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PROJECT FINANCE

NewsWire

November 2014

US Renewable Energy After the November Elections

The United States went to the polls on November 4. The news organizations described the election results as a Republican sweep. The Republicans now control both houses of Congress. They are likely to end up with 53% or 54% of the seats in the US Senate. They increased their majority in the House to 56% of that body. There are now more Republican governors at the state level: 62% of states will now have Republican governors compared to 58% before.

Four veteran Washington lobbyists for power companies talked 34 hours after the polls closed about what the election results mean for the US renewable energy and independent power markets.

The four are Richard Glick, a former top aide to the US Secretary of Energy in the Clinton Administration and currently head of the Washington office for Spanish utility Iberdrola, which owns the number two wind company in the United States as well as a group of regulated utilities in the Northeast, Jonathan Weisgall, head of the Washington office for Berkshire Hathaway Energy, the holding company for three US utilities — MidAmerican, PacifiCorp and NV Energy — and a prominent player in the US wind, solar and geothermal markets, John Stanton, former chief lobbyist for the Solar Energy Industries Association and now executive vice president for policy and markets at SolarCity, a rapidly growing US solar rooftop company, and Joe Mikrut, formerly tax legislative counsel for the US Department of the Treasury under President Clinton and, before that, on the staff for the Joint Committee on Taxation in Congress and currently a partner in Capitol Tax Partners, */ continued page 2*

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THE INCOME METHOD can be calculated in more than one way to value a project.

The Minnesota Tax Court chose a method that looked back in time rather than at projected earnings.

Minnesota Energy Resources Corporation is a local gas distribution company in Minnesota. It owns 3,611 miles of transmission and distribution lines. Property tax assessments of real property are handled by each county, but personal property — equipment — is assessed by the state.

The state assessed the company's gas lines at $118.2 million in 2008 rising to $161.5 million by 2012. The company challenged the assessments. An appraiser hired by it said the state overvalued the gas lines, and the correct figures should have been $51.5 million in */ continued page 3*

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a prominent lobbying shop in Washington. The moderator is Keith Martin with Chadbourne in Washington.

Tax Extenders

MR. MARTIN: Joe Mikrut, will tax extenders be pushed into 2015 or will Congress deal with them before adjourning later this year?

MR. MIKRUT: It is possible they will be pushed into 2015, but unlikely. The most likely scenario will be some compromise in 2014 between the Senate version of tax extenders, which is a two-year extension of just about every expiring tax provision, and the House version, which is a permanent extension of a limited number of provisions. The most likely outcome will be a two-year extension of most everything, with some of them made permanent.

The Republican win makes corporate tax reform more likely.

If those negotiations break down, then you are probably looking at a one-year extension of just about everything, with Congress taking another look in 2015. It is hard to see action on extenders being postponed until 2015.

MR. MARTIN: Is there anyone on this panel who believes Congress will deal in the time that remains this year only with spending authority for the government to keep operating past December 11 and not much else? [Silence.]

Then Joe Mikrut, sticking with you, will the final tax extenders package include an extension of the construction-start deadline for wind, geothermal, landfill gas, biomass, incremental hydro and ocean energy projects and, if so, will it be a simple date change to the end of 2015 with only a one-year extension to the end of 2014 as a fallback?

MR. MIKRUT: I think the production tax credit will be included. The PTC has clearly become a bit more controversial over time, but I think the group of extenders will ride together so that, if one gets extended, then they all will be extended. I think everything will be simple date changes. That is usually what happens in a lame-duck session as the old Congress winds down and time is short.

MR. MARTIN: Rich Glick, you are with a prominent wind company. Do you think the PTC will be extended?

MR. GLICK: I do. I put the likelihood at 75%. There is a lot of momentum behind tax extenders. I don't think it is very likely that there will be no action on extenders in the lame-duck session because extenders are important to lots of key members of Congress for a variety of reasons. Undoubtedly, the House will take as its starting position in negotiations with the Senate that we need either to get rid of the PTC or dramatically reduce its value. The PTC is a very high priority for both the White House and the Senate. I think the time pressure to wrap up the session so that Congress can adjourn will work in the Senate's favor in the negotiations.

MR. MARTIN: So two votes "yes" for a PTC extension in late November or December. Jon Weisgall, your company is also heavily into wind. Yes or no?

MR. WEISGALL: Yes. I think the PTC will be extended. It is not a slam dunk, but the odds of an extension are better than 50-50. You have very prominent Republicans — Mitch McConnell, the Senate Republican leader, Orrin Hatch, the senior Republican on the Senate tax-writing committee — stating publicly that they want to see tax extenders done. This is not just a Democratic play. I think that the next time the subject of any extension comes up in late 2015 or 2016, it will be time to start looking at a phase out, but a simple extension is the most likely outcome in 2014.

MR. MARTIN: Let's be clear that the extension is measured from the end of 2013. So when people talk about a two-year extension, they mean a project can qualify for tax credits if it is under construction by the end of 2015. And a one-year extension . . .

MR. MIKRUT: A one-year extension would require a project be under construction by the end of 2014 which, for the renewable energy companies and a lot of other folks who are concerned with extenders, would not allow much time to act.

MR. MARTIN: Right. John Stanton from Solar City, will the current deadline for solar projects to be completed by December 2016 to qualify for a 30% investment tax credit be changed to a deadline merely to start construction by December 2016 as part of the lame-duck tax extenders bill?

MR. STANTON: There is a chance if the Senate Finance extenders package is reopened or if floor amendments are allowed in the Senate. However, if Senate leaders stick to the existing package and defend it from amendment on the Senate floor, then there will not be an opportunity to make that change.

If a manager's amendment in the nature of a substitute is offered in the Senate in which changes are made in the extenders package reported last April by the Senate Finance Committee, then I think Democratic leaders will try to get parity of treatment for solar, fuel cells, micro turbines and combined heat and power with respect to the construction-start rules.

MR. MARTIN: So in play, but a heavier lift. Joe Mikrut, how do you handicap the solar provision?

MR. MIKRUT: As with any policy change, it is very difficult when you get to the end of the session and when leadership is making the decisions rather than leaving them to the tax committees. I agree with John Stanton. It depends on the process, but lame duck sessions generally are not the place to make policy changes.

MR. MARTIN: Richard Glick and John Weisgall, do you agree?

MR. GLICK: I tend to agree, but just keep in mind that converting the deadline for solar into a deadline merely to start construction is a priority for Harry Reid. He is still the majority leader until the end of the year. You never want to count Senator Reid out, but it is an uphill battle.

MR. WEISGALL: I agree. The difficulty getting a construction-start deadline for solar in 2014 is the ITC for solar has another two years to run. Congress has a tendency to put off decisions until the deadline.

MR. MARTIN: Joe Mikrut, will the 50% depreciation bonus be extended?

MR. MIKRUT: I think it will also be in the mix. The Senate Finance Committee voted last April to extend it. The House voted in July to make it permanent. This created an expectation that companies can rely on it. It will be difficult to back away from that expectation.

MR. MARTIN: So there is an expectation that the 50% depreciation bonus will be part of the extenders package. Does anyone disagree? [Silence.]

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2008 rising to $120.5 million by 2012. An expert hired by the state put the values even higher than the state assessments: $200 million rising to $297.9 million.

The Tax Court decided the correct 2008 value was in between the state assessment and the gas company figure, but it put the 2012 value above the state assessment. Its final figures were $94.7 million in 2008 rising to $174.7 million in 2012.

The court looked at the three standard methods for valuing equipment: depreciated replacement cost, comparable sales and the income method. It said there was not enough data publicly available about recent sales of similar assets or companies to use the comparable sales method.

It calculated the depreciated replacement cost, or the cost to build new gas lines, and then adjusted the amount for the age of the gas lines in question.

Turning to the income method, it said it was more comfortable relying on historic revenue rather than what the company was projecting it would earn in the future because the company had been consistently wrong in its earnings projections. It then used two approaches to distill the numbers to a market value.

Under one approach — the "direct capitalization method" — it divided the company's net operating income for the year in question — for example, the 2008 net operating income — by a "capitalization rate" that is the weighted average cost of equity and debt for a comparable company. It used 7.51% as the capitalization rate in 2008 falling to 5.87% in 2012. It subtracted 5% of the prior year's revenue as the value of working capital and 5% of business enterprise value as the value of intangible assets, neither of which is subject to property taxes.

The other way to calculate value under the income method is to discount projected cash flow. However, the court rejected that approach due to its lack of confidence in the gas company's revenue projections, which it said experience has shown are 30% to 35% overstated. It did not

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More Gridlock?

MR. MARTIN: Let me ask a large question. There is a split among Washington insiders about whether we are headed for two more years of gridlock or to a short period, before the 2016 elections take center stage, when Congress and the President will find common ground. Rick Glick, in which camp are you?

MR. GLICK: I am in the camp that says the gridlock will continue. Certainly at the beginning of the next Congress, there will be a concerted effert by both political parties to try to work together and pass relatively uncontroversial items, such as patent reform. There may even be efforts on the Keystone XL pipeline and things like that, but when it comes to major legislation, the bigger concern is not whether the Democrats and Republicans will be able to work together, but whether the House and Senate will be able to find common ground.

I do not see House Republicans willing to compromise on major issues so that bills can get through the Senate. So my prediction is for some initial restorative action early on, but then back to the same old gridlock.

MR. MARTIN: So your gridlock is good for the news media; it is Republicans versus Republicans, House versus Senate. Jon Weisgall, in which camp are you, gridlock or a post-election Congress that will get something done?

MR. WEISGALL: Put me in the camp of Charlie Brown and "Lucy, don't pull that ball away." I have hope in the face of experience that leaves little ground for optimism. I do not expect action on immigration or other big issues. I see a greater chance for action in the energy field.

The Republicans are going to feel an obligation to show they can get something done while they are in charge. They will have a tough time retaining control of the Senate in the 2016 elections. Seven Republican Senators will be up for reelection in 2016 in states that Obama carried. Six of those seven are freshmen who were elected in a mid-term election in which low voter turnout tends to favor Republicans. Now they will be running in a presidential election year when higher voter turnout and demographics will favor the Democrats.

I agree with Rich Glick that the greatest challenge Congress faces in trying to function will be the dynamic within the Republican party. The party will have to contend with Ted Cruz, Mike Lee and a vocal Tea Party faction that does not believe in compromise.

Despite all of that, I can see a modest energy bill with energy efficiency provisions, streamlining of regulation, approval of the Keystone pipeline, expediting approvals to build new LNG export terminals, and authorization for crude oil exports. Something like that could actually pass.

MR. MARTIN: So we have one gridlock, and one Charlie Brown willing to try again to kick the football despite the inevitable disappointment when Lucy pulls the ball away. John Stanton, I think you are also Charlie Brown.

MR. STANTON: My sense of it is that the Republican caucus wants to show that it can govern, especially now that Harry Reid and the Democrats will no longer be standing in the way. The challenge will be for House leaders to send bills to the Senate that are not inherently antagonistic.

Probably the first real bill coming out of the House will be an energy bill. That energy bill will have as its centerpiece authorization for the Keystone pipeline. How that bill is packaged will be an early indication whether House Republicans are willing to write bills that will be acceptable to the Senate or are just designed to trigger an allergic reaction.

There is plenty of room for consensus on energy. Plenty of Democrats support Keystone. This will be an early sign whether any break in the gridlock is possible. I am optimistic despite recent history.

The House and Senate will still have trouble working together.

MR. MARTIN: Joe Mikrut, more gridlock or a Congress that can get something done?

MR. MIKRUT: The last Congress set such a low bar in terms of getting things done that it is hard to do any less, so I predict things will be a little more active. I agree with Rich Glick that the real friction will be between the House and Senate, and I agree with the other points that were made that a few things will pass at the margins.

All of the Above

MR. MARTIN: Rich Glick, the national Republican party says it favors an all-of-the-above energy policy. What will that mean in practice over the next two years?

MR. GLICK: I am not a fan of that term. It is like saying you are for motherhood and apple pie. Jon Weisgall listed earlier some of the modest items that might be packaged together in an energy bill. They are a group of relatively uncontroversial items plus the Keystone XL pipeline.

I have to believe that if President Obama does not sign off on the Keystone pipeline relatively soon, then the Republican Congress will pass a bill requiring him to approve it. We may see some legislation promoting LNG exports, essentially expediting the approval process for export facilities. There may be something on energy efficiency. These are all what I would consider relatively minor energy issues. They make some difference here or there, but for the most part, even the efficiency bill is incredibly modest. The fact that it could not pass the Senate this year despite bi-partisan support was a prime example of the gridlock in the current Congress.

I do not see any action on significant measures that would move the country in one direction or the other, whether it is pro oil or pro renewables.

MR. MARTIN: Jon Weisgall, you already gave us your list of what energy measures you think are likely to move in the next Congress. You heard Rick Glick just give a list. Do you have anything to add?

MR. WEISGALL: Streamlining federal permitting to accelerate construction or upgrading of energy infrastructure, geothermal projects and maybe public lands bills. We may see Congress authorize more drilling for oil and gas on public lands, although the issue is complicated because a whole new industry has grown up around the shale revolution that probably feels there is already enough drilling. Congress could try to extend the deadline to 2020 to comply with the new Environmental Protection Agency regulations that reduce carbon and other greenhouse gas emissions from existing power plants that use fossil fuels.

Let's remember that the last major energy bill, the Energy Policy Act in 2005, had something like 18 separate titles that threw in something for everybody. You could call */ continued page 6*

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believe that a potential purchaser would rely on the company's forecasts.

In the end, the court assigned 80% weight to the income method and 20% weight to the depreciated replacement cost approach. One of the experts argued that the cost approach is less reliable than the income method because it does not measure the market value of a group of assets when they are used in combination with one another.

The case is Minnesota Energy Resources Corporation v. Commissioner of Revenue. *The court released its decision on September 29.*

AN IRS BUSINESS PLAN showing what guidance the US tax agency plans to issue by next June lists several items of interest to the project finance community.

The plan was released in late August.

The Internal Revenue Service said it hopes to issue "regulations on prepaid forward contracts." This could affect the pattern in which income must be reported under prepaid power purchase agreements.

In January 2008, the agency issued a revenue ruling analyzing the tax treatment for a forward contract to buy euros. The holder paid \$100 on January 1, 2007, at a time when \$100 was worth €75, for a contract requiring delivery of €75 plus a return three years later on January 1, 2010. The forward contract paid the holder the dollar equivalent of €75 plus a compound stated rate of return, with conversion into dollars occurring at the exchange rate on January 1, 2010. The IRS said the instrument was in substance a euro-denominated loan by the holder to the issuer. The IRS said in a separate notice the same day that it is studying the tax treatment of prepaid forward contracts, and it asked for comments on a list of questions, including whether the seller under a prepaid forward contract that is in fact a forward sale, rather than a loan, should be required to accrue income during the term of the forward contract and, if so, how the amount of income each year should be calcu- */ continued page 7*

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that a mish mash or Congress's version of a comprehensive energy policy. I think it is possible to get something modest in the next two years.

Big Deal?

MR. MARTIN: John Stanton, apart from a tax credit extension, the renewable energy industry has been unable to advance its agenda in Congress since 2010. Is it now clear that that will remain the story through 2016, and was there any more agenda, other than another tax credit extension, to advance in any event?

MR. STANTON: Keith, going back to your point about an all-of-the-above energy policy, I think it is worth mentioning that the modern solar investment tax credit can be traced to a Republican, Bill Thomas, who was chairman of the House tax-writing committee and who tried to get a two-year solar tax credit into the Energy Policy Act in 2005. And when the solar credit was last extended in 2008, the extension was supported by both political parties in both chambers.

US action on global warming is less likely.

On the Senate side, you had Gordon Smith, a Republican, and Maria Cantwell, a Democrat. On the House side, you had David Camp, a Republican, and Nancy Pelosi, a Democrat. Both the original tax credit and the extension were signed into law by George W. Bush.

The Republican caucus, especially in the House, has gotten a lot less moderate. One would like to think there will be an opportunity for a balanced energy bill that does not just double down on traditional incumbent fossil energy interests but rather looks forward and says "all of the above" also means new technologies like wind and solar, micro turbines and combined heat and power that should be part of America's energy future and deserve the same type of favorable tax treatment that is accorded to traditional energy interests.

Once again, that's an optimistic view, but at least as of today — two days after the election — Kevin McCarthy and the rest of the House leaders have vowed to lead with energy and to do so in a way that will not cause a knee-jerk rejection by the Senate.

MR. MARTIN: Rich Glick, is there any more to the renewables agenda in Congress besides extending tax credits at this point?

MR. GLICK: Not really, but two points.

First, no industry achieved its legislative agenda after 2010, so the renewable energy industry is not alone on that. The gridlock has been all encompassing.

Second, let's not forget that there is more than just legislation when it comes to policy making. Most of the policy making in the last few years has been before the regulatory agencies. Look at the Environmental Protection Agency regulations to limit not just carbon emissions, but also mercury, nitrogen oxide and sulfur dioxide emissions. The Federal Energy Regulatory Commission has issued a number of rulemakings and orders that encourage construction of new transmission lines to bring renewable energy from remote areas to population centers. It issued other rules that will help integrate intermittent renewable resources, such as solar and wind, into the utility grid.

This is how the renewable energy agency has been advancing in this country. The regulatory arena rather than the legislative arena will remain the primary focus over the next two years.

MR. MARTIN: So is it a big deal that the Republicans took control of Congress if there was not really a renewables agenda that people were trying to advance in Congress anyway?

MR. GLICK: Tax incentives are still an extremely important element of the renewables agenda. The big question going forward is what will the new Congress do about extenders and fundamental corporate tax reform. I am optimistic about an extension of the tax credits in the lame-duck session before the new Congress takes office. I am pessimistic about the chances of any action on renewable energy incentives in the new Congress that takes office in January and runs through 2016.

MR. WEISGALL: Can I jump in on that point?

We do not have a federal energy policy. We have a federal tax policy, and we have a federal environmental policy. We have never had a comprehensive energy policy. I am not sure we ever will. We are just too big a country. We have so many interests, whether it is hydro in the Northwest or coal in the Midwest or natural gas or nuclear east of the Mississippi.

The three biggest drivers for renewable energy in the United States are tax incentives, indirectly EPA regulations — especially the section 111(d) rule on greenhouse gas emissions from existing power plants — and renewable portfolio standards at the state level.

Inaction at the federal level has led some states to take more of a leadership role. Some of the most significant drivers of this industry going forward will be state actions, not just renewable portfolio standards but also other policies to support new technologies.

Incoming Flak

MR. MARTIN: Obama seemed to give up on Congress four years ago acting on renewable energy and global warming, so he moved earlier this year to limit carbon emissions from existing power plants by regulation. Rich Glick and Jon Weisgall both mentioned that. Will that effort remain on track or will it now be derailed by a Republican Congress by perhaps denying spending authority to implement the regulations?

MR. WEISGALL: It is a concern. There are lots of ways that a Republican Congress could impede implementation. The easiest and the least successful track would be to bar implementation of the section 111(d) rule. I doubt that would pass the Senate.

So what tools do opponents have? They have authorization and appropriations bills, oversight hearings and maybe the Congressional Review Act. There will probably be an attempt to cut off spending on EPA implementation. The form of attack that is most likely to succeed is a bill delaying implementation until 2020. I suspect that is what Republicans will go for since it would have the best chance of bipartisan success.

I think stopping the Environmental Protection Agency in its tracks on the separate new source performance standards will not succeed.

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lated.

The IRS said in the new business plan that it will issue "guidance on the energy credit under section 48." Jaime Park, chief of the IRS branch that handles energy credits, said the guidance will address performance and quality standards for small wind turbines.

The IRS said it will issue "guidance under section 7704(d)(1)(E) regarding qualifying income for publicly traded partnerships." This is a placeholder for guidance about master limited partnerships or MLPs. (*See the March 2006* NewsWire *starting on page 1 for a survey article about MLPs.*)

The IRS has had a hold since February 2014 on private letter rulings about whether some businesses can be organized as MLPs. There is a great deal of interest in the market about whether paper and packaging companies can put part of their businesses in MLPs, thus avoiding a corporate-level tax on earnings from the businesses. The hold does not appear to have affected rulings in this area.

An "integrally related" or "hamburger stand" issue is holding up some other rulings. The boom in US oil and gas production has led to a string of private letter ruling requests about whether companies that provide services to oil and gas producers can organize as MLPs. The key to qualifying as an MLP is to have at least 90% of the gross income the MLP earns each year be from passive sources — like interest and dividends — or from "exploration, development, mining or production, processing, refining or transportation . . . or the marketing of any mineral or natural resource." A company engaged directly oil or gas production qualifies.

Does a company providing services to an oil or gas producer qualify? For example, would a hamburger stand set up next to a gas field to feed workers involved in gas production qualify? The IRS has been issuing private rulings that allow income from some such services to be treated as good income for an MLP. It put a hold on further rulings while it figures out */ continued page 9*

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MR. MARTIN: John Stanton, Obama has been pushing the Department of Defense and other federal agencies to buy renewable energy. Is there any chance that could be derailed?

MR. STANTON: The issue with federal procurement is the current insistence by the Office of Management and Budget that, apart from the Department of Defense realm, if the federal government wants more renewable electricity, it essentially must own the underlying hardware. That sets the bar higher than it needs to be because ownership requires a large upfront outlay. That means the agency must get an appropriation from Congress.

It would be far better if the federal government just entered into power contracts. This would allow use of the same third-party ownership models that are propelling the solar rooftop industry to 100% annual growth rates in the private sector. The OMB position that the federal government must own the equipment is not required by law. It puts up an unnecessary barrier to greater use of renewable energy by the federal government.

MR. MARTIN: Is anyone following the travails of the US Export-Import Bank? The bank has authority to operate only through June. There is a split in the House Republican caucus about whether to shut down the bank. Will the bank be around past June?

MR. WEISGALL: The mainstream Republican leadership wants to see the bank remain in business. This will be a moderates-versus-Tea-Party struggle within the Republican caucus. How this issue is decided will be a sign of whether the Republican party can move back into the mainstream.

MR. MARTIN: And since it was the mainstream wing of the Republican party that seemed to have prevailed in elections for Senate seats, that is at least an early positive indicator.

MR. WEISGALL: That's right. Every other country has something like it. We would really be shooting ourselves in the foot to get rid of it.

MR. MARTIN: Rich Glick, House Republicans have been critical of the Department of Energy loan guarantee program. Do you foresee any effort to shut it down?

MR. GLICK: There are two separate loan guarantee programs. One was adopted under the Energy Policy Act in 2005. The other was adopted in early 2009 as part of the Obama stimulus, the American Recovery and Reinvestment Act. The 2009 loan guarantees have pretty much expired. The original loan guarantee program remains and is being used to help finance big nuclear power plants that are being developed down south. There is a lot more support among House Republicans for that program than there was for the other loan guarantee program that was used mainly to promote renewable energy.

I do not expect Congress to spend a lot of time on the loan guarantee program because it is not as good a political issue for the Republicans as it was a couple years ago.

MR. MARTIN: Joe Mikrut, Congress must increase the federal borrowing limit by next March, although the US Treasury usually finds ways of pushing its borrowing authority out to the summer. Do you foresee any drama around the next debt-ceiling vote?

MR. MIKRUT: No. We had drama around the debt limit and the government shutdown before. I think the last Congress learned its lesson. The public does not like government shutdowns. There is no better way to signal government dysfunction than to shut down the government.

Electric Vehicles

MR. MARTIN: Demand for electricity in this country has been growing at a paltry rate. Demand increased by 0.7% a year in the last decade. It is expected to increase at a 0.9% annual rate going forward. John Stanton, solar rooftop companies like yours are making things a little worse for the utilities by making inroads into utility market shares in some states. However, some big utility CEOs and market analysts see hope for the future in that widespread adoption of electric vehicles could cause electricity demand to shoot up.

Do the election results make electrification of the transportation sector more or less likely?

MR. STANTON: The elections were a neutral factor. The low growth in demand for electricity is not due to installation of rooftop solar panels but to widespread adoption of energy efficiency measures. For example, one simple step, like ordering that incandescent light bulbs be phased out in favor of more efficient light bulbs, offset several years of growth in electricity demand. Solar is 0.3% of electricity generation in this country. It is just not a significant factor.

Turning to electric vehicles, one would think that the utilities would embrace them to a greater degree than they have to date. Our sister company, Tesla, has an amazing product. We think that the future for electric vehicles is very, very bright, but the election results will not affect how widely they are adopted, and I don't see the utilities doing much to stimulate that market.

MR. MARTIN: Jon Weisgall and Rich Glick, both of you work for utilities. Do either of you think the election will affect support for electric vehicles?

MR. WEISGALL: I don't see an effect. This is largely a state issue. The state public utility commissions could play more of a role in promoting installation of charging stations, but they have not been particularly active to date, and I see a lot of challenges for states going forward to try to advance that market.

MR. GLICK: It is not a policy issue at the federal legislative level. The barriers have more to do with technology and consumer choice. As consumer demand increases for electric vehicles, then I think utilities will certainly embrace them and they are embracing them somewhat now. The biggest technology issue that still needs to be addressed is batteries that will allow electric vehicles to travel longer distances between charging stations.

MR. MARTIN: Joe Mikrut, Congress must restore the highway trust fund. It has run out of money. The trust fund is how we pay for highways in this country. Republican orthodoxy is to oppose any new taxes. There has been talk about allowing US companies with earnings trapped in offshore holding companies to repatriate the earnings, pay the tax at a low rate and then have the taxes collected go into the trust fund. How do you see the trust fund being replenished?

MR. MIKRUT: I don't think the repatriation tax will be the answer. Congress will continue to struggle with a longer-term solution. Taxes on gasoline are used currently to fund the trust fund, but because autos are getting higher mileage per gallon, the gas tax is no longer an adequate source of funding. I doubt Congress will find a permanent solution by the middle of next year when it has to act. My bet is it will continue to kick the can along the road until someone comes up with a solution that is tied to highway transportation.

MR. MARTIN: A fix that Congress can call a user fee rather than a tax?

MR. MIKRUT: People are more accepting of highway taxes dedicated to highway use than tax increases for general spending.

Corporate Tax Reform?

MR. MARTIN: I have been thinking of the prospect of corporate tax reform like a hurricane that hits the east coast. It has the potential to sweep all tax incentives out of the US tax code in order to allow the tax rate to be reduced. Maybe that is a caricature of what would actually happen, but do you foresee major corporate tax reform in 2015 of 2016?

MR. MIKRUT: Introduced? Yes. Enacted? Maybe. Will it be comprehensive? No. */ continued page 10*

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where to draw the line.

Curt Wilson, the IRS associate chief counsel with responsibility for the area, said at an oil and gas conference in New York in early November that the IRS has some "tentative ideas about where we are headed" on a standard that would allow the agency to lift the IRS rulings freeze. "The next step for us to do is to put that on paper and then circulate that paper and get buy-in from all the people who have a say in this." He said he would like to reopen the rulings window once there is internal agreement on concepts without waiting for formal guidance. He said rulings are still being issued as long as they do not raise the integrally related issue.

The IRS also hopes to issue guidance on whether property held simultaneously for sale and lease can be depreciated. Equipment that a company holds for sale is considered inventory. The company cannot normally place such property in service or depreciate it. Equipment that a leasing company holds out for lease is in service and can be depreciated.

The agency hopes to issue "regulations under section 267 regarding the application of § 1.267(b)-1(b) to partners and partnerships." Many renewable energy projects are owned by partnerships. The partnerships usually show tax losses due to depreciation for the first several years. US tax rules prevent the partnership from claiming net losses if electricity from the project is sold to a related party. A taxpayer cannot sell to an affiliate and claim a loss on the sale. As a consequence, most tax equity partnership documents make the partners covenant that they will not be related to the offtaker for the electricity. Denial of loss deductions when there are related-party sales occurs mainly through IRS regulations under section 707(b) of the US tax code. Any new regulations that the IRS issues under section 267 to deal with losses in a partnership setting will be read with interest by tax counsel for any possible application to renewable energy deals.

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Touching the individual side of taxes is sort of a third rail. The administration would like to get the deficit under control by increasing taxes on higher-income individuals. The Republicans clearly do not want to do that. So I think individual taxation is off the table.

But there can be a resolution between a Republican Congress and the Obama administration on either business taxes broadly or perhaps just corporate taxes or at least international taxes. And that could be labeled tax reform. And it could move forward within the next two years.

Congress could force a delay in implementing new emissions limits for existing power plants.

MR. MARTIN: Kevin Brady and Paul Ryan, two House Republicans, are vying to head the House tax-writing committee. Brady, who is from Texas, would pick up with a tax reform bill that the current committee chairman, Dave Camp, released in February. Any idea what Ryan would do?

MR. MIKRUT: I think Messrs. Brady, Ryan and Camp are all working from a similar set of principles. They all want a simpler and fairer system, presumably with a broader base.

They think the top rate should be 25% percent. They want to do international tax reform. Camp demonstrated when he released a discussion draft of a comprehensive corporate tax reform bill earlier this year how difficult it will be to get there. I think Ryan, assuming he takes over as chairman, will be looking at the same product and making changes, but using the Camp draft as a starting point. So would Brady. [*Ed. For a discussion about how the Camp bill would affect power companies, see the February 2014* NewsWire *starting on page 9*.]

Ryan is already talking about changing the baseline against which tax bills are scored to measure the potential revenue effects in a way that could make tax reform easier to achieve.

MR. MARTIN: If corporate tax reform moves forward, is it clear that accelerated depreciation will be repealed?

MR. MIKRUT: It is very difficult to do tax reform without looking at accelerated depreciation. MACRS is the single largest domestic tax preference in terms of revenue effect. The discussion draft that Dave Camp released earlier this year would have reduced the corporate rate from 35% to 25% over several years.

The rate reduction would cost $680 billion in lost revenue over 10 years. Camp would have repealed MACRS and replaced it with a form of straight-line depreciation that is indexed for inflation. That would have raised $270 billion. So 40% of the revenue lost by reducing the corporate tax rate can be recovered by eliminating MACRS and moving to a different form of depreciation. [*Ed. For more on how depreciation might be calculated after tax reform, see the December 2013* NewsWire *starting on page 12*.]

It is very, very difficult to think seriously about tax reform without also thinking seriously about accelerated depreciation.

MR. MARTIN: If accelerated depreciation is repealed, will companies that are depreciating existing assets be affected?

MR. MIKRUT: Unlikely. Traditionally, any depreciation changes have been prospective.

MR. MARTIN: There has been a move in the corporate sector to find ways to operate without having to pay corporate income taxes. Examples of this have been the wave of corporate inversions, where US companies merge with smaller foreign companies and relocate offshore, the spinoffs of buildings and other assets by casinos, prisons, data centers, and telephone and billboard companies into real estate investment trusts, and the interest in yield cos and master limited partnerships. These are all variations on the same theme. The Camp discussion draft in the House would have rolled back use of real estate investment trusts to the original form as vehicles for individual investors to pool capital to invest in buildings. Camp proposed taxing master limited partnerships like corporations except for those involved in minerals and natural resources.

Where do you see this going? Will any tax reform bill enacted affect existing REITs and MLPs?

MR. MIKRUT: There are two issues. First, it is very difficult to do corporate tax reform without at least asking what type of entities should pay entity-level corporate taxes. Should the corporate tax be viewed as a toll charge for access to the public markets? Should all entities be subject to corporate taxes once they reach a certain size? Many MLPs and REITs, as well as some privately-held partnerships, are very large businesses. Should Congress draw lines based on the activities in which the entities are engaged? Should it draw lines based on whether they are active businesses or merely vehicles for holding passive investments?

Second, if we only do corporate tax reform and leave the individual tax system alone, then the corporate tax rate may be driven down as low 25%. The individual rate will remain at 39.6% with all the add-on taxes for health care, etc. That would drive a lot of entities out of the flow-through regime back into the corporate regime to take advantage of the lower tax rate on corporations, notwithstanding that corporate earnings are subject to two levels of taxation.

MR. MARTIN: So the effect of a corporate tax reform bill could be a mass exodus away from partnerships back to corporations.

State Battles

MR. MARTIN: Jon Weisgall, you watch the states. Tax credits at the federal level and renewable portfolio standards at the state level have been keys to growth of the renewable energy industry in this country. Several conservative groups have been fighting to roll back state renewable portfolio standards, but so far with only limited success. Ohio froze its target for two years. Have the elections made roll backs more likely?

MR. WEISGALL: State capitals across the country will be more Republican than at any time in nearly 100 years. Republicans will have sole control of 29 state legislatures. That means both state chambers of state legislatures (and Nebraska where the legislature is unicameral) and the governors' mansions. That will be the largest level of Republican control since 1928.

The trend has been for states to go more conservative. Two states — Massachusetts and Maryland — that historically have been among the most liberal just elected Republican governors. The Democrats did not take over any legislative chambers that were held previously by Republicans.

Therefore, it is reasonable to believe / continued page 12

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hopes to issue regulations to address how gain should be reported in sales where part of the purchase price is contingent on future events.

TREASURY CASH GRANTS have moved into a litigation phase.

There are 20 pending lawsuits against the US Treasury by companies that feel the Treasury paid smaller cash grants on renewable energy projects than they were entitled to receive. Many renewable energy projects placed in service between 2009 and 2013 had the option of being paid 30% of the cost of the project in cash by the Treasury in lieu of taking federal tax credits. Some solar projects still retain that option if they are completed by December 2016. The payments are made under section 1603 of the American Recovery and Reinvestment Tax Act.

Twenty-two lawsuits in total have been filed against Treasury, but the taxpayers withdrew two after the Treasury filed counterclaims accusing the companies of fraud.

All the suits have been filed in the US Court of Federal Claims. The oldest pending suit was filed in July 2012. Companies have six years after a grant is paid to decide whether to litigate.

Some taxpayers have asked the court to decide their cases at "summary judgment," meaning they feel there is no disagreement about the facts and the judge should decide the cases based on legal briefs filed by each side. The government has opposed some summary judgment motions on grounds that it needs to do more discovery to establish the facts, but filed its own motion for summary judgment in others.

Meanwhile, a US Claims Court judge ordered the Treasury in October in a case involving a solar rooftop company to disclose the benchmarks it used from the start of the program to pay grants on rooftop systems and to disclose limited information about how it dealt with the compa- / continued page 13

Elections

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we will see more pressure to roll back programs for renewable energy. You are right: the roll-back movement had one partial victory in Ohio this year. Efforts were made in the last three years to roll back renewable portfolio standards in 14 other states and every one of them failed. I suspect there will be renewed efforts in those states.

MR. STANTON: I agree with that. These RPS mandates were originally passed over the objection of the incumbent energy suppliers. What happened in Ohio was telling. The state froze the RPS target, which had been scheduled to increase, for two years. Then, on the heels of that, it sought to unwind the deregulation compact by allowing American Electric Power, the dominant utility, to put two coal-fired power plants into its rate base and get cost recovery for them from ratepayers even though the units are owned by an unregulated subsidiary of AEP.

The story in Ohio was not just let's freeze the RPS target, but let's also double down on our support for traditional energy interests. Unfortunately, I think that we will see more of that. Truth be told, renewable energy interests just do not have the power that fossil and traditional incumbents have.

MR. MARTIN: There was not much federal leadership during the Bush administration on renewable energy and global warming. It led a number of states to act on their own. Perhaps it will happen again, although it sounds less likely than before because of the shift to Republican control.

John Stanton, are there other issues in play at the state level that could be affected by the elections?

MR. STANTON: Actually, I think the Bush administration did its part to promote renewables. They just wanted to do it in a very Republican way, which was to lower levels of taxation. The solar investment tax credit was extended to 2016 in 2008 with administration support.

MR. MARTIN: Jon Weisgall, are there other issues in play at the state level that could be affected by the elections?

MR. WEISGALL: The only thing that comes to mind is it is now quite clear there will not be any federal legislation on fracking. The industry probably should recognize that this makes it more likely that individual states will step in. Frankly, states have their fingers on the pulse of fracking politics and local concerns. That is the only one that comes to mind.

MR. GLICK: The Illinois and Kansas gubernatorial elections might have an effect on renewable energy.

In Kansas, Republican Governor Sam Brownback, who was narrowly reelected, had been a very strong supporter of the state renewable portfolio standard. However, because it was such a close race and the Koch brothers put a lot of money behind his reelection effort, he has backed off somewhat from his earlier support, and another effort will almost certainly be made to repeal the state target.

Illinois also elected a Republican governor. Legislation is expected in Illinois about how Exelon can be compensated for the cost of its nuclear power plants. It is possible that the same bill could modify how the state pursues renewable energy targets. This will not be a roll back, but the modifications are not expected to help. The new governor is a blank slate on renewables. We are not sure what position he will take. He replaced a Democrat who was an Obama ally. ◎

Renewables Face Daytime Curtailments in California

by David Howarth and Bill Monsen, with MRW & Associates, LLC in Oakland, California

As California marches toward fulfilling — and probably exceeding — a renewable portfolio standard (RPS) that requires 33% of its electricity to come from renewable energy sources by 2020, grid operators are beginning to face operational challenges that could have implications for existing renewable and non-renewable generators and that will shape opportunities for future projects.

For example, existing renewable generators might be curtailed more than in the past. If the system operator curtails renewables, then the generator might not receive full compensation for curtailed energy.

Existing gas-fired generators might need to increase their flexibility to allow for more starts, faster ramping and lower minimum levels of operation.

New projects — both renewable and conventional — may need to provide greater levels of flexibility or accept greater levels of curtailment.

The California Independent System Operator (CAISO) is concerned that there may be times when there is so much variable wind, solar and other renewable energy being scheduled onto its system that the other generators who will have to adjust to accommodate it will not have the flexibility needed to do so.

When scheduled generation exceeds scheduled demand in the hour-ahead market, the price of energy falls below zero in an attempt to balance supply and demand. In other words, when prices are negative, generators must pay others to take the electricity they produce. After accounting for changes in generation and load between the hour-ahead and real-time markets, if generation still exceeds load and there are no more generators willing to be paid to reduce their output, then the CAISO must order generators to curtail output in order to maintain system frequency.

Why would generation exceed load?

Some generators, such as nuclear, small hydroelectric and most geothermal and combined heat and power plants, need to run and have little ability to shut down because they have limited flexibility. A certain amount of gas-fired power plant capacity must also be operated at minimum levels to provide upward ramping needed later in the day or to provide ancillary services such as regulation and load following. If the combination of must-run generation plus gas-fired generation needed for system operations exceeds demand (particularly in low load hours), then the CAISO must take action.

Growing Curtailments

The CAISO is already beginning to see these types of overgeneration events. (See Sidebar 1.) In February through April 2014, the CAISO had to curtail wind and solar generation four times for a total of six hours to balance supply and demand on its system. On one occasion, the maximum curtailment reached 485 megawatts of wind and 657 megawatts of solar. The impact on individual generators depends on the terms of their power purchase agreements, but typically there is no compensation for curtailment that is ordered by the grid operator.

In the absence of any changes to address the underlying issues, the CAISO forecasts overgeneration and renewable energy curtailment to increase in the future as more renewable energy is added to the system.

Looking ahead to 2024, which was recently modeled by the CAISO, curtailment is expected to remain relatively modest if RPS energy levels remain at 33%. Total curtailment is forecast to be less than two-tenths of 1% of the total RPS supply. However, if RPS energy levels increase to 40% (which has been proposed by California Governor Jerry Brown as an */ continued page 14*

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ny's applications. However, the judge declined to compel disclosure of other information, including what the Treasury paid on comparable applications, or information about how it developed its general screening policies or the lower benchmarks it used to make payments than the amounts for which the company applied. Discovery in the case is now scheduled to run into early August 2015, making a decision in the case unlikely before 2016.

The earliest decision in any of the pending lawsuits could come in early 2015 in a case involving a biomass project that the Treasury says qualified for only a partial grant because it produced both steam and electricity and only the part of the project related to electricity generation qualified for a grant. (*For earlier coverage of the biomass case, see the February 2013* NewsWire *starting on page 27*.) The court is scheduled to hear arguments in the case starting on December 15.

In other developments, the Treasury said in October that grants approved for payment between October 1, 2014 and September 30, 2015 will be subject a haircut of 7.3% due to budget sequestration. The figure was 7.2% for grants approved for payment in fiscal year 2014. Sequestration will continue through fiscal year 2021 unless rescinded by Congress.

A technical corrections bill awaiting action in the "lame duck" session of Congress would clarify that Treasury cash grants do not have to be reported as income by companies paying taxes under the alternative minimum tax. The American Recovery and Reinvestment Tax Act made clear that the grants are not income for regular income tax purposes. However, Congress failed to say anything at the time about the alternative minimum tax. US corporations must compute their taxes under the regular corporate income tax and the minimum tax and pay essentially whichever tax is greater. The technical correction has been waiting for Congressional action since 2010.

The IRS has given up waiting and feels it must enforce the law as */ continued page 15*

SIDEBAR 1

A Duck Sighting

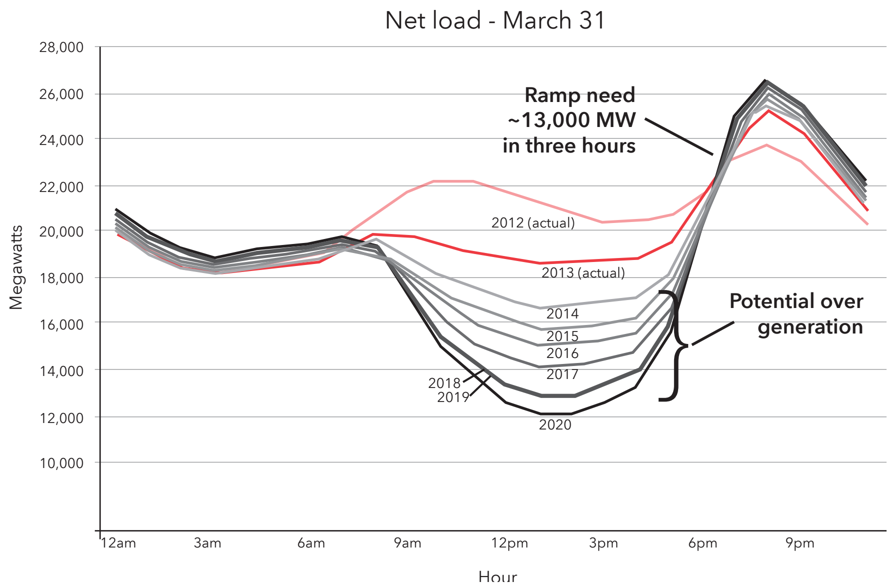
To illustrate the challenge posed by increasing levels of variable renewable generation, the CAISO has produced what has become known as the "duck chart." The duck chart shows the net load on the system — that is, the electricity demand to be served by generation after subtracting the variable generation over which the CAISO does not have dispatch control — on a spring day with relatively high hydroelectric generation and low demand.

As shown in the chart, the "belly of the duck" grows in each successive year with the addition of solar resources that reduce the net electricity demand during the daytime. Already, the CAISO sees utility-scale solar on its system approaching 5,000 megawatts, plus an additional 2,000 megawatts of solar resources on the customer side of the meter. These solar additions have the effect of shifting the minimum net load from early morning to the middle of the afternoon (that is, from 3 a.m. to around 2 p.m.). The growing belly also contributes to the steep ramp to meet peak net demand after the sun sets. By 2020, the three-hour ramp (from 4 p.m. to 7 p.m.) is expected to reach 13,000 megawatts.

The effect of solar additions can also be observed in the changing distribution of negative real-time energy prices, which provide an indication of the risk of overgeneration. As shown in the chart below, the incidence of negative real-time prices in 2014 increased significantly during the middle of the day compared to prior years. However, there was no significant change in negative real-time prices during other periods.

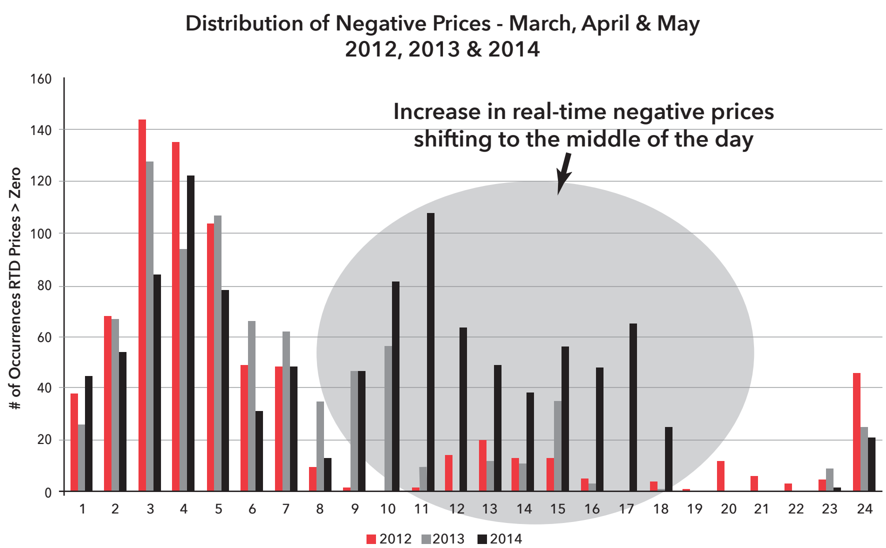
The overgeneration events that occurred in 2014 are also consistent with the duck-like shape of the net load curve. Only one event occurred at night (at 3:44 a.m.). The other three involved solar curtailments and occurred starting at 8:40 a.m., 11:11 a.m. and 12:40 p.m., respectively. On one of those days, April 12, 2014, energy prices were negative during 43% of the 5-minute real-time dispatch intervals. Based on observations of negative prices and curtailment in 2014, Brad Bouillon, CAISO director of day-ahead operations and real-time operations support, reported to FERC that "the belly of the duck has already arrived."

Chart 1



Source: CAISO

Chart 2



Source: CAISO

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achievable goal), then the CAISO forecast of renewable curtailment jumps to more than 2.5% of RPS supply. (See Sidebar 2.) This means that a significant portion (15%) of the incremental renewable energy added to move from a 33% RPS to 40% would be curtailed. Under this scenario, which assumes a solar-dominated renewable energy portfolio, California would fall short of 40% renewable supply unless even more renewables were added to make up for the curtailed RPS energy, at considerable extra expense and with diminishing returns.

The CAISO has made certain market changes designed to improve the management of overgeneration through economic dispatch as well as to require utilities to procure enough flexible capacity to ensure reliable operation under a range of conditions. On May 1, 2014, the CAISO reduced its bid floor from -$30 per megawatt hour to -$150 per megawatt hour, with provisions to reduce it further to -$300 per megawatt hour after a year.

In other words, if the market-clearing bids are at the floor price, then generators will have to pay $150 per megawatt hour to deliver their electricity to the system.

By reducing the bid floor, the CAISO hopes to provide an additional incentive for renewable generators and less flexible conventional generators to provide market bids rather than simply operate as must-take resources. The CAISO has also implemented a 15-minute market to allow for intra-hour scheduling and to provide another opportunity for renewable generators to submit economic bids and adjust schedules close to real time, thereby reducing the likelihood of overgeneration.

The CAISO is proposing to establish a flexible capacity requirement to ensure that utilities have enough ramping capability. The CAISO is also proposing to procure backstop flexible capacity to meet any system-level deficiencies. The Federal Energy Regulatory Commission approved both proposals on October 16, 2014.

The specter of overgeneration may dampen demand for new renewable generation that would contribute to excess supply during certain hours. This appears to be especially true for solar photovoltaics, which have dominated recent RPS procurements as a low-cost resource and are driving down "net load," (which is equal to sales plus losses less must-take renewables) during the middle of the day. Baseload renewable generators such as geothermal and biomass should not */ continued page 16*

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written until the technical correction is enacted. The correction would be retroactive as if included in the original statute.

REITS continue to draw attention.

The comprehensive corporate tax reform bill that Dave Camp (R-Michigan), the outgoing chairman of the House tax-writing committee, released as a discussion draft in February would effectively return real estate investment trusts to their roots as vehicles for investors to pool capital to invest in office and apartment buildings and other real property, but rule out their use to own cell towers, billboards, transmission lines and similar business assets.

A REIT must hold at least 75% "real property" or mortgages on real property. It can also hold some assets through a taxable subsidiary that do not qualify for be held by the REIT directly. The Camp bill would defined "real property" for REIT purposes to exclude assets with shorter depreciable lives than 27.5 years.

Harold Hancock, a tax counsel to the House tax-writing committee, told a DC Bar tax section meeting in late October, "A number of [businesses were] engaging in spinoffs that were not started as a vehicle for everyday investors to invest in real estate but instead were actual operating companies that figured out a way to put real estate into a REIT and then have the actual business operations be conducted in a [taxable REIT subsidiary]. We don't like these types of transactions."

The Camp bill is expected to serve as a starting point for drafting if the next Congress decides to take up corporate tax reform.

Hancock said timber is not treated as real property under the draft because the committee staff believes timber should be treated as inventory. He said the staff has discussed the issue at length with the timber industry, and he expects the discussions will continue.

Meanwhile, Martin Sullivan, an economist who writes for *Tax Notes* magazine, estimated in September that 20 corporations that have spun off timber, casinos, data */ continued page 17*

SIDEBAR 2

Forecasting Curtailment in 2024

The CAISO submitted testimony to the California Public Utility Commission in August 2014 based on modeling it performed of the electrical system in 2024.

The forecast assumptions were largely determined in advance by the CPUC with input from the California Energy Commission. There were five scenarios specified by the CPUC: 1) the current policy trajectory with a 33% RPS, 2) the current trajectory without the Diablo Canyon nuclear plant, 3) high loads, 4) a 40% RPS, and 5) expanded slate of preferred resources like energy efficiency and distributed generation.

The CAISO's curtailment forecasts for each of these scenarios are summarized in the table below.

Given a 33% RPS, the CAISO forecasts 96 hours of renewable curtailment, with a maximum curtailment of almost 6,000 megawatts. Total curtailed RPS energy is expected to be 153 GWh. Under a 40% RPS scenario, curtailments are forecast to increase to 822 hours with a maximum curtailment of over 13,000 megawatts. At 2,825 gigawatt hours, the amount of curtailed renewable energy in the 40% RPS scenario is forecast to increase by almost 20 times compared to the 33% RPS scenario.

The highest level of curtailment occurs in the expanded preferred resources scenario, which relies on energy efficiency and customer distributed generation to reduce net electricity demand significantly. In this scenario, renewable energy curtailments would occur during almost 1,200 hours (13% of all the hours in a year), with a maximum curtailment of almost 15,000 megawatts. Curtailments are lower in the scenario without Diablo Canyon since minimum generation levels would be reduced by removal of this baseload nuclear resource. There is relatively little difference in curtailments between the high load and trajectory scenarios because the renewable generation and loads both increase in proportion to each other.

Since the CAISO analysis does not include all of the capacity resources currently being procured to ensure local reliability in Southern California (following the modeling instructions provided by the CPUC), CAISO's assessment probably overestimates curtailment. This is because the approximately 2,000 megawatts of new capacity not included in the analysis is likely to be more flexible than much of the existing fleet and will reduce the minimum generation needed to be operating at a given time. However, with forecasted curtailments of up to 15,000 megawatts in the 40% RPS scenario, the CAISO will still need additional tools to address overgeneration in the future.

Scenario	Number of hours curtailed	Maximum curtailed (MW)	RPS energy curtailed (GWh)	RPS actually achieved
Trajectory (33% RPS)	96	5,927	153	32.9%
Trajectory without Diablo Canyon	24	3,383	26	33.0%
High load	87	5,841	136	32.9%
40% RPS	822	13,402	2,825	38.7%
Expanded preferred resources	1,165	14,599	4,637	37.5%

Source: CAISO

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necessarily expect a boost, however, since they also contribute to the problem of minimum generation levels. To the extent that such generators can be made dispatchable, they should be more valuable going forward.

Generators in California may have to pay others to take some electricity they produce.

Potential Opportunities

There may be an opportunity for existing gas-fired generators to be part of the solution by improving their operating flexibility. However, it remains to be seen whether procurement mechanisms will develop that allow such generators to recover the costs of making flexibility improvements to their existing plants. When utilities procure new capacity resources — and with little or no load growth being forecast in California, it might be a while before they add to the procurement pipeline — we would expect flexibility characteristics to factor into procurement decisions. Projects that are able to ramp quickly and start multiple times per day will be preferred.

Storage facilities should also benefit from the situation since they can increase demand by charging during periods of potential overgeneration — while getting paid to store the excess electricity — and then use that stored energy to meet peak demand and provide ancillary services, thereby reducing the amount of gas-fired generation needed to operate at minimum levels to provide reserves.

Demand response may also be able to meet some of those peak ramping needs and reduce minimum generation levels.

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centers, prisons, cell towers and billboards recently into REITs or have announced an intention to do so, will save $900 million to $2.2 billion a year in corporate income taxes, assuming their earnings remain at 2014 levels. Sullivan said the estimates overstate the revenue loss to the government because they fail to take into account larger tax payments by the REIT shareholders, many of whom are individuals. REITs must distribute at least 90% of their income each year. Life Time Fitness Inc., which owns health clubs, saw its stock shoot up 15% immediately after it announced an intention to convert into a REIT in late August. Sullivan said, "Expect announcements like this to continue" when a company can increase its market capitalization by $250 million "in a matter of minutes."

REIT conversions can be expensive.

Iron Mountain, a data center company that spun off assets into a REIT as of January 1, 2014, said in its latest financial statements that it expects to have spent $145 to $155 million on legal fees, tax work, advisory fees and similar costs to convert over the period 2012 through 2014, plus another $40 to $45 million in capital costs such as reprogramming information systems to operate as a REIT, plus another $15 million a year on REIT compliance.

Equinix, a data center company, estimates its costs will run to $84 million over the same period, plus $5 to $10 million in annual compliance costs. Penn National, a casino company that converted in 2013, estimated its cost to convert was $125 million. "I can't overemphasize the complexity," the CEO said.

INDIA lost a round in court over whether taxes can be triggered when a foreign parent company makes a capital contribution to its Indian subsidiary in exchange for shares.

The Bombay High Court said no in October in a case involving Vodafone.

India has been

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We would also expect to see changes in rate design with an emphasis on getting better price signals to customers to encourage load shifting to times of surplus generation, which might be in the middle of the day. This would be a reversal of historic conservation efforts designed to reduce consumption during historic peak periods such as noon to 6 p.m. in the summer months.

An unknown factor in addressing overgeneration is whether excess generation in California can be exported to other areas. The CAISO says that there have never been fewer than 2,000 megawatts of net imports into California, and therefore, it has assumed zero net exports from California in its modeling. With greater regional coordination, grid operators may be better able to dispatch resources across larger geographic areas, which should reduce the likelihood of overgeneration and curtailment. A first step in this direction was the creation of the energy imbalance market between the CAISO and PacifiCorp that began operating on October 1, 2014; this new market is expected to expand to include Nevada Power in 2015. The CAISO has indicated that it is open to greater regional cooperation, but will move slowly and only in collaboration with other balancing authorities in the West.

The CAISO recently put the overgeneration issue front and center, making it a major theme of its annual stakeholder symposium in October. It hopes that by raising these concerns now, California can avoid the reliability, environmental and economic impacts that would result from pursuing an expanded renewable energy policy without also addressing the concomitant integration issues that threaten to undermine the policy.

Given this attention and the various tools available to regulators and grid operators to address the underlying causes of overgeneration, it is not a given that the CAISO's forecasted curtailment levels will actually occur during the 10-year time horizon that was modeled.

In fact, preliminary results from the California 2030 low-carbon grid study being performed by the National Renewable Energy Laboratory and sponsored by a group of clean energy companies, foundations and trade associations suggest that, with substantial increases in energy efficiency, demand response and storage and greater cooperation across the West, California's electrical system in 2030 would be able to accommodate a diverse portfolio of incremental renewable generation equivalent to a 50% RPS with minimal renewable curtailment to address overgeneration. ◎

Corporate Inversions: Slowed But Not Stopped

by Keith Martin, in Washington

The US Treasury outlined six measures in late September that the Internal Revenue Service plans to implement in future regulations to discourage US companies from inverting.

The measures will apply to companies that invert on or after September 22, 2014. They are described in IRS Notice 2014-52.

The Treasury is still considering whether to take additional steps to discourage "earnings stripping." However, any such action could affect European and Asian companies with US subsidiaries since such companies tend to capitalize their US operations with part debt and part equity. The debt allows US earnings to be brought home in the form of interest, allowing it to be deducted in the United States. Any action to limit earnings stripping could increase the tax burden on inbound US investment.

Inversion

In a corporate inversion, a US company with substantial foreign operations inverts its ownership structure to put a foreign parent company on top with the aim of keeping future earnings from its overseas businesses outside the US tax net. The foreign parent may also strip earnings from the US subsidiary by capitalizing the US subsidiary with debt so that earnings can be pulled out of the United States as deductible interest on the debt.

Congress amended the US tax code in 2004 to make it painful for US companies to invert. Most inversions today involve a merger of a US corporation with a smaller foreign corporation. The shareholders of the US company retain less than 80% of the shares of the combined enterprise. If they retain 80% or more, then the IRS will treat the foreign parent as a US corporation, subjecting it to tax in the United States on its worldwide earnings. If they retain at least 60%, then a toll charge is collected on any appreciation in asset value when the company leaves the US chadbourne

tax net. A merger done properly allows the merged company to incorporate in a third country with lower taxes.

US multinational corporations have $1.95 trillion parked in offshore holding companies. The earnings cannot come back to the United States without being taxed. A key driver in many inversions is greater flexibility where to invest offshore earnings without subjecting them to US tax.

New Obstacles

The aim of the new Treasury measures is to make deals in the 60% to 80% range less economically appealing. The Treasury took three steps to prevent companies from circumventing existing US anti-inversion rules and three steps to prevent the new foreign parent from tapping into earnings in offshore subsidiaries without triggering US taxes on them.

It tightened existing anti-inversion measures as follows. First, it made it harder for inverting companies to use "cash boxes" by stuffing passive assets, like cash and marketable securities that are not used for daily business functions, into the foreign parent to ensure US shareholders do not own 80% or more of the foreign company. The Treasury said it will ignore shares in the foreign parent that are attributable to such passive assets when testing for whether shareholders of the inverted US company continue to own 80% or more of the redomiciled combined enterprise. However, this would only apply for a foreign corporation with at least 50% passive assets.

Second, the Treasury said it would also ignore "skinny-down dividends" — extraordinary dividends paid by the US company in the 36 months before the inversion to try to reduce the US company's size so that its shareholders will not end up owning 80% or more of the merged enterprise.

Third, the Treasury took aim at "spinversions," where a large diverse US company drops part of its assets into a newly-formed foreign subsidiary and then spins off the subsidiary to its public shareholders. The Treasury said it will continue to treat the spun-off foreign corporation as if it were a US company.

Three new steps are being taken to prevent the new foreign parent from getting access to earnings trapped in offshore subsidiaries without paying US taxes on them.

The United States taxes US corporations on their worldwide earnings. It taxes foreign corporations only on income from US sources. Therefore, many US multinationals are careful to own their investments and business operations outside the United States through offshore holding companies. The earnings are pooled in the offshore holding companies / *continued page 20*

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asserting the right to tax multinational corporations that make capital contributions in exchange for shares in Indian subsidiaries to the extent the shares are worth more when issued than the contributed capital.

The tax authorities claimed that share issuances by Vodafone India Services to its offshore parent in August 2008 led to income in the next two years.

Vodafone subscribed to 289,244 shares in Vodafone India for 8,000 rupees a share that the Indian authorities said were worth 50,000 rupees a share. Indian authorities hit the telecom company with a 13 billion rupee transfer pricing adjustment. They said the difference in value must have been paid by the parent company, but then loaned back to the parent so that Vodafone India should be reporting continuing interest on the loan. They imputed a 13.5% interest rate. The tax authorities said this added about $490 million to the subsidiary's income for the two years.

The court said the share subscription was fundamentally a capital contribution that does not give rise to income.

Shell is challenging a transfer pricing adjustment of 152.2 billion rupees ($2.86 billion) with which it was hit after an equity subscription by Shell Gas BV in Holland in shares of Shell India.

CHILE increased taxes on foreign investors under new tax reforms signed into law in late September.

Chile taxes companies currently at a 20% rate, and there is a further 35% tax on dividends at the shareholder level. However, the shareholder receives a credit for the corporate-level tax paid, so the net additional tax is 15%.

Under the original version of tax reform proposed by the government, foreign shareholders would have had to pay tax on their shares of income at the corporate level without waiting for the income to be distributed. The business community objected. A compromise was worked out in the Chilean / *continued page 21*

Corporate Inversions

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for reinvestment outside the United States. As long as the foreign earnings are from active businesses, they are not subject to US taxes until they are repatriated to the United States. However, if they are passive income like interest or dividends, then the US will look through the offshore holding companies and tax the US parent on the earnings without waiting for the earnings to return to the United States.

US multinationals look for ways to have the use of the earnings in the United States without formally repatriating them. Section 956 of the US tax code makes this difficult. That section treats any investment of the earnings in the United States as effective repatriation. Lending the money to the US parent or using it as collateral to allow the US parent to borrow from a third party is caught by section 956.

Some inverted companies get around the section by having the offshore holding companies make loans to the new foreign parent, bypassing the now intermediate US parent. These "hop-scotch loans" are not considered investments in US property. The Treasury said new regulations will treat buying debt or stock of a foreign related person as an investment in US property, thus tripping section 956, when the debt or stock is acquired by an expatriated offshore holding company.

Section 956 only applies to offshore holding companies that are owned 50% or more by US shareholders — so-called "controlled foreign corporations." In some inversions, the new foreign parent buys enough stock of an offshore holding company to reduce the US shareholders to under 50%. These "out-from-under transactions" then give the foreign parent access to the deferred earnings of the offshore holding company without ever paying US taxes on them. The Treasury said new regulations will prevent the new foreign parent from pulling the inverted offshore holding companies under it for 10 years after the inversion. Such companies will continue to be treated as controlled foreign corporations during this period.

Finally, the Treasury said some inverted companies are draining earnings from offshore holding companies by having the new foreign parent sell stock of the US parent — now its US subsidiary — to the offshore holding company. This has the effect of moving deferred earnings in the offshore holding company to the foreign parent. The stock sales proceeds will be treated as a dividend to the US subsidiary.

Earnings Stripping

The Treasury continues to look for ways to attack earnings stripping to drain earnings from US companies after inversions.

It said any such actions will apply prospectively after they are announced, unless the Treasury can figure out a way to limit the new rules solely to inverted groups, in which case they will apply to companies that inverted on or after September 22, 2014.

Brenda Zent, a tax specialist who works under the international tax counsel at Treasury, told a DC Bar tax section luncheon at the end of October that among the steps the Treasury is weighing are reducing the available interest deductions or reclassifying some debt as equity. "It's possible that earnings stripping rules could be limited to inverted companies. And it's also possible that [they] wouldn't be limited," Zent said at another conference the same day. "Inverted groups will definitely be targeted; the question is will other groups." Douglas Poms, a senior counsel in the same office, said in early November that one or more additional notices are possible. One may address additional inversion issues, and the other would address earnings stripping. However, he said the timing of any additional guidance is uncertain.

Possible US action to limit "earnings stripping" could hit foreign investors.

Meanwhile, the likelihood of action by Congress to stop inversions has receded at least in the near term. Republicans will control both houses in the new Congress. Republican leaders believe the way to fight inversions is to reduce the corporate income tax rate and believe that narrowly-targeted measures will ultimately prove ineffective.

Market Reaction

Early evidence is that the Treasury actions in September may deter some companies from inverting, but will not halt all inversions.

Four deals appear to have unraveled as a consequence of the Treasury action. A merger of Irish food company Ffyfes Plc with larger US rival Chiquita Brands International was called off. US drugmaker AbbVie abandoned plans for a $55 billion inversion with Irish competitor Shire Plc. AbbVie said the new rules "reinterpreted longstanding tax principles in a uniquely selective manner designed specifically to destroy the financial benefits of these types of transactions." AbbVie said it would pay Shire a breakup fee of $1.64 billion. Auxilium Pharmaceuticals Inc. cancelled an inversion with QLT Inc., a Canadian biotechnology company. Salix Pharmaceuticals Ltd. dropped plans to merge with Cosmo Pharmaceuticals SpA in Italy.

At least five deals that were in play before September 22 are still moving forward, including a plan by Burger King Worldwide Inc. to merge with Tim Hortons Inc. and move to Canada.

At least three new inversions were announced after the Treasury action.

Wright Medical Group Inc. said in late October that it will merge with Tornier N.V. in The Netherlands. Both companies make orthopedic implants. The new company will have its tax domicile in Holland but keep its US headquarters in Memphis. Wright shareholders will own 52% of the combined company. Steris Corp offered to buy Synergy Health Plc in the United Kingdom. Civeo Corp., an oilfield housing supplier in Houston, said it will move to Canada for tax purposes.

The CEO of US pharmaceutical company Pfizer said in late October that the company has not ruled out inverting, but he acknowledged concern about the possibility of additional Treasury actions.

There is speculation that eBay and PayPal could become merger and inversion targets. eBay is spinning off PayPal. eBay had $14 billion in offshore earnings at the end of 2013. Both companies draw an increasing share of their earnings from outside the United States.

Forty-one companies reported lobbying on inversions and related issues in the latest lobbying filings for the quarter ending on September 30, up from 16 in the previous quarter. Many could be affected by any future limits on earnings stripping. ◎

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Congress under which shareholders have the option of paying taxes on their shares of corporate earnings as the income accrues, rather than waiting for it to be distributed. However, anyone who waits until actual distribution to pay tax will pay more. The tax at the corporate level will rise to 27% by 2018 and shareholders would be allowed a credit for only 65% of the corporate-level tax. This would bring the total tax to 44.5%, with 17.5% of it paid by the shareholder after crediting the corporate-level tax.

On the other hand, if the shareholder pays tax on an accrual basis, then the combined rate would remain at 35%. The corporate-level tax would rise to 25% in 2018, and the shareholder would pay an additional 10% rather than 15%.

Shareholders in countries with tax treaties with Chile would not be subject to the 65% cap on the corporate-level taxes that could be credited. Chile has 26 tax treaties, including with Canada, Portugal, Spain, Switzerland and the United Kingdom.

The lower house of the Chilean Congress ratified a tax treaty with the United States in late September. The upper house must still act. Ratification of the treaty by the US Senate has been blocked by Senator Rand Paul (R-Kentucky), who objects to provisions in it and four other treaties permitting the sharing of information between tax authorities in the US and the other countries.

The treaty has been awaiting ratification since 2010. It would limit withholding taxes on dividends paid cross border to 5% where the shareholder receiving the dividends owns at least 10% of the stock of the company paying the dividends. Otherwise, the limit would be 15%. Withholding taxes on interest would be capped at 4% if the interest is received by a bank or the interest is on a purchase money note in connection with an installment sale of equipment or machinery.

VALUE-OF-SOLAR tariffs */ continued page 23*

Yield Cos: Where to Next?

Several veterans of the independent power market talked about the pros and cons of yield cos — when it makes sense for a company to form one, how they affect the cost of capital, whether they are good investments for shareholders and what the future holds for them — at a meeting organized by Bloomberg and Chadbourne in New York in late October. The following is an edited transcript. The panelists are Christopher Radtke, a director in the investment banking division at Credit Suisse, Jerry Peters, managing partner of Energy Power Partners, Gerhard Hinse, a managing director of SunPower Corporation, and Ted Brandt, CEO of Marathon Capital. The moderator is Eli Katz with Chadbourne in New York.

MR. KATZ: Chris Radtke, let's set the table by describing the basic structure of a yield co and what it is designed to do. Let's pick NRG Yield as an example because it was the first and possibly the simplest to understand.

MR. RADTKE: NRG had a large number of both renewable and fossil assets with contracted cash flows. The average life of the cash flows was more than 15 years, and NRG believed it was not getting full credit for the asset value in its stock price. So it set up a yield co. It dropped operating assets with contracted cash flows into a limited liability company that is a partnership for tax purposes. The partnership is owned by the yield co. The yield co is owned by NRG and the public. Cash earned by the projects moves from project companies to the partnership and from the partnership to the yield co, and almost all of the cash gets distributed by the yield co. This type of vehicle trades on the amount of distributions and the yield on those distributions.

Why Now?

MR. KATZ: Ted Brandt, people have been talking about yield cos for three or four years, but the product began to take off only recently. What made all the stars finally align, and what is making yield cos so attractive now that almost everyone is talking about them?

MR. BRANDT: There are two factors. The first has been the continuing policy of the United States to run a near-zero interest rate leaving few places that anybody can invest for yield. There is little yield in corporate or municipal bonds. The second factor is the section 1603 cash grant program. That program meant that there are a lot of contracted cash flows that are not tied up in tax equity deals. The cash is free to move into a yield co. Those have been the driving factors behind virtually each one of the six yield cos that has come to market.

MR. KATZ: If low interest rates and the cash grant program were the impetus, what does that say about the prospects for more yield cos in the future?

MR. PETERS: History has shown that whenever debt rates increase, the return on equity must also increase. Yield cos are equity investments. As interest rates rise, there will have to be a corresponding increase in returns that yield cos must pay to attract capital, and when we get to the point where they will be competing with other sources of capital, such as my private equity capital, I think you will see a decline in this product generally.

MR. KATZ: What about Ted Brandt's point that yield cos really only work with renewable energy projects that were paid Treasury cash grants? That program has now expired. What does that say for future deal flow to support yield cos?

MR. HINSE: I think what is driving yield cos is low interest rates. It is not a novel concept to separate operating assets from a development pipeline and spin off the operating asset company. What is different about this wave is that the current yield cos are able to self-shelter income from taxes by using the tax benefits associated with the renewable energy assets. This makes them essentially into entities whose earnings are subject to only one level of taxes. Viewed this way, the opportunity should remain for solar assets that qualify for 30% investment tax credits through 2016. Even wind projects will still have depreciation deductions, and wind projects that were under construction by December 2013 also qualify for tax credits.

The real issue is the inefficiency of trying to monetize tax benefits and at the same time put the assets under a yield co to raise cheap equity. That is a problem the market is still trying to solve.

MR. KATZ: To Ted Brandt's point, the story for the yield co investor is much simpler if he just sees cash coming up from the projects. If a tax equity investor is introduced into the mix, then it is a more complex story. Maybe the yields go up. Is that the point?

MR. HINSE: Yes. And remember that the recapture period on many of these assets is five years after the project is placed in service. For a project that has a 20- or 30-year life, that is only a small part of the asset's life. Investors can still invest solely on the basis of cash flows more than five years out. That might be enough.

Discount Rates

MR. BRANDT: One way to look at yield cos is as a way to pull some cash out of projects while still retaining control over the projects. They are an alternative to selling the projects.

Assume you have a project that throws off $100 million of free cash. If you sell the project into a market where buyers use an 8% discount rate to bid, then you should be able to get $1.25 billion. At a 7 % discount rate, the number goes to $1.42 billion. At 5%, it is $2 billion. At 3%, to use the current yield at which NRG Yield is trading, it is $3.3 billion.

So make no mistake about it, a lot of what is driving the yield co boom is this simple math. Of course, the 3% yield assumes some rate of growth, and the math behind growth and yield accretion is much more complex.

MR. KATZ: Let me pull on that thread a bit. Yield co investors are now getting somewhere in the 3% to 5% range in current yield. That is too low for an equity return, so anyone buying is counting on some amount of growth. How much growth does one need to justify investing at a 3% to 5% dividend yield?

MR. RADTKE: The investor is looking for a total return. The yield is only one component of that return. Another component is going to be growth of the distributions, which will then carry on into growth in the stock price.

We have seen this over the 18-plus months since NRG Yield has been public. There has been a substantial growth in the stock price. The shareholders have been expanding from niche investors into more mainstream portfolio managers who are starting to see the potential in these stocks. In terms of the total return needed, most yield cos went public hoping for growth in the 10% to 15% range. Add the dividend yield to that and you get a total expected return in the mid-teens.

Both NextEra and NRG have pushed those boundaries and said, "We think we can do even better." NextEra announced recently that it expects to grow its distributions substantially. If you graph the distribution yield against the growth expectations, there is a high correlation, both in MLPs and yield cos, in that the higher growth expected, the lower the current yield.

Good for Investors?

MR. PETERS: As an investor, I would worry about both yield and growth.

I would worry about yield because we do not know what the tax situation will be in the near to mid-term. Production tax credits for wind, geothermal and biomass projects have already expired, and the investment tax / continued page 24

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in two US states may be addressed by the IRS.

A homeowner in Austin, Texas sent the agency a letter in late September to ask whether he can claim a federal tax credit on a solar system he installs on his roof if he sells the entire electricity output to the local utility in exchange for credits that he can use against his utility bill.

Homeowners in the United States can claim a federal tax credit for 30% of the system cost for rooftop solar systems installed through December 2016. The electricity must be put to personal use. That is not true in this case at least in form. The homeowner also asked the IRS whether the credits he receives for the electricity must be reported as income from the sale of electricity.

Forty-three and the District of Columbia states allow homeowners with rooftop solar systems to sell the excess electricity produced above what the homeowners use themselves back to the local utility through "net metering" where the utility meter runs backwards. Some utilities complain that they end up paying for such electricity at the retail rate rather than the wholesale rate they would have to pay to buy the same electricity in the broader market.

Austin, Texas and Minnesota are moving away from retail rates for net metering to a price that attempts to value the solar electricity by taking into account the costs of operating the grid as well as societal benefits like reduced carbon emissions. Under both programs, a homeowner sells all his electricity to the grid at the value-of-solar tariff and buys back what he needs at the retail rate. In Austin, the homeowner receives nontransferable credits to use against his utility bill. Austin has already implemented the program. Minnesota approved the practice in 2012, but it is not yet in use. The value of solar rate in Austin is currently 10.7¢ a KWh and is recalculated annually according to a formula. Current retail rates are 1.8¢ to 11.4¢ depending on the pricing tier.

The Austin homeowner who sent the IRS the letter asked the IRS to issue / continued page 25

Yield Cos

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credit for solar is scheduled to drop from 30% to 10% after 2016. It is also possible that we will see changes in the tax depreciation schedules. Without these tax benefits, a yield co will have to pay dividends in after-tax dollars. And if your after-tax dollars are reduced because the yield co is now paying taxes, it will not be able to maintain the current yield. That will push yields down.

Growth is also a concern because you have the old NextEra or NRG still developing projects. Each one of these yield cos seems to have a different arrangement with respect to competition from the parent company that contributed the assets. Some do not have any limits on competition; at best, the yield co has a right of first offer on the assets of the development company. A right of first offer is really nothing more than setting the target price that you try to beat. I would be very concerned about the assumption that there will be an unlimited pipeline of projects available to the yield co from the parent company that contributed the original assets if other cheaper sources of capital begin to compete for the same assets.

MR. KATZ: Does anyone know if each of the existing yield cos has a right of first offer on all of the assets of its parent company?

MR. RADTKE: They do not. The right applies only to specific assets, but there is an expectation that the parent company will sell its assets into the yield co. The broader point is that the company takes operating assets, which have a larger buyer base than projects that are merely under development, and matches the assets with capital providers. The existing yield cos have produced benefits both for the yield co investors and for the parent company investors.

MR. KATZ: Gerhard Hinse, it is no secret that SunPower is thinking about a yield co. What are some of the factors that weigh in favor or against creating such a vehicle?

MR. HINSE: We announced that we are exploring one. We are still working through the issues. We have the same concerns as anyone thinking of investing in a yield co. We want to make sure that the long-term strategy fits with what we are trying to accomplish. We are not particularly worried about the asset growth in the vehicle. The solar market is going through a period of rapid growth that will outpace the 10% to 12% growth needed for a yield co. One concern is what happens when interest rates change significantly. Will yield cos still be the cheapest source of capital? The yield vehicle will have a right of first offer, but if there are cheaper forms of capital, it may not be the highest bidder for the assets. What is the long-term yield necessary to support these vehicles?

MR. BRANDT: Let's go back to the math I used in my example. I can take my $100 million in cash flow and, at current yields of 4% to 5%, I will have a market capitalization of $2 billion. Let's say that is $20 a share for 100 million shares, and I have committed to annual distributions of $1 a share.

How do I grow this pool of assets? The existing assets are running down, and they basically have a series of flat cash flows with escalating costs. Thus, my cash flows are probably declining over time.

The yield co needs to buy new assets. The only place for it to get the cash to do so is to issue new shares to the public. The formidable challenge is how to issue those new shares to purchase assets in a competitive market and still show the required growth rate to the existing shareholders. That is why I think most of the growth and value accretion will come from drop downs from the developer pipeline. The open question is whether the developer is willing to support the yield co stock price, given that it owns a large share of the stock, by dropping assets in and retaining control, or will it sell to other buyers with cheaper capital? That is the open question.

Contrary to perception, yield cos are not always the high bidders for assets.

High Bidders?

MR. KATZ: Yield cos have become the high bidder in asset auctions. Do you agree?

MR. BRANDT: We don't think so. They have won a couple large auctions, but we think there are other buyers that out compete the yield cos.

MR. KATZ: Who would that be?

MR. RADTKE: At the end of the day,

the best bidder is a corporate with a long-term strategy and tax appetite because it will pay a premium to market, and it will not have to pay high yields to attract a tax equity investor. We have seen some utilities play this role very successfully. But the yield cos can be fiercely competitive as well because they can achieve tax deferral for a substantial period of time and pay tax-free distributions to shareholders. In terms of growth, the potential is there for yield cos to expand beyond renewables. There is no limit to the types of assets with contracted long-term cash flows that can eventually fit in this asset box.

MR. KATZ: So looking at yield cos as an acquisition vehicle, what is your best estimate of their cost of capital for renewable energy assets?

MR. BRANDT: That is the most important question we have discussed today. The funny thing is that every solar developer thinks it is the dividend yield. It is not. It is the price on a leveraged piece of equity that will allow the yield co to give a raise to its current shareholders and sell enough shares to raise the needed capital. I think it might be in the 10% to 13% after-tax range.

MR. PETERS: I was talking to a friend in the space, and he concurs with that range. When I heard those numbers, they were music to my ears because we private equity funds can probably compete with that cost of capital.

MR. RADTKE: NRG Yield disclosed a useful data point from its recent acquisition of the Alta wind farms from Terra-Gen, and that was an 8% leveraged cost of equity in the first year. It took into account the existing financing that was already in place. That probably made NRG Yield the high bidder.

MR. HINSE: That was an interesting deal because the lease equity was already in place, so NRG Yield was just buying cash flows. That may not be a representative transaction.

MR. RADTKE: Correct. It is hard to give a one-size-fits-all answer because each opportunity will have a different underlying capital structure.

MR. KATZ: Maybe then the answer is that yield cos win when the deal already has financing and tax equity, and the corporates with tax appetite have the inside track on greenfield deals, at least until the yield cos put the pieces of that puzzle together. Turning to asset mix, a recent Bloomberg chart showed that yield cos predominantly hold renewables, although NRG Yield has plenty of thermal assets as well. Bloomberg predicts that small-scale PV is where the growth will be. Gerhard Hinse, do you agree?

MR. HINSE: Yes.

MR. RADTKE: Distributed solar in */ continued page 26*

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an "information letter" addressing the tax consequences of value-of-solar tariffs.

It is not clear an information letter would give the homeowner what he wants. An information letter is a statement issued by the IRS national office or a district office that "calls attention to a well-established interpretation or principle of tax law . . . without applying it to a specific set of facts."

Rooftop solar companies are no fans of the value-of-solar movement. Some utilities are also wary of it.

Advocates of such programs say there is no difference in substance between the programs and more traditional net metering. The form as a sale and repurchase is just an accounting device to calculate the net amount the utility should credit the homeowner for the electricity that actually reaches the grid.

However, the IRS may have already tied its hands on the issue. It said in a set of questions and answers about residential solar credits last year that any homeowner selling more than a minimal amount of electricity to the local utility through net metering must reduce his residential solar tax credit on the system by the fraction of total output that will end up being sold to the utility. It suggested the homeowner should be able to claim a 30% investment tax credit instead on the fraction of the solar system that does not qualify for the residential credit since that part of the system would be considered put to business use. The IRS position is in Notice 2013-70 at Q&A27.

> *Once the decision is made that electricity is being sold, then the conclusion that the credits are income to the homeowner would seem to follow, since they are consideration for the sale. Value-of-solar advocates might do better to change the form.*

SOLAR POLE MOUNTS qualify for tax credits as part of a solar system, the IRS said.

The IRS made the statement in a private letter ruling that it made public in late October. The ruling is Private Letter Ruling 201444025.

The ruling was issued */ continued page 27*

Yield Cos

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the commercial and industrial space is still a big problem. There is no great financing solution for this sector yet.

MR. HINSE: The distributed solar markets are becoming far more efficient. SolarCity proved with its securitizations that there is a stable revenue stream from these assets. That is really the big news of the last three to five years. Historically, when people began aggregating solar rooftop systems, the question was whether you could achieve pools of assets with an investment grade. That question has now been answered. We have very long contracted cash flows with investment-grade quality. There should be significant growth in this sector.

MR. KATZ: Where do you think the yield cos will get the distributed solar systems? Will they rely on the parent company or buy them from other developers?

MR. HINSE: The third party ownership model for rooftop solar is only about seven years old in the US. The sector is still evolving. It will eventually standardize its financial arrangements, and yield cos will probably be a key part of the financing chain.

MR. KATZ: Bloomberg put up a slide earlier that shows where yield cos are focused geographically. So far they have been heavily weighted in the US and certainly in the Americas. To grow these vehicles, do you think they will have to venture outside these areas? How do you think they will fare in other parts of the world?

MR. BRANDT: I think they will grow wherever the assets are located. The Pattern yield co has been investing in Chile and Canada.

MR. HINSE: It will be interesting to see where this goes. We are seeing a lot of activity today in Latin America and Mexico, but we are not sure how much appetite there will be from yield co investors for non-dollar-denominated deals. That being said, if there is good credit behind foreign deals, then there could be significant growth in those regions.

MR. RADTKE: I agree. Any OECD-type country should fit within the box. We have already seen the six existing yield cos own assets in the United States, Canada, Spain and other countries. When TerraForm went public, it disclosed that it is thinking about forming a separate yield co to acquire assets in non-OECD countries. As long as there are contracted cash flows with low risk and the sovereign risk is kept within certain bounds, the assets should fit in these types of vehicles, and so why not expand internationally?

How Many More?

MR. KATZ: We have six yield cos so far. Chris Radtke, I imagine one of your mandates is to bring more to market. How many more do you think we will see in the near term, and can you give us a sense of what the profile is for a good yield co candidate?

MR. RADTKE: I think we will see at most another 10 yield cos in the next couple years. The types of companies who might do it are companies like SunPower, equipment manufacturers who have usually sold their projects. They could benefit by forming a public-sector vehicle as an outlet for their projects. Another good candidate is utilities that have grown a substantial amount of renewable assets. Lastly, you have independent developers who are looking at aggregating projects and then taking them public. I think you will see new yield cos by all three of these types of actors.

MR. BRANDT: There are several private equity groups in the market that are very aggressively trying to get the critical mass to have enough distributable cash flow to float sometime in 2015 or 2016. This is where some of the most aggressive capital is in the market right now.

MR. KATZ: So those guys will have no pipeline when they go public? They are effectively just a closed-end acquisition vehicle?

MR. BRANDT: That's right. I think everybody knows there are two kinds of vehicles: the drop-down vehicles which is everyone except Pattern and then something like a closed-end fund. We may well see growth in the closed-end funds.

MR. BRANDT: Is it a rule of thumb that you need at least $300 million in assets to go public?

MR. RADTKE: The rule of thumb was always based on amounts of distributed cash flows. Once upon a time, it was in the $100-million range. Then it dropped to the $50-million range, and I think that we are now inside that in the current market. ◎

US Solar Market Outlook

A panel of solar industry CEOs and one utility executive shared insights about the US solar market at the Solar Power International 2014 convention in Las Vegas in late October. The following is an edited transcript. The panelists are Lyndon Rive, CEO of SolarCity, Ryan Creamer, CEO of sPower, Michael Silvestrini, CEO of Greenskies Renewable Energy, Paul Nahi, CEO of Enphase Energy, and Stacey Kusters, vice president for renewable energy *and origination at Nevada utility NV Energy. The moderator is Keith Martin with Chadbourne in Washington.*

MR. MARTIN: The International Energy Agency in Paris predicted last month that solar will be the dominant energy source by 2050. It is currently 0.85% of generating capacity worldwide and 0.3% in the United States. Lyndon Rive, from where you sit, does the IEA forecast seem realistic?

MR. RIVE: It will be a big lift to meet that number. However, we have no choice. Renewable energy must be the dominant source of energy by 2050 to address global warming. Solar energy is the one application that can be applied almost everywhere. The industry has a very high growth rate currently. It will be harder to maintain that growth rate as solar becomes a larger share of generating capacity, but I think we can get there.

MR. MARTIN: Lyndon is optimistic by nature. Mike Silvestrini, does the IEA forecast seem feasible?

MR. SILVESTRINI: Yes. I do not know the date when solar will pass natural gas as a primary energy source, but it has to happen. The figure 0.3% for the United States is discouraging considering how much momentum there is today, but once we get past that 1% Mendoza line, things will move faster. I think it is achievable.

MR. MARTIN: Stacey Kusters, how far in advance does NV Energy do resource planning for generating capacity?

MS. KUSTERS: We look out 30 years, but, not surprisingly, our most intense focus is on the next five to 10 years. We are looking during the next five years at replacing 812 megawatts of coal with 550 megawatts of base-load resources and 300 megawatts of renewable energy. We have a request currently in front of the public utility commission for 215 megawatts of solar, 200 of which is the Tava project that RES Americas is developing and another 15 megawatts is a project that SunPower plans at Nellis Air Force base. We are planning to purchase two existing gas-fired power plants. We are replacing coal in a manner that gives us sustainable fuel diversity.

MR. MARTIN: What percentage of your generating capacity currently is solar?

MS. KUSTERS: Approximately 10%.

MR. MARTIN: Where will you be in 10 years?

MS. KUSTERS: We hope to be significantly farther along. We also have to consider the rate implications and look for fuel diversity.

MR. MARTIN: I think you said backstage that the 10% today will grow to about 15% when the near-term projects you mentioned are in service. / continued page 28

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to a company that designs and sells solar panels that are mounted on poles, but it retains some to own and operate itself. The poles are of varying heights. The electricity produced powers equipment like lights and speed cameras. There is a base that holds the pole firmly in place. There may also be special doors at the base that lock for security reasons. The poles are sized for the solar panels, and are not suitable for use other than supporting the panels.

A 30% investment tax credit can be claimed on "equipment which uses solar energy to generate electricity." The IRS said the panels, battery, control equipment, conversion equipment and wiring all qualify and the pole does as well because it is "essential to the functioning of this equipment."

However, the IRS said, the company must allocate part of the cost to any lights, surveillance equipment, motion detectors, two-way transmission systems and other attachments that protect such equipment from foul weather. These items are not used to generate electricity and do not qualify for a tax credit.

Separately, IRS officials in Washington are concerned that some taxpayers installing solar systems are replacing the roof at the same time and may be improperly claiming a federal tax credit on the cost of the roof replacement. This is of particular concern where the solar panels or tiles double as the roof. The IRS says the taxpayer must back out of tax basis for the credit what it would cost solely to replace the roof without also installing solar panels.

ROOFTOP SOLAR draws more utilities.

The Arizona Corporation Commission is expected to decide by year end whether to allow Arizona Public Service, the state's largest utility, to lease space on approximately 3,000 customer roofs to install 20 megawatts of solar systems that the utility would own and put in rate base.

The utility would give the customers credits of $30 a month to use against their utility bills. Each lease would run 20 / continued page 29

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Biggest Opportunities?

MR. MARTIN: Whitewater kayakers are experts at reading rivers. They can tell where the breaks are in the rapids ahead. Successful CEOs must be experts at reading markets. Ryan Creamer, where do you see the opportunities in the next two to five years?

MR. CREAMER: The opportunities are really broad. As I told Keith backstage, he inspired me at a conference in San Diego three years ago when he said there are opportunities in solar. I jumped into the industry in 2012 after having worked in the nuclear and coal services businesses. It has been an amazing ride in just two years. We have good relationships with utilities. The amount of capital pouring into the sector will help to propel us forward.

MR. MARTIN: Paul Nahi, where do you see the opportunities in the next two to five years?

MR. NAHI: The dynamics that are making solar as powerful as it is today are doing nothing but getting better. Retail electricity rates continue to increase, while the cost of solar energy is falling. That dynamic alone will open enormous possibilities in the commercial, residential and utility-scale scale sectors for solar, not just in the United States but also in other countries.

As distributed generation is adopted more widely, we will see the solar companies move beyond pure generation into energy management. New technologies are coming to market that will allow homeowners to store electricity and optimize energy usage by drawing from the solar system, a storage device or the grid at different times of day. The potential cost savings for consumers will make distributed solar even more attractive.

MR. MARTIN: You are already putting your money to work where you see the opportunity. Your company makes micro inverters that are part of each solar panel. You make software that collects data that helps better manage systems. You just announced development of a new plug-and-play battery. Mike Silvestrini, where are the opportunities in the next two to five years?

MR. SILVESTRINI: We see a two-step process to getting the industry to a point where it will really take off. The first step is to reduce costs. When we started installing solar rooftop systems, the installed cost was about $8 a watt. Things like net metering and storage were not part of the strategy at that time. Our entire effort was directed at reducing the costs, weaning ourselves from incentives and building a more sustainable platform for growth. In a lot of ways, we are still in step one. We still have a way to go to reduce costs.

The next step after that will be grid integration, the challenges of storage, and the challenges of working with an existing system that never contemplated widespread adoption of distributed generation.

The conversation is starting to move toward that second phase of storage and complex technical aspects, but we cannot take our eyes off the ball and the need to keep driving down costs. We need to make sure we tick the cost-reduction box within the next couple years.

MR. MARTIN: You see challenges to get where you want to go. Lyndon Rive, you are a visionary. You try all sorts of new things. Where is the biggest opportunity?

MR. RIVE: For the next two years, the industry's focus should be on cost reduction. We need to look at the balance-of-system costs to see where savings are possible. Look upstream; we are making an aggressive decision to go into panel manufacturing to help reduce our costs and achieve higher efficiency.

We will hit a cliff when the industry moves from a 30% investment tax credit to only a 10% tax credit. We must reduce costs in the next two years by more than the reduction in the tax credit for the industry to continue past 2016. We are facing a two-year sprint.

Great strides are being made in storage. We are already deploying storage systems. We are deploying hundreds of them, but we are not yet doing so in the tens of thousands. You will probably see more storage deployed next year and then every year more and more. Storage will be deployed first in states with the highest retail electricity rates, so expect to see it first in Hawaii and then in places like California.

People often mistake the value of storage. It is not a backup. The primary value is for large-scale grid integration. It will make the grid more stable to be able to manage peak loads so that thousands of micro-power generators can supply electricity to the grid and, in the process, help firm up the grid. These benefits of storage are likely to be achieved over the next five to eight years. Within that time period, we will reach a point where each solar system will have a storage device attached to it.

MR. NAHI: I could not agree more with the point about reducing costs. However, the focus should be on cost per kilowatt hour and not cost per kilowatt.

Far too little attention is being paid to long-term O&M. We know how to manage a coal-fired power plant. We know how manage a gas-fired power plant. We do not know how to manage 10,000, 100,000 or 10 million roofs each with its own power plant. There needs to be an O&M protocol: a process by which we can sustainably monitor and upgrade and manage 10 to 20 million individual micro-power plants.

Batteries

MR. MARTIN: Lyndon Rive says bring the costs down, and storage is a big opportunity. Paul Nahi you say that having 10 to 20 million individual rooftop solar installations with storage is a management challenge.

Let's drill down on storage. How will the market change when storage is widely adopted, and what is standing in the way of that widespread adoption? Lyndon Rive, you said you are able to put in only hundreds rather than thousands of batteries today. Is the fact there is not wider adoption today due more to technology issues or economics?

MR. RIVE: Cost is probably the biggest factor preventing deployment of thousands of systems today. The cost is coming down at an aggressive pace. I think you will see a lot more deployed next year, and the number will climb year after year. As Paul Nahi said, the key as we deploy storage on a large scale is to have a control system in place. We are investing heavily already in resources to allow our customers and the distribution system operator to manage when the battery charges and discharges and to allow a lot more services besides electricity — for example, voltage control — to be brought to the grid.

MR. MARTIN: Mike Silvestrini, are you planning to add batteries to your commercial and industrial rooftop systems?

MR. SILVESTRINI: We have a laser focus for now on cost reduction before we start tackling the technical challenges of grid stability.

MR. MARTIN: So storage adds to cost.

MR. SILVESTRINI: Yes. We need for now to reduce the cost, period. Until that mission is accomplished, we cannot move to these other challenges, as great as it is to see others already trying to address them.

MR. RIVE: I would like to add to that. We certainly see traction in commercial, but not necessarily in the residential side. In commercial, you have demand fees. When you have demand fees, depending on the utility, you can install a solar system with a battery today and the incremental cost of the battery is more than offset by the savings on demand fees.

MR. MARTIN: Ryan Creamer, are you adding storage to your commercial and small utility-scale projects?

MR. CREAMER: We spend a lot of time looking into different technologies, but I agree with the main / continued page 30

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years. The credit amount would not be adjusted for inflation.

The Arizona Corporation Commission staff recommended in early November that the commission reject the proposal.

Rooftop solar companies argue that such proposals are an effort to prevent competition for retail electricity supply in utility service territories, and the utlities have an unfair advantage. Utilities already have a leg up in any competition through existing customer relationships and infrastructure. The ability to put systems into rate base would guarantee utilities the ability to recover their costs plus a return through the rates charged all utility customers. Utilities argue that customers would prefer to deal with a company that they know has staying power rather than with newer solar companies that they worry may not be around for the full term of a contract.

Meanwhile, Tucson Electric Power proposed separately that it be allowed to put solar systems on customer roofs and then charge the customers a fixed monthly charge for 25 years for use of the systems.

In South Carolina, Governor Nikki Haley (R) signed a bill over the summer that would let utilities lease solar systems to customers, but they cannot put the systems into rate base. They would have to own the systems through non-regulated affiliates.

Solar companies are watching to see whether a bill the Washington state legislature rejected this year will be reintroduced in 2015. The bill would have given any utility that wants to enter the solar leasing business a monopoly over the leasing of solar systems in its service territory.

In Utah, the Public Service Commission rejected a request by Rocky Mountain Power in late August to charge customers who feed excess electricity from rooftop solar systems into the grid through net metering a backup charge of $4.65 a month. The commission said the utility failed to prove that the charge was "just and reasonable," but said it was open to / continued page 31

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points made by the other panelists. Our focus in the near term has to be on reducing costs. I agree with Paul Nahi that the focus should be on the cost per kilowatt hour rather than per kilowatt. Distributed generation grows in places where it can have the greatest impact on people's utility bills. In some utility service territories, demand and time-of-use premiums are as large a factor as the actual electricity used. We continue to evaluate the different storage technologies — everything from mechanical to chemical — for use in these markets. The smart money is moving into storage. There will eventually be tremendous opportunity to pair storage with electricity generation at a price point that makes it economic.

MR. NAHI: Government policy will play a huge role in this. It can change the economics of storage almost overnight. We have a very large presence in Australia. In Australia today in the residential market, storage pencils because of certain requirements in areas like Queensland.

Shortages are expected in 2016 as solar companies race to finish projects before the tax credit expires.

MR. MARTIN: What is the policy change that would make storage work in the United States?

MR. NAHI: It depends on the region. As an example in Australia, the view is that there is a tremendous amount of solar concentration in some areas so the utilities do not want you to export solar, but, at the same time, they want to encourage you to use solar. The only way to solve those two problems is to add storage to the solar facility such that when you are not using the energy, instead of sending out to the grid, you store it. There are economic incentives to make that happen.

In areas like Hawaii, as Lyndon mentioned, the technical challenges could be resolved through policies such as I just mentioned.

Potential Shortages

MR. MARTIN: Fair enough. Lyndon Rive, you said recently that one reason SolarCity bought its own solar panel manufacturer is that you expect there to be panel shortages by 2016. That would be a stunning turnaround for the solar panel manufacturers from where they were just a couple years ago. The US Department of Energy just said that solar rooftop systems dropped 12% to 19% in cost in 2013 and a further 3% to 12% reduction in cost is expected in 2014. This does not sound like a market that is headed for panel shortages. What is the evidence?

MR. RIVE: I am not sure where the year 2016 came from. I do see a panel shortage in the future, but we will face other shortages before panels become an issue.

MR. MARTIN: Such as?

MR. RIVE: In 2016, the biggest challenges will be operations and capital. You have a cliff around the corner. Everybody is going to start to go solar. Everybody who has been on the fence is going to think, "I better do it now before the ITC expires." So the operational capacity of all the solar companies will be maxed out. The capital capacity — people's working capital and people's financing capabilities — will be maxed out. All of this will be maxed out.

I think shortages of these items, rather than a shortage of solar panels, will be the biggest constraint in 2016. There will eventually be a panels shortage if the industry continues to grow the way it is. I see that closer to late 2017 or 2018. Of course, the significant wild card is what happens in Japan and China and whether they continue to encourage widespread adoption of solar. I see the constraint among tier 1 suppliers of solar panels, not for solar panel supply in the market as a whole, but solar panels that you can finance and persuade someone to take a 30-year risk on the asset.

MR. NAHI: I respectfully disagree. If you look at the capital expenditures that are being made currently by many of the module manufacturers, there may be some intermittent and arguably not even noticeable shortages, but I think there will be plenty of capacity from quality manufacturers in 2017 and 2018.

MR. MARTIN: Ryan Creamer, we have two things on the table — a solar panel shortage perhaps by 2017, and a shortage of operating capacity and capital when people may be rushing to install in 2016 before the 30% investment tax credit expires. Do you agree?

MR. CREAMER: The ITC cliff will create a spike in demand. I think there will be a heavy push. I can see shortages in supply not only of panels and resources in the field, but also of EPC capacity, transformers and inverters. We will all be making a dash to the finish line. We have a couple hundred megawatts in the ground now and would like to have a gigawatt in by the end of 2016.

Another potential shortage will be tax equity, which I view as the longest pole in the tent, as you will have so many projects coming on line by late 2016 and the problem solar faces, unlike other renewables, is that tax equity has to be in the deal before the project is finished or shortly thereafter. It does not work like wind and other renewables that claim production tax credits where the tax equity can come in at any time after the project is already operating.

MR. MARTIN: Mike Silvestrini, are you having trouble finding capital? You are a smaller developer than SolarCity.

MR. SILVESTRINI: Not right now. It feels like there is a lot of capital for this type of product. The technology is considered proven. A lot of hurdles we used to have to overcome in order to close on financing have been removed. It really comes down to the quality of the portfolio. We focus on customers with high-quality credit. I look around the space, though, and not everybody has been able to put together that type of portfolio. The challenges of raising financing increase the more mixed and varied the portfolio.

MR. CREAMER: Can I ask Lyndon a question? SolarCity recently launched a debt product where you are offering low-cost financing to customers who want to buy systems. When you say you think capital will be in short supply, are you talking about tax equity, debt or both?

MR. RIVE: I am referring to all the capital needs of a company. The challenges could vary dramatically from company to company. If you are running a business in which you are expecting 30% growth in 2016, then the challenge may not be so dramatic. But I think most of you should be / *continued page 32*

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revisiting the issue in the future if the utility could produce more data. In the meantime, it approved a 1.9% rate increase on all customers. There are about 2,700 customers in the utility's service territory who use net metering.

NORTH CAROLINA issued guidelines in October for state tax credits for investing in renewable energy equipment.

The state allows a 35% tax credit to be claimed on new solar, wind, geothermal, biomass, hydroelectric and combined heat and power equipment. It is available for equipment placed in service through 2015. The credit is claimed entirely in the year the equipment is put in service if the equipment is put to personal use. It is claimed ratably over five years if the equipment is put to business use.

A homeowner with a rooftop solar system who sells all of its output to the local utility and buys back what it needs is putting the system to business use.

The credit belongs to the person who put the equipment in service. However, if the equipment is leased, then either the lessor or the lessee may claim the credit. It belongs in the first instance to the lessor, but the lessor can pass it through to the lessee by providing the lessee a "written certification that the lessor will not claim the credit." It does not matter whether the lease is a capital lease or an operating lease.

The state has issued several rulings about strategies for transferring tax credits. These rulings are private. However, leases are the preferred structure. The tax credit is claimed by a partnership of a state tax equity investor and developer that then leases the project in form immediately after placing it in service to a separate partnership of a federal tax equity investor and the developer. The "lease" is treated as an installment sale of the project to the lessee for federal income tax purposes. The North Carolina Department of Revenue put in the guidance what it has said in rulings so that it will not have to keep answering the / *continued page 33*

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planning on 100% growth in 2016. It is the time for massive growth. [Audience cheers.]

MS. KUSTERS: Those are your fans.

MR. RIVE: I believe everybody should be staying with 100% growth in 2016. When any company is growing at this rate, there will be constraints on its ability to do that, and one of the big constraints will be working capital. Another is tax equity. Another will be straight-forward debt financing on top of these assets. You have to go out and create all these relationships with new investors, and if you did not build that foundation in 2014 and 2015, then you will be constrained in 2016.

Let's assume you solve the capital constraints. How then do you actually get the stuff installed? What type of investments are you making now to ramp up? Those investments have to be made in 2014 and 2015 to achieve these growth rates in 2016. It may be a little easier for a large utility-scale developer, but there are challenges on the residential side. Growth will not magically happen without laying a foundation in 2014 and 2015.

US import duties on solar panels are undermining cost cutting efforts by solar installers.

Capital Structures

MR. MARTIN: How much capital do you have to raise a year?

MR. RIVE: For next year, we are going to have to raise probably close to $3 billion.

MR. MARTIN: What is the capital structure of your company: what percentage debt, what percentage equity, what percentage tax equity?

MR. RIVE: Tax equity accounts for around 35% to 40% of our total capital. Debt is 30% to 35%. The rest is equity.

MR. MARTIN: Ryan Creamer, what is sPower's capital structure by percentage?

MR. CREAMER: If you are asking about capital structure at the project level, it is probably 55% balance-sheet equity and 45% tax equity.

MR. MARTIN: Mike Silvestrini?

MR. SILVESTRINI: Our capital stack is similar to what Lyndon just described. A year ago, I would have said a third equity, third debt and third tax equity, but it has been shifting in the last year as we see better terms on offer for both debt and tax equity so that each of them now accounts for more a little over a third of our total capital. The effort is obviously to reduce the percentage of true equity, since that is the most expensive type of capital.

MR. MARTIN: Stacey Kusters, what does the capital stack look like for a big utility like NV Energy: how much debt and how much true equity? I assume the utility has its own tax base and does not have to use tax equity.

MS. KUSTERS: There is no tax equity. It is 52% debt and 48% equity.

MR. MARTIN: Paul Nahi, you are not financing at the project level, so I imagine you are heavily equity and maybe some debt.

MR. NAHI: Exactly. We do not do projects. We are a technology company.

US Import Duties

MR. MARTIN: At a breakfast this morning, Tony Clifford, CEO of Standard Solar, commented on the effect US import duties on solar modules from China and Taiwan are having on the market. He said solar panels would cost perhaps 55¢ a watt if it were not for the tariffs. Instead, panels cost currently something like 72¢ a watt. Lyndon Rive, do these numbers sound correct?

MR. RIVE: I do not think the cost has gone up. The biggest effect is that the cost did not go down. The fact that module prices have hit a plateau in the 70¢ range has created a balancing system where everybody asks for the same pricing. It does not create a naturally competitive downward slope. If it were not for the tariffs, I am not sure module prices would be 55¢, as that is pretty low, but the price definitely would be below 70¢.

MR. MARTIN: Ryan Creamer, have US import duties had an effect on your company?

MR. CREAMER: Absolutely. We probably spent an extra $15 to $20 million this year on panels due to the tariffs. It is wasted money. It is not helping anybody. It is affecting the ratepayers.

MR. MARTIN: That is $15 to $20 million more on panels this year out of a total budget for panels of how much?

MR. CREAMER: We estimate that the Chinese trade case will increase panel prices by about 15%. Our total panels budget this year is north of $100 million.

MR. MARTIN: Mike Silvestrini, what effect have US import duties had on you?

MR. SILVESTRINI: It is tragic because we have been working on system improvements like putting string and burrs on racks in our warehouse in order to save time on installation and shave 2/10ths of a penny off the installed cost of solar systems, and then we lose 20¢ a watt on a tariff. It is the opposite cost trajectory that our industry needs, and it is continuing to make it challenging for us to wean ourselves off government incentives.

MR. MARTIN: We have an audience question from John Eber, head of tax equity investments at JPMorgan Capital Corporation.

Investment Tax Credit

MR. EBER: Listening to all the comments about 2016 concerns made me wonder whether our panelists feel the 30% investment tax credit should be extended.

MR. RIVE: The best thing for Congress to do would be to tax pollution. [Audience applause.] The challenge of taxing pollution is that those who are polluting are extremely influential so it would be a huge lift. The alternative, if you are not going to tax those who pollute, is to incentivize those who do not. The idea that we are going to have a reduction in something that is solving the world's biggest problem is mind blowing to me. If we fast forward 20 or 30 years from now, our kids will say, "You had the technology, you had the solution, you had everything you needed to solve our biggest problem and decided to stop. What the hell were you thinking?" So we have to extend it. Extend it until you can tax pollution. [Audience cheers.]

MR. MARTIN: We are two weeks from election day in the United States. It is clear from the audience that Lyndon could be elected. [Laughter.]

Stacey Kusters, how much rooftop solar penetration is there in the NV Energy service territory?

MS. KUSTERS: Approximately 1%. However, we are receiving multiple applications. We have probably received more applications in the last two months than in the last / continued page 34

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same questions.

The tax credit is 35% of the cost of the equipment. If a lessee claims the credit, then the "cost" is eight times the annual rent, unless the lessor claims a federal investment tax credit or Treasury cash grant on the equipment, in which case the credit is calculated by the lessee on the lessor's cost or possibly on the fair market value of the equipment. The state expert on the credit is unsure whether fair market value can be used, but says the state follows the federal basis rules. Under the federal rules, the lessee calculates its credit on the fair market value. In all other cases, "cost" means cost.

The cost must be reduced to the extent the equipment was paid for partly with public funds. However, there is no reduction on account of having received a Treasury cash grant.

The credit cannot be used to offset more than 50% of tax liability in a year. Unused credits can be carried forward up to five years. There is no recapture of the credit if the equipment is sold, destroyed, retired from service or moved out of state. However, any remaining installments of the tax credit could not be claimed. (Vested, but unused, credits can still be carried forward.) Equipment will be presumed to have been taken out of service if it is shut down for repairs and the repairs do not start within 60 days. A "detailed" explanation must be sent to the state tax authorities to avoid the presumption.

Suppose a partnership places a project in service for business use, the first installment of the tax credit is claimed by partners A and B and then B sells his interest in year 2 to C. A and C can continue sharing in the remaining installments of the tax credit unless the sale of B's interest causes the partnership to terminate for federal income tax purposes. The state views the credit as belonging to the partnership. If the partnership terminates, then it no longer exists.

The credit can be claimed on improvements to an existing project, but only if they increase the generating capacity. If the improvements are entirely new equipment, / continued page 35

10 years combined. I agree with Lyndon's comment that our ability to keep the pace on installing rooftop solar between now and the end of 2016 will be a challenge not just for the installers, but also for the utilities who must inspect each system and authorize parallel operation before the system can be used.

MR. MARTIN: Do you see the growth of rooftop solar in your service territory as more threat or opportunity?

MS. KUSTERS: We see rooftop solar as something that our customers want. Our goal is to ensure that there is price transparency about the cost to the customer. We are looking for a distributed generation tariff that takes into account not just the cost of distribution, transmission and generation, but also the value of solar coming back onto the grid. Transparency is good for consumers. They will also be better off if the utility can participate in that space alongside third parties. At the end of the day, we all want what is best for customers: competition in the sector with transparency on costs.

Wisdom

MR. MARTIN: Here is my last question for each of you. Someone once said, "No mistakes, no experience, no experience, no wisdom." Each of you has been in business for a while. What hard-won lessons have you learned along the way? Paul Nahi?

MR. NAHI: I think we underestimated how complex the technology must be in order to support reliable, sustainable distributed generation, not just at the site, but also the requirements to integrate with the grid. The big data management, big data monitoring, the communications technology is a far, far more complex technology problem than we anticipated.

MR. MARTIN: Mike Silvestrini, seven years ago, you were in the Peace Corps in Mali, and here you are just a few years later running a company. What hard-won lesson did you learn along the way?

MR. SILVESTRINI: It was that you really have to keep control over the construction and quality of your installations. You have to be intimate with that process from the design all the way through operations and maintenance. You cannot step back and be a financial participant. We have had to learn to love the construction aspect as much as the financing aspect.

MR. RIVE: We have learned many lessons along the way, but one in particular that stands out is the need to put more effort into engaging with the government on policy. Policy debates may feel like a distraction. The effort cannot be quantified in terms of a return on investment. But you can actually make a difference. So over the years, we have come to realize that you must invest in policy and to do so on a large scale. To all our solar leaders, although the industry is under a tight budget, look at the budget, think what the industry would be like if the policy was wrong, make the investment, go deep, make the investment in policy. If we all work together, we can get solar to 50% by 2050, but we cannot get there if we do not engage with the government. We will have policy work against us, and we will still live in a fossil fuel-based environment, which would be a catastrophe for our children. [Audience applause.]

MS. KUSTERS: Never assume you know what the customers want. Always make sure you remain in front of the customers asking what they want or need so that you can design it, whether it is the right tariffs or the right policy to meet customers' needs.

MR. CREAMER: We learn from every project. We need to continue working to increase the level of trust, increase the transparency and strive as an industry to produce the highest quality product. ◎

Current Issues in Holdco Loans

by James Berger and Evelyn Lim, in Los Angeles

Holdco loans are becoming an increasingly common strategy for financing renewable energy projects in the United States. Holdco loans are sometimes referred to as back-leveraged debt or mezzanine financing. Regardless of the nomenclature, these loans are not directly secured by the underlying project assets. They depend instead on the share of project cash flow that is distributed to the sponsor.

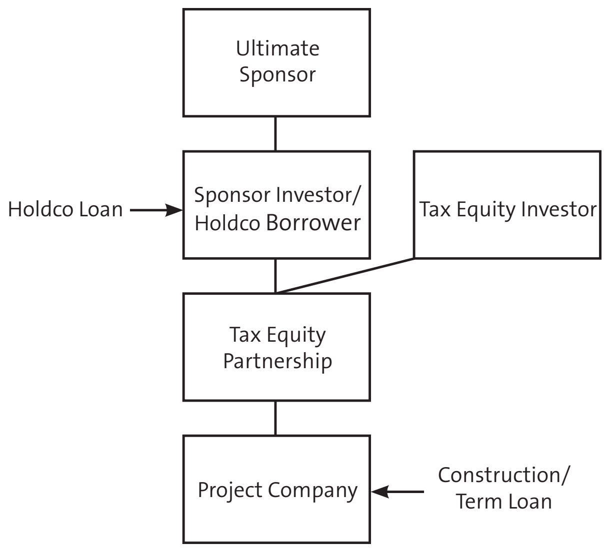
Most US renewable energy projects are financed with some combination of true equity, debt and tax equity. Holdco loans allow project sponsors to reduce the cost of capital by replacing some expensive equity in the project with cheaper debt.

Most holdco loans are entered into after construction of the project is completed.

This article focuses on a basic holdco loan structure and some issues to take into consideration when evaluating a holdco loan. It does not cover the many potential variations in structure, and readers may come across situations where holdco loans are entered into during construction or where holdco loans occupy a different space in the capital structure.

Most projects require construction financing to construct the project, and construction lenders typically rely on tax equity to repay a portion of the construction loan while the remaining construction debt converts into term debt. Because most tax equity investors are not willing to invest in leveraged projects, the portion of the construction loan that would otherwise convert into term debt, because it exceeds the tax equity available to pay down the construction debt to term, is repaid by debt that is structurally subordinate to the tax equity investor.

A simplified financing structure is shown in the figure below:



Loan Repayment

Because the holdco borrower is simply a holding company, it does not earn any revenue and must rely on distributions from its subsidiaries to pay its obligations. These distributions are often subject to claims by structurally-senior financing parties, such as a tax equity investor.

Virtually all funds that eventually are distributed to the holdco borrower originate as revenue from sales of electricity and renewable energy credits at the project company level. Funds remaining after paying operating costs are distributed to the tax equity partnership for distribution to the tax equity investor and the holdco borrower. The funds that flow to the holdco borrower will be the only funds available to repay the holdco loan.

The structural subordination of the holdco loan puts pressure on sizing the debt to take into account project performance and potential project underperformance. In addition, project-level cash flows are subject to cash traps, cash sweeps or other reallocations of distributable cash in favor of the tax equity investor in connection with indemnity claims or */ continued page 36*

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then a credit can be claimed on the full cost. If the improvements replace other equipment on which a credit was already claimed, then only a fraction of the replacement equipment qualifies. The fraction is the increase in capacity divided by the capacity after the replacement. Thus, for example, if the capacity of an existing solar facility is increased from 50 to 55 megawatts by replacing some of the equipment, and a credit was already claimed on the project, then the credit on the improvements is on 5/55ths of the cost.

No credit can be claimed on a battery added to an existing solar system since it does not increase the capacity.

The amount of credit is capped. Only $2.5 million may be claimed "per installation" for equipment put to business use. The cap is $10,500 "per installation" for equipment put to personal use. These are the limits for solar equipment used to generate electricity and wind, biomass and combined heat and power equipment. An "installation" is equipment that "standing alone or in combination with other machinery, equipment, or real property, is able to produce usable energy on its own." Each separate array at a solar facility is treated as a separate installation, even though all the electricity passes through a single step-up transformer, as long as there is a disconnect switch allowing each array to be shut down and the array has its own inverter. The North Carolina Department of Revenue said, "Each individual solar energy system should include at least a PV array and an inverter."

Monitoring equipment can qualify as part of a solar facility, but only up to 5% of the cost of the complete solar system. A battery can be included in the cost of a facility, but only up to 35 KWh of storage capacity per kilowatt of PV capacity (DC rated). If equipment serves two or more functions, such as doubling as the roof or siding, then the "cost" for calculating the tax credit must be reduced by the cost of a comparable product for the non-solar function.

A fuel cell that runs */ continued page 37*

Holdco Loans

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project underperformance. Such mechanisms prevent cash from being distributed to the holdco borrower and constrain the holdco borrower's ability to pay debt service.

Holdco lenders will usually size holdco debt based on a scheduled amortization profile, but will often also have a target amortization profile and will sweep cash distributed to the holdco borrower for debt service in order to remain within the targeted amortization schedule. More aggressive lenders may forego such sweeps, giving the borrower more latitude on debt service, and their pricing will reflect the additional risk being taken by such lenders.

In situations where cash could potentially be trapped, swept or otherwise diverted before it reaches the holdco borrower, holdco lenders try to negotiate provisions that lead to greater cash-flow certainty. These could take the form of a limited distribution to the holdco borrower when needed to service debt, but such distributions are hard to sell to tax equity investors. In tax equity transactions in which the tax equity has the benefit of a sponsor guaranty backing certain obligations of the holdco borrower in its capacity as a partner in the tax equity partnership, holdco lenders will usually require sponsors to perform under such guarantees to prevent cash sweeps: for example, by contributing more equity to the project company to address issues that, if left unremedied, would lead to cash sweeps. In other cases, holdco lenders require that the sponsors provide acceptable credit support, often in the form of guarantees or reserves, that can be called upon if cash is swept before reaching the holdco borrower, introducing an element of limited recourse in what is otherwise a non-recourse transaction.

Change of Control

Change of control is another issue in holdco loan discussions. Holdco lenders typically receive a pledge of the equity in the holdco borrower. The holdco lenders may also receive a pledge of bank accounts, the interest that the holdco borrower holds directly in a tax equity partnership and any other assets. Most lenders focus on the equity pledge. A foreclosure on the collateral could constitute a change of control.

Most tax equity partnerships restrict changes of control in partners in the partnership. Holdco lenders must determine whether these provisions could prevent the holdco lenders from foreclosing on their collateral after a default. Even if the change-of-control provisions do not prevent the closing of the holdco loan, they could effectively prevent the holdco lenders from exercising their remedies under the holdco loan.

Holdco lenders will try to negotiate some flexibility around change-of-control restrictions with tax equity investors. These negotiations are sensitive and whatever agreement is reached is usually reflected in a separate consent between the holdco lender and the tax equity investor as opposed to being contained in the tax equity documents. The primary sticking points in these negotiations center around the ability to transfer the equity interests to third parties in connection with a foreclosure. This is separate from, and should not be confused with, the forbearance agreement that is common in tax equity deals where there is debt at the project company level. The senior lenders in such cases usually agree to forbear from foreclosing on the project or pushing out the tax equity investors for a period of time to allow the tax equity investors to reach a target yield.

It is also important to review the project documents, especially the power purchase agreement, for change-of-control provisions that could be implicated in connection with an exercise of remedies by the holdco lender.

Control Over Subsidiaries

Finally, two closely-related issues with holdco loans are the amount of control that the holdco lenders have over the project and the level of holdco lender consent required for certain actions by holdco borrower's subsidiaries (like the project company).

Construction and term lenders at the project company level have significant consent rights and limits on the unfettered ability of the project company to act. In contrast, holdco lenders have limited consent rights and there are fewer restrictions on the project company and tax equity partnership actions. Sponsors focus on limiting the holdco lenders' ability to block decisions that have been made or agreed to by financing parties who are structurally senior to the holdco lender while the holdco lender will want to protect its investment. Some holdco lenders approach decision making as if they are lending at the project level while others are very hands off and focus only on key matters. The differences in these approaches are, not surprisingly, reflected in pricing.

The Biggest Change to Power Supply Since Edison

by Arnold Leitner, with YouSolar outside San Francisco

Adding batteries to solar rooftop installations will lead to a fundamental change in power markets.

The levelized cost of energy produced by solar rooftop systems with batteries in Germany is expected to fall below the retail price of electricity purchased from the grid by the end of 2015. In the US, such systems are already competitive in Hawaii and should become competitive in other US states by 2020. These systems are also already cheaper than small diesel generators everywhere today.

Basics

This article uses the term "solar-battery systems" to refer to batteries that are located at the customer site and are thought of as being "behind the meter," meaning they generally do not provide power back to the utility through net metering where the utility meter runs backwards as the utility customer feeds any extra electricity it produces back into the grid. However, customers with such systems typically purchase some power from the utility to achieve full reliability.

Such a system could also engage in net metering with the utility, but the trend is away from net metering and, for that reason, the goal is to design solar-battery systems that use as much of the solar energy as possible so that they do not have to engage in net metering to be economical.

In addition to a PV array and a battery, these systems also include an inverter, controls and other power electronics. Their sizes are from one to tens of kilowatts and target residential and small commercial customers.

These solar-battery systems use local solar energy as the primary energy source and supplement energy from a traditional utility connection. The battery of the system fulfills two functions. First, it stores excess solar energy that cannot be used directly by the customer for use at a later time. Second, the battery is able to meet all of the instantaneous power needs of a homeowner or small business. Such a solar-battery system can be controlled by energy management systems that aim to meet certain performance targets and may rely / *continued page 38*

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solely on gas qualifies potentially as a combined heat and power system, but only if it qualifies for a federal investment tax credit as a CHP system. If the fuel cell runs on biomass or biomass and gas, then it may qualify as biomass equipment, but there is a reduction in the credit in that case to the extent there is co-firing with gas.

ECONOMIC SUBSTANCE may be lacking.

The IRS warned in October that it remains free to pick apart transactions with more than one leg to deny tax benefits on any leg that is tax motivated while allowing the rest of the transaction to stand. It said it is not limited to accepting or rejecting the transaction as a whole.

The IRS warning is in Notice 2014-58.

The IRS had already used this approach successfully before the warning. (For example, see the April 2013 *NewsWire* starting on page 31.)

The economic substance doctrine is one of several tools the IRS has available to attack transactions that it considers to be little more than a play for tax benefits. Congress wrote the doctrine into the US tax code in 2010. The doctrine as codified requires a transaction to change the taxpayer's economic position in a meaningful way and for the taxpayer to have a substantial business purpose, other than federal income tax effects, for entering into the transaction.

The IRS warned that "[w]hen a series of steps include[s] a tax-motivated step that is not necessary to achieve a non-tax objective," the government may deny tax benefits on the "tax-motivated steps that are not necessary to accomplish the non-tax goals." It said the tax-motivated steps could take many forms, including interposing an intermediate entity whose involvement is unnecessary to achieve the real or purported business objective.

NO REAL PARTNERSHIP was created, a US appeals court said.

Dow Chemical did two partnership transactions with foreign banks / *continued page 39*

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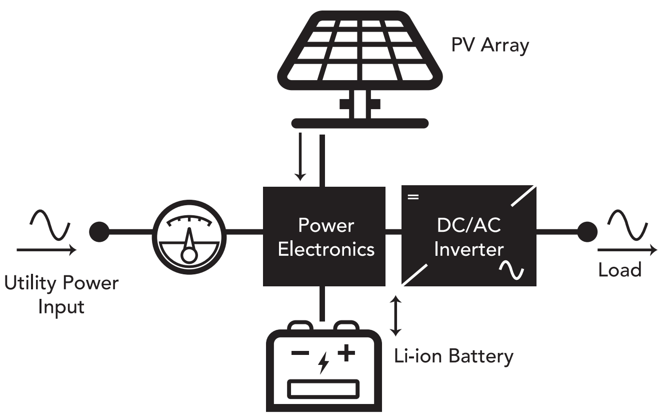
on learning to forecast demand. The solar-battery system is effectively a private utility.

Exhibit 1 below shows a schematic of a solar-battery system that is behind a meter.



Net metered solar systems use the utility as a "battery." The utility system is not designed for this function and providing this service is not cheap. In a net metering scheme with a tariff, the economics for the customer are also poor, since he transfers electricity to the utility during off-peak hours in the middle of the day and buys back at peak rates in the evening.

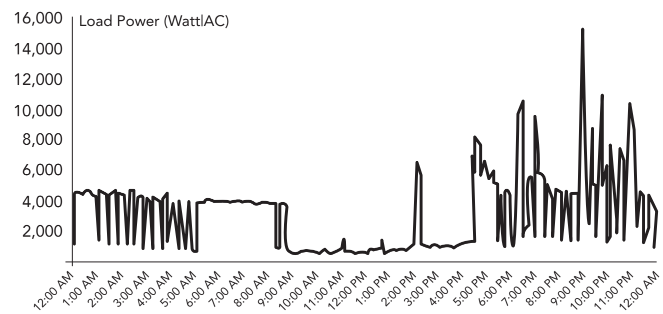
The utility provides power to the customer of a net-metered solar system to help the customer meet its peak load. This is needed because a solar system sized to generate energy equal to the customer's load during a year — for example, a "net-zero" home — still does not produce enough power, even at maximum sunshine, to meet daily peak demands.

Take the example of a net-zero home with a 12.5-KW DC solar system with a production factor of 1,600 KWh AC for each kilowatt of DC capacity, which produces the home's annual demand of 20,000 KWh, or an average of 1,670 KWh per month.

Assuming a de-rate — or power loss to convert the electricity from direct current to alternating current so that it can be used in a house or other building — of 80%, such a system has a maximum output from the inverter of 10 KW AC. This is much less than the up to 40 KW of peak demand that such a home can have. These peak levels are not rare events; a home hits these peak values almost daily. Even during the sunniest hour of the day, the solar system cannot deliver enough power to meet these peak demands. Thus, the utility must act as a power "booster." This is an essential service as otherwise the inverter would shut down due to overload or electric appliances could sustain damage as the voltage and frequency in the home circuits sag.

For a net-metered home, the utility balances energy and boosts power. The net-metering customer needs the utility more for these services than the utility needs the excess electricity the customer feeds into the grid. A net-metered, customer-located solar system provides some distributed energy generation, which enhances the power supply system, but such systems only partially decentralize the power supply and can even be difficult to manage on the grid.

Exhibit 2 shows the instantaneous demand of a home for a typical summer day.



Power Flows

A solar-battery system is different from a net-metered solar system as it stores excess solar energy in its battery and is able to meet all the peak power needs of the customer.

In a net-zero net-metered home, about 35% to 40% of the solar energy is used directly by the home, and 60% to 65% is sent to and later repurchased from the utility. These percentages can vary from home to home, but the fact that there is a split is pretty universal as it reflects the typical electric consumption pattern of a home: some morning demand, little demand during the day, and then high demand after work and into the night versus the output of the solar system during the day, which has the shape of an inverted parabola.

Using a battery in the home increases the percentage of the solar energy produced that the customer uses himself. A self use of 75% is achievable for a net-zero home with a battery that is sized to hold about two hours of maximum solar production. For higher self-use percentages, the levelized cost of energy for a solar-battery system increases quickly. Customer behavior like running a dishwasher or washing machine during the daytime can increase the self-use percentage to 85%.

The solar-battery system used for purposes of illustration earlier has a lithium ion battery with 20 KWh of useable capacity and a gross capacity of 28 KWh. As can be seen in Exhibit 2, the peak demands for that day are between four and 10 KW, with one spike to 15.5 KW.

These power levels are no challenge for a 20 KWh net and 28 KWh gross battery that can discharge easily at 50 KW. The maximum discharge rate is three times higher than the highest load in the day shown in Exhibit 2 and well within the battery specifications.

There is no need for the utility to boost the system's power. In a residential application, the power demands on the battery by the loads are no problem for the battery against a storage size that is required to reach a self-use fraction of 75%. These lithium ion batteries are assumed to cycle once per day and can last 10 years or more. In contrast, automotive applications are much more demanding on discharge rates of lithium ion batteries resulting in shorter battery life.

Moving from a net-zero and net-metered solar system that needs to balance 60% to 65% of the energy with a utility to a solar-battery system that purchases (or balances) only 15% of the electricity from the utility is a significant change in the reliance on utility energy.

The customer of a solar-battery system no longer needs power boosting services from the utility. To a solar-battery system, the utility becomes de facto just another energy source — no different than the solar energy. This dramatically reduces the role and leverage of incumbent utilities with customers of solar-battery systems.

Levelized Cost of Energy

The performance of solar-battery systems is impressive. Lithium ion batteries enable solar PV in markets without net metering and vastly expand and deepen the penetration of solar PV in all markets.

Power from a solar-battery system is already competitive in many markets today. It will be cheaper than retail power in Germany by the end of 2015, and it is cheaper than diesel power everywhere today. Already solar-battery systems are used in Germany to arbitrage retail power prices against the feed-in tariff. In markets where power is unreliable and of poor quality, solar-battery systems further eliminate power cuts and protect electric equipment from harmful voltage or frequency fluctuations.

The levelized cost of energy or "LCOE" / continued page 40

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that used a financial product developed by Goldman Sachs called SLIPs, for special limited investment partnerships.

The transactions allowed Dow to claim large deductions on assets that had already depreciated.

Dow identified assets with a high value but zero or little tax basis, contributed them to a partnership and brought in foreign banks as limited partners. Each partnership lasted about five years.

In the first deal, Dow had its subsidiaries contribute 73 patents worth $867 million. Dow had a zero tax basis in 71 of the patents. It also contributed $110 million in cash and a shell corporation.

Five foreign banks contributed $200 million for the limited partner interests. The partnership was owned 18% by the foreign banks.

Dow continued to use the patents and paid royalties to the partnership that were not tied to the patent use. It indemnified the banks against any liabilities tied to the assets or taxes.

The partnership — called Chemtech I — operated from April 1993 through June 1998. The Dow royalty payments were its main source of income. The banks received 99% of profits until the profits reached a 6.947% priority return plus a relatively small distribution to cover Swiss tax liability, since the partnership was considered to be managed from Switzerland.

The partnership contributed the remaining cash from the Dow royalty payments to the shell corporation, which lent most of it back to Dow. If profits fell short of the priority return, then the partnership still had to pay the banks 97% of their priority return.

Here are numbers for 1994 as an illustration. Dow paid deductible royalties of $143.3 million. The partnership distributed $13.9 million to the banks. It contributed $136.9 million to the shell corporation that the shell corporation lent back to Dow. The partnership had taxable income of $122.4 million. It allocated $115 million of this income to the banks and / continued page 41

Batteries

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from a solar-battery system is primarily determined by four inputs. The first two inputs are the costs of the solar array and the battery pack; these two components are the vast majority of the system cost. The third input is the battery capacity required to reach the desired self use. The fourth is the local solar production factor.

The table on the right shows the primary assumptions for calculating the LCOE of the solar-battery system used for purposes of the illustration earlier. These assumptions are valid in many markets around world.

The LCOE over 10 years is 33.6¢ per KWh. This may seem high for those of us living inside the North American natural gas bubble, but outside of it, this is a pretty competitive number, especially to customers on unreliable grids in emerging markets. These customers experience power outages that can last many hours and can occur almost daily and have to rely during grid outages on expensive diesel generators or lead-acid battery systems that store energy from the grid. And the solar-battery LCOE is only getting more competitive since the cost of solar-battery systems is on a fast downward curve, while the cost of conventional power will stay, at best, flat.

With the ability to deliver reliable and high-quality power at a cost of 34¢ per KWh, declining to 25¢ per KWh by 2020, in our estimate, solar-battery systems are competitive.

Smart controls and the ability to monitor, trouble shoot and control key system components over the internet makes it a solution that is imminently practical. Former US Energy Secretary Steven Chu predicts that solar-battery systems will be "as disruptive to electricity distribution and generation as the internet [was to brick-and-mortar businesses]." However, a better analogy is to compare the predicted impact of solar-battery systems to the impact mobile phones had on telecommunication. Mobile phones did not replace landlines. Landlines still exist, but mobile phones decentralized telecommunication and dramatically increased the access to and use of telecommunication. Solar-battery systems are about to do the same to power markets.

Today's solar-battery systems give consumers the ability to have reliable, high-quality electricity no matter where they live and a choice of how they want to meet their energy needs. Customers can combat global warming with a zero-carbon "private utility" without compromising the modern lifestyle that we all aspire to or by paying a high premium. For the billions of people who do not have the privilege of our prosperous life in the United States, but who aspire to and deserve what we already have, solar-battery systems promise a cheaper and faster path to reliable power than waiting for the traditional power supply system to serve them, without adding to global warming. Solar-battery systems give emerging markets a fighting chance to avoid the dramatic increase in electricity-related carbon emissions that would otherwise be associated with fulfilling these aspirations. Generally, decentralized solar-battery systems can turn power supply systems "green" faster and more effectively than finding consensus to build a high-voltage transmission system for transporting electricity from areas with relentless wind and harsh sun, where people usually do not live, to where the customers are.

Solar-battery System Cost and LCOE

Item	Amount
Solar production factor	1,600 KWh|AC per KW|DC
Gross solar power	12.5 KW|DC
Solar panels	$8,750
Gross battery capacity	28.6 KWh
Specific battery cost	$500/KWh
Battery	$14,286
Inverter, DC power electronics	$3,500
Cabinet and cables	$3,140
Racking and installation	$1,923
Installed system cost	$31,599
Sales margin	30%
Installed system price	$41,078
Real interest rate	5%
Financing term	5 years
Self-use	75%
Power Conversion and Storage Losses	6%
Effective LCOE over 10 years	33.6¢/kWh

Solar rooftop systems with batteries will generate electricity at below retail rates by 2015 in Germany and 2020 in the US.

Solar-battery systems will not replace the utility system, but they will grow power supply faster and more cheaply than a central power supply system could.

Utility power will continue to play an important role in meeting industrial demand, serving customers in densely-populated areas, or acting as an energy input to decentralized solar-battery systems. Unlike for net-metered solar systems, operating and safety concerns for the utility grid do not impede penetration of solar-battery systems that are behind the meter. These systems are also outside the influence of utilities and their regulators. Utilities will be powerless against customers of these solar-battery systems who reduce their energy needs to a small fraction, say 15%, of what they consumed before. At the same time, a market where utilities can rely on net-metered solar-battery systems for some utility system demand and supply balancing would be even more efficient. Either way, a decentralized power system will be much more resilient than what we have today.

Solar-battery systems are about to bring the biggest change to power markets since Edison, and it is already happening. ◎

chadbourne

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$28.1 million to Dow.

The partnership agreement listed 23 things that could cause the partnership to terminate. Many were typical of default triggers in loan agreements. Upon termination, the banks would receive the balance in their capital accounts plus 1% of any gain or less 1% of any loss resulting from any change in the partnership's asset value. The banks were compensated for any shortfall in their expected return if the partnership terminated before seven years.

Dow terminated the partnership in February 1998 because of new US tax regulations that could subject the banks to 30% withholding taxes.

Dow would have had to indemnify them for the withholding taxes. The banks were repaid their capital account balances plus 1% of the increase in value of the patents.

Dow then formed a new partnership to do the same thing. It contributed a chemical plant in Louisiana worth $715 million but with a tax basis of $18.5 million. The new partnership leased the plant to Dow. Dow paid rent. A US affiliate of Rabobank contributed $200 million in June 1998 as limited partner in exchange for a 20.45% interest. The bank had a 6.375% priority return and could terminate the partnership after roughly five years.

In March 2003, the bank and Dow negotiated a new partnership agreement that reduced the bank's priority return to 4.207%. The partnership continued to operate under the new terms for roughly another five years through June 2008.

A federal district court said no real partnerships were formed between Dow and the banks. In reality, the banks made loans to Dow.

A US appeals court agreed in September that no partnerships were formed. It rejected Dow's argument that it first had to decide whether the banks were lenders or partners. Dow said they could not be lenders because there was no fixed maturity for repayment of their investments.

The court said the following persuaded it that no real partnerships / *continued page 43*

Power Privatizations in Africa: Key Lessons

by Kevin Atkins, in London, and Ikenna Emehelu, in New York

Privatizations in sub-Saharan Africa offer key lessons for investors seeking to enter newly-deregulated power markets in Africa.

This article looks at the cases of Uganda and Nigeria where, in recent years, the governments have implemented privatization reforms aimed at increasing private-sector participation in power markets formerly dominated by state monopolies.

When a government monopolizes the power sector, a single entity usually controls generation, transmission and distribution. This can result in poorly performing management systems (with no competitors offering viable alternatives) and cross subsidization among the generation, transmission and distribution sectors leading to apparent support of one another when, in reality, risk is being passed to consumers through volatile pricing and power shortages.

Privatization reforms are usually designed to stimulate competition and make the particular sector concerned a more financially viable and attractive environment for investment that can sustain itself without the need for government subsidization. Increased competition in the power marketplace offers consumers a number of viable alternatives for power supply and helps to stabilize prices through market forces. A competitive market for generation and distribution helps to increase power volumes and improve reliability and coverage to satisfy growing domestic demands of emerging economies, particularly in rural areas. In addition, a privatized and unsubsidized power sector is more likely to produce profits for investors who enter the market. The investors will pay taxes to the government, which will also have reduced its costs by no longer subsidizing a failing power sector with volatile price swings.

Uganda

The privatization of the Ugandan power sector took place within the context of widespread deregulation throughout the Ugandan economy. A national "Electricity Act" was passed in 1999, at a time when collection rates for electricity bills were approximately 50%. The Electricity Act ordered the power sector to be privatized through the unbundling of production, transmission and distribution systems, all of which were under the control of the Uganda Electricity Board. The Electricity Act also established the independent Electricity Regulatory Authority, which was created for the purposes of regulating the power sector, issuing licences, establishing tariff systems and enforcing codes of conduct for system operations.

In 2001, the Uganda Electricity Board was decentralized and unbundled into three separate specialist companies: the Uganda Electricity Generation Company Limited or "UEGCL," the Uganda Electricity Transmission Company Limited or "UETCL," and the Uganda Electricity Distribution Company Limited or "UEDCL." While the UEGCL retained ownership of the Nalubaale plant and the Kiira plant (formerly the Owen Falls Dam hydro project), operations at the two plants were handed over to Eskom, the South African state-owned electricity company, in 2003 under a 20-year concession. All the power generated by the plants was then sold to the UETCL. In 2005, Eskom and Globeleq formed a joint venture that signed a 20-year concession with the Government of Uganda to assume UEDCL's operations and sales to the retail market.

At the same time it privatized the power sector, the Ugandan government pursued development of the Bujagali and Karuma Falls hydro projects, which were awarded to AES and Norpak Ltd respectively. A World Bank report on the Bujagali project noted that a thorough examination of the institutional risk of a delayed or underperforming distribution system post-privatization was missing from the overall economic appraisal of the project.

Certain reports have also commented that the privatization policies implemented by the Ugandan government proceeded largely without consultation with the private sector and those businesses and other consumers that would be principally affected. One example that has been cited in this regard was the introduction of a value-added tax in 1996, prior to which the business community was largely ignored and little to no effort was made to consult with business leaders and educate them on the implications of the tax and its rationale.

Much like in the business community, there was a fundamental mistrust of the privatization process at the consumer level. The benefits of privatization were not explained to the general public, many of whom saw the process as a means of enriching government officials.

Despite these criticisms, the Ugandan government remained committed to its course. The Bujagali project was successfully tendered in 2005 with new project sponsors (after the withdrawal from the project by AES in 2002) and eventually came on line and became fully operational in 2012.

However, despite improvements, 15 years after the privatization process started, rural areas remain largely without power and electrification to these areas needs to be fast tracked. Additionally, while transmission losses have been reduced from approximately 38% to approximately 26%, the figures are still high and lost volumes need to be addressed. One way of doing this could be to invest in smart metering and remote metering to prevent power theft.

Nigeria

Nigeria launched power sector reforms in 2005 with enactment of the "Electric Power Sector Reform Act" that outlined a reform process to unbundle the state-owned power company, the National Electric Power Authority, into separate entities for generation, transmission and distribution.

The unbundling process took place via a transition holding company, the Power Holding Company of Nigeria, and was designed to create a competitive market for power supply within Nigeria through private-sector participation.

The government released a power sector roadmap in August 2010 that set a timeline for investors to bid to acquire separate generating companies (each owning a single power plant) and distribution companies (each servicing a particular region within Nigeria). The timeline was supposed to work as follows:

- December 2010: Commencement of bidding process
- July 2012: Submission of bids
- October 2012: Approval of bids
- January 2013: Completion of negotiations
- March 2013: Payment of deposit
- August 2013: Payment of balance

In November 2013, the shares in 11 distribution companies and five generating companies were in fact sold to successful bidders for an aggregate price of approximately US$2.5 billion. The government is in the process currently of dealing with bids from potential purchasers of 10 newly-built national integrated power projects that are being sold by Niger Delta Power Holding Company. Preferred and reserve bidders for no fewer than seven of these projects have been selected with an aggregate purchase price of more than US$4 billion.

The privatization process took longer than expected because of labor unrest, with workers threatening to strike if their severance benefits were not met. The Nigerian government eventually set aside up to 50% of the proceeds from sales of the distribution and generating companies for the / continued page 44

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were formed. The banks earned a fixed annual return regardless of the success of the underlying business. They had only a 1% interest in any appreciation in asset value. They took virtually no risk tied to the patents or the chemical plant. Dow indemnified the banks for any liabilities tied to the patents or chemical plant and for any tax liability.

Various steps were taken to eliminate what little risk there was, such as requiring each partnership to hold collateral worth 3.5 times the unrecovered capital contributions of the banks. If the banks perceived any risk they could terminate the partnership and get their money back. For example, they could terminate if the partnership failed to distribute at least 97% of the expected preferred return each quarter.

The bottom line, the court said, is there was no intention to join together to form a real business with a sharing of profits from that business. The assets were assembled with tax attributes in mind and, in the case of the patents, did not include all the rights that any licensee would need to function as a real business. The banks had downside protection and virtually no upside.

The case is Chemical Royalty Associates, L.P. v. United States. *Dow said it was disappointed by the decision and is evaluating its options.*

ARGENTINA addressed a VAT issue.

The Supreme Court held in September that the base for calculating value added taxes on payments to foreign suppliers includes any tax gross up to cover income taxes on fees paid to the foreign supplier.

Puentes del Litoral holds a concession to build a toll road between two cities, Rosario and Victoria. It made payments under services agreements with foreign companies who provided the know-how. The foreign companies submitted separate invoices for gross ups for Argentine income taxes on the service fees. The general VAT rate in Argentina is 21%. VAT applies to fees for services.

The Argentine tax / continued page 45

Africa

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workers.

International lenders distanced themselves from the privatization process out of concern that the bidding timeline was too short to come to grips fully with the unpredictability and volatility of the Nigerian markets. As a result, local banks have provided close to 70% of the funds required to pay the purchase price for the distribution and generating companies. Absent wider international lender participation to refinance and syndicate these loans, it is unclear how successful bidders will be able to finance the capital requirements to build out generating and distribution facilities.

Investors should look for four things before diving into a deregulating African power market.

The power sector is inextricably linked to the gas market as Nigeria possesses the world's ninth largest gas reserves. Theft and vandalism remain rife and have led to lost gas and a lack of feedstock for new plants that, in turn, has led to a number of new gas-fired plants remaining idle after being commissioned. The government has responded by adopting the gas master plan to reduce gas flaring (which has halved over the past five years), to replace diesel, which is a more expensive alternative, as the domestic fuel of choice and to support the investment of capital into combined-cycle gas-fired power projects.

Lessons Learned

The experiences in Uganda and Nigeria suggest potential bidders in a privatization should look for four things before diving into a deregulating African power market.

First, an independent regulator should be in place before privatization to oversee the market and enforce supply and demand economics.

An independent regulator can also respond to market criticisms and issues as they arise, and avoid such mishaps as the Bujagali and Karuma Falls hydro projects, where the concessions were entered into before the Electricity Regulatory Authority was created.

Market participants in a liberalized power sector will need robust guidelines, codes and regulations governing access to the market, service quality, pricing mechanics, nomination procedures and liability regimes.

Next, concessions should be awarded through transparent and fair bidding processes, free of any allegation of corruption or political influence. To achieve transparency, governments should engage with business leaders, consumer groups and key stakeholders to ensure that the merits of privatization and the desired goals are understood by those who will be affected and there is general buy in for the reforms.

Transparency is also imperative to attract international participation as the international lender market will be vital in sharing funding risk and providing developers with access to much needed capital.

Next, the market must be viable. International investors will need guaranteed access to fuel to ensure that power plants can run and bankable power offtake contracts to ensure a fixed revenue stream. Without guaranteed fuel and bankable contracts, the plant cannot generate revenue and, hence, service its debt. Long-term gas sales agreements will need to be secured and gas sellers may require credit support from generating companies for take-or-pay obligations (which may be more forthcoming if and when gas prices can be de-linked from volatile crude oil prices and tied instead to hub prices for which we are seeing pressure in Europe).

Tariffs must be set at an optimal level to enable consumers to pay and to enable generators and distributers to cover their costs and make a profit. Without an attractive power price, international investors are unlikely to be willing to participate unless the price to buy the privatized assets and ongoing operating costs are minimal enough to allow a profit.

Privatization reforms require real-time nominations and balancing and settlement mechanisms to support transmission capacity and required demand, especially in times of unexpected shutdowns of generating facilities, which will create a robust trading platform for power where prices can be determined by the market forces of supply and demand.

Balancing will allow generators, transmitters and distributers to submit bids to the power grid to sell power and offers by the grid to buy power to ensure the market is balanced. Settlement will allow monitoring and metering of actual positions compared to contracted positions.

Finally, there must be a strong political commitment to privatization. Privatizing an entire power sector and putting in place an investment climate that is suitably attractive to international investors will not happen overnight and requires a long-term commitment. Weak political support can lead to short-term fixes that lead, in turn, to longer-term problems, and it is unlikely to attract the international institutions whose participation will be needed to finance the privatization.

Privatization does not work without long-term certainty about fiscal terms as a stable economic base is fundamental for any successful project. ◎

Some Types of Government-Supported Power Contracts Hit Headwinds

by Bob Shapiro, in Washington

Two federal court decisions in September will affect some types of government-supported power contracts that independent generators sign with utilities.

A US appeals court in New Jersey ruled in mid-September that a New Jersey program under which the state public utilities commission solicited bids for gas-fired capacity / *continued page 46*

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authorities take the position that VAT must be paid on tax gross ups because the gross ups are part of the cost of the services. The Supreme Court agreed. The Federal Tax Court had been split on the issue: two of the four "chambers" agreed with the tax authorities and two did not.

VAT is paid by the Argentine company receiving the services.

COLOMBIA removed the Cayman Islands, British Virgin Islands and Bermuda from a list of tax havens.

Forty-one jurisdictions remain on the list. The remaining jurisdictions can be removed by entering into agreements to share information with the Colombian tax authorities. Payments that Colombian companies make to suppliers in tax havens are subject to a 33% withholding tax. The payor must collect the tax. If he does not, then he cannot deduct the payments for Colombian tax purposes.

Many Latin American countries have some form of tax haven blacklist.

INDIANA does not tax out-of-state investors if the investment is structured properly.

Vodafone had a 45% interest as a general partner in a Delaware general partnership with Verizon Wireless through which the two companies provided cell phone services.

States tax income that is earned in the state. Vodafone treated its share of income from the partnership as earned in Indiana, but then thought better of it and asked for a refund of the taxes it paid during the period 2005 through 2008. The company argued that the income was from an intangible asset — its partnership interest — and companies only have to pay taxes on income from intangibles if they are domiciled in the state.

It lost in court. The Indiana Tax Court said in June 2013 that the income was income from an operating business. "[T]he mere fact that Vodafone was a partner in a general partnership gives its income from that partnership the / *continued page 47*

Power Contracts

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and required the New Jersey utilities to sign long-term power purchase agreements with the winning bidders was unconstitutional under the supremacy clause of the US constitution.

The decision is consistent with a similar opinion by another US appeals court in June 2014 that invalidated a similar directive by Maryland requiring utilities to sign long-term contracts for gas-fired capacity following a state-mandated solicitation.

Both courts found that the state directives infringed on the exclusive jurisdiction given to the Federal Energy Regulatory Commission over wholesale electric rates.

Meanwhile, a US appeals court in Texas ruled in September that a state regulatory commission can decline to require utilities to enter into power contracts with wind (and by analogy solar) generators – notwithstanding a 1978 federal law called the Public Utility Regulatory Policies Act, or PURPA, that requires utilities to buy electricity from small power producers whose projects are up to 80 megawatts in size — because wind projects do not produce "firm power." The Texas decision is at odds with the Federal Energy Regulatory Commission interpretation of the PURPA rules on this point.

State-Mandated Contracts

The parties in the New Jersey litigation have 90 days to ask the US Supreme Court to review the decision. Review by the Supreme Court is discretionary, and the fact that two appeals courts have each unanimously reached the same legal conclusion makes it less likely that the Supreme Court will take the case. Maryland already announced that it will seek Supreme Court review of the June appeals court decision involving the Maryland program, and it received an extension from the Supreme Court until November to file its appeal.

Although each of the courts emphasized that its holding applies only to the state-specific program at issue in each case, the holdings have broader implications for other state programs that require regulated utilities to sign wholesale electricity contracts.

As a general matter, the Federal Power Act gives FERC the exclusive jurisdiction over wholesale electric rates in interstate commerce in the lower 48 states.

There are exceptions. Rates of "qualifying facilities" under the PURPA can be established under state rules that must follow FERC implementation requirements. ERCOT in Texas is electrically isolated from the rest of the country and is outside the Federal Power Act. Finally, municipal utilities and most electric cooperatives are not subject to FERC rate jurisdiction.

States have jurisdiction over the retail rates charged by utilities, utility resource plans and generating facility and transmission facility construction matters.

The issue in the New Jersey and Maryland cases concerns the extent to which a state program can encourage the construction of generating plants by providing incentives that implicate wholesale rates.

What New Jersey Did

The state mandate in the New Jersey case required utilities to sign a "contract for differences" for generating capacity under a state program known as the long-term capacity pilot program or "LCAPP." Each selected winning bidder under the contract for differences had to bid its capacity into the PJM capacity auction, which occurs every year, to supply capacity for a year three years in the future. FERC had approved the capacity auction mechanism that PJM used to set a specific capacity price for all projects that are selected in the auction. If the bidder was selected by PJM, then the bidder would receive from or pay to the electric utility counterparty the difference between the PJM auction capacity price and the fixed price in the contract for differences. Thus, the contract for differences in essence fixed the capacity price for a long term, in this case 15 years, regardless of the capacity price that the bidder receives in the annual PJM capacity auction.

New Jersey argued, among other things, that it did not set a wholesale price by contract, but rather conducted a bidding program that resulted in a contract with a bidder's own price. In addition, it argued that the contract for differences was not a wholesale contract at all, but rather a financial hedge because it only provided a pricing hedge and the offtakers did not actually purchase anything. In addition, New Jersey argued that the FERC-approved PJM auction price was not disturbed by the contract for differences mechanism, as the bidders had to follow the PJM bidding rules and the PJM capacity results and rules if selected. The bidder continues to receive the established auction price in the PJM market, but the contract adjusts the payments to the bidder if the market price is higher or lower than the fixed contract price.

What the Court Said

The appeals court asked FERC to give its views to the court in an amicus or "friend-of-the-court" brief. FERC told the court that it believed that the New Jersey program was preempted under the supremacy clause of the US constitution because it "directly affects wholesale rates, and, to that extent, is a preempted intrusion upon the Commission's exclusive jurisdiction to regulate wholesale rates" and "the state subsidy is directly and explicitly tied to the wholesale rate."

The court did not view the argument that the New Jersey program had only an incidental effect on the interstate wholesale price of electric capacity to be a legitimate basis for finding preemption. In fact, it said that a decision that New Jersey was impermissibly affecting the wholesale electricity price through its program would leave the states "with no authority whatsoever to regulate power plants because every conceivable regulation would have some effect on operating costs or available supply." However, the court said that, in approving bid prices for capacity and requiring utilities to pay those prices in the long-term contracts, the state was regulating wholesale capacity rates, the "same subject matter that FERC has regulated through" the PJM capacity auction and, therefore, had a direct conflict.

The court, like the appeals court before it that reviewed the Maryland program, found that the New Jersey contracts for differences were more than mere financial hedges created to remove the risk of market volatility. It said the contracts "provide for the supply and sale of capacity as well" by requiring the seller to sell into PJM markets and, in exchange, requiring that the seller receive a price that is not tied to the PJM capacity auction price. According to the court, this directive "essentially sets a price for wholesale energy sales" in violation of the Federal Power Act and is, therefore, preempted by federal law.

The court was careful to point out that states retain a legitimate role in the regulation of energy markets.

In particular, it gave examples of other permissible state action to encourage the development of new generation to meet state energy goals, including the use of tax-exempt borrowing authority, the granting of property tax relief, the ability to enter into favorable site lease agreements on public lands, the gifting of environmentally-damaged properties for brownfield development, and the relaxing or acceleration of permit approvals. However, it should be noted that none of these alternative state actions involves a state program that directs utilities to sign contracts with specific wholesale rates.

Potentially Broader Implications

Although several state commissions / continued page 48

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character of operational income." The fact that Vodafone had only a minority interest was not enough to change the character of the income; as general partner, it was not merely a passive investor.

Vodafone appealed, but the parties told the court this summer that they reached a settlement under which the Indiana Tax Court decision will stand. The appeal was withdrawn. The case is *Vodafone Americas Inc. v. Department of State Revenue*. The court order dismissing the appeal did not surface until October.

Indiana does not tax income that the owner of a minority interest in a limited liability company receives as a passive investor.

SOUTH CAROLINA said that generating electricity is "manufacturing."

The decision, in a case involving Duke Energy, affects what share of income Duke must treat as earned in South Carolina. Duke operates in more than one state. Manufacturers must allocate income to South Carolina based on the share of total property, payroll and sales the manufacturer has in the state. If Duke were not a manufacturer, then it would allocate based solely on the share of total sales in South Carolina.

Duke said it overpaid income taxes in South Carolina for the period 1978 through 2001 by $126.2 million because it incorrectly calculated the amount of income it earned in the state. It assumed it was a manufacturer.

The state tax department said Duke's calculations were correct and refused to refund the money. Duke lost two rounds in the South Carolina courts, most recently in the court of appeals.

The court said that while "manufacturing" is not defined in the state tax code, electricity generation is manufacturing under the "plain and ordinarily meaning of the word" since it creates an electrical charge that did not exist previously. The state Supreme Court ruled in 1926, and again in 1930 in a case involving Duke,

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intervened in support of the New Jersey program and argued that an adverse decision on constitutionality could have an adverse impact on other types of state programs, the appeals court refused to consider the implications of its holding on those other programs, which was also the case with the appeals court that reviewed the Maryland program.

The court said the defenders of the New Jersey LCAPP "fret that a decision in favor of preemption will hamstring state-led efforts to develop renewable and reliable electric energy resources." It responded that it was only deciding that the particular LCAPP program improperly occupied the field of capacity prices left exclusively to FERC.

But the difficulty with the appeals court decisions about both the New Jersey and Maryland programs is that their attempts to limit the holdings of unconstitutionality to state actions to fix wholesale capacity prices for a long term pursuant to state programs also arguably applies to state action to fix wholesale energy prices for a long term pursuant to state programs. Except for the previously noted exceptions not applicable here, FERC has exclusive wholesale ratemaking jurisdiction over energy prices as well as capacity prices.

Neither appeals court provided any indication whether there could be an acceptable state program that would involve a directive to a regulated utility to sign a long-term wholesale power contract to purchase capacity or energy.

A majority of states now have renewable portfolio standard laws that require regulated utilities to purchase a minimum percentage of their energy needs from renewable sources, and many of those states require competitive bidding or bilateral contracting for those resources with the result that the utilities must sign long-term power contracts with fixed energy prices. The courts have not provided guidance about the constitutionality of these programs, nor has FERC offered, or been asked to offer in court, its view about the consistency of such programs and contracts with FERC's Federal Power Act jurisdiction.

There may well be sufficient factual distinctions between the LCAPP program and other state programs for RPS projects and other generating resources that set long-term wholesale purchase rates that are sufficient for both the courts and FERC to conclude that these state programs are compatible with the dictates of the Federal Power Act. But the two appeals courts have provided no roadmap for the states from their recent decisions.

Because the courts have refused to provide guidance for other state programs, it is not possible to predict whether such programs will be vulnerable to similar constitutional challenges or, if such challenges are successful, whether existing contracts signed pursuant to such programs would be vulnerable to challenge as well. Courts have broad discretion in fashioning remedies in cases of invalidation of state action on constitutional grounds and would probably take into account the impact on parties that have detrimentally relied on the lawfulness of the affected state program, particularly if the program has been in existence unchallenged for a period of years. While there can be no assurance that existing contracts would be "grandfathered" from change following a successful constitutional challenge to a state program, the equities would weigh heavily in favor of such a result.

PURPA Contracts in Texas

The Federal Energy Regulatory Commission issued regulations under PURPA that required utilities to purchase electricity produced by independent generators known as "qualifying facilities" or "QFs" at the utility's "avoided cost", meaning the cost the utility would have spent to generate the electricity itself or to purchase it from another source. QFs are small renewable power projects up to 80 megawatts in size as well as cogeneration projects of any size. When it issued rules to implement PURPA, FERC said that a QF could require the utility to purchase the QF's output pursuant to a "legally enforceable obligation," typically a long-term contract.

This federal program is wholly independent from state RPS programs that may involve the same or different types of renewable projects, may cover smaller or larger sized projects, and may have different pricing parameters. However, under the PURPA program, the states must follow the federal rules.

In the Texas case, Exelon Wind, which owned several wind projects, challenged a Texas Public Utility Commission regulation, issued in response to PURPA, that says that only QFs with "firm power" can require a utility to enter into a legally enforceable obligation. According to the Texas PUC, since wind is an intermittent resource, it is not "firm" and, therefore, under the PUC rule is not entitled to a legally enforceable obligation. After losing before the PUC, Exelon Wind asked FERC to enforce its PURPA rules against the PUC. Although FERC declined to take enforcement action against the PUC, it issued a declaratory order finding that FERC's PURPA rules, which the state was required to implement, were not limited to "firm" power, Exelon Wind has the "right to choose to sell pursuant to a legally enforceable obligation, and, in turn, has the right to choose to have rates calculated at avoided costs calculated at the time that obligation is incurred," and the PUC order was inconsistent with federal regulations implementing PURPA.

In a 2-1 decision, a US appeals court in Texas refused to give deference to FERC's declaratory order interpreting its PURPA rules. It concluded that, under its own interpretation of the federal PURPA rules, FERC's PURPA rules gave discretion to the PUC "to determine the specific parameters for when a wind farm can form a legally enforceable obligation." The court went on to defer to the PUC's interpretation of the PUC rules implementing PURPA.

It should be noted that this court holding applies only with respect to Texas rules implementing PURPA. Its impact may be limited even in Texas, since few long-term QF contracts have been signed with Texas utilities in recent years and wind projects have relied more on federal tax credits for support. In addition, the decision does not require any other state to modify its PURPA rules. However, it remains to be seen whether any other state may wish to revisit its rules based on the decision and, if so, whether the Federal Energy Regulatory Commission might decide to take a more active role in defending its PURPA rules in future court proceedings. ⊚

DOE Nuclear Loan Guarantees: Part Deux

by Kenneth Hansen, in Washington, and Chadron Edwards, in New York

The draft solicitation recently issued by the US Department of Energy breaks new ground for support of the US nuclear energy industry through the loan guarantee program.

The new solicitation will welcome small modular reactors (in contrast to a 2008 solicitation that focused on large-scale nuclear projects), reduce certain regulatory requirements for eligibility, streamline the application process, and reduce some fees.

The new draft solicitation proposes to redeploy capacity that was originally offered in 2008 in two separate solicitations, but that went largely unused. One offered $18.5 billion in loan guarantees for advanced technology nuclear generation facilities. The other offered $2 billion for front-end */ continued page 50*

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that electricity generation is manufacturing. Duke argued that the supreme court decisions were stale and decided in other contexts. The appeals court disagreed.

The case is Duke Energy Corporation v. South Carolina Department of Revenue. *The court of appeals released its decision in the case on October 8. Duke asked the court on October 22 for a rehearing.*

PILOT PAYMENTS can be deducted as property taxes, the IRS said.

"PILOT" stands for payments in lieu of taxes. Developers in some states arrange for a county or state agency to hold title to a project as a way to reduce sales and property taxes. Equipment purchased by a state or county agency is usually exempted from sales taxes, and property owned by the agency is not subject to property tax. The developer negotiates payments in lieu of property taxes that are a fraction of the property taxes it would otherwise have had to pay.

US taxpayers can deduct property taxes.

A condominium association asked the IRS for a ruling that PILOT payments are a form of property tax that can be deducted. The association owns a condominium building on land that a not-for-profit corporation leases from a state development authority and then subleases to the association. The association makes PILOT payments to the not-for-profit corporation which makes them, in turn, to the state development authority. Each condominium owner pays his share of the PILOT payments.

The IRS said payments qualify as a tax if they satisfy three tests. These do. The payments must be measured by or equal to amounts imposed by regular taxing statutes. They must be imposed by a specific state statute. The proceeds must be designated for a public purpose rather than for some privilege, service or regulatory function, or for some other local benefit tending to increase the value of the property upon which the payments are made.

In this case, state law exempts land owned by the state development */ continued page 51*

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nuclear fuel processing facilities.

The new solicitation will cover both industries, again allocating $2 billion to nuclear fuel processing and offering $10.6 billion for assorted nuclear energy generation projects. That $10.6 billion is roughly the difference between the $18.5 billion originally offered for generation projects in 2008 less the $8.33 billion allocated to the construction of two new reactors at the Vogtle nuclear power plant in Georgia, the one nuclear project to close under the 2008 solicitation.

While the resources are largely carried forward from 2008, the terms of the solicitation have evolved. The new draft solicitation explicitly extends eligibility to small modular reactors and plant uprates and upgrades, which were not mentioned in the 2008 nuclear generation solicitation, though not explicitly excluded. There are also other innovations, such as with respect to eligibility and fees.

Emerging from Solyndra

Nearly three years passed since the high-profile bankruptcy of Solyndra and the sunset of the "section 1705" loan guarantee program created by the American Recovery and Reinvestment Act, each of which occurred in September 2011, without the DOE loan guarantee program closing any further financings or even having any windows open for new energy project applications.

However, there has been a recent flurry of signs of life. In February 2014, DOE closed a $6.5 billion financing for the Vogtle nuclear power plant in Georgia providing funds for the construction of two new reactors (with a further $1.8 billion committed to the project). Vogtle is a complex and costly project using technology being deployed in the US for the first time. As such, it was a strong candidate for a program designed to bridge the gap between technical viability and mainstream commercial acceptance. In another milestone for the loan guarantee program, on July 1 of this year, DOE issued a $150 million conditional commitment in support of Cape Wind, the nation's first offshore wind project.

In December 2013 and July 2014, DOE released two new solicitations. The first, for advanced fossil energy and carbon-capture projects, is open for applications until October 30, 2015. The second, for renewable energy and energy efficiency projects, is open for applications until December 2, 2015. And now comes the new draft solicitation for more nuclear projects. The program is back open for business. How that business will go remains a question.

Elephant in the Room

While the draft solicitation contains welcome improvements, challenges remain, including how to deal with credit subsidy costs. That issue was reportedly responsible for scaring away several applicants under the 2008 nuclear power generation solicitation.

Credit subsidy costs are risk premiums, akin to insurance premiums, sufficient, on average, to compensate the government fully for any projected losses from making a loan or issuing a guarantee. They are required by the Federal Credit Reform Act of 1990 to be paid to the Treasury Department from non-federal funds, so, unless commercial co-financing is available, it is an equity charge. Further, the amount due is not determined until about a few days prior to closing. Thus, a potentially substantial equity cost is unknown, at least with precision, until just before it must be paid.

Relatively little data exists to help estimate the range of credit subsidy costs that would apply to projects under the loan guarantee program. The stimulus-related "section 1705 program' ultimately supported 28 loan guarantees totaling $15.1 billion, requiring a total credit subsidy cost of about $1.9 billion (an average rate of just over 12.5%), all funded by the US government.

DOE will open the window for up to $12.6 billion in loan guarantees for nuclear projects.

The section 1705 program, while encouraging clean energy technologies, was primarily passed as an economic stimulus during the economic turndown of 2008 to 2009, and provided an appropriation to cover credit subsidy costs. The draft nuclear solicitation is pursuant to the original section 1703 program, which extends back to the Energy Policy Act of 2005 and has been substantially unfunded, forcing borrowers to pay their own credit subsidy costs. Vogtle was, and Cape Wind will be, the first DOE loan guarantee program projects to be responsible for covering their own credit subsidy costs, though the rate determined for Vogtle was 0%. Cape Wind's credit subsidy cost has not been publicly disclosed.

In March 2011, Congress enacted a modest credit subsidy cost appropriation of $169,660,000, but it appears that these funds will be used to support renewable energy projects. In any event, DOE has been clear that it does not expect to provide coverage of any credit subsidy costs under the upcoming nuclear solicitation.

Credit subsidy costs are in the first instance calculated by DOE, but are then reviewed and confirmed (or not) by the Office of Management and Budget. Rumors abounded in the early years of the loan guarantee program that the energy staff at OMB did not trust the DOE to implement a loan guarantee program sensibly and were inclined to inflate credit subsidy costs to protect the taxpayers from likely project failures. The breathtaking speed with which Solyndra (the DOE loan guarantee program's first project to close) collapsed following financial close did little to reassure OMB.

Concerns have also been expressed concerning other sources of a risk of upward bias in the determination of credit subsidy costs. As the projects supported under the stimulus, which include all of the energy projects closed to date except Vogtle, had to close by September 30, 2011, both borrowers and DOE were anxious to meet that deadline. Some closings were delayed while prospective borrowers waited for DOE and OMB to agree on the appropriate credit subsidy cost in the final days before closing. Since those costs, once determined, were fully paid by a Congressional appropriation, both borrowers and DOE were more concerned about timing than the amount of credit subsidy costs. Congress had initially appropriated more funding than DOE appeared to need, so DOE's incentive was to move the process through OMB quickly rather than to fight hard to minimize the amount that was calculated. This dynamic has led to a concern that earlier loan guarantees may have set precedents with relatively high credit subsidy costs that will carry over into determinations made for projects, such as those under the coming nuclear solicitation, that must pay their own credit subsidy costs.

However, there are some grounds for / *continued page 52*

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authority from taxes, but requires the authority to collect PILOT payments and use the payments either to improve or maintain the property involved or transfer them to the general fund of the city for general public purposes.

The IRS analysis is in Private Letter Ruling 201442020. The agency made the ruling public in October.

MICHIGAN utilities do not have to pay sales and use taxes on new equipment that they will use to distribute electricity and gas.

The sales and use tax rate in Michigan is 6%.

Sales taxes are collected on sales of equipment in state. Use taxes are collected on equipment bought out of state and brought into the state for use in Michigan.

A Michigan appeals court ruled in October that equipment used to distribute electricity or gas is exempted from taxes under an "industrial processing exemption." The exemption applies to equipment that will be used to convert or condition "tangible personal property" for use in manufacturing a product that will ultimately be sold at retail. The court said electricity and gas are tangible. The utility sells them to retail customers. The issue, it said, is whether the utility converts or conditions electricity or gas in the process of distributing it to customers. The court said it does.

It said the utility had to prove that it changes the "form, composition, quality, combination, or character" of the electricity or gas while moving it to consumers. The utility presented exhaustive evidence, the court said, that the electricity and gas are not safe or usable when they first enter the distribution lines or pipes. They are converted on the way to consumers.

The case is Consumers Energy Company v. Department of Treasury. *The Michigan Department of Treasury had tried to collect $21.2 million in taxes from Consumers Energy after an audit of the period October 1997 through December 2004. The court reached the same conclusion* / *continued page 53*

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optimism. While loan guarantee program projects besides Solyndra have failed, their numbers have been small. Overall the performance of the portfolio has been terrific, with, notwithstanding the huge hit taken with Solyndra, a loss rate less than 3% in a program dedicated to finance technologies that are deemed too risky for commercial lending. That track record should support more modest credit subsidy cost determinations.

Guarantees will be available for small modular reactors.

A good sign in this arena is that the credit subsidy cost recently determined for the Vogtle project was 0%, though that was more a function of strong corporate backing than programmatic track record.

Apart from Vogtle, Constellation Energy's Calvert Cliffs project proceeded the farthest in the DOE nuclear loan guarantee process, having applied and moved well into the diligence process before withdrawing in October 2010, motivated, at least in part, by an unexpectedly large projected credit subsidy cost of 11.6% on a $7.6 billion loan, yielding an additional equity charge at closing of about $880 million.

It is interesting to explore why the numbers played out so differently for Calvert Cliffs and Vogtle, since the credit subsidy cost can be a make-or-break proposition for the feasibility of DOE financing. While OMB's calculation mechanics are not public knowledge, some relevant factors distinguishing Vogtle and Calvert Cliffs are evident. Calvert Cliffs was being developed as a non-recourse project financing; Vogtle was structured as a full-recourse project, with the massive Southern Company balance sheet and smaller (but still substantial) Oglethorpe balance sheet backing the loan guarantees. Vogtle is located in Georgia, which allows costs of plant construction to be passed on to customers before completion, whereas Calvert Cliffs was proposed in Maryland, which requires construction to be completed first. Additionally, Calvert Cliffs was proposed as a merchant plant, while Vogtle benefitted from long-term take-or-pay power purchase agreements.

The DOE loan guarantee program is designed to support innovative projects that are having trouble getting financing on reasonable terms in the commercial market. Yet allocating a high risk premium to these types of projects in the form of credit subsidy costs takes what is expected to be an unmanageable private market risk premium and shifts it to an upfront payment, discouraging the very projects the program was designed to assist. Whether credit subsidy cost requirements end up being more like Vogtle or the early estimates for Calvert Cliffs may determine whether the nuclear solicitation leads to effective support of any projects.

Eligibility

Nuclear reactors of any size, including small modular reactors (defined as 300 megawatts or smaller), uprates (improvements or modifications to existing operating reactors to operate more efficiently), and upgrades (improvements or modifications to reactors that are to reactivate them or to prevent their shutdown) are all eligible under the draft solicitation.

Of the total $12.6 billion in loan guarantees offered, $2 billion are allocated to front-end nuclear fuel processing projects (for example, advanced technology uranium conversion, uranium enrichment and nuclear fuel fabrication). While no partitions of the remaining $10.6 billion are made, three kinds of projects specifically cited here — small modular reactors, uprates and upgrades — were not previously mentioned, so a notable development in the draft solicitation is its specific indication that DOE is willing to consider extending loan guarantees for such projects.

In what may be of particular interest to the small modular reactor industry, the draft solicitation lowers the regulatory hurdles facing applicants. The previous nuclear solicitation was only open to projects that had applied for a combined construction and operating license with the Nuclear Regulatory

Commission, or those that would be ready to do so in a short time period (12 days after the part II application due date). The previous solicitation also required projects to use NRC-approved reactor designs or ones that were included in filed applications already accepted for technical review by the NRC.

The new draft solicitation does not prescribe any NRC licensing requirements as preconditions to project eligibility, other than that borrowers must have filed for, or have obtained, required regulatory approvals prior to execution of loan guarantees, with specific licensing requirements to be addressed on a case-by-case basis. DOE's stated rationale for this change to the NRC requirements is to provide eligibility to a broad range of reactor technologies and to offer flexibility regarding reactor technology and site location.

However, note that, in what appears at least to be confusing drafting, a separate part of the draft solicitation defines eligible "nuclear power facilities" as projects and their associated nuclear reactor designs that are either under NRC licensing review or under the NRC pre-application phase for certification, construction permit, or combined construction and operating license review.

In what may be another benefit for small modular reactors, the draft solicitation says DOE will look favorably on projects that will have a catalytic effect on the commercial deployment of future advanced nuclear energy projects that replicate or extend their innovative features. While this could extend to any advanced nuclear technology being deployed commercially for the first time, small modular reactors in particular may be good candidates for such consideration given their emphasis on modularity and standardized design.

Part of the application process requires submitting a description of the applicant's prior experience successfully implementing similar projects of the same scale. In a note that will help developers of technologies that have yet to be successfully implemented at the same scale, the draft solicitation offers an alternative. Applicants may instead provide a detailed description of facts sufficient to demonstrate that the applicant has the necessary expertise.

One aspect of the draft solicitation that may make sense for developers of large nuclear, uprate, upgrade, and front-end fuel processing projects, but that might be frustrating to developers of small modular reactors, is a limit of only one project using the same technology per project sponsor. Unfortunately, this limit comes directly from the loan guarantee program regulations.

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in an earlier case involving Detroit Edison.

THE US ENVIRONMENTAL Protection Agency released additional thoughts for comment in late October on some of the more controversial aspects of its June plan to reduce carbon dioxide emissions from existing power plants that use fossil fuels. Comments are due by December 1, 2014, a date that may be challenging for some states with closely-contested governors' races. The June plan set individual state goals for reducing carbon dioxide emissions (expressed in lbs CO2/MWh) and listed measures states could use to cut emissions.

The June plan also suggested that states could convert these goals expressed in emissions per megawatt hour into tons of CO2 emisisons per year, which would be easier to implement for states that develop or enter into cap-and-trade programs.

Although the ultimate targets in the June plan would not need to be achieved until 2030, there are interim targets to take stock of how states are doing in 2020. EPA suggested use of the following four measures (also termed "building blocks") to reach the emissions targets: improved heat rates at coal-fired power plants, increased use of low-emitting power sources like natural gas, increased use of zero- and low-emitting power sources like solar energy and increased demand-side energy efficiency. EPA is required to finalize the plan by June 1, 2015.

Critics of the plan complain that meeting the 2020 interim targets does not allow states enough flexibility to choose how best to cut emissions. The plan also appeared to assume that some states could readily increase the use of combined-cycle natural gas-fired power plants by dispatching those power plants up to about a 70% capacity factor. EPA is now suggesting that states could count early reductions for puposes of demonstrating compliance with the 2020 targets. Such reductions may be in the form of energy efficiency programs implemented before 2020 and would give states */ continued page 55*

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Application Process

The draft solicitation contemplates multiple rounds of applications, with applicants providing part I submissions, which will be reviewed competitively against one another, and with qualifying applicants being invited to submit part II applications.

This presents two key items that differ from the previous nuclear solicitation, in which applicants were ranked based on their initial applications (and possibly re-ranked based on updates to other pending applications).

First is a potential first-mover advantage. DOE has indicated that all part I submissions will be competitively evaluated against all others submitted during the corresponding round of review. Applicants presenting strong projects in earlier rounds may well enjoy an advantage of being compared against fewer competitors for a larger allocation of loan guarantees.

It is unclear how large a credit subsidy cost or premium will be charged.

DOE has indicated that part II submissions may be filed at any time after DOE invites an applicant to do so, subject to the final part II deadline, but that all part II submissions received during each round of part II review will be competitively evaluated against one another. It is unclear how these rounds will be structured but, as with the part I submission, it is possible that there will be a first-mover advantage to applicants that complete and submit their part II submissions (which are quite voluminous) sooner than their competitors.

More generally, given a program anxious to demonstrate its post-Solyndra validity and viability, the early entrants are likely, all else equal, to receive particular attention and support from DOE.

While DOE has specified that it may defer consideration of a part II submission to a later round, DOE has not said whether the same rule will apply to part I submissions, or if applicants rejected at the part I step would be allowed to edit their applications and reapply in later rounds and, if so, whether they would be required to pay the corresponding fee. However, DOE said in a presentation posted on its website that "pending applicants" (apparently referring to surviving applicants from the 2008 solicitations that have not withdrawn their applications) would not need to reapply under the draft solicitation or pay fees unless they wish to modify their proposals significantly.

The second notable change to the application process is a reduction of application costs. The part I submission contains overall descriptions of the project and the involved parties to determine eligibility, as well as business and financial plans and technical information about the project. While it entails some detailed analysis, it does not require the same level of detail required by the part II submission, which includes submission of detailed project cost analysis, financial and technical information (including drafts or executed copies of various contracts and agreements), financial, O&M and decommissioning plans, engineering reports, a proposed term sheet for the guaranteed obligation, and a preliminary credit assessment for the project from a nationally recognized rating agency.

Under the previous solicitation, the sole part II due date was less than three months after the part I due date, requiring applicants to begin preparing part II submissions before learning the fate of their part I submissions. However, under the new draft solicitation, applicants whose part I submissions are deemed worthy of further consideration can pick an earlier or later part II deadline for finalizing their applications. While applicants may need to begin parts of their part II submissions earlier to ensure timely completion, certain items may be able to be delayed until after DOE invites the filing of a part II submission. Flexibility with respect to choosing a part II deadline has an immediate benefit over the previous solicitation because a large fee is due along with the part II submissions.

Applicants will now have the option of knowing that their part I submissions have been accepted before incurring this fee.

Specific dates and time frames were not included in the draft solicitation. However, the form and related discussion suggest that there will be multiple part I and multiple part II deadlines, with applicants free to mix and match their chosen deadlines however best fits their circumstances. This suggests that aggressive developers will be able to seize a first-mover advantage, while more conservative developers will be able to apply knowing that they will not incur the expense of filing or preparing a full part II submission unless their part I submission is approved.

Fees

The fee structure for applicants under the draft solicitation reflects increases to some fees but drastic reductions in others, including reduced fees for projects requesting smaller loan guarantees (another move that may encourage application by developers of small modular reactors).

The part I application fee is $50,000, down from $200,000 in 2008. A further application fee, payable with the part II submission, is $100,000 for projects seeking a guaranteed loan up to $150 million or $350,000 for projects above that threshold. The part II application fee in the 2008 solicitation was $800,000. In total, the reduction in application fees alone is $400,000 (or $650,000 for smaller loan guarantees).

However, facility fees under the draft solicitation have risen from 0.5% of the guaranteed obligation to the sum of 1% of the first $150 million of guaranteed debt plus 0.6% of any additional amounts. While the amount of the fee has become more onerous, the timing of its payment has been improved. Previously, the facility fee was due upon commencement of negotiations of a draft term sheet or, if earlier, the issuance of a term sheet, although it has never been clear how it would be possible for that to happen earlier. Under the draft solicitation, 25% of this fee is paid on or prior to the issuance of a conditional commitment, with the remaining 75% payable by the financial closing date.

An annual maintenance fee is also payable to DOE for post-closing monitoring. This amount, previously estimated to be between $200,000 and $500,000 per year, has increased now to an expected $500,000 per year, regardless of the size of the project.

These fees are in addition to the payment of the credit subsidy cost as well as the fees and expenses of DOE's outside counsel and independent consultants during the due diligence process and payments to DOE for DOE's time or expenses incurred while monitoring the loan (for example, in connection with reviewing requested amendments and waivers).

The public comment period for the draft solicitation concluded October 30. The nuclear solicitation is expected to be issued by the end of 2014. ◎

IN OTHER NEWS

more time to phase in other reduction measures. EPA is also suggesting phasing in improvements of heat rates at coal-fired power plants and increases in the dispatch rates of natural gas-fired power plants.

The agency also in October passed along some suggestions that some people who commented on the June plan made for how states might incorporate the use of new natural gas-fired power plants and co-firing of natural gas in existing coal-fired boilers to meet the required emissions targets. EPA said it might also look at the regional availability of renewable energy to set state renewable energy targets.

The emissions goals set in the June plan were based on 2012 power sector data. Some have suggested that this baseline may not have been representative, so the agency released data for years 2010 and 2011 and is taking comments on whether state emissions targets should be based on an average of several years of information.

MINOR MEMOS. The US Department of Energy reported in late September that the price of solar rooftop systems in the United States fell 12% to 19% in 2013. Another drop of 3% to 12% is expected in 2014 . . . . The top 10 US wind companies and their market shares as of the end of Q2 2014 were NextEra 20.07%, Iberdrola Renewables 10.48%, EDP Renewables 7.07%, E.On 6.49%, Invenergy 5.74%, NRG Energy 4.11%, EDF Renewable Energy 3.57%, Duke 3.48%, BP 3.09% and Enel 3.05%, according to Platts. The top 10 account for 67% of the market. There were 78 US wind companies making wholesale electricity sales.

— contributed by Keith Martin and Sue Cowell in Washington

Mozambique's New Petroleum Regime

by Kevin Atkins, Julien Bocobza and Alex Neovius, in London, with the assistance and co-operation of AG Advogados (in association with F. Castelo Branco & Associados), in Mozambique

This year has seen the passing of the much awaited new petroleum legislation in Mozambique. The need for an overhaul of the prior regime, which dates back to 2001, arose following the discovery of vast commercial quantities of gas in the Rovuma Basin offshore Mozambique. The discovery has transformed the domestic upstream sector and given Mozambique some of the largest gas reserves in the world, potentially making it also the third largest exporter of LNG behind Qatar and Australia. The revised law (Law No. 21/2014) came into force on August 18, 2014.

This article looks at some of the key changes brought about by the new petroleum law and its related fiscal legislation and draws on an English translation of the new law kindly provided by AG Advogados (in association with F. Castelo Branco & Associados), who have co-authored this article and provided Mozambique law input.

Rovuma Basin

While the new legislation will apply to all future projects, the existing Rovuma Basin projects are specifically exempted from the new regime.

During September 2014, the Mozambique parliament approved development of a new separate special legislative regime for LNG projects in the Rovuma Basin. While the exact scope of the Rovuma Basin regime has not been identified, it is expected to deal with, among other things, procurement rights for goods and services, terms and conditions of financing arrangements, labor rights, work permitting, customs rules and the design, construction and operation of facilities, and is intended to give the relevant oil and gas stakeholders (Anadarko and ENI) much needed clarity on how much tax they will be required to pay.

The parliamentary approval granted in September 2014 is understood to be on the basis that the Rovuma Basin regime is implemented by December 31, 2014. The status of the regime is unclear, although it is commonly acknowledged that a near final form has been in existence since early 2014. In any event, in addition to the December 2014 deadline, both Anadarko and ENI need the regime to be finalized before they can proceed to their final investment decision.

LNG Projects

The new petroleum law applies to future LNG projects.

The law deals with petroleum and production operations and expressly includes liquefaction activities. "Petroleum" is defined to include "treatment, including liquefaction, storage and preparation for the loading and transport of petroleum," and the phrase "production operations" is defined to include "loading as a commodity, in the form of liquefied natural gas."

The law also allows the government to authorize projects for the design, construction, installation, ownership, financing, operation and maintenance of facilities and related equipment for the production, processing, liquefaction, delivery and sale of natural gas. However, the new form of oil and gas concessions to be issued under the new law may include specific authorization for LNG projects as part of the production phase of an oil and gas investment (in which case a further separate LNG authorization will not be required).

Interestingly, though, the new law does not apply to refining and refined products (such as LPG, naphtha, diesel and fuel oils) which are excluded from the scope of the law. It is unclear whether they will be covered by a separate legislative regime.

Investor Criteria

Any Mozambican or foreign company can carry out oil and gas operations in Mozambique.

However, the mere fact of incorporation in Mozambique does not mean that a company is treated as Mozambican, as a majority of its shareholders must also be Mozambican for this to be the case. A local branch office or Mozambican subsidiary of a foreign company will not be treated as a Mozambican entity for the purposes of the new petroleum law.

Foreign investors and their intermediate group holding companies must be incorporated in a "transparent jurisdiction" where the government of the jurisdiction can verify the ownership, management, control and fiscal situation of the investor. While this provision obviously has not yet been tested in the courts, it appears to prohibit the use of offshore holding companies in corporate groups, which may be a problem as a number of African investments are routed through offshore tax-efficient holding companies to mitigate against withholding taxes and other tax leakage.

A last-minute change that was included in the new law is that oil and gas investors must also be listed on the Mozambique Stock Exchange. It is unclear when the listing must take place and how much of a free public float is required, and obviously any international institutional investors appetite for such a listing would reduce the local share ownership for any Mozambican company. This requirement is likely to prove burdensome to investors, as the initial public offering timetable will need to be factored into the project timeline and public shareholders will need to be aware that where the company is project financed, as is likely to be the case where heavy capital expenditures are envisaged for LNG infrastructure, revenue streams will be locked down and fully secured which will prohibit distributions until there is enough free cash flow.

Mozambique welcomes foreign investment in oil and gas, but project companies must list on the stock exchange.

State Participation

The participation of the Mozambican government in oil and gas projects is not subject to any cap or thresholds. The state "reserves the right to participate in any petroleum operations whatsoever," and such participation may take place "during any phase of petroleum operations" and the Mozambican government shall "progressively promote an increased level of participation in the oil and gas enterprise."

This instruction is very unclear, and investors will need certainty as to what proportion of a project is reserved for the Mozambican government before deciding whether to invest.

As currently drafted, the cap on government ownership is to be agreed as part of the negotiations in a concession award, meaning that investors in new award rounds will probably be in competition with each other to offer up attractive state participation terms to give themselves the best chance of a concession award. Obviously, the extent to which the Mozambican government can fund its own share of costs and expenses for the duration of a project will also be another key concern for investors. The new law says that the government's share will be funded by "revenue from existing resources and other forms to be defined by the Government."

The new law also includes an obligation to commit 25% of production to the domestic market, with pricing for such sales to be determined by the Mozambican government. This will affect revenue streams as sales to the domestic market may not attract the same price as sales in the international market, where Asian buyers are actively pursuing gas purchases in the LNG sector, and there is a lack of visibility as to what pricing will be adopted by the Mozambican government.

Consistent with trends across the African continent, the new law also stresses the importance of local content and the use of local contractors and service providers throughout oil and gas projects, even if this comes with extra costs. In particular, investors are required to "give preference to local products and services when analogous in terms of quality to international materials and services that are available within the timeframe and quantities required, and when the price, including taxes, is not in excess of ten percent of the price of imported goods."

In addition, where foreign contractors and service providers are used, they must work in partnership with Mozambican persons.

This implies that where an international oilfield services provider is selected instead of a Mozambican equivalent (for example, because it was more than 10% more cost effective), the international service provider must provide the services in a joint venture or a partnership with a Mozambican person anyway. This could severely delay project timelines, as any international service provider would arguably need to establish a local joint venture relationship in order to provide services in-country, and agreements as to intellectual property ownership and know-how development will need to be agreed among the joint venture parties.

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Sales and Marketing

Another important change is that the national oil company (Empresa Nacional de Hidrocarbonetos, E.P., or "ENH"), which is a partner in all oil and gas projects and the vehicle through which the Mozambican government participates in projects, is required to lead the marketing and sales of all production.

The precise scope of this obligation is unclear and whether or not this will work in practice is also unknown, as it is unlikely that ENH will have as thorough a knowledge of the buyers in the international market as international oil and gas investors that routinely participate in that market.

It may be that while ENH takes the lead in sales and marketing, the back-room technical work and responsibility for such sales and marketing efforts is carried out by the investors under some sort of technical co-operation arrangement, as is frequently the case where national oil companies take operatorship roles in oil and gas projects.

In any event, project finance lenders will want to ensure that the most economic and effective revenue streams possible are used. Leaving sales and marketing solely in the hands of ENH is unlikely to be viewed favorably.

Government Consents

The new law also includes a requirement to obtain government consent upon an indirect transfer of concession rights through a sale of shares.

This is to prevent exit transactions that are structured so as to avoid the need for prior Mozambican government consent and to avoid Mozambican tax being payable on the capital gains. However, the provision is so broadly drafted that it could conceivably apply to trading in shares in Anadarko on the New York Stock Exchange. Notwithstanding the deliberately broad drafting of the new law, in practice the scope of share transactions that require prior government consent may be narrowed by the subordinate legislation to be issued in support of the new law or may also be narrowed by the specific terms and conditions of concession awards that are negotiated between the government and oil and gas investors, as concessions are customarily interpreted as clarifying those areas of legislation that are ambiguous.

Under the previous legislative regime, consent was only required upon a sale at the asset level by the oil and gas investor, but prior concession awards often extended this requirement to sales of shares where a change in control of the concessionaire occurred.

At least 25% of production must be committed to the domestic market.

The new law will obviously affect exit strategies. All sale transactions, however structured and irrespective of the stake being sold, will require government consent as a condition precedent and, as with any sale and purchase agreement, responsibilities for obtaining this and the consequences of not obtaining it on any deposits paid will be hotly negotiated. As with the prior regime, the new law does not provide for a specific timeframe to achieve government consent nor is there a deemed or implied consent right. In any case, where technical and financial capabilities are satisfied and capital gains tax liabilities are agreed, consent is likely to be swift.

Like the prior regime, the new law is silent as to whether government consent is required for the creation of security interests over oil and gas assets. However, prior concession awards have been drafted and interpreted such that the granting of security is subject to prior government consent and, unless the new subordinate legislation provides otherwise when published, this is likely to remain a requirement under the new regime.

To the extent that any gas fields cross concession areas and need to be unitized, entry into any unitization agreements will also require the prior consent of the Mozambican government and must be agreed within six months of a declaration of commerciality. To the extent that any such consents are not forthcoming, this may also cause delays. Risks in this regard may arise if fields in the Rovuma Basin (which, as noted earlier, will be governed by a new regime specific to the Rovuma Basin) are later found to cross boundaries into other concession areas that are governed by the new general petroleum regime, as the Mozambican government is likely to prefer as much as possible of the discovery to fall within the boundaries of the concession as the concession has more favorable fiscal terms for the Mozambican government.

As another interesting point to note, Mozambican anti-trust laws are also being developed at present (with the first-ever competition law having been published in April 2013), although the full suite of subordinate legislation and regulatory authority rules and codes has not been finalized. However, as and when the anti-trust regime is established, it is currently expected, on the basis of current draft documentation, that filings and clearance from the Competition Authority will be required for future corporate transactions where, as a result of the merger or acquisition concerned, a party holds a 20% market share in Mozambique and generates turnover in Mozambique of MTN 100 million (approximately US$3.3 million).

Fiscal Provisions

The tax regime implemented as part of the new legislative package changes the capital gains landscape by applying capital gains tax to indirect transfers of concession rights through a sale of shares and also imposing joint liability on the purchaser and the seller for payment of the tax.

This broadens the scope of capital gains tax to include share transactions as well as the customary asset level sale and ensures that new entrants purchasing oil and gas projects in Mozambique, whether directly at the asset level or indirectly at the share level, are also directly liable for the payment of such taxes.

It will affect the economics of any transaction, and share sellers will want to ensure that there are tax treaty protections in place to mitigate the adverse effects of a double tax hit.

As is typically the case, capital gains tax is normally for the seller to pay as it is obviously the seller that will generate any capital gain on a sale. However, the concept of the new regime is to prohibit sellers from exiting the country, defaulting on their tax liability and leaving no assets in-country that the Mozambican government can pursue, while in the meantime the purchaser is successfully pursuing the project and generating more corporate profits. In practice, though, purchasers will not take any risk of failure by the seller to pay the capital gains tax, and purchase and sale agreements should enable purchasers to direct a proportion of the payment, equivalent to the capital gains tax charge generated by the sale, directly to the Mozambican government. Otherwise, the Mozambican government may take action against the operating company in-country at that point owned by the purchaser.

Additionally, holders of multiple concessions will be subject to ring-fencing rules that prevent losses from one concession being applied to offset profits from another concession as each concession will be taxed separately from each other.

Investment Protections

The new law includes guarantees and investment protections and provides that "expropriation may only occur on an exceptional basis and must be substantiated" and any expropriation must "serve the public interest and is subject to the payment of fair compensation," which must be determined within 90 days and payable within 190 days (presumably from the date the expropriation takes place).

While it is better to have these protections in than not, there is no frame of reference as to what is meant by "fair compensation" or as to what would constitute a substantiated case of expropriation, and these are clearly the most fundamental concepts in the protection mechanism.

Any disputes with the Mozambican government arising out of concessions awarded under the new law will be settled pursuant to ICSID arbitration unless other institutions are agreed to in the terms of the concessions. From an enforcement perspective, this is favorable to investors, although, unlike most other arbitral rules, any challenges to an award cannot be brought in the courts of the host state, but must be brought internally to the ICSID annulment committee.

Past Dealings

It is likely that a major rationale for some of the changes introduced in the new law is the exit from Mozambique by Cove Energy in 2012 where the shareholders of

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Cove, a publicly-listed oil and gas explorer, approved a public takeover of the company by PTTEP (the national oil company of Thailand).

Cove held an 8.5% interest in one of the offshore gas fields in the Rovuma Basin (and a 10% interest in an onshore non-producing field), but structured the deal so that no Mozambican tax was payable on the capital gains, as the assets in Mozambique were not being sold, but rather the corporate group was being taken over. Consequently, the Mozambican government held up the proposed takeover and threatened to impose taxes on the sale as part of its consent process. Initial rumors speculated that the tax hit could be as much as 40%, although the eventual figure was settled at 12.8% and was accepted by the parties to the transaction.

This transaction followed swiftly on the heels of the Tullow Oil purchase from Heritage Oil in Uganda where an exit tax was imposed on Heritage Oil (that the company failed to pay) and held up Tullow Oil's future development of its upstream assets in Uganda. (*See the September 2014* Newswire *starting on page 20*). A general concern for all investors is the fiscal stability of high margin cash generating projects in Africa, as there is precedent for host governments to take action and increase their shares of the pie. Therefore, good host governmental relations are absolutely key with any project.

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