Oil and Gas News Briefs
Compiled by Larry Persily
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Guyana profits from rapidly growing oil production

(Offshore Engineer; Jan. 16) - Guyana said it expects to receive some $2.1 billion from oil exports and $320 million from royalties this year as crude production continues to rise, an increase from the $1.62 billion it received in 2023. The South American nation's gross domestic product is expected to increase by 34.3% in 2024, the fifth consecutive year of an economic growth of more than 20%, according to the official budget presented by Finance Minister Ashni Singh to parliament on Jan. 15.

After about 40 offshore oil and gas discoveries in recent years, the energy sector's performance has been key to economic growth and will remain the nation's most important source of revenue. With a third floating production facility reaching full output this year, the sector is expected to expand 44.7% in 2024.

The three floating production, storage and offloading facilities deployed at Guyana's Stabroek block, operated by a consortium led by ExxonMobil, are projected to produce an average 550,000 barrels a day this year, ramping up to over 600,000 in the latter part of the year, the government said. By 2027, the nation's output is expected to reach 1.3 million barrels per day. Guyana's production averaged 377,000 barrels per day last year.

Shell strikes deal to sell onshore Nigeria assets to local companies

(Bloomberg; Jan. 16) - Shell has agreed to sell its Nigerian onshore oil business to a consortium of local companies for more than $1.3 billion, a historic shift in a crucial yet controversial part of the energy giant’s global operations. If approved by the government, the deal would fulfill Shell’s long-term goal of extracting itself from a challenging operating environment in the Niger Delta. For decades, the company has been at odds with communities over spills and accusations of human rights violations, something that increasingly clashed with its efforts to become cleaner and greener.

Even so, Shell will retain many connections to Nigeria through its natural gas business and deep-water oil fields. It will also provide the buyers of the business with $1.2 billion in loans, and will receive additional cash payments of as much as $1.1 billion on completion of the deal. The buyer of the business, known as Renaissance, is formed of exploration and production companies ND Western, Aradel Energy, First E&P, Waltersmith and Petrolin, all of which are based in Nigeria.

The gradual departure of international oil majors from the West African country has tended to boost the presence of local companies, but is by no means a guarantee that a deal will get approval from Nigerian authorities. ExxonMobil agreed to sell its shallow-water oil assets to Seplat Energy almost two years ago, but the transaction has yet to complete amid objections from state-owned Nigerian National Petroleum Co. Eni and Equinor are also waiting for regulatory approval to finalize the sale of Nigerian assets.

Nigeria starts up $19 billion refinery for domestic demand, exports

(S&P Global; Jan. 14) - Nigeria's colossal 650,000-barrels-per-day Dangote refinery has begun fuel production, potentially creating a new domestic market for Nigeria's crude oil and helping the OPEC member end gasoline imports, Dangote Group announced. The $19 billion facility will produce diesel and jet fuel at the start, before progressing to producing gasoline, the Nigerian conglomerate said in a statement on Jan. 12.

"Dangote Petroleum Refinery can meet 100% of Nigeria's requirement of all refined products, gasoline, diesel, kerosene and aviation jet (fuel), and also have surplus of each of these products for export," the company added. The refinery has so far received six million barrels of crude oil. The first crude delivery was done on Dec. 12. In September, Dangote chief executive Devakumar Edwin said the refinery would start production at 370,000 barrels per day before eventually ramping up to 650,000. S&P Global analysts predict the refinery will not hit full operating capacity until mid-2025.

Located on the outskirts of Nigeria's commercial capital Lagos, the project was officially completed in May but had yet to refine any oil products due to a lack of domestic crude feedstock. The project has faced years of delays and cost overruns. Nigeria is Africa's top oil producer, but exports almost all its crude due to the lack of local refining capacity. Virtually all the country's state-owned refineries are currently shut down for repairs.

Occidental CEO warns of insufficient oil supply starting in 2025

(Reuters; Jan. 16) - The oil market could be heading for a supply crunch from 2025 onward as oil exploration fails to keep pace with demand, Occidental Petroleum Chief Executive Vicki Hollub said on Jan. 16. Hollub, who spoke on the sidelines of the World Economic Forum in Davos, said U.S. West Texas Intermediate crude prices could trade in the $80- to $85-a-barrel range from 2025. Prices averaged about $78 last year.

"In the near term, the markets are not balanced; supply, demand is not balanced," Hollub said, adding: “2025 and beyond is when the world is going to be short of oil.” From the mid-1950s to the late 1970s, oil companies were finding around five times as much oil as was used, a ratio that has steadily declined to about 25% in 2023. She said

that from 2012, U.S. companies moved away from exploration and focused on tapping shale oil reserves, which have a much shorter lifespan than conventionally produced oil.

Hollub expects energy-transition scenarios will have to be adjusted for more oil exploration. "I think the industry is looking at a scenario where we will be able to do all the things that we need to do as a part of the transition." The market will move from near-term oversupply to a long period when the world will need more oil, she added.

Norway awards oil and gas exploration licenses in Arctic waters

(Reuters; Jan. 16) - Norway on Jan. 16 awarded stakes in 62 offshore oil and gas exploration licenses to 24 energy companies, including state-controlled Equinor, boosting the amount of acreage offered as the country seeks to pump for decades to come. The annual award was up from 47 licenses a year ago when 25 firms received permits. The increase involved drilling permits in the Arctic Barents Sea and the adjacent Norwegian Sea, the country's energy minister told a conference.

The annual predefined-area rounds of exploration acreage are central to Norway's strategy of extending its oil and gas production, a policy fiercely opposed by environmentalists, dozens of whom picketed the event. The license awards in the Barents Sea, a vast ocean off the northern tip of continental Europe, rose to eight in the new round from just two a year ago, as energy companies expressed more interest in the remote and environmentally harsh region.

"Last year I asked companies to look more closely at Barents Sea opportunities. … This award shows that more companies have responded positively and are taking responsibility," Minister of Energy Terje Aasland said. While Norway backs the Paris climate accords and the global goal to transition away from fossil fuels, the country also says the world will need access to oil and gas for many years. "The government's policies continue to be on a head-on collision course with a sustainable climate," Friends of the Earth Norway head Truls Gulowsen said in a post on social media X.

OPEC sticks with forecast of continued increase in oil demand

(Reuters; Jan. 17) - OPEC on Jan. 17 stuck to its forecast for relatively strong growth in global oil demand in 2024 and said 2025 will see a robust increase in oil use, led by China and the Middle East, in a surprise early prediction. The 2025 forecast is in line with the Organization of the Petroleum Exporting Countries' view that oil use will keep rising for the next two decades, in contrast to bodies such as the International Energy Agency, which predicts it will peak by 2030 as the world shifts to cleaner energies.

OPEC, in a monthly report, said world oil demand will rise by 1.85 million barrels per day in 2025 to 106.21 million. For 2024, OPEC sees demand growth of 2.25 million, unchanged from last month. Oil prices, though, have started the year on a weak footing as uncertainty in the market about demand has offset the impact of a new round of supply cuts by OPEC and its allies, known as OPEC+.

The 2025 forecast was published on the same day as OPEC Secretary General Haitham Al Ghais published an article disputing that oil demand was near a peak and reiterated the group's call for continued oil industry investment. "What is clear is that peak oil demand is not showing up in any reliable and robust short- and medium-term forecasts," he wrote. "It is a challenge to see peak oil demand by the end of the decade, a mere six years away."

New U.S. rule requires oil and gas industry cut methane emissions

(New Hampshire Bulletin; Jan. 16) - Within two years, a new federal rule will force oil- and gas-producing states to crack down on methane emissions — a major driver of climate change. A handful of states already have rules that force drillers to increase monitoring and upgrade equipment, which advocates say provided an effective template for the federal action. But many other states will be starting from scratch. In those states, some officials and oil industry leaders say the burden on regulators and fossil fuel producers may outweigh the benefits of reduced emissions.

While carbon dioxide is emitted in far higher quantities, methane is a much more potent greenhouse gas. It also breaks down much faster in the atmosphere, meaning reducing methane emissions can have a more immediate impact than reducing carbon dioxide, which lingers for longer. “That makes it a huge opportunity,” said Jon Goldstein, senior director of regulatory and legislative affairs with the Environmental Defense Fund, a legal advocacy group. “If we can get after those emissions quickly, we can start to bend the curve on the climate problem quickly.”

Oil and gas operations are the largest industrial emitter of methane. The U.S. Environmental Protection Agency estimates that its new rule will prevent 58 million tons of methane emissions by 2038 — equivalent to the carbon emissions produced by the entire power sector in 2021. While some Democratic-led states have gotten a head start on methane regulations, other oil-producing states, many under Republican control, say the new requirements are going to require large amounts of data collection and analysis for both companies and regulators — and it’s unclear how that work will be funded.

Winter cold hits refineries in Texas, cuts North Dakota oil flow in half

(Reuters; Jan. 16) - A severe winter storm shut a U.S. Gulf Coast refinery in Texas on Jan. 16, triggered malfunctions at other refineries and halved North Dakota oil production as it dumped snow and rain across a broad area of the nation. TotalEnergies' 238,000 barrel-per-day refinery in Port Arthur, Texas, was examining its production units after a plantwide power outage on Jan. 16 as a winter storm brought frigid temperatures to the U.S. Gulf Coast, sources familiar with the company's operations said.

ExxonMobil returned a gasoline-producing fluidic catalytic cracker and a coker at its 564,440 barrel-per-day refinery in the Houston suburb of Baytown, Texas, to normal operation after a malfunction triggered by severe cold crossed the area on Jan. 15. Flint Hills Resources said its 343,000 barrel-per-day refinery in Corpus Christi, Texas, was significantly impacted by unseasonably cold weather, especially at its West Plant where instrumentation to operate equipment was affected by freezing rain overnight.

North Dakota's oil production fell by half on Jan. 16 due to extreme cold weather and operational challenges, the state's pipeline authority said. Oil production was estimated to have fallen between 600,000 and 650,000 barrels per day, according to the North Dakota Pipeline Authority.

China’s crude oil imports set record in 2023; so did refined exports

(Reuters columnist; Jan. 15) - China's imports of crude oil, coal and iron ore all soared to record highs in 2023, but this seemingly strong performance by the world's top commodity buyer comes with a few caveats. Crude oil imports rose 11% in 2023 from the prior year to 11.28 million barrels per day, according to customs data released on Jan. 12. This eclipsed the prior record of 10.81 million from 2020 and came as China reopened its economy after ending its strict zero-COVID policy at the end of 2022.

But is the gain in crude oil imports as impressive as it first appears? In volume terms, 2023's arrivals were 1.11 million barrels per day higher than those in 2022. However, this is well below the forecast for a 1.8 million increase in China's oil demand from the International Energy Agency. Of course, imports and total demand aren't the same thing, but looking at the other factors at work in China's crude oil market doesn't offer much support to the optimistic view of growing domestic consumption.

China's exports of refined products jumped 16.7% in 2023 from the prior year, which works out to about 1.37 million barrels per day. This was the highest refined product exports since 2019, about 190,000 higher than the level recorded in 2022. Putting all the factors together shows that while China imported record crude oil volumes, it also boosted fuel exports, kept crude flowing into storage inventories and fell well short of the optimistic forecasts for a surge in domestic demand and consumption in 2023.

Gazprom sets record for domestic gas supply amid frigid weather

(S&P Global; Jan. 15) - A total of 64 billion cubic feet of gas was supplied to Russian consumers on Jan. 13, a new record for deliveries to the domestic market, gas giant Gazprom said Jan. 14. The company said gas consumption had spiked across Russia on the back of extreme cold, with average temperatures having fallen to almost minus 4 degrees Fahrenheit across the country.

"On Jan. 13, the absolute historical record for daily gas supplies was achieved," Gazprom said. The company added that customers were supplied both from domestic production and from gas in storage. Gazprom built up its gas stocks ahead of the current heating season to a record high 2.572 trillion cubic feet and raised its peak withdrawal capacity to an all-time high of 30 billion cubic feet per day. Filling stocks to record highs came as Gazprom's pipeline exports to Europe remain low, which has also led to a major drop in its gas production.

While supplying the domestic market with record levels of gas, Gazprom has also raised its exports to China via the Power of Siberia pipeline. It said Jan. 13 that its gas exports to China National Petroleum Corp. via the giant pipeline reached a new daily record the previous day. It did not provide a volume. Supply via Power of Siberia is expected to ramp up through the course of 2024, so the new record for deliveries is not a surprise.

Exxon signs on to buy more LNG from West Coast Mexico project

(Reuters; Jan. 16) - Mexico Pacific said on Jan. 16 that it will supply ExxonMobil with an additional 1.2 million tonnes per year of liquefied natural gas. ExxonMobil LNG Asia Pacific tied up the agreement to purchase the LNG from a proposed third train at Mexico Pacific's Saguaro Energia project on Mexico's West Coast, Houston-based Mexico Pacific said in a statement. Exxon will purchase the LNG over a 20-year term.

The deal adds to an agreement last year for Exxon to buy 2 million tonnes per year from the first two production trains at the export terminal. With the latest agreement, Mexico Pacific has reached the sales required to make a final investment decision later this year on a third production train, CEO Ivan Van der Walt said in the statement.

The Saguaro Energia project is set to ship 15 million tonnes per year of LNG — produced from U.S. Permian Basin gas — to Asia. The project has a price tag of over $15 billion, officials from the Mexican state of Sonora said last year. First LNG is planned for 2029, if the company commits this year to construction.

TotalEnergies invokes force majeure on its stake in Russian LNG

(Agence France Presse; Jan. 16) - French energy giant TotalEnergies said Jan. 16 that it had invoked force majeure in relation to its investment in Russia's Arctic LNG-2 project after the U.S. imposed new sanctions. The project, controlled by Russian gas company Novatek and designed to tap into the country's vast Arctic resources, was seen as a key example of Moscow's deepening cooperation with international energy companies.

But unprecedented Western sanctions in response to Moscow's war on Ukraine have forced foreign energy majors to write off billions of dollars in Russian assets and leave the country. The declaration of force majeure by TotalEnergies, the largest foreign investor in Arctic LNG-2, is the latest example of a Western energy company further retreating from Russia. Force majeure is a legal clause that allows companies to absolve themselves of contractual obligations based on factors beyond their control.

"Consequently, no offtake of LNG from Arctic LNG-2 by TotalEnergies is planned in 2024," the company said. Output at the terminal is planned for 19.8 million tonnes a year. It had an estimated cost of $21 billion and is located on the Gydan Peninsula, close to Yamal LNG, another Novatek project that began operating in 2017. But Arctic LNG-2 faces possible delays after the U.S. targeted it with sanctions last November. Novatek said it expects to start shipping LNG from its first production unit this winter.

Wave of new LNG supply could knock down prices later this decade

(Financial Times; London; Jan. 16) – The world of liquefied natural gas is no stranger to booms and busts. A dearth of new projects raises prices, leading to a rush to bring new gas to market. Now, the next big upswing in capacity is beginning, with a wave of new production visible over the horizon. That’s good news for gas-starved utilities and countries fretting over energy security — less so for companies seeking to sell LNG.

Supply has been tight the past two years as Europe has bought a lot of LNG originally destined for the Asia market. But market tightness is about to change. Export projects capable of producing 140 million tonnes per year are set to come on stream between 2025 and 2027, according to analysts at Bernstein. That’s more than 30% of the current market demand. New projects are likely to leave the market amply supplied and drive spot gas prices down, at least until demand catches up toward the end of the decade.

That’s particularly significant for Europe, where long-term contracts are indexed to the spot price. LNG sellers, however, face choppy seas. U.S. developers such as Cheniere, Venture Global and NextDecade tend to be protected by long-term capacity contracts at fixed prices. But a slump could squeeze profits for portfolio LNG companies — often oil and gas majors such as Shell and TotalEnergies — whose large bets on gas form part of energy transition strategies. These companies buy gas from multiple sources, in addition to their own production, and try to place it where it is most profitable globally.

TotalEnergies could resume work this year at Mozambique LNG

(Bloomberg; Jan. 17) - A group led by TotalEnergies will likely resume work on a liquefied natural gas project in Mozambique early this year, according to the International Monetary Fund, after a raid by Islamic State-linked militants led to a near three-year freeze on the $20-billion-plus project. Mozambique's government in 2021 called for military help from the Southern African Development Community bloc and Rwanda. Since then, the troops have dislodged the insurgents from towns they held and killed their leaders. Hundreds of thousands of people who fled have returned.

"Security conditions in the north continue to improve and the large LNG project that was stopped in April 2021 is expected to restart in early 2024," the IMF said in a report published Jan. 16. The resumption of the project may be crucial in helping Mozambique avoid having to restructure a $900-million eurobond on which the government is due to begin repayments in 2028. TotalEnergies' has forecast it would take four years after work resumes to complete construction and begin exports.

An even bigger LNG export project that ExxonMobil plans next to TotalEnergies' plant will start shipping in 2029, according to the IMF, though Exxon has not announced a final investment decision on its multibillion-dollar development.

Canadian gas producer strikes LNG deal with commodity trader

(Offshore Energy; Jan. 16) - Commodities trading group Trafigura has inked a long-term LNG agreement with Canada's largest natural gas producer, Tourmaline, marking the first time the two parties have signed such an agreement. Tourmaline said it entered into a netback agreement with Trafigura based on 62.5 million cubic feet of gas per day to be liquefied into about 500,000 tonnes of LNG per year for a seven-year term starting in January 2027, with an option for an extension up to December 2039.

Tourmaline said it will receive netback pricing based on a European gas index, minus deductions and costs. Tourmaline last year started sending some of its gas production to the U.S. Gulf Coast, where the fuel was liquefied and loaded aboard tankers for deliveries overseas. Canada's first LNG export terminal is a year away from completion in British Columbia, pushing Western Canada gas producers to look for new markets.

Australia LNG producers may see temporary output drop

(Australia Financial Review; Jan. 15) – Liquefied natural gas production will fall for at least two years at Woodside and Santos, the two largest oil and gas producers on the Australia stock exchange — and perhaps longer if environmental issues and legal

challenges delay work on A$22 billion in projects. A court is expected to rule on Jan. 15 whether Santos can proceed with a pipeline that is fundamental to its controversial A$5.8 billion Barossa gas project in the Timor Sea, off the Northern Territory coast.

Woodside also requires approvals for its A$16.5 billion Scarborough gas project in Western Australia, a development that has also been held up by activist-backed appeals. Woodside and Santos have been discussing a mega-merger, creating a global LNG player, although some investors in the smaller company, Santos, want a big price to agree to any deal. Production at the merged company would dip in the short term as older units cease operating.

Santos was on track to stop production at its 3.7 million tonnes-per-year Darwin LNG plant in the Northern Territory by the end of last year, with the shutdown to continue until replacement gas from Barossa starts flowing. Woodside is foreshadowing the shutdown of one unit this summer at its North West Shelf plant near Karratha — the country's biggest LNG venture at 16.9 million tonnes per year capacity — as gas supplies run short. The decline in LNG output would continue until 2025 when Barossa is scheduled to begin operating and only reverse in full in 2026 when Scarborough starts production.

Santos wins court ruling for undersea pipeline to gas field

(Reuters; Jan. 15) - Australia's Santos can proceed with construction of an undersea pipeline vital to its Barossa gas project after a court on Jan. 15 ruled in favor of the company in a dispute with an Indigenous man looking to pause the work. Work on the line, which will connect the Barossa gas field to a processing plant in Darwin, was paused by court order in November after a suit by a member of an Indigenous group regarded as traditional land owners from the nearby Tiwi Islands.

Simon Munkara sought to halt work and force Santos to do a fresh assessment of the pipeline's impact on underwater cultural heritage. The challengers argued, among other things, that the pipeline would disturb the travels of, and anger, two "ancestral beings" — a rainbow serpent known as Ampiji and Jirakupai, or the Crocodile man. However, Justice Natalie Charlesworth on Jan. 15 dismissed Munkara's application and lifted the court injunction, opening the door for Santos to commence work on the pipeline.

Charlesworth said there was "significant division" among Tiwi Islanders over traditional accounts of Ampiji and Jirakupai and only a "negligible chance that there may be objects of archaeological value in the area of the pipeline route." The decision clears a major hurdle blocking the long-stalled multibillion-dollar project. Citi analysts had said a ruling against Santos could delay the vital growth project — where the company aims to start producing gas in the first half of 2025 — by more than a year.

EPA signs off on plan to store carbon underground in California

(Los Angeles Times; Jan. 14) - The U.S. Environmental Protection Agency has signed off on a California oil company's plans to permanently store carbon emissions deep underground to combat global warming — the first proposal of its kind to be tentatively approved in the state. California Resources, the state's largest oil and gas company, applied for permission to send 1.46 million tonnes of carbon dioxide each year into the Elk Hills oil field, a depleted oil reservoir 25 miles outside of downtown Bakersfield.

The emissions would be collected from industrial sources nearby, compressed into a liquid-like state and injected into porous rock over one mile underground. Although this technique has never been performed on a large scale in California, the state's climate plan calls for such operations to be widely deployed across the Central Valley to reduce carbon emissions from industrial sites. The EPA issued a draft permit for the California Resources project, which is poised to be finalized in March after public comments.

As California transitions away from oil production, a new business model for fossil fuel companies has emerged: carbon management. Oil companies have heavily invested in transforming their vast network of exhausted oil reservoirs as long-term storage sites for planet-warming gases. California Resources is the state's largest nongovernmental owner of mineral rights. "It's kind of reversing the role," said Chris Gould, the company's chief sustainability officer. "Instead of taking oil and gas out, we're putting carbon in."

LNG tankers divert from Red Sea and Suez Canal

(Bloomberg; Jan. 16) - The global LNG tanker fleet appears to have stopped using the Red Sea and Suez Canal, as continued Houthi attacks on ships reroute flows of the power-station and heating fuel. Two empty ships controlled by Qatar have turned away from the northern entrance of the Suez Canal in the Mediterranean Sea in the past day, according to ship-tracking data compiled by Bloomberg. A third Qatari vessel, which was also heading to the canal, reversed course off the coast of Morocco. The tankers will likely head to the Persian Gulf state via the longer route around Africa.

Qatar is the biggest user of the Red Sea and Suez Canal for the LNG trade. Other suppliers, including those in Russia and the U.S., have also stopped using the waterway, and ship-tracking data doesn't currently show any LNG vessels heading to the area. While the longer journeys will tie up tankers and boost freight costs, they're not expected to lead to shortages in Europe, given high stockpiles and subdued industrial demand there. Moving the fuel from Qatar to the U.K. via southern Africa takes about 27 days, compared with 18 through the Suez Canal, according to ICIS.

Ships that divert away from Red Sea will need to refuel elsewhere

(S&P Global; Jan. 15) - Shippers and exporters are opting for alternative ocean transportation routes as the Red Sea situation remains volatile, with ports in East and West Africa and the Arabian Gulf likely to benefit as a rising number of ships refuel there instead, industry sources said. Some 35,000 ships that sail through the Red Sea annually could be impacted as escalated attacks on merchant ships continue in the region, according to the industry sources.

Under an extended threat, ship and freight forwarders face disruption and increased freight costs because moving goods around Africa can add as much as 30 days to a voyage, global bunker company Glander International Bunkering said in a statement Jan. 12. "As a result, we are seeing an increase in bunker demand in East/West Africa and the Arabian Gulf," it said. Effects include longer lead times as fueling barge schedules are booked up and cargo/supplier availabilities become tighter, the company said, adding that this translated to higher premiums which could disrupt bunker plans.

"We certainly expect to see more fuel oil heading to South Africa as more container vessels take bunker fuel," said Rahul Kapoor, head of shipping analytics research at S&P Global Commodity Insights. "South Africa will need a lot of oil. They might not be fully prepared for the drastic surge in bunker fuel demand," a source said Jan. 12.

Partners looking at small nuclear power plants for Alberta oil sands

(Calgary Herald columnist; Jan. 16) - The notion of nuclear power in Alberta’s oil sands has kicked round for decades, including the wild 1950s Project Cauldron proposal to detonate a bomb underneath the province to assist in bitumen recovery. That idea fizzled out, but the concept of developing nuclear power in Alberta has resurfaced several times over the years. The prospect of building a small modular reactor (SMR) to provide electricity to Alberta’s power grid took a notable step forward Jan. 15 with a new partnership between Edmonton-based Capital Power and Ontario Power Generation.

It involves two serious players, with decades of experience operating generation facilities in Alberta and nuclear power units in Ontario, coming together to examine the feasibility of SMRs in Alberta. “This is a significant announcement because it is not about the oil sands, it’s about the grid and it involves a major electricity provider in this province,” said Mount Royal University political scientist Duane Bratt, who teaches on the science and politics of nuclear energy.

“And it involves a partnership, Bratt said, “not between the government of Alberta and Ontario, but with the people who actually do the work.” At a news conference in Edmonton, the leaders of Capital and Ontario Power Generation discussed their plan to jointly assess within two years the deployment of small nuclear plants in the province, including possible ownership. Ontario Power Generation hasn’t put out final cost estimates, but that step will occur in early 2025.