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CALIFORNIA ENERGY MARKETS

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[1] HECA Project Faces Rising Costs, Unresolved Issues

A rendering of the proposed HECA project. *Courtesy SCS Energy/Hydrogen Energy California.*

A joint review of the $4 billion Hydrogen Energy California Project by the CEC and the U.S. Department of Energy found a number of significant issues with the proposed project. HECA may not comply with California's greenhouse-gas emissions performance standard, but staff needs more information to understand how the project would operate. Project water usage may deplete local aquifers, and construction and operation would affect a local environmental-justice community. In addition, the developer has told DOE it expects project costs could jump 20 percent. ***Steep hurdles for HECA, at [11].***

[2] Panoche Valley Solar Project Clears Litigation Hurdle

A California appeals court has ruled that San Benito County's approval of the proposed 399 MW Panoche Valley Solar Farm complies with state law. The court's decision upholds the county's certification of an environmental impact report for the project and the cancellation of Williamson Act contracts on lands slated for development. The Santa Clara Valley Audubon Society and Sierra Club sued the county claiming the EIR for the project, co-developed by PV2 Energy and Duke Energy Renewables, does not adequately address impacts to the San Joaquin kit fox and other endangered species. ***Weighing the impacts of green energy at [12].***

[3] Cost Questions Remain for SONGS

Consumer groups continue to call for the CPUC not to let Southern California Edison recover from ratepayers all of its 2012 costs related to the now-closed San Onofre Nuclear Generating Station. Those costs could total more than $700 million, the Division of Ratepayer Advocates has warned. But the forced shutdown of the plant in January 2012 means it has not benefited ratepayers for more than a year. Ratepayer groups and others want much of the plant's costs taken out of rates as of its shutdown date, urging immediate refunds of 2012 collections and complaining that Edison has not clarified the amounts it spent on safety-related functions that it could recover in rates. ***At [10], advocates want refunds.***

[4] PUCN Staff: Nevada Law Bars Utility Merger

The staff of the Public Utilities Commission of Nevada filed a motion recommending the commission dismiss an application to merge NV Energy subsidiaries Nevada Power and Sierra Pacific Power. Staff cited a 2001 statute adopted during the Western energy crisis. Meanwhile, PNM outlined its plan to replace 340 MW of power generation it would lose with the retirement of Units 2 and 3 at the San Juan Generating Station. ***At [14], NV Energy subsidiary merger could be scuttled.***

[5] NuScale Takes Next Step to Bring Small Modular Reactors to Market

Portland-based NuScale Power has applied for up to $226 million in funding from the U.S. Department of Energy to help complete the design and certification of its 45 MW small modular reactor, with the aim of achieving commercial operation by 2025. The company has selected the Idaho National Laboratory as the preferred location for a six- to 12-module (270-540 MW) demonstration plant. ***At [13], new nuke not for the impatient or faint of heart.***

[6] EPA Sends White House Reworked Power-Plant GHG Proposal

The Environmental Protection Agency on July 2 sent to the White House a reworked proposal setting greenhouse-gas emissions limits for new fossil-energy plants, but kept details under wraps. Meanwhile, EPA extended until Sept. 20 the comment period for a proposal limiting toxic effluent discharges from power plants. ***EPA agrees to reconsider reciprocating combustion-engine emissions rule, at [15].***

News In Brief

[7] Feed-In Tariff Approved for Glendale Water & Power

Glendale Water & Power is looking to purchase electricity generated by local renewable-energy projects under the public utility's newly minted feed-in tariff program.

The Glendale City Council approved the framework and rules for the 4.2 MW FIT program on June 25 in order to comply with SB 1332, a state law that requires utilities with 75,000 or more customers to adopt a feed-in tariff.

GWP has about 84,500 customers, and the 4.2 MW program size represents Glendale's proportional share of a 750 MW statewide FIT cap established by legislation.

The size limit for individual projects, 1.4 MW rather than the 3 MW limit allowed by the law, represents the maximum ampacity (capacity of amperes) that can flow through GWP's distribution system, according to the utility.

The rates for GWP's program, which kicks off on July 26, are not fixed, but will be based on market conditions and adjusted on a quarterly basis.

The calculation of the quarterly FIT price will take into account the avoided cost of energy that would otherwise be purchased from the spot or short-term market, the value of the green attributes, avoided greenhouse-gas compliance costs, and the value of avoided transmission and distribution.

The estimated rates for the first quarter of the FIT program, from July to September, are 9.3 cents/kWh for on-peak power and 7.5 cents for off-peak power. Contracts can be signed for terms of 10, 15 or 20 years.

While other utilities in the state have established FIT programs that provide fixed prices for long-term contracts, the utility believes dynamic prices will better reflect the cost of energy, while also preventing cost shifting to non-participating customers.

"If we set it at one rate for a 20-year period, it's a little bit harder to tie that to your actual cost of energy," Chief Assistant General Manager Steve Lins explained to the council. "We didn't want to go that route."

Jim Jenal, founder of Pasadena-based solar-project developer Run on Sun, said GWP's prices are too low to attract small and mid-sized projects.

Jenal calculated that a 100 kW project, for example, would earn an internal rate of return of 4.1 percent and take 12 years to break even under the GWP tariff.

The same 100 kW project in the Los Angeles Department of Water & Power's service territory, where the FIT price for a 100 MW program is around 16 cents/kWh, would have an IRR of 11.1 percent and payback in year six, Jenal said.

"The only projects that this pencils out for are projects up in the 1.4 MW range," Jenal stated. "It does nothing for getting solar throughout the city on rooftops where people can see it and understand that this is a technology that makes sense."

Lins pointed out that in a recent evaluation, LADWP's ratepayer advocate found the FIT prices in Los Angeles to be far above market prices, placing an incremental burden of up to $268 million on ratepayers over a 20-year period. The ratepayer advocate recommended last month that the program be halted and the FIT rate reconsidered in light of declining solar prices.

LADWP, however, intentionally set its prices at levels that exceed avoided costs in order to attract participation. The FIT rates started at 17 cents/kWh in February and will decline in 1-cent increments to 13 cents/kWh as each 20 MW block is filled (see *CEM* No. 1215 [16]).

Craig Lewis, executive director of the Palo Alto-based Clean Coalition, said GWP's feed-in tariff prices appear to be "out of whack" compared with what other utilities are offering, and questioned the cost-of-energy analysis.

"I just can't imagine them going below 10 cents," Lewis said ***[L. B. V.].***

[7.1] Quick Bites: Energy News Roundup

A draft decision at the CPUC would put up to $66 million toward energy-efficiency financing pilot programs *[A12-07-001]*. The commission had previously adopted 2013-2014 efficiency programs for the four major investor-owned utilities and included preliminary approval of ratepayer money to fund new efficiency financing pilot programs, but had not yet set specific financing programs (see CEM No. 1206 [11]) The pilot programs aim to help consumers undertake deeper energy-efficiency retrofits than traditional programs can. The programs will also test whether ratepayer support for more access to efficiency financing in underserved market sectors will trigger self-supporting programs in the future ***[H. C.].***

Western Price Survey

[8] Western Power Prices Moderate

Western peak-power prices fell sharply this week after rocketing above $100/MWh during a stifling heat wave that stretched across the western U.S.

California-Oregon Border prices reached a $195/MWh high July 1, while Palo Verde was at $130/MWh.

By July 3, however, average peak prices plunged to between $33 and $50/MWh.

Higher prices in general could stick around for a while. Western energy prices should be 19 percent higher on average this summer compared with 2012, according to a report by ICF International. The analysts also said that "significant congestion on the major paths into Southern California" should continue causing a differential in Northern and Southern California power prices.

Markets were closed Thursday for the July 4 holiday.

Here's how average peak prices at Western hubs fared since Friday, June 28:

- **Mid-Columbia:** Down $11.60 to $39.60/MWh.
- **California-Oregon Border:** Lost $19.05 to $42.95/MWh.
- **North of Path 15:** Last traded July 3 at $49/MWh.
- **South of Path 15:** Dropped $31.30 to $44.70/MWh.
- **Palo Verde:** Fell $39.60 to $43.65/MWh.

Off-peak prices dipped in Friday-to-Friday trading, with losses ranging from $1.15 at Palo Verde to $4.20 at the California-Oregon Border. Off-peak values July 5 ranged from $11.15 at Mid-C to $27.28 at Palo Verde.

Working gas in storage reached 2,605 Bcf as of Friday, June 28, according to U.S. Energy Information Administration estimates, a net increase of 72 Bcf from the previous week. Storage levels are now 15.9 percent less than a year ago and 1.1 percent below the five-year average. Storage estimates were released a day early this week due to the holiday.

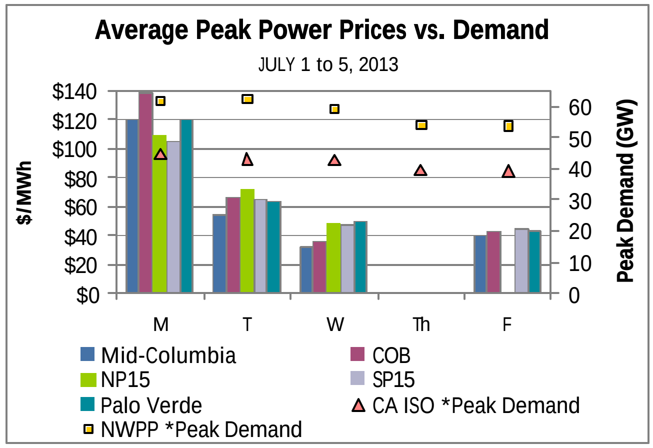
This week's natural gas addition was less than expected, which Barclays analysts said balances recent stronger-than-expected injections. "The market remains well supplied ahead of the hottest months of the year, with production still on the rise and the year/year storage deficit firmly on a downward trajectory," they noted in Barclays' weekly commodities report.

Henry Hub natural gas values lost 5 cents since June 28, trading July 5 at $3.52/MMBtu. Western prices were mixed, with PG&E CityGate up 4 cents to $3.77 while Malin gas dropped 10 cents to $3.31 by Friday.

Peak demand on the Cal-ISO grid reached 44,814 MW Monday, the week's high. Northwest Power Pool peak demand reached 62,243 MW Tuesday.

The Pacific Northwest should be in good shape for the summer, according to the Bonneville Power Administration. The most recent water-supply forecast shows runoff at 98 percent of the 30-year average, BPA spokesman Michael Hansen said, "but the rain we received in June has really helped push the runoff number up to near normal." Runoff was 130 percent of average in 2011 and 120 percent of average last year.

What's ahead: The National Weather Service forecasts an increased probability of above-normal temperatures from Washington into Southern California and Arizona from July 10 to July 18 ***[Linda Dailey Paulson].***



Western Electricity Prices
Week of July 1-5, 2013
($/MWh)

	Peak	Off-Peak
Alberta Pool ($C)	10.98 – 1000	7.75 – 66.41
Mid-Columbia	31 – 165	8 – 14.25
COB	35 – 195	11 – 18.75
NP15	48 – 130	36.25 – 39
SP15	44.45 – 120	32.50 – 39
Palo Verde	43 – 130	21 – 33

Western Natural Gas Prices
($/MMBtu)

Permian Basin, TX	3.24 – 3.50
San Juan Basin, NM	3.30 – 3.48
Southern California Border	3.53 – 3.97
Malin, OR	3.27 – 3.48
Alberta Hub	N/A

Bottom Lines

[9] Natural Gas: Bright Prospects Abound, but Limits Could Emerge

For all the buzz surrounding the transformative prospects of natural gas in the energy sector, experts at an annual conference hosted by the Northwest Gas Association and Northwest Industrial Gas Users June 5-6 pointed out a number of issues that could limit its bright future.

The shale-gas bonanza and its key implications are widely known, yet worth a brief reiteration.

Hydraulic fracturing and horizontal drilling have propelled North American shale gas from about 6 percent of overall supply in 2007 to about 30 percent today, and shale is forecast to provide most domestic gas within a decade, according to Navigant Consulting. The U.S. Potential Gas Committee's latest tally shows 2,384 Tcf of technically recoverable U.S. gas, which Idaho energy consultant David Hawk said at the conference equals roughly 100 times the current annual total domestic gas consumption.

Meanwhile, natural gas prices plunged toward $2/MMBtu in 2012. And although they have since risen—our price survey of four Western hubs for June 24-28 ranged from $3.37 to $3.88—many forecasts peg them in the $4 to $7 range for at least the next decade.

Among other consequences, this has led to the pivoting of proposed West Coast liquefied natural gas import terminals to export facilities designed to serve higher-priced international markets. Lower prices also benefit U.S. manufacturers using natural gas.

Should renewables continue to drop in price and energy storage advance sufficiently, gas could find itself disadvantaged.

Natural gas for power generation has surged as well. In our region, gas is now the second-largest utility generating resource, at slightly more than 8,000 MW capacity, narrowly ahead of wind and coal, according to the 2013 Northwest Regional Forecast from the Pacific Northwest Utilities Conference Committee. Gas has made up about half of new supply-side capacity for Northwest utilities since late 2011.

Natural gas famously rivaled coal for a spell in early 2012 as the leading source of U.S. power generation, although with increasing gas prices, coal has since reclaimed its top spot—recent preliminary data from the U.S. Energy Information Administration shows coal generated 40 percent or more of U.S. electricity each month from November 2012 through March 2013, and natural gas about 25 percent.

Nonetheless, the larger trend of more gas-fired power and less coal-fired electricity in recent years has contributed to a 12 percent decline in national CO_2 emissions from 2007 to 2012, given that gas' CO_2 emissions are roughly half those of coal.

Domestic abundance, low cost, reduced emissions, economic advantages—lots of good stuff.

Nonetheless, while the natural gas outlook indeed looks rosy on many fronts, a rosy long-term future is not assured.

Environmental concerns associated with shale-gas production are yet to be resolved, with their consequences not fully understood and suitable regulatory responses hanging.

Numerous speakers at the NWGA conference recognized the need for environmentally responsible practices in bringing gas out of the ground and to markets.

Jill Cooper, group lead for the environment at Encana Oil & Gas, discussed environment-related aspects of her company's production processes, focusing on the Rocky Mountain region. She made a number of credible points—for example, the extent of existing regulations covering gas production; using a single pad for drilling dozens of individual wells; pipeline networks that greatly lessen truck traffic for moving gas, condensate and water; closed-loop drilling; groundwater monitoring in cooperation with other entities; and the use of fracking in mining and geothermal industries as well as gas.

On the other hand, prepping for a media panel I participated in, I watched the documentary "Gasland." It features anecdotes about fracking's perceived negative impacts on neighboring lands and residents' health, notably including a dramatic visual of a guy lighting tap water on fire (although the gas industry has said, citing a state government investigation, that the methane in this incident is naturally occurring).

"Gasland" also portrayed industry and government officials as generally either duplicitous or clueless on fracking's effects. I thought this documentary failed to present solid, scientific evidence to bolster its claims.

Resource-depletion rates for shale are another potential limit on long-term supplies. So are LNG exports, notes NWGA's Outlook.

On the demand side, natural gas is subject to the vagaries of economy and weather, although those tend to be shorter-term influences. For example, Josh McCall of BP North America Gas & Power told conferees that mild winter weather in 2012 was the "single biggest piece" in the price plunge toward $2/MMBtu.

NWGA's 2013 Outlook, meanwhile, projects regional gas-demand growth averaging 1.2 percent annually over the next decade, although overall regional gas demand isn't expected to reach pre-recession levels until the end of this decade.

Power generation is anticipated as the biggest growth sector for Northwest gas, forecast to increase

2.6 percent annually through 2022. Northwest utilities value gas for attributes such as flexibility, reliability, lower CO_2 emissions than coal, proven technology, available fuel and cost-effectiveness.

However, the latest regional forecast tallies 2,400 MW of planned utility-resource capacity acquisitions through 2023, of which only about a quarter are natural gas; the remainder are various renewables, hydro upgrades and cogeneration. We shall see if this is temporary, or a more sustained trend toward resource diversity.

Should renewables continue to drop in price and energy storage advance sufficiently, gas could find itself disadvantaged as a power resource, especially if/when further CO_2 emissions limits emerge.

Transportation is considered a potential growth market for gas, especially for vehicle fleets—an NWGA white paper noted fleets can take advantage of central fueling stations and limited travel distances, effectively avoiding the lack of widespread natural gas-fueling infrastructure.

But even under the most optimistic projections, gas as a major transportation fuel is a long-term undertaking. Less than 3 percent of current North American gas demand goes to transportation, the NWGA white paper said.

Two other known unknowns: price and policy.

Many current gas-price charts feature a needle peak on the left, reflecting the big spike in 2008 and subsequent sharp fall, and a gently rising forecast line on the right. I won't predict future gas prices, but we all know their historic volatility.

On the policy front, President Obama favors substituting natural gas for coal-fired generation; natural gas is widely seen as a bridge fuel toward a less-carbonized electric future. But no one knows the length of that bridge, which could be shortened by severe carbon-driven restrictions on burning fossil fuels.

Then there are black-swan events, such as a catastrophic incident involving natural gas (even beyond the tragedy of San Bruno) that would cast a pall over the entire industry and its future.

At the gas conference, Avista Utilities Chief Economist Grant Forsyth opened his talk by saying that gas-industry people seem generally happier than their electric-industry counterparts, based on his observations at recent gatherings.

Still, while the circumstances for natural gas are generally propitious, they are tinged with enough uncertainties to warrant a little caution amid all the enthusiasm ***[Mark Ohrenschall].***

Regulation Status

[10] SONGS Costs Get Review *(from [3])*

Consumer groups have continued calls to stop rate recovery for some of the costs associated with the idled San Onofre Nuclear Generating Station.

The CPUC is investigating costs related to the plant, which shut down in January 2012 after a steam-generator tube in one unit leaked reactor coolant and steam-generator tubes in both units showed significant wear *[I12-10-013]*. The investigation's first phase looks in part to determine whether Southern California Edison, the plant's majority owner, acted reasonably and whether Edison should recover from ratepayers all of the costs connected to SONGS in 2012 (see *CEM* No. 1226 [13]).

In June 28 filings, the Division of Ratepayer Advocates suggested halting recovery of revenue requirements for SONGS, as well as the facility's steam-generator replacement project, as of Jan. 31, 2012—the date of Unit 3's outage. Edison announced earlier in June it would permanently shut down SONGS, which supplies 2,150 MW of power to the grid.

Edison's SONGS-related revenue requirement for 2012 could total about $739 million and SDG&E's SONGS-related revenue requirement could total about $252.8 million. The division supported letting the utilities recover safety, security and environmental costs, but called for verifiable evidence of those actual 2012 costs.

The division argued that insufficient evidence exists so far to find any other costs reasonable, including capital and operations and maintenance expenses.

The commission should defer any determination on the reasonableness of 2012 costs until after it reviews the outcome of ongoing U.S. Nuclear Regulatory Commission investigations, the division said. The NRC oversees SONGS safety issues and continues inspecting and reviewing the plant's failures, the division noted.

The division also argued that evidence does not show that Edison's actions and expenditures were reasonable regarding repair and replacement options the utility considered in 2012 for the steam generators.

"At no point in 2012 did [Edison] do a cost/benefit analysis of a long term repair or replacement plan," the division said. And there is no way to verify that the information that Edison gave the NRC about its plan to restart SONGS Unit 2 was sufficiently developed, or even realistic, to warrant the expenditures incurred.

The Utility Reform Network called for Edison and SDG&E to take full responsibility for financial consequences from a recent steam-generator replacement project—and its "unprecedented mistakes" that TURN called "one of the biggest utility debacles in California history."

TURN urged the commission to separate costs needed to operate and maintain SONGS and costs for work that would not have occurred but for the failure of the steam-generator replacement.

TURN suggested that Edison be allowed the opportunity to recover—after further review—a total of nearly $354 million in operations and maintenance costs. SDG&E would have the chance to recover a total of more than $70.7 million in O&M costs. Those totals reflect expenditures unrelated to steam-generator inspection, repair or other activities.

TURN also questioned Edison's decision to move new fuel into Unit 2, given the significant uncertainty at the time about restarting it. The result destroyed value that the utility could have recouped through reselling the unused fuel, TURN said.

The World Business Academy questioned how Edison had spent more money managing a non-operating SONGS in 2012 than it spent on an operating SONGS in 2011. The utility has not given a clear accounting of its 2012 SONGS costs, the academy said.

The academy called for refunding SONGS-related costs to ratepayers and ridiculed Edison's attempts to deem some expenditures reasonable or necessary. Edison "continues to stand by its patently absurd claim that it costs virtually as much to operate SONGS in full power mode in 2011 as it did in shut down mode in 2012," the academy stated.

Edison has refused to separate safety-related 2012 costs so that it can instead try to categorize all its 2012 SONGS costs as safety costs and recover them from ratepayers, the academy added.

Meanwhile, Edison argued that its actions and expenses to maintain SONGS in the required condition were reasonable. The utility touted its prompt reporting to the NRC of the leak in Unit 3 and its prompt hiring of independent consultants to investigate the tube wear. Edison defended its plans to restart Unit 2 and to pursue long-term repair options for both units.

The utility also defended its 2012 costs, including more than $350 million in operations and maintenance expenses; $17 million in severance costs; $141 million in steam-generator inspection and repair expenses; $168 million in capital expenditures; $16 million for turbine systems; and $45 million in refueling-outage costs ***[Hilary Corrigan].***

[10.1] San Bruno Pushes Back Against Credit Possibility in PG&E Penalty

The City of San Bruno wants to make sure that Pacific Gas & Electric cannot put past funding for pipeline-safety work toward any penalty related to the deadly explosion in San Bruno.

The 2010 rupture of a PG&E gas transmission line in San Bruno killed eight people, injured dozens and destroyed a neighborhood.

The CPUC's Safety and Enforcement Division has recommended a $2.25 billion penalty for PG&E in investigations related to the utility's practices leading up to the explosion *[I12-01-007, I11-02-016, I11-11-009]*. Ratepayer groups and San Bruno have warned that the safety division structured that penalty in such a way that PG&E would get credit for spending on system work that it has already done or had already planned to do—an amount that the utility has said reaches about $2.2 billion—and so would face no additional financial impact from the CPUC investigations (see *CEM* No. 1236 [13]).

In a July 1 motion at the CPUC, the city asked to strike the safety division's references to any credit from the case record. The credit proposal "is completely unmoored from any support in the exhaustive evidentiary record," the city said, arguing that evidence in the case record does not support past expenses as credit.

Parties also did not get a chance in the case to vet the credit concept, the city said. So any credit crafted in a decision would be an untested, unverified, back-of-the-envelope calculation of alleged PG&E shareholder expense.

"To award PG&E a massive, and in San Bruno's view underserved, 'credit' against the significant fines, penalties and remedies warranted by PG&E's decades of irresponsible and deadly mismanagement in this manner does not comport with due process or offer the residents of San Bruno any measure of justice," the city said ***[H. C.].***

[11] Numerous Issues With Proposed Hydrogen Energy California Project *(from [1])*

The proposed $4 billion Hydrogen Energy California Project faces a number of significant issues, including contributing to power-sector carbon pollution in the state, according to a preliminary assessment and draft environmental impact statement released June 28.

The assessment and DEIS come on the heels of an audit noting the project costs could jump $800 million, or 20 percent, and comments from the Sierra Club on the project's air-pollution permit stating among other issues its concerns that the project is relying on invalid emissions-reduction credits for certain criteria pollutants.

The HECA project, designed as a polygeneration plant to produce and sell electricity, carbon dioxide and fertilizer, would gasify coal and petroleum coke to make a hydrogen-rich synthesis gas to fuel a combustion turbine. About 90 percent of the project's CO_2 emissions would be captured and piped to the nearby Elk Hills oil field, where Occidental Petroleum would use the CO_2 for enhanced oil recovery and sequester the carbon in deep underground oil reservoirs.

Project owner SCS Energy, a Massachusetts developer that acquired the project in 2011 from former owners BP and Rio Tinto, has also proposed a fertilizer-manufacturing component that at times of low energy demand would make 1 million tons a year of ammonia- and nitrogen-based fertilizer products.

HECA is proposed on a 453-acre site (with a 653-acre buffer zone) in unincorporated Kern County, about seven miles west of Bakersfield.

HECA's publicly stated cost is $4 billion, but that price tag is likely to rise by about $800 million, according to a current update to financial models SCS officials provided to the U.S. Department of Energy. Under the DOE's Clean Coal Power Initiative, the agency has agreed to provide $408 million to the project as a cost share for certain aspects of the power and manufacturing plants, carbon-capture equipment and sequestration.

Tiffany Rau, a spokeswoman for the project, said the company had no comment on the audit.

"HECA is participating in a rigorous and comprehensive permitting and review process to ensure the project results in a safe, environmentally responsible, and economically beneficial project for Kern County and the State of California," Rau said in an e-mailed comment. "HECA is currently reviewing the 2,000+ PSA/DEIS report and will respond by the comment deadline. We look forward to participating in upcoming public workshops and working to resolve open issues."

Much Information Still Outstanding

The combined CEC/DOE preliminary staff analysis/draft environmental impact statement, at a voluminous 2,155 pages, details numerous problems with many of the 22 technical areas analyzed in the document. The proposed project would result in significant, unavoidable impacts to the blunt-nosed leopard lizard, for example, and about three-quarters of the HECA project components are sited in areas considered sensitive for buried archaeological artifacts. Among other issues, the staffs have concluded the 7,500 acre-feet of water the project would use could impact aquifers. Another conclusion is that construction and operation of the project could have significant impacts on an environmental-justice community (more than half minority) situated within the project buffer zone.

'Staff is not aware of any other project that has been licensed by the [CEC] that might have been a net consumer of energy.'

Large amounts of data and information remain outstanding in many other areas; the agencies need more information in 13 of the 22 technical areas to make their determinations.

In the area of carbon sequestration and greenhouse-gas emissions, for example, the likely operating profile of the plant is not known, since the project owner in its application has used more than one potential profile to describe the facility's expected operation, according to the assessment.

More evaluation of different operating profiles would be needed. However, staff says some operating profiles may result in the project not complying with California's emissions performance standard, which requires long-term contracts for baseload power to meet a standard of 1,100 pounds of CO_2 per MWh. Staff said it cannot make a determination on EPS compliance at this time, but that it is designing conditions of certification "that would enforce the carbon sequestration that is necessary for this project to comply with" the EPS.

CEC and DOE staff included the Occidental enhanced oil-recovery component in their emissions accounting under the EPS, as well as power used by the air-separation unit and power generation for the fertilizer-manufacturing component, an approach that the developer disagrees with, according to the report.

The assessment further states that "while the proposed project's operation may not result in a cumulative overall reduction in GHG emissions from in-state power generation and out-of-state imported power," when other sectors and system-wide benefits are considered, the project would not lead to an overall increase in worldwide GHG emissions. In California, it would lead to an overall net reduction in GHG emissions, according to the agency staffs. Other benefits considered include the fertilizer production that could alleviate the need to transport fertilizer to the region, and production of crude oil and natural gas (because of the relatively small amount of oil that will be produced as a result of the project's EOR operation, it will not add to total GHG emissions from the oil and gas sector, according to DOE); reductions in imported power from coal or unspecified sources (which are assumed to have higher GHG emissions); and reductions in GHG associated with overseas transportation of pet-coke from California refineries, among other things.

As of late June, HECA does not have a contract with Occidental Petroleum for the enhanced oil-recovery and sequestration portion of the project, and staff said it requires a signed contract covering a number of areas before it finalizes its recommendation on the project.

All commercial discussions are still under way and are confidential, Rau said.

Staff is also requiring a complete energy balance for the HECA project, including all sources of generation and consumption. When all auxiliary loads are considered, the project's net contribution to the grid is far smaller than its gross capacity. On a gross basis, the project would generate between 405 MW and 431 MW (both figures are used by the developer; the CEC is seeking clarification on the gross figure). Those figures drop to between 151 MW and 266 MW on a net basis after accounting for on-site auxiliary power loads.

And when the air-separation unit and the electricity Occidental needs for the enhanced oil-recovery operations are taken into consideration, the net energy available to the grid drops to 52.5 MW. (The enhanced-oil operation would require 940,000 MWh/year, or about a third of HECA's annual generation total.) At times of maximum fertilizer production the project would be a net consumer of 61.8 MW from the grid, according to the assessment.

"Staff is not aware of any other project that has been licensed by the energy commission that might have been a net consumer of energy," said CEC spokeswoman Sandy Louey in an e-mailed response to questions about the project.

She also said the CEC could override a project's nonconformance with a state law "if it finds the project is required for public convenience and necessity and there are no more prudent and feasible means of achieving such public convenience and necessity." Staff has not taken any position at this time on whether it would recommend an override, she added.

Sequestration Questions

Once the CO_2 is shipped to Elk Hills, via a three-mile pipeline, Occidental would sequester it through injection into hundreds of wells in the Stevens reservoirs. The EOR processing facility is expected to use 720 producing and injection wells, including 570 existing wells and 150 new well installations, according to the environmental assessment. Overall about 1,231 wells penetrate the reservoirs.

Large amounts of pore space exist in the formation, since it is a mature field with oil extracted over a number of decades. Atop the reservoir are several layers of sand and shale, which according to the environmental review make it favorable for storing CO_2 gas and preventing leaks.

Staff has concluded that CO_2 leakage through the geologic formation is unlikely; staff is more concerned about CO_2 leakage through well bores in an area that is seismically active.

"In the presence of the numerous surface faults in the region staff is concerned that increased pore pressure associated with the injection of the carbon dioxide can cause increased stresses on faults, which can cause those faults to slip and the apertures to dilate and allow for leakage of CO_2," the assessment states.

Staff recommends in the assessments that HECA enter into an agreement with Occidental requiring a robust monitoring network capable of detecting CO_2 leaks from all well bores—active, shut in, plugged or abandoned—to ensure any leaks are detected immediately ***[Mavis Scanlon].***

[11.1] Inspector General's Audit Raises Questions on HECA

A recent audit by the U. S. Department of Energy's inspector general concluded the department is facing increased risk in its management of an agreement with the large-scale carbon capture-and-storage Hydrogen Energy California Project.

The audit report, released in mid-June, stated the department had not obtained or reviewed documentation to substantiate key financial projections used to support DOE's approval of a modified agreement with HECA.

DOE first awarded financial support to the HECA project in September 2009 with money from the American Recovery and Reinvestment Act. Under DOE's Clean Coal Power Initiative, the agency awarded HECA $308 million, or about 10 percent of the $2.8 billion project cost. Owned by BP and Rio Tinto at the time, the project proposed to gasify coal and petroleum coke to produce hydrogen, which would fuel a combustion turbine. Most of the project's CO_2 emissions would be sequestered in the nearby Elk Hills oil field.

By early 2011, after DOE and the project owners had spent $75 million, BP and Rio Tinto abandoned the project. Rising capital costs and difficulties in obtaining a power-purchase agreement played into that decision, according to the inspector general's audit, which was conducted from November 2011 to May 2013.

Later in 2011, SCS Energy acquired the project, modifying its design substantially to include a large fertilizer-production facility. That also raised the price tag, to approximately $4 billion. In September 2011, DOE modified its cost-sharing agreement with the project to recognize the change of ownership; the new cost share was $408 million.

But in assessing the viability of the modified project, DOE "relied on financial projections that were not always fully supported and that the department had not ensured that only allowable costs had been included in the recipient's cost-share contribution," the IG audit stated.

DOE did not require supporting documentation for certain financial projections, even though comparable information was available from other reports and project at the time HECA was being modified, the IG found.

Examples include HECA interest-rate projections of 5.25 percent for bonds and 6.5 percent for a bank loan. DOE had previously identified higher interest rates of 8.5 percent for high-risk power projects with less debt, shorter repayment periods, and more equity than HECA was projecting.

In addition, DOE did not require supporting information for projected operations and maintenance costs. The inspector found HECA's projected O&M costs were 36 percent lower than a similar but smaller carbon-capture power plant.

"This information, while available at the time of the change in ownership, raised concerns, in our judgment, as to the reasonableness of HECA's assertions," the audit said. The audit also found DOE accepted estimates for property-tax and insurance cost projections that were considered only "placeholders" by SCS. A spokeswoman for the project said the company had no comment on the audit ***[M. S.].***

[11.2] Redesigned Palen Project Would Comply With Most Laws, Standards

With the adoption of certain conditions, the Palen Solar Electric Generating System would comply with most laws and standards, a joint environmental review of the project by the CEC and the U.S. Bureau of Land Management found.

The CEC initially licensed the project, then known as the Palen Solar Power Project, in late 2010 as a 500 MW facility using solar parabolic-trough technology. The project changed hands last year after the previous owner, Solar Millennium, filed for bankruptcy protection. BrightSource Energy, which acquired the project, applied to amend the license to allow it to build a similar-sized project using its solar power-tower technology.

The modified project would consist of two 250 MW solar fields, each with an array of 85,000 mirrored heliostats surrounding a 750-foot-tall tower. The heliostats focus the sun's rays on a solar-receiver steam generator perched atop the tower.

In the area of visual resources, staff found that the project would cause "substantial adverse impact" to existing scenic resources from at least six key observation points in the project vicinity and in the

Chuckwalla Valley area. Staff found these impacts would be significant and unavoidable based on three of four California Environmental Quality Act criteria, and that they could not be mitigated to less than significant levels.

As one example, staff determined that the solar receivers would remain "prominent" at one key observation point, northwest of Desert Center/Big Wash—a distance of 15 miles from the towers. At another key observation point, along eastbound Interstate 10, a distance of five to six miles from the power towers, the receivers "would be perceived as extremely bright light sources demanding attention and causing visual discomfort when in the field of view." Glare from the project's receivers would be moderately high from this point, rendering "views in the direction of the project largely unviewable within a large area of the wilderness."

Staff also concluded that the project would not be consistent with several goals and policies of the Riverside County Integrated Plan.

Large amounts of data remain outstanding in five of the technical areas analyzed in the review, including air quality/greenhouse gases, biological resources, cultural resources, traffic and transportation, and geology and paleontology. Staff therefore could not determine for those areas whether the project complies with all laws, ordinances, regulations and standards.

Three alternatives will be analyzed in the final staff assessment, including a solar-photovoltaic project with single-axis tracking technology; a parabolic-trough alternative; and a reduced-acreage alternative ***[M. S.].***

[12] Appeals Court Rejects Challenge to 399 MW Panoche Valley Solar Project *(from [2])*

Plans to build a 399 MW solar farm in Panoche Valley in San Benito County are back on track now that a California appeals court has deemed the county's evaluation of the project complies with state law.

In *Save Panoche Valley v. San Benito County*, the Sixth District Court of Appeal on June 25 upheld a trial court ruling supporting the San Benito County Board of Supervisors' certification of a final environmental impact report for the proposed Panoche Valley Solar Farm. The court also upheld the cancellation of Williamson Act land-conservation contracts to free up thousands of acres for its development.

The appellants in the case, Save Panoche Valley, the Santa Clara Valley Audubon Society and Sierra Club, assert the project EIR, certified in 2010, does not adequately address impacts to the San Joaquin kit fox, giant kangaroo rat and blunt-nosed leopard lizard, all considered endangered and at significant risk of extinction according to the environmental review documents.

The groups also contend the county's reasons for canceling the Williamson Act contracts on land secured for project development are insufficient under the Williamson statute, and that the county approved the project despite the existence of a feasible alternative, in violation of the California Environmental Quality Act.

In denying the appeal, the three-judge panel made several findings that validate the county's review of the solar project, co-developed by PV2 Energy and Duke Energy Renewables. The project site encompasses about 4,900 acres of grazing land, with 26,000 acres set aside to provide habitat for impacted species.

"We disagree with Save Panoche Valley's contentions, and find no error with the board's approval of the FEIR and its cancellation of the Williamson Act contracts," states the court's June 25 opinion, authored by Judge Eugene Premo.

More specifically, the judges found that the project's mitigation measures—such as the conservation easement; the creation of a 22-acre "buffer zone" for each blunt-nosed leopard lizard found in a preconstruction survey; and measures to avoid disturbing kit fox-occupied dens—are adequate.

The judges also determined the board did not violate the Williamson Act, a farmland-preservation law that provides a means for landowners to pay reduced property taxes if they agree, by way of a contract, not to develop the land for a minimum of 10 years.

The Williamson law stipulates a county can cancel a contract if the public benefits substantially outweigh the objectives of the act and there is no suitable alternative site—determinations San Benito County made in this case.

'There will be a lot more opportunities for the public to engage in this process.'

Such Williamson Act contract cancellations are becoming more common as counties throughout the state seek to encourage renewable-energy development (see *CEM* No. 1191 [13]).

An economic analysis of the Panoche Valley project cited by the court estimates it will create 770 jobs and generate about $80 million from the additional retail impact in the county due to the increased amount of disposable income.

"There is substantial evidence in the administrative record," the opinion notes, "that the solar project will help further the state's progress toward achieving its goal for increased renewable energy and reduced greenhouse gas emissions, as the proposed project would generate renewable energy for the state while providing jobs to local residents."

The court further found the county adequately reviewed the feasibility of a less environmentally sensitive alternative site—one touted as superior by the appellants. The alternative was found to be impracticable because it spans two separate counties; the project could not be completed in a reasonable amount of time at that site; and the developer was unable to negotiate an acceptable purchase price with the landowner.

"We are pleased with the court's decision," said John Pimentel, president of San Francisco-based PV2 Energy. "We've been working hard to develop a project that's good for the environment and good for the community."

Pimentel said the project still has to obtain permits from state and federal agencies, including the U.S. Fish and Wildlife Service and the California Department of Fish and Wildlife. And the developers have yet to secure a power-purchase agreement for the project, which had an estimated price tag of $1.8 billion in 2010 (Duke Energy spokeswoman Tammie McGee said this figure is likely lower now, but could not offer an updated estimate).

"We have been in conversation with multiple utilities" as well as several nontraditional parties, including energy service providers and community-choice aggregators, Pimentel stated.

In terms of interconnection to the grid, the project site is located "immediately underneath" an existing 230 kV line with available capacity, according to Pimentel, "making it a unique value to California ratepayers."

However, Shani Kleinhaus, environmental advocate for the Santa Clara Valley Audubon Society, does not see any value in the project, and said the group will fight the issuance of permits by state and federal agencies.

"We're obviously disappointed that the court did not see how important species conservation is to the state," Kleinhaus said. "But there will be a lot more opportunities for the public to engage in this process."

The California Farm Bureau Federation estimates about 16 million acres of land in the state—about half of the state's farmland—is protected by Williamson Act contracts. These lands could become even more attractive to developers if the state increases the renewables portfolio standard from the current level of 33 percent.

Sarah Owsowitz, a land-use and CEQA attorney at Best Best & Krieger, said the court's decision in the Panoche Valley Solar Farm lawsuit provides a "road map" for how to make the case that the cancellation of Williamson Act contracts is in the public's interest.

"I would assume public agencies in the future will follow that guide," she said ***[Leora Broydo Vestel].***

[13] NuScale Moves Plan Forward for Small Modular Reactors in West *(from [5])*

Portland-based NuScale Power announced July 3 that it had applied for funding from the U.S. Department of Energy to help complete the design and certification of its 45 MW small modular reactor, with the aim of achieving commercial operation by 2025.

If NuScale succeeds, early installations of the "right-sized" technology could be hosted by the Idaho National Laboratory, Washington's Energy Northwest, and the Utah Association of Municipal Power Systems. The company has selected INL as its preferred location for a six- to 12-module (270-540 MW) demonstration plant.

The funding opportunity—DOE's second and final one for small modular reactors (SMRs)—would cost-share up to 50 percent of the effort with a maximum award of $226 million disbursed over five years, and scores applicants higher if they put in more than half of the funding.

Babcock and Wilcox won the first solicitation in November 2012 with its 180 MW mPower plant, in a partnership that includes the Tennessee Valley Authority and Bechtel. NuScale participated in the first solicitation as well, but this time around has brought to the table utility partners—Energy Northwest and UAMPS—and endorsements by the governors of Oregon, Idaho and Arizona.

"I think there's a better understanding by all involved of the importance DOE is placing on a strong team approach," Michael Paoli, an Energy Northwest spokesman, told *California Energy Markets* via e-mail.

Another edge NuScale says it has—in addition to a test facility in operation since 2003—is majority ownership by global engineering giant and nuclear-power veteran Fluor, a Fortune 500 firm.

It also says its "first-of-its-kind passive safety design, years of real-world testing of its technology and almost 100 patents" make it "uniquely positioned" to qualify for the DOE program.

The containment vessel of a single unit looks like "an 82-foot by 15-foot thermos bottle," Mike McGough, NuScale's chief commercial officer, told *CEM*. It houses the reactor vessel, which is installed below ground.

'The entire thing can be built in a factory as a single component for just-in-time installation.'

"The entire thing can be built in a factory as a single component for just-in-time installation," McGough added, and then shipped to the plant site, almost a "plug-and-play" effort. Up to 12 units can be combined for a capacity of 540 MW—a limit he said was based on market research about the future baseload needs of likely utility users.

McGough said NuScale's was the only SMR design "that can achieve cooling and shutdown in a Fukushima situation"—referring to the host of problems that arose in 2011 when a massive earthquake cut power to the multi-unit Fukushima Daiichi nuclear plant in Japan, and the ensuing tsunami flooded emergency generators, causing them to fail. This meant that once backup batteries were exhausted, there was no way to circulate cooling water over the core, which, though scrammed to prevent continuing fission, was still hot enough from ongoing radioactive decay to overheat.

McGough said NuScale's design enters a safety mode when external power is lost that passively closes some valves and opens others so that natural convection of the module's 11-million-gallon water inventory can cool the fuel indefinitely. The loss of power also automatically inserts control rods into the fuel assembly, shutting down fission.

But the competition for the DOE funding is likely to be fierce, even though the department could choose more than one winner. Also submitting applications for this second solicitation by the July 1 cutoff date are Westinghouse and spent-fuel cask manufacturer

Holtec International, which is teaming with engineering firm URS and New Jersey utility PSEG Power.

The process of bringing an SMR to market is not for the impatient or faint of heart. The design review alone will cost on the order of $1 billion and take more than three years to complete, according to McGough.

In parallel with this, he told *CEM*, the owner of the proposed plant—a utility, for example—would submit an operating/construction permit application that would be approved around 2019 at the earliest, and take another three years to build the plant, so power could be brought on line no earlier than 2022 or 2023.

On top of this, the cost of building SMRs isn't clear. The DOE funding opportunity explicitly recognizes that applicants would be undertaking "first of a kind" (FOAK) efforts that would cost more than so-called nth-of-a-kind (NOAK) units, where experience and routine production have brought costs down. But even in these cases, economies of scale could render larger plants (capacities on the order of 1,000 MW) cheaper on a per-kilowatt basis.

Nevertheless, the reasoning goes, the upfront and total costs of SMRs are likely to be much less for appropriately sized plants, and would therefore be accessible by smaller utilities or industrial firms.

Having to use multiple control rooms for a single facility could negate some of the cost savings.

These advantages were affirmed in a recent study by Ahmed Abdulla and others based on the opinions of 16 experts. Published in the June 11 issue of *Proceedings of the National Academy of Sciences* ("Expert assessments of the cost of light water small modular reactors"), there was consensus that SMRs could be built and brought on line about two years faster than large reactors.

The experts also noted that factors that could make SMRs economically viable included "more affordable unit cost, factory fabrication, and shorter construction schedules."

A hurdle for plants comprising multiple SMR units, as NuScale contemplates, is that current Nuclear Regulatory Commission regulations bar the operation of more than two reactors from a single control room, according to the study. Having to use multiple control rooms for a single facility could negate some of the cost savings.

The partnership NuScale brought to the solicitation is rooted in a Western Governors' Association initiative that Idaho Gov. Butch Otter launched in 2010, when he chaired the WGA, to consider the future of nuclear energy, McGough said.

This yielded policy proposals in a June 2011 report, "The Future of Nuclear Energy: Shaping a Western Policy," that included WGA's first mention of the importance of SMR for the West, he said.

Under the leadership of Utah Gov. Gary Herbert, the WGA last month issued its 10-Year Energy Vision, which cited among its goals for Western states finding "ways to accelerate the introduction of small modular reactors into the marketplace."

This led to the formation of the Western Initiative for Nuclear (WIN) last month by NuScale after conferring with WGA members at their annual meeting.

The company described WIN as a "broad, multi-Western state collaboration" that would "study the demonstration and deployment of a multi-module" plant using several NuScale 45 MW units at a "site like the Idaho National Laboratory" and be operational by 2024.

This first project, it added, "is viewed as the initial demonstration project for a potential series of projects that may be developed in other states," and would "likely be developed, built and owned by a consortium of regional utilities like WIN, and operated by one of these utilities."

In addition to endorsements by Govs. John Kitzhaber (Oregon), Otter (Idaho) and Jan Brewer (Arizona), Gov. Jay Inslee of Washington has stated that he supports the deployment of small-module nuclear technology at DOE's Hanford site in eastern Washington, Jaime Smith, a spokeswoman for Inslee, said.

Energy Northwest's support of NuScale's design was not given lightly. The agency launched a two-year SMR feasibility study in 2009 with eight other public-power entities (Asotin, Benton, Ferry, Franklin, Grant, and Kittitas County PUDs, Benton County Rural Electric Association, and PNGC Power) and two investor-owned utilities, Idaho Power and Portland General Electric.

"The group concluded that NuScale's light-water reactor offered the most feasible design for Northwest baseload generation needs," Energy Northwest's Paoli said, adding that CEO Mark Reddemann had encouraged DOE to award NuScale first-round SMR funding.

In the current proposal, however, Energy Northwest is now part of NuScale's team, and has "the first right of offer to operate the proposed facility," Paoli said.

Funding winners would be notified by mid-September, and awards granted after contract negotiations by mid-January 2014 ***[Rick Adair].***

[13.1] FERC Approves Cal-ISO, PacifiCorp Agreement for EIM

FERC on June 28 approved the implementation agreement between Cal-ISO and PacifiCorp that establishes the scope and schedule to launch an energy imbalance market by October 2014.

The EIM will optimize scheduling and dispatch between the two balancing authorities on a 15-minute and five-minute basis, respectively.

The implementation agreement specifies that PacifiCorp will pay Cal-ISO a $2.1 million fixed startup fee to participate in the ISO's existing energy imbalance market, which FERC found reasonable *[ER13-1372]*.

The EIM is expected to produce up to $128 million in annual benefits, though stakeholders have expressed concerns that those benefits could evaporate if Cal-ISO does not control costs for congestion and convergence bidding (see *CEM* No. 1238 [15]).

Stakeholders have asked for more time to evaluate the design of the EIM. Cal-ISO on July 2 released a revised straw proposal on EIM market design that would entail pushing back by a month the release date of a final proposal until September, though it still plans for the market to launch in October 2014 ***[Chris Raphael].***

Southwest

[14] Nevada Commission Staff Says Law Prohibits Utility Merger *(from [4])*

Public Utilities Commission of Nevada staff on July 28 advised the commission that a Nevada statute prohibits the proposed merger of Nevada Power and Sierra Pacific Power, two subsidiaries of NV Energy.

As part of a merger application filed in May, NV Energy asked the commission to approve transferring Sierra Pacific's generating assets to Nevada Power. But the PUCN staff cited Nevada Revised Statutes Section 704.7591, which states that an electric utility may not transfer generation assets to another subsidiary of the holding company, NV Energy.

The Nevada Legislature adopted the provision in 2001 as part of AB 369, which reversed the Legislature's 1997 decision to open the state's electric-power industry to retail competition.

Because of the statute, the staff urged the commission to dismiss NV Energy's application requesting approval for the merger. NV Energy offered no immediate comment.

If the PUCN does not dismiss the case, staff recommended the commission require the electric utilities to provide more information about the effect of the merger on power rates.

For example, NV Energy did not discuss the implementation of SB 123, which became law on June 11, 2013, and which requires Nevada Power to sell coal-fired generation assets and buy replacement generation, staff said.

Staff also questioned whether it is in the public interest to consider merging NV Energy's utility subsidiaries when some of the review may be duplicated during PUCN consideration of Berkshire Hathaway's proposed $5.6 billion acquisition of NV Energy.

In addition, staff said that NV Energy should elaborate on plans to keep its current general rates for a year or longer, although Nevada Power and Sierra Pacific Power exceeded their authorized rates of return in 2012. Nevada Power earned an 8.71 percent rate of return in the 12 months ending in December 2012, compared with an authorized 8.17 percent rate of return, according to data NV Energy provided to staff. Sierra Pacific earned 8.5 percent over the same period, compared with an authorized 8.06 percent rate of return.

Also, staff questioned NV Energy's proposal to alter the formula for allocating costs between northern and southern Nevada customers for the One Nevada Line. NV Energy and LS Power are jointly developing the 231-mile, 500 kV ON Line, which will connect the Nevada Power and Sierra Pacific territories late this year.

Sierra Pacific currently is responsible for 5 percent of NV Energy's $620 million share of ON Line costs. Nevada Power is expected to pay the other 95 percent of NV Energy's costs in the transmission project.

The Nevada utilities estimated that Sierra Pacific's share of ON Line costs should increase to 23 percent, reducing the balance borne by Nevada Power to 77 percent of NV Energy's share of the project.

The new transmission-line allocation would quadruple Sierra Pacific's share of ON Line costs "without any alleged corresponding increased benefit to [Sierra Pacific] customers," staff said.

In its May 2013 application, NV Energy mentioned several advantages to merging its two utility subsidiaries.

The combined utility would need to prepare fewer regulatory and legal documents than they do as separate entities, NV Energy said. The combined utility every three years would prepare one general electric rate case and one integrated resource plan, rather than two general rate cases and two integrated resource plans, according to the application. The merged utility also would make one rather than two quarterly filings for changes in fuel and power costs, ending the practice of filing two separate quarterly rate-adjustment cases.

In addition, merging the two NV Energy subsidiaries would eliminate the need for compliance with FERC regulations that apply to separate utilities, NV Energy said.

Were Nevada Power and Sierra Pacific to remain as separate legal entities, FERC would regulate trading between the two affiliates as wholesale transactions, the application explained. The utilities would need FERC approval for agreements on cost and revenue allocation related to capacity, energy, and purchases and sales of power and transmission services. NV Energy said it would need to establish an affiliated services company to administer and support the agreements.

The two utilities already have combined back-office, power-generation, transmission, energy and fuel procurement, and customer-service functions, according to NV Energy's application ***[John Edwards].***

[14.1] PNM Looks to Nuclear Power, Gas to Replace Retiring Coal Units

PNM expects to use nuclear generation and gas-fired power plants to replace some of the 340 MW in generation it would lose with the retirement of Units 2 and 3 at the coal-fired San Juan Generating Station under an agreement with the U.S. Environmental Protection Agency.

In February 2013, PNM announced a settlement with EPA for reducing nitrogen-oxide emissions at San Juan, an 1,800 MW power plant near Farmington, N.M.

After negotiating with New Mexico state officials and PNM, the EPA agreed to work with San Juan owners for a plan to install selective non-catalytic reduction equipment on Units 1 and 4. In addition, San Juan would shut down the other two units to further reduce regional haze from San Juan NO_x emissions by 2017.

To replace some of the lost generation, PNM may purchase nuclear power, Ron Talbot, chief operating officer at PNM Resources, told the New Mexico Public Regulation Commission on July 3.

PNM Resources, the holding company for PNM, owns 135 MW of capacity in Unit No. 3 at the Palo Verde Nuclear Generating Station and sells power from the unit on the wholesale market. The holding company is proposing to sell or transfer the nuclear assets to PNM, which could use the nuclear power for its retail customers. The utility would also be authorized to earn a rate of return on the nuclear generation assets as part of its rate base.

As previously reported, PNM intends to build a 150 MW to 200 MW natural gas peaking plant in the Four Corners area.

In addition, PNM is negotiating to buy an additional 78 MW of capacity from an unidentified owner of generating capacity in San Juan Unit No. 4, which would continue to be operated under the agreement with EPA.

However, the utility probably will not use either wind or solar energy to offset the loss of capacity at San Juan, because the renewables do not produce much electricity during periods of peak demand, Talbot said.

New Mexico's wind does not blow when temperature peaks on summer afternoons, Talbot said, and solar-photovoltaic facilities generate only 55 percent of their nameplate capacity when demand peaks because the sun is low.

PNM intends to file an application seeking approval of the San Juan plant changes and related rate-increase requests by year's end. The utility also needs approval from the New Mexico Environmental Improvement Board and final approval from the EPA.

Other San Juan owners are Tucson Electric Power, Southern California Public Power Authority, Tri-State Generation and Transmission Association, M-S-R Public Power Agency, the City of Anaheim, the City of Farmington, Los Alamos County (N.M.), and Utah Associated Municipal Power Systems ***[J. E.].***

Potomac

[15] White House Gets Reworked EPA GHG Emissions Proposal *(from [6])*

The Environmental Protection Agency on July 2 sent the White House a reworked proposal setting greenhouse-gas emissions limits for new fossil-energy power plants, but kept its details under wraps.

The proposal, being reviewed by the Office of Management and Budget, is one in a suite of executive actions President Barack Obama announced June 25 to limit power-plant carbon-dioxide emissions. Obama directed EPA to reissue a proposed rule for new plants by Sept. 20.

The actions Obama announced do not require approval by Congress, where cap-and-trade legislation stalled three years ago and any climate bills would face stiff odds.

Energy-industry critics of EPA's original proposal, issued in 2012, said its emissions limit of 1,000 pounds per MWh would effectively dry up the market for new coal capacity.

The Edison Electric Institute last year advocated differentiated standards for coal and gas plants, with a limit of 2,000 lbs/MWh for coal and 1,100 lbs for gas plants.

Comment Period on Plant Discharges Extended

EPA on July 3 extended the comment period for proposed limits on power-plant discharge of toxic effluents into water bodies to Sept. 20.

Following a consent decree settling litigation from environmental organizations, EPA offered four alternatives for limiting discharge into rivers and lakes of coal ash and of waste byproducts of air emissions controls, including flue-gas desulfurization and electrostatic precipitators.

According to EPA, more than half of U.S. coal plants already comply with the proposed limits, which would be phased in between 2017 and 2022.

The proposal would update standards on the books since 1982. It aims to cut pollution discharges by 470 million to 2.62 billion pounds per year, and reduce water use by 50 billion gallons to 103 billion gallons annually, the agency said.

DOE Issues Draft CCS Loan-Guarantee Solicitation

The Department of Energy on July 2 released a draft loan-guarantee solicitation for carbon-capture and other fossil-energy technology projects.

DOE plans to make up to $8 billion in loan guarantees available, part of the menu of executive actions to limit GHG emissions President Obama announced June 25.

In addition to carbon sequestration, other eligible technologies include underground coal gasification, oxy-combustion of coal and natural gas, and waterless fracturing technologies for producing gas.

Energy Secretary Ernest Moniz said June 30 expanded use of carbon dioxide captured from coal-fired power plants could play a big role in ensuring coal's future.

In an interview with Platts Energy Week TV, Moniz said using CO_2 is "very attractive," noting 300,000 barrels of oil per day are produced in the U.S. using CO_2 to enhance recovery from aging fields.

"That could increase by a factor of 10, to about 3 million barrels daily, which would require 600 million tons of CO_2 per year. We could only get that by capturing it from industrial sources, power plants," Moniz said.

Bill Would Strip DOE of Spent-Fuel Authority

Senate Energy Chairman Ron Wyden (D-Ore.) and three other senators introduced legislation on June 27 to take spent nuclear-fuel management away from DOE and establish a "consent-based" siting process.

The measure, S. 1240, would codify the Blue Ribbon Commission's 2012 recommendations for revamping nuclear-waste management and disposal, and is based on a discussion draft released in April.

It also calls for establishing a pilot interim storage facility to hold spent fuel, as long as funds have been set aside to pay for parallel development of a permanent repository.

In addition, the legislation specifies that revenue from the 0.1-cent spent-fuel fee charged to nuclear utilities would be deposited into a special Treasury fund and available without a congressional appropriation. The estimated $28.2 billion already collected, however, would remain subject to appropriation.

Under consent-based siting, a cooperative agreement with states, localities or Indian reservations agreeing to host a permanent repository would be required.

In a statement, Wyden said "the bill takes immediate steps to more safely store the most dangerous radioactive waste, and lays out a clear plan for a permanent solution."

Co-sponsors include Sen. Lisa Murkowski (R-Alaska), ranking Republican on the Energy and Natural Resources Committee, and the leaders of the Appropriations Committee's energy and water panel, California Democrat Dianne Feinstein and Tennessee Republican Lamar Alexander.

House Measure Expands Offshore Drilling

The House approved legislation on June 28 to expand oil and gas drilling off Southern California and other coastlines, but the bill is thought to have little chance in the Democrat-controlled Senate.

On a largely party-line vote of 235-186, the House passed the legislation, HR 2231, which would require the Interior Department to lease all offshore areas containing at least 7.5 trillion cubic feet of undiscovered, technically recoverable gas.

In addition, the measure—sponsored by Natural Resources Chairman Doc Hastings (R-Wash.)—would require sale of leases in California's Santa Maria and Santa Barbara/Ventura basins no later than Dec. 31, 2014.

The House rejected Rep. Peter DeFazio's (D-Ore.) amendment to bar drilling in Alaska's Bristol Bay.

House Panel Cuts DOE FY 2014 Budget by $2B

The House Appropriations Committee reported out a money bill on June 26 cutting DOE's fiscal year 2014 budget by more than $2 billion from this year.

The House legislation would appropriate $24.95 billion for DOE in fiscal 2014, down from the fiscal 2013 level of $27 billion.

Meanwhile, the Senate Appropriations Committee's energy panel on June 25 reported out a significantly different energy and water money bill that would provide DOE $28.21 billion in fiscal year 2014.

The Senate measure would appropriate $2.3 billion for energy-efficiency and renewables R&D, a $470 million increase from this year. The House bill, on the other hand, would chop efficiency, renewables and reliability funding nearly in half, to $982.6 million.

GAO Calls Safety-Review Revamp Burdensome

Converting gas-pipeline safety assessments from mandated seven-year intervals to a risk-based system would impose heavy workloads on both regulators and pipeline operators, the Government Accountability Office said in a report released June 27.

Pipeline operators told GAO that switching to risk-based assessments for pipelines in "high consequence" areas would require greater data analysis, although 21 of 27 operators GAO contacted said they preferred moving to a risk-based system.

Officials from the Transportation Department's Pipeline and Hazardous Materials Safety Administration, which regulates pipeline safety, said moving to a risk-based system could increase inspectors' workloads. The report spotlighted "lack of guidance for operators to perform risk modeling."

Federal law currently requires a maximum seven-year interval between safety assessments. GAO in 2006 recommended Congress drop the seven-year requirement to allow pipeline operators to make assessments "based on risk factors, technical data, and engineering analyses," the report said.

EPA to Revisit Part of Finalized Engine Rules

EPA agreed on June 28 to reconsider three issues in connection with a rule finalized last January limiting hazardous air emissions from reciprocating internal combustion engines.

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In a letter sent to environmental organizations seeking reconsideration, Assistant Administrator Gina McCarthy said EPA would take another look at compliance timing for a requirement to use ultra-low-sulfur diesel fuel for emergency engines operating more than 15 hours per year.

McCarthy also said the agency would reconsider reporting requirements for such engines, and conditions for engines operating under non-emergency conditions for up to 50 hours per year as part of a contract with another entity.

EPA's rule requires diesel engines of 100 horsepower or more in use more than 15 hours per year to use ultra-low-sulfur fuel beginning in 2015.

In addition, the rule allows engines of any size to be used up to 50 hours per year to prevent voltage collapse or line overloads.

EPA Issues Revised Fridge Standards

EPA on June 27 released revised Energy Star standards for residential refrigerators and freezers.

Units meeting the revised limits will use at least 10 percent less energy than models meeting 2014 federal minimum efficiency standards.

The standards include optional smart-grid connectivity, which EPA said would offer consumers "convenience and energy-saving features," such as real-time energy-consumption data and participation in utility demand-side management programs ***[Jim DiPeso].***