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# NUCLEAR INTELLIGENCE WEEKLY®



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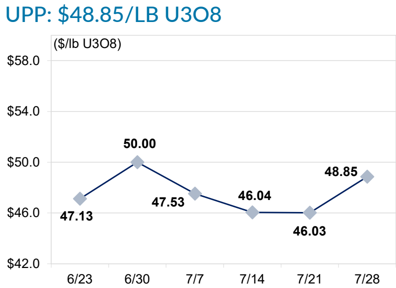
## Market Points

Cameco said in its earnings call this week that it has the flexibility to move the production needle at its Cigar Lake mine between 15 million and 18 million pounds U3O8 in 2024.

Orano CEO Philippe Knoche said in a Jul. 30 earnings call the French nuclear fuel producer needs "long-term business commitments" to make the capital expenditures to increase production capacity, and these talks with customers have just started.

Spot uranium prices were meanwhile boosted by improved investor sentiment in nuclear energy, with Energy Intelligence's Uranium Price Panel delivering an average price of $48.85 per lb. U3O8 for Thursday, Jul. 27, up nearly $3 from $46.03/lb. on Jul. 21.

UPP: $48.85/LB U3O8




NIW Assessment

WEEKLY ROUNDUP

# Manchin U-Turn May Mean More US Nuclear Subsidies

- Washington's influential centrist Democrat Sen. Joe Manchin of West Virginia this week surprised his fellow party members with a compromise on energy and climate legislation labelled the "Inflation Reduction Act" — revised from the previous "Build Back Better Act." Unveiled late on Jul. 27, the new bill includes a $15 per megawatt hour production tax credit for existing nuclear plants, with offsets for higher realized revenue from electricity prices and government subsidies and bonuses for meeting prevailing wage standards. The tax credit takes effect as of December 2023. But unlike prior iterations of the nuclear production tax credit provision that only extended the credit to 2026 and 2027, the new legislation would extend the credit to December 2032. The bill would also allow advanced nuclear reactors to qualify for an investment tax credit beginning in 2025, and allocate $700 million to the Energy Department's effort to procure high-assay low-enriched uranium for advanced reactors.

- Georgia Power announced on Jul. 29 that it has completed all 398 regulatory inspections, tests and analyses for Unit 3 of the twin-unit AP1000 Vogtle newbuild project in the US state of Georgia. Parent company Southern Co. said in its earnings report this week that Georgia Power's 45.7% share of total capital costs increased by another $52 million to about $10.5 billion, but the project is on target to meet its latest in-service dates: Vogtle-3 in first quarter 2023 and Vogtle-4 in fourth quarter 2023. Any further delays, however, could result in "additional base capital costs for Georgia Power of up to $35 million per month for Unit 3 and $45 million per month for Unit 4," among other testing- and construction-related costs. The announcement follows two lawsuits filed by minority project owners over whether the total capital cost has exceeded a threshold that allows them to freeze payments to Georgia Power in exchange for a smaller project share.

- In June Orano started using depleted uranium UO2 powder produced via a "wet process" at its Melox plant, where the material is mixed with plutonium to produce mixed-oxide fuel assemblies. Melox production has plunged over the past decade after the French fuel cycle giant switched its UO2 source to Framatome's Lingen plant in Germany, which uses a "dry" process. Since 2019 Orano has been building its own "wet" UO2 production line at its Malvesi plant in southwestern France to be commissioned next year. But Orano has already "switched back to a wet process with supplies from another provider," Orano CEO Philippe Knoche said in a Jul. 29 earnings call. That supplier appears to be Westinghouse's Vasteras plant in Sweden, which according to the French regulator produced 6 tons of UO2 in 2021 for use in Melox. Knoche predicts that this will have "a positive impact helping to ramp up the Melox production," but that's starting from a low point: Melox produced only 51 metric tons of Mox last year, down from a peak of 150 tons in 2012. These Melox production problems have led to a worrying buildup of separated plutonium at Orano's La Hague reprocessing plant.

## NUCLEAR FUEL MARKET

# Cameco Highlights Production Flexibility

Canada's Cameco said this week that thanks to delays in the restart of its McArthur River uranium mine and Key Lake mill in northern Saskatchewan, the operation will only produce 2 million pounds U3O8 this year, down from the 5 million lbs. it had previously hoped to produce.

The uranium producer still plans a ramp-up by 2024 to an annual output maintained at 15 million lbs. per year, and given the flexibility at its nearby operational Cigar Lake uranium mine, Cameco indicated it could increase production in 2024 with relative ease.

Already Cameco and France's Orano, its joint venture partner in both McArthur River and Cigar Lake, are apparently able to make up for that 3 million lbs. shortfall from 2022 McArthur River output with higher output from Cigar Lake. The companies had planned to produce 15 million lbs. from Cigar Lake this year, but that figure has, in the company's Jul. 27 earnings statement, increased to 18 million lbs. "after successfully catching up on development work deferred from 2021," according to the company.

In February Cameco and Orano announced their intention to bring the mothballed McArthur River mine and Key Lake mill into operational readiness this year, although CEO Tim Gitzel this week revealed "challenges with respect to the availability of critical materials, equipment and skills."

And though Cameco has announced it would reduce Cigar Lake's annual output to 13.5 million lbs. output by 2024, it seems to now be weighing its options. "We are actually planning to bring Cigar Lake down in 2024 to 15 million lbs," Gitzel said. "So obviously we can vary between 15 and 18 without much difficulty." He added that the miner's "ability to increase production in McArthur" would require "a little bit of work" and capital expenditure, but can be reasonably done if needed. "We have got that flexibility at our two sites," he said.

Separately Cameco and Kazatomprom, its joint venture partner in the Inkai in situ recovery uranium mine in Kazakhstan, continue to work together to secure an alternative route from Kazakhstan to Europe via the Caspian Sea "that doesn't rely on Russian rail lines or ports," Cameco's earnings report states. "In the meantime, we continue to delay shipment of our share of Inkai production destined for our Blind River refinery" in Ontario. Cameco is entitled to purchase 4.2 million lbs., or 50% of JV Inkai's updated planned 2022 production of 8.3 million pounds this year, "assuming no production disruptions due to the COVID-19 pandemic, supply chain disruptions or other causes."

New sanctions in Canada seemed to prohibit the loading of nuclear fuel cargoes onto Canadian vessels at the port of St. Petersburg in Russia, although Energy Intelligence understands that as non-Russian material, Kazakh uranium should be exempt from the sanctions. While it's not totally clear that Cameco is exempt from using Russian services to transport Inkai material through Russia, Gitzel said that Cameco does "not, at this point want to be using Russian rail lines or ports to ship our material, that is contrary to us, for our values as a company."

The new Canadian sanctions have once more threatened to constrain existing Russian nuclear fuel supply. But without regulatory certainty or a strict prohibition of Russian nuclear fuel supply to utilities in the US or Europe, the prospect is not sufficient enough to signal to western fuel cycle firms such as Orano a need to ramp up capacity to offset Russian supply.

Orano is "expecting market signals" and EU or US authorities "are calling for improvement in production capacities" at western conversion and enrichment plants, but "you're talking long-term investments," Orano CEO Philippe Knoche said in the company's Jul. 30 earnings call. New capacities require a huge capital expenditure, "so we need to have clients' commitments to pave the way for such sites to be made operational by 2040."

Meanwhile, in the US, a compromise on energy legislation that promises to support nuclear energy with tax credits helped push up spot prices this week. Energy Intelligence's Uranium Price Panel delivered an average price of $48.85 per pound U3O8 for Thursday, Jul. 27, up from the previous week's price of $46.03/lb.

*Jessica Sondgeroth, Washington*

## URANIUM PRICE PANEL

*For the week ended July 28, 2022*

| Weekly Spot Market Prices | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Jul | | | | June | | | | | May | | | |
| | Chg. | 28 | 21 | 14 | 7 | 30 | 23 | 16 | 9 | 3 | 26 | 19 | 12 | 5 |
| Price ($/lb U3O8) | 2.83 | 48.85 | 46.03 | 46.04 | 47.53 | 50.00 | 47.13 | 47.39 | 52.25 | 49.40 | 46.67 | 47.14 | 50.41 | 54.00 |
| *Total Assessments* | *-1.00* | *9.00* | *10.00* | *9.00* | *10.00* | *10.00* | *10.00* | *11.00* | *10.00* | *10.00* | *12.00* | *10.00* | *9.00* | *11.00* |
| *% within 1 StDev* | *-24.44* | *55.56* | *80.00* | *55.56* | *70.00* | *60.00* | *90.00* | *72.73* | *70.00* | *40.00* | *75.00* | *80.00* | *77.78* | *72.73* |
| Low ($/lb U3O8) | 2.75 | 48.50 | 45.75 | 45.50 | 47.00 | 49.25 | 47.00 | 46.60 | 51.70 | 49.00 | 46.00 | 47.00 | 49.00 | 53.50 |
| High ($/lb U3O8) | 3.00 | 49.25 | 46.25 | 46.75 | 48.50 | 50.75 | 47.50 | 48.50 | 52.50 | 50.15 | 47.50 | 47.50 | 52.00 | 55.00 |
| Variability* | 0.00 | 0.00 | 0.00 | 0.31 | 0.50 | 0.16 | 0.06 | 0.09 | 0.40 | 0.32 | 0.05 | 0.00 | 0.28 | 0.50 |

*This represents the value of the potential range of conceivable final averages that might result when random elimination is used to balance market positions within the panel.

CORPORATE

# EDF's Headaches Set to Remain Post-Nationalization

EDF's €5.3 billion ($5.4 billion) net loss posted this week for the first half of the year, and its warning of lower earnings in the second half, underlines just how intractable the nuclear giant's difficulties will remain even after it is fully nationalized. And while EDF did receive some good news this week, as France's Nuclear Safety Authority (ASN) signed off on its strategy to inspect its entire domestic fleet of 56 reactors, the utility is unlikely to improve its balance sheet until key structural issues in the French power market change. In particular the French government looks set to continue to use EDF as a tool to help cool the power market.

If revenues were everything, EDF would be perfectly positioned to take advantage of soaring European — and particularly French — power prices: the utility racked up €66.3 billion in sales in H1 2022, up 66.4% from the same period in 2021. In the UK, where EDF continues to operate a fleet of 10 reactors, H1 nuclear output was up 2.3 Terrawatt hours over H1 2021, for a total of 23.2 TWh. But increased prices helped EDF's Ebitda (earnings before interest, taxes, depreciation and amortization) from its UK operations jump to €860 million this past half year—some 3.4 times the €267 million Ebidta in H1 2021.

But in France EDF produced far less power than it had anticipated, and in many cases pre-sold, and plunging production from its French nuclear fleet, alongside "historically low" hydro-power availability, meant it scrambled to buy expensive kilowatts on the spot electricity market. "We still have to buy back volumes in order to compensate the lack of nuclear generation in France," EDF head of finance Xavier Girre told analysts in a Jul. 28 earnings call. And given the amount power prices keep soaring, the total H2 Ebidta "is expected to be significantly lower than the first half of the year," when EDF realized an Ebidta of €2.7 billion.

That is likely to lead to an eye-popping 2022 loss for EDF. The €5.3 billion loss for H1 was already historic — the only other negative net income figure the company has posted in the past two decades was the €700 million loss it saw in H1 2020, thanks to Covid — but the size of EDF's 2022 losses will likely easily surpass the €9.7 billion the French state plans to spend on EDF's 100% nationalization.

EDF's situation has been exacerbated by government demands for the company to sell more of its nuclear output to competitors at the fixed "Arenh" tariff well below current market prices. French tariffs so confine EDF, the regulatory measures cost the utility some €6.2 billion in the first half of this year. As a reference, of the 400 TWh EDF sold last year, 33% was "driven by market price" and 61% was "Arenh-driven", according to EDF.

## Nuclear Troubles

With all this said, EDF's nuclear outages remain its biggest problem, and they cost it €7.3 billion in H1. Nuclear output fell by 27.6 TWh over the period to 154.1 TWh, as more than half of EDF's French nuclear fleet remained offline.

That largely boils down to a problem with stress corrosion in key piping of multiple reactors first detected late last autumn at Civaux-1, one of four 1,450-megawatt "N4" reactors, that was then in the middle of its second 10-year inspection outage. The corrosion detected in that reactor prompted EDF to start checking other reactors — particularly the younger ones in the N4 and the 1300 MW series of reactors — some of which have remained shut once serious stress corrosion was detected.

This week the ASN found that EDF's inspection strategy "is appropriate." It referenced more than 70 assessments that have been conducted in the laboratory on welds sampled from eight reactors. These assessments "were able to identify the geometry of the pipes and the thermomechanical stresses to which they are subjected as being the main factors liable to influence the appearance" of stress corrosion, the ASN said on Jul. 26.

These identified "susceptible" components of the N4 reactors and the twelve 1300-MWe reactors of the Belleville, Cattenom, Golfech, Nogent-sur-Seine and Penly plants. Across the rest of EDF's French fleet, including the 34 reactors of its 900-MWe series and the eight 1300-MWe reactors of the Paluel, Saint-Alban and Flamanville plants, "it would appear that the susceptibility of the reactors" to the stress corrosion phenomenon "is very low."

The ASN largely backed EDF's plans to inspect its entire French fleet by 2025, while prioritizing the "more susceptible" reactors, and the regulator praised a "new, non-destructive ultrasounds process" that EDF has developed over the past six months. The results "are encouraging and should enable this new inspection method to be deployed as of the second part of 2022."

The only real pushback from the regulator came at the 1300 MW Belleville-2 reactor, where the ASN "considers that inspection of this reactor — scheduled for 2024 — needs to be brought forward." EDF CEO Jean-Bernard Levy told analysts the company "will of course comply" with this decision, and said it will have "no impact" on the EDF's 2022 French nuclear output projections of 280-300 TWh, and 2023 projections of 300-330 TWh.

## Continued Arenh Allocations

EDF will continue to be forced to sell much of those volumes under the Arenh tariff to its competitors. The government is using this as a pressure valve for French power buyers. This is why while EDF must normally sell 100 TWh of its nuclear output at a tariff of €42 per megawatt hour to competing energy suppliers, the government in January required it to sell an additional 20 TWh under the Arenh tariff, though at a slightly elevated price of €46.2/MWh. This would help "preserve the purchasing power of the French and the competitiveness of business", the government said at the time.

Last month the government's Energy Regulatory Commission (CRE) proposed that EDF's Arenh volumes in 2023 be raised to 130 TWh, and earlier this week French Minister for Energy Transition Agnes Pannier-Runacher told the National Assembly that volumes of 135 TWh in 2024 and 2025 would be "a reasonable compromise" between the government's desire to push the volumes up to 150 TWh and EDF's desire to minimize its Arenh obligations.

While none of this is yet set in stone, it's clear that the government has a significant appetite to use a state-owned EDF to help cool French retail power prices. Parliament has given some pushback: the bill the National Assembly just passed to appropriate funds for EDF's full nationalization included hiking the Arenh price to €49.5/MWh, which would relieve some of EDF's pain. This legislation is now being reviewed by the Senate.

To no surprise, EDF continues to advocate a complete redesign of the electricity market, both in France and Europe more broadly. Maybe the market "sort of worked during normal years, normal periods," said Levy. But the outgoing EDF CEO said that the current situation "is unbelievably volatile with unbelievably high prices", and argued that "with the war in the Ukraine, supply chain issues, inflation and so on, I think there is no doubt that the market design needs a good chunk of repairs or maybe a total reshuffle."

*Phil Chaffee, London*

UNITED STATES

# DOE Taking Advanced Nuclear Loan Applications

The US Department of Energy's (DOE) Loan Program Office has for several years urged the US nuclear industry to apply for nearly $11 billion in federal loan guarantees to accelerate the commercialization of advanced reactors, including small modular reactors (SMRs). But with advanced reactor technologies still in the design, testing and demonstration phases, a number of vendors say it's too early to begin the process of securing federal debt financing. The one exception appears to be Holtec International, which is seeking financing for its SMR-160 that it plans to build first at its Oyster Creek decommissioning site and then elsewhere in the US.

The Biden administration seeks to decarbonize the US electricity sector by 2035, and to that end has breathed new life into the DOE Loan Program Office. This follows nearly a decade of uncertainty over the office's future after one of its 2009 awardees filed for bankruptcy in 2011. With new leadership and some tweaks to the loan guarantee statute from Congress in late 2020, DOE is making available more than $40 billion in loans to commercialize clean energy technologies, including advanced nuclear, carbon capture, battery storage, renewables, and electric vehicles, just to name a few.

To date the loan program's only nuclear beneficiary has been Georgia Power's large-scale newbuild project at Vogtle, still under way, with $12 billion in federal debt financing. Of what remains from 2007 and 2009 allocations for the nuclear share of the program, about $8.9 billion is available for nuclear power facilities, with a focus on advanced reactors, but including upgrades and uprates at existing reactors and hydrogen production generated by nuclear power. And $2 billion is available for "front end" fuel cycle technologies to supply advanced reactors. All of this was included when in early 2020 the government relaunched a 2014 loan offering to US nuclear suppliers.

The DOE declined to provide any information about any existing nuclear industry loan applicants, but several vendors — including NuScale, TerraPower and X-energy — told Energy Intelligence this week they are aware of the federal debt financing option for new nuclear projects but are focused on the existing use of DOE's Advanced Reactor Demonstration Program (ARDP) cost-share awards to first license or demonstrate their technology.

Although applicants are not eligible for the federal loan or loan guarantees until their respective technology is ready for commercial deployment, Congress in 2020 amended the DOE's loan guarantee statute to allow applicants to at least begin the loan application process earlier.

At least one vendor is taking advantage of that change. Holtec International on Jul. 20 announced it is seeking $7.4 billion "to help build four SMR-160s and to expand the company's manufacturing capacity to build the first wave of nuclear reactors in large numbers." On Mar. 9 the DOE approved the first part of Holtec's loan application, first submitted in November 2021, and Holtec then submitted the second part on Jul. 19.

The first part of the formal DOE loan application submission considers technical eligibility, such as whether the project is "innovative" and meets greenhouse gas emissions requirements and the second part determines project viability and whether the applicant is prepared to move into the third phase of the process involving due diligence and term sheet negotiations. Prior to the 2020 amendments, due diligence was conducted in the second stage of the application process.

## Eligible to 'Reasonably' Eligible

With $116 million in funding from the DOE's ARDP for the SMR-160 to "enable completion of the remaining research and development work," Holtec expects to file its application for the SMR-160 with the US Nuclear Regulatory Commission in 2024. Holtec spokesperson Joe Delmar told Energy Intelligence the company must complete that ARDP milestone "before the DOE [Loan Program Office] would disburse any money as a loan."

Congress in 2020 amended the DOE clean energy loan program to allow DOE to move an applicant through the first and second part of the application process so long as the project is close to eligible. As long as DOE determines that the initial part of an application "adequately describes" an eligible project or a project that "may reasonably become" eligible, it can — at the same time the loan office does its due diligence — "offer a Preliminary Term Sheet to be utilized by an Applicant for the purpose of obtaining its third-party contracts or offtake agreements."

Securing purchase or offtake agreements helps check off another criterion for eligibility — that the project has a "reasonable prospect of repayment." For the Vogtle newbuild, loan repayment has been aided by utility power purchase agreements with minority project owners and supportive state policies in a regulated market, i.e. the ability of majority project owner Georgia Power to pass on project costs to ratepayers.

For its part, Holtec is still looking for power purchase agreements along with SMR-160 locations beyond a first-of-a-kind unit at Holtec's own Oyster Creek site in New Jersey. "Holtec's loan application to the DOE identifies several locations for the first SMR-160 plants, as any deployment requires securing the requisite financial support for the plant's construction and a long-term purchase power agreement from the candidate host states," Holtec said in a Jul. 20 statement. Early prospects include sites within the service area of US nuclear operator Entergy, which signed a memorandum of agreement with Holtec to evaluate the feasibility of deploying one or more SMR-160s. Holtec also noted that its existing state-of-the-art manufacturing plant near Oyster Creek "will likely be located in the region where the first SMR-160s will be deployed."

## Fuel Cycle Eligibility

Of the $10.9 billion in loan funds devoted to nuclear energy, about $2 billion has been designated for "front-end" nuclear fuel cycle projects or facilities "that convert U3O8 powder into a gaseous form of uranium hexafluoride, transform natural uranium or uranium tails to a higher isotopic content of U235, or fabricate nuclear fuel." So far, it would seem that no existing nuclear fuel producers in the US have applied for this funding, which makes sense considering suppliers are still awaiting firm demand signals — such as long-term contracts — before launching capacity expansions.

But Australia's Silex Systems told Energy Intelligence it has in recent years "had several discussions" with the DOE loan program office over its US-based Global Laser Enrichment (GLE) technology for tails re-enrichment. This would produce natural-grade uranium at an annual rate of around 2,000 metric tons UF6 and potentially high-assay low-enriched uranium for advanced reactors. GLE is a joint venture with Canadian uranium miner Cameco. Silex said the DOE is "keen for GLE to keep in touch."

But to qualify, GLE must first complete its pilot demonstration of the scaled laser enrichment technology and sufficiently demonstrate a reduction in "technology risk." GLE is currently targeting commercial pilot demonstration in 2025. Once the technology is demonstrated, "GLE's owners (Silex and Cameco) will assess the merits of pursuing a loan facility through the DOE's [Loan Program Office], or whether not to pursue," said a Silex spokesperson.

*Jessica Sondgeroth, Washington*

INDIA

# Slow Pace of Indigenous Newbuilds Irks Lawmakers

India's 700 megawatt pressurized heavy-water reactor, dubbed the "IPHWR," is intended to be the workhorse of the Indian nuclear power program. New Delhi plans to bring 16 of the indigenous reactors on line by 2031, producing some 11.2 gigawatts. But while serious procurement has already been launched for the long-lead items needed for a "fleet mode" project to build 10 IPHWRs nearly simultaneously, there are major questions about the rollout of both the reactors already under construction and the commissioning of the first-of-a-kind reactor, which is India's largest indigenous design.

Parliament in particular is cognizant of the distance between nuclear planners' promises and the actual performance of the newbuild program. India is the world's third-largest greenhouse gas emitter, and following a massive power crisis during India's summer season from April through July, New Delhi has gone relatively quiet on nuclear power while doubling down on domestic coal mining — and, to be fair, building out solar and wind farms. V. Vijayasai Reddy, a lawmaker in the Rajya Sabha, asked the government this month why, given its commitment to building out non-fossil fuel generation capacity of 500 GW by 2030, India's ambitious nuclear newbuilds are moving at a "snail's pace"? Separately MP Shashi Tharoor last week expressed concern at these delays, and asked if there are any design flaws or safety issues that have been identified with IPHWR.

Construction delays aren't just being experienced at the indigenous IPHWRs, but also at the four VVER-1000s being supplied by Russia's Rosatom at Kudankulam in the southern state of Tamil Nadu. Jitendra Singh, the minister responsible for Atomic Energy, told Reddy that while work on Indian newbuilds is "in full swing," there have been delays due to "factors like delay in supply of critical equipment by domestic industries, financial crunch, cash flow problems of contractors, shortage of skilled contractor manpower, restrictions during [the] Covid-19 pandemic, implementation of recommended design changes following the Fukushima incident etc." The "ongoing Russia-Ukraine conflict" also impacted the four Kudankulam newbuilds.

But no matter the broader context, it's impossible to deny the IPHWR's teething issues. When Unit 3 of the Kakrapar nuclear power plant in the western state of Gujarat was synchronized to the grid on Jan. 10, 2021, it was touted as a milestone for India's nuclear program, and ramp up to full commercial operation was anticipated by Mar. 31, 2021. But to date that milestone hasn't been achieved, and the commissioning of the first-of-a-kind IPWHR looks just as troubled as its construction, which started in 2010 and lasted through to first criticality on Jul. 22, 2020.

## Modifications, But 'No Design Flaws'

NPCIL and AERB did not reply Energy Intelligence questions. But the government must respond to parliamentary questions, and "there are no design flaws or safety issues in the design" of the IPHWR, Singh argued in his response to Tharoor. And yet Singh acknowledged that several modifications are under way at Kakrapar-3 following the observation of elevated temperatures in "certain areas of the reactor building" during the ramp-up process.

A Jun. 1 filing from state-owned Nuclear Power Corp. of India Ltd. (NPCIL) with the Central Electricity Regulatory Commission was more revealing: Kakrapar-3 has been turned off since Apr. 28, 2021 as modifications have been made to the pump room ventilation system. "These modifications, which are complex in nature, are being implemented after undergoing several stages of detailed review and require clearance from the regulatory body for implementation," read the filing, which noted that the reactor can only be restarted after the modifications are implemented.

Singh claims Kakrapar-3 is now expected to restart and ramp up to commercial operations by December, but this is dependent on obtaining "stage-wise regulatory clearances" from the Atomic Energy Regulatory Board.

Meanwhile Singh revealed that Kakrapar-4, which the government claimed as recently as Mar. 3 was to start operations this year, is just 94% complete. In a May 27 filing of the Central Electricity Regulatory Commission, NPCIL said that "in line with" Unit 3, "major modification works on civil structural beams and ventilation systems of reactor building need to be carried out," and these modifications must be completed before starting testing of the primary heat transport system. Kakrapar-4 first began drawing electricity from the grid to help with start-up operations in April 2021, and thanks to delays from the reactor modifications and Covid-19, the Central Electricity Regulatory Commission has allowed it to continue to draw that power through July 2023.

## Snail's Progress On Site

The delays related to Covid-19 are very real, of course: there was a complete pause on all reactors under construction from Mar.

NEWBUILD

# New Delhi Slowly Ordering 'Fleet Mode' Components

While progress remains slow, over the past year India's nuclear planners have signed major supply-chain contracts for the buildout of 10 additional 700 megawatt indigenous pressurized heavy-water reactors, or IPHWRs: two at Kaiga in Karnatka, two at Gorakhpur (Units 3 and 4) in Haryana, two at Chutka in Madhya Pradesh and four at Mahi Banswara in Rajastan. This ambitious 1.05 trillion rupee ($13.20 billion) "fleet mode" program, which New Delhi first committed to in 2017, would see construction of the newbuilds start sequentially between 2023-25, and to be completed in 2031. All of that is on top of the twin IPHWRs planned but not yet under construction as the first two units of Gorakhpur.

Last August state-owned heavy engineering firm BHEL won a tender for the engineering, procurement and construction of the turbine island package for six IPHWRs, worth 108 billion rupees ($1 billion). That's in addition to the already-announced "fleet mode" orders for reactor header assemblies and steam generators it had secured the previous month.

"The fleet mode ordering has happened," BHEL Managing Director Nalin Shinghal said in a May 21 earnings call, and "I think nuclear will continue to play a very strong role."

Two months ago GE Steam Power signed a $165 million contract with BHEL for the supply of three nuclear steam turbines from its factory in Sanand, Gujarat. While GE Steam Power, the nuclear division of which is theoretically being sold to France's EDF, will be acting as a subcontractor to BHEL, it's not immediately clear which IPHWRs will be supplied by its turbines. GE Steam Power confusingly listed all four of the the Gorakhpur newbuilds, only two of which are technically in the "fleet mode" program, as well as the twin IPHWRs planned for Kaiga.

"Most of the purchase orders for bulk procurement of critical equipment" such as steam generators, pressurizers and reactor headers "have been placed" for this fleet of IPHWRs, said Larsen & Toubro in its annual report, but further "fleet procurement" is "also expected" over the next two to three years.

On the ground, meanwhile, the only real evidence of "fleet mode" activity is at Kaiga, where site excavation for IPHWR Units 5 and 6 began on Apr. 28. First nuclear-safety concrete is likely to be poured on the IPHWRs at Kaiga next year.

*Rakesh Sharma, New Delhi*

24, 2020 through May 24, 2020, barring "only essential activities including preservation," the Department of Atomic Energy said in its most recent annual report. This led to restrictions on "inter-state movement of equipment and personnel, etc. and effected the contractor and vendor support for ongoing activities at site," NPCIL claimed in its filings to the Central Electricity Regulatory Commission.

NPCIL has also been pointed to Covid-19 restrictions impacting both employees and contractors. The IPHWR needs "stringent quality assurance on the design, selection, qualification, operation and maintenance of critical equipment like reactor components, steam generators and pressurizer," NPCIL said in another filing. "Their manufacturing and pre-service inspection have added to the delay in supply of these equipment. There are limited qualified vendors in India for making nuclear-grade reactor equipment and components."

That may help explain at least some of the other reactors in or near construction. Rajasthan-7, the first of two twin IPHWRs at Rawatbhata in the western state of Rajasthan, was to be synchronized with the grid this year, but is just 95% physically complete. Rajasthan-8 is only 81% physically complete. And the first pour of nuclear-safety concrete for Gorakhpur-1, the first of two IPHWRs in the northern state of Haryana was to happen in 2019, hasn't happened yet.

But things may be moving faster, at least in the supply chain. In its latest annual report, privately held construction giant Larsen & Toubro noted that it delivered the four 700 MW steam generators for Gorakhpur-1 and -2 some 6-12 months ahead of the contractual delivery date, despite Covid-19. It also dispatched the pair of end-shields for the reactors some three months ahead of schedule. But Larsen & Toubro separately noted that its order book for the fiscal year ending Mar. 31 was down 9.8% year on year, mainly due to the deferral of orders in the nuclear equipment system business and fertilizer and petrochemical business.

*Rakesh Sharma, New Delhi*

JAPAN

# Fukushima Water Release Plan Clears Hurdle

Last week's regulatory green light for a scheme to release nearly 1.4 million tonnes of tritium-laced water from the Fukushima Daiichi site into the Pacific Ocean was a key milestone, but significant hurdles remain if water releases are to start by the middle of next year as planned. Before that happens site owner Tokyo Electric Power Co (Tepco) must secure three critical local approvals and install complex new installations on site. Just as importantly Tepco and the Japanese government must manage the pushback from plan opponents, in particular the Japanese fishing industry and nearby governments in Beijing, Seoul and Taipei alarmed at the prospect of the tritium contaminating their waters.

In mid-2023 Tepco hopes to begin releasing treated and diluted water from the Fukushima Daiichi site, under the plan adopted as national policy in April 2021 and approved by the Nuclear Regulation Authority (NRA) last week. Water releases would then continue over three decades until the scheduled completion of decommissioning of the broader Fukushima site in 2051.

"If Japan insists on putting its own interests above the public interest of the international community and insists on taking the dangerous step, it will surely pay the price for its irresponsible behavior," Chinese foreign ministry spokesman Wang Wenbin said only hours after the NRA's Jul. 22 approval of the plans Tepco formulated with the Japanese government's Ministry of Economy, Trade and Industry (Meti). "The disposal of nuclear-contaminated water in Fukushima could affect the global marine environment and the public health of Pacific-rim countries. It is by no means a private matter for Japan."

South Korea and Taiwan voiced similar objections, and both are already expanding marine-monitoring systems and developing new ocean dispersion simulation models to test Tepco's claim that the greatest concentrations of tritium will not extend beyond "2-3 kilometers" offshore from the Fukushima facility.

As of Jul. 21, some 1.3 million cubic meters of contaminated water was stored in more than 1,020 tanks at the Fukushima Daiichi site, and each day that grows by some 150 cm as more water is used to cool the plant's three melted-down reactors. Of the water in storage some 411,500 cm has been fully treated by the "Advanced Liquid Processing System" (Alps) system that reduces the concentration of radionuclides other than tritium, which cannot be removed by purification. Tepco plans to re-purify 68% of this water, or 854,900 cm, by running it through the Alps system a second time. All the water would then be diluted over 100 times before being discharged into the Pacific Ocean from the outlet of a kilometer long undersea tunnel.

As water discharges, and water storage tanks are dismantled, it would clear needed space for the solid radioactive waste that will be generated during the dismantling of the four disabled reactors at the site.

## Seeking "Advanced Consent"

All of that can happen, however, only once Tepco clears a number of hurdles. The NRA approval was a big one: the regulator confirmed the safety of the designed program after the month-long period of public comment following the approval of the plan by the NRA's five commissioners on May. 18, 2022. Going forward, Tokyo may struggle to contain criticisms from China, South Korea, Taiwan and the Pacific Island Forum, but the biggest hurdles to the water release plan are closer to home.

Under safety agreements signed Dec. 21, 2021 with the Fukushima Prefecture and the Okuma and Futaba townships where the Fukushima Daiichi plant is located have "advance consent" rights, or effective veto power. Only after Tepco has secured "advance understanding" from these local authorities can it start construction work on the planned Alps-treated water dilution and discharge facilities.

This process is already underway. The decommissioning monitoring committee of Fukushima Prefecture already gave conditional approval on Jul. 26 to a draft report on the Tepco plan for referral to the three local governments. This report stated that "the safety of the surrounding area should be ensured" by the plan implementation measures Tepco "has shown so far." However, the committee issued eight "requirements" for more detailed information Tepco must provide on key issues, notably all of the radionuclides involved, measures to cope with any "troubles," and, in response to Tepco's intention to squeeze its work schedule by two months after beginning construction, a promise "to put safety above meeting schedules," the *Fukushima Minyu Shimbun* reported Jul. 27.

Tepco appears convinced that it will obtain the approvals next month. A spokesperson told Energy Intelligence that the utility will begin construction on related installations, such as the one-kilometer tunnel and discharge outlet, in August, "pending approvals" from the three local authorities. Tepco then aims to complete the engineering work by mid-April 2023, whereupon the NRA will conduct a pre-operational inspection. The spokesperson said a more itemized work schedule would be disclosed after the local consents are obtained.

Tepco's ability to deduct two months from the original 10.5 month construction schedule is likely due to the utility commencing early site work before receiving any approvals. The Sendai-based *Kahoku Shimpo* reported Jul. 13 that "environmental preparatory work" has been proceeding since last December, and has included excavating parts of the vertical shaft as well as the seabed at the site of the discharge port of the one-kilometer undersea tunnel. The Tepco spokesperson told Energy Intelligence that a 43.7 billion yen (US$320 million) allocation for expenses on preparatory engineering and construction of the Alps-treated water discharge facility was included in a 237.6 billion yen allocation of funds approved by Meti on Apr. 12, 2022.

Actual construction on the planned installations, such as the one-kilometer tunnel and discharge outlet, can begin only after the Fukushima and the two host townships give their consent.

## The Next Challenge

When the dilution and discharge facilities are completed, presumably in mid-April 2023, Tepco faces three final hurdles before it can begin the water releases.

The first hurdle is a pre-operational inspection by the NRA of the completed facilities. A second is from Meti, which according to one Meti official plans to integrate findings from an International Atomic Energy Agency review mission in its assessment of the project's radiation impact on humans and the environment.

Finally Tepco must secure the acquiescence of the National Federation of Fisheries Cooperative Associations, whose leadership reaffirmed its "categorical opposition" to the ocean release scheme in a Jul. 22 manifesto. This reminded Tepco of commitments first agreed in 2015 that action would not be taken without the federation's "understanding"; the government also promised to create a "super fund" to defend fisheries against "reputational damage."

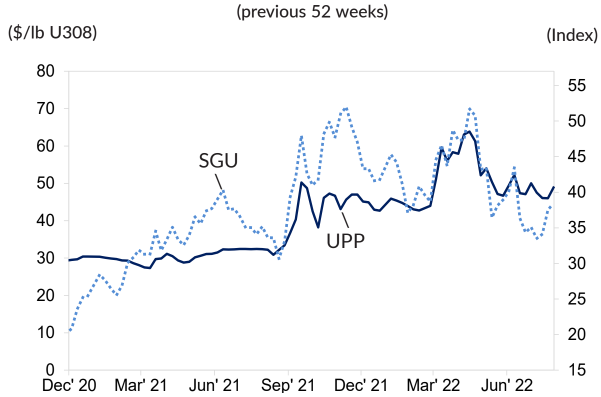
In its Jul. 26 meeting, the Fukushima Prefecture reminded Tepco executives of this commitment, *Fukushima Minyu Shimbun* reported.

*Staff Reports*

# URANIUM MARKET UPDATE

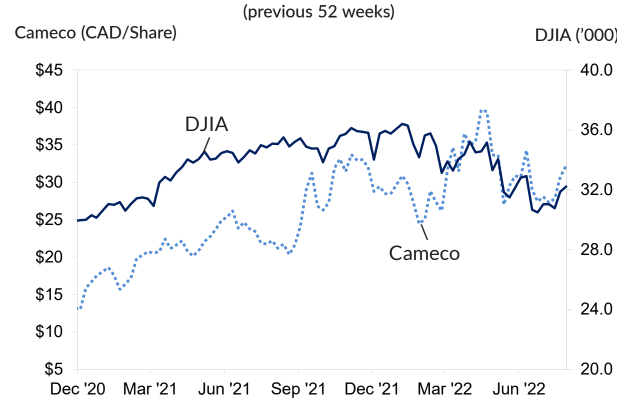
*All prices as of Thursday, July 28, 2022*

## UPP VS. SOLACTIVE GLOBAL URANIUM INDEX
(previous 52 weeks)



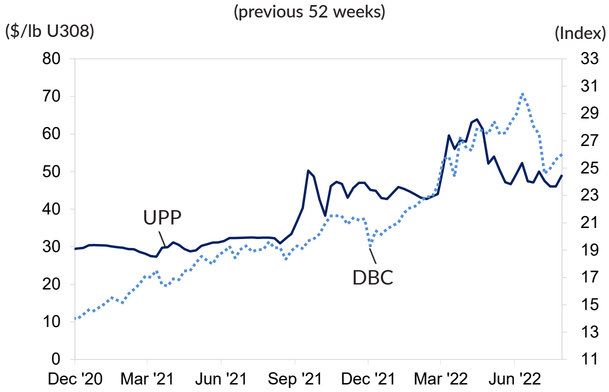

The Solactive Global Uranium Total Return Index, created by Structured Solutions AG, tracks the price movements in shares of companies active in the uranium mining industry. Calculated as a total return index and published in US$, its composition is ordinarily adjusted twice a year.

## CAMECO VS. DOW JONES INDUSTRIAL AVERAGE
(previous 52 weeks)



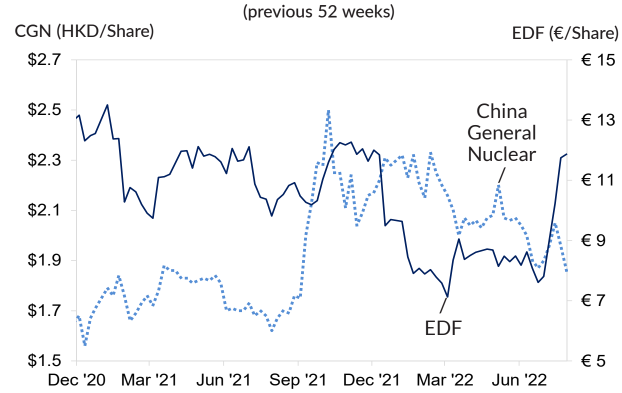

Canadian uranium miner Cameco's stock is valued in Canadian dollars compared with the US dollar on the Dow Jones Industrial Average (DJIA). Roughly two-thirds of DJIA's 30 component companies are manufacturers of industrial and consumer goods. The others represent industries ranging from financial services to entertainment.

## UPP VS. POWERSHARES DB COMMODITY INDEX
(previous 52 weeks)




The PowerShares DB Commodity Index Tracking Fund is designed to provide investors with a broadly diversified exposure to the returns on the commodities markets. It is based on the Deutsche Bank Liquid Commodity Index, which is composed of futures contracts on 14 of the most heavily traded and important physical commodities.

## EDF VS. CHINA GENERAL NUCLEAR
(previous 52 weeks)




The stock valuation of France's Electricite de France (EDF), largely owned by the French state, is in euros compared to state-owned China General Nuclear (CGN) Power Co., valued in Chinese yuan renminbi. Both companies build nuclear power facilities, design and service reactors, operate nuclear reactors and supply nuclear components and technology.

## MONTHLY SPOT MARKET PRICES

| | | 2022 | | | | | | 2021 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Chg. | Jun | May | Apr | Mar | Feb | Jan | Dec | Nov | Oct | Sep | Aug | Jul |
| **Uranium** ($/lb U3O8) | | | | | | | | | | | | | |
| Low | +1.00 | 45.50 | 46.00 | 52.50 | 51.00 | 42.50 | 43.00 | 42.00 | 43.00 | 36.00 | 36.00 | 32.20 | 32.20 |
| High | -1.50 | 52.50 | 54.00 | 64.00 | 60.00 | 44.50 | 46.50 | 47.00 | 47.50 | 48.00 | 51.00 | 36.00 | 32.50 |
| **Conversion** ($/kgU) | | | | | | | | | | | | | |
| Low | - | 30.00 | 30.00 | 28.00 | 26.00 | 16.00 | 16.00 | 16.00 | 15.00 | 16.00 | 19.00 | 19.00 | 19.50 |
| High | - | 33.00 | 33.00 | 30.00 | 28.00 | 17.00 | 17.00 | 17.00 | 18.00 | 19.00 | 21.00 | 21.00 | 21.50 |
| **Enrichment** ($/SWU) | | | | | | | | | | | | | |
| Low | - | 84.00 | 84.00 | 82.00 | 100.00 | 59.00 | 57.00 | 56.00 | 56.00 | 55.50 | 55.50 | 54.00 | 54.00 |
| High | - | 150.00 | 150.00 | 150.00 | 150.00 | 61.00 | 59.00 | 57.00 | 57.00 | 57.50 | 57.50 | 56.00 | 56.00 |

NIW monthly UF6, SWU and U3O8 prices rely on the general consensus of direct market participants and is informed by actual market transactions. This section was previously known as the Nukem Weekly Report and the Nukem Price Bulletin. The methodology for NIW's weekly UPP price is different – more information about the methodology behind that price is available on page two.

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