

## PROJECT FINANCE

# NewsWire

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## How The US Tax Changes Affect Transactions

by Keith Martin, in Washington

At least a dozen provisions in a massive tax-cut bill that cleared the US Congress in mid-December will affect transactions in the power and broader infrastructure markets.

### Tax Credits

The existing tax credits for renewable energy remain unchanged.

The House had voted to make it tougher for renewable energy projects to be considered under construction in time to qualify for tax credits. The final bill leaves in place the existing phase-out schedules for tax credits and the existing Internal Revenue Service policies on what it means to start construction.

The House wanted to roll back production tax credits for wind projects to the 1992 level of \$15 a megawatt hour and not to adjust the credit amount for future inflation. The change would have applied to projects that start construction in the future.

The House also wanted to eliminate a permanent 10% investment tax credit for solar and geothermal projects after 2027.

None of these provisions made it into the final bill.

Tax credits for “orphan” technologies — fuel cells, CHP projects, geothermal heat pumps, fiber-optic solar property — and for nuclear power plants were not / *continued page 2*

### IN THIS ISSUE

- 1 How the US Tax Changes Affect Transactions
- 8 Financing Projects with CCA Contracts
- 18 Energy Storage: Drivers and Pitfalls
- 25 The Liberal Art of Project Finance
- 29 California Cap-and-Trade Program Recovers
- 34 Net Metering and Community Solar
- 38 Risk Management for Solar Projects
- 45 Environmental Update

### IN OTHER NEWS

**SOLAR COMPANIES** are bracing for a decision by President Trump on whether to impose tariffs on imported solar cells and modules.

The President has until January 26 to “take action” after the US International Trade Commission found in November that growing imports of solar cells and panels have injured US panel manufacturers and Trump’s trade representative, Robert Lighthizer, asked the commission in December for a supplemental report.

Lighthizer wants it to “identify any unforeseen developments that led to the articles at issue being imported into the United States in such increased quantities as to be a substantial cause of serious injury.”

The move may be an effort to ensure that any / *continued page 3*

## Tax Changes

*continued from page 1*

extended. Most of these tax credits expired at the end of 2016. Nuclear power plants must be in service by the end of 2020 to qualify. The House wanted to extend the already-expired tax credits and to waive the in-service deadline for new nuclear power plants, but the Senate, facing harder choices to make the math for its bill work, jettisoned them in favor of taking some of them up in a separate “tax extenders” bill before year end.

### Corporate Tax Rate

The corporate tax rate will be reduced from 35% to 21% starting in 2018.

The change should make operating projects more valuable because the owners will be able to keep more of the revenue from electricity sales after taxes.

It could accelerate or slow down flip dates in tax equity financings, depending on how much time has elapsed since the tax equity financing closed. The earlier in the deal the tax rate is reduced, the more likely the flip date is to be extended.

## At least a dozen provisions in a new 503-page US tax law will affect project finance transactions.

The lower tax rate will reduce the amount of tax equity that can be raised to help finance wind, solar and other renewable energy projects. Such projects qualify currently for a tax credit worth at least 30¢ per dollar of capital cost and depreciation worth 26¢. The depreciation will be worth less at a 21% corporate tax rate than at 35%. Tax equity accounts currently for 50% to 60% of the capital stack for a typical wind farm and 40% to 50% for a typical solar project. These percentages will be lower in the future. Developers may try to fill in the gap with more debt.

In many tax equity deals that closed in 2017, investors sized their investments based on a higher tax rate. Many such deals require a one-time repricing at the end of 2018 (or sooner after the tax bill is enacted). The fact that Congress settled on a 21% rate means developers may end up having to give the investor a larger share of future cash flow to resize the investments.

### BEAT

Renewable energy companies worried that a new base erosion anti-abuse tax, called BEAT, could further reduce the amount of tax equity by making it harder for tax equity investors who are subject to the new tax to know, when a tax equity deal closes, whether they will receive the tax credits on which they are counting.

The base erosion tax requires an annual calculation. Tax equity investors will not know until the end of each year whether they will have to pay back tax credits on which they were counting that year.

The final bill subjects more banks potentially to the tax, but limits the potential for it to claw back tax credits to 20% of renewable energy and low-income housing tax credits claimed during the period 2018 through 2025.

Credits claimed after 2025 are at risk of being fully clawed back, but the expectation is that Congress will vote by then to limit the maximum claw back after 2025 to 20% of tax credits.

The aim of the base erosion tax is to prevent multinational companies from reducing their US taxes by “stripping” earnings across the US border by making payments to foreign affiliates

that can be deducted in the United States. An example of such a payment is interest on an intercompany loan or a payment to a back office in India for services.

The goal is to ensure that multinational companies do not use cross-border payments to reduce their US taxes to less than 10% of an expanded definition of taxable income.

Large corporations would have to calculate two amounts each year: A and B.

If B is less than A, then the US government will collect the entire gap as a tax.

A = 10% (11% for banks and securities dealers) of the corporation's taxable income after adding back two amounts: deductible cross-border payments to affiliates and a percentage of any tax losses claimed that were carried from another year.

B = the corporation's regular tax liability reduced by all tax credits other than an R&D tax credit.

The problem for tax equity investors is that entering into tax equity deals has the potential to create a gap by reducing B. More tax credits will reduce B.

House and Senate negotiators decided that B does not need to be reduced by 80% of renewable electricity production credits, investment tax credits for energy assets or low-income housing credits or, if less, 80% of the gap between A and B if B were reduced fully for these tax credits. The 80% number was the most they felt they could afford.

All tax credits — including the R&D credit — will reduce B after 2025.

The tax rate for calculating A will start at only 5% in 2018 (6% for banks and securities dealers), making 2018 something of a transition year when the tax is less likely to be triggered. The rate will increase after 2025 to 12.5% (13.5% for banks and securities dealers). Thus, a gap is more likely after 2025 when A will be a higher number and B will be a lower number.

Manufacturers with global supply chains complain that the tax will discourage them from manufacturing in the United States because cross-border payments to affiliated components suppliers will end up being added to A.

Cross-border payments to affiliates are not added to A if the US collected a 30% withholding tax on the payment at the border. Many types of cross-border payments are subject to US withholding taxes, but the rates are often reduced due to tax treaties. A reduced rate means part of the cross-border payment would be added back.

Some cross-border derivatives payments and some cross-border payments for services that merely compensate an affiliate for the services at cost would also not have to be added to A.

The calculations will have to be done only by large corporations.

Deductible cross-border payments must amount to at least 3% of a corporation's deductions for the year for the corporation to be caught up in the provision. It is 2% for banks and securities dealers. The corporation would also have to have average gross receipts over the prior three years of at least / *continued page 4*

tariffs Trump imposes can survive if challenged before the World Trade Organization. The WTO appellate body has held that a country must explicitly find that escalating imports are a result of "unforeseen developments" before it may impose restrictions.

The last time the US imposed safeguard tariffs like Trump is considering was in 2002 when then-President George W. Bush slapped a 30% tariff on imported steel. The tariff had to be withdrawn two years later.

Meanwhile, an internal White House four-page paper that is circulating within the Trump administration for comment suggests that Trump may be planning to impose stiffer tariffs on Chinese-made solar equipment. Chinese cells and panels are already subject to countervailing and anti-dumping duties.

The paper criticizes the use of renewable portfolio standards and federal and state tax incentives to promote renewable energy, calling them "overseas job creation programs" that boost demand for renewable energy that is met by overseas equipment suppliers at a cost to US taxpayers.

Suniva, the bankrupt solar panel manufacturer that petitioned the US International Trade Commission in April for import tariffs, told the bankruptcy court in October that it was seeking another \$2.3 million loan from SQN Capital, an institutional asset manager that advanced Suniva \$5.3 million earlier in the year to let the company continue operating. SQN made it a condition to the earlier loan that Suniva had to ask the US International Trade Commission for tariffs.

Documents filed in the case in late November suggest the company may be considering a sale. However, a Suniva creditor characterized the offers the company has received to date as from vulture purchasers and scrap dealers.

More than 60 witnesses testified at a public hearing in early December in the offices of the US Trade Representative about what action Trump should take.

Meanwhile, Fox News / *continued page 5*

## Tax Changes

*continued from page 3*

\$500 million. All related companies with more than 50% common ownership are treated as a single corporation for purposes of these tests. However, only income earned in the United States is taken into account.

The tax equity market should continue to function. However, one consequence of BEAT is some tax equity investors may try giving credit for only 80% of tax credits in pricing through 2025 and zero after 2025. This may cause wind developers, whose BEAT issues are more acute than solar, to switch to investment tax credits or move to a “pay-go” structure for tax credits after 2025. An investment tax credit is claimed entirely in the year the tax equity deal funds, giving the investor a better chance of predicting its BEAT exposure for the year than trying to project BEAT exposure out 10 years in deals with production tax credits.

Most investors in existing tax equity deals are at risk for any tax credits that are clawed back under BEAT. The credits are credited against their returns even though the investors may not receive them in fact.

### 100% Expensing

The bill will allow the full cost of equipment to be written off immediately rather than depreciated over time.

The change applies to equipment acquired and put into service after September 27, 2017.

Equipment that straddles September 27 — it was acquired or was under a binding contract to be acquired before September 27 and is put in service after — will qualify for an immediate write off of from 50% to 30% of the cost, with the rest of the depreciation to follow, depending on when it is put in service. Straddle equipment qualifies for a 50% bonus if put in service in 2017, 40% in 2018, 30% in 2019 and 0% after that.

Full expensing will end in December 2022, but then phase down at the rate of 20% a year through 2026. Most assets must be in service by then to qualify for any bonus. However, assets, like transmission lines, gas pipelines, and gas- or coal-fired power plants would have an extra year to get into service, but only the tax basis built up through the deadline without the extra year would qualify for whatever bonus applies.

Expensing is essentially a 100% depreciation bonus. There is currently a 50% depreciation bonus, but it only applies to new equipment. The 100% bonus can be claimed on used equipment. However, the used equipment cannot be acquired from a related

party, meaning from another company with whom the buyer has more than 50% overlapping ownership.

Regulated public utilities do not qualify. Real estate businesses have a choice: they can choose between a 100% bonus or being able to borrow without a new limit on interest deductions described in the next section.

Most tax equity investors have been uninterested in the existing 50% depreciation bonus. They would rather spread their scarce tax capacity over more projects. However, most have been claiming it in 2017 as a way of mitigating the effects of potential future tax rate reductions. It is better to deduct as much as possible in 2017 before the tax rate goes down.

The bill lets developers opt out of the 100% bonus and depreciate assets more slowly. This will help manage how quickly tax equity investors exhaust their capital accounts in partnership flip transactions. Once the capital account is exhausted, the remaining depreciation shifts back to the developer and could drag tax credits with it.

### Interest Deductions

The bill will make some borrowing more expensive.

It will deny interest deductions on debt starting in 2018 to the extent a company's net interest expense exceeds 30% of its adjusted taxable income. Its income for this purpose means income ignoring interest expense, interest income, NOLs and — only through 2021 — depreciation, amortization and depletion. Thus, the limit on interest deductions is less likely to come into play through 2021 than after when the 30% will be 30% of a smaller number.

Any interest that cannot be deducted in a year can be carried forward indefinitely.

The limit on interest deductions will not apply to any business with average gross receipts of \$25 million or less.

It will not apply to regulated public utilities. It is elective for real estate businesses.

Congress estimated that 95% of businesses will not be affected through 2021.

The limit is calculated at the partnership level where a project is owned by a partnership. Any interest that cannot be deducted by the partnership because of the limit would be allocated to the partners in the same ratio as net income and loss and held by the partners for use solely to offset any future “excess” income they are allocated by the partnership. These deductions cannot be specially allocated to partners.

They will reduce the “outside basis” of the partner. Once a partner’s outside basis hits zero, any further cash distributions from the partnership must be reported by the partner as capital gain.

Only a fraction of the future income allocated to the partner in any year is considered “excess” income that can be offset by the deferred interest deductions that have been moved to the partner level. The numerator of the fraction is 30% of the partnership’s income for the year, less the interest the partnership cannot deduct that year. The denominator is 30% of the partnership’s income for the year.

The bill does not grandfather existing debt.

### Accelerated Income

The bill will require companies to report income to the US tax authorities, starting in 2018, no later than they report it on financial statements.

This applies solely to companies that use accrual accounting.

It does not apply to prepaid rent in leases, but will apply to original issue discount on debt instruments. Any acceleration of past OID can be taken into account over six years.

The bill has a hierarchy of financial statements. The first place to look for how quickly income is being reported for book purposes is a 10-K or annual financial statement filed with the US Securities and Exchange Commission.

If there is none, then the focus shifts to the company’s audited financial statements shown to creditors, shareholders or partners. If there is none, then the IRS will look at filings with other federal agencies.

Foreign companies with US income, but without any of these items, should look at filings with the equivalent of the US Securities and Exchange Commission or with certain other government agencies to be identified by the IRS.

### Prepaid Power Contracts

The bill will probably prevent future use of prepaid power contracts.

In some power purchase agreements, the utility taking the electricity pays in advance for a share of the electricity to be delivered over time. The structure is used mainly where electricity is being sold to a municipal utility or electric cooperative. It is also used to supply natural gas to such utilities.

The generator or gas supplier reports the advance payment over the period the electricity or gas is delivered.

*/ continued page 6*

host Sean Hannity and the conservative Heritage Foundation urged Trump not to impose tariffs. Hannity posted an on-line ad attacking Suniva and SolarWorld as “foreign-owned companies” who are “attempting to use our trade laws” to give themselves an advantage.

Trump is not bound by the recommendations of the US International Trade Commission. The four trade commissioners made three separate recommendations for what he should do.

Two of the four recommended that up to 1.2 gigawatts of solar cells in year 1, 1.2 GW in year 2, 1.4 GW in year 3 and 1.6 GW in year 4 should be allowed to enter the US tariff free. Solar cell imports above these levels and all module imports would be subject to a tariff of 30% in year 1. The tariff would drop 5% a year in each of the next three years.

One commissioner recommended a similar approach, but with a lower volume of solar cells that could enter at a reduced tariff. The cell quota would be .5 GW in year 1, increasing by .1 GW a year in each of the next three years. The tariff for cells up to the amount of the quota would be 10% in year 1, dropping by .5% in each of the next three years. Cells above the quota would be subject to a tariff of 30% in year 1, dropping by .1% in each of the next three years. All modules would be subject to a tariff of 35% the first year, dropping by 1% in each subsequent year.

Any import relief is supposed to be temporary and not remain in place for more than four years. However, the period can be extended for up to eight years. Any tariffs that remain in place for more than a year must phase down at regular intervals.

Finally, one commissioner recommended something along the lines that the Solar Energy Industries Association proposed. She would set a combined import quota for both cells and modules of 8.9 GW in year 1, increasing to 10.3 GW in year 2, 11.7 GW in year 3 and 13.1 GW in year 4. These figures are in line with expected imports. Importers would have to compete in a public auction for import */ continued page 7*

## Tax Changes

*continued from page 5*

Prepayments are also common in the solar rooftop market.

The bill will require such prepayments to be reported immediately as income or, at best, partly in the year the prepayment is received and the balance in the year after. The income hit can be offset by taking the 100% depreciation bonus in the first year, but that would reduce the amount of tax equity that can be raised to finance such a project.

## A new base erosion and anti-abuse tax, called BEAT, is getting attention from banks.

### Partnership Terminations

Transfers of partnership interests after 2017 will no longer cause a partnership to terminate for tax purposes.

The market goes to great lengths currently to avoid terminating partnerships for tax purposes. A partnership terminates currently if 50% or more of the profits and capital interests in a partnership are transferred within 12 months. The depreciation has to restart, causing some loss in time value of tax benefits.

### Pass-Through Rate

Individuals will only have to report roughly 80% of income they receive from partnerships, S corporations and other pass-through entities.

The actual percentage is complicated to calculate.

The bill has “guardrails” to prevent lawyers, doctors and other professionals from qualifying.

Partnership and S corporation income is reported on schedule E of individual tax returns in the US. Partners and S corporation shareholders will be allowed to deduct a percentage of that income, thus paying tax only on what remains.

The deduction is 20% of such partnership and S corporation income.

However, it may be less.

First, the deduction cannot exceed 50% of the partner’s or shareholder’s share of the wages paid by the business to employees as reported on W-2 forms sent to the IRS. If greater, the partner or shareholder can use as its cap 25% of wages plus 2.5% of its depreciable basis in property being used in the business.

This wage cap only applies in years when the partner or shareholder earns more than \$415,000 (on a joint return, or \$207,500 if single). For individuals earning between \$315,000 and \$415,000 (on joint returns, or \$157,500 to \$207,500 if single), the 20% deduction he or she can claim without the wage cap is subject to an alternate adjustment.

The wage cap does not apply to income received from master limited partnerships.

Second, the deduction cannot be more than 20% of the ordinary income the partner or shareholder reported for the year from all sources.

The deduction is not available for income that individuals earning more than \$415,000 a year (on joint returns, or \$207,500 if single) receive from law, accounting, brokerage and consulting firms, medical practices and other businesses where the principal asset is the “reputation or skill of 1 or more of its employees.” It is not available to investment management firms, traders or dealers in securities, partnership interests or commodities.

Anyone earning between \$315,000 and \$415,000 a year (on a joint return, or between \$157,500 and \$207,500 if single) gets some deduction for income from such businesses, but not the full amount.

The deduction takes effect in 2018. It ends after 2025.

Investors in master limited partnerships can deduct not only as much as 20% of income allocated to them by the MLP, but also gain from sale of MLP interests to the extent the gain is taxed as ordinary income.

### Net Operating Losses

Corporations will not be able to use net operating losses incurred after 2017 to reduce income by more than 80% in a year, and they will no longer be able to carry such losses back two years as



they have been allowed to do in the past.

Some workout advisers say this will make it more challenging for distressed companies to get back on their feet.

The bill will allow such losses to be carried forward definitely.

### Government Grants

The House bill threatened to make it more expensive for independent power plants to connect to the utility grid. This provision did not make it into the final bill.

However, the final bill will require corporations who receive help from a government or civic group to report the contribution as income. In the past, a payment by a town to a railroad, for example, to cover the cost of moving tracks to an overpass above a highway so that trains will not block traffic was not considered income to the railroad. Some people have asked whether property tax abatements fall in this category.

### Mandatory Repatriation

The bill moves the US closer to a territorial tax system where US companies are taxed only on their income from US sources.

US companies have at least \$2.6 trillion parked currently in offshore holding companies.

The bill subjects these untaxed earnings to US tax as if the earnings had been brought back to the US, thereby triggering a tax. All post-1986 net “earnings and profits” will be taxed at a 15.5% rate to the extent they are being held in cash or cash equivalents and at an 8% rate otherwise. Companies must calculate the earnings as of November 2, 2017 and December 31, 2017 and pay US tax on whichever amount is higher.

The taxes can be paid ratably over eight years. Eight percent of the tax would have to be paid in each of the first five years starting in 2017, increasing to 15% in year 6, 20% in year 7 and 25% in year 8.

Foreign taxes paid on the earnings would be available for use as an offsetting foreign tax credit, but with appropriate adjustments to reflect the reduced level of US tax.

Mandatory repatriation only applies to US shareholders holding at least a 10% voting interest in the foreign corporation with the undistributed earnings.

### Foreign Earnings

US corporations will no longer be taxed on dividends from foreign corporations in which they own at least 10% of the shares by vote or value to the extent the / continued page 8

licenses. The licenses would sell for a minimum of 1¢ per watt.

She suggested that .72 GW of the quota in year 1 should be set aside for imports from Mexico. The set aside for Mexico would increase at the rate of .115 GW a year for the next three years.

One of issues facing Trump is whether to exempt imports from countries with which the United States has free trade agreements.

All four commissioners suggested no exemption for Mexico and South Korea. One commissioner would also put Canada in this category.

All the commissioners recommended that imports from the following free-trade countries be exempted from tariffs: Australia, Colombia, Costa Rica, the Dominican Republic, El Salvador, Guatemala, Honduras, Israel, Jordan, Nicaragua, Panama, Peru and Singapore.

### US ENERGY SECRETARY RICK PERRY'S PROPOSAL

to require grid operators in competitive markets to dispatch coal and nuclear power plants ahead of other types of power is expected to lead to some form of time-limited directive to grid operators to develop incentives to keep baseload power plants operating, according to Bob Shapiro, a regulatory lawyer in the Norton Rose Fulbright Washington office.

Perry asked the Federal Energy Regulatory Commission in late September to order competitive regional transmission organizations or RTOs — like PJM, MISO, the New York ISO and ISO-New England — that FERC regulates not only to dispatch coal and nuclear first, but also to modify their rate structures to pay coal and nuclear plants high enough prices for electricity to guarantee such power plants a profit.

FERC was supposed to act within 60 days, but delays in appointing and confirming commissioners left the commission short-handed until the new chairman, Kevin McIntyre, took his post in early December. McIntyre promptly asked Perry for more time.

Perry set a new deadline of January 10 in response, but warned that / continued page 9

## Tax Changes

*continued from page 7*

dividends are paid out of earnings earned outside the United States.

This applies to dividends paid after 2017.

The shares must basically have been held for more than a year. The US corporation must have been at least a 10% shareholder during the entire time.

## Cross-Border Sales

Income from cross-border sales of electricity, turbines and other “inventory” will be treated as earned in the country where the items were made.

This has tax implications. Income that a US company earns, for example, from generating electricity in Canada or Mexico and selling across the border into the United States would be considered foreign-source income. If the Canadian or Mexican project is owned by a local project company that is a corporation for US tax purposes, then dividends of the earnings would not be taxed in the United States.

Until now, income from inventory sales was treated as earned in the country where title passes, with the exception that companies have had a choice of three methods for splitting income from inventory produced in the one country and sold in another, one of which has been to divide it equally between the two countries.

## Outbound Payments

Starting in 2017, the US will no longer allow some cross-border interest and royalty payments to related parties to be deducted.

This would happen if the other country treats the payments as something other than interest or royalties for its tax purposes or the two countries treat the US company making the payments differently: for example, one treats it as a corporation and the other treats it as fiscally transparent or vice versa.

Once the provision is triggered, deductions would be denied in the US to the extent the payment does not have to be reported as income in the foreign country.

Two companies are considered related if there is more than 50% common ownership by vote or value. ☺

# Financing Projects with CCA Contracts

*As many as 23 counties in California have, or are in the process of forming, community choice aggregators, or CCAs, that procure electricity — usually from renewable energy — to supply to local residents. The staff of the California Public Utilities Commission estimated that as much as 85% of the electricity load in California will be served by CCAs and other non-utility suppliers by the mid-2020s.*

*At least one utility-scale solar project — the 100-megawatt Mustang project in Kings County, California — was able to raise back-levered debt in 2016 based on offtake contracts with Marin Clean Energy and Sonoma Clean Power. The developer, Recurrent Energy, had already raised tax equity in 2015. Another 100-megawatt utility-scale solar project was financed in the tax equity market in 2017 as part of a portfolio of solar projects, and a wind project is currently in the market for both tax equity and debt.*

*About 250 people attended an Infocast conference on CCAs in Santa Clara in November to learn more about the business model. The following is an edited transcript of a discussion about the challenges of financing projects with CCA contracts. The panelists — representatives of two CCAs, three bankers and one developer — are David McNeil, finance manager at Marin Clean Energy, Siobhan Doherty, director of power resources at Peninsula Clean Energy, Elizabeth Waters, a managing director and deal team leader at MUFG, Magali Cohen, a director with the power and infrastructure group at Investec, Sondra Martinez, a senior director on the originations team at NORD/LB, and Vince Plaxico, director of project finance with Recurrent Energy. The moderator is Deanne Barrow with Norton Rose Fulbright in Washington.*

MS. BARROW: Let's start by getting a sense of the market. Vince Plaxico, apart from the Mustang deal, has Recurrent signed power purchase agreements with any other community choice aggregators?

MR. PLAXICO: Yes. We have a new PPA with Peninsula Clean Energy for a project that is expected to go into service in 2019. We see CCAs as an important market for our growth in California.

Recurrent has a competitive advantage because we are the only solar developer that has fully financed a project where the entire output was committed to a CCA. It takes a lot of time to work through the issues in these deals. On Mustang, we were able to achieve that with a lot of information sharing and the



helpful attitudes of our lenders and our partners, Marin Clean Energy and Sonoma Clean Power.

MS. BARROW: The Mustang deal was financed with a mixture of back-levered debt and tax equity. What's the plan for your new project with Peninsula Clean Energy in terms of financing?

MR. PLAXICO: The delivery is in 2019, so we have more development work to do on that project before we start focusing on the financing, but I expect it will be back-levered debt and tax equity.

MS. BARROW: Sondra Martinez and Magali Cohen, has NORD/LB or Investec done any other project financings of CCA projects, other than Mustang?

MS. WATERS: To my knowledge, Mustang is the only transaction that has term debt on it. I know there is at least one other in the market that is currently getting done, but there are a couple other clients that have deals coming with whom we are in active discussions about financing that are pure CCA offtakes.

MS. COHEN: We have closed the Mustang transaction so far, and we are actively talking to several counterparties and looking at doing additional deals.

MS. MARTINEZ: There are several transactions where CCAs are part of a portfolio with other, non-CCA projects, and I think that is what Beth was alluding to. Those look different in the way we bankers think about them. In terms of a pure financing of a CCA, to my knowledge, there is just Mustang.

MS. BARROW: Beth Waters, can you speak to the portfolio structure?

MS. WATERS: Sure. This is very common, not just for CCA projects, but also whenever a developer has an assortment of assets with different credit profiles. In the early days of solar, the individual projects were not big enough for banks of our size, so the developers presented portfolios of projects. The particular client I have in mind had a number of solar projects, and one of them happened to be with a CCA as the offtaker.

When there is only one CCA in a portfolio, we run a sensitivity analysis. The CCA represented only 10% of the projected cash flow. You ask what happens if none of the CCA revenue is there. Can the developer still repay the debt. In this case, the answer was yes.

It was toe-dipping exercise, meaning a way to get used to CCAs. A standalone large project with all the output going to a CCA requires a different analysis.

MS. BARROW: So portfolios are good toe-dipping exercises. Baby steps.

MS. WATERS: It is like what is happening / *continued page 10*

he did so reluctantly and said the Department of Energy would be looking for other ways to do what Perry wants.

"The better course would be for the Commission to adopt the Proposal within [the original] reasonable deadline," Perry said in a December 8 letter to McIntyre. If the commission cannot act within that time, Perry said, he has to extend the deadline, but "[i]t is solely within my authority" to decide whether the commission should have more time. In the meantime, he said, the Department of Energy will "continue to examine all options . . . to take remedial action [on its own] as necessary to ensure the security of the nation's electric grid."

**CFIUS** may be given authority to review more inbound foreign investment into the United States and to charge filing fees for doing so.

Bills introduced in early November in the US Senate and House would make reporting of some proposed foreign investments in US companies or projects mandatory. Until now, all such reporting has been voluntary, but CFIUS has authority to unwind transactions after the fact that were not submitted for review.

CFIUS stands for the Committee on Foreign Investment in the United States, an interagency committee of 16 federal agencies, headed by the Treasury Department, that reviews potential foreign acquisitions for national security implications.

Review normally takes 30 days, but there has been a backlog this year. Transactions that raise potential issues move into an investigation phase that takes another 45 days.

CFIUS reports annually to Congress. The most recent report was for 2015. During the period 2009 through 2015, 40% of filings moved into an investigation phase and 7% of proposed deals were withdrawn. The top three countries of origin for companies making filings in 2015 were China, Canada and the United Kingdom. (For a summary of the most recent report, see "CFIUS" in the October 2017 *NewsWire*.)

*/ continued page 11*

## CCAs

*continued from page 9*

currently with energy storage. You are only seeing energy storage in current project financings as part of other projects rather than as standalone assets.

### Scale of Market

MS. BARROW: David McNeil and Siobhan Doherty, give us a sense of the market from your perspective. How many megawatts do you have under contract, for what kinds of resources, and also give us a sense of the tenors of the PPAs that you are signing.

MS. DOHERTY: Sure. Peninsula Clean Energy has been operating for about a year now and, in the past year, we have signed nine PPAs for a total of 550 megawatts, and there is a big range in the tenors of the contracts.

We have PPAs with a term of one year and all the way up to 25 years. We have signed solar, wind and small hydro PPAs, with sizes that range from two megawatts to 200 megawatts. We are working to build up a diverse portfolio.

MR. MCNEIL: Marin Clean Energy has about \$2 billion worth of energy under contract right now. Of that, about \$1.8 billion is renewable, long-term PPAs. Those range in terms from 10 to about 25 years. Large wind and solar PPA terms vary from 12 to 20 years. In 2016, Marin Clean Energy entered into long-term, renewable PPAs with contract values totaling more than \$800 million.

MS. BARROW: Siobhan Doherty, you gave quite a range. Do you have a sweet spot in terms of size, length and also resource? There are a lot of developers in the room.

MS. DOHERTY: We do not have a sweet spot. We want to build a diverse portfolio. We have a goal of 100% renewables by 2025,

and so we are looking at ways to fulfill our load shape with different sources of renewable energy. Our board has asked us to look at a variety of term lengths, and a variety of resources, to help us reach our goal.

We are going through an exercise right now of looking at where there are holes in our portfolio. We will be putting out a request for offers early next year in an effort to fill in holes.

MR. MCNEIL: The same thing is pretty much true for Marin Clean Energy. We have a lot of solar in our portfolio today. We are focused on filling in high-demand hours, so we will be looking at wind projects and possibly storage in our next open season.

MS. MARTINEZ: From a financing perspective, when we were looking to finance the Mustang solar project, what they are describing was really important to the banks because they should be managing their portfolios like a utility thinks about managing its portfolio. It is a good thing that the CCAs are looking for a variety of short- and longer-term contracts and for diversification in terms of assets. That is something that we spend a lot of time getting information on and understanding how they operate. The creditworthiness of the CCA is our risk as a lender. If a CCA is poor at managing its portfolio, then it could lead eventually to operating losses.

MR. PLAXICO: Taking that a step further, from the developer's perspective, we are bidding for PPAs with the CCAs. We look at all their publicly-available information, their business plans, what does it look like in five years, what type of reserves will they have built up in that time, and what risk-mitigation strategies do they have in place?

We do all that at the front end before we even approach any of the CCAs, as that will put us ultimately in a better position to deliver what we promised.

MS. BARROW: Is it hard as a developer to monetize a shorter offtake contract and, for that reason, are you looking solely for long offtakes?

MR. PLAXICO: We have done short-term offtakes with Marin and in some other places. We are flexible, but in general, you need a longer-term PPA in order to support the initial capital cost of the project.

MS. WATERS: The bankers had to deal with an influx of corporate PPAs before we started to

**CCAs are expected to sign a significant number of new power contracts during the next four years.**

see PPAs with CCAs. I have felt as a banker that there has been a communications gap. I understand why it is important for CCAs to have a mix of contracts in their portfolios, but a developer will not be able to finance a new project without a long-term contract.

MS. MARTINEZ: Or the developer will have a large bullet payment to make on the loan at the end of the short-term contract and a merchant tail that may not be possible to refinance.

### Cost of Capital

MS. BARROW: Let's get into pricing. What were the margins like in the Mustang transaction? Was it more like a typical utility deal or a merchant deal?

MR. PLAXICO: Mustang was a first-of-its-kind deal. Depending on the sponsor, project characteristics and other factors, the spread for future CCA deals should be around 50 to 75 basis points above a plain-vanilla deal.

MS. COHEN: It was the first deal with CCA-only offtakers, which required a significant spread premium at the time. The market dynamics have changed since then. There is a lot of liquidity in the bank market right now. It is definitely a sponsor's market. That will work in Recurrent's favor in the next deal.

MS. MARTINEZ: We saw the same thing in the merchant gas space. It is really important to get a number of lenders across the line on the first transaction. From NORD/LB's perspective, we do not consider every community choice aggregator as equivalent. We got very comfortable with Marin Clean Energy and Sonoma by doing a deep-dive analysis, much like how Vince Plaxico mentioned he does as a developer, so I am not sure pricing would be the same for every community choice aggregator. It is a sponsor's market, but at the end of the day, it will be about execution, and Vince probably knows this better than anybody that these deals can be difficult for banks to execute.

Some banks will remain completely out of the market because they will not look at a project that has an offtaker without a third-party credit rating, so you already have a limited universe of banks that can do this type of deal.

MR. PLAXICO: The key is information. We are all working together to lower the prices that we are able to offer CCAs. A part of the electricity price is the cost of debt. The more information the lenders have that they can bring to their credit committee, the more likely they are to get approval.

The way that Marin, Sonoma and Peninsula share information online makes it easier for us to track their / continued page 12

CFIUS cannot block acquisitions directly, but makes recommendations to the US President.

In the 27 years since CFIUS was established, four deals have been formally blocked, including one by Trump and two by Obama of Chinese acquisitions of US companies.

The Senate Banking Committee held a hearing in September on potential reforms. Senior members of the Trump cabinet, including the Treasury, Defense and Commerce secretaries and the attorney general are said to favor giving CFIUS broader jurisdiction over inbound US investments.

CFIUS has power currently only to review acquisitions that give a foreign person control over a US business.

The bills would add to the list any purchase or lease of a site near a US military base or other sensitive US government facility and any active — as opposed to passive — investment in a “United States critical technology company” or “United States critical infrastructure company.” CFIUS would also be given authority to review any joint ventures, including outside the United States, between a foreign person and US critical technology company.

A US company is considered a critical infrastructure company if it owns or operates, or primarily provides services to another company that owns or operates, assets that are “so vital to the United States that the incapacity or destruction of such systems or assets would have a debilitating impact on national security.”

Passive investments are okay. To be passive, the investor cannot have a seat or observer rights on the board or any involvement in substantive decision making about a project other than through voting of its shares. It cannot have access to any technical information about the project or business that is not public.

CFIUS would have the option to draw up a “white list” of countries that are not the focus of the latest expansion in review authority. These would basically be countries with which the US has mutual defense pacts.

/ continued page 13

## CCAs

*continued from page 11*

balance sheets, what the last board meeting was about, and so on. Transparency is really important. We spend a lot more time than you think looking through those documents.

MS. MARTINEZ: We probably started talking about the financing and sharing information in February, and then really started to nail down terms in April, and the deal closed in July. We had our credit people involved in the discussions, in order to understand the structure, as early as February to make sure people are getting comfortable and ensure that we can execute on the transaction.

MS. COHEN: Information sharing is critical since, as Sondra mentioned, CCAs have different characteristics, so it will be critical for the next deals to be able to analyze the specific credit profile of the offtaker.

MR. MCNEIL: My suggestion for other CCAs is to build your credit package. At Marin Clean Energy, we put together a data room that contained all sorts of pertinent information — the joint powers agreement, all the government documents, all the financial statements — and then constructed a risk profile that can be read and valued by the credit committees and investors who are involved in the process. The easier you can make their jobs, and the clearer the story you can tell about your CCA, the better the odds you will be able to get your deals financed.

MS. MARTINEZ: It was really helpful that both Marin and Sonoma not only were easy to get on the phone with us, but they also answered written questions. There was a nice working relationship.

MR. MCNEIL: The better your credit pack, the less time you will have to spend on the phone answering questions.

MS. WATERS: As was already mentioned, there is a lot of liquidity in the market, which will make lenders more aggressive on pricing. The more lenders there are chasing deals, the more aggressive each bank will have to be to get a piece of any one transaction.

MR. PLAXICO: Great! [Laughter]

MS. BARROW: Siobhan Doherty, tell us more about information sharing. One thing that makes CCAs different from investor-owned utilities is that they are locally-elected government bodies subject to the Brown Act, which is a 1953 statute that guarantees the public's right to attend and participate in meetings of

locally-elected bodies. Can you share a little about Peninsula's stance on information sharing?

MS. DOHERTY: We share a lot of information. I came from a developer background and that was one of the things that has taken some getting used to. In the developer world, you hold your cards very close to your vest. In the CCA world, almost everything is public. We have monthly board meetings that are open to the public. We publish our agenda a couple days in advance. We publish our slides. We publish our contracts. We can redact certain commercially-sensitive terms. For every CCA, you can go onto its website and get a ton of information.

Similar to what David said, we have created a section of our website with all of our financial documents. We have our quarterly financials going back to the beginning of our launch last year, as well as our joint powers agreement and formative documents.

### Unique Challenges

MS. BARROW: It takes time for any new business model to be accepted by the financial community. There is a learning curve where lenders struggle to get comfortable with risks.

Let's talk next about some of the unique challenges in CCA financings — we touched on some already — and also get some lessons from Mustang. Sondra Martinez, are there any key take-aways or pieces of advice you want to share?

MS. MARTINEZ: Sure. Much like Beth Waters mentioned, NORD/LB financed several short-term PPAs with CCAs as part of a package with a long-term utility offtake. We dipped our toes in initially to understand what CCAs are, but it was easy to take the risk because, as Beth mentioned, even if the CCA contracts fell away, we still felt comfortable that our debt would be repaid.

When it came to Mustang, that was completely different. There was no external credit rating. It was really important to our credit guys that we needed to be able to value on a regular basis the creditworthiness of the entity. One reason we were able to do the transaction is we had NORD/LB do its own internal rating of the offtakers. We needed the financials to do that.

It was important for us to put into our credit documentation that we would receive quarterly unaudited and annual audited financial statements so that we can monitor whether the financial health of the CCA is deteriorating. That was a driver of structural mitigants, such as a blocking of cash, cash sweeps and things like that.

As a lender, you worry about long-term creditworthiness. You can diligence all you want, but if you start to see the credit deteriorating, you want to be repaid faster or you want the sponsor to step up and right size the loan or you want to do something to make it painful enough to the sponsor and its return that it will help solve the problem on the financing side.

We compared the PPA price to potential merchant curves, things of that sort, but you also have to believe that the regulators are going to stay out of the way and let CCAs develop.

## At least two large solar projects with long-term contracts to sell electricity to CCAs have been financed to date.

MR. PLAXICO: We constructed Mustang using a different type of financing, and then we refinanced that later. What Sondra did not mention in her timeline of February to July 2016 is that Recurrent had already been talking to more than 20 banks before her timeline started. Most gave a thumbs down due to lack of a credit rating.

MS. BARROW: Magali Cohen, any thoughts?

MS. COHEN: A critical element for us was to make sure that the value proposition to customers would be sustainable and to ensure that the CCAs had an adequate power procurement and operating reserve strategy. We spent a lot of time analyzing the counterparty risk. Investec is used to financing complex transactions that may include unrated offtakers, but we need quarterly financial statements and historical operating data. We read the information that the CCAs provided on their websites to be able to understand their business strategies and the regulatory framework they operate under. We evaluated the CCAs' financial and operating performance to establish an internal rating.

MS. MARTINEZ: It is a long-term partnership, right? We are looking at long-term amortization profiles for the debt.

MR. MCNEIL: Marin Clean Energy has a reserve policy that is helpful. We accumulate surpluses over time in order to build balance sheet strength. It sends an / *continued page 14*

## IN OTHER NEWS

The bills would give CFIUS more time to review submissions. The initial review period would be 45 days rather than 30 days, and CFIUS could add another 30 days in "extraordinary circumstances."

The bills would create a new process where short-form notices, called "declarations," could be submitted containing high-level information about a transaction. Submission of such a declaration would be mandatory in any covered transaction where the foreign person will have at least a 25% voting interest in the target company and the foreign person is owned at least 25% by a foreign government. Some foreign utilities engaged in renewable energy development in the United States are government owned.

CFIUS could make filings mandatory in other situations.

Mandatory declarations would have to be submitted at least 45 days before a transaction closes. If a full filing is made instead in situations where a filing is required, then it would have to be received by CFIUS at least 90 days before closing.

The bills would give CFIUS the authority to collect filing fees for processing submissions. The fees could not exceed 1% of the transaction value or, if less, \$300,000. The \$300,000 will be adjusted for inflation.

The bills are S. 2098 in the Senate and H.R. 4311 in the House. The Senate sponsors are John Cornyn (R-Texas), the number two Republican in the Senate, Dianne Feinstein (D-California), a former chairman of the Senate Intelligence Committee, and Richard Burr (R-North Carolina), the current committee chairman.

**SOLAR PROJECTS** were being built at an average cost in the United States of \$1.03 a watt in the first half of 2017, according to GTM Research.

The cost had dipped to 98¢ a watt early in the year before being driven back up after Suniva petitioned the US government to impose tariffs on imported solar cells and modules. The average price for the entire first half of the year was below

*/ continued page 15*



## CCAs

*continued from page 13*

important message to lenders in terms of strategic direction and the capital structure of the business.

I encourage CCAs that do not have reserve policies to develop one. We take an approach of contributing a percentage — in our case, 4% — of our annual revenues to reserves, so that's the amount of our annual surplus. It is predictable. You can see the growth over time.

You can take a different strategy. You can take a strategy of accumulating more reserves faster in the earlier part of your development. I think that would also be a reasonable approach. But having a policy document that is approved by the board, so that there is organizational buy-in to the strategy, is an important part of the credit story.

MS. BARROW: Siobhan Doherty, does Peninsula Clean Energy also have reserves?

MS. DOHERTY: We do. We set aside 5% of our revenues currently. We are going through a process to refine that and add some more details to it, but we have a similar reserve policy to Marin Clean Energy and are looking to build those reserves over time.

MS. BARROW: I understand you also use a lockbox account. Could you explain how it works?

MS. DOHERTY: We set up a lockbox when we launched as a way to help partners that were unfamiliar with the CCA and were concerned about the credit structure. Revenues from the sale of electricity to our customers are directly deposited into a separate trust account. PPA providers that are part of the lockbox are paid directly out of that account each month. It is not until we pay all of those invoices that any of that money gets swept over to PCE to pay for operating expenses. It is a way for a developer or other counterparty to feel more secure that it will be paid ahead of us putting aside money into our reserves or spending it other ways.

MS. BARROW: Beth Waters, as a new entrant dipping its toes into this market, what concerns you?

MS. WATERS: CCAs remind me of when we started financing coops eight or nine years ago. You look at the balance sheet and go, "Oh, my God, there's nothing here" because they are not-for-profit and they are not meant to be profitable. CCAs are also not-for-profit, so it took a lot of time, but it helped that we were already lending to coops on the other side of the bank as that was a way to educate our credit people.

I remember spending a month or two writing a strategy paper to help our credit people understand what CCAs are, how they function, why we should not be concerned. Most banks in our business do not finance a coop unless it is rated. There are very few that will finance coops when they are unrated.

We came up with an in-house tool that we use to provide a shadow rating. That makes credit comfortable, and so we are moving ahead.

I remember eight or nine years ago when the first corporate PPA appeared with someone like Google, our bank was like, "What? Who are they? Wait a minute. We know who they are, but they've only been around 10 years. Why are we lending on their credit? They are not a utility. They are not a load-serving entity."

The sanctity of the contract is key to this business. PPA prices a couple years ago were \$100 a megawatt hour, and now they are \$25. But that does not mean you can walk away from that prior contract. Markets go up and down. The entire system relies on certainty that offtakers must honor contracts over the long term.

MR. MCNEIL: There are important distinctions between non-profit and for-profit organizations. But it is important to understand that CCAs like Marin Clean Energy are actively accumulating surpluses every year. Our revenues exceed our expenses. We retain those surpluses in the organization in the form of reserves.

We do so in order to project financial strength and to demonstrate creditworthiness to our counterparties. It is a fundamental part of our strategy. In that respect, we are similar, at this stage of our growth, to a for-profit organization. The reserves are always retained in the entity. Our JPA members have no claims on any of the reserves in the organization. We do not pay dividends. We do not distribute funds to our members.

MS. MARTINEZ: That is an important point. There have been periods of time when CCAs were charging rates that were higher than the incumbent utility, and yet customers stayed with them. The reserve and not having to funnel that money back to your member city, but instead being able to use it in case there are blips in the market — for example, Sonoma has been affected recently by wildfires — is important. The reserve makes a CCA better able to weather those types of events.

MS. DOHERTY: When I looked at our Q3 financials, we had about \$40 million in cash. We continue to set aside money to ensure we have a strong balance sheet. We will be pursuing a credit rating over the next couple years. The reserves will be important to demonstrate liquidity to the credit rating agencies.

MR. MCNEIL: We have about \$70 million in assets and \$35 million in cash. We enter into long-term PPAs, but those are not considered assets on the balance sheet. The way we incentivize renewables — with tax credits — in the United States is an impediment currently to CCA ownership of generating assets. However, the day will come when those tax subsidies go away and, at that point, we will be looking at acquiring assets and financing those on balance sheet, but that is probably five or six years away at a minimum.

MS. MARTINEZ: The assets are the customers, right? From a lender perspective, we thought a lot about the customer base and the stickiness of those customers.

MR. MCNEIL: That is true. Customers are obviously the source of revenue.

### Opt-Out Risk

MS. BARROW: If customers are your biggest assets, let's talk about the fact that customers can opt out at any time. They pay a nominal fee — I think it is \$25 for a commercial customer and \$5 for a residential customer — to exit. Let's start with opt-out rates. What is the current opt-out rate for Marin Clean Energy?

MR. MCNEIL: That's a great question. We don't as an industry do a great job of explaining opting out, so let me try.

You have a total population that you can serve, and then you are only providing service to a certain percentage of that population. In our case, it is about 90% of eligible customers. So our opt-out rate by definition, is 10%. Most of those opt outs take place during the enrollment period. Minimizing opt outs during the enrollment period is incredibly important to Marin Clean Energy from a mission and revenue perspective.

However, the opt-out rate during an enrollment period does not really matter from a risk perspective because we are not procuring for that load over the long term. The risk that CCAs have is that you have a whole bunch of customers, you procure for those customers, and then they opt out.

So we have an opt-out rate of 10%. I think Peninsula has an opt-out rate of about 2%. You can have an opt out rate of 15%. From a risk management perspective, what matters is that you retain customers once the enrollment is complete. In our experience going back seven years, customers remain with the program.

MS. BARROW: Do you see opt outs once you get past the enrollment period?

MR. MCNEIL: We are going through the eighth enrollment in the company's history this coming April. We have been enrolling communities every 12 to 18 months / continued page 16

\$1 in only six western states, compared EPC pricing below \$1 in 26 US states before the tariff petition.

GTM reports that the primary panel suppliers to the US market today are in Malaysia, Vietnam and Thailand. China and Taiwan are less attractive because of countervailing and anti-dumping duties directed at them.

Module prices moved from 33¢ a watt in the first quarter of 2017 to 44¢ a watt in the fourth quarter, driven by demand for solar panels that can get past US Customs before any duties are imposed by the US government. However, GTM said installed system costs increased by only 5¢ a watt during the same period as vendors of other parts of the systems found ways to cut costs.

**TWO LAWSUITS** that test whether the amount paid to buy a power project must be allocated partly to the power purchase agreement are moving forward.

The issue is important because an investment tax credit and accelerated depreciation can only be claimed on the cost of electric generating equipment and not the cost of a power contract, site lease or other intangible assets. Therefore, buyers try to allocate as much of the purchase price as possible to the power plant.

Oral arguments are scheduled in one of the cases on January 12. The case, called *Alta Wind I Owner v. United States*, is before the US appeals court for the federal circuit.

The Court of Federal Claims held in the case on October 2016 that a power contract that requires electricity to be supplied from a particular power plant has no value independently of the power plant. It is like a lease encumbering a building. Nothing is allocated separately to tenant leases when someone buys the building. (For more details, see "Treasury Loses Key Case" in the December 2016 *NewsWire*.)

The government appealed. Briefs were filed in the case over the summer.

/ continued page 17

## CCAs

*continued from page 13*

since inception in 2010. The opt-out rate has fallen over time. We were as high as 20% in some of the early communities and, over time, the rate has fallen to 10%.

MS. BARROW: Siobhan Doherty, from your perspective, PCE has been in the game for less time than Marin Clean Energy, but what has PCE seen for opt-out rates?

MS. DOHERTY: Our opt-out rate is about 2%. We have had two enrollment periods. Our first one was in October last year and then in April of this year. We saw higher opt outs during those periods, and we are very conscious about managing those. We look at our opt outs on a weekly basis. We look to see who has opted out both in terms of the type of customer — whether it is a large industrial customer or a residential customer — and where the customer is located, and we do a lot to manage that.

## One CCA has already signed nine power contracts for 550 megawatts.

If we see a particular number of opt outs from one city, we can do outreach in that city and drill down into what is causing opt outs in that particular city. If they are caused by social networking sites posting information that may be inaccurate, we can try to counter the misinformation.

MS. BARROW: David McNeil, do you have anything to add to what causes opt outs?

MR. MCNEIL: The biggest driver of opt-out rates has been negative advertising about CCAs and Marin Clean Energy. We experienced a lot of that in the early stages of our existence. A code of conduct was eventually enacted for the investor-owned utilities, so they cannot use ratepayer money to market against CCAs. Since then, opt-out rates have declined.

Customers are to some extent rate sensitive. We were about

an average of 4% more expensive on a total-bill basis from January 1, 2016 through the end of August 2016. Residential customers were 5% higher on average. We saw virtually no change in customer count over that period.

However, if there were a bigger gap — say we are 10% to 15% more expensive — the truth is we do not know what would happen, but we also do not see that scenario on the horizon.

MS. BARROW: I also understand there is a bit of opt up that can be a mitigant to opt out. Can you unpack that one for us?

MS. DOHERTY: I can start. At PCE, we offer our customers two different products. Our default product is about 50% renewable energy, 80% greenhouse gas-free, and we have priced that one 5% below PG&E rates. Then we offer a second product that is 100% renewable and customers can choose to opt up to that product, and it is slightly more expensive. It is 1¢ per kilowatt hour higher than our default product. We have seen a bit under

2% of our customers choose to opt up to that product. We have not done aggressive marketing. We have been operating for only a year, so we have been focusing more of our marketing on brand recognition as opposed to getting people to opt up.

We had a lot of success with our cities. Twelve of our cities plus the county of San Mateo have opted up their municipal accounts to the 100% product.

MR. MCNEIL: Marin Clean Energy has a deep green product for which we charge a slightly higher rate. It is a 100% renewable product. The margins on that are thinner than the 50% default product, so I am not sure it would offset loss of revenue from opt outs. I don't see it as a terribly material factor in our overall financial picture.

MS. BARROW: I have one more question for the panel. We talked about opt out on the customer level. What about opt out at the JPA level? It is not really opt out, but what happens when a municipality withdraws from the JPA? Lenders, is that possibility of concern to you? Did you look into that risk in Mustang?

MS. MARTINEZ: It was a concern. I think it is one that is relatively easily mitigated. We looked into the cities. Many of those cities have their own goals for renewable energy. We are familiar with JPAs and SCPPA. There is a long history of how joint powers

authority regulation works, so I think we were less worried about cities opting out since there are significant barriers for them to do so that are much higher than when an individual resident says, “I have changed my mind.” There would be a financial impact to them exiting. At the end of the day, we were less worried that they would opt out.

MS. COHEN: We did a similar analysis to understand the financial penalties and termination payments associated with an entire community opting out. We view the individual customer attrition risk as more of a threat than the entire city opting out.

MS. WATERS: If you are embracing CCAs, you must be embracing that the members of one of these groups are not looking to leave. You can do a sensitivity analysis to see what is breakeven and see how many you would have to lose before it starts becoming a problem for the financing. There are a number of things you can do to get your arms around the risk and get comfortable.

MS. BARROW: I think there’s also a provision in most JPA agreements that says that before a municipality can leave, the JPA must authorize the exit and the municipality will remain liable for any power costs that were procured on its behalf before it left. That is also a mitigant.

MS. WATERS: Meaning it makes a hole in their portion.

MR. MCNEIL: You nailed it. That’s exactly what it implies.

There is a provision in the JPA agreement that requires the board of the JPA to approve the departure of the member community, and the exiting community has to make the JPA whole for any losses that arise as a result of the departure of their customers from the service.

MS. DOHERTY: PCE’s works the same way. ☺

Separately, the owners of a 550-megawatt solar project in California filed suit before the claims court in December over a similar issue. The project cost \$2.129 billion to build. First Solar was the original developer. It sold the development rights to a joint venture of two other companies, who then hired First Solar to build the project for them. The owners eventually applied for a section 1603 payment from the US Treasury for 30% of the \$2.049 billion they said was their basis in the generating equipment, for a grant of \$614.8 million. They say the Treasury paid \$59.3 million less than the amount for which they applied.

The Treasury said part of the basis claimed should have been allocated to two power contacts to sell the electricity from the project to the Southern California Edison Company and Pacific Gas & Electric Company.

According to the complaint, the Treasury also argued that the owners paid more than they would otherwise for the project because the project came with rights to a federal loan guarantee from the US Department of Energy.

Lawsuits against the Treasury complaining about the amount of grants paid have been taking at least two years to be decided. More than 30 suits have been filed in total. The Treasury has been filing counterclaims in some cases to discourage more litigation. Companies who feel they were shortchanged have up to six years to file suit.

**PROVISIONS IN SOME “RED” STATES** to require super-majority votes by state legislatures before taxes can be increased are serving as an impediment to imposing taxes on wind farms.

Wyoming imposes a tax of \$1 a megawatt hour on electricity generated from wind.

State Senator Cale Case (R) has been trying to increase the tax to \$5 a megawatt hour. Case failed in an effort to advance his proposal in the Joint Revenue Committee in December. He plans to try again next year, but acknowledged the difficulty getting the proposal through the legislature, which requires a [/ continued page 19](#)

# Energy Storage: Drivers and Pitfalls

by Caileen Kateri Gamache and Deanne Barrow, in Washington, and Ken Collison and Shankar Chandramowli with ICF in Fairfax, Virginia

Deployment of energy storage, especially batteries, will increase substantially in the next few years.

Three underlying trends in the energy markets will drive the growth. They are favorable federal and state regulations on energy storage, falling costs for batteries due to advances in technologies, and an improved ability by energy storage owners to tap into multiple revenue streams.

However, as with any novel technology, the array of opportunities for storage brings new types of risks. Project developers and investors need to understand the risks so that they can plan for contingencies and mitigate risks.

This article describes changes in the market that are driving deployment and improving the economics of storage and then identifies unique risks for storage projects and how participants in such projects can mitigate the risks.

## Regulatory Drivers

The storage market is poised for exponential growth. By 2022, Greentech Media is projecting an annual market of 2,600 megawatts, which is nearly 12 times the size of the 2016 market.

New market rules will enable owners of energy storage systems to earn revenue from a growing number of sources, such as deferred transmission and distribution upgrades, integration of intermittent resources, reduced demand or increased generating capacity to address peak load, the provision of ancillary services, and enhanced grid reliability and resiliency.

Until recently, storage was a square peg jammed into the round hole of historic regulation.

The existing federal regulation of wholesale power sales and transmission in interstate commerce was designed for a world largely devoid of any significant energy storage. Although pumped-storage hydroelectricity has been around for a long time, it has very different characteristics from modern storage technologies such as batteries, flywheels or thermal energy storage projects.

Federal and state governments are moving to encourage storage. Storage has benefited at the federal level from targeted loan and incentive programs offered by the US Department of Energy and from efforts by the Federal Energy Regulatory Commission to clear a path to wholesale market participation.

FERC has issued four orders in recent years that help energy storage. It also issued a notice of proposed rulemaking, or NOPR, in November 2016 proposing transparent market rules for energy storage facilities to participate in organized markets run by regional transmission organizations (RTOs) and independent system operators (ISOs). If the NOPR is adopted as proposed, storage would be eligible to provide all capacity, energy and ancillary services in such markets. The problem storage faces trying to participate in such markets today is the rules were developed for power plants and demand response companies and may unnecessarily limit the scope (and therefore compensation) of storage services. Most comments received by FERC in response to the NOPR were favorable — the comment window closed in February 2017 — but the proceeding was placed on hold while FERC sat without quorum for much of 2017. It remains to be seen whether the newly-reconstituted commission will pursue the NOPR.

The federal government also allows a 30% investment tax credit to be claimed on some storage facilities that are seen as part of solar and some wind projects. The key to eligibility is the storage equipment must be coupled to a renewable energy project and operated in a manner that it is considered power conditioning equipment or part of the generating equipment. At least 75% of the energy stored by the storage device should come from the renewable generator to which it is coupled. A stand-alone energy storage project would not qualify.

Many state governments have enacted, or are in the process of enacting, mandates or regulations to promote storage (see box 1). States will probably lead the charge on storage development in the near term since they have smaller constituencies and tend to be more nimble than the federal government in responding to market conditions. Some state and local governments also have a stronger appetite for renewable energy deployment than the current federal government. For example, the governors of 11 states and Puerto Rico and the mayor of the District of Columbia committed to comply with the Paris climate agreement after the Trump administration pulled out the United States.



## Improving Economics

Energy storage should follow the same pattern as other new technologies, such as solar.

Battery cell costs declined from \$3,000 a kilowatt hour in the 1990s to \$200 a kilowatt hour by 2016.

Utility-scale energy storage systems with four-hour storage capacity installed in the third quarter of 2017 had a median price of \$525 a kilowatt hour. GTM Research projects this price to drop to \$450 a kilowatt hour by 2019. The cost per unit capacity for these systems was in the range of \$1,300 to \$1,500 a kilowatt in 2017. It is expected to decline to \$800 to \$1,100 a kilowatt by 2020. This compares to an installed cost of \$978 to \$1,100 a kilowatt for a combined-cycle gas-fired power plant today.

Bloomberg New Energy Finance projected in 2015 that the installation costs of battery technologies will decline at 6% a year, meaning that the unit installation cost should, by 2025, be half of what it was in 2015.

ICF recently simulated the operation of a battery storage device for a utility in the US Eastern Interconnection system and estimated that \$2 million a year, or \$102 per kilowatt hour, would be earned from capacity, energy and ancillary services (Exhibit 1). At a fixed charge rate of 10%, the break-even capital expenditures for the project would be about \$900 per kilowatt of capacity. Considering the current installation cost for a lithium-based energy storage resources is \$1,300 to \$1,500 per kilowatt, the modeled application would not currently be economically viable. However, this type of storage should cross the break-even point in the next few years, even if these are the only revenue streams available to storage.

The true value of storage resources is not limited to capacity, energy and ancillary services. There are numerous sources of potential additional value (see box 2). Many regions already have markets that let energy storage owners tap into some of these additional revenue streams, and others will follow as government policies change.

Storage projects have unique risks stemming from unstable regulatory regimes, unprepared market structures, unique liability exposure, and unproven performance records. Creativity, flexibility and preparedness will help manage these risks.

## Regulatory Risks

There are two main types of regulatory risks.

One is the generic risk that a changing regulatory environment poses to new technologies. The other is the more specific risk that the investment tax credit may not be available or as beneficial as expected.

*/ continued page 20*

two-thirds vote to increase taxes. Case said he is looking at a ballot initiative as an alternate route.

**WIND REPOWERINGS** are expected to involve as many as 30% of US wind farms by the end of 2020, according to Bloomberg New Energy Finance.

BNEF estimates that 10,000 megawatts of US wind turbines are already 10 years old, and that another 14,000 megawatts will hit 10 years by the end of 2018.

The US offers production tax credits of \$24 a megawatt hour on the electricity output from new wind turbines. The credits can be claimed for the first 10 years after a new turbine is first put in service.

If turbines are replaced, 10 years of tax credits can be claimed on the output from the new turbine. A turbine is considered new if at least four times the value of any retained equipment is spent on improvements. Each turbine, pad and tower is considered a separate facility for this purpose.

Tax credits for wind farms are phasing out. Any project that starts construction this year would qualify for tax credits at only 80% of the full rate. The IRS looks at the number of turbines that the owner plans to repower and assesses whether that “project” was under construction in time. Then separate tests must be done on each turbine, pad and tower to assess whether enough work was done on each separate facility to turn it into a new turbine. (For more detail, see “IRS Clarifies Rules for Starting Construction and Repowerings” in the December 2016 *NewsWire*.)

Some tax equity investors insist that there must be more behind the repowering than an interest solely in qualifying for new tax credits before they will finance such a project.

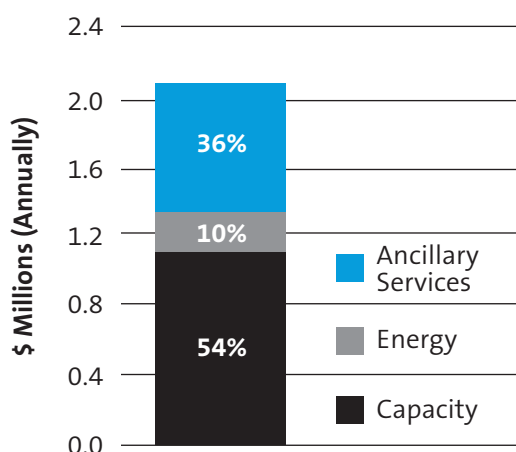
**SOLAR SECURITIZATIONS** set a new record in 2017.

However, the massive tax-cut bill that cleared Congress in [/ continued page 21](#)

## Energy Storage

continued from page 19

### Exhibit 1. Projected break-even analysis for proposed grid battery storage resource



#### Energy Storage Parameters

Size	20 MW, 1 Hr
Capital Cost (\$/kW)	\$1,500
Fixed O&M (\$/kW yr)	\$10
Roundtrip Efficiency	90%
Useful Life (years)	20
Discount Rate	8%

#### Annual Revenue Calculation

##### Annual Revenues (\$)

From Ancillary Services (\$)	\$732,321
From Energy Markets (\$)	\$196,810
From Capacity Markets (\$)	\$1,104,574
Total Annual Revenues (\$)	\$2,033,705
Total Annual Revenues (\$/MWh)	\$101,685
Total Annual Revenues (\$/kWh)	\$102
Breakeven Capex (\$/kW)	\$900
Current Capex (\$/kW)	\$1,500

One need look no farther back than 2015 for an example of regulatory risk at the state level. The Nevada Public Utilities Commission terminated the state net metering policy; residential rooftop solar companies announced they were pulling out of the state. Although key aspects of the policy were later restored, the experience is a lesson to anyone trying to develop a new technology that relies on favorable government policy for support.

At the federal level, the risk currently is the lack of clarity about the regulatory treatment for energy storage. This is becoming more relevant in projects that combine energy storage with renewable power generation and make retail sales.

It is not clear under existing law whether the storage unit qualifies for regulatory exemptions typically claimed by small-scale renewable energy generators or how adding storage to a small power plant affects the generator's own regulatory exemptions. (For a discussion of these risks, see "Solar + Storage: US Regulatory Issues" in the August 2017 *NewsWire*.)

For example, FERC includes storage within the definition of "generating facility" in its form small generator interconnection agreement and has proposed to do the same for its form large generator interconnection agreement.

However, energy storage is a unique animal. It is a hybrid in the sense that it shares some features in common with generating facilities and other features in common with transmission assets and load. This means it should be able to provide, in theory, a broader range of services than these other assets. The storage NOPR is one step toward integration of new storage technologies into wholesale markets, but a lot of work remains to be done to realize the full potential of storage.

One smart strategy for tackling regulatory risks is to combine energy storage with other generating assets. For example, many rooftop solar companies are deploying storage alongside solar installations. Combining storage with generating assets with stable revenue and well defined market participation rules helps mitigate the risk that changes in market rules may reduce or eliminate revenues from a specific storage service.

Another option in the face of regulatory uncertainty is to try to get certainty.

For example, one can ask for interpretive guidance or a declaratory order from FERC stating how the commission will apply its regulations to a certain set of facts. These options typically require both time and filing fees, but they could help settle important questions.

Some state regulators also offer a procedural option of requesting declaratory relief or an advisory opinion on regulatory

## The energy storage market is expected to grow 12 times in size by 2022.

matters. For example, in September 2017, Tesla obtained an advisory ruling from the Massachusetts Department of Public Utilities that said certain small-scale batteries paired with solar generating facilities are eligible for net metering. The ruling was issued in fewer than four months after Tesla filed a petition and prompted Massachusetts to open a general docket on eligibility of energy storage for net metering.

A third mitigation strategy is to draft storage contracts to address potential changes in the regulatory regime. This could mean including a mechanism to revisit pricing in the event of a change in law. Alternatively, the parties could be required to enter into good-faith negotiations to restore the benefit of each party's bargain after a change in law.

The other regulatory risk is that an investment tax credit will be claimed on the cost of a storage facility, but then the mix of electricity stored changes over the first five years when the credit is exposed to full or partial recapture. The IRS requires no more than 25% of the energy stored come from other sources than the solar or wind facility of which the storage device is a part and then the percentage of other energy storage determines the amount of investment tax credit that can be claimed. For example, if 10% of the storage energy is from other sources the first year, then only 90% of the full ITC can be claimed. If the percentage of other energy stored increases in any of the next four years, the credit is subject to partial recapture.

The best mitigation method for this type of risk is thorough and accurate modeling of system operation under the full range of operating conditions, and with the system providing all anticipated energy services, to estimate the fraction of charging energy supplied by the linked solar or wind project. To the extent the offtaker has a right to control charging, the owner may want to build in a right to recover any ITC-related recapture or losses.

*/ continued page 22*

## IN OTHER NEWS

December could make it more challenging in the future to securitize future revenue streams that are payments for electricity or rents to lease rooftop solar systems.

Separate securitizations completed this year by Tesla, Sunnova and Dividend Finance and two by Mosaic add up to more than \$1 billion in capital raised.

In a securitization, a solar company takes receivables — amounts that it expects to receive over time either as repayment of loans to homeowners who bought rooftop solar systems or power purchase or lease payments from customers who signed contracts to buy electricity or lease rooftop solar systems — and borrows against them. By so doing, it converts future payment streams into current cash.

The quality of the receivables is rated by a rating agency.

Greentech Media, which analyzed the securitizations this year, said they reflect a shift in the solar rooftop market from the third-party ownership model, where a solar company retains ownership of rooftop systems and enters into 20-year contracts with customers to sell the electricity or lease systems, to direct sales of systems to customers. It said “the tables turned in Q4 2016, and now more customers buy their own systems.”

The Structured Finance Industry Group, a trade group representing more than 350 participants in the securitization market, complained in a letter to Congress that new limits on interest deductions in the tax-cut bill will make securitizations where the income is in the form of lease payments (rather than interest on customer receivables) uneconomical.

That's because the bill limits the ability to deduct interest starting in 2018 to the extent interest expense exceeds 30% of income, but interest expense can still be offset — despite the new limit — against interest income received in the same year. In a securitization, interest income is received by a securitization vehicle that makes interest payments to [/ continued page 23](#)

## Energy Storage

*continued from page 21*

### Market Risk

ISO and RTO market rules allowing “merchant” storage are often the same rules developed for conventional generators and, as such, may not adequately reflect operating capabilities or performance risks that are unique to energy storage. This may limit the ability of storage to compete in the market and make the

potential revenue stream more unpredictable than it is for other market participants.

FERC regulations designed to provide fair compensation for the unique operating characteristics of energy storage would eliminate some of these risks.

FERC adoption of the 2016 NOPR would help. Until it does so, the best mitigation for this type of risk is to become intimately acquainted with the rules of the market you intend to bid into, and to write into contracts a right to renegotiate penalties and revenue allocation should market rules change.

### Box 1: State Storage Mandates and Regulations

- **California:** The self-generation incentive program, called SGIP, offers rebates to certain distributed energy technologies, including energy storage. The SGIP program has a rebate budget of \$567 million for the years 2017 through 2019, 79% of which is allocated to the energy storage category. California has also adopted the nation’s most ambitious storage procurement mandates. Assembly Bill 2514 requires the state’s three investor-owned utilities to procure 1,300 megawatts of storage by 2020, 700 megawatts of which must be grid-scale storage at the transmission level. In addition, the California Public Utilities Commission has ordered the three utilities to procure 500 megawatts of grid-scale storage at the distribution level. These procurements are well underway, and are intended to be a stepping stone to further market deployment.
- **Hawaii:** The Hawaii Public Utilities Commission approved a power supply improvement plan submitted by Hawaiian Electric Company, the state’s largest electric utility, that proposes deploying battery storage systems across all five island grids, including 170 megawatts on Oahu by 2022.
- **Maryland:** Senate Bill 758 provides a tax credit for 30% of the cost of a customer-sited energy storage device, subject to a cap of \$5,000 for residential installations and \$150,000 for commercial installations. Beginning in 2018, a total of \$750,000 per year is available under the program.
- **Massachusetts:** Recently-passed energy storage legislation requires procurement targets to be set for “viable and cost-effective” energy storage resources. The Massachusetts Department of Energy Resources set a statewide target in June 2017 of 200 megawatt hours by 2020. Massachusetts is also among the first states to consider the eligibility of energy storage for net metering, following the opening of an inquiry into this issue by the Massachusetts Department of Public Utilities in October 2017.
- **Nevada:** Two recently-enacted laws require the state Public Utilities Commission to evaluate energy storage requirements for utilities and to establish incentives for energy storage as part of the state’s solar incentive program.
- **New York:** Recently-passed legislation requires the state to establish an energy storage deployment program, including a storage procurement target for 2030. The ‘Reforming the Energy’ (REV) initiative is expected to promote energy storage deployment, primarily as a non-wire alternative to conventional transmission and distribution system upgrades. REV is also developing a tariff structure that captures locational value of storage — a value that is tied to deferral of T&D capacity expansion by having storage use the existing infrastructure. New York launched a grant program in April 2017 that will make available \$15.5 million in funding for energy storage projects through 2019.
- **New Jersey:** The state established an Energy Resiliency Bank in 2014 following Hurricane Sandy to finance resilient power projects, including solar + storage.
- **Oregon:** House Bill 2193 requires Oregon’s main electricity providers to have at least five megawatt hours of energy storage in service by January 1, 2020.

The ISOs and RTOs also offer various working groups and stakeholder forums in which to raise issues and become involved in market design. It may be prudent to take full advantage of these opportunities if a substantial investment is anticipated.

### Interconnection Risk

Few utilities currently have significant experience with storage, and developers proposing novel storage projects to inexperienced utilities should expect that the interconnection process will take time.

In addition, if a proposed project will provide frequency regulation or any other service that may require on-peak charging, it is possible that the utility will require costly network upgrades that would otherwise not be necessary.

The best mitigation may be to recognize that as more utilities gain experience with storage, the duration of the interconnection agreement process will decline. Until then, developers can minimize delays by ensuring that their interconnection applications are clear and complete, by responding rapidly to utility information requests, and by maintaining frequent communication with utility personnel.

The cost of network upgrades required for interconnection may be reduced by avoiding services that will require on-peak charging, but the value of such services may exceed the incremental cost of the network upgrades. Developers can ask the utility to do an interconnection feasibility assessment early in the process. This will help identify the lowest cost interconnection location.

### Litigation Risks

State programs to encourage particular types of participants in wholesale markets are at an increased risk of litigation following the Supreme Court decision in 2016 in *Hughes v. Talen Energy Marketing*.

The case involved efforts by two states to encourage construction of new gas-fired power plants. (For a discussion about the decision, see “Supreme Court Nixes Two PPAs” in the June 2016 *NewsWire*.) The decision has led to questions about exactly where the line is between state and federal jurisdiction when a state’s actions may affect wholesale power markets.

Challenges to other state subsidies are currently working their way through the courts and may provide greater clarity. (For example, see “Zero Emissions Credits Upheld” in the August 2017 *NewsWire*.) Any state laws or programs that favor storage may be at risk to challenge.

/ continued page 24

## IN OTHER NEWS

the lenders. No offset is possible against other forms of customer payments.

**A GOVERNMENT CORPORATION** formed to act as developer of a gas pipeline or LNG project will not be subject to federal income taxes, the IRS said.

A state formed the corporation and charged it with developing one of two projects in order to promote greater use of gas produced in the state. One option is to build a gas pipeline to transport gas produced in the state. The other is to build a gas liquefaction terminal to turn gas into LNG. The corporation is authorized to pursue both projects, but plans only to build one.

Any profits from the projects will belong to the state.

The IRS said in a private letter ruling issued to the corporation that it will treat the corporation as a “political subdivision” or extension of the state. Therefore, it is not subject to federal income taxes. The ruling is Private Letter Ruling 201741010. The IRS made it public in October.

The corporation has eminent domain power to take property for public use.

It has a seven-person board of directors. Five of the directors are members of the public who are appointed by the governor and confirmed by the state legislature. The other two are heads of state agencies. The corporation submits an annual budget that is folded into the state budget the governor submits each year to the legislature. Upon dissolution, all of the corporation’s assets would pass to the state.

There is no definition in the US tax code of “political subdivision” of a state. However, to be a political subdivision, the corporation must have been set up for a traditional governmental purpose. The IRS said the aim of maximizing the value of gas produced in the state for the benefit of state residents is a governmental purpose.

The corporation planned either to buy gas from gas producers in the state or to enter into tolling agreements with them. As long as these contracts have arm’s-length / [continued page 25](#)



## Energy Storage

*continued from page 23*

Energy storage is also subject to other general litigation risks, including environmental, human impact and intellectual property risks, but at a higher level due to its novelty.

The environmental risk varies greatly depending on the technology and siting. Battery leakage is one example of an environmental hazard that is unique to some storage technologies. There is also environmental risk associated with disposal after the equipment is decommissioned. New technologies have no track record.

The evolving nature of the storage market and rapid deployment of new technology makes storage a prime target for intellectual property challenges.

The parties to a storage contract can allocate litigation risks in the contract. Consideration should be given to requiring liability insurance for the various environmental, intellectual property and other risks.

### Performance Risks

New technology carries obvious performance risks. Poor performance jeopardizes contracts and could subject developers to heavy non-performance penalties in certain wholesale markets.

#### Box 2: Examples of Possible Sources of Energy Storage Value

- Capacity
- Energy
- RTO/ISO ancillary services
- Reduced reserve requirement
- Reduced uneconomic dispatch
- Reduced revenue sufficiency guarantee payments
- Improved renewable resource integration
- Reduced renewable resource curtailment
- Reduced fuel price volatility risk
- Improved black start capacity
- Fast ramping capacity
- Voltage/VAR optimization capacity
- Energy arbitration
- Deferred capital investment

Manufacturer warranties and other performance guarantees and even insurance policies can help. They exist currently for rooftop solar, for example. They need to be developed for storage. Developers should make sure that adding storage to other forms of generation will not invalidate any performance guarantees attached to the generating facility.

Performance risk should be considered both in terms of initial system performance risk and long-term performance risk.

Developers usually buy batteries directly from the manufacturer and focus primarily on system integration. If the developer does not have a comprehensive understanding of battery capabilities and limitations, such as maximum charge and discharge rates, thermal requirements and cycle life, there is a strong possibility that the control room will mismanage the battery, and the overall system will be unable to satisfy power purchase agreement performance expectations, with the potential for adverse financial impacts or litigation.

The primary mitigation for this type of risk is to have a thorough understanding of battery capabilities and limitations and to design a system that will reliably provide all contracted services for the duration of the contract.

This requires accurate modeling of battery system operation. Some battery services, such as fast ramping, demand-charge reduction and spinning reserve, can be much more taxing on some batteries than others. This should be reflected in the model.

Many PPAs have terms that exceed expected battery lives.

If storage services are required for 20 years, then the developer must plan for battery replacement at appropriate intervals. Earlier replacement will be required for batteries that allow deep discharge than for storage devices that are designed primarily for backup power and frequency regulation. Developers frequently underestimate the costs of system operations and maintenance.

The main mitigation for this risk is to come up with an appropriate O&M plan based on a thorough understanding of how the battery will work. In addition to periodic battery replacement, this includes having spare power conditioning equipment (inverters, voltage converters) and service technicians available to address unplanned outages or degraded capabilities. Most energy storage systems have continuous monitoring and, to an increasing degree, developers are providing this service in-house. This enables faster detection and resolution of system performance. Independent engineers evaluating system design usually also evaluate the O&M plan. ☺

# The Liberal Art of Project Finance

by John L. Schuster, with JLS Capital Strategies LLC in Washington

For many of us, the Thanksgiving and upcoming winter holiday break mean the return of children from college and, at our house, opportunities for greatly appreciated parental guidance on the value of the liberal arts educations children are receiving.

Actually, guidance may be less than fully appreciated. To those who are steeped in coursework on literature, philosophy, history, language, quantitative reasoning, and other enjoyable but seemingly impractical pursuits, it all seems theoretical: just another set of parental lessons to be filed away.

For once, mom and dad may be right. Critical thinking, logical reasoning and writing are extremely valuable in the business world. Studies show that philosophy majors wind up doing very well in their later professional lives. But to those who see all the paying jobs going to computer science and engineering majors, the value of liberal arts in the real world outside of academia seems far away.

There are many reasons why guidance receives only lip service. First, it comes from dad, always a questionable resource. He's the one who recounted ancient teachings that, like "W" is sometimes a vowel, are a source of ridicule among family and friends and now among *NewsWire* readers and, for the record, dad never said "W" was a vowel, just that his Cincinnati public schools taught him that it was in diphthongs such as "ow" and "aw". But that's another story. Movie themes also don't help, as the only film focusing on liberal arts -- the 2012 Josh Radnor film *Liberal Arts* -- has as part of its happy, redemptive ending, the liberal-arts-educated Jesse Fisher (Josh Radnor) continuing his book store job, hardly a helpful career life lesson. The only other movie character extolling the virtues of a classical education is *Die Hard* villain Hans Gruber.

To be fair, parental guidance is being heard, just not about how liberal arts may apply to the business and finance professions the parents have chosen. To those practitioners and their children reading this article with liberal arts educations who can learn, or have learned, to appreciate the joys of project finance, this article is for you. Taking as a basis the core curriculum of my own Georgetown liberal arts education, this article is a presentation of how classic liberal arts subjects can feature prominently in an exciting life in project finance. / continued page 26

## IN OTHER NEWS

terms, the IRS said, any private benefits that gas producers get from the projects is merely incidental to the larger public purpose being served by having the corporation develop the projects.

**A SOLAR INCENTIVE PAYMENT** from a utility counts as good income for a real estate investment trust.

A REIT asked the IRS about such a payment. The REIT will share in the incentive payment as a partner in a partnership that owns a shopping center. The partnership plans to buy or lease a solar rooftop system to put on the roof.

The local municipal utility will make a one-time lump-sum payment to the partnership as a reward for installing solar. The amount of the payment is tied to the installed cost of the system or else calculated under a formula based on the expected output. If the output formula is used, then the payment amount is also affected by whether the partnership will keep the renewable energy credits to which it will be entitled for generating renewable energy or transfer them to the municipal utility. If it transfers them, then the incentive payment will be higher, but part of it will be considered purchase price for the future RECs.

REITs are corporations or trusts that do not have to pay income taxes on their earnings to the extent the earnings are distributed each year to shareholders.

However, they must be careful to ensure their assets are largely real estate and their income is largely passive income from the use of real estate.

There is both a 95% and a 75% income test. At least 95% of the REIT's gross income each year must come from dividends, interest, rents from real property, or gain from the sale of stock, securities and real property. At least 75% of gross income must come from rents from real property, interest on mortgages secured by real property or gain from sales of real property.

The REIT asked the IRS / continued page 27

## Liberal Arts

*continued from page 25*

### Philosophy: the Existential Truth

Let's start with a big challenge — philosophy and theology — hardly a subject in any MBA program.

Existentialism is never discussed in any case study group at business school or in real life, and no one ever impresses someone at a job interview by recounting its core concept: “existence precedes essence.” But that concept is critical. Whereas classical philosophers like Plato and Aristotle conversely taught that essence comes first, that people and things strive to achieve their preceding essence — chairs strive to be chairs — people should strive to find their natural law essence. Existentialism teaches us that there is no preceding, defining essence and that we should all create our own existential way forward.

Applying the Heraclitus adage about not being able to put one's foot in the same river twice, no two project finance deals are the same and deals are constantly changing.

What's more, there is no need to make deals conform to some ideal by imposing uniform terms and conditions. Lending terms do not have to follow any laws, natural or otherwise, and seeking to force deals into a mold just gets in the way of finding workable outcomes. Dictating a fixed debt-equity ratio or a debt coverage ratio without considering a project's characteristics is never persuasive. More importantly, imposing precedent terms uniformly can prevent deal makers from achieving the end goal of structuring a viable deal and achieving the win for both sides. Having a manageable amount of debt and leverage is all about preventing a borrower from carrying an excessive debt burden that will become troublesome for a particular project based on its contracts, costs and market conditions.

How to find the correct solution for a specific project finance

deal is akin to finding its truth, something that can really only be achieved through inquisitive due diligence and constructive negotiation. This is a chance to apply another theological construct — Gandhi's Satyagraha — taught, among other places, at Father Francis Winters' old class at Georgetown. Satyagraha is the insistence on truth, and for Gandhi, one only arrives at the truth through creative conflict with others. Gandhi's better-known philosophy of non-violence is actually secondary to the insistence on truth. Because the truth only emerges from all of us, killing someone destroys the truth.

Negotiation in project finance and other business deals is only really effective when all parties work together to solve the problems of the deal. Both sides need to listen and focus on their mutual interests and jointly formulate solutions. Strong-arming and forcing a point upon another is akin to killing the truth of a viable and mutually agreeable deal, leading to a fragile deal that will fall apart and ultimately serve no one's interest.

### Simple Math

Let's pick an easier subject next — math and science — obviously part of every project finance deal, but a topic with deeper lessons.

Many schools now allow math requirements to be met not just through calculus or statistics, but also through more abstract quantitative reasoning courses. Suppressing my father's math genes, I am okay with this, as the subject's real value is not just how to structure a spreadsheet model or apply calculus to dynamic economic or physical relationships, but also how to understand relationships and distill them into an easy to understand set of data points. Even those of us with coursework in calculus, statistics, operations research and applied economics rarely use all of that math on a daily basis. The more important skill is understanding, distilling and applying basic mathematical relationships to real-life problems.

Before developing or applying any financial or mathematical model, one should first derive a logical and understandable result through simple math.

What are the overall capital costs of a project and what are its ongoing operating costs? How much equity is available and how much debt is needed?

**Classic liberal arts subjects can feature prominently in an exciting life in project finance.**

What can go wrong and how much buffer or contingency is needed? What are the expected project cash flows? Are they sufficient to cover ongoing costs? Debt? Even a huge financial model can be reduced to a few key numbers. If that does not work, tinker a bit and only then should one proceed with the larger model. Anything else misses the bigger picture and is a waste of time.

### Lit Majors and the Documents

Math was too easy, so let's pick a much tougher one. English, and in my case also French literature, are subjects that even Lit majors never really enjoyed, although they might say they did. Looking behind the choices of words used and the meter of a stanza, researching an author's background and prior work and applying that to every single passage of a literary work can be tedious or even dreadful. Anyone who has spent several classes analyzing Baudelaire's description of a nut cake rues every minute spent doing so, and never thinks such an exercise could ever be useful in the real world. But the exercise is useful, and the lawyers publishing and reading the *NewsWire* know that it is.

Language in a project finance agreement or any legal document, is everything.

Whether a provision is governed by consents, event of default provisions, or force majeure can be critical. How a term is defined and where it is used or not can affect an entire agreement. Those who fail to understand this wind up agreeing to things they do not understand and face disappointment once an agreement is placed into actual use, especially when specific unforeseen issues arise and interpretation is needed.

One can learn much of this in law school, but that does not help those without formal legal training. Even lawyers can capture the spark of the importance of language from their early Lit classes as their inspiration to achieve excellence.

### Foreign Language Requirement

Most schools still have a foreign language requirement, which is of course very useful for speaking to colleagues and counterparties in a foreign language. But even those of us who speak several languages to varying levels of proficiency may not use those skills often in a business world where English has become the de facto Esperanto. What's the use? Why maintain the requirement?

The answer is simple. The requirement is very useful. Foreign language training expands how one sees everything — our own language, other people, different cultures, opposing perspectives — everything. The exercise of learning one / *continued page 28*

for a ruling that the base incentive payment — the amount it would receive if it kept the RECs — is good income. The IRS said yes.

The IRS said that even though solar incentive payments are not listed in its regulations as good income for the 95% and 75% income tests, the legislative history behind the REIT provisions in the US tax code indicates that the purpose of the gross income tests is to ensure that the REIT receives largely of passive income rather than income from the active conduct of a business. Treating the incentive payments as good income would “not interfere with or impede the objectives” of Congress in setting up the two gross income tests, the IRS said.

It made the statement in a private letter ruling made public in late October. The ruling is Private Letter Ruling 201742013.

REITs must also show that at least 75% of their assets are real property or interests in real property. Examples of such assets are land, site leases, buildings and mortgages secured by real property.

Solar advocates were disappointed with regulations the IRS issued in 2016 that said rooftop solar panels are normally considered equipment rather than real property. The IRS said the only circumstances where a solar rooftop system would qualify as a “structural component” of the building on which it sits is if it performs a utility-like function for the building, such as providing electricity to tenants. The electricity must be part of what the tenants receive for their rent for use of the space, the REIT must own or have the same legal interest in the solar equipment and the building, and the solar equipment must be expected to remain permanently in place.

The REIT in this latest case told the IRS the solar system qualifies as a good asset for the asset test. It did not ask for a ruling on that issue. (For a discussion about what solar equipment the IRS considers a good asset, see “Solar REITs” in the October 2016 *NewsWire*.)

*/ continued page 29*

## Liberal Arts

*continued from page 27*

language makes learning another language easier and increases knowledge and appreciation of one's own language.

In international deals or in any deal involving those from other countries, the most difficult counterparties who are the least likely to be open to creative solutions are those who have never made serious efforts to learn another language or culture.

## History Lessons

History is often considered the quintessential impractical subject, especially if that history is a long time ago.

But the abiding lesson of history is always critical, as it is about how people once lived and thought about the world, how they experienced triumph or difficulties, and then changed or failed to change over time. Things were not always as they were and as they are now. A mentor of mine once put on his wall that "Santayana was right." George Santayana is famous for saying that those who do not learn history are doomed to repeat it.

In the financial world, those lessons are obvious but always repeated: just look at the Tulip Bulb Crisis of the 1630s and compare that to the Credit Default Swaps and the resulting Global Financial Crisis of 2008. But the lessons are deeper, both more recent and more distant. Lebanon's surprising descent into chaos is the historical event behind the theory of Black Swan

events that Taleb popularized in his 2008 work.

The key to learning from history is to think expansively and to protect oneself from the Black Swans that no one fathoms can happen. Looking back at what could have been done to prevent or reduce the impact of historical events is the key to fashioning solutions for today's problems. With this knowledge, we can find the adjustments and modifications that may turn monumental events to ordinary occurrences. The way to do this is to integrate disciplines and incorporate the teachings of Satyagraha and explore solutions with others through negotiation.

## Responsible Life Learning

All of this leads to the fundamental value of a liberal arts education: to learn from others but to think critically and independently for oneself.

Whether one embraces existentialism or not, a liberal arts education teaches one to take personal responsibility to learn constantly and to think for oneself.

In a project finance deal, this means understanding all of the aspects of a project and to learn how to listen and learn from others, including those on the other side of the table. To put the lesson in elementary and popular terms, one can be taught that "W" is a vowel in school and still remember that lesson, but learn to rise above it.

The Jesse Fishers of the world can find redemptive business relationships, not just personal ones. Maybe the Hans Grubers could even learn not to destroy the truth in the Takagis and Ellises of the world and make better "million-dollar deals for breakfast" and other times as well. ©

One can be taught incorrectly in school that "W" is a vowel, but learn to rise above it.



# California Cap-and-Trade Program Recovers

by Brandon Charles and Laura Norin, with MRW & Associates, LLC in Oakland, California

Prices for greenhouse gas emission allowances under the California cap-and-trade program have rebounded in 2017. Legal and regulatory uncertainties that had cast a shadow over the program's future in 2016 have generally been resolved or are in the process of being addressed.

Furthermore, regulatory changes have been made to support a more robust allowance market, both in the near-term and into the future.

Although additional potential changes to the program remain under consideration, developments over the course of 2017 have clarified the future program structure.

In 2016, a surplus of allowances in the market, combined with uncertainty over the future of the program, limited trading and kept prices low. In the quarterly state-run auctions for greenhouse gas allowances, just 52% of the allowances that were up for bid in 2016 and in the first auction of 2017 were sold, with fewer than 20% of available allowances sold in two of these auctions.

In contrast, in each of the subsequent three auctions, all the available allowances were sold. This increase in auction sales was accompanied by an increase in auction settlement prices above the floor price for the first time since 2015.

The change in market sentiment over the course of 2017 has been pronounced and appears to be driven in large part by increasing confidence in the future of the cap-and-trade program after resolution of legal challenges and progress on writing regulations to allow the program to continue after 2020. Structural tweaks to the program also appear to be boosting both market activity and prices. Finally, the fact that 2017 is the final year of the second compliance period probably also contributed to the strong demand for allowances once legal authority for the program was confirmed.

Looking forward, the beginning of a new compliance period, coupled with a continued surplus of allowances, could lead to a flattening of price escalation, or even / continued page 30

## IN OTHER NEWS

**A JOINTLY OWNED COMPANY** formed by a group of municipal utilities and electric cooperatives to enter into a long-term contract to buy electricity from a private gas-fired power plant is not a tax-exempt entity, the IRS said.

The municipal utilities and coops applied to the IRS for status as a section 501(c)(6) entity, a type of tax-exempt entity that is used by some trade associations, chambers of commerce and football leagues that are not organized for profit.

The IRS said the only activity of the joint venture will be to hire a law firm to negotiate a power purchase agreement with the project developer. The only expenses expected are the legal fees. Once the PPA and perhaps other contracts are negotiated, the joint venture will terminate, the IRS said.

It is not clear why the joint venture needs to be a tax-exempt entity since the members can split the legal fees, and a joint venture organized by them to enter into a contract on their behalves — as a partnership — would not be subject to income tax. If they had any concerns, they could elect out of partnership status by filing an election under section 761 of the US tax code, in which case each member would be treated as owning an undivided interest in the power contract directly. Each would have to take its percentage interest of the electricity in kind.

The project had not been built yet. It appears another reason for the joint venture was to enter into a development-stage agreement with the developer so that the developer can secure development financing to begin detailed engineering work on the project.

The IRS said section 501(c)(6) status is reserved for business leagues “whose purpose is to promote the common business interest and not to engage in a regular business of a kind ordinarily carried on for profit. Its activities are directed to the improvement of business conditions of one or more lines of business rather than the performance of particular services for individual persons.”

The problem with / continued page 31

## California

continued from page 29

short-term declines. However, developments over the course of 2017 appear to have laid the foundation for program stability and continued demand for allowances over the long term.

### Basic Concepts

As discussed in more detail in the August 2016 *NewsWire* (“Uncertainty and Surplus Allowances Dog California Cap-and-Trade Program”), the California Air Resources Board (CARB) officially launched the cap-and-trade program in 2012, with mandatory compliance obligations beginning in 2013.

The program establishes an annual cap on California greenhouse gas emissions so as to reduce emissions to 1990 levels by 2020 and below this amount in subsequent years.

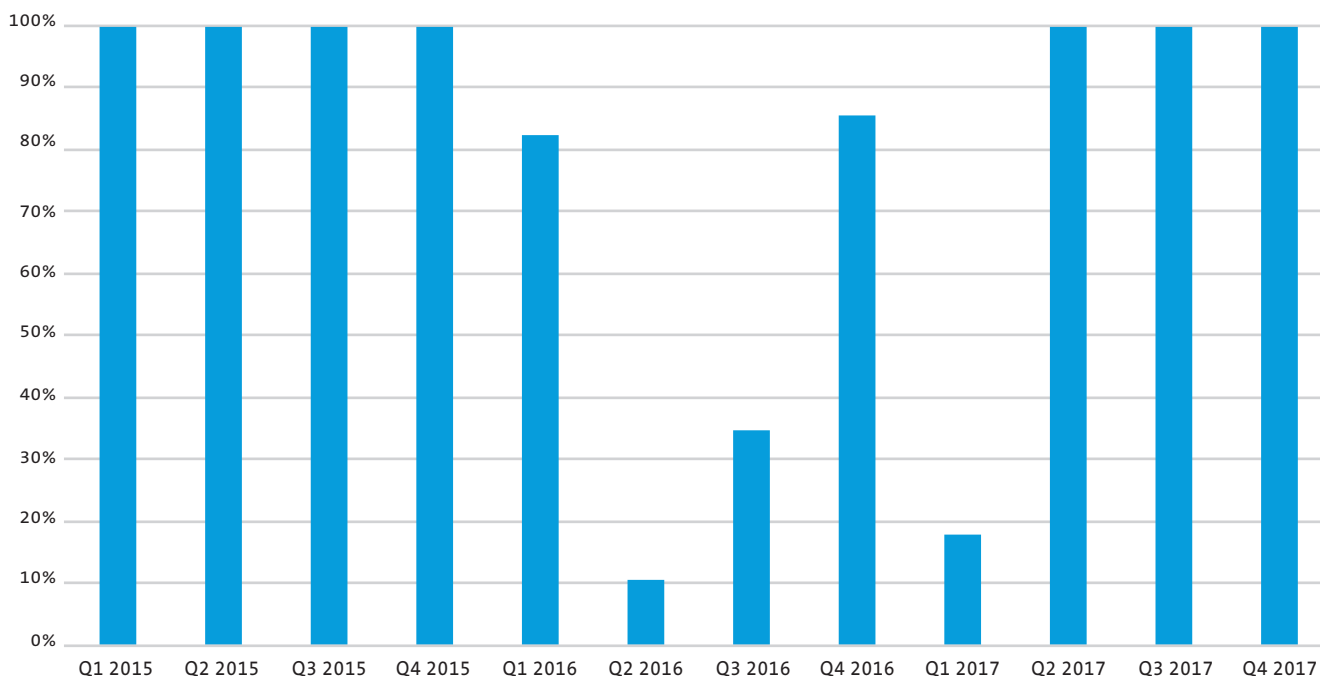
Entities covered by the program include electric utilities with retail loads, large industrial energy users, and, as of 2015, natural gas suppliers. Covered entities must submit an allowance to CARB for each metric ton of CO<sub>2</sub>-equivalent that they emit. The number of allowances available each year is equal to the number

of metric tons of emissions that is allowed under that year’s cap.

Certain covered entities receive free allowances from CARB to cover a share of their emissions. For the electric utility sector, the amount of these free allowances was set to exceed the utilities’ allowance requirements, in recognition that utility customers have been paying for greenhouse gas emission reductions since before the start of the cap-and-trade program, such as through procurement of renewable resources and energy efficiency.

Investor-owned utilities are required to bid all their free allowances into state-run auctions, while other entities with surplus allowances may bid allowances into the auctions or sell them via the Intercontinental Exchange (ICE) trading market for California cap-and-trade allowances or via bilateral trades. Covered entities that do not receive allowances from the state or whose emissions exceed the allowances they are issued must buy allowances through one of these mechanisms. Entities without compliance obligations may also participate in the program by voluntarily reducing their own emissions or by trading allowances as a liquidity provider. The state also participates by offering a slate of allowances for sale into each auction to cover the anticipated allowance needs of covered entities while keeping the total

**Figure 1: Percentage of Available Allowances Sold in Each Auction**



## The 2017 rebound in prices for greenhouse gas emissions allowances in California provides a window into future pricing.

number of allowances below the cap.

In 2014, Quebec linked its cap-and-trade program with California's, and Ontario will do the same beginning in January 2018. Allowances issued for these programs may be used to comply with California cap-and-trade requirements, and vice versa, and the quarterly, state-run auctions cover allowances for all linked programs.

### Market Rebound in 2017

Uncertainty dogged California's greenhouse gas cap-and-trade program throughout 2016 due to lawsuits questioning the legality of the program and uncertainty about the program's future after 2020.

As a result of these uncertainties, as well as an oversupply of allowances available in the market, interest in allowances was weak during much of 2016 (Figure 1), and allowance prices remained at floor-price levels in the auctions and dropped below this level on the ICE secondary market (Figure 2).

Demand for allowances rebounded in the second quarter of 2017, and prices rose accordingly, with auction prices remaining above the floor price since the May 2017 auction.

The settlement price for the most recent auction, held on November 14, 2017, set a record high for the auctions at \$15.06 per allowance, which is \$2.33 higher than the settlement price throughout 2016. Moreover, ICE secondary market prices have generally remained higher than auction prices, with price premiums to purchase allowances on the ICE secondary market reaching up to about 11% above auction allowance prices. All told, California cap-and-trade / continued page 32

## IN OTHER NEWS

the joint venture in this case is its focus seems to be to pool resources to pay legal expenses of negotiating a private business deal for its members.

The IRS analysis is in Private Letter Ruling 201749016. The IRS made the ruling public in early December.

**MORE CREBs** money is available, but the new tax-cut bill passed by Congress repeals the authority to issue new bonds after this year.

CREBs or clean renewable energy bonds are bonds that can be issued by municipal utilities, government agencies, Indian tribes, electric cooperatives and US possessions like Puerto Rico to finance wind, solar and other renewable energy projects. In theory, no interest has to be paid to the lender or bondholder. It receives federal income tax credits instead. Holders of bonds issued after 2010 receive tax credits worth as little as 70% of the interest payments.

The amount of such bonds that can be issued is limited. Anyone wanting to issue them to finance a project had to apply to the IRS for an allocation. All the money has already been allocated, but the IRS said in October that it has identified \$379.5 million in unused bond authority that was forfeited by earlier applicants and is available for reallocation to any public power provider. It said applications are due by June 19, 2018. The announcement is in Notice 2017-66.

However, that was before Congress passed a massive tax-cut bill in mid-December. The bill repeals authority to issue new CREBs bonds after 2017.

— contributed by Keith Martin in Washington

# California

continued from page 31

allowance prices have been much stronger in 2017 than they were in 2016, with auction settlement price increases of about 18% from November 2016 to November 2017.

## Why?

A number of factors came together to support the market recovery.

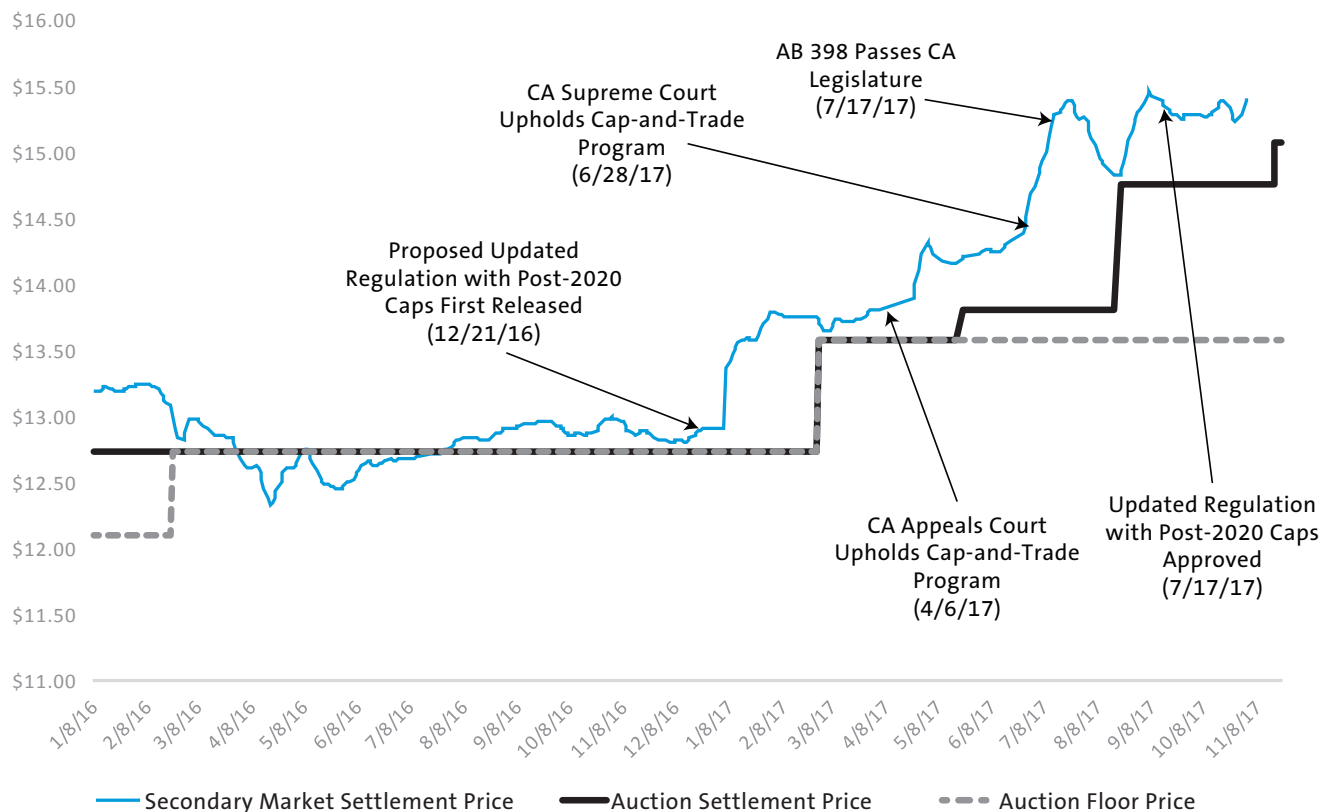
First, much of the legal and regulatory uncertainty surrounding the program was resolved over the course of 2017. Critically, a lawsuit challenging the legal basis for the program was rejected by the state appeals court, and the state supreme court declined to consider a further appeal, effectively ending the litigation. Adoption of new cap-and-trade legislation and regulatory amendments addressing the post-2020 program structure also provided important assurance about the program's future.

Figure 2 highlights key legal, legislative and regulatory developments that bolstered the market over the past year.

Although market sentiment may be influenced by any number of factors, the steep increase in prices following the supreme court action upholding the legality of the cap-and-trade program suggests that the legal uncertainty had been depressing prices and demand for allowances. The new legislation and regulatory amendments that set the stage for the cap-and-trade program to continue to operate with ever-tightening allowance budgets each year through at least 2030 may also be contributing to near-term demand because allowances purchased today can be banked for future use as a hedge against prices that should rise over time as the supply of allowances is further restricted and the auction floor price is further increased.

Structural factors also contributed to the market recovery. In particular, given that 2017 is the last year of the 2015-to-2017 compliance period, all allowances for this three-year period must be procured by the end of the year. In 2015 and 2016, by contrast, entities had the option of not purchasing up to 70% of their compliance obligations for those years and instead waiting to see how the lawsuits or other factors played out. Some of the demand increase observed over the course of 2017

**Figure 2: 2016 through Early-November 2017 Cap-and-Trade Allowance Prices and Key Legal and Regulatory Events Addressing Program Viability and Design**



probably derives from entities that had been taking a wait-and-see approach and are now addressing unmet compliance obligations from 2015 and 2016 as well as meeting the current year's obligations.

An additional structural influence contributing to the price recovery is a stabilizing mechanism that is in place to address surplus allowance conditions. In particular, allowances that are designated for auction by a greenhouse gas program regulator (currently, CARB or Quebec) and that are not sold are withheld from subsequent auctions and returned only after settlement prices in two consecutive auctions rise above the auction floor price. This mechanism led to removal of 153 million allowances from auctions in 2016 and 2017, helping to stabilize prices.

### 2018-to-2020 Outlook

While the cap-and-trade allowance market experienced robust price increases in 2017, there are headwinds that could make it difficult for prices to sustain the upward momentum in 2018.

First, 2018 is the start of the third cap-and-trade program compliance period, which lasts from 2018 through 2020. Thus, allowance purchases could again largely be deferred until 2020 if compliance entities want to wait and evaluate future auction and secondary market prices before purchasing the full amount of allowances they require, perhaps due to cash-flow considerations or expectations of price declines.

Furthermore, in the near term, a large number of allowances that were auctioned by state agencies in previous auctions, but went unsold, will re-enter the market. This began to happen in November 2017. Per the regulations, the number of re-auctioned allowances was restricted to 25% of allowances previously designated for that auction, or about 16 million allowances, so as not to flood the market with too many allowances at once. This means, however, that the impact of this mechanism will continue over many more auctions, as 137 million additional allowances are awaiting re-entry.

To prevent these reintroduced allowances from depressing the market, beginning in January 2018, current-vintage allowances auctioned by state agencies that remain unsold for more than 24 months will be removed from the market and placed in an allowance price containment reserve fund, to be released back in the market only if prices rise to the point that action is needed to control allowance price increases.

Table A estimates the number of expiring allowances that will be removed from the market because they remain unsold for more than 24 months. Per this assessment, allowances will start to be permanently removed from the market in May 2018, with nearly 60 million allowances removed through February 2019. The removal of these allowances is not expected to have an immediate impact on pricing since allowances will also be reintroduced into the market over this same time period; however,

**Table A: Reintroduction and Removal of Unsold Allowances from 2016-2017 Auctions (in millions)**

Initial Auction Date	Nov 2015	Feb 2016	May 2016	Aug 2016	Nov 2016	Feb 2017
<b>Cumulative unsold allowances</b>	0	11	56	98	111	153
Auction Date 24 months later	Nov 2017	Feb 2018	May 2018	Aug 2018	Nov 2018	Feb 2019
<b>Cumulative reintroduced allowances</b>	16	32	48	64	80	95
<b>Cumulative allowances removed from the market</b>	0	0	8	35	35	58

Note: The analysis presented in this table assumes that a similar number of allowances as was reintroduced in the November 2017 auction continues to be reintroduced to the auctions through February 2019, that auction prices continue to exceed the floor price in each auction, that all current-vintage allowances available in each auction are sold, and that unsold allowances are pulled from the market in the auction 24 months after the initial auction date.

*/ continued page 34*



## California

*continued from page 33*

removal will help to stabilize pricing in the intermediate term.

On balance, the start of a new compliance period in 2018 and the lingering impact of unsold allowances on auction results suggest that allowance prices could flatten or even pull back somewhat in 2018.

However, the certainty that the program will continue past 2020, thereby ensuring that allowances will continue to have value in the future, and the fact that excess allowances will eventually be removed from the market make it unlikely that prices will collapse back to levels seen in 2016 and early 2017. This is the case both with respect to auction prices, which are subject to annual floor price increases, and also with respect to secondary market prices, which are not subject to regulatory price controls.

Looking farther out, additional upward pricing pressure can be expected beginning around May 2019 after all the excess allowances from the 2016 and 2017 auctions have been dispensed with (either via reintroductions to earlier auctions or via removal from the market), and again during the second half of 2020 as the third compliance period draws to a close. Annual auction floor price increases and annual reductions to the total number of available allowances will also contribute to upward pricing pressure.

## Post-2020 Program Developments

At this stage, regulations governing the cap-and-trade program after 2020 remain under development, but important steps were taken in 2017 to set the stage for the post-2020 program.

AB 398, passed by the California legislature and approved by Governor Jerry Brown in July 2017, extends the cap-and-trade program through 2030 with the goal of reducing the state's greenhouse gas emissions to 40% below 1990 levels by 2030. In October 2017, CARB adopted annual emission allowance budgets for the years 2021 through 2030 consistent with this legislation, with declines in the number of allowances of about 5% per year.

Pursuant to AB 398, CARB will also establish price ceilings and intermediate price containment points below the price ceiling and will evaluate additional changes that may be made to the cap-and-trade program for the post-2020 period. For example, AB 398 directed CARB staff to address concerns about the potential over-allocation of allowances for 2021 to 2030, and CARB is seeking stakeholder feedback on this issue.

Going forward, the declining allowance budgets set by CARB in October 2017 should provide a tailwind for allowance prices by continuing to drive demand. However, the upside for prices could also be limited by the price ceiling and price containment measures that will be adopted by CARB. Overall, CARB's many tools for steering allowance pricing — such as reducing allowance budgets over time, setting an auction price floor and ceiling, removing surplus allowances from the auctions and reintroducing them when prices are higher — aim for a long-term trend of steadily increasing prices without extended slumps or spikes. ☺

# Net Metering and Community Solar

by Ana Vucetic, in New York

The shifting net metering policies in the United States affect the economics of community solar as well as residential solar.

Community solar relies on economic incentives offered by state net metering policies to attract subscribers and maintain viability. As traditional net metering continues to come under scrutiny, the effect of decreased compensation has the potential to hinder the deployment of community solar.

## Terminology Breakdown

Traditional net metering policies give credits to utility customers at retail rates for excess energy exported to the grid, effectively “rolling back” the meter for excess energy that onsite systems feed back into the grid and charging the customer only for the “net” energy the customer uses.

Virtual net metering and community solar, as the terms are most commonly used, are variations on traditional net metering.

“Virtual net metering” extends the benefits that a customer would receive by feeding excess electricity from his or her own solar system into the grid to customers who do not share the same meter as the solar installation. The customer may be in a different location or the same location as the solar installation. A typical example of a customer in the same location is an installation on the roof of an apartment building, the earned net metering credits of which are distributed among participating tenants on all floors.

“Community solar” projects, “solar gardens” or “solar farms” are utility-scale solar arrays that feed their electricity to the local utility but sell subscriptions in that electricity or in certain panels to local residents. The local residents receive bill credits from the local utility for their shares of the electricity. Put differently, such projects use virtual net metering to bring the benefits of net metering to customers through a solar installation in a different location than the subscribers. A developer can build a solar array at a site location optimal for solar power production that is miles away from its subscribers located in multiple buildings, and still distribute earned net metering credits among all of those

subscribers. The key to financing community solar is whether a project has and can maintain subscribers. Those subscribers are motivated in large part by utility bill savings offered by net metering.

Net metering and community solar policies are largely created and regulated at the state level.

## Trends

The general trend is for state-level re-examination of traditional net metering policies with a focus on revisiting compensation rates in particular. Nevada and Hawaii were the first two states to walk back their net metering programs. The two states overhauled their net metering programs at the end of 2015, disrupting solar markets particularly in Nevada. A trend toward gradual changes in policy has since emerged in other states. (For more detailed reporting on this trend, see “Net Metering Debate Moves East” in the June 2016 *NewsWire* and “Net Metering: Opportunities on the Road to Reform” in the October 2016 *NewsWire*.)

At the same time traditional net metering policies are being re-evaluated, community solar appears to be gaining in popularity. Seven states and the District of Columbia took action on community solar in 2015. As of the third quarter of 2017, at least 13 states have taken action. Twenty-six states have at least one community solar project in operation. The balance of this article examines developing community solar policies in two key community solar states — Massachusetts and Illinois — and how they intersect with net metering.

## Massachusetts

Massachusetts is one of the top four US states with the largest amount of installed community solar capacity as of mid-2017. The state is expected to remain among the top four in terms of new community solar capacity installed over the next two years. The current community solar regime in Massachusetts offers net metering coupled with solar renewable energy credits, or SRECs, but a replacement program is expected to become effective in 2018.

Massachusetts has statewide caps that limit the percentage of a utility’s load that can be net metered.

After a statewide cap on total net metered systems was reached in mid-2016, Massachusetts implemented a new policy preserving close to retail rates for net-metered electricity from new systems sized at 25 / continued page 36

## Net Metering

*continued from page 35*

kilowatts or below and systems with public offtakers, but reducing compensation to 60% of excess generation for new projects over 25 kilowatts with private offtakers.

Massachusetts enacted an SREC and successor SREC II program to support its renewable portfolio standard targets.

Community solar development in the state has benefited from the SREC II program. The current SREC II program allows qualifying facilities to generate SRECs that generators can then sell on the open market or, if that fails, sell through the Solar Credit Clearinghouse Auction II. Utilities need SRECs to demonstrate the percentage of their electricity that is supplied from renewable energy. Any utility that comes up short at the end of the year must pay an alternative compliance payment.

The SREC II program assigns different types of projects a multiplier as to the amount of SRECs to which it is entitled for electricity generated based on factors such as type, size, location and ratepayer level of income.

Community solar projects fall into the category with the highest multiplier. Projects that qualify for the SREC II program can generate SRECs for 10 years. These projects may continue to generate and sell SRECs after any new program is implemented.

Massachusetts is replacing the SREC II program with the Solar Massachusetts Renewable Target (SMART) program.

The SMART program is intended to replace SRECs and temper the pricing volatility of the SREC market. The Massachusetts Department of Energy Resources adopted final regulations at 225 CMR 20.00 in late August. The program aims to add 1,600 megawatts of solar capacity using an innovative approach.

Eligible projects must be five megawatts or smaller. The program will first set a base incentive price for the first 100 megawatts of projects through a competitive bidding process, then allocate eight 200-megawatt blocks of solar energy over time using declining incentive prices.

Based on the initial clearing price, different types of projects will be eligible for different rates of compensation and term lengths based on factors such as system size, location, type of offtaker (community solar, low-income and public entity offtakers each have an adder), use of battery storage and use of a solar tracker. There are also subtracting factors for use of certain types of land including greenfield land. The base compensation rates decline 4% per capacity block. Compensation rate adders will decline by 4% per tranche of capacity. The first tranche for each adder is set by the program at 80 megawatts, with the Department of Energy Resources choosing the capacity of additional tranches.

The SMART program also includes provisions preventing segmentation of larger facilities into smaller facilities to obtain more favorable rates as well as several consumer protection provisions. Systems 25 kilowatts or below are eligible to receive compensation under the SMART program for 10 years while systems over 25 kilowatts are eligible for 20 years.

In calculating incentive payments, the program distinguishes between standalone solar generation units, which do not serve an associated on-site load before being interconnected to the grid, and behind-the-meter solar generation units, which do serve an on-site load and receive compensation under existing programs including net metering. The program offers an alternative on-bill credit for standalone solar generation units that do not fall under the existing net metering regime, but are enrolled in a tariff establishing a bill credit.

This bill credit tariff is likely to be particularly relevant for community solar projects, as three of the main Massachusetts utilities have already hit their net metering caps.

The SMART program does not lift the current statewide caps on net metering. Draft bills S. 1824 and H. 2712 are currently under consideration by the Massachusetts legislature, each proposing to raise public and

## Changes in net metering policies in Massachusetts and Illinois will affect community solar projects.

private net metering caps by 5%.

The SMART program directs electric distribution companies to file tariffs for approval. The distribution companies filed a draft model tariff in docket D.P.U. 17-140 that is currently open for comment. They also issued a request for proposals on November 13 for the initial 100-megawatt block. Bids had to be submitted between November 27 and December 5. The results will be announced by January 11, 2018. The aim is to have the SMART program in place in early 2018.

## Illinois

Illinois offers net metering coupled with SRECs, similarly to the current scheme in place in Massachusetts.

SB 2814 or the Future Energy Jobs Act passed in Illinois in December 2016 directing electric utilities to expand net metering to apply to community renewable generation projects, facilities on property owned or leased by multiple customers within a utility service territory and projects that service multiple customers within a single building, each up to two megawatts. The new law also directs the Illinois Power Authority to develop a draft procurement plan.

Net-metered systems in Illinois are generally credited at the retail rate, but capped when net-metered systems account for 5% of the total peak demand of a utility's eligible customers, measured in the previous year. After the cap is reached, new installations are credited for the cost of energy only. The state does not expect caps to be reached before late 2019, when it intends to update the final plan.

The new law requires each electric utility to file tariffs for community renewable generation projects by August 2017, meaning the amount each utility will pay for net metered electricity. The tariffs were filed and approved in late September.

The Commonwealth Edison Company tariff was approved in docket no. 17-0350. Notably, the tariff does not include compensation for transmission- and distribution-related charges. The MidAmerican Energy Company tariff was approved in docket no. 17-0368. The approved tariff compensates customers at only the supply charge, modified by certain adjustment factors. The Ameren Illinois Company's revised rate similarly compensates subscribers at a lower-than-retail rate.

The Illinois Power Authority released a long-awaited long-term renewable resources procurement plan on September 29. The plan is part of a larger effort to meet the state RPS targets.

Among other things, the plan commits the Illinois Power Authority to implement an "adjustable block program" that

includes administratively determined prices for renewable energy credits rather than pricing through competitive procurement, as well as a "community renewable generation program" that is a subset of the adjustable block program for community solar.

The adjustable block program brings some certainty to REC pricing. Two types of projects are eligible to participate in the program: "photovoltaic distributed renewable energy generation devices" and "photovoltaic community renewable generation projects."

Photovoltaic distributed renewable energy generation devices cannot be larger than two megawatts in size. They must connect to a distribution system rather than the transmission grid, be on the customer side of the meter and be used primarily to offset that customer's own electric load.

Photovoltaic community renewable generation projects are similar, except they must credit the value of the electricity generated to subscribers.

At least 25% of RECs awarded under the adjustable block program must come from distributed renewable energy generation devices no larger than 10 kilowatts, 25% from distributed renewable energy generation devices above 10 kilowatts up to two megawatts, 25% from photovoltaic community renewable generation projects and the remainder are allocated by the Illinois Power Authority at its discretion in response to demand.

There is a statutory requirement for utilities to prepay the purchase price in full for REC contracts entered into for systems no larger than 10 kilowatts, and 20% of the purchase price for larger systems and community renewable generation projects. Contracts must be at least 15 years in length. Community solar projects must demonstrate a minimum level of subscribers before receiving payment for RECs. At least 50% of project capacity must be subscribed under the current draft of the plan.

The adjustable block program uses a "block" concept. A block represents a certain amount of generating capacity at a certain REC price. Progression from one pricing block to the next is triggered by volume of deployed capacity. When a block's allocated capacity is filled, it closes and the next block opens at a different price, predicted to be 4% lower than the price for the previous block.

To pre-empt end-of-block rushes, all projects submitted within 60 days of the opening of the program will be included in the first block regardless of capacity filled, and for future blocks, the power authority will announce when capacity has been met but hold the block open for 14 days. Opening block volumes would be initially allocated at 22 megawatts / continued page 38

## Net Metering

*continued from page 37*

each for small systems, large systems and community solar projects in group A (projects in Ameren, Mt. Carmel Public Utility and rural electric cooperative service territories) and 52 megawatts each in group B (projects in ComEd, MidAmerican and municipal utility service territories).

The Illinois Power Authority intends loosely to set pricing of the blocks using its own REC pricing model with adders for certain types of systems.

Adders to the base price are proposed for systems in the large system and community solar project categories (decreasing as size increases) as well as an additional adder for projects in the community solar project category that have 50% or more residential subscribers.

Community renewable generation projects cannot have a single subscriber accounting for more than 40% of the nameplate capacity of the project. Subscriptions must be portable for a customer moving within the service territory and transferable by the customer to another subscriber within the territory. The IPA is required to purchase RECs from subscribed shares of community renewable generation projects.

There are extensive proposed consumer protection measures.

The comment period for the draft plan ended on November 13. The plan must be approved by the Illinois Commerce Commission before it can take effect. Objections were required to be made to the ICC by December 18, and the ICC must decide by December 26 whether hearings are necessary. The ICC must confirm or modify the plan by a statutory deadline set for April 3, 2018. ©

## Risk Management for Solar Projects

*The Solar Energy Industries Association published a guide called “Best Practices for Solar Risk Management” in September. Jason Kaminsky, chief operating officer of kWh Analytics and the author of the guide, Ed Rossier, a director of project management for renewable energy investments at US Bank, and Mike Mendelsohn, senior director of project finance and capital markets at the Solar Energy Industries Association, talked about the topic during a webinar in November. The following is an edited transcript. Keith Martin with Norton Rose Fulbright in Washington is the moderator.*

MR. MARTIN: Jason Kaminsky, what is the difference between an asset manager and a risk manager? The guide suggests the difference is important.

MR. KAMINSKY: The sponsor does asset management. It has the asset. Bankers and tax equity investors do risk management. They want to make sure they will be repaid or reach their target returns.

An asset manager at a sponsor is responsible for supervising technicians, overseeing O&M agreements, managing spare parts and the other physical aspects of making sure the project performs. He or she is also responsible for things like sending and correcting invoices, preparing financials, getting auditing and accounting help, and preparing reports for the financiers.

Risk management is what a banker or tax equity investor does in preparation for and after an investment. That includes things like tracking, monitoring, reporting on, and managing the health of the investments after they have been made, and managing internal stakeholders who have an interest in the financial health of the portfolio.

MR. MARTIN: How did you come up with the best practices you recommend in the guide?

MR. KAMINSKY: First, kWh Analytics works closely with a number of investors. We drew on their insights. Second, I drew on my own experience at Wells Fargo. I was one of the early members of the solar tax equity team, so we basically built our own risk management platform from scratch. Third, various members of the solar energy advisory council at the Solar Energy Industries Association read and commented on the guide, and then we had peer review by about a dozen other reviewers from industry that included other lenders and tax equity investors.



## Identifying Risks

MR. MARTIN: Ed Rossier, you have a huge portfolio of tax equity positions in solar projects. Risk management has to start for you when you are first looking at a potential project. I suspect you end up cataloging all the risks, and then you write into the deal documents which party takes each risk. The ones that US Bank will take have to be quantifiable if you are going to invest.

People sometimes say that it is not important to eliminate all risks. You just have to be able to quantify them. Whose job is it at a tax equity bank like US Bank to identify these risks? Start at the front end of the process.

MR. ROSSIER: Most banks are probably organized with three lines of defense. There are the business lines, then risk management and compliance, and then an internal audit group that makes sure everybody is doing what he or she is supposed to be doing.

Our business line is the world that I live in. These are the revenue-generating individuals at the company.

MR. MARTIN: You originate deals.

MR. ROSSIER: It is everything facing the customer. There is a separate line that is concerned with implementing policies and approving investments. That is separate from the team that originates, closes, and manages the assets. Within that world of the customer-facing business-line function, different banks choose different ways of organizing things.

We are organized into three groups: we have business development officers, who are originators who source new customers and new investment opportunities and take them through the letter of intent. Once the letter of intent is signed, it is transitioned to my team which we call project management, but it is really underwriting, negotiating and closing.

That team will take an investment from signing of the letter of intent through closing on the definitive deal documentation. At that point, the investment is transitioned to our asset management team, which holds it through the life of the investment until we exit.

MR. MARTIN: You are in the middle position. The letter of intent has already been signed. Now the deal has to be documented. You have to understand the risks. You bring in a lot of consultants, including lawyers, to help you understand everything. There is also diligence done by the internal team.

MR. ROSSIER: At this point, the due diligence requirements for most deals are pretty standard, depending on the deal type. Most people will circulate a due diligence closing checklist pretty early in the process that covers the waterfront.

Our internal team will review everything in conjunction with outside counsel. We engage a variety of other experts, including independent engineers, appraisers and accounting firms.

MR. MARTIN: Could someone contemplating raising tax equity from US Bank ask you in advance for the checklist so that he or she can get a head start on setting up a data room?

MR. ROSSIER: Yes, it happens occasionally. A big caveat is that until the specifics of the assets are known, it is hard to cover everything in a checklist.

MR. MARTIN: There are three different business lines involved in moving the deal to completion and then afterwards during the operation phase. One is a group that gets it through the letter of intent, then you come in as part of another team that does the diligence and documents the deal. Then the baton is passed to an asset manager.

MR. ROSSIER: Not to confuse terms, but that is the term that we use. At our bank, the asset managers process all of the post-closing fundings and then any amendments or issues that come up in deals. They manage through exit.

MR. MARTIN: How many solar projects does US Bank have in the asset manager stage at this point?

MR. ROSSIER: Something like 250 investments.

MR. MARTIN: How many asset managers do that many projects require?

MR. ROSSIER: Our team is around seven, and then there is another group of portfolio analysts that supports them, which is about five or six people. There is some permeability between people in different business lines, and there is a lot of cooperation, because every investment that we do is either with a repeat customer or a customer that we hope will become a repeat customer.

The information from each group has to be shared with the others because the originators need to know how projects that already closed are performing, and underwriters need to understand what might have gone wrong so that they can incorporate that information into their underwriting. We all sit together. There is constant communication among the groups.

MR. MARTIN: What does a portfolio analyst do that the asset manager does not?

MR. ROSSIER: They collect everything that is required to be delivered and then dig into financial statements, operational statements, tax returns and the like and are available to help do a deeper dive into any asset that might be troubled or where we want to pull a little more data out of our portfolio.

*/ continued page 40*

## Risk Management

*continued from page 39*

MR. MARTIN: That's a lot of work. What is left for the asset manager to do?

MR. ROSSIER: That's a good question. [Laughter].

MR. MARTIN: There are seven of them compared to five or six of the people you just described.

MR. ROSSIER: The bulk of their time is spent on fundings. We do a lot of residential solar and portfolios of small utility-scale solar, and each of those investments will have multiple fundings. You could have monthly fundings or twice-monthly fundings all year long for one investment. There is a lot to review in connection with each funding.

After that, most of the work is annual and quarterly reviews of the portfolio and then, of course, any project or sponsor that has distress of any kind will draw the bulk of their remaining attention.

MR. KAMINSKY: One of the surprises to me when I first joined Wells Fargo is that you have the business line, as Ed mentioned, and then there are lots of other internal stakeholders who have an interest in what you are doing. A bank has an accounting group that is working on the bank's accounting. It has a tax group. You might work with an equipment leasing group. You have internal audit.

A lot of the time is spent directing traffic and making sure that all those other teams have what they need to do their jobs.

## Big data can help rank asset performance against the broader market.

### Current Hot Buttons

MR. MARTIN: Ed Rossier, you said the portfolio analysts and asset managers sit pretty close to the deal originators so that you can learn from each other. Is there a formal process? Are there regular meetings? Can you think of anything that has been passed to the deal originators recently from experience on the asset manager's side?

MR. ROSSIER: Yes. Our company made a conscious decision to integrate the teams by having people from different teams mixed together. We don't have silos. We think communication is important.

For example, the tax equity investor often has an outside completion deadline, and if you have a lender that is bridging the tax equity investment, it will want a cushion between the maturity date and the outside completion date on the tax equity commitment to ensure it is not left without a takeout. The outside completion dates are negotiated during the term sheet phase by the business development officer. They are essentially a conversation between the business development officer and the customer about an outside date to complete the project that the customer feels confident will be met.

The deal then transitions over to my team. Maybe there are eight to 12 weeks of negotiation, underwriting and closing and, during that time, the schedule might move, but the outside completion date might not. That can create a problem if asset managers are having to ask for extensions after closing because the lender extended its deadline in order to accommodate the construction schedule. The tax equity investor gets asked to extend as well. The delay might be due to a new schedule the utility imposed for interconnection, for example. The delay was not incorporated into the internal credit approval.

This causes heartburn for sponsors and lenders and creates work for asset managers, so we try to learn from the experience and come up with a different approach for setting future outside completion dates at the front end.

MR. MARTIN: Make sure all the dates synchronize. Jason Kaminsky, you worked at Wells Fargo for a while in a similar capacity as Ed Rossier. Are there other ways that you have seen teams organize themselves?

MR. KAMINSKY: Organizations that do not have the volume and head count of US Bank sometimes divide up by customer. This affects the way such a bank makes investments and evaluates risk. The same person takes the deal from start to finish and also acts as the asset manager.

Where the investment group sits within the banks also influences its perspective. Sometimes, like at US Bank, it sits alongside groups handling low-income housing and other tax-credit investments. Other times the group sits within a principal investing group, or an energy lending group or a leasing practice. This influences everything else about the accounting, the oversight and the risk perspective. We see people come at solar from different starting points, and I think it influences the way they evaluate the deal.

MR. MARTIN: Ed Rossier, you mentioned a lot of people who have to sign off and, Jason Kaminsky, you said that a lot of the work is acting as a traffic cop by steering things to people who will need them in order to sign off. The people who sign off include the tax equity business unit, the credit committee, internal and external auditors, the bank regulators, and maybe the tax department.

You probably get to a point fairly quickly where you know the hot buttons of each of these groups. Name a couple of current hot buttons that are getting a lot of attention.

MR. ROSSIER: It can change from year to year and from month to month, depending on the topic du jour. Risk mitigation tied to tax reform is a hot topic today. It is requiring a lot of coordination among departments within the bank.

Another one that is new this year is module supply security and tracking where modules are as a direct result of the Suniva tariff case. The potential for import tariffs creates pricing uncertainty.

Other ones that are popular this year include interparty terms of lenders where debt or back leverage is added to investments after closing, and post-closing changes in sponsor ownership. There have been a fair number of upstream acquisitions of developers, and that has created a lot of work for asset managers.

## Best Practices

MR. MARTIN: The risk management guide is really just a compilation of best practices for managing risk. It breaks these practices into three categories. There is risk measurement and monitoring over time. Then there is comparison against industry benchmarks, and finally there is compliance. The guide recommends a dozen best practices. Let's talk about some of them.

Let's start with operating risk. This is the first place to focus because it determines the cash flow from the project. The guide recommends tracking a weather-adjusted performance index. Jason Kaminsky, what is that?

MR. KAMINSKY: It is comparing actual output to the projected production in the project pro forma. Is the project or the portfolio hitting its target? If not, is it because of something that the sponsor can control? The main variable is usually weather. If it was poor sun, then it is not usually the sponsor's fault. On the other hand, if there is an operational issue, we will want the sponsor to address it.

Backing out the influence of the weather — that's essentially the weather adjusted performance index — can isolate any operating issues.

MR. MARTIN: Who maintains this index? Is it the sponsor, the tax equity investor or the lender?

MR. KAMINSKY: It is usually monitored by the sponsor and then delivered to the various stakeholders as part of the reporting package.

MR. MARTIN: Does the sponsor come up with its own model or is this something that is purchased from outside?

MR. KAMINSKY: It is a blend of both. External information is sometimes used to support an internal model.

MR. MARTIN: How do big data and industry benchmarks play a role?

MR. KAMINSKY: We see a lot of requests for benchmarks. That gives investors a sense of whether assets are underperforming in relation to the broader market. If so, that might be a sign of a bigger problem. The other area we have had a lot of questions about is a significant weather event, like a big snowstorm, fire or hurricane. These events seem to be becoming more common.

MR. ROSSIER: I am a big fan of aggregating data and standardizing data fields. We participated in Orange Button, a US government effort, when the group was determining the taxonomy. I think more standardization is helpful at both the data level and the contract level.

*/ continued page 42*

## Risk Management

*continued from page 41*

MR. MARTIN: How does standardization help you?

MR. ROSSIER: There are two sides to this. One is we are an active syndicator. We will try to raise about \$500 million of third-party tax equity next year and deploy it alongside our own bank's tax equity. As part of our reporting to third-party investors, the more we can benchmark, the better the product we are delivering to our third-party investors.

The other side is accessing new market segments that are not currently served by tax equity. Two great examples are low-FICO customers, like subprime homeowners, and the commercial and industrial solar market, which has people scratching their heads over how to tackle it.

MR. MARTIN: The data and the benchmarks get you comfortable eventually that a low FICO score is not a problem.

MR. ROSSIER: In theory they could. Or they could tell you the opposite. For now, we don't know. We recently began working with kWh Analytics to help us aggregate our data, and we use the aggregated data to support our syndications business and underwriting practices. For example, Fannie and Freddie publish a lot of mortgage data. This allows people to do analysis and draw conclusions based on the data. It is much more difficult in solar because every sponsor holds its data as a proprietary source of value for its own use.

MR. MARTIN: How could data help you get comfortable with the C&I solar market where the problem seems to be lack of standardization for the offtake contracts?

MR. ROSSIER: It will not help with the issue of offtake contract standardization, but it does help when you are trying to evaluate default risk or credit risk generally of offtakers or the likelihood that solar equipment will remain in service. There may be ways to look at it on a portfolio level and draw conclusions about default rates or periods of lost revenue. Banks might not start there, but there might be an opportunity for insurers to be first movers in that market.

MR. MARTIN: Next question. The guide says, "Nearly every large portfolio to date has seen the insolvency of a vendor or sponsor." That is referring to rooftop solar, correct?

MR. KAMINSKY: It is true across the solar market, but more so in the C&I and residential segments.

## Risk Matrix

MR. MARTIN: You go on to point out in the guide that there is also regulatory risk as net metering policies, tax law and renewable portfolio standards sometimes change, sometimes with retroactive effect. The guide tackles this by recommending investors track exposure at both the project and portfolio level by looking at how many dollars are exposed to different equipment types, geography and what else?

MR. KAMINSKY: I guess the best way to answer this is with a few examples. With the recent wildfires in northern California, investors are trying to scope very quickly what kind of exposure they have to assets in that region. Zip code is the key metric. Investors who have their assets divided by zip code can determine their exposures quickly.

In addition to geography, assets might be tagged by installer, equipment vendor, servicer, offtaker and offtaker credit. A robust data set helps an investor respond quickly to the changing market.

MR. MARTIN: So having a matrix on your computer screen or a big spreadsheet showing exposures is a powerful risk management tool. One of the uses is being able to respond quickly to questions from credit. Are there other uses for such a matrix?

MR. KAMINSKY: Yes. Sometimes within a bank you are managing exposures to risks like geographic concentration, low-FICO customers, lots of battery storage, for example. There is a misconception that if there is a problem, you can't really do anything about it.

I learned very early in my career that problems are okay, but surprises within a bank environment are not.

If you see a problem on the horizon, often if you get a lot of smart people together, you can come up with a pretty good mitigation strategy. That might include financial support. It might include alternative O&M strategies. Using this sort of matrix allows you quickly to scope your risk and decide how you want to manage that risk.

MR. MARTIN: Offtaker credit risk is another issue, especially in the residential solar portfolios and the utility-scale projects with corporate PPAs. What are the best practices to deal with these kinds of risk?

MR. KAMINSKY: You can't manage what you don't measure. Today in the residential solar sector, we don't even have a clear definition of what a default is. We are still figuring out what is

the right time to call a default and how to track different performance metrics across the portfolio. The challenge is how to normalize the data or metrics so that people like Ed can make better investment decisions.

MR. ROSSIER: The challenge on the residential side is the market is currently structured and willing to serve the prime homeowners, meaning a FICO score of at least 680 or 700. There is often an allowance for some portion of the portfolio to be unrated with either partial prepayments or ACH requirements to mitigate that risk. That's just where people have been comfortable, and in the absence of any broad data-based conclusion, I don't see that changing much.

In the C&I sector, it is really just commercial credit underwriting for the offtakers on a credit-by-credit basis. This is why I think that market has not really grown much because the only time we have been successful doing these types of portfolios are ones where they have, for example, a FedEx contract covering 50 FedEx locations so that you can underwrite a single offtaker and a single form of PPA and it is all standardized. The PPA wraps some of the site-control risk.

Those work, but in terms of my brother-in-law's gym getting solar on the roof, that is probably not going to be financed by US Bank because there is too much work to do to get comfortable with the credit. A handful of companies are trying to solve this problem using technology and web-based underwriting platforms to make that underwriting a little more systematic. They might be successful, but ultimately that gets to a second regulatory area for banks, which is third-party risk management. If you are relying on a third party to underwrite your risk, then you have

to be comfortable with the creditworthiness of the third party, and the bank regulators will hold it to the same standard as the bank. That means there is another door to get through.

MR. MARTIN: It sounds like a lot of this lends itself to artificial intelligence.

MR. ROSSIER: Yes. Our tax equity subsidiary was a community development corporation that was originally focused on affordable housing and new markets tax credits. We were always compliance-focused. Tax credit recapture was our first risk category. Other banks may start with the asset-level risk and then go up the chain.

MR. MARTIN: Is this a case where the more you know, the more risks you see or the more you know, the more the list of risks shortens?

MR. ROSSIER: I don't know that it is either. With any new investment type, you uncover some risks that maybe you did not think of at first. The risks in solar are pretty well known at this point. Performance is the unknown.

If we could go back 10 years and rebuild our platform and money were no object, every bank would develop a proprietary underwriting database that could tap into other sources of data, allowing you to make the case to your credit or risk management folks that you can underwrite 100 different commercial offtakers in a single fund. That is something that artificial intelligence might eventually make possible.

MR. KAMINSKY: Even if you have identified a risk, it doesn't mean a bank is always best suited to wear it, especially if it leads to volatility in cash flows. Currently within the lending market, there is a lot of capital, but a finite number of deals. I think in that

market, the question is how either to stretch your risk appetite or to find innovative ways to structure around risks. We have secured insurers to accept untraditional risks. In our case, insurers take production risk, and we are finding lenders are able to underwrite projects more aggressively with these policies in place. That is important in today's competitive market.

*/ continued page 44*

**A matrix showing assets by zip code, equipment type, offtaker and other metrics helps to manage risk.**



MR. MARTIN: Let's work Mike Mendelsohn in here. The US Department of Energy's Sunshot Initiative office has been working with the solar industry on an Orange Button data standard. Ed Rossier mentioned it. The standard is described in the guide as a taxonomy for solar data transfer and reporting. What is it? When will it be available?

MR. MENDELSON: Essentially it is a dictionary of all relevant data terms so that there is a consistent name and definition for each term. That allows for interchangeability of data and facilitates greater liquidity in the financial market. We expect to see something in the next couple of quarters.

MR. MARTIN: You worked at the National Renewable Energy Laboratory. That is where most of us in the solar market got to know you. The Solar Energy Industries Association hired you away from NREL. NREL had run out of budget for your program. You were working mainly on model contracts for solar deals. Now that you have moved to SEIA, you have also come up with sets of best practices for installation and O&M and for consumer protection. Is the focus of these efforts rooftop solar or are you working more broadly?

MR. MENDELSON: We started with distributed generation. We are now thinking about doing standard contracts for the utility-scale market. We recently improved on the commercial and industrial PPA that is designed for relatively small C&I projects. We are in the process of bolting on some different components to that: for example, a PACE addendum and a storage addendum. We are trying to build out our suite of contracts to include other technologies and other finance models.

MR. MARTIN: Where can people find these contracts?

MR. MENDELSON: Search in Google for "SEIA model contracts." Or navigate through the SEIA website. You can always contact me as well.

MR. MARTIN: You suggested your next focus as a group may be on utility contracts. Is there any other potential focus at which you are looking?

MR. MENDELSON: We are looking across the investment ecosystem. How can we facilitate reduced transaction costs or allow project cash flows to be pooled into structured finance products?

We were talking a little bit earlier about the C&I sector and how difficult it is to finance. A lot of that is because the originators are too small to come up with a contract portfolio of sufficient scale to reduce risk across that portfolio. Building portfolios across originators has been too difficult to date because of the risks inherent with that. I think we will be able to solve for a lot of those issues and develop portfolios that are large enough where any single project within the portfolio does not represent too much concentrated risk. That will be a valuable barrier to overcome. ☺

# Environmental Update

A top credit rating agency, Moody's Investors Service Inc., put coastal communities in the United States on notice in late November that they must either start preparing for the impacts of climate change or risk paying more for credit.

Moody's explained in the report to clients how it incorporates climate change into its credit ratings for state and local bonds. If states and cities fail to address risks from more intense storms and sea surge and other effects of climate change, Moody's will consider them to be at a greater risk of default. The greater the risk of default, the higher the interest rates those states or municipalities will pay.

The report lists six indicators that Moody's uses to "assess the exposure and overall susceptibility of US states to the physical effects of climate change." Chief among them are the share of homes in a flood plain, the degree of economic activity that comes from their coastal areas, and hurricane and extreme-weather damage as a share of the economy.

Texas, Florida, Georgia and Mississippi are among the states most at risk from climate change, according to Moody's.

## Clean Power Plan

The US Environmental Protection Agency held public hearings in late November on its plan to withdraw the agency's Obama-era greenhouse gas emissions standards for existing power plants, known as the Clean Power Plan.

EPA Administrator Scott Pruitt set the hearings in Charleston, West Virginia as outreach to "coal country" to build support for the Trump policy of reversing Obama-era regulations.

The agency took testimony on its proposal to withdraw the Clean Power Plan, which it now says is required because the

Clean Power Plan exceeds its statutory authority.

Though most of the industry groups that testified called for a replacement plan — not just outright withdrawal — the hearings dealt only with the repeal proposal and not also a potential replacement. Most of the witnesses who testified complained that the Obama administration had been waging a "war on coal."

EPA will accept comments on its repeal proposal through January 16, 2018. EPA plans to hold additional public hearings on the repeal plan in three states. Pruitt has long said he wants to withdraw the Clean Power Plan without waiting for a replacement because it is unclear how long the US Supreme Court's 2016 stay of the plan will remain in effect, and he wants to provide the coal power sector with certainty straightaway.

Many industry groups renewed calls for a replacement in their testimony because they wish to avoid an extended period of regulatory uncertainty given that the courts have held the EPA is required by law to regulate greenhouse gases from the power sector.

For example, the National Rural Electric Cooperative Association supported withdrawal, but "strongly encourages EPA to propose and finalize a 111(d) rule, consistent with the history of the regulation. Both actions are needed to provide America's electric cooperatives and their members with a rule that is clear and durable." Other witnesses called for a replacement plan that would give states the primary authority to implement unit-by-unit emissions caps.

An "endangerment finding" by EPA in 2009 is viewed by many lawyers as requiring EPA to regulate carbon emissions from power plants.

Pruitt told the House Energy and Commerce Committee in early December that EPA will be "introducing a replacement rule to replace the Clean Power Plan under Section 111" of the Clean Air Act. In a subsequent court filing, EPA said it now plans to release an advance notice of proposed rulemaking seeking public comment on potential proposals to replace the Clean Power Plan in / *continued page 46*

**Moody's told coastal communities they will have to start preparing for climate change or risk paying more to borrow.**

## Environmental Update

*continued from page 45*

the next few weeks. EPA will “solicit information on systems of emission reduction that are in accord with the legal interpretation that has been proposed by EPA.”

Neither the West Virginia hearings nor Pruitt’s House testimony shed any light on whether Pruitt will try to revisit the agency’s “endangerment finding.” Some conservative groups have urged him to withdraw it as well. Reversal of the endangerment finding would undermine the legal foundation on which all federal greenhouse gas regulations are built.

In a recent interview, Pruitt criticized the 2009 finding, but said the endangerment issue is “untethered” to the EPA’s immediate plan to withdraw the Clean Power Plan and then consider a possible replacement.

Some in industry argue that EPA could move to revise its earlier determination that the 2009 endangerment finding applies to power plants. Others are concerned that industry will be vulnerable to citizen suits until some form of replacement for the Clean Power Plan is approved that arguably fulfills the obligation imposed by the endangerment finding. This may be why Pruitt now aims to replace the plan with something EPA can claim fulfills its obligation.

Meanwhile, the long-running litigation over the legality of the Clean Power Plan remains in limbo. The plan remains on the books, but enforcement has been suspended by the US Supreme Court while the agency that created it is moving quickly to withdraw and replace it. EPA filed an obligatory status report with the court on October 10, citing the agency’s

new proposal to withdraw the Clean Power Plan and arguing the court should continue the stay until the withdrawal is final. The report said the agency is contemplating the scope of any potential replacement to cover carbon emissions from existing power plants, but did not provide any details.

Many argue that it would be useless for the court to adjudicate a plan that is stayed and that the agency is in the process of withdrawing. Supporters of the Clean Power Plan argue that the appeals court should nevertheless assess its legality because many of the issues being litigated will come up in the forthcoming legal fight over withdrawal and any potential replacement offered by EPA. The appeals court appears likely to dismiss the case.

Pruitt appears to be weighing how he can limit any replacement plan through further reevaluation of the agency’s legal authority. In a recent interview with *Time*, Pruitt said his priority is to reexamine EPA’s authority to regulate greenhouse gas emissions from power plants instead of revisiting the endangerment finding. Pruitt said, “A lot of people just start with the endangerment finding and the scientific questions about the underpinnings of that. They don’t ask about what authority we have to do it ultimately anyway, and both are very important.”

As for timing, it appears the agency intends to ask the court for a dismissal first, but then delay any replacement. Pruitt said the agency’s review of its authority to regulate greenhouse gases under the Clean Air Act will be ongoing for “months into the future.”

**EPA has barred its scientists from making presentations about climate change.**

### Federal Climate Change Report

One obstacle Pruitt will face to overriding the endangerment finding is a report the US government released in early November about the cause of climate change that said “it is extremely likely that human activities, especially emissions of greenhouse gases, are the dominant cause of the observed warming since the mid-20th century.”

The report is part of a Congressionally mandated review conducted by a federal interagency group every four years, known as the “national climate assessment.” The report is produced by hundreds of experts within the government and academia, guided by a federal advisory committee and peer-reviewed by the National Academy of Sciences.

The report is billed as “an authoritative assessment of the science of climate change, with a focus on the United States.” What was released in early November is the first of two volumes of the fourth national climate assessment.

It said the “[g]lobal climate is changing and this change is apparent across a wide range of observations. The global warming of the past 50 years is primarily due to human activities. Global climate is projected to continue to change over this century and beyond. The magnitude of climate change beyond the next few decades depends primarily on the amount of heat-trapping gases emitted globally, and how sensitive the Earth’s climate is to those emissions.”

According to the report, “For the warming over the last century, there is no convincing alternative explanation supported by the extent of the observational evidence.”

A decision by a Trump EPA to withdraw the agency’s endangerment finding would be less likely to survive court challenge as the Trump administration would be in the position of having to discredit the repeated conclusions of US government scientists vetted by the broader community of experts in the field that the release of greenhouse gases by man has caused significant warming.

In August, President Trump disbanded the advisory committee attached to the national climate assessment by failing to renew its charter. The advisory committee had helped take scientific findings from the national climate assessment and turn that information into guidance for both public officials and the private sector.

The EPA is currently prohibiting its scientists from presenting scientific reports on climate change and has exorcized the topic from its website. Pruitt has indicated his “red team” review of climate change science could begin as soon as next month.

## Science and Censorship

The Trump Administration has repeatedly insisted that our current knowledge of climate science is insufficient to conclude that emissions of greenhouse gases are causing climate change, even at times casting doubt on climate change itself.

It has moved at the same time to gut or otherwise restrict program after program designed to study climate change and its causes, barring the use of the words “climate change” from government websites, removing access to agency information and restricting agency talking points.

In early December, the Trump administration disbanded one of the last federal government organizations to discuss climate change openly, the Community Resilience Panel for Buildings and Infrastructure Systems. The panel was a cross-agency organization created within the National Institute of Standards and Technology at the US Department of Commerce to advise local officials and utilities on how best to protect infrastructure and residents from extreme weather and other natural disasters. The panel was created in 2015 after “super-storm” Sandy.

## Clean Water Act Jurisdiction

EPA and the US Army Corps of Engineers are working on a new proposed definition of the “waters of the United States.” The federal government has jurisdiction over such waters under the Clean Water Act. The new definition would eventually replace the Obama-era definition, the implementation of which is currently stayed by a court, with a narrower, but as yet undefined standard.

The Trump EPA has attacked the Obama-era definition as an unlawful or at least unwarranted expansion of agency power to regulate small, short-lived or isolated streams and wetlands.

The deadline to comment on the topic before EPA releases its new definition was the end of November.

The comments received by the agency highlight the sharply conflicting views of industry groups, states and environmentalists on how the agency should define the term in the future. The stark differences are a foretaste of the issues that will eventually be addressed in the inevitable litigation that will follow release of the new definition.

In February, Trump signed an executive order directing EPA and the Army Corps to reconsider the Obama-era definition. EPA’s most recent public agenda suggests the agency will withdraw it by April 2018 and propose a replacement a month later, with any new definition taking effect no earlier than June 2019.

The new definition will probably use the jurisdictional test favored by the late Justice Antonin Scalia in a Supreme Court case called *Rapanos v. United States*. The / continued page 48

## Environmental Update

*continued from page 47*

justices split 4-4-1 in that case. Scalia's test would limit Clean Water Act jurisdiction to "relatively permanent" water bodies that share a "continuous surface connection" with navigable waters.

A plan to adopt the Scalia test may have been complicated by a federal appeals court decision in late November in the 9th circuit — the appeals court for the US states along the west coast, including Hawaii and Alaska — that said that court will follow Justice Anthony Kennedy's "significant nexus" test for Clean Water Act jurisdiction. His test is to look at whether wetlands, for example, have a significant nexus with navigable waters. If so, then the US government may regulate them, including by imposing criminal penalties for filling in wetlands without a permit.

The Obama EPA used Kennedy's test as the basis for its definition of "waters of the United States" in 2015. The Trump EPA now argues that the regulation expands the water law's scope beyond what Congress intended.

In the interim, the Trump EPA is seeking to delay implementation of the Obama definition for two more years to give it time to come up with a new definition before a nationwide stay of the Obama-era definition is reviewed by the Supreme Court.

— *contributed by Andrew E. Skroback in Washington*

### CHADBOURNE MERGER

Chadbourne & Parke merged into Norton Rose Fulbright on June 30. The combined firm has 4,000 lawyers in 59 offices in 33 countries.

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