chadbourne

PROJECT FINANCE
NewsWire
December 2016

Renewable Energy After the US Elections

Donald Trump said three things during the campaign about energy: he favors an all-of-the-above energy policy, he wants to bring back 30,000 coal jobs, and he favors moving forward with the Keystone oil pipeline. He offered few other specifics.

Five experts in Washington who follow energy and tax policy closely talked barely 36 hours after the polls closed in November about the potential effects of a Trump presidency on the US renewable energy market. More than 2,800 people registered to listen.

The five are Richard Glick, general counsel on the Democratic side of the Senate Committee on Energy and Natural Resources and, before that, head of the Washington office for Iberdrola (now Avangrid) and a former senior policy adviser to the US Secretary of Energy, Mark Menezes, vice president for federal relations for the Berkshire Hathaway Energy Company and former chief counsel on the Republican side of the House Energy and Commerce Committee, Joe Mikrut, a partner with Capitol Tax Partners, a heavyweight lobbying shop in Washington with former high-level tax policy types, both Republican and Democrat, and a former tax legislative counsel at the US Department of the Treasury, Kathy Weiss, vice president for government affairs with First Solar, and Greg Wetstone, president and CEO of the American Council on Renewable Energy and a former head of government and public affairs for the American Wind Energy Association and former chief counsel for environmental issues on the House Energy and Commerce Committee staff. The moderator is Keith Martin with Chadbourne in Washington.

/ continued page 2

IN THIS ISSUE

1 Renewable Energy After the US Elections
13 California: A Shifting Market for Solar
20 Chile: Solar Outlook
22 Lessons from Community Solar Financings
26 Wind Tax Equity Market
34 DOE Loan Guarantee Program: New Rules
37 Infrastructure Opportunities After The US Elections
49 Infrastructure Funds Move Into SEC Spotlight
52 Environmental Update

IN OTHER NEWS

CHANGE-IN-TAX-LAW risk is getting more attention in deals.

The Trump victory in November and Republican control of both houses of Congress make corporate tax reform more likely in 2017. House Republicans are focused on a tax reform blueprint that they released last June. (For more details, see "House GOP Tax Reform Plan" in the August 2016 *NewsWire*.)

The plan would reduce the US corporate income tax rate from 35% to 20% and greatly accelerate depreciation on new equipment. Companies would be allowed to "expense" such equipment, meaning deduct the full cost immediately.

/ continued page 3

Elections

continued from page 1

MR. MARTIN: Rich Glick, what effect will the Trump win have on the US renewable energy market?

MR. GLICK: I don't think it will have much of an effect in the short term. The significant growth that has occurred in renewable energy over the last several years is due primarily to technological advances that have reduced costs, to state policies such as restrictions on carbon emissions and state renewable portfolio standards, and to federal tax credits.

I don't expect any of those three to change as a result of the Trump win. I expect we will talk more later about the Clean Power Plan, which was expected to drive renewable energy in the medium term beyond 2020. At least for the short term, I do not expect there will be much of an impact.

The risk of a change in tax law is getting more attention in deals.

MR. MARTIN: Mark Menezes.

MR. MENEZES: I agree with what Rich Glick said, with one caveat. I would watch for tax reform proposals as part of the first-100-day plan of the Trump administration.

MR. MARTIN: Joe Mikrut.

MR. MIKRUT: Focusing on the tax pieces, I don't foresee a lot coming up in the near term under the new administration. Energy tax issues really were not a focus of the campaign, so I think the issues for energy are going to be outside the tax world.

MR. MARTIN: Does that mean you do not believe Congress will tackle corporate tax reform in 2017?

MR. MIKRUT: Tax reform is a different issue. We have been talking about tax reform in Washington since at least the Bush administration. The years of talk with no action demonstrate how hard it is to do.

Having both the administration and both houses of Congress under Republican control will make it a little easier. As to what corporate tax reform might look like, a blueprint that the speaker of the House, Paul Ryan, and the chairman of the House tax-writing committee, Kevin Brady, released last June is the probable starting point. Brady's staff on the House Ways and Means Committee has been working to convert the blueprint into legislative language over the last few months. We will get into more detail in a bit.

MR. MARTIN: Kathy Weiss, what are you telling First Solar will be the effect of the Trump win?

MS. WEISS: Trump called during the campaign for an all-of-the-above energy policy. I think we will have to keep fighting to make sure that there is equal treatment among the market segments. I would caution against overstating our sector's dependence on government policy to continue making advances.

Although renewable energy remains a relatively small part of the overall energy supply, the transformation has begun. We are moving from a mandate-driven push market to a customer-driven pull market. It is hard to see how that can be reversed. The market dynamics are overtaking government policy as the real driver.

MR. MARTIN: Greg Wetstone.

MR. WETSTONE: I agree with what has been said. I think we are looking at three or four years of solid growth that has already been baked in.

We had $44 billion in combined wind and solar investment last year. The main factors that are driving that investment are falling equipment costs and rising efficiency. Renewable energy is more competitive. There is more demand for renewables among residential and corporate consumers. Aggressive state policies are part of the picture. Federal tax credits remain in place. None of these is likely to change on account of the election.

The real question is what happens once we get past 2020. Will the longer-term drivers like the Paris agreement and the Clean Power Plan remain in place?

Clean Power Plan

MR. MARTIN: That is a good bridge to the next question, which is Trump wants to jettison the Clean Power Plan. For listeners outside the United States, the Clean Power Plan is an effort by the US Environmental Protection Agency, with encouragement from Barack Obama, to reduce greenhouse gas emissions from US power plants.

Greg Wetstone, can Trump simply revoke the Clean Power Plan or is it more complicated than that?

MR. WETSTONE: It is more complicated. The plan is tied up in the federal courts. The US Supreme Court put an unprecedented stay on it before the lower courts had finished hearing the arguments about the plan. It had never intervened in that fashion before. The plan is currently before a US appeals court in Washington. If the appeals court upholds the plan, then it goes to the Supreme Court. The Supreme Court is short one justice. Presumably we would be looking at a 4-4 tie, which would leave the appeals court decision in place, unless Congress clears a new justice, who would be a Trump appointee, before the case is heard by the Supreme Court.

That is a pretty big point of vulnerability, but there is also the reality that if the Supreme Court strikes down the plan, the plan would go back to the Environmental Protection Agency. Under Trump, the agency is more likely to try to kill the plan than to move forward with it. I think you have to say the plan is on life support at this point.

MS. WEISS: There are currently 19 states that are actively planning for compliance with the Clean Power Plan. Those states have invested considerable time looking into the current available technologies for controlling emissions and their costs. They see the potential for new economic development as people invest in clean energy technologies. You have major companies poised to move into states where they can make these investments.

MR. WETSTONE: That is exactly right. The Clean Power Plan might still serve as an important blueprint for states that want to move forward on their own.

MR. MARTIN: This may feel like a return to the Bush administration when the federal government had little appetite for federal action to promote renewable energy and so the action devolved to the states. You get different state approaches. You have nine states in New England and the mid-Atlantic, for example, with a RGGI regime to reduce greenhouse gas emissions, California is moving forward with its own plan, and so on.

Greg Wetstone, correct me if I am wrong: the action by EPA to control greenhouse gases was compelled / continued page 4

IN OTHER NEWS

However, the centerpiece of the plan is a shift to a destination-based cash-flow tax.

US companies would not be taxed on earnings from exports of goods and services. They would not be allowed to deduct the cost of imports. This could have a significant effect on the renewable energy sector, since a substantial amount of wind and solar equipment is manufactured overseas.

Battle lines are already forming around the denial of cost recovery on imported equipment, with Koch Industries and retailers like Walmart lining up against it.

Republicans on the House tax committee have scheduled two days of meetings in mid-December to focus on how the plan would work.

A November 30 paper circulating in Washington by Alan Auerbach, a Harvard-trained economist, and Douglas Holtz-Eakin, a former director of the Congressional Budget Office, explains. The authors compare the border adjustments to what happens under a value-added tax in Europe. Any VAT paid on goods that are ultimately exported is refunded. Imported goods are fully taxed. The authors argue that denying cost recovery on imported equipment is equivalent to subjecting such equipment fully to US tax.

Interest would not be deductible under the House tax plan, so companies with more debt in their capital structures would generally fare worse and those with higher capital investment would fare better because of expensing, but firms that have both high debt and high capital investment in imported equipment would be much worse off.

The paper suggests the dollar should strengthen, taking some of the sting out of the loss of cost recovery for imported equipment since that equipment will be cheaper to purchase; it will cost less in dollars.

Companies that export a lot may end up with large tax losses for their costs in the United States, but no income.

It appears the Trump / continued page 5

Elections

continued from page 3

by a finding of endangerment under the Clean Air Act, so somebody would have to unravel the endangerment finding first to withdraw the Clean Power Plan altogether. Correct?

MR. WETSTONE: It is possible for the plan to be sent back to the agency and then the agency could come up with a new proposal. The question is what such a proposal from the Trump administration would look like and how quickly we would see it.

MR. GLICK: There is also the possibility the Supreme Court might uphold the Clean Power Plan rather than send it back to the agency. A Trump EPA would have to go through a process of initiating a new regulatory process. It might start by revisiting the earlier finding that CO2 is a pollutant that endangers public health and welfare.

Another option is for EPA to keep the endangerment finding, but go through the rulemaking again and come out with a much more limited Clean Power Plan. For instance, a revised plan might only require coal-fired power plants to make changes to their efficiency levels as opposed to going beyond the so-called fence to address renewable energy and energy efficiency. I think that is the more likely scenario with the endangerment finding left in place.

MR. MARTIN: So cripple the plan. The initiative moves to the 19 or so states that are keen to deal with global warming. Greg Wetstone, is Trump expected to roll back other environmental laws and regulations: for example, the Endangered Species Act, federal restrictions on wetlands, and limits on SO2, NOx and mercury emissions from power plants?

MR. WETSTONE: We have not heard any specific plans in these areas, other than an interest possibly in rolling back some rulings under the Clean Water Act. It is important to keep in mind that once a regulation is issued and tested in the inevitable litigation that follows any new environmental regulation, it is difficult to turn back the clock. The Clean Power Plan is different because it has not gone fully through the courts, and implementation was suspended by the Supreme Court. We saw how efforts by the second Bush administration to reverse some Clean Air Act rules and forest protection rules from the Clinton administration ran into difficulty in court.

It takes a pretty exhaustive process to reverse a final rulemaking of any sort.

MR. MARTIN: It is exhausting to put environmental regulations in place. It is exhausting to dismantle them. Mark Menezes, one of the things Trump wants to do is to preserve 30,000 coal mining jobs in the United States. Coal stocks were up yesterday in anticipation. Any idea how he might do this? Is it possible we might see construction of new coal-fired power plants?

MR. MENEZES: I see the potential for a two-pronged approach. One part is an effort to roll back some of the existing air emissions regulations that tend to hit coal-fired power plants. There are regional haze and any number of other rules on which the agency might take a more lax approach to enforcement or reissue the rules as Rich Glick described. That is one way to help the coal industry.

The other way is Trump could resume leasing federal lands for coal mining. The Obama administration made it difficult to extend existing coal leases or enter into new ones.

The Trump administration might also push Congress to provide new incentives to use coal much like we have for renewable energy. There might be ways to encourage carbon capture and sequestration like we have seen in the past.

MR. MARTIN: Your parent company has coal-fired power plants. Do you foresee any new construction?

MR. MENEZES: No.

Tax Changes

MR. MARTIN: Let's go back to Joe Mikrut. The Trump win and the fact that Republicans are in charge of both houses of Congress make overhaul of the US tax code more likely. How likely is major tax reform? You sounded a somewhat pessimistic note earlier about the prospects. If tax reform does move forward, on what timetable will it move?

MR. MIKRUT: When people talk about a greater likelihood of tax reform under an all-Republican Congress, they are thinking it will be folded into a budget reconciliation bill. Such bills require only 51 votes to pass the Senate. Other bills take 60 votes. It looks like there will be only 52 Republicans in the Senate in the next Congress. That is the reason why people think the odds of moving tax reform have improved after the election.

But even then, a major overhaul of the US tax code is very difficult. There are problems with moving tax reform as part of a reconciliation bill. The most important challenge is such a bill cannot have negative budgetary effects outside a 10-year window. So we could end up enacting a new tax code that would remain in place for nine years and then spring back to the current tax code.

MR. MARTIN: Unless the rewrite of the tax code is revenue neutral?

MR. MIKRUT: Unless it is revenue neutral, but the proposals that are in front of us are certainly not revenue neutral. There are significant procedural and policy challenges with moving tax reform through budget reconciliation.

What is more clear is the direction tax reform may take. If you look at the tax reform blueprint that the speaker of the House, Paul Ryan, and the chairman of the House tax-writing committee, Kevin Brady, released in June, and you look at what the Trump campaign talked about during the run up to the election, there are many similarities.

The process will start in the House. The opening bid will be something similar to what Ryan and Brady released in June.

MR. MARTIN: For anyone interested in the House Republican blueprint, you can find details on the web. A Google search with the terms "blueprint Republican tax plan Chadbourne" will lead you to a short paper on how it would affect renewable energy and the project finance market.

Joe Mikrut, correct me if I am wrong, but most people like you are waiting at this point to see the actual bill language. When do you expect it to be released?

MR. MIKRUT: The Ways and Means Committee staff has been drafting, but the staff is basically taking a 30-page blueprint and trying to write a whole new Internal Revenue Code. It will take time.

The proposed blueprint would make a fundamental change. Most people have focused on the fact that the blueprint calls for significant cuts in US tax rates, both on the individual side and the business side. But on the business side, there are even more fundamental changes. The blueprint would convert our current income tax system into a consumption-based tax.

There would be immediate expensing for all capital expenditures. No interest deductions. We would move to a destination-based tax, meaning the cost of imported goods and services will no longer be deductible, and earnings from US exports will no longer be taxable. When you consider the volume of goods the US imports, this will be a huge, huge change that will affect a lot of firms.

MR. MARTIN: Does that mean, for example, that companies that use imported wind turbines or solar panels in new renewable energy projects would not be able to depreciate the cost?

MR. MIKRUT: Correct. Neither depreciate nor what would happen under the proposal, write off the cost immediately. If you have a domestically-produced turbine, you could deduct the entire cost in year one. If you have a foreign-sourced turbine, you get no cost recovery. / continued page 6

IN OTHER NEWS

team is gravitating toward the House plan. Two possible differences are Trump called during the campaign for a 15% corporate tax rate, and he proposed to give US companies a choice between cost recovery and deducting interest.

The risk of corporate tax reform is playing out a number of ways in deals.

Sponsors already take the risk of a shift in tax rate in most tax equity transactions in the renewable energy market.

Increasingly lately, they also take the risk that the depreciation calculations will change. Any acceleration of depreciation will work to their benefit.

There has been more focus since the election in tax equity transactions where there is more than one funding on the point in the legislative process at which the tax equity investor can stop funding. For example, in the solar rooftop market, the tax equity investor makes continuing investments over a year as new tranches of solar systems are added to the financing. This has led to debate over whether funding can stop when either house of Congress passes an adverse tax law change or whether funding can stop earlier: for example, when a tax committee first votes or the House Republican tax plan is first released in bill form.

The last time Congress did a comprehensive overhaul of the US tax code was in 1986. It repealed the investment tax credit, effective at the end of 1985, and it slowed down depreciation allowances effective in March 1986. There were numerous transition rules to let companies that committed to investments before the effective date see their investments through with the old tax benefits.

The key was the companies had signed binding contracts. For example, the fact that a company signed a binding construction contract or a power purchase agreement committing to build a particular project was enough to entitle the company to transition relief.

Tax reform bills tend to start moving through Congress without transition / continued page 7

Elections

continued from page 5

MR. MARTIN: To repeat some of what you said, the Republicans want to move to so-called expensing. Instead of deducting the cost of equipment over time as depreciation, companies would be able to deduct the full cost in the year the equipment is put in service.

MR. MIKRUT: That is correct.

MR. MARTIN: Income from exports would not be taxed at all, so if you have a power plant on the US side of the Mexican border and sell the power across the border, there would be no US tax on the income.

MR. MIKRUT: That is also true.

MR. MARTIN: Trump wants to reduce the corporate tax rate to 15%. How realistic a goal is that?

MR. MIKRUT: It is really hard. Several years ago, the then-Republican chairman of the House Ways and Means Committee, Dave Camp, tried to reduce the rate to 25% on a revenue-neutral basis. He essentially had to eliminate all tax preferences. The House Republican caucus never fully embraced the proposal.

The Trump plan, if it follows the blueprint, would eliminate many tax preferences, but it would also allow expensing, which has a huge cost. It is hard to see how the math works. You do get a dynamic effect from changing into a consumption-based tax, but the plan may not come close to paying for itself. A 15% rate will be difficult to achieve if you want to keep things on a revenue-neutral basis.

ITC and PTC

MR. MARTIN: How likely is it that the solar and wind tax credits will be on the chopping block? A dramatic rate reduction is almost like a hurricane hitting the east coast; it sweeps a lot of things out of the way in order to pay for the rate reduction.

MR. MIKRUT: There are two schools of thought in the blueprint itself. The blueprint would eliminate all the general business credits, except for the low-income housing credit and the research credit. But the blueprint also suggests Congress will be open to transition rules.

One could look at the existing phase-out of the wind and solar credits as a transition rule. Congress could decide to leave them alone.

On the other hand, it is possible that Congress could decide to cut off the remaining tail of wherever you are in the 10-year window for production tax credits, since companies will benefit after tax reform from a lower corporate tax rate.

The outlook is unclear. All tax credits are in the bull's eye as a possible way to pay for the rate reduction.

MR. MARTIN: The investment tax credit was repealed at the end of 1985, and depreciation was slowed down after 1986, to help pay for the last overhaul of the tax code in 1986, but transition rules allowed anyone who had committed to an investment before the changes to see the investment through and still claim the old tax benefits. There was an outside deadline of three to five years, depending on the assets, to put power projects in service.

If Congress were to sweep away the renewable energy credits to help pay for a corporate rate reduction, isn't the most likely approach to cut short the remaining construction-start deadlines? And is it fairly certain that if the credit periods are cut short, anyone who already committed to an investment would be allowed to see the investment through with the existing tax credits?

MR. MIKRUT: You would think that would be true based on concepts of fairness and what Congress has done historically when it has pulled away tax benefits. But this is a brave new world. The economists on the Joint Tax Committee staff may think about whether the same approach makes sense when the people who are holding on to grandfathered tax credits are also benefiting from a significant reduction in the corporate tax rate. Everything will be examined. Everything will be on the table.

MR. MARTIN: I have three more quick tax questions. Fuel cell and geothermal heat pump companies, and developers of cogeneration projects and other renewables like biomass, geothermal and landfill gas, are hoping that Congress will give them the same phase down of tax credits that applies for wind or solar. The hope is this will happen in a lame-duck session of Congress that runs from mid-November into December. How do the election results affect the odds of that happening?

MR. MIKRUT: Folks were probably a little more confident a week ago than they are today. The Senate Democratic leader, Harry Reid, has fought hard for these provisions, and he says he has a promise that they will be addressed in the lame-duck session. The Republicans are still trying to determine what to tackle in the lame duck. These credits are on the table. The Senate Republican leader, Mitch McConnell, said so in a press conference yesterday. But the odds of it happening are lower after the election than they were before.

MR. GLICK: You have to separate these provisions into two categories. There is an investment tax credit for fuel cells, CHP projects and geothermal heat pumps that was left off the table, probably by mistake, when the ITC was extended at the end of last year for solar.

chadbourne

Senator Reid is very, very committed to getting that done, and this is his last chance before he retires at the end of this year. He has had a number of discussions not only with the Republican leader, Senator McConnell, but also on the House side. While the election has certainly created more uncertainty, I think when there is a will, there is a way. I remain optimistic that somehow this gets done.

The other category is a phase-out of production tax credits for geothermal, biomass and so on to mirror the phase-out that Congress adopted last year for wind. Given the election results, Congress is less likely to consider a tax extender bill addressing these provisions. The issue still could be addressed in the next Congress.

MR. MARTIN: There is debate about whether there will be much of a lame-duck session. There is a view among Republicans that they should do only what is absolutely necessary in the lame-duck session and kick other issues into 2017 when they will no longer have to negotiate with President Obama.

I have two more quick questions. Energy storage is expected to transform the electricity sector. There is a bipartisan bill to allow a 30% investment tax credit for storage like the current tax credit for solar. The bill has been gradually picking up support. How have its prospects been affected by the election?

MR. MIKRUT: If you look at the themes in the House Republican blueprint for tax reform, these types of tax credits probably do not fare as well as they would have if you were simply trying to rationalize the current income tax system. My guess is that creating a new tax credit like this probably is not in the mix in the lame-duck session.

Maybe something happens early in 2017, but as we go deeper and deeper into tax reform, these sorts of provisions will have a tough time getting traction.

MR. MARTIN: There has been a push by renewable energy companies the last several years to be able to operate as master limited partnerships. The House blueprint and a comprehensive tax reform proposal introduced in 2014 by the House tax committee chairman, Dave Camp, proposed rolling back use of MLPs to a narrower class of companies that were given permission to use them in 1988. The eligible class has expanded a little since 1988.

In which direction do you see this debate moving?

MR. MIKRUT: I think MLPs are in a pretty good spot. Kevin Brady, the current House tax committee chairman, is a big supporter of master limited partnerships. He is from Texas. They are used today mainly by the oil and gas industry. I don't think he is opposed to other uses.

/ continued page 8

IN OTHER NEWS

relief. The Joint Tax Committee staff expects companies that would be treated unfairly by a tax law change to come describe their situations. The committee staff can then fashion broad transition rules to cover deserving cases. The tax committee chairmen also tend to use transition relief as leverage to pick up votes for the larger package of tax reforms.

A TRUMP INFRASTRUCTURE CREDIT could subject returns of infrastructure investors to a negative 113% income tax rate.

Two Trump economic advisers, incoming Commerce Secretary Wilbur Ross and economics professor Peter Navarro, suggested in October that a Trump administration might allow an 82% tax credit to be claimed on equity investments in new infrastructure projects.

Martin Sullivan of *Tax Notes* magazine calculated that the tax credit could leave equity investors in new infrastructure projects with significantly more tax shelter than the taxes they would have to pay on their earnings from such projects. He assumed a corporate tax rate of 15% and earnings commensurate with a 9% internal rate of return.

THE US TREASURY lost a significant case in the US claims court.

The decision could eventually lead to more lawsuits against the Treasury by renewable energy companies that feel shortchanged by the cash grants they received under the section 1603 program. There is a six-year statute of limitations on filing suit.

Roughly 28% of the 107,433 section 1603 payments made by the Treasury have been for less than the companies expected.

More than 30 lawsuits have been filed. The government has now won two and lost two of the cases that went to trial. A fifth case ended in a draw. A number of cases have been dismissed or withdrawn by the taxpayers. The government has been filing counterclaims this year against some companies that sue to discourage anyone else from suing.

/ continued page 9

Elections

continued from page 7

If you look on the other side of the Capitol, Orrin Hatch, the Senate tax committee chairman, is interested in corporate tax integration. He wants corporate earnings to be taxed only once instead of twice at both the corporate and the shareholder level. MLPs are a way to tax earnings only once.

The theme of having one level of tax plays well. I think the prospects are fairly good of expanding the available types of assets that could be owned by an MLP.

Energy Policy Bill

MR. MARTIN: Rich Glick, a bipartisan energy bill is stuck in conference between the House and Senate. Many people say it is dead. Do you agree?

MR. GLICK: Not necessarily. A significant amount of work has been put into this effort. Both Republicans and Democrats in the Senate worked on a bipartisan basis and got 85 votes. How many times do you see 85% of either house of Congress voting for anything in the current partisan atmosphere?

There is a lot of interest in seeing whether we can still get it done in this Congress. We have had 50 or so meetings between the House and Senate staffs over the last few months to try to resolve the differences in the bill.

Senator Murkowski and Senator Cantwell, the top Republican and Democrat on the Senate Energy Committee, and others put together a list of bipartisan revisions to the bill to try to address some of the concerns that have been raised by the House. That list is pending before the House.

There is more uncertainty about where this is headed in the aftermath of the election, but I think everyone needs to ask whether it will be any easier to get a bill done in the next Congress and, if the answer is no, work as hard as possible to get it done this year.

Even with a new president, you will still need cooperation by both Democrats and Republicans to get anything done in the Senate.

MR. MARTIN: Mark Menezes, let's say that it becomes too great a challenge to get the energy bill unstuck this year, particularly given that the lame-duck session may be cut short. Do you see a bill along the same lines reemerging in the next Congress and, if so, what if anything in it is likely to have a significant effect on renewable energy?

MR. MENEZES: Excellent question. One consequence of the election is you have a lot of excitement on Capitol Hill and in the incoming administration, with one party in control of both houses of Congress and the White House, about the possibility of getting something done for a change. There is true enthusiasm to get as many things done as possible.

Rich Glick is right. It would be easier to finish the bill this year given how much effort has already been put into it. However, the pattern in the past has been to build on what was started in a previous Congress. You carry forward much of the work that preceded you.

MR. MARTIN: What if anything in the energy bill would have a significant effect on renewable energy?

MR. GLICK: There are a couple of relevant provisions in the bill. None of them is earth shattering. The bill would promote more renewable energy development on public lands. It would help modernize the electricity grid in a manner that would help integrate intermittent resources like wind and solar.

It is too early to predict how the content of the bill might change if the process had to start over again in the next Congress.

PURPA

MR. MARTIN: Let's move to the next topic. PURPA is a 1978 law that requires utilities to buy electricity from independent generators. The statute was largely emasculated in 2005. It has continuing currency in parts of the United States that lack organized electricity markets.

PURPA has emerged as a new battleground. What are the battle lines and what, if anything, do you see happening?

MS. WEISS: I could see whatever recommendations come out of a technical conference that the Federal Energy Regulatory Commission held this fall on PURPA folded into a comprehensive energy bill if there is such a bill next year.

FERC has not released its recommendations yet. It is wrestling with some contentious issues, including how to determine avoided cost and how to determine whether multiple small projects should be combined with the result that they are too large to be qualifying facilities. The technical conference was a compromise between Republicans, who want to repeal PURPA, and Democrats, who would like to see it expanded.

There is also the potential to make headway on issues around streamlining the siting and permitting of utility projects on public land.

MR. MARTIN: So the issues are how much should utilities pay for electricity from independent generators — utility pay the avoided cost they would have incurred to generate the electricity themselves — and from what types of projects must utilities buy power — there are size limits on qualifying projects — and how to determine whether projects are inside or outside those size limits, since developers sometimes break a single, large project into smaller units to try to qualify. FERC held a technical conference. It will report soon to Congress.

MR. GLICK: A number of issues were raised at the technical conference, and then interested parties had the opportunity to file comments. FERC will decide whether to undertake any initiative, such as revising its regulations, to address some of the concerns that were raised about avoided cost determinations and other issues that have arisen around PURPA. FERC will have to decide first to what extent the issues can be addressed administratively.

The United States is expected to cut its corporate tax rate to perhaps as low as 20%.

There will be some discussion in Congress about what to do. Congress revised the statute in 2005. It is unclear whether there is additional appetite for amending the statute further. The Democrats on the Senate Energy Committee are thinking that maybe some of the issues can be addressed administratively by FERC. They are not necessarily interested in pursuing legislative changes at this point.

Infrastructure Push

MR. MARTIN: Next topic: Trump wants $1 trillion in new spending on infrastructure over the next 10 years. This is supposed to be part of his first-100-day plan. He wants an 82% tax credit to induce more private investment. There is also talk of allowing US companies with earnings parked in offshore holding companies to bring those earnings back to the United States at a reduced tax rate in exchange, presumably, for investing the funds in infrastructure.

/ *continued page 10*

IN OTHER NEWS

Three cases were decided since late October.

In the most significant of the three, the US Court of Federal Claims ordered the US Treasury in late October to pay the owners of six Alta wind farms in California another $206.8 million in cash grants. The case is *Alta Wind I Owner v. United States*.

The government has not decided whether to appeal.

The court reached two significant conclusions. First, it said a power contract that requires electricity to be supplied from a particular power plant has no value independently of the power plant. Therefore, any amount paid for the PPA is basis in the power plant and goes into the calculation of tax benefits.

Second, the court implicitly rejected the approach the Treasury has been using of determining the tax basis in a project by starting with the actual cost to construct the project and then adding a markup. It said the tax equity investors in the Alta projects were entitled to use the prices they actually paid for the projects, absent proof that the prices were not arm's-length prices.

The case involved six Alta wind farms in California. Five of the wind farms were financed in sale-leasebacks. One was sold to EverPower.

The owners of the projects— mostly tax equity investors — applied for grants based on what they paid for the projects rather than what the developer, Terra-Gen, spent to build them.

The court said the bases that the parties used to claim Treasury cash grants were correct. It ordered the Treasury to pay the project owners a total of $206.8 million, which is the amount by which the owners said they had been shortchanged.

The judge rejected the testimony of the government's sole expert witness — a senior lecturer at the Massachusetts Institute of Technology — because the witness failed to disclose a full list of articles he published in the last 10 years, as required by the claims court rules. The witness gave the court a list running longer than 10 years, but

/ *continued page 11*

Elections

continued from page 9

How strong a consensus do you see on Capitol Hill for doing something here, and what form do you see any federal push in this area taking?

MR. MIKRUT: Infrastructure spending is probably something on which both parties can agree. Both candidates had it in their plans. The tough issue is how you pay for it.

Chuck Schumer, the incoming Senate Democratic leader, and Paul Ryan, the speaker of the House, had conversations a year ago about using a tax on offshore earnings to fund infrastructure spending. However, the corporate tax reform blueprint that House Republicans released in June would use any revenue collected from repatriating offshore earnings to fund the corporate rate reduction and international tax reform. Unless you double count the revenue, once for infrastructure and again for tax reform, Congress will have to find another way to pay for infrastructure.

Infrastructure may well be part of the 100-day plan, but exactly what form it takes — whether it is tax credits or direct spending — and how it is funded, are significant issues that will have to be ironed out.

MR. MARTIN: Does anyone think that electric transmission lines and gas pipelines are likely to be considered part of infrastructure for this purpose?

MR. GLICK: Both political parties recognize that there has been insufficient infrastructure investment not only in roads, bridges and ports, but also in the energy sector. Electric transmission is a good example. We need significantly more electric transmission in order to reach remotely-located renewable resources.

The issue is to what degree the incoming administration and Congress will want the federal government involved in funding versus merely encouraging private investment. Any federal involvement could take the form of tax credits or other incentives. There is an interest in seeing whether people can use the infrastructure bill to promote additional investment in transmission.

MR. MARTIN: Does anyone foresee any federal action to make it easier to site new transmission lines? Obama was unable to make progress on this. Is it fair to say that Trump will be unable to do so either and he may not have an interest in doing so because of states' rights issues?

MR. GLICK: I do not think the election results change the fact that both Republicans and Democrats in Congress have been reluctant to get involved in the issue of eminent domain for electric transmission siting.

MR. MARTIN: There were some interesting votes at the state level on ballot questions. A carbon tax was voted down in Washington state. An anti-solar constitutional amendment failed in Florida. Nevadans voted to break the monopoly on local utility supply by NV Energy. Are these votes unique to particular states or are there larger messages?

MS. WEISS: If there is a larger message, it is that clean energy is starting to have a visible effect on jobs. In solar alone, we are expecting to move from 200,000 jobs today to 400,000 jobs by 2020.

Another theme is people want more control over their energy choices.

Both of these have the potential to affect decisions being made at the ballot box and at a policy level in Washington.

MR. WETSTONE: Things seem likely to happen fairly rapidly in a number of other states as well. One prominent example is Ohio where the freeze on the state renewable portfolio standard is ending, and we may see proposals to overturn or soften very harsh setback requirements that have limited wind development.

In Maryland, the Republican governor, Larry Hogan, vetoed a higher renewable portfolio standard. We are likely to see an effort to overturn the veto soon. Kansas is another example where a Republican governor, Sam Brownback, has been fairly aggressive in saying they need to do more. He wants to grow more renewables in Kansas, expand

The tax reform bill taking shape in the House would deny depreciation on imported equipment.

into solar as well as wind, and adopt measures that might open the door toward greater corporate procurement.

Audience Questions

MR. MARTIN: Let's move to audience questions. Someone asks, "It sounds like Joe Mikrut is saying there is a 50-50 chance that the tax credits might be cut short — not just whether a project qualifies in the first instance for 10 years of production tax credits, but also whatever tail remains on the 10-year period. Does anyone else have a probability to attach to this outcome?"

MS. WEISS: Let me preface it by saying the track record of predicting tax reform is probably about as good as the polls leading up to Tuesday's election. That said, I would give very low odds, if not no odds, to the investment tax credit and production tax credits being rolled back. Every conversation I have had with the bipartisan supporters of these credits in Congress on the Hill to folks on the Trump transition team suggests there is zero interest in rolling back these tax credits.

I agree that once you get into negotiations, people take stands to improve their negotiating positions, but I think there is widespread recognition that companies are making important investment decisions by entering into contracts for projects, and businesses need certainty. Tax reform is by no means certain to move forward. It is a huge undertaking. There will be transition rules if we get into tax reform.

MR. MARTIN: Important point, Kathy. And to be fair to Joe Mikrut, he did not put odds on this. He just said it is something to keep an eye on.

MR. WETSTONE: I agree with Kathy Weiss. The fact that the wind and solar credits are already on a phase-down schedule makes it less likely Congress will choose to revisit the phase down, particularly given the bipartisan support behind renewables. Even if the Republicans try to push tax reform through the Senate by folding it into a budget reconciliation bill so that it can clear with only 51 votes, several Republican Senators are interested in seeing the existing tax credits be allowed to phase out as scheduled.

MR. GLICK: I agree with both Kathy Weiss and Greg Wetstone, but there is something on which solar companies need to keep an eye. The 30% solar investment tax credit phases down over the period 2019 through 2021 to its permanent level of a 10% investment tax credit. It does not go to zero. The potential loss of the 10% permanent credit is what I would be more worried about as part of the tax reform discussion.

MR. MARTIN: Joe Mikrut, a number of */ continued page 12*

IN OTHER NEWS

omitted several articles he wrote for Marxist and East German publications in the 1980's and failed to disclose that he had been an editorial board member for two years in the 1990's of a company that published "A Journal of Marxist Thought and Analysis."

The Alta owners had unusually strong evidence to support the prices they paid for the projects. Terra-Gen, the sponsor, had put the projects out for sale in an auction.

The prices paid by the tax equity investors were at most 2% above the bids received in the auction.

The investors claimed 93.1% to 96.9% of their bases in the projects were in eligible assets for the cash grants. Cash grants can only be claimed on equipment and not on land or contracts, goodwill, going concern value and similar intangibles. Edward Settle, the public face of the Treasury cash grant review team at the National Renewable Energy Laboratory, testified that NREL had a rule of thumb that 95% of the cost of the average wind farm is basis in eligible equipment.

The court said the "transactions were negotiated by sophisticated parties at arm's length."

It rejected the government's view that the tax equity investors had to assign part of the value in the projects to intangibles by first adding up the value of the equipment and treating what remained as basis in intangibles like customer goodwill or going concern value. (Going concern value is the notion that there is an extra intangible value in a group of assets that someone has already assembled as a going business.) The court said the approach of assigning a value to each of the hard assets and then treating the rest as value in intangibles only applies to the sale of the kind of business that has customer goodwill. There is no customer goodwill in a power plant that is not yet operating and that has only a single utility as a customer under a long-term PPA, the court said.

/ continued page 13

Elections

continued from page 11

people have asked various forms of the following question. Is it possible the Trump administration could roll back or revoke the five notices the IRS has issued interpreting when renewable energy projects are considered under construction?

MR. MIKRUT: Everything is possible. Trying to predict what President Trump will do is hard since the campaign did not release a lot of detail about what he might do as president, but let me make a couple points.

Once we get into next year, production tax credits are already phasing out. We will be in the years when starting construction of any new project qualifies the developer for tax credits at only 80%, 60% or 40% of the original level. There is a question whether there is any real reason to revisit issues in this area. These issues have already been decided. Why not move on to more important matters?

I think that would be the more likely view of whatever new team takes over the tax policy positions at Treasury. That said, there is a tradition whenever there is a change in administrations, particularly when there has been a change in political party, for the new team to look at what the old team put out and decide whether to let it stand or make modifications.

So, as in anything, you are never completely safe, but I think in this instance, the most likely outcome is the guidance will remain as is.

MR. MARTIN: Greg Wetstone, someone asks whether a new Supreme Court justice could be in place by the time the US Supreme Court hears the Clean Power Plan case.

MR. WETSTONE: Possibly. The court is currently at a 4-4 tie between liberals and conservatives. A US appeals court still needs to issue a decision about the plan before the case can move to the Supreme Court. The Senate could try to move quickly on confirming a new justice. Even if it does not, it may be the court would schedule any argument until later in the year.

MR. MARTIN: Another audience question: "What impact do you see the Trump administration having on US Department of Energy loan guarantees for renewable and energy efficiency technologies?"

MR. GLICK: As everyone listening knows, there has been a bitter history over the last several years with the loan guarantee program and heated debate between Republicans and Democrats about one guarantee in particular that was issued to a solar company that later went bankrupt.

As I understand it, there is still some funding remaining in the program at the Department of Energy, but not a significant amount. I do not expect to see any new funding from Congress or the Trump administration for the program. In terms of carrying out the existing program, I am cautiously optimistic that the program will continue.

MS. WEISS: I agree with Rich Glick, but it is important to note that this was an incredibly successful program. It made money for the Treasury. It enabled what at the time were innovative projects to transition from government support to the ability to stand on their own with private sources of financing. I hope that with the support the Trump campaign expressed for innovation and new technologies, we can move past the stink of what happened five years ago. There is recognition that the loan guarantees have been important to advancing other technologies like nuclear and clean coal.

MR. MARTIN: We have more than 100 questions and limited time. A number of people ask what the outlook is under Trump for the renewable fuel standard and RINs. This was an important issue during the campaign in Iowa and in the rest of the corn belt.

MR. MENEZES: Jack Gerard of the American Petroleum Institute just put out a report calling for the repeal and overhauling of the renewable fuel standard.

The renewable fuel standard and the DOE loan guarantee program were both creatures of the Energy Policy Act in 2005. The RFS is highly contentious. The oil companies would like to get rid of it. The report by API is the opening shot across the bow. It will put heightened scrutiny on it in the upcoming Congress.

MR. MARTIN: Next question: "How do you assess clean energy as a component of an infrastructure spending priority, and what are the chances that an infrastructure bank will be used to promote infrastructure investment?"

MR. GLICK: I am not sure what the chances are for an infrastructure bank in the new political environment, but in terms of infrastructure and clean energy, this is an opportunity for Democrats and Republicans to work together. There have already been some encouraging signs that they might do so.

Clearly on the Democratic side and some on the Republican side, there are infrastructure proposals related to clean energy. There are bills on electric transmission, energy storage and smart grids. It is too soon to tell, but it is possible that those types of technologies might be addressed in an infrastructure bill.

MR. MARTIN: Let me ask a general question. We now have one party in control of both houses of Congress and the White House. Some people think that means we will have a rare period when there is no gridlock in Washington and something will actually get done. What do you think?

MR. MENEZES: I think that is right, but keep in mind the following. When I served on Capitol Hill, there was a unified government, but you still had to operate within the rules and even if you put together a bill in the House, it remains subject to points of order, and it takes a lot of cooperation to get the bill through the full House.

Then it goes to the Senate where, absent a budget reconciliation process, you have to get 60 votes to move the bill.

The Republican caucus is not a unified caucus. It is never an easy process, even with one party in control.

All of that said, this is the best chance in more than a decade for new legislation to move. ◎

California: A Shifting Market for Solar

by Laura Norin and Naina Gupta, with MRW & Associates, LLC in Oakland, California

The California Public Utilities Commission is in the process of changing two key constructs that are central to the economics of solar in California.

The two are net energy metering that allows customers to sell extra electricity generated from rooftop solar panels to the local utility at the full retail rate and time-of-use pricing that values solar energy at a premium based on the time of day of solar output.

The changes will create new challenges for the solar industry in California, both for rooftop solar companies and utility-scale solar developers.

However, they should be seen as market corrections in response to the overwhelming success of solar in the state and not as an indication of the state's attitude toward solar development. In the long term, opportunities for new solar development in California continue to be strong. Near term prospects are somewhat more limited, especially at the wholesale level. However, opportunities are still available, particularly when solar is paired with energy storage or otherwise structured to maximize value to the grid or to meet specific needs.

/ continued page 14

IN OTHER NEWS

The court also said there is no going concern value to which part of the purchase price has to be allocated. It said a power plant that is not yet operating has none.

However, the court said there is "turn-key value." A power plant is worth more at the end of construction because it is "ready to use." It said this premium goes into basis in the power plant itself as opposed to an intangible.

The court said the government failed to prove there were any peculiar circumstances that cast doubt on whether the prices paid by the tax equity investors in the sale-leaseback transactions are not arm's-length prices. "[T]he Court should disregard the purchase price as basis only if the evidence shows that peculiar circumstances have highly inflated the purchase price," it said. A sale-leaseback transaction is not automatically peculiar, it said.

The evidence of market value was better in this case than most, the court said, because the price was established in an auction.

Terra-Gen prepaid part of the rent under the lease back of each project. The court declined to view the real purchase price paid by each lessor as the net purchase price after subtracting the rent prepayment each lessor was immediately repaid at closing. "[T]here is simply no evidence that these prepayments inflated the purchase price in any way," it said.

Of the remaining two cases, the government largely won one and the other was a draw.

One involved a biomass power plant. The government believes such a plant must be split between the parts that produce steam and electricity. A grant – and, by extension, an investment tax credit — can only be claimed on the part that generates electricity.

GUSC Energy completed a new power plant in November 2013 at an industrial park in Rome, New York, that uses wood chips to produce steam and electricity. The plant ran for only one winter in late 2013 and early 2014 and has been largely shut down since then due to low natural gas prices. During the one / continued page 15

California

continued from page 13

Background

Net metering allows customers with rooftop solar panels to manage the timing differences between their solar energy production and their need for power. In California, net-metering customers can sell surplus power back to the utility at the full retail rate, allowing a customer essentially to exchange power purchased from the utility during the night with surplus power the customer produces during the day. The retail price that net-metering customers receive is far above the price that wholesale generators would typically be paid for their power. However, sales from a net-metering customer in excess of the amount of power that the customer purchases from the utility over the course of a year are valued at a price that more closely reflects wholesale power prices.

A time-of-use rate structure prices electricity differently at different times of the day and year. For instance, prices could be lower during the night than in mid-afternoon and higher in summer than in winter. This type of rate structure is supposed to encourage customers to reduce electricity consumption during periods of peak demand when prices are high and shift electricity usage to other times when demand and prices are lower. Ideally, the rates in each time-of-use period are aligned with the cost to produce electricity during that period.

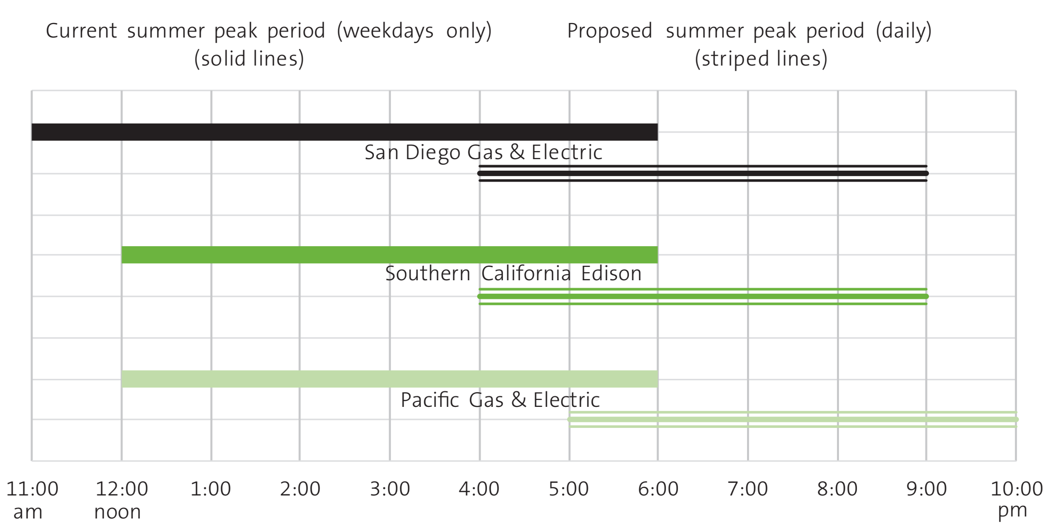
With few exceptions, non-residential customers of the three large investor-owned utilities in California are required to take service under time-of-use rates. These rates are currently optional for residential customers. Residential customers will be moved automatically to time-of-use rates beginning in 2019, unless they opt to remain under the old rate structure.

Net metering and time-of-use rates have contributed to the success of distributed solar in California. Net metering allows customers to size their solar systems to cover a large share of their electricity usage without concern for timing mismatches between solar generation and electricity need. Time-of-use rates have made net metering more valuable because the highest cost period under most rate schedules falls during summer weekday afternoons when air conditioning demand drives high electricity consumption and when solar panels are at peak output.

By installing solar, customers are able to avoid paying the utility for electricity use during high-cost hours and, through net metering, to sell their extra solar electricity to the utility at the high-cost rate. The ability to sell electricity at peak hours and rates has been a key driver of distributed solar economics in California for non-residential customers and for some residential customers.

Time-of-use pricing has also been of benefit to larger-scale projects bidding into utility power solicitations. The utilities apply time-of-delivery factors that place a higher value on power that is generated during times of higher system cost when evaluating bids. The overlap between the high-cost hours and the high solar hours means the utilities assign a higher value to mid-day solar generation than to power generated during the early morning hours or power generated evenly throughout the day.

Figure 1: Current and Proposed Summer Weekday Peak Periods for the IOUs



Expected Changes

The California Public Utilities Commission approved a new framework for the net-metering tariff — commonly known as NEM 2.0 — in January 2016.

NEM 2.0 will require net-metering customers to take service under a time-of-use rate and will increase their costs.

Their costs will increase because of a new interconnection fee of up to $150 to connect rooftop solar to the grid, plus an extension of public purpose charges and certain other utility charges to all electricity purchased from the grid, even electricity that is offset at a different time of day by self-generated power.

The additional charges will have the effect of reducing the value of power sold back to the grid to less than the full retail price of power.

The NEM 2.0 tariff will apply to customers that interconnect a new solar system after July 1, 2017 or after a utility reaches a previously set cap on new solar installations that are eligible for net metering, whichever happens first.

The cap has already been reached for San Diego Gas & Electric and is expected to be reached by the end of 2016 for Pacific Gas & Electric.

In addition to NEM 2.0, the California Public Utilities Commission has four regulatory proceedings underway to re-evaluate the structure of time-of-use periods for the three large investor-owned utilities and to reassess which hours during the summer peak period should have the highest rates.

In particular, the success of solar in California is driving a push to shift the highest rates to the evening when there is little or no solar electricity generation.

Electricity use remains high during summer afternoons, but the large amount of solar generation during these hours has reduced the need for relatively high-cost generation that used to be needed when customers turned on their air conditioning. There can sometimes be an oversupply of electricity in the afternoon hours, particularly during the spring months when air conditioning use is minimal and solar and hydroelectric generation are plentiful. Wholesale market prices tend to be relatively low during the afternoon hours due to the influence of solar. Energy use remains high in the evening, but the supply of solar power ebbs as sunlight fades, leading to higher wholesale market prices. Consequently, there is a push to move the summer peak-period, which is currently from around noon to 6 p.m., out to 4 to 9 p.m. or later (see Figure 1).

Figure 1 shows what the investor-owned utilities are proposing for their new peak hours.

The utilities' new peak hour definitions would reduce the value of solar electricity during weekdays because the hours when solar is at peak output would no longer be peak pricing hours. The impact on solar on weekends is less clear because weekends are currently considered */ continued page 16*

IN OTHER NEWS

season it operated, it supplied 46.7% of the steam heating needs of the industrial park but only 2.8% of the electricity.

The owner applied for a grant of $5,469,028, but was paid only $316,609 (after a 7.2% haircut due to budget sequestration).

GUSC Energy argued that the entire project is used to generate electricity. The court disagreed. It also disagreed with how the Treasury decided the share of the project cost that was for generating electricity. Treasury treated only 6.6% of the cost as eligible because only 6.6% of the steam was converted into electricity.

The government witness said this approach was flawed. The court was not happy with his approach either, but had nothing else to fall back on. He suggested dividing the electricity the plant generated by the electricity that a plant using fuel with the same energy content would generate if all the energy went to electricity generation. This led to 15.24%.

The court applied this fraction to give the plant owner an additional grant of $456,860. The Treasury had removed costs related to site cleanup, landscaping, ornamental iron work and paving. The court put them back into the basis used to calculate the grant.

The case is *GUSC Energy v. United States*. The court released its decision in early November.

Finally, the Treasury ended up with a draw in a case involving a solar company in Dallas called RCIAC that two individuals formed to install LED lighting and capacitor banks for businesses. They shifted to solar at the urging of their electrical materials supplier.

The company installed 18 solar panel systems in 2010 and 2011. The two individuals asked Treasury a number of questions. They got back answers that might have been useful to a tax lawyer, but not to an electrical contractor with a high school education. RCIAC was led to believe from the answers that it could claim a basis in the solar systems of $10.50 a watt. The Treasury paid a grant at that */ continued page 17*

California

continued from page 15

entirely off peak, while under the proposed new time-of-use periods, weekends would also include higher cost periods, allowing some share of weekend solar output to fetch higher prices than at present, but with the remaining generation valued at off-peak prices that may be lower than at present.

The net change in value would depend on what share of solar hours are included in the high-cost weekend period over the course of the year and how great the pricing differentials are between the different time-of-use periods. These issues remain subject to debate along with other critical details, including when the new time-of-use periods will be implemented and what protections will be afforded to customers with existing solar installations. However, the overall impact is expected to be somewhat negative.

Each utility's proposal is being considered in a separate proceeding at the CPUC. Decisions in these proceedings are expected over the next year or so, with SDG&E's proposal likely to be addressed first, possibly as early as late spring 2017. The commission is widely expected to approve shifts to the peak hours that are similar to the utility proposals, though details may vary.

For residential customers of PG&E and Southern California Edison, the high-cost hours have already been shifted somewhat later in the day in the standard optional time-of-use schedules, and the Figure 1 proposals would not be implemented immediately. The current PG&E "Schedule E-TOU" has high-cost hours from 3 to 8 p.m. or, optionally, from 4 to 9 p.m. The current Southern California Edison "Schedule TOU-D" has high-cost hours from 2 to 8 p.m.

These high-cost periods still include some peak solar hours, so they are less detrimental to solar customers than the proposed non-residential peak periods (Figure 1). Also, most residential customers continue to take service under non-time-of-use rates.

Changes will be more significant for residential customers who are considering installing solar since customers who are subject to NEM 2.0 will be required to take service under time-of-use rates. In addition, over time, the non-residential peak periods are likely to be applied to residential customers as well.

The changes to net metering and time-of-use periods on existing solar customers will have a somewhat muted effect due to grandfathering provisions.

In particular, customers who are already engaged in net metering will remain under the existing net-metering tariff for 20 years from when they first connected their solar systems to the grid. In addition, a proposed decision currently before the CPUC, if adopted, would allow existing solar customers to continue to take service under current time-of-use rate periods for five years from their date of solar interconnection. However, this is a hotly contested provision, and it may be adjusted upward or downward prior to adoption. It is also possible that other relief may be provided to existing solar customers along with, or in place of, a time-of-use grandfathering period, such as a special earlier on-peak period.

New solar customers will take service under the new time-of-use periods and the NEM 2.0 tariff. They will have less incentive to install solar than before. The impact for a given customer will depend on the customer's usage profile, solar generation profile and utility, as well as the size of the solar system relative to the customer's electricity use and the particulars of the time-of-use periods and rates that are adopted.

Table 1 shows the combined impacts for an illustrative small commercial customer in San Bernardino, California of the NEM 2.0 changes and the new time-of-use periods that Southern California Edison has proposed. For this illustrative customer, these two changes combined would increase the customer's annual electricity bill by 60%. Yet, even with this large increase in the customer's utility bill, the savings the customer would realize from installing solar would be only 10% less after the new rules go into effect than before. This result may not hold for all customers.

Table 1: Impact of NEM and Time-of-Use Period Changes for Illustrative Small Commercial Customer

	Annual Electric Bill	Savings from Solar
Without Solar	$1,765	N/A
With Solar: Before NEM/TOU Changes	$270	$1,495
With Solar: After NEM/TOU Changes	$430	$1,335
Impact of NEM and TOU Changes	+$160	-$160
Impact of NEM and TOU Changes (%)	~60%	~10%

Illustrative customer is located in San Bernardino, California. The customer has a 6.5 kW-DC distributed solar system that is sized to meet annual electricity needs of about 10,000 kWh, and the customer takes service under Southern California Edison Schedule TOU-GS-1.

Changes to the time-of-use period structures additionally introduce regulatory uncertainty for customers who are considering installing solar.

The proposed decision on time-of-use periods before the CPUC would guarantee net-metering customers a minimum of five years under whatever time-of-use periods they start. While this five-year commitment is helpful, the prospect of further time-of-use period shifts after five years creates added risk for solar systems that require more than a five-year payback period. The prospect of additional future net-metering changes is less of a concern because the CPUC has already guaranteed that NEM 2.0 customers may continue receiving service under that tariff for 20 years.

The new time-of-use periods the utilities are proposing would apply only to retail rates, but the same shift is underway in the time-of-delivery factors that are used to value wholesale solar generation that is sold to the utilities.

In many cases, these time-of-delivery factors have already been updated in recent years to shift the highest value hours to later in the day. For example, PG&E's time-of-delivery factors assign the highest value to power delivered from 4 to 10 p.m. The correlation between the peak periods used for retail rates (time-of-use periods) and for wholesale procurement (time-of-delivery factors) is still subject to discussion at the CPUC; however, they should move into general alignment over time. The shift to later peak periods will affect both distributed solar and utility-scale solar.

Solar Outlook

The NEM 2.0 and time-of-use period changes are a response to widespread adoption of solar in California. Solar remains a preferred resource in the state, and the California Public Utilities Commission wants to maintain a viable solar market, but it wants a regime that requires lower rate support, given regulators' desire to avoid unnecessary subsidies between customers and in light of lower underlying costs: between 2007 and 2015, median installed prices for utility-scale solar fell by nearly 60% nationwide, and further cost reductions are anticipated.

California continues to encourage solar adoption. While the CPUC increased costs for net-metering customers, the NEM 2.0 changes are much less drastic than changes to net-metering programs that have been adopted or are under review in other states such as Nevada and Arizona. In addition, the CPUC rejected (for now) a request by the investor-owned / *continued page 18*

IN OTHER NEWS

level on the first system. The company then moved to install others.

Its actual cost to install was $4.79 a watt, but it claimed grants on a "retail" price that was 1.8 times higher. It expected a Treasury cash grant for 66% of the actual system cost and a rebate from the local utility, Oncor, for another 47% of the cost. (Oncor paid rebates to installers as a reward for installing solar.)

RCIAC never really collected the retail price from anyone. The systems were leased to customers, but the company was lax about collecting rent. The leases ran five years, after which the customers had options to buy the systems. At some point, RCIAC understood the IRS to say that the same company could not be both the installer and the owner, so it formed a separate company, LCM Energy, to own the systems.

The Treasury paid grants on a basis of $4.79 a watt plus 20%, for $5.70. The two contractors sued for the difference. The government then accused them of fraud and asked for the money back.

The US claims court said they were not sophisticated people trying to defraud the government, but were merely trying to understand the program based on what they thought they were told by Treasury. The Treasury contributed to the confusion by paying the first grant. The court let them keep what they were already paid, but declined to pay them more.

The case is *LCM Energy v. United States*. The decision was released in late October.

Treasury cash grants remain subject to budget sequestration, an effort by Congress to control the federal budget by cutting spending across the board. Grants approved for payment through September 30, 2017 will suffer a 6.9% haircut.

The new Congress that takes office in January could junk or revise the sequestration statute. Some Republicans want to eliminate sequestration for the defense budget. Democrats would resist without also dropping it for domestic spending. Any change / *continued page 19*

California

continued from page 17

utilities for demand charges for residential net-metering customers, and the CPUC is considering allowing net-metering customers to be grandfathered from changes in time-of-use rates period for five years.

A customer may be able to improve the economics of installing solar by combining solar with energy storage.

This would reduce the impact of the NEM 2.0 cost increases since less power would be sold back to the utility under the new net-metering tariff. The customer could also get the highest price for power solar back to the grid by storing the power until the high-cost hours. The CPUC has ruled that a solar system with storage is to be treated the same as a solar system without storage, so these uses are available without restriction.

Electric vehicles could also be used in combination with solar installations to increase the value of both systems. For example, for a system with excess solar power during the middle of the day, using the power to charge an electric vehicle may in some cases be more beneficial than selling the power back to the utility during hours that are outside of the high-cost period.

A less expensive option would be to orient solar systems toward the west (rather than south) to benefit from later-in-the-day sunlight. While this would not provide the same benefit as energy storage, it is a low-cost measure that could provide incremental value for some customers.

With these sorts of strategies and by passing along cost reductions, solar developers should continue to find a market for distributed solar in California, even though the market may not be as robust as in recent years.

Utility-scale solar is not affected by the changes to the net-metering tariff, but it is affected by the shift in time-of-delivery factors. It, too, can be helped by orientation of the solar system to follow the sun or to capture more sunlight from later in the day and can be combined with large-scale storage. The CPUC has directed the investor-owned utilities collectively to procure 1,325 megawatts of storage by 2020 and to implement this procured capacity by 2024. Storage installations that are linked with solar qualify under this storage requirement. In addition to aligning the hours of solar output with peak time-of-delivery periods to increase the value of the power generated, storage could also provide the opportunity to use solar as a flexible resource, further increasing its market value. For example, during the early evening when solar output falls while demand remains high, there is a need for a large amount of fast-ramping power. Storage facilities can quickly dispatch stored solar power to meet these ramping needs, providing a valuable grid service.

A bigger issue for utility-scale solar than the regulatory changes is the near-term glut of renewable power. While California has a very aggressive renewable portfolio standard, requiring 33% of procurement from RPS-eligible power by 2020 and 50% by 2030, the investor-owned utilities are not expected to need new RPS power until the early-to-mid 2020s (Table 2).

The California utilities will eventually be back in the market for renewable power. Table 3 shows the full renewable procurement needs of the three investor-owned utilities in 2030 compared to the amount of renewable power currently under contract.

Significant gaps remain, particularly for Southern California Edison. In addition, in a settlement agreement that is under CPUC review regarding closure of the Diablo Canyon nuclear power plant, PG&E has agreed to replace the nuclear power with

Table 2: California Investor-Owned Utility RPS Procurement Needs

	RPS Procurement Under Contract for 2020 (33% requirement)	Year New RPS Generation First Needed
PG&E	37.0%	2026
SCE	36.9%	2023
SDG&E	43.1%	2025

Table 3: California Investor-Owned Utility RPS Procurement 2030

	Total RPS Procurement Needed in 2030 (GWh)	RPS Procurement Under Contract for 2030 (compare to 50% RPS)	Additional RPS Procurement Needed for 2030 (GWh)
PG&E	21,427	40%	4,340
SCE	38,533	28%	16,847
SDG&E	7,478	40%	1,552

greenhouse gas-free resources, some of which is likely to be solar power, and also to increase its RPS target voluntarily to 55% of retail sales during the period 2031 to 2045. If this agreement is adopted, then PG&E's RPS requirement will increase by approximately 2,000 GWh per year above the amount shown in Table 3 for each of these years.

In the near term, utility-scale solar developers may do better to focus on municipal utilities and community choice aggregators, called CCAs. (For earlier coverage about CCAs, see "Huge Potential New Demand for Power" in the October 2016 *NewsWire* and "Another Potential Offtaker: Community Choice Aggregators" in the August 2016 *NewsWire*.)

CCAs are entities that procure power on behalf of investor-owned utility customers in their jurisdictions, with the local utility continuing to distribute the power. California has seen explosive interest in CCAs in recent years, and the projected growth in CCAs is contributing to utility RPS surpluses as the utilities shed customers to CCAs.

CCAs must meet the same RPS requirements as the utilities must meet, and many have even more aggressive renewable targets. For example, the Marin Clean Energy CCA currently operates with a resource mix of 51% renewable energy, and is committed to a longer-term goal of sourcing 80% of its electricity needs from renewable sources. In addition, many of the existing and planned CCAs have goals for the development of new, local renewable resources, which could include new solar projects.

The changes to time-of-use period (and the closely related time-of-delivery factors) that are being evaluated in California will continue to be reexamined as the power grid continues to evolve.

The introduction of larger amounts of storage and electric vehicles on the grid will shift the power supply and demand curves in ways that are not yet known. In addition, a process is currently underway to better integrate (and perhaps combine) the California grid with the grids of other western states. With this closer integration, a wider portfolio of resources is becoming available for dispatch, which is helping to even out the intermittency of renewable generation more efficiently and cost effectively. This, too, may shift the hourly makeup of supply that is available in California and may push the high-cost hours to other periods or lead to more consistent pricing throughout the day.

While future time-of-use period changes are uncertain, as costs for solar continue to trend downwards, the available subsidies and rate supports should be expected also to diminish.

The near term may be the most */ continued page 20*

IN OTHER NEWS

in the sequestration statute would affect grants paid after the effective date.

STATE PLANS to promote renewable energy and nuclear power are at risk in two widely watched lawsuits in New York and Connecticut.

Five independent generators, the Electric Power Supply Association and the Coalition for Competitive Electricity filed suit in federal district court in New York in October to block the state from awarding "zero emissions credits" worth $17.48 a megawatt hour in 2017 and 2018 to owners of up to four nuclear power plants.

The case tests whether a state can offer such credits as a supplement to wholesale power prices without running afoul of federal law. The Federal Energy Regulatory Commission supervises the wholesale power market.

The value of the credits will be reset after 2018. The program is expected to run 12 years.

At least three of the six New York nuclear plants are expected to receive the credits.

The credits were approved by the New York Public Service Commission in August as part of a plan to try to keep the nuclear power plants open. Nuclear power accounts for roughly 31% of total New York generating capacity. The state says the nuclear power plants are important to limiting carbon emissions.

The program is scheduled to take effect in March 2017.

The nuclear owners will sell the credits to the New York Research and Energy Development Authority, NYSERDA, at the price established by the New York Public Service Commission. NYSERDA then will resell them to New York utilities on a *pro rata* basis in proportion to each utility's share of total New York electricity load.

Low natural gas prices are forcing nuclear power plants across the country to shut down.

The credits represent a significant subsidy on top of what the nuclear plants are being paid currently for their electricity.

The generators, who compete with the nuclear plants for a share of */ continued page 21*

California

continued from page 17

challenging as customers adjust to the new time-of-use periods and new NEM 2.0 tariff, and as wholesale procurement is limited due to a glut of RPS power at the investor-owned utilities. Opportunities for wholesale contracting should open up again more widely in the early 2020s, and time-of-use periods (and time-of-delivery factors) may shift further during this period, possibly in a direction that would benefit solar economics. In the meantime, CCAs and municipal utilities may provide avenues for medium or large-scale solar projects, and opportunities remain available in the residential and commercial markets for systems that are competitively priced.

Chile: Solar Outlook

by Brian Greene and Monica Borda, in Washington

Chile had 6.7 megawatts of installed solar capacity at the end of 2013. Three years later, the installed solar capacity in Chile is more than 1,200 megawatts, and there are more than another 1,600 megawatts under construction and more than 12,000 megawatts in development.

We decided to take a closer look at Chile to understand the reasons for this incredible growth and the prospects for the Chilean market going forward.

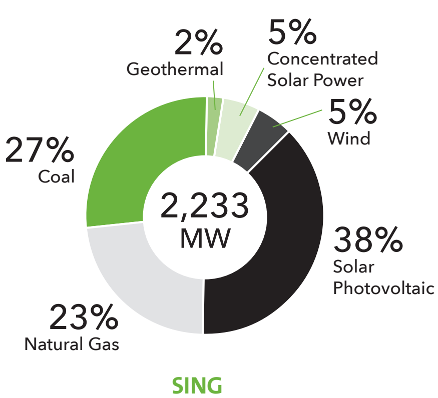
Catalysts

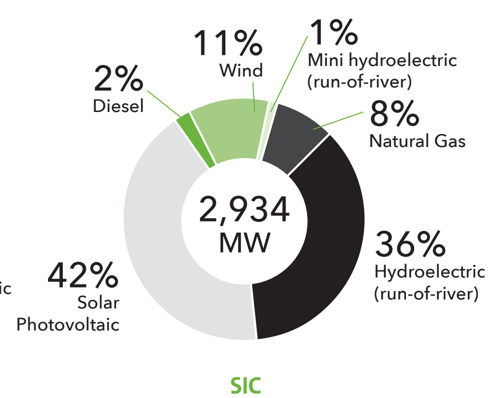
The reasons for the explosive growth are economic and political. The Atacama desert in the north of Chile provides for one of the best — if not the best — solar resource on earth. Chile also benefits from a stable economy and historically high energy prices due to a lack of domestic fossil fuel production.

In Chile, the term "non-conventional renewable energy" is used to refer to all types of renewable energy excluding hydro projects larger than 20 megawatts. The Chilean Ministry of Energy set a target in May 2014 of generating 20% of Chilean electricity from non-conventional renewable energy by 2025, with 45% of the electric generating capacity to be installed in the country from 2014 to 2025 to come from such non-conventional renewable sources. In September 2015, the 2050 Energy Advisory Committee — a public body established to develop a long-term energy policy — released an even more ambitious renewables forecast — its Energy Roadmap 2050: A Sustainable and Inclusive Strategy — in which the government targeted at least 70% penetration of non-conventional renewable energy in Chile's energy systems by 2050, with more than 20,000 megawatts of wind and solar generation. Solar energy was projected to meet 19% of this electricity demand. Thus, while Chile did not offer any tax credits or feed-in tariffs, the solar industry was greeted in Chile with enthusiasm and cooperation by the Chilean government.

These conditions led to a flurry of large utility-scale solar projects being constructed and financed in a short period of time, including First Solar's Luz del Norte project (141 megawatts), SunEdison's Amanecer (100 megawatts), San Andres (50 megawatts) and Maria Elena (73 megawatts) projects and Total's Salvador project (70 megawatts).

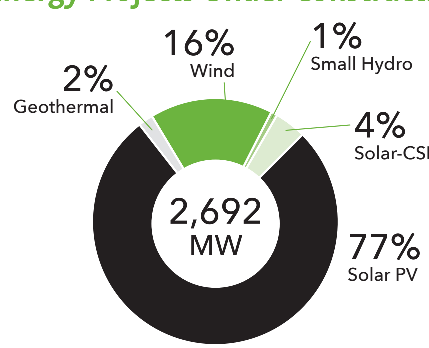
Figure 1: Power Projects Under Construction





Source: Comisión Nacional de Energía,
Reporte mensual sector energético, *Vol. No. 14, p. 5 y. 6 (April 2016)*

Figure 2: Non-Conventional Renewable Energy Projects Under Construction



Source: Centro Nacional para la Innovación y Fomento de las Energías Renovables Energías renovables en el mercado electrico Chileno, *p. 3 (April 2016)*

Utility-scale solar now accounts for 5.23% of total installed capacity in Chile. Solar is the fastest developing source, representing 38% of all power projects under construction in the Northern Interconnected System (known as "SING," short for *Sistema Interconectado del Norte Grande*), 42% in the Central Interconnected System (known as "SIC," short for *Sistema Interconectado Central*), and 77% of all renewables, with a portfolio of almost 2,200 megawatts under construction in both systems.

Figure 1 shows power projects under construction in SING and SIC, and Figure 2 shows renewable energy projects under construction in all parts of Chile.

Headwinds

With success has come competition.

In recent government auctions, the price of winning bids has dropped from an average price of US$79 a megawatt hour in October 2015 to US$44.70 a megawatt hour in August 2016, with the lowest bids in the August 2016 auction being offered at an incredible US$29.10 per megawatt hour. The low prices have reportedly discouraged some developers from pursuing potential projects.

Transmission issues have also created risks for both operating projects and projects in development.

Chile's solar energy generation has expanded so quickly that transmission has not been able to catch up. A solar PV plant may be operating in one year or one and a half years, including environmental assessment and construction time. New transmission lines often take between three and four years, or longer, to build.

The increase in solar PV projects is also driving the need for upgrades to existing transmission lines to dispatch larger volumes of energy at "peak times" during the day. During 2016, spot prices dropped to zero at certain nodes in northern Chile for a record 113 days, according to a recent Bloomberg report. Transmission has become an issue for both developers and lenders looking at potential new projects.

New Developments

Chile has two main transmission systems, the central grid — SIC — which is the grid for the central region and carries about 70% of the national electricity generation serving more than 90% of Chile's population, and the northern grid – SING — which accounts for about 20% of Chile's electricity generation.

These transmission networks are not currently connected to each other. This will soon change.

A July 2016 law (Law 20,936) is / continued page 22

IN OTHER NEWS

wholesale power sales, charge the program is illegal state interference with the wholesale power market. Only the Federal Energy Regulatory Commission can set wholesale power rates for electricity sold in interstate markets. States retain the right to regulate retail sales of electricity within their borders.

The generators say the credits will artificially depress wholesale power prices by keeping generators in business who would otherwise have dropped out of the market. The state argues that it has the right to establish a new state credit program just as it has done for renewable energy credits or RECs for solar and wind projects.

The generators also charge the program is an impermissible interference with interstate commerce; and it is an effort to "save jobs at subsidized generators . . . to preserve the local industry from the rigors of interstate competition."

The "dormant" commerce clause to the US constitution bars state actions that discriminate against or unduly burden interstate commerce. However, not every state action that affects interstate commerce runs afoul of the commerce clause. The action must discriminate against interstate commerce in favor of in-state commerce. A statute that incidentally burdens interstate commerce is still valid unless the burden imposed on interstate commerce is excessive in relation to the local benefit.

Recent court decisions in other states have tested whether renewable portfolio standards and laws to discourage the use of coal to generate electricity impede interstate commerce. (See "Renewable Portfolio Standards" in the September 2015 *NewsWire* and "Minnesota Carbon Statute Invalidated" in the August 2016 *NewsWire*.)

The New York case is *Coalition for Competitive Electricity v. New York Public Service Commission.*

An environmental group filed a separate suit to block the credits on November 30 in state court. It charges the program also violates the state constitution. The / continued page 23

Chile

continued from page 21

supposed to modernize the transmission system and connect SIC and SING. The new law will restructure a significant part of the current electricity market by increasing competition and boosting development of renewable energy.

It does four things. It creates a new centralized entity to control the grid. It addresses the interconnection of SIC and SING, with the objective of strengthening the transmission system and reducing operational costs (in effect, creating a single power grid where renewable energy projects in the north will be able to export surplus energy to Santiago and the rest of central-south Chile when a shortage of hydro generation occurs. Next, it launches a new financing model for grid improvements under which consumers will pay the entire cost to construct new transmission lines. Finally, it gives the Chilean government the ability to designate development hubs for power generation, thereby facilitating expansion of transmission lines to places where there is a great potential for renewable generation in order to incentivize its development.

Two major projects are under construction to provide near-term relief for transmission gridlock.

First, the 600-kilometer (373-mile) *Mejillones Cordoba* transmission line will connect SIC and SING. The *Mejillones Cordoba* line, which is being constructed by a joint venture between Engie Energía Chile and Red Eléctrica Internacional, is expected to start operating in the second half of 2017.

Second, the 753-kilometer (468-mile) *Cardones Polpaico* transmission line, that will run through the Atacama, Coquimbo, Valparaiso and Metropolitana regions, is also under construction and is expected to be operational by the end of 2017. The *Cardones Popaico* line is being sponsored by the commercial group ISA, and will alleviate congestion in the northern parts of the central grid, the area where grid congestion is most extreme and where spot prices have been driven to zero earlier this year.

Another emerging opportunity for solar developers is the "Small Means of Distributed Generation" program (*Pequeños Medios de Generación Distribuidos* or PMGD), which is open to projects that are smaller than nine megawatts.

The PMGD program provides developers with two important incentives.

First, the owner of a PMGD project may choose between two revenue models. Electricity can either be offered on the spot market or sold at what is called a "node" or "stabilized" price that is fixed for six-month periods. This price currently is around USD$64 per megawatt hour and is based on a complex calculation of power purchase agreement rates. Its existence will reduce price risk.

Second, PMGD projects that are smaller than three megawatts are not required to have an environmental impact assessment, reducing project costs and shortening the development period. PMGD projects must still comply with other local environmental laws and land permits. Because they are relatively small in size, PMGD projects require less land and may be built closer to Santiago and other urban areas where there is high energy demand. Some developers are looking at pooling PMGD projects and financing them as a portfolio.

Lessons From Community Solar Financings

by Jim Berger, in Los Angeles

Community solar projects are starting to be financed by traditional lenders and tax equity investors, but many sponsors still struggle to figure out how to attract financing.

Financiers are still learning how to underwrite this asset class. Financing of community solar projects will, at least for the time being, probably take longer and be more difficult than other, more traditional solar projects while the market still feels its way.

However, community solar developers can take a number of simple, concrete steps to facilitate financing. These steps include focusing on the credit quality of offtakers, assembling large enough portfolios that have limited geographic diversity and combining community solar with better-understood solar assets. In the short run, some developers may also want to look for other sources of capital.

Community solar is a relatively new solar asset class that lets customers who do not want to (or cannot) have a solar system on their property to do the next best thing. A community solar project is a solar array, typically around one megawatt in size, in which customers subscribe to shares of the electricity output or buy one or more solar panels.

Community solar projects are utility-scale solar facilities. The customers who subscribe to them are in the same utility service territory as the solar facility. The electricity goes to the local utility. The customers receive credits for their share of the electricity that can be used against their electricity bills from the local utility. They continue to buy their electricity from the local utility. The customers can be individuals, commercial or industrial businesses or municipalities.

There are many types of community solar regimes: some where the utility runs the show and others where the customers own the panels. This article focuses on the dominant model in use in Colorado, Minnesota and Massachusetts.

Community solar developers should limit project portfolios to no more than three to four states.

There are currently at least 14 states plus the District of Columbia with community solar enabling legislation. In other states, some utilities permit community solar projects, despite the lack of appropriate enabling legislation. Through 2015, only 88.5 megawatts had been installed. This is expected to reach 1.5 gigawatts by 2020, with California, Massachusetts and Minnesota leading the way.

Lenders and tax equity investors are comfortable financing utility-scale solar projects, portfolios of residential rooftop installations and commercial and industrial (C&I) projects. Community solar is fundamentally not much different than these other types of solar assets and, in fact, combines some of the strongest features of these other solar asset classes. However, the perceived novelty of community solar means many financiers still need to be better educated by developers about state program nuances and other distinct attributes of community solar.

Offtakers

One of the most important aspects of any project finance transaction is the credit quality of the offtaker. With community solar projects, the offtakers can be residential / continued page 24

IN OTHER NEWS

case in state court is *Hudson River Sloop Clearwater v. New York Public Service Commission*.

In Connecticut, a solar developer, Allco Finance, is challenging an auction the state government ran to buy renewable energy. The state legislature authorized the Connecticut Department of Energy and Environmental Protection in 2013 to solicit proposals to supply renewable energy for up to 4% of the state's electricity supply and to order the two main utilities — Connecticut Light & Power and United Illuminating — to enter into power purchase agreements with terms of up to 20 years with the winners.

Connecticut selected two winners in the 2013 auction: a large wind project in Maine and a small solar project in Connecticut.

Allco sued to have the results set aside and lost both in a federal district court and on appeal. It lost in part because the courts said it should have gone first to the Federal Energy Regulatory Commission.

The state asked for more bids in 2015 after the Maine wind farm failed to meet milestones in its power contract.

Allco sued again in an effort to prevent Connecticut from accepting bids from any projects that are more than 80 megawatts in size and, therefore, too large to be "qualifying facilities" — or QFs — under the Public Utility Regulatory Policies Act, a 1978 federal law that requires regulated utilities to buy electricity from cogeneration facilities, and other independent power plants of up to 80 megawatts that use waste or renewable energy, at the "avoided cost" the utility would spend to generate the electricity itself.

The lawsuit is, at heart, a challenge to the state's renewable portfolio standard, since the state's solicitation is based on the RPS law. Allco lost in federal district court in August. A US appeals court issued an injunction in early November blocking Connecticut from awarding any more power contracts under the program until it can hear the case. / continued page 25

Community Solar

continued from page 23

consumers, businesses or municipalities. Finding the right mix of offtaker and maximizing the offtakers' credit are vitally important to attract financing.

With respect to residential offtakers, financiers usually require that individuals have a certain minimum FICO score. This can be complicated when the enabling legislation requires a certain percentage of subscribers be low income, as is the case in Colorado. A customer with little income could still have a good credit record. Some developers have suggested that acquiring customers (regardless of FICO score) is most important. For now, financiers beg to differ. To attract financing, developers focused on residential customers should acquire as many such customers with high FICO scores as possible.

The community solar statute in Colorado requires a mix of low-income customers.

There are a couple important advantages with residential offtakers.

First, each individual customer represents a very small percentage of the overall portfolio. Consequently, the loss of any one residential customer will have minimal effect on cash flow.

Second, residential customers can be easily replaced if they default or move out of the service territory. The developer should try to build a waiting list of customers who want to subscribe to a community solar project so that customers that default can be easily replaced.

The financiers will need to be comfortable that the developer is a capable operator and can find customers and manage substitutions quickly. In addition, some term financiers will finance projects that are not fully subscribed, but they are unlikely to make the full commitment available to the developer at inception. The financing will probably involve a mechanism that makes available an increasing percentage of funds as the project becomes fully subscribed.

Non-residential customers, like businesses and municipalities, are larger and a single customer could represent a material portion of the portfolio. Given the importance of such customers to cash flow and economic viability of a portfolio, financiers may require the offtaker to be rated as investment grade. If the entity is not publicly rated, some financiers will allow the sponsor to use a shadow rating. Without a rating, financiers will limit the amount of non-residential customers that they are willing to finance.

One way financiers gain some comfort with larger, non-residential offtakers is through the use of a termination payment. The customer agreement with the non-residential customer should require the payment of a certain amount of money if the customer defaults or terminates the agreement. The payment is used to "right size" a financing by paying down debt or making a special distribution of cash to a tax equity investor. The credit quality of the customer will be very important because the financier will want assurances that the payment will be made.

The percentage of residential customers versus non-residential customers in portfolios is important. There may be state rules about offtaker mix. Financiers already know how to underwrite C&I customers. They also know how to underwrite residential portfolios. The perceived novelty of community solar makes it advantageous to mix the two types of offtakers in order to reduce risk and accelerate financing. The developer should find out the preferred mix of the financiers with whom it hopes to deal.

Most community solar projects are relatively small: in the one to two megawatt range. A single project is too small to finance individually other than on balance sheet because the transaction costs are too high. Finding the right size portfolio is important. The portfolio must be large enough to justify not only the developer's, but also the financiers' transaction costs.

chadbourne

Portfolio Spread

While assembling a portfolio that is large enough to be financed efficiently, the developer should keep an eye on the locations of projects and the number of states where the projects are located. It is easier to finance a portfolio of projects in a single state. The portfolio should not include projects from more than three or four states at the outside.

There are two reasons to limit the number of states.

First, each state has a different and complicated regulatory regime. Financiers need to understand each regime, how it works and how it could change in the future before they will close on a financing. Some regimes are so new that developers are still engaged in the rulemaking process. Financiers will look favorably on portfolios in states in which the developer has a deep understanding of the regulatory and business environment. However, the financiers will also want as good an understanding.

Second, each state usually has its own forms of contracts that are used in community solar projects, especially to set up the unique utility relationship. The more states and the more forms a financier must review, the longer financing takes and the higher the transaction costs.

Another way to help some financiers gain comfort is to include other, better understood assets, such as some C&I projects, in the portfolio. Financiers are generally already more comfortable with C&I projects, so including them reduces perceived risks of the portfolio. Rather than underwriting a portfolio entirely made up of community solar projects, which may be too risky for some financiers, a portfolio that is 50% to 70% community solar may more easily attract financing.

Many large lenders and tax equity investors are hesitant to lend to or invest in projects developed and owned by inexperienced developers. Until the developers prove themselves, they may need to seek other non-balance sheet methods to finance their initial portfolios.

Some developers have successfully raised financing from regional banks and high-net-worth individuals. These sources of capital are likely to have less rigorous processes and be able to move more quickly through diligence with lower transaction costs. However, they may require higher margins. It is also unlikely that developers can use this type of capital for large portfolios.

The difficulty smaller developers have raising financing may lead eventually to consolidation. ◎

IN OTHER NEWS

However, the appeals court removed the injunction in mid-December and said that a written decision would be issued soon.

The case is called *Allco Finance v. Klee*.

Allco also argues that Connecticut cannot restrict awards of renewable energy credits to projects in New England and New York. The same federal district court disagreed in August. The state honors RECs from renewable energy projects in and around Connecticut that will have a measurable effect on clean air in the state. The states involved have a unified REC tracking system. The court said the credits are a subsidy funded by state residents, and the state is not required to spread the benefit of the subsidy to generators outside of New England. The appeals court is expected to address this issue at the same time it decides whether Connecticut is exceeding its authority by directing utilities to enter into PPAs.

US SOLAR GENERATING CAPACITY looks likely to increase by more than 50% in 2016.

The United States added more than 4,134 megawatts of new PV installations in the third quarter 2016, a record. Total solar capacity stood at 35,800 megawatts at the end of the quarter. Residential rooftop systems account for 21% of total solar capacity.

One third of all residential rooftop systems are in a single utility service territory: the Pacific Gas & Electric Company in northern California.

The top 10 states for new solar installations in the third quarter were California, Utah, Texas, Georgia, Colorado, North Carolina, New Mexico, Arizona, Oregon and New York.

California is the first state to have reached 1,000 megawatts of new installations in a single quarter.

Average system costs, measured using a bottom-up approach of adding up wholesale prices of system components, dropped 5.1% to 6.8% in the third quarter alone. Residential system costs fell 5.1%. Commercial and industrial system costs fell 5.6%. / *continued page 27*

Wind Tax Equity Market

Two prominent tax equity investors, whose banks accounted for roughly 30% of the big-ticket US renewable energy tax equity market in 2015, and two wind developers talked to a packed room in October in New York about the current state of play in tax equity. The discussion took place at the annual finance conference organized by the American Wind Energy Association.

The panelists are John Eber, managing director and head of energy investments for J.P.Morgan, Jack Cargas, managing director, Bank of America Merrill Lynch, Dan Elkort, executive vice president and general counsel of Pattern Energy, and Martin Torres, managing director at BlackRock and formerly on the tax equity desk at Morgan Stanley. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Most wind companies have been focused on starting construction of as many projects as possible before year end to qualify for tax credits at the full rate. Those who can afford to incur at least 5% of the project cost have already arranged to do so. Now is the time of year when companies who lack the money to incur 5% of the cost start thinking about limited physical work at the site on turbine foundations or roads or at the factory on step-up transformers. They want to be in a position to raise tax equity later. What advice do you have for them?

Physical Work Test

MR. CARGAS: The physical work test is challenging to satisfy as there are some grey areas around interpretation of the test. The more work completed before the construction-start deadline, the better. It is important that sponsors keep detailed records, including construction logs and time-stamped photographs, and hopefully have those records verified by an independent expert. We will invest in projects that relied on the physical work test.

MR. EBER: Projects that rely on the physical work test could be more difficult to finance. There will be investors who will not want to take the risk on such projects. I would encourage developers not to be thinking about doing the least amount possible and thinking in the opposite direction, either incurring at least 5% of the project cost or going as far as they can on initial physical work so that they are well beyond what they think might be necessary.

MR. MARTIN: This is the fourth time that the wind industry has faced a deadline to start construction. What lessons should be drawn from the last three times?

MR. ELKORT: We have observed over the four successive extensions that the tax equity market has gotten tighter, the thresholds for establishing start of construction required by tax equity have gotten higher, and the terms of tax equity financing have gotten tougher.

The start-of-construction requirement has not changed, but if you approach starting construction like you did four or five years ago, I think you will meet a relatively unresponsive tax equity market.

I would flip the question that you asked Jack Cargas and John Eber to you, Keith. On some level, the tax equity market responds to the opinions of tax counsel. When we started looking into this in terms of how much physical work we needed to do, we reached out to a couple tax equity counsels and got a sense of how much work they would require in order to write an opinion that construction started in time. So rather than asking them, I think we should ask you: What do you require to give an opinion?

MR. MARTIN: If we are talking about work at the project site, we like at least 10% of the turbine foundations dug to at least six feet. They must be used in the project. You should be far enough along in your planning that you have an idea what turbines will be used and how they will be positioned so that the turbine foundations do not have to be re-dug. Alternatively, we like to see at least a mile of turbine string roads finished to the permanent surface. It is even better if you can do both.

Let me ask another question related to this. The production tax credit will phase out after this year. If you start construction this year, you get the full PTC. It phases down in amount over the next three years 2017 through 2019. The following question is for our tax equity investors: when the PTC starts phasing down, do you think wind companies will be able to compete for your attention with the solar companies who will still have full tax credits?

MR. CARGAS: I think there will continue to be investor appetite for transactions that allow for a single investment of a large amount of capital while spreading the use of tax capacity over 10 years. Therefore, my view is the tax equity market will remain interested in wind projects despite the decreasing importance of PTCs to the economics.

I think the question ought to be to the sponsors: how much value will the sponsors attribute to the PTC after it starts declining in value?

MR. MARTIN: We will ask Daniel Elkort and Martin Torres in a moment. John Eber, do you think wind will be able to compete with solar after tax credits for wind projects start phasing down?

MR. EBER: We probably have about four years before we have to worry about that, given that everyone is out starting construction of as many projects as they can in order to qualify for tax credits at the full rate. I am hoping we do not have to face that question for a number of years.

Competition With Solar

MR. MARTIN: Will wind projects that qualify for PTCs at 80%, 60% or 40% of the full rate be able to compete for tax equity with solar projects that still have several more years to start construction to qualify for tax credits at the full rate?

MR. EBER: That is probably the better question. I think the answer is they will have a serious challenge.

MR. MARTIN: A serious challenge. Daniel Elkort, Jack Cargas asked whether projects are economic at 80% or 60% of the full PTC rate. Where is the break point?

MR. ELKORT: We are starting to analyze what happens to projects with PTCs at 80% of the full rate. We still think they are economic, but keep in mind this is in a market in which PPA prices are also falling steadily, and that is as alarming to a sponsor as the decline in the PTC.

At a certain point, tax equity becomes pretty expensive. It is already expensive capital now and as you reduce the amount of the PTCs, then the percentage of your capital that is coming from tax equity goes down.

MR. MARTIN: Or you have to give more cash to the tax equity investor to raise the same amount of tax equity, which is too expensive at tax equity yields.

MR. ELKORT: Correct. If we are going to maintain ever-increasingly competitive projects, we have to bring in lower-cost capital. So John Eber would either have to reduce his prices or loosen up the restrictions on leverage so that we can replace the reduced tax equity with cheaper debt.

MR. MARTIN: The trend in the solar market has been for solar developers to keep as much cash as possible and then monetize it at a debt rate through back leverage. We have not seen that in the wind market. Why not?

MR. TORRES: Maybe it is just not as visible. We have seen a number of wind projects that have been financed with back leverage. While I was at Morgan Stanley, we participated in a number of those transactions, but the transactions are not necessarily as public as asset-level financings.

/ continued page 28

IN OTHER NEWS

Fixed-tilt utility-scale costs fell 6.8%.

The average cost for a residential rooftop system was $2.98 a watt during the third quarter. It was $1.69 a watt for flat roof C&I solar. Utility-scale costs were $1.09 on average for fixed-tilt systems and $1.21 for single-axis tracking systems.

The data is in a "US Solar Market Insight" report issued by GTM Research and the Solar Energy Industries Association in early December.

SOME FOREIGN-OWNED US COMPANIES will have to disclose their foreign owners and transactions with affiliates starting in 2017.

The requirements are in new regulations the IRS issued in early December.

All US limited liability companies that are owned by a single foreign individual or entity must apply for an "employer identification number" or EIN on IRS Form SS-4. This will require disclosing the foreign owner.

The LLC will also have to file an annual information return on IRS Form 5472 reporting any transactions between the LLC and its foreign owner or any other foreign related parties. This is the same annual information that section 6038A of the US tax code already requires be filed by US corporations with 25% or more foreign ownership.

The new filing requirements apply in tax years starting on or after January 1, 2017.

An LLC with a single owner does not exist for US tax purposes. The IRS is concerned that such entities are being used to shield foreigners from reporting obligations that apply to other types of entities. The proposal is essentially to treat them the same as foreign corporations with at least 25% foreign ownership for purposes of reporting obligations.

MINOR MEMOS. Electricity prices for offshore wind farms continue to set new record lows. Shell won a tender in early / continued page 29

Wind

continued from page 27

I want to go back to the question you asked Jack Cargas whether it makes sense to have tax equity as part of the capital structure at an 80% PTC rate.

It is a math exercise. You can figure out what the incremental cost is from a return perspective to structure the capital without tax equity and carry the PTCs forward to shelter income from the project.

Market Size

MR. MARTIN: John Eber, you are always looking for new tax equity participants to bring in as co-investors. Do you see more investors coming into the wind market? If so, what kinds: corporates, insurance companies, whom, and how many active tax equity investors do you think there are currently in wind?

MR. EBER: We count 32 investors in the energy tax equity market. Not all of them are investing in both wind and solar. Probably 23 of them are interested in wind. The wind market is probably up five or six institutions from where it was a year ago.

Wind developers relying on physical work to start construction should go well beyond the minimum required.

The investors are there. They are big companies. They are putting a lot of dollars out and their participation is part of a trend of a gradually expanding marketplace. Part of the problem for new investors is just getting in on deals. Those of us who have been in the market for a long time have relationships with the sponsors, and we tend to see the deals first. It is hard for some new investors to break in. That said, there is more than enough capital, and it is coming mostly from big financial institutions.

MR. MARTIN: We have heard from some corporates that they earn more by putting their money into their own businesses than they would earn in the tax equity market.

MR. EBER: Yes, we have heard that for years. That is pretty much a standard refrain we get from most of the corporates we talk to about investing.

MR. MARTIN: Martin Torres, Daniel Elkort, you are out looking for tax equity. Do you agree with the numbers we just heard from John Eber?

MR. TORRES: I agree directionally. We have seen a number of new entrants, particularly insurance companies. While it is great to have new investors, execution risk is something that we focus on quite a bit. Tax equity financing is complicated. There is a much greater risk in working with a new entrant unless it is part of a club with more experienced investors.

Less Cash

MR. MARTIN: John Eber, at the REFF conference in New York in June, you said that falling electricity prices mean there is less cash in tax equity deals and that is creating structuring challenges. What are those challenges?

MR. EBER: The primary challenge is with deficit restoration obligations. The DROs are creeping up in amount and they are taking longer to reverse. The tax losses are still the same as before and, in fact, maybe greater, but there is less taxable income to reverse a deficit capital account after the deal turns tax positive. The economics of the underlying deals are a lot weaker. This means tax equity investors have to agree to higher DROs to absorb depreciation. Some investors are less comfortable than others with the size of the DROs.

MR. MARTIN: Let's focus on that. Would you say today that DROs are getting to 42%, 43% of the original investment? Is this due solely to the paucity of cash?

MR. EBER: I would not say the typical wind deal is at 40% yet. That is the upper end of the spectrum.

MR. CARGAS: The big driver is paucity of cash, as you put it. The paucity of cash has led to a couple of other challenges as well.

One of them is there is more pressure on the pre-tax internal rate of return. Investors need at least a minimum pre-tax IRR. It is harder to get there in deals with less cash. There is also pressure on downside scenarios. It is taking a lot longer to reach the target yield in a P95 or P99 scenario in a deal where there is less wind, less power sold at a lower price, and less cash.

MR. MARTIN: Is it still the case that tax equity covers on average about 75% of the cost of a typical wind farm?

MR. ELKORT: That has not been our experience. It has been closer to 50% to 60%.

MR. EBER: I think that is high.

MR. CARGAS: We have had a couple of deals like that, but they are the exception rather than the rule.

MR. EBER: You can push it up that high, but usually the tax equity would have to take more cash to justify a tax equity investment that large. If a sponsor is trying to optimize the tax equity, it should take the least amount of tax equity consistent with leaving as much cash as possible with the sponsor. Tax equity is usually in the 50% range for most wind deals.

MR. MARTIN: Is it still the case that you do not see project-level debt in partnership flip deals?

MR. EBER: We have not done one in some time.

MR. TORRES: We have not seen project-level debt in wind deals.

MR. MARTIN: Jack Cargas is shaking his head no.

MR. CARGAS: It has been replaced by back leverage. We are seeing a lot of back leverage in the deals we are doing. Most of our clients are looking to bring in bank debt. It is lower-cost capital. They are doing it at the holdco level through a variety of mechanisms.

MR. MARTIN: John Eber, how do you structure a deal so the sponsor keeps as much cash as possible?

MR. EBER: If you keep the tax equity in the 50% range, then there is a lot more cash retained by the sponsor.

You structure the allocations so that they are more accommodating to back leverage, like instead of giving the sponsor practically no cash before the flip and almost all of it after, you have a more constant sharing ratio through the 10-year term. Maybe the tax equity investor is distributed 30% or 40% of cash. The sponsor gets the rest from day one.

MR. MARTIN: How common is it in the wind market to see the tax equity investor take cash equal to 2% of its investment as a preferred cash distribution and some modest percentage of what remains?

MR. EBER: As preferred? I don't think we . . .

MR. MARTIN: The 2% is a preferred cash distribution. It comes out first. I gather neither Bank of America nor J.P.Morgan does that structure.

/ continued page 30

IN OTHER NEWS

December to supply electricity from a wind farm off Holland for the equivalent of US$58 a megawatt hour. Vattenfall won a contract in November for a wind farm off Denmark with a record low bid of US$53 a megawatt hour.

— contributed by Keith Martin in Washington

Wind

continued from page 29

MR. EBER: No.

MR. ELKORT: We have not seen it either.

Current Issues

MR. MARTIN: It is not uncommon in the solar market. Next question, what issues are taking up the most time currently in deals?

MR. CARGAS: For us, it is economics, the normal arguments back and forth about after-tax yield, pre-tax IRR, tenor and downside scenarios. We base our pricing on assumptions given to us by sponsors and, from time to time, those assumptions turn out to be rather more rosy than what the third-party experts see. There is a constant reevaluation of what the actual assumptions in the base case model ought to be. That set of conversations continues throughout the negotiations.

MR. MARTIN: John Eber, Jack Cargas said it is economics. What is your biggest current issue in deals?

MR. EBER: I don't really have one. The market is pretty mature. Most of the sponsors we deal with have been doing these deals for a while. We have established relationships with most of them. I cannot think of any one particular item that causes deals to bog down or eats up an inordinate amount of time in deals, unless it is something unique to a specific deal. Most deals have some unique feature on which you end up spending a bit more time.

MR. MARTIN: Daniel Elkort?

MR. ELKORT: I agree with John. If you did not have a relatively simple 20-year PPA, proven technology, no basis risk, no congestion, no merchant risk, no . . . .

MR. EBER: Bring me that deal.

MR. ELKORT: . . . then it is pretty well established. My view is the tax equity wrap themselves around anything unusual or different in a deal. So if you have congestion, you spend a lot of time arguing about congestion. If you have back leverage, you spend a lot of time negotiating the cash turnoffs.

We did a deal recently where we had a relatively significant fixed transmission charge. We spent an inordinate amount of time getting the tax equity comfortable with that element because it was a new structural feature. Tax equity investors are thorough. They are very careful. They look at everything three different ways to make sure they get it right. So if there is anything new in a transaction, that is where you end up focusing 60% of your time.

MR. MARTIN: Martin Torres, do you want to add to the list?

MR. TORRES: The offtake structure is the one feature of a transaction that gets more focus than any other. If you have a long-dated utility PPA, then not a lot of time is spent focusing on the offtake. But so many deals today have synthetic corporate offtakes, financial hedges and the like, and a lot more focus is being paid to the details or how they actually work and how they are likely to perform over time.

MR. ELKORT: That's a good point. The new forms of PPAs add risk. When you combine them with low levels of cash, there is not a lot of margin for error. There is more pressure when analyzing deals with new offtake arrangements.

Corporate PPAs

MR. MARTIN: Let's stick with that. Jack Cargas, Bank of America has done at least one corporate PPA deal. Do you analyze projects with corporate PPAs as if they are merchant wind farms?

MR. CARGAS: We do not. We look at them as if they are corporate PPAs.

MR. MARTIN: What is the difference?

MR. CARGAS: There is a party with a credit behind the obligations to purchase power.

The number one issue for us in corporate PPA deals is the creditworthiness of the corporate offtaker. What is the credit structure?

The offtaker may not be a publicly rated company. It may not be easily judged from a credit perspective and, therefore, there may be a guarantee behind it from a more creditworthy affiliate. In a number of cases, we have also seen downgrade protection. That is not something

Wind farms may be competing for tax equity the next three years with solar projects that do not have construction-start issues.

you generally see with PPAs with investor-owned utilities.

MR. MARTIN: How is the downgrade protection structured?

MR. CARGAS: If the credit of the entity decreases one or two notches, then some sort of credit security is required to be delivered: for example, a letter of credit.

MR. MARTIN: John Eber, are corporate PPAs financeable? How do you analyze them?

MR. EBER: They are financeable. We have done a fair number of them over the last year and a half. I agree with Jack. You focus on the creditworthiness of the offtaker. Fortunately, many of them are J.P.Morgan clients, so we can get to that decision within a reasonable period of time.

What we are having a bigger challenge with is that most corporate PPAs also come with a lot of basis differential risk. That is what we are beginning to worry about a lot more.

MR. MARTIN: Let's go there. Daniel Elkort, what is basis risk?

MR. ELKORT: It is the difference in electricity price between the bus bar where the project injects its energy into the grid and the pricing node on the grid where the electricity is delivered to the offtaker. When that price starts to separate, it affects cash flow.

MR. MARTIN: Usually the sponsor takes basis risk in a corporate PPA. A utility takes it in a utility PPA. John Eber, why do the tax equity investors care about who takes basis risk?

MR. EBER: It can significantly affect the cash that might be available for distribution to the tax equity investor. The reason we all want PPAs is so that we can get a fixed price for our power and worry more about whether or not the power will be produced than the price at which it will be sold.

When you have basis differential risk, you have to worry about whether or not the net value from electricity sales will be what you thought going into the deal. The basis differential can move around quite a bit. We are finding that in certain parts of the country where there has been an excessive build, the difference between the prices at the bus bar and the node can be significant.

When the wind is really blowing in Texas, all the wind is being delivered and you start to get a greater and greater basis differential, just at the time when you want to be selling your power.

MR. MARTIN: It is an unquantifiable risk.

MR. EBER: Corporate offtakers try to put this risk on the sponsor. With a traditional utility PPA, the utility buys the power at the bus bar. It pays a fixed price and whatever happens between there and the point of delivery is its risk.

Tax Equity Yields

MR. MARTIN: Daniel Elkort, Martin Torres, how would you characterize the cost of tax equity today?

MR. ELKORT: Too high.

MR. MARTIN: I knew you were going to say that. I am looking for details. [Laughter.]

MR. ELKORT: You want details? Way too high. [Laughter.]

MR. MARTIN: Martin Torres, can you do better than that?

MR. TORRES: I would have to second that.

MR. MARTIN: What do you think is the cost of tax equity today in the wind market? What is the range?

MR. TORRES: There is probably more of a range across the spectrum than there was historically. It is probably fair to say somewhere in the 7% range for large, well-known sponsors and . . . .

MR. ELKORT: For clean deals.

MR. MARTIN: Seven percent seems lower than we see. What fees should a sponsor expect to pay these days on top of the tax equity yield?

MR. CARGAS: Commitment fees are becoming more common. The amount depends on how far forward a commitment is required. Sometimes they are characterized as a structuring fee.

MR. MARTIN: Unused commitment fees paid over time or a flat commitment fee at the start?

MR. CARGAS: We have not seen the ticking fee concept. It is more likely to be paid up front.

MR. ELKORT: We do not usually see fees, but if the tax equity is committing to a fixed price at the start of a long construction period, it may want a fee to hold the price. In deals where a lead tax equity investor has put together a club, it wants a fee on other people's money to compensate for the work of bringing the club to the table. Otherwise, we have not seen fees on top of the already too high tax equity rates.

MR. MARTIN: How much are the fees?

MR. ELKORT: They are pretty modest. .

MR. MARTIN: .75%, 1%, 1.5%, 2%?

MR. ELKORT: The lower end of that range.

Developer Fees

MR. MARTIN: Jack Cargas, how common are developer fees and how much are they?

MR. ELKORT: Way too low. [Laughter.]

MR. CARGAS: They are common. We see them in many deals. Not every sponsor wants to have a developer fee. We always remind sponsors that we need to get a */ continued page 32*

Wind

continued from page 31

return on investment with respect to that fee as it is included in the cost of the project. So, in some sense, they have to pay us back for the fee at the end of the day. Different sponsors analyze the value differently.

As for the level, we have views, but they are specific to individual transactions and we are happy to talk about them with our sponsors, but it is hard to have such a conversation in a general forum. We need to see an independent third-party appraisal supporting the fair market value of the project, and we usually want to see that from at least two perspectives: discounted cash flow and cost.

MR. EBER: We take the same approach. If the developer fee is supported by the appraisal, we are okay including it.

MR. ELKORT: A developer fee may be helpful in terms of optimizing the tax equity financing. You do not want to be paying for extra equity, particularly if you are paying for it with cash. If you can increase the amount of tax equity raised by stepping up the asset basis and still hold your flip targets, then that is optimal.

Obviously the tax lawyers will have limits on the size of any developer fee. We generally see something in the 10% range as not too troublesome to the law firms.

However, you should consider including a developer fee if it helps optimize the amount of tax equity efficiently raised.

MR. MARTIN: Two more questions from me, and then let's turn to audience questions. It seems like some tax equity investors are moving to take just 2.5% of the cash after the flip instead of the more typical 5%. Does this seem like a general market trend?

MR. CARGAS: Not from our perspective. In fact, we think it is not a good idea. We would have real difficulty with it. We prefer to stick with the 5% that has been market practice for a long time and is mentioned in the IRS partnership flip guidelines.

MR. MARTIN: A number of tax equity investors are asking lately for withdrawal rights. They want the ability to get out of a deal after a point in time, usually for fair market value, if the sponsor does not exercise the sponsor call option. How common are withdrawal rights?

MR. EBER: They are beginning to show up more often in deals because of the regulatory pressures on banks. Most of us in the banking business are investing under what is called merchant banking authority, and that authority allows us to invest equity for up to a 10-year period.

Thus, from a regulatory standpoint, we are required to exit the deal at year 10. The more assurance we can give our regulators that we will be out of the deal by year 10, the easier life will be. A withdrawal right makes it easier to demonstrate that we will be in compliance with regulatory requirements that are taking on increasing significance in the world of banking.

MR. MARTIN: Sponsors, presumably the withdrawal right would be exercised in cases where you chose not to exercise the call option. Presumably you had a reason not to exercise. How do you feel about withdrawal rights?

MR. ELKORT: We have not had a chance to consider them. We want to control our projects. If there is a way to take over the post-flip interest, that is what we want to do.

I cannot even begin to posit why we might fail to exercise our fair market value purchase option. We might choose to walk away from it if the appraisal value came in ridiculously high, and wait for the next time to exercise the option in the hope of seeing a more rational valuation.

In terms of how we would approach a put, we would probably look at it the same way. As long as it is structured to roll forward if we do not like the price, then it would probably not be too troublesome for us.

Audience Questions

MR. MARTIN: Let's turn to audience questions. Some have been sent by email to the iPad I am holding. One person asked, "Guidance from Treasury clarified it does not matter how much is spent on physical work at the site for PTC qualification. Why are the panelists and the moderator being so conservative?"

MR. ELKORT: Half the panelists.

MR. EBER: What the IRS national office says and what the IRS field might do later on audit are often two different things. I do not think the IRS has said it does not care. The reality is the guidance we have been given by the Treasury and IRS has changed over time, and it can change again when we get to audit.

You cannot be too careful. There is way too much value in PTCs to run any risk by trying to cut something close to the edge in terms of making sure a project qualifies. There is way too much money on the table to do that.

MR. MARTIN: Here is another audience question: "How are wind projects generally performing? Are they coming close to the economics that were expected at closing?"

MR. CARGAS: Our portfolio is performing generally in accordance with what our expected case was. However, our expected case is different from the base case model that we priced and negotiated. We run a number of sensitivity cases for every wind farm, and we also look at a number of sensitivities for our portfolio as a whole. The performance has been in line with the expectations we had, but not necessarily with the P50 base case.

MR. MARTIN: John Eber, you told me in the distant past that your portfolio was performing at a P90 level. Is that still true today?

MR. EBER: I have two portfolios. They are a pre-2008 portfolio and a post-2008 portfolio.

With the pre-2008 portfolio, we took the engineers' numbers and we were dealing with an industry that was not as mature as it is today. That portfolio performed under expectation on average by about 10%, and some deals performed almost 20% to 25% below expectation.

Since 2008, performance has been much more in line on average with our expectations. That is because the engineers got a little better, probably due to pressure from us and other investors. We also started applying our own haircuts to the engineers' forecasts.

There is a range. So some deals underperform. Others over perform expectation. On average, we are pleased with the performance.

MR. MARTIN: Next audience question: "The market is now financing standalone merchant wind farms, at least in ERCOT, with hedges. What term must a hedge have? Are you seeing such deals in other markets besides ERCOT?"

MR. CARGAS: We have done a lot of these deals along with our colleagues at Merrill Lynch Commodities, who are the hedge providers. We see 12- and 13-year hedges in ERCOT. We do not think of the deals as merchant. We think of them as contracted with a hedge.

We expect to see hedged wind deals in PJM in the relatively near future.

MR. MARTIN: How common is tax insurance in the current market?

MR. EBER: We have used it in solar, but we have not seen it used in the wind market. I know everybody is talking about it. I suspect we will see it in the future to cover the risk that a project was under construction in time to qualify for tax credits, especially in projects where construction started based on physical work rather than the 5% test. The sponsor feels it did enough physical work to qualify. If the sponsor is not a strong credit, then its promise to pay an indemnity may not be enough for get a tax equity investor to do the deal. I expect such sponsors to offer insurance as a backstop to their indemnity obligations.

MR. MARTIN: Would you do a deal with insurance where you are not comfortable that the project was clearly under construction in time?

MR. EBER: I don't know.

MR. CARGAS: We have not been seen tax insurance in the wind market.

MR. MARTIN: Sponsors, are you being pitched for insurance and if so, to cover what risks?

MR. TORRES: We have not been, and we have not used tax insurance in any of our transactions.

MR. MARTIN: Here is another audience question for the tax equity investors: "How much does the offtake agreement structure affect the tax equity return requirements?" Think of a corporate PPA versus a merchant or hedged project versus a utility PPA.

MR. EBER: Utility PPAs are still considered to be stronger offtake agreements, and they will attract more tax equity. If you have a good sponsor and a utility PPA, you are likely to get a better deal than somebody with a corporate PPA that may carry basis differential risk or only have a term of 10 or 12 years versus 20 or 25 years for a utility PPA.

MR. MARTIN: The return is a function partly of your assessment of risk.

MR. EBER: It is partly that and also partly the attractiveness of the deal. If you have a deal that is right down the middle of the fairway, every tax equity investor will want to participate in that deal and you will obviously get more competition and better pricing than if it is a deal that will appeal to only half the investors in the market.

MR. ELKORT: A lot of those non-PPA deals are in ERCOT, and certain tax equity investors may bump up against concentration limits. My guess is that is a big driver of the price increases for hedge deals compared to PPA deals.

New Developments

MR. MARTIN: Here is the last question. Are there any other new developments that we failed to mention today?

MR. ELKORT: We are starting to see a lot more pay-go structures. We considered a pay-go structure on one of our recent deals, and we have been working on manipulating the cash sharing arrangements. This is more tinkering around the edges than something completely novel.

MR. MARTIN: What is driving the interest in pay-go?

MR. ELKORT: The tax equity investors drive the use of pay-go. If they feel the deal has too much risk and there are only a couple risks that they are willing to wait for the flip / continued page 34

Wind

continued from page 33

to protect them on, they will move a portion of the PTC payments into a pay-go structure. This reduces the upfront tax equity investment, but you get it out over time if the project performs. At the end of the day, if the project performs, we should be relatively indifferent.

MR. MARTIN: In a pay-go deal, the tax equity investor makes up to 25% of its investment over time as a function of the production tax credits it is allocated. In the old days, tax equity would charge a higher yield under a pay-go structure because it is not earning a return on the full capital commitment from the start. Is that still true?

MR. ELKORT: We have not seen a pricing difference in recent pay-go structures.

MR. TORRES: We have been seeing pay-go deals since the old days. From our perspective, they did not go away. They became a bit more popular with the growth in hedge transactions in Texas as a way to mitigate some of the perceived exposure. We have not seen a pricing differential with the structure, even in the old days.

MR. MARTIN: John Eber, are there any other new developments that we failed to mention?

MR. EBER: We have been heavily involved in the last few months in looking at repowering of existing wind farms. It is a whole new game for tax equity. It involves a different risk. If you do it right, you get PTCs for another 10 years, and if for any reason you do it wrong, you get zero. There is a good volume of potential transactions, and we are taking a pretty hard look at it.

MR. MARTIN: Jack Cargas, anything else new?

MR. CARGAS: We are seeing more private equity sponsors than in the past, and that is affecting how deals are structured. Private equity has different goals for how and when to exit these investments.

MR. MARTIN: You mean the tax equity investor usually requires a guarantee from the sponsor parent of indemnity obligations. It is hard to get a private equity fund to provide such a guarantee.

MR. CARGAS: But it can be done.

MR. MARTIN: Daniel Elkort, do you agree with that? You used to have a private equity fund owner.

MR. ELKORT: We still do. I agree that private equity-sponsored deals can get done. ◎

DOE Loan Guarantee Program: New Rules

by Kenneth Hansen and Shalini Soopramanien, in Washington

The US Department of Energy has adopted mid-course corrections to its loan guarantee program for financing projects that use innovative technologies.

The changes, which become effective Jan. 17, 2017, will address several issues that made the program unnecessarily challenging to navigate.

Meanwhile, the DOE is considering a substantial number of new loan guarantee applications from project developers.

New Risk Premium

One change is the introduction of "risk-based charges." This is making prospective loan guarantee applicants nervous, but may prove to be a net positive for program users.

Loan guarantees are meant to help projects that use promising new technologies obtain financing in cases where commercial financing is not available.

The loan guarantee program's attractions have included not only the availability of financing, but also a very low interest rate. Each loan guaranteed by DOE and funded by the Federal Financing Bank to date has been provided at a spread of 35 basis points above US Treasury bonds of a similar average life. All but one of those loans have been subsidized by Congressional appropriations under the American Recovery and Reinvestment Act of 2009 to cover the credit subsidy cost mandated by the Federal Credit Reform Act of 1990. The credit subsidy cost is the fee that the developer must pay at closing to compensate the government for its exposure from making the loan guarantee.

DOE has some credit subsidy cost appropriation available for current applicants under the existing renewable energy solicitation. However, DOE has told applicants to assume that they will be on their own to pay in full the credit subsidy cost of their loans, subject to a limitation. DOE has promised that credit subsidy charges in the renewable energy project solicitation will not exceed 7% of the loan guarantee or, more accurately, any charge above 7% will be paid by DOE (up to a total per loan subsidy of $17 million). The bottom line is the next round of loan guarantees will not be as inexpensive as earlier loan guarantees.

Against this backdrop, some have interpreted the proposed risk-based charges, which will be an additional spread added to the existing Federal Financing Bank spread, as an unwelcome piling on that reduces the attractiveness of the program. That reaction misses an important point.

Under federal law, the credit subsidy cost must be paid in full at financial close and cannot be financed with federal loans. Thus, the credit subsidy cost becomes a substantial additional equity cost, one that could easily increase equity costs by 5% to 15%. For example, a $100 million project funded with 60% DOE-guaranteed debt and $40 million of equity that is assigned a credit subsidy rate of 5% would require $3 million to cover the credit subsidy charge. The effect is a 7.5% increase in the equity requirement for the project.

The benefit to be weighed against that up-front cost is the discounted interest rate of federally-guaranteed financing over the life of the loan. Adding a risk-based charge to the interest rate makes the debt more expensive. However, the risk-based charge will reduce the credit subsidy cost.

Under the Federal Credit Reform Act, the credit subsidy cost is determined as the projected cost to the government from making or guaranteeing a loan minus the government's projected receipts. The present value of the future stream of payments of the risk-based charges will count, dollar-for-dollar, to reduce the credit subsidy cost required to be paid at closing. Thus, while federally guaranteed loan proceeds cannot be used to pay credit subsidy cost funds, the requirement to pay additional risk-based charges over time will reduce the amount of the credit subsidy charge required to be paid at closing. Though how the math will sort out in practice remains to be seen, unofficial rumors suggest that there is some hope that the net effect of all this will be to reduce the credit subsidy cost required to be paid at closing to roughly zero.

Multi-Site Projects

Previously, a developer could not receive financing under any solicitation for more than one project using the same innovative technology.

DOE had agreed to consider supporting multi-site projects by treating them as a single project in appropriate circumstances. The parts of the project spread over multiple sites had to be "integral components of a unitary plan."

This standard was applied to approve conditional commitments to two distributed solar projects and a multi-site manufacturing enterprise.

DOE has now simplified the standard by eliminating the reference to DOE discretion and by providing that a qualifying project can be "comprised of installations or facilities employing a single New or Significantly Improved Technology that is deployed pursuant to an integrated and comprehensive business plan."

Distributed energy projects were possible before, but now their eligibility will be clearer.

Communication

Another key change is communication with applicants.

Past applicants will remember that getting straight answers from the DOE staff was not always an easy task. The staff was concerned, or had been instructed by DOE procurement specialists to be concerned, that providing any information to one applicant that was not available to all applicants could give that applicant an unfair advantage. At first, many sensible questions went unanswered. In due course, the program developed a process where questions would, or at least might, be answered by means of responses to "Frequently Asked Questions" published on the program's website.

Experience has shown that running a financing program targeted at multiple participants developing disparate projects requires a different approach from that involved in a single source procurement. With these changes, DOE will welcome meetings and questions from potential applicants. DOE's new procedures provide that:

> [A] potential Applicant may request a meeting with DOE to discuss its potential Application. At its discretion, DOE may meet with a potential Applicant, either in person or electronically, to discuss its potential Application. DOE may provide a potential Applicant with a preliminary response regarding whether its proposed Application may constitute an Eligible Project. DOE is not permitted to design an Eligible Project for an Applicant, but may respond, in its discretion, in general terms to specific proposals.

The opening of channels of communication between DOE and applicants is real progress from the experience faced by earlier participants in the program. */ continued page 36*

DOE

continued from page 35

The responses to questions may not be the last word on issues raised:

> DOE's responses to questions from potential Applicants and DOE's statements to potential Applicants are pre-decisional and preliminary in nature. Any such responses and statements are subject in their entirety to any final action by DOE with respect to an Application...

Once an application has been filed, DOE is less receptive to client interaction while the application is under review. During this phase, DOE does reach out to applicants to seek clarification on questions that arise during its review.

Solicitation Structure

The prior regulations contemplated a pre-application preceding a formal application, but that approach was used only once, in the program's first-ever outreach a decade ago.

Only one commitment for a new DOE loan guarantee has been issued since 2011.

In practice, DOE has adopted a two-step application process comprising a part I submission followed by a part II submission, if the part I passes muster.

The part I submission allows for initial screening to determine whether a project qualifies under the relevant solicitation as well as its readiness to proceed. The part I submission focuses on "a description of the project or facility, technical information, background information on management, financing strategy, and progress to date of critical path schedules." The part II submission goes much deeper and is meant to provide the basis for a judgment as to the bankability of the proposed project financing.

To encourage applications, DOE splits the application fee, with payments weighted toward the part II submission, reducing an applicant's cost commitment until DOE has provided, based on the part I submission, at least some level of preliminary review and encouragement. For instance, under the current renewables solicitation, the part I application fee is $50,000. The part II fee depends on the amount of financing being sought. For up to $150 million in financing, the part II application fee is $100,000. For greater amounts, the part II application fee is $350,000.

These changes formalize how the program has been operating in practice.

Non-Revisions

Some quirks in the traditional program have survived. Two surpass the others.

One is that DOE has the right, for any reason (or even without one) to cancel a conditional commitment to issue a loan guarantee at any time prior to execution of the loan guarantee agreement.

This is especially troublesome since, by the time a conditional commitment is issued, applicants will have been required to pay, in addition to the part I and part II application fees, 25% of a facility fee. The facility fee is 1% of the first $150 million of loan guarantee sought and 0.6% of any additional amount sought. Thus, for example, for a $200 million DOE-guaranteed loan, the facility fee is $1.6 million, of which $400,000 will be payable (and non-refundable) in advance of the conditional commitment.

The application fee and the facility fee are in addition to the substantial costs that an applicant will have incurred when reimbursing DOE for the fees of its legal and technical advisors whose support will be required to achieve that commitment and paying for the applicant's own advisors. This is an awfully expensive endeavor for DOE to have the legal right to abandon the process for no reason at all.

The consolation is that, in the near-decade since the program has been in effect, conditional commitments have never been rescinded by DOE on a whim. The only cases of cancellation of which we are aware are projects whose prospects of meeting a September 2011 statutory deadline to issue some loan guarantees were dim. The program staff and management fully recognize that the exercise of the 'nuclear' option would severely adversely affect the program's reputation and, to date, they have declined to exercise it.

Another peculiarity of the loan guarantee program is the restriction against applications by a single applicant under a particular solicitation for multiple projects that use the same innovative technology. This is an unfortunate restriction for a program whose mandate includes broadening the use of innovative technologies.

This provision has made developers of distributed generation projects nervous since they necessarily envision multiple projects on multiple sites using substantially identical technology. DOE, which had been both open and anxious to support such projects, found a way forward by treating them as a single project if certain conditions were met. As already discussed, these conditions have been revised and simplified, dispelling any doubt as to the eligibility of distributed energy projects for DOE-guaranteed financing.

Still beyond the permitted scope, however, are cases where a single developer wants to build two similar facilities. To date, DOE has proven cooperative by, at least on one case, treating one facility as "phase 1" of a project and the second facility, to be constructed at a later point in time, as "phase 2."

The latest changes suggest another possible flexibility, though we are not aware of a precedent for this approach. If there are multiple projects using the same innovative technology all seeking DOE-guaranteed financing, each of which had multiple equity participants, the language suggests that, since not all sponsors need to be included as the applicant, one sponsor could apply as the applicant for one project while a different sponsor could serve as applicant in a separate, but similar, project.

It may be useful to discuss with DOE whether such a work-around might be possible.

Program Status

According to its website, the Loan Programs Office is currently managing a portfolio of more than $30 billion in loans, loan guarantees and conditional commitments covering more than 30 projects across the United States.

With the exception of the $8.3 billion financing in support of the Vogtle nuclear power project, provided in a series of closings over 2014 and 2015, and advanced technology vehicles manufacturing financings, the loan guarantee portfolio consists of renewable energy projects financed under an earlier wave of loan guarantees that had to reach financial close prior to September 30, 2011.

The future prospects for the DOE loan guarantee program remain an open question. Only one "conditional commitment" has been issued for an energy project since September 2011. That was for the storied Cape Wind project off the Massachusetts coast, which, to date, has not closed.

The loan guarantee program still has more than $40 billion in loan authority available to finance innovative clean energy projects and advanced technology vehicles manufacturing projects.

There are currently three open solicitations for energy projects — one offering up to an aggregate of approximately $4 billion in financing for renewable energy and energy efficiency projects, another offering up to $8 billion in financing for advanced fossil energy projects and yet another offering $12.5 billion for advanced nuclear energy projects. Multiple applications are now proceeding under these open solicitations.

The part I and part II application deadlines under the renewable energy projects and advanced fossil energy projects solicitations have been extended into early 2018. They had been scheduled to expire at the end of November 2016. The deadline for advanced nuclear energy projects solicitations has been extended to mid-2019. The next part I application deadline under each outstanding solicitation is scheduled for January 18, 2017.

The constraint on the volume of the program's operations is likely to be Congressional support to fund it rather than qualifying projects seeking its support.

These changes to the program should yield an experience for current and future applicants for loan guarantees that will be somewhat smoother than that experienced by earlier applicants. ◎

Infrastructure Opportunities After The US Elections

The November 8 federal elections in the United States could have a significant effect on the US infrastructure and P3 markets. A large group of industry participants gathered in New York two days after the elections for a breakfast roundtable discussion about US P3s hosted by InfraAmericas and Chadbourne. The following is an edited transcript of the panel discussion.

The panelists are Patrick Foye, executive director at The Port Authority of New York and New Jersey, former New York Governor George Pataki, a counsel at Chadbourne, John Porcari, president, US advisory services, at WSP|Parsons Brinckerhoff and interim executive director at Gateway Development Corporation, DJ Gribbin, national director strategic / continued page 38

Infrastructure

continued from page 37

consulting at HDR, and former general counsel at the US Department of Transportation, Mike Parker, US infrastructure advisory leader at Ernst & Young, and Mike Lapolla, managing director at Globalvia. The moderator is Doug Fried, a partner in the Chadbourne New York office.

MR. FRIED: Donald Trump said in his acceptance speech that he wants to make US infrastructure "second to none." Pat Foye, infrastructure investment and P3s were not a hot topic of debate during the Presidential campaign. Do you believe that Trump will make a push for more private investment in US infrastructure?

Consensus

MR. FOYE: Definitely.

There are two things I don't know anything about: one is Washington and the second is Donald Trump. [Laughter.] But I will note the following:

Donald Trump is a builder. He has written about visiting construction sites with his father, Fred, who was one of the great real estate entrepreneurs in New York. Fred built more than 27,000 apartments in Brooklyn and Queens, the value of many of which was determined by their proximity to subways. Donald Trump's first major transaction was a place called the Commodore Hotel, which is basically in the Grand Central Terminal.

This was a largely issue-free campaign, but one of the few issues on which there was bi-partisan agreement was that American infrastructure is in an unacceptable state. It is a current drag on the nation's economy. It poses threats in the short term and the long term to the nation's economic competitiveness and to job creation. If you look at why Donald Trump got elected, it is because of concerns about job insecurity and the fact that on a real basis American wages for middle class people have declined over the last 10 to 20 years. That is really the first time that has happened outside the Great Depression.

I think there is a bi-partisan consensus on three things.

One is that America's infrastructure issues have to be addressed.

Two is that private capital is going to play a significant role. That is not an unusual conclusion for someone like Donald Trump who has spent his career in the private sector doing deals, some of which, like the Commodore Hotel, were done with government assistance.

Three is the need to revise the National Environmental Policy Act, building on the work that was done by President Obama, Transportation Secretaries LaHood and Foxx and John Porcari, the executive director of the Gateway Program Development Corporation who is sitting here. There is a consensus that the NEPA environmental permitting process for transportation infrastructure is broken. This is especially true for projects that replace existing facilities. The Gateway program is a good example.

The Gateway program is replacing existing Amtrak tunnels that opened in 1910 and were severely damaged by Superstorm Sandy. The tunnels are safe — Amtrak inspects them regularly — but at some point their useful lives will end. If that happens before new tunnels are built, it will be a transportation disaster, an economic disaster and an environmental disaster. It will be an environmental disaster because tens of thousands, perhaps even hundreds of thousands, of people who currently take Amtrak from Washington and other points north on the way to New York City will be forced to take other modes of transportation, including private cars, buses and planes. It will be an environmental disaster for a region whose air quality does not currently meet the Environmental Protection Agency standards.

This is a transaction that ought to be hurried along, which we are doing under John Porcari's leadership and with the cooperation of the US Department of Transportation, Amtrak, New Jersey Transit, and The Port Authority, which has been helping lead the drive to create urgency here.

President-elect Trump talked about the need to rebuild our aging infrastructure starting a minute or two into his victory speech. He has tweeted about it regularly over the years and compared the state of our infrastructure to China's. There was talk from the Trump campaign about tax credits for investors of private capital. I think there will be significant amounts of private capital put to work.

MR. FRIED: Pat Foye, how much of an impact do you think Trump will have on what The Port Authority will be doing?

MR. FOYE: We have had a very robust $27 billion capital plan in place since 2014. We are in the process of reviewing it. Our board just made a contribution to the Portal Bridge North portion of the Gateway program, and is working closely with John Porcari on figuring out how the tunnel can be financed. The financing will probably come from a combination of sources, including user fees and private capital. The fact that the President-elect is focused on this area will help.

He can also push through NEPA reform. Most of our projects — for instance, the Goethals bridge — are replacement projects.

We are also raising the roadway on the Bayonne bridge, which in many ways is a new bridge. The LaGuardia Airport project is a replacement project. The President-elect can also help by creating an infrastructure czar in the White House who has responsibility for working with the US Departments of Transportation and Commerce and EPA to streamline approval processes.

MR. FRIED: John Porcari, what do you think are the most significant challenges with respect to our nation's infrastructure that Donald Trump will face?

MR. PORCARI: First, you must have the will to build infrastructure. By any objective measure, we have fallen behind on this as a nation. We are not spending 7% or 3% or even 2% of our GDP on infrastructure. That is not investing for the next generation.

On the positive side, the candidates talked about infrastructure during the campaign. Secretary Clinton had very detailed plans for a $275 billion, five-year-plus plan to increase infrastructure spending. President-elect Trump said several times he would double that, and, in fact, at one point he said he would triple it, but without providing details.

The point is that if there is anything even remotely near bipartisan in Washington, it is infrastructure. Infrastructure is at the top of the list of what could be done during the first 100 days of the new administration. There are a couple plans already that could serve as vehicles. For example, on the House side, Congressman Delaney has a bill with 60 co-sponsors that would allow US companies to repatriate overseas earnings and pay a reduced tax rate. The additional taxes collected would be used for infrastructure.

What does it mean in terms of actually getting more roads and bridges built? As DJ Gribbin and others here who have been on the inside know, tangible results require a lot of hard work. The new secretary of transportation should spend the first week in office talking to every governor and every state transportation secretary and make sure Washington understands each state's top five priorities. Obviously Nebraska and California have different needs. The new administration should follow those priorities in an agonistic way. This would have a remarkable effect in focusing the mind. The approach is consistent with our governing philosophy in America, which is federalism. There is a misunderstanding that the transportation network is some kind of national plan. Even the interstate highways were not a national plan. They were a bunch of local priorities, or city-pairs, that were aggregated into a national system.

The point for the President-elect is you can start with the state priorities and build a national program from that very quickly.

MR. FRIED: DJ Gribbin, as John Porcari mentioned, you were an insider at US Department of Transportation when it started focusing on P3s. Do you think private investment in infrastructure will be a priority for the Trump administration?

MR. GRIBBIN: Absolutely. Pat and John have done a good job of explaining why that is. Taking a step back on the question of what Donald Trump is likely to do, I don't think anybody knows, including Donald Trump. This is a whole new era. We have never been here before. But if you think about his background, what he does, what he prides himself on: it has a lot to do with building things, as Pat mentioned. And Pat and John both touched on the fact that there is a strong bi-partisan consensus around infrastructure. If we were talking about almost any other issue, there are substantial differences between the parties, between Donald Trump and the Democratic Party, and actually between Donald Trump and some of the Republican Party. [Laughter.]

When it comes to infrastructure, there is a general consensus about the right thing to do. The first substantive issue Trump mentioned in his acceptance speech was infrastructure. It came ahead of veterans. It came ahead of the economy. It is what he knows. If you think about private involvement, that is what he has done. That is his background. It is natural for Trump to advocate the value of private investment in infrastructure.

MR. FRIED: Mike Parker, you work with state and local officials who are responsible for delivering infrastructure projects. What are they hoping for from President-elect Trump?

Potential Agenda

MR. PARKER: I think everybody is recalibrating and trying to think about how they react to the news, and then, what are they asking for. It would have been the same had Clinton been elected.

Let me highlight three areas.

One is long-term funding and predictability. Funding is needed for large projects. Predictability is important because these projects take many years to plan and deliver.

Another is process reform, including, as Pat Foye mentioned, NEPA reform, particularly as more projects become multi-modal or bi-state. We need to reduce the cycle time for completing NEPA.

Lastly, can there be a different track for projects that are self-funding perhaps 50% or more of their costs? We are getting to a point where states and localities have become significant players. Can there be a different alignment of roles when substantial local money is contributed? For example, could the local money confirm the priority of the projects? One person's bridge to nowhere may be another person's critical */ continued page 40*

Infrastructure

continued from page 39

bridge, but if there is half local match, that is a pretty good way to confirm the project has merit.

MR. GRIBBIN: What Mike Parker just said is absolute genius. Historically, we talked about a federal program. What federal money do we get? Over time, the federal share, especially on highways, has decreased. The Trump campaign promised to double whatever funding Secretary Clinton promised. I encouraged the transition team to think about incentives for investment of non-federal dollars. Think about growing the whole pie as opposed to just the amount of federal dollars that we are putting in. Over time, we will see counties, cities and states playing a much bigger role in transportation infrastructure dollars than the federal government.

MR. FRIED: Mike Lapolla, what are the infrastructure companies hoping to see from Donald Trump?

Trump wants $1 trillion in new infrastructure investment.

MR. LAPOLLA: I am the token crazy liberal Democrat here. I am very depressed about the results. [Laughter.] I wore the red tie as a sign of transition. A friend of mine texted me yesterday that she is so depressed that if a clown invited her into the woods, she would go. [Laughter.] That is how I feel today. I think Doug Fried was surprised to see me walk into the room.

The Trump plan calls for $1 trillion over 10 years with $187 million in tax credits. The support will only be for projects where there is a revenue stream. It specifically said toll roads. I am cautiously optimistic.

My company is based in Madrid. We want stability and predictability. We do not want chaos or the rancor that we saw during the campaign to continue after January 20. I hope things calm down and there is actually a policy.

MR. FRIED: DJ Gribbin, what do you think will have a bigger impact on infrastructure: the new President or the new Congress?

MR. GRIBBIN: Both. It will be interesting to see the extent to which the new administration works with Congress as a co-equal branch of government. It helps that both will be in Republican hands. It is the first time since 1928 that Republicans have held the House, Senate and the White House at the same time.

That said, Congress has a bigger role potentially in infrastructure because it appropriates funds. Congress passes a reauthorization bill for the highway program, for the airport program and for the water program, and Congress sets the ground rules for how those programs can incorporate private funding.

We touched on NEPA earlier and the need for process reform. Congress determines what NEPA does and does not require. Thus, for infrastructure writ large, the answer is Congress.

For just P3s, the President plays a bigger role. The current administration has set a great example in terms of how to help lead in this area. It helps when the White House, US Department of Transportation, EPA, and the Army Corps of Engineers are out front saying that P3s are something that they think are important.

MR. PORCARI: Making infrastructure a priority really has to come from the White House.

MR. FOYE: I agree.

The Republican Congress has been talking about privatizing the air traffic control system. The idea has not gone anywhere. It might go someplace in an environment like this. That would be incredibly important in New York and New Jersey because a third of flights in the entire country are affected by delays in New York, New Jersey and Philadelphia airports. Being able to make progress on that would be unbelievably important to the regional economy.

Congress can also think about revenue sources, like the passenger facility charges authorized by the federal government that are an important source of funding for airport investment all over the country, including our P3 for the central terminal building at LaGuardia airport. PFCs have not increased in a long time. Having a revenue source is incredibly important. The President-elect mentioned toll roads the other night. I am not sure that the optimal use of tax credits is on toll roads because toll roads already have a source of revenue.

The Trump campaign talked about some type of national tax increment financing. That is an intriguing concept. There was an article in one of the papers today about the average rent on 2nd Avenue in New York for a residential unit being expected to go up something like $500 dollars a month when the 2nd Avenue subway is completed. It is unfortunate that the Metropolitan Transportation Authority cannot capture some of that. The MTA should focus on capturing it going forward. The MTA is talking about doing four new Metro North stations in the Bronx. The Bronx is not 2nd Avenue, but there are real opportunities for value capture.

MR. GRIBBIN: Whenever you build infrastructure, the property around that infrastructure becomes more valuable, and yet governments have consistently underperformed in capturing that value.

MR. PARKER: Governments are not completely underperforming. New York City will capture all the property tax value. The question is whether it will use the additional revenue to pay for infrastructure.

MR. FOYE: From a Port Authority point of view, having real estate developers and owners contribute over a long period of time can be part of the financing package for infrastructure projects. How to do it on a national level is a fascinating issue.

MR. PARKER: Doug also asked about Congress and, while DJ Gribbin said the president could have the greater role to play with respect to P3s, if a new infrastructure agenda is authorized, Congress will be where it happens, and choices in legislation could have a big impact on P3s.

People always ask us why the US P3 market is so slow to develop. They want to know why value-for-money processes do not justify more P3s in the United States. The reality is that value is in the eye of the beholder. Other countries are prioritizing P3s. Some of the project-by-project discussions about the value of a P3 would be settled in the United States if there were a prioritization of P3s at the federal level. Otherwise making the case for P3s, particularly in some sectors, can be harder in the United States than in other countries because here you have federally subsidized tax-exempt debt as an alternative to private finance.

Those of us who work in the industry see benefits in P3s around certainty of performance and certainty of delivery. If you look at how money actually comes in through programs like the Federal Transit Administration's New Starts capital grant program for major transit projects, sometimes the money comes in a considerable amount of time after the projects are delivered.

Perhaps this points to a way to incentivize using contracting methods that provide greater certainty of outcomes. A federal program need not push for a P3 or other delivery approach, but instead might just tell grantees that it does not matter how you build and deliver the project. The money is coming in only after you have completed the project, or in amounts over the first five or 10 years as operational performance metrics are met. Some states and localities might choose to manage those projects themselves, and others might choose to transfer that risk to a private partner. That's a risk that the private sector is well equipped to manage.

If Congress was bold or looking for budget savings, it could look at tax-exempt debt, either make it more available to private infrastructure or, in the extreme, get rid of it for future public infrastructure. These are examples of very significant legislative options that, if considered, would certainly affect the P3 market.

MR. PORCARI: You do not need legislation for some of the opportunities related to P3s. Objectively, if you look around the country at deals that have cratered, they crater, usually at the 11th hour due political risk. Federalism, which is a real strength of our country, works against us in this case. The deal could be changed at the local level at the eleventh hour.

MR. GRIBBIN: Going back to what Mike Parker said, you have to give local elected officials all the way up to the governor some political cover. If what they are saying is, "Listen, we get additional funding from Washington if we consider this method," that is huge.

MR. PORCARI: Absolutely, but I am also suggesting you build in some consistency and predictability. It is okay to say, "No, you can't do it" at the 11th hour. If there were federal funds involved, you could have a process where those kind of threshold political viability questions at the local level had to be asked and answered earlier in the process. You would bring that consistency and predictability. You do not need legislation to do that.

MR. FOYE: I agree. It is another reason to shorten the NEPA process. By shortening the NEPA process, you reduce the escalation of construction costs and capitalized interest costs. You reduce the risk of electoral cycles, the risk of a new mayor or new governor coming in, from a different party, or with a different philosophy.

MR. GRIBBIN: These projects are incredibly controversial. Every day that a project is under consideration, it is like a piñata. People are just whacking at it. If you can shorten the NEPA cycle, shorten the procurement process, and end the last-minute changes, that would be huge.

MR. FRIED: Mike Lapolla, I want to get your take on what you think is the most important thing the */ continued page 42*

Infrastructure

continued from page 41

new Congress can do to facilitate P3s?

MR. LAPOLLA: The big question is whether Paul Ryan can get congressmen who think tolls are a tax to go along with anything. You cannot do nuanced tax credit proposals. The voter does not understand what a tax credit translates into for jobs. Voters understand if the federal government gives $50 million to their county to build something. I think P3s are going to be a small part of a much bigger policy discussion among all sides.

Trump Team

MR. FRIED: DJ Gribbin, a handful of former state and local officials may be moving to Washington to help the new administration with infrastructure. What experience would you like to see these officials bring to the table and how important is it that they have private sector experience?

MR. GRIBBIN: I worked on the Bush-Cheney transition in 2000 and I think the media got about 20% of it right in terms of who is likely to come in.

If you think about the characteristics that you want in the transportation secretary, private sector experience is beneficial. The public and private sectors have different cultures. They have different rhythms.

Public sector experience is also very important. One of the concerns that I have about the President-elect is whether he understands that he is just a third of the government and not a CEO. He can have really good ideas, but he needs to bring a lot of people with him to execute on those ideas.

It would be good to have a new transportation secretary who has worked with legislatures.

Sales experience is also helpful because he or she will have to sell new ideas.

When you look across the country, I think someone like Pete Rahn would be phenomenal. He is the former director of the New Mexico Department of Transportation, former director of the Missouri Department of Transportation and the current head of the Maryland Department of Transportation. He may be the only person in America has led the transportation departments in three states. And he started off his life as an insurance salesman.

You may think that technical, engineering, legal and financial skills are important for someone at that level, but it is most important to have somebody who can convey ideas clearly and simply and get other people to buy into them.

MR. PORCARI: It would be a real bonus also to have real projects experience in the public or private sector. I had many frustrations as a state transportation secretary trying to deal with the US Department of Transportation. It included not only things like the NEPA issues we have been talking about, but also people returning your phone calls. How the people who are actually building projects are treated is important.

State Ballot Initiatives

MR. FRIED: Mike Parker, I know you were following the regional and local ballot measures to increase funding for major transit agencies in cities like Los Angeles, Seattle and Atlanta. Were these measures successful and will any of them let transit agencies pursue major projects that otherwise would not have been pursued?

MR. PARKER: This is a really big part of the story of the election.

You now have funding in Los Angeles not only to do major projects, but also to plan some very large projects that will be transformative there. The fact that Los Angeles is already focused on delivering major projects is no surprise, but the level of funding that was approved in the local ballot measure is a significant differentiator.

The Seattle area is at a different place than Los Angeles in terms of decisionmaking on project delivery. It may continue to evolve. Washington State has had a mixed history with consideration of P3 projects. There have been successful measures in Atlanta.

These types of local initiatives should be considered in the design of a new federal program. You saw a possible issue with the Obama stimulus, where when the federal government stepped up, some states considered pulling back. Federal funding should complement local revenue.

MR. FOYE: Governor Christie pushed for a constitutional amendment that passed in New Jersey and that will allow New Jersey Transit to borrow against the increased gasoline tax revenues.

MR. GRIBBIN: Will the focus then shift from states to localities? For those in the room who are pursuing P3s, should they spend a little less time on states and a little more time on localities?

MR. PARKER: The answer may be different state by state and place by place. Many of the states are dependent on the federal program. Agencies like Caltrans have seen their programs depleted as the level of funds goes down and their operating costs, which are CPI linked, or worse, go up.

There are many different types of states. The coalition that supported Donald Trump includes people from states that do not have the kind of funding Los Angeles has. Part of this election was perhaps about making sure that the economic improvements on the coasts are not leaving behind other states.

Public-Private Partnerships

MR. FRIED: Pat Foye, The Port Authority has been through a number of P3s at this point. How would you advise a new governor or new mayor who wants to understand the merits of a P3 and the P3 model?

MR. FOYE: The elected official is trying to figure out what is the best risk-adjusted way to deliver a project.

We want to do more P3s at The Port Authority. I would not be surprised if in two or three years we are well on our way toward a P3 deal bigger than LaGuardia. I think that P3s could have significant roles in a Port Authority bus terminal project, the Gateway program and other things on which we are working.

The advice is as follows:

A P3 does not fit all cases. We are doing two airport deals. The LaGuardia Central Terminal Building is being done as a P3. Terminal A at Newark is most likely going to be done as a design-build with additional Port Authority financing.

We are also building two bridges at the same time. On the Goethals bridge, the first lanes will open in February. We did that as a P3 thanks to a $500 million TIFIA loan, which is an important part of the capital stack. On the Bayonne bridge, we decided to do the project using traditional Port Authority tax-exempt financing. We will look at every project above a certain size, say $500 million, through the prism of P3s. P3s are complicated deals. You need a certain size to justify the complexity.

You have to pick your spots.

The advantages to The Port Authority on both Goethals and LaGuardia were as follows. While the private equity will earn a higher return than the traditional Port Authority tax-exempt capital, The Port Authority got innovation from the private sector on both LaGuardia and Goethals. We also transferred risk, which is incredibly important.

We have a $27 billion capital plan, and $9 to $9.5 billion of it will be delivered through the LaGuardia and Goethals P3s and a deal we made with Delta at LaGuardia. We have fixed price commitments from creditworthy parties. If the transactions are late or they go over budget, then it is someone else's problem.

That gives the board a great deal of comfort in capital-constrained times. P3s ought to be something that every executive is looking at for projects above a certain size even if they are not a good fit in every case.

MR. FRIED: Would you say that risk transfer was the tipping point of your decision to do a P3?

MR. FOYE: There are three things. One is risk transfer. Two is innovation. Three is that while government is good at lots of things, given the operating costs and cost of construction of some projects, government is going to be better off having a creditworthy private party do the project with a big balance sheet backing up the obligation.

MR. FRIED: Pat Foye, what would you say were the biggest challenges of getting Goethals and LaGuardia over the finish line?

MR. FOYE: John Ma and I are going to write a book. It will not be a bestseller. [Laughter.]

These transactions are all tough, complicated transactions. LaGuardia is a project with an international profile. There were certain things that were really important to get it done. One was full-throated support from Governor Cuomo, Governor Christie and the board. Another is we had the full-throated support of labor on both of those transactions, and no P3 is going to get done, at least in this part of the country, unless labor is behind it. The construction and building trades in both New York and New Jersey recognize that in capital-constrained times, P3s will result in projects getting done that would not otherwise get done. Men and women are going to go to work who would not otherwise have been employed.

LaGuardia was a roller coaster. Had the transaction failed, it would have been devastating to P3s in the region and in the country. Fortunately, we got an unbelievable execution and are proud of the deal.

MR. FRIED: Governor Pataki, what should Donald Trump do to make sure that investing in infrastructure is not a partisan issue, but instead draws support from both parties?

GOVERNOR PATAKI: He has to try to bring people together across the partisan divide. I am enough of an optimist to hope that the effort is made. From a policy standpoint, I think the place where that would be the easiest is infrastructure.

Hillary Clinton had about a quarter trillion dollar infrastructure plan that she advanced. Donald Trump had about a half trillion dollar infrastructure plan. There are bills now in Congress, with Democrats and Republicans sponsoring them together, to do things on infrastructure.

/ continued page 44

Infrastructure

continued from page 43

The other thing that President-elect Trump has talked about is lowering the corporate tax rate to bring money back from overseas. There is a real opportunity early in the next session of Congress to do something along these lines. A temporary reduction might bring as much as $2 trillion back, with a low tax rate such as 10% on the amount that is brought back, to use to fund a massive infrastructure program in America. This is something that I think could achieve broad bi-partisan support. The economy has been slowing, and it is likely to slow more. With the interest rates as low as they are, this is exactly the time when we should be doing a trillion dollar investment in roads, bridges, mass transit and other infrastructure projects, like health and water projects.

MR. FRIED: Do you think that the Republicans in Congress will support private investment in infrastructure?

GOVERNOR PATAKI: Yes. They have always been more in favor of P3s and private investment. With the low interest rates, pension funds and insurance companies with enormous financial assets are getting very low returns. Investing in infrastructure projects is something where you could put in place financial protections to guarantee a sufficient return to attract enormous capital.

MR. FRIED: How do we make sure that there is no gridlock in Congress with respect to private investment in infrastructure?

GOVERNOR PATAKI: There has not been gridlock in the last 90 years. [Laughter.]

I think the attitude of the American people now is that we can't continue with the partisan bickering the way it is. The Republicans will control both houses of Congress and the presidency, but still in the Senate you are going to need 60 votes for any significant legislation, which means you are going to have to achieve a bi-partisan consensus. I think that can be done. Senator Chuck Schumer will be the Democratic leader in the Senate, and he has always been willing to make a deal. And then you have Donald Trump who claims that he always wants to make a deal.

MR. FRIED: Governor Pataki, are there any new governors, mayors or other officials on whom we should keep an eye from a private investment and infrastructure perspective?

GOVERNOR PATAKI: In New York State this year, revenues are something like $900 million less than they were projected to be at the beginning of the budget year. You will see that repeated across the country. Having been a governor, it is a terrible thing when your revenues go down. This creates the opportunity for P3s. One of the reasons it has gone a lot slower than I had hoped for, because I'm a great believer in P3s and accessing private capital, is because budgets have been largely okay. The deterioration in state budgets creates the opportunity all over the country where governors will be looking to have infrastructure projects that require private capital.

One other point: when Mike Pence was governor of Indiana, he was very active in P3s and infrastructure investment. I would hope that he has some significant input going forward.

Now is the time. Pat Foye hit it on the head. Interest rates are low. Long-term treasury yields are at 1.8% or 1.85%. If ever there was a time to make intelligent, long-term investments in infrastructure, now is the time.

Gateway

MR. FRIED: John Porcari, as interim executive director for the Gateway Development Corporation, what can you tell us about the Gateway project that is supposed to add rail capacity on the northeast corridor between Newark and New York? Will there be P3 components to Gateway?

MR. PORCARI: First and foremost, it is a real project. It has been talked about for a while, but it is actually underway.

There are three essential project partners: The Port Authority, New Jersey Transit and Amtrak. The most useful way to think about Gateway may be that it is a program of projects starting with replacing the Portal Bridge North over the Passaic River in New Jersey, then going to the new tunnels under the Hudson and then there are subsequent phases that include Penn Station, Secaucus Loop and a lot of other pieces.

Gateway is the most urgent infrastructure project in America. It is the single biggest choke point in the entire northeast corridor. The northeast corridor has roughly 20% of America's GDP. You have 106-year-old tunnels and a 106-year-old bridge. The tunnels flooded during Sandy, and they are far beyond their design life. Just to give you a sense of what an engineering achievement it was when they were built, the year those tunnels opened, Henry Ford moved from a wood body to a metal body Model T. The Wright Brothers went from a Model A to a Model B flyer, and a shipyard just laid the keel for the Titanic. It is well past the time to replace those facilities. If you picked a center of the US economy with a single point of failure like this and tried to find one more acute, you could not.

The good news is that The Port Authority and the other partners have identified the local funding that will allow the project to apply for a federal core capacity grant. That grant application is in. The US Department of Transportation is treating this as a priority. It has been put on the President's dashboard of priority projects. The Portal Bridge North is ready to go to construction. We could do that late next year. The tunnels are under design, and the NEPA process is greatly accelerated. The Tappan Zee-type NEPA process of concurrently reviewing a number of the elements of an environmental impact statement is underway on Gateway.

While you cannot pre-judge the procurement methodology, to me, the tunnel part of the project providing capacity under the Hudson, what we call Phase 1B, may fit the profile for a P3. The primary beneficiaries are New Jersey Transit and the 200,000 commuters a day that need to get into New York, but there are also commuters on Amtrak and the northeast corridor. Beyond that there might be other rail users, and the tunnels might provide for high priority, air freight-type, off-peak use. The line might be used as a utility corridor. That portion of the Gateway program, as a discreet element or even as part of the larger program of projects to follow the Portal Bridge North, could well be a P3. Agencies like The Port Authority have experience doing projects that way.

The bottom line is that it is the most urgent infrastructure project in America, period. We should treat it like that. It should be at the top of an agenda for an incoming administration, and I would be saying this no matter who won the election.

MR. FOYE: Let me add two things. One is to praise the responsiveness and sophistication of the US Department of Transportation team led by Secretary Foxx, Andrew Right and the Build America Bureau, the Federal Railroad Administration and the Federal Transit Administration. They have been extraordinary. We will make a filing, either in draft or in final, and we will get comments literally days or a week or two later, which is extraordinary.

The other thing is this is a project with bi-partisan support. This project is led by Governor Cuomo and Governor Christie, and the four Senators from New York and New Jersey provide bi-partisan support. One could see a deal in this Congress made involving the President, the Republican House, and the Republican Senate that would relate to infrastructure spending, including Gateway because of its importance.

Bi-partisan support for some form of new funding is expected from Congress.

US P3 Market

MR. FRIED: There has been an expansion of the P3 model to other types of projects. The Massachusetts Bay Transportation Authority is procuring a P3 for an automated account fare collection system. The Chicago Infrastructure Trust has shortlisted teams for a Chicago smart lighting P3. Mike Parker, do you think that the P3 market will continue to diversify for projects with new technology solutions?

MR. PARKER: Yes. We are seeing this model applied in a number of places. The model is not workable in every setting. Lenders and investors have to get comfortable taking on a project finance risk and must be sure they can replace the technology provider with creditworthy counterparties. There are issues that we have to think about or, in some instances, we have to invent different types of models if we cannot apply the models used earlier.

Some of the areas you mentioned could see more P3s, like communications-related infrastructure. We are also starting to see a cluster of what we would refer to as resiliency-related infrastructure. One such project that many are aware of is a flood relief and flood prevention project in the central part of the country. We are also in Toronto working on a resiliency project on the waterfront, and we are going to be looking at another US project that would transfer water when there is a drought. We are also seeing initiatives like the Pacific Forest Trust that could lead to new ways of thinking about resiliency for aquifers and about using natural infrastructure. There is also a discussion about far-reaching resiliency projects in New York City, among other places.

/ continued page 46

Infrastructure

continued from page 45

MR. FRIED: In terms of the expansion of the P3 market into other areas, the University of California Merced recently reached financial close on a major campus expansion. Ohio State University is procuring a major P3 for energy utility systems. Mike Parker, do you think other universities will catch on to this? It seems like a natural fit if it works for these schools.

MR. PARKER: Yes. Merced is a unique place in that it is a new campus. Not every university system is looking at an entirely new half of a campus. There are different types of P3 programs. The student housing market has been robust as has been the military housing market. So there has been private sector involvement for a long time. There is also significant recognition of real estate development potential at the edges of campuses as universities think about themselves more as part of an overall area. This is certainly an area of interest.

Sometimes on the energy side, if universities are looking at projects that are complex and they have not built a cogeneration facility or managed one in a long time, the benefits of a P3 approach could be very significant. It should be easy to define performance requirements for these types of projects.

Lastly, these institutions will remain under budgetary pressure, so they also should be looking at how to focus on their core missions. It is a robust area where industry can play a significant role, but it is one where we may not see $1.5 billion deals every time.

MR. FRIED: Mike Lapolla, recently the Indiana toll road sold for $5.7 billion and the Chicago Skyway sold for $2.8 billion. Are there more brownfield sales on the horizon?

MR. LAPOLLA: There are great opportunities in brownfields. My company was recently named the successful bidder for the Pocahontas Parkway. There will be more opportunities, but they will vary across jurisdictions. Virginia is a model for P3s and understands the nuances of brownfields, greenfields and other projects. In some places people talk like they understand P3s, but they really don't.

I talked earlier about leadership at the federal level. When Secretary Foxx was going to create the P3 office within the US Department of Transportation, he was in Madrid visiting our company, and he and his staff spent six hours with us trying to understand how such transactions work.

Whether there will be a lot of opportunities also turns on the political will of individual governors, state transportation commissioners and others. We talk too often in broad strokes about political risk, but the risk is specific to the people with whom you are involved, what positions they are in politically, how strong they are, and how committed they are to the project.

MR. FRIED: Governor Pataki, when will New York get P3 legislation?

GOVERNOR PATAKI: The Cubs just won the World Series. [Laughter.] That only took 108 years. I don't know whether New York will ever have comprehensive P3 legislation. I hope that it will. Governor Cuomo will be looking to do a lot of P3s, with his Tappan Zee experience and his desire with LaGuardia and other places to do significant infrastructure projects. It is more likely to be done on a case-by-case basis as opposed to a generic authorization.

MR. FRIED: The District of Columbia released a P3 project pipeline recently. Mike Parker, do you think that Washington, DC could prove an attractive place for P3s?

MR. PARKER: One of the privileges of doing the type of work we do is to have a good understanding of a lot of clients. On the other hand, an essential part of that is also having some discretion about what we can say about them. We are working with the Washington, DC Department of Transportation already on the South Capitol Street bridge, which is a design-build project. I grew up in Washington, DC. There is a lot to do there, and when you do it the visibility is tremendous. There is also a federal partner at times.

Washington, DC has some significant requirements with respect to its own finances and how those function. You have leadership that is interested in doing P3s. To the degree projects work within the framework that they have, including the revenue and funding models that they have, I think you will see significant activity. You have a mayor who is really committed to doing things, but it is a city and it lacks the girth of a state. There will be a number of things that are important to think through and understand, but the city is off to a great start.

MR. FRIED: Maryland recently closed the Purple Line light rail P3. John Porcari, what do you see for the future of P3s in Maryland?

MR. PORCARI: The future is bright. As the Maryland transportation secretary at the time, the Port of Baltimore Container Terminal deal that we did was actually one of the few large deals to close in 2009. It was a great educational process for the public at large, the elected officials and the internal DOT people. We followed that with replacing the welcome centers on I-95 through a P3, and then the Purple Line.

I think the future is very bright, notwithstanding the fact that I have personally been involved with the Purple Line since 1994, and it is now in what is hopefully its last legal challenge. The compelling P3 aspects of the Purple Line really speak for themselves. The healthy competition for that project and ultimately the stability of the partnership between the private team and the governmental entity is something that will serve the project very well in the future.

Design-Build-Finance Projects

MR. FRIED: Texas, Georgia and Florida have all procured highway projects using a design-build-finance or DBF structure. Arkansas is considering a DBF structure for the I-30 project. Mike Lapolla, do you expect to see more of these projects?

MR. LAPOLLA: I don't know. The decision to go that route is political. The appetite for P3s in Texas has waned. In Florida, it had more to do with the people who are now in charge of making decisions. In terms of getting a project done, having lived through some battles when projects are P3s, it is easier to get to the private money through a DBF and have operations and maintenance with a government logo on it. This makes it a government project. You do not have to deal with contractors and unions who complain about a P3.

MR. PARKER: When you are a public official, you want to get projects done and you have to use the tools that are available to you.

These are not cases of not doing a P3 and settling for a DBF. There may not be flexibility to issue state debt, or there may be a need for short-term financing.

In Florida, for a long time — now the law has changed – the state had two different buckets. It had a bucket for GARVEES and a separate bucket for P3 projects that could be used to leverage the State Transportation Trust Fund. The only way to get at the second bucket was either through availability payments or DBF. In other states, it may not be convenient to access commercial paper or other types of short-term debt to advance a project. For them, the DBF, especially in this financing market, becomes appealing. States doing that get experience, and places like Georgia were able to build up confidence around having private investment in procuring projects. That can end up a stepping stone to more complicated arrangements like P3s.

Federal P3s

MR. FRIED: DJ Gribbin, most of the P3 activity is at the state and local level. Do you think we will see P3s for federal infrastructure?

MR. GRIBBIN: Yes. The US Army Corps of Engineers is doing a project in Fargo, but for the most part, while the federal government has been a strong advocate of P3s at the state level, it has not been as quick to use them itself.

Part of the challenge is OMB Circular A11, Appendix B, which is used for government accounting. It basically says that if the federal government were to lease a building for 20 years, it can account for those payments one year at a time. If it were to lease the building with the option to buy it — which is how a P3 concession would be treated – it would have to consider all those payments as made in year one. The Office of Management and Budget did this because there was some abuse of accounting in the 1970s.

Those accounting rules may have made sense at the time when the government was leasing battleships. We have tried to make the government understand that the current accounting system creates some perverse incentives.

P3s are hard. You are giving up a bit of your fiefdom. There are not a lot of government employees who say, "I currently oversee X number of people, but I would like to oversee half of that number five years from now."

MR. PORCARI: An incoming president can sweep away Circular A11 and change that with executive action.

MR. GRIBBIN: Absolutely. Treasury Secretary Jacob Lew wrote Circular A11 when he was a staffer at OMB. We approached him about changing it. The challenge was that it had other incremental budgeting ramifications that they were not willing to accept.

Final Thoughts

MR. FRIED: Let's get the final thoughts of each of the panelists on where they see the P3 market going in the US.

GOVERNOR PATAKI: We will see a complete change in Washington when it comes to infrastructure for the better, including on things like P3s. Love Trump or hate Trump — and there are not a lot of people on the fence [laughter] — he comes from the private sector. He understands the importance of infrastructure. He is a builder. He will not want the government building these things. I could tell you a couple of the battles that I had with him when he wanted government infrastructure to help his private projects, and we didn't do it. I expect very significant changes and federal government support for P3s that has been lacking in the past.

As Governor I got to see a lot of great things. I would be down in sewer and water tunnels and the caissons of bridges. I would always think, "Those people 100 years ago were really smart and really thinking ahead." Government today */ continued page 48*

Infrastructure

continued from page 47

has not been very good at that.

It is our turn. It is our obligation so our grandchildren or great-grandchildren 100 years from now are looking at something like the Gateway project or the brand new Penn Station or a high-speed Maglev train from Washington to New York City that I know Governor Hogan has been so supportive of, and is a prime project for P3, and they will say that those people were smart, too.

MR. FOYE: One thing the federal government should look at is monetizing large government loan portfolios. Surprisingly, the US Department of Agriculture may have the largest.

I am incredibly bullish about the prospects for infrastructure projects. We will see more P3s because of the condition of the economy, the fact that infrastructure has been ignored for such a long period of time, the bi-partisan recognition that it is a current drag on our nation's economy and competitiveness, the fact that there is not enough money to go around to do it all and that private capital can supplement that money.

State and local ballot measures passed that will put more public money into infrastructure.

Progress will be lumpy. You asked Governor Pataki a good question. What could derail us? In my mind, one thing that could derail P3s is a serious scandal or a deal that really goes bad. There are some natural opponents to P3s in the political system, and that will remain the case.

MR. PORCARI: I want to very quickly identify a potential P3 opportunity. The LaGuardia deal is a signal for opportunities around the country. There are medium-hub airports throughout the country that are boxed in on their landside development by a passenger facility charge cap. They may have flat passenger numbers, but they desperately need landside development. The framework for the LaGuardia deal, scaled down, can be replicated for a number of medium-hub airports that are desperate for something like that right now.

MR. FOYE: Based on the calls we have had from advisors and airport operators around the country, I would expect that to be the case.

MR. LAPOLLA: I do not want to play the cynic on the panel, but I laid out my political concerns earlier. I am more optimistic that P3s can be used, and that the federal government may, in this administration, keep an open mind and give us opportunities.

I worked in government for 25 years before joining my company. I listened to the discussion about the Gateway project. Prior to Gateway, this project was called the "Access to the Region's Core" project. I attended the organizing meeting for ARC in 1988. Hope springs eternal that big projects can get done.

You have to approach this state by state and agency by agency because the financial situations of the states, counties or authorities are going to be so different that some may be turning to P3s because they lack alternatives, and others because they are willing to try new things. It is impossible to make blanket statements. Even if we get these opportunities under the new administration, it will end up a local decision.

MR. PARKER: Our focus as a firm is on delivering the project. This is the public's focus, too. We need to remain focused on three things. First, have you actually moved some money into projects? It is not so easy to move money. Have we had a net increase in spending, and not just changed the type or source of spending? Second, have we delivered meaningful tangible projects? Have we picked good projects? Third, are we delivering the projects efficiently? Are they performing the way we expected?

Lastly, it is important to recognize that 10 years from now when some of these infrastructure projects are ready for use, there will be new technologies that have changed how we live and travel and use infrastructure. Our infrastructure will increasingly be a networked system.

We need to plan new programs with a more nuanced understanding of regions and of what is going to deliver a truly modern system.

MR. GRIBBIN: Two quick things: one is good news and the other is a challenge. It has been about 20 years since I started doing P3s. We spent a lot of time talking to people about what a P3 is. People are now coming to us asking whether a project can be done as a P3. People are better educated about the alternatives.

The challenge is there is still a big misunderstanding about "why the F" — why the finance? What does private equity bring to the deal? There is still a big knowledge gap in terms of folks understanding why someone would use more expensive equity to build something when they have access to lower-cost capital. The answer goes to risk allocation, alignment of incentives, spurring innovation and all of that. As far as we have come in the last 20 years in terms of excitement for P3s, we are still in relatively early days of making political leaders understand why it makes sense to tap private equity for a transaction. ◎

Infrastructure Funds Move Into SEC Spotlight

by Scott W. Naidech, Ikenna Emehelu and Jacqueline Hu, in New York

Infrastructure fund managers should focus on the types of fees they charge their funds and the manner in which fees and conflicts are disclosed to fund investors.

The private equity industry is under increasing scrutiny by the US Securities and Exchange Commission, with particular focus on the conflicts inherent in private equity business models and the manner in which fees and expenses are charged to funds and their portfolio investments.

To date, the SEC's enforcement actions and guidance have focused primarily on traditional private equity sponsors.

Last year, Marc Wyatt, acting director of the SEC office of compliance inspections and examinations, said the SEC is expanding its focus to private equity real estate advisers that operate more "vertically integrated" platforms, including sponsors that provide a variety of third party services directly to portfolio investments after acquisition.

Fees and Expenses

In a recent speech, Andrew Ceresney, director of the SEC enforcement division, divided private equity enforcement actions to date into three categories.

Some actions have been against advisers who receive undisclosed fees and expenses. For example, a recent SEC action involved a private equity sponsor who failed properly to disclose its monitoring agreements with portfolio companies in which its funds invested. In particular, although the sponsor disclosed in its offering documents the payment of monitoring fees from portfolio companies for board and advisory services, it failed to disclose the fact that the sponsor received accelerated monitoring fees upon termination of the monitoring agreements (for example, upon an initial public offering of shares in a portfolio company).

Another category of actions has been against advisers who impermissibly shift and misallocate expenses. Three examples of such enforcement actions are the following. The first action involved an adviser that allocated broken deal expenses entirely to its flagship fund and not to other managed co-investment funds that typically invested alongside the funds in completed acquisitions. The second action involved an adviser that misallocated portfolio company expenses between two managed funds. The third action involved an adviser that misallocated expenses between the adviser and the fund.

The last category of enforcement actions has been against advisers who fail adequately to disclose conflicts of interest, including conflicts arising from fee and expense issues. Two recent cases involved private equity sponsors who failed to disclose conflicts to (or obtain proper consent from) the limited partner advisory committees of their funds.

In one case, the adviser caused the funds and their portfolio companies to enter into affiliated contracts without properly disclosing them to investors in advance, and without properly disclosing or seeking limited partner approval. In particular, the adviser entered into certain monitoring agreements with its portfolio companies that were not netted against management fees as required under the fund's operating agreements. The adviser asked fund investors to provide $4 million in connection with an investment in a portfolio company without disclosing that $1 million of the capital call would be used to pay its affiliate. It also paid three former employees of the sponsor $15 million in incentive compensation from the sale of a portfolio company for services that they provided when they were employees of the sponsor without disclosure to the limited partners. Finally, it failed to disclose each of these payments as related-party transactions in the financial statements it provided to investors.

In the second case, the SEC charged the sponsor with failing to disclose and obtain limited partner consent for a series of loans to portfolio companies, resulting in the adviser obtaining interests in portfolio companies that were */ continued page 50*

Funds

continued from page 49

senior to the interests held by the funds. The sponsor had multiple funds invest in the same portfolio company at differing priority levels, potentially favoring one fund client over another. It also allowed the funds to exceed investment concentration limits in the governing documents of the funds.

Conflicts

Last year, Julie M. Riewe, co-chief of the asset management unit in the SEC enforcement division, emphasized similar themes in a speech on compliance and other issues affecting investment advisers at an IA Watch conference.

She said, "In nearly every ongoing matter in the asset management unit, we are examining, at least in part, whether the adviser in question has discharged its fiduciary obligation to identify its conflicts of interest and either eliminate them, or mitigate them and disclose their existence to boards or investors. Over and over again we see advisers failing properly to identify and then address their conflicts."

To fulfill their obligations as fiduciaries and avoid enforcement action, fund managers must identify and then address those conflicts. She said each fund manager should "take a step back and rigorously and objectively evaluate its firm, its personnel, its business, its various fee structures, and its affiliates."

Where conflicts have been identified, she offered a number of important questions to be vetted internally.

For each conflict identified, can the conflict be eliminated? If not, why not? If the adviser cannot, or chooses not to, eliminate the conflict, has the firm mitigated the conflict and disclosed it?

Is there someone — a person, a few individuals or a committee — at the firm responsible for evaluating and deciding how to address conflicts? Is that person, a group of individuals or committee sufficiently objective?

Is the process used to evaluate and address conflicts designed to be objective and consistent?

Does the firm have policies and procedures in place to identify new conflicts and monitor and continually re-evaluate ongoing conflicts?

As to mitigation, are the firm's policies and procedures reasonably designed to address the conflicts the firm has identified, and are they properly implemented?

As to written disclosure, has the firm reviewed all of the relevant disclosure documents — among others, Forms ADV used by investment advisers, private placement memoranda, limited partnership agreements, client agreements and prospectuses — to ensure that all conflicts are disclosed and disclosed in a manner that allows clients or investors to understand the conflict, its magnitude and the particular risk it presents?

Does the firm review those documents regularly to ensure that new or emerging conflicts are disclosed in a timely way?

Is the adviser keeping the chief compliance officer and any boards of directors informed about conflicts of interest, particularly the adviser's analysis and decisions on whether to eliminate or mitigate a conflict?

Infrastructure Funds

The SEC is broadening its attention to focus on asset classes adjacent to traditional private equity. In particular, the private funds unit at the SEC has undertaken a "thematic review" of private equity real estate advisers based on the observation that real estate managers, especially those executing "opportunistic and value-add strategies," tend to be much more vertically integrated than traditional private equity fund managers, and often provide property management, construction management and leasing services for additional fees, and potentially charge back the cost of their employees who provide asset management services and their in-house attorneys.

Accordingly, when examining private equity real estate advisers, the SEC can be expected to focus on those ancillary services being provided to managed funds and their projects, and whether the limited partners are being provided with adequate disclosure regarding fees and expenses at both fund level and project level.

Infrastructure fund advisers tend to operate similar vertically integrated platforms. As part of their platforms, they may provide a range of ancillary services and activities to their managed funds and their portfolio companies and project investments.

For example, the infrastructure fund adviser or its affiliates may provide early-stage, pre-construction development services to their project investments, including siting, permitting and negotiating power purchase or other offtake agreements. These activities may be funded by the infrastructure fund in the form of equity contributions or loans to the project company or pursuant to a monitoring agreement with the fund adviser. Infrastructure funds tend to seek compensation for development efforts by negotiating reimbursement of development costs or payment of a developer fee by subsequent equity investors in the project or as loans from the project's construction lenders.

The SEC is focusing on disclosure of fees and conflicts of interest by fund managers.

Another example is construction management services and fees. Some infrastructure funds may cause a project company to enter into a construction management agreement with the fund's adviser or its affiliate as construction manager, typically on or around financial closing on the construction debt.

The fund manager may also collect fees for acting as a contract operator of a project once the project is in operation.

It might also charge asset management or administrative service fees for doing such things as filing forms, causing tax returns to be prepared, and handling other administrative tasks.

Infrastructure Action Items

Based on recent SEC speeches and actions, infrastructure managers should focus on how they manage and disclose fees and conflicts.

Here is a list of questions to answer while fundraising to make sure the fund will not run afoul of SEC rules.

What are the types of services expected to be provided by affiliates of the sponsor to the fund and the portfolio companies in which the fund invests?

Is the sponsor or its affiliates the exclusive provider of those services or may services be bid out to third parties?

How are fees disclosed to and approved by investors in the fund? Are they set at market rates? How may the rates be altered throughout the life of the fund?

Are there any fee offsets under the fund's operating agreement? Does the operating agreement expressly provide which services are included within or excluded from the offset?

What is the role of any limited partner board or committee in disclosing or mitigating conflicts and in reviewing affiliate contracts and fees?

For infrastructure fund managers, vetting and disclosing conflicts and fees may pose particular challenges. For example, unlike typical monitoring fees that may be charged by private equity fund managers, it may be difficult to maintain consistency of service fee pricing among project companies in the portfolio, as fee amounts are usually subject to approval by third-party debt or equity providers. Furthermore, debt or equity providers may agree to compensate the infrastructure fund for third-party, out-of-pocket costs, but not for "soft" or "internal" costs such as salaries, travel and overhead costs of the fund adviser. Thus, the infrastructure fund could be asked to cover the fees under the monitoring agreement for certain projects in the portfolio, but not others.

Infrastructure sponsors must balance the desire for flexibility with disclosure obligations. While it may be tempting to "solve" all conflicts by requiring limited partner advisory committee approval for all affiliate services contracts and fees, such a mechanism may be sand in the gears and create uncertainty for the sponsor.

As the SEC focuses more on real estate advisers, its findings and actions will offer guidance. ◎

Environmental Update

Anyone who suggests he or she knows what will happen with environmental regulation and energy policy under a Trump administration is pulling your leg. But there are plenty of tea leaves to read, and they appear to spell out portents of deregulation, a slew of battles to loosen regulatory standards at the federal level, litigation from environmental organizations in the face thereof, behind the curtain infighting among soon-to-be-appointed environmental appointees and demoralized agency staff, and a stark shift in leadership on these issues from the US government to states and other countries. Here is what we know.

Trump on Climate Change

Mr. Trump said in November 2012 that "[t]he concept of global warming was created by and for the Chinese in order to make US manufacturing noncompetitive." The allotted 140 characters did not allow for elaboration on why he believed that might be the case. In February 2015, Trump extolled that "[t]he only global warming we should fear is that caused by nuclear weapons — incompetent pols."

Candidate Trump tweeted in October 2015, "It's really cold outside, they are calling it a major freeze, weeks ahead of normal. Man, we could use a big fat dose of global warming!" In December 2015, Trump told a rally, "Obama's talking about all of this with the global warming and . . . a lot of it's a hoax. It's a hoax. I mean, it's a moneymaking industry, okay? It's a hoax, a lot of it." In January 2016, in response to criticism, Trump explained his views on a morning talk show as follows: "Well, I think the climate change is just a very, very expensive form of tax. A lot of people are making a lot of money. I know much about climate change. I [have] received environmental awards. And I often joke that this is done for the benefit of China. Obviously, I joke. But this is done for the benefit of China, because China does not do anything to help climate change. They burn everything you could burn. They couldn't care less. They have very — you know, their standards are nothing. But they — in the meantime, they can undercut us on price. So it's very hard on our business."

In a prominent speech on energy policy in May 2016, Trump condemned "draconian climate rules" and advocated rescinding "all the job-destroying Obama executive actions, including the Climate Action Plan." He went on to promise that he would "cancel the Paris Climate Agreement and stop all payments of US tax dollars to UN global warming programs." "President Obama entered the United States into the Paris Climate Accords unilaterally and without the permission of Congress," Trump said. Although the Paris accord is without enforcement mechanisms, Trump insisted it "gives foreign bureaucrats control over how much energy we use right here in America."

Post-election, many in the press suggested that Trump seemed to soften his campaign rhetoric on climate change and his vow to "cancel" the United Nations Paris Climate Change Agreement when he told the New York Times that he would keep an "open mind" about the agreement. This may be true or it may have been a symptom of Trump's desire to please the audience directly in front of him. A look at the full transcript is more enlightening.

In the interview, Trump said he has "an open mind" on climate change. He said he is also open to the "other side."

Asked whether he plans "to take America out of the world's lead of confronting climate change," Trump said, "I'm looking at it very closely . . . . I have an open mind to it. We're going to look very carefully. It's one issue that's interesting because there are few things where there's more division than climate change. You don't tend to hear this, but there are people on the other side of that issue . . . ."

In follow-up, Trump was asked, "When you say an open mind, you mean you're just not sure whether human activity causes climate change? Do you think human activity is or isn't connected?" Trump responded, "I think right now . . . there is some connectivity. There is some, something. It depends on how much. It also depends on how much it's going to cost our companies. You have to understand, our companies are non-competitive right now."

When reporters raised the destructiveness of Hurricane Sandy and the notion of climate change affecting weather patterns, Trump said "we've had storms always" and then appeared to suggest that the atmosphere is not getting hotter on average. "You know, the hottest day ever was in 1890-something, 98. You know, you can make lots of cases for different views."

Mr. Trump's statements demonstrate a profound lack of understanding of climate change as a process. When climate change skeptics cherry pick temperature readings, or Mr. Trump tweets that, "it's snowing . . . freezing in NYC. What the hell ever happened to global warming," they ignore that global warming as a concept means that global average temperatures are on the rise. They also ignore irrefutable data demonstrating that 16 of the 17 hottest years on record have all been in the 21st century, with the 17th being 1998. The current year, 2016, is on track to be the hottest on record, surpassing the previous records set in 2014 and 2015.

Closing out the subject, Trump referred to himself as an environmentalist and affirmed, "I absolutely have an open mind. I will tell you this: Clean air is vitally important. Clean water, crystal clean water is vitally important. Safety is vitally important."

A few days later, in late November, the incoming White House chief of staff, Reince Priebus, clarified the position Mr. Trump took in the New York Times interview: "As far as this issue on climate change, the only thing [Trump] was saying after being asked a few questions about it was, look, he'll have an open mind about it. But he has his default position which, most of it is a bunch of bunk."

In early December, Ivanka Trump, rumored to hold different opinions than her father on climate change, arranged a meeting between Al Gore and the President-elect.

Transition Team

Whether or not his mind is currently open, Trump's pick of advisers has now revealed who will be on the inside helping to close it.

To head his EPA transition team, Mr. Trump named Myron Ebell, director of environmental and energy policy at the Competitive Enterprise, a libertarian advocacy group in Washington, DC. This is a significant pick because it will be Mr. Ebell who will help the new administration set the direction of the federal agencies that address environmental policy, and he has been guiding Trump's choice of key personnel to lead those agencies.

Mr. Ebell is a climate change denier who happily disagrees with the scientific consensus that climate change is real, a significant threat and directly tied to human activity. In an interview from 2012, Ebell explained to PBS's Frontline why he and others went to work to try and dismantle that consensus. "We believed that the consensus was phony . . . . We believed that the so-called global warming consensus was not based on science, but was a political consensus, which included a number of scientists."

Mr. Ebell has asserted that whatever warming is caused by greenhouse gas pollution is modest, and that such warming could actually be beneficial. Ebell argues that the science is less than certain and suggests the concerns cited are pretext for expanding government regulation. It is uncertain whether Mr. Ebell attributes the pretext to the Chinese.

Infamous among environmentalists, his critics are legion. They have called Ebell an "oil industry mouthpiece" and point out that his Institute receives significant funding from the coal industry. The Sierra Club said in a statement in early December that Ebell is "not a 'climate contrarian' or 'skeptic' as the media has irresponsibly taken to calling him. He's one of the single greatest threats our planet has ever faced. Simply put, Ebell doesn't believe in science."

Ebell's views on climate have also prompted criticism from some Republicans. For example, David Jenkins, president of Conservatives for Responsible Stewardship, reportedly said, "There is nothing prudent nor conservative about Ebell and his agenda. Ebell, a fervent advocate for polluters, has never met a pollution limit he likes. His life's mission seems to be opposing environmental laws and attacking any scientific conclusion that finds pollution harmful, including climate change."

Others in the EPA transition team now include the Heritage Foundation's David Kreutzer, The Federalist Society's Austin Lipari, Energy and Environment Legal Institute's David Schnare, Caesar Rodney Institute's David Stevenson, the Sugiyama Group LLC's George Sugiyama, and Amy Oliver Cooke, a fracking supporter. David Schnare, who may be a candidate for a political appointment inside EPA, was a staff attorney at EPA for three decades who now runs his own law firm and acts as general counsel of the free-market Energy & Environment Legal Institute. Last year, Schnare suggested a new administration could scuttle EPA's finding that greenhouse gases endanger health and welfare. In the face of the scientific evidence supporting that finding, this seems implausible, but a Trump EPA could certainly try to narrow the finding's scope.

EPA Administrator

As for the top job at EPA, Trump nominated Oklahoma's Attorney General Scott Pruitt. Pruitt is a climate change denier whose experience in environmental law appears rooted in the numerous lawsuits he has brought to challenge high-profile rules established by EPA under the Obama Administration, several of which remain active. Pruitt sued to dismantle or defeat the Clean Power Plan, mercury air toxics rule, waters of the US rule and regulations on haze. One lawsuit failed to block EPA from finalizing its greenhouse gas rule for existing power plants, but another he was involved in won the / continued page 54

Environmental Update

continued from page 53

stay of the rule from the US Supreme Court. Pruitt has no science degrees or other apparent environmental background. While a private lawyer, his practice reportedly focused on litigation, Constitutional law, contracts, insurance and labor law.

As EPA Administrator, Pruitt will face far fewer hurdles than he faced in court to limit EPA action. His Federalist stances are likely to drive regulation to the state level. While Pruitt has recognized that "[t]here are clearly air and water quality issues that cross state lines and sometimes that can require federal intervention," he told a House committee in May 2016 that, "[a]t the same time, the EPA was never intended to be our nation's foremost environmental regulator. The states were to have regulatory primacy."

Senate Democrats have limited power to oppose executive branch nominees. Since the Senate, in 2013, eliminated the filibuster for nominations other than Supreme Court vacancies, we expect Democratic efforts to focus on publicizing any nominees' histories of lobbying, potential conflicts from industry experience, and arguably anti-environment policy positions in order to summon public pressure and sway the votes of moderate Republicans. Pruitt is likely to be questioned about his financial ties to the coal, oil and gas industries and past collusion between his office and those industries in opposing EPA rules. Any such opposition to his nomination is unlikely to succeed.

Obama Regulatory Legacy

What will happen to the Obama administration's current and planned federal climate change initiatives once the Trump administration takes the reigns at the Environmental Protection Agency?

Current EPA Administrator Gina McCarthy said in early December 2016 that she foresees some degree of continuity between the Obama and Trump EPAs, including with respect to greater water infrastructure funding. "If [the Trump administration], as they said, is interested in infrastructure investment, they recognize it as good for the economy and jobs, I do really hope that they will add water and wastewater infrastructure as opportunities to grow the economy plus deal with what we know is a core need of this country," McCarthy said.

Many of McCarthy's statements about potential common ground — such as on rulemaking for existing source performance standards for oil and gas extraction — seemed to rely heavily on a naive will to believe in the persuasive power of information with the next administration's environmental and energy team.

Acting EPA air chief Janet McCabe also expressed optimism in a post-election speech that the greenhouse gas and other air pollution programs will continue. "EPA is the career staff," she said, and that staff will not leave when Obama's political appointees do. This may have been a wink at the likely internal infighting between soon-to-be-appointed environmental appointees and a dispirited career staff, who are able to hinder as well as help. "I'm not worried, really, the work will go forward," McCabe said.

Off the record, an EPA staff attorney recently likened the mood inside the agency since the election to being aboard the Titanic. They know an iceberg is coming, but no one knows when it will hit and everyone remains focused on rearranging the deck chairs as the band plays on.

The Paris Agreement to address climate change that was reached in December 2015 officially went into effect in November 2016, just days before the US presidential election, with 94 signatory countries having ratified it. Those nations, including the United States, China and India, represent 66% of total global greenhouse gas emissions. It took more than two decades to negotiate the agreement.

Its goal is to prevent the most destructive effects of climate change by limiting the increase in global temperatures to two degrees Celsius (3.6 degrees Fahrenheit) or less. Such destructive effects include prolonged heat waves, worsening drought, extended wildfire seasons, more intense weather and, most devastating, a significant sea level rise. However, even if every country delivers on its initial pledges, the increase is expected to be closer to 2.7 degrees Celsius. Nations are supposed to agree to take further steps in the coming years to achieve the deeper reductions that are needed. If left unchecked, global greenhouse gas emissions are likely to drive temperatures up between 2 and 5 degrees Celsius (3.6F to 9F) with a sea level rise of between two to four feet, according to some reports. Average global temperatures have already increased more than 0.8 degrees Celsius (1.5 degrees Fahrenheit) over the past century.

The United States must give three years' notice to withdraw from the Paris accord under its terms. However, Trump could try another route.

The Paris agreement is considered part of the 1992 UN Framework Convention on Climate Change, which the US ratified under Republican President George H.W. Bush. Since it is not considered a treaty, the US Senate was not required to ratify the Paris accord. President Obama committed the US to it earlier this year by executive authority.

Trump could take the position that the agreement is a treaty and submit it to the Senate for ratification as a means to kill it, since that would require 60 votes. During the United Nations climate talks in Paris in 2015, Ebell reportedly said he was there to argue the agreement was "in fact a treaty" that requires Senate ratification. "We'll have won if we convince the Congress that it's a treaty."

Trump need not cancel the Paris agreement to blow up the process. Paris does not obligate each party to do any more than to pledge emissions reductions and then reveal what it has actually done to meet those pledges. Trump can simply ignore the obligations to which the United States committed itself. Aside from the domestic Clean Power Plan and the Paris accord, Trump could go further by weakening federal support for clean energy or regulations to improve vehicle efficiency. While the pledges are not enforceable, the specific transparency mechanism, still being negotiated, will be legally binding. If the United States does abandon its leadership role, then the global consensus achieved in Paris could be in jeopardy. China and India, the world's first and third largest emitters of greenhouse gases respectively, would face an economic incentive not to fulfill their pledges under the agreement if the world's second largest emitter defaults. India's chief climate negotiator told reporters that a US withdrawal from the process risked spreading "like a contagious disease" to other countries.

The incoming Environmental Protection Agency head has been a strong critic of US environmental regulation.

A failure to implement US climate and clean power pledges would not reverse coal's decline in the nation's energy mix, which has more to do with the availability of cheap natural gas than federal regulation. A report on the world energy outlook by the International Energy Agency, or IEA, a policy adviser to the United States and 28 other nations, suggests the amount of electricity generated from coal would fall by 41% from 2014 levels by 2040 if the Paris accord and the Clean Power Plan are implemented compared with a 21% drop if they are not. Natural gas usage would rise 56% percent under the regulatory regime compared with 27% if climate change efforts are scrapped. The report suggests that growth in solar and wind power would slow, but only marginally because falling costs will keep them competitive.

Trump has promised to rescind "job-killing" regulations, but details about what he might kill and how he intends to kill them are in short supply.

New Climate Leadership

The change of priorities appears fundamental. With few exceptions, the Obama administration raised climate change actively in engagements with foreign governments. The administration pivot toward China brought together the lead greenhouse gas emitter from the developed world and the lead emitter from those nations who claim developing status, but are nevertheless major sources of emissions. This effort broke real ground at the highest level, eventually allowing bilateral channels to run between hands-on negotiators for the US and China. This change allowed ideas to be taken to the larger community of nations and pressured both sides of the developed-developing divide to move toward agreement.

A Trump administration will likely create a vacuum of leadership on climate issues that others will be forced to fill. In the face of a federal abdication of leadership, states and cities will likely lead climate and energy policy in the United States, as they did before Obama took office and stepped up federal activity. Acting EPA air chief Janet McCabe said recently that, whatever happens at EPA, action by states and cities "will not be stopped."

Many suggest the revolution in electricity generation and transportation is happening not because of federal regulation, but because it is being driven by the states. Prime examples include California programs to cut greenhouse gases and other pollutants. Others suggest we may be moving toward a more federalist regulatory system under Trump, where EPA and other federal agencies defer more to the states on policy issues. Success at the state level will be tied, at least to some degree, to continued federal funding of those efforts. Obama increased resources for the */ continued page 56*

Environmental Update

continued from page 55

states in recent years, but future funding decisions will be made by the next administration and the next Congress. If the requirement for states to meet obligations under the Clean Power Plan and other regulations is rescinded, then that could create a divide between those states whose politicians favor such protections and those who do not.

What will industry do? Facing the prospect of a US retreat from climate action, there have been a number of private sector calls to support of the Paris Agreement. For example, 365 businesses and investors, including Fortune 500 companies such as DuPont, Hewlett Packard Enterprise, the Kellogg Company and Unilever, all called for continued engagement on climate change in a November 2016 statement. "Implementing the Paris Climate Agreement will enable and encourage businesses and investors to turn the billions of dollars in existing low-carbon investments into the trillions of dollars the world needs" to expand clean energy, the statement said. "Failure to build a low-carbon economy puts American prosperity at risk."

Nicholas Akins, CEO of American Electric Power, an Ohio-based electric utility that generates power in 11 states, told *The New York Times* after the election that his company is making investments in energy generation aimed at 20 to 40 years from now. He assumes that carbon pollution will be regulated in the long run, whether or not the Trump administration dismantles the Clean Power Plan. "We will not be building large coal facilities. We're not stopping what we're doing based on the new administration. We need to make long-term capital decisions. I don't think the course will change."

Will other nations step into our shoes on climate change? Chinese President Xi Jinping said China intends to continue with its plans to cut carbon emissions without regard to what Trump does. China pledged under the Paris agreement that its emissions will drop after 2030, and that China will put in place a national system next year to force companies to pay a fee for their carbon pollution. It will be ironic if China steps firmly into a leadership position on climate change as America backs away.

Naming Names

In early December, Trump's transition team took the peculiar step of asking the US Department of Energy to provide the names of all employees and contractors who attended climate change policy conferences. The questionnaire asked for "a list of all Department of Energy employees or contractors who have attended any Interagency Working Group meetings" to create a measurement known as the social cost of carbon, which has been used by the Obama administration to measure the economic consequences of greenhouse gas emissions and to justify the economic cost of climate regulations. Another request was for "a list of Department employees or contractors who attended any" United Nations climate change conference "in the last five years."

The Trump transition team distanced itself from the questionnaire after DOE declined to provide names. ◎

– contributed by Andrew Skroback in Washington

Project Finance NewsWire
is an information source only. Readers should not act upon information in this publication without consulting counsel. The material in this publication may be reproduced, in whole or in part, with acknowledgment of its source and copyright. For further information, complimentary copies or changes of address, please contact our editor, Keith Martin, in Washington (kmartin@chadbourne.com).

Chadbourne & Parke LLP

chadbourne.com

New York
1301 Avenue of the Americas
New York, NY 10019
+1 (212) 408-5100

Washington, DC
1200 New Hampshire Avenue, NW
Washington, DC 20036
+1 (202) 974-5600

Los Angeles
350 South Grand Avenue, 32nd Floor
Los Angeles, CA 90071
+1 (213) 892-1000

Mexico City
Chadbourne & Parke SC
Paseo de Tamarindos, No. 400-B Piso 22
Col. Bosques de las Lomas
05120 México, D.F., México
+ 52 (55) 3000-0600

São Paulo
Av. Pres. Juscelino Kubitschek, 1726
16° andar
São Paulo, SP 04543-000, Brazil
+55 (11) 3372-0000

London
Chadbourne & Parke (London) LLP
Regis House, 45 King William Street
London EC4R 9AN, UK
+44 (0)20 7337-8000

Moscow
Riverside Towers
52/5 Kosmodamianskaya Nab.
Moscow 115054 Russian Federation
+7 (495) 974-2424
Direct line from outside C.I.S.:
(212) 408-1190

Istanbul
Chadbourne & Parke
Apa Giz Plaza
34330 Levent, Istanbul, Turkey
+90 (212) 386-1300

Dubai
Chadbourne & Parke LLC
Boulevard Plaza Tower 1, Level 20
PO Box 23927, Burj Khalifa District
Dubai, United Arab Emirates
+971 (4) 422-7088

Johannesburg
Katherine & West
114 West Street
Sandton, Johannesburg
South Africa
+27 (087) 980-1340

01-01 PF NewsWire October 2016