Petroleum news

page 3 EIA forecast: natural gas prices up on demand, reduced production

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Former Rep. Tom McKay named to fill AOGCC public member seat

TOM MCKAY

Gov. Mike Dunleavy has named former state Rep. Tom McKay of Anchorage was named Jan. 22 to fill the public member seat on the three-member Alaska Oil and Gas Conservation Commission. The position requires approval by the Legislature.

McKay fills a vacancy left by Brett Huber Sr. who held the public member seat from 2023-24. The term of the seat expires March 1, 2027.

Jessie Chmielowski has held the petroleum engineering seat on the commission since 2019 and Greg Wilson has held the geologist seat since 2022.

see **MCKAY TO AOGCC** *page 4*

House Energy hears plans for Cook Inlet LNG import terminals

During a Jan. 27 meeting of the House Energy Committee officials from Harvest Midstream, Enstar Natural Gas Co. and the Regulatory Commission of Alaska talked about plans for importing liquefied natural gas to Southcentral Alaska in response to pending shortages of adequate gas supplies from gas and oil fields in the Cook Inlet basin.

There are three projects for the establishment of LNG import facilities around Cook Inlet.

Harvest has been moving ahead with a project to convert the existing LNG export facility at Nikiski on the western shore of the Kenai Peninsula into an LNG import facility. Harvest has an agreement with Chugach Electric Association

see **INLET LNG** *page 8*

State, feds summer lease sales? ANWR 1002 maybe, NPR-A no go

On Feb. 5, the Alaska Department of Natural Resources' Division of Oil and Gas posted a public notice saying they will offer all available state acreage in the Beaufort Sea, North Slope and North Slope Foothills Areawide oil and gas lease sale areas, tentatively in the summer of 2026.

Why summer? And does this preclude the regular fall or winter lease sale normally held in conjunction with federal lease sales?

Summer because the feds are looking to hold NPR-A and ANWR 1002 (coastal plain) area lease sales this summer. And no, this does not preclude a fall/winter (usually November) lease sale.

The federal NPR-A lease sale is scheduled to begin opening

see **LEASE SALES** *page 6*

Federal oil and gas lease sale in NPR-A scheduled for March 18

KEVIN PENDERGAST

The Department of the Interior's Bureau of Land Management, or BLM, Alaska State Office will hold an oil and gas lease sale bid opening for more than 600 tracts totaling approximately 5.5 million acres in the National Petroleum Reserve-Alaska, or NPR-A, at 10 a.m. Alaska Standard Time, or AKST, on March 18, said Kevin J. Pendergast, state director, Alaska.

All sealed bids must be received by BLM by 4 p.m. AKST on March 16, 2026.

Sealed bids must be received at the BLM-Alaska State

see **NPR-A SALE** *page 6*

EXPLORATION & PRODUCTION

27 Cook Inlet wells

Hilcorp plans most active Southcentral drilling season since '14 — all gas wells

By KRISTEN NELSON
Petroleum News

LUKE SAUGIER

Hilcorp has drilled 192 wells in Cook Inlet since it came to the region in 2011 and plans 27 wells this year — all gas wells — the most since it drilled 28 wells in 2014.

This information was part of a briefing Luke Saugier, Hilcorp Alaska senior vice president, gave the Alaska Legislature's House Resources Committee Jan. 28 as part of a group presentation which included ConocoPhillips and Santos. (Hilcorp's comments on its North Slope work were included in a story in the Feb. 8 issue of Petroleum News.)

Cook Inlet was where Hilcorp came to Alaska, acquiring assets from Chevron in 2012, Saugier said, reminding the committee that in 2012 there was concern the area was running out of natural gas.

Hilcorp immediately began to invest in the assets it acquired and has invested more than $1.5 billion in Cook Inlet since 2012, continuing to invest hundreds of million each year.

Hilcorp is "running two rigs full-time all year," Saugier said, something which is quite challenging for the company and the first time Hilcorp has been able to do that.

A graph illustrated Cook Inlet drilling since 2005. Prior to 2012, when Hilcorp began drilling, the peak during that period was 23 wells drilled by all operators in the inlet.

Hilcorp drilled four wells in 2012, 10 in 2013 and

see **HILCORP INLET WELLS** *page 6*

EXPLORATION & PRODUCTION

Conoco grows in Alaska

Fourth quarter report, earnings call: $9B Willow Project nearing 50% complete

By KAY CASHMAN
Petroleum News

RYAN LANCE

ConocoPhillips touted its growing presence in Alaska on Feb. 5 in an earnings call, with company officials emphasizing that the $9 billion Willow Project is nearing 50% complete and on schedule to produce oil in early 2029.

They also pointed out that further developing the company's Alaska assets is a top priority this year.

"We remain focused on infrastructure-led exploration and are shifting our focus this year to Alaska where we have four wells fully permitted and are looking to unlock additional resources near to our infrastructure hubs, building on our decade of disciplined exploration and appraisal spend in Alaska," said Andy O'Brien, chief financial officer of ConocoPhillips.

"We anticipate realizing approximately $1 billion of incremental free cash flow in each year from '26 through '28, with another $4 billion from Willow coming online in 2029. And that's a growth profile that's unmatched in our industry," said ConocoPhillips Chairman and Chief Executive Officer Ryan Lance.

In the Q&A part of the Feb. 5 conference call, Betty Jiang, Barclays analyst said: "I want to ask

see **CONOCO GROWTH** *page 4*

FINANCE & ECONOMY

ANS hugs $70 level

Oil jumps Feb. 11 as Trump administration mulls Iran tanker seizures

By STEVE SUTHERLIN
Petroleum News

After making a geopolitically-fueled second run in a trading week to mere pennies below $70, Alaska North Slope crude dipped below $69 per barrel Feb. 10, down 45 cents to close at $68.90. West Texas Intermediate shed 40 cents to close at $63.96 on the day and Brent ticked 24 cents lower to close at $68.80.

Oil trading saw a choppy week as saber rattling in the U.S.-Iran standoff contended with hopes for a peaceful negotiated settlement to the tensions.

On Feb. 11, crude futures surged higher on indications from U.S. officials that the Trump administration had considered seizure of tankers carrying Iranian oil, but held off on concerns of Iranian retaliation, according to a Wall Street Journal report.

"Taking similar action with Iran would be escalatory and would likely see the market needing to price in an even larger risk premium than it already is," ING analysts said.

Brent was up 2.2% in early trading but closed 60 cents or 0.9% higher at $69.40. WTI rose 67 cents to close at $64.63.

Feb. 11 gains were muted by a huge surprise

see **OIL PRICES** *page 7*

EXPLORATION & PRODUCTION

Baker Hughes US rig count up 5 at 551

Texas up 6 week over week; January international rig count 1079, up 14 from December, with land rigs up 3 and offshore rigs up 11

By KRISTEN NELSON
Petroleum News

Baker Hughes' U.S. rotary drilling rig count was 551 on Feb. 6, up by five from the previous week and down 35 from 586 a year ago. The domestic rig count has ranged from the 530s through the 550s since the beginning of June.

For 2025, the count peaked Feb. 28 (and again March 21) at 593, hitting its low point Aug. 29 at 526. For 2024, the count peaked March 1 (and again March 15) at 629, hitting its low point June 28 at 581. In 2023 the count peaked early in the year at 775 on Jan. 13, bottoming out Nov. 10 at 616.

A drop of 17 to 731 on May 12, 2023, was the steepest weekly drop since June of 2020, during the first year of the COVID-19 pandemic, when the count also dropped by 17 to 284 on June 5, following drops as steep as 73 rigs in one week in April. The count continued down to 251 at the end of July 2020, reaching an all-time low of 244 in mid-August 2020.

When the count dropped to 244 in mid-August 2020, it was the lowest the domestic rotary rig count had been since the Houston based oilfield services company began issuing weekly U.S. numbers in 1944.

Prior to 2020, the low was 404 rigs in May 2016. The count peaked at 4,530 in 1981.

The count was in the low 790s at the beginning of 2020 prior to the COVID-19 pandemic, where it remained through mid-March of that year when it began to fall, dropping below what had been the historic low in early May with a count of 374 and continuing to drop through the third week of August 2020 when it gained back 10 rigs.

The Feb. 6 count includes 412 rigs targeting oil, up by one from the previous week and down 68 from 480 a year ago, with 130 rigs targeting natural gas, up by five from the previous week and up 30 from 100 a year ago, and nine miscellaneous rigs, down by one from the previous week and up by three from a year ago.

Fifty-five of the rigs reported Feb. 6 were drilling directional wells, 483 were drilling horizontal wells and 13 were drilling vertical wells.

Texas (232) was up by six rigs from the previous week, while Louisiana (39) was up by one.

California (7) and New Mexico (101) were each down by a single rig.

Rig counts in other states were unchanged from the previous week: Alaska (9), Colorado (14), North Dakota (27), Ohio (13), Oklahoma (46), Pennsylvania (19), Utah (16), West Virginia (7) and Wyoming (16).

Baker Hughes shows Alaska with nine rotary rigs active Feb. 3, unchanged from the previous week and down by one from a year ago when the state's count was 10.

The rig count in the Permian, the most active basin in the country, was down by one from the previous week at 241 and down by 62 from 303 a year ago.

Baker Hughes' monthly international rig count for January, issued Feb. 6, was 1,079, up by 14 from December and down 20 from a count of 1,099 in January 2025, with land rigs up three to 839, month over month, and offshore rigs up 11 to 231.

Baker Hughes began providing a monthly international rig count in 1975. The international count excludes North America, which is included in the company's worldwide figures.

The Middle East accounted for the most rigs in the international totals for January, 518, followed by Asia Pacific with 206, Latin America with 136, Europe with 119 and Africa with 100.

The U.S. rig count averaged 545 in January, down by one from 546 in December and down 38 from January 2025, while the Canadian count for January averaged 197, up by 26 from 172 in December and up 11 from January 2025.

Worldwide the rig count averaged 1,821 in January, up 39 from 1,783 in December and down 69 from 1,890 in January 2025. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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FINANCE & ECONOMY

Natural gas price forecast up on demand

EIA February Short-Term Energy Outlook highlights increased Henry Hub gas price, 2026 now at $4.31 up from $3.46 in January STEO

By KRISTEN NELSON
Petroleum News

U.S. natural gas prices were up sharply in January, the U.S. Energy Information Administration said Feb. 10 in its February Short-Term Energy Outlook. Cold weather in January resulted in an average Henry Hub price of $7.72 per million British thermal units from increased demand while also resulting in reduced production, leading to record storage withdrawals.


TRISTAN ABBEY

"Winter Storm Fern caused significant short-term pressure on natural gas markets, but we expect higher prices in the near term will increase drilling, resulting in higher production later this year and helping to replenish storage," said EIA Administrator Tristan Abbey. "Ultimately, this will result in lower natural gas prices next year than we had forecast. Our updated forecast anticipates Henry Hub prices will average $4.30/MMBtu in 2026 and $4.40/MMBtu in 2027, 5% lower than our January forecast."

The agency said the Henry Hub spot price set a nominal record of $30.72 per million Btu on Jan. 23.

In January EIA's forecast was for Henry Hub spot prices to average $3.46 per million Btu this year and $4.59 per million Btu in 2027. The new forecast is an increase of 24.6% for this year and a decrease of 4.5% for 2027.

EIA said the January natural gas price was up 81% from December with withdrawals by the end of March expected to leave less than 1.3 trillion cubic feet of gas in storage, 8% below the agency's previous forecast.

As demand intensified in the latter half of January and production declined due to temporary well freeze-offs, there was a withdrawal of 360 billion cubic feet for inventory, "the largest storage withdrawal on record," EIA said.

Because of the drawdown, the agency said it raised its spot price forecast for February and March by an average of almost 40% from the January forecast. Price increases are expected to moderate as higher prices drive drilling activity.

Drop in gas production

EIA said it estimates a drop of 4 bcf per day, 3%, in Lower 48 natural gas production from December to January because of frigid weather conditions, with the production drop expected to be temporary and almost all of the production back online in February.

Most of the production which was offline was in the Northeast Appalachia region.

Production is expected to ramp up in the second half of the year as new pipeline capacity comes online in the Permian basin and drilling activity is increased in response to higher prices, with U.S. dry natural gas production forecast to grow by 2% this year and by 1% in 2027.

Growth is expected to be slower in the first half of 2026 "as weather-related disruptions and lack of sufficient Permian pipeline takeaway capacity affect production in the Lower 48 states," the agency said.

Once new pipeline capacity comes online in the Permian in the second half of the year, production is expected to ramp up. In 2027 higher gas-oil ratios in the Permian and increased drilling in the Haynesville region driven by higher prices are expected to result in overall production growth.

U.S. dry natural gas production is forecast to be 110 bcf per day this year and more than 111 bcf per day in 2027 — both forecasts up more than 1 bcf per day from the January forecast, EIA said.

Brent price up

EIA said the Brent spot crude oil price averaged $67 per barrel in January, the highest since last September, "as weather-related events disrupted the global crude oil supply and escalating tensions with Iran put upward pressure on prices."

The agency's forecast for Brent is $58 per barrel this year, dropping to $53 per barrel in 2027, both down from the 2025 average of $69 per barrel.

The decline in Brent this year is the expected result of global oil production exceeding global oil demand, EIA said, causing inventories to rise.

Global inventories are expected to continue rising in 2027.

The agency attributed the rise in oil prices to disruptions in U.S. and Kazakhstan crude oil production but said despite near-term price increases and oil supply disruptions, "we forecast that strong growth in global oil production will result in high global oil inventory builds over the forecast, causing crude oil prices to fall."

U.S. disruptions to oil production were cold weather related, with an estimated reduction of 320,000 barrels per day in January, while in Kazakhstan there were power outages at the major Tengiz oil field as well as a drone attack and severe weather at the producer's primary export terminal in Russia, resulting in a reduction of more than 400,000 bpd in January.

EIA said total unplanned disruptions were up in both December and January, for a total of some 3 million bpd, the most since September 2024.

Crude oil demand was up in the northern hemisphere in January because of cold weather at the same time as the disruptions, adding to upward price pressures.

In spite of disruptions, EIA said, "we assess that strong global oil production growth will continue to outpace oil consumption over our forecast, driving our assessment that global inventories will increase," both this year and next. Global oil inventory growth is forecast to average 3.1 million bpd this year compared to 2.7 million bpd last year, before decreasing to 2.7 million bpd in 2027. ●

Contact Kristen Nelson at knelson@petroleumnews.com

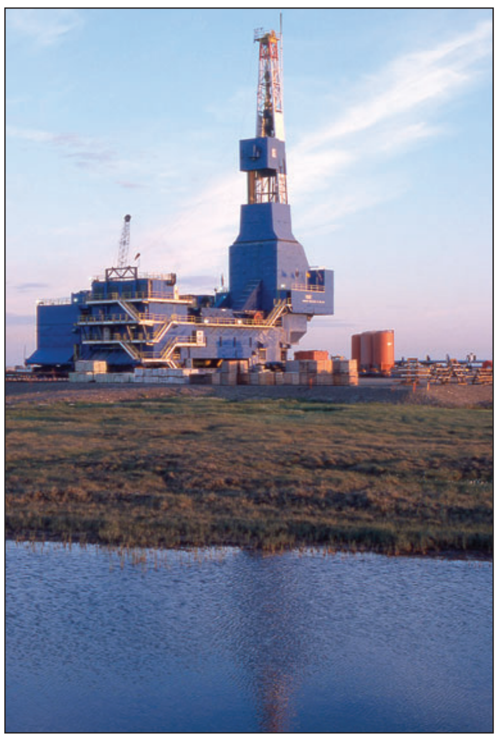
EXPLORATION & PRODUCTION

Building ice road over Trouble Creek

On Feb. 11 the Alaska Department of Natural Resources' Division of Oil and Gas issued a public notice for a land use permit applied for on Feb. 6 by Nabors Alaska Drilling Inc. requesting to build an ice road over Trouble Creek to bypass the bridge during a rig move.

Trouble Creek is approximately 12 miles southwest of the Kuparuk Airstrip.

Nabors proposes to build a 1,500-foot ice road over Trouble Creek on the North Slope adjacent to the Spine Road to safely transport Nabors Rig 245 across the creek.


JUDY PATRICK

Nabors Rig 245

The bridge over Trouble Creek is currently not strong enough to support the rig.

The ice road would start from the Spine Road near DS-2M Pad and end at the Spine Road junction to Mustang Pad and Pikka Unit.

The purpose of the project is to move the Nabors Rig 245 from 12-Acre Pad near Oliktok Point to the Cama'i Pad west of the Kuparuk River Unit.

Construction is proposed to begin March 1, 2026.

The proposed project will be adjudicated under AS 38.05 and 11 AAC 96.030. The division is providing public notice and an opportunity to comment.

The application package is available for review at the Division of Oil and Gas' Permitting Section, 550 West 7th Ave., Suite 1100, Anchorage, AK 99501, or online at http://dog.dnr.alaska.gov/Newsroom.

Send comments to dog.permitting@alaska.gov or to the division address above. All comments must be in writing.

A copy of the final decision will be sent to any person who provides written comments.

An eligible person affected by this decision may appeal or request the commissioner's reconsideration in accordance with 11 AAC 02.

All comments must be received by the comment deadline: 4:30 pm, Alaska Standard Time, Feb. 25, 2026.

—KAY CASHMAN

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● UTILITIES

Chugach Electric pursuing Southcentral hydroelectric projects

PETROLEUM NEWS

Chugach Electric Association is pursuing hydroelectric projects as part of efforts to reduce reliance on natural gas and achieve decarbonization goals set by its board of directors. Chugach said in a Feb. 10 release that it is moving forward in investigation of potential Southcentral hydroelectric sites.


ARTHUR MILLER

Preliminary permit applications with the Federal Energy Regulatory Commission and water right applications with the Alaska Department of Natural Resources were filed Feb. 6 for feasibility studies of four projects:

•Canyon Creek, run of river, expected capacity 6 megawatts;

•Godwin Creek, storage, expected capacity 16 megawatts;

•Boulder Creek, storage, expected capacity 12 megawatts; and

•Caribou Creek, storage, expected capacity 8 megawatts.

Preliminary steps give Chugach site priority, enabling engineering due diligence and outreach to groups potentially impacted by development.

Decarbonization goals use a baseline of 2012 and aim to reduce carbon intensity by at least 35% by 2030 and by at least 50% by 2040, without a material negative impact on rates or reliability.

Previous and upcoming work

Chugach said it began initial site investigations more than 2 years ago, surveying 158 potential locations and developing an initial list of criteria for site selection, excluding any projects with dams or diversions on anadromous reaches.

Over the past six months Chugach has met with regulatory agencies, tribes, landowners and non-governmental organizations to discuss guiding principles and solicit input on site selection. The site selection criteria were revised, with the selected sites based on input from stakeholders.

"As we are all focused on the energy future of Alaska, we know hydro is dependable, is the lowest cost long-term energy source for ratepayers, allows us to reduce the need for fossil fuels, and helps us meet our decarbonation goals," said Chugach CEO Arthur Miller. "Our early outreach to potentially impacted stakeholders and partners has received a very positive response as Alaskans understand the need for future energy diversification and low-cost power."

Timeframe

Miller said timing is important. Hydro projects take years to study and construct and there are significant investment tax credits available for projects which begin construction by Dec. 31, 2033.

"The runway is long and we need to move forward on the investigation of possible hydro projects. That's why we started months ago engaging with stakeholders," Miller said. "With the preliminary permits filed, we can continue to investigate how to minimize and mitigate impacts from potential projects, look for fatal flaws, and only move forward on projects that are economical, and benefit thousands of Alaskans."

The next step is a public comment period for each application.

Chugach said the goal for 2026 is to identify any fatal flaws with the proposed sites and remove those projects early, with remaining projects advanced through FERC licensing or the state permitting process for non-FERC jurisdictional projects. ●

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MCKAY TO AOGCC

McKay served in the Legislature from 2021-2024, chairing the House Resources Committee in the 2023-24 33rd Legislature.

He earned a B.S. in petroleum engineering from Montana Tech in 1980 and an M.S. in environmental engineering from the University of Alaska Anchorage in 2000.

McKay has worked for Amoco, ARCO Alaska, ConocoPhillips and BlueCrest Energy Alaska.

He served as chairman of the Alaska Republican Party.

—KRISTEN NELSON

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CONOCO GROWTH

about the Alaska exploration program. So we just started this year, the first of a multi-year program. Can you speak to the objective of that exploration program? What's the risk; how big is the scale of the resource being targeted? And if successful, are we talking about extending the plateau for Willow? Or is it more upside to the ultimate production capacity of that project?"

Kirk Johnson, ConocoPhillips Executive Vice President, Global Operations and Technical Functions responded as follows: "Yes, certainly pleased to report that we're out in front of this winter season here. We got an early start, just based on weather under ice road activity. And of course, we have all of the permits required for both the wells as well as the seismic that we have planned up there … this year. And even to that end, we were able to spud the first of those four wells just within the last couple of days.

"So strong progress that we're seeing on those four. But again, to your question around intent and objectives here, we're out there exploring to the west of Willow and actually to the south. And so as you've certainly heard from us before, our objective is to continue to find what we might describe even though it's onshore as tieback oppor-

see **CONOCO GROWTH** *page 5*

continued from page 4

CONOCO GROWTH

tunities into both Willow and actually into our WNS Alpine asset as well.

"So to your point, this is an opportunity for us to identify continued volumes, continued resource plays to bring into this existing infrastructure and Willow being the next hub, if you will.

"And when we look back on our performance history there in Alaska, we have and continue to project or expect we'll produce well over double the volumes through those existing facilities through that existing infrastructure over double what we originally premised when we took FID on those. And so naturally, then that's our same objective here for Willow specifically as we explore to the west, we'll be looking for those resource opportunities to just keep that infrastructure full.

> *"We anticipate realizing approximately $1 billion of incremental free cash flow in each year from '26 through '28, with another $4 billion from Willow coming online in 2029. And that's a growth profile that's unmatched in our industry," said ConocoPhillips Chairman and Chief Executive Officer Ryan Lance.*

"Obviously, a bit early to start making a call on total resource size, et cetera. But naturally, we have some pretty high aspirations and targets that we're pursuing, and we'll be going after this for several years here. We've got four wells here premised this year but we've got a multiyear plan that we intend to carry out again, so that we can maximize as we do globally the infrastructure that we have and our ability to bring new volumes into that, that creates this advantaged cost of supply for us using the existing kit," Johnson finished.

Fourth quarter report

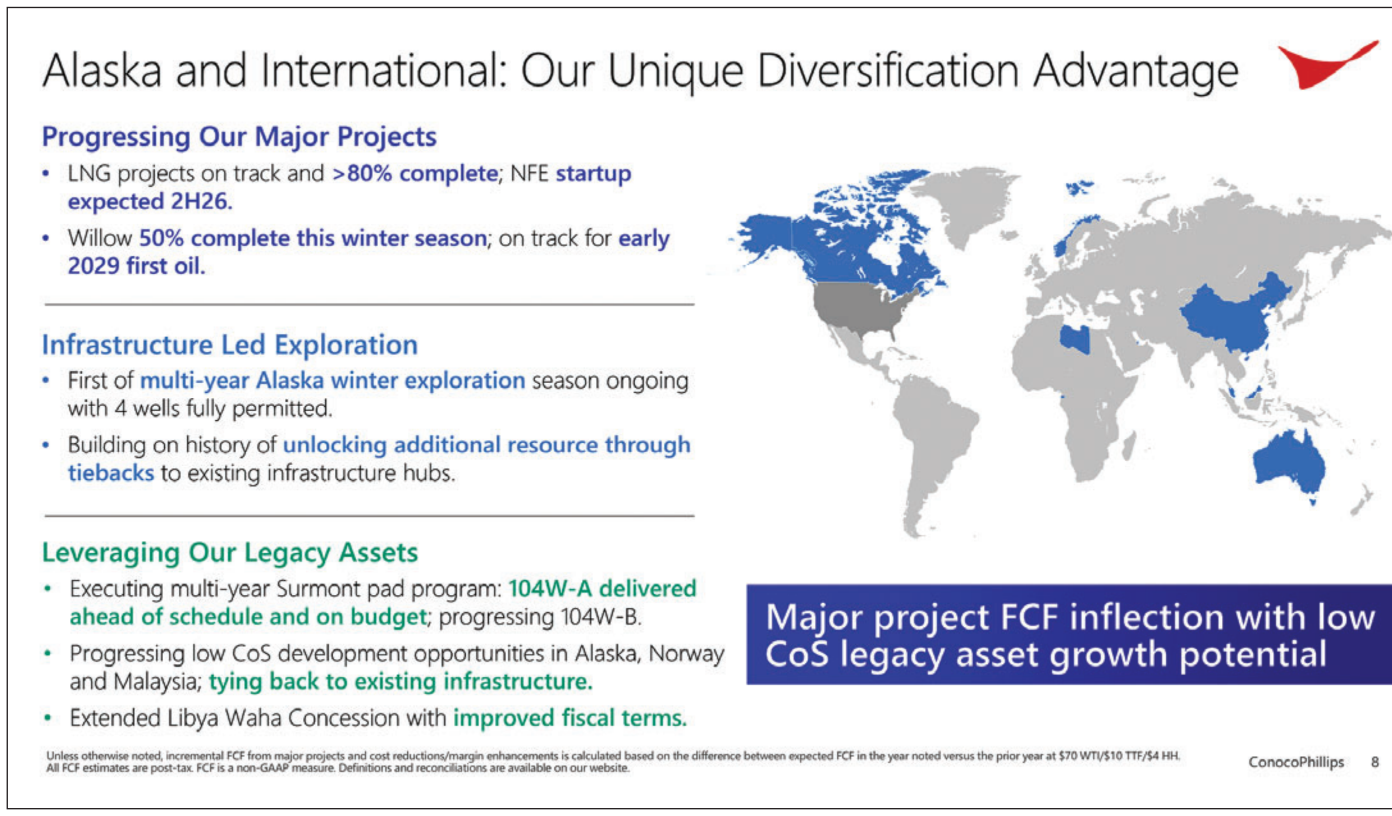
Houston-based ConocoPhillips reported fourth-quarter 2025 earnings of $1.4 billion, or $1.17 per share, compared with fourth-quarter 2024 earnings of $2.3 billion, or $1.90 per share.

Excluding special items, fourth-quarter 2025 adjusted earnings were $1.3 billion, or $1.02 per share, compared with fourth-quarter 2024 adjusted earnings of $2.4 billion, or $1.98 per share. Special items for the quarter primarily relate to a gain on asset sales and restructuring costs.

Full-year 2025 earnings were $8.0 billion, or $6.35 per share, compared with full-year 2024 earnings of $9.2 billion, or $7.81 per share. Excluding special items, full-year 2025 adjusted earnings were $7.7 billion or $6.16 per share, compared with full-year 2024 adjusted earnings of $9.2 billion, or $7.79 per share.

"ConocoPhillips delivered another year of strong performance in 2025, achieving our CFO-based (CFO means cash flow from operations) return of capital target and growing our base dividend at a top-quartile S&P 500 rate, in line with our returns-focused value proposition. We outperformed our initial production, capital and cost guidance; successfully integrated Marathon Oil, doubling our synergy capture; and made strong progress on our incremental cost reduction and margin enhancement efforts," said Lance. "Looking ahead, we're focused on driving a $1 billion reduction in our capital and costs in 2026, while returning 45% of our CFO to shareholders." ●

Contact Kay Cashman at publisher@petroleumnews.com



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LEASE SALES

bids on March 18.

What this means is the division can't hold a simultaneous sale with BLM for NPR-A this time. The division must complete the call for new information process, then must issue a sale notice at least 45 days before a sale. BLM is only required to issue notice 30 days prior to a sale.

For the ANWR coastal plain sale area, BLM is still in the call for nominations and comments phase. If they give the Division of Oil and Gas enough notice, and the division's best interest finding review process is complete, it is possible the division might be able to hold a simultaneous sale. If they do, readers will see a notice from the division's leasing emailer.

On Feb. 5, the Division of Oil and Gas said it is requesting substantial new information concerning Beaufort Sea, North Slope and North Slope Foothills that have become available over the past year.

Based on the information received, the division will either issue supplements to the findings or issue decisions of no substantial new information for these lease sales.

The most recent Beaufort Sea Areawide final best interest finding was issued in 2019. The most recent North Slope Areawide final best interest finding was issued in 2018. The most recent North Slope Foothills Areawide final best interest finding was issued in 2021. No supplements have been issued for these areawide lease sale areas.

The findings and supplements are located at: http://dog.dnr.alaska.gov/Services/BIFAndLeaseSale.

Areawide lease sales

Alaska holds annual competitive oil and gas lease sales in five defined geographic areas, called areawide lease sales. Before the division may hold an areawide lease sale in any of the five geographic areas, Alaska law requires a written finding saying it is in the state's best interest to have a lease sale.

A best interest finding is generally valid for 10 years. It describes facts and relevant laws pertaining to the proposed lease sale area and discusses the potential effects of oil and gas exploration, development and production, and transportation. It also contains mitigation measures that lessees must follow.

The Beaufort Sea Areawide lease sale area covers about 1.7 million acres, 572 tracts ranging in gross area from 520 to 5,760 acres. These tracts are located within the North Slope Borough and mostly consist of state-owned tide and submerged lands in the Beaufort Sea between the Canadian Border and Point Barrow.

The North Slope Areawide lease sale area covers about 5.1 million acres, 3,137 tracts ranging in gross area from 640 to 5,760 acres. These tracts are entirely within the North Slope Borough between the Canning River and ANWR on the east and the Colville River and NPR-A on the west.

The North Slope Foothills Areawide lease sale area covers approximately 7.6 million acres, divided into 950 tracts ranging in gross area from 480 to 5,760 acres, between ANWR and NPR-A, south of the Umiat baseline south to the Gates of the Arctic National Park and Preserve.

Only those tracts in which the mineral estate is free and unencumbered are included in any lease issued.

Substantial new information must be received by the division by 5:00 p.m. on March 10 to be considered.

—KAY CASHMAN

Contact Kay Cashman at publisher@petroleumnews.com

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NPR-A SALE

Office, ATTN: Wayne Svejnoha (AK932); 222 West 7th Ave., #13; Anchorage, AK 99513-7504.

BLM manages more than 22 million acres of surface estate plus the subsurface mineral rights to an additional ~650,000 acres in the NPR-A.

The BLM manages the NPR-A under the Naval Petroleum Reserves Production Act, which mandates an "expeditious program of competitive leasing" while safeguarding key surface resources.

The BLM is currently implementing new direction to help unlock Alaska's energy potential through Executive Order 14153 and Secretary's Order 3422 and the One Big Beautiful Bill Act (Public Law 119-21).

Under the One Big Beautiful Bill Act, the BLM is reinvigorating the NPR-A oil and gas leasing program and resuming lease sales. The Act requires BLM to hold at least five lease sales over the next 10 years, offering a minimum of 4 million acres at each sale beginning with an initial lease sale no later than July 4, 2026.

The upcoming lease sale will follow the guidelines set in the 2020 Record of Decision, or ROD, with updates to the high-potential area boundaries.

The opening and reading of the bids for the 2026 lease sale will be available for online public viewing via video livestreaming at http://www.blm.gov/live.

Svejnoha can be contacted by phone at 907-271-4407 or via email at wsvejnoh@blm.gov.

Individuals in the United States who are deaf, deafblind, hard of hearing, or have a speech disability may dial 711 (TTY, TDD, or TeleBraille) to access telecommunications relay services for contacting Svejnoha. Individuals outside the United States should use the relay services within their country to make international calls to the point-of-contact in the United States.

The Detailed Statement of Sale includes a description of the areas the BLM is offering for lease, as well as the lease terms, conditions, special stipulations, required operating procedures, and directions for how to submit bids. If you plan to submit a bid(s), please note that all bids must be sealed in accordance with the provisions identified in the Detailed Statement of Sale.

Federal Register

The Detailed Statement of Sale is supposed to be published in the Federal Register on Feb. 11, specifying precisely what acreage will be auctioned off in the March 18 lease sale.

The BLM said the United States reserves the right to withdraw any tract from this sale prior to issuance of a written acceptance of a bid.

"The National Petroleum Reserve in Alaska plays a vital role in advancing America's energy independence, and Congress has repeatedly made clear their intent for timely leasing and responsible development in the region," said Acting BLM Director Bill Groffy. "This lease sale — the first in the reserve since 2019 — marks another exciting milestone as we work to unlock the full potential of this area."

Currently, about 1.6 million acres are leased in the petroleum reserve. Since 1999, BLM lease sales in the area have generated more than $294 million, with revenues supporting both the U.S. Treasury and the State of Alaska. Half of all proceeds — along with future rental payments — are directed to the State of Alaska's Impact Grant Program to support local communities.

—KAY CASHMAN

Contact Kay Cashman at publisher@petroleumnews.com

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HILCORP INLET WELLS

peaked at 28 wells in 2014. The company's inlet drilling rate has varied since, ranging from a low of five in 2018 to 22 in 2022. Last year the company drilled 20 Cook Inlet wells — and as previously noted plans 27 wells this year.

Natural decline

Saugier told the committee that wells naturally decline, with the decline varying depending on location of the well and nature of the reservoir.

"When you drill a well, that first day of production from the well is really the best day that well is ever going to have," he said. After that, the decline rate in Cook Inlet is about 30-40% a year.

Southcentral uses 65 billion to 70 billion cubic feet of natural gas a year — a little less when it's warm in winter, a little more when it's cold.

Saugier used a slide showing that Hilcorp's gas production has remained steady at around 50 bcf per year since 2016, while production from all other operators combined recently ranged from a high of 31 bcf per year in 2017 to a low of 9 bcf in 2025.

Eleven operators, including the state, drilled wells over the 2005-25 period.

But from 2020 through 2023, Saugier noted, Hilcorp was the only company drilling, something he called a "serious problem."

Furie, under John Hendricks, is now drilling. "That's important for Southcentral Alaska," Saugier told the committee.

There are several reasons for the ability Hilcorp has had to hold at that 50 bcf per year, he said: a very high activity level with a lot of wells drilled; fixing "a lot of broken equipment"; and "re-completing a lot of wells, always looking for gas."

Storage

What has happened as overall Cook Inlet production declined and by 2023 total production was below the 65-70 bcf per year of demand?

Southcentral has been drawing out of storage, and not refilling storage as completely as would be ideal, Saugier said.

Gas storage is drawn down in winter when demand is heavier and gas is injected into storage in the summer.

There are four gas storage facilities around the inlet, he said: Pretty Creek, KGSF, CINGSA and Pool 6, with varying amounts of storage and deliverability. CINGSA is the only storage not operated by Hilcorp and was the only storage facility commercially available.

After some really cold weather in 2024 coinciding with some operating challenges at CINGSA, Saugier said some of Hilcorp's customers expressed an interest in being able to use Hilcorp's storage facilities.

To make that happen, Hilcorp applied to the Regulatory Commission of Alaska to make Pool 6 commercially available, and recently signed storage agreements with a couple of utilities, he said.

Pool 6 could be expanded for storage as it is a large reservoir with only a small portion currently used for storage.

Saugier said that over this year Hilcorp is going to try to provide access to its other storage facilities if utilities are interested. The other facilities are in different parts of the basin with access to different pipelines and can deliver gas at different rates.

But that's emergency backup.

Additional supplies

Things Hilcorp is doing to continue providing gas include developing Pretty Creek on the west side of the inlet and making structural changes to the Tyonek platform to allow more drilling at the North Cook Inlet field.

There is no road access to Pretty Creek, so work there requires barging which limits development in the area to summer when the inlet is ice free.

Hilcorp has built a new pad and drilled new wells at Pretty Creek, work done in one year, he said, to get the gas online. Also on the west side, Hilcorp operates the Beluga River field which it operates on behalf of itself and two-thirds owner Chugach Electric Association.

Eight wells were drilled on the west side of Cook Inlet in the summer of 2025, a record for Hilcorp, and drilling is expected to continue on the west side.

At the Tyonek platform, Hilcorp's largest gas producing platform, there were no more slots available in the platform legs for drilling, so to add wells Hilcorp began this summer to add huge steel shells, called ice breakers, to the side of the legs, allowing the company to drill more wells. The first of the steel shells, manufactured at Steel Fab in Anchorage and weighing as much as a Boeing 737, was installed in the summer of 2025, requiring two cranes on the platform to lower it over the side. Because the deck of the platform overlaps the legs, the ice breaker then had to be winched into place so it could be welded to the leg.

What about the oil?

Saugier said all the 2026 wells are "100% focused on gas." He was asked about Cook Inlet oil, since the Kenai refinery depends on that oil.

"There's no nice way to say it," Saugier responded. "The oil producing assets in the Cook Inlet are exceptionally challenged." Cook Inlet oil wells are "very expensive to operate — particularly offshore."

Fixed costs are very high, oil prices are fairly low and the company's oil wells are "almost subsidized by the gas assets."

But operating those oil wells as long as possible is important, Saugier said, and Hilcorp believes oil prices will recover, making the company's Cook Inlet oil assets competitive again. ●

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OIL PRICES

surge in U.S. crude inventories shown in data released by the U.S. Energy Information Administration.

U.S. commercial crude oil inventories for the week ended Feb. 6 — excluding Strategic Petroleum Reserve levels — leapt 8.5 million barrels from the previous week to 428.8 million barrels — 3% below the five-year average for the time of year, the EIA said.

Analysts in a Reuters poll estimated on average that crude inventories rose by some 800,000 barrels on the week.

Total motor gasoline inventories rose 1.2 million barrels over the week to 259.1 million barrels — 4% above the five-year average for the time of year, the EIA said. Distillate fuel inventories decreased 2.7 million barrels to 124.7 million barrels — 4% below the five-year average for the season.

Analysts in the Reuters poll estimated that gasoline inventories likely fell by some 1.3 million barrels, while distillate levels likely fell by 400,000 barrels.

ANS rose 88 cents Feb. 9 to close at $69.36, as WTI rose 81 cents to close at $64.36 and Brent rose 99 cents to close at $69.04.

On Feb 6, ANS rose 62 cents to close at $68.48, WTI rose 26 cents to close at $63.55 and Brent rose 50 cents to close at $68.05.

Crude fell sharply Feb. 5, clawing back a chunk of the gains on the previous day. ANS plunged $1.42 to close at $67.86, WTI plunged $1.85 to close at $63.29 and Brent plunged $1.91 to close at $67.55.

ANS leapt $1.35 Feb. 4 to close at $69.28, while WTI leapt $1.93 to close at $65.14 and Brent leapt $2.08 to close at $69.46.

ANS gained 97 cents over the trading week from its close of $67.93 Feb. 3, to $68.90 on Feb. 10.

Russian crude stranded afloat

A flotilla of tankers laden with unsold Russian oil are floating at sea, threatening fiscal hurt for Moscow, the Wall Street Journal reported Feb. 11.

Some 143 million barrels were on the water Feb. 10, seeking buyers, according to ship-tracking company Vortexa.

Russia's crude buyers are demanding the deepest discount to global oil prices since early in the Ukraine war.

Despite sanctions after the 2022 invasion of Ukraine, Russia evaded sanctions, rebuilt its own shadow shipping fleet and found new buyers for its crude.

Today, European sanctions against specific ships, military ship seizures on the high seas, and President Trump's efforts to put a wedge between Russia and India, have left Moscow's most important industry in a precarious state, the Journal said.

Russia's main crude grade — Urals — trades for some $45, a record $27 below Brent, according to commodities-data firm Argus Media.

Russia needs $59 per barrel to balance its 2026 fiscal budget.

China's teapot refineries, independent outfits that often operate without links to Western finance and insurance, appear to be absorbing some of the glut, according to Natasha Kaneva, head of global commodities strategy at JPMorgan.

But the teapots are likely to drive a hard bargain.

"When oil is sitting on a tanker off the coast, hoping for a buyer, the seller is not in a good negotiating position," said Ronald Smith, founding partner of Texas-based Emerging Markets Oil and Gas Consulting Partners. ●

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Petroleum news

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INLET LNG

to use the terminal to supply Chugach Electric with gas via the terminal.

Glenfarne, the company planning to build a gas pipeline from the North Slope, has a plan to build a new LNG import facility, also at Nikiski. Enstar anticipates obtaining gas via that terminal. Once the North Slope gas pipeline has been fully completed the new LNG facility would be converted into an LNG export facility.

And, as previously reported by Petroleum News, Cook Inlet LNG LLC is planning an offshore liquefied natural gas import facility using a Floating Storage and Regasification Unit, or FSRU, connected to the Osprey platform on the west side of Cook Inlet.

The House Energy meeting only discussed the Harvest and Glenfarne projects.

Firm gas supplies are essential

The key issue that the utilities are facing is the need for firm gas supplies, either from gas producers or from gas held in storage facilities, to ensure continuity of supplies for consumers. Unless and until a gas pipeline from the North Slope comes into operation, local gas supplies will need to be bolstered by imported LNG, as supplies from Cook Inlet decline and firm supplies in required quantities cease to be available.

John Sims, president of Enstar, told the committee that the availability of firm gas supplies is already becoming an issue. A forecasted extreme cold spell in January, which fortunately did not transpire, would have required Enstar to request the military to cut back its gas consumption. And Matanuska Electric Association might have had to switch from gas to diesel for its power generation, Sims said.

A timing issue

Sims commented that, ultimately, the Glenfarne import facility could import sufficient LNG to meet all the utilities' needs. Unfortunately, however, there is a timing issue, in that the firm gas supplies for different utilities come to an end in different years. For example, Chugach Electric's firm gas supplies end in 2028, before the Glenfarne terminal can realistically go into operation — hence Chugach's involvement with Harvest's Nikiski terminal conversion. That terminal is expected to come online in 2028. Enstar has previously indicated that the existing Nikiski terminal will not have sufficient capacity to support all the Southcentral utilities, including Enstar. Hence the need for the Glenfarne terminal.

Status of the Harvest Midstream project

Sean Kolassa, president of Harvest Midstream, talked about the status of his company's project to convert the existing Nikiski LNG export terminal for LNG importing. The project involves the construction of five new compressors, two LNG vaporizers, six new LNG pumps and the modernization of the control room. A meter site will need to be built. The plan is to use the existing marine dock, with some upgrades to the infrastructure. Those upgrades will support current LNG vessel sizing, Kolassa said.

The project provides speed, certainty and flexibility, Kolassa told the committee. Importantly, while the facility site has a large footprint with the capacity to accommodate additional infrastructure that may eventually be needed, the facility already has pipeline connectivity to the gas transmission pipeline system.

"What makes this project very cost-efficient is the ability to utilize the existing footprint and infrastructure, and specifically the dock and tankage," Kolassa said.

He said that on Nov. 11 appropriate experts had completed an inspection of the facility and established that the facility had been very well maintained and was well positioned for the importing of LNG. The facility also preserves the option to be part of an LNG export solution, if a North Slope gas pipeline is constructed, Kolassa said.

Can meet Southcentral's near term needs

Kolassa said that Harvest is pursuing a permitted capacity of about 20 billion cubic feet per year of gas, a volume sufficient to meet Southcentral's near term needs. However, the facilities that are being installed will have an import capacity of up to 73 billion cubic feet per year, he said.

The capital cost of the project is estimated in the range of $300 million to $350 million and Harvest is moving towards making a final investment decision that will tighten the cost estimate. The company has already spent millions of dollars on front-end engineering design to define the project scope and establish the project timeline, Kolassa said.

Kolassa also emphasized that the import capacity could be expanded through permit amendments with FERC and the Coast Guard. For example, further tankage could be added. And the company is maintaining flexibility, so that the site could revert to becoming an LNG export facility in the future, if necessary.

"The project is scoped to function either as a temporary or a long-term solution for Railbelt gas needs, depending on how supply options evolve," Kolassa said.

The fact that the project involves the modification of an existing facility results in straightforward permitting. And, based on current planning assumptions, the facility is expected to come online in late 2028, Kolassa said. He also commented that Harvest needs customer commitments to the use of the terminal before a final investment decision can be made and that those contracts would require RCA approval.

Recovery of costs for Glenfarne project

Sims talked about the planned Glenfarne import terminal. He emphasized that Glenfarne is itself proposing to develop its LNG import facility, with Enstar as its customer. Enstar will have no capital investment in the project, he said. The planned capacity of the facility is 300 million cubic feet per day, with the possibility of future expansion.

"We're promoting this project because after two years, $4.6 million of research, analysis, understanding market demand, this was the project that rose to the top," Sims said in response to a question regarding whether Enstar was promoting the project simply to make a significant rate of return.

He commented that, based on Enstar's current gas supply contracts, the utility will need access to imported LNG starting in 2033. And a particular appeal of the Glenfarne project is the manner in which the recovery of the cost of the facility can be spread over perhaps a 30-year term, regardless of whether the facility continues to be used for LNG importing or whether it becomes an LNG export facility.

"And, so, that's what we want to do for our customers is to spread out the cost as much as possible, so there isn't that huge impact," Sims said, comparing the financing arrangements to a long-term mortgage.

The cost of gas

The cost of gas obtained through the import facility would be the sum of the cost of the imported LNG, the operating costs of the tugs needed for the terminal, and the cost of operating the terminal. The total estimated cost of gas from imported LNG in 2033 would then be about $15 per thousand cubic feet, assuming that only Enstar was using the terminal. If, however, the imported gas that all the utilities needed came through the terminal, that cost would drop to about $13 per thousand cubic feet. If, on the other hand, it became unnecessary to import LNG, Enstar would remain committed to paying its share of the terminal cost, Sims said.

However, if the gas pipeline from the North Slope comes into fruition, and the Glenfarne LNG import terminal becomes an export terminal, the entities exporting LNG, not Enstar, would become responsible for the terminal costs.

This flexibility does not exist in the Harvest LNG terminal option, Sims suggested. He commented that, if the gas pipeline is built, the Harvest terminal, unlike the Glenfarne terminal, would become a stranded asset. Moreover, the Alaska LNG project that Glenfarne is conducting is the only project with the potential to reduce the cost of energy in Southcentral Alaska he said.

Tim Fitzpatrick, communications director for Glenfarne, has told Petroleum News that the Glenfarne import terminal, together with the eventual export terminal and the Alaska LNG pipeline, will give Alaska utilities the only flexible and efficient long-term solution for reliable, affordable energy aligned with Alaska's future. The fully permitted LNG terminal will feature significant dual-use infrastructure like jetties, piers and storage capacity that will accommodate imports and enable exports without Alaskans investing in infrastructure, he said.

Duplication of import capacity

There was discussion during the House Energy meeting about potential issues relating to the duplication of import capacity resulting from the implementation of more than one import facility. Would this result in unnecessary costs that would need to be recovered from gas and electricity consumers in Southcentral? And would government regulators be willing to permit the construction of duplicating facilities and approve any impact of the duplication on the cost of gas?

John Espindola, chair of the Regulatory Commission of Alaska, told the committee that, while the RCA is responsible for regulating the costs of the energy that public utilities supply to consumers, the RCA does not regulate the construction of LNG terminals. The Federal Energy Regulatory Commission has regulatory authority over the siting and construction of LNG terminals. RCA regulation would not come into play for terminal duplication until a utility makes a filing that encompasses the cost impact of LNG importing from a second terminal, Espindola said.

Sims questioned whether it would be necessary to obtain rate approvals from the RCA in order to proceed with the LNG terminal projects. He agreed that the RCA has a role in the situation, but commented that, as in the development of the Cook Inlet Natural Gas Storage Alaska facility a number of years ago, the RCA could conduct confidential discussions, asking some very challenging questions about the plans.

—ALAN BAILEY

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