these investments.”

Phillips 66, for example, would have to spend more than $1bn to restart its Alliance refinery in Louisiana that was shut after damage from Hurricane Ida, Bloomberg Intelligence estimates. LyondellBasell Industries NV has opted to shut its Houston Refinery no later than the end of 2023 over cost concerns related to keeping the 104-year-old facility running.

A portion of shuttered plants are now being converted into smaller renewable-diesel facilities, including Phillips 66’s refinery in Rodeo, California, which was confirmed this week.

As for selling those assets to someone who could ramp up production, no one’s buying — even as industry players are sitting on massive piles of cash. “We feel we’ve got higher returns, better uses for the capital to employ than buying a refinery that’s on the market at this point in time,” Valero chief executive officer Joe Gorder said in a conference call

with analysts in late April.
To be sure, there could be some small-scale relief ahead. US refiners ran at 90% last week, and that percentage will increase as seasonal maintenance wraps up this month. Some units can then even run 10% or 20% beyond their nameplate capacity to maximise production in the short term.
But that’s a rate that can’t be sustained without risking damage. A few refineries are also focusing on debottlenecking or even adding new units inside existing facilities to boost capacity, though it’s a drop in the bucket volumewise compared to the total already lost — and it won’t come until 2023 or 2024. In short, “too much refining capacity was closed during the pandemic,” Bloomberg Intelligence’s Valle said. “Diesel shortages and the price surge are likely here to stay.”

U.S. diesel shortages lift refining margins to a record

LONDON, May 10 (Reuters) – Global stocks of refined petroleum products have fallen to critically low levels as refineries prove unable to keep up with surging demand especially for the diesel-like fuels used in manufacturing and freight transportation.

The result has been a surge in prices refiners receive for selling fuels compared with prices they pay for buying crude and other feedstocks, boosting their profitability significantly.

In the United States, refiners currently receive roughly an average of more than $150 per barrel from the sale of gasoline and diesel at wholesale prices, while paying only around $100 to purchase crude.

The indicative 3-2-1 margin of $50 per barrel is based on the assumption a refinery produces two barrels of gasoline and one barrel of diesel from refining three barrels of crude.

The margin is meant to be representative for an “average” refinery and is a gross figure out of which refiners have to pay for labour, electricity, gas, hydrogen, catalysts, pipeline transport and the cost of capital.

Net margins are narrower and refinery costs have been rising rapidly as result of widespread inflation ripping through the economy following the coronavirus pandemic.

Nonetheless, even allowing for rising input costs, gross margins have more than doubled from $20 at the end of 2021, ensuring refiners have a strong financial incentive to maximise crude processing and fuel production.

DISTILLATE FOCUS

Gross margins are currently higher for making diesel (almost $60 per barrel) than for gasoline ($45 per barrel) reflecting the relative shortage of middle distillates.

(Chartbook: https://tmsnrt.rs/3PdSJdC)

U.S. distillate fuel oil stocks are 31 million barrels (23%) below the pre-pandemic five-year average compared with a deficit of only 6 million barrels (3%) in gasoline.

The squeeze on fuel inventories and refinery capacity is compounding already high prices for crude caused by sanctions on Russia and output restraint by OPEC+ and U.S. shale producers.

The resumption of international passenger aviation as quarantine restrictions are lifted is tightening the fuel market even further because jet fuel is broadly similar to diesel and gas oil.

The effective wholesale price of diesel has climbed to over $160 per barrel while gasoline is trading at over $150, based on futures for delivery in New York Harbor.

Once distributors’ and retailers’ margins and taxes are included, the average price at the pump paid by motorists has climbed to $236 per barrel for diesel and $186 per barrel for gasoline.

The refining margins and fuel prices cited in this column are all for the United States but the same shortage of refining capacity and fuel inventories is boosting diesel prices in Europe, and dragging up gasoline prices with them.

SLOWDOWN AHEAD

There is scope for refiners to increase fuel production by postponing non-essential maintenance and running refineries flat out into the early autumn.

And some room to adjust the output mix by switching from maximum gasoline to maximum diesel mode in downstream processing units.

But any increase in diesel production is unlikely to be able to reverse the depletion of inventories fully and return them to pre-pandemic levels.

Prices will therefore have to continue rising until they begin to restrain consumption or the economy enters a cyclical downturn.

Consumers can reduce fuel use in the short term by consolidating freight loads (fewer voyages, flights and deliveries), reducing speeds (slower voyaging, flying and driving) and eliminating engine idling.

But the fuel savings are relatively modest and tend to degrade service levels, reduce capacity and increase capital costs.

By contrast, a slowdown in the business cycle delivers large simultaneous reductions in diesel use – absolutely or relative to trend – by freight firms, manufacturers, miners and construction firms.

Business cycle slowdowns have therefore tended to be the main path by which the distillate market and other fuel markets have rebalanced in the past.

The adjustment process is probably underway in 2022. The cyclical slowdown and reduced fuel demand could occur in one, two or all three of the major consuming regions.

Parts of China’s economy appear to be in recession already as coronavirus lockdowns paralyse factories and transport systems and depress consumer spending.

Europe’s economy is on the verge of recession as Russia’s invasion of Ukraine, the sanctions imposed in response, soaring energy prices and rampant inflation disrupt manufacturing and depress household spending.

The only major economy with significant momentum is the United States, but there, too, the rate of expansion is slowing, which will likely result in slower growth in distillate consumption later in the year.

Sea border talks between Israel and Lebanon on verge of imminent collapse

Why did Biden’s energy envoy issue a poison pill that is sure not only to kill the deal but give Hezbollah a new reason to fight?

When President Biden appointed his personal friend and former Obama administration energy coordinator Amos Hochstein as his own energy envoy last summer, it seemed that the decades-old deadlock between Lebanon and Israel over their sea boundary, and potentially tens of billions of dollars in energy resources, might finally be resolved.

Hochstein was assumed to be trusted by the Israelis (he was born in Israel and served in the IDF in the early 1990s). He was perceived positively by some of the main Lebanese actors as a foe of a former U.S. envoy, Ambassador Frederic Hof, who had tabled a deal ten years before known as the “Hof Line” boundary that was widely seen in Lebanon as exceptionally unfair. And he came with a deep background in the complexities of the energy sector.

Perhaps most importantly, however, the Biden administration seemed hungry to claim a success in the Arab-Israeli conflict. Although a mutually agreed-upon sea boundary between Lebanon and Israel would fall far short of any Abraham Accord-type arrangement, such a deal would represent a UN-recognized boundary between a democratically elected Arab government and Israel. Given the extensive power of the armed Lebanese political party Hezbollah, which Israel considers its most formidable non-state enemy, the removal of a large offshore area from the regular military exchanges between the two sides onshore would also help to structurally diminish the prospects of another devastating war in the Middle East, something the Biden administration very much wants to avoid.

Unfortunately, eight months on, according to several senior Lebanese officials directly involved in the negotiations, the deal that Hochstein unveiled a few weeks ago in Beirut, one which apparently has Israel's blessing, falls far short of Lebanon's minimum acceptable position. As a result, the talks are in imminent danger of collapsing, perhaps in the coming weeks. Asked about this prospect, the State Department and U.S. Embassy in Beirut both declined to comment.

Hochstein, it seems, badly misunderstood the Lebanese side. First, in proposing that Israel and Lebanon share a potentially rich hydrocarbon field between them (known as the Qana Prospect after a town in South Lebanon), he has ensured that any deal is dead on arrival. No Lebanese political actor can muster the votes to essentially go into business with a state that is officially an enemy and regularly in military conflict with the most powerful political and military actor in the country, Hezbollah. Hochstein surely should know this (a similar offer he made at the end of the Obama administration was rejected by Lebanon), which is why it is especially confounding that after all of his discussions with different Lebanese parties, he still ended up proposing a "unitization agreement."

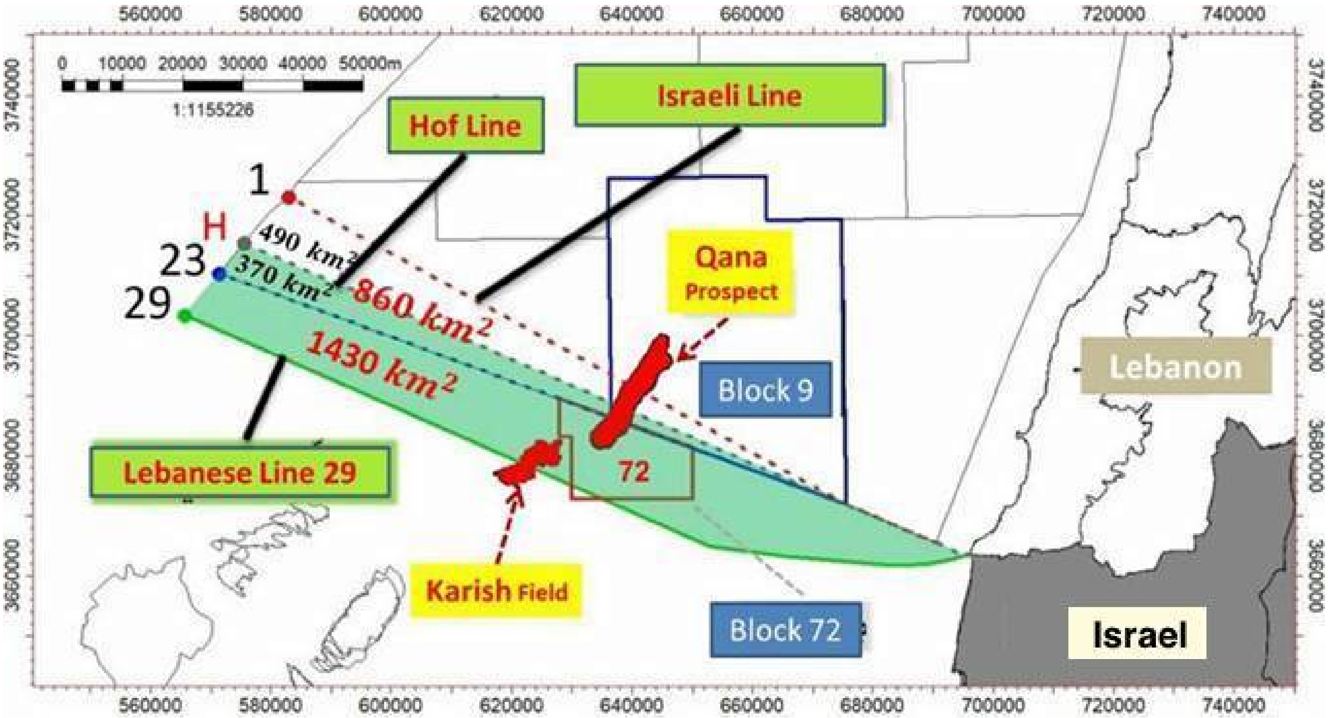
Was he lulled into thinking that Hezbollah's uncharacteristic quiet on the maritime issue over many years offered a rare opportunity for initiating material cooperation between Lebanon and Israel? If this was his assumption, he burned a golden opportunity consecrated when Hezbollah delegated the indirect negotiations to its two allies, Parliament Speaker Nabih Berri and President Michel Aoun.

Indeed, instead of using Hezbollah's self-removal to box it into accepting a deal seen as reasonable by the vast majority of Lebanese on legal, commercial and nationalistic grounds, rather than on imperatives related to an enduring struggle against Israel, Hochstein's field-sharing proposal played right into Hezbollah's hands. In fact, Hezbollah MP Mohammad Raad felt confident enough a few weeks ago, despite the country's mounting economic problems, to deliver the party's first fiery "redline" speech on the issue: "They tell us…it may turn out that you will need to share the gas field with the Israelis…We'd rather leave the gas buried underwater until the day comes when we can prevent the Israelis from touching a single drop of our waters."

Hochstein's "poison pill" deal, as some Lebanese are now calling it, also squandered a second opening the Lebanese side has offered since the fall of 2020 when the Trump administration resumed Washington's mediation efforts.

Although it is the source of much political intrigue and enmity in Beirut, for whatever internal reasons Lebanon opened the indirect talks on the basis of a new, extended boundary claim known as "Line 29" but without officializing it as countries are legally entitled to do given relevant changes in international legal rulings. As a result, and probably for the first time in modern maritime negotiations, the Lebanese team came to the table with a well-grounded "maximalist" position (Line 29) but without having actually deposited it de jure at the United Nations.

This goodwill concession over an additional 1,430 square kilometers of sea unofficially claimed by Lebanon prevented the likely early breakdown of talks by allowing Israel and private companies like Greece's Energen and America's Halliburton to legally move forward with exploitation activities over the last year and a half in the energy-rich Karish field, as well as its northern environs (including the southern part of the Qana Prospect). All of the former and some of the latter are outside of Lebanon's current "minimalist" legal claim known as "Line 23."



Of course, Lebanon's restraint in not officializing its new "maximalist" Line 29 also gave Lebanese politicians a convenient way to accept a deal far less than what their own experts and lawyers have been saying for years should be granted to Beirut. After all, anything roughly comparable to Lebanon's current "minimalist" Line 23 could technically be spun as a victory.

Hochstein's proposal, however, that Israel and Lebanon go into business together by sharing the Qana Prospect, decisively quashed any such maneuverability.

Should talks break down in the coming period, as now seems likely, at least two negative outcomes are almost certain. First, with the talks dead and the country sinking ever deeper into a “Deliberate Depression,” Lebanese leaders will have little to lose from officializing the “maximalist” boundary claim they are legally entitled to assert and then taking punitive action in multiple fora. This will put significant pressure on private companies operating in the (soon to be) “disputed” Karish field as well as the Qana Prospect.

Second, and perhaps most important, by offering an unworkable deal that leads to a negotiation breakdown, the U.S. and Israel will be handing Hezbollah a powerful new raison d’être as a resistance group by creating a “Maritime Shebaa,” in reference to the strategic strip of land between Lebanon, Syria and Israel that is occupied by Israel. Lebanon claims this land and considers military operations there, including by Hezbollah, as both legal and necessary in order to liberate it. The United Nations considers Shebaa to be part of Israeli-occupied Syrian land, but Syria itself supports Lebanon’s claim.

In short, a “Maritime Shebaa” will be far more evocative and unifying for more Lebanese — to Hezbollah’s distinct political benefit — than the issue of “Land Shebaa” since Lebanon’s case is much stronger in the water, just as the loss of potentially tens of billions of much-needed dollars to Israel will be daily more evident to everyone. This will likely lead to periodic military engagements in the area that negatively impact drilling and perhaps lead to deaths. At worst, this part of the Eastern Mediterranean sea could become the spark for a devastating new regional war.

Finally, at a time when Europe’s current and future gas needs have suddenly been destabilized following the Russian invasion of Ukraine, any further disruption of international supplies will only create more negative fallout. Just a few weeks ago, Israel and Energen announced that Karish had been hooked up to the national grid, with gas expected to flow in the coming months. Crucially, this extra capacity is now being seriously considered for export to the European Union via Egypt as early as September, according to Israeli and Egyptian officials. A combination of Lebanese legal actions and Hezbollah threats could substantially disrupt this schedule, however, not to mention harm Lebanon's own hoped-for exploitation of its own blocks.

Given these dangerous consequences, the Biden administration should urgently consider whether proposing a different deal might better serve U.S., Israeli and Lebanese interests as well as regional stability. As it currently stands, there is a narrowing window for creating a stable sea boundary between Israel and Lebanon, one that must avoid, first and foremost, the "poison pill" of a shared field by trading Israel's imminent exploitation of all of the Karish field for Lebanon's exploitation of the Qana Prospect (which, it should be recognized, is less certain of producing hydrocarbons).

Such an arrangement would likely have to go beyond Lebanon's current de jure Line 23 claim with a "zig-zag" around the Qana Prospect in order to be politically viable in Lebanon. This will undoubtedly be difficult for Israel to swallow since successive governments have long hoped Washington could extract for them a large chunk of the sea behind Lebanon's current claim (as the "Hof Line" proposed a decade ago) and part of the Qana Prospect. But this compromise will also be difficult for Lebanon to accept. Beirut severely undercut its own position by officially sticking with a poorly grounded, "minimalist" boundary claim that failed to take advantage of international legal rulings over the last decade. Generations of Lebanese will have to bear some measure of loss for this.

For both sides, however, and for the U.S., all of these perceived losses should pale in comparison to the immediate and long-term benefits of finally having a stable maritime boundary between Israel and Lebanon, with the stable exploitation of valuable natural resources and the immediate strategic benefit of de-escalating — rather than inflaming — one conflict in a part of the world that simply can't bear another.

Written by
Nicholas Noe

Global LNG demand to more than double to 800mn tonnes by 2050: GECF

Pratap John

Global LNG demand will more than double from 356mn tonnes in 2020 to 800mn tonnes by 2050, "fuelled by solid demand from Asia and a rise in gas use for powering hard-to-electrify sectors", according to the Gas Exporting Countries Forum (GECF).

The biggest regasification capacity additions to 2050 are expected in Asia Pacific, GECF said in its 'Global Gas Outlook 2050'.

Total regasification capacity rose from 572mn tonnes per year (MTPY) in 2010 up to 947 MTPY in 2020.

By 2050, regasification capacity is projected to grow to 1465mn tonnes per year, significantly outrunning the actual projected LNG demand.

That will include, by 2050, almost 1050 MTPY in Asia, and 190 MTPY in Europe. China will top the list of regasification capacity by 2050 with almost 340 MTPY, followed by Japan with 210 MTPY, South Korea with over 150 MTPY and India with 100 MTPY, GECF said.

Some eight new regasification terminals were commissioned in 2020 with a total LNG regas capacity of 26 MTPY, primarily in Asia Pacific region as well as Latin America (Brazil, Puerto Rico). Gas infrastructure build-out, coal-to-gas switching and market deregulation are the main determinants for LNG demand growth.

South and Southeast Asia are likely to drive LNG demand growth in the future as the countries are investing heavily in gas pipelines and regasification terminals. India offers the most demand growth potential in the region due to the scale of its infrastructure expansion. The South and Southeast Asia region might grow its share of global LNG demand from 14% in 2020 to over 40% by 2050.

Around 150 MTPY of new LNG regasification terminals are under construction, of which about almost three-fourth, or 110 MTPY is in Asia Pacific, where the top countries are China (over 50 MTPY), India (20 MTPY) and 28 MTPY in the Middle East, in Kuwait and Bahrain.

By 2050, the majority of incremental growth in natural gas imports will be undoubtedly attributed to Asia Pacific with almost 650 bcm additions over 2020-2050.

Latin America and Europe, with total increases of 55 bcm and 35 bcm, respectively will follow. The underlying demand will be balanced out by supply increases from primarily Eurasia (285 bcm) Middle East (230 bcm) together with North America (160 bcm) and Africa (50 bcm) over the long term.

Asia Pacific will account for the highest share of global imports by 2050, while the share held by the European market will be gradually decreasing as import volumes increase slowly by 2030, GECF noted.

Big Oil Spends on Investors, Not Output, Prolonging Crude Crunch

By
Kevin Crowley and Laura Hurst

May 7, 2022, 10:30 AM GMT+3
Big Oil is raking in historic amounts of cash, but the windfall isn’t being invested in new production to help displace Russian oil and gas. Instead, executives are rewarding shareholders — setting the world up for an even tighter energy market in the years ahead.

The West’s five biggest oil companies together earned $36.6 billion over and above their spending in the first quarter, or about $400 million in spare cash a day. It was the second-highest quarterly free cash flow on record and enough to relegate billions of dollars of Russia-related writedowns to mere footnotes in their recent earnings reports.

Oil booms typically spark a chase for higher production — but not this time. All five supermajors have kept their capital expenditure budgets firmly in check and pledged that this discipline will hold in future years — even as oil prices have closed above $100 a barrel on all but five days since Russia invaded Ukraine in February. With wells naturally declining in production every year and large projects taking half a decade or more to come online, any expansion lag happening now will push the possibility of new production even further into the future.

“In prior cycles of high oil prices, the majors would be investing heavily in long-cycle deepwater projects that wouldn’t see production for many years,” said Noah Barrett, lead energy analyst at Janus Henderson, which manages $361 billion. “Those type of projects are just off the table right now.”

In short, if consumers are looking for Big Oil to replace Russian production with any urgency, they better look elsewhere.

The last time crude was consistently over $100 a barrel in 2013, Big Oil’s combined capital expenditure was $158.7 billion, almost double what the companies are currently spending, according to data compiled by Bloomberg. The group includes Shell Plc, TotalEnergies SE, BP Plc, Exxon Mobil Corp. and Chevron Corp.

“Discipline is the order of the day,” BP Chief Executive Officer Bernard Looney told analysts Tuesday. The London-based major isn’t budging on its $14 billion to $15 billion spending plans for the year, with its mid-term guidance creeping up to a maximum of $16 billion despite 10% cost inflation in some parts of its business.

Shell, which posted record profits that exceeded even the highest analyst estimate, was equally clear. In her first set of results as chief financial officer, Sinead Gorman repeated time and time again that Shell would keep within its $23 billion to $27 billion range. “Nothing has changed in terms of our capital allocation framework,” she said.

Instead of spending on new projects, companies are opting to reward shareholders after years of poor returns. Exxon, BP and TotalEnergies increased share buybacks while Chevron is already repurchasing record amounts of stock.

There are clear reasons why Big Oil is choosing not to spend more. Chief among them are climate concerns and uncertainty over the future direction of oil demand. Years of pressure from investors, politicians and climate activists came to a head in the past two years, when all the oil majors pledged some form of net zero target by mid-century. BP and Shell actively positioned themselves to move away from oil and gas over the long-term. All are under added pressure to improve returns that dwindled over the past decade due to cost blowouts and low prices.

“Any decision to increase, support or add-in new fossil projects today could see returns risk within a few years,” said Banco Santander SA analyst Jason Kenney. Climate change, technology developments like electric cars and rapidly evolving government policy on emissions are major risks today when deciding whether to invest billions in a new project, he said.

Against that backdrop, investment in the upstream oil and gas sector slumped 30% in 2020, while last year’s spend of $341 billion was 23% below pre-pandemic levels, the International Energy Forum wrote in a report.

“Two years in a row of large and abrupt underinvestment in oil and gas development is a recipe for higher prices and volatility later this decade,” warned Joseph McMonigle, Secretary General of the IEF.

That message has not gone down well with consumers around the globe. From Pakistan to Paris, billions of people are suffering a cost-of-living crisis fueled in large part by high energy costs. In the U.S., President Joe Biden has implored oil companies to reinvest profits from surging oil prices into more production to help ease the shortages caused by Russia’s war against Ukraine. Some U.S. and European politicians have called for a windfall tax on companies’ profits to help ease the burden on consumers.

To be fair, that doesn’t mean companies aren’t investing in growth at all. But they will “focus only on low risk, high return assets” such as shale or expanding offshore fields near existing operations, according to Kenney.

Exxon and Chevron, for instance, are spending aggressively to grow production in the U.S.’s Permian Basin, the world largest shale oil region, with planned growth rates of 25% and 15%, respectively. BP is boosting investment in U.S. shale, but the company won’t be able to ramp up Permian production until it finishes building two large gathering systems at the end of the year.

However, most Permian growth will largely offset declines from elsewhere in the U.S. supermajors’ global portfolio, rather than adding to total barrels. Exxon’s first quarter production of 3.7 million barrels per day was the lowest since its merger with Mobil in the late 1990s. Together Exxon and Chevron plan to spend more on buybacks and dividends this year than they do on production.

“For so long the industry has been told by investors and politicians we need less oil and executives remember that,” said Barrett of Janus Henderson. “If the world needs an extra million barrels a day to ease prices, I’m not sure where it will come from.”

No place to hide: Dollar’s surge cuts across markets

LONDON, May 6 (Reuters) – “Our currency, your problem,” were the words of a former U.S. Treasury secretary in 1971 to other finance ministers aghast at the dollar’s surge. More than 50 years on, relentless dollar strength is again leaving a trail of destruction in its wake.

The U.S. currency vaulted to two-decade highs this week, and its strength is tightening financial conditions just as the world economy confronts the prospect of a slowdown.

The surge threatens “to damage the broader market environment and expose the economic and financial cracks in the system,” said Samy Chaar, chief economist at Lombard Odier.

The 8% gain in the dollar index this year may not reverse in the near future.

Safe-haven appeal for the greenback is intact, with a dollar financing stress indicator from Barclays near its highest level in seven years. And analysis of past peak-to-trough ranges implies the dollar index could rise another 2% to 3%, Barclays said.

IMPORTED INFLATION

The dollar’s latest bout of strength has hit other G10 currencies, from the British pound to the New Zealand dollar, as well as those from developing countries that have big balance of payments deficits.

Even the quintessential safe-haven Swiss franc has not been spared, trading near a March 2020 low versus the greenback.

While currency weakness normally benefits export-reliant Europe and Japan, the equation may not hold when inflation is high and rising, as imported food and fuel become costlier as do companies’ input costs.

Euro zone inflation hit a record 7.5% this month and Japanese lawmakers are fretting that the yen, at 20-year lows, will inflict damage on households. Half of Japanese firms expect higher costs to hurt earnings, a survey found. read more

But growth concerns may prevent central banks, especially in Europe and Japan, from tightening policy in line with the Federal Reserve. Many reckon that could push the euro down to parity with the dollar, a level unseen since 2002.

“With economic recession risk present, who cares how hawkish the ECB (European Central Bank) is or what is priced into the rates curve?,” Societe Generale strategist Kit Juckes said.

A rising dollar helps to tighten financial conditions, which reflect the availability of funding in an economy.

Goldman Sachs, which compiles the most widely used financial conditions indexes (FCI), says a 100-basis-point tightening in its FCI can crimp growth by one percentage point in the following year.

The FCI, which factors in the impact of the trade-weighted dollar, shows global conditions are at their tightest since 2009. The FCI has tightened by 104 basis points since April 1. While equity and bond selloffs had a bigger impact, the dollar’s more than 5% rise in this period will have contributed as well.

EMERGING MARKET PROBLEMS

Almost all past emerging market crises were linked to dollar strength. As the dollar rises, developing countries must tighten monetary policy to head off falls in their own currencies. Not doing so would exacerbate inflation and raise the cost of servicing dollar-denominated debt.

This week, India implemented an unscheduled interest rate rise while Chile put in a bigger-than-expected 125-basis-point rate hike.

Median foreign-currency government debt in emerging markets stood at a third of GDP by the end of 2021, Fitch estimates, compared to 18% in 2013. Several countries are already seeking assistance from the International Monetary Fund and World Bank, and further dollar strength could add to those numbers.

Investors are increasingly wary. Emerging market currencies (.MIEM00000CUS) are at a Nov. 2020 low, while the premium demanded to hold EM dollar bonds versus Treasuries is up some 100 basis points this year (.JPMEGDR)

COMMODITY GAIN AND PAIN

The rule of thumb is that a firmer greenback makes dollar-denominated commodities costlier for non-dollar-based consumers, eventually subduing demand and prices.

That's yet to happen this time as problems such as the war in Ukraine and China's COVID lockdowns hamper the production and trade in major commodities.

Dollar strength generally means higher revenues for commodity exporters such as Chile, Australia and Russia, though that is offset by higher costs for machinery and equipment.

But as rising U.S. yields and a stronger dollar threaten global growth, commodity prices are starting to suffer. JPMorgan said this week it was reducing exposure to the Chilean peso, Peruvian sol and others to position for "challenging times."

The Fed might welcome a rising greenback that calms imported inflation – Societe Generale estimates a 10% dollar appreciation causes U.S. consumer inflation to decline by 0.5 percentage points over a year.

With U.S. gas prices at record levels, the dollar's surge has so far provided little relief. Money markets expect 200 basis points of rate hikes in the United States over the remainder of the year and see the Fed's policy rate peaking around 3.5% by mid-2023.

However, if upcoming U.S. inflation data for April show price pressures peaking, those bets could be dialled down.

Reporting by Saikat Chatterjee and Sujata Rao; Additional reporting by Pratima Desai; Editing by Paul Simao

Public-private decarbonisation

As we mark the 52nd Earth Day, we must recognise that achieving net-zero carbon dioxide emissions by 2050 will require significant investment to finance the necessary economic and social transitions. McKinsey estimates that this will take $9.2tn of annual global investment over the next 30 years – an increase of $3.5tn per year from what is spent today on clean, renewable energy.

Most of these investments will come from the private sector, which is already leading the charge. The value of assets under management with net-zero commitments is now $57tn. The 450 members of the Glasgow Financial Alliance for Net Zero, representing more than $130tn in assets, have pledged to align their portfolios with the Paris climate agreement's 1.5° Celsius warming target. The First Movers Coalition (whose founding members include companies like Amazon, Apple, Boeing, Trane, and Volvo) has pledged to create demand for early-stage clean technologies in “hard-to-abate” sectors like steel, cement, and aviation. In the United States alone, private investment in clean-energy assets reached a record $105 billion in 2021, 11% higher than in 2020 and up 70% over the previous five years.

Moreover, last fall, the International Financial Reporting Standards Foundation created a new International Sustainability Standards Board to develop industry-specific climate disclosure guidelines that will build on reporting standards developed by the Sustainability Accounting Standards Board. By the end of 2021, 258 institutional investors, representing $76tn in assets, had adopted the SASB’s voluntary standards. And, in a significant policy move, the US Securities and Exchange Commission recently proposed new rules that would require public companies to disclose information about their carbon emissions and their plans for addressing climate-related real asset and transition risks.

As these examples suggest, the net-zero challenge cannot be solved by private actors alone. Public-private co-operation and co-ordination will be critical to deploying private capital at the necessary speed and scale. The public sector – from international organisations like the International Monetary Fund and the International Bank for Reconstruction and Development to national, state, and municipal governments – must shape incentives and issue regulations to fuel the necessary private investment in clean-energy projects and infrastructure.

In the US, public-private collaboration has already yielded some clean-energy commercial success stories – most notably Tesla, which was created with the help of a US Department of Energy loan. Government-furnished funding for research and development, loans, and tax incentives have accelerated the growth of the electric-vehicle industry and supported a remarkable reduction in the costs of solar and wind energy over the past 15 years.

Publicly funded and directed innovation has a long history of success in the US. In California, standards set by the

California Air Resources Board led to the widespread adoption of the catalytic converter, reducing tailpipe emissions in the state by 90% between the mid-1960s and the early 1980s. The technology then became a standard part of all motor vehicles sold in the US, because automakers needed to comply with the regulations set first by California (and then by the newly formed Environmental Protection Agency).

Owing to the size of the California market, the fuel-efficiency standards it sets continue to be adopted by major car manufacturers. And within the state, private capital is now being mobilised through public initiatives like the Self-Generation Incentive Program, which provides rebates to organisations that install onsite energy-storage technologies, and through investment tax credits for solar and storage.

As William H Janeway notes in a recent Project Syndicate commentary, the explosion of venture capital in the information-technology and health industries over the past half-century occurred only after the government had invested billions of dollars in upstream R&D and advance-purchase commitments for new products and services. Historically, alternative-energy and decarbonisation technologies have received nowhere near the support provided by the US Department of Defense and the National Institutes of Health for information-technology and biomedical innovations. Increased government support for R&D of climate technologies would accelerate venture capital investment, which has lately gathered momentum.

Policymakers and business leaders should take advantage of this moment to supercharge public-private partnerships for climate-change adaptation and mitigation. The new $1tn Bipartisan Infrastructure Deal allocates $62bn to the DOE to accelerate the developing and scaling up of clean-energy technologies through R&D support, demonstration projects, an expansion of the DOE loan program, and targeted tax credits. These are major first steps. The $555bn of climate provisions in the Build Back Better bill would provide additional de-risking incentives to unlock the private investment required

for the net-zero transition.
Although Russia's war in Ukraine has forced the US to look for ways to increase fossil-fuel production in the short run, it has also provided a wake-up call. Domestic clean-energy production will be key not just to mitigating climate change but also to energy security over the long run. The climate policies in the Build Back Better legislation would accelerate progress toward both of these goals.
But regardless of what happens at the federal level, states and cities can follow California's example and implement bold climate policies of their own. California has pledged $37bn over the next six years – more than most national governments – to combat climate change, and has introduced its own new loan program to encourage innovation in clean-energy technologies.
This is a unique and critical moment for the private sector. It must step up and deploy its capital, building on public-policy catalysts to drive innovation and investment for a sustainable future. – Project Syndicate

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LNG liquefaction investment may have scaled up to $23bn in 2021: GECF

Qatar’s $29bn FID on North Field expansion is a game-changer, noted GECF Global Gas Outlook 2050

LNG liquefaction investment that dropped in 2020 may have scaled up to more than $23bn in 2021 led by Qatar, US and Russia, according to Gas Exporting Countries Forum (GECF).

Qatar’s project, with a final investment decision (FID) of $29bn taken in February 2021 on North East Field expansion, which will add 33mn tonnes per year (mtpy) to the currently existing 77mtpy, is a game-changer, noted the GECF Global Gas Outlook 2050.

Asia Pacific, the main destination of the world’s LNG at present and by 2050, will represent the largest transformational challenge for the currently fragmented natural gas market. Asia Pacific with 70% share of LNG trade in 2020 to make up for even more impressive over 80% by 2050.

The top four largest LNG importers emerged in Asia Pacific and will remain so in 2050 with India becoming second largest LNG importer. China became the top global LNG importer in 2021 overtaking Japan as the leader in the consumption of liquefied

gas, followed by South Korea, and India.
By 2050, the majority of incremental growth in natural gas imports will be undoubtedly attributed to Asia Pacific with almost 650bcm additions over 2020-2050. Latin America and Europe, with total increases of 55bcm and 35bcm, respectively will follow, the GECF noted.
The underlying demand will be balanced out by supply increases from primarily Eurasia (285bcm) Middle East (230bcm) together with North America (160bcm) and Africa (50bcm) over the long term.
Asia Pacific will account for the highest share of global imports by 2050, while the share held by the European market will be gradually decreasing as import volumes increase slowly by 2030 due to a significant drop in domestic production but will later slow down till 2050. The overall natural gas demand in Europe is starting to decrease as decarbonisation and the “green deal” efforts are seen to move gas out of energy mix.
Slow LNG demand is seen in Africa, the Caribbean and partially in the Middle East. A very few import terminal projects are currently being built there.
Pipeline trade will see relatively modest growth, mainly due to shifting the export focus from the European to the Asian market, ramping up exports from Russia and Turkmenistan to China.
According to the GECF, a rapid shift in demand for LNG from traditional markets to emerging markets will be envisaged in the coming 30 years. The Asian natural gas market is anticipated to stay the largest regional market over the 2020-2050 period, as more countries start importing natural gas with existing importers from predominantly developing Asia ramp-up the existing inflow trade.
The incremental growth in Asian imports will be attributed to China (195bcm) and India (107bcm), 14bcm by South Korea, with the balance taken by new importers from South and Southeast Asia and other developing Asia. Legacy importers such as Japan and Taiwan will slowly decrease gas imports.
The share of global demand met by the traditional markets – Japan, South Korea, and Taiwan – will drop from 39% in 2020 to 18% by 2040, mainly due to lower gas demand for power generation in Japan, the GECF said.