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Off to the Races

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The tax credit sale market should ramp up quickly now that the Internal Revenue Service has issued guidance on such sales.

The guidance, issued on June 14, will require revisiting some tax credit sale transactions where documents have already been signed.

The Inflation Reduction Act allowed companies to sell tax credits to other companies for cash. Such sales became possible on January 1, 2023.

Some transactions have already closed, but not yet funded. Most sales have been in the 90¢ to 93¢ range per dollar of tax credit, but prices have been creeping up, and many people expect them to settle around 95¢ or 96¢. Prices vary by technology, the creditworthiness of the seller and the time period between when the purchase price must be paid and when the buyer can apply the tax credit to offset a tax liability to the government. The shorter the time period between cash payment and use, the more the buyer should pay.

The new guidance is in the form of proposed regulations. The IRS will take comments through August 14.

The proposed regulations will require buyers to do careful diligence before buying tax credits.

They make the tax credit buyer responsible if the tax credits are later disallowed or reduced by the IRS on audit. After an audit adjustment, the IRS will collect 120% of the disallowed tax credits from the buyer as a penalty. The buyer can avoid the penalty, / continued page 2

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BUYERS of projects that qualify for government payments that will be received after the projects are placed in service must allocate part of the purchase price to the future payments, the US Court of Federal Claims suggested in mid-June.

The court reserved for trial whether part of the purchase price must also be allocated to any indemnity from the seller to protect the buyer against a reduction in the future payments.

The court said the part of the purchase price allocated to such payments must be treated as basis in an intangible asset. No investment tax credit or accelerated depreciation can be claimed on it.

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but not the obligation to repay the disallowed tax credit amount, by doing careful diligence. Although the IRS did not say which party — the tax credit seller or buyer — will have to pay the interest and any other penalties on the back tax adjustment, the buyer should expect to have to pay those as well. It is the buyer's tax return that will be audited. Interest and other penalties can add significantly to the back taxes owed.

The proposed regulations also require buyers to repay the US Treasury in cases where investment tax credits and so-called section 45Q credits for capturing carbon dioxide emissions are recaptured — for example, because a wind or solar project on which an investment credit is claimed suffers a casualty or is sold by the owner within five years after it is placed in service or where captured CO2 that has been sequestered leaks from underground within the first three years after sequestration.

Buyers will demand creditworthy indemnities if the tax credits they purchase are denied later on audit. The indemnities will have to compensate the buyer not only for the lost money it paid for the tax credits, but also for the amount it must pay the US Treasury.

The proposed regulations do not allow a project owner to sell only a bonus tax credit on a project — for example, for putting the project in an "energy community" or using enough domestic content — and keep the base tax credit. However, a partnership that owns a project can sell one or more partners' shares of tax credits while allocating the remaining tax credits to the other partners.

Individuals will have a hard time being tax credit buyers.

Buyers can carry back the tax credits they buy up to three years and use them to recover taxes paid in the past.

There is a danger that the IRS will disallow the whole transaction if the buyer pays less than the full market value of the tax credits in cash.

Tax credit sellers will have to do a number of things, including registering transactions on an IRS electronic portal and providing buyers with proof that projects exist, are exempted from or have complied with wage and apprentice requirements and qualify for any bonus tax credits that are included in the sale. Failure to provide this "minimum documentation" will negate the sale.

Eleven Credits

Eleven types of tax credits can be sold.

They are tax credits under the following US tax code sections: 45, 45Y, 48, 48E, 45Q, 45V, 45U, 45X, 45Z, 48C and 30C.

The 11 credits are tax credits for generating renewable, nuclear or other zero-emissions electricity, tax credits for capturing carbon emissions or producing clean hydrogen and clean transportation fuels (like sustainable aviation fuel), tax credits for manufacturing wind, solar and storage components or processing, refining or recycling 50 types of critical minerals, tax credits for building new factories and re-equipping existing assembly lines to make or recycle products for the green economy and reduce greenhouse gas emissions at existing factories by at least 20%, and tax credits for installing electric vehicle and other clean fuel charging stations in low-income and rural areas.

Tax credits can only be sold once. Thus, a buyer cannot resell the tax credits it purchases.

Tax credits that a project owner has assigned to another party cannot be sold.

For example, some projects are financed using inverted leases where the owner leases the project to a tax equity investor and passes through the investment tax credit on the project to the investor. (For more detail, see "Inverted Leases" in the June 2017 *NewsWire*.) Another example is where a company capturing carbon dioxide emissions at an ethanol plant or factory chooses to transfer the section 45Q tax credits for carbon capture to the company that sequesters the captured CO2 underground or uses it for enhanced oil recovery or in a permitted commercial application. The inverted lessee or assignee of such tax credits cannot sell them.

Developers building projects, like offshore wind farms, that have normal construction periods of at least two years, can claim investment tax credits on progress payments made to the construction contractor during construction rather than waiting, as in the normal case, until the project is placed in service to claim the full tax credit. These so-called QPE tax credits — QPE stands for qualified progress expenditures — cannot be sold. Thus, an offshore wind developer planning to sell tax credits should not claim investment tax credits on construction progress payments.

The lessor in a sale-leaseback can sell the investment tax credit on a project. It is entitled to the tax credit by virtue of owning the project. (For more detail on sale-leasebacks, see "Solar Tax Equity Structures" in the December 2021 *NewsWire*.)

Tax Credit Sale

The deadline to sell tax credits for a year is the due date for the annual tax return for the year, including extensions. Thus, a project owner using a calendar tax year could complete a sale of 2023 tax credits as late as September 15, 2024 if the seller is a partnership or October 15, 2024 if the seller is a corporation or individual, assuming it delays filing its 2023 tax return until then.

The buyer must pay cash.

The IRS will negate any tax credit sale where the buyer pays the purchase price only partly in cash. Thus, there is a danger in transactions where the cash paid is less than the market value that the IRS will say the seller received something other than cash and negate the sale.

The full cash purchase price must be paid between the first day of the seller's the tax credit year and the earlier of the date the seller or buyer files its annual tax return. For example, a seller using a calendar tax year and selling 2023 tax credits must be paid the full purchase price between January 1, 2023 and when the seller or buyer files its tax return reporting the tax credit sale.

The proposed regulations require buyers to pay year-by-year for production tax credits. Production tax credits are claimed over time, unlike investment tax credits that are claimed in the year a project is put in service. Developers making forward sales who want the full purchase price at inception would have to borrow bridge debt against the future revenue stream from a bank or other lender, including by structuring any payment by the tax credit buyer for future tax credits as a loan. It is unclear why the Treasury cares.

Tax credits that are carried forward or backward into a year from another year cannot be sold.

The tax credit buyer cannot be related to the seller.

It is related if it has more than 50% overlapping ownership. A buyer is related to a corporate seller if the buyer or an affiliate owns more than 50% of the stock. A buyer is related to a partnership seller if the buyer or an affiliate has more than a 50% profits or capital interest in the partnership.

A seller can transfer all or part of the tax credits. For example, the sale can be for a percentage of the tax credits. It can probably be for a set dollar amount of tax credits.

If a partnership owns the project, the tax credits must be sold by the partnership. Individual partners cannot sell their shares directly. The buyer can also be a partnership. A buyer partnership must allocate the tax credits it purchases among the buyer partners in the same ratio that a type of loss called a "section 705(a)(2)(B) expenditure" is allocated. If the buyer partnership makes no special provision for such losses, then they are allocated in same ratio as other losses.

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M&A transactions involving renewable energy facilities where investors expect future tax credits, but the government does not appear to intend it to be read that broadly.

The claims court decision is in a case called *Alta Wind I Owner Lessor C v. United States*. The court released it on June 20. The decision could be reversed on appeal.

The case is part of the long-running saga of Alta Wind challenging Treasury cash grants it received under the section 1603 program in 2012. Terra-Gen finished developing and built six wind projects and sold and leased back five of them to special-purpose entities owned by various institutional buyers. At the time, the government was paying owners of new renewable energy projects the cash equivalent of a 30% investment tax credit on their projects. The owners then would forego the tax credits.

The project owners received $495 million in section 1603 payments on the projects. They believed they should have received another $206 million.

The claims court sided with Alta Wind in 2016 and ordered the government to pay the shortfall. The government appealed. The appeals court set aside the decision and sent the case back to the claims court for another trial before a new judge. (For more detail on the earlier rounds in the case, see "Tax Basis Issues: Alta Wind" in the August 2018 *NewsWire*.)

The latest decision was in response to a motion by Alta Wind for "summary judgment" on two questions that the government is raising in the new trial about the projects that were sold at fair market value to lessors at the end of construction and leased back.

One is whether part of the purchase price paid by the lessors should have been allocated to the incremental value the projects had because they qualified for Treasury cash grants.

The other is whether purchase price should also have been allocated partly to the indemnity the lessors received from Terra-Gen to compensate them to the

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A buyer partnership might be used to syndicate purchased tax credits. However, the tax credits are considered "extraordinary items," meaning that new partners can only share in tax credits that arise after they enter the partnership. For example, an investment tax credit arises on the date the project is placed in service. Production tax credits arise as electricity, hydrogen or manufactured components are sold or in some cases used.

The seller must provide the following "minimum documentation" to the buyer. It must provide proof that the project exists. This proof could come from a third party, like a county board or other government entity, a utility or an insurer. The seller must also provide documents substantiating that the project is exempted from or has complied with the wage and apprentice requirements and that it qualifies for any bonus tax credits included in the sale. (For more detail about those requirements, see "IRS Issues Wage and Apprentice Requirements" on www.projectfinance.law, "Energy Community Bonus Credit Guidance" in the April 2023 *NewsWire*, and "Domestic Content Bonus Credit" on www.projectfinance.law.) Finally, the seller must provide evidence of qualifying costs, sales or other activities that determine the amount of the credits.

The tax credit sales market should ramp up quickly.

The buyer must keep the minimum documentation for as long as there could be an IRS audit adjustment.

Tax Consequences

The seller does not have to pay federal income taxes on the sales proceeds. The proceeds are treated as tax-exempt income.

If the seller is a partnership, the tax-exempt income is allocated to partners in the same ratio as the sold tax credits would have been allocated to the partners. This income pushes up partner capital accounts and outside bases. Then when the cash sales proceeds are distributed to the partners, the distributions reduce partner capital accounts and outside bases.

However, if the partnership only sells the tax credits belonging to one of the partners, then the tax-exempt income can be allocated solely to that partner and the cash from the tax credit sale can be distributed to it.

The cash sale proceeds do not have to be distributed to partners in the same ratio as they are allocated tax-exempt income. There are no restrictions on how the seller uses the cash.

The buyer cannot deduct its purchase price.

Payment of the purchase price by a partnership buying tax credits is considered a "section 705(a)(2)(B) expenditure" that does not affect partner capital accounts or outside bases.

The Treasury has not decided yet whether the buyer should roll its transaction costs into the tax basis in the tax credits it purchased. That would not allow the buyer to deduct them.

A buyer who pays 92¢ for a dollar of tax credits has an economic gain of 8¢ when it uses the tax credits to pay a tax liability to the government. The buyer does not have to report this gain as income.

The buyer can take tax credits that it has purchased or intends to purchase into account when making quarterly estimated tax payments during the year. It does not have to wait for the tax credits actually to transfer. However, it is responsible for any underpayment of estimated taxes.

A buyer should check the tax year of the seller. Suppose the seller uses a tax year that ends in June and the buyer uses a calendar year. The seller sells tax credits to which it was entitled during the period July 2023 through December 2023. The buyer must use them in its 2024 tax year. If the buyer and seller have different tax years, the buyer uses the tax credits in its tax year that started in the seller's tax year but ends after.

The seller can only sell tax credits to which it is entitled. For example, an investment tax credit cannot be claimed on a project that is leased to, or otherwise used by, a tax-exempt or government entity.

The buyer may be hampered in its ability to use the tax credits it purchases. For example, tax credits can only be used to reduce income taxes in a year by up to 75%. A buyer must treat purchased tax credits as passive investments. An individual can usually only use such tax credits to offset income from other passive investments, but in this case, the IRS adopted a more restrictive approach. An individual buying tax credits can only use them to offset taxes on income from the project that is the source of the tax credits. This will prevent most individuals from buying tax credits.

The Treasury is seeking comments about whether there are circumstances where an individual should be able to use purchased tax credits to offset other income.

The sale proceeds are not passive income to the seller.

Partnerships selling investment tax credits must ask their partners who are individuals, S corporations or closely-held C corporations whether they used nonrecourse debt to make their investments. (A closely-held C corporation is a corporation in which five or fewer individuals own more than half the stock.) If yes, then the partnership must work through at-risk limits in section 49 of the US tax code that may limit the ability of the affected partner to claim tax credits from the partnership. These limits are easy to avoid, but if the debt is not properly structured, they will reduce the amount of investment tax credits that the partnership is able to sell.

Any limit is calculated as of the end of the partnership tax year in which the project is placed in service.

Basically, the partnership would be limited to tax credits calculated on the equity that the partners have in the project.

As nonrecourse debt is paid down over time, equity builds and the partnership would be entitled to more tax credits. However, any such additional tax credits will go to the affected partners. Any such additional tax credits cannot be sold.

A subtlety in partnership accounting should be reflected in any financial model where tax credits are sold by a partnership. Suppose a 50-50 partnership is entitled to a $1 tax credit that it sells for 90¢. The partnership has 90¢ in tax-exempt income. Each partner is allocated 45¢ in income and is distributed the same amount in cash. However, the depreciable basis that the partnership has in the project must be reduced by half the $1 tax credit, or by 50¢. The partner outside bases are also reduced by 50¢.

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extent the Treasury cash grants were less than expected.

The court said the expected future cash grants were intangible assets. The appeals court that reviewed the earlier Alta Wind decision said that the purchase price should have been allocated among all the assets in the project using a "section 1060 method," meaning the project assets should be divided into seven asset classes, from easiest to value like cash and cash reserve accounts to the hardest to value like going-concern value and goodwill.

The purchase price is allocated to assets in these seven asset classes by assigning value to assets in each class up to the full fair market value of the assets in that class before moving up to the next class. The power plant is in class V. Class VI includes power purchase agreements and other contracts. Class VII is going-concern value and goodwill.

If the full purchase price is used up before reaching classes VI and VII, then there is nothing to allocate to them.

The claims court said the following: "The portion of the purchase price pertaining to consideration for the anticipated Section 1603 cash grants is grant-ineligible intangible property under Class VI (contract rights) or Class VII (goodwill or going concern value)."

The court said, "the Court cannot consider a premium associated with the anticipated value of a grant" to be purchase price paid for the power plant.

The same logic, by extension, could apply to tax credits that will be claimed in the future.

However, the court did not go that far. The Alta Wind lessors cited two claims court decisions in 1976 and 1979 where the court acknowledged that investment tax credits could be calculated on the full amount spent on ships, even though the amounts were drawn from capital reserve funds on which the ship owners had not paid taxes (because they deducted the deposits into */ continued page 7*

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Recapture

Investment tax credits are recaptured if there is a "disposition" of the project within five years after it is placed in service. The investment credits vest ratably over the five years. Thus, if in year two the owner sells the project or distributes the project to its partners or shareholders or the project suffers a casualty, then 80% of the tax credit — the amount that is unvested — must be repaid to the US Treasury.

If this happens to a project on which tax credits were sold, the seller must inform the buyer. The buyer must then calculate the recapture liability and let the seller know. The buyer must then repay the Treasury.

The seller increases its depreciable basis in the project by half the recaptured investment tax credit and is entitled to more depreciation.

This will frustrate buyers for two reasons. They will end up having paid the seller for the tax credit and also have to pay the Treasury. The seller has control in most cases over whether recapture will occur. The buyer has no control.

The seller must notify the buyer of the recapture event, and the buyer must notify the seller of the recapture amount, in time for each to take the information into account by the due date — without extensions — for its tax return for the recapture year.

Normally, investment tax credits on a project owned by a partnership are also recaptured if a partner sells its partnership interest or its share of partnership income is reduced by more than a third within the first five years after the project is placed in service. Only the unvested tax credits are recaptured. The tax credits that were allocated to that partner are recaptured at the partner level. In cases where the tax credit is sold, the partner in the seller partnership would owe the Treasury the recapture amount. There is no need for the partnership to inform the buyer and no liability for the buyer.

Production tax credits for capturing CO2 emissions can be recaptured if the captured CO2 that has been sequestered leaks from underground storage within three years. The IRS section 45Q regulations require the company capturing the CO2 to reduce the tax credits to which it would otherwise be entitled to claim on CO2 captured in the leak year by the tax credits on the leaked CO2. Thus, if the capture company would be entitled to $100 in tax credits in year 3, but CO2 on which $5 in tax credits were claimed leaked that year, the capture company would only be able to claim $95 in tax credits in year 3.

However, the proposed transferability regulations require the tax credit buyer to repay the Treasury for the tax credits on the leaked CO2. Presumably the capture company will not have to reduce its year 3 tax credits. Otherwise, there will be double recovery by the government.

Disallowance

Congress was concerned about inflated tax bases used to calculate investment tax credits.

The Inflation Reduction Act authorizes the IRS to collect a penalty of 120% of any excessive tax credit claimed where part of the tax credit is later disallowed for any reason, and not just due to an inflated tax basis.

The proposed transferability regulations make the tax credit buyer responsible for the penalty.

It can avoid the extra 20% penalty, but not the obligation to repay the disallowed tax credit, by showing it had reasonable cause to claim the full tax credit.

The most important factor when showing reasonable cause is the length to which the buyer went to confirm the seller was entitled to the tax credits it sold. The buyer must show it reviewed the seller's records relating to the tax credit amount, including wage and apprentice compliance or exemption and the grounds

Buyers will have to repay the government if tax credits are recaptured or disallowed on audit.

for claiming any bonus credits. It must have been reasonable to rely on any third-party experts who advised the buyer. For example, it may be unreasonable to rely on an aggressive or poorly reasoned tax opinion. The representations on which it relied from the seller must be credible. The buyer should review any audited financial statements filed by the seller with the US Securities and Exchange Commission.

The disallowance is charged first against any tax credit the seller retained. For example, suppose a company believes it is entitled to $100 in tax credits. It sells $50 and keeps $50. The IRS later disallows $50 in tax credits. There is no penalty on the buyer since its tax credits were not disallowed. The $50 in tax credits that the seller retained are disallowed. There is no penalty for an excessive tax credit transfer since the disallowed tax credits were not transferred.

If the company had sold $80 and kept $20 in tax credits, then the $50 disallowance will come first out of the $20 in tax credits retained by the seller and $30 in tax credits sold to the buyer. The buyer will owe 120% of $30, or $36, unless it can show reasonable cause to support the $30 it claimed. If it had reasonable cause, then it owes the IRS $30 for the disallowed tax credits, but not the additional $6.

The seller must report any amount it was paid for disallowed tax credits as taxable income.

The IRS is on the lookout for transactions where sellers overcharge or undercharge for tax credits.

A seller may overcharge in an effort to avoid reporting the full purported purchase price as income when it was partly a payment for something else.

A seller may undercharge in an effort to give the buyer a larger tax deduction by making it look like part of what was really purchase price for tax credits was a deductible payment for something else like services.

Sale Mechanics

The seller must register the transaction on an electronic portal that the IRS is expected to open by year end. The IRS will assign a unique number to each transaction.

The seller must file an election with the IRS for each sale transaction on its annual tax return. It must already have registered the transaction so that it can include the registration number. The election must be on the seller's original tax return for the year. The seller cannot amend an already-filed return to make the election, and the IRS will not grant relief to sellers who miss the deadline. / continued page 8

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the reserve accounts).

The government argued — and the court accepted — that these decisions did not apply to Treasury cash grants to be paid in the future because tax credits could be claimed on the full amounts spent on the ships regardless of the source of the funds. "The government alleges [the ship cases do] not apply . . . because [the ITC statute] does not allow plaintiffs to include a yet-to-be-received Section 1603 grant — unlike the tax credit . . ." the court said.

The court said there were too many factual issues to sort out to be able to rule now on whether separate value had to be assigned to the indemnity and reserved that issue for the retrial.

The parties have been doing new discovery and filing motions as they approach retrial.

PROJECT DEVELOPERS are having a hard time getting the data they need from manufacturers to do the calculations required to claim a domestic content bonus tax credit.

The US Treasury appears to have made the calculations easier for some equipment like wind turbines and solar trackers.

The Treasury and White House are aware of the problems and may have to rework the guidance that the government put out in May. (For more details about the guidance, see "Domestic Content Bonus Credit" on www.projectfinance.law.)

The Inflation Reduction Act allows a 10% bonus tax credit for using enough domestic content.

Developers must divide the equipment and other materials coming to the project site for incorporation into a project into two categories: construction materials and manufactured products.

Construction materials are items that are primarily steel or iron and are structural in nature. They must be 100% US-made. Examples are rebar and steel foundation posts at solar projects. The rest of the / continued page 9

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A buyer, unlike the seller, can amend an already filed tax return to claim tax credits it purchased.

A separate registration and separate election must be made for each “facility” for each year tax credits will be claimed and for each buyer.

Batteries will require a separate election from a co-located solar or wind facility after the investment tax credit for storage facilities moves in 2025 from section 48 to section 48E of the US tax code.

The Treasury is considering whether a single election should be allowed for an entire “energy project” to be defined in future guidance.

If a project is owned by a partnership, the partnership makes the election. If the project is owned by a disregarded entity, the “regarded” parent makes the election. If it is owned by a corporation that is included in a consolidated return with other corporations, then the corporation that owns the project makes the election, although the consolidated parent usually acts as the agent for the individual group members.

In a sale-leaseback, any sale of tax credits is by the lessor, and the lessor makes the election.

Both the seller and buyer must attach a “transfer election statement” and an IRS Form 3800 to their annual tax returns for the tax credit year. The seller must also attach a form for the particular type of tax credit.

The “transfer election statement” must include the registration number for the tax credit sale. Both parties must acknowledge their obligations after any recapture of tax credits. Both must represent that the seller and buyer are not related to each other and that no other corporations with whom they join in filing consolidated returns are related. The seller must represent that it provided the buyer with the “minimum documentation.”

The seller must report any change in facts between registering the transaction and making the tax credit sale election on its annual tax return. An example is where the project is sold to a tax equity partnership that then sells the tax credits. The transaction might have to be re-registered and a new registration number assigned before an election can be made to transfer the tax credits. Timing could be a concern given the hard-and-fast deadline to file the election. ◎

Tax Credit Sales

The Inflation Reduction Act lets companies sell nine types of federal tax credits to other companies for cash. The window opened on such sales on January 1. Many people have been interested in how quickly the market will develop and at what prices tax credits will trade. Five market veterans discussed these and other questions during a live podcast at the end of April.

The panelists are Jack Cargas, managing director and head of tax equity origination for Bank of America, Rubiao Song, managing director and head of energy investments for JPMorgan, Ted Brandt, CEO of Marathon Capital, Jamie Stahle, senior managing director of the CCA Group, and Billy Lee, president of Reunion, which is one of several digital platforms to match tax credit sellers with buyers. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

MR. MARTIN: Jack Cargas, how would you characterize the tax credit sales market? Are deals closing? Is there strong interest, or is it just getting started?

MR. CARGAS: The market is really just getting started. There are a few deals that have closed, including by Bank of America, but many market participants continue to await guidance from the Treasury. There is strong interest in the concept of tax credit transfers, as indicated by the size of your audience. But at this early juncture, that interest is coming more from prospective sellers than from prospective buyers.

MR. MARTIN: Rubiao Song, same question.

Mr. SONG: It has been a slow start, but that should not be a surprise. We are still waiting for Treasury guidance. Potential buyers and sellers are still in the price discovery phase. We see a lot of letters of intent being signed and due diligence documentation underway, but there is no actual cash changing hands. That will have to wait until the guidance comes out.

MR. MARTIN: Ted Brandt, what is your sense of the market?

MR. BRANDT: We have been focused on trying to expand the market by finding additional investors, particularly around section 45Q tax credits for carbon capture where we are seeing acute shortages of supply versus demand. It is very early, and everybody is waiting for guidance. We have seen some incumbent investors trying innovative new structures. We are hearing lots of talk. We have not seen a lot of closings.

MR. MARTIN: Jamie Stahle, your view?

MR. STAHLE: No large-scale transactions have closed yet. A number are in various stages of diligence or LOI execution. Everyone is waiting for guidance. The good news is there is a lot of forward activity from a number of players that have an interest in in developing this market.

Some of the issues that are probably limiting the activity currently, at least among bank and insurance company buyers, is figuring out what the regulatory or capital requirements are going to be for this type of product. Sellers are still trying to assess how tax credit sales compare to other possible transactions.

MR. MARTIN: Billy Lee, how do you view the market?

MR. LEE: We are seeing strong interest on both the buy side and sell side. We are actively working on documenting a few transactions and have a number of term sheets outstanding. The market is young, but developing rapidly. We are super excited to be part of it.

Prices

MR. MARTIN: We are seeing prices mainly in the 90¢ to 92¢ range per dollar of tax credit, but there are some deals in the 80¢ range and we are seeing some creep higher, like 93¢. Billy Lee, where are you seeing prices settle?

MR. LEE: The 90¢ to 92¢ range is generally what we are seeing currently for projects that are placed in service in 2023.

MR. MARTIN: Ted Brandt, do you agree?

MR. BRANDT: Yes.

MR. MARTIN: Many people believe prices will go up over time as more buyers come into the market. Where do you think they will settle ultimately?

MR. BRANDT: It is really important to bring duration into the conservation. A credit is worth a certain amount from the settlement date until the next quarterly estimated tax payment date when the credit will be used. The other variable besides duration is the creditworthiness of the seller. For ITCs, the sale is a one-time transaction. For PTCs, sales occur over time and sponsors will probably want to borrow against the future payment stream. Borrowing against a future payment steam requires an investment-grade buyer. Both duration and creditworthiness will affect pricing.

MR. MARTIN: Does anyone else want to weigh in on pricing?

MR. STAHLE: We agree about the current price range of 90¢ to 92¢, although it depends on when the seller will receive the proceeds. There is still some question around whether the actual payments will be made in the current year or the following year. That has a bearing on the present value of the purchase price payments.

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materials used in the project are "manufactured products" that, as a group, must be at least 40% US-made initially, increasing to 55% over time. (The starting percentage for offshore wind is only 20%.)

Developers need factories from whom they procure equipment to disclose three "direct costs" in order to do the manufactured products calculation. The direct costs are the wages paid to workers to make the equipment, payroll taxes on those wages, and the amount paid to suppliers for parts supplied directly to the factory.

To date, manufacturers have been reluctant to disclose this information, even though disclosing the three direct costs is a far cry from disclosing their profit margins. Manufacturers have lots of other costs, including depreciation, rent, overhead, employee benefits, insurance and property taxes.

Some manufacturers have offered percentages, but percentages do not tell the developer what it needs to do the calculation.

Foreign manufacturers and US manufacturers that use all-US components could get away with giving developers a single number: the sum of the three direct costs.

However, most US factories use some imported parts. Any such US factory would have to provide two numbers: the sum of its three direct costs to put in the denominator and a single number to put in the numerator. The numerator number is the sum of costs paid by the US factory to its US parts suppliers.

Some foreign manufacturers have suggested that if they use all US-made components, this allows the full factory cost to go in the numerator. It is hard to see how that is true. The foreign factory would have to have no more than merely assembled the product like a piece of Ikea furniture rather than to have done any manufacturing.

The Treasury appears to have made a policy call to let wind turbines, trackers and some other products be / continued page 11

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the larger-scale, more mature projects to newer technologies and asset classes, you start to see some divergence in price based on the characteristics of the project or the counterparty. That is particularly true of PTC deals, because there is a lack of liquidity and investor depth in that market. It is harder in that market to get a real beat on where pricing will settle.

MR. MARTIN: Jack Cargas, we just heard that prices will vary by type of tax credit, by creditworthiness of the seller and by when the buyer must pay for the tax credits. Why should prices vary by type of tax credit?

MR. CARGAS: I think it depends on the buyer. Some buyers may find ITCs less attractive than PTCs due to recapture risk. PTCs are often financed on a pay-go basis, meaning purchased in arrears, so there is minimal tax-credit risk. ITCs, on the other hand, might be paid for in advance and remain subject to recapture risk over the next five years.

MR. MARTIN: Playing it out further, are all PTCs equivalent? For example, would you expect wind PTCs to price at the same level as carbon capture PTCs?

MR. CARGAS: Potentially, but the perceived creditworthiness of the seller is important. To the extent a seller is offering a legal conclusory representation backed by an indemnity, or perhaps a seller can provide strong evidence of the provenance of the tax credits, for example, to prove the PTCs emanated from that wind turbine with that serial number, the PTCs may be more attractive and command a slightly higher price.

MR. MARTIN: Rubiao Song, do you agree with what Jack just said about differences in pricing for different types of tax credits?

MR. SONG: Yes. Duration is a significant differentiating factor, such as whether you are talking about a 2023 tax credit or a five-year commitment.

The type of tax credit also matters as Jack mentioned: whether a PTC is from a certain wind farm that can be easily traced or whether it is a section 45Q or 45V tax credit. It will take some time to make investors comfortable with newer types of tax credits. There will not be as deep a market for them, and that will affect the price.

Another issue with ITCs besides recapture risk is tax basis risk.

New Asset Classes

MR. MARTIN: Jamie Stahle, do you expect much of a market for things like section 45Q credits for carbon capture, 45V for making clean hydrogen, 45Z for making clean transportation fuel, and 45X for manufacturers who make components for wind, solar or storage projects?

MR. STAHLE: In time. By the time many of those new types of projects are built, the market probably will have evolved and be better educated about them. The price depends on demand and supply. However, we expect wind and solar tax credits about which the market is already familiar to fetch better prices than the newer credits that sponsors will be trying to sell into a more shallow market.

MR. MARTIN: You are assuming that the buyer is exposed to audit risk. If a buyer of 2023 tax credits has an all-events indemnity and the IRS pursues solely the seller after an audit adjustment, should the buyer really care whether the tax credits are section 45, 48, 45Q, 45V, 45X or 45Z credits?

MR. STAHLE: Yes. The newer credits have added complications. That said, to the extent you have a creditworthy seller, that probably gets people to a point of comfort. This market will have to broaden beyond the universe of existing tax equity investors. The more complicated the risks are to understand, the more limited the universe will be of investors. Sellers will have to find a way to wrap all of the risks.

Diligence

MR. SONG: Traditional tax equity investors will not fund into an indemnity. We will do at least part of — and in many cases most of — the same diligence we would do in a traditional tax equity deal.

MR. MARTIN: What if the Treasury ultimately says the person exposed to audit risk is the seller? I suppose it is hard to imagine the IRS will release buyers completely from audit risk.

MR. SONG: It is not expected and, even if it were, large corporations are usually not comfortable entering into transactions for tens of millions of dollars without careful diligence.

MR. MARTIN: Billy Lee, how much diligence do you expect buyers on your electronic platform to do?

MR. LEE: In the early days, I think there will still be diligence of the kind everyone has been talking about. Over time, we are trying to commoditize the tax credits and transactions.

I am more bullish than my fellow participants that a tax credit is a tax credit.

We are building a marketplace that facilitates trading of these credits. We see three critical pillars to have a successful marketplace.

One is having a deep supply of tax credit buyers. This will obviously be an education process.

Another is portfolio diversification. We need to offer projects from multiple sponsors and different technologies. When most people think tax credits, they think wind, solar and storage, but let's not forget biogas, carbon capture, hydrogen and so on.

Finally, we need a robust technology, meaning a platform that not only standardizes diligence but also organizes and increases the velocity of transactions and achieves risk diversification that you can't achieve in purely bilateral transactions. That type of portfolio diversification takes some of the pressure off individual transactions and reliance on indemnities from creditworthy sponsors.

Our vision is to run regular auctions that settle based on buyer bids and seller asks for both spot and forward contracts. Ultimately, we are trying to provide liquidity, efficiency and transparency in pricing.

PTC Sales

MR. MARTIN: Ted Brandt, coming back to you, will PTCs be sold on a year-by-year basis or do you expect forward sales?

MR. BRANDT: We expect a combination, but a lot depends on how the projects are financed. There is no real secondary market for tax credits today, even if the PTCs are separable, because the full 10 years of tax credits are spoken for in a tax equity transaction.

The big question is whether new structures will emerge that allow the financing to occur in such a way that there will be some flexibility as to when sales occur. We are working on a model that would convert PTCs into a quarterly-in-arrears sale, and we think there will be some buyers that will want 40 quarters and some buyers that will want two quarters.

MR. MARTIN: Jack Cargas, do you agree with that and, if so, will buyers in forward sales be willing to pay upfront as in a tax equity deal or only over time as the tax credits are claimed?

MR. CARGAS: I think we will see three approaches.

One is on a year-by-year basis in arrears. That could be where a company is just looking to manage its effective tax rate. I think we will also see PTCs sold on a forward basis for maybe five or 10 years where the buyer pays a stated discounted price up front to purchase of all of the projected PTCs from a particular project. Then possibly we will see tax credits trade on a hybrid basis where the purchaser pays at the outset a portion of the overall projected value of the PTCs and then commits to buy / *continued page 12*

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treated as manufactured at the project site. That would make the construction contractor the "manufacturer," and the focus would shift to the contractor's direct costs rather than the costs of the factory. Construction contractors tend to be more transparent about their costs.

Table 2 in IRS Notice 2023-38 lists the main components in utility-scale solar, onshore wind, offshore wind and storage projects.

The table shows a "wind turbine" as the manufactured product, made from "manufactured product components" consisting of a nacelle, blades, rotor hub and power converter. The government appears to read this to mean that whoever puts the equipment together to make the turbine is the manufacturer. Since this occurs at the project site, that makes the construction contractor the manufacturer, notwithstanding what the contractor does seems closer to assembly than manufacturing.

The table lists a "photovoltaic tracker" as a manufactured product. Trackers are put together on the project site using components from various companies. The tracker company basically assembles a kit that goes to the project site. The government appears to read the table to say that the construction contractor pulling the kit together is the manufacturer.

The domestic content rules remain in flux. First Solar stock increased 26.48% immediately when the domestic content guidance was released after the market decided that it was a big winner. However, the stock price gave up the entire gain over the next month in a sign the market was having trouble figuring out how the guidance works.

MANUFACTURERS who plan to apply for an initial round of $4 billion in tax credits for building new production lines and re-equipping existing lines to make products for the green economy have until noon eastern time on July 31 to submit concept papers to the US Department of Energy.

The papers are / *continued page 13*

Tax Credit Sales

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any excess PTCS above that upfront portion on a pay-go basis, probably paying those amounts in arrears after the PTCs are actually earned.

MR. STAHLE: I agree with Jack. There will also be capital providers that want to staple together different pieces of capital with a PTC transaction.

There may also be investors with long-term liabilities that are willing basically to commit to tax credit transfers in exchange for being able to apply different forms of capital — term loans or what have you — to the transaction that acts as a surrogate for filling the capital gap that needs to be filled with a prepayment. Jack mentioned a variation on that theme, but there are various ways you can structure it to adapt to different investors who are looking to add assets to their balance sheets.

Early Buyers

MR. MARTIN: Many people listening will wonder why have the two biggest tax equity investors on this call. Aren't they competing against tax credit sales? But in point of fact, you two have been major buyers of tax credits as the market starts to take off, or at least you are negotiating such purchases. Why buy tax credits rather than do traditional tax equity deals?

MR. SONG: We are still primarily a tax equity provider, but the ability to buy tax credits directly gives us another tool to help clients on certain projects. The diligence is a little lighter than in a full tax equity deal. It is less resource-intensive for our clients.

MR. MARTIN: Jack Cargas, I know you are both investing tax equity and buying tax credits. Why do one or the other?

MR. CARGAS: We plan to continue to do both. We are building a strong inter-disciplinary team to tackle all of this. We want to be a major participant in this market for years to come.

We can imagine circumstances where we enter into a tax equity partnership where perhaps we keep 50% of the tax credits and the partnership sells the other 50% to a corporate buyer.

We are also seeing transactions where sponsors choose simply to sell tax credits and not do a tax equity deal. We think we can help make that market. An example is a merchant project that is not a good fit for tax equity, but the sponsor can't use the tax benefits.

There could also be cases where the sponsor has enough tax capacity itself to use the depreciation, but doesn't have enough to use the tax credits. We want to be able to make that market, too.

MR. MARTIN: The ability to sell also gives the parties more time to syndicate the tax equity position.

Indemnities

MR. MARTIN: Billy Lee, what sort of indemnities will your buyers expect?

MR. LEE: For now, anything in the control of the developer will need to be indemnified. For ITCs, tax basis and recapture risk will have to be indemnified by the developer. Obviously, the developer will also have to agree to post-closing covenants against major renovations that could trigger ITC recapture.

We expect over time that many tax credit buyers will not have had experience with renewable energy. We need to be able to offer as low-risk a proposition as possible to expand the number of tax credit buyers.

MR. MARTIN: What you described sounds like an indemnity for breach of representations and warranties as opposed to an all-events indemnity.

MR. LEE: I am not sure exactly how the market will develop, but those are the primary risks in an ITC transaction that will have to be borne by the seller. Also, we don't have structural risks to worry about as with a full tax equity partnership transaction, meaning the risks that the transaction has been properly structured to transfer tax benefits.

MR. MARTIN: Jamie Stahle, in the term sheets on which you are working, how are the indemnities structured? Are they reps-and-warranties or all-events indemnities?

MR. STAHLE: It depends on the buyer. The traditional tax equity investors will want indemnities that look like they get in their current tax equity deals. Pure tax credit buyers with little understanding of renewable energy probably need something broader.

MR. MARTIN: Ted Brandt, will smaller companies that are less creditworthy have a tough time selling tax credits and will they need an insurance policy to stand behind the tax indemnities?

MR. BRANDT: Time will tell. I hope Billy's optimism turns out to be warranted. We at Marathon expect insurance to be required. We think there needs to be the equivalent of title insurance to cover risk that the tax credit was fraudulent or otherwise deficient. All of a sudden, the buyer has some explaining to do internally and will need to get its money back, probably grossed up for all the additional expenses.

MR. MARTIN: Jack Cargas, will Bank of America as a tax credit buyer routinely require tax insurance?

MR. CARGAS: Not routinely. It depends on the seller. If the seller is a long-time, experienced and trusted operator, we may be comfortable with standard fact-based representations and indemnities. If it is a new asset class to the market or the seller, then we will need indemnities more like what Ted described.

MR. MARTIN: Rubiao Song, you said earlier that deals are being signed, but the Treasury will have to issue guidance before people actually make payments. What guidance do you feel the Treasury needs to issue to conclude deals?

MR. SONG: Mostly on procedural questions. An example is what documents have to be given to the IRS before the actual tax credit transfer can happen. Other questions are whether the tax credits can be transferred to multiple transferees, how the partnership capital accounts will be credited or debited in cases where a partnership owns the project, and whether transferred tax credits can be used to offset current-year estimated tax liabilities.

The Joint Committee on Taxation answered other questions in a document it released last week. It answered questions about imputed interest and whether buyers have to report the discount they receive to the full credit amount as taxable income.

MR. MARTIN: Our experience is deals are moving forward anyway, although there are some questions people want answered.

MR. STAHLE: Another big question is whether PTCs on projects that were already in operation before 2023 can be sold. There is a high confidence that they are, but the market would appreciate confirmation. The answer has a pretty big bearing on the volume of PTCs that would be available.

Documentation

MR. MARTIN: Billy Lee, how complicated do you think tax credit sales on your electronic platform will be to document?

MR. LEE: Putting aside whether the sale is on our electronic platform or in a bilateral transaction, I think it will be far less complicated than tax equity. I have done many tax equity deals in my career. There are no partnership or equity capital contribution agreements to negotiate. The buyer is not making an equity investment into a project.

That said, it will be a lot more complicated than a short as-is purchase agreement. If you are talking to a seller about buying tax credits and you get a two-page purchase agreement, buyer beware. There should be a host of representations and warranties, pre- and post-closing covenants, conditions precedent, indemnities, and so on.

MR. MARTIN: I should say I have seen term sheets anywhere from three pages to 31 pages, so there / continued page 14

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submitted through a DOE eXCHANGE portal at https://48C-exchange.energy.gov.

The portal is expected to open around June 30.

Another $6 billion in tax credits will be allocated in a second round. The deadline to submit concept papers for it has not been announced yet.

The credits are available under section 48C of the US tax code. They are 30% of the cost of a new factory or assembly line. Manufacturers must apply to the IRS for an allocation. The IRS has $10 billion in such tax credits in total to allocate.

The Inflation Reduction Act gave manufacturers a choice of two tax credits.

The other is a section 45X tax credit for making components for wind, solar and storage projects and extracting or processing 50 critical minerals. Section 45X credits are generally fixed amounts for each wind, solar or storage component produced and sold through 2032. For example, the tax credit is 4¢ a watt for making solar cells and 7¢ a watt for making solar modules. The tax credit for minerals producers is 10% of the cost of the extraction or processing done in the United States without any time limit.

Manufacturers who have the option to claim both section 48C and 45X credits must ordinarily choose one.

However, the Internal Revenue Service opened the door on May 31 for some manufacturers to claim both tax credits.

An example in Notice 2023-44 describes a factory with two production lines that operate in serial fashion. One makes photovoltaic wafers and the other uses the wafers to make photovoltaic cells. The factory owner claimed a section 48C tax credit on the wafer production line. The line that makes cells can function independently of the other production line. Therefore, the notice says, it is treated as a separate "facility" and section 45X credits can be claimed on it. / continued page 15

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has been a wide range of approaches as the market evolves. Jack Cargas, will buyers like you require tax opinions?

MR. CARGAS: Yes. Buyers are going to want an expert to confirm they will be entitled to claim the tax credits.

It is one of the most interesting questions in the market. It will have to be answered on a deal-by-deal basis. Opinions differ as to how it will play out. It matters what kind of a deal you negotiated with the seller, what size deal it is, and maybe what the tax credit pricing is. If the tax credits are sold for 99.5¢, then it will not be a big negotiation, but if they are sold for 90¢, that could be a pretty significant negotiation.

Other Issues

MR. MARTIN: Ted Brandt, are depreciation-only tax equity deals feasible?

MR. BRANDT: We have not seen demand for them on the investor side. In the various tax-credit-sale structures on which we have been focused, the glaring deficiency is the depreciation does not get monetized. Our initial conclusion is that on the higher net-capacity-factor PTC deals, selling tax credits is still worthwhile, despite being unable to monetize the depreciation. The answer may be different if the project has a low capacity factor.

This is a rapidly developing area. Who knows where the market will land. If this market takes off, there will certainly be a huge amount of stranded depreciation left on sponsors' balance sheets. We should all pray that an investor base will develop that will monetize depreciation.

Prices started for the most part in the 90¢ to 92¢ range, but are creeping higher.

MR. MARTIN: Rubiao Song, large tax equity investors like JPMorgan and Bank of America have been capping the basis step-ups they will accept in tax equity transactions involving investment tax credits at 15% or 20% above construction costs. What happens in tax credit sales?

MR. SONG: We will enforce the same policy.

MR. MARTIN: Step ups will be less common when a developer is just selling the tax credits, unless the step up is done by combining a traditional tax equity structure with a tax credit sale.

Another question: if a tax equity partnership sells tax credits for 90¢ on the dollar, what gets credited against the tax equity investor's yield? Is it the full dollar tax credit or only 90¢?

MR. SONG: That is a negotiated point, but we think the right answer is only 90¢ gets credited rather than the full amount of the credit.

MR. MARTIN: Jack Cargas, what is your view?

MR. CARGAS: The tax equity investor would prefer to credit only the 90¢, but the sponsor is going to want a credit of the full dollar, especially if the flip date gets delayed solely because the tax equity investor directed the partnership to sell part of the tax credits.

MR. MARTIN: Jamie Stahle, what other issues are you seeing in tax credit sales?

MR. STAHLE: On the depreciation question, some hybrid structures are being used where the project is sold to a tax equity partnership to monetize the depreciation, and the partnership sells the tax credits. That is probably the solution for dealing with stranded depreciation.

MR. MARTIN: Are there other issues anyone else wants to mention that are coming up in transactions?

MR. SONG: Insurance is in short supply, particularly when it comes to buying storm or hurricane insurance. That is an issue in ITC sales where the tax credits could be recaptured after a casualty affecting the project and in forward PTC sales if a large share of the purchase price is paid up front.

MR. CARGAS: Another issue is the 15% global minimum tax, otherwise called Pillar 2. Other countries could impose a top-up tax on large multinationals to the extent they use tax credits to reduce their US tax bills. Treasury has been working with the other OECD countries, but there is no clear solution in terms of exemption for US renewables credits.

MR. STAHLE: Another issue is the challenge for corporations to be able to forecast future tax liabilities. It is an execution risk.

MR. MARTIN: Rubiao Song, you, Jack and I were on a cost of capital outlook call in January. Both of you said then you expect the tax equity market to be $20 to $21 billion this year. That's not tax credit sales. It is traditional tax equity deals. Is that still your expectation four months into the year.

MR. SONG: It still looks good. There are a lot of constraints in terms of tax and regulatory capital capacity. However, some tax equity investors who sat on the sidelines for a couple years are now coming back. We also see some new entrants, particularly from corporations who are very much ITC focused. There was also a good development on accounting for tax credits. Adoption of proportional amortization would solve a lot of issues for PTC investors. We are seeing a robust tax equity market this year.

MR. MARTIN: So it sounds like, if anything, we will be on the more optimistic end of the estimated range. Jack Cargas, do you agree?

MR. CARGAS: Twenty billion remains our best estimate. We are already seeing a few deals slip over year end.

Your real question may be whether we think tax credit transfers will take deals away from the tax equity market. We see tax credit sales as additive and even complementary in some transactions.

As for how large the combined tax equity and tax credit sales markets may be this year, there is obviously a lot of speculation. The Joint Committee on Taxation estimated the price tag of the climate bill would be $369 billion over 10 years. We saw one respected market observer state that it foresees an annual tax credit transfer market alone of $60 billion within a few years. Assuming that is accurate, you might be talking about a tax equity plus tax credit transfer market of $70 to $80 billion a year within five or six years. That may be overly optimistic, but my overall point is that we expect tax credit sales to be additive.

We expect the market to grow after the Treasury guidance is issued. We expect there to be interest in many of the new tax credits. Nine new credits were created.

MR. MARTIN: Jamie Stahle, what types of entities are the current buyers? / continued page 16

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After reading the concept papers, DOE will "encourage" or "discourage" applicants from submitting actual allocations.

A portal will open to applicants seven days after receiving the DOE letter so that they can submit applications. Applications must be filed within 45 days later.

All of the first round allocations will be made by March 31, 2024.

Section 48C requires at least 40% of the $10 billion in tax credits to be allocated to projects in census tracts or directly adjoining tracts where a coal mine closed after 1999 or a coal-fired generating unit was retired after 2009. The IRS issued a table with a list of such census tracts on April 4. It supplemented the table on June 15 with a few more census tracts in Michigan, New Jersey and Texas.

Roughly $1.6 billion of the first-round $4 billion in tax credits will be allocated to facilities in such census tracts. At least 50% of the square footage of the facility must be in such a census tract to qualify.

DOE will rank projects and make recommendations to the IRS. Projects must be commercially viable. The highest rankings will be given to projects that will create the greatest number of jobs, lead to the greatest net reduction in or avoidance of greenhouse gas emissions, involve the most technical innovation and will take the shortest time to complete.

Projects must be completed within two years after receiving an award. Applicants must notify DOE through the exchange portal within two years that the facility was put in service.

There is no benefit to rushing an application. All applications will be treated as submitted on the last day of the applications window.

Applicants must inform DOE and the IRS of any significant change in the plan described in the concept paper or application. A change is significant if it could have adversely affected the DOE ranking for / continued page 17

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MR. STAHLE: The buyers are both new entrants and existing tax equity investors. Some new entrants are focused on managing their tax positions. They may be subject to the new book minimum tax or have high effective tax rates. Some have an ESG focus and want to encourage renewable energy.

Then there is a third group, which is investors that are offering other capital and have tax capacity that they can use to win deals. Examples are life insurance companies and non-US companies with active subsidiaries here who want to add assets to their balance sheets.

MR. MARTIN: Billy Lee, do you expect all of the above on your electronic platform? Do you expect other types of buyers beyond what Jamie Stahle described?

MR. LEE: A lot of the focus on this call has been on large corporates with large tax bills. That is obviously a very interesting sector, but let's not overlook the medium-sized corporations that have some tax liability and maybe have even participated in tax equity deals before. The tax equity market has struggled for years to attract new corporate tax equity investors, because the transactions have been too complicated, too far from these companies' core businesses, and the deals have had unattractive GAAP treatment. The fact that the tax credits were always on the verge of expiring did not help. Transferability and the IRA solve all these problems.

Lots of medium-sized companies pay significant taxes and have treasury departments that look at tax credit purchases as just another tool in the toolbox to do short-term treasury planning. We are really excited about them.

Another category is corporate purchasers of renewable energy. They should emerge over time as buyers of tax credits. Over time, chief sustainability officers will think more about using tax credit purchases as a tool in their overall company sustainability impact goals. That is another focus of ours in terms of educating the market.

Audience Questions

MR. MARTIN: We have a couple hundred audience questions. Yesterday, the House passed a debt ceiling bill that basically repealed most of the Inflation Reduction Act. It is not expected to pass the Senate. Is the House vote to repeal having any effect on the market?

MR. CARGAS: Keith, I usually look to you on these matters, so this is a role reversal. It is hard to tell what can happen in gridlocked Washington. I personally don't think the vote will affect the market.

MR. MARTIN: Several listeners are asking about wage and apprentice requirements and what sort of substantiation tax credit buyers will require that those requirements have been met or that the project is exempted. Rubiao Song, what is the answer?

MR. SONG: Still developing. Most of the projects we are working on today are exempted from the wage and apprentice requirements.

MR. MARTIN: Ted Brandt, several listeners are asking about the availability of bridge debt. If you have 10 years of PTCs to sell, will a lender provide bridge debt to convert the 10 years of tax credits into current cash?

MR. BRANDT: Our survey is we don't think lenders are willing to take unguaranteed PTC price risk. There probably needs to be some type of an insurance policy that will take that risk, and we are working on a solution. Even the mezzanine lenders are saying that they would probably not

Buyers can carry back tax credits and recover taxes paid up to three years in the past.

take that risk on a pure nonrecourse basis.

MR. MARTIN: We heard from some lenders who say they are negotiating bridge loans. We saw a proposed advance rate of 50% in one deal. Others are still in negotiation.

MR. BRANDT: I don't think 50% will be attractive to the sponsors, but we are all getting educated.

MR. MARTIN: A lot of listeners are asking about tax basis step ups in tax credit sales. That is a little too complicated a subject for the last two minutes of this call. Here is another question multiple listeners are asking: will lenders be allowed to have a first lien on project assets in cases where the tax credits are sold?

MR. BRANDT: The premise on which we have been working is that there can be traditional senior debt combined with insurance.

MR. SONG: The ability to take a first lien of the assets is not a foregone conclusion. In an ITC deal, if the lenders foreclose, it could trigger ITC recapture. If there is insurance, great. If not, the lenders are going to have to agree to forebear from foreclosing in a manner that would trigger ITC recapture. In most tax credit sales deals at which we are looking today, there is no senior debt at the project level. ◎

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the project or the IRS decision to make an allocation.

If the change occurs after an allocation has been made, the tax credits will be forfeited. A change made during the review process could cause the project to be bumped to the next allocation round.

Applicants who are denied tax credits can receive a briefing from DOE about where they fell short.

Tax credits cannot be claimed on equipment that is already in service when the applicant receives an award.

Manufacturers can claim section 48C credits for doing any of three things.

One is building a new production line or re-equipping an existing line to make a long list of products for the green economy. Notice 2023-18 has a list of both eligible and ineligible products.

Tax credits can also be claimed for re-equipping an existing factory to reduce greenhouse gas emissions by at least 20%.

They can also be claimed for building a new facility or re-equipping an existing facility to process, refine or recycle any of 50 critical minerals.

The tax credit is 30% of the amount of the new invested capital. The manufacturer must ensure that mechanics and laborers working on the project during construction are paid at least the same wages that are paid on federal construction jobs. Qualified apprentices must also be used for 12.5% to 15% of total labor hours, depending on when construction starts. (For more detail, see "IRS Issues Wage and Apprentice Requirements" on www.projectfinance.law.)

Tax credits will not be awarded to any projects in census tracts that were allocated some of the $2.3 billion in similar tax credits that the federal government awarded in 2010 and 2013.

An award cannot be transferred, even to a successor in interest to / continued page 19

Potential Stimulus for Carbon Capture and Clean Hydrogen

by Scott Burton in Los Angeles, Bob Greenslade in Denver, and Eddie Lewis in Houston

The next phase of the ongoing war over electric power plant emissions has arrived.

Proposed new regulations the US Environmental Protection Agency issued in late May to reduce greenhouse gas emissions from power plants will create more demand for carbon capture and sequestration and low-carbon hydrogen at coal- and gas-fired power plants to achieve emissions reductions if they are ultimately adopted.

They have to pass first through a gauntlet of court challenges.

Proposed Standards

EPA is proposing two sets of standards for fossil fuel-fired power plants to reduce greenhouse gas emissions: one for new and reconstructed power plants and another for existing and modified plants.

The specific requirements depend on a number of factors, such as fuel type, use and expected retirement date, but as a general matter both sets of standards rely heavily on carbon capture and sequestration and co-firing with clean hydrogen as the core mechanisms for reducing power plant emissions.

If adopted, the new rules will have an immediate impact on development of new fossil fuel-fired power plants and consideration of renewable energy projects as alternatives. Although only a proposal at this time, the proposal date establishes whether an affected power plant will be treated as "new" or "existing."

Therefore, any fossil fuel-fired power plant that commences construction on or after May 23, 2023 will be considered "new." As a result, developers will need to consider the additional costs of compliance when deciding whether to move forward with their projects or consider alternatives.

The proposals are controversial.

For example, EPA's proposed "low-GHG hydrogen" definition may exclude so-called "blue" hydrogen, meaning hydrogen produced from natural gas combined with carbon capture and sequestration, as a permitted way to reduce emissions. This will meet resistance from stakeholders who believe electrolytic "green" hydrogen production is inadequately demonstrated to assure large-scale commercial availability.

Proposed fuel shifting from coal to natural gas, and broad adoption of carbon capture and sequestration also are far from uncontroversial.

Potential Stimulus

Cost and feasibility of carbon capture and sequestration are likely to be a primary area of argument. Opponents will assert that widescale CCS still is too costly, not adequately demonstrated and, therefore, cannot be imposed as an emissions control standard.

If the CCS provisions survive, they will provide certainty as to the future need for increased CCS capacity resulting in a stimulus effect for the nascent CCS industry.

Likewise, the clean hydrogen co-firing provisions will also be challenged. These provisions would require that a certain amount of the fuel used be replaced by low-GHG hydrogen. Opponents will argue that this mechanism has not been adequately proven at high percentages of co-fired hydrogen fuel.

The effect of the co-firing provisions on the hydrogen industry may depend on where EPA lands on the issue of what qualifies as low-GHG hydrogen.

EPA proposes that this would include only hydrogen produced through a process that results in a greenhouse gas emission rate of less than 0.45 kilograms of CO2 equivalent per kilogram of hydrogen on a well-to-gate basis, consistent with the most stringent system boundary established in section 45V of the US tax code. Section 45V provides a tax credit of up to $3 a kilogram for producing clean hydrogen. (For more detail about the hydrogen tax credits, see "Hydrogen Tax Credits" in the October 2022 *NewsWire*.)

If the proposed definition is adopted, then it will probably cover only green hydrogen produced by electrolysis employing electricity provided by non-emitting power plants, such as solar, wind, nuclear and hydroelectric plants.

Whether the definition will be expansive enough to include blue hydrogen produced from natural gas with CCS remains to be seen. However, if it does, the EPA effort to reduce emissions could provide a stimulus effect for both green and blue hydrogen, with an additional stimulus for CCS due to the additional demand associated with blue hydrogen production.

New EPA rules should create more demand for carbon capture and low-carbon hydrogen.

Long History

The new proposed rules are merely the latest chapter in a decades-long back and forth over air emissions standards for power plants.

The greenhouse gas aspects of this regulatory trench warfare are more recent, commencing with two Obama-era rules in 2015. The first established standards for new, reconstructed and modified fossil fuel-fired power plants, notably including a partial carbon capture and sequestration standard for new coal-fired power plants.

The second 2015 rule, known as the Clean Power Plan, generated significant controversy because it included requirements to reduce greenhouse gas emissions from existing fossil fuel-fired power plants by shifting generation to lower-carbon options, such as solar and wind.

The generation-shifting aspect of the Clean Power Plan was vacated by the US Supreme Court in a 2022 decision called West Virginia v. EPA. (For more detail about what the Supreme Court said, see "Effects of West Virginia v. EPA on Power Sector" on www.projectfinance.law.)

The court noted the significant economy-reshaping impacts likely to result from EPA's proposed approach and held that the Clean Air Act did not provide clear authorization for such economy-wide impacts. ◎

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the original applicant, without IRS permission. Any request to transfer must be made to the IRS at least 30 days before the due date for the successor in interest's tax return for the tax year the transfer occurs.

This creates a potential obstacle for tax equity financings where the project is moved into a tax equity vehicle. The application would have to be filed in the name of the special-purpose project company that is then moved under the tax equity partnership.

The IRS will not approve a transfer if there has been a significant change in the information provided by the original applicant.

The IRS will publish the names of award recipients and how much they were awarded. Applicants can try to prevent any confidential or proprietary information from being released in response to Freedom of Information Act requests by marking such information as confidential in the application.

CONTRACT MANUFACTURING is becoming more important as some manufacturers angling for section 45X credits for making components for wind, solar and storage projects farm out the physical work to other companies.

An example is where a battery or tracker company hires out the physical work to a for-hire factory to make parts of its batteries or trackers using proprietary designs.

Section 45X is a new tax credit in the Inflation Reduction Act for manufacturing components for wind, solar and storage projects. The tax credits are generally fixed amounts per component. For example, the tax credit for making torque tubes — the horizontal rod on which solar panels sit — is 87¢ a kilogram. It is $35 a kilowatt hour of storage capacity for making battery cells.

The tax credits can be claimed on such components produced and sold through 2032, but they start to phase down in amount after 2029. / continued page 21

Key Issues for Hydrogen Developers

by Jim Berger, in Los Angeles

The hydrogen offtake agreement is the most important component of developing a hydrogen project. There is no merchant market for hydrogen, so a project developer will need a long-term hydrogen offtake agreement in order to finance a project.

Few Buyers

However, hydrogen buyers can be hard to find. The largest use of hydrogen is currently in oil refining, followed by ammonia and methanol production. The next sectors that are potential buyers are steel, cement and sustainable aviation fuel production.

Most of the current hydrogen used by these industries is made from fossil fuels, usually through steam methane reforming of natural gas.

Many current users of hydrogen desire — or are under political or regulatory pressure — to switch to green hydrogen. This creates an opportunity for a project developer to find a quality counterparty.

If the hydrogen economy grows as many expect, there will be other potential buyers in the future, such as long-distance trucking, aviation and energy storage. For now, developers should focus on targeting the industries that already use significant amounts of hydrogen as potential buyers.

Once a project developer finds a buyer, the creditworthiness of the buyer is vitally important. Financiers will require a creditworthy buyer or a buyer with a creditworthy parent that can provide a guaranty or other credit support. Without this, it may be impossible to finance a project.

Next, the terms and conditions of the offtake agreement will be important.

Financiers are likely to amortize the debt based on the length of the agreement, so the longer the agreement, the more debt that will be available. The more debt available, the less equity a sponsor will need, although financiers will require some minimum amount.

Financiers will also examine the amount of fixed revenue likely to be generated under the offtake agreement. This can take many different forms such as a fixed reservation payment or capacity or demand charge, but the most common form is likely to be a take-or-pay obligation.

With a take-or-pay obligation, the buyer is required either to take the hydrogen and pay for it or just pay for it. This ensures that a project can expect a minimum level of revenue. The buyer will want a minimum production guarantee to ensure it receives an agreed-upon minimum amount of hydrogen every year.

This form of offtake requires a balancing act by the project developer. A developer will want to increase the minimum volume to increase revenue. However, because these types of projects are new, the developer may want flexible output targets in case there is more downtime at the plant than expected so that the developer can avoid penalties for underperformance.

Location

The location of a project could be the next most important issue.

Some developers try to site projects close to buyers to minimize the need to transport hydrogen. Others site projects close to the inputs, such as electricity and water for electrolysis or biomass or other materials for gasifiers. There is no right answer.

The two main hydrogen delivery methods are by pipeline and truck. Transporting hydrogen by pipeline is significantly less expensive than by truck, but creates other issues. Hydrogen is less dense than gas and escapes more easily. It can corrode metal. There is also not currently any regulatory certainty around hydrogen pipelines, which is an obstacle to pipeline construction. The Federal Energy Regulatory Commission is expected to assert jurisdiction over hydrogen transmission. This will create regulatory certainty for pipeline developers.

Transportation of hydrogen by truck may be the only option if the end users are widely dispersed, such as hydrogen refueling stations. If the ultimate destination is overseas, then the hydrogen or ammonia will be piped to a port and loaded on a ship.

If the project is producing carbon dioxide that it intends to sequester, this adds additional complexity. This is another waste product that must be accounted for and it complicates siting decisions due to the very limited number of sites where sequestration is permitted and the need to pipe the carbon dioxide to the injection well. There are only a couple currently permitted wells in the country. Several dozen others have permit applications pending with the EPA.

Related to the location are the inputs needed for a successful project. An electrolyzer needs significant volumes of water. Gasifiers need whatever material will be converted into hydrogen and other gases (for example, waste or biomass).

Negotiating water rights can be tricky. Ownership of water depends on its location. Generally, the state owns surface water while groundwater is typically owned by the landowner.

Ownership of surface water cannot be conveyed, but a user can obtain rights to it by permit. Groundwater can be sold, but there can be other legal restrictions around its use.

If other inputs are needed, where will they come from and how will they be delivered are important considerations. Electricity is relatively easy to access. Biomass or other materials that are feedstocks for gasifiers must usually be trucked to the project. The number of trucks and the timing of deliveries may be regulated by the project permits. Heavy truck traffic creates safety and pollution issues that will be of concern to the local community.

Risks

Financiers care about the technology and pay close attention to how the construction, revenue and other project contracts fit together.

Some of the technology used to produce hydrogen is well established and has a long history. Other hydrogen production technology is newer. Financiers want proven technologies. The tax equity and debt markets do not take technology risk.

For projects using new technology, there must be a successful track record somewhere such as in Europe or Asia. An independent engineer must stand ready to explain the technology to the financiers. If the technical experts are uncomfortable with the technology, the financiers will remain on the sidelines.

A green hydrogen project is significantly more complicated than a typical solar or wind project.

Some hydrogen projects have fully wrapped construction contracts, meaning a prime contractor takes responsibility that the various pieces of the project provided by different vendors will work together when fully assembled. The exception is the electrolyzer because it is a packaged, modular piece of equipment. If the gold standard of a fully-wrapped construction contract is not available, then the developer usually must make do with different contractors for different parts of the project.

This creates risks as to timing, technology compatibility, finger-pointing and potential liquidated damages mismatches. All of these can be addressed by an experienced developer, but financiers will want an independent engineer to verify that all of these types of risks have been adequately mitigated.

The eventual financing of a planned project must be kept in mind at all times during development.

The developer must keep a close eye on the financeability of the project documents as each contract / continued page 22

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Cases where a for-hire factory does the physical work raise questions about who is the "manufacturer" for purposes of claiming tax credits.

Anyone in this position would be wise to do the following. If the goal is to have company A rather than for-hire factory B claim section 45X tax credits, then A should supply the raw materials used to make the product and retain title to the raw materials and finished products during manufacture.

It should hold the patents and other intellectual property rights needed to make the product. Factory B should not make the product for anyone else and not sell any excess product to anyone else. Company A should decide the amount of output to be produced. The more A is engaged in directing product design, controlling manufacturing-related logistics and managing costs, the better.

Ideally B should be paid on a cost-plus-fixed-fee basis so that A bears the costs to manufacture the articles.

The contract between A and B should make clear that the parties will treat A as the "producer" and it, rather than B, will claim any section 45X tax credits.

The same question which of A and B is the manufacturer for purposes of taxes or tax benefits comes up in at least three other contexts.

The federal government collects manufacturer's excise taxes from the manufacturers of various products. The issue is whether the company selling the product or the for-hire factory should pay the excise tax. In contract manufacturing situations, the "manufacturer" is the person who supplies the raw materials and retains title to the raw materials and the finished product during manufacture.

The IRS and the courts have analyzed a series of situations where B manufactures articles under contract to A using B's own materials and labor. A is the manufacturer if it owns the patent required / continued page 23

Hydrogen Developers

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is negotiated. This means ensuring adequate cure periods when obligations are inadvertently breached, adequate liquidated damages, appropriate time frames and deadlines and limits on the ability of the counterparty to terminate the agreement.

The potential financial incentives, such as federal tax credits and state-level low carbon fuel standard credits need to be worked into the financial architecture of the deal. They can also enhance a project's economics.

Green hydrogen projects are significantly more complicated than the typical wind or solar project.

Tax Credits

The most complicated part of the capital structure to account for is the federal tax credits for producing clean hydrogen.

Hydrogen producers can choose between an investment tax credit or a production tax credit. The ITC is taken in the year the project is placed in service. PTCs are claimed over 10 years on the hydrogen output.

The amount of the tax credit depends on the carbon intensity of the hydrogen being produced. To qualify for the maximum tax credit, the hydrogen production process must produce fewer than 0.45 kilograms of CO2-equivalent emissions per kilogram of hydrogen.

The emissions are measured on a lifecycle basis "well to gate" using the GREET model developed by the Argonne National Laboratory. The US Treasury is wrestling with a number of issues, including under what circumstances emissions from using direct grid electricity to run electrolyzers can be offset by buying renewable energy credits, or RECs, from owners of renewable energy power plants. (For more detail, see "Hydrogen Tax Credits" in the October 2022 *NewsWire*.)

If a developer chooses PTCs, it can also choose to have the IRS pay the cash value of the PTCs for the first five tax years after the hydrogen plant starts operating. After that, the PTCs could be sold to another company, but it would be at a discount. (For more detail, see "Transferability: Selling Tax Credits" in the March 2023 *NewsWire*.)

If the project will use clean electricity generated by a wind or solar project that is owned by an affiliate of the hydrogen plant owner, it will create a "section 707(b) issue." The owner of the wind or solar plant will not be able to claim tax losses on it. No losses can be claimed on property sold to an affiliate. This is complicating structuring of hydrogen projects. (For more detail, see "Section 707(b): Related-Party Electricity Sales in the June 2021 NewsWire and "Another Utility Tax Equity Structure" in the February 2022 *NewsWire*.)

Finally, because the green hydrogen industry is still nascent, many developers partner with large, established companies that are sources of capital, equipment or construction expertise. If the partner will be a co-owner, then there will be a lot to negotiate, such as how to split responsibilities, protect each party's intellectual property, determine who owns newly-developed intellectual property, provide for downside protection in case one party fails to fulfill its obligations or fails to fund and decide on potential buy-outs. ◎

Hydrogen Pipeline Regulation

by Chris Psihoules in Washington, and Daniel Salomon Sotomayor in New York

The US has no clear framework for regulating interstate hydrogen pipelines.

There are three possible regimes. The Federal Energy Regulatory Commission may have authority to regulate them under the Natural Gas Act or the Interstate Commerce Act. Alternatively, the Surface Transportation Board may have authority to regulate them under the Interstate Commerce Commission Termination Act.

None of these regulatory frameworks specifically addresses the transportation of hydrogen.

While the Natural Gas Act (NGA) has been applied to the interstate transportation of hydrogen when hydrogen is blended with natural gas, it has not been applied to transportation of pure hydrogen.

The Interstate Commerce Act (ICA) has been used historically as the regulatory regime for the interstate transportation of oil or oil derivatives. FERC has extended its reach to other petrochemicals with potential energy applications and non-petrochemicals that directly compete with energy petrochemicals.

The Interstate Commerce Commission Termination Act (ICCTA) serves as a comprehensive umbrella statute over transportation of all commodities, especially if not regulated by FERC. It is the current source of transportation oversight for pure hydrogen pipelines. It does not cover transportation by pipeline of water, gas and oil.

The Surface Transportation Board engages in limited economic regulation over the rates and terms of service of interstate hydrogen pipelines, and it provides a forum to resolve disputes related to pipelines within its jurisdiction. Parties who wish to challenge whether a rate or another aspect of a pipeline's service is "just and reasonable" may petition the STB for a hearing.

Regulation of hydrogen pipelines is not expected to remain with the STB long term.

Interstate hydrogen pipeline transportation should eventually be regulated by FERC under the NGA or ICA. There is a good chance Congress will choose the NGA.

Regulating pipeline transportation of hydrogen under the NGA or ICA comes with benefits and drawbacks for pipeline project developers.

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to manufacture, decides on the amount of output to be produced and has exclusive rights to the output so that B is not free to sell to others. However, change one fact — let B produce more product than A requires and sell the excess to third parties — and B is the manufacturer.

The federal government allowed taxpayers engaged in domestic production in the United States through 2017 to deduct 9% of the income from such activity, leading to an effective tax rate on such income of 31.5% compared to the 35% rate that applied at the time to other corporate income. The deduction was an inducement for American companies to do their manufacturing at home.

In contract manufacturing cases, the IRS focused on which of the two parties had the "benefits and burdens of ownership of the [product]" during manufacture to determine which was the producer entitled to the deduction.

IRS regulations gave examples of how the IRS analyzed who had the benefits and burdens. In one example, A designed a machine and hired B to build them. B was the manufacturer under the following facts: A owned the intellectual property and allowed B to use it solely to manufacture machines for A. However, B retained control over how they were manufactured, sold them at a fixed price per machine to A, suffered a loss or earned a profit depending on its cost to manufacture and had legal title until the machines were conveyed to A.

Another context where contract manufacturing comes into play is where US manufacturers create offshore holding companies in an effort to shift profits from offshore manufacturing to tax havens. The United States looks through foreign corporations that are controlled by US shareholders and taxes the US shareholders on any earnings considered "subpart F" income without waiting for the earnings to be repatriated to the United States.

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Hydrogen Transportation Agreements

Regardless of the statute under which pure hydrogen pipelines are regulated, pipeline developers should be sure to address the following subjects in transportation agreements with hydrogen producers.

1. **Liability allocation:** Hydrogen is more likely than natural gas to leak because it has lower density. The transportation contract should have indemnities to cover damages after a leak. Title and risk-of-loss provisions should be scrutinized as part of the liability allocation.

2. **Gas quality and pressure:** The product being offered to and received by the hydrogen pipeline must comport with the gas quality specifications to protect pipeline and downstream customer integrity. The hydrogen should be delivered at a sufficient pressure to be received by the pipeline and delivered to the delivery point.

3. **Force majeure and curtailment:** Hydrogen pipeline operators need protection in the event of force majeure or an upstream loss of hydrogen that requires shippers to be curtailed.

4. **Priority of service:** Pipelines prioritize service based on the class of service. Depending on whether jurisdiction falls under the NGA or ICA, negotiated rates and discounted rates may play a role in service class priorities.

5. **Imbalances:** Imbalance provisions and audit rights become even more important in hydrogen agreements than in other transportation agreement because hydrogen has a higher leak rate.

6. **Nominations and scheduling:** Scheduling coordination will be paramount for successful receipt and delivery of green hydrogen because production will rely on intermittent power sources.

Hydrogen Pipelines

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Natural Gas Act

The NGA is a federal law enacted in 1938 that governs the interstate transportation and sale of "natural gas."

It provides a regulatory framework to ensure a stable and reliable gas market. It grants FERC authority to regulate rates, terms and conditions of interstate natural gas transportation. The agency is charged with ensuring that prices are "just and reasonable." This promotes market stability, facilitates long-term investment in pipelines, and makes it more likely that gas will be available to consumers.

If hydrogen pipelines end up regulated under the NGA, pipeline developers would have to obtain a FERC certificate of public convenience and necessity to construct an interstate hydrogen pipeline. With a certificate come two important powers: federal eminent domain authority giving the pipeline developer the power to take or condemn property in exchange for just compensation, and state preemption allowing the pipeline developer to preempt conflicting regulation by state and local governments.

The process for obtaining such certificates may be lengthy. FERC commissioners are political appointees subject to political pressures. FERC is required to undertake an environmental assessment of each new pipeline project. FERC scrutinizes high-emitting pipeline projects, and its pipeline environmental review has been under attack by non-governmental organizations.

A low-carbon hydrogen pipeline may be a quicker way to secure a certificate. Under the NGA, FERC is the lead agency performing the environmental assessment. This should streamline the developer's environmental permitting process.

If a gas pipeline is converted to a pure hydrogen pipeline, the developer would also need abandonment authority from FERC to do so.

The NGA requires open access.

Open access is the principle that gas pipeline operators must provide non-discriminatory access to their pipeline systems to all shippers or customers who meet the necessary qualifications and requirements.

FERC promotes open access to gas pipelines to ensure fair competition and efficient operation of the gas market. Open access requirements for natural gas pipelines rely on a number of principles.

One is non-discrimination, or the idea that pipeline operators must offer the same terms, conditions and rates to all similarly-situated shippers without any undue preference or advantage given to any specific shipper or customer.

Open access means pipelines must file tariffs with FERC for approval. Tariffs are the rates, terms and conditions for transportation services. The tariffs must be made available to all potential shippers and customers, and the tariff rates must be just and reasonable.

The pipeline must be transparent about the capacity allocations it makes to the shippers and customers it serves.

It must post information about available capacity, rates and terms where it will be accessible to the public. This allows potential shippers and customers to make informed decisions and encourages competition.

Open access under the NGA will help to facilitate hydrogen market participation.

The NGA has no common carrier requirement and allows for pipelines and its customers to contract for capacity in bilateral agreements that may charge higher or lower rates than the pipeline's tariff rate.

Without a common carrier obligation, pipeline developers are able to lock in capacity commitments before building the hydrogen pipeline, which is important to secure financing. Capacity commitments are often secured through precedent agreements under which developers seek reimbursement for certain construction costs. Pipelines regulated under the NGA receive a set rate of return that applies to the rate base in order to cover the cost of capital.

It is unclear whether FERC could regulate hydrogen pipelines under the NGA without Congressional action. The NGA defines natural gas as "either natural gas unmixed, or any mixture of natural and artificial gas." FERC could arguably assert jurisdiction over pure hydrogen pipelines by treating hydrogen as an artificial gas.

Congress is likely to act. The Senate Energy Committee chairman, Joe Manchin (D-West Virginia), is proposing as part of an "Energy Independence and Security Act" that could be debated later this year to amend the NGA to treat hydrogen as a "natural gas."

Intrastate pipelines that move gas received from interstate gas pipelines to which they are connected are not regulated under the NGA but under the Natural Gas Policy Act (also administered by FERC). If hydrogen pipelines end up being regulated under the NGA, an interesting question is whether the NGPA will require amendment so that intrastate */ continued page 26*

One type of subpart F income is "foreign base company sales income" that the foreign corporation earns by buying goods from a related person and reselling them to a third party, or by buying goods from a third party and reselling them to a related person. This is intended to prevent a US company from shifting income to a tax haven. An example is where a US company forms a subsidiary in the Cayman Islands that it uses to buy goods manufactured by an affiliate in Germany and to resell the goods to customers in France.

The US does not usually look through the foreign corporation if the corporation manufactured the goods.

This raises the question who is the manufacturer where the foreign corporation hires out the physical work to the German affiliate. IRS regulations treat the foreign corporation as the manufacturer only if it makes a "substantial contribution" to manufacture of the product through its own employees.

The regulations have a list of seven activities that are evidence of such a contribution, including oversight and direction of the manufacturing, material selection, vendor selection and control of raw materials, work-in-process or the final goods, developing or directing product design, managing costs, such as through efficiency initiatives and hedging raw materials, and controlling manufacturing-related logistics.

PRODUCTION TAX CREDITS for producing renewable electricity will be higher this year than in 2022, but the amount varies depending on when the project went into service.

The IRS announced the annual inflation adjustments in a notice in the *Federal Register* on June 21.

Production tax credits for generating electricity from projects that use wind, geothermal steam or fluid or closed-loop biomass (plants grown to be used as fuel in power plants) and were placed in 2021 or earlier are

Hydrogen Pipelines

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hydrogen pipelines can interconnect to interstate hydrogen pipelines to provide interstate service.

Interstate Commerce Act

The ICA was enacted in 1887 and puts jurisdiction over oil pipelines with FERC.

Broadly speaking, it provides a regulatory framework to ensure fair and equitable practices in the transportation of goods, including oil, through pipelines.

It does not require pipeline developers to obtain certificates as FERC does not regulate pipeline siting, construction or abandonment under the ICA. Lack of FERC siting scrutiny may have the effect of fast-tracking construction of new hydrogen pipelines. Some states, such as Texas and Louisiana, have very limited looks at pipeline siting.

Regulation under the ICA would mean that pipeline developers would not need abandonment authority from FERC to convert an oil pipeline to pure hydrogen. However, lack of certificates means that pipeline developers will not have the power of eminent domain or state preemption. In states where pipeline siting is regulated by the public service commission, this may make it more difficult to secure rights-of-way required to site hydrogen pipelines. FERC does not serve as the lead agency for environmental permitting, leaving environmental permitting to the individual states.

Pipelines regulated by FERC under the ICA must have tariffs on file and approved by FERC that include tariff rates, rate schedules and terms and conditions of service. The tariff rates must be just and reasonable. Many tariff rates are subject to annual indexation based in part on inflation. Any changes to the rates and terms and conditions of service must be approved by FERC. The pipelines are not allowed to charge more or less than the tariff rates. NGOs have not provided much opposition at FERC with respect to ICA-regulated pipelines.

The focus of regulation under the ICA is to ensure that pipelines satisfy their obligations as "common carriers." Hydrogen pipelines regulated under the ICA cannot be fully committed: they must have at least 10% capacity reserved for new shippers.

FERC generally approves contracts with committed shippers that underpin a pipeline construction or expansion. It allows committed shippers priority to use pipeline capacity, as long as enough capacity is reserved for walk-up shippers. If the nominations of walk-up shippers are greater than available walk-up shipper capacity, the available capacity is usually allocated pro rata based on the nominations of the walk-up shippers. Also, the requirement of having a tariff on file is waived for pipelines that transport only their own product or that of the pipeline's affiliate as long as no third party requests transportation service.

The ICA has been interpreted by FERC to apply to interstate transportation of petrochemicals with potential energy application, such as ethane and other natural gas liquids, and non-petrochemicals that directly compete with energy petrochemicals.

This wider scope could align more easily with hydrogen's different sources and applications. Hydrogen produced by electrolysis or other methods is arguably subject to regulation under the ICA because it competes directly with fossil energy commodities.

The US has no clear framework for regulating hydrogen pipelines.

Pipeline Safety

The Pipeline and Hazardous Materials Safety Administration (PHMSA) has been regulating hydrogen pipelines since 1970.

Its rules in this area are called the "Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline."

These regulations focus primarily on natural gas and treat hydrogen as a "flammable gas."

Pipeline operators must comply with various requirements, including materials, design, construction, metering, corrosion control, operations, maintenance, and reporting.

PHMSA has recognized the need to establish adequate codes and standards for all aspects of a hydrogen economy. Forthcoming regulations are expected to address the safety and operations requirements of hydrogen pipelines in particular. They will take into account such factors as the potential for hydrogen to cause metal brittleness, its wide range of flammable concentrations in air, and its lower ignition energy compared to gasoline or natural gas.

The Occupational Safety and Health Administration (OSHA) also has jurisdiction over regulating gaseous and liquefied hydrogen systems on consumer premises under its "Regulations Relating to Labor."

Regulatory authorities, gas suppliers and midstream service providers should still take these provisions into account to ensure consistency. Authorities should strive to avoid overlaps or discordances when issuing new regulations, suppliers should consider these rules when entering into supply agreements, and midstream service providers should align the technical specifications of their assets with the requirements of end-user facilities.

Importantly, these regulations also pose interpretation challenges when distinguishing midstream and consumer practices, especially in cases where hydrogen is processed into ammonia and requires additional downstream logistic services. ◎

2.8¢ a kilowatt hour in 2023, 0.2¢ higher than in 2022.

PTCs for the same projects put in service in 2022 or 2023 will be 2.75¢ a kilowatt hour because of a change the Inflation Reduction Act made in how the inflation adjustment works for newer projects.

The tax credits will be 1.4¢ a kilowatt hour in 2023 for generating electricity from open-loop biomass, landfill gas, trash, incremental hydropower and ocean energy placed in service in 2021 or earlier. Such projects qualify for PTCs at only half the full rate. They qualify for PTCs of 1.5¢ if placed in service in 2022 or later, except that incremental hydropower and ocean energy projects qualify for PTCs at the full rate if placed in service in 2023.

The credits are adjusted each year for inflation as measured by the GDP price deflator. They run for 10 years after a project is originally placed in service.

Projects must comply with wage and apprentice requirements or be exempted from them to claim credits at the full rates. (For more details on these requirements, see "IRS Issues Wages and Apprentice Requirements" on www.projectfinance.law.)

The credits phase out if contracted electricity prices from a particular resource reach a certain level. That level for wind in 2023 is 15.1¢ a KWh. The IRS said there will not be any phase out in 2023 because contracted wind electricity prices were 3.74¢ a KWh going into 2023. It said it lacks data on contracted prices for electricity from the other energy sources.

— contributed by Keith Martin in Washington

Wage and Apprentice Negotiations

by Gabrielle Jacques, in New York

Developers had until January 28 to start construction of projects to avoid being subject to wage and apprenticeship requirements in the Inflation Reduction Act. With the cutoff date now nearly five months in the past, developers are eager to get language into their construction contracts to make sure they meet the requirements and qualify for higher tax credits.

The wage and apprentice requirements are the fine print behind the new tax credits in the Inflation Reduction Act. (For more detail, see "IRS Issues Wage and Apprentice Requirements" on www.projectfinance.law.)

Even with the initial IRS guidance published last November, questions linger. The eventual project owner claiming tax credits bears the burden of compliance under the statute. Contractors claiming to satisfy the requirements are charging owners higher prices to account for paying their employees prevailing rates.

Developers have a balancing act to ensure the wage and apprenticeship requirements are met while not incurring unnecessary costs. For example, the wage and apprentice requirements do not usually apply to construction work on gen-tie lines, so there is no need to pay prevailing wages or engage apprentices for such portions of a project.

However, carving out some parts of the work runs the risk of going too far. Developers do not want to be in a situation where they pay for bare minimum compliance, but are ultimately found to fall short and cannot claim full tax credits.

There are a lot of moving pieces and uncertainties as the market waits on more guidance. Developers are trying in the meantime to push as much of the responsibility as possible to comply with the new requirements on construction and O&M contractors.

Most developers attempt to describe the wage and apprentice requirements in construction and O&M contracts by repeating what is in the statute and leaving room for additional detail in future guidance.

Contractors want to know what they are getting themselves into. They are pushing back on references to the Internal Revenue Code and proposing the parties agree to static definitions that can be measured and understood when the contract is signed.

Proposed regulations are expected on the wage and apprentice requirements in late June or July.

Tax Credit Haircut

The Inflation Reduction Act changed the way tax credits are calculated. President Biden campaigned on a platform that green jobs would be well-paying jobs. To make sure that is true, most tax credits in the IRA require the same wages that are paid on federal construction jobs be paid to mechanics and laborers during construction and on alterations and repairs for a period after the project is in operation.

Developers also have to use "qualified apprentices" for 12.5% to 15% of total labor hours. The idea is train a larger green energy workforce by requiring apprentices be used to work along experienced construction workers. Labor compliance consultants report that, except in California and parts of Texas, apprentices are generally unavailable.

The prevailing wage and apprentice requirements apply not only to wind, solar and other new renewable energy power plants, but also to storage, hydrogen, biogas and carbon capture projects and electric vehicle charging infrastructure. Failure to comply leads to an 80% haircut in the tax credits that can be claimed on a project.

Prevailing wages must be paid not only to laborers and mechanics employed directly by the developer, but also to those employed by contractors or subcontractors.

The US Department of Labor publishes prevailing wage rates by job type and location. If the wage determination available online does not include all relevant labor classifications, or if there is no wage determination for the location and construction job, developers can ask by email to have a wage determination made. It is unclear how long it will take the wage and hour division to respond. It was receiving 1,000 requests for wage determinations a year, and had a backlog, before the Inflation Reduction Act was enacted.

Whether "qualified apprentices" must be used for 12.5% or 15% of total labor hours depends on the year construction started for tax purposes.

The figure 12.5% applies to projects that start construction for tax purposes in 2023, and 15% applies to projects that start construction thereafter. Projects that started construction by January 28, 2023 are exempted from the wage and apprentice requirements. There is a "good faith" exception for cases where apprentices are requested but are unavailable.

Damages

If a project is subject to the wage and apprentice requirements, meeting them is an all-or-nothing test. The project either qualifies for tax credits at the full rate or it does not.

Any failure, no matter the duration or extent, leads to the 80% haircut in the tax credits. However, the project owner can make cure payments to restore the full amount.

It would have to pay underpaid laborers and mechanics the difference between the actual wages paid and the then-prevailing wage rates plus interest. It must also pay a $5,000 per worker per year penalty to the US Treasury for each underpaid laborer or mechanic.

Some contractors believe they can cure a failure to pay prevailing wages within a year without incurring the $5,000 per worker penalty. In other words, the contractor believes it has complied if the annual wages paid are at least equal to the hours worked times the prevailing rate, even if an employee was underpaid during a portion of the year and overpaid to compensate during a later portion. The statute does not suggest this is the case. The statute says back pay and the penalty are due for any laborer or mechanic who was underpaid for any period during the year.

The cure amount for failing to comply fully with the apprentice requirement is $50 for each labor hour missed. There is no additional penalty per worker.

If a failure is found to be due to "intentional disregard" of the requirements, the penalties are significantly higher.

The penalties ultimately fall on the project owner claiming the tax credits, even if it is a contractor's act or omission that causes the failure. Contractors are generally agreeing to indemnify developers for back pay and cure penalty payments in instances where they fail to comply with the prevailing wage and apprentice requirements as understood as of the date the contract is signed.

Project owners want uncapped developer exposure for the full amount of the cure payments.

Some contractors demand limits on their liability for cure payments. Some argue the cure payments are liquidated damages and should be counted as such against the contractor's liquidated damage cap. Most project owners want at least a separate cap for cure payments.

The contractor's liability for cure amounts must survive for at least the statute of limitations for an IRS income tax audit for the return year the credits were claimed. Project owners have up to 180 days after a final IRS determination to cure a prevailing wage deficiency.

Beyond cure expenses, there is risk of lost tax credits if the labor requirements are not met and not cured in time. For example, if the contractor did not maintain the proper records to prove enough apprentice hours were worked, the project owner will not be able to claim tax credits at the full rate. This could require a massive amount be paid to the IRS on a large-scale project. Now that project owners have the option to sell renewable energy tax credits to other companies for cash, the risk can extend to parties beyond the developer and contractor. Few contractors are agreeing to liability for lost tax credits.

O&M workers handling alterations and repairs must be paid the same wages that are paid on federal construction jobs.

Recordkeeping and Reporting

Project owners must keep records to prove the prevailing wages were paid and the apprentice hours were worked.

However, in cases where laborers or mechanics are not directly employed by the developer, the contractor or subcontractor employing the workers is best positioned to prepare these records.

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business in the public sector are familiar with Wage Form 347. It is an optional form for contractors to submit certified weekly payrolls for contracts subject to the Davis-Bacon and related acts. Even though the Inflation Reduction Act is not a traditional Davis-Bacon related act, the IRS guidance implementing the wage and apprentice requirements incorporates certain Davis-Bacon concepts and requirements. Project owners are requiring contractors to provide certified payroll reports that would comply with Davis-Bacon requirements if asked by the project owner to do so.

Most contractors are agreeing to provide labor reports to project owners on a monthly or quarterly basis. Some contractors argue that it is the developer's responsibility to review the reports for errors. If an error is not communicated to the contractor within a stated review period, some contractors argue they should not be liable. There could be hundreds of laborers and mechanics performing work at a project site. Reviewing the labor detail for each worker would require extensive manpower on the developer's part. Most developers are rejecting a shift in liability to the developer for unidentified errors.

There is a debate about how long contractors should fill out labor records. This issue is ensuring that any warranty work performed that may be considered "alteration or repair" is covered. Most contracts require contractors to fill out labor reports during the full period production tax credits will be claimed or for at least five years for projects on which investment tax credits are claimed. It is important the contractor keep information on former employees. If back pay is required to cure a wage shortfall, a contractor must know how to reach the underpaid worker.

Beyond Construction Contracts

Developers are wondering whether they need also to address the prevailing wage and apprentice requirements in agreements beyond the construction contract. The answer depends on the work performed.

The prevailing wage requirements apply not only during construction, but also to repairs and alterations after the project is in operation. For production tax credit projects, the wage requirements apply through the full credit period, meaning 10 years for a solar or wind power plant on which PTCs are claimed or 12 years for a carbon capture project on which section 45Q credits are claimed. For investment tax credit projects, the wage requirements apply for the five years after the project is placed in service during which the ITC remains subject to recapture.

Project owners are adding prevailing wage provisions to their operations and maintenance agreements for alteration and repair work.

Application of the apprenticeship requirements after a project is in service is less clear. The prevailing wage subsections explicitly refer to the extended five-to-12-year compliance period after operation, but the apprentice requirement provisions do not. However, there are six references to "alteration or repair" work in the apprentice provisions in the statute. The IRS said the phrase "alteration or repair" has the same meaning as "construction, prosecution, completion, or repair" in 29 CFR § 5.2(j). Determining application of the apprentice requirements to post-operational work may require interpretation by the US Department of Labor.

The responses by project owners vary. Some are requiring O&M contractors to use qualified apprentices to make alternations and repairs. Others are not bothering unless the IRS says that the apprentice requirements apply.

What about supply contracts where the manufacturer installs the equipment at the project site or performs on-site commissioning work?

The answer again comes down to whether the work is "construction, alteration, or repair" within the meaning of the US Department of Labor regulations. Factors to consider include the nature of the work (for example, construction v. mere furnishing of materials), the techniques, materials and equipment used, the worker's skills (for example, a licensed engineer v. an electrician), and if union labor would customarily have been used pre-IRA to perform the work.

All contracts usually include including language to revisit the wage and apprentice issues in good faith after the IRS issues additional guidance and to adjust the contract price to account for unforeseen expenses. ◎

LMI Bonus Credit Guidance

by Keith Martin, in Washington

The Treasury filled in more detail in late May about new LMI bonus tax credits that are expected to be claimed on some community and rooftop solar installations.

The Inflation Reduction Act authorized an additional 10% or 20% "bonus" investment tax credit to be claimed on small solar and wind projects that are less than 5 MWac in size. It is called an LMI bonus credit because the projects must be in low- and moderate-income areas or be aimed at serving low-income households.

There are 1,800 megawatts in such tax credits each year. Companies must apply to the Internal Revenue Service for an allocation.

They will be hard to claim on 2023 projects. No tax credits will be given to projects that are already in service when the awards are made.

The IRS has not set a date yet to allocate 2023 credits, but the date is expected to be in the fall. It hopes to allocate all of the 2023 tax credits in one round.

The US Department of Energy will review the applications and make recommendations to the IRS.

Developers have four years after receiving an allocation to complete a project. Developers counting on the bonus tax credit will have to view 2023 as a lost year and use any 2023 allocations for projects they install during the period late 2023 through late 2027. The IRS is trying to direct tax credits to projects that would not be built without them.

The latest details are in proposed regulations released in late May.

The IRS answered other questions about the LMI bonus credits in February in Notice 2023-17. (For earlier coverage, see "LMI Bonus Tax Credits" in the March 2023 *NewsWire*.) The bonus credit is in section 48(e) of the US tax code.

The complexity is vastly out of proportion to the small size of the projects.

Annual Cap

The 1,800 megawatts the IRS has to allocate each year are of DC capacity.

A project must receive an allocation for the full DC capacity — rather than the net or AC capacity — to avoid a haircut in its bonus tax credit. For example, if a project has a nameplate capacity of 5.5 megawatts, but the net capacity is only 4.8 megawatts and it is allocated only 4.8 megawatts of tax credits, then it will only be able to claim 87% of the bonus tax credit (4.8/5.5). This was in the Inflation Reduction Act.

The IRS will allocate 1,800 megawatts a year through the year greenhouse gas emissions from the US fall at least 75% from 2022 levels. It will allocate them at least through 2032 even if greenhouse gas emissions reach this threshold more rapidly.

Four categories of projects qualify potentially for LMI bonus credits.

The IRS will use sub-caps to divide the 1,800 megawatts for 2023 among the four.

An extra 10% investment credit can be claimed on projects that are in low-income census tracts that qualify for new market tax credits or are on Indian land.

An extra 20% investment credit can be claimed on projects mounted on top of multi-tenant buildings whose tenants receive housing assistance or where "at least 50 percent of the financial benefits of the electricity produced" goes to households with incomes below 200% of the poverty line or below 80% of the area median gross income.

The sub-caps for 2023 bonus credits for these categories are as follows: 700 megawatts for projects in low-income census tracts, 200 megawatts for projects on Indian land, 200 megawatts for projects on multi-tenant buildings and 700 megawatts for projects whose electricity benefits lower-income households.

However, the 700 megawatts for projects in low-income census tracts will be further divided, with 560 megawatts reserved for solar panels mounted on dwellings and other "residential behind-the-meter" facilities and only 140 megawatts for "front-of-the-meter" projects that connect directly to the utility grid or that serve businesses.

Batteries

The proposed regulations addressed 10 topics. The IRS is taking comments through June 30.

It is concerned about developers splitting larger projects in order to remain under the size cap of less than 5 MWac.

This is also a potential issue with rooftop solar installations on multi-tenant apartment buildings. Some owners hope to treat the solar systems on each building as a separate project to stay under a 1-MWac size limit for / continued page 32

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exemption from the wage and apprentice requirements. (For more details, see "IRS Issues Wage and Apprentice Requirements" on www.projectfinance.law.)

The IRS said it will use a list of factors in section 7.01(2) of Notice 2018-59. to determine when two or more purported small projects are really one large project.

The LMI bonus credit can be claimed on batteries that are part of a small solar or wind project. However, the batteries must have power ratings that are less than two times the capacity of the generating equipment.

The battery is part of the solar or wind project if it is owned by the same legal entity, is physically adjacent, connects to the same interconnection point and shares the same environmental or "other regulatory" permits.

If the battery is too large, then an LMI bonus credit can still be claimed if the project owner can prove that at least 50% of the electricity used to charge the battery comes from the generating equipment. Presumably this means in the first 12 months after the battery is placed in service. It would be wise to maintain the same charge level for at least the first five years.

The battery is ignored when testing whether the capacity of the project is too large to qualify for a bonus credit.

Projects aiming for a 10% bonus credit in low-income census tracts or on Indian land must have at least 50% of their capacity in such a location.

Sharing Benefits

Projects aiming for a 20% bonus credit because they serve low-income people face a daunting task to prove qualification.

A project on a multi-tenant building whose residents qualify for rent subsidies must share the "financial benefits of the electricity produced . . . equitably among the occupants of the dwelling units of such building."

The IRS said calculation of the financial benefit that must be shared with low-income tenants varies depending on whether the generating equipment is owned by the building owner or by a separate renewable energy supplier.

If the building owner owns everything, then the financial benefit is the greater of two numbers. The calculation starts with the electricity the building draws from the system, times the metered price the building otherwise pays for electricity, plus any revenue earned from selling excess power from the system. The financial benefit that must be shared with low-income tenants is 25% of that number or, if greater, the full amount minus the annual cost to operate the system. These are proxies for the profit margin. The annual cost to operate includes debt service, maintenance, a replacement reserve and other operating costs.

The building owner must have a signed benefits sharing agreement with the tenants.

If a third party owns the solar system and enters into a power purchase agreement or "other contract for energy services" with the building, then the building must share 50% of the bill credits and cash payments for "net excess generation" it receives or, if greater, 100% of that amount minus the subscription fee or other payment it makes for the electricity. This formula works for community solar projects, but not where a building is simply buying electricity from a solar company that owns solar panels mounted on the roof.

In this community solar model, the subscription agreement must bind the building owner to share its savings with low-income tenants.

Bonus tax credits of 10% or 20% of project cost can be claimed on some community and rooftop solar projects.

The IRS has not decided in either case what the effect should be on the calculations if the low-income tenants pay the building for their electricity.

Whatever financial benefit is calculated must be shared equally or in proportion to electricity usage by each tenant who can prove he or she is low income. The IRS did not address the time period for the electricity usage data or low-income status in relation to when the electricity is supplied.

However, the actual sharing may depend on whether the building has a master electricity meter or sub-meters to track electricity used by each dwelling unit. It may not be possible to share the benefits with tenants in proportion to electricity usage in buildings with master meters.

In buildings with sub-meters, the tenants must receive credits on their utility bills for their shares. The credits can affect tenants' utility allowances and annual income for purposes of calculating rent under HUD-assisted housing programs. The US Department of Housing and Urban Development (HUD) has already issued guidance to building owners who participate in community solar programs on how the bill credits affect these two items.

In buildings with master meters, the building must pass the savings through to tenants by other means, such as providing other benefits to tenants beyond those they received before the solar or wind system was put in service.

In some places, the building owner cannot legally or administratively apply bill credits to reduce residents' electricity bills. The IRS asked for suggestions.

Projects that provide at least half the "financial benefit of the electricity" to households below 200% of the poverty line or below 80% of the area median gross income also qualify for 20% bonus credits.

The IRS limited bonus credits for such projects effectively to community solar projects by requiring the projects to serve multiple households.

It said at least half the "total output" from the project must go to qualifying low-income households.

Such households cannot be charged subscription fees that exceed 80% of the bill credits they receive. The IRS said each such household must receive at least a 20% "bill credit discount rate." The "bill credit discount rate" is (A minus B) divided by A, where is A is the bill credits given to household and B is the subscription fees or other payments made by the household to receive the bill credits.

The community solar company must provide proof that each low-income household claimed is in fact low income. Documentation must be presented to the IRS when the community solar project is put in service that identifies each qualifying low-income subscriber, the output allocated to each in kilowatt hours and the method used to verify each household's income.

The permitted forms of proof are household participation in a needs-based government or utility program with income limits at or below the bonus credit thresholds. A state agency may be able to provide verification. If the household is not enrolled in a qualifying program, then the community solar company can produce copies of paystubs or tax returns or rely on income verification through crediting agencies and commercial data sources.

It cannot rely on self-attestations by the households.

Priorities

Priority will be given to projects that satisfy at least one of two selection criteria. The criteria focus on ownership and location.

If there are more priority projects in a category than there are tax credits for that category, then the IRS will give priority to projects that satisfy both criteria.

No administrative appeals of allocation decisions are possible.

Starting with ownership, priority will be given to projects owned by five types of entities.

One is projects owned directly or indirectly at least 51% by Indian tribes. Ownership is not defined. The tribe must have the power to appoint and remove more than half the individuals who are on the board.

Another favored owner is any consumer or purchasing cooperative formed to buy electricity for its members that owns at least 51% of the project. It must be controlled by members who are either low-income households or workers. Each such member must have an equal vote.

A "qualified renewable energy company" will also receive priority. It must be at least 51% owned by individuals or favored types of entities (Community Development Corporation, agricultural or horticultural cooperative, Indian tribe, Alaska native corporation or native Hawaiian organization) and have fewer than 10 full-time equivalent employees and less than $5 million in gross receipts the previous year. Companies under common control will be combined for purposes of testing the number of employees and gross receipts.

In addition, it must have installed or operated the types of projects that qualify for LMI bonus credits at least two years before applying for a bonus credit and / continued page 32

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installed or operated at least 100 kilowatts of such projects in low-income census tracts that qualify for new markets tax credits or on Indian land. It is possible the applicant will not have to have both types of experience, but rather only the type most relevant to the category of project for which it is applying for a bonus credit.

Projects owned by tax-exempt charities, religious organizations, state or local governments or governments of US territories like Puerto Rico and Guam, Indian tribes and rural electric cooperatives will also receive priority.

The complexity is vastly out of proportion to the small size of the projects.

Turning to location, priority will be given to projects in "persistent poverty counties" where at least 20% of the residents have experienced high rates of poverty over the past 30 years, using US Department of Agriculture data, or in census tracts designated as "disadvantaged" in a "climate and economic justice screening tool" known as CEJST.

The IRS has a checklist of documents that must be submitted by applicants.

Applicants must report to the US Department of Energy after a project is placed in service and submit additional documents at that time.

Change

If there is a change in a project after it is awarded a bonus credit, the project can lose the right to the credit or have to repay the Treasury if the bonus credit has already been claimed.

The IRS wants to discourage material changes in project plans, such as significant reductions in project size that could use up part of the 1,800-megawatt cap that could have gone to other applicants.

A project will be disqualified after receiving an allocation if one of five things happens before the project is placed in service.

The five are the location changes, the nameplate capacity increases above the 5 MWac limit or decreases by at least 2 kilowatts or, if greater, by 25% of the allocation awarded, the project cannot satisfy the financial benefits tests as planned, it is not placed in service within four years, or the allocation was made based on ownership priority selection criteria that are no longer satisfied.

An exception has been made to accommodate tax equity arrangements where the developer's ownership of the project drops during the first five years after the project is placed in service to give a tax equity investor an interest. Ownership must revert to the original owner or the original applicant must have a "right of first refusal" to take back the project.

The bonus tax credit will be recaptured if any one of five events happens during the first five years after the project is placed in service. However, an owner can cure if it acts to restore eligibility within 12 months after becoming aware of the failure (or after it should reasonably have been aware).

The recapture events are failure to provide the required financial benefits (including the minimum 20% discount to any household) or to allocate savings properly among tenants, the building that the project serves drops out of a covered housing program, or the project "output" is 5 MWac or greater, unless the project owner can prove the increase is not attributable to the original project but to one that has been so extensively rebuilt as to qualify as a different project.

The bonus credit is just that: an addition to the base investment tax credit of 30%. The base credit would be recaptured if the project were sold. Presumably the bonus credit would be recaptured at the same time. ◎

Comparing Carbon Offset Credits

by Christy Rivera, in New York

Demand for voluntary carbon credits is outpacing the supply of high-quality carbon credits available.

Supply is hampered by concerns about quality of the carbon credits. Carbon offset claims by sellers can be challenging to verify.

A new standardized approach for comparing carbon credits is starting to take shape. Developers of renewable energy and carbon capture projects should be able to use the new core ratings principles as a guide for how to ensure their carbon offset credits are rated of high quality.

Voluntary Market

The carbon offset market is a potential additional revenue source for projects. (For more detail, see "Carbon Offsets as a Potential Source of Revenue" in the February 2022 *NewsWire*.)

A voluntary carbon credit — sometimes referred to as a carbon offset — represents one metric ton of carbon dioxide or equivalent greenhouse gases (GHG) that has been avoided or removed from the atmosphere.

Carbon credits are sold in voluntary markets.

When a buyer purchases carbon credits listed on a registry, it may enter into forward sales having terms of six months to a year, with terms of up to two or three years occurring less frequently. Much longer forward sales of 10 to 20 years are not uncommon when a buyer invests directly in the underlying project that will eventually produce the carbon credits.

Many buyers are companies that have set voluntary emissions targets and want to use carbon credits to offset their emissions.

Buyers do not want to purchase just any carbon credits. Like most people, they want to know what they are buying. Buyers focus on purchasing carbon credits that have been well-vetted and are created by projects that have been independently verified to reduce or remove the amount of GHG emissions that the project developers claim. Verification of the carbon credits and underlying projects gives buyers comfort that the carbon credits purchased are credible. Validation of the carbon credits also increases the price that buyers are willing to pay to developers for these credits.

However, there is no single uniform system used to validate carbon credits. Instead, there are various carbon-crediting programs, each with different standards, that developers can use to register carbon credits from developed projects.

A carbon-crediting program is a program that reviews projects and registers the related carbon credits. Also referred to as registries, carbon-crediting programs include The Gold Standard, Climate Action Reserve, American Carbon Registry and Verra.

Each carbon-crediting program has its own criteria for evaluating projects that wish to register carbon credits with the program, and each program has its own methodologies for testing the underlying projects against those criteria. While the registries look at similar factors, there is no easy way to compare on a "apples-to-apples" basis a carbon credit registered on one registry to a carbon credit registered on another registry.

The lack of a single uniform system to verify credits makes it more difficult for a buyer to identify high-quality carbon credits and properly value those credits across different types of projects.

An independent organization – the Integrity Council for the Voluntary Carbon Markets – is taking steps to fix this lack of uniformity in the carbon markets.

Core Principles

The Integrity Council published a final set of "core carbon principles" in late March.

These core carbon principles are intended to set a global threshold standard for determining the quality of carbon credits. Whether credits meet this threshold will be tested under an "assessment framework" that looks at both the carbon-crediting program and the categories of carbon credits.

The Integrity Council also released the first part of its assessment framework for evaluating the carbon-crediting programs. The framework identifies criteria that the Integrity Council recommends be used to determine whether the various carbon credit registries comply with the core carbon principles. Compliance by these registries would, according to the Integrity Council make it easier for buyers to evaluate the carbon credits being sold on that registry.

The 10 core carbon principles and the related criteria for carbon-crediting programs are as follows.

First, the carbon-crediting program must have effective governance in place to ensure transparency, accountability and overall quality of the carbon credits. Good governance helps ensure that the program's rules and pro- */ continued page 36*

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cesses are followed when registering the credits.

Second, the registry used by the carbon-crediting program must uniquely identify, record and track the credits. Ultimately, it should be easy for market participants to identify each individual carbon credit generated by any project. This is important for preventing fraud.

Third, the program must be transparent in sharing information on the mitigation activities that create the carbon credits. The mitigation activities are the projects that reduce or remove greenhouse gas emissions. For example, solar developers engage in mitigation activities by generating solar energy. A solar project displaces a more carbon-intensive power plant.

Fourth, the program must require independent third-party validation and verification of the carbon credits. In order for a third party to verify the credits, the program must set out clearly the rules that projects must follow in order to register carbon credits.

Fifth, the GHG emission reductions or removals from the project must be "additional," meaning the GHG reductions or removals would not have occurred but for the incentive created by the ability to sell carbon offset credits. Registering today a carbon credit for a solar or wind farm that was constructed many years ago does not fulfill this additionality requirement.

Sixth, the GHG reductions or removals must be permanent or, if there is risk for reversal, measures must be in place to limit the potential for reversal. For example, carbon credits can be issued for forestry projects that keep carbon in trees and soil, which reduces GHG emissions. However, if the forest is harvested by a lumber company or burns down, the trapped carbon may be released, reversing the earlier GHG reduction. A mitigation measure would be to bar tree harvesting and to take steps to reduce fire risks.

As another example, carbon capture projects looking to qualify for carbon credits under the core carbon principles must identify, and then take steps to mitigate, risks that arise in connection with sequestering carbon underground. Carbon-crediting programs should evaluate what steps a developer has taken to help ensure the carbon dioxide remains safely stored after injection.

Seventh, the GHG reductions or removals must be robustly quantified based on conservative approaches and scientific methods. A thorough, conservative approval process gives the market participants comfort that the GHG reductions or removals represented by the caron credits ultimately registered are legitimate. By registering carbon credits for a project, a carbon-crediting program is asserting that X metric tons of carbon dioxide or GHG gases have been avoided or removed from the atmosphere by a particular project. That assertion needs to be tested. The tools or methodologies used by the verification program to quantify the emission reductions or removals must be evaluated.

Eighth, the GHG reductions or removals must not be double counted. Two carbon credits cannot be issued for the same metric ton reduction or removal of GHG emissions. Once a carbon credit is used, it must be clearly retired.

Ninth, the carbon-crediting program must have clear guidance and compliance procedures to ensure that projects generating carbon credits comply with industry "best practices" for social and environmental safeguards.

Tenth, the projects creating carbon credits must truly reduce or remove GHG emissions. Projects that use technologies or carbon-intensive practices that are incompatible with achieving net zero global GHG emissions by 2050 will not qualify. Projects will be evaluated not only for consistency with zero or low GHG emissions but also for whether the technology is transformational or among the best currently available. Carbon-crediting programs must take this into account in evaluating projects.

Timetable

Carbon-crediting programs are expected to apply to the Integrity Council soon to be assessed against the criteria identified in the assessment framework.

Later this year, the Integrity Council will begin announcing those carbon-crediting programs that are in compliance.

The Integrity Council intends to publish a separate assessment framework for evaluating categories of carbon credits in the coming months.

If a registry satisfies the 10 core carbon principles for evaluating registries and a project satisfies the forthcoming separate princi-ples for evaluating the credits themselves, then the carbon credits issued by the registry for that project will be "CCP-eligible."

The registries will be able to label both existing and new carbon credits as "CCP" approved. That tag will give buyers more comfort that what they are buying has been vetted and buyers may be willing to pay a premium for that tag.

Project developers should watch for the forthcoming credit-level assessment framework. That framework may give guidance on steps developers can take to ensure carbon credits from their projects are rated of high quality. ◎

Split-Scope Battery Purchase Contracts

by Luke Edney in Houston, Jim Berger in Los Angeles, Jeremy Tripp in Houston and Tian Bai in New York

Splitting the equipment procurement and construction work on a battery energy storage project (BESS) among multiple contractors is a complicated process that can be done, but that carries risk.

The most common split is having different contracts to procure the DC block, AC block and energy management system of the battery separately, instead of procuring a fully-integrated BESS system.

Such split contracts require careful attention to avoid gaps among contracts. There are also financing considerations with such a contract structure.

This is the third article in a series. In previous articles ("Battery Purchase Contracts" in the December 2021 *NewsWire* and "Battery Purchase Contracts: Key Pitfalls" in the August 2022 *NewsWire*), we analyzed typical construction contract structures for BESS projects and the key pitfalls when negotiating equipment procurement contracts.

Technical Integration

The most prominent risk with a split-contract structure is that the equipment being purchased is not compatible.

A developer procuring equipment from different suppliers must confirm, itself or through third party advisors, that the equipment will not only work together as an integrated system, but that it will also be capable of serving the business use case that the developer has in mind for its project.

The separated procurement creates higher risk for developers that equipment may have to be modified or replaced in order to operate or that the developer may have to accept operational limitations not contemplated by its business use case.

The market has adopted three approaches to address the technology risks.

One is insisting on proven designs and equipment. Using a combination of technologies that other developers have used successfully reduces the technology risk, as others have tested it and incurred the expense of troubleshooting issues. This also applies to using equipment for a proven use case, such as resource adequacy, frequency control and load shifting.

A related approach is to rely on a third-party integrator to integrate the BESS components in a tested and proven manner. There is a price to pay for this knowledge and the warranty value from such an integrator must be considered to confirm whether the service offered makes commercial sense. Integrators seek to limit their liability to the amount paid for services rather than the cost of remedying the impact.

A similar option is to involve a technical advisor or engineering consultant, from the initial stages of project development, who can provide expertise necessary to review specifications and advise on the technology integration.

Another approach to minimizing integration risk is to use off-the-shelf equipment. Using stock DC blocks, AC blocks and energy management systems further reduces integration and execution risk, as it allows current design, installation, operations, maintenance manuals, specifications and materials to be used. Presumably these have already been proven.

Once equipment has been chosen, the developer should collect data and have a single source do the detailed engineering work for the project. By doing this, scoping and procurement can be completed using one design for the entire project.

Cost and Schedule

Another challenge with using multiple contractors to build a project is one contractor's action may affect the work being done by other contractors and may entitle the other contractors to receive cost or schedule relief.

Wind and solar developers have learned to manage risk associated with multiple contracts. Wind projects have a turbine procurement contract and a separate balance-of-plant construction contract. Solar projects have a module procurement contract and a separate balance-of-plant construction contract.

However, the risk is multiplied when additional contractors and suppliers get involved, as can happen in battery energy storage projects.

It is easy for projects to experience a snowball effect of split scope where multiple contractors can cause multiple impacts across project agreements, with overall project cost and schedule being materially affected.

In battery energy storage, this can be complicated by issues related to battery degradation and storage requirements for battery units, causing the developer to have to spend money to store and maintain the batteries when other contractors or suppliers are behind schedule.

The key to managing cost-and-schedule risk associated with multiple contractors is to have a */ continued page 38*

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detailed timeline and to keep close watch on it.

For example, the timeline might have three phases.

During phase 1, the focus is on getting advice on the various project equipment packages and designs that will be incorporated into the project. Developers may have an integrator set up standard configurations and write out the information for engineering the entire project, including all the equipment design, installation and operational information.

Phase 2 has two parts. In phase 2a, the detailed engineering and design work are completed. Then a detailed balance-of-plant contracting cost and schedule are set up. In phase 2b, if the equipment options are locked in, then procurement can start.

Phase 3 is the balance-of-plant contracting. It is done last because it requires completion of the detailed engineering and completion of the equipment specifications to ensure pricing and schedule can be fixed.

When a project needs to split the scope of work among multiple contactors, several terms in the separate construction contracts can be designed to fill in the gaps caused by such splitting.

Split contacts to buy and then install utility-scale batteries require careful attention to gaps.

"Interface activities" need to be priced in the contracts, including via representations and warranties about each contractor's scope of work.

Project information must be incorporated into each contract and shared among the various contractors.

Liquidated damages regimes must be coordinated to cover critical path events that affect other contractors.

Individual contract schedules must be consistent among contracts so that the developer can merge schedules and manage key milestones.

Finally, the scope of work under each contract must, when reviewed as a whole, cover the full scope of the project. This last step of checking the various work scopes often ends up being the biggest single risk mitigant that a developer can deploy.

A common way to ensure the scope has been fully executed among all contractors is to use one contractor — almost always the balance-of-plant contractor — to perform "all other activities necessary to complete the project."

To do this, BOP contract should incorporate the requirements for installation, operation and maintenance of the owner-supplied equipment — equipment that the developer procures directly from vendors and supplies to the contractors to install — into its scope and performance requirements. The balance-of-plant contractor should warrant that the engineering and installation and balance of site will be capable of supporting full operation of the owner-supplied equipment and comply with all manufacturer requirements.

Implementation

Implementation risk ultimately tests a developer's ability to man-age contracts during the design and construction phase. Developers implementing a split-scope procurement approach must consolidate design and delivery schedules, create consolidated progress reporting, address flow-on impacts between contractors, and manage multiple contractors at the project site.

Fully-wrapped projects do not require developers to have as much management skill.

However, it is critical in BESS projects for the developer to have enough capacity to run multiple agreements, manage multiple contractors and address the impacts of individual contractor failures to perform.

Strong owner control can help mitigate implementation risks. If the developer lacks the resources itself to do the job properly, then it should bring in third-party consultants to manage these activities for it.

Financing Considerations

The procurement and construction period are the most risky for lenders. They will be concerned about how the developer performs the tasks described in this article.

Although lenders tend to be relatively flexible on schedules (but will still set deadlines for when a project must be on line and earning revenue), they are more sensitive to the cost-and-schedule risk for a merchant project.

Lenders are also much less flexible when there is a deadline in an important agreement such as an offtake contract or interconnection agreement to be in commercial operation or to reach a key milestone.

Supply-chain issues have been a focus for lenders since the pandemic.

Taking these potential delays into account when building the project construction schedule either through contingencies or a more conservative schedule can help make the project more likely to be financed.

Lenders are also focused on potential operational issues after the project is completed. For example, they will want to know what operational risks are covered by warranties and guarantees, who is standing behind the warranties and guarantees and how creditworthy are they. If a piece of equipment fails, is there a back-up readily available to install? If not, how long will it take to procure back-up equipment? Proactively procuring spare parts to replace vital equipment (such as a main power transformer) could reduce project downtime from many months to only days.

Integration of the equipment is one of the operational risks that lenders tend to review closely. For financing purposes, the developer must make clear which contractors have responsibility for which equipment or service so that there are no gaps in warranty coverage. Ensuring that an independent engineer is comfortable with the split of responsibilities will be vital to closing on the financing.

Another issue for financiers is that there are limited warranties and remedies for failed engineering and design work compared to the overall value of the project.

This is because balance-of-plant contractors who pick up the equipment information after the engineering work has been completed come in at a later stage in the development cycle. Flaws with the design can be discovered too late without sufficient remedies or warranties. Having the engineering work done early in development, such as during phase 2, can help to mitigate some of these risks and increase the level of comfort for lenders and overall bankability of the project. ◎

Sports Stadiums and Renewable Energy

by Sidney Owens, in Chicago

Sports stadiums consume massive amounts of energy, making them ideal candidates to integrate solar, wind and other renewable energy technologies that reduce operating costs and carbon footprints and help boost a team's brand as a responsible corporate citizen.

Moneyball

Some stadium operators are already installing solar panels and wind turbines or signing power purchase agreements to buy renewable electricity.

Lincoln Financial Field, home of the Philadelphia Eagles football team, installed 11,000 solar panels through an arrangement with NRG, a retail electricity supplier. NRG owns the equipment and sells power to the stadium at a reduced price. It sells the remaining electricity not needed by the stadium to power other parts of Philadelphia. The arrangement is expected to save the Eagles more than $60 million in energy costs over the next two decades.

Indianapolis Motor Speedway, the host of the Indy 500 auto race, leased land adjacent to the race track to a private developer that built the world's largest solar farm in a sports facility, a nine-megawatt solar power plant with 39,312 solar panels, in 2014. Clenera and Swinterton built the project on behalf of Centaurus Renewable Energy. The electricity is sold under a long-term power purchase agreement to the Indianapolis Power & Light Company. Centaurus sold the project to Boralex in 2020.

The Minnesota Vikings football team is buying renewable energy credits from wind farms to cover 100% of the electricity used in its US Bank Stadium. The team claims its stadium is the first stadium to be fully powered by wind energy. The team has also taken a series of other measures to reduce its energy costs by $1.26 million a year. They include using a transparent plastic polymer roof structure that allows natural daylight to light the stadium and allows heat to dissipate for cooling to reduce reliance on lighting and HVAC systems.

The Miami Heat basketball team installed a 24,000-square-foot so-lar canopy at its American Airlines Arena to reduce energy costs by $1.6 million a year. The canopy has 14 solar skylight rings with a combined capacity of 19 kilowatts. It covers an outdoor amenity space on the east end of the / continued page 40

Sports Stadiums

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arena overlooking Biscayne Bay. A color-changing LED lighting system is concealed in the soffits of the skylights and produces changing light patterns.

Government Incentives

Some stadium owners may be tapping into section 179D tax deductions at the federal level and benefiting from public funding at the state level.

Section 179D of the US tax code provides a tax deduction for building owners and designers who implement energy-efficient systems and technologies in commercial buildings that are 25,000 square feet or larger.

Sports stadium owners can use this tax deduction to offset the costs of installing renewable energy systems such as solar panels, wind turbines, and geothermal systems. (They may also be able to claim fed-eral tax credits on new equipment to generate renewable electricity.)

Under section 179D, building owners could claim a tax deduction of up to $1.80 per square foot for qualifying energy-efficient improvements to lighting, HVAC systems and the building envelope. The Inflation Re-duction Act increased the deduction to as much as $5 a square foot.

In the case of sports stadiums, this tax deduction can be applied to renewable energy systems that contribute to the overall energy efficiency of the building. Previously, to qualify for the deduction, improvements had to reduce energy consumption by at least 50% compared to a reference building. The Inflation Reduction Act lowered the energy consumption reduction threshold to 25%.

Many sports stadiums receive large amounts of public funding for their construction and maintenance.

For example, Nashville and the state of Tennessee agreed in April 2023 to give the Tennessee Titans football team $1.26 billion to build a new riverfront stadium in Nashville.

Governments that fund stadiums are increasingly requiring the stadiums to use designs that qualify for LEED certification from the US Green Building Council. LEED is a voluntary non-government program that measures all aspects of the development, construction and operations. A facility can earn up to 110 points, over seven categories, based on its impact on climate change. It is rated for impacts, among other things, on human health, water resources, the "green economy," the local community and natural resources. Awarded points determine the level of LEED certification: certified (40-49 points), silver (50-59 points), gold (60-79 points) and platinum (80+ points).

Thirty-two stadiums in the US professional baseball, football, basketball, ice hockey and soccer leagues have been recognized by LEED. They represent 25% of the stadiums in those leagues.

Defending the Environment

Sports stadiums have a significant environmental impact due to their high energy consumption and carbon emissions. These massive facilities host thousands of spectators and require large amounts of electricity for light, HVAC and other equipment.

The average sporting event in a stadium uses enough energy to power 5,000 American households for a similar length of time.

Thousands of sporting events are hosted every year, and it is easy to see the tremendous amount of energy expended on them and potential carbon emissions. Renewable energy is being used to reduce the carbon footprint of many sports stadiums.

Cypto.com Arena, which hosts games for the LA Lakers and LA Clippers basketball teams and the LA Kings ice hockey team, installed 1,727 solar panels that provide enough energy to reduce 10,000 tons of CO2 emissions. The stadium also established a bank of fuel cells that generate electricity onsite and will displace 1,100 tons of CO2 emissions over its lifetime.

Inuit Dome, the LA Clipper stadium currently under construction and set to open in 2024, plans on being the first climate-positive stadium. The stadium will use batteries and onsite solar power to run on 100% carbon-free power.

Footprint Center, home of the Phoenix Suns basketball team, in-stalled a 17,000-square-foot solar array on the roof, producing enough energy to eliminate 440,000 pounds of CO2 emissions annually.

The Baltimore Ravens football team installed 1,210 solar panels on its M&T Bank Stadium. The energy produced through the panels would cre-ate 317 tons of CO2 emissions annually if produced through nonrenewable energy sources. The equivalent carbon footprint is 13,000 tailgaters using propane grills.

The New England Patriots football team installed 3,000 solar panels on its stadium that generate 60% of the facility's energy needs. The solar system is expected to prevent the release of 8,800 metric tons of CO2 emissions over the next 20 years.

The San Diego Padres baseball team installed 716 solar panels on its stadium, Petco Park. The panels produce enough energy to offset 28 metric tons of CO2 emissions annually.

Sports stadiums use large amounts of electricity during games, making them good candidates for renewable energy.

Light the Beam

The sports world is in a prime position to popularize renewable energy as it has the eyes and ears of the public.

Studies show that around 13% of Americans follow science and technology news, while 71% follow sports.

Golden 1 Arena, home of the Sacramento Kings basketball team, is the world's first sports stadium 100% powered by solar energy. The stadium has a large purple laser beam that lights the sky after every home win, creating a viral internet meme. Unaware that the laser uses around the same amount of energy as a household dishwasher, sports commentator Colin Cowherd attacked the beam saying it was an "egregious waste of energy." The backlash to Cowherd's comments went viral on social media. It led to discussions about energy use and Golden 1 Arena's use of renewable energy — an example of how sports can draw the attention of a broad audience to the transition to renewable energy.

Being seen as socially responsible and investing in renewable energy is also a good business practice for sports teams. In 2022, two-thirds of consumers said they were willing to pay more for a product they believed to be sustainable.

It also unlocks sponsorship offers from green-conscious companies that do not normally partner with sports teams. After announcing that its stadium would be 100% renewable energy, the Las Vegas Raiders had sponsors reach out to partner with it on deals worth millions of dollars. ◎

Power Play

Understanding state laws and regulations can provide teams with leverage to access renewable energy at competitive prices.

An example is Allegiant Stadium, home of the Las Vegas Raiders football team, which is set to become 100% powered by renewable energy in 2023 after three new solar farms are completed.

Legal maneuvering helped to reach this renewable energy milestone. The team used Nevada Revised Statutes Chapter 704B to opt out of the public utility company and purchase energy on the open market. This then opened the door to negotiations with multiple potential electricity providers and lowered the energy price through competition. The team eventually agreed to a 25-year contract with the local utility, NV Energy, at a lower price. The electricity NV Energy supplies comes from three new solar projects developed by independent power companies.

Environmental Update

The bill President Biden signed on June 2 to raise the federal debt ceiling also amended the US National Environmental Policy Act, or NEPA, in a bid to streamline and fast-track its environmental review procedures.

Since 1970, NEPA has required federal agencies to analyze the potential impacts of major government actions that could affect the environment – such as federal permitting decisions, federal funding and allowing the use of federal lands.

Federal agencies will now be required to focus on "reasonably foreseeable environmental effects" in their reviews of projects, in contrast to more abstract or downstream impacts. However, this language is largely consistent with current case law. It also does nothing to limit the analysis of climate change-related impacts under NEPA.

Under the NEPA amendments, the range of alternatives to a proposed project that must be analyzed now need only include those that are technically and economically feasible.

The changes also expand agency authority to use "categorical exclusions" approved by other agencies to excuse NEPA analyses, though that decision will be subject to oversight by the Council on Environmental Quality.

Most importantly, the law looks to fast-track NEPA environmental reviews.

The law now creates a default deadline of two years for agencies to complete an environmental impact statement, if one is needed, with a one-year cap imposed where a less complex environmental assessment will suffice.

The new law allows agencies to extend deadlines in consultation with a project sponsor. However, it both requires the relevant lead permitting agencies to report all missed deadlines to Congress and creates a new mechanism by which project sponsors can challenge delays in court.

In addition, the law also requires a lead agency be set for each environmental review, sets page limits for environmental impacts statements and environmental assessments, and streamlines procedures for reviewing energy storage projects.

NEPA ensures that federal agencies will assess the environmental impact of a project before they approve it. However, there is general agreement in Washington that NEPA too often imposes significant time and monetary burdens on infrastructure projects. These burdens hit all projects, including those needed to combat climate change. Delays in NEPA and other permitting reviews can also be blamed on understaffing. Unless the understanding is addressed, accelerating deadlines will lead to shallower reviews.

Nevertheless, the new fast-tracking of the NEPA review process will benefit all infrastructure projects requiring federal involvement, including projects driven by renewable power as well as by fossil fuels. While the new deadlines allow some flexibility, they are at least likely to prod agencies to issue assessments within a more reasonable amount of time.

The final deal negotiated between House Speaker Kevin McCarthy and President Joe Biden does nothing special to expedite transmission line permitting.

Speeding the transmission line approval process is crucial to advance the US renewable power industry. Such transmission is needed to bring renewable energy from areas where it is best produced to areas where the power is most needed.

Suggestions that the law should require grid regions to improve transmission to neighboring areas went unheeded. Instead, the law only requires the North American Electric Reliability Corp. to consult with regions and utilities and conduct a two-year study of "prudent additions" to total power "transfer capability" between regions.

The NEPA amendments also clarify when when a federal action does not rise to the level of a "major federal action" that requires NEPA review.

Projects that will not trigger NEPA review as a major federal action now include those that have no "or minimal federal funding" and no other triggering agency involvement or where a project uses federal loans or other financial assistance but no federal agency exercises "sufficient control and responsibility" over the use of the funds. NEPA review will also not be required in the future where a project relies on business loan guarantees provided by the Small Business Administration, where the federal actions result solely from nondiscretionary agency activities, and where they represent extraterritorial activities or decisions with effects located completely outside US jurisdiction.

An unintended consequence of the new law is that its passage will probably delay release of a "phase 2" NEPA rule by the Council on Environmental Quality.

The CEQ completed the first of a two-phase process of amending the federal implementing regulations for NEPA on May 20, 2022. The administration reversed a number of changes made to NEPA during the Trump administration. Phase 2 of those rules has been undergoing interagency review since

January and was expected to be published this June. Now, the proposed regulations will have to be revised to take the statutory amendments to NEPA into account.

The new law did not advance other permitting reform agendas being debated in Congress, such as streamlining review processes under other statutes like the Endangered Species Act.

Wetlands

The US Supreme Court stripped federal protection under the US Clean Water Act from more than 50% of the nation's previously regulated wetlands in a 5-4 decision at the end of May.

The Supreme Court stripped protection under the Clean Water Act for more than 50% of the previously-regulated wetlands.

The case is called *Sackett v. EPA*. A slim majority ruled that only wetlands that are "indistinguishable" from adjacent protected water bodies are protected by the Clean Water Act.

The court endorsed the previously divisive "continuous surface connection" test for federal Clean Water Act jurisdiction over wetlands and protected waters that was first suggested by the late Justice Antonin Scalia in a 2006 case called *Rapanos v. United States*. The court has now clearly rejected the broader "significant nexus" standard that emerged from a competing opinion in the same case.

The core of the *Sackett* decision reads as follows: "To determine when a wetland is part of adjacent 'waters of the United States,' the Court agrees with [Justice Scalia in] Rapanos . . . that the use of 'waters' in [Clean Water Act] §1362(7) may be fairly read to include only wetlands that are 'indistinguishable from waters of the United States.' This occurs only when wetlands have 'a continuous surface connection to bodies that are 'waters of the United States' in their own right, so that there is no clear demarcation between 'waters' and 'wetlands'."

That is a much narrower standard than the Environmental Protection Agency and Army Corps of Engineers used in a 2022 regulation defining "waters of the United States." The decision effectively guts the approach the Biden administration has taken to wetlands protection.

It goes farther than even the Trump administration's approach that allowed wetlands that are cut off from downstream waters by such things as roads and berms to remain within federal jurisdiction. Now, only wetlands with a continuous surface water connection to waters such as rivers and lakes appear to receive Clean Water Act protection.

The ruling creates a bright-line test that could help landowners better identify regulated wetlands or streams that are subject to federal protection. Such clarity has been elusive.

Despite that clarity, the implications from the decision are not yet fully understood, but they will be as wide ranging as they are surprising.

The court established a new, much narrower reading of which streams and tributaries are covered. The Clean Water Act now covers "only those relatively permanent, standing or continuously flowing bodies of water 'forming geographic features' that are described in ordinary parlance as 'streams, oceans, rivers, and lakes.'" That can be read to eliminate federal protection for thousands of miles of streams that flow only when it rains, which is common today in the drought-stricken West. / continued page 44

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All nine justices seem to have agreed that the specific wetland at issue in the underlying case should not have been subjected to regulation under the Clean Water Act.

It is well known that wetlands function as natural sponges that trap and slowly release surface water, rain, groundwater, melting snow and flood waters. This combined water storage and braking action lowers flood heights and reduces erosion.

In a minority opinion supported by three other justices, Justice Kavanaugh found that "[b]y narrowing the Act's coverage of wetlands to only adjoining wetlands, the court's new test will leave some long-regulated adjacent wetlands no longer covered by the Clean Water Act, with significant repercussions for water quality and flood control throughout the United States."

The difference between "adjacent" and "adjoining" in this context is not merely semantic or academic. The court's rewriting of "adjacent" to mean "adjoining" will matter a great deal in the real world. In particular, the court's new and overly narrow test may leave long-regulated and long accepted-to-be-regulable wetlands suddenly beyond the scope of the agencies' regulatory authority, with negative consequences for waters of the United States.

For example, the Mississippi River features an extensive levee system to prevent flooding. Under the court's "continuous surface connection" test, the presence of those levees (the equivalent of a dike) would seemingly preclude Clean Water Act coverage of adjacent wetlands on the other side of the levees, even though the adjacent wetlands are often an important part of the flood-control project.

The *Sackett* decision only limits the reach of the federal Clean Water Act.

President Biden is promising to use other legal authorities to try to fill in the regulatory gaps created by the Supreme Court decision and is calling on states to strengthen their water quality regimes.

States technically have the power to impose broader regulations if they choose to do so. However, about half the states currently have laws that prohibit their regulators from adopting stricter standards than that the federal government has done, and the federal limits have suddenly become far less strict. ◎

— contributed by Andrew Skroback in New York