Energy Intelligence

VOL. 16, NO. 21
MAY 27, 2022
WWW.ENERGYINTEL.COM

NUCLEAR INTELLIGENCE WEEKLY®

CONTENTS

2 LOWER UF6, U3O8 INVENTORIES IN US
3 EDF'S PROBLEMS WORSEN
4 CALIFORNIA'S REVERSAL ON DIABLO
5 PALISADES' ABRUPT SHUTDOWN
6 INTERVIEW: AMORY LOVINS ON AP1000
11 URANIUM MARKET UPDATE

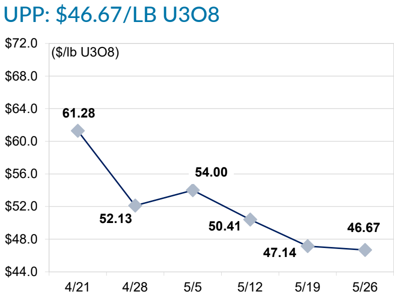
Market Points

The latest nuclear fuel data out of the US show domestic inventories at 141.7 million pounds U3O8 equivalent at the end of 2021, up by 8% from 2020.

Much to the dismay of bullish nuclear fuel investors, US supplier holdings of uranium concentrate increased by about 11 million lbs. in 2021 from the prior year.

This news was no help to the U3O8 price, which slipped to $46.67 per pound on May 26, from $47.14/lb. on May 19, according to Energy Intelligence's Uranium Price Panel.

UPP: $46.67/LB U3O8



NIW Assessment

WEEKLY ROUNDUP

Ukraine Regulator Accuses Grossi of Repeating 'Russian Propaganda'

- The Ukrainian nuclear regulator fired back at International Atomic Energy Agency (IAEA) Director General Rafael Grossi this week for suggesting the Ukraine's Zaporozhye nuclear plant is holding large quantities of plutonium and enriched uranium that could be diverted for weapons use. Grossi said in a May 25 World Economic Forum panel discussion that the IAEA wants to visit Zaporozhye — which has been under Russian occupation since early March — "to prevent that either there is a problem or we end up finding out that a few hundred kilograms of nuclear weapon-grade material has gone missing." He described the situation at the plant, still operated by Energoatom, as "unsustainable." The State Nuclear Regulatory Inspectorate of Ukraine (SNRIU) in a May 26 Facebook post called Grossi's remarks "a cheeky lie of Russian propaganda," pointing to Ukraine's 2010 voluntary offer to dispose of "all highly enriched uranium" at the 2010 Nuclear Security Summit in Washington. SNRIU added that the country lacks the technology to proliferate and proposed the IAEA postpone its visit "until the territory is liberated from Russian invaders."

- Bucharest this week selected the site of a former coal power plant in central Romania for a planned small modular reactor (SMR) plant, which planners hope will be the first in Europe. The Doicesti power plant site achieves "all the qualifications" and is "appropriate for NuScale's design," state nuclear operator Nuclearelectrica CEO Cosmin Ghita said in a May 23 statement. Nuclearelectrica hopes to build a six-module 462 megawatt NuScale "VOYGR" plant, and this week it also updated its October 2021 "teaming agreement" with NuScale with an agreement to "conduct engineering studies, technical reviews, and licensing and permitting activities" at Doicesti. Meanwhile, Nuclearelectrica this year hopes to contract an external front-end engineering and design study and a full project cost assessment. Ghita told a press conference that "we're having discussions with a number of investors that expressed initial interest" in the project. Ghita added that the same site could also be used to deploy solar capacity, with NuScale SMRs available for load-following.

- US-based Westinghouse and South Korea's Hyundai Engineering & Construction this week signed a strategic cooperation agreement on global AP1000 projects, not long after Westinghouse's private equity owner made clear that the company was on the market. Hyundai expects to apply its "exceptional engineering, procurement and construction [EPC] capabilities" to Westinghouse's AP1000 design, said company CEO Yoon Young-joon in a May 24 statement. Since its 2017 bankruptcy, Westinghouse has repeatedly made clear its aversion to future newbuild construction risk, so a partnership with Hyundai may be an attempt to sweeten Westinghouse's offerings in prospective newbuild markets. Less clear is how this will align with the company's existing partnership with US EPC firm Bechtel in multiple European nuclear markets. For Hyundai, the move represents a step change in its nuclear business, adding to existing work with Holtec on the latter's SMR design and its move into decommissioning. Last month Hyundai agreed to cooperate with Holtec on the latter's Indian Point decommissioning project.

NUCLEAR FUEL MARKET

EIA Data Show US Fuel Inventories Up in 2021

The latest nuclear fuel data out of the US show utilities ending 2021 with higher inventories of enriched and fabricated nuclear fuel, but lower inventories of UF6 and U3O8, where bullish investors are anticipating a supply shortage. Such a shortage depends on whether Russia's war in Ukraine leads to a bifurcated nuclear fuel market, and so far there is little to no evidence that the US government will ban or further constrain Russian fuel imports.

US nuclear fuel inventories totaled 141.7 million pounds U3O8 equivalent at the end of 2021, up by 8% from 2022, according to the US Energy Information Administration's (EIA) *2021 Uranium Marketing Report* released this week. That increase is largely attributed to US suppliers procuring more uranium alongside various investors and funds increasing their physical holdings.

That activity has slowed of late, helping push prices lower through the month. The uranium price delivered by Energy Intelligence's Uranium Price Panel dipped to $46.67 per pound U3O8 on May 26, down from $47.14/lb. on May 19, and $54/lb. on May 5.

Total year-end nuclear fuel inventories held by US utilities increased in 2021 from the prior year, with most of the increase concentrated in enriched UF6, according to the EIA.

The US nuclear fleet saw the shutdown of Indian Point-3 in New York in 2021, while the twin-unit Vogtle newbuild plant in Georgia has been procuring and preparing fuel for the planned Unit 3 start-up in 2023 and Unit 4 in 2024, although the project has faced continuous delays and cost overruns. As of today, with the closure of the Palisades reactor in Michigan last week, the US has 92 operating power reactors.

With 93 reactors at the end of last year, the US fleet held 43 million lbs. U3O8 equivalent as enriched UF6, up from 40.1 million lbs. in 2020. And US utility fabricated fuel inventories increased to 9 million lbs. U3O8 equivalent from 6.5 million the previous year.

In 2021, US utilities purchased 14 million separative work units (SWU) from 11 sellers at an average price of $99.54/SWU, with volume and price "virtually identical" to the prior year, according to the EIA. In 2021, 19% of that SWU was US-origin, meaning it came from Urenco's LES plant in Eunice, New Mexico, while 28% came from Rosatom's Tenex, and the remaining 41% from Urenco's European enrichment facilities.

US utilities may be well stocked in enriched and fabricated fuel, but stocks of UF6 and U3O8 declined. Depending on the extent to which US utilities procure non-Russian supply in future years — amid the fallout of Russia's continued aggression in Ukraine — US buyers could see a bottleneck in UF6 production.

Utility inventories of UF6 declined by 12% to 36.4 million U3O8 equivalent. Fortunately for buyers, US-based ConverDyn plans to bring its Metropolis plant online next year at 7,000 tU capacity. Metropolis' parent companies General Atomics and Honeywell are understood to be evaluating the cost and risk of scaling up plant capacity further, although that could delay start-up. And if US buyers are going to divert away from Russian supply, ConverDyn needs to see more robust supply commitments to make the capital commitments to lock in future production at higher levels.

The sourcing of future supply contracts, whether from Russia or not, will determine how much UF6 and subsequently U3O8 from elsewhere is required.

While US utility inventories of U3O8 fell by 11% to 19.7 million lbs., supplier inventories increased from 17.7 million lbs. in 2020 to 28.5 million lbs. in 2021, according to the EIA. Some of that extra 11 million lbs. could help feed the Metropolis restart.

US supplier inventories in total increased to 33 million lbs. U3O8 equivalent in 2021, up by 37% from 2020, but the vast majority of that is held as U3O8. That's hardly surprising given the extent to which the influx of investor interest has encouraged mining juniors to increase their U3O8 holdings in part as a hedge against rising costs and, at times, to feed into existing supply agreements.

Jessica Sondgeroth, Washington

URANIUM PRICE PANEL

For the week ended May 26, 2022

Weekly Spot Market Prices														
		May				Apr				Mar				
	Chg.	26	19	12	5	28	21	14	7	31	24	17	10	3
Price ($/lb U3O8)	-0.47	46.67	47.14	50.41	54.00	52.13	61.28	63.88	63.07	57.94	58.34	56.00	59.63	51.07
Total Assessments	2.00	*12.00*	*10.00*	*9.00*	*11.00*	*9.00*	*10.00*	*10.00*	*9.00*	*10.00*	*9.00*	*9.00*	*10.00*	*11.00*
% within 1 StDev	-5.00	*75.00*	*80.00*	*77.78*	*72.73*	*55.56*	*60.00*	*90.00*	*77.78*	*80.00*	*66.67*	*66.67*	*80.00*	*72.73*
Low ($/lb U3O8)	-1.00	46.00	47.00	49.00	53.50	51.25	59.00	63.75	63.00	57.50	58.00	55.00	59.00	50.50
High ($/lb U3O8)	0.00	47.50	47.50	52.00	55.00	53.00	63.25	64.00	63.50	58.75	58.50	57.00	60.25	52.00
Variability*	0.05	0.05	0.00	0.28	0.50	0.50	0.75	0.08	0.00	0.28	0.13	0.50	0.25	0.16

*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 'Annus Horribilis' Gets Worse

Ratings agencies this past week warned that EDF's creditworthiness may be further downgraded. This followed two dire announcements from the French nuclear operator last week underlining vulnerabilities in both its operating fleet and its newbuild arm.

With more than half of EDF's 56 domestic reactors out of service, many thanks to an emergent problem with stress corrosion in key piping, on May 19 EDF further cut its guidance for 2022 French nuclear output from 295-315 terawatt hours to 280-300 TWh. This will likely cost the utility billions of euros. On the same day EDF announced major new delays and cost overruns at one of its two major nuclear newbuild projects under way — the twin EPRs at Hinkley Point C in the UK — in a move almost certain to kneecap its further newbuild ambitions in the UK as well as in potential markets from India to France.

"In our view, these developments, alongside the uncertainty on the company's remedy measures and the type, timing and amount of any new government support, this creates significant downside risk to EDF's credit metric recovery," said S&P Global Ratings as it placed EDF on CreditWatch negative May 24. S&P argued that additional domestic and UK capital expenditures on the back of these announcements "will add to the group's inflexible investment program of about €17 billion [$18 billion] expected annually from 2022, leading us to anticipate for 2022 a mid- to single-digit billion euro Ebitda loss."

The ratings agency further warned that industrial challenges across EDF's French nuclear fleet "raise concerns on the resilience of the group's domestic nuclear generation."

Enormous Challenges at Home

EDF had optimistically pointed out that multiple investigations of the 12 reactors shuttered for stress corrosion inspections had confirmed "slow ... propagation" of the problem, and shown "the existence of a compression zone which blocks the propagation of the phenomenon." It also announced that while a stress corrosion inspection program has been launched for the entire fleet, "at this stage" it doesn't see it necessary to schedule any new reactor outages this year.

Planned 10-year inspection outages at EDF's 900 megawatt reactors, including Tricastin-3, Gravelines-3, Dampierre-2, Blayais-1 and Saint-Laurent B2, will go forward, while an inspection program for the 1,300 MW reactors "will be established after integrating the lessons learned from the appraisals and checks in progress on the auxiliary circuits of the Penly 1 reactor" — the 1,300 MW reactor that was the first to show traces of the stress corrosion previously thought to have been limited to the newer and larger N4 reactors at Civaux and Chooz B.

But significant safety and regulatory risks remain, warned the ratings agencies. "The risk that EDF again revises its estimates for 2022 and/or 2023 appears elevated," Moody's said in a May 20 note. "The group has not completed the metallurgical audit driven by the corrosion defects' detection" in late 2021, and the ASN, France's nuclear safety regulator, has yet to approve "its planned repair program. In addition, EDF's track record with regards to its French nuclear fleet's availability is negative, as evidenced by the structural decline of the nuclear output over the last ten years."

Just this most recent cut will have dire implications for EDF's balance sheet. Moody's explained that this is because EDF sells forward its estimated nuclear power output before the end of the budget year, and each new cut in output means it must purchase the electricity on a spot market where prices continue to climb in the pan-European energy crisis exacerbated by tensions with Russia. "For illustration," said Moody's, "a 15 TWh shortfall will result in c. €4.2 billion of extra costs, assuming EDF's c. €62-€65 per megawatt hour 2022 hedged price and current wholesale price of c. €280/MWh."

A Collapsing Newbuild Pitch

At Hinkley Point C, EDF pushed the first electricity generation target for Unit 1 from June 2026 to June 2027, and boosted the total project completion cost from £22 billion-£23 billion ($28 billion-$29 billion) to £25 billion-£26 billion — both in 2015 sterling. While this won't have anything near the balance sheet impact of the French output guidance cuts, it is an enormous blow to EDF's efforts to attract investors for a near-replica of the twin-EPR project at Sizewell C, also in the UK.

"EDF has this gaping wound called Hinkley," one industry source told Energy Intelligence. "There's no upside left in Hinkley for them. If you run their schedule and costs through the original model — their returns are evaporating really really quickly."

Indeed, while EDF was touting a 9% internal rate of return (IRR) for Hinkley Point C when it formally launched the project in 2016, this has slowly deflated, from 8.5% in a July 2017 estimate to 7.1%-7.2% in a January 2021 revision. In last week's estimate EDF made no mention of an IRR, although it did note that "there is no impact for UK consumers" in the 12% capital cost increase. That's because the financial model for Hinkley Point C pushes all construction risk to the project owners.

Given the parlous state of its finances EDF has no capacity to similarly backstop Sizewell C, which is why it worked hard to push through the UK's new nuclear regulated asset base law. Theoretically this will push enough construction risk to ratepayers and the government that EDF can attract private investors to take a minimum 60% equity stake in the Sizewell C project company, with the remainder perhaps split by EDF and the UK government. However, details on practical implementation of the law, as well as any project-specific arrangements, remain murky and are possibly still quite embryonic. Even with clarity on the law, both private and public backing depend on EDF demonstrating its ability to control newbuild projects — on budget and schedule — such that they don't pose inordinate risk.

EDF defended the Hinkley Point C situation by pointing to the unusual circumstances it has faced: "During more than two years of the Covid-19 pandemic, the project continued without stopping," the company said in a May 19 statement. "This protected the integrity of the supply chain and allowed the completion of major milestones. However, people, resources and supply chain have been severely constrained and their efficiency has been restricted. In addition, the quantities of materials and engineering as well as the cost of such activities, including, in particular marine works have risen."

This may not be enough to entice wary investors to Sizewell C, particularly as EDF in the same statement undermined its "fleet effect" pitch promising that successive EPRs would be built faster and be cheaper than those that preceded them. At Hinkley Point C, EDF has applied lessons learned on Unit 1 to accelerate milestone achievements at Unit 2 — which is officially one year behind the first unit. This acceleration has been reflected in each announcement of a schedule revision beginning with the first in July 2017. In that announcement the risk of further delays at Unit 1 was put at 15 months and Unit 2 at only nine months. But for the first time last week, a schedule update pushed each unit back by 15 months, revealing considerably greater slippage for Unit 2.

All of this points to EDF continuing to pay ever more for Hinkley Point C via its growing piles of corporate debt. "It's still worth doing," said the industry source of Hinkley Point C. "If they do a good enough job, even 10 years late, they can still refinance" on the back of a price guarantee for all the plant's output for 35 years. "There's a lot of debt capacity on a post-construction basis," said the source, "but it is killing them today."

Phil Chaffee, London

UNITED STATES

California Asks DOE to Expand Nuclear Credit Rules

California's governor is asking the US Department of Energy (DOE) to loosen the criteria for its new $6 billion Civil Nuclear Credit Program to allow the Diablo Canyon nuclear plant to qualify. With $1.2 billion to allocate in fiscal year 2022, the new DOE funding, aimed at keeping uneconomic reactors in the US operating, could extend the life of the two-unit plant beyond 2025. Otherwise, the money would roll over into future awards for qualifying reactors.

Because the DOE restricted the first tranche of the program to reactors scheduled to close by 2026, the only possible applicants were the two-unit Diablo Canyon plant and the single-unit Palisades plant in Michigan. But the Palisades reactor abruptly shut down for good last Friday, May 20, after developing a leak in a control rod drive mechanism seal. That has left only Pacific Gas & Electric (PG&E) to make a play for the entire allocation. As a regulated utility that recovers some of its operating costs from ratepayers, PG&E has to follow state energy policy and has thus been letting the state take the lead on the matter.

In a policy reversal, Gov. Gavin Newsom has been "evaluating a temporary delay of the planned retirement" at least since DOE opened the credit program last month. Evidently lacking confidence that the plant meets the program's revenue requirements, Newsom's office is requesting a change to DOE's April 2022 guidance, which states that if more than 50% of reactor costs are recovered "from cost-of-service regulation or regulated contracts" the applicant "will not be deemed to compete in a competitive electricity market." Newsom wants the DOE to strike that sentence from its guidance, according to a May 23 letter from his Cabinet Secretary Ana Matosantos to Energy Secretary Jennifer Granholm.

In pleading the state's case, Matosantos says that the DOE should apply a more liberal interpretation to the $1.2 trillion Infrastructure Investment and Jobs Act signed last November that created the nuclear credit program. To qualify, the act requires that a nuclear reactor applicant operates "in a competitive electricity market."

PG&E receives some revenue from the California Independent System Operator's competitive electricity market as a must-take resource, but according to Matosantos, not enough to keep the plant operating beyond 2025, when PG&E would incur "operating losses" with "no existing cost recovery mechanism" to offset the losses. These costs include potentially significant capital expenditures to "obtain licenses and permits" largely associated with state marine life protections and other environmental rules, which PG&E was seeking to avoid when it struck the 2016 joint proposal with the state and stakeholders to keep the plant operating to 2025.

Since PG&E has no other mechanism to recover costs associated with an extended plant operation, Matosantos also requested that the DOE clarify that such losses include "costs not recovered through cost-of-service ratemaking" and "include grid reliability and support for state clean energy goals, as well as emissions reductions, as a rationale for extending operations."

Matosantos also pointed to delays in California's energy transition, including "supply chain disruptions, tariff issues, and other factors that are delaying new clean energy installations, as 6,000 megawatts of existing generation is scheduled to retire." Of that, Matosantos said in her letter, the "single largest resource" is Diablo Canyon with 2,256 MW that supply about 8.5% "of California's total electricity generation and provides capacity during the 'net peak' evening hours."

While the governor is proposing massive state investments in clean energy, there is "a projected gap of 1,800 MW between energy demand at net peak and already ordered procurement" without taking into account "extreme events and further delays in projects coming on line," she said in her letter. "To maximize options to maintain electricity reliability as new projects come on line, the state is evaluating a temporary delay of the planned retirement" of Diablo Canyon.

Interpreting Congressional Intent

Since Diablo Canyon receives a portion of its revenue from competitive markets, it's always possible that the DOE's guidance could be stretched to include the plant, but the decision on California's request will likely boil down to how the agency ultimately interprets congressional intent. The DOE has not yet responded to Matosantos' request, but if Newsom's office is successful in convincing the agency to modify the credit program's rules, the agency could very well extend that interpretation to future program awards. However, even with federal money California would still face considerable legal hurdles to keep Diablo Canyon open, given that the 2016 agreement was codified in law in 2018.

Unlike the DOE's first award period, which was restricted to reactors scheduled to close by 2026, future award cycles "will not be limited to nuclear reactors that have made public filings announcing their intentions to retire," the agency says on its website. The agency is planning its next award cycle in the first quarter of 2023, with new guidance to be administered in the previous quarter.

Whether or not Diablo Canyon qualifies in the first and current award cycle will determine if the $1.2 billion allocated for fiscal year 2022 is rolled over into subsequent award years. Each award is intended to credit a qualified reactor over a four-year period, with funds distributed annually.

The DOE's deliberation on California's request will undoubtedly be watched closely since reactors in competitive markets that don't receive ratepayer support are generally far more vulnerable than those operating in regulated markets where costs can be passed onto ratepayers. The agency says on its website that it "intends to allocate credits to as many certified nuclear reactors as possible consistent with the intent of the Act." But that risks spreading funds too thinly to have any serious impact, a concern expressed by stakeholders in comments on the guidance.

Jessica Sondgeroth, Washington

SAFETY

Entergy's Abrupt Final Exit From Merchant Markets

US nuclear operator Entergy achieved its long-term goal of exiting deregulated electricity markets with its May 20 closure of the aging Palisades reactor on Lake Michigan. The decision to stick with its plan disappointed nuclear supporters, who argue that keeping such reactors operating is necessary to help the fight against climate change. Opponents breathed a sigh of relief, citing Palisades' long and checkered history of safety and environmental violations.

In one sense, the 811 megawatt reactor ended its life May 20 on a high note, having continuously generated electricity for 577 days since its last and final refueling. That is a "site and world-record production run for a plant of its kind," Entergy spokesperson Val Gent told Energy Intelligence in an email. But the utility pulled the Combustion Engineering reactor, of which there were just 14 in the US, off the grid a decade before its 2031 license extension expiry date, and 11 days shy of its planned May 31 closure. The reason for the sudden shutdown was a problem that has gnawed at Palisades' operators for decades and forced multiple unplanned shutdowns, namely defective control rod drive mechanism (CRDM) seals.

"For reasons unknown to me (the Nuclear Regulatory Commission [NRC] and the plant's owners), the CRDM seals at Palisades experienced more leaks than any other plant in the United States and perhaps the world," reactor safety expert Dave Lochbaum told Energy Intelligence in an email. "That the company was unable to figure out how to stop the problem and stop the revenue interruptions is puzzling."

Michigan Gov. Gretchen Whitmer had fought to keep the plant open, writing to Energy Secretary Jennifer Granholm last month that she would support a "compelling" application to the Department of Energy's (DOE) $6 billion Civil Nuclear Infrastructure Credit program aimed at preventing uneconomic nuclear plants from closing. She said it would save jobs and "help us fight climate change by generating clean energy." But that argument fell on deaf ears at Entergy, which has been exiting deregulated electricity markets since 2014, when it shut down Vermont Yankee. Subsequently, in 2017 it sold its Fitzpatrick plant in New York to Exelon; and then permanently shuttered Pilgrim in Massachusetts in 2019 and its two remaining Indian Point units (also in New York) in 2020 and 2021. "Entergy remains committed to its four nuclear plants in Arkansas, Louisiana and Mississippi," said Gent.

In a May 20 statement, Entergy said that "after careful monitoring, operators made the conservative decision to shut down the plant early due to the performance of a control rod drive seal." The operator appears to have had no other option, however, because of regulatory requirements governing leak detections within the containment. These are based on a long-recognized "leak before break" concept that seeks to prevent the core from overheating by treating any leak within the containment as a possible precursor to a large pipe fracture. "To halt progress down that pathway before reaching 'break,' the technical specifications require that the reactor be shut down within hours," says Lochbaum. Thus Palisades was shuttered "because of regulatory requirements in the reactor operating license."

Patchy Safety and Environmental Records

In its statement Entergy boasted of "more than 50 successful years of safe, secure and reliable generation of clean, carbon-free electricity at Palisades." But the pressurized water reactor's lengthy operating record suggests a far different story: the reactor boasts a lifetime capacity factor of 71.6%, and even in recent years it has struggled to produce a capacity factor over 80%, remaining well below the US industry average.

Palisades' performance issues started with a year-plus outage a couple of years after the NRC's predecessor the Atomic Energy Commission granted an operating license for the plant in 1971, according to a 38-page record of events at the plant that Lochbaum has kept. This includes multiple shutdowns over decades, above-limit releases of radioactive water that in some cases were not sampled or monitored, and embrittlement of the reactor pressure vessel. Embrittlement, due to neutron bombardment, weakens the walls and welds of reactor pressure vessels. While it's a common phenomenon in aging reactors, in the case of Palisades the NRC pegged it as being the worst case in the US due to the reactor's age and the construction materials used to build it.

Palisades' previous owner Consumers Energy, seeking to sell the plant, laid out some of its biggest concerns in an August 2006 briefing to the state of Michigan, revealing that it was facing "significant" future capital expenditures to maintain the reactor, including for "reactor vessel head replacement, steam generator replacement, to address reactor vessel embrittlement issues, and various other life extension projects."

On Jul. 31 of that year, the plant operator reported that a water storage tank "leaked 2,790 gallons of processed liquid radioactive waste from a flange onto the ground, with some seepage through the wall of the vault below ground level." The same NRC file in which this was reported contains "historical cooling tower overflow incidents," which led to ground contamination "to a depth of approximately six inches" because the non-radioactive cooling water subsequently flowed through a building with "radiologically contaminated equipment," the operator stated.

The plant was sold to Entergy in 2007 for approximately $380 million with undertakings by the new owner to deal with some of the problems, including the vessel head replacement. These went largely unfulfilled, according to multiple sources. Entergy announced in December 2016 that it would shutter Palisades on Oct. 1, 2018, after Consumers said it wanted early termination of a power purchase agreement (PPA) with the plant. However, both sides eventually agreed to continue the PPA through the spring of 2022, and in September 2017 Entergy announced it would keep the reactor open to coincide with the end of the PPA.

Just prior in 2016, Entergy hired Chris Bakken as its chief nuclear officer to improve performance throughout the company's fleet of reactors, in both regulated and deregulated markets. At that point, the NRC had on several occasions given Palisades poor marks for its safety performance, including putting it in the "degraded cornerstone" category (its second-worst of five categories) of its Action Matrix — for four consecutive quarters in 2011-12. The matrix indicates the level of severity of performance issues as well as whether the regulatory response is required at the regional or agency level. Degraded cornerstone requires response at the agency level.

Bakken seems to have kept Palisades out of any NRC penalty boxes since then, but the CRDM control seals continued to cause problems, with five unplanned shutdowns in 2017-18 attributed to that issue. It's unclear what steps the utility may have taken to resolve the problems but whatever they were wasn't enough — and on May 20 another CRDM leak proved the final straw.

"The problem plagued Palisades for most of its 50-year life," says Lochbaum. "Had Palisades been a horse, it would have been put down years ago for mercy."

Stephanie Cooke, Washington

INTERVIEW

Amory Lovins on MIT's AP1000 Cost Report

In our Apr. 29 edition, we invited the author of a recent MIT study on the economics of the AP1000, MIT's Professor Koroush Shirvan, to elaborate on his findings. In an interview this week with Energy Intelligence's Stephanie Cooke, Amory Lovins responded to some of those findings. Lovins is adjunct professor of civil and environmental engineering at Stanford University. This interview was conducted via email, and was shortened and condensed. The hyperlinks are from Lovins.

Q: In his recent Q&A, MIT's Professor Shirvan asserted that "we know historic nuclear power plants can operate safely to 80 years" and that in operating costs, or once their capital costs are paid off, they become competitive "with any source of electricity." Do you think that's possible now, and if not now, could it be possible for a new reactor in another 20 years for a reactor built today?

A: The world's two longest-running power reactors, Beznau-1 in Switzerland and Nine Mile Point-1 in the US, are only in their 53rd year, so 80 is speculative. NRC [Nuclear Regulatory Commission] just suspended prior perfunctory license extensions from 60 years to 80 and will re-examine "aging management programs." In 2022, would you count on a 1942 car, however expertly maintained and refurbished? Can a reactor even run reliably and economically for 60 years? A chronic control rod drive seal leak closed Palisades 11 days early at age 51. The 40 US units closed by mid-2021 — 30% of total nuclear grid connections — averaged 22 years, and only eight had reached 40; the six closed in 2016–20 averaged 46 but were licensed for 60; and many if not most operating reactors cost more to run than they can earn in competitive markets.

In the actual competitive landscape, I don't see how nuclear newbuild of any type or size can compete in economic dispatch against unsubsidized renewables whose lifetime Levelized Cost of Energy (LCOE) in many countries has fallen through $30 and then $20 per megawatt hour — even to $10. By the time the next US AP1000 could be built, still-cheaper renewables will undercut Shirvan's claimed $20-$40/MWh nuclear dispatch cost by even more. His critique of SMR [small modular reactor] economics seems directionally correct and implies neither SMRs nor traditional LWRs [light-water reactors] could pencil out: their bleak prospects of competing in operating costs after 2050 can't justify their huge investments now.

No standard empirical dataset finds nuclear newbuild competitive with unsubsidized renewables. But nuclear probably becomes even less competitive if we count grid integration costs, which tend to be larger for big thermal plants because their forced outages are generally bigger, longer, more abrupt, and far less predictable than variable renewables'.

Q: You've criticized the MIT report for ignoring renewables. Asked about that in his interview with Energy Intelligence, Shirvan cited the fracking/natural gas boom as the reason nuclear was ignored back in 2008. Furthermore, he says that while nuclear can't compete with renewables that will not be the case as markets approach "net-zero" emissions targets. He cites studies that he says conclude that at less than 5 grams of equivalent carbon dioxide per kilowatt hour, an AP1000 with an LCOE of $80-$120/MWh can compete with solar/wind. What is your response to that?

A: Shirvan compares AP1000s only with other reactors, ignoring demand-side and renewable competitors. Yet renewables have already taken around 95% of the world market for net capacity additions, versus nuclear's less than 1% (and in seven of the past 13 years, less than 0%). PV [photovoltaic] and wind power are the cheapest bulk power source in over 91% of the world and rising (says BloombergNEF), with three to eight times (Lazard) or 5-13 times (BloombergNEF) lower LCOE than nuclear. IPCC [the Intergovernmental Panel on Climate Change] also says the demand side can provide 40%–70% of global decarbonization.

Investors and owners rejected nuclear newbuild because it had no business case, so in 2001-20, the world opened three fewer power reactors than it closed. But newbuild does worse against efficiency and renewables today than against gas in 2008. Grid models like MIT's can make hypothetical $80-$120/MWh new nuclear compete with new solar and wind only by conjuring a need for "firm" power. They do this by constraining or omitting most of the 10 kinds of carbon-free grid-balancing resources — a portfolio so ample that the costliest kind, bulk electricity storage, is seldom needed.

Shirvan's low AP1000 cost projections assume doubled construction productivity, near-record construction speed, unobserved learning curves, orders of at least 10 units to trigger those assumed cost drops (circularly assuming US market prospects that high early costs destroyed), 4%–8% cost of capital with no apparent nuclear risk premium, and decades-long PPAs [power purchase agreements] or equivalent utility reregulation. These "should cost" fantasy assumptions make AP1000s look prohibitively costly rather than astronomically costly, but wishing will not make it so. Especially in the nuclear industry's advanced state of decay, such make-believe numbers merit scarcely more credence than Westinghouse's original claims that simplicity and modularity would yield AP1000s buildable for $1 per watt in 36 months. Well, if we had some ham, we could have some ham and eggs, if we had some eggs.

Far from gaining climate relevance, nuclear newbuild makes climate change worse, because it costs far more — probably an order of magnitude more — than other carbon-free competitors, so it saves proportionally less carbon per dollar, and does so more slowly. Why pay extra for less-effective climate solutions? The more worried we are about climate, the more vital it is to buy fast, cheap, sure options — not slow, costly, speculative ones.

Q: You've taken issue with the methodology used in the MIT report — specifically the use of overnight costs as compared to total costs, including finance. Could you explain why you don't agree with that approach?

A: Traditional overnight cost metrics are economically meaningless because they exclude financing costs (and often major owner's costs, too, which Shirvan estimates at $1.9/W initially, falling to $1.3/W). Financing costs are sensitive to two linked variables: construction duration and cost of capital. Nearly all the carefully analyzed modern nuclear programs worldwide have been significantly over budget and schedule: among 180 reactors, 92% showed cost overruns averaging 117%, while 175 units showed schedule overruns averaging 64% or 36 months. Capital markets therefore charge nuclear risk premia of typically several to many hundreds of basis points.

Omitting financing costs is thus likely to mislead. For example, Shirvan estimates Vogtle 3–4's EPC [engineering, procurement and construction] overnight cost at around $21 billion or approximately $9.3/W as of February 2022 (in 2018 dollars), twice MIT's 2009 estimate; but the May 2022 total cost estimate is around $34 billion or $15.2/W and rising, with no assurance of ultimate operation. The inferred financing cost, totaling in the neighborhood of $10 billion, would be far higher without $12 billion of federal loan guarantees and access to Treasury-window rates. Shirvan finds Vogtle's costs are in line with other post-TMI [Three Mile Island] US nuclear construction costs, but those are financeable only in imaginary markets or with Vogtle's conscripted capital.

Q: Based on 2018 dollars, Shirvan says the EPC cost of a new AP1000 "should" be $4.3/W — less than half Vogtle's cost, which he puts at $9.3/W. Questioned about the impact of inflation and Covid-19 since then, Shirvan says the costs would rise by at least 20%. What's your best estimate of the cost of a new AP1000?

A: Nobody knows: "at least" is vague and unbounded. That's partly why the private capital market won't finance them. Why even try to guess a number as imaginary as the weight of a hippogriff? Being less materials-intensive than an EPR (with some corresponding safety questions) is as irrelevant in today's market as comparing hippogriffs to minotaurs. Vogtle 3-4 is America's first-of-a-kind AP1000 only because so many others previously fell by the wayside, such as Bellefonte 3-4, Summer 2-3, Levy County 1-2, Harris 2-3 and Turkey Point 3-4. Vogtle continues only because taxpayers are holding the bag.

Q: Putting it slightly differently, how much does financing and decommissioning add to the cost of building and running a nuclear plant?

A: Financing can easily add plus 30% to bare EPC costs; for distressed projects, plus 50%. Shirvan's paper shows that each $1 of Vogtle original EPC cost incurred $1.55 of site construction management cost (quadruple expectations), 45¢ of owner's cost, 13¢ of interim payments and liens, thus $3.13 of overnight cost, plus 95¢ of project financing, raising total capital and financing cost to $4.07 per $1 of EPC cost. (This excludes 85¢ from Toshiba related to the Westinghouse bankruptcy, and imputed interest during construction, plus any local taxes, on compulsory pre-funding by ratepayers.) Financing cost rises with market capital, or long duration (the world average is nearly a decade but projects vary widely), or both.

No one really knows yet what decommissioning a big old US LWR will cost — only that it'll probably exceed the escrowed funds. Global decommissioning experience with roughly 6 GW completed so far, mostly small reactors, reveals systematic underestimation of duration and cost; German decommissioning cost more than construction. Many retiring US reactors are being quietly transferred from accountable owners to special subsidiaries of disposal firms that can pay themselves the billions in the decommissioning accounts, then if the work isn't finished, apparently leave the rest to the taxpayers.

Q: Could you explain the significance of net capital additions (NCAs) to nuclear plant costs? Shirvan puts them at $5/MWh, included in his LCOE estimates for an AP1000. Percentage-wise, how much do you estimate NCAs add to nuclear plant capital costs over a 40- or 60-year lifetime?

A: NCAs are maintenance, safety, or betterment investments that don't nominally pay back within a year, so they're capitalized rather than expensed. The Nuclear Energy Institute [NEI] says 2020 US NCAs totaled $4.2 billion and averaged $5.34/MWh (2020 dollars)—18% of $29.37 total generating cost (excluding various listed owner's costs). Restoring seven omitted years, US NCAs in 2002-20 averaged $7.90/MWh (2020 dollars), which if sustained for 40-60-80 years at (say) a 5% annual real discount rate would have a present value of $122-$134-$139 per kilowatt plus financing. Future NCAs are speculative and unforecastable, but corrosion, fatigue, wear and radiation damage may well make them rise with age, much as they do for our bodies.

US NCAs peaked in 2012 at $12.42/MWh (2020 dollars) — 27% of that year's total nuclear generating cost of $45.39. The high 2010-12 NCA values were raised by "enhancements" — presumably upratings and lifetime extensions if safety improvements are counted as "regulatory." NEI ascribes the post-2012 NCA decline chiefly to program completions; the influence of plant retirements and regulatory relaxations is unknown. The largest NCA type since 2016 has been "sustaining," implying repairs and upgrades to keep operating. NEI has concealed top-quartile operating-cost data since 2016; perhaps they're embarrassingly high. If high enough, they can force closures.

Q: Nuclear advocates often argue that "learning experience" significantly lowers capital costs from an inaugural plant to an "nth of a kind" — or tenth plant — and that this has been demonstrated in France, South Korea and Japan. Shirvan argues that follow-on AP1000s in China realized significantly lower construction times and consequently lower costs. He says the same was true with the ABWR in Japan. Why don't you buy that argument?

A: Shirvan's evidence, if any, for a learning curve needs independent expert scrutiny. Competent literature reports no observed learning curve for modern reactors anywhere — specifically not in France, where real costs rose with experience. (The Flamanville-3 fiasco then confirmed the fragility of institutional learning: the 14-year ordering gap lost a generation of seasoned managers and supply-chain capabilities needed to sustain such a complex and finely tuned construction process.) The paper on which Shirvan relies for his claim of nuclear learning curves in "many countries" was demolished by three leading experts (and by another paper whose senior author later cited the paper he'd debunked as his own key reference for arguing the opposite). Several noted nuclear-cost scholars have found Kepco's South Korean cost data unanalyzably opaque, shifting and unverifiable. I've seen no literature dissecting the inscrutable and unverifiable cost data from Japan — or from China, where AP1000 experience was mixed and BloombergNEF says new nuclear is two to three times costlier per kWh than new solar and wind.

Details matter: e.g. Shirvan cites his own co-authored paper as claiming that Japan's four ABWRs were all built in under four years, but IAEA's [International Atomic Energy Agency] Pris database says their duration from construction start to commercial operation rose from just over four years to 4.5 to 4.6. No power reactor on Earth has even achieved grid connection in under four years since 1970. But Shirvan measures construction time as ending with fuel load, not with commercial operation. He likewise celebrates that Haiyang-2's civil works took less than four years, without noting that its total completion took 8.3 years, versus 4.8 years planned.

Q: Often one hears that renewables provide only "intermittent" power. You say that adjective would best be applied to baseload power sources instead, and that renewables are better described as variable. Please explain.

A: No generator is 24/7/365, but their outage characteristics differ. Renewables are generally dispatchable except PVs and wind power, whose output varies with weather and the Earth's rotation. But those variations, which Shirvan calls "unpredictable," are very predictable — often more so than electricity demand — making (for example) east Danish wind power biddable into the hourly day-ahead auction just like thermal capacity. In contrast, big thermal plants' forced outages can lose a gigawatt in milliseconds, often for weeks or months, and typically without warning — behaviors properly called "intermittent." Well-designed PV and wind projects' and portfolios' variations tend to be milder, brief, shorter, and far more predictable, so they're best called "variable."

The venerable honorific term "baseload" has at least five meanings — none useful in a world where, as Miso's [Midcontinent Independent System Operator] strategist Jeff Bladen said, we'll no longer be forecasting demand and scheduling supply, but instead forecasting [renewable] supply and scheduling demand. One generator does not serve one load; rather, all generators serve the grid, which serves all loads. Customers care about timely statistical deliverability of total resources, not single units. In an era when generators were less reliable than the grid, we built the grid to back up failed thermal units with working ones. Now in the same way, but often at lower cost, the grid can back up PV or wind output with each other, with other renewables in other places, or with demand response, storage (electrical, chemical or thermal), or other resources like industrial cogeneration.

So what's really intermittent? This year, France is officially forecast to have more nuclear capacity shut for repairs and safety checks than total German nuclear closures throughout 2000-21. The 2022 French nuclear capacity factor is forecast at 55%–59% (versus 2020's 61% average) but has lately been 42%–52%. Like Japan's post-Fukushima shutdowns, a nuclear monoculture can suffer large-scale common-cause failures. Germany's diversified, competitive, half-renewable power supply now looks not just cheaper than France's (beating French wholesale annual-average costs in all but one year since 2007) but also more reliable and resilient — fortunately, since Germany's long-standing net power exports to France lately hit new highs.

Q: The American Nuclear Society says that the US fleet has "maintained a median capacity factor near 90% for 20 years." How does that compare with the output relative to capacity of wind power in the US? Or solar?

A: An unknowable combination of improved operations (with all due credit to Inpo and Naval reactor culture), culling lemon plants, and laxer regulation has indeed kept the average capacity factors of the surviving US units around a commendable 90% (versus IAEA's global cumulative average of about 75%), falling below 90% in only three years since 2007. The US 2020 nuclear average of 92.4% compared with utility-scale 2020 averages of 69% geothermal, 65% "other non-fossil gas," 63% nonwood biomass, 58% wood, 41% hydro, 35% wind and 24% photovoltaic. All resources' LCOEs account for their respective capacity factors and shouldn't be double-counted. Grid integration costs are generally small for variable renewables but larger for big thermal generators.

Risk-conscious investors are also aware of the 92 operating US power reactors' survivor bias. Of 259 units ordered, by mid-2017 only 28 — some now slated for closure — had been built that remained competitive in their regional markets and did not suffer at least one outage of a year or more.

Q: Finally, what is your model for getting to "net zero" in 2050, or could it be sooner?

A: Let me summarize a few conclusions from a recent review paper and its terse summary. Global fossil-fueled power generation peaked in 2019 and, by a fluke, in 2021, but renewables can already or will imminently meet all the further demand growth. IEA [International Energy Agency] says the world added about 294 GW of renewables in 2021, and expects about 305 GW more in each of the next five years, but so far has underestimated their growth.

Renewables' business case is so decisive that if markets and policies plausibly overcome or bypass obstructions, the US could cut its fossil-fueled power generation to about zero in the 2030s, with huge financial savings (even bigger in India and China). The energy transition could be even faster and cheaper if demand-side resources too were systematically competed or compared with supply-side resources — especially as integrative design makes electrical savings severalfold larger, yet cheaper, often with increasing returns.

With its roughly three-to-thirteenfold higher LCOE (and probably higher grid-integration costs) than unsubsidized renewables, nuclear power has no business case and hence no climate case. It's therefore winning about 10-20 times less global investment and adding hundreds of times less annual output. The US government is lavishly subsidizing and promoting virtually every kind of reactor— shredding decades of patient nonproliferation efforts, so DOE [Department of Energy] is undermining DOD's [Department of Defense] national-security mission — but even these tens of billions of dollars of new largesse are unlikely to prevent the stagnant nuclear industry's slow-motion collapse. Nuclear trainwrecks will multiply as taxpayers' billions are spent, deceived customers are fleeced, and rosy claims prove false.

Nuclear advocates tout new roles for process heat, desalination, hydrogen, etc., but new uses can't remedy grossly uncompetitive prices. Nor can putatively soaring electricity needs to electrify transport and heat — doubtful if energy efficiency and materials efficiency are competed or compared with supply and storage — build a nuclear business case. I doubt any vendor has cumulatively made money selling reactors—only fueling and fixing them. A modern grid also has no reliability or operational need for "firm" generation. Renewables' global potential is orders of magnitude greater than plausible long-run need. Nuclear power has finally run out of reasons to exist, except as an enabler and cover for bomb programs and a sinecure for lobbyists.

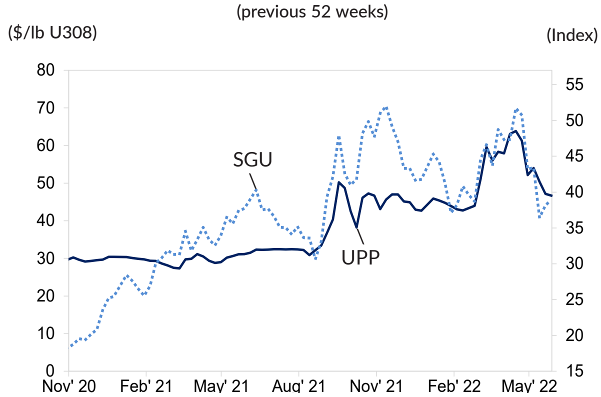
The famous Nuclear Renaissance (boosted by a faulty MIT analysis) has saved no carbon. Maybe it never will — but its $40 billion-plus cost could have saved far more carbon sooner by buying efficiency and renewables. Should we now repeat that error?

URANIUM MARKET UPDATE

All prices as of Thursday, May 26, 2022

UPP VS. SOLACTIVE GLOBAL URANIUM INDEX

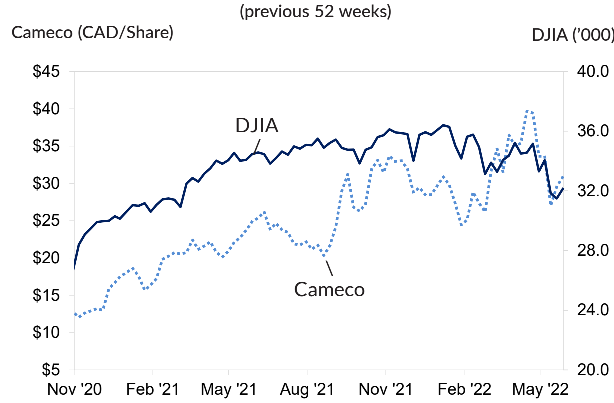
(previous 52 weeks)



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

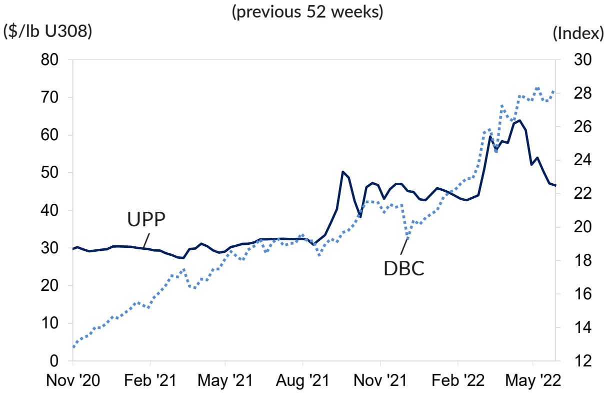
(previous 52 weeks)



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

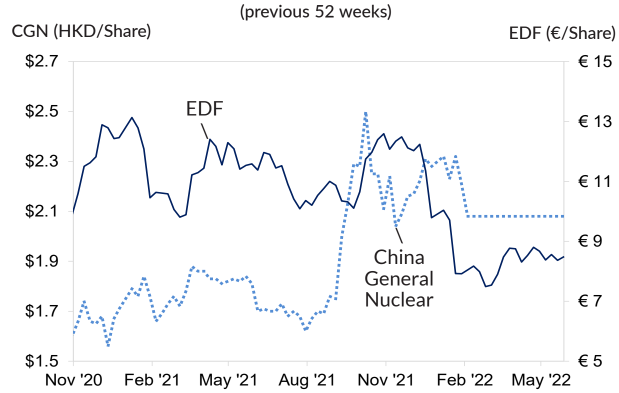
(previous 52 weeks)



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.	Apr	Mar	Feb	Jan	Dec	Nov	Oct	Sep	Aug	Jul	Jun	May
Uranium ($/lb U3O8)													
Low	+1.50	52.50	51.00	42.50	43.00	42.00	43.00	36.00	36.00	32.20	32.20	31.00	29.15
High	+4.00	64.00	60.00	44.50	46.50	47.00	47.50	48.00	51.00	36.00	32.50	32.50	31.35
Conversion ($/kgU)													
Low	+2.00	28.00	26.00	16.00	16.00	16.00	15.00	16.00	19.00	19.00	19.50	19.50	19.50
High	+2.00	30.00	28.00	17.00	17.00	17.00	18.00	19.00	21.00	21.00	21.50	21.50	21.50
Enrichment ($/SWU)													
Low	-18.00	82.00	100.00	59.00	57.00	56.00	56.00	55.50	55.50	54.00	54.00	54.00	52.00
High	-	150.00	150.00	61.00	59.00	57.00	57.00	57.50	57.50	56.00	56.00	56.00	54.00

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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