PRACTICAL PROJECT FINANCING

Getting Renewable Energy Projects Done In Tough Times

Although public sector funding and incentives have waned and wholesale renewable electricity prices are low, project developers still may have viable options available.

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THERE have been four recent pieces of good news for renewable energy developers: The "Fiscal Cliff" legislation (H.R. 8, signed into law January 1, 2013) extended the Code § 45 Production Tax Credit (PTC) for renewable electricity generation facilities by well over an additional year. Under that legislation, developers also may elect, in the same timeframe, to use the 30 percent lump sum Investment Tax Credit (ITC) for their eligible projects in lieu of 10 years of annual production-dependent PTC credits. H.R. 8 further extended for another year the availability of 50 percent bonus depreciation for new generating equipment, on top of the accelerated depreciation typically available to renewable energy projects. In addition, markets (and returns on investment) are surging for compressed or liquid renewable vehicle fuels made from landfill gas or other nonfossil inputs such as biogas generated by anaerobic digesters.

Otherwise most news affecting renewable energy project development has been bad, and conditions generally are daunting.

On the tax side, Code Section 1603 Cash Grants in lieu of the 30 percent ITC mostly expired in 2012, bumping developers back to last-century tax equity strategies instead of receiving 30 percent of "eligible basis" upfront by cash wire from the U.S. Treasury. The tax equity needed to monetize PTCs or ITCs remains relatively limited, costly, and difficult to capture for smaller projects. Bonus or accelerated depreciation benefits can be difficult to convert to income, even where tax equity is available. Reasonable project finance debt may be beyond reach for projects under $20 million capital expenditure (CAPEX). Traditional "friends and family" sources of early-stage development equity took a hike after 2008 and mostly have not returned.

On the revenue side, U.S. carbon markets generally are dormant, low-value or difficult to access. Many state Renewable Energy Certificate (REC) markets are close to oversubscribed or near historic price lows. In states with Renewable Portfolio Standards (RPS) that are less than robust, covered utilities reportedly are declining to renew facilities' existing Power Purchase Agreements (PPAs) or offering rates below the seller's costs of production. In some states where RECs cannot be freely traded to meet electric utility RPS compliance obligations but must to be sold with energy, only the PPA off-taker (usually the serving utility) can "purchase" the RECs, further limiting this market for renewable energy producers. Finally, the "shale gas boom" has driven down natural gas and wholesale power prices to levels unforeseen even three years ago, making many new or merchant electricity projects (as well as those coming off long-term PPAs) financially problematic.

WHAT'S A DEVELOPER TO DO?

What project development funding options are available, and how can projects use them to reduce current hurdles? As always, smaller projects, existing facilities or other projects with sunk capital costs generally will have fewer choices and less flexibility than larger projects that are in earlier development stages. Nevertheless, no technically sound project should lack options, though feasibility analysis may indicate its best path is to suspend development or sell any existing assets and move on.

The possibilities include (but are far from limited to) capturing larger or additional revenue streams (e.g., through sales of "capacity" — the electrical generation that the facility is capable of continuously producing — separate from energy actually generated); repurposing projects to reach alternative markets (e.g., producing compressed or liquid renewable fuels rather than electricity); using tax-related and other mechanisms to boost project returns (e.g., by teeing up projects to cut capital costs and enhance prospects for optimal leverage); and deploying new platforms such as crowdfunding, Real Estate Investment Trusts (REITs) or Master Limited Partnerships (MLPs) to raise development or restructuring funds. Each of these is discussed in this article.

HARD-TIMES DEVELOPMENT "RULES"

Options cannot meaningfully be identified or assessed in a vacuum. Before developers dive into mind-numbing details (or hire a consultant to dive), a cold-eyed look at their project(s) using principles gleaned from hard experience may save time, sweat and dollars. These principles can include:

• Target your efforts. Ask what type or size of project makes sense now, and how that choice may affect sources of capital, financing structures and off-take opportunities. Except in special circumstances, conventional energy-only sales "to the grid" may not make sense for the next several years.

• Remember timing is everything. Don't delay in hopes of securing additional dollars — "pigs get fat but hogs get slaughtered," as the saying goes. If the returns from a deal on the table pencil out, take the money and run. That deal may not be there next week. Your next project can capture the increment, should it materialize.

• Comb projects to cut costs. Find cost reductions that don't compromise quality, and then look for possible sources of additional revenue. For example, try to procure equipment through an Engineering, Procurement and Construction contractor (EPC) with vendor relations strong enough to capture rock-bottom prices and assure timely deliveries — then give that EPC the incentives to do so through cost-sharing arrangements that let it retain a portion of all savings beyond defined baselines. Explore possible reductions in insurance premiums, equipment or cash reserves. Apply for permits or other approvals sequentially rather than "all at once," despite the desire to get to construction as quickly as possible. While the "all at once" approach often makes sense, "critical path analysis" may suggest not spending money on approvals that are relatively certain to be secured eventually, until you know whether the one that could kill the project is sure to be in hand.

In addition, look carefully at possible capacity sales and the extent to which their perceived risks are real or can be mitigated. If power prices are in the pits, look at special off-take arrangements with (for example) municipalities or groups of municipalities that may accept above-market rates that are more than offset by expected upsides in the out-years. Look at tiered or synthetic PPAs (see glossary) that respectively can peg per-kWh prices to forward gas curves (i.e., what gas futures are trading for on a recognized exchange) or guarantee a "floor" rate that works financially. Neither tiered nor synthetic PPAs currently are available for more than about seven years. But they can act as bridges that help preserve projects for sunnier days.

Then comb the project for cost reductions again.

• Don't freeze when faced with bad trends. A good example is shale gas effects. Prices and rates don't just go down and stay down. Natural gas pricing has been incredibly volatile historically. Many observers believe domestic gas will "go global" like oil due to multiple liquefied natural gas (LNG) export terminals within the next five years. In fact the U.S. Energy Department already has approved permits for four coastal export terminals as of this writing, with more than a dozen other applications pending. That could mean sharp future increases in gas prices and wholesale power rates, since natural gas pricing currently is more than double domestic pricing in the European Union and more than three times such pricing in Southeast Asia.

To the extent these projections are accurate — or historic volatility roars back for other reasons such as stringent fracking regulations, constrained pipeline capacity, or the disappearance of low-hanging inexpensive shale gas fruit — the "price" issue may be tactical, not strategic, i.e., knowing how to structure projects to bridge the next few years. That could be quite different than trying to develop projects assuming $3 wholesale gas prices or 5 cent wholesale power prices for the next two decades.

• Structure financeable *and* acquirable projects. Remember the project should be not just financeable (to get built), but *easily acquirable* by tax equity or other third-party purchasers — at least if you plan to sell operating projects, not own them. The two sets of criteria may overlap but are seldom the same. Different criteria also may apply where you plan (or may be compelled) to sell projects before construction rather than at completion.

• Don't fear getting creative. There always are options. But developers must be prepared to do the hard work of determining what it may take to fit within those boxes — and addressing their potential pitfalls.

CAPTURING ADDITIONAL REVENUE

Projects can be strengthened (or salvaged) by capturing additional revenue streams as well as reducing costs. The two paths are not mutually exclusive. Consider, for example, the following options:

• Selling some or most energy at a "Firm" price (under which the generating project generally guarantees delivery of all or a set volume of electricity per year, whether or not it is operating), not just on a "Unit-Contingent? basis. Firm transactions may make sellers nervous, though the contracted risks often may be less — or structured to be less — than commonly perceived.

• Selling (or pricing) capacity separately. Capacity values — the project's value for system reliability rather than its actual energy output — historically have been a fraction of energy values. In addition, capacity values often have been masked by utilities buying bundled energy and capacity for a single undifferentiated price.

This scenario is changing. In many regions capacity values now can be significant and are expected to increase, particularly in deregulated regional transmission areas where large coal-fired capacity is scheduled to go off-line. They conceivably could tip the scales for baseload operations with high capacity factors like qualified renewable hydro, landfill gas (LFG) or anaerobic digesters. However, even in areas like the Southeast that remain "regulated" and do not have viable capacity markets, developers may benefit tactically or substantively by seeking to split off capacity for separate pricing under their PPAs. Even if they don't get a separate price for capacity, this often may allow developers to infer how the off-taker is valuing capacity as part of a bundled purchase that only has one price for energy and capacity (and sometimes RECs). At a minimum this may provide a better sense of what capacity may be worth.

• Selling "ancillary services," or at least reserving projects' rights to such assets. Ancillary services — the ability of distributed generation to support grid reliability and efficiency by, for example, minimizing electricity-current frequency variations or damping reverse power flows — can help underpin true "smart grid" approaches. These services are a rapidly emerging market under recent orders of the Federal Energy Regulatory Commission (FERC) which basically require utilities under its jurisdiction that sell power wholesale to buy the "ancillary services" separately. Many state public utility commissions are expected to follow FERC's lead at the retail level (where states have jurisdiction over retail sales to end users).

• Seeking ultra long-term PPAs (e.g., 25 years) at relatively high initial flat rates that may offer municipal or other counterparties substantial upsides in the out-years, if they believe (as many now do) that natural gas and wholesale power prices inevitably will rise over time. In these cases a project may find it beneficial to sacrifice potential long-term upside for a rate that means workable financing now.

• Creating "synthetic PPAs" or similar structures where a third party (e.g., a creditworthy power marketer or large industrial end user) pays the project if hourly per-kWh Locational Marginal Prices (LMPs; see glossary) fall below a negotiated strike price (the predetermined price, as in a stock option, at which a buyer must buy and a seller must sell), while the project pays that third party the difference if LMPs exceed the strike price. LMPs typically are calculated at a project's interconnection node and tracked on a day-ahead or hour-ahead basis by the pertinent regional transmission authority. Such hedging arrangements (sometimes called "contracts for differences") in effect can guarantee the project a PPA price floor during the term of the contract.

• Optimizing revenues from RECs or from carbon reductions.

A project usually can't capture both revenue streams.

However, the value of RECs sold for 20 years as part of a PPA may outweigh what the project can capture through shorter-term REC spot or "strip" sales (a projected sale of RECs to be generated during any period longer than the current year), even after price and Net-Present-Value (NPV) discounts. Conversely, a project in a state where the RPS is moribund may capture supplemental value by exporting qualified RECs to a state with greater REC demand (for example, exporting Class I RECs from Ohio to New Jersey through the PJM Interconnection).

On the carbon market side, LFG or digester projects that destroy (combust) carbon to create "direct" reductions have a potential advantage over projects like wind or solar that merely displace fossil generation to create "indirect" reductions. "Direct" reductions often may qualify to be credited under applicable state or voluntary greenhouse gas programs. In some cases, depending in part on how the applicable RPS is written, such projects arguably may receive carbon credits without diminishing their RECs. Developers should be aware, however, that while REC trading has been greatly simplified over the last five years in key states that allow it, the third-party verification and documentation costs of "carbon trades" can be substantial (and sometimes prohibitive).

• Have contracts for every available revenue stream, including by-products of anaerobic digestion such as liquid fertilizers. Contracted revenues with creditworthy counter-parties "count" for debt and other financing purposes. Prospective potential sales usually don't — they're often discounted near zero. While some lenders to projects in established, relatively liquid REC markets now have gotten comfortable with projected revenues from uncontracted future spot or strip sales, the overall difference in ability to access debt, or secure longer debt terms or better interest rates, can make or break a project. Contracted revenues can be particularly important to third-party project purchasers who plan to "leverage off the back end" (i.e., to increase equity returns by borrowing against project revenues after acquisition).

• Potential benefits of converting planned or existing projects from renewable methane-based power generation to compressed or liquid renewable fuels production. This choice can be complex. It involves multiple tradeoffs some of which currently may be difficult to assess or contract, in part because EPA's Renewable Fuel Standard rules are complicated, evolving, and presently under broad attack by the petroleum industry. Moreover, the equivalent of long-term "PPAs" generally is not available in the fuels world, which tends to operate on three to five year horizons. However, the combination of selling RINs (see glossary) — the renewable fuel counterpart of RECs — at 50 cents or more per gallon-equivalent, together with two sets of potentially lucrative tax credits (e.g., for renewable fuel production and for running compressors on biomass-derived power) may justify the effort.

• "Bundling" projects to create critical financing mass. Especially for smaller projects whose CAPEX doesn't meet equity thresholds or institutional lender debt minima, bundling several projects into a single umbrella transaction can be a path forward or a lifeline of last resort. Importantly, bundling is not mutually exclusive — it can complement other options. It also may reduce perceived risk by spreading uncertainties across a diverse "portfolio" of projects. Bundling tends to be most feasible where projects are similar in type and capacity, under common ownership, and implemented by near identical project-level contracts. However, it does not change the basic hurdles for viable projects: Each project may still have to "pencil out" on its own. Moreover, if investors still believe they need to perform detailed diligence on each project or restate numerous agreements, this option can be derailed.

ADDITIONAL SOURCES OF CAPITAL

If developers don't have a sufficient balance sheet or want to supplement existing sources of credit or capital, they should keep an eye on options that include:

• REIT funding. Real Estate Investment Trusts under Code § 856 et seq. already have been approved for leasehold or mortgage interests associated with cell towers, data centers, power lines and gas pipelines — facilities that have sufficient real property aspects and generate long-term steady passive income streams. Thus, what constitutes qualifying "real estate" interests is a somewhat flexible concept. Contrary to conventional wisdom, REITs (which originally were authorized during the Eisenhower Administration) can be used *right now* to raise public capital without double taxation of income at company and shareholder levels, based on land interests underlying properly-structured renewable energy projects. REITs and Master Limited Partnerships (discussed next) can let projects (more likely, portfolios of projects) in effect become publicly-traded without numerous complications.

Unfortunately, such use is most defensible where the bulk of pertinent real estate holdings constitute traditional mortgages and where other stringent tests are satisfied. Several Private Letter Ruling (PLR) requests currently seek IRS approval of REIT funding for leasehold interests associated with solar "farms" where the projects lease rather than own the land on which they are sited. If a third party owns the land or the lease and then leases or subleases it to the project on a long-term basis, a REIT could be the lessor or sublessor, assuming the project is sufficiently creditworthy and meets other tests. Whatever the PLR outcome, it may be worth noting that most renewable energy projects usually have similar leasehold interests.

• Master Limited Partnership funding. Like REITs but with different mechanisms and requirements, MLPs under Code §§ 613 and 7704(d) can allow direct lower-cost access to public capital by selling partnership interests like stock shares. They too can sidestep corporate double taxes on income and "dividends" (in this case, partnership distributions). As originally authorized in 1987, MLPs only could be used to raise capital for activities involving "depletable natural resources" like timber and fossil fuels. A 2008 Code amendment narrowly extended their availability to renewable-related fuel pipelines and storage facilities. Bills now are pending in the U.S. Congress that would allow MLPs to fund most renewable energy production, marketing and transportation activities (e.g., the Coons-Moran "Master Limited Partnership Parity Act"). Together with REITs these bills have generated intense industry interest, since MLPs are estimated to lower the cost of capital by 30 to 50 percent. However, these measures seem unlikely to move except as part of a last minute year-end omnibus tax extenders measure or — less likely — comprehensive tax reform.

• State-level "green banks." Funded from system-benefit charges and other sources, these currently exist only in Connecticut but are under development in New York and other states (see www.coalitionforgreencapital.com). Their initial focus typically has been to provide cheap debt for behind-the-meter rooftop solar residential and small commercial installations. Nevertheless,

GLOSSARY

Locational Marginal Prices: LMPs are the clearing price for power delivered to a particular node in a transmission or (sometimes) distribution system, usually determined by the Regional Transmission Operator (e.g., PJM or ISO-NE) on both a historical and a day-ahead basis.

Renewable Electricity Production Tax Credit: Since its enactment in the early 1990s the § 45 [Renewable Electricity] Production Tax Credit (PTC) regularly has been extended, though with growing uncertainty and for progressively shorter periods. Until this year, to receive credits otherwise qualifying facilities had to be "placed in-service" — generally be completed and begin operating — within the pertinent "in-service window" (e.g., by the end of 2014). H.R. 8 for the first time allowed otherwise eligible facilities to qualify *by simply "commencing construction"* within those windows, as long as construction is reasonably pursued to completion. In addition, IRS guidance allows projects to "commence construction" by incurring less than 10 percent of their total as-built costs. Thus the effect of this PTC change is to extend dramatically the period within which a facility must be placed in service, especially for biomass (including anaerobic digestion), geothermal, hydroelectric or other projects with long construction timelines.

Renewable Identification Numbers: "RINs" are tracking numbers assigned to each gallon of qualified renewable fuel under EPA's Renewable Fuel Standard (RFS) rules. They initially were authorized by the Energy Independence and Security Act of 2007 signed into law by President George W. Bush. Like Renewable Energy Certificates, they may be sold separately from physical fuel to covered refiners who must meet specified mandates to purchase and blend into fossil vehicle fuels (or use or sell directly) defined quantities of ethanol or other renewable fuels. As of this writing, the approximate average price of a RIN had increased from around \$0.05/gallon-equivalent in 2010 to \$0.50/gallon-equivalent in January 2013, and to over \$1.10/gallon-equivalent in August 2013.

Synthetic Power Purchase Agreement (PPA): "Synthetic PPAs" exist where a third party that is not the physical off-taker utility places a "hedge" against the price of electricity delivered by the project "to the grid." The third party could be another utility, but often is a power marketer. In some cases, it could be a large power-hungry industrial company like a multistate cement company or big-box retailer. Such "hedge counter-parties" in effect are betting that their own power costs will be reduced over the life of the synthetic PPA, i.e., that the pertinent LMPs will rise over time.

Tiered Power Purchase Agreement: A "tiered PPA" can mitigate current depressed power rates by setting both a shorter-term "floor" rate indexed, for example, to forward natural gas curves, and a long-term permanent rate triggered when the index exceeds a defined price for a defined period of time. Off-takers may be offered (or demand) part of the excess over the "trigger rate."

their charters often are not limited to such applications. Green banks could become vehicles for development funding of other renewable energy facilities in the relatively near future.

• "Crowd-funding" under the 2012 federal JOBS ("Jumpstart Our Business Start-Ups") Act. Among other things, the Act loosens certain SEC restrictions by authorizing broad solicitations to nonaccredited investors, potential funding by citizen-investors at up to \$2,000 per company per individual, and sharply reduced reporting burdens for so-called "emerging growth companies." However, because the SEC has not yet issued implementing regulations, outside California and New York only accredited investors currently can "crowd fund."

• Commercial PACE programs. Property-Assessed Clean Energy (PACE) programs have been legislatively authorized (though in some cases not yet implemented) in states including New Jersey, California and Massachusetts. They basically allow qualified renewable energy facilities to be funded by inexpensive public sources like revolving tax-exempt bond funds, with debt repaid through (i.e., added to) ongoing real property tax bills in ways that largely neutralize the risks of site-host turnover or bankruptcy. Use of PACE approaches to fund residential applications like rooftop solar facilities has been virtually paralyzed nationwide by Fannie Mae concerns that collateral for federally subsidized mortgages would be subordinated to PACE-expanded tax liens. But nonresidential sectors have not been affected, and are expected to grow.

• Prepaid PPAs. "P-PPAgs" can provide what amounts to inexpensive development equity through lump-sum prepayment of a substantial portion of the energy committed to be sold over the term of a PPA, with such "advance" payment typically made by local government utility departments that will buy the power and secure the prepayment funds by issuing tax-exempt or taxable bonds.

• Tax-exempt or taxable bond funding. The "cheapest capital first" stack starts with zero interest state or federal grant funds and typically proceeds through 1603 Cash Grants in lieu of ITCs or rough state equivalents, debt guarantees from the Rural Electrification Agency or U.S. or foreign Export-Import agencies, and monetization of tax credits or accelerated or bonus depreciation through tax equity-type transactions. But bond funding should not be overlooked: at current interest rates it may come second-in-line. Tax-exempt "small issues" of up to \$10 million at interest currently running around 3.5 percent may be one option. However, in general they only are available for facilities that "manufacture" — perhaps unless a renewable energy project can be defended as "integral and subordinate to" such manufacturing. Taxable bonds currently running at around 5 percent interest may be more accessible for appropriate projects. Either type of bond funding can have important advantages over conventional project financing, especially for smaller projects or small project portfolios. For example, such bonds often can fund a higher proportion of total capital requirements, involve less onerous reserve requirements, and provide construction and term debt in a single transaction. ■

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