PRACTICAL PROJECT ENGINEERING

Getting Renewable Energy Projects Done In "Still Tougher Times"

Update to 2013 BioCycle article focuses on new hurdles and additional options to structure cost-effective renewable energy projects, get them financed, and move them to the finish line.

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MY September 2013 article, "Getting Renewable Energy Projects Done in Tough Times," surveyed some bright spots in a generally bleak finance landscape and identified ways that renewable energy developers could deal with rising hurdles. This article builds on that one. It focuses on new hurdles and additional options to structure cost-effective renewable energy projects, get them financed, and move them to the finish line.

Here is some of the landscape that anaerobic digestion (AD) project developers are facing in these still tougher times. Only two years remain to put projects "in service" before the 30 percent Investment Tax Credit (ITC) expires. In addition, while *retail* electricity rates may be going up, many regions' *wholesale* rates for energy sales "to the grid" are even lower than last year's due to the shale-gas boom. Thus Power Purchase Agreements (PPAs) between utilities and renewable energy projects with sufficient rates and tenors have become even harder to secure.

Despite the "economic recovery," tax equity remains difficult to tap, particularly for smaller projects. When it can be tapped, providers often limit their acceptance of depreciation benefits to preserve room for other projects, making such benefits theoretical. The hoped for entry of nonbank entities into the tax equity market generally has not materialized, leaving the fate of many projects to less than two dozen large tax equity-providing banks or funds.

Well-funded efforts to roll back Renewable Portfolio Standards (RPS) have continued. In Ohio, for example, a three-year RPS freeze has largely wiped out investment and the Ohio Renewable Electricity Credit (REC) market. Most other state REC markets remain sluggish or price-depressed. On the biogas-to-fuel front, RINs (see glossary) prices under EPA's Renewable Fuel Standards (RFS) program in October 2014 were down more than half since August 2013.

Recent bills that seek a 30 percent credit for building new biogas digesters seem headed for the same limbo as past "green gas" efforts. Despite short-term Congressional action (see Legislative Outlook below), prospects remain uncertain for major extension of numerous tax credits, including the Production Tax Credit (PTC), the ability of PTC projects to "jump" to the lump-sum 30 percent ITC, and renewable-fuel production credits worth up to \$1.01/gal. The latter remain largely unusable *to finance* most projects due to short actual production lives. And ongoing global oil prices below $50/barrel could hit anaerobic digestion vehicle fuel projects particularly hard.

Beyond all this, Republican control of the Senate likely will not change Congressional gridlock. Republicans still will not have a Senate super-majority able to override Presidential vetoes. Nevertheless, a Republican Majority Leader will control what can be voted on, further damping positive tax (and possibly other) prospects for renewable energy and renewable fuels.

ON THE OTHER HAND . . .

There's more good news than last year for AD and other renewable energy developers. For example, the recent [113th] Congress did grant a one-year extension of numerous tax benefits through 2014 as it was hurrying out the door. The IRS already has issued three rounds of retroactive guidance clarifying how projects may preserve PTC/ITC eligibility by having "begun construction" before 2014, and generally is expected to apply that guidance to projects that "began construction" before 2015. The U.S. Department of Energy has granted permits for nearly a dozen LNG (liquid natural gas) export terminals, meaning U.S. gas — and wholesale electricity — prices could rise towards higher global equilibrium. "Virtual net metering" — by which "excess" generation can be allocated to off-site users, reducing their retail electric bills — has been expanding in some states.

State-level Low Carbon Fuel Standard (LFCS) programs may supplement or replace federal tax credits for renewable fuel producers, now that California's LCFS has been judicially affirmed. EPA's proposed "Clean Power Plan" greenhouse gas (GHG) rules for existing power plants strongly encourage adoption of state emissions trading programs to meet their reduction mandates, highlighting credits for new renewable energy. [See 79 FR 34830; June 18, 2014.] Whatever may befall those regulations if and when they go final in 2015, *state rules* adopted in response to them should have independent legal validity, potentially allowing new renewable power or fuel producers to sell lucrative carbon credits to large electric generators. These prospective benefits would be enhanced by EPA's recent upgrade of methane's CO_2-equivalency factor from 21X (X=times) to 25X — a 16 percent increase in the volume (though not necessarily the unit price) of credits potentially generated.

Perhaps more important, EPA's final "RFS Pathways II" Rule created sweeping AD opportunities to receive "Code D-3" RINs credits — the most highly-valued RINs subset — for production of "second-generation cellulosic biofuels." [See 79 FR 42127; July 18, 2014.] That Rule treats compressed or liquid fuel produced from most digester gas as "100% cellulosic" despite being partly derived from noncellulosic components. Thus *all such fuel* will generate D-3 RINs gallon-for gallon, with no "noncellulosic" discount. In addition, the Rule provides — for the first time under the RFS — that *electricity* generated from such fuels will be D-qualified if used "as a fuel" to charge electric vehicles.

Equally important, the RFS Pathways II Rule could allow D-3 biogas fuel producers to automatically qualify for *both* the IRS Code Section 40 "second-generation fuel" tax credit *and* a special 50 percent bonus depreciation for second-generation biofuels equipment under Code Section 168(k) — assuming these benefits are extended. (see "Legislative Outlook" below). This is because the Code's definitions of qualified "second-generation" biofuels track those in the RFS and the Rule. Resulting possibilities for biogas fuel producers could include properly structured projects potentially being able to capture the PTC or ITC, *plus* 50 percent bonus depreciation, *plus* the $1.01/gallon tax credit for 10 years of second generation production under IRS Code Section 40(b)(6) *plus* D-3 RINs presently selling for around $0.50/gallon-equivalent.

WHERE DO I START?

Production Tax Credit

Contrary to some perceptions, this tax credit has not "expired" in one important sense. Due to Tax Code amendments at the end of 2012, projects that "began construction" before 2014 still may qualify for the PTC (and "jump" to the ITC) if they're completed in a reasonable time. Code amendments adopted in December 2014 extended "before 2014" to "before 2015." (See H.R. 5771, the "Tax Increase Prevention Act," 113th Cong. 2nd Sess., enacted Dec. 19, 2014.) Thus, any project that has "begun construction" in or before 2014 may qualify. And, a "reasonable time" might be several years. This is because what it takes to "begin construction" can be a relatively low hurdle, and some IRS "safe harbors" apply.

Under current IRS guidance documents, there are two broad ways — physical or financial — to "have begun" construction. What follows assumes this guidance will be updated to track the December 2014 short-term extensions, though that's not entirely clear.

• *Physical*: A project may *begin physical construction* in or before 2014 by relatively small actions and still qualify for the PTC, as long as it pursues "a program of continuous construction" until completion. "Physical construction" includes off-site work done by digester or other equipment providers under binding contracts, as well as site work on biomass supply roads, interconnection to distribution circuits, or other tangible things "integral" to the project. "Physical construction" can be as little as pouring foundations for one wind turbine on a 20-turbine wind farm (though developers who do the bare minimum may find their projects rejected by investors later on). It need not be "continuous" in the sense of work done every day, as long as the project keeps moving forward. Normal *force majeure* exceptions generally should cover uncontrollable work suspensions, such as agency delays issuing permits that have been pursued in a timely manner. Moreover, projects *will be deemed* to have "continuously constructed" if they're completed before 2017, although this expanded IRS "safe harbor" guidance may not apply to projects that did not start or continue work in 2014.

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• *Financial*: Alternatively, a project may have *"begun construction" financially* if its developer "spent or incurred" 5 percent of that project's total cost in or before 2014, and then made "continuous efforts" towards completion. "Continuous efforts" is easier to meet and subject to fewer investor concerns than "continuous construction." Funds may be "spent or incurred" directly or indirectly (for example, by paying equipment vendors under binding contracts), even if delivery occurs after 2014. The same safe harbor as for physical construction should presume that projects completed before 2017 have made "continuous efforts." Projects that no longer meet their 5 percent "spend or incur" target due to cost overruns still may qualify *separable project portions* under a "partial financial safe harbor," if they spent or incurred at least 3 percent of total cost before 2015 and the portions' cost is not more than 20 times what was "spent."

Under either the "physical work"

test or the "financial" test for having "begun construction," developers who miss completion by the end of 2017 still may be able to show that they "continuously constructed" or made adequate "completion efforts." Moreover, the two tests are complementary — a developer may invoke part of one test to backstop the other and may qualify its project under either. Developers also may qualify by acquiring other projects that timely "began construction," or by shifting qualified components from their other projects.

These IRS clarifications afford *project investors* greater certainty. But they also conceal pitfalls for *developers* seeking to use them. Examples include: Real money, not just a vendor note, must be "spent" in order to claim construction has begun. Title as well as dollars typically must pass for costs to be "incurred." While the "physical construction" test does not mandate such spending, it still requires a "binding contract" that implies timely *ability to pay*. "Preliminary activities" like design or site grading generally *do not* count as "physical construction," but *do count* for the financial tests. Only costs of *certain depreciable property* — not land or intangibles — count for the numerator and denominator of the financial "percent" tests. The 3 percent "partial safe harbor" only applies to separable "facilities" within a project, such as dual AD trains; projects that are integral "facilities" are excluded. Moreover, if transferees of otherwise qualified project components are not "related parties," the *whole project under development* basically must be transferred to preserve "begun construction" status. In the IRS' view, selling only qualified equipment to unrelated third parties invites manipulation, and will not work.

Despite such pitfalls, look-backs to determine if projects may qualify based on past activities should not be ignored. Look-backs could be particularly critical in light of the recent one-year extension through 2014 (i.e., before 2015) of the period when construction must have "begun," as additional development activity likely occurred on many projects during 2014.

Creative Tax Benefits

A little thought (tempered by tax advice) may add certain tax assets to project value. For example, using on-site biogas to fuel microturbine or cogeneration units that are installed before 2017 to power a project's compressors (or furnish process heat) could qualify those units for a 10 percent ITC under IRS Code Sections 48(c)(2) & (3), independent (and potentially on top) of a plant-wide ITC. ITC-eligible projects (including those that "jump" from the PTC to the ITC because they "began construction" before 2015) with long build-out times may claim "progress payment" installments of the 30 percent ITC in some cases, *before* they're placed in service. Under the Code's arcane MACRS scheme, it may be possible to "move" all or parts of a project to more beneficial accelerated depreciation categories.

CAPTURING DEVELOPMENT CAPITAL/ SUPPLEMENTAL REVENUE STREAMS

Tax equity can be much cheaper than "straight equity," which usually requires returns of 20 percent or more. Tax equity also is one way of *attracting* capital — for example, the ITC operates as a 30 percent buy-down of project costs.

Unfortunately for developers, such buy-downs mostly benefit project *acquirers*. This is because tax equity typically must be materialized by shifting project ownership (with tax benefits) to a buyer with "tax appetite" seeking to shelter otherwise taxable income. These transactions usually do not happen without long-term site control, long-term off-take agreements with creditworthy counter-parties, all permits in hand, and (for power projects) a signed interconnection agreement. In other words, tax equity generally is not accessible until a project reaches at least the start-of-construction stage. Developers somehow must cover earlier costs. Where a developer plans to sell a project after build out, it also must cover engineering, procurement and construction (EPC) expenses, plus the utility's interconnection costs.

How can developers get the dollars ("development capital") needed to reach start-of-construction? If they want to keep the project — or improve their returns by selling an operating project — how can they cover the additional costs? How should they structure the project to be both financeable *and* readily sellable? Possible approaches tend to fit in two overlapping categories: Finding workable development capital, and strengthening *pro formas* to improve the chances of (and terms for) selling all or part of a project. Many of them involve cutting costs or capturing additional revenue streams. Even if some added revenues may not "count" (or count much) for *pro formas*, they could yield the developer "gravy payments" down the road.

SOME THOUGHTS ABOUT HOW TO PROCEED

• Get a creditworthy codeveloper. The choice may be tactical or strategic. It may involve an EPC contractor or equipment vendor seeking market penetration, or a fund seeking to lock in desirable projects by moving farther up the development chain. Beyond "straight" development dollars, contractors or vendors may defer payment if a third-party project take-out is in place, in effect providing significant construction funds as well as development funding. A codeveloper that has other projects in development may present a "natural bundling" opportunity to increase scale economies and enhance critical mass for project placement. The developer still will have to bear some initial costs, and will have to grant a codeveloper substantial project interests. But most development costs could be funded through a codeveloper arrangement, and the project more likely will get built.

• Look at state-level "Green Banks." Several of these now exist in some form, with New York's $1+ billion entity the most recent. Green Banks, typically charged with financial gap-filling, have struggled to balance support for local renewable energy with the difficulty of funding projects that "regular banks" won't finance due to early-stage issues like insufficient collateral or unfamiliar risks. They often start cautiously with PACE (Property Assessed Clean Energy programs funded by inexpensive public sources) or similar loans for load-on-site ("behind the meter") residential or commercial projects, then expand to funding, for example, long-term purchases of environmental attributes or making zero interest grants repayable from earnings if a project succeeds. Some of them may be ripe for focused development funding. Their low costs of capital (typically from appropriations, tax-exempt bonds, RPS alternative-compliance payments, and/or system benefit charges) may make it easier — to a point — for them to assume nonconventional risks and absorb predictive losses.

• Explore alternatives to conventional grid sales. These may include prepaid PPAs ("P-PPAgs") with municipal utility departments (see glossary); "synthetic PPAs" with third parties that put an above-market price floor under project energy sales (see glossary); or ultra-long-term PPAs with power-hungry entities who believe that paying more now is worth the hedge against high retail rates later. They also may include "virtual net metering" options in states like Massachusetts and California. Such steps may assure or increase "bankable" electricity revenues for *pro forma* purposes. For example, virtual net metering may allow projects to sell net-metering "credits" to third-party power users at close to retail electricity rates rather than at low utility "avoided costs." P-PPAgs may provide or promptly reimburse development and construction costs.

• Sell — or preserve project rights to sell — capacity, environmental attributes and ancillary services. Many observers believe deregulated markets for capacity unbundled from energy — selling capacity values (i.e., the project's value for system reliability rather than its actual energy output) — will explode in coming years, due to increased system-reserve mandates (see glossary) and retirement of thousands of gigawatts of coal-fired generation. This "capacity asset" could be significant for baseload renewable facilities like digester-to-power operations.

Due to intense competition for quality projects and how YieldCos typically are structured, they need a steadily increasing "deal flow" to assure appropriate returns to their investors.

"Ancillary services" include voltage or frequency regulation and reactive power control, which support grid reliability. "Reliability" focuses on the ability of the programmable inverter or other device (e.g., transformer) that serves as project interface to the grid either to: (a) run above or below nameplate capacity to adjust to distribution-line over- or under-loads; or (b) neutralize out-of-phase electrons that might compromise system reliability. The latter involves "reactive power," measured in "vars." These services will become increasingly important as such grid factors move to center stage. The Federal Energy Regulatory Commission (FERC) has opened proceedings to determine when and how ancillary services should be compensated by wholesale transmission utilities. [See, e.g., FERC Order 784, 78 FR 46178; July 30, 2013)("Third-Party Provision of Ancillary Services")] As with many FERC actions, the results should trickle down to state Public Utility Commissions (PUCs) and electric distribution tariffs.

"Environmental attributes" may include not only RECs or RINs, but offsets from displacing sulfur dioxide (SO_2), nitrogen oxide (NOx), or other emissions from fossil-based transportation fuels. They also may include direct carbon "credits" under state or regional power plant GHG or LCFS-type regimes. Even outside such regimes, some state Departments of Transportation have step-down mandates to cut their annual GHG emissions below defined baselines. They could meet such mandates by contracting for biogas fuel and using it in state vehicle fleets. Or a project could sell them carbon attributes and sell the fuel elsewhere.

Capacity, ancillary services and attributes may not be mutually exclusive. Depending in part on state-level regulatory definitions, these "intangible assets" could yield multiple revenue streams.

• Optimize tradeoffs between RECs and RINs. This is easy in states without meaningful REC markets — the project should "just go for the RINs." It gets more interesting where REC markets are robust, D-3 RINs are available, and the issue is what mix of renewable power and renewable fuel a project should produce. It may get still more interesting if the project also can arrange to inject biogas into a pipeline, have it withdrawn downstream by a generator qualified for PTCs but short of qualified fuel (e.g., because a supplying landfill's gas (LFG) has declined), and share in those credits' value through side agreements. While past "purification" of LFG to interstate pipeline standards generally has not been cost-effective, differences in e.g., digester gas composition or local pipeline criteria, may shift the outcome.

• Contract "long-term" for every project input and output. This includes sales of fertilizer or landfill cover made from digester residuals. It also includes digester feedstock, fuel or power outputs, RECs or RINs, and criteria- or designated-pollutant reductions. Importantly, it further includes cost- or risk-shields like strong equipment performance (not just workmanship) warranties. With rare exceptions, only revenues or cost-shields under contract with creditworthy parties "count" for financing purposes. However, what "long term" means may vary substantially for different energy "commodities." For example, PPAs generally must run for more than 15 years to be considered "long-term," while "strip"contracts with tenors exceeding three to five years are rare for RECs, RINs or renewable fuels. Due to the greater uncertainties of predicting these commodity markets in the outyears, longer term agreements may not be available, or may involve substantial price haircuts for projects.

HOW DO I FIND THE RIGHT PROJECT BUYER?

Real Estate Investment Trusts (REITs) and Master Limited Partnership (MLPs) can raise inexpensive public capital by stock-like sales of interests because they're statutorily exempt from corporate-level tax (see glossary). YieldCos are "synthetic MLPs" that can achieve the same result by sheltering distributed earnings with booked net operating losses. In all three cases more revenues can be passed to "shareholders," and the buyer should be able to pay more for projects. All three cases have been held out as options to sidestep some or most tax equity constraints and cut the costs of renewable energy project capital by 20 percent or more. In addition, securitizations (see glossary) have been touted for their ability to achieve similar results on the debt side of renewable energy financing.

REITs, MLPs, YieldCos and securitization entities each are possible targets for project acquisition or cheaper debt. However, the usual cautions apply in spades where developers seek to capitalize on such hyped new trends. Among other things, "one-off" projects (especially AD projects under 1 MW) face longer odds than a portfolio of projects; geographic- or otherwise-diverse project portfolios likely will be more attractive due to diversified risk; standardized project documents (preferably prevetted by a reputable law firm or potential acquirer) are usually imperative to reduce transactions costs; REITs or MLPs can have complex tax- or policy-driven eligibility criteria; and a flood of recent entrants, combined with skeletal web information, can make developer investigation of potential buyers difficult.

Nevertheless, it may be worth focusing on at least one of these categories. In the last year, at least five major YieldCos plus numerous smaller ones have emerged. Due to intense competition for quality projects and how YieldCos typically are structured, they need a steadily increasing "deal flow" to assure appropriate returns to their investors. The general result seems to be strong YieldCo appetite for projects that are not solar or wind; for baseload projects in particular; and for projects whose smaller size might not have met previous buyer thresholds. Not all YieldCos are created equal. Many still look to tax equity investors to optimize project-level tax benefits, carrying forward those constraints. Some already and some are struggling to maintain promised returns. But that by itself could present opportunities for developers.

LEGISLATIVE OUTLOOK

In December 2014 a Senate-driven deal to extend virtually all tax provisions benefitting renewable energy two years through 2015 (and make some of them permanent) collapsed due to

Glossary

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.

P-PPAg: A lump-sum prepayment of a substantial portion of the energy committed to be sold over the term of a power purchase agreement (PPA), typically funded by tax-exempt bonds. Under current IRS determinations, only municipal or similar government utilities generally may implement P-PPAgs.

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 can let projects (more likely, portfolios of projects) in effect become publicly-traded without numerous complications. The IRS recently indicated in proposed rules that portions of solar PV facilities with permanently affixed "real property-like" attributes should be eligible for REIT financing. However, the proposal drew numerous comments, and its final scope is uncertain.

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.

Securitizations: Typically involve pooling relatively large amounts of debt and "reselling" that debt payment stream to investors via shares of the overall pool. For example, Fannie Mae and Sallie Mae have long conducted such "debt repackaging" to reduce the overall cost to consumers (and banks) of home mortgages and student loans, respectively. As the 2008 housing bubble demonstrates, however, sound securitizations are highly dependent on the pool's investment rating and can involve large risks when they are extended beyond traditional spheres.

Synthetic Power Purchase Agreement: Synthetic PPAs are created when a third party that is not the physical off-taker utility places a "hedge" against the floating price of electricity delivered by the project "to the grid." The "hedge" party commits to pay a project the difference between the lower floating price and a negotiated "strike price," in exchange for the project's commitment to pay the difference if and when the floating price exceeds the strike price. 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 counterparties" in effect are betting that their own power costs will be reduced over the life of the synthetic PPA.

System-Reserve Mandates: State public utility commissions and regional transmission operators like ISO-NE in New England, MISO in the Midwest, and CAISO in California seek to assure system reliability by requiring regulated electric utilities periodically to demonstrate that more generating capacity is available to be drawn upon than predicted "peak loads" will consume. The "countable capacity " of renewable energy generators may vary significantly among transmission regions, but can help utilities make such demonstrations.

Tapping Tax Equity: Tax credits like the ITC generally can't be "sold to buyers" standing alone. Sufficient "tax ownership" of the whole project generating such credits usually must be transferred to the buyer. This typically involves either a project sale with a leaseback to the developer, or creation of a partnership with the buyer.

White House objections. Faced with a rapidly-closing window in a lame-duck session, Congress punted by adopting "one year" extensions through December 31, 2014 of the PTC, the "jump" to the ITC, certain renewable fuel credits, and various depreciation provisions (including both general and "advanced biofuel production equipment" 50 percent bonus depreciation). [see H.R. 5771, cited above] Because this interim extension also preserved the "begun construction" clause, qualifying projects need only have "begun construction" by December 31, 2014 under one of the two tests outlined above, making potential look-back qualification even more important.

Congressional adoption of a "one year extension" that technically ends less than two weeks after enactment has been characterized by renewable energy proponents as "not having the shelf life of a carton of eggs." That statement ignores the significance of potential look-back qualification. Nevertheless, the fate of further tax benefit extensions or modifications in the next, Republican-controlled 114th Congress is unclear. ■

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