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PROJECT FINANCE

NewsWire

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Mexico: Prepare to Launch

Is it still hurry up and wait or is the race to build new power projects finally underway in Mexico? New power market rules are expected in final form soon. The country revamped its electricity sector to great fanfare at the end of 2013. Raquel Bierzwinsky, a partner in the Chadbourne New York and Mexico City offices, and Sean McCoy, an international counsel in the Chadbourne Mexico City office, talked to Keith Martin about the potential opportunities in Mexico at the Chadbourne global energy & finance conference in June.

MR. MARTIN: Many of us in this audience have been following Mexico. We know the constitution was amended in late 2013 to open up the power sector to private competition. We also know that implementing legislation was finally enacted last year, but that is not enough because you still need guidelines to implement the implementing legislation. Sean McCoy, when are those guidelines expected?

MR. McCOY: This July, hopefully.

MR. MARTIN: You have a draft of them that came out in February, I believe.

MR. McCOY: Yes. A draft was issued in February by the Ministry of Energy and was published for public comment in an effort to improve the rules. The idea is to publish an official version after revising them to take into account the public comments.

MR. MARTIN: Let's review the new opportunities that will be created for independent generators. I know you have written a fair amount about this over the last two years. I have pulled some of this out of your writings. Let me see if I have this straight. Independent generators will be able to sell electricity, but only at wholesale and basically / continued page 2

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A TAX EXTENDERS BILL may start to move through the US Congress this month.

Wind companies are looking for more time to start construction of new projects to qualify for production tax credits. Such projects had to be under construction by December 2014. Solar companies hope to convert a December 2016 deadline to complete solar projects to qualify for a 30% investment tax credit into a deadline merely to start construction.

Senator Orrin Hatch (R-Utah), who heads the Senate tax-writing committee, said on July 7 that he may ask his committee to vote on a tax extenders bill as early as July 15. Democrats on the committee want to extend expired or expiring tax breaks by two years to spare Congress from having to deal with extenders again until 2017 when / continued page 3

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to the CFE, the national utility. Is that correct, or can they also make retail sales?

MS. BIERZWINSKY: They will be able to make retail sales. The new legislation allows independent power producers to enter into bilateral power purchase agreements to sell electricity. The key point is that specific categories of consumers will be able to enter into PPAs. Consumers must have at least a minimum load before they can purchase from the market directly or enter bilateral PPAs. Beginning in August of this year, the minimum load is two megawatts. It will drop to one megawatt next year and, thereafter, the Ministry of Energy will determine whether that goes down further.

MR. MARTIN: So if a factory has at least a two-megawatt load, as of this August, it can enter into a direct contract with an independent generator to buy electricity. If it has at least a one-megawatt load, it can do so, but must wait until August 2016.

MS. BIERZWINSKY: That is correct.

A growing class of commercial customers in Mexico will be able to buy electricity from independent generators.

MR. MARTIN: Are there any restrictions on the contract terms or can they be whatever the parties negotiate?

MS. BIERZWINSKY: They can be whatever the parties negotiate.

MR. MARTIN: What about the electricity price? Can it be whatever the parties work out?

MS. BIERZWINSKY: Yes, more or less whatever the parties work out on price. I think that the model will continue to be similar to what we have seen in the past, which will be based off the market price with perhaps some discount.

October Auction

MR. MARTIN: There will also still be the option to sell electricity directly to the CFE. CENACE —- the national independent system operator — plans to hold a capacity auction later this year. Sean McCoy, when is the auction expected? How much capacity do you expect to be up for auction?

MR. McCOY: The auctions are planned for October. How much capacity is not clear. Details remain to be worked out, but it is clear that CFE needs to replace 10,000 megawatts of existing capacity. The new generation will be mainly set up in central Mexico, which is one of the main industrial areas in the country. Basically, that is the main area in which new generating facilities are expected to be built.

MR. MARTIN: So 10,000 megawatts in total are expected to be auctioned, but some small increment of that will be this fall, perhaps in October. Do we know how long the power contracts with CFE will run?

MS. BIERZWINSKY: There are two options. There is a medium-term contract for gas-fired power plants, which right now under the rules is three years but we expect the final rules to set it at five years, and then there is a 10-year contract. We have heard from a lot of renewable energy developers in Mexico that they are not content with just 10-year PPAs. Obviously there is no fuel risk for them, so they would like to go to at least to 15 or 20 years, if possible.

MR. MARTIN: What if one wanted to build a merchant power plant? Is there a national power pool where this electricity can be sold?

MS. BIERZWINSKY: Yes. That is part of what is new in Mexico. There was no national power pool until the new legislation was enacted, so now there will be one. There is a newly-created independent system operator that will run a wholesale electricity market. That market will start operating for day-ahead sales on December 31, 2015 and for same-day sales on January 1, 2016.

MR. MARTIN: How confident are you the government will stick to these timelines?

MR. McCOY: That is the key question. The government is rethinking how fast it makes sense to implement the reforms, but it has chadbourne

stuck to all of its deadlines to date, and I believe the wholesale power pool will start operating next year as scheduled.

MS. BIERZWINSKY: I am pretty certain the government will stick to the timeline.

MR. MARTIN: So a high degree of confidence from both of you. Will private intermediaries be able to trade electricity?

MR. McCOY: Yes. That is the basic idea. Before the energy reform, there was only a state utility company, CFE. Now the idea is to increase the pool of suppliers in order to lower electricity rates.

MS. BIERZWINSKY: I think that is one of the great opportunities in the new market because no one has the experience or the technology currently to do this in Mexico. We have discussed this a lot internally. Whoever has that experience and can go to Mexico and do that successfully right now — not wait several years until the market is fully developed – will do well. If you are interested and able, I think this is the right time to offer those services in Mexico.

MR. MARTIN: The national grid will remain in government hands under a new agency called CENACE.

MR. McCOY: Yes.

MR. MARTIN: All independent generators will have to have an interconnection agreement with CENACE. How easy will it be to get such interconnection agreements?

MR. McCOY: The government published the rules for interconnection criteria last week. These rules cover both power plants and offtakers seeking to interconnect. The idea is to reduce the period of time by reducing from 20 to 10 the number of steps that will be required. The basic principle is open access to the grid.

MR. MARTIN: Will people connecting have to pay for network upgrades to the grid to accommodate the additional electricity?

MR. McCOY: Yes.

MR. MARTIN: Clean energy certificates, called CELs, will be handed out to generators who use clean energy sources. These can be bought and sold. Who needs them? Will the CFE have to turn in a certain number of them at the end of each year?

MS. BIERZWINSKY: The way the government has structured this is that offtakers who are able to purchase electricity directly from the electricity market will be obligated to purchase a certain percentage of clean energy certificates based on their aggregate loads. Thus, the independent generators who are issued the certificates will be able to sell them to offtakers or sell them in a market that is expected to develop for them.

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Congress may be looking at a broader rewrite of the corporate income tax code. The committee must decide what can be included — for example, whether to limit the bill only to tax benefits that have already expired — how long to extend and whether to add offsets to pay the cost before the tax extenders bill can make progress.

Any move to deal with extenders this summer would be a break from recent practice. In 2014, Congress waited until three weeks before year end, leaving companies little time to act on the extensions and, in some cases, wastefully throwing incentives retroactively at companies that were supposed to induce the companies to do things that they had already done.

Meanwhile, production tax credits for wind farms continue to take flak from House Republicans as battle lines form around a possible extension.

The US allows owners of new wind, biomass, geothermal, landfill gas, incremental hydroelectric and ocean energy projects to claim production tax credits on the electricity sold to third parties from such projects for the first 10 years after the projects are put in service. Production tax credits can also be claimed for producing "refined coal," which involves treating raw coal to make it less polluting.

Eighty-five wind companies wrote Rep. Kenny Marchant (R-Texas), a senior member of the House tax-writing committee, and 21 other Republican cosponsors of a House bill called the "PTC Elimination Act" in mid-June asking them to reconsider.

Marchant's bill, introduced in late April, would make three changes in the production tax credit statute. It is H.R. 1901.

The tax credit amounts are adjusted currently each year for inflation. The bill would eliminate any further inflation adjustments after 2015.

Production tax credits are only available currently for new renewable energy projects on which construction started by December 2014. The IRS requires not only that construction must have started in time, but also that there must be continuous work on the project after 2014. The IRS will assume there has been continuous work on any project that is completed by December 2016. The type of work that / continued page 5

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The program has been designed this way to meet the Mexican policy goal of having at least 35% of electricity in Mexico produced from clean energy sources by 2024. The scope of what qualifies as clean energy is still being worked out. Renewables obviously qualify, but there is also talk of adding natural gas and possibly clean coal power plants.

MR. MARTIN: The certificates will be handed out starting when, and will they be given solely to new generators who come on line after that date?

MS. BIERZWINSKY: The certificates will be handed out starting on January 1, 2018. They will be issued to generators that come on line after the enactment of the laws last year and to existing generators that have built additional capacity based on clean energy sources.

Rooftop Solar

MR. MARTIN: Here is my last question, and then we will let the audience ask some. We had a discussion earlier this morning about the potential for rooftop solar in Africa. The outlook there is a mixed bag at least until the regulatory regimes settle. What is the outlook for rooftop solar in Mexico, and has rooftop solar already taken hold?

MR. McCOY: It is a huge opportunity in Mexico. Obviously the country has lots of sunlight. It has taken a couple years for the utility-scale solar market to develop, and that market was set to boom until the reference price on offer from the CFE fell dramatically to a point where new projects are becoming harder to build. Rooftop solar will get the best traction with retail customers who pay the high-end tariffs for electricity. We have many industrial parks in this category with rooftops that are suitable for solar equipment.

MR. MARTIN: What is the business model in Mexico for rooftop solar? Is it third-party ownership where solar company retains ownership of the equipment and sells electricity to the owner of the building or leases the equipment to the owner of the building?

MS. BIERZWINSKY: This is still fairly new in Mexico, Keith. We are still working out the business model. The business model we have seen to date is the solar company retains ownership of the system — for example, we have seen this approach used for systems put on Walmart stores and carports — but it is not as well developed as here in the US or in other places.

MR. MARTIN: We have time for a few audience questions.

MR. DANIELS: Ed Daniels with Panda Power Funds. You mentioned the possibility of winning a power contract with a five-year term with the CFE in the October auction for gas-fired power plants. Do you know what the forward start is? Will the contract term start in 2017 or will it start further out?

MR. McCOY: The target is to have such contracts start in 2018.

MR. HUNT: Chris Hunt from Riverstone Holdings. I understand there is a prior system of grandfathered power purchase agreements for wind and solar generators and that there is actually quite a large number of such contracts representing potentially billions of dollars of grandfathered projects. Do you see those projects going forward or could the rules change such that many of those projects may not get built?

MS. BIERZWINSKY: There was a rush to apply for permits before the new law was enacted in August 2014. There are about 15,000 megawatts worth of applications. I do not see them all going forward. There is a specific requirement in the new law for grandfathered permits that requires those projects to have at least 30% of total project costs invested by December 31, 2016. Anyone who fails to reach this threshold will have his permit revoked.

MR. McCOY: Some of the developers are already struggling to reach the 30% target. A new trend we are seeing is for other developers to acquire the rights to these grandfathered projects in order to interconnect and bid into the CENACE auction expected in October.

MS. BIERZWINSKY: We have a very active M&A market currently in these projects. Some of the target entities either have applied for or already have grandfathered permits for what we call self-supply, meaning they are authorized to supply electricity to a group of offtakers directly under a contract with a term of 20 years.

MR. COOK: Ben Cook with SolarCity. You talked about the business model behind the meter for residential and commercial customers. You said rooftop solar will get the most traction with customers who pay the highest tariffs. I would be interested in your views about the rate-setting process and how political changes might affect it. How likely is the current rate structure to remain place in the medium to longer term?

MR. McCOY: That's the rub because certain tariffs will be subject to political change as recently happened when tariffs dropped by 30%. However, the DAC — the acronym in Spanish for the domestic high consumption tariff — will remain a regulated tariff. Although this tariff is set by the government, it is least likely to change, because the government understands that manipulating it will disturb the open market rates. I foresee a really stable DAC tariff, and that is huge.

New Financing Trends

The market is awash in liquidity. Banks are moving up the risk curve in the chase for deals. Bank deal volume was down in the first half of 2015, but is expected to pick up. Demand for tax equity is expected to accelerate. Discount rates used to bid for assets have dropped by at least 100 basis points from a year ago. The talk in banking circles is about "total return vehicles" and the move from "warehouse 1.0" to "warehouse 2.0."

Four investment bankers and one commercial banker talked about these and other financing trends at the Chadbourne 26th annual global energy & finance conference in June. The panelists are Ted Brandt, CEO of Marathon Capital, Michael Proskin, a managing director in the power and utilities group at Credit Suisse, Andrew Redinger, managing director and head of utilities, power and renewables at KeyBanc Capital Markets, Thomas Emmons, managing director and head of project finance for the Americas at Rabobank, and Jon Fouts, a managing director in the global power and utilities group at Morgan Stanley. The moderator is Rohit Chaudhry with Chadbourne in Washington.

MR. CHAUDHRY: Let me start by going around the panel to ask each of you what you think are the trends in the market this year.

MR. BRANDT: Massive liquidity; lots of competition around cost of funds and a trend to move backwards away from de-risked projects toward projects that still have risk left in them.

MR. PROSKIN: Liquidity is certainly a theme. Low gas prices have changed the market for LNG. Things like debt warehousing facilities and other forms of cheaper capital continue to fuel the M&A dynamic.

MR. REDINGER: These are somewhat longer-term trends, but I see four. One is distributed generation. We are at the very early stages of changing the utility model. How we generate electricity in this country is changing.

Another that perhaps we will be talking about at this conference next year is total return vehicles. Sempra just announced a yield-oriented vehicle. It plans to launch a master limited partnership that it calls a total return vehicle. We already have yield cos formed to own renewable energy assets. MLPs and REITs will wake up and realize that they can get / continued page 6

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must be shown for projects that slip past 2016 depends on how the project started construction. If the developer incurred at least 5% of the total project cost to get the project under construction by December 2014, then the developer must show "continuous efforts" on development-type tasks after 2014. If the developer relied on physical work at the project site or a factory to get the construction underway in 2014, then it must show "continuous construction" after 2014, which requires continuous physical work at the site and factory.

The bill would retroactively rewrite the construction-start rules by eliminating the 5% test and by overriding the IRS presumption that there was continuous work on any project that is completed by December 2016.

Finally, it would repeal production tax credits for renewable energy projects after 2025. The effect would be to deny renewable energy projects that are put in service after 2015 a full 10 years of production tax credits. The owners would still have the option of claiming a 30% investment tax credit in the year projects go into service.

It would be very unusual for Congress to repeal a tax benefit retroactively after taxpayers have been induced to make investments based on the benefit.

Any effort to extend the construction-start deadline for wind and other renewable energy projects will have to originate in the Senate. The House is expected to oppose the extension. Assuming the Senate acts, the fate of the extension will come down to bargaining between the two houses.

COMMUNITY SOLAR projects in Minnesota will be smaller than most developers want under a settlement worked out between Xcel and a small group of community solar advocates and approved by the Minnesota Public Utilities Commission in late June.

Some larger developers are urging the commission to revisit a five-megawatt cap on project size before issuing the final order. They argue that a 10-megawatt / continued page 7

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into this asset class, too. We will start hearing more about total return vehicles in the future.

The next trend is warehouse facilities. There has been a warehouse facility 1.0, and warehouse facility 2.0 is already being discussed. We will get into what it means in more detail later.

Finally, there is ethane. You may not have heard much about ethane. It is a by-product from processing natural gas. Ethane is currently a dollar cheaper than natural gas, and this is especially true in PJM. I think we will see a lot of thermal power plants start burning ethane in place of natural gas, especially in PJM where ethane prices may fall even lower than they are today.

MR. EMMONS: I see two trends. Deals have gotten bigger in 2015 compared to 2014. The average deal size has moved to $500 million in the first half of this year compared to $300 million in 2014. The second trend is liquidity. Last year, 20 banks, during the whole year, committed $300 million each, but this year, only through May, 20 banks have already committed at least $300 million, so 2015 will be a year where a small number of banks are committing significantly larger amounts of money than they did last year.

MR. FOUTS: It is hard to add to that list. Focusing on market dynamics, what we are seeing this year is a greater appetite for risk, whether it is taking shorter terms for power purchase agreements, taking and financing merchant risk, and taking emerging market risk and foreign exchange risk. There has been a noticeable move by the capital markets toward accepting higher risk. That is partly because the returns just are not there for the investors. People are having to move up the risk spectrum to get the returns they need.

The US bank market remains awash in liquidity.

MR. CHAUDHRY: So a lot of liquidity in the market. People are taking more risk. Let's move to M&A tends and then get into some of the trends on debt and financings. Ted Brandt, what was the deal volume for M&A transactions in the power sector in 2014?

Discount Rates

MR. BRANDT: I did a bit of research and found four different numbers. I thought the most solid number was a Bloomberg New Energy Finance report that pegged last year's M&A volume at $9 billion. It is still early to have a definitive view on 2015, but we think trends are up. There is an awful lot of inventory that should trade between now and the end of last year. Bid rates are continuing to compress.

MR. CHAUDHRY: What kind of metrics are buyers in this liquid market using to buy these assets? What kind of valuations are you seeing?

MR. BRANDT: I can't speak to fossil fuels as well as other panelists. There is a dearth of to-be-built, fully-contracted wind farms, but if you have one, we have seen unleveraged after-tax discount rates over a 30-year pro forma falling in the last year to below 8% after what had been six to seven years of seeing bids come in between 8 1/2% to 9 1/2%. For solar, rates had been between 7% and 8% unleveraged after-tax on a 30-year pro forma, but they are now moving closer and closer to 6%.

MR. CHAUDHRY: Jon Fouts, what do you see for gas-fired assets?

MR. FOUTS: Gas-fired assets are slightly higher, probably in the 8% to 9% range. For yield cos bidding on renewable energy assets, particularly where the yield co has incentive distribution rights, we have seen discount rates bid even a little lower than what Ted said. A sponsor buying assets can justify taking a lower internal rate of return on a project that it plans to roll into a yield co with IDRs because it will get some of the valuation back as the IDRs move into the high splits. How some of these assets are being bid in some ways defies the physics of finance.

MR. PROSKIN: There is a lot of inexpensive private money chasing long-dated, contracted infrastructure. Whether it is gas-fired power plants, pipelines or other forms of infrastructure, you do not need yield cos as bidders to see nice valuations.

MR. REDINGER: Add to that that we are seeing a lot more activity from the Canadian pension and infrastructure funds. The Canadians are becoming very aggressive in pursuing these kinds of assets. While the Canadian infrastructure funds used to demand 12% and 13% returns, they are competing directly with yield cos at lower yields. The point is there is a lot of money driving this train.

MR. CHAUDHRY: Are the valuations you mention for operating assets and development assets? How do people price construction risk?

MR. PROSKIN: Buyers are not discounting the price once a project is under construction. They take risk as if it were already operating.

MR. BRANDT: I would agree with that. I think the bigger price point is whether the project has a long-term offtake contract.

MR. REDINGER: Last year, we saw projects still under development with power contracts trading at $89 a kilowatt. They are trading at north of $100 a kilowatt today.

MR. CHAUDHRY: Michael Proskin, are these all contracted assets? Is there a market for merchant assets and, if so, how do the valuations differ from contracted assets?

MR. PROSKIN: There is a market for merchant assets. However, the yield cos have not been as interested in them, and you lose some of the other infrastructure players who are not looking for commodity risk and are investing long-dated, hold-it-forever-type money.

MR. CHAUDHRY: How do valuations differ?

MR. PROSKIN: They are a couple of hundred basis points higher on an IRR basis than contracted assets.

MR. CHAUDHRY: Jon Fouts, you said the valuations are defying the physics of finance. What is driving that? Is it the competition from yield cos?

MR. FOUTS: Part of it is just the liquidity in the market. People are stretching for returns in any asset class and it filters through the system. There used to be a difference between what public investors in yield cos were willing to pay for assets compared to what the private investors would pay. Yields are compressing. That is one of the reasons why M&A activity is up.

Another reason is it is hard to construct a picture from a macro perspective that is more favorable than today, whether it is gas prices, interest rates, liquidity. A lot of our / continued page 8

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cap would make such projects more economic for subscribers.

Community solar projects are small utility-scale solar arrays in which individuals or businesses who are unable to put solar equipment on their roofs can participate by buying panels or a share of the electricity. The output is sold to the local utility. The subscribers get credits for their shares of the power that they can use against their utility bills.

Nine or 10 US states have laws currently that enable such projects to work. Xcel, the parent company of one of the main electric utilities in Minnesota, was flooded with more than 750 megawatts of proposals after it started accepting applications for community solar projects in December 2014.

The utility worked out a settlement with a handful of community solar advocates to limit projects to no more than five megawatts in size. Multiple arrays on the same site will be aggregated and treated as a single project if they "exhibit characteristics of a single development, including, but not limited to, a common ownership structure, an umbrella arrangement, shared interconnection, revenue-sharing arrangements, and common debt and equity financing."

The 5-MW cap will apply to co-located projects that were in the queue as of June 25, 2015 as well as to projects for which applications are submitted "prior to" September 25, 2015. A 1-MW cap will apply to projects for which applications are submitted "after" September 25, 2015 through September 15, 2016. The Minnesota Public Utilities Commission will have to decide what caps apply after that.

The first set of projects covered by the 5-MW cap will be entitled to interconnection agreements within 50 days after the application is complete.

Applications will be treated as complete as of June 1 for co-located projects of more than 1 MW AC in size that had met at least three of seven milestones. The milestones include site control, sufficient project financing, possession of required local permits, / continued page 9

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clients on the sell side are asking themselves whether it makes sense to hold assets and are being really thoughtful and disciplined about it. It is hard to construct a scenario where asset values will get better in the next 12 to 24 months. It is really hard.

MR. BRANDT: I would add that not only is it tough to see valuations improving from where they are today in dollar terms, there are also a lot of investors who own dollar assets that they translate back into euros and, with the euro down 35%, this is just a great time for a number of European asset owners to sell. The valuations look good in dollars, but when they are translated back into euros, the sales price is a home run.

MR. CHAUDHRY: Who else in addition to yield cos is buying these assets? Is it basically a domestic play or do you see money coming in from Asia and Europe?

MR. BRANDT: I will speak to renewables. There is interest from all the sectors, but it varies by type of asset. If you are bringing operating assets to the market, the obvious buyers at this stage are the yield cos. The two big deals so far this year are the Atlantic Power deal that TerraForm bought and the Wind Capital deal that Pattern bought. Both sets of assets were heavily bid and the yield cos won, but if you look at something like a hedged merchant wind deal or a to-be-built wind project that still needs a significant amount of tax equity, we are still seeing the Europeans, the EDFs of the world, be competitive. There are fewer Asians. NextEra is still doing a deal here and there.

MR. FOUTS: I agree. The Europeans are struggling with the lack of growth in Europe. They are looking for opportunities in the US. The big change is we do not see the bids from the Asians that we did 24 months ago.

MR. CHAUDHRY: Except, Michael Proskin, you still see them in LNG, right?

MR. PROSKIN: Yes. The Asians are still bidding on projects that produce things the Asians want. They see a benefit to owning interests in such projects rather than just being the offtake.

Financing Trends

MR. CHAUDHRY: Let's move from M&A to financing trends. I read a report that said in the first quarter of 2015, project finance debt volume was down 11 1/2% compared to the first quarter of 2014, down from $8.7 billion to $7.7 billion. And the number of term loan B deals that closed in the first quarter was down from seven last year to two this year. Tom Emmons, how do you reconcile all the liquidity that you say there is in the market with these figures?

MR. EMMONS: I guess everybody can quote different databases. I am not sure the source of your numbers.

MR. CHAUDHRY: I got them from the internet. [Laughter.]

MR. EMMONS: Then they must be true. [Laughter.] In the project finance market, a 10% swing is statistically insignificant because it is such a lumpy market. So my internet source, IJ Online, shows an increase in volume from $11 billion at this time last year versus $18 billion driven by LNG and renewables. Conventional power is down. The number of deals is down from around 50 last year at this time to around 40, which leads to a higher average deal size.

MR. CHAUDHRY: Andy Redinger, you look like you want to add to that.

MR. REDINGER: I agree that a 10% drop is insignificant. The drop may be due in large part to the smaller number of refinancings. Everyone who might be driven by falling interest rates to refinance has already done it. The reason why there are fewer term loan B transactions is banks are stepping in and taking that role in place of the institutional market.

MR. PROSKIN: Another reason that volume is down in the term loan B market is new regulatory requirements facing Wall Street have changed the nature of the product that can be brought to market.

Merchant Projects

MR. CHAUDHRY: Okay, but there has been a spike in the number of merchant deals that are coming to market in PJM. I can think of four such projects quickly. How many merchant megawatts do you see being added in PJM?

MR. REDINGER: I think there are 18 plants under development in PJM on the gas side. I don't know how many megawatts, but it is a significant number.

MR. CHAUDHRY: Are lenders concerned about this volume? Will it lead to lower electricity prices? Will we see a repeat of what happened in the 1990s when too much merchant gas-fired capacity was built within a short period. Tom Emmons, why will things turn out differently this time?

MR. EMMONS: It is a matter of supply and demand. I remember 1999 when people were saying we have to do merchant because that is all there is to do. By 2003, the effect of that was obvious. There were lots of write offs. We are not looking to finance gas-fired merchant projects ourselves.

MR. REDINGER: I do not think it is a question of whether these deals get financed in the bank or the capital markets. It is the hedge market. That market is not deep enough to do 18 deals.

MR. CHAUDHRY: How many do you think will get done?

MR. REDINGER: It is hard to find a hedge even today. It is hard to say.

MR. CHAUDHRY: So if you are a financial advisor to one of these gas-fired projects, and Andy, you are a financial advisor on at least one prominent one, what do you advise in terms of developing a merchant gas deal in PJM? Go for it? Or the market is too frothy?

MR. REDINGER: The project I am advising is early. It should be in commercial operation in September. The market for our project is still open. My advice is to move as fast as you can.

MR. CHAUDHRY: Most of these projects are getting financed today in the bank market as opposed to the term loan B market, correct?

MR. REDINGER: Yes. The bank market is offering more favorable terms at the moment. The banks have gotten more aggressive on pricing.

MR. CHAUDHRY: Until last year, there were really no merchant deals that were getting financed in the bank market. They were all term loan Bs. Jon Fouts, when did banks start taking merchant risk again?

MR. FOUTS: I think it goes back to the liquidity point. We have seen just a tremendous bid in the market, and so we pass it on to the investors. I can't really point to a single point in time or a catalyst that has driven it. It is just an outgrowth of the momentum in liquidity.

MR. REDINGER: I am not sure it is the same type of merchant project that we saw 16 years ago. You have in many cases heat rate call options that provide runway for the loan. There are an awful lot megawatts of coal supposed to retire, which these assets in PJM will replace in many cases. If you compare the numbers of new capacity under development to what the coal gurus say will shut down, we are actually short on capacity.

You have a capacity market in PJM that should provide us a bit higher capacity payments than we had in the past. We will know a lot more by July or August. It is not quite as gloom and doom as that whole thing from the late 1990's of "Let's just build megawatts because megawatts equal earnings equal higher stock prices equal more megawatts."

MR. FOUTS: There have also been some developments in the hedge side of things in terms of what are able to do as an industry. Maybe the hedges are shorter, but you can do puts. You can do future call options on hedges. That / *continued page 10*

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subscriptions for at least 50% of the project output, and equipment and panel procurement contracts. For applications that were not complete as of that date, Xcel and the developer will have to come up with a timeline intended to demonstrate that the project can get into service by the end of 2016.

> *The projects are expected to be connected to Xcel distribution lines. However, the utility will not be required to connect any project that requires more than \$1 million in upgrades to its distribution system to accommodate the interconnection where upgrades are required for "safety, reliability or prudent engineering."*

CONSTRUCTION-START QUESTIONS continue to receive attention.

Wind, biomass, geothermal, landfill gas, incremental hydroelectric and ocean energy projects had to be under construction by December 31, 2014 to qualify for 10 years of production tax credits on the electricity output or for a 30% investment tax credit on the project cost.

There must also be continuous work on the project after 2014. The Internal Revenue Service will not make anyone whose project is completed by December 2016 prove continuous work. However, projects completed after that will have to provide proof.

Jennifer Bernardini, a lawyer in the branch in the IRS national office that handles construction-start issues, said at an American Bar Association tax section meeting in May that the informal view in the national office is that continuous work must be shown only after 2014, even for projects on which construction started in 2013.

She was also asked at the meeting whether a single wind farm not all of whose turbines make it into service by December 2016 can be broken up so that only the turbines that got into service in time qualify for tax credits. The answer was no if any of the remaining turbines is installed. / *continued page 11*

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technology is not new, but I think financiers have gotten more comfortable with it. It preserves the upside for the equity. There have been some pretty creative innovations in how hedges are structured.

MR. REDINGER: It is not a stretch to think that these new merchant plants will be dispatched first and will force other plants out of the market. It does not take a huge leap of faith to conclude they will operate 100% of the time. These are some of the factors that are causing banks to get comfortable with financing them.

Discount rates used to bid for assets have dropped significantly in the past year.

MR. CHAUDHRY: Is there enough capacity in the bank market to finance all of these projects?

MR. REDINGER: It is a lot of projects.

MR. CHAUDHRY: If they get hedges, is the bank market there for all of these projects?

MR. FOUTS: I don't know if it is there for all of them. There is definitely a first-mover advantage. A lot of them will get financed under current market conditions. You do not want to be the last guy when the music stops.

MR. CHAUDHRY: All of these projects we just talked about are in PJM. Merchant deals have been done in ERCOT. Are there other markets that are ready for merchant financings: New England, for example?

MR. FOUTS: New England, PJM and ERCOT are all attractive for merchant. It gets pretty skinny after that.

MR. CHAUDHRY: Has the financing closed on any merchant plant to date in New England? I get that the Footprint Salem Harbor project was quasi-merchant. Anything else?

MR. FOUTS: Nothing that I can talk about. We are working on a couple right now.

MR. CHAUDHRY: Tom Emmons, there have not been any merchant solar financings, correct?

MR. EMMONS: I have not seen any.

MR. CHAUDHRY: Is anyone considering doing merchant solar or is that just out of bounds?

MR. EMMONS: We have not been asked to look any merchant solar projects.

MR. REDINGER: I don't want to give my merchant speech, but I say this all the time. Our bank lends merchant all the time, but just in other industries. I get on my soap box internally every day. Listen, we lend merchant to industrial companies, to shoe companies . . . . We don't require McDonald's to pre-sell their hamburgers when we make loans to them. [Laughter.]

MR. CHAUDHRY: I understand, but do you lend merchant to solar?

MR. REDINGER: I'm working on it. [Laughter.]

MR. CHAUDHRY: You will do merchant shoes, but not solar?

MR. REDINGER: I'm working on it. [Laughter.]

MR. BRANDT: We have a Texas merchant solar deal in the market currently and, unfortunately, with gas prices rolling down, it is about $3, maybe $4, out of the money. A little bit of a blip and it would be in the money, so we think the market is there. There is no reason that Texas wind hedge deals work and solar deals do not. Solar is correlated better with load, there is no marginal cost, and capital costs have been coming down dramatically.

Warehouse 2.0

MR. CHAUDHRY: I want to go back, Andy Redinger, to some of the trends you talked about in your introduction. You mentioned warehouse 2.0. What is warehouse 1.0 and how is 2.0 different?

MR. REDINGER: Warehouse 1.0 is just a more efficient way to finance. Instead of doing project financing for individual projects, you basically pool them and create one debt facility where you can save on legal costs. You create . . .

MR. CHAUDHRY: Why would you want to do that? [Laughter.]

MR. REDINGER: I'm not sure. One facility. It is basically the same thing we are doing on an individual basis. We will lend 80% of cost, and we do not require a take out from a yield co because if the lender is not taken out, then the debt converts into a permanent loan and becomes like any other project finance loan. It will amortize over the life of the power purchase agreement. That is basically what a warehouse facility is. We get comfortable maybe doing a little bit less diligence. We get comfortable getting paid on one facility.

With warehouse 2.0, the advance rate is 90% rather than 80%, and it is 90% of the takeout expected when the yield co buys the assets from the warehouse, which is typically at a higher price than cost. The effect is to finance more than 100% of the cost to construct in some cases. That's where things are headed. It is just an "ask" at this point. We will have to see what gets done.

MR. CHAUDHRY: Are there any leverage constraints?

MR. REDINGER: Nope. We are lending against the projected metrics for the project after it is in operation. This can lead to an advance rate that is higher than cost. However, we want at least 10% equity during construction even if the numbers suggest the project could support more debt.

MR. FOUTS: The couple that we have worked on have a restricted payments basket that would be something like two or two and a half times the debt service coverage ratio before the equity can start taking money out.

MR. BRANDT: So what is driving this? Why is there pressure to go from warehouse 1.0 to 2.0? Is it just competition among institutions? Liquidity? It is not as if the yield co will end up with any better price.

MR. FOUTS: The "ask" is there. The banks have the liquidity. We get comfortable with the risk and some of the specific credit metrics. And then a lot of it is that the yield cos want to put some assets off to the side so they can manage growth. It is early days still. I think we will see the next variation very soon with portfolios of emerging market assets.

MR. CHAUDHRY: Tom Emmons, are you buying into this warehouse 2.0?

MR. EMMONS: It is a reaction to the strong economics of some projects. It is a high-quality problem to have situations where a buyer will pay more than the cost to construct. So yes, we will lend against firm take outs if the residual risk is a construction risk. We are very happy with construction risks. Of course, then there are fine points like whether the full fee goes to the developer upfront or does it get paid at the end? Again, it is a high-quality problem. / continued page 12

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Lawyers in the IRS national office continue to answer other questions by phone.

There are two ways to have started construction in time. One is to have incurred at least 5% of the total project cost by December 2014. Some developers took delivery of wind turbines, blades, towers or other equipment at the factory in 2014, but without knowing at which project the equipment will be used. The IRS national office view is that a developer with such equipment who then, after 2014, assembles a site, interconnection agreement, permits and similar intangibles, for a project at which stockpiled equipment amounting to at least 5% of the project cost will be used, can treat the project as eligible for tax credits, and anyone later acquiring the development rights, together with the stockpiled equipment, would be able to do so, as well. However, ideally the developer selling the equipment and project rights should have had one or more potential projects in mind when it originally bought the equipment, even though it decides to use the equipment ultimately at another project.

Another way to have started construction in time was to have started significant physical work at the project site or at a factory on equipment for the project. In that case, the developer must be able to show there was "continuous construction" after 2014 if the project slips into 2017 or later. However, the IRS excuses breaks in construction that are outside the control of the developer, including "financing delays of less than six months." IRS lawyers in Washington believe that lack of funding can excuse a failure truly to get construction underway and that this excuse is not solely for situations where funding falls away after substantial site work has already started.

In a related development, the CEO of Plug Power, a fuel cell manufacturer, sent the assistant Treasury secretary for tax policy, Mark Mazur, a letter in early May in advance of a meeting with Mazur to / continued page 13

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Back-Levered Debt

MR. CHAUDHRY: Let's talk about holding company loans. Andy Redinger, you told me earlier that holdco loans are a new trend in the market. There has been a significant increase. What is driving it?

MR. REDINGER: Frankly, the reasons are the clients are offering up capital market business and the market is maturing. Developers that used to be developers with a bunch of projects are turning into real companies. Real companies usually have a revolver up top and a separate working capital facility.

MR. CHAUDHRY: Holdco loans enable a company to finance a portfolio of projects with a single loan as opposed to individual project financings. Tom Emmons, are you seeing much project-level debt with tax equity or has the entire market moved to back-levered debt that is behind the tax equity in the capital structure?

MR. EMMONS: The demand for back leverage is increasing. One of the reasons is that tax equity is scarce, giving it more market power to demand unleveraged projects.

We as lenders — and this is post-COD — are being pushed to do back leverage. This, in turn, means that the developers are pushing the tax equity investors to agree on a structure where there is enough predictable cash flow going to the developer to support back leverage.

Another reason for the move to back leverage is that many of the new projects in places like Texas and Oklahoma have high capacity factors, and the tax equity component of very these energetic wind projects is huge, giving the tax equity investors more ability to drive the capital structure.

MR. CHAUDHRY: Do you still see any project debt that is senior to tax equity?

MR. EMMONS: There are very few projects where post-COD senior debt coexists at the project level with tax equity, very, very few.

MR. CHAUDHRY: Is failure to agree on forbearance terms an additional stumbling block?

MR. EMMONS: It is as simple as tax equity wants us out of the project, and so we have to move upstairs. And since they are scarce and increasingly driving the capital structure in the very energetic projects, we and the sponsor figure out how to provide leverage, but it is one level up.

MR. CHAUDHRY: When you go one level up, you do not have any security on assets, correct?

MR. EMMONS: We have a security interest in the membership interest of the sponsor, and there is a negative pledge on the assets of the project.

MR. CHAUDHRY: So you have an unsecured project as far as the lender is concerned. What is the pricing on these back-levered loans? That is the part that surprises me.

MR. EMMONS: There is a premium because the debt is farther away from the assets. The premium depends on the tenor. It depends on whether there is a PPA or a hedge. It depends on the leverage. It is usually between 50 and 100 basis points.

MR. CHAUDHRY: Andy Redinger, I have heard a much lower differential.

MR. REDINGER: I am not going to argue that. [Laughter.]

MR. CHAUDHRY: What have you seen, Ted Brandt?

MR. BRANDT: I think Tom has described the market accurately. I do not think we have seen a leveraged wind deal for a while, other than a section 1603 or an investment tax credit deal. There are rare investment credit solar deals with leverage at the project level. Because liquidity is so vast, we are seeing some other banks that are not KeyBanc or Rabobank and that are less disciplined offer tighter spreads.

MR. CHAUDHRY: Some of the recent pricing from these back-levered loans has been as low as 1 5/8ths over LIBOR.

When you have back leverage, what kind of skin-in-the-game do developers still need to have? You have tax equity providing a large share of the capital cost of the project, and then you have back leverage on top of that. Do the two combined cover 100% of the project cost or do the back-levered lenders still require some equity?

MR. EMMONS: That is another high quality problem. If the economics can support more than 100% financing, given those different components, that is a great project. We would like see the sponsor still have at least some equity. It is a matter of negotiation.

MR. REDINGER: We like to see some equity, both during and after construction.

MR. CHAUDHRY: How much?

MR. REDINGER: We have been inside 10%. It really depends on the project.

MR. BRANDT: In wind, because the capacity factors are increasing and the capital costs are falling, we have been seeing about 70% of the capital structure coming from tax equity, leaving about 30%. The back leverage will cover something like two thirds of that.

LNG

MR. CHAUDHRY: Let's move to LNG for the last topic. Michael Proskin, there was a recent Moody's report that was pessimistic about the prospects for future LNG projects. Do you agree with that view?

MR. PROSKIN: The report was interesting. As commodity prices have changed, the home run of $5 or $6 of free money has gone away as oil prices have fallen from $100+ to $60 a barrel. What you see is more parity between LNG prices at Henry Hub and in international markets like Japan.

What this means is that there is no room for 20 LNG projects. The ones that are already financed and under construction will be built. There will be more projects beyond those, but I think you can count them on one hand.

The key is an offtake contract. We have talked to some offtakers in Europe and Asia who are still looking to sign deals. There have been new filings in the last few days for expansions of existing facilities. But it will all come down to whether there is an offtake contract. Anyone who is not already far along in negotiating such a contract will have a hard time securing one in this market.

MR. CHAUDHRY: So no new contracts beyond what is already far along in negotiations.

MR. PROSKIN: There have been some pretty high-profile examples of contracts that were not fully inked, but that were heads of agreement and that have been deferred. We have seen projects that one would have thought would have already announced an LNG offtaker that have not done so yet. At the same time, there is less urgency in many cases. A few years ago, the thought was that one had to sign up a whole train. Now trains are securing financing without the full output being under contract.

MR. CHAUDHRY: The ticket sizes for these deals by individual lenders, as Tom Emmons talked about earlier, are just staggering. People are bidding $500 million up to $1 billion per lender, right? And some of the large LNG deals — Freeport, Corpus Christi — were widely oversubscribed. How much was Freeport oversubscribed? Four and a half times?

MR. PROSKIN: Sounds right.

MR. CHAUDHRY: Corpus Christi was looking for $11 billion and that was oversubscribed multiple times also.

MR. PROSKIN: Correct.

MR. CHAUDHRY: Do you see that trend toward oversubscription continuing on the remaining financings?

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complain about denial of three Treasury cash grant applications on fuel cell projects. The Treasury paid a cash grant to one Plug Power customer in 2012, but then began questioning in February 2013 whether other customers could count toward the 5% test the cost of components that Plug Power had set aside in stock in 2011 to make fuel cells for these customers. The customers' projects had to be under construction by December 2011 to qualify for grants.

The issue was Plug Power ordered components for fuel cells when it felt close to concluding a purchase order with a customer, but before it had the binding purchase order in hand. The Treasury cash grant guidance says "[i]n the case of property manufactured . . . for the applicant by another person under a binding written contract that is entered into prior to the manufacture . . . of the property," the customer can count toward the 5% test costs incurred by the manufacturer to fill the customer's order. The CEO sent another letter June 1 thanking Mazur for the meeting and complaining about the "veritably Talmudic interpretation of various texts from guidance documents and Q&As put out by the [Treasury] Department."

Meanwhile, an ad hoc group of companies involved in "every aspect" of renewable energy development asked the US Treasury and IRS in a letter on May 1 for more guidance about what it will take to prove continuous work on projects that slip past 2016. The group wants "one or more mechanical or objective tests." It suggested two such tests. One is to say work was continuous if the taxpayer can show a certain percentage of project cost was incurred by a deadline, such as the end of 2016, and then the project is put in service soon after, such as by some date in 2017. Another potential objective test is to treat work as continuous if the developer met "certain delineated tests necessary and common to the construction process by milestone dates and the facility was placed in service soon thereafter (e.g., by some date in 2017)."

A lobbyist for a developer working on a waste-to-energy project asked the / continued page 15

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MR. PROSKIN: I think it comes back to the point that we have all been talking about, the current liquidity in the market. If there is a good project with a long-term contract seeking financing, the banks will show up in force. There is a lot of money looking for good credits.

MR. CHAUDHRY: If you take just Freeport and Corpus Christi, that is about $20 billion of mini-perm debt that will have to be refinanced in the bond market. Jon Fouts, do you think the bond market will be interested in refinancing $20 billion in bank debt in the next couple years?

MR. FOUTS: Yes. I am probably not the best person to ask, but based on conversations with our capital markets team, the market today is pretty robust.

MR. CHAUDHRY: Michael Proskin?

MR. PROSKIN: I think the market will be there. I think for project paper you probably do not want to do it all on the last day. Cheniere had a pretty good template with its Sabine Pass financings where the debt was taken out in increments over time. It should be possible for these other projects to refinance it over the course of the seven-year mini-perms.

MR. CHAUDHRY: You mentioned seven-year mini-perms. I thought that was the norm in the commercial bank market, but NextEra managed to borrow 18-year debt on Silver State South. Some of the Japanese banks had been lending long term all along, but now European banks are doing it, too. Are tenors back to long tenors or are we still in a mini-perm market with short tenors?

MR. EMMONS: I think it depends. We try to stay under 10 years. Some banks certainly are going longer than they did before, but that is only part of the market. I do not think it is a larger trend.

MR. FOUTS: You have a lot more liquidity at the mini-perm level than the 18-year level.

Audience Questions

MR. CHAUDHRY: We have time for a few audience questions.

MR. CIRINCIONE: Guy Cirincione with Siemens Financial. What are typical tenors and coverage ratios for back-levered debt on wind farms?

MR. EMMONS: The tenor will depend on the terms of the operating agreement. It really depends on the pattern of projected cash flow. It could be effectively a mini-perm loan. If the cash flows are predictable for 18 or 20 years, then it would be a mini-perm loan just like you would structure on a senior debt basis, but probably with a couple of notches higher coverage than you would have if the debt were at the project level.

MR. MULLENNIX: Stephen Mullennix with SolarReserve. If there is less than 10% real sponsor equity, how are the banks looking to handle asset management over the medium and long term?

MR. FOUTS: We are looking to third parties rather than the sponsor to operate.

MR. EMMONS: You usually have an equipment manufacturer who will effectively run the equipment. That is certainly true in wind. It is a little less true in solar. We are finding more and more focus by lenders globally, but especially in the United States, on who the OEM people will be and what kind of commitments the OEM makes. There are some OEMs who are making guarantees of output and around availability that are very, very important and can positively affect pricing.

MR. GREENWALD: Steve Greenwald, Credit Suisse. On the warehouse 2.0 facilities where you are banking on the yield co, is the price at which assets will be dropped into the yield co predetermined? Or are the banks taking interest rate risk on what the yield cos will pay for the assets two years down the road?

MR. REDINGER: The price is predetermined.

MR. DAVIS: Glen Davis with RES. Are there enough data points to give you a sense of what kind of premium, if any, is being paid for the acquisition of entire enterprises over the acquisition of individual projects?

MR. BRANDT: An amazing thing that we have watched over the last 18 months is that there is positive net present value being assigned to whole enterprises, pipelines and teams. That is completely different from what we saw from mid-2008 through mid-2014 where there was no premium and, in fact, in a lot of cases, there was a discount.

MR. FOUTS: I totally agree with that. Big change.

MR. MORALES: Carl Morales from Sumitomo. The question is for Andy Redinger about warehouse 2.0. Are you saying that the "ask" is for banks to size the debt based on a capital markets take out? If so, what happens if the capital markets shut down? Will the cash flow from the project be enough to repay the bank debt?

MR. REDINGER: We are relying on the yield co to stand behind its obligation to purchase the project. We are also relying on the price that was set to be an arm's-length price. Because the yield co is affiliated with the borrower, the price may have been subject to a fairness opinion.

MR. HOWARD: Rob Howard with Carlyle. We heard about a liquidity glut. There was talk of unreasonable tolerance for lower yields and higher risks. There were talk of defying the physics of finance. No one said "bubble," but what breaks this pattern?

MR. FOUTS: It is a great question and one we debate a lot. We are less worried about interest rates ticking up. The warehouse or the yield co model should hold within reasonable interest moves. The bigger issue is if there is an event where a yield co or one of the banks or warehouses has a big, very public miss on a dividend payment or a default.

MR. REDINGER: It is important to point out that these projects that go into a warehouse have power purchase agreements. This is not speculative buying and selling. These are real projects.

MR. EMMONS: The music stops when lenders lose money. I think they will keep lending until they don't. ◎

New Trends: Developer Perspective

Developer optimism about the renewable energy market is on the upswing. A lot more money is chasing renewable energy today than two years ago. The degree of penetration of renewables into the global energy supply has accelerated substantially. Roughly a third of the US coal-fired fleet is expected to be retired during the period 2017 through 2020. Demographic changes among US voters could lead to a tipping point in US public opinion about the need for tougher action on global warming.

Five top developers had a wide-ranging discussion about market trends at the annual REFF Wall Street conference hosted by Euromoney and ACORE in New York in late June. The five are Andrew de Pass, CEO of Conergy, a developer and construction contractor of solar photovoltaic projects, Bud Cherry, CEO of Eagle Creek Renewable Energy, an aggregator and owner of small hydroelectric projects, Kevin Smith, CEO of SolarReserve, a developer of solar thermal projects and molten salt storage facilities, Tristan Grimbert, CEO of EDF Renewable Energy, the North American arm of Electricité de France, and Thomas Plagemann, executive vice president for capital markets at Vivint, a rapidly-growing solar rooftop company. The moderator is Keith Martin with Chadbourne in Washington.

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IRS in a separate letter on May 1 to give power plants that use municipal solid waste or other waste fuels to generate electricity four years to finish construction without having to prove continuous work.

> *Christopher Kelley, a senior IRS lawyer, said at a conference in New York in May that he "wouldn't be too optimistic" that the government will issue more guidance on construction-start issues. The IRS has already issued four notices.*

SEVERAL TAX POLICY ISSUES of interest to the infrastructure trade may be in play in the next IRS business plan.

The agency usually releases a list in August of subjects about which it plans to issue guidance over the next year. IRS plan years run from July 1 through June 30.

The Edison Electric Institute, the trade association for the regulated electric utilities, is asking the IRS to commit in the next plan to issue guidance about net metering and "buy all, sell all" arrangements.

In many states, utility customers with solar panels on their roofs can feed any excess electricity into the grid, causing their utility meters to run backwards. Utilities complain that this forces them to buy electricity at retail rates that they could buy in the wholesale market at lower cost. In a "buy all, sell all" arrangement, the customer is treated as if he sold all his output to the local utility and then bought back what he needs, even though the entire output may be used by the customer and there is never any physical delivery of electricity to the utility. The customer pays only his net utility bill to the utility. For example, Austin, Texas and Minnesota are experimenting with assigning a value to electricity that customers sell to the utility. In Austin, the customer sells all of his electricity in form to the local utility for what the local regulators have decided the electricity is worth, taking into account the social benefits of moving to renewable energy as well as costs, and the customer then buys back what he needs at the retail utility rate.

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Developer Trends

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MR. MARTIN: Andrew de Pass, what is different about the renewables market today than even two years ago?

MR. DE PASS: I come at this from the perspective of a solar company. Two years ago, oil prices were higher, so it was not as difficult to make competitive bids to supply electricity in certain countries. Of course today we also have the whole yield co craze whereby long-duration cash flows are in vogue. This has the potential, with the launch of vehicles like the SunEdison yield co aimed at emerging markets, to give developers like Conergy more transparency and visibility on take-out pricing in those markets. So one change is the fossil fuel pricing and a second is the attractiveness of the long-duration cash flows in the capital markets.

There is growing optimism among US renewable energy developers.

MR. MARTIN: So both reasons for optimism. You do not see any clouds on the horizon.

MR. DE PASS: We can start talking about regulatory issues, but that would be depressing.

MR. MARTIN: Bud Cherry, what is different today?

MR. CHERRY: Andrew's perspective on finance is spot on. The significant penetration of renewables into the broader energy supply has accelerated substantially since a couple of years ago. If there is a cloud, it may be concerns in some states that renewable portfolio standards are driving up electricity prices.

MR. MARTIN: So the rate of growth in renewables is accelerating, but you worry about the potential for erosion in political support?

MR. CHERRY: I worry about the political factor that is beyond the control of the primary players in the business.

MR. MARTIN: Do you, as a hydro developer, need renewable portfolio standards to thrive? Hydro does not qualify as a form of renewable energy under all state RPS programs.

MR. CHERRY: We do not qualify in all states, but we qualify in many states and, to the extent there is an RPS in place, it is certainly helpful to us.

MR. MARTIN: Kevin Smith, what is different today?

MR. SMITH: We have seen a big increase in international activities in some markets where people would never have considered going in the past. The African continent is now the hot place to go for renewable energy activity. Some countries where you would never have imagined going a few years ago are now open for business.

MR. MARTIN: Which countries in particular?

MR. SMITH: We have been very active in South Africa, but the continent as a whole is opening up. The fact that yield co funds are now looking at targeting emerging markets will help drive more business.

Another change is that for the first time over the last couple years, you see renewable energy being chosen as the least-cost alternative in a lot of markets, including not only in some states in the United States, but also in South Africa, Chile, some other countries in Latin America and Dubai. Renewable energy is now being viewed as the least-cost alternative over all other fuels in a growing number of markets.

MR. MARTIN: Tristan Grimbert, what is different?

MR. GRIMBERT: First, there is a lot more money looking to move into renewable energy. It is not only yield cos. There is an imbalance between the amount of money and the number of projects available for investment.

Second, our business is becoming more and more technical. Being able to deliver on the business plan requires more and more technical knowledge and resources. I am thinking in particular about turbine performance, congestion risk and basis risk. As there is more and more penetration of renewables, the ability to understand and act on business risk and market conditions is becoming more and more important.

The third thing that is different is we have reached a turning point in the last year in the US where we can talk again about carbon pricing and about moving away from subsidies to something that would recognize the cost of carbon. My hope is that, within the next five years, we will move away from renewable portfolio standards and all the subsidies to a truly market-based mechanism for carbon pricing. That is my hope.

MR. MARTIN: Thomas Plagemann, what is different?

MR. PLAGEMANN: Let me address the question from the perspective of a residential solar developer. There are three things.

There has been tremendous growth in distributed generation. It has become a much larger part of the total renewable energy installed capacity in the last couple years and, along with that, has come an increased acceptance by financial investors to do the work required to understand consumer risk and accept a portfolio of either commercial offtakers or residential offtakers as a substitute for utility-scale offtakers. We have also seen the tax equity market rebound rather nicely in the last couple years.

MR. MARTIN: Surprisingly, as the tax credits are about to expire, more tax equity investors come into the market.

MR. PLAGEMANN: If you look at the market history after the financial crisis, there was not a lot of profitability. I think in 2009, perhaps $1 billion of tax equity was done, but as financial institutions become more profitable, more money is shifting into tax equity.

Access to Capital

MR. MARTIN: Tristan Grimbert said there is a lot more money chasing renewable energy projects today than two years ago. There have been periods in the life cycle of this industry when developers have felt people are throwing more money at them than they can usefully deploy. Are you feeling that today and, if so, is the imbalance of money to projects being reflected in the cost of capital? Kevin Smith, let me start with you.

MR SMITH: I think so. It is not only yield cos chasing projects but also strategic investors, and the competition is driving down the cost of capital in the US deep into the single-digit numbers. Even in some of the emerging markets, the returns are being pulled down into the low teens. A few years ago, people would not have touched some of those markets unless the projected return was 18% to 20%, and now they are moving into the same markets for expected returns of 12% or 13%.

MR. MARTIN: It is not only the equity returns that are falling, but also developer returns? / continued page 18

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EEI wants the IRS to address whether solar customers engaging in net metering and "buy all, sell all" arrangements should be viewed for tax purposes as selling electricity to the utility so that they would have to report income from such sales. According to the trade association, "There is no specific authority that would render this exchange nontaxable, and other rules and theories for non-recognition are of dubious applicability." The utilities also want to know whether they have to send customers Form 1099s at year end. Such forms could be required if customers received at least $600 in payments or bill credits that must be reported as taxable income.

EEI also asked the IRS to provide guidance about use of money in qualified funds set up to cover the decommissioning costs of nuclear power plants.

There are approximately 93 nuclear plants operating currently in the United States. They produce 19% of US electricity. Seventeen plants are in various stages of decommissioning.

The utilities are allowed by section 468A of the US tax code to deduct amounts they set aside in qualified funds to cover future decommissioning costs, but there are strict rules for spending from the funds. The utilities were holding more than $50 billion in such funds at the end of 2014.

The IRS position is that only "otherwise deductible" decommissioning costs can be paid out of a fund. EEI says various issues have come up about what this means. For example, nuclear plant operators have been making payments to the US Department of Energy since 1983 for the US government to dispose of their spent nuclear fuel, but disagreements in Congress about where to put the fuel have delayed disposal. The government was supposed to have taken the spent fuel no later than January 31, 1998. Many companies have made claims against the government for their incremental costs. Some have won lawsuits against the government. This raises questions about whether some decommissioning-related costs are "otherwise deductible" because taxpayers cannot deduct amounts for which they have a / continued page 19

MR SMITH: Equity returns, but after a time lag, the falling cost of capital ultimately pulls down developer returns as well because everyone is bidding lower and lower prices to supply electricity. There is always a bit of a time lag, so those that participated in the first wave of yield cos got nice premiums for projects, but then when they have to go back into the market to rebid, everyone is bidding lower power prices so asset valuations will eventually come down.

MR. MARTIN: Andrew de Pass, is access to capital no longer an issue for this industry?

MR. DE PASS: The cost of capital and availability vary at different stages from early-stage development, mid- to late-stage development, during the construction cycle from notice to proceed to the commercial operation date, and then for operating assets.

The market for operating assets is extremely competitive, and there is price visibility and good availability of capital.

In certain markets, construction finance remains a challenge. For example, as we look to finance projects in new markets like Turkey or Mexico or Southeast Asia, construction finance is more challenging and expensive. In the US, it is available for properly structured projects.

Late-stage development capital is available and the returns have definitely been pushed down. For example, in the UK where we developed, constructed and operate more than 200 megawatts in the last 12 months, we were buying later-stage development rights for a cash-on-cash return of 1.25 to 1.5 times investment, and that has now been pushed down to 1.1 times.

The returns are still very attractive in early-stage projects where the dollars per megawatt to develop are low in solar, $25,000 to $50,000 maximum, and the returns can be multiples. But you have to work with a portfolio because you can lose money in any one project.

The point is it is important to differentiate among stages of development.

MR. MARTIN: So capital is not a problem for solar, especially as one gets farther along in the development cycle. Bud Cherry, hydro developer, plenty of capital?

MR. CHERRY: It is important to note that our business plan is to deal primarily in operating facilities. Only a couple percent of our portfolio is in what I would describe as late-stage development. We have seen the impact of a significant amount of new money entering the space and, as a result of that, we have gone back to our original business plan which was negotiating bi-lateral deals rather than bidding into large auctions with multiple bidders.

MR. MARTIN: So plenty of capital means that you are being pushed out of the market? You are backed by private equity, so you are not able to compete with the yield cos for operating hydro projects?

MR. CHERRY: We look for deals that are not attractive to the yield cos and other players who lack the ability to fix facilities that need work, either mechanical, structural or in their capital structures. We go after projects with some amount of challenge and do negotiated deals instead of participating in auctions.

Greatest Challenges

MR. MARTIN: Let's move to the next broad question. What are your greatest challenges today? Bud Cherry, you just mentioned one of yours, so Andrew De Pass, let's go back to you.

MR. DE PASS: Conergy has a global footprint and so the challenges vary by country. We operate in 15 countries.

One of our challenges in the developed markets is they are moving away from utility-scale to distributed generation including industrial rooftop. We expect this trend to continue over the next five years. Distributed generation is a different business than utility scale because you have to acquire customers, you have challenges with credit assessment, you have to scale up, and the projects are relatively small. The question is how are we going to make money consistently in such markets?

MR. MARTIN: You need lots of employees, and the business has more in common with the cable television business than with power.

MR. DE PASS: We are too late in the US to tackle residential, but we are a leader in solar in many other markets where residential is starting to take hold, and the discussion amongst senior management and the boards is do we or don't we do this? The projections say that residential could be 30% of these markets and then you ask, "What is the business, and how do we do it effectively?" It is a customer acquisition business; it is not a technology business. What can we learn from the best practices in the US, and can they apply in other markets? Some do, and some don't. So our challenge is, in addition to the complexity of managing a global solar downstream company, how do we make money consistently in distributed generation specifically with rooftop?

MR. MARTIN: In which countries are you trying to move to distributed?

MR. DE PASS: In the US, we are focused on small-scale utility as well as commercial rooftop. We think in the US market you have to have financial innovation, so we recently closed on the first commercial PACE deal with tax equity with the project owned by Conergy. In the UK, we launched a commercial industrial product. In Germany, we have rooftop partnerships with utilities like RWE and local residential players. And this morning, in our operating management board, we agreed that The Philippines are now emerging as a rooftop opportunity.

MR. MARTIN: Kevin Smith, what are your greatest challenges today?

MR. SMITH: There are two sides to our business. One is the development side where we are looking at PV and solar thermal, and we also have a technology side where we are developing large-scale storage. Our Nevada project, which is a solar thermal facility with storage, is just going into operation.

We started with energy storage when the company was founded. It is a key part of our business model. The challenge is finding those markets where storage is critical and can be integrated into the grid and where we can do it at a cost that is competitive.

MR. MARTIN: Your Nevada project is a power tower project with molten salt storage. Are you planning to do storage as a stand-alone business or always in aid of solar thermal electricity production?

MR. SMITH: Putting large-scale storage facilities in the US is difficult because of market conditions, but we are very competitive in places like Chile or South Africa or Saudi Arabia where they do not have $4 natural gas and they need help with grid reliability.

MR. MARTIN: Tristan Grimbert, greatest challenges?

MR. GRIMBERT: Defining a viable business model in the distributed space is a challenge with the lack of differentiation and the repetitiveness and credit issues. A lot of people are moving into that sector. It is very difficult to figure out how to make money. That is one area with which we are struggling.

Another challenge is finding the right balance for spending on the development pipeline in relation to the size of the market when the tax incentives are always on the verge of expiring. Five years ago, there were too many projects under development. I think the wind pipeline was something like 351 gigawatts for an annual market of six to eight gigawatts, so it was 50 years of projects. Today, the number has been reduced significantly.

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reasonable prospect of recovery.

The National Association of Bond Lawyers is asking the IRS to update guidelines it published in 1997 for management contracts. This would affect private contractors who manage schools, roads, hospitals and other public facilities that were financed partly with tax-exempt bonds. States and cities must be careful not to allow more than 10% "private business use" of such facilities in order to retain the tax-exempt status for the bonds. Private management contracts can be considered private use of the facilities. The current rules for such contracts are in Revenue Procedure 97-14.

AN MLP OVERPAID for an interest in an LNG terminal.

The Delaware Chancery Court said a master limited partnership called El Paso Pipeline Partners, L.P. paid at least $171 million too much for 49% interest in an LNG terminal on Elba Island, Georgia in November 2010. The MLP bought the interest from El Paso Corporation, which had organized and retained control over the MLP. The MLP paid at least $931 million.

A master limited partnership is a large partnership with ownership units that are listed on a stock exchange.

The decision, in a case called *In Re: El Paso Pipeline Partners, L.P. Derivative Litigation* in late April, is a warning to MLPs and yield cos to be careful about the prices paid for "drop-down" assets from affiliates.

The El Paso MLP partnership agreement required that any asset purchases from El Paso be approved by a special conflicts committee composed of qualified members of the board of the MLP general partner, an El Paso subsidiary.

The committee could approve purchases that meet one of four standards: either the board had to believe in good faith that the transaction was in the best interests of the MLP, or the purchase had to be approved by common unit holders who were unaffiliated with the general partner, or the purchase had to be on terms that were no less favorable to the MLP than those avail-

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Lastly, it is a challenge to forecast the price and cost curves accurately. We must take a view on the future price for electricity and the future cost of solar and wind equipment and the future cost of capital. We have been talking about yield cos and their impact on the cost of capital the last couple of years, but at some point the cost of capital will start going back up. You do not want to be caught in a trap where you have offered an aggressive electricity price to win a power purchase agreement and then the cost of capital goes back up.

MR. MARTIN: It has been a good business model for the past few years to bid low electricity prices figuring that by the time the project has to be built, equipment prices will have fallen. You do not want to be caught short when the pattern reverses.

MR. GRIMBERT: More on the capital side. On the equipment side, we expect the costs to keep falling. The issue is whether you are super wise or super lucky. I think it has been a mix of both, and we are trying to be wise.

MR. MARTIN: Thomas Plagemann, greatest challenges for Vivint?

MR. PLAGEMANN: The challenge and the opportunity both are to manage rapid growth, to continue scaling up and to maintain a track record of improved efficiencies and cost reduction. That is reduction in both operating costs and capital costs. We continue to look for ways to reduce the total cost of tax equity and debt financing. On the operating side, we are using software to reduce timing between different stages in the process, to reduce errors, to reduce rework, and ultimately to reduce costs. We are using technology, too, to reduce costs.

MR. MARTIN: The technology you envision using is . . . ?

MR. PLAGEMANN: We are working with our vendors to try to reduce the all-in cost of equipment. There is an operating side and a process side.

MR. MARTIN: Interestingly, none of you mentioned this. We are all in the business of selling electricity, and demand for electricity is barely growing. Isn't that a challenge?

MR CHERRY: It has always been like that, and it is always going to be like that.

MR. MARTIN: It is just life as we know it?

MR. CHERRY: Yes.

MR. SMITH: Except that it varies by market. Certainly in the US, growth in electricity demand has been slow for a decade and the forecast is it will remain slow for another decade, but older generating capacity is retired and must be replaced. In certain international markets, electricity demand is growing by 6%, 7%, 8% a year.

Opportunities

MR. MARTIN: Something like 38% of US electricity supply is from coal. Consultants expect a third of that to be retired between 2017 and 2020, but there is a debate about whether that creates a lot of opportunity to replace that capacity. Does anyone think this is a great opportunity?

MR. CHERRY: It is unclear whether all that base-load generation can be replaced in the time frame that is being discussed, but it is helpful for us as a hydro owner and operator.

MR. MARTIN: Because you are a form of base-load generation that can replace coal? These other guys with wind or solar do not have the same opportunity?

MR. SMITH: Unless we have storage.

MR. GRIMBERT: There is room with or without storage. The coal retirements will allow us to keep a market in the range of five to 10 gigawatts of new wind capacity additions a year, and that is critical. You do not need a lot of storage to allow much more penetration of wind and solar. The coal retirements driven by the Clean Power Plan will allow the utility-scale wind and solar markets to continue adding capacity over the next 15 years at the current level. It was suggested earlier that the

Equity and developer returns are falling as companies bid lower electricity prices.

growth rate is accelerating. I do not think we have an acceleration of the growth rate, but I think we will have stable growth.

MR. MARTIN: The mood this morning is one of optimism. Let's probe on storage. Many people say the widespread adoption of batteries will lead to a fundamental change in this market. Do you agree? When do you see that happening?

MR. SMITH: I am a bit biased because we have an alternative to batteries, and the cost of batteries is pretty outrageous. Our molten salt facility in Nevada has 1,100 megawatt hours of storage. I think the largest battery storage facility is 50 times smaller than that and 10 times the cost.

MR. MARTIN: Into how many hours of storage does that translate?

MR. SMITH: We have up to 10 hours of storage for about 110 megawatts. This is a tremendous benefit in places like South Africa and Chile where they need help with the grid. The outlook for storage in the US is a little less clear. Various pilot projects are underway.

I agree with Tristan that not much storage will be needed to facilitate more wind and solar capacity additions. At some point, a tipping point will be reached where we will need a lot more storage, but in the near term. California has storage requirements, but without a lot of teeth behind them. Turning to batteries, Tesla has sold out for a couple years on batteries because a lot of people decided that having a battery is the fashionable thing to do.

MR. MARTIN: What do you mean Tesla sold out?

MR. SMITH: Reports in the trade press are that Tesla has already sold two years' of production.

MR. DE PASS: We have a different perspective from Kevin because of the potential scale of the storage solution. We are focused on batteries. Conergy has an R&D lab focused on storage in our headquarters in Hamburg because we think it is critical to integrate storage into our system offering in the medium term. Our R&D specialists in storage used to think it would take four or five more years to become economical; we see the trend accelerating to a point where we now expect batteries with a couple hours of storage to become economical in the next two years.

In Germany, solar kits are offered today with storage. This makes sense in Germany because there is no residential net metering. We have pilot projects that are relatively small for the use of lithium ion batteries for small utility-scale solar projects. In Australia, we have a / *continued page 22*

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able from unrelated third parties, or the terms had to be fair and reasonable to the MLP. The committee used the first approach.

All the assets the MLP acquired over time came solely from El Paso.

The conflicts committee had an outside law firm and financial adviser advising it from one transaction to the next.

The committee decided that the Elba purchase made sense after concluding it was accretive to the limited partners when, the judge said, the committee should have focused on whether a fair price was paid. "An accretion analysis says nothing about whether the buyer is paying a fair price," the judge said. "Accretion depends on how the acquisition is financed, and 'anyone can make a deal look accretive just by playing with the consideration used.'"

The MLP had bought a 51% interest in the same LNG terminal in the spring the same year for a lower price than it paid for the remaining 49% interest. After the earlier deal was announced, the MLP units dropped 3.6% in market value. One key committee member told the others in an email after the first purchase, "Next time we will have to negotiate harder." When El Paso came back with the proposed sale of the remaining 49% interest, a committee member told others by email that it is "really not in the best interests of [El Paso MLP] to have too much of its assets tied up in the LNG trade," to which another committee member responded, "It is as though you were reading my mind." In the end, the MLP paid a higher price than before. The judge said the picture that emerged was one of committee members going through the motions.

He had harsh words for the financial adviser. The adviser had a conflict of interest: it was paid a flat fee of $500,000 per transaction for a fairness opinion, but on a contingency basis where it was paid only if the deal closed. It was briefed about each transaction by El Paso executives before the transactions were presented to the MLP and the conflicts committee. The adviser appeared to fiddle in its / *continued page 23*

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13-megawatt project we are developing, and funding that will be an important global pilot for the use of storage.

MR. MARTIN: You are installing a 13-megawatt lithium ion battery?

MR. DE PASS: The solar project as a whole is 13 megawatts. The battery is relatively small compared to the total system size. The economics make sense for us because we have a government grant for 50% of the capital cost to demonstrate that this works.

MR. MARTIN: Peter Rive of SolarCity says it costs about $5,000 to install a battery with a rooftop solar system, and the homeowner gets about $500 of that back in time-of-use arbitrage. The battery does not seem economic at the moment, yet you think within two years . . .

MR. DE PASS: I was commenting on Germany. It is hard to generalize across the globe. In places with time-of-day pricing where a homeowner can capture that arbitrage, batteries may become economical sooner than in other markets without this form of pricing.

MR. MARTIN: Thomas Plagemann, when does Vivint see itself installing batteries routinely with rooftop solar?

MR. PLAGEMANN: The economics of the battery are entirely driven by the regulatory structure and rate framework in a region. It does not make economic sense today so, as Kevin says, it is currently a customer choice. The batteries that are being marketed today for residential use are really for backup. They are not really for cycling. We will watch the market evolve. We continue to work on developing battery solutions with our vendors. We are not in the manufacturing business. We will find the best vendors to partner with and offer the solutions that customers want when it makes sense.

MR. MARTIN: When do you expect it to make sense?

MR. PLAGEMANN: It depends on what happens on the regulatory side. If batteries were $500 tomorrow, then people might buy them today as a hedge against some kind of demand charge being imposed in the future, but as long as the cost remains $5,000, it is a completely different economic question.

MR. MARTIN: So Andrew de Pass is the biggest optimist in terms of when we will start to see widespread installation of batteries, but he has a global perspective and may not see them so rapidly in the US. Kevin Smith and Thomas Plagemann, you think it will take longer.

MR. SMITH: You have to ask the question market by market. Germany has different issues certainly than the US. If Germany had residential net metering, then homeowners might be more inclined essentially to use the local utility for storage than to install a battery.

MR. MARTIN: Tristan Grimbert, some of your competitors — Duke, AES, First Wind, which is now part of SunEdison — have installed 20- or 30-megawatt batteries with wind farms. Do you see EDF going in that direction?

MR. GRIMBERT: We are already. We are building a 20-megawatt battery storage project right now in PJM, and we have more in development.

Storage is a diverse universe. We can talk about a battery bought by a residential customer all the way to a pumped storage hydroelectric project or thermal storage facility for a city that is huge in scale. I think it will be all of the above. You need to manage the grid in a way that you can provide some load-shifting equipment or load-following equipment.

The question about battery storage is the timing. The timing depends on the transition to distributed generation. Battery storage at the residential or commercial level is only viable if there is no net metering. Net metering is not viable above a certain percentage of distributed generation because it imposes a cost on the utility. Someone has to assume the storage. If distributed generation grows quickly, then we will reach the ceiling for net metering and any additional storage will have to done by the customers.

Storage will happen; there is no question about it. Whether it happens in three, four or five years depends on the market.

Residential solar is more of an equipment business. It is not a capital business. You are mostly just selling equipment, and, honestly, that is not a business in which we are really interested.

MR. MARTIN: You are installing a 20-megawatt battery currently in PJM?

MR. GRIMBERT: Correct.

MR. MARTIN: Why is that economic to do? Will you earn enough revenue from providing frequency regulation and other ancillary services to cover the cost?

MR. GRIMBERT: Yes. PJM has opened a new tariff for ancillary services, and quite a few players — you named some of them — jumped on it. We built the project. PJM does not need a lot of storage in order to be able to manage the intermittent generation on the grid, so that market reached saturation quickly. Keep in mind, the potential storage market is about a tenth of the wind capacity: rough calculation, back of the envelope, you need an order of magnitude less capacity in storage than you need in intermittency.

So, yes, storage is a market for us, and we are in it, but it is a small fraction of the potential market in terms of capital deployment as the solar or the wind market itself.

Fundamental Change?

MR. MARTIN: Will storage cause a fundamental change at some point in the power market? Is it a potential game changer?

MR. SMITH: We have a tendency on this panel to talk about all markets at the same time.

MR. MARTIN: You and Andrew de Pass are more globally focused.

MR. SMITH: Yes, and not only in terms of geography, but also focused on residential all the way to utility scale. There is no question that storage has value in load shifting and time of day. In California, the peak load is up to 8 o'clock at night. If you dump a bunch of PV into the grid in the middle of the day, you are going to have issues. Then you can go in the other direction into South Africa where the capacity margins are less than zero, so they are having blackouts, and most of the blackouts are 5 p.m. to 10 p.m. at night, and so storage is of massive value in South Africa because it will help to meet load. The Chilean market is a 24-hour-a-day market, with a lot of mining sector customers. A few merchant PV projects have been built in Chile, but you are not going to be able to compete in that market without storage.

MR. MARTIN: So storage may be a game changer, but not as much in the US? Look first to South Africa and Chile?

MR. SMITH: Battery storage in the US is more of a niche market. We believe that large-capacity storage will ultimately be required in these markets. The US is not pricing storage into the model today. In other markets, it is being priced today into the model.

MR. GRIMBERT: Keep in mind that storage is a transmission asset. The more reliable and the more structured the grid, the less you need storage. Storage is a market today in Africa. If you do not have a functioning grid, you need storage, period. The European grid is very solid; you need less storage. It can absorb up to 40% intermittency in some cases with limited issues. The US grid is not as strong because it is more spread out than the European grid.

MR. MARTIN: Will storage bring about a fundamental change in the US power market? How will it affect developers? Thomas Plagemann, for Vivint it probably accelerates growth for rooftop solar and allows customers with / *continued page 24*

analyses with discount rates and other metrics to try to show the proposed price for each transaction was down the fairway, even at the expense of using inconsistent approaches to analyze the initial purchase of a 51% interest compared to the later purchase of the remaining 49% interest, and gave no apparent consideration to a softening of the LNG market between the two transactions.

The adviser made "a minimal effort" and did little more than try to "justify [El Paso's] asking price and collect its fee" rather than help the committee do a real analysis, identify arguments and negotiate, the judge said.

The committee members appeared misinformed about the scope of guarantees by oil majors of the offtake contracts and could offer few specific recollections of their thinking at trial. They never learned enough about the facts to determine that the price was fair, the judge said.

EXCHANGING IDRS IN AN MLP for common units did not trigger income taxes, the IRS said.

The key was the parties structured the exchange so that there was no capital shift among the partners.

The IRS analyzed the exchange in an internal memo written by the national office to the field, or the part of the IRS that audits taxpayers. The memo, released as Chief Counsel Advice 201517006, was made public in late April.

IDRs, short for incentive distribution rights, are a right the general partner of a master limited partnership or yield co retains to an increasing share of cash flow as distributions to investors increase over time. For example, the general partner might be distributed 15% of net cash flow off the top after cash distributions to investors take them above 125% of minimum quarterly distributions and 25% after distributions to investors move past 150%.

The general partner in the case under audit traded incentive distribution rights for new common units and less valuable IDRs with higher thresholds before the general partner would receive more cash and a lower percentage of cash for the / *continued page 25*

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rooftop solar systems on their roofs to disconnect completely from the grid.

MR. PLAGEMANN: I don't know that residential homeowners are going to start disconnecting from the grid because batteries are available.

The speed of broad adoption has to do with the rate at which intermittent renewable resources penetrate the market and create the need for some solution, whether that solution is transmission or whether it is storage, how the regulatory environment reacts to it and what kind of rate structure is imposed to compensate the players. All of these issues remain unresolved in the US market. They are what will drive the ultimate outcome.

MR. MARTIN: Will storage bring fundamental change? If so, how are you affected?

MR. GRIMBERT: No, it is not a fundamental change. It is a relatively small addition to the grid. It is one way to manage a grid. It is one of the many pillars that you need to support the grid.

MR. MARTIN: Not a game changer?

MR. GRIMBERT: It is another market.

MR. MARTIN: Kevin Smith, not a game changer?

MR. SMITH: No. The increase in storage is accelerating pretty dramatically from a small base, but it is like all these other markets. There will be continuing growth, certainly in the US and pretty dramatically in the international markets because of grid issues. It will become a bigger market over time, but it will not cause a fundamental change in the power business.

Carbon Tipping Point

MR. MARTIN: Let me take this in a different direction. Tristan Grimbert said one difference today compared to two years ago is there is a public conversation again about carbon pricing. I was thinking about how rapidly US public opinion has shifted on two issues recently: gay marriage and symbols of the Confederacy. Opinion shifted on both issues almost overnight. Bud Cherry, is there the potential for US public opinion to shift just as dramatically on carbon?

MR. CHERRY: Renewable energy has always been an area with a lot of politics. Every one of these renewable technologies has its group of advocates, and there are also opponents on the other side.

MR. MARTIN: Andrew de Pass, do you think we will see an abrupt shift in public opinion on carbon in this country?

MR. DE PASS: I do. We have to create a level playing field and simplify. When you compare the US to other markets from a regulatory and incentive standpoint, this whole tax equity thing is a nightmare. ITC and PTC: they are a nightmare for developers and operators to understand. We have to work through archaic documentation. Whether or not the tax credits are extended, we really need a level playing field. We have to price fossil fuels correctly. A carbon tax should be part of the mix. It makes logical sense and is the right thing to do.

Can we do it politically? I think so.

What will be the tipping point? Demographics. With the people in the younger generations, the need to do something about climate change is ingrained. Once they vote in greater numbers, they will have an impact.

MR. GRIMBERT: I hope you are right because it would be very nice to subtract the political uncertainty from every aspect of the business.

Carbon pricing is the most American way to address global warming. What is more volatile than CO2? It goes everywhere. It is a global issue, and carbon pricing is the capitalist way to address it. Cap and trade was proposed by Americans, and then it was shut down. Carbon pricing would be a better way than a haphazard mix of subsidies with, for example, a New Mexico

Demographic changes among US voters should tip US public opinion toward stronger action to address global warming.

PTC and some tax exemptions and different provisions in Arizona. No. Let's price what is creating the problem and, then, if we have to produce massive wind in California or Texas, we will do it because the market is sending the right price signals. It may take some catastrophic climate event, but I have no doubt it will come because it is the American way to address global warming.

Developer Returns

MR. MARTIN: What are developer returns today? Single digits? Low single digits? Medium? High? Where? Tristan, you are smiling, so you are first.

MR. GRIMBERT: Too low. I am not in the business of deploying at the lowest cost of capital. I am in the business of creating value. The cost of capital is one part of the equation, but the job is to find differentiators. It is not the size of the market; it is not the growth; it is how much better you are than your competitors. The returns for this effort are always too low.

MR. MARTIN: So single digit returns?

MR. GRIMBERT: It would be hard to be in that business for single digits.

MR. MARTIN: You remind me of the inspector in the film *Casablanca*. [Laughter.]

MR. SMITH: We have developed some PV deals where the returns were 5% to 6%. There are some people today who are buying operating PV projects at 5% or 6%. It depends on how far advanced you are along the development spectrum. Developers working on earlier-stage development projects earn a higher return. The international markets are completely different. Returns there are in the 10% to 25% range, depending on country risk.

MR. MARTIN: So that's why you are more focused overseas today.

MR. GRIMBERT: It is a difficult question to answer because it depends where in the development cycle you take over the project.

MR. DE PASS: I think you have to ask about early-stage development versus late-stage development. Early-stage development where you might spend $10,000 to $50,000 a megawatt and sell it for $250,000 or so on completion will allow you to make money. There are fewer sites available that work that way, and it depends on geography. Where returns are really being squeezed is late-stage development in developed markets. The returns for late-stage development on a cash-on-cash basis — we don't really think about the percent / continued page 27

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general partner at each threshold. The new units were designed to give the general partner the same amount of cash overall as before.

Each partner has a "capital account" that is his claim on the assets if the partnership liquidates.

The partnership assets had appreciated significantly by the time of the exchange. However, the capital accounts had not been adjusted to reflect this appreciation. IRS regulations allow partnerships to "book up," or adjust capital accounts for appreciation, after certain events, such as when a new partner or existing partner makes a capital contribution in exchange for a partnership interest. According to the IRS, the general partner would have taken a capital account in the new common units it received for the IDRs that was above the capital accounts the investors had in their equivalent common units, making the common units no longer fungible.

Therefore, the general partner made a capital contribution for the new common units, allowing the partnership to book up the investor capital accounts for the appreciation. There was enough appreciation in partnership assets to equalize the capital accounts on the common units without having to reduce anyone's capital account.

The IRS national office told the field that such a restructuring of the general partner interest was simply an adjustment in the ratio in which the existing partners shared in partnership returns and not a taxable exchange. The memo suggests that the result might have been different if there had been a capital shift from some partners to other partners.

NORTH CAROLINA extended a deadline for completing renewable energy projects to qualify for a 35% state tax credit.

The deadline had been December 2015. The governor signed a bill in early May allowing until the end of 2016 to complete any project on which the developer has "incurred" at least a minimum percentage of project / continued page 27

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return because you can cycle your capital in six months — are 1.0, 1.1 or 1.2 times investment.

MR. MARTIN: The reason the returns are so squeezed for late-stage development projects is you are competing with yield cos and others trying to buy the project at low discount rates?

MR. DE PASS: The yield cos really come in mostly at COD, but there is enough capital that understands the risk when you are about to start construction that people are chasing the late-stage development.

MR. MARTIN: Is the market assigning any discount for construction risk?

MR. SMITH: There used to be an arbitrage. A developer would try to use construction financing with a tax equity take-out at the back end in order to get to COD and sell then, but the potential arbitrage is no longer worth it.

MR. DE PASS: You can spend $500,000 developing your project and make a $3 million premium. When you ask about returns on the development side, they are all over the map.

MR. CHERRY: There is a modest upside to late-stage development in hydro. There is a modest premium because there are not that many people doing it.

SolarReserve

MR. MARTIN: Let me move to a lightning round. I want to ask a few questions about each of your companies. Keep the answers short. Let me start with SolarReserve. Kevin Smith, your company is up for sale. Why?

MR. SMITH: It is a confidential sales process, so thanks for announcing that publicly. I don't know that I would say we are for sale as much as dealing with a need for capital. We are looking for strategic investment in the company. We talk about private equity. It is more appropriate capital for the development cycle, but we are looking now for strategic investment because we have assets in which we should be retaining larger long-term ownership positions.

MR. MARTIN: There is a view that nothing is likely to happen in the next 12 to 24 months to increase asset valuations above where they are now.

MR. SMITH: Pipelines go in and out of fashion. A few years ago, pipelines were worthless. Now there is a huge recognition of pipeline value. Therefore, this may be a good time to raise equity.

MR. MARTIN: Your Nevada project is nearing the end of construction. Is it on schedule? Behind schedule? Ivanpah, another power tower project, has had a challenging start up.

MR. SMITH: Schedule is relative. It is the largest power tower project in the world by a factor of five to 10. We have had our challenges during construction. We are building in the middle of the Nevada desert, but we are now well into start up. We are circulating salt to the receiver and, as far as we are concerned, the technology has proven itself. Efficiencies are exactly what we expected. Actually, performance is a bit better than expected. We should reach full operation in the next few months. Large projects are challenging, and we have had our share of issues during construction.

MR. MARTIN: There was a period a few years ago when many people thought solar thermal would win the competition between solar thermal and PV at a utility scale. Today PV has eclipsed solar thermal in the US market. But solar thermal has gotten good traction in places like South Africa and Saudi Arabia. Why is it working better there?

MR. SMITH: For two simple reasons. One is the US has $4 natural gas. The rest of the world does not. In Chile, gas is $12 to $15 if they can get it, so that completely changes the cost structure. We are competing against conventional energy projects in those other markets. In Saudi Arabia, 60% to 70% of power generation is from oil.

The other reason is transmission. The US and Europe have large, robust transmission systems. Africa, Asia and certain parts of Latin America will have to depend on storage and 24-hour bid solutions. PV is an intermittent resource.

Vivint

MR. MARTIN: Thomas Plagemann, your CEO said your costs fell from $4.25 a watt to $2.95 a watt from the start to the end of last year, but he expects only another 5¢ to 15¢ improvement this year. Why the large fall last year but not this year?

MR. PLAGEMANN: We are in the direct door-to-door market for the most part so, as we ramp up, new offices open and we hire for those offices. I think we were at $3.21 in Q1 2015. We left the end of last year at around $3.00, and we averaged about 3.20 for 2014 as a whole. We want to leave this year at about $2.90.

MR. MARTIN: So continuing improvements, but the pace is slowing?

MR. PLAGEMANN: Last year was a year of significant build up for the company. At the end of 2013, Vivint was a fairly small organization. We have close to 3,500 employees today. Costs were higher last year because of all the ramping up. We are looking forward now to sustained cost decreases on the order of what we are projecting this year. Our costs are now in line what where we think the rest of the market is.

MR. MARTIN: One of your competitors, SunPower, has just launched a yield co, 8point3. Do you see Vivint moving to form its own yield co?

MR. PLAGEMANN: We are already publicly traded and are a pure-play residential solar company. SunPower and First Solar are both solar manufacturers, so they may have been driven to form a yield co for reasons that are unique to them.

MR. MARTIN: A jointly-owned yield co may give each the ability to sell product to the yield co and book the profit as an unrelated-party sale?

MR. PLAGEMANN: When I was at First Solar, owning projects just was not in the cards because the investor base was looking to be invested in a solar manufacturer. A yield co was a good solution for them, but not necessarily for us.

MR. MARTIN: One more question. What percentage of the total cost of an installed residential solar system is the customer acquisition cost? Some companies have said it is as high as 25%.

MR. PLAGEMANN: It is on that order.

MR. MARTIN: Is that the lowest hanging fruit in terms of squeezing out future costs?

MR. PLAGEMANN: I think we have some room to move on the equipment cost side, so that is an area at which we will look as well as a host of other operating costs.

EDF Renewable Energy

MR. MARTIN: Tristan Grimbert, some of your competitors have yield cos. Pattern Energy is an example. Do you see EDF moving in that direction? Are you at a disadvantage in bidding for power contracts without one?

MR. GRIMBERT: No, I don't. Right now our business model is that we develop projects for ourselves and we sell up to 50% to co-investors. Sometimes we sell more, and sometimes less. We do tap the market by selling assets. We see yield cos playing in that market, but they are a portion of that market and there are plenty of investment firms and other people who are trying to deploy long-term capital at competitive rates, so we do not think it necessary to have our own yield co.

MR. MARTIN: You can always sell to the existing yield cos if you want.

MR. GRIMBERT: We can sell to yield cos or we can sell to people who are not yield cos but have an efficient cost of capital and are looking for long-term investments.

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costs and completed a minimum percentage of "physical work" by December 31, 2015. The percentage is 50% for projects with a DC capacity of 65 megawatts or more. It is 80% for smaller projects.

The developer must notify the state tax department by October 1 this year of any potentially eligible 2016 projects by letting the department know each location, total cost estimate and project size. A processing fee of $1,000 per MW must be paid with each application. There is a minimum fee of $5,000 per application.

The developer must then submit documentation by March 1, 2016 confirming that enough costs were incurred or enough physical work was completed on each project to qualify for the tax credit. The taxpayer will have to certify that the thresholds were met and also enclose a notarized report from a North Carolina certified public accountant confirming that enough costs were incurred or from an independent engineer licensed in North Carolina confirming that enough physical work was completed.

The state is expected to follow the federal rules for determining when costs are "incurred." Costs are not incurred under the federal rules merely by spending money. Rather, the developer must take delivery of equipment or services to count the costs, with one exception. A payment at year end for equipment or services that will be delivered within 3 1/2 months of payment counts as a 2015 cost, assuming the developer is authorized to use the 3 1/2-month rule as a "method of accounting."

It is less clear whether the state will follow the federal rules for determining percentage of completion. Bobby Weaver, the expert on the renewable energy credit with the state tax department, said in an email in mid-May that "I anticipate that we will be providing guidance to taxpayers in the near future."

North Carolina allows a 35% tax credit to be claimed on new solar, wind, geothermal, biomass, hydroelectric and combined heat and power equipment. The credit is claimed entirely in the year the equipment / continued page 29

Developer Trends

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MR. MARTIN: You have been a buyer of development rights to projects from smaller developers. Cielo is an example. Is that pipeline getting smaller, stronger, or remaining the same?

MR. GRIMBERT: We have done some acquisitions. What is difficult about the development business is that when you think you are 90% done, it means you are only half way through. Getting the project to be completely de-risked is what really trades value.

Because the market has run faster than anybody expected, the pipeline is a little small today. We started about a year ago to rebuild our pipeline. We are doing that partly by acquisition. We announced our fourth transaction with Cielo this week. We may buy a pipeline. We may buy a project. We will keep developing ourselves. The overall supply of new projects is low compared to the appetite of the market. I attribute this to the impending expiration of the tax credits.

Eagle Creek

MR. MARTIN: Bud Cherry, you have 42 operating hydro projects. A lot of other people have also been interested in buying small hydro. Why the great interest in this sector?

MR. CHERRY: We can be very competitive for smallish facilities. As the facilities get too large, we run into the much larger competitors with much lower costs of capital, so we tend to focus on smaller projects. We have succeeded in raising financing on those projects. We have put together an accordion-type project finance facility with one of our banks that has worked well for us. We have had a five-fold increase in capacity over four years and a seven-fold increase in generation, and that is continuing.

Conergy

MR. MARTIN: Andrew de Pass, Conergy stumbled initially. It went through a preliminary insolvency process in Germany. It said that the fact that it was a vertically-integrated manufacturer of solar panels as well as a developer made it vulnerable to falling panel prices as the Chinese pushed into western markets. It has re-emerged as a pure developer and construction contractor. Why did the vertically-integrated model work for SunPower and First Solar, but not for Conergy? What was different?

MR. DE PASS: There were a number of factors. First Solar and SunPower moved earlier than Conergy into development. They have differentiated technology in thin film and polysilicon. And it was a question of timing and capital structure. The old Conergy had significant holding company debt. It got caught in a financial crisis as it built factories in Germany just as the Chinese were moving in with a much lower-cost product. The fact that those other companies had moved more strongly to development gave them a hedge.

Wisdom

MR. MARTIN: The last question is for each of you, starting with Tristan Grimbert. You have all been in business a long time. Someone once said, “No mistakes, no experience. No experience, no wisdom.” What have you learned along the way that would count as wisdom?

MR. GRIMBERT: There are so many things that we have learned.

MR. MARTIN: Just one.

MR. GRIMBERT: Do not be afraid to pay the right price when it is the right project.

MR. SMITH: I have been in the market for 35 years, and it has been a roller coaster ride. What was out of fashion five years ago is in fashion today. I think there are two takeaways. One is do not be afraid to walk away from a deal because the timing is wrong. The other is do not be afraid to hang on to something because it could come back in vogue. It is a very difficult balancing act to decide what to walk away from and what to hang on to because the markets go through three- or four-year cycles. People still say, “That’s never going to happen again.” And it does with a three- or four-year lag.

MR. CHERRY: Watch out for projects and opportunities that require political support to be able to pull off.

MR. MARTIN: That has been a refrain for you. We will have to probe next time into what happened to have burned that lesson so deeply into your consciousness. Andrew de Pass?

MR. DE PASS: I have two lessons. First, never move away from a disciplined assessment of risk and an aversion to risk. If you do, you will lose money. Second, development is extremely difficult and something can always be missed, so attention to detail in your development staff is critical.

MR. MARTIN: Thomas Plagemann, you have the last word.

MR. PLAGEMANN: Take a long-term perspective as often as you can, and treat your partners fairly. ◎

Rooftop Solar Outside the US

by Taylor Lane, in New York

There is enormous potential for rooftop solar outside the United States in markets with high insolation levels or favorable governmental policies. However, growth in such markets has been decidedly mixed.

In contrast, residential solar remains the fastest-growing segment of the electricity market in the US with over 50% annual growth in each of the past three years. In 2014 alone, the US installed more than 1,200 megawatts of residential capacity. Major drivers of this growth include the falling cost of solar installations, the investment tax credit and new financing mechanisms, in particular the third-party ownership model. Progress in other countries can be divided into three categories based on the degree of market maturity.

Mature Rooftop Markets

Australia has a robust rooftop solar market that was initially focused on direct sales, but that is turning lately toward third-party ownership.

After the introduction of a state-wide feed-in tariff program in 2008, rooftop installations soared as customers capitalized on falling solar equipment costs in order to save money on high retail electricity rates. A feed-in tariff model incentivized direct ownership because rooftop systems had short, two- to three-year payback periods and customers could earn money over the lifetime of the installation through renewable energy credits.

Recently, third-party financing has gained traction as the government cut feed-in tariffs and international developers entered the market with offers of more financing options that allow households to install solar without the upfront capital cost. The Australian government is helping to promote third-party financing. Last summer, the Clean Energy Finance Corporation, a government entity, announced an investment of US$113 million in three solar leasing and PPA programs run by SunEdison, Tindo Solar and Kudos Energy. The market is expected to turn increasingly towards solar leases and PPAs to sustain growth.

Western Europe boasts a large installed base of rooftop solar. Growth has been fueled by government incentives and high electricity prices. Third-party financing */ continued page 30*

chadbourne

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is put in service if the equipment is put to personal use. It is claimed ratably over five years if the equipment is put to business use.

Meanwhile, a longer extension of the tax credit may also be possible. The North Carolina House voted in late May to extend the existing credit for another two years for projects completed through December 2017 without the need to meet construction thresholds by the end of 2015. Projects larger than 1 MW would qualify for a 35% tax credit if completed in 2016, but only a 20% credit if not completed until 2017. The North Carolina Senate has not adopted the extension, and the issue has gone to a House-Senate conference committee along with a number of other issues. The conference committee has until August 14 to act.

The state legislature is also debating whether to freeze the percentage of electricity that utilities in the state must supply from renewable energy at 6% rather than let it rise to 10% in 2018 and 12.5% in 2021 and whether to reduce the maximum size of projects for which "standard offer" contracts are available to sell electricity to North Carolina utilities from five megawatts to 100 kilowatts.

> *Standard offer contracts for up to five megawatts could remain available for projects to generate electricity from swine and poultry waste.*

REFLECTIVE ROOF surfaces installed to reflect sunlight to the underside of bifacial solar panels qualify for a federal investment tax credit, but the tax credit can be claimed only on the incremental cost of the roof surface above the cost of a non-reflective roof, the IRS said. The IRS made the statement in a private letter ruling released to the public in June. The ruling is Private Letter Ruling 201523014.

WASTE HEAT AND CLEAN COAL projects would benefit from two tax bills that cleared the Senate tax-writing committee and are awaiting action by the full Senate.

Such bills are difficult */ continued page 31*

Rooftop Solar

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models only recently began making inroads due to historically high levels of government subsidies that encouraged ownership rather than third-party financing arrangements.

There is strong potential for commercial rooftop solar in Mexico and parts of the Middle East and Africa.

The Netherlands is increasingly seen as a testing ground for the new financing models. Several downstream solar companies have recently announced partnerships with utilities, including E.ON and Trianel GmbH, in The Netherlands to introduce a leasing option for residential customers. In contrast with the third-party model that has gained traction in the US, leases are being offered in partnership with a utility to the utility's existing customer base rather than to all customers directly.

A similar model has gained strength in Germany in which the utility giant RWE is collaborating with Conergy to provide a solar leasing option to RWE's customers with RWE having ultimate ownership of the system and revenues.

Growing Markets

Rooftop solar has not benefited in other regions from the generous and continued support of a government feed-in tariff or tax subsidies, but markets are starting to develop.

There is a strong potential for commercial rooftop solar development in Mexico, the Middle East and Africa. These regions have high insolation levels. Recent changes to the regulatory landscape in combination with persistently high electricity prices for the industrial sector create a strong business case for rooftop solar through direct ownership. The outlook for residential rooftop is more mixed.

In Mexico, the government subsidizes residential electricity prices, thus eliminating one of the primary drivers for rooftop solar. However, the government is preparing to launch a new, wholesale competitive electricity market by the end of 2015 and will release final electricity market guidelines in July 2015. (See related story in this issue starting on page 1.) Private power producers will be able to make retail sales directly to customers with on-site loads of at least two megawatts as of August 2015, and the threshold will fall to one megawatt starting in January 2016. As part of the transition from a market dominated by the national utility, Comisión Federal de Electricidad (CFE), the Mexican government has also created an auction system for electric generating capacity and introduced tradeable clean energy certificates called "CELs" to encourage renewable energy generation. Projects smaller than 500 kilowatts will not qualify for CELs, but are also exempted from many of the permitting requirements and regulatory costs associated with participating in the wholesale market. Even though Mexico's new regulations do not directly support rooftop solar, the changing marketplace will drive investment in renewables across the country and may incentivize small-scale installations by reducing the administrative burden for these systems.

There are still critical barriers to developing rooftop solar in Mexico. Political manipulation of tariffs for electricity creates uncertainty that has inhibited both utility-scale and rooftop solar development. For example, the government reduced residential tariffs by 30% in advance of the most recent elections as a political ploy, thus making potential customers more cautious to enter into a PPA. It remains to be seen whether the government will continue subsidies at these levels when the wholesale market is launched later this year. In addition, Mexico lacks a uniform system of measurements for solar construction. At the residential level, there is not a clean construction policy or a standardized system of components for solar installations. This barrier is less of an obstacle in the commercial market.

The availability of financing options for residential solar remains an issue in Mexico as well. The national banks cannot extend credit to homeowners for solar installations. As a result, there must be an intermediate bank that will then lend directly to homeowners for solar installations. Only two such banks offer loans currently. Given that the majority of the population does not have an established credit history, many banks, especially international banks, are wary of being involved with such lending.

Commercial installations provide the greatest opportunity in Mexico. Electricity prices for industrial customers are high. However, customer education will be key to realizing this potential. Many companies are resistant to investing in a solar system that has a payback period of 15 years or longer when they could expand their operations instead. Third-party financing has helped to overcome these barriers in the US by enabling companies to see immediate savings in what they are paying for electricity. Certain multinationals, such as Walmart and Home Depot, have already embraced rooftop solar outside of their US operations. Once new wholesale market and interconnection regulations are in place, the contours of the rooftop market will become clear and developers can evaluate the potential.

Like Mexico, Dubai is also a solar market in the midst of a significant transformation. In January 2015, the Dubai government published an executive resolution allowing persons to connect solar photovoltaic systems to the grid. Dubai benefits from strong drivers for rooftop solar development, including high levels of solar insolation, economic and social goals to create a more diversified economy and the falling cost of solar equipment. Electricity prices are heavily subsidized for residential consumers. Commercial and industrial customers also benefit from subsidies but to a lesser degree. As a result, commercial and industrial installations have the greatest potential.

In contrast with Mexico, Dubai's local banks are keen to participate in solar power financings, and its commercial market for rooftop solar benefits from lower credit risk. Even though the regulatory framework remains uncertain in some respects, local lenders in Dubai are more likely to take a risk on financing solar installations due to a higher tolerance for regulatory uncertainty in this market and a strong desire to support government policies. Some local lenders have already expressed support for commercial-scale solar development, and at least one international bank has expressed interest in financing a portfolio of local projects.

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to move all the way through Congress until a larger energy tax policy bill emerges.

One bill, proposed by Senators Tom Carper (D-Delaware) and Dean Heller (R-Nevada), would allow a 10% investment tax credit to be claimed on equipment that generates electricity from "exhaust heat or flared gas from an industrial process that does not have, as its primary purpose, the production of electricity" or from "a pressure drop in any gas for an industrial or commercial process." The generating capacity of the project cannot exceed 50 megawatts. The tax credit could only be claimed on the incremental cost of the waste heat conversion equipment, but the baseline for comparison is confusing. The Senate Finance Committee said in its report on the bill: "Where waste-heat-to-power property is fully integrated into other industrial property, the amount eligible for credit is the incremental difference in cost between the property that has the ability to capture and convert waste heat to electricity and similar property that lacks such functionality."

The other bill could spare owners of clean coal power projects that receive "clean coal power initiative grants" from the US Department of Energy under section 402 of the Energy Policy Act of 2005 from having to report the grants as taxable income.

Government grants received by corporations sometimes do not have to be reported as income either because Congress specifically exempted them from taxes or else because they are treated under section 118 of the US tax code as capital contributions to the corporation by someone who is not a shareholder. An example of a government grant that is not taxable because it is treated as a capital contribution is where a government makes a grant to a railroad to put its tracks on an overpass above a highway so that trains do not block traffic. The railroad has no income in the sense of an accession to wealth. It is no better off with the overpass than without; the work is done solely for the public benefit.

Under this standard, most government grants must be reported as income.

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The local utility, the Dubai Electricity and Water Authority, has a monopoly on electricity sales, similar to Mexico's CFE before the recent reforms. Therefore, the model of third-party ownership with a solar PPA would be hard to make work. The market is developing as a direct-sale market, but there is the opportunity to introduce new financing models for commercial development, such as leases. Owners who use solar equipment for self-consumption can offset any surplus electricity produced by the solar system against the amount of power they take from the grid.

Jordan, with the most advanced solar market in the Middle East, provides an interesting contrast with Dubai. While Dubai provides significant subsidies to residential customers, Jordan cannot afford to subsidize electricity to the same extent. Since Jordan relies on expensive diesel generation, solar has already reached grid parity in most of the country. Banks, telecommunications companies and other consumers with high electricity consumption are incentivized to install solar panels as a result of high tariffs for electricity. Owners of distributed generation facilities can sell surplus power to the national transmission company and any of Jordan's three distribution companies.

Rooftop solar development in Jordan has overwhelmingly favored the ownership model thus far as a result of continued regulatory uncertainty as to whether a user needs to own the rooftop system, according to Ali Sharif Zu'bi Advocates & Legal Consultants CPSC. Since consumers rarely own off-grid systems, the potential for a third-party financing model would be subject to regulatory approval. In the agreement that a consumer signs with a distribution company for distributed generation, there is a clause governing the circumstances under which the company can disconnect the solar installation. However, the agreement does not specify whether the system should be owned by the user. The majority of consumers would prefer to lease rather than purchase solar installations due to the high upfront costs and issues surrounding creditworthiness. If the ownership issue is clarified, then this is expected to unlock a burgeoning commercial solar market in Jordan in which hospitals, mosques, schools and telecommunications companies are looking to install solar in order to reduce electricity costs.

South Africa is well positioned for growth in commercial rooftop solar as a result of concerns over energy security and its well-established base of solar developers and manufacturers.

In contrast with Mexico, Dubai and Jordan, overall electricity rates for industrial consumers in South Africa are fairly low. However, Eskom, the national utility, has recently proposed a 25% increase in electricity rates, which will help to support the case for distributed generation. Over the past year, the growing occurrence of load shedding has prompted many municipalities and companies to consider owning and installing rooftop solar. Since the regulatory framework does not allow owners of distributed generation to sell power into the grid, the third-party financing model is not expected to drive growth in the rooftop market. Rather, companies will purchase rooftop installations for self-consumption in order to go off the grid or to reduce reliance on the grid. For example, pension funds in South Africa own a series of shopping malls and are interested in adopting rooftop solar in order to increase energy security.

South Africa's rooftop market will also benefit from the foundation of utility-scale solar in the country. In late 2011, the Department of Energy introduced a "Renewable Energy Independent Power Producer Procurement Program" (REIPPP) under which the government expects to procure 1,450 megawatts of utility-scale solar installations. As a part of the REIPPP, solar developers, including SunPower, had to establish some element of local manufacturing and engineering, procurement and construction capacity. South Africa now has a domestic manufacturing and contracting base that is looking for new opportunities to expand and can support

Third-party ownership models are gaining traction in Australia and Holland.

the growth of rooftop solar within the country.

In East Africa, Kenya and Tanzania present a similar opportunity for commercial solar development with a different set of drivers than in South Africa. While both regions have superb solar resources, the primary driver of rooftop development in East Africa is the high cost of diesel-based electricity. Similar to the situation in Jordan, businesses in East Africa, including lodges, banks, hotels and phone companies, pay an estimated 30% of capital expenditures on diesel-based generation and are eager to invest in rooftop solar in order to reduce costs. However, the commercial-scale market has been constrained by a lack of financing to support these transactions. There are few financing options for businesses to purchase solar equipment unless they have collateral. The high transaction costs of checking credit, local regulations for electricity generation and the fact that only 10% to 20% of property is owned through a mortgage are all barriers to widespread deployment. More recently, investment funds, such as CrossBoundary Energy, have been formed to bridge the gap between the enormous potential for commercial rooftop systems and the high upfront costs of capital. The mobile phone card model, where customers pay in advance for a quantity of electricity, is also gaining some traction.

Nascent Markets

The rooftop markets in Poland and Turkey remain in the earliest stages of development.

The Polish and Turkish governments have both created feed-in tariff programs that are specifically directed at residential rooftop projects under one megawatt in size. High electricity prices and growing energy demand create significant potential for the rooftop market in both countries. However, the potential remains largely unrealized due to regulatory uncertainty.

Poland has to reach a renewable energy share target of 20% by 2020 under European Union Directive 2009/28/EC. It implemented quota obligations for renewable energy with tradable certificates and is approximately halfway to reaching its target under the Directive 2009/28/EC. However, the solar market in Poland is virtually non-existent because its quota obligation system did not pay enough to incentivize the market for solar and the price of tradable certificates was highly unstable.

In February 2015, Poland enacted a renewable energy law that replaces the quota obligation system with an auction system and creates sub-markets based on project size. The Polish government will require local electricity companies to buy all surplus energy produced by projects below / *continued page 34*

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Section 118 applies only applies to grants received by corporations.

The bill would spare partnerships receiving clean coal power initiative grants after 2011 from having to report them as income if a corporation receiving such a grant would not have to report it.

The partnership would have to pay the US Treasury 1.18% of the grant received and also reduce its depreciable basis on any part of the project put in service, within 12 months after the basis of other assets by any excess not used to reduce basis in the project.

Senator John Cornyn (R-Texas) proposed the bill.

Three projects that received clean coal initiative grants, and have not been cancelled, are two integrated-gas combined-cycle power plants being developed by Summit Power near Midland, Texas and by Hydrogen Energy International, BP Alternative Energy and Rio Tinto in Kern County, California, and a post-combustion carbon capture demonstration project that NRG Energy, Inc. is developing in Thompsons, Texas.

A TRANSACTION LACKED ECONOMIC SUBSTANCE, a US appeals court said in May, but the court set the transaction aside only in part.

BB&T Bank did a STARS transaction with Barclays in 2002 that was supposed to generate large foreign tax credits and interest deductions for BB&T. STARS stands for "Structured Trust Advantaged Repackaged Securities." The transaction was a "tax product" being marketed 15 years ago by KPMG.

The IRS disallowed foreign tax credits of $498.2 million and interest deductions of $74.6 million, imposed taxes of $84 million on cash payments that BB&T received from Barclays, disallowed deductions for $2.6 million in transaction costs, and imposed penalties of $112.8 million.

A lower federal court agreed with the IRS.

The US appeals court to which BB&T took the appeal described / *continued page 35*

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40 kilowatts for 15 years, and will subsidize the local electricity company if the market does not pay enough for this power. The maximum price that can be paid to the local electricity companies under this guarantee system will be published this fall. If the price is set at a reasonable level, then this will spur creation of a rooftop solar market. However, there is significant uncertainty surrounding the guaranteed price the government is likely to offer. In addition, the Polish government has submitted several proposals to reduce the feed-in tariff for small-scale facilities and may limit the size of the rooftop sub-market.

Turkey's nascent solar market illustrates what might happen to the Polish rooftop market if the regulatory framework for small-scale generation remains uncertain. Like Poland, Turkey exempted projects of up to one megawatt from the Energy Market Regulatory Authority's licensing requirements for generation. Contrary to expectations, rooftop solar and other forms of small-scale generation have not grown substantially. A combination of continued administrative burdens and a delay in promulgating regulations have outweighed the incentives created by the feed-in tariff system and high demand for energy. For example, rooftop systems would still need to be approved by distribution companies in their regions as generation that does not require a license. Regulators in Turkey are considering amendments to this program in order to exempt certain segments of small generation from all administrative burdens. Currently, all projects under one megawatt are treated exactly the same, although a 10-kilowatt installation on a household differs significantly from a 900-kilowatt installation on a commercial enterprise. The market will remain underdeveloped as long as the regulators allow uncertainty to persist or create additional administrative burdens for rooftop solar compared to larger-scale solar installations. ◎

Analyzing Solar Rooftop Portfolios

by Jason Kaminsky and Richard Matsui, with kWh Analytics in Oakland

Investors in rooftop solar companies and portfolios, and lenders to the sector, are using big data to draw useful insights and improve their valuation techniques, creating an opportunity for thoughtful developers to differentiate their operations by skillfully demonstrating transparency into the performance of their assets.

Such data is becoming an essential element of underwriting and will be critical to attracting the volume of capital needed to scale.

Solar is entering a new era in which operating portfolios are changing hands.

Projects are being refinanced after only a few years of operation, and current investors are seeing that their investments have liquidity in a secondary market, whether by banks, insurance companies or yield cos.

As tax equity vests through the five-year holding period and securitization becomes more prevalent, the market will see more opportunities for refinancing portfolios and for more liquid debt products.

Residential solar portfolios are a unique financial product that straddles consumer credit risk and project finance. On the one hand, there is an individual customer; on the other, there is an operating asset. This has major implications for the types of data available as a tool for risk management and underwriting. With a few years of operating history and thoughtful analysis, an investor is better able to evaluate the risk of an existing portfolio vis-a-vis a new portfolio.

Unique characteristics of the solar industry, including the potential for "underwater" leases or power purchase agreements, make this a particularly important assessment.

Potential Insights

In the same way that a high debt-to-income ratio may predict an impending consumer default on a credit card, or an underwater home mortgage may predict a homeowner default on the mortgage, there are important leading indicators that an investor in solar assets can assess.

Figure 1

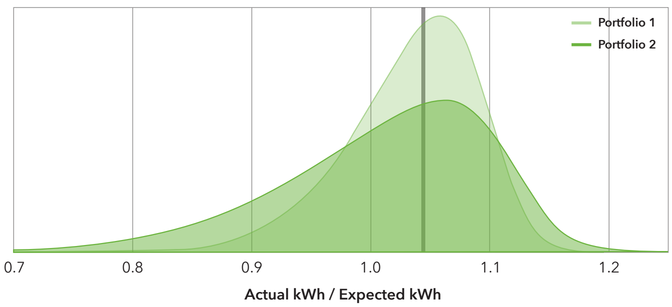

Figure 1 shows electricity production of two portfolios of rooftop solar systems. Most people agree that portfolio 2 in the probability distribution is a riskier portfolio; although both portfolios have the same mean performance ratio, the variance in portfolio 2 is higher.

Going into a deal, all investors must make assumptions about system production. However, with even a couple years of operating data, a colorful picture of the actual portfolio performance emerges. Investors are analyzing more than just the average performance ratio of the portfolio, since the average conceals problems hidden in the tails. They want to look at the distribution of performance and understand what quantity of homeowners have grossly underperforming or over-performing systems — and why — since those customers are more at risk of having an upside-down value proposition. Those customers may not be realizing the promised savings or may resent purchasing electricity and then giving it back to their utility for free.

Our data shows that it is not uncommon for solar portfolios to have a double-digit percentage of systems with performance materially different than what was underwritten.

The production data can then be combined with other data sets to quantify the risk of "underwater" leases or power purchase agreements. By analyzing asset-level information, an investor can determine the probability that a homeowner's solar contract is or will become an out-of-the-money contract.

This risk is particularly acute in California, where impending utility rate reform spurred by AB 327 is guaranteed to change the economics of solar for both new and existing solar customers. To appropriately assess the embedded risk of "underwater" contracts in the portfolio, it is critical to run scenario analyses of contract terms against future utility rates. These customers are more likely to be upset and seek a renegotiation of their contracts (or worse), jeopardizing expected cash flows and putting increased pressure on the servicer */ continued page 36*

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the deal, in a notable understatement, as a "complex transaction."

BB&T put $5.755 billion in income-generating US assets it owned into a trust and appointed a UK trustee, thereby subjecting the income generated by the assets to income taxes in the United Kingdom.

Barclays paid BB&T $1.5 billion for equity interests in the trust. The payment was in substance a $1.5 billion loan to BB&T because Barclays was contractually obligated to sell its trust interests back to BB&T whenever the transaction terminated for $1.5 billion plus a floating return of the one-month LIBOR yield plus 25 basis points. Either party could terminate the transaction at any time with 30 days' notice.

The cash generated by the assets was distributed to BB&T after subtracting UK income taxes and management fees to the trustee. However, the distributions ran through a "Barclays blocked account" at BB&T and then back to the trust for distribution to BB&T. This circular motion generated deductions for trading loses for Barclays on its UK tax return.

Barclays was also able to claim tax credits in the UK for the UK income taxes paid by the trust on account of its equity position in the trust.

Barclays made monthly "Bx payments" to BB&T for a share of its tax savings. The payments were calculated as 51% of the UK taxes paid by the trust. Each month, the Bx payment was netted against the interest BB&T owed Barclays and only the net amount paid. Each month, Barclays made net payments to BB&T.

A look at numbers will help make things clearer.

Assume the trust earned income of $100. It paid $22 in UK taxes on the income, leaving $78 for distribution. Barclays was subject separately to tax on the income at a 30% rate as a trust beneficiary, but given an "imputation credit" for the $22 already paid by the trust, for a net tax to Barclays of $8.

The trust distributed the $78 left at the trust level to BB&T after first running the money through the Barclays blocked */ continued page 37*

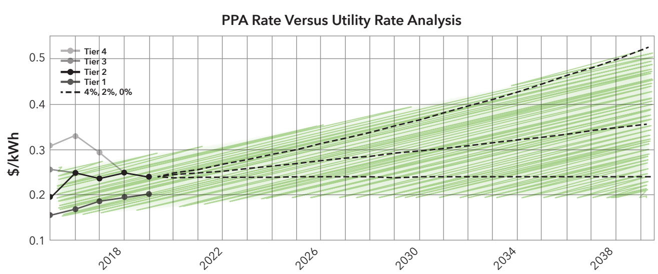
Rooftop Portfolios

continued from page 35

of the contract to manage these situations.

The shaded area in figure 2 is an overlay of sample PPA rates as compared to the proposed decision by the California Public Utilities Commission on rates for Southern California Edison. In this example, a significant number of customer contracts will be underwater by 2019 if the proposed decision is ultimately approved, with the majority of the portfolio upside down by the end of the contract term if utility rates increase at a nominal 2% inflation rate. (Note: The proposals were still under review by the CPUC as of the time of this writing.)

Figure 2



Underwater contracts, contract transfers and operating performances all place more burden on the servicer, and there is historical data on servicing, too. An analysis of default rates and servicing issues is a preview of other hidden risks of a portfolio.

The servicer is the first line of defense in seeing how concerned customers are being managed and the quality of the customer's experience. In mortgages, the value of a mortgage security is a function of not only the underlying assets, but also the quality of the servicer and its ability to deal with upset or delinquent customers. It is commonly accepted in the timeshare industry that the value of a timeshare cash flow stream is partly a function of the originator of the timeshare contract; similarly for solar, there will be variances in default rates depending on the choice of servicer and sales partner. (Was the customer oversold?) In other asset classes, investors rely on industry data to benchmark servicers and managers against one another, and we observe the solar industry starting to do the same. In fact, our data shows that FICO scores are only one component of default risk, and that detailed portfolio analysis can be used to better scope the financial risk in a deal.

The key to enabling these analyses is historical data, and the ability to look beyond a simple average to see the strengths and weaknesses of a diverse, distributed portfolio. Investors are increasingly building in-house capabilities or working with third-party risk management firms to keep tabs on their portfolio performance. Not only is this data management prudent from an asset management and portfolio surveillance perspective, but they also know that this data will increasingly be required for the secondary market. The ratings agencies have continued to push for greater data disclosures about the historical performance of distributed solar portfolios, which has resulted in delayed or cancelled transactions for would-be issuers who are unprepared for the sudden need for quality data management.

Credit Migration

Institutional investors have lots of options for their investments. In the consumer fixed income market, they can buy into investment products backed by residential mortgages, autos, student loans, credit cards, among others — and now solar.

Solar investments are long-dated deals. Most consumer products that are securitized are short-term consumer agreements; for example, the average term for auto deals is 5.5 years and for credit card receivables is usually eight to 10 months. The average term of a solar loan/PPA/lease, by contrast, is 15 to 30 years, which is really long for an unsecured loan and makes some investors uncomfortable. The head of securitized products at Janus Capital Group recently shared with Bloomberg that Janus is unsure of the solar asset class due to the long weighted-average life of the investment. The notable exception is mortgages, which also have a 20 to 30 year term and lead to a robust set of loan-level data sharing requirements.

A solar panel is a great product because its value proposition to the homeowner is clear: as long as the solar system is generating electricity, it is worth at least as much as the electricity being delivered, less the cost of upkeep. It provides a cash flow benefit to the homeowner every single month, in contrast to an auto that may sit in the garage unused. A home with a purchased solar system on the roof is worth more than one without solar.

However, there is an open question regarding the value of a system that has to be removed from the roof. With hardware costs reaching record lows while the costs of customer acquisition, construction labor, permitting and other expenses remain relatively high, most industry observers agree that the salvage value of the underlying collateral is minimal and that, therefore, the most economical solution in the event of a default is a negotiated settlement with the homeowner.

The value on the home is, therefore, a function of system production (kWh) and utility rates ($/kWh). This adds a heavy dose of project finance to the deal: bond repayment requires the system to work, is dependent on utility rates and servicing costs, and has latent warranty risk if manufacturers go bankrupt. The data about these risks are essential to underwriting.

There are no other consumer securitizations that rely on the functioning of an asset for repayment. While there is a lemon law for autos and people do expect their houses to provide shelter, repayment is not directly tied to the miles per gallon of the car or the amount of rain the house shields.

Additionally, the construct of the solar agreement is such that the contract usually stays with the home. People go through divorces, deaths, work transitions, or any of a number of other life events where they need to leave their homes.

We have seen portfolios with double-digit percentages of reassignments in fewer than five years.

A few interesting things may happen when a customer wants to leave his or her home before the end of the contract term. First, the customer will scrutinize the current contract and may choose to renegotiate the contract, particularly if the customer is in an underwater contract. Second, the customer may prepay to buy the system, or pay to move it to a new home. Alternatively, the contract could transfer to the new homeowner, in which case the credit characteristics of the portfolio have just changed.

Although the solar issuer has the authority to reject transfers for poor credits, we see that in practice this is damaging to its reputation and that credit migration does occur over time.

Two, five or 10 years after a deal initially closed, the characteristics of the borrowers in the portfolio may be dramatically different than at inception.

In just a few years, the solar rooftop industry has grown from using "kilowatts" to "megawatts" to "gigawatts" as the unit of measure to quantify growth. Owing to the tremendous volume of projects already deployed, the industry now has valuable information about important risk factors, such as system performance and customer payment performance. Investors are recognizing the importance of mining this data before making investments. ◎

account to give Barclays a tax deduction in the UK for $78 that, at a 30% UK rate, yielded it tax savings of $23.40. The $8 in tax Barclays had to pay was more than offset by this deduction, giving Barclays a net tax savings of $15.40.

The Bx payment by Barclays to BB&T of 51% of the UK taxes at the trust level is $11. Barclays could deduct the $11 against its UK taxes, giving it another $3.30 in tax savings.

The net benefit to Barclays, after factoring in the $11 it had to pay BB&T, was $7.70 for each $100 in earnings.

Meanwhile, BB&T claimed a foreign tax credit in the United States for the $22 in UK taxes paid at the trust level, and it also had interest deductions.

BB&T anticipated making $44 million a year on the deal.

KPMG initially approached the BB&T tax director about the deal in November 2001. The transaction closed in August 2002. Sidley issued a tax opinion in April 2003. PwC advised BB&T on how large a tax reserve it should establish on account of the deal.

The IRS published proposed regulations in March 2007 to prohibit "highly-engineered transactions where the US taxpayer benefits by intentionally subjecting itself to foreign tax." Six days later, BB&T terminated the transaction.

The US appeals court said the trust portion of the deal lacked economic substance under general tax principles. (Congress wrote a version of the economic substance doctrine into the US tax code that applies after the tax years at issue.) However, the court said the loan was real.

Therefore, it denied the foreign tax credits BB&T claimed, but allowed the interest deductions. It also said BB&T had to report the Bx payments as income.

The trust, the court said, was "a contrived transaction performing no economic of business function other than to generate tax benefits."

The lower court had also denied the loan because it said the loan served no purpose but to "camouflage" the tax deal and, stripped of the tax deal, BB&T paid an above-market interest rate on the loan. However, the appeals court said the loan still led to a change / continued page 39

Corporate PPAs

Apple, Facebook, Google, Microsoft, Walmart, Mars, IBM, Amazon, Whirlpool, General Motors and Dow Chemical all announced long-term contracts to buy electricity from utility-scale renewable energy projects in the last year. Power marketers swarm industry conferences looking for capacity to trade. How much potential is there to bypass utilities and deal with their large customers or traders directly?

A panel discussed this question at the Chadbourne global energy & finance conference in June. The panelists are Gary Demasi, director of operations, global infrastructure, at Google, Paul Scanlan, senior program manager of energy strategy at Microsoft, Theresa Perry, global energy and sustainability manager at Cisco Systems, Rob Threlkeld, global manager for renewable energy at General Motors, and Quayle Hodek, founder and CEO of Renewable Choice Energy, which helps Fortune 500 companies buy renewable energy. The moderator is Paul Kaufman with Chadbourne in Los Angeles.

MR. KAUFMAN: How much interest is there among large companies in buying renewable energy directly from the renewable energy companies?

MR. HODEK: We had deal flow of about 400 or 500 megawatts of corporate PPAs in 2013. It more than tripled in 2014 to 1,500 megawatts. Through just the first quarter of this year, we reached half the 2014 volume, so we are on track to double the 2014 volume in 2015 if the first quarter pace remains level for the full year.

There are a lot of different drivers for corporates to be doing long-term renewable energy purchases. There is a sustainability driver and a price hedge driver, and it is rapidly becoming a simple financial decision. Renewables are no longer more expensive than buying from the local utility. Many of these are virtual PPAs that function as hedges against future electricity price hikes.

MS. PERRY: Cisco Systems has had plenty of experience with people coming to us, which has been great. We have also had great experience with people responding to our formal request for proposals. We put out a request for proposals recently and had people knocking on the door to respond to it. Our experience to date has been very favorable. We have had several unique opportunities come to us in terms of the types of deals that people are proposing.

Multiple Structures

MR. KAUFMAN: If you look at the websites for your various companies, there is a range of contractual relationships, from simple power purchases, swaps and differences contracts to even owning facilities and being tax equity investors. Theresa Perry, I noticed that on your website that Cisco is also buying a significant amount of renewable energy credits. Has your form of participation in the renewable energy market changed over time?

MS. PERRY: We are moving away from simply buying RECs and looking for local energy projects that can sell us electricity bundled with RECs or green tags.

MR. KAUFMAN: Rob Threlkeld, your website at General Motors suggests the company is buying power from landfill gas projects. What are your plans to buy more?

MR. THRELKELD: Some of our landfill gas projects go back to 1993. We have a corporate goal of procuring 125 megawatts. We are looking to leverage resources within the communities where we have manufacturing facilities and to drive green energy to those facilities. We actually invested our own capital recently to generate our own electricity from landfill gas and solar.

We are obviously interested in the electricity prices on offer. We signed a large PPA recently with a renewable energy supplier. Offsite procurement is the easiest way to move to a green source and drive stability into our pricing. We did a big deal in Mexico for about 25% of our power with a wind farm, and we are looking seriously at doing the same thing here in the US.

I have global responsibilities, so I am following other markets as well as they evolve. Examples are Brazil and China. We are looking at a potentially diverse portfolio of renewables to serve our far-flung manufacturing facilities.

MR. KAUFMAN: Paul Scanlan, at what is Microsoft looking?

MR. SCANLAN: We are looking at a broad range of opportunities and trying ultimately to find the most efficient engagements in the renewables sector. To date, we have committed to 285 megawatts of new-build utility-scale projects, but we have big REC purchases as well. We are also interested in carbon offsets.

MR. KAUFMAN: Gary Demasi, I owe you an apology. You do not have a beard in your official photo, so I may called you by a different name. I hope the stress from choosing among different renewables proposals has not caused you to stop shaving.

MR. DEMASI: No, just trying something new.

MR. KAUFMAN: So tell us about your plans at Google? Google has been in this market a long time.

MR. DEMASI: We first started in 2009 and 2010 by doing some pretty large fixed-for-floating swaps in the Midwest. It was really one of the fastest ways to move toward carbon neutrality for our large data centers in the region.

We have now contracted for more than 1,000 megawatts of renewable energy globally. We have 13 major data center campuses around the world. They are all in very different markets and so it takes a multifaceted approach.

We continue to do fixed-for-floating swaps. We have done some direct contracting with our utilities. In places like Europe where the market is really deregulated, we have more flexibility to do interesting things.

We are still playing catchup in terms of growth. We are looking at doing more innovative things in the future, such as direct investment in renewable energy facilities.

We have a request for proposals out now and are open to all kinds of structures. We try to be innovative in our space in all respects, and we invite our partners to be as innovative as we are.

Special Challenges

MR. KAUFMAN: Quayle Hodek, contracting with renewable energy companies that are used to dealing with utilities can be an interesting experience. What are the challenges when negotiating such deals? Your experience is vast in this, so give us a sense of what you have seen in all the different sectors.

MR. HODEK: Just starting with the Fortune 500, there are hundreds of companies that either have a 100% renewable energy goal or a carbon reduction goal. The pressure may be coming from the board. It may be coming from customers.

What are the challenges? Most of these companies, even when they are spending hundreds of millions of dollars on electricity, have either been procuring electricity on a short-term basis in the spot market or are buying from the local regulated utility. Entering into a 12-, 15- or 20-year power purchase agreement is a completely different decision for them. It requires a long-term commitment that they have not had to make previously. It requires focusing on everything from avoiding derivative accounting treatment, which is a major piece of this, structuring the deal properly, doing the origination process and making sure they are talking to the right developers with the right projects, understanding local retail sale restrictions, and then making the financial case to the chief financial officer, the executive finance committee, the board or other ultimate internal decision maker, and explaining to Wall Street how this is not taking on more risk for the business, but is actually a hedge or effective hedge against electricity price risk.

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in the economic position of BB&T. BB&T had unrestricted access to $1.5 billion and paid Barclays for use of the money.

The last issue in the case was the penalties.

It is a defense to accuracy-related penalties if the taxpayer had reasonable cause for its position and acted in good faith. BB&T pointed to the tax opinion it had from Sidley that the transaction worked. The lower court said Sidley had an inherent conflict of interest, making reliance on the opinion unreasonable, and the appeals court said this conclusion was not "clearly erroneous," the standard for appeals court review. Sidley had worked with KPMG to develop the structure. KPMG then recommended Sidley to clients using the structure. Sidley sent BB&T a redacted tax opinion about the transaction when it was first engaged, a circumstance, the court said, that "should have raised a red flag that Sidley was not a truly 'independent' advisor" since it had written the opinion on the transaction "before it even started exploring the specific circumstances of the transaction for the client."

PwC did not opine, but ultimately arrived at a "less than should" level of comfort that the IRS would accept the transaction.

The case is *Salem Financial, Inc. v. United States*. The case was heard in the US appeals court for the federal circuit. The decision is the first to address STARS deals at the appeals court level. Oral arguments in two other STARS cases involving AIG and Bank of New York were heard by the US appeals court for the second circuit in May. Decisions in the cases are expected later this year.

The IRS warned in October 2014 that it remains free to pick apart transactions with more than one leg to deny tax benefits on any leg that is tax motivated while allowing the rest of the transaction to stand. The IRS announcement was in Notice 2014-58.

NEBRASKA expanded a nameplate capacity tax on wind farms to apply to solar, biomass and landfill gas projects of 100 kilowatts or more in size in early June. The expanded tax will take effect on January 1, 2016.

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Corporate PPAs

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These deals are not an easy lift for corporates, but they are absolutely where the market is headed. We have been in this business for 14 years. It started with companies showing an interest in promoting greater use of renewable energy by doing some unbundled REC transactions.

The companies today are trying to capture value and are considering the best way to do that, whether it is being an equity investor or the long-term offtaker or participating in some other fashion. I have said enough. Paul, you are nodding.

MR. SCANLAN: Yes. We are focused on trying to find ways to help bring renewables to the grid, and there are many ways to do that, but to Quayle's point, there are many challenges in getting there, both internally and externally.

We are excited about the progress the industry has made. The improvement has just been incredible over the past several years in offtake pricing.

There is still work to be done. Low natural gas prices are a major headwind. One question corporates have to answer when they head down this path is: are they going for sustainability, are they going for economics, or is it some combination of the two? The value proposition is still a challenge in some markets.

Roughly 1,500 megawatts of corporate PPAs were signed in 2014.

For the market ultimately to reach scale, the economics are going to be important. The deals have to make sense economically.

MR. KAUFMAN: Rob Threlkeld, you are in a more traditional manufacturing business. Do you think there are differences in the way that your company looks at renewable energy procurement compared to these other companies?

MR. THRELKELD: We are in a transportation business, manufacturing automobiles. Oil prices dropped dramatically within the last year, and everybody said, "This is going to have a huge impact on your renewables projects."

I asked, "In how many places in the United States are we generating our electricity from oil?"

Obviously, people in our company are tuned into fuel costs and oil and natural gas prices and follow them closely, but they have not thought as deeply about the effect of commodity prices change on electricity or renewable energy. One of our internal challenges is the education process.

One way we are trying to think about renewable energy is as a portfolio of projects, no different than a portfolio of power trains we offer in our vehicles.

Long-term contracts are a challenge because we get into derivative accounting.

The other interesting accounting challenge is dealing with the concept of a variable interest entity. Even though a wind farm is 100 miles or even 1,000 miles away, the accountants say that the fact we are 100% of the offtake means that it creates a capital risk. You have to find an offtake where you are only 50% or less.

MR. KAUFMAN: Theresa Perry, you are nodding your head.

MS. PERRY: Yes. I agree with much of what has been said, especially about the internal struggles of trying to educate upper-level executives who need to approve this after you have found a fantastic deal.

That has really been a difficult thing for us. The other challenge is getting the developer to understand why it is taking so long to get that approval. While we are trying to jump over internal hurdles, the developer is asking, "It's such a great deal. What's the problem? Are you guys upset with the deal?" It is not that at all. It is just a completely foreign business proposition.

We usually try to bring in external expertise to help us. We have done that quite a bit with different projects in different locations because we are a fairly lean team inside.

Internal Evolution

MR. KAUFMAN: Gary Demasi, have you seen a change in the acceptance of renewables inside Google? Tell us a bit about the progression.

MR. DEMASI: When we first started, we were making what seemed a fairly unique request of the market. Developers were accustomed to dealing solely with utilities.

Even proposing initial structures internally was a significant challenge, but our company has had a carbon-neutral pledge since 2007, and so we were given a lot of leeway to be creative in how best to reach this goal.

Luckily, we had a tremendous amount of support all the way up to the C level. We have talked to a lot of peer companies, and we understand there are a lot of hurdles that these other companies face.

We did not face a lot of those hurdles. We certainly had to make sure the accounting was done properly and that we were not triggering any kind of treatment that was undesirable.

We had a lot of support internally. As the company evolves, and as we look for more creative ways to source renewables globally, because we have demonstrated so much success, this has built momentum internally to be open to innovative structures and new approaches.

In addition to the gigawatt-plus that we have procured for our facilities, Google has also invested now more than $2 billion in renewable energy projects globally. The investments are done by a different part of the company, but the commitment to renewable energy is obviously something that is intrinsic to how we do business and something that has a tremendous amount of conviction all the way up to the top.

MR. KAUFMAN: Has the long term of a power purchase agreement, hedge or other contract been an issue for Google?

MR. DEMASI: The answer varies around the world and our contracts have varying terms depending on the location, but obviously term is really important to developers. They need to get these projects financed. We understand that internally, and we also believe that long-term renewable energy makes sense from a cost perspective. We would not do this if we did not believe that it made business sense for the company.

Having long-term price certainty with respect to energy has a tremendous amount of value for a company with a fairly large energy consumption at data centers.

MR. KAUFMAN: Several of you mentioned that renewable energy companies are used to dealing / *continued page 42*

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The tax has applied to wind farms since 2010. It is $3,518 per megawatt of nameplate capacity and must be paid annually. It is imposed in place of personal property taxes that otherwise would be collected on such projects.

MINOR MEMOS. Martin Meyers, director of research at Photon Consulting, said on a UBS conference call in May that he expects US solar module prices in the US to fall to 70¢ a watt in 2015 and to 51¢ a watt by 2019. He expects total solar installations to reach 7,800 megawatts in 2015 and 10,000 megawatts in 2016, and then fall to 7,000 megawatts in 2017, 6,000 megawatts in 2018 as California reaches saturation, and recover to 7,000 megawatts in 2019. A 30% investment credit for solar equipment expires at the end of 2016 . . . . GTM Research reported in June that there were roughly 700,000 individual installed solar systems in the US at the end of the first quarter 2015. SolarCity had approximately 218,000 customers, Sunrun had 79,000 and Vivint had 42,000. GTM says the average cost of a residential solar system in Q1 2015 was $3.48 a watt. That is a 10% reduction from Q1 2014 . . . . Wholesale electricity sales from US wind farms were down 9% in Q1 2015 compared to the year before, according to filings by 87 wind generators with the Federal Energy Regulatory Commission, *Megawatt Daily* reported in June. The trade paper attributed the reduction partly to warm dry weather in California that reduced wind velocities. Wind farms in California were running at an average capacity of just 13% in the first quarter compared to 21% the year before. Wind farms in Texas were running at an average capacity of 27.9% compared to 38% the year before. Wholesale sales of solar electricity were up 68% from the year before, based on filings by 40 utility-scale solar generators. Total solar sales in the first quarter were 3.2 million megawatt hours compared to 36.5 million megawatt hours for wind.

— contributed by Keith Martin in Washington

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mainly with utilities. What difference does this make? How has this affected your negotiations?

MR. SCANLAN: Our negotiations have been a collaborative process. Ultimately we are talking to dozens of parties about different projects, different structures, different opportunities, both domestically and globally.

There are some similarities with their previous utility engagements. I think we are looking at a potential contract very much like the developer is, only we are on the other side of the table. Maybe it takes some new thinking to shift from the utilities space to dealing with corporates, but I see mostly similarities.

MR. KAUFMAN: Rob Threlkeld, to what extent do you guys integrate the developer in your internal discussions?

MR. THRELKELD: At General Motors, although each of the regions has been delegated authority for purchasing, we are the purchasing agent for energy so we are the first point of contact for the company and then we engage the other parties. What I hear internally is, "That's great. You are the first-line contact, but then who else do you plan to involve with that process?"

The answer is I end up involving half a dozen other folks as part of the negotiating team, even though I will be the lead.

We have dollar thresholds for internal approvals. If the purchase commitment will hit $X, then it will take eight people to approve. The term of the contract may also affect the internal approvals required. It is an open, collaborative and transparent process for what it will take to get a deal done.

Obviously there will be internal hurdles. I am going through one now where all of a sudden tax staff got in the middle of something. The issue has to do with what value to assign to a piece of the land. Those things happen. We are open with our counterparties. We might say something like, "There probably is going to be a two week delay." We usually have a pretty good idea how long it will take to get approvals.

MR. HODEK: It is really important to manage expectations out of the gate. You have a developer community that is used to dealing with banks that can move quickly and with utilities and their processes.

When you are working with corporates, it may not be clear who the final decision maker is. Will the deal have to go to the board or can the CFO or CEO sign off? How engaged has that person been already in the discussions? As a buyer's agent for the largest corporates, we try and get everyone in the room together because it ultimately speeds the process.

When we have a list of finalist developers, we bring in everyone: finance, tax, accounting, legal, sustainability, procurement, energy, PR, marketing. Developers need to understand that there are a number of hurdles to get these deals to the finish line. Legal is certainly not the only one.

MR. SCANLAN: One of the challenges we had initially as a technology company is that some of this energy stuff seems exotic and unknown. We worked internally with legal and finance folks and across the whole spectrum, really kind of peeling the onion and getting more comfort and socializing the nature of these deals. We are a major industrial-scale user of energy. Energy is a major part of our business, so socializing that and getting more comfort with these structures was a process, but it has been successful.

Choosing Among Developers

MR. KAUFMAN: When you pick a developer, do you use RFPs or do you use some other process and how do you select the winner? How do you distinguish among developers? Theresa Perry, can you take a stab at that question?

MS. PERRY: We do use an RFP process, and we look at all of the responses. We first vet the developers for such basics as do they have a reputation, do they have enough financial backing to complete the project? After that, we are looking at price point. If they met all our other criteria, we end up evaluating based on price point.

Volume is on track to double in 2015.

MR. KAUFMAN: Is that the price compared to your otherwise available retail rate or price compared to something else?

MS. PERRY: We do a series of calculations. We look at the forward market price over the entire term and do several types of analyses. We are interested in what we would have to pay compared to the price for electricity from alternative sources. Because each of the offers is different –- they have different price escalators, for example –- the offers require modeling. At the end of the day, we are interested in who is offering us the best deal on price.

MR. KAUFMAN: Gary Demasi, how does Google choose among developers?

MR. DEMASI: We have moved to an RFP process with a fairly comprehensive set of deal parameters that work for us. We want to vet for deal parameters early. If you are not creative, then we are probably not the right customer for you.

With respect to the developer, obviously track record is really important. The specific team is really important, and the projects are really important.

With respect to the projects, the things we look at are the quality of the interconnection, permitting, delivery. Where do we want the electricity delivered? Do we want it at a hub or are we willing to take it at the node?

MR. KAUFMAN: When you are looking at the project and the arrangement is a hedge or other financial transaction, does it matter where the project is located? Do you look at the environmental impacts of the project?

MR. DEMASI: We have a set of standards. We consider them to be fairly high standards in terms of which projects that we want to participate in. We look for projects that are reasonably close within the same grid as our data centers. If the electricity cannot be delivered physically to the data center, which is really preferable, we will still want the electricity to be delivered within the same grid.

We have a data center in MISO. We have done projects in MISO. We have a data center in SPP. We have done projects in SPP. We prefer to take physical ownership of the power as well as the renewable energy attributes over a long period of time.

MR. KAUFMAN: What do you do in states where you are not allowed to take direct service? Or are you only locating data centers in states where customer choice is available?

MR. DEMASI: We are certainly constrained by market structure. We have done some interesting things with our utilities, and we have really pushed our utilities hard. For instance, we have worked with Duke Energy at length to help design a green energy tariff that is currently in the pilot stage.

We were able to secure renewable energy directly from our utility in Oklahoma, as an example. We are actively advocating in places where we are constrained by the market structure to have more freedom, to allow everyone to have better access to renewables in a scalable way.

It is not possible everywhere. There are other markets where significant policy changes will have to happen over a period of time before we can get to the kind of procurement and access to renewables that we want.

MR. HODEK: There has been a trend recently toward virtual power purchase agreements. A company might look at its load within North America or within the United States and try to find the best priced renewable asset relative to the current and forward prices of power, and do a fixed-for-floating swap transaction or contract for differences.

Most corporates refer to that as a virtual PPA. The term is more easily understood within their organizations and sounds less scary than a fixed-for-floating swap or a contract for differences. Virtual PPAs really open up the market to all developers to offer projects to a broader audience of potential buyers — to the extent the electricity is aggressively priced.

MR. THRELKELD: I think Gary and Quayle hit the nail on the head. A lot of our facilities have been in place for 30, 40, sometimes 50 years. We rank them on a global basis. We have an A, B and C list of what facilities have the best opportunity to cut electricity costs, whether it is through an RFP or a little more collaboration with the local utility to come up with a rate structure that works for us.

In some cases, it is nearly impossible to do anything. The facilities may be in a countries or utility service territories where there is not much to be done. Those facilities are ranked C. We have plenty to do to work through the A and B lists. Hopefully by the time we have done that, the regulations in places where the C plants are located will have changed.

MR. SCANLAN: For us, geography is important, but a larger consideration is price correlation. We want to find projects with pricing that is ultimately correlated to our larger portfolio. We operate a very diverse and dispersed portfolio, and finding that price correlation is very important.

Another challenge we are encountering in wholesale engagements is the divergence between wholesale and retail pricing in many markets, and there is not necessarily a correlation between the two.

MR. KAUFMAN: Developers who / continued page 44

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enter into traditional PPAs with utilities find the utility is interested in how the project is being built. The utility may have a preference for a particular turbine type. It may have a preference for a lot of things. How much involvement do you have in a developer's development process, construction process, and then operation of the project?

MR. SCANLAN: Partnering with reputable developers is critical, and we have been very fortunate in that regard on our two engagements to date.

Using only tier-one technologies for wind and solar projects is critical, as well. We are only interested in late-stage developments. There is a lot of uncertainty as you go through the development life cycle of a project. We are not interested in committing before the project has reached a late stage of development.

MR. KAUFMAN: Gary Demasi, in cases where Google is taking physical delivery of power, how involved is it in how the project is built and later operated?

MR. DEMASI: We are not all that different from the way a utility looks at it. We very much care about the delivery of the project. We put a lot of work into it. It takes a lot of resources to negotiate a long-term power purchase agreement, so we care about it actually being delivered.

The PPA will have performance criteria in it, milestones, things like that. We try to pick quality projects that we are confident will get delivered with quality developers.

In terms of the operations, absolutely we care. We look at the quality of the technology. We look very closely at the financial models that are being developed in support of the project. O&M is an important part of that. The O&M plan is important to us.

MR. KAUFMAN: With the traditional utility PPA, the utility sends the PPA. The project finds its own financing. There may be some discussion about consents in the process of the financing. Is that the level of involvement you have in the financing process or have you found yourself drawn in further than that?

MR. DEMASI: That is essentially the level.

MR. KAUFMAN: Rob Threlkeld, how does General Motors approach these issues?

MR. THRELKELD: We deal pretty much with tier-one suppliers. We were involved with some solar projects in 2004 and 2005 where we got burned on a couple issues. We have come a long way understanding the technology and working with the tier-one suppliers. We have periodic meetings with our suppliers.

We have a lot of electrical expertise in house because our factories can run to a 30-megawatt load. We can offer that expertise to work collaboratively with our suppliers. If we work together hand in hand, the project will be successful. We like to understand the permitting and confirm that the environmental impact studies were done. We do diligence to ensure we are protecting the environment as well as sourcing green power to our facilities.

MS. PERRY: We like to know what is happening. We ask the right questions, but we are not driving how the developer does his job. We are just making sure that we are comfortable with the way he does it.

Audience Questions

MR. KAUFMAN: Audience questions?

MR. SCAYSBROOK: David Scaysbrook with Private Energy Partners. How do you distinguish in your procurement between greenfield projects and brand new construction?

MR. SCANLAN: At Microsoft, we have been focused on new-build projects bringing new renewable energy to the grid. We feel like that provides the most value to the industry.

MR. HODEK: We see other corporates taking similar positions. The large corporates are focusing on getting new assets built, but there is also an economic element. There may not be as big of a delta or potential savings for the offtaker on existing assets, so we are seeing a lot of new development.

MR. DEMASI: The only thing that I would add is our team just contracted to repower part of an Altamont Pass wind farm for our

One challenge is how to avoid derivative accounting treatment that requires contracts to be marked each year to market.

headquarters facility. There is the potential to upgrade some existing wind farms to be more productive.

MR. SAXENA: Himanshu Saxena from Starwood Energy Group. We support a number of developers, and those are the developers that come to you for PPA discussions. I am curious about your strategies when and if production tax credits expire for wind projects. The price for power would have to go up by at least $23 a megawatt hour. Will that change significantly what you procure going forward?

MR. THRELKELD: Obviously it will have some impact in the United States, but will not affect what we do in other markets. China is our largest market. Brazil is our largest South American market. Section 111(d) issues are another area where US policy could affect our procurements of domestic renewable energy.

MR. HODEK: PTC expiration is a major issue. We see corporates looking at solar opportunities alongside wind as a consequence of that. They are watching the cost curves very carefully. For a corporate trying to get its first deal done, the deal needs to be a slam dunk financially. It will be more challenging without the PTC.

MR. BARCOTT: Rye Barcott from Double Time Capital. Could you speak a little bit about any GAAP accounting considerations that you need to address and how you address those with CFOs and the accounting teams?

MR. HODEK: I suspect everyone on this panel deals with it a little differently.

The main thing that companies try to avoid is triggering derivative treatment where they have to mark a contract to market. There are ways to avoid such treatment. One way is to do a physical transaction with your utility partner or on your own if you plan to put a FERC license in place.

Some companies prefer to treat power purchase agreements as leases, so they structure the contract to allow such treatment.

It can be a heavy lift within organizations to figure out what is acceptable on the accounting side and then how to make that work with the sponsors and the tax equity community in a transaction that can get financed and built.

MR. KAUFMAN: Keith Martin.

MR. MARTIN: Let me ask two questions briefly. First, do you care whether the project is solar, wind, geothermal, landfill gas? Second, you have a lot of eager renewables developers in this audience who are eager to pick off a large utility customer. Are the utilities approaching you with special deals?

MR. DEMASI: Wind has been the most competitive from a price perspective, which is why we have done a lot of projects in the Midwest as well as Europe, but we are agnostic. We think there is a great opportunity in solar for Google moving forward. We just have not done a major solar project yet. Certainly we are open to other kinds of renewables.

MR. SCANLAN: It is the same for us. We are looking ultimately for the greatest value propositions, regardless of the technology.

MR. MARTIN: Are the utilities offering special deals to hold you in place as a customer?

MR. THRELKELD: Interestingly enough, yes. Michigan, our home base, is like an island. We have two utilities, Detroit Edison and Consumers, that are investor-owned, and each has approached us after seeing what we have done in other locations, asking how they might work with us to hold down electricity costs.

We are having some discussions with them about how we can structure deals to support the renewable energy industry and keep the rates level for everyone, not just a specific corporation getting a special deal.

Yield Co-Induced Highs

Yield cos are driving up asset valuations. Are they a fad or here to stay? Can yield cos maintain current growth rates? What happens if they cannot? Will developers without affiliated yield cos be at a competitive disadvantage when bidding for power contracts?

Chadbourne hosted a lively debate on the topic in June. The debaters are Stephen Herman, managing director of Energy Capital Partners, and Wyatt Wachtel, managing director of York Capital Management, for the view that yield cos will remain a permanent feature of the power industry landscape, and Paul Segal, CEO of LS Power, and Ed Feo, co-founder and president of Coronal Group, arguing that they are a temporary phenomenon.

An audience vote before the debate showed 52% of the audience viewing yield cos favorably and 48% not so favorably. The moderator is Kenneth Hansen with Chadbourne in Washington.

MR. HANSEN: The precise topic on which we have focused the debate is, “Resolved: Yield cos are not a fad, but are here to stay.” Steve Herman, you have up to five minutes to make an opening statement in favor of the resolution. */ continued page 46*

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Large Growth Potential

MR. HERMAN: My job is to convince the naysayers to turn around and be in a position to make a lot of money. I would like you to think back to the 2007, 2008 and 2009 time period, when hydraulic fracturing, known as fracking, was getting off the ground.

How many of you in this audience saw the potential for that activity to change the entire energy industry? One. Well, you should not be here because you should have invested and have been off somewhere by now enjoying all your money.

Most of us did not see the potential. I submit that the formation of yield cos and this financial vehicle will transform energy finance in a major way, and for those who do not take advantage of yield cos, they will leave on the table a tremendous amount of value for others to collect.

I want briefly to describe what a yield co does and where the real value in the yield co is, and where it unlocks not phantom value, not investment banker-type value, but real value.

At the top you have a sponsor. The sponsor can be an independent power company. It can be a private equity fund. It can be a development company. It forms a yield co and sells some of the equity of the yield co to the public market. The other part of the equity continues to be held by the sponsor. The yield co will remain controlled by the sponsor even after the public offering.

The sponsor drops down assets to the yield co. Over time the yield co pays for those assets. The sponsor is paid the value of the assets.

What is the appeal to the public market?

It is a unique appeal that no other security, other than a master limited partnership, really fulfills, and that is the investors get a relatively stable distribution with a large potential for growth over time in the distribution and that growth is visible, unlike an ordinary equity, say, General Electric or IBM. I would not call the growth certain, but it is reasonably visible.

The reason is the sponsor has a large number of assets that over time it can drop down to the yield co and create more income distribution for the yield co, which the sponsor will do because the sponsor still owns a lot of that equity.

That is the real benefit. There is no other asset class that the public can buy that meets that criteria. That is very important in a time period in which yields are very low. At least in the western world, growth rates are projected to remain low.

So you see benefits to the sponsors. You see benefits to the public investors.

What happens if interest rates rise? Are yield cos going to crash?

The data shows otherwise. If you look at MLPs, which are the closest analogy to yield cos, and you look back at their long track record, MLPs have not fared badly in a period of rising interest rates on a relative basis compared to utility equities or REITs or anything else.

Why? Because they have that growth element to them. In fact, yield cos should not be called yield cos. They are really growth cos.

Another point: where is this growth going to come from? Will yield cos just compete for a limited number of assets and drive the asset prices up so that we have a bubble?

No. The potential class of yield co assets is tremendous. Even if you look at just what has been done to date. RBC Capital, which put out an excellent report at the end of April said that yield cos have only tapped 10% of the renewable energy market. But the growth is going to come not just from renewables. Traditional power assets are a potential asset class. Transmission assets are another.

TerraForm is now bringing in overseas assets. The RBC report projected that by 2030, $6.3 trillion in assets will qualify for yield cos.

MR. HANSEN: Thank you, Steve Herman. Speaking in opposition to the proposition, we have initially Paul Segal for five minutes.

Law of Large Numbers

MR. SEGAL: Steve Herman did a great job of laying out the proposition. These are companies that are supposed to buy or own high-quality, contracted cash flows and distribute those cash flows to their owners and investors, and they are supposed to grow that cash flow yield significantly over time.

The basic difference between MLPs and REITS is that these are taxable entities, but investors, at least at this point, are willing to ignore that distinction in large part due to the promise of very significant growth and the promise that the underlying assets supporting that significant growth will be of very high quality. They will generate cash flows under long-term contracts. That is the basic covenant between the investor and the yield co.

If investors stop providing the yield cos with a highly-priced currency so that they can do acquisitions and grow, that structure falls down, and if yield cos cannot provide the growth, or perhaps move up the risk curve, then the investors may run away.

It is important to step back and see how we got here and talk about whether or not that basic relationship is a durable one. It is less than two years since NRG basically did the first power yield co.

Since then, by the end of 2014, the big six power-related yield cos — NRG, NextEra, Pattern, TerraForm, TransAlta and Abengoa — have now over a $17 billion equity market cap.

From a financial metrics perspective, that translates into a roughly 5% 2015 cash-flow-available-for-distribution yield and a roughly 4% dividend yield. The markets are accepting these low yields, in one part because overall alternative investments are also yielding very low rates, but also because they expect 15% compound annual growth, at least that is what the market has been told to expect by the sell-side and management teams.

It is important to explore whether or not that is sustainable. The underlying assets that most of these companies own do not inherently grow cash flow. The assets have stable and in some cases declining cash flows, and so these companies need to rely on acquisitions.

If you look at that $17 billion equity market cap and the current financial metrics, these companies would need to buy roughly $6 billion worth of equity value in high quality contracted assets in 2015. When you move that forward into 2016, to achieve that 15% growth rate, that number becomes $15 billion and, by 2017, it becomes about $150 billion. These are astronomical numbers, and I think none of us believes such a staggering volume of acquisitions is likely without one thing: moving way down the risk curve.

When we look at single asset transactions, we are not seeing, outside of drop downs, many yield cos being the preferred or winning bidder on assets. Instead, what we see yield cos do is one of two things. They are buying large portfolios that usually have a development component, and they are participating in sponsor drop downs.

Why are they playing here as opposed to playing in the single asset, fairly transparent opportunities? It is primarily because in the large portfolio transactions, they are able to allocate value between the yield co and the sponsor, where the sponsor allocates any incremental value in excess of what it would take for the underlying transaction to be accretive for the yield co so that the yield co can hit its growth targets.

That ignores the fact that allocating that value will make it very difficult to re-contract those assets at an accretive price that will allow the assets to be dropped down to the yield co on an accretive basis.

The yield cos are also participating in drop downs. Those drop downs at this point are still benefitting from a much more robust contracting environment from a few years ago, and as those assets make their way through the drop-down pipeline and are transferred to the yield cos, they need to be replaced. The current contracting opportunities are much less lucrative.

Yield cos offer investors reasonably visible growth in future cash distributions.

So where do yield cos go from here? They will turn increasingly to emerging markets where they will take on more risk to get their yields.

They will move down the curve in terms of contract duration, perhaps moving to a place where contracts do not matter that much any more. And the question really becomes how long are investors willing to put up with that?

The growth is achievable, assuming that the investors are prepared to give up on a construct that was premised on long-term contracted cash flows. If the investors give up on that concept and accept that this growth can come from anywhere, then the yield cos can continue to buy assets accretively and grow. Otherwise, I believe that this structure will quickly disappoint.

MR. HANSEN: Thank you. With a follow-up statement in favor of the proposition, Wyatt Wachtel. */ continued page 48*

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Momentum Investor

MR. WACHTEL: As a momentum investor, I do not need to convince the other side of anything. I just need to convince you in the audience to buy more.

Let me first give a disclaimer. We are an anchor investor behind Everstream in the new TerraForm Global Emerging Markets yield co, so as somebody who has to answer to his boss every day, I had better believe my story.

This debate is couched as a discussion about yield cos, but it really fundamentally is a question of whether you believe in renewables. If you look at the size and the opportunity of renewables, this product has to go somewhere.

The current dividend yields of the various yield cos vary depending on how credible the market views each growth story.

It can sit within a large corporation or a large utility. However, when you look at the fundamentals of corporate finance and how to unlock value, the assets have to go somewhere outside of the developer. The natural home for them is in a yield co or an MLP.

The yield co structure is incredibly efficient. There will be mistakes made. Paul Segal made the point earlier about yields becoming very tight. I absolutely agree, particularly in the United States. They are tight and will continue to tighten, and mistakes will be made given new technology.

If you look back at the history of new financial technology, things like CDOs, CLOs, MLPs, they have all gone through periods of dislocation. However, as a product, yield cos make sense because this product specifically, unlike MLPs, has the ability to retain earnings, which gives it the ultimate amount of flexibility.

The one thing that will need eventually to shift is the holders of most of the yield cos are momentum investors, hedge funds such as myself. Because the yields are low and they view this as a growth story, these investors are not buying the yield. Eventually this will have to shift. A key metric for success for yield cos will be when you start to see more traditional, long-only investors come into this product.

Part of that will be driven by a longer-term track record and transparency, which is absolutely critical for a lot of these long-only investors, and the flexibility. When the long-only investors look at it from a portfolio-managed perspective, the ability to put multiple asset classes in yield cos will allow much more consistency in earnings and visibility on earnings.

So my view as an investor in this space is I view yield cos as a very efficient, tax-efficient means of investing. I view them as a basic corporate finance vehicle that is very efficient in terms of unlocking value. I view them as something that, so long as there is transparency, will start to attract more traditional investors which will support the values of the yield cos and, in turn, unlock value in more projects for the developers allowing them more quickly to recycle cash.

MR. HANSEN: Thank you very much. With that, I would like to turn to Ed Feo for an opening statement in opposition.

Investment Banker's Dream

MR. FEO: Yield cos are yet another piece in a long and honorable tradition of Wall Street dreaming up schemes for companies to move assets from point A to point B to generate investment banking fees. That is what this is about.

Before yield cos, the assets we are talking about arranged their equity through long-term investors — insurance companies, pension funds, funds that had funds from those folks — and they would hire people who would look at these assets and carefully evaluate the risks and think about the tenor of the investment. They would match the investment with the life of the asset and price it accordingly.

What yield cos do is say, "Let's jump the hedge. Let's go to the yield-starved public investor, those twitchy folks out there in the boondocks on Scottrade, and let's sell them these assets on the following proposition: We will pay you a really crummy cash payment, on the one hand, but on the other hand, we are going to give you really monster growth."

We have all heard about how the growth story is going to work. Is there anybody here who thinks that that guy on Scottrade in Lompoc knows more about these assets than, say, Grant Davis?

My co-debater, Paul Segal, has highlighted the squeeze that will occur with yield cos. To be fair, we have to differentiate between the two types of yield cos.

The first group includes the guys with megawatts in a cupboard. We know who they are. They are going to do the drop downs. They have seasoned assets. Drop them down. Create managed growth.

And then you have the other group, which is the got-to-grow group. They have no assets, but they have to buy them or develop them. The got-to-grow group is already out in the market and it is already in trouble because it has already bid up asset values, so each deal it does is less accretive than the last, and almost as importantly, this group has effectively told the market where the bottom is.

Where has this led? Developers are out doing power contracts with assumed capital costs of something like 6%. So the next deal the yield cos do will even be less accretive. And, of course, we can think of exogenous events, such as interest rates going up. Add to that the law of big numbers that Paul mentioned, and the return squeeze will occur.

Every deal will be less attractive and will have a harder and harder time to make the numbers work. So the yield cos will do what Paul described, which is they will go back to the S-1 and say: "Wait a minute. Yes, we did say we are going to do long-term contracts with investment-grade entities, but it says we can do other stuff. So we are now doing merchant deals in Rwanda."

Or the yield co will say, "The offering prospectus says we can do energy-related transactions, so we talked to our friends at Chadbourne and they said, 'That can be interpreted broadly.' Solar energy through photosynthesis creates wood. Wood, with the energy of saws and hammers, creates furniture. Well, we bought a furniture factory servicing the Burundi market. That's our new market. High yield."

We have all seen this before. Somebody will blow up. Somebody will push it too far and when one of these guys blows up, the whole sector will be tainted, the public investors will run for the exits, and the spiral will start.

We have these two classes of yield cos and I want to differentiate between them, because I do not want you to think that I am biased or that I have not thought about this.

The got-to-grow group will do what drowning people always do. They will glom onto each other. In Wall Street speak, they will do "strategic combinations." And to their aid will come opportunity folks who will explore the opportunity of separating those funds from their assets at a steep discount, and they will consolidate that side of the market.

The other side of the market, the fellows with a lot of seasoned megawatts in the cupboard, will say, "We are immune." But they will not be. The cost to keep the game going will have to be a higher cash payment and a better overall return. The sponsor will then look at every drop down and say, "Hmm, this does not look so good."

While they are in that quandary, the investment bankers who sold them the deal in the first place will come back and say, "Wait a minute. Do a stock buyback. Don't keep this thing alive. You sold it for a dollar, buy it back for 50¢. It's a slight premium over the public market. Those investors will be ecstatic. They have already gotten hammered. The market is going to pay them 46¢, you pay them 50¢. They are gone."

And so, ladies and gentlemen, those two circles will combine and all these assets will go back to the private hands where they started. It is all one big circle.

MR. HANSEN: Nicely done. At this point we are going to turn to some Q&A within the panel. Steve Herman, might you have a question for Ed Feo?

Real or Sham Growth?

MR. HERMAN: I do. I heard a couple things that I could not quite put together. On one hand, you said that the investors in yield cos were very sophisticated hedge funds and, at other times, you referred to them as Scottrade traders.

But, whatever kind of investor, can you think of another asset class where the growth, at least in the intermediate term, is absolutely locked in?

The sponsor has the assets. The assets have a predictable cash flow. The yield co has a right of first offer on the assets. The sponsor has an incentive to sell them to the yield co because the sponsor owns part of the equity and may even have something called incentive distribution rights.

So can you think of another asset class, / continued page 50

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if you were a public investor, where you can see almost certain visible growth in cash distributions?

MR. FEO: The distinction I was making was between sophisticated investors such as pension funds and insurance companies and the very skilled people they hire, some of whom are here today with us, who really know how to evaluate these assets and properly price an equity investment in those versus the yield co which is essentially providing liquidity to a public investor.

Liquidity is the one thing that it provides in exchange for what is essentially a negligible return, but somewhat more than the negligible return you might get from treasuries.

The growth story is a bit of a sham, frankly. The drop down mechanism is not growth. That is just moving assets from point A to point B, still controlled by the same people, and just taking some money off the table from the public investor.

Is there another asset class? I would rather invest in a REIT because I can look at a market that has matured with real growth and not manufactured growth.

MR. HANSEN: Paul Segal, will you have a question for Wyatt Wachtel?

MR. SEGAL: You mentioned the tax efficiency of this structure. One of the things that I scratch my head about is that seems to work fine as long as growth is continuing at a very rapid pace.

If growth were to stop or pause or the markets were to become diverted, what happens in that case? The yield co is a C corp. It has accelerated MACRS depreciation. It has tax credits. What happens when the tax attributes run off, and how do investors think about that?

MR. WACHTEL: From an investor standpoint, I look beyond the tax credits because expiration is coming up on us quickly. If you believe in renewables and the size of the market, then yield cos are a sensible investment. I am not saying that yield cos will not hit periods of bumps because they are a newer technology. What will ultimately happen in the event that growth slows is you will see different investors rotating into this stock. You will see a different type of investor. It is no different than any other stock.

Sometimes stocks go from growth into different points in the lifecycle, and you will see shifts in the investor base. It happened for Microsoft. Microsoft moved from a growth stock into a large cap dividend-type of stock. You will eventually see that in yield cos.

You will see a re-pricing and a shift. But, in my view, that is very far off in the distance. Given what is happening in the energy space, I do not think you need to go to Rwanda or Burundi to grow your portfolio.

You can go to developed markets. You can go to the likes of Japan. You can go to the likes of other parts in Asia. You can go to China, India, and other markets like that may not be fully developed. If you have been to China and have seen the amount that is going on, you have a clear view to growth for the next five, 10, 15 years.

And then when you add on what in my view will happen to a number of utilities and how they will ultimately have to hive off different parts of their businesses to unlock value, to maintain their dividends, moving transmission into other types of structures that are more efficient, I just see a longer-term growth pattern.

MR. HANSEN: Wyatt Wachtel, might you have a question for Paul Segal?

Corporate Finance 101

MR. WACHTEL: Points were made earlier that private investors ultimately should be the most appropriate owners. How does that reconcile with corporate finance 101, which suggests that a public currency is always cheaper than a private currency? How can a private currency ultimately compete for these assets with a lower-cost public currency?

MR. SEGAL: Many of the tax attributes for renewable businesses, particularly here in the United States, are best used by C corps or individuals who can use them efficiently. If they are stuck in a publicly-traded yield co and used over the course of nine years instead of an average life of two, there should be a very different cost assigned to that capital.

Many of the investors in yield cos are ignoring the fact that depreciation is great on the front end. It sucks five or 10 years out in the future when you have to pay that money back, assuming that you get into a world where you actually have to pay your creditors back, which many of the yield cos are using as a convenient tool to optimize front-end cash flow available for distribution.

We are not seeing a lot of amortizing debt in these structures. We are seeing bullets. Bullets are great because you do not have to pay back the principal. The yield cos are optimized to maximize that very near-term metric. That very near-term metric becomes very difficult to sustain absent growth.

MR. HANSEN: Thank you. Ed Feo, do you have any questions for Steve Herman?

MR. FEO: I do. Steve, you are in the business of investing in energy assets and you have investors and you undoubtedly have a target rate of return. The interesting thing about the yield cos is the high returns being projected on contracted assets. What, in your view, is the appropriate level of return associated with this asset class, even in a public vehicle?

MR. HERMAN: You are looking at yield cos, if I have it right, that are currently trading at about six times EBITDA. You see public sponsors maybe targeting 13 times EBITDA, so you are trying to get that arbitrage. We do not have a yield co yet.

MR. FEO: Where is your S-1 by the way? [Laughter.]

MR. HERMAN: We have an MLP, which is similar, but I would like to submit that yield cos are better because MLPs can only invest in certain limited types of assets. Yield cos can invest across the board in anything, but a lot of MLPs have done extremely well and the public investors of the yield cos have done very well. They are more than satisfied.

MR. HANSEN: Wyatt Wachtel, I would like to invite you to ask a question of Ed Feo.

MR. WACHTEL: I am struggling with the concept of how this is different than an MLP. I understand there are tax attributes that are specific to this asset class, but the MLPs out have withstood the test of time.

This vehicle has the ability effectively to retain earnings because it is a C corp. What is the difference between the MLPs and this, given the track record and the history of MLPs, albeit there have been some blowups at various points in time in the MLP space, but by and large, MLPs have been proven to work.

MR. FEO: MLPs have a long track record. They have worked their way through whatever issues they had from their early days.

There is a lot more variability in the MLP market, in terms of the kinds of investments that are available, whether it is a growth vehicle or a low-growth vehicle, and the kinds of assets they invest in. The fact that it is a deeper market and broader product mix helps avoid the kind of catastrophic event I described because you can, you know, put things in different places and you are selling to different markets.

While MLPs are limited in what they can invest in, they are dealing with an asset class that is gargantuan.

Renewables are a good asset class. I don't have any doubts about that, but is the asset class as large as what the MLP market can get its hands on?

We're having fun here. The reality is yield cos make sense, but there will be teething issues. They are relatively new and the risk is that people will push the envelope and, if somebody blows up, it will set back the whole sector. MLPs have been around for 20 years.

MR. HANSEN: Ed Feo, would you like to respond with a question to Wyatt Wachtel?

MR. FEO: I know a little bit about hedge funds. My question for you is: which of the yield co stocks are you shorting? [Laughter.]

MR. HANSEN: Wyatt, you have up to three minutes. [Laughter.]

MR. WACHTEL: If you knew York very well, you would understand. We are long and strong just about everything. We are not very good at shorting stocks and so we are not short any yield cos.

With that said, I am able to traverse between publics and privates, and I view our private side effectively as a positive carry short on a number of utilities. That is about as close as we get to a short. We are only really short when we have positive carry. Otherwise, the market could whipsaw us too hard, and we have learned our lesson over the past 23 years, that sometimes that whipsaw can be vicious.

MR. HANSEN: Steve Herman, do you have a question for Paul Segal?

MR. HERMAN: Paul, forgive me as I am going to get very personal with you. I view LS Power as one of the best, if not the very best, developers in the United States. One of the great things that you have done is you were forging ahead in transmission development and, in my opinion, you have one of the very best developers, Sharon Segner, leading that effort.

Given your track record, you are going one day to make some money on this and develop lots of transmission assets. Why wouldn't you consider putting those assets in a yield co? Wouldn't that give you much more value? Why are you going to ignore that as a potential way to reap the rewards of your hard work?

MR. SEGAL: Steve, thank you for the very nice comments about the organization. I want to hit on a couple things quickly, and then I will answer your question directly.

A big difference between MLPs and yield cos is what has been sold to the investors. The concept is that we are not going to do anything under a 10-year contracted life and that we are going to be buying high-quality cash flows.

Once you abandon that concept, the whole universe opens up very broadly and there is no reason why Calpine or Dynegy or NRG parent are not yield cos or could not become yield cos overnight.

So if that is the concept, yes, the whole universe opens up and assuming that investors do not care about the shift in focus, you may well be right.

I submit that investors will care. When / *continued page 52*

Yield Cos

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you look at the refining MLPs, those trade very differently. Drilling MLPs trade very differently than the less risky pipeline MLPs.

Back to transmission and maybe some of our own personal motivations: we are a flow-through entity and in the environment that we have been living in with MACRS and bonus depreciation, there is nobody who will be better situated to use those tax benefits than us. Once we develop a project and take those tax benefits, we sure are not going to trigger recapture by selling them to a yield co.

REITS are different. There are a lot of really interesting structures that you can undertake with a REIT to defer the tax consequences of transferring those types of assets. So the underlying yield co structure is less advantageous than REITS and the way that it has been advertised to investors is very different than MLPs.

MR. HANSEN: For the final question of our structured round, Paul Segal, do you have a question for Steve Herman?

MR. SEGAL: Why do you think the universe will be so big and investors will be willing to tolerate the shift in concept in terms of target acquisition opportunities?

MR. HERMAN: You can start with renewables. If you think the renewables sector is going to grow, it will remain a great source of projects for yield cos.

There are plenty of traditional power assets with long-term contracts. That is another an area of potential growth.

I have a lot of confidence in the creativity of the hedge market to open up merchant assets, just like the creativity on the fracking side. It was creativity and it continues to be creativity that drives this sector.

One day, you will either have your own yield co or sell your so-called merchant hedge projects to yield cos. I look at other asset classes: transmission, for example. I don't want to take time, but I can make an argument that transmission belongs more appropriately in a yield co than it does in a REIT and it certainly has a defined revenue stream.

Going to other parts of the world, there is political risk there, sure, but there is also such risk in the United States. We have all been bitten by California political risk, New York political risk, New England political risk, manipulating capacity markets.

I could argue in other parts of the world there is no more political risk than there is in the United States, so that is another big area of growth.

MR. HANSEN: Okay, thank you. A whole new debate topic. We are going to move now a little more informally to questions from the audience.

Deer in the Headlights

MR. FONG: Christian Fong with Renewable Energy Trust. Sponsors were trading at a dollar or two. With the advent of yield cos, they are up 10 or 20 times. Liquidity was a huge concern, and yield cos are a great vehicle to add liquidity.

Fast forward. There is no lack of liquidity. What happens to the sponsor's share price if the yield co cannot keep up the growth or it is going to be taken private or those sorts of events? Just walk through how the dominoes will fall leading to that sort of event and how it affects the developers.

MR. FEO: Here is the scenario. Market conditions change, the Fed increases interest rates, people are reevaluating risk and repricing structures. At that point in time, let's say the underlying business for the yield cos is still fine, the underlying assets are working.

It becomes increasingly difficult to buy the incremental asset at an attractive rate of return. The drop downs get exhausted.

The acquisition machine begins to fail because you don't have an accretive currency with which to do those acquisitions. A couple of years go by, and all of the front end-loaded tax depreciation begins to reverse. These

The law of large numbers means that to maintain high annual growth will require buying lots more assets each year than the year before.

companies now have to pay real taxes on earnings. Dividends begin to get cut, and prices of the yield cos come down.

The healthier sponsors will say this was an excellent exercise in raising capital. They may now go out and take a longer-term view on the underlying assets and buy them back, and I think others will be deer in the headlights.

MR. HANSEN: Any thoughts from the other side?

MR. HERMAN: In any investment, you can come up with a horrible set of assumptions. I don't criticize you for that. I have overstated things as a way of framing issues in the debate. I see more greys than I have let on today.

MR. HANSEN: Keep that in mind when you vote after we are done here. [Laughter.]

MR. HERMAN: Right, right, but you could posit horribles in any situation.

I could posit a horrible for your financing of these merchant plants where we have hyperinflation and you have not locked in your long-term service agreements or your O&M or anything else, and the debt goes to hell in a hand basket.

Look, you have to take risks to do business. Given the spectrum of risk taking, the reason yield cos will grow and be very attractive is because they offer less risk both to the sponsor and the investor, maybe not the hyperinflationary environment, but we may all be dead in a hyperinflationary environment.

MR. HANSEN: Further question from the floor?

MR. HO: Paul Ho from Hudson Clean Energy Partners. It strikes me that the yield co acquisitions will stop when the true cost of capital for a yield co – not the dividend rate, but the true cost of capital — exceeds the rate of return on the assets being purchased.

Given the degree to which competition has driven down asset yields and how big of a delta there is today, at what point could there be a switch over when the cost of capital exceeds the available asset yield?

MR. HANSEN: Volunteers?

MR. FEO: I think we are there.

MR. HERMAN: I don't think we are there because the market is saying otherwise. I am sure there are people in this room, including the guys standing in the back of the room, who are working on new yield cos as we speak and the new yield cos are going to be even more creative than the ones before. You have to put your money somewhere. And what is the alternative? Do you want to put it in a public utility?

MR. WACHTEL: I think ultimately the way this market will evolve is it is going to be like flavors of ice cream. You will have somebody who likes higher risk, somebody who likes lower risk, and you will have everything in between.

MR. HANSEN: With that, I think it is time again to vote. I see our counters are in place. Let's see whether there has been a shift as a function of the discussion this morning. Counters have it? [Pause]

So who was the one person who changed his or her mind? [Laughter.] We went from a two vote majority for the view that yield cos are here to stay to a three vote majority.

Community Solar: The Next Big Thing?

Community solar is gaining ground with the 49% to 80% of utility customers who are not candidates for rooftop solar. How does it work, why has it taken root to date only in eight states and what is its potential?

A panel answered these and other questions at the Chadbourne global energy & finance conference in June. The panelists are David Amster-Olszewski, founder and CEO of SunShare, Mark Boyer, chief capital officer of Clean Energy Collective, David Feldman, senior financial analyst with the National Renewable Energy Laboratory and author of a paper on community solar business models, Steven Miriani, general counsel of SoCore Energy, and Erik Stuebe, co-founder and president of Ecoplexus. The moderator is John Marciano with Chadbourne in Washington.

MR. MARCIANO: What is community solar? The term means different things to different people.

MR. BOYER: At Clean Energy Collective, we define community solar as building utility-scale solar arrays that are interconnected to the grid. The electricity from the project is sold to the local utility. Customers of the local utility can purchase as little as a single panel worth of the project all the way up to a large industrial customer who may want to participate in half the project. The customers receive bill credits for the electricity sold to the utility from the project. The credits can be used to offset what they owe the local utility for the electricity they buy from the local utility.

MR. MARCIANO: You might have many people with ownership shares in the project or you might have just one or two.

MR. BOYER: We average about 300 per facility.

MR. MARCIANO: Some people describe */ continued page 54*

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such projects as a form of virtual remote net metering.

MR. BOYER: That's correct.

MR. MARCIANO: David Amster-Olszewski, what form of participation do your customers have in such projects? Do they own individual panels?

MR. AMSTER-OLSZEWSKI: Mark gave a great summary. Our customers are everything from individuals —- I am a participant, our employees are participants — all the way up to the city of Denver and the University of Colorado. They are everything from large AA and AAA credit quality customers to residential customers with a 700+ FICO score. The business model is similar to SolarCity's business model. The only difference is we take the panels off the roof, put them in a field, reduce the system cost, dramatically reduce the customer acquisition cost, and increase the market potential by five times because there is no appliance on the roof and there is no shading issue.

Community solar really is something that brings solar to the masses with large projects. Rather than have a thousand households with a thousands systems, you can have a thousand households and large customers all in one project where you control the assets.

MR. MARCIANO: I believe community solar works currently in eight states. What makes a state a good state for community solar?

MR. FELDMAN: There are actually nine or 10 states that have passed some sort of legislation to facilitate community solar. The authorizing legislation usually takes one of three forms. There could be some form of virtual net metering regulation that allows customers to get credits on their bills for generation from something that is not connected to their meters. There are also incentives that provide money or some other form of inducement to share ownership of a community solar project. Then there is a third type of legislation that is more comprehensive in trying to advance community solar rather than just allowing things to develop on their own.

There are other states that do not have legislation, but where utilities may be interested in promoting these types of projects as an alternative to net metering. All you need in those states is to work out some of bill credit mechanism. It may not require legislation.

Utility Response

MR. MARCIANO: Why would a utility be interested in promoting such projects?

MR. FELDMAN: They have a lot more control over the assets. They potentially have a lot more control over the rates. The utility does not lose its customers. It can still charge the full retail rates. The bill credit is for the wholesale rate. The project can be put in a more ideal location than on the customers' roofs. A larger project has the potential to generate electricity more cheaply.

MR. STUEBE: Truth be told, utilities are generally resistant to community solar just as they have been resistant to net metering. It is inherently in conflict with their business model which involves earning a regulated return on invested capital. The fact that the project is owned by a third party means it is not in the utility's rate base. We have seen resistance across the board in California, Minnesota and other states, and by developers and utilities will ultimately have to compromise over the allocation of costs to ratepayers and other stakeholders.

MR. BOYER: We try to function in a number of states, and about 60% of our business is with electric coops and municipal utilities. If you think about their missions and community solar, the two are well aligned. So I think the coops and munis are receptive. We have been successful in signing power purchase agreements with them directly; no state mandate or state legislation is required. You have to help them figure out how to provide the bill crediting, which can be difficult, but that is one area where we are able to help.

MR. AMSTER-OLSZEWSKI: Granted I agree with you; the utilities can take a long time to recognize that something good is coming to them and then a longer time to adopt it. But we are starting to see the shift, especially from four years ago when nobody knew what community solar was.

I think utilities are starting to see community solar as a vehicle to maintain control over their customer relationships. For example, with a community solar farm, we are using the grid that exists. We need the grid. There will not be a battery backup system, a storage package in the customer's basement, that is tied into a rooftop solar array. The utility is not losing the customer and, in many states, we can start negotiating with utilities about rate recovery to solve some of their concerns as well and even operating community solar farms for the utility.

The problem in the community solar space has been in cracking this nut of how to make solar work for the utility.

Community solar is gaining ground with the 49% to 80% of utility customers who are not candidates for rooftop solar.

Xcel signed well over 100 megawatts of power purchase agreements last year and, in the Denver Post, there was a paragraph about two inches long.

There is no comparison between that and the amount of positive attention that a community solar project brings for the utility. It is a full-page article starting on the front page of the Post. It is a completely different level of consumer interaction that utilities are able to garner through community solar programs. I think you are going to start seeing the number of such projects increase dramatically over the next five years.

MR. MIRIANI: There is great demand in both the residential and the commercial and industrial spaces for community solar, but things need to be worked out with the utility. Minnesota is an example of a state where the legislation is in place, but there are still issues on which developers have spent a lot of time and money. There is plenty of demand for the subscriptions in Minnesota. The issues are with Xcel and various implementation aspects of the program. People are still working through the issues.

MR. MARCIANO: Yet it is in the utilities' interests to work through these issues rather than have customers disappear to rooftop solar companies?

MR. AMSTER-OLSZEWSKI: Yes. The question for utilities is whether they move fast enough to seize the opportunity in front of them. The people at utilities recognize the rooftop alternative could lead eventually to a death spiral. The question is whether they can turn those large ships fast enough to take advantage of the opportunity.

MR. BOYER: We have been doing this for five-plus years. When we first went in to see utilities, it was always, "You want to do what?" Now there is a conversation about how the utility can participate in it. They see the benefit. I agree with David that they move very slowly through any process.

MR. MARCIANO: If you have 300 participants in an average project, what does that make the average project size.

MR. BOYER: Our average is just north of one megawatt, or 1.2 megawatts DC.

Risks

MR. MARCIANO: How do your investors or lenders get comfortable with the risk that a customer might stop paying?

MR. BOYER: The utility has a take-or-pay arrangement, so it will pay. That is the standard financing structure, and it makes it easy to arrange financing.

In some cases, like with Xcel, the utility will only pay the avoided cost of any power that comes to it without a subscriber. One way to address this is to have a prepaid program from the customer so that you are moving through the financing much faster, and the debt is paid off much more quickly.

The beauty of community solar is the easy transferability. If a customer stops paying, you are not stuck with a system on its roof. You simply replace the customer. In some cases, you can do it right away and move their bill credits to another customer. If a customer moves but stays within the same utility service territory, it is a simple telephone call. The customer still gets its bill credits. If the customer moves farther away, we tell the customer we will resell the customer's interest in the project. We sort of view ourselves as the Coldwell Banker of community solar for our deals. Come back, and we will resell your interest.

MR. MARCIANO: One of the challenges for rooftop solar companies is what happens if a customer stops paying. You cannot really remove the system easily from the roof and redeploy, at least not economically, so the customer has you over a barrel. You are saying you are in a better position than the rooftop companies.

MR. BOYER: Yes. I think the way to look at it from a financial perspective is this is the first solar product where you have a recoverable asset. I control the field that the panels are in. I control the panels. It takes my team about 20 seconds to unsubscribe a customer from the online system. If the customer does not pay, I unsubscribe him and my lost / *continued page 56*

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cost is not the $15,000 dollars of remaining payments in the contract, although the customers under our contracts are still responsible for that. In reality, the lost cost to us is the number of months it takes to find a new subscriber and the cost of customer acquisition for that new subscriber.

It is like a cell phone business model that you can start moving to as you start having more creative financing options that are available for community solar. We are not there yet, but that is the direction in which it is moving. You do not have a cell phone contract that is meant to pay off the cost of a cell phone tower. You know that your customer acquisition cost is $200 dollars and you subscribe a new customer every five minutes. That is the way that financiers are starting to look at community solar.

MR. STUEBE: Those are great points, and I completely agree. I would add that it is important to vet the creditworthiness of subscribers carefully. Our approach is to go in with either municipalities, school districts or Fortune 1000 offtakers. Then you have the added benefit, in the event one of them defaults, of the ability to swap them out.

Reaction Among Financiers

MR. MARCIANO: Are lenders and tax equity investors interested in participating in these projects?

MR. STUEBE: Yes. We have worked with several tax equity investors. From a financing perspective, community solar projects are similar to net metered projects with creditworthy offtakers, with added downside protection from the ability to swap out a subscriber in the event of a default. The community solar construct is also flexible enough that it can accommodate customers who need to move or expand their facilities.

MR. MARCIANO: Steve Miriani, you do more than community solar. How do the financing costs differ between community solar and other forms of solar?

MR. MIRIANI: I do not think they differ. It comes down to credit quality of the offtaker. In many ways, community solar is easier to finance than other forms of distributed solar. You are not on somebody's roof. You have the ability to remarket the power if you have a credit quality issue. You have a diverse enough portfolio that the banks can get past that.

MR. STUEBE: There is the potential to finance solar customers who would not otherwise qualify. For example, in some states there is an opportunity to have low-income participants be involved. Ecoplexus has developed more than 10 projects in which low-income renters are subscribers.

MR. BOYER: There is definitely an education process with investors. We financed 4 1/2 megawatts of community solar in Colorado last year, and there were definitely groups of investors that did not want to do the heavy work to come up to speed on the program and the subscriber agreements. Eventually we got it done.

MR. AMSTER-OLSZEWSKI: We have seen change over time. When we did our first two megawatts using Treasury cash grant panels four years ago, no one knew what community solar was. Multiple customers in a portfolio? That gives me a brain hemorrhage.

Meanwhile, they are financing 10,000 residential rooftop systems with 10,000 different customers each with a different rooftop configuration and system size. There is a little irony there.

Now we have 12 megawatts in the ground working with GE Energy Financial Services as the tax equity. We have another 200 megawatts under development this year and the first part of next year in Minnesota and Colorado.

The industry is moving quickly toward scale. In Minnesota, 750 megawatts AC are in the queue; add another 20% to get to DC. The Minnesota program opened for business in December. That is an explosive growth rate in just six months. It is $2 billion worth of projects in a state like Minnesota, where the installed capacity today is less than 15 megawatts.

MR. MARCIANO: What has been the key to the success in Minnesota?

MR. AMSTER-OLSZEWSKI: We have been working with Xcel for years now in Colorado. It supported a community solar bill in the Minnesota legislature. I do not think they wanted it to be unlimited, but that was thrown in at the last minute, so you have an unlimited community solar market in Minnesota that was confirmed by the public utilities commission even though the utility wanted to put caps on it.

What the program creates for customers is free choice. You have a regulated market with a regulated monopoly, but then you also have a free-choice customer option where any customer can choose to use renewable energy and any developer that has the foresight to find a piece of land and connect to the grid can pull together customers and the financing to build projects.

MR. MARCIANO: With that kind of growth, are you having to pay for expensive network upgrades to the grid to accommodate the additional electricity?

MR. AMSTER-OLSZEWSKI: It is too early to tell because the system impact studies are still being done. Many of these projects are connected to distribution lines rather than transmission lines.

MR. BOYER: Interconnection costs are still unknown and are difficult to control. Interconnection with Xcel in Colorado has been relatively inexpensive. When you get to Massachusetts and have to deal with National Grid and NSTAR, it is a different ballgame. We are still waiting for numbers.

MR. MARCIANO: National Grid seems to have a pretty expensive view of what it takes in Massachusetts.

MR. BOYER: It does, but there is opportunity in that as well. We did a project with a coop in southern Colorado, and the coop told us where it wanted the project. It said it has a problem on a particular transmission and could use more generation on another line. It asked us to put the project somewhere between a particular substation and the load. Things worked out perfectly. The project is literally in the middle of nowhere. We built a megawatt there. The interconnection costs were almost negligible because of that. This is another opportunity for community solar that might not be available to larger projects.

MR. MARCIANO: Can you earn extra revenue for placing the project in the right place and providing a sort of ancillary service?

MR. BOYER: We were able to use the location to get a slightly higher electricity price in the PPA.

MR. AMSTER-OLSZEWSKI: There is actually a tariff in Minnesota that provide additional compensation for locating systems in the right areas, so, as Mark was saying, a lot of the game and expertise in this is getting to the market early. Having a good interconnection engineer who can find the right location is essential. It is not like you go on the internet to find the best spot on the grid to connect the system. One of the competitive advantages is having an engineer who worked for either the public utilities commission or utility and who knows where the good spots are so that you can be first in the queue for those spots. That leads to the lowest interconnection cost. That is one of the areas where I think we have differentiated ourselves: being first to market and first in the queue with the lowest interconnection costs.

Audience Questions

MR. MARCIANO: Let me stop there. Any questions from the audience?

MR. HERMAN: Steve Herman with Energy Capital Partners. Let me raise a policy issue. Is there not a social or economic justice issue with community solar? Put aside where there is a mandate for low income, which I think is the exception. I heard someone suggest you have to have a 700+ credit score to participate in this.

MR. AMSTER-OLSZEWSKI: That is a great question. That is the reason I got into community solar, right at the heart of the passion. Right now solar requires a good rooftop, owning your own home generally, and a 700 or higher similar credit score. What we are moving toward with community solar will eventually be a product that can be sold to anyone. Community solar is the great equalizer in solar energy. That is one of the things that is driving it so fast — from nobody knowing about it and no state laws five years ago to now 10 states having laws and another 22 states that have policies in the process of either being approved by regulatory commissions or legislation.

It is moving so fast because of that popular appeal of the ability to bring it to everyone. The last challenge now to crack is flexible financing terms so that we can truly provide it to anyone.

MR. FELDMAN: I agree. The issues are not dissimilar across distributed solar in general. The economic inequality issue is an unfair burden to pin on these companies. Electricity rates are not inherently fair in general. Certain people pay more than others. No individual customer is paying the actual cost of energy. There are a lot of places, particularly in California, where higher income households are paying more on average for their energy because they consume more. There is a recent study that showed that, even with distributed solar on their roofs, the higher-income communities are still paying a higher average rate than other customers.

The argument is unfair, but even if you have a problem with distributed solar, community solar has the potential to make it more fair.

MR. EBER: John Eber with JP Morgan Capital Corporation.

This is the first time I have heard a panel talk about distributed solar and not really mention net metering. Does net metering not exist in the world of community solar? If so, won't community solar eventually replace rooftop solar?

MR. AMSTER-OLSZEWSKI: In short, I would say that is the opportunity.

MR. STUEBE: We view the Minnesota structure as a form of remote net metering. The only difference between remote net metering and more conventional net metering is that the solar facility is not co-located with the load.

MR. EBER: What I meant by net metering */ continued page 58*

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was the ability to offset more than the power that you are using in your home. With a typical rooftop solar system, the homeowner is getting some benefit beyond the amount of power that he needs in his home. Is the same thing happening with community solar?

MR. AMSTER-OLSZEWSKI: There is usually a cap. For example, in Colorado, community solar can be used only up to 120% of a subscriber's existing load. From our experience, very few people participate at a level above 100% of their load. The average is probably around 50% to 60% of load for the average residential subscriber.

MR. STUEBE: Our company has done about 45 net metering projects in California, and never once has the available roof space been able to offset more than 80% of the load. Often it is 30% or 40%, so the advantage with community solar is you can offset up to 100% without being restricted by the size of the roof.

Roughly $2 billion worth of community solar projects have been proposed in Minnesota.

Another important advantage is, in California, 44% of residences are multi-tenant facilities. The landlord of a multi-tenant facility has little incentive to try to help renters save on their utility bills or, if the landlord wants to help, it requires complex accounting. Community solar can address that problem by allowing renters to contract with a community solar company directly.

MR. AMSTER-OLSZEWSKI: You are touching on an important policy point.

Colorado has net metering for rooftop systems, so let's say the retail electricity rate is 11¢ per kilowatt hour. Someone with a rooftop solar system generates a kilowatt hour and sends it to the grid. His meter rolls backwards by 11¢.

For community solar what we negotiated with the utility there, via the public utilities commission process and a legislative process years ago, was a different type of rate. It is not the full retail rate. It is the retail rate minus transmission and distribution cost. That is the customer credit. The customer might be paying 11 cents per kilowatt hour for electricity from the utility, but the community solar bill credit may be 8¢ per kilowatt hour, so the utility is still getting compensated by that customer for the cost of its transmission and distribution system.

That's the type of compromise that has the potential to get utilities on board with community solar. You allow utilities to recover some of their fixed costs, specifically for the transmission and distribution systems, with community solar in a way that they are not able to do with rooftop solar and net metering.

There are PPA deals being done in Colorado for between 5¢ and 6¢ per kilowatt hour. If I sell to a customer for 8¢, that is not a bad spread. I do not need the 11¢.

MR. SALANT: Marshal Salant from Citibank. I like where you are going on the size of the credit, but have a follow up to John Eber's question about net metering. We at Citi would love to start financing community solar, but we have spoken to law firms and our counsels are saying very clearly, stop, this is going to be challenged by utilities. This is going to end up in the courts. This could end up at the Supreme Court. It could end up needing legislation from Congress because it has not been adjudicated yet.

What do you say in response to that? You are making it sound like there is no controversy. I am just trying to figure this out.

MR. AMSTER-OLSZEWSKI: That's a good question. We have not seen any controversy in the community solar space until recently in Minnesota, when you went from zero to 750 megawatts in the queue in six months and you can probably figure out why there is some controversy there.

The utility is thinking, "Whoa, we just let the cat out of the bag. How do we reel it back in?"

All of our projects in Minnesota are 10 megawatts because community solar is supposed to be distributed generation and the tariffs say that distributed generation is 10 megawatts and under. Some companies that have gone out and proposed 30-, 40- and 50-megawatt projects.

If you stay under the 10 megawatts, you will be safe. Just like anything else, if you follow the rules of the program and if you have the right policy supporting you and you have the right people on your team in the community that are well engaged with the utility and with the policymakers, you can set up strategies ahead of time that allow you to move past the risks.

Some folks moving into Minnesota thought they saw a good opportunity to combine multiple 10-megawatt projects on the same site because the utility commission allowed for a decreasing marginal cost of interconnection. There is no tariff for interconnecting anything over 10 megawatts.

Of course you are going to have a problem if you co-locate projects like this.

MR. BOYER: Xcel has raised the co-location issue in Minnesota. We think that will be resolved fairly quickly to the satisfaction of the financial community. We cannot be certain what the resolution will be, but we think the eventual resolution with Xcel on board will give the certainty the banks need to move forward.

MR. MIRIANI: In terms of the timeline, these settlement discussions are about the caps on individual project size. The authorizing legislation is clear that there is no cap on the program as a whole. The public utilities commission is expected to issue a ruling by around June 30. The market expects this to be resolved quickly.

MR. SMUTNY-JONES: Jan Smutny-Jones with the Independent Energy Producers Association representing wholesale private power producers here in California. It sounds like to me like these arrangements are sales of electricity for resale, which would bring federal jurisdiction into play. How has that been addressed.

Related question: you are exempted explicitly from being a utility or is the public utilities commission actually regulating you as a utility?

MR. BOYER: This is a new field. We have had to spend a lot of time and legal dollars to make sure that we are vetting these issues relative to the federal Public Utility Regulatory Policies Act and the Federal Energy Regulatory Commission. The fact that the utility is collecting the T&D charge as part of the rate it charges the customer helps with the potential regulatory issues at the federal level, including the sale-and-resale stuff. We have been through this a number of times and I know that SunShare has as well.

MR. AMSTER-OLSZEWSKI: I would also point out that virtual net metering community solar is not new. It is new at the scale we are seeing in Minnesota, but our company has had about 10 virtual net metering projects in California operating for about four years. Some of them have up to 260 subscribers, so this model has been vetted and what is in question in Minnesota is not the essence or the structure of the program itself or whether it passes muster under federal and state law. What is at issue is only the size of the individual solar project. We are not seeing challenges to the legality of community solar.

The Partnership Flip Guidelines and Solar

by Keith Martin, in Washington

The Internal Revenue Service said in an internal memo made public in June that its guidelines for tax equity partnership flip transactions do not apply to solar facilities or other projects on which investment tax credits are claimed.

Instead, the IRS said, transactions involving investment credits should be tested under general partnership principles.

The memo was written by the IRS national office to the part of the IRS that audits taxpayers.

It should not cause the solar market to back away from partnership flip transactions or to alter the core terms of such transactions, but it may require law firms to revise how they analyze the transactions in tax opinions.

Internal IRS Debate

There has been an internal debate within the IRS for a number of years about whether the agency should issue separate guidelines for solar transactions. Some IRS lawyers have wondered whether the fact that the tax equity investor in a solar project is likely to reach its return much more rapidly than in a wind deal, through an upfront investment credit plus possibly a depreciation bonus and utility rebates, and the fact that these elements of the return are not tied to project performance, require that solar transactions be analyzed differently from wind deals.

At the end of the day, the basic question / continued page 60

Partnership Flips

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is the same: is the tax equity investor a real partner with meaningful upside and downside risk of a business or is it a bare purchaser of tax benefits or a lender earning essentially a fixed return?

The IRS issued partnership flip guidelines for wind transactions in 2007 after it received several private letter ruling requests that suggested the wind market was adding embellishments to the basic partnership flip structure.

In a partnership flip, a developer brings in a tax equity investor to own a renewable energy project with the developer. The partnership allocates the tax benefits and taxable income largely to the tax equity investor until a set date in the future or when the investor reaches a target yield, after which the investor's interest drops usually to 5% and the developer has an option to buy out the investor's remaining interest. Cash flow may be split in a different ratio.

The embellishments that some wind companies wanted to add before the IRS guidelines were issued were things like pay-go features where the tax equity investment is made over time as a percentage of tax credits or the investor is guaranteed a minimum return. The guidelines were an attempt to draw lines and allow the IRS to save on resources by not having to repeat itself in numerous private letter rulings.

The guidelines are in Revenue Procedure 2007-65.

The lines the IRS drew in these guidelines should remain relevant to solar, but, the IRS said in the new memo, they are not a "safe harbor" that ensures that a solar flip transaction will be respected.

The IRS has debated periodically since 2007 whether to issue separate guidelines for solar transactions.

Richard Probst, who wrote the IRS memo, said most of the pressure for such guidelines has come from the IRS field. The new memo was written last November, but only just made public. It is heavily redacted. It is Chief Counsel Advice 201524024.

Probst said he tells IRS agents in the field to apply basic case law going back to a 1949 Supreme Court decision called *Commissioner v. Culbertson* to determine whether there is a real partnership. He said he hopes that a solar transaction will be referred to the IRS national office by a field agent as part of a request for technical advice so that there can be something for people to read beyond the heavily redacted memo. The national office would then issue a technical advice memorandum, which is a memo written by the national office to settle a legal dispute between a taxpayer and an agent on audit.

Audited Transaction

The new memo analyzes a solar partnership flip deal with aggressive terms that go well beyond anything that the mainstream tax equity market does.

The transaction had the following features.

An LLC acquired a portfolio of solar systems from an S corporation that was owned by two individuals, A and B. The S corporation took back a nonrecourse note for part of the purchase price. It represented that the LLC would be able to claim the full purchase price, including the note, as basis in the solar systems for purposes of calculating tax benefits.

The LLC then leased the systems to another S corporation owned by A, one of the two individuals that own the seller, and one other related individual. The rent appears to be a fixed amount per month. The length of the lease term is redacted. The rent paid under the lease is the sole source of revenue for payment of the purchase money note that the LLC gave the seller for the balance of the purchase price. If the LLC stops payments on the note, then the seller's remedy is to take back the systems.

The LLC is owned partly by the same individual, A, that owns both the seller and the lessee of the systems. A owns its interest through yet another S corporation.

IRS guidelines for partnership flip transactions are not a "safe harbor" for solar deals.

The part of the purchase price that the LLC paid for the systems in cash, as opposed to agreeing to pay over time under a nonrecourse note, was paid in three increments: a little at inception, a little more "on the date" the systems are placed in service, and the balance when the LLC files its tax return for the year it claims the investment tax credits on the systems. The second and third cash payments were contingent in amount.

The S corporation through which A owns part of the LLC guaranteed the other investor — the tax equity investor — the amount of investment tax credits that it would receive and that it will have enough capital account and outside basis to absorb the full tax credits and depreciation bonus on the systems. If the tax credits are less than expected, including due to a recapture event or an IRS audit, then the S corporation must make capital contributions to the LLC, plus interest on the shortfall, that are distributed to the tax equity investor. If the tax credits are more than the guaranteed amount, then the tax equity investor must make capital contributions to the LLC that are distributed to the S corporation. If the solar systems were already in service before the sale to the LLC, then the S corporation can buy out the tax equity investor by refunding its money plus interest.

The tax equity investor receives annual preferred cash distributions from the LLC that presumably are a small percentage of the capital it put into the deal plus an annual "asset management fee." A letter of credit has been posted to ensure the preferred cash distributions will be made each year. The preferred cash distributions stop after the flip date.

If there is an operating deficit in the LLC, the S corporation must fund it by making a non-interest-bearing loan to the LLC that is repayable only out of LLC cash flow after the LLC has made the cash payments to the tax equity investor: the annual preferred cash distributions and management fee and any tax indemnity payments.

The S corporation has a call option to buy the tax equity investor's interest in the LLC 90 days after the flip for fair market value. If the call option is not exercised, then the tax equity investor has a "put" to force the LLC to buy its interest a year later for fair market value or, if less, the balance in the tax equity investor's capital account. ◎

DOE Loan Guarantees Return

The US Department of Energy is trying to breathe new life into the loan guarantee program. It is prepared to lend up to another $40 billion at low fixed rates to support innovative renewable energy projects and for other energy-related uses. Will the program be easier to use this time?

Peter Davidson, the outgoing head of the program, talked to Keith Martin of Chadbourne during the Chadbourne global energy & finance conference in early June.

MR. MARTIN: Peter Davidson, you took over as head of the loan guarantee program in 2013. The program had basically been shut down at that point due to brickbats from Congress. You showed a great deal of courage. You put out an open-for-business sign and invited companies to apply to up to another $40 billion in loan guarantees. How much of that is available for renewables and other energy projects?

MR. DAVIDSON: There is $24 billion available for energy projects.

When I took over in May 2013, the loan program office had not made any loans since 2011, and the loans we had made were against the section 1705 economic stimulus program. We had no new solicitations out on the street. Over the last 18 months, we have put out three separate solicitations under which we are actively seeking projects where we can provide senior debt financing.

We have $12 billion for nuclear large-scale nuclear projects, small modular reactors and upgrading of existing nuclear facilities.

We have an active solicitation out for $8 billion in loan guarantees for fossil fuels, oil, gas and coal, and for energy efficiency as it applies to the grid and to improve the efficiency of existing fossil projects.

We have an additional $4 billion to use for loan guarantees in the area renewable energy and energy efficiency in the renewable energy sector.

We have a completely separate program, our advanced technology vehicle manufacturing program, that originally had $25 billion authorized but is now down to $16 billion after about $8 billion loans to Ford and Tesla and various other companies.

That is a total of $40 billion available / continued page 62

Loan Guarantees

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under all market segments.

MR. MARTIN: So $24 billion of that for energy, and $4 billion of that is for renewable energy. What response have you had to date to the renewable energy solicitation?

MR. DAVIDSON: As you know, Keith, we take very seriously the fact that most companies that apply to us view the fact they have applied for a loan guarantee as confidential. We take confidentiality very, very seriously for our applicants. We do not even like to say how many applications we have. We do not like to say who is in the queue. We put out the renewable energy solicitation last July, so we are nine months in, and we have had a great deal of interest in the renewables area and a great deal of interest in the fossil area.

MR. MARTIN: Is it still possible for other renewables, developers to apply?

MR. DAVIDSON: Absolutely. Even if we have a large funnel of projects, by the time deals emerge from the funnel, there is a smaller number. We encourage people to apply. The advanced vehicle technology manufacturing program has no application deadlines. Companies can apply through the online application portal at any time.

The energy program has rolling deadlines for part I and II applications. They are every other month. The last part II deadline is March 2016. There is no need to worry about that because, if we have any unused authority after that date, we have the right, unilaterally, to extend the deadline. We will extend it if there is any unused authority.

We certainly encourage people to apply sooner rather than later, just because this money was one-time authorization from Congress in the Energy Policy of Act of 2005 and once it is gone, it is gone, unless Congress decides to reallocate new money to this program.

MR. MARTIN: We are talking to Peter Davidson, head of the DOE loan guarantee program. There are $4 billion available for renewable energy developers and $8 billion for fossil fuel. There is still time to apply. In theory, you have to be through phase II of the queue by March 2016, but that deadline can be extended. Peter, the term "loan guarantee" is a misnomer, right? It is really just direct borrowing from the Federal Financing Bank?

MR. DAVIDSON: That is the way it has worked for the majority of our loans. The Department of Energy issues a loan guarantee. The borrower, at the borrower's option, can take that and give it to a commercial lender or apply it to its bonds in the bond market. Most of our borrowers choose to have us give that loan guarantee to the Federal Financing Bank and then the Federal Financing Bank, which is part of US Treasury, makes a direct loan to the company.

Debt Coverage

MR. MARTIN: How much of the project costs can the loan guarantee cover?

MR. DAVIDSON: The title 17 legislation authorizing loan guarantees for energy projects says we can lend up to 80% of eligible project costs. As a consequence, every application we receive is for us to fund 80% of the project costs. The amount we actually fund is tied to project economics. What are the cash flows? How long will it be before there is cash flow? What are the debt service coverage ratios?

Where we have ended up historically is an average of 65% to 70% of project cost can be covered by debt.

MR. MARTIN: What debt service coverage ratio do you require? I suppose it varies by project.

MR. DAVIDSON: Hard to say, because everything we do is based on the particulars of a transaction. Deals can be radically different. If someone comes in with a utility-scale solar facility with a 25-year off-take contract with an AA-rated utility, and the project has a fully wrapped EPC contract, the required debt service coverage ratio will be lower than for an advanced technology vehicle manufacturing loan and a new type of energy storage with an untested business model. We would still need to see some type of innovative technology or process for the project to qualify.

MR. MARTIN: I did not hear a range. Is there a range, maybe 1.3x or 1.4x debt service in the typical renewable energy deal?

MR. DAVIDSON: We are different than a traditional commercial lender in that the Department of Energy is willing to take technology risks, both in new technology or technology integration, or in helping to finance the most recent deployment of an existing commercial technology such as a more advanced boiler or a more advanced wind blade. If a project has been deployed overseas, but never in the United States, we will step forward as the first lender if the commercial banks are not willing to participate. The goal of our program is not to take the place of private market lenders. If a developer can raise money from private lenders, our program is not a good fit. Our program is for projects where traditional lenders are unwilling to proceed because of technology risks, implementation risks or process risks.

MR. MARTIN: The technology cannot have been put to more than three commercial applications in the United States, but when you came to visit us a couple weeks ago in Washington, you made an important point. The new part of the project that cannot have been deployed at least three times does not have to be the whole project. How small a piece of it can the new technology be?

MR. DAVIDSON: Excellent point. The legislation says there can have been no more than three commercial deployments within the last five years. Therefore, if there is demand to deploy 20 within the first five years of the first one going commercial, we could theoretically finance all of those. There is a fairly broad definition of what can work. We have 25 engineers on our staff. We have 160 people in the loan program office, making us one of the largest project finance lenders. The engineers help us do the vetting of new technology, new processes and new ways of integrating projects.

MR. MARTIN: Could the new component be, for example, a higher tower for an existing wind turbine?

MR. DAVIDSON: Yes. Examples are higher towers, longer blades. It could be a more efficient boiler in a coal plant. It could be a better way to handle recycled water. By recycling water, you would minimize the truck traffic going back and forth, which would lower the greenhouse gas footprint of a gas plant for fracking. There are many ways it could work. And to your point, eligible project costs are the entire project and not just the new component. The new component could be as little of 5% or 10% of the total project cost, but it must be a crucial part of the project to satisfy the innovation threshold.

Interest Rate

MR. MARTIN: Two quick questions: number one, what interest rate can people expect to pay on the guaranteed debt?

MR. DAVIDSON: The interest rate is fixed. Say it is a 20-year loan. We would look at the 20-year Treasury bond, and then we would apply a spread to that of anywhere from 50 to 150 basis points. The spread is based on the underlying credit of the borrower: the more creditworthy the borrower, the lower the spread.

MR. MARTIN: Twenty-year fixed-rate debt at 50 to 150 basis points above Treasuries. That is pretty good.

Last question: a big issue in the past has been how time consuming it is to deal with the government. How long should it take to move a loan guarantee from start to finish?

MR. DAVIDSON: We have made a great deal of effort to make our process more commercial, more transparent and more streamlined. We have done that in a number of ways. We now have a part I application process. We commit to get back to every borrower within 60 days on that. The applicant fills out the part I application on our online portal, which is energy.lpo.gov. We have a great deal of information on that site. There are Power Point slides with guidance for how to fill out the application.

We try very hard to help the applicant to qualify, but if the project is not a fit, we want to tell the applicant that within 60 days.

After that, we are into the same normal due diligence process that any commercial lender would undertake.

We think an application can move from start to finish in as short a period as nine months, between initial application and conditional commitment. If the borrower has all the information ready to go, we can work expeditiously. ◎

Long-term, fixed-rate debt at 50 to 100 basis points above Treasury bond yields may be available through the DOE loan guarantee program.

Energy Storage Economics

The storage business is about to take off. A total of 363 megawatts of storage projects were announced in 2014. Investment in storage is expected to be running at $5 billion a year by 2020. But has anyone figured out the economics?

A panel discussed this and other storage questions at the Chadbourne global energy & finance conference in early June. The panelists are Glen Davis, CEO of Renewable Energy Systems Americas Inc., The Honorable Carla Peterman, a commissioner on the California Public Utilities Commission and author of the key ruling setting storage targets for the California utilities, Peter Rive, co-founder and chief technology officer of SolarCity, Kevin Sagara, president for renewables of Sempra US Gas & Power, and John Zahurancik, president of AES Energy Storage. The moderator is Todd Alexander with Chadbourne in New York.

MR. ALEXANDER: Extravagant claims are being made about energy storage. It will be a game changer. It will be the greatest thing of all time. John Zahurancik, what is the real opportunity in energy storage over the next five years? Is it possible to make money?

MR. ZAHURANCIK: AES started its energy storage business in 2007 and 2008 when we put our first large battery project on line. We have done several since then, so we have been finding ways to make money in energy storage for a while now.

The most interesting near-term development is the California program. The state is looking for ways that storage can be beneficial and valuable to the grid and to put storage on a comparative basis with the other things that we buy as part of the electricity we receive. In the next five years, storage should begin to substitute for some of the things we are currently buying but of which we will no longer need as much, such as peaking power plants and transmission and distribution upgrades. Storage has the potential to relieve grid congestion and mitigate reliability concerns. Storage is an alternative to some of the things we buy today.

MR. ALEXANDER: Glen Davis, where does RES see opportunity?

MR. DAVIS: Energy storage facilities provide anywhere from a dozen to 20 different services from the point of view of the grid. Most of those are related to reliability. For instance, storage can help integrate renewables on a system-wide basis by allowing a particular renewable energy facility to smooth out its electricity deliveries to the grid. Storage can provide frequency regulation; we all know of several frequency regulation machines.

The combination of these types of potential benefits, facilitated by lower technology and installation costs, is creating a growth potential in the market.

MR. ALEXANDER: It is tough to make money in frequency regulation in today's market. Are there ways to make money by doing peak shaving and smoothing out electricity deliveries?

MR. DAVIS: The conventional wisdom among those of us in the energy storage market is that an arbitrage play, peak shaving or anything that relies on a difference between peak and off-peak pricing, will not pencil out by itself. It can be part of the revenue from a storage project, but it is not enough to carry the project.

Revenue from providing frequency regulation depends on the rules of the local market and whether you have consumers of frequency regulation who are willing to take extended positions. For instance, in Ontario, we have a four-megawatt, two-megawatt-hour battery that benefits from a three-year contract with a system operator. We have two projects under construction that will go operational this year in Illinois that have three-year hedge contracts.

MR. ALEXANDER: Peter Rive, SolarCity is putting batteries behind the meter, so you probably think differently about storage than our other panelists. How do you convince customers to pay for batteries as part of rooftop solar systems if peak shaving will not be enough to pay the cost?

MR. RIVE: We actually see our customers saving a lot of money from peak shaving. We have customers, like Walmart and Yahoo, who are buying a product that we call Demand Logic. The peak period varies by utility service territory. It may be noon to 9 p.m., noon to 7 p.m. or 2 to 7 p.m. If you try to take advantage of the difference in rates between peak and off-peak periods with a stand-alone battery, it is expensive, but combining a battery with a solar system is more cost effective; you can intelligently discharge the battery when the sun is setting or the solar system is not producing.

The customer is buying power from us at 12¢ a kilowatt hour instead of the 16¢ retail rate, so the customer is seeing additional savings, and it has backup power as well. So if you are a Walmart or other retailer, you will save 4¢ a kilowatt hour on your peak demand charges, and you have the additional benefit of keeping the registers going when the power goes out. It is a great value proposition. We are getting incredible traction with it.

Rooftop Math

MR. ALEXANDER: How does the math work in states that have net metering? If you can deduct the high retail rate for power, is it worth installing the battery?

MR. RIVE: I have been talking entirely about commercial and industrial applications.

For residential installations, all of the solar energy goes directly into the battery. There is no plan to have the battery export any energy that did not come from the solar power system, but one could look at time-of-use rates, as an example, and there are ways in residential applications to offset the costs of a battery. For example, in our current offering, which is around $5,000 to the customer for back-up power, the customer will be able to realize about $500 in time-of-use benefits over a 10-year period, depending on the usage pattern. This will not pay for the battery completely, but it helps to offset the cost of having a back-up power source.

The frequency regulation market in PJM is not far from being saturated after being in play for only a short time.

MR. ALEXANDER: Kevin Sagara, how does adding a battery enhance the returns from a utility-scale project?

MR. SAGARA: Let me comment first on some of what has already been said. The most interesting thing about storage is the range of potential applications and technologies. There are many different types of batteries. Each has a different chemistry.

We have a battery in Maui. We have a 21-megawatt wind farm there. Maui is an island grid, and it only has an average daily load of about 200 megawatts, so the intermittent output from our wind farm can really disrupt the local grid. Our power purchase agreement with Maui Electric requires us to install an 11-megawatt battery, with a 4.4-megawatt-hour storage, to control the ramp rate from our wind farm. When the wind farm trips off, the battery helps to ramp down the power supply in a gradual way so that we do not damage the grid. It also modulates the intermittency of the wind, on a minute-by-minute basis, by helping to smooth out the rate at which our electricity is going into the grid. That is one of many possible applications for batteries.

We are very early in the storage business. No one has really figured out all the potential business models and how to make them economic. At the same time, the costs of storage devices are falling rapidly.

MR. ALEXANDER: Does the Maui battery pay for itself? Do you receive a higher power price in exchange for installing the battery? How you justify the additional capital cost?

MR. SAGARA: Our battery was required under the PPA. We would not have a project without it. The project with the battery is economic at the contract electricity price.

MR. ZAHURANCIK: Let me ask a question of the panel. People talk about an amazing array of possible battery and other storage technologies, but I suspect the reality is everyone here is using lithium ion batteries.

MR. DAVIS: Lithium ion, thermal storage through air conditioner control and fly wheels.

MR. ZAHURANCIK: But the majority of it is lithium ion. I am just trying to simplify because, although there are many possible applications and technologies in theory, there are not 20 business models in practice. There are a few business models.

I go to these conferences and I find storage being described as the unknown of unknowns. We call it the holy grail because we think true storage projects do not exist in real life because the economics do not work, and yet there are real projects that you can visit. Everyone on this panel has a project that you can come see. The point is we need to move beyond the holy grail to another analogy. Storage has been found. [Laughter.]

MR. ALEXANDER: So tell us in which markets storage projects are currently economic. Is it PJM? California? Or just island grids?

MR. ZAHURANCIK: We are all aware of / continued page 66

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California. There is a lot of activity here. California has had a very successful initial launch.

We went very quickly from a view that we did not know how to tackle storage to solicitations where we are seeing a huge amount of competition from bidders. Storage is competing with the traditional electricity generators.

We have a whole range of projects in the PJM market. What PJM has done very effectively is to create a transparent pricing mechanism for storage, and other markets are looking at what PJM has done. PJM figured out how to take something that benefits it and send the right price signals so that the developers, the technology and the financiers show up to provide storage. Those are just two places in the US. ERCOT is doing a lot now. We just announced a project in MISO in Indiana. Around the world, we are working on projects in The Netherlands, Northern Ireland and The Philippines. We already have a project in Chile. These are not isolated events.

MR. ALEXANDER: All of the projects use lithium ion batteries?

MR. ZAHURANCIK: Yes. We say we are technology agnostic, but highly opinionated. [Laughter.] That is the technology for now, I guess.

California Timetable

MR. ALEXANDER: Carla Peterman, California is trying to encourage use of batteries to allow for greater use of renewable energy. The two go hand in hand. It is true, as John Zahurancik just said, that some large batteries have been deployed, but people are not that sure exactly how to do it or how to recover their costs. How do you regulate in a market like that?

MS. PETERMAN: Carefully, is the short answer.

Good morning. Let me comment first of what John said. There is a continuum of technologies and applications. John is right that most of the companies bidding into the California solicitations are proposing a handful of business models, but we expect to see more technologies, more applications and more business models over time.

We are focusing on how to make the rules for the next few years. It was two years ago this month that I issued an assigned commissioner ruling proposing energy storage targets. There were a wide range of reactions. We had people urging us to set the targets at zero and others asking for the targets to be 6,000 megawatts. So we have come a long way in terms of organizing around a goal.

The next couple years will be busy. We had the first storage solicitation by the utilities, and we will be issuing a proposed decision early next year. We are seeing procurement happen through the long-term procurement plan process. Edison and SDG&E did a preferred resources pilot to meet some local reliability needs. That brought more storage for the system earlier in time than we expected. There has been significant interest among developers and financiers in the storage solicitation.

We expect to issue four decisions related to storage in the next year and a half because there will be the 2014 solicitation results, and then we have to decide on the 2016 solicitation plans. Two decisions will come out of our newest proceeding, which is moving ahead on two tracks: track one is focused on what are some of the policy and rule changes we need to make in advance of the investor-owned utilities submitting applications for 2016 and track two will focus on other outstanding issues.

The California Independent System Operator is also working separately to develop rules and answer your initial question around revenue opportunities.

I see my role as a regulator at the California Public Utilities Commission and the role of the ISO to make sure that rules are in place to allow companies to take advantage of potential revenue opportunities. For example, one issue that has come up recently is multiple use applications for energy storage. A storage facility might be used to supply services to different entities or different markets. What would it look like to have shared or communal storage, providing storage, for example, to multiple electric vehicle customers. We need to make sure our rules are flexible enough to accommodate new potential applications.

We are talking this morning about the revenue opportunities in the next couple years, but ultimately I think this is a long game. Where we are moving as a state is toward more renewables and time-of-use pricing. These trends, plus wider adoption of electric vehicles, should make storage more attractive and valuable.

MR. ALEXANDER: So now is your chance guys. We always hear about how the market is not assigning enough value to things like renewables and storage by fully recognizing their contribution to reducing carbon emissions. What should the state say in its regulations to make storage more attractive? Peter Rive, you seem anxious to answer.

MR. RIVE: Yes. Storage equipment provides a lot of benefits

SolarCity hopes to install batteries with every one of its rooftop solar systems within the next five to 10 years.

to utilities if they were to take advantage of them. For example, including smart inverters and batteries as part of solar rooftop systems allows the systems to provide reactive power and voltage control.

Traditionally, utilities have solved these problems by procuring their own equipment because that is the only way they can earn an income. The current regulations stipulate that they can only earn a rate of return on additions to rate base. If instead they could earn income on procuring services from distributed resource providers, that would encourage them actually to use those as alternatives.

An analogy is if you want to try to host a website. One option is to procure it from Amazon instead of buying a whole bunch of servers. That is a common approach in the larger business world, but it does not work in the regulated utility sector. Utilities have no incentive to take the cheapest path by paying something like a dollar a month to a distributed solar provider and passing through the cost.

The regulations could be amended to allow this approach. The only objection I have heard from the ratepayer advocate is that a utility should only buy the service rather than the equipment if doing so is the cheaper approach.

That is one minor change the state could adopt and it would make a huge difference.

MR. ALEXANDER: Glen Davis, what will you tell Carla Peterman when you walk out the room with her after the panel?

MR. DAVIS: Good job! [Laughter.]

MS. PETERMAN: Good answer! [Laughter.]

MR. ALEXANDER: You guys can leave now. [Laughter.]

MR. DAVIS: The regulations should recognize the value embedded in storage services across the board. PJM has recognized that frequency regulation is a service that has value and a market can be formed around it. Other regional transmission organizations have not done that yet.

Storage units provide various services and benefits to utilities. There is no pricing or transaction mechanism built around them. While the PPA model covers most of them, a generator simply hands over the right to all the services to the utility. What we need is more transparent pricing for each of the services.

You also want to create other areas in which transactions can occur that bring benefit to utilities. It can be as simple as develop and transfer a storage facility. At RES, we have both an EPC shop and a development shop, and we are less concerned about owning the facility in the end, giving us the ability to be very flexible in terms of commercial structures.

MR. ALEXANDER: Carla Peterman, how do you respond to these types of requests?

MS. PETERMAN: We did an energy storage road mapping exercise last year with the ISO and the California Energy Commission focused on the question of what are the barriers for energy storage and what we can do to remove them. For example, interconnection for stand-alone storage facilities can be a regulatory barrier. What we did was identify which agency was responsible for each issue. Some issues are more specific to the ISO. Some are more specific to the California Public Utilities Commission.

We are working through the issues on the list. We always want to hear what will help facilitate storage, but we also have to be consistent with the other resources that we regulate. Some of the challenges going forward will be making sure that our rules for storage do not get ahead of rules for other areas and that any new rules work across technologies.

We are in the midst of a distributed resource planning process where our utilities will submit next month resource plans about how they will incorporate different types of distributed resources.

Taking on a question like how to aggregate energy storage and have that be a resource that can bid into the wholesale market is a larger question than just storage. Thus, one of the things we are doing is identifying common issues that we can address for all resources instead of / continued page 68

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just doing it piecemeal for storage.

We remain open to all suggestions.

Financing Storage

MR. ALEXANDER: Let's shift from the regulatory side to the finance side since most of us are involved in finance. How can you structure battery deals so that they are financeable even though the battery may be used to provide services to different people? Does a utility-scale battery need to be co-located with a wind or solar project?

MR. SAGARA: You need an offtake contract with a creditworthy counterparty to provide a revenue stream that can serve as a basis for the financing. In California, you would be looking for some kind of capacity contract around your storage project plus an O&M charge. It gets trickier when you get into other kinds of revenue models.

MR. ALEXANDER: We saw at least one lithium ion battery catch fire, literally.

MR. SAGARA: It was not a lithium ion battery, and ours did not catch on fire. [Laughter.]

A homeowner with rooftop solar who spends $5,000 today on a battery might realize $500 in time-of-use savings over 10 years.

MR. ALEXANDER: Okay, so not totally accurate. [Laughter.]

There was a project that caught on fire, and people who are less technologically sophisticated may be a little bit concerned about technology risk and the inability to get a full wrap and long-term warranties. Some of the leading developers are out of China and may not offer the long warranties as we have seen offered in the solar business with some modules. How do these issues affect your ability to raise financing?

MR. SAGARA: If, as John Zahurancik suggests, everyone is using lithium ion, then there are some suppliers who are providing substantial warranties that could underpin a financing. Financeable projects will probably trend toward proven technologies. It will be interesting to see who is willing to bet as an offtaker or lender on some of the less-proven technologies like flow batteries.

MR. ALEXANDER: Peter Rive, SolarCity has a close working relationship with Tesla. Tesla has made a huge bet on a particular battery technology. How do you see that battery becoming financeable?

MR. RIVE: It is pretty straight forward. On the commercial side, the customer is leasing a battery and SolarCity is providing a guarantee. The battery is considered to be part of the solar system as long as at least 75% of the energy stored in the battery comes from the solar system, so the battery is eligible for an investment tax credit, with the amount of the credit tied to the percentage of solar energy above 75% stored each year during the first five years of use.

MR. ALEXANDER: John Zahurancik, you have done utility-scale battery projects on a stand-alone basis. Have you found commercial banks willing to finance them?

MR. ZAHURANCIK: There is a lot of appetite to do things. We have financed some batteries on a project finance basis, but they were part of another asset, like a wind farm or conventional power plant. We have been able to help educate the financial community to some degree on what to care about within this energy storage facility.

The market has gotten comfortable with equipment like solar panels that scale and have a predictable rate of degradation, as long as there is a balance-sheet behind the supplier warranty. The other side of it is having enough visibility into the revenue side to feel comfortable with the revenue projections. That is where California is trying to ensure fair access to the same kinds of contracting structures for storage that we have used for conventional and renewable energy generating units in order to mobilize low-cost capital.

At some point, we will get to a portfolio of storage assets with some variability in pricing and still be able to do a financing around that. We will see the cost of technology come down as the market reaches scale. That will allow storage to be deployed in more places and to serve the customers more effectively. We will see lower-cost financing that will further reduce the cost of installed systems.

Beating the Competition

MR. ALEXANDER: Who is your competition? Is it peaking natural gas power plants?

MR ZHURANCIK: Yes. Peaking facilities are built with the idea of running them maybe 7% a year. Storage is a better option. We can get a lot more use out of it. We can put it in a place where we can take better advantage of the existing transmission infrastructure. It is much more complimentary to all of our long-run goals.

One of the challenges for policymakers is to make sure we are getting the best value. The challenge is to place the right value on some of the other attributes we care about in bid situations. If we want to move toward a lower carbon future and are supporting renewables on the one hand, we need to make sure we are not buying resources on the other hand that crowd out our ability to take energy from renewables. We see this in a number of markets. For example, we are actively bringing wind to Northern Ireland but trying to keep the thermal power plants running for system reliability, with the result that we end up chasing our tail.

It is a challenging policy environment because you want the least-cost asset for this particular use, but you have to look at the bigger picture.

MS. PETERMAN: I agree that all-source solicitations have been helpful, and we have seen more storage bid and procured in such solicitations than we expected.

I want also to acknowledge the role that government plays in financing less proven technologies. California has had public interest energy research for decades. It has had 10 years of experience doing research and development around energy storage. That made me comfortable as a PUC commissioner to say we can set targets as the technologies are there. We are continuing to fund new commercialization of energy storage projects through EPIC, short for an Electric Program Investment Charge. That is the best place for any new technology because those projects are then grandfathered into our storage target.

MR. ALEXANDER: Glen Davis, there are news reports about the declining cost of batteries. This has some parallels to what has happened in solar. Some developers bid low electricity prices into solicitations for power contracts, figuring that by the time their projects had to come on line, solar panels would have fallen enough to make the projects economic. To what extent is this a sensible strategy for batteries?

MR. DAVIS: It is a good analogy. In solar, you had manufacturers giving you their forward cost curves and then it was a question of whether you wanted to go further down compared to what the technology providers were telling you.

MR. ALEXANDER: What has the cost curve looked like over the last few years?

MR. DAVIS: The costs have been falling more rapidly than the manufacturers have been telling us. What we have not yet seen is the effect of the Tesla giga-battery factory on costs. One of the things that drove down the cost of solar panels was everybody driving toward larger and larger factories.

MR. RIVE: The full system cost versus just the cell cost is actually pretty bad right now. You can get a cell for $350 per kilowatt hour of storage, but the full cost of the battery after installation is between $500 and $700. One of the big breakthroughs that has to happen is you have to try to design DC-compatible batteries so that they can use the same inverter as the solar system.

I think we saw that with solar systems as a whole. Panel prices were initially driving the overall cost. Those came down rapidly. The focus has turned since then to the balance-of-system cost. You have to look at the architecture of the storage system. It has to be complete. It has to do what you need it to do on the power grid. It is not just putting a box of batteries somewhere. It has to work to do the jobs that we need it to do at a very reliable level. When we talk about a kilowatt hour, battery guys get very squishy about what a kilowatt hour is. You start to get into things like amp power and c-rates and similar items. We need to simplify it. Useable kilowatt hours, useable kilowatt and a complete system. I totally agree the balance of plant is where we will be chasing gains over the next few years.

MR. DAVIS: One of the things in solar that allowed people to make money off of falling technology and overall system costs is the time between when they committed in a PPA to a price based on current market conditions, and the time when equipment had to be ordered. The lag could have been 18 months to years, depending on whether you were in the permitting process.

That float is less likely to play out with batteries. In some markets, you may have a PPA, and California may be one of them. The utilities do not want delivery until 2018 or 2019, so you have a long enough time frame, but, / *continued page 70*

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more often than not, you are talking about a simpler permitting process and a very short construction period. It is not a PPA. It is just a bill of transfer. You may not have the opportunity to harvest as a developer the falling technology cost the way people did it in solar.

MR. ZAHURANCIK: I think what we will find is that we will average our way down. We do not have to worry about every project being the ultimate end point cost. The project cost that we are seeing today is the result of projects that we did years ago and the effort to get the manufacturing and financing communities interested in doing something forward.

When we started going to some of these events and talking about this in 2007, 2008 and 2009, we were talking to battery companies that were small and working on novel products, even on the lithium ion side. We started working with A123. A123 had to go through the life cycle of a battery company, which seems to involve bankruptcy at some point. [Laughter.]

Now we are talking about LG, Samsung and Panasonic. These are significant, large sophisticated players who represent the global supply chain.

Part of the reason we have made a leap in cost is we have gone from these early guys to big guys who already have manufacturing scale and even they are talking about moving to the next level of manufacturing scale.

Potential Market

MR. ALEXANDER: Glen Davis, what size storage market do you see in the near term for your own company? Does it have the potential to grow as rapidly as solar has grown?

MR. DAVIS: I do not have hard figures, but my general sense is that the growth path is quite interesting and obviously that is why we are in it. The overall potential is probably not a match for solar. Despite all the growth in solar, it is still only 1% of generating capacity and it still has lots of room to grow. The frequency regulation market in PJM has not been in play for very long and it is already not far from being saturated.

MR. ALEXANDER: Peter Rive, how many batteries are you expecting to add this year to your systems and what growth do you see going forward?

MR. RIVE: We are seeing something like 10-times growth in our battery business year on year; it is crazy, crazy growth. Our goal has always been to deploy a battery with every one of our solar power systems within the next five to 10 years. It our goal to make solar the best energy source — period. And it just isn't right now. The fact that solar is intermittent and not available at night leaves one saying, "Guys, it is nice, okay, and it offsets a lot of carbon dioxide, but it is not the best source of power." It is our goal with Tesla to firm up solar with batteries at every single one of our solar power systems when the costs are low enough to do so.

MR. ALEXANDER: We have time for one more question.

MR. MCCREADY: Dan McCready with Double Time Capital. Peter Rive, I am not very familiar with the economics of batteries in a residential or commercial setting, but I thought I heard you say earlier that the cost is $5,000 for a battery and then the offsetting expense reduction may only be $500 over perhaps a decade. I am not sure if that factors in any benefit from the investment tax credit, but how is it with those economics that the business is still growing 10 times year on year?

MR. RIVE: I was talking about the residential application and only time-of-use arbitrage. That is not what I think will be the long-term economic opportunity in batteries. The primary reason why the residential customers are buying the battery is for back-up power. The backup generator market is bigger than the solar power market. Roughly 2 1/2% of Americans have a backup power source. A solar battery has a lot of benefits above and beyond a natural gas co-located generator. ◎

Line Drawing for MLPs

by Keith Martin, in Washington

The Internal Revenue Service made clearer in May where it plans to draw the line on the types of minerals and natural resources businesses that may operate as master limited partnerships or MLPs.

It said it will give most companies that are already operating as MLPs at least 10 years to adjust to the new rules.

The new rules are in the form of proposed regulations. They interpret section 7704(d)(1)(E) of the US tax code. The IRS is accepting comments through August 4.

An MLP is a partnership whose ownership interests are traded on a stock exchange or secondary market. The United States usually taxes publicly-traded companies as corporations. However, it makes an exception for partnerships that receive at least 90% of their gross income each year from passive sources, like interest or dividends, or from activities tied to minerals or natural resources. Such companies are able to operate without having to pay corporate income taxes. Their income is taxed to the owners directly.

The proposed regulations explain how closely tied a partnership's activities must be to minerals or natural resources to produce good income.

An IRS proposal would make it harder for paper companies and olefins producers to operate as MLPs.

The IRS has been fielding a growing number of requests for private letter rulings from companies that provide services to the oil and gas trade and want to operate as MLPs. It put a hold on any further rulings in February 2014 while it evaluated where to draw the line. For example, is a business that sends catering trucks to sell meals to workers at gas fracturing sites closely enough related to production of natural gas to be able to operate as an MLP? The agency lifted the hold in early March 2015 and said that proposed regulations would follow. It said it received more than 30 ruling requests in 2013 compared to fewer than five a year before 2008.

Proposed Line

The proposed regulations treat income as qualifying income only if it is from engaging directly in "exploration, development, mining or production, processing or refining, transportation or marketing" of minerals or natural resources or from providing a limited class of services to companies that are directly engaged in such activities.

The agency said the regulations provide an "exclusive list" of what direct activities qualify. Any additions to the list in the future will require an IRS notice or other written guidance that may be time consuming to obtain.

In general, any activity that involves retail sales or distribution to retail sellers or end users goes too far. Thus, for example, supplying gasoline to service stations does not qualify. However, there are exceptions for certain bulk and wholesale sales to end users, such as supplying fuel to electric utilities.

A number of paper companies had been considering converting parts of their operations into MLPs. The proposed regulations make clear that converting timber into wood chips, sawdust, untreated lumber, veneers (without any substances added), wood pellets, wood bark and rough poles is an acceptable activity for an MLP. However, it goes too far to produce pulp (at least if chemicals are added), paper, paper products, treated lumber, oriented strand board, plywood or treated poles. Many paper company shares were down on US stock exchanges shortly after the IRS announcement.

The IRS said making plastics and similar petroleum derivatives is not a qualifying activity. At least two chemical companies are using MLPs to own facilities that convert ethane and propane into olefins that are used to make plastics after receiving private rulings from the IRS in 2012 and 2013 that such businesses qualify. It appears that MLPs will still be able to earn income from some refinery-grade olefins, like ethylene, that are produced as an adjunct to making gasoline and other fuels. The IRS ruled out olefins because it believes they are produced through manufacturing rather than "processing." Curt Wilson, the IRS associate chief counsel for MLP issues, said at a conference in New York in May that "Congress did not intend manufacturing activities to qualify, although it said processing does. Drawing that line has been very, very difficult, and so we relied on a lot of IRS engineers to tell us what [manufacturing] means." Wilson said he remains open to being persuaded that olefins should qualify.

Services to the oil and gas trade qualify only if they pass three tests.

The services must be specialized, essential and significant to the direct activity being undertaken by / *continued page 72*

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the oil or gas company.

They are "specialized" if the workers who perform them require special training unique to minerals or natural resources industries. If the company is providing property, then the property must be of limited use outside the direct activity and not be easily converted to another use. An MLP can provide injectants, like water, lubricants and sand, for use in fracturing, provided it collects the injectants after use and cleans, recycles or otherwise disposes of them as required by law.

Services are "essential" if they are necessary physically to complete the direct activity or to comply with federal, state or local law regulating the direct activity. An example is water delivery and disposal to a gas fracturing site. Legal, financial, consulting, insurance and similar services are not considered essential.

To be considered "significant," the services must require partnership employees to be an "ongoing or frequent presence at the site" and the employees must be doing something that is necessary for the direct activity. The IRS said the work can also be offsite. An example is offsite monitoring.

Transition Relief

Renewable energy companies have been lobbying Congress since 2004 for the ability to operate as MLPs. They are not able to do so currently mainly because their income does not come from "minerals or natural resources." Energy sources like the sun or wind are not natural resources because they are inexhaustible. The phrase refers only to things that deplete. Senator Chris Coons (D.-Delaware) reintroduced a bill in late June to allow MLPs to own a broader class of assets. The assets include not only renewable power projects, but also fuel cells, combined-heat-and-power projects, electricity storage devices, renewable chemicals companies, installers of energy efficiency improvements, biofuels producers, power plants and large industrial facilities that capture and store their carbon dioxide emissions and gasification projects that gasify coal, petroleum residue, biomass or other materials and that capture and store a significant percentage of the carbon dioxide emissions.

Interest in MLPs among renewable energy companies has been waning after the industry discovered yield cos, which are a form of synthetic MLP and do not require any action by Congress to implement.

Most companies already operating as MLPs will have 10 years from the end of the partnership tax year in which the IRS republishes the proposed regulations in final form to adjust to the new rules. Republication will take at least another year. This transition relief will be given to any existing MLP that, before May 5, 2015, had a private letter ruling, treating as a qualifying activity, an activity that the IRS regulations now treat as ineligible or that was treating an activity as qualifying under a reasonable interpretation of the US tax code before the proposed regulations were issued. The IRS said merely having a "reasonable basis" for a position is not good enough.

There is no current plan at the IRS to revoke any existing private letter rulings. At least 10 to 12 such rulings are at odds with the proposed new rules. The rules are not yet final. In addition, some companies have been concerned that if the rulings were revoked, then they would not be able to rely on them during the transition period.

At least 149 MLPs are trading currently on US exchanges. Of that number, 93 involve oil and gas (including oilfield services MLPs). The remaining MLPs include seven that own coal mines, 10 that are engaged in marine transportation, four that are propane MLPs and 10 that are in other natural resources. ◎

Time For Desalination Plants?

California is in year four of a record drought. The governor has ordered a 25% cutback in water usage. Is it time to roll out plans for $1+ billion desalination plants? Large combined water and power projects are commonplace in the Middle East. Carlos Riva, CEO of Poseidon Water, and Sandra Kerl, deputy general manager of the San Diego Water Authority, talked about the economics of desalination projects at the Chadbourne global energy & finance conference in June. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Carlos Riva, you are working on a large desalination plant in Carlsbad, California between San Diego and Los Angeles, about 60 miles south of here. Let's get some metrics. How much is the project expected to cost?

MR. RIVA: It is a $1 billion project. The financing of it was $930 million and then, in addition, the water authorities spent something like $80 million making improvements to their systems to be able to accommodate the water. The water is 50 million gallons a day, 365 days a year.

MR. MARTIN: How many households will that supply?

MR. RIVA: That is about 8% of the water supply for San Diego County.

MR. MARTIN: Is that the water supply of just the county or the city of San Diego, as well?

MR. RIVA: We will sell all of our water under a 30-year contract to the San Diego Water Authority, which is the wholesale agency, and they will resell the water to their members, who are the local water districts.

MR. MARTIN: How many districts can there possibly be in and around San Diego?

MS. KERL: We have 24 member agencies.

MR. MARTIN: I didn't realize California had such an intricate government. Why do you need more than one water agency for San Diego?

MS. KERL: That's a really long topic. [Laughter.]

MR. MARTIN: Carlos Riva, how long is it taking to build the Carlsbad project?

MR. RIVA: The construction is fairly straight forward. We have a contract that guarantees no longer than a 35-month construction period. We are trending a little ahead of that, so we expect to be commercial, knock on wood, by the end of September or early October 2015, which will be two months ahead of schedule.

MR. MARTIN: Do you expect a shakedown period before the project is fully operational?

MR. RIVA: That includes the shakedown period. We are in commissioning now. The plant is more than 95% complete and so we are wet commissioning it now and then there will be a 30-day acceptance period at the end of which the plant will be commercial and sales will commence under our water contract.

Economics

MR. MARTIN: In the Middle East, these projects include a power plant and a desalination facility. Yours produces only water. Where are you getting the electricity from to run it?

MR. RIVA: Our plant is different than many of the desalination projects in the Middle East that use a distillation process. Ours uses a reverse osmosis process, which uses high pressure to drive water through special filters that purify the water, and that is driven by electricity rather than thermal processes. We get our electricity from the grid, from San Diego Gas & Electric.

MR. MARTIN: You are paying a retail rate?

MS. KERL: In the water purchase agreement, the risk for energy usage per unit volume of water is on Poseidon and for the price is on the water authority. The water authority has the ability to supply power to the project at any time. We are looking at all of our options, including the possibility of building a hydropower pumped storage project with the city of San Diego.

MR. RIVA: We have the ongoing incentive to try to find ways to reduce the energy consumption for each unit of water produced. There is a lot that can be done as new technologies for membranes and the like start to be developed over the life of the plant.

One thing again that I found very interesting about this technology is, unlike those of us that have been used to large power projects, where when you buy your turbine, for instance, you have that turbine for life and the turbine represents a major single point failure potential and also a major expense.

Here, out of a $1 billion project, the cost of the membranes is something like $10 million. There are 14,000 of them. They last maybe five to seven years, so you are constantly in a position of monitoring and swapping them.

A lot of people may have heard some of the new innovations in membranes with new materials, graphene and the like. We have the ability to introduce those technological changes into

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our plant as part of the normal process of maintenance, and that is where we see a lot of future benefit in reducing energy.

MR. MARTIN: A lot of benefit, but also continuing high capital costs to replace these membranes?

MR. RIVA: No. No. Absolutely not. The cost is already factored into the O&M budgets for the units going forward.

MR. MARTIN: Let's talk about financing. You used $734 million in tax-exempt debt. You said it was $930 million in total financing. How was the balance covered?

MR. RIVA: The balance came from an infrastructure fund, Stonepeak Infrastructure Partners, and they are the source of the permanent equity for the project.

MR. MARTIN: So the balance up to $930 million was equity. The water authority provided $80 million. In what form did the water authority provide that?

MS. KERL: In addition to the plant, there is a 10-mile conveyance pipeline to get the water into the water authority system, and then the water has to be pumped up quite a distance. We put in a pump station as well as made improvements to our water treatment facility to accept the water.

We will be moving the water in our aqueduct in the opposite direction than it moves today. We had to strengthen that aqueduct pipeline to withstand the pressure, and that accounts for the $80 million.

MR. MARTIN: So about 73% of the capital cost was debt, the balance equity. What sort of returns were the equity investors promised?

MR. RIVA: It was actually 18% equity and 82% debt. The extra $80 million dollars that Sandy spoke about was not part of the financing. That was done by them.

I think that the returns that the equity investors were looking at were consistent with the kind of returns that large infrastructure projects that have 30-year take-or-pay offtake contracts would expect.

MR. MARTIN: So high teens?

MR. RIVA: I wish, but no.

MR. MARTIN: The Carlsbad project was 12 years in the making, right? You had to work through the regulatory maze. I think you spent six years getting permits. Do you have other projects that are equally far along?

MR. RIVA: Our next project is just up the coast in Huntington Beach. It is a similarly-sized project. We think we are about a year away from starting construction, so that will be another 30-some months of construction.

That project has most of its permits, although It is missing one critical one from the California Coastal Commission. We have signed a term sheet with the Orange County Water District to sell the full output of the unit for, in this case, 50 years.

Offtake Contract

MR. MARTIN: Sandy Kerl, you signed a contract to buy the output from Carlsbad for the entire output from the plant. But there is a minimum take requirement. You have the option to take above that.

MS. KERL: Yes, our minimum take is 48,000 acre feet a year. The plant can produce up to 56,000 acre feet a year. If we take that additional increment, it is only at the variable cost, so there is an incentive for the water authority to take it.

We wanted to ensure that we were only committing to take the amount of water that we believe we can use. However, given where we are in California, in the fourth year of a drought, I suspect that we will probably be heading upwards of the top limit

A $1 billion desalination plant nearing the end of construction in Carlsbad would supply up to 8% of the water supply around San Diego.

of the plant. Nevertheless, we wanted to ensure that we were not taking water and storing it from the plant.

MR. MARTIN: What happens if the water authority does not take more than 48,000 acre feet per year? You simply produce at the lower number? There is no one to buy the extra output?

MR. RIVA: We don't produce it, but we will recover all of our costs at that level of output.

MR. MARTIN: Sandy Kerl, is your payment solely the equivalent of an energy payment –- it is just for water taken –- or is there also a capacity payment?

MS. KERL: We are purchasing water. We take the amount that we have committed to. If for some reason we can't take it under certain conditions, we still pay for the water, but we do not pay for anything unless Poseidon delivers the water at the quality and consistency that we require.

All the risk for operating is on the project, and the obligation to the water authority is to make that minimum 48,000 acre feet purchase a year.

MR. MARTIN: In terms of cost, I think you buy your water currently from various sources, correct?

MS. KERL: We have several sources. We get about 48% of our water from the Metropolitan Water District, which takes water from the Colorado River as well as the Bay Delta project. We also have something called the Quantification Settlement Agreement, where we have done a deal with the Imperial Irrigation District to get water that has been saved through farming conservation.

That is our water that comes directly to us. Then the desalination project is a next increment to make sure that we have a diversified portfolio of water. It will represent up to 10% of the total water needed in San Diego County.

MR. MARTIN: How does the amount you pay Poseidon compare to what you pay others for water?

MS. KERL: There are two markers to look at on that. Today, it is about double the cost of what we pay to Metropolitan for water, but over time those lines will cross. Because we have a contract and specific provisions for how costs increase, we have some level of control.

We do not have similar control over the Metropolitan water. We believe the cost lines will cross in about the 2020s. If we try to develop other new sources of supply – for example, potable reuse projects and water that is conserved from the lining of earthen canals, the All-American and Coachella canals — the cost of that water will be what we are paying for desalination. The next new increment is double what we are paying today. There is no cheap water available.

MR. MARTIN: This is a concept with which we are familiar in the power industry with front-loaded power contracts, where the utility pays more up front to allow the project to get financed in exchange for paying less later.

In a way, this is an insurance policy. You have a 30-year water contract. You are buying insurance for 8% of your supply, yet you are down more than 8% currently in the state due to the drought. Would it make sense to buy more such insurance?

MS. KERL: It is a balance of risk and cost, and right now I think our board feels that we have the right balance, but over time, we will be continuing to look for opportunities for sources of supply.

We are doing some pilot testing of a desalination plant out on Camp Pendleton. That project, if it moves forward, is probably an early 2030 project that could be the size of Carlsbad or even three times the size of the Carlsbad project.

MR. MARTIN: And that would be one you own?

MS. KERL: Potentially.

MR. MARTIN: Just to put things into perspective, the Carlsbad project is the largest in the Americas, correct?

MR. RIVA: That is correct.

MR. MARTIN: And there is a large number of desalination plants already in the US, but they are small.

MR. RIVA: That is correct. The second largest, in Florida, is about half the size of Carlsbad, and then there are many that are a tenth the size or smaller.

Fickle Climates

MR. MARTIN: Sandy Kerl, there was a long article in the New York Times, and there was a similar one in the Los Angeles Times recently, that suggested we will not see any more desalination plants in California because, by the time they are built, the rains will return and they will be shut down.

MS. KERL: Don't we wish.

MR. MARTIN: What do you think the appetite is among water agencies in California for more of these plants?

MS. KERL: I think all eyes are on the Carlsbad project right now, and after four years of drought, we do not know what will happen in 2016 and beyond. We will continue to be in more drought years than wet years, so looking to a new source of water supply for the west should be something in which many communities in California are interested.

MR. MARTIN: Carlos, those two newspaper articles also mention that Santa Barbara built a / continued page 76

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desalination plant, at a cost of $34 million, in the late 1980s. The plant was completed in 1992, by which time the rains had returned.

It was put through start-up testing, and then immediately mothballed. Australia spent something like $12 billion on six desalination plants in 2006. By 2012, four of them had been shut down. What do you think when you see such statistics? Is this a good business to be in?

MR. RIVA: It is a fair question. I think Santa Barbara is a bit of a different case because the technology has moved on so much since the 1980s, and they are putting another one in. It will use more modern technology and will be maybe four times more efficient from an electrical standpoint.

The project was financed with 82% debt.

I think Australia is a different case, too, and it is not a uniform case. In western Australia, the plants are operating, and they are an essential part of the supply. Eastern Australia went through a prolonged drought. They were built as an insurance policy.

When the rains returned, they did not need the coverage, but by the same token, you cannot look back at life insurance and complain because you didn't die.

Southern California is very different as well because these projects were not built to address a drought. They were begun well before this epic drought. Part of the motivation was drought that occurred back in the 1980s and early 1990s, but nevertheless, they were built to secure a local supply of water because San Diego County has enough water for only about 10% of its needs.

The balance back then was all imported, as Sandy said, so they really wanted a local supply because it was drought-proof and because the water coming from long distances was subject to all sorts of other hazards, including seismic risk and the like.

Over time, this is a lower cost option than continuing to buy imported water from other sources, so there are a lot of compelling drivers for that. Those are not going to change when the rains finally come back.

MR. MARTIN: Why not?

MR. RIVA: Because I think those same drivers will be there; people want to have a local supply. Water is too critical to them to leave it to chance of either drought, politics or earthquakes, and they want to be able to control it in ways that they can't with imported water.

MR. MARTIN: Sandy Kerl, you negotiated the contract with Poseidon Water. What was the one biggest impediment to reaching a deal? The toughest issue.

MS. KERL: I think the biggest challenge was for us to come to an understanding about the difference between the public sector and the private sector. Everything we do in the public sector has to be completely transparent, so every cost component and every aspect of the deal we struck was subject to public review and comment.

I can't speak from the private sector because I have not been in the private sector, but for Carlos it was like, "What do you mean we have to share this with everyone?" We have to be fully up front with where the costs are coming from and what the rate of return is.

That was challenging, but once we got over that hump and came to a mutual understanding, I think we had a very powerful working relationship. Once we got the water purchase agreement done, we went on the road and met with investors together.

It was really a public-private partnership. It is a BBB minus rated project and the fact that the water authority, which is a AA plus credit, was the sole offtaker of the water helped in terms of the overall financing package. I think it is the transparency.

MR. MARTIN: Carlos, what did you take away as a lesson from the experience at Carlsbad that you will apply to the next project?

MR. RIVA: I think Sandy hit on it. It is the fact that doing deals with municipal agencies is very different than doing them with corporates, especially when you look at Sandy's board, for instance, with thirty-some members.

MS. KERL: Thirty six.

MR. RIVA: A number of those are elected officials, which means that you are actually doing a deal with the electorate, with the public, and they have demands for transparency. They want to know how you got to the outcome.

It is not like going into a room with closed doors and negotiating, coming out and saying, "This is our deal, isn't it great?" They want to know every step along the way.

That was a revelation for us because we had not really experienced it in the power sector. Sandy touched on it: even though this is a bilateral contract where we produce water and sell it to them, we had to get over the mental construct of that to understand that this is really a partnership. It was never going to happen until the water authority was comfortable that everything was done according to standards that would meet its requirements for transparency.

Also, Sandy at one point said to me, "This may well be fine; that's a contract, but you have to understand that if you guys screw up and something happens to the contract, it is still 10% of our water supply, so we need to own that."

Once that got through our thick skulls, we made a lot of progress. That lesson is something that we will bring to the next negotiation.

MR. MARTIN: It sounds like the good relationship the two of you developed during negotiations was central to pulling off the project. It also sounds like the best time to do a deal like this is right after an election, rather than becoming tied up in the election, with 36 board members having to comment, many of whom are elected officials. ◎

China Launches a Multilateral Infrastructure Bank

by Li Zhang, in London, and Xuanwu Jin, with the Sunshine Law Firm in Hangzhou

China is moving to form a New Silk Road Fund and an Asian Infrastructure Investment Bank that will finance power and other infrastructure projects along six corridors in Asia, the Middle East and eastern and northern Africa.

They are both part of a "One Belt, One Road" development strategy that China hopes will lead to greater cooperation among countries on Asian, European and African continents.

The strategy has two main components — a land based "Silk Road Economic Belt" and the oceangoing "21st Century Maritime Silk Road." Both were first unveiled by Chinese President Xi Jinping during visits to Kazakhstan and Indonesia in 2013, but have since attracted close attention.

The Silk Road Economic Belt is an initiative to improve land transportation such as road and rail routes and other means of connection, including oil and natural gas pipelines and IT infrastructure, in an area that stretches from China to central and South Asia, Russia, the Mideast and Europe. As its equivalent on the sea, the 21st Century Maritime Silk Road is an initiative to create a network of ports and industrial parks scattered across South and Southeast Asia, East Africa and the northern Mediterranean Sea.

In addition to infrastructure development and construction, the One Belt, One Road development strategy also calls for promoting greater financial integration and removing trade barriers such as customs and restrictive border controls in the regions. There will be a particular emphasis on strengthening cooperation in the energy sector through investing in new projects and establishing investment zones.

China is considering developing up to six major economic corridors along the Belt and Road, according to a recent blueprint released by China's top economic planning agency, the National Development and Reform Commission (NDRC). The six corridors are shown in map 2 and are referred to in China as the New Eurasian Land Bridge, China-Mongolia-Russia, China-Central and Asia, China-Indo-China Peninsula, China-Pakistan, and Bangladesh-China-India-Myanmar. */ continued page 78*

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A number of new financial institutions have been established to provide financial support. The most important are the New Silk Road Fund (NSRF) and the Asian Infrastructure Investment Bank (AIIB), which are considered to be the financial arms of the "One Belt, One Road" strategy.

The NSRF was established in late 2014 in the form of a limited liability company under Chinese law with an initial capital of US$40 billion. It will fund investment that is essential to the development of trade routes along the "One Belt, One Road" area. The initial shareholders of the fund are all from China, including the country's sovereign fund, China Investment Corp., and two leading Chinese policy banks — The Export-Import Bank of China and China Development Bank. However, the fund will be open to investors from other countries. The fund has already started operation. A memorandum of understanding for a pilot hydroelectric project in Pakistan was signed on April 20, 2015.

AIIB

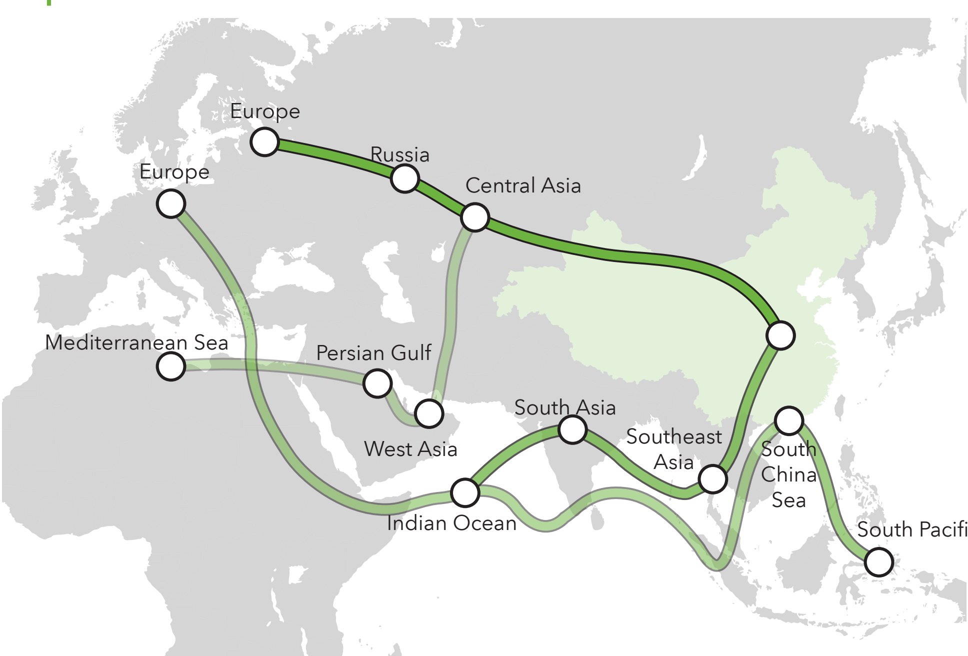
The AIIB was designed to be a multilateral organization and to mimic the roles of several Washington-based international lending institutions and the Asian Development Bank in Manila. It has currently 57 founding members comprised of 37 Asian countries, 18 European countries, Australia, New Zealand, two African countries and Brazil. The authorized capital of the AIIB is expected to be US$100 billion and will be used exclusively for infrastructure projects in sectors such as energy, transportation, telecommunications, agricultural development, urban development and logistics in Asia.

Map 1

Silk Road Economic Belt and Maritime Silk Road in the making

Source: xinhuanet.com, and Barclays Research

Map 2



As a regional development bank, AIIB's regional members will be the majority shareholders while non-regional members will hold smaller equity shares of the bank. Seventy-five percent of the AIIB shares will be reserved for Asian countries, of which China and India are supposed to hold 25% and 10% respectively. This shareholding arrangement reflects the commitment and ownership of regional members while providing non-regional members the opportunity to participate. The prospective founding members of the AIIB are shown in map 3.

The new Asian Infrastructure Investment Bank organized by China is expected to start with roughly US$100 billion in capital.

The AIIB will make loans and equity investments and provide guarantees. In addition to the capital subscribed by members, it is anticipated that the AIIB will raise funds primarily through the issuance of bonds in world financial markets as well as through the inter-bank market transactions and other financial instruments.

The founding members agreed on the articles of association of the bank in May 2015. Upon signing, signatories to articles will start their domestic ratification procedures. The AIIB is expected to start operations by the end of 2015. It is supposed to fill a gap between the region's infrastructure financing needs and the financial resources available from existing multilateral and bilateral development institutions.

Additional funding for such projects may soon be available. Another new development bank is being established by the BRICS — Brazil, Russia, India, China and South Africa — that will have a capital of US$100 billion and a reserve currency pool worth another US$100+ billion. A separate new Shanghai Cooperation Organization development bank is being established by Russia and China to focus on / continued page 80

Table 1

Regulatory Approvals Required	Old Regime	New Regime
State Council approval	Resource-related projects with an investment of US$200 million or more by a Chinese investor and projects that use more than US$50 million in foreign exchange.	Projects in a sensitive country or a sensitive industry with an investment of US$2 billion or more by a Chinese investor.
NDRC approval	All projects except for those that are subject to State Council approval.	All other projects that involve either sensitive countries or sensitive industries.
NDRC filing	Not applicable	All projects that involve either sensitive countries or sensitive industries.
MOFCOM approval	Projects with any one of the following features: In a sensitive country; In a sensitive industry; Uses a special-purpose vehicle; or Chinese investor invests US$10 million or more.	Projects in a sensitive country or a sensitive industry.
MOFCOM filing	Not applicable	All other projects not subject to MOFCOM approval.
SAFE registration	All projects	

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financing interstate infrastructural projects and foreign trade cooperation.

China is trying to address two problems with one leap with the "One Belt, One Road" strategy.

China's economic growth is slowing down. The days when it enjoyed double-digit growth rates are gone. The growth rate for 2014 was 7.4% and is expected to slide to 7% in 2015. To make things worse, overcapacity that was caused by the US$4 trillion economic stimulus package introduced to combat the financial crisis of 2008 is taking its toll on the country's economy. The industry sectors that received massive financial aid through the stimulus are now all struggling with overcapacity. The most affected sectors are steel, cement, aluminum and photovoltaics, each having an average capacity utilization around only 70%. Therefore, exploring new markets overseas has become vital for the Chinese economy.

At the same time, Asia faces a massive infrastructure gap. Many Asian countries have long been suffering from outdated or insufficient infrastructure devolvement. The Asian Development Bank (ADB) estimates that for the period between 2010 to 2020, Asia needs US$8 trillion for infrastructure construction. Unlike countries such as China and Japan, the majority of Asian countries have neither the money nor the industrial capability to undertake infrastructure overhauls that are considered long overdue. The ADB is doing the best it can to help with the situation, but a little help from a new lender should be welcome: apart from infrastructure projects, the ADB invests in a wide range of projects such as public health and education, which means only a fraction of its US$160 billion capital is devoted to infrastructure; in contrast, the newly-established AIIB will apply all of its US$100 billion exclusively to infrastructure.

Chinese Outbound Investment

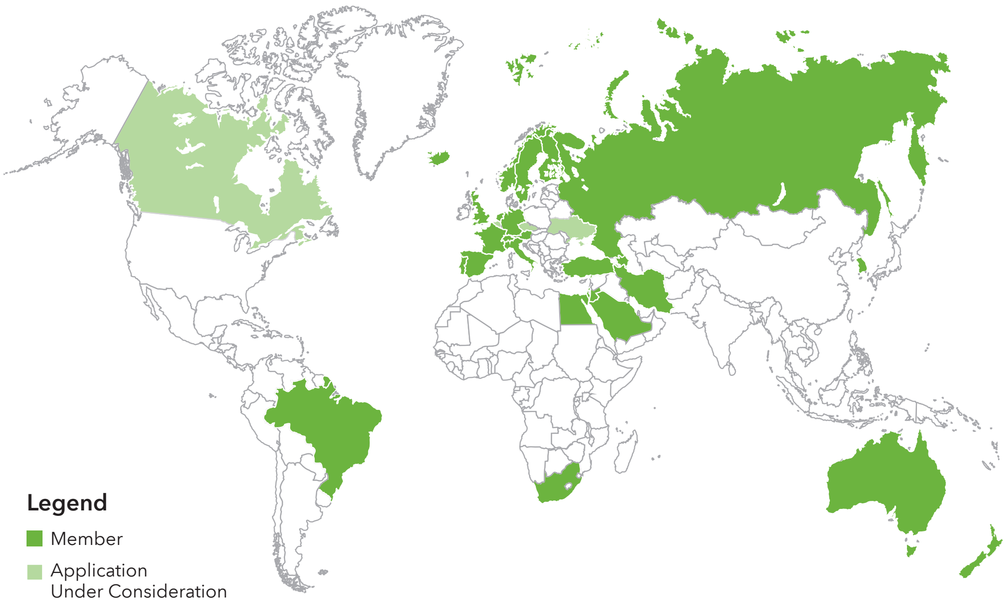
China has also made recent regulatory changes to promote outbound investment. China launched a "going out" strategy 10 years ago to encourage Chinese companies to make overseas investments and acquisitions. Chinese companies are expected to gear up their outbound investment activities further in view of the additional financial support on offer. In the meantime, the latest, and by far the most significant, round of legal reforms has been completed, setting the stage for a new wave of outbound investment. Three Chinese regulatory bodies — the National Development and Reform Commission (NDRC), the Ministry of Commerce (MOFCOM) and the State Administration of Foreign Exchange (SAFE) — each rolled out new rules loosening state control of outbound investment in the last year (see table 1). The new regime supersedes a previous one that had been in place since 2004.

No more registration with SAFE, banks keep records of foreign exchange use, no extra procedure to be followed.

The new regime shifts from an approval-based process to a filing-based process, reduces the number of outbound investments that needs approval of the government and shortens the time required for approval. It also cancels the requirement of foreign exchange registration with SAFE to allow funds to move

Map 3

Prospective Founding Members of the AIIB



more quickly. The administrative procedures for overseas investment have been significantly simplified.

The business sector has reacted positively to the changes. Outbound investment in foreign companies by Chinese firms soared to a record high of 246 in 2014, an increase of 30% compared to the year before. The trend continues in 2015: in the first quarter of 2015, 77 deals were completed with an aggregate deal value of US$20.2 billion. Both figures are record highs. Although popular investment destinations include all countries along the Belt and Road, ASEAN stands out as a key region largely because it is currently hosting most of the member states of the AIIB.

Eighteen European countries have following the lead of the United Kingdom and joined the AIIB as founding members. Being founding members gives these countries the right to participate in formulating the new bank's policies. This is important in view of concerns about transparency of how the AIIB will be governed. There are, of course, more tangible benefits. Joining the AIIB will allow these countries to tap into the huge infrastructure market in Asia. Countries like the UK, Germany and France all have companies with household names in the infrastructure sector in the region. These companies are expecting to reap the economic benefits by landing contracts relating to projects that are financed by the AIIB. Smaller companies from other European countries will be trying to land sub-contracts with the bigger firms.

Another opportunity from which the European countries may benefit is the new bank may decide to raise capital by issuing bonds, given that the AIIB's initial capital of US$100 billion is still modest compared to the ADB's capital of US$165 billion, let alone the US$8 trillion funding shortage for infrastructure in the region. Any such bonds may be placed in European markets. ◎

Seeking Investments

Investment managers at three private equity funds talked at the Chadbourne global energy & finance conference in June about where they see the best opportunities currently in the market. The panelists are John Breckenridge, managing director and chief operating officer of Capital Dynamics, Christopher Hunt, managing director of Riverstone Holdings, and Drew Murphy, senior managing director of Macquarie Infrastructure and Real Assets Inc. The moderator is Noam Ayali with Chadbourne in Washington.

MR. AYALI: Drew Murphy, start us off. Tell us your current focus.

MR. MURPHY: We have a global business platform at Macquarie Infrastructure and Real Assets or MIRA, as we call it, but our funds are all pretty much regionally focused, so what we do out of the New York office is really focused primarily on North America.

Our traditional infrastructure funds look at core infrastructure: utilities and regulated assets, public-private partnerships, contracted power and some mid-stream oil and gas. We have access to capital for new funds to the extent we see opportunities.

In terms of dollar size, we are generally looking for larger investments, so $200+ million. We might go a little below that, but $200 million to up to $1 billion where we have co-investors alongside of us is our sweet spot. We have one vehicle in the US that is a publicly-traded fund or infrastructure company that has invested in smaller transactions where the equity checks have been $10 or $20 million as part of a portfolio approach to investing.

MR. AYALI: John Breckenridge?

MR. BRECKENRIDGE: Capital Dynamics Clean Energy and Infrastructure Fund is basically a mid-market power fund. We have invested in Australia, the UK and North America primarily, although we have some current vehicles that have broader geographic focus. Our sweet spot is a late-stage development asset. We do the last mile of development work, financing construction and then owning the assets. I probably represent the smaller end of the equity check bite size on this panel, probably about $50 to $100 million per transaction. We have invested in gas-fired generation, done a significant amount of wind, solar, biomass and landfill gas, and have done a number of other transactions across the power generation gamut with the exception of coal.

MR. AYALI: Chris Hunt?

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MR. HUNT: Riverstone has assets under management of about $30 billion. That extends across the energy spectrum, everything from E&P to pipelines to refineries, service companies and, of course, power.

We are slightly different than other private equity firms in the sense that we set up a dedicated fund to do clean energy work that is in large part solar and wind, but also includes natural gas-fired generation.

We are currently investing a $3 1/2 billion fund that we call Renewable and Alternative Energy II. That fund has done several transactions that are probably relevant to this conference, one of which is Pattern Energy, which was one of the early yield co companies. We also did a lot of the solar assets that led to the formation and initial public offering of TerraForm Power. We also recently listed one of the first renewable master limited partnerships, which is a company called Enviva Biomass that sells wood feedstock to coal producers. We have also done a number of service-type investments for the power industry. Generally, it has been a favorable fund, but it is not without its daily challenges.

MR. AYALI: A few numbers might give us all a sense of perspective. According to Bain's Global Private Equity Report, 2014 was a record year for private equity exits, $450 billion worth across the private equity spectrum, so the figure is not solely energy and infrastructure. It was also a very strong year for new fundraising: $1.2 trillion was raised across the private equity spectrum and, out of that, $400+ billion is earmarked for buyouts alone. In terms of private equity returns, 2014 produced returns that exceeded the S&P index. Obviously it was a very strong year for the sector.

What do 2015 and beyond hold? What are the challenges?

MR. HUNT: This year and next year, I would rather be a seller than a buyer. I am currently selling several businesses and am finding the interest levels quite high. There are a lot of buyers for well-structured wind and solar projects. The pricing is great. A comment was made yesterday that you are probably never going to find a time when there are better valuations.

Once we sell this current wave of assets, we then have to create the next wave and that is going to be a bit more of a challenge. I am a little nervous about what happens when my cupboards run bare and I do not have anything else to sell and have to go out and fill them up again.

Some private equity funds are selling assets and will have to restock later.

MR. AYALI: John Breckenridge, what keeps you awake at night?

MR. BRECKENRIDGE: There are two ways to look at the overall market today for power assets. You have an overall low growth environment, low power price environment, low cost of capital environment. It has been hard to find a way to make money in the solar sector. It is easy to have a negative outlook currently as an investor.

On the flip side is there is a tremendous amount of change underway in the industry. Gas is cheap. You have a huge amount of coal. We talked about numbers yesterday, that even for me sounded like big numbers, for coal retirements. You have a big change in the cost of capital that is spurring lots of development.

It is hard to have a thematic view of the market, but, because of all this change, there is tremendous room to be opportunistic. I have been surprised about the number of middle-market transactions that we have coming into our office given my overall view that the market as whole is not so exciting.

MR. AYALI: Drew Murphy, your challenges?

MR. MURPHY: The first panel yesterday of investment bankers talking about new trends sort of pulled me up short. I came here thinking I would talk about the fact that we are looking at PJM assets and the unique idea of paying for a development pipeline and buying a management team, and then it turns out that other people are willing to pay for that, too. That is a challenge.

There is a lot of money looking for a home. There are new entrants in the space looking for opportunity. You have to pick your spot. There is a tremendous number of assets available for sale.

You need to have a thesis-driven approach to each opportunity, to whether it fits the thesis and there is room to optimize it. That means going deep and doing more work on assets than you might otherwise have had to do previously.

This is also a market undergoing rapid change. We heard yesterday about at what pace section 111(d) might drive coal retirements. Those types of regulatory changes could mean more renewables and transmission opportunities for us. While it is a sobering time for us because of the amount of capital and the need to be careful what you buy, it is not market without opportunities.

Shadow Capital

MR. AYALI: One of the themes of the past year has been "shadow capital." The term refers to the competitive position of the fund versus its limited partner investors who are now looking to chase the same transactions and assets in which the fund is interested, not so much through the private equity but alongside the private equity or in competition with the private equity. Is this a challenge or an opportunity?

MR. MURPHY: It is a definite trend. The larger investors are looking for ways to deploy more capital and reduce the fees they pay. It is a reality that we have to recognize.

We view it as more opportunity than challenge. We are focused on giving our investors the opportunity to come in alongside us on interesting deals. For example, we announced last fall the acquisition of Cleco, the electric utility company in Louisiana. That was a deal that required about $2.2 billion of equity, more than our infrastructure fund in the US can do on its own. A large part of it came in as co-investment with relationship investors who are also in the fund and they appreciated that we led them to the deal and did a lot of the work for them. We hope to continue that pattern and avoid getting into a competitive head-to-head situation.

MR. HUNT: Most funds have a concentration limit. Usually it is in the 20% range, so if you just do simple math, it means that any fund is going to cap out on the size of transaction it can do. If you take the right perspective on co-investment and, as you call it, shadow capital, it just means that you can look at more deals. You still have to do the administrative work of getting your co-investors into the deal, and negotiate the governance rights and fees or no fees that go with it. It is a bit more work, but it opens up a whole new set of transactions that you can do. I mentioned Pattern earlier. That was large check, and the only way we could do it was by having direct investment from some of our investors.

MR. AYALI: I have seen reports that private equity has started to narrow its focus to sub-segments of the renewable energy space. For example, I read that one private equity fund is exiting the wind sector to focus on solar. How common is this, and is the direction toward solar?

MR. BRECKENRIDGE: We are still agnostic about technologies. I am surprised to hear that direction because I would have said the movement is in the other direction.

It is hard to make money on utility-scale solar. Obviously, residential rooftop solar is another business, and we are not in that business. We still think wind is interesting and, for a late-stage development investor, wind fits us very well.

We tell our investors that it is important for them to be invested with people who are agnostic about the technology because the opportunities move around rapidly, so you have to be nimble and be able to move from one to another

MR. AYALI: The last couple years have seen a tremendous focus from the private equity sector on natural gas, mid-stream assets, a lot of shale opportunities and then culminating in some headline-grabbing LNG investments, Blackstone and Cheniere, IFM and Freeport, and GIP and EIG now in Corpus Christi at Cheniere's new terminal. Prices of oil have obviously been plummeting and are affecting opportunities in these sectors. Chris Hunt, how do you see low oil price affecting both your current holdings?

MR. HUNT: Did the oil price go down? [Laughter.]

MR. AYALI: There was a rumor.

MR. HUNT: Those of us who are 30-year veterans of this industry have seen this cycle before. This is not the first time we have seen oil prices drop, and it will not be the last time.

The good private equity companies that have made investments in this space do it in a manner in which you can sustain cyclical movements.

The oil price drop will affect those who / *continued page 84*

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got over extended and did not set up capital structures to allow them to weather a difficult period. And there are many of those. Their travails will create opportunity for further investment by other private equity companies. You should see a lot of good and a lot of bad come out of this period. It will show who was properly prepared and who was not.

Emerging Markets

MR. AYALI: Shifting toward opportunities in the OECD countries versus emerging markets, Drew Murphy, how do you decide whether to look beyond the safe OECD investments? What kind of hurdles do you need to hit in emerging markets?

MR. MURPHY: Our funds are generally focused on specific regions. For example, we have a specific Mexico fund. It was set up with the kind of return thresholds that we thought we would need to show investors in Mexico. We are launching a LatAm fund for which we are in the process of fundraising now. It will focus on Mexico, Brazil and maybe one or two other countries. Returns will have to be at a level that compensates for the additional market risk in these countries.

We have stayed away from what we would consider the true emerging markets. We have had a presence in Africa, but we are not very active there right now as it is pretty challenging. Our Asian funds have mostly focused on the more developed countries: Korea is very active for us, Australia, India is a bit challenging, Japan and China, but we are more focused on the more developed countries because we are better able in such countries to get our arms around the risk and return.

MR. AYALI: Chris Hunt, does Riverstone use dedicated country funds?

MR. HUNT: We tend really to have only three kinds of funds. We have a conventional energy fund and a renewable energy fund, and we started a credit fund that we are in the process of raising now. We tend to go global. We do not put geographic restrictions on where we can go.

If you look at where we have actually placed most of our capital, it has been in North America with some Europe. We are now doing a fair amount in Mexico and are looking at some things in Japan.

It is an obvious question to ask a private equity guy whether he goes to the emerging markets given how full the market is in the United States. I can only speak for my specific area, which is power and renewables. I started in the emerging markets. You will remember the infamous Dabhol project. So many of us have lived through some very difficult scenarios in the emerging markets, and it is hard to see a viable case for investing in such markets at the current return levels on offer. I see people doing deals with relatively low yields in places like South Africa and Brazil and now even India, and it is hard to imagine that is an appropriate risk-reward ratio, so we plan to wait and watch.

MR. AYALI: Let's talk some details. Are you looking for control positions? Are you looking for significant minority positions?

MR. BRECKENRIDGE: We do not have a preference. It does not matter whether we are the lead investor or a partner. It is a matter of who the team of equity investors is and whether their goals are aligned. Sometimes we do better by having a co-investor with whom to talk out issues.

MR. AYALI: Chris Hunt, you are shaking your head.

MR. HUNT: If you are going to have a partner, you want a partner that you get along with and that brings something to the table. I have been involved

Fund managers need to have a thesis-driven approach to each investment.

in investments where things sour and you sometimes make bad decisions if you have a partner with whom you do not get along and who has different objectives. I have also been in situations where our partners see things that I missed and bring a lot to the table. However, recognize that in every private equity company relationship, you have a partner by definition in your management team, and sometimes if you add another partner on top of that, you get into exponential partnership management issues, which can be tough.

MR. AYALI: Drew Murphy, how important is control?

MR. MURPHY: It depends on the situation. Our general view is that we want to be in a position where we have significant influence and that could include a significant minority stake where you have the right to control major decisions.

Standing Out

MR. AYALI: There is a lot of liquidity, a lot of money-chasing opportunities. Chris Hunt, you mentioned that there are lots of new entrants. How do you stand out in such a crowded market?

MR. HUNT: It is not easy, but I learned some things in the course of doing this that seem so obvious now, but did not seem so obvious at the time.

When you raise a fund, it is a five- to 10-year fund. The first thing I learned is you take your time. A lot of people are in a rush to spend the money immediately and get it out the door in the first year. I have learned that my best investments are those investments that I make over an extended period of time. You wait, you watch, you study and you pounce at the appropriate time. If someone were to give me $1 billion today and say where would you spend it, I would say I will get back to you in six months and we will talk about it. There is so much money out there that you really have to be circumspect, sit back and do not get forced into an investment solely for the sake of doing an investment, particularly now when valuations are so high.

MR. MURPHY: Each deal is not just an investment. It is not doing a deal and then putting it into a portfolio. You are going to live with it for a long time, so it is critical to take the time up front to have a deep view of the business plan. That is the only way you can actually add value because things change the minute you buy the project, and you know that the business plan will evolve and you have to be able to follow along. Make sure that you can commit the time and resources to it on an ongoing basis. That is what will differentiate you from the other funds for the investors. ◎

Environmental Update

The US Supreme Court sent Environmental Protection Agency rules requiring power plants to reduce mercury and other toxic air emissions back to a lower court for reconsideration. The Supreme Court decided the closely-watched case at the end of June.

It told the lower court to consider whether EPA adequately weighed the costs to comply when choosing the path it did.

The rules, called MATS for mercury and air toxics standards, have an effect on how quickly coal-fired power plants may be retired by setting emissions limits for mercury, hydrogen chloride (a stand-in for acid gases) and filterable particulate matter (a stand-in for toxic metals). The five-to-four ruling in *Michigan v. EPA* reversed an appeals court decision that had upheld the MATS rule earlier.

EPA estimated the standards would cost the power industry $9.6 billion a year to comply. The court conceded that the agency took costs into account when the agency set the actual maximum achievable control technology standards for power plants, but the court said it violated the Clean Air Act by failing to consider cost when it made its initial findings that the mercury and air toxics standards are needed.

Most power plants were required to be in compliance by April this year, so the impact of the decision is expected to be limited in the broader power market. However, 170 coal-fired power plants received extensions of up to one year either to install emissions controls or to close down.

The Supreme Court held that EPA must consider cost — including cost of compliance — before deciding whether air emissions regulations are "appropriate and necessary" as directed by the Clean Air Act.

Industry groups claim that the MACT rules impose annual costs of $9.6 billion to achieve just $6 million in benefits. EPA counters that the rules will produce tens of billions of dollars largely in health benefits.

The case has been sent back to a US court of appeals for further proceedings. Because the agency already considered the cost of compliance in setting control technology standards under the rule, the decision is not expected to save non-compliant coal-fired plants from regulation in the long term.

Clean Power Plan

Another pair of EPA rules that affect the timetable for retiring coal-fired power plants are carbon dioxide emissions limits for new power plants and the "Clean Power Plan" that the Obama administration released in 2014 to reduce carbon dioxide emissions from existing or modified power plants.

A US court of appeals rejected as premature two challenges to the rules in late June. The rules are being challenged by coal companies and coal states, but not by electric utilities.

Earlier this year, EPA announced that it would delay finalizing both the rule to control carbon dioxide emissions from new power plants and its Clean Power Plan to reduce emissions from existing or modified power plants until sometime this summer. The Clean Power Plan would set unique carbon dioxide emissions rates for the power sector in each state, with state regulators developing their own plans on how best to achieve those emissions goals. The final version of the plan is currently at the White House Office of Management and Budget for review.

The petitioners in *In re Murray Energy Corporation* and *West Virginia v. EPA*, two coal companies and 12 states, argued that the court should set aside carbon emissions limits on both new and existing and modified power plants because EPA lacks authority to regulate carbon dioxide under section 111(d) of the Clean Air Act. The appeals court side stepped that question when it rejected both lawsuits as premature. The court said the issues will remain premature until EPA issues final rules in this area.

Clean Water Rule

EPA and the Army Corps of Engineers jointly released controversial new Clean Water Act regulations on May 27 aimed at restoring the federal government's authority to limit pollution in US rivers, lakes, streams and wetlands. The US government exercises jurisdiction over "waters of the United States," which include traditional navigable waters, their tributaries and adjacent wetlands. The regulations clarify what falls into this category.

The Clean Water Act gave the Environmental Protection Agency broad authority to limit pollution in major water bodies, as well as in streams and wetlands that drain into those larger waters. However, two US Supreme Court decisions, in 2001 and 2006, muddied the scope of federal government authority to

The US Supreme Court remanded mercury emissions limits from coal-fired power plants for further work and said it is premature for coal companies to challenge carbon emissions limits.

regulate smaller streams and headwaters, as well as other water sources such as wetlands.

The new regulations refine the scope of federal authority by creating eight categories of "waters of the United States," six of which are subject to Clean Water Act jurisdiction in all instances, and two where jurisdiction is to be determined on a case-by-case basis.

The new regulations are a significant change in the existing regulatory framework, which has frequently required case-by-case jurisdictional determinations. Now, six categories would be designated "jurisdictional by rule," and no further analysis of their characteristics would be required to establish Clean Water Act jurisdiction. These six categories include traditional navigable waters, interstate waters, territorial seas, impoundments of jurisdictional waters, tributaries of navigable waters, and waters adjacent to navigable waters.

Two other categories will remain subject to a case-by-case analysis to determine whether they have a "significant nexus" to the other six categories where federal jurisdiction is automatic. These include waters within 100-year flood plains and certain "water features," including prairie potholes, Carolina and Delmarva bays, pocosins, western vernal pools in California, and Texas coastal prairie wetlands. The regulations explain that these waters have a significant nexus to "waters of the United States" if they significantly affect the chemical, physical or biological integrity of traditional navigable waters, interstate waters or the territorial seas.

Since the regulations were published, more than a third of the states have sued EPA and the Army Corps of Engineers, arguing the regulations are an unconstitutional and impermissible expansion of federal power over the states.

Unless set aside, the regulations will take effect on August 28, 2015.

Greater Sage-Grouse

In an attempt to keep the greater sage-grouse off the endangered species list, the US Bureau of Land Management and the US Forest Service released 14 land management plans in May that will apply to public lands across 10 western states.

The move will limit activities, such as petroleum drilling and solar and wind development, on public lands in the West where the greater sage-grouse is found.

The US Fish and Wildlife Service must determine whether to list the greater sage-grouse as an endangered species by September 30, 2015. The deadline follows from a 2010 finding by the agency that the bird is in need of protection. There are now as few as 150,000 greater sage-grouse remaining.

The US Department of the Interior and officials in the affected states are making an effort to persuade the US Fish and Wildlife Service that a listing is unnecessary because BLM and the Forest Service are taking significant steps, through the 14 new land management plans, to preserve federally-owned sagebrush lands that serve as a habitat for the greater sage-grouse across the American West, including in California, Colorado, Idaho, Montana, Nevada, North Dakota, Oregon, South Dakota, Utah and Wyoming.

The 14 new land management plans minimize new or additional surface disturbances, improve habitat conditions, and reduce the threat of rangeland fires. The plans establish buffer zones around areas where greater sage-grouse gather for breeding, many of which abut or are inside oil and gas fields. The plans will affect approximately two million acres of mostly federal land, but would allow the exercise of existing rights for energy development, minerals, rights of way and other permitted projects. */ continued page 88*

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BLM said while releasing the plans that large-scale wind and solar projects have an adverse effect on greater sage-grouse populations. The plans direct wind and solar projects to areas outside of priority greater sage-grouse habitats. With respect to transmission lines, the plans direct developers to try to avoid placing transmission lines in greater sage-grouse habitats and require mitigation when such placement is unavoidable.

Meanwhile the US Department of the Interior says that the vast majority of federal lands within the most important sage-grouse habitats have little to no potential for oil, gas, solar or wind energy development. In other priority areas, the plans would limit conventional oil and gas drilling, but could allow for horizontal drilling that would not disturb the surface.

The impact on development in the West is expected to be far greater if the greater sage-grouse is listed as endangered.

Solar Energy Zones

The US Bureau of Land Management approved the first three solar energy projects under a new streamlined permitting process for such projects in the western US in June.

The three solar projects are the Harry Allen Solar Energy Center being developed by Invenergy, a First Solar project called Playa Solar and the Dry Lake Solar Energy Center being developed by NV Energy. They have a combined capacity of 440 megawatts. The permitting for the projects was completed in less than 10 months.

The "Western Solar Plan" that is supposed to speed up permitting has been in effect since October 2012.

It applies to projects in 19 "solar energy zones" covering 298,000 acres of public land. The zones are supposed to cover areas with the highest resource potential and lowest potential for conflicts. BLM says projects in the 19 zones could produce as much as 27,000 megawatts of solar electricity. ◎

— contributed by Andrew Skroback and Richard Waddington in Washington

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