

Project Perspectives



Global Project Finance

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Around Akin Gump



Akin Gump is pleased to announce that Dario Frommer has joined the public law and policy practice as a partner in Los Angeles. Dario is a former majority leader of the California State Assembly. He maintains a practice that provides a mix of legal and strategic political advice to key clients on high-stakes matters before state and local government entities. Dario's broad experience includes energy, climate change, government procurement and election law. Dario's energy clients include investor-owned utilities, renewable energy developers and transportation fuel vendors. He has represented clients in investigations and in rulemaking and enforcement proceedings before the California Energy Commission, California Air Resources Board and the California Public Utilities Commission. Prior to his private practice, Dario had a long and distinguished record of public service in the state of California. In addition to serving as the Assembly's majority leader, Dario chaired that body's Health Committee and served in a number of other high-level state government posts, including as appointments secretary to Gov. Gray Davis. Additionally, Dario is a current member, and former chairman, of the California Transportation Commission, which oversees billions of dollars in funding for highway, road and transit projects.

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Oil and Gas Industry Discussion

This past fall, Akin Gump Strauss Hauer & Feld held its annual Global Project Finance Client Retreat at the Lodge at Torrey Pines in La Jolla, California. The conference featured several panels covering a range of cutting-edge energy industry topics. Steve Davis, a partner in Akin Gump's energy practice, moderated a panel discussion on trends in the oil and gas industry. The panel included Steve Otilar, a partner in the Akin Gump energy practice, Shaun Parvez, the President and Chief Investment Officer at SK USA, and Jeff Pendergraft, a Partner at the Galway Group. The following is an edited version of the discussion.

Steve Davis: "LNG," Liquefied Natural Gas, "LPG," Liquefied Petroleum Gases, "NGL" Natural Gas Liquids. All of these are topics or words that we're hearing more and more often as a result of the really impressive development that we've had here in the United States and in Canada over the last seven or eight years, in particular development that is tied into the shale play and the continuing advancement of technology in horizontal drilling, which has been around for a very long time, and hydraulic fracturing, which has been around since the 1940s. These technologies have been getting better and better and better. And the combination of the ability to drill these horizontal wells where the well will start vertically and then bend and the distance that they can get the lateral today is just remarkable and that combined with the ability to do the hydraulic fracturing by putting water in together with some sand and a little bit of chemical, put pressure on it and then fracture the rock way down deep below the earth, has just led to the resurgence that we have here in the United States and the wonderful opportunity it presents the country, and indeed the rest of the world.

Steve Davis: One of the transactions, Shaun, that you were instrumental in pulling together was the execution last month of a major agreement with Freeport LNG that will give SK E&S, one of the SK subsidiaries, access to U.S. LNG export capacity, with a 20-year contract that will begin after the financing and construction of the facility. Why would SK, and indeed why would other foreign companies, come over here to the United States and try to get LNG export capacity?

Shaun Parvez: That's a great question. Globally SK has been a leader in the telecom space, and with several publicly traded entities, our telecom division is one of them.

What we saw happen in telecom is what we see happening today in natural gas. And by that I mean, we saw dial tone become commoditized over the last 20 years and become virtually free and the industry responding to revenue-based opportunities and value-based opportunities by finding other means of monetizing the dial tone. We see that exactly happening with natural gas and the fact that natural gas has become truly commoditized in the sense that the economics driving the value behind natural gas are far different today given fracking technology than they were 20, 30, 40 years ago when drilling was conventional. Then it was a hit or miss and therefore returns had to be really high. Now, the risk growth profile has changed. Knowing what has happened to natural gas in the United States gave us the confidence that natural gas is going to be a very stable low cost source of energy for us and we should try to find other ways to monetize the natural gas, the same way the telecom companies found other ways to monetize their investments in telecom service infrastructure because dial tone became nearly worthless. For example, when you're flaring 25 percent of produced gas, on the margin it's worthless, so you find other ways to make money from it. We found that if we could do multiple things, starting off with the least risky, we could make a lot of money getting exposure to stable low-cost natural gas from the United States. So, the motivation was to secure a very, very low-cost fuel for our own internal consumption in Korea.

There are, I lose count, 15 or 16 free-trade countries with the United States, Korea being the largest and most creditworthy and securing that natural gas supply from the United States was actually relatively easy in terms of getting the requisite permissions. What was hard was actually competing in the open market for capacity at a terminal. And we tried to do that and worked on it for about two years and, with Steve's help, were able to get it done last month. What that has done for us is, it has secured a very stable, very profitable fuel source for our power plants. In Korea, there are roughly almost



three gigawatts worth of power plants that are either under construction or about to be developed and all of those are going to be fed with U.S. natural gas. We'll generate, just from the fuel alone, north of \$400 million dollars from these plants.

But once we've, I use the term dropped anchor, here in the U.S. with this large transaction, we are now looking at every single possible way to continue expanding the value creation chain. So the very next transaction you'll see us announce, probably be within the next year, will be an upstream purchase of a gas field. And when we have our own molecules in the ground, that we're not only going to be shipping gas to Korea, we're actually going to be investing in U.S. industries that use natural gas for a host of things such as chemicals, natural gas refueling of trucks and cars and the conversion of diesel uses into natural gas uses.

Steve Davis: Jeff, in addition to LNG, what other trends are you seeing as result of so much natural gas here in the United States?

Jeff Pendergraft: I think maybe it might be useful for me to step back and take a look at the micro- and macro-economic level of the natural gas space. Let's start with the supply side in natural gas. The shale gas development has had a dramatic influence. Today shale gas represents more than 50 percent of the natural gas production in the U.S. Total recoverable reserves of natural gas in the U.S. are 2400 trillion cubic feet, 2.4 quadrillion cubic feet of gas. That represents a hundred years' worth of supply at today's consumption rates and

assuming that there aren't any technological advances. So this is a huge resource base in the United States. And for that gas to be developed the price does not have to be dramatically higher than what it is today. Our analysis is that a gas price of roughly \$5.00 would be more than adequate to develop this resource base. So what's the demand side of the equation? Where is this gas going to be utilized? How's it going to be developed? Well, obviously everybody's talking about exports, and the investment that SK, and a number of other foreign firms, have made to acquire natural gas here in the U.S. is a dramatic example of one of the uses for this resource base.

But if you look at the overall world supply demand balances, the estimates are that the total amount of natural gas that's going to be exported from the U.S. is maybe 25 percent of world demand, as you go out to 2020, and what does that mean? That means something in the range of 3½ to 4 tcf, roughly 15 percent of the current consumption in the U.S. So, that's significant but it's not the kind of thing that is going to dramatically impact the overall development of this resource base. It'll have its effect but what are the other uses? What other markets do we see that are going to experience significant growth as result of this very attractive low-cost resource base? Well, obviously, there's land-based transportation. So the use of natural gas for long-haul trucking is already beginning to develop, the use of natural gas ultimately as a fuel for vehicles, generally not just fleet vehicles and long-haul trucking, but automobiles. In that regard you've got a number of countries around the world that are far ahead of the U.S. in the use of natural gas – China being one of them,



Israel being another. For the most part that's compressed natural gas (CNG) or liquefied natural gas (LNG), but it's going to take a while for that demand to develop.

We're already seeing the use of natural gas as a substitute for diesel in the oil field for drilling rigs, for fracking rigs, natural gas is dramatically cheaper than diesel and you're seeing those kinds of uses being developed. One market that we think it is particularly attractive is the Marine Bunker fuel market. You've got international conventions coming into effect in 2015 that the industry frankly is not at all prepared to comply with, but it requires that within 200 miles of the coast, marine vessels have to use ultra-low sulfur for diesel fuel or an equivalent environmentally attractive option. Well, that's liquefied natural gas and the cost differential between ultra-low sulfur diesel, if you can buy it, there isn't going to be enough available from the refinery to secure it, is dramatic. Our analysis is that if everybody in the supply chain made the conversions necessary to implement the use of natural gas for marine vehicles with a 30 percent return, there's still a \$7.00 per mcf differential that's available to capture to make that change. So those are the kind of things that we're going to see developing here in the U.S. as a result of this incredible resource base. It's being driven obviously by price differential between natural gas and oil alternatives and it's also being driven by the environmental issues on natural gas being a much cleaner burning fuel.

Steve Davis: But is in fact shale a U.S. or North American play? Steve, tell us a little about what we're seeing internationally, where that may head.

Steve Otilar: It is interesting, just think back to seven or eight years ago. We would have been sitting here at a panel in the U.S. talking about Peak Oil, LNG regasification and bringing natural gas to the United States. So who knows where we're going to be in a couple of years? I believe this revolution that we are seeing in North America, and certainly the United States (I think in terms of barrels of oil equivalent, just because that is where the money is, as opposed to MMCF and gas equivalents), the shale plays that have been identified and that people are working on purportedly contain about 43 billion barrels of recoverable reserves. In the rest of the world there are another 175 billion BOE. So think of what has happened in North America and extrapolate that around the world. Now there are a variety of things we could talk about as to why it hasn't accelerated internationally at the same pace it has accelerated here in North America. But, for example, in Argentina there is one particular field called the Vaca Muerta that reportedly has 23 billion barrels of reserves. That's just one field just in Argentina with almost half of what we believe we have here in North America. The second largest field is in Western Siberia, and is 80 times the size of the Bakken Shale Play in North Dakota. The Bakken has made that state, I think, the second largest producer of oil in the United States. So this is kind of the tip of the iceberg.

In terms of the technologies being utilized, it is not just the horizontal drilling, it's not just the fracking, it's also micro-seismic. I mean these guys can pinpoint almost exactly where they want to drill and that precision is really the third leg of the stool that has led to the shale revolution, without a doubt.

So we can talk about the reasons why unconventional development has not quite expanded as fast internationally as it has in the U.S. We have a particular legal system that works here: private land ownership, water use, population density, a variety of different reasons, but think about what is just south of our border, what you see in Mexico. The Eagle Ford, which is one of the largest producers in Texas, alone I think would be close to the top five countries in the world producing oil. It doesn't just stop at the Rio Grande, it goes south. What is going on right now in Mexico I personally believe will be revolutionary. It is going to have the same impact on Mexico that natural gas and shale development has had on us here in the United States without a doubt.

Just think about renewable energy. Yesterday, I was shocked to hear that the cost of wind power was down 50 percent.

We should be dancing in the aisles and there should be wind towers everywhere, except for cheap natural gas in the United States. This gas supply is going to continue, and you are seeing countries like Mexico that look north of their border. Not that every farmer is going to get a new truck, I mean that is a big driver here, but the people can benefit locally. They see the growth, the job creation, they see the cheap access to energy and they understand it and it is coming. This, in my opinion, really is the beginning, and we are going to see a lot more potential for natural gas development.

Audience Member: Do you have a view of how far into the future you have parity between oil and gas, and at that point what is a moderate price point that gives that parity?

Steve Davis: Well, from an energy equivalency perspective today we are just dramatically different. Natural gas is so much cheaper on an energy equivalent basis than is oil. So are we ever going to get back to that level? Historically people talk about a 6 to 1 ratio because that tied into the energy equivalency. If you look at \$4.00 mmbtu gas that would imply \$25.00 oil basically, \$25.00 a barrel oil, and today we're well beyond that. So are we ever going to get back to the point where it is going to come back to some degree of parity, well the answer is yes probably, but when? By the time that you ever get to that point will we have moved on to some other form of energy supply? One of the things that Rontec Shell has talked about for years is that LNG is the bridge to a renewable future and so if indeed the price for renewable generation of electricity doesn't continue coming down because of improvements in technology and a wide variety of reasons, will we at some point begin seeing less need for crude oil to be burned if you substitute gas for diesel or if you take natural gas and through a gas-to-liquids process, which we have clients who are very actively pursuing, are you going to be able to, in effect, just go directly from natural gas to a liquid that competes directly with a refined product? I don't know if any of you have a view on that.

Jeff Pendergraft: Yes, I guess I've got a dissenting view that I might throw on the table. My answer to your question is I don't think you get back to parity in the historical sense on a BTU or heating value basis. I would make the argument that with the worldwide supply of natural gas, not just the figures I mentioned but throw in everything that Steve talked about in terms of worldwide supply, oil then, as a scarcer commodity, becomes far more valuable for use in the petrochemical industry and for uses other than just burning it as a fuel. And so, talking about price parity on a fuel basis I'm not sure we will ever get back to that.

Shaun Parvez: SK's strategy was based on the premise that gas purchased from the U.S. would be priced on a delinked basis from oil on a very long-term perspective, and so, unlike LNG which is priced in the Asian market on an index to Brent, the exposure, just to give you a perspective today, the largest importer of LNG in the world is a Korean company, a Korean government-owned company called Kogas, and up until last year they were the sole importer of LNG into Korea. The price at which they source LNG to the spot-market for LNG in Asia is around \$16-\$18 depending on the time of the year. The weighted average cost is a monthly published number. The weighted average cost of LNG by Kogas into the Korean market is about \$14. We made our play here in the U.S. based on an analysis of all of the contracts which Kogas has signed, which are all publicly available because it's a government-owned company, that indicate that by the time gas starts exporting from the U.S., which is in the 2017-19 time frame, our contract will start shipping in 2019, the weighted average cost of Kogas LNG in Korea is going to be \$19. So, our ability to secure natural gas here in the U.S. for \$11-\$13 gets better and better.

Audience Member: Shaun, you've mentioned that it's relatively easy to get an export permit for a free-trade country like South Korea. However, it has been reported that here in the U.S. you'll find there are some political risks to LNG exports. Will the Obama Administration be as willing to issue



export permits? How do you guys gauge that globally? Is it a country-by-country issue? Is there going to be a strong push for infrastructure resourced here in the United States?

Shaun Parvez: My understanding of the issue is that there are really two issues here and it comes down to who you are. You're either a free-trade country or you're not. And the question that is being presented to the White House, in a deal by industry watchers, is how many non-free-trade countries are you going to allow to export natural gas? Now, if you're a free-trade country there's no limit to how much gas you can export except that of the capacity to liquefy it.

Steve Davis: And the restriction that it go to that free-trade agreement country. You can't go there and then re-export it.

Shaun Parvez: That's right. So once it comes to Korea, it stays in Korea. We can't re-export to China, for example. So we can export as much as we want to the extent that there is a terminal here in the U.S. that has been permitted and financed and constructed and somebody's behind it to liquefy that gas, and that's really the constraint. And so the value in these plays is on these terminals and their ability to secure non-FTA licenses from the DOE.

Audience Member: I have a question for Jeff. Jeff mentioned that five dollars gas is adequate to develop the resource base and the numbers that Shaun is putting up, the \$11 to get the resource and liquefied and transported and sold for \$19 in Korea. Do you see enough of that happening that it's actually going to move the price of natural gas that we have? Are we going to see these export factors drive it from four bucks to nine bucks in relatively short order? How do you see that happening?

Jeff Pendergraft: My own view and I think our firm's view is that what you're going to see is some modest increase in natural gas prices to something below \$4 today to up around \$5, so \$5 is what's going to be required to sustain the development of the resource. Shale gas, unlike conventional natural gas, has decline curves on each of the wells which are relatively steep. In other words, the wells come in at a certain volume and then they decline pretty rapidly. So in order to maintain production from the fields, you have to keep drilling wells. And the economics of that in most of these shale gas plays, particularly in the shale gas plays that don't have liquids associated with them, where the liquids help create a lot of the value, are going to require a gas price in about the \$5 range. So that's one factor. The other factor is, alright, what's the impact of exports going to have on today's natural gas price? Well if you accept our figures that exports are only going



to represent about 15 percent of the domestic consumption or the domestic demand, it's not going to have a significant impact. This was an issue that was highly debated in the DOE filings on the export permits. The chemical companies were arguing that it was going to be — have a serious adverse impact on the chemical industries in the U.S. and the aluminum industries because of the increase in natural gas prices as a result of the exports. And I think most of the data really doesn't suggest that that's the case. I mean at most, maybe you've got a buck or a buck and a half increase as a result of allowing the exports out of the U.S. And, so what we see is gas price stabilizing, in the \$5 to \$5.50 range here domestically. The \$11 figure that Shaun quoted is an all-in cost to get it delivered to Korea or elsewhere in Asia because as he said you have to take the natural gas price, the transportation here in the U.S., liquefaction, transportation from the U.S. to overseas, when you build all that in, you come out with an \$11 or \$12 price.

Steve Otilar: Just to add to that, Deloitte came out with a survey in the last week or two where they looked at hypothetical estimated U.S. gas exports of about 6 billion cubic feet per day. They determined the price impact by 2030 would maybe be \$.15 per MMCF. More than local price impact, the really big drivers they thought would come out of U.S. LNG exports would be the delinking of oil prices from natural gas internationally. Going forward, natural gas prices would become priced against Henry-Hub or some other gas



index. Maybe the impact on foreign pricing would be greater, perhaps with the cost per MMCF dropping to maybe \$.84 or \$.85. Thus, the impact could be relatively negligible for U.S. prices, unfortunately for the new oil industry, but fortunately for the petrochemical industry, I suppose.

Shaun Parvez: Can I add one more response to that question? If you were to look at a chart that represented a hundred years of gas but had horizontal lines creating sort of a stratified structure representing the cost to produce that gas from the various resources. So you'd have some fields that could produce gas for about a dollar because the gas is really easy to get to and then you'd have other fields that were harder to get to, so they'd cost two dollars and three dollars. By the time you got to the five dollar mark, you were able to capture almost all the gas that's able to be produced. There's still more gas out there that you could produce for eight dollars. So, you capture most of the gas at around the five dollar mark, but there's even more gas available if you're willing to spend eight dollars to drill it. So, when foreign companies looking at the United States for natural gas -- look to hedge their exports with an upstream gas field purchase the way we are, we are far less sensitive to competing for an asset that can produce two dollar gas because we've got such a large margin in the Asian markets to deal with. So, if a two dollar gas field costs a billion dollars and a five dollar gas field costs two hundred million dollars, I can afford to buy the five dollar gas field, because

I've got a lot of margin built into how much I can export for. And so, while the United States producers and consumers are focused on using the cheapest gas available, the exporters or I should say the foreign buyers of this gas aren't necessarily competing all the time for the cheapest piece. They're looking at the cheapest piece as a component of their supply, but they're really hedging it with the \$4.50 or \$5 gas field.

Audience Member: If you look out 20 years, what's your view as to the volume of natural gas as compared to the assets?

Shaun Parvez: It's very positive, I mean, virtually every sector that we're looking at has extremely strong projections. We are acutely focused right now, for example, on the power sector. And, we're going to lead our investment thesis in that space with natural gas and co-generation, for example. So if you look at what the city, the state and federal government is doing at a variety of levels, there is a big push for co-gen. And I think President Obama's, if I remember the number right, is 20 percent of U.S. power to be sourced from CHP or co-generation by 2030. That's a pretty big number to go from 2 percent or 3 percent today to 20 percent in an area like that and that's just power. We see the same trends in transportation. We see the same trends in chemical facilities. We see the same trends in conversion of many different products from oil-based feedstock, such as something called naphtha to a natural gas-based feedstocks.

Jeff Pendergraft: Let me just add maybe a little different perspective on that same issue. Instead of thinking -- I mean, the demand, the economics for these growth markets for natural gas are compelling. So what are the constraints? The constraints are infrastructure and the development of the infrastructure whether you're talking about service stations for transportation fuel or pipelines to move the gas to market or wherever. There is a huge infrastructure issue that has to be addressed, there is a huge capital requirement that has to be addressed and the cost of that capital and that access to that capital is another constraint. The labor pools are a major constraint, this is an industry where the average age of the work force is maturing, the engineering and construction services that have to support the infrastructure built are constrained. So, I think the issue is not so much what are the economics in the marketplace to allow for the growth and the natural gas demand to move exponentially, but how quickly are those constraints going to be addressed to allow that to occur?

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The False Claims Act: The Government's Sword in Cash Grant Audits

By David K. Burton

The past three years have been difficult for applicants to Treasury's Cash Grant program. First, there were Treasury's *haircuts* to Cash Grant application requests. Then there was the unexpected news that the Cash Grant program was within the scope of the budgetary sequester rules. One would think that not much more bad news could emanate from a single program. Unfortunately, Cash Grant recipients have another concern: the False Claims Act (the Act).

A False Claims Act problem could arise if Treasury pays an applicant a Cash Grant and then, as the result of a Treasury Inspector General or an IRS audit or a whistleblower lawsuit as described below, it is determined that the Cash Grant paid exceeded what the applicant was entitled to and the excess payment was the result of a false statement in the grant application. The Department of Justice could then bring an action against the applicant under the Act.

In contrast to typical civil litigation, the False Claim Act provides for treble damages that may not be waived by a judge.¹ There is also an additional penalty of up to \$11,000 per false claim per project application.²

False Claims Act Background

The False Claims Act was enacted in 1863 to address improprieties by government contractors supplying the Union Army during the Civil War. However, its scope is far in excess of just government contractors; it is commonly asserted in the case of improprieties associated with federal research grants and Medicare payments to medical providers.

Further, the Act authorizes private citizens to assert claims that the federal government made payments in response to a false

1. Often the Department of Justice will agree to settle for less than treble damages (usually double damages), which provides a significant incentive for settlement.

2. Bryce Friedman, et al., *The Impact of the False Claims Act on Municipal Lawyers*, PLI Municipal Institute (Jul. 20, 2011).

statement or submissions. Such suits are referred to as "qui tam" suits. If the Department of Justice agrees with the private citizen, it will join the action. This process was exemplified when disgraced professional cyclist Floyd Landis brought a qui tam case against Lance Armstrong on behalf of their former sponsor, the U.S. Postal Service. The Department of Justice elected to join that case; however, Landis could have continued the action, even if Justice had passed on it.

If a court finds there was a false claim that resulted in an improper payment, the private citizen/qui tam relator is awarded between 15 and 30 percent of the recovery. The private citizen scenario seems unlikely in the Cash Grant context, unless a disgruntled employee of a Cash Grant applicant views the False Claims Act as a potential jackpot (which is a motivation for many a qui tam relator). A recent tax case held that the private citizen who files a qui tam suit may in calculating his taxable income deduct his legal fees from his share of the recovery.³

The Act has been a potent weapon for the federal government in recent years. For instance, in 2009 \$2.4 billion⁴ and in 2010 \$2.5 billion⁵ was recovered under the False Claims Act. Further, the gun sights of the False Claims Act extend beyond Tony Soprano-types whom we typically think of as tangling with the Department of Justice. The False Claims Act has been used against even those that may be considered sympathetic parties, such as counties, cities and school districts.

Elements of False Claims Act Liability

The elements of False Claims Act case are that the defendant must have made a claim for payment to the United States

3. *Bagley v. U.S.*, 2013 WL 4007774 (C.D. Cal. 2013).

4. Bryce Friedman, *Overview of the Fed. False Claims Act for Municipal Lawyers in 11th Annual Municipal Law Institute* (M. Mullen & J. Witterschein, co-chairs), 2010.

5. Bryce Friedman, et al., *The Impact of the False Claims Act on Municipal Lawyers*, PLI Municipal Institute (Jul. 20, 2011).



government; the claim must have been false or fraudulent; and the defendant must have known it was false or fraudulent.⁶ There is no requirement to prove a specified intent to defraud the government. It is sufficient if the defendant (i) had actual knowledge the information was false; (ii) acted in deliberate ignorance of the falsity; or (iii) acted in reckless disregard of the falsity.⁷

The statute of limitations rules are complicated and have been the subject of much litigation.⁸ The best reading appears to be that the government has 10 years from when the Cash Grant application was submitted to bring a false claims action.⁹

Further, the Cash Grant approval process raises an interesting statute of limitations question. The reviewers of the application frequently ask follow-up questions between the time the application is submitted and approved. The process to address what can be several rounds of follow-up questions can take a number of months. Does the statute of limitations clock start when the applicant submitted the application or when

6. 31 U.S.C. § 3729(a)(1)(A).

7. Bryce Friedman, et al., *The Impact of the False Claims Act on Municipal Lawyers*, PLI Municipal Institute (Jul. 20, 2011).

8 See, e.g., *U.S. ex rel Sanders v. N. Am. Bus. Indus.*, 546 F.3d 288, 293 (4th Cir. 2008).

9. See 31 U.S.C. § 3731.

it provides its response to the last follow-up question? The answer would appear to depend on whether the responses were relevant to what is being asserted as the false claim.

Preventive Measures

Three of the questions in the Cash Grant application have some subjectivity to them and arise in areas of the law that in some aspects are less than clear. First, the applicant is asked to certify as to its “qualified cost basis.” This requirement can be less than straightforward if the project changed hands several times or part of the cost was paid to related parties. Second, it asks when the project was “placed in service.” That is a concept generally defined by case law and IRS rulings that even Treasury’s officials have referred to as a “grey area.” Third, for projects placed in service after 2011, the applicant must demonstrate that it started construction on the project before 2012 (or at least incurred five percent of the cost of the project before 2012) and was placed in service prior to the sunset date applicable to the technology in question (e.g., before 2017 for solar). This third requirement in some instances can raise technical issues, some of which have not been clearly addressed in Treasury’s published guidance.

If you are one of the few Cash Grant applicants that still has not submitted its final Cash Grant application use care in preparing it and carefully review it. If there are difficult or subjective questions regarding valuation or tax law issues, you should obtain independent appraisals or tax opinions, as applicable, to avoid later accusations that you acted recklessly in completing the application.

If you have already submitted your final Cash Grant application and you know of an inaccuracy, you should request to amend the application or otherwise withdraw it and claim the appropriate amount of the investment tax credit.

If you are audited by the Treasury Inspector General or the IRS, you should involve counsel experienced in these issues from the outset of the audit. Similarly, if your company is separating with an employee who was involved in Cash Grant applications and has raised questions about the company’s participation in the Cash Grant program (or otherwise appears disgruntled or disillusioned with the company), you should engage counsel experienced in these matters to assist with the separation arrangements and minimize the prospects of creating a future qui tam relator.

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More information on these topics are available on Akin Gump’s blog, www.TaxEquityTelegraph.com.



Is a 50 Percent Renewables Portfolio Standard in California's Future?

By Dario J. Frommer

Will California adopt a 50 percent Renewables Portfolio Standard (RPS)? It is a question that may dominate energy policy in the Golden State this year.

Long a leader in renewable energy policy, California adopted the nation's most ambitious RPS in 2011. It mandates that 33 percent of all retail electricity sales by both public and private utilities come from renewable energy resources. In addition, the law requires utilities to procure much of their renewable power from sources located within the state and limits which renewable technologies are eligible. Currently, renewable energy accounts for more than 20 percent of retail electricity sales by the state's three large investor-owned utilities (IOUs).

Now, environmentalists and renewable energy advocates are talking about increasing the RPS requirement to 50 percent of all retail electricity sales. Indeed, at the time he signed California's current RPS standards into law, Gov. Jerry Brown called the 33 percent goal a "floor" and said, "[o]ur state has enormous renewable resource potential. I would like to see

us pursue even more far-reaching targets. With the amount of renewable resources coming online, and prices dropping, I think 40 percent, at reasonable cost, is well within our grasp in the near future." Gov. Brown recently signed legislation that allows the California Public Utilities Commission (CPUC) to increase renewable energy procurement targets for the IOUs above the 33 percent mark.¹

While no legislation has been introduced thus far to boost the RPS to 50 percent, the corridors of the State Capitol are already buzzing with discussions of how to best meet that ambitious goal. Resistance to expanding RPS beyond 33 percent is already being voiced by utilities, businesses and some environmentalists.

There are growing concerns about the cost of reaching a 50 percent goal or even a 40 percent RPS goal. A study by Energy and Environmental Economics (E-3) commissioned by

1. AB 327 (Chapter 611, Statutes of 2013).

the state's major municipal and IOUs, found that a 50 percent RPS scenario could increase utility rates by between 9 percent and 23 percent relative to the 33 percent RPS requirement.² The study also identified over-generation of renewable energy as a significant problem as the RPS requirement grows beyond 33 percent.³ Some business organizations, like the California Manufacturers and Technology Association and California Business Roundtable, are raising questions about the impact on already high electricity rates by RPS and compliance with California's landmark Global Warming Solutions Act of 2006 (AB32). Even Gov. Brown, a champion of green energy, has sounded a note of caution about the cost of the RPS. One major IOU is considering a proposal to scrap the RPS altogether in favor of a GHG-based standard for electricity procurement.

The environmental community may also be divided over how to best expand the use of renewable energy and the role of utility-scale wind and solar in a 50 percent RPS scenario. Increasingly, utility-scale solar and wind developers are finding themselves at odds with allies in the environmental community who are growing critical of the impact that utility-scale solar and wind plants may have on the fragile habitat, ancient tribal grounds and pristine view sheds. Some environmental groups are talking about an approach that favors distributed generation over large-scale, renewable power plants.

Yet utility-scale solar and wind facilities, along with a diversity of other renewable resources, would be an inherent part of any successful strategy to meet a 50 percent RPS goal. Increasing the goal would not only be a shot in the arm to struggling solar developers, but could also be a driver of investment into California's nascent biomethane and biodigester sector, given the Legislature's recent adoption of legislation to make it easier for in-state pipeline transmission of biogas.

While the E-3 study illustrated the costs of going to a higher RPS, it also highlighted opportunities for greater regional cooperation among governments and utilities that could allow California to become an exporter of renewable power to other states. Such cooperation could create new opportunities for in-state renewable energy development and address concerns about the costs and impacts of excess renewable generation.

The growing number of customers installing rooftop solar and the rise of microgrid technology that allows residential and commercial customers to unplug from the grid completely will

also drive discussions this year. Expansion of so-called distributed generation in the form of small solar facilities and rooftop solar is sure to be a major focus of any new renewable power initiative. Indeed, Gov. Brown has called for the installation of 12 gigawatts of local solar power by 2020—the equivalent of about 12 nuclear power plants.

Gov. Brown paved the way for further growth of distributed generation last year when he signed AB 327, which averted a suspension of the state's popular net metering program that allows customers to bank credits for solar energy they feed back into the grid. California's major IOUs have long complained about the financial and logistical impacts of the current net metering program, which requires them to take excess power generated by residential and business solar panels. The compromise struck by the Brown Administration allows the state's net metering program to continue while the CPUC designs a new program that will make a greater number of customers eligible for net metering without limiting the size of their systems. In exchange, IOUs will be allowed to charge a monthly fee of up to \$10 for all residential ratepayers to cover the costs of integrating distributed generation into their grids.

Whether California will up the ante on RPS remains to be seen. What is certain is that the state will continue to be the center of a lively debate over the best way to expand the use of renewable energy to power homes and businesses.

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2. Energy & Environmental Economics, "Investigating a Higher Renewables Portfolio Standard in California." Jan. 2014.

3. *Id.*

State Tax Update: A Summary of Recent State Renewable Energy Tax Law Developments

By David K. Burton and David A. Snyder

Arizona. In a series of rulings, the Arizona Department of Revenue has clarified the effect of leases and power purchase agreements on a taxpayer's eligibility for the solar energy device tax credits available in the state.¹ Arizona provides solar energy credits for corporations and individuals installing solar energy devices in an amount equal to 10 percent of the device's installed cost for corporations and 25 percent of the device's installed cost for individuals.

As it pertains to leases of solar energy devices, the commercial credit is available to lessee-taxpayers if their leases are structured as capital leases (an agreement providing that the lessee has acquired, or will acquire, title to or an equity in the property and is in reality a conditional sales contract) that have the purported lessee automatically acquire title to the property. Because the lessee incurs the cost of the device and is considered owner of it the day such property is placed in service, the lessee is entitled to claim the credit. On the other hand, an operating lease in which the lessee obtains no ownership interest in the device does not qualify for the tax credit. Also, the residential credit is not available to either of the individual taxpayer or the lessor when the leased device is installed on the taxpayer's residence.

Although the rulings use the terminology "capital lease" and "operating lease" from U.S. GAAP, it appears that the rulings are actually referring to a "conditional sale" that is treated as debt for tax and a "true lease." The Arizona property tax manual provides that the state follows GAAP lease characterization for property tax purposes.² However, there does not appear to be comparable authority that extends the GAAP leasing definitions to AZ income tax matters; as states

generally start with federal taxable income in determining the state tax liability, most states, including Arizona, follow the federal income tax rules with respect to lease characterization.³

Power purchase agreements (PPAs) do not enable an individual taxpayer to qualify for the commercial credit. Under a PPA, the individual resident pays for the power, while the PPA seller owns the solar property and incurs the costs associated with such property. In such a scenario, the individual taxpayer cannot claim the credit because the taxpayer does not pay for the device itself notwithstanding whether the individual taxpayer pays for the installation.

California. Signed into law on October 4, 2013, a bill enacted by the California Legislature that provides an exemption to the local utility user tax (a tax that the board of supervisors of any county may levy on the consumption of gas and electricity in the unincorporated area of the county), imposed by any local jurisdiction, for the consumption of electricity generated by a clean energy resource for the use of a single customer or customer's tenants.⁴ This exemption applies for any "clean energy resource," as such term is defined by the legislation, "located on the customer's premises and used solely for the customer or the customer's tenants."⁵ As enacted, the exemption will remain in effect until January 1, 2020, as of

3. See generally John Amato & Donna Fiammetta, *Equipment Leasing: State Income and Franchise Tax Considerations* (CCH Inc. 2001). There is no single definition of true lease versus conditional sale for federal income tax purposes because the concepts are based in the common law. The leading authorities with respect to the question are *Frank Lyon Co. v. U.S.*, 435 U.S. 561 (1978); *Rev. Rul. 55-540* and *Rev. Proc. 2001-28* as to what constitutes a true lease, and *Helvering v. F. & R. Lazarus & Co.*, 308 U.S. 252 (1939); *IL Power Co.*, 87 TC 1417, and *Rev. Rul. 72-408* as to arrangements that are in form leases but are recharacterized as conditional sales.

4. Cal. AB 792 (Oct. 4, 2013).

5. Cal. Rev. & Tax. Code § 7284.5(b)(1).

1. AZ LR 13-2, 13-3 and 13-4 (Sept. 16, 2013).

2. AZ PPM Chapter 5 – Special Properties, Lease-Purchase (Jan. 1, 2004).



which date it will be repealed unless deleted or extended by another statute.⁶

Louisiana. On September 24, 2013, the Louisiana Department of Revenue issued an information bulletin explaining changes to the former Wind or Solar Energy Systems tax credit as enacted by Act No. 428 of the 2013 Regular Session of the Louisiana Legislature.⁷ Under Act No. 428, the tax credit for wind energy systems was repealed and replaced with a solar energy systems tax credit for which solar electric and solar thermal systems could qualify. In addition to the wind energy system repeal, the act limited the residential tax credit to installation at a residence or home that is a single family dwelling and repealed the credit for installations in a multi-family dwelling such as a residential real estate complex.

Other requirements of the act include the mandatory installation and purchase by someone licensed by the Louisiana State Licensing Board of Contractors and compliance with the federal American Recovery and Reinvestment Act. There were also additional restrictions placed upon leased energy systems — both relating to the systems that may qualify for the credit and the eligible costs for determining the amount of the credit.

The act also created a sunset date that only allows systems installed before January 1, 2018, to qualify for the solar energy tax credits.

New York. In an advisory opinion issued on September 9, 2013, the New York State Department of Taxation and Finance clarified the meaning of “at the time” as contained in New York Tax Law § 606(g-1)(2)(A). Under that law, “the term ‘qualified solar energy expenditures’ means expenditures for the

purchase of solar energy system equipment that is installed in connection with residential property located in New York and is used by the taxpayer as his or her principal residence at the time the solar energy system equipment is placed in service.”⁸ The advisory opinion concludes that “at the time” refers to “when the installation of the qualified solar energy system equipment is complete and the taxpayer has begun to use the residence as his or her principal residence.”⁹ This credit is allowed at the time the equipment is “placed in service,” which is when “the solar energy equipment installation in the new home is complete and the new home construction is ready for occupancy.”¹⁰

North Carolina. Various state tax credits are scheduled to sunset beginning with the 2014 tax year. In light of this, the North Carolina Department of Revenue issued a notice on September 18, 2013, that allows remaining installments and carryforwards of various tax credits to be taken after their sunset.¹¹ More specifically, a taxpayer may continue to take any remaining installments and carryforwards of its tax credits—despite the sunset of such credits—as long as “the taxpayer continues to meet the statutory eligibility requirements for each particular credit.”¹²

Such tax credits to which this notice applies include, among others, the tax credit for a renewable energy property facility which sunsets for any renewable energy property facility placed in service on or after January 1, 2014.¹³ However, as indicated in the notice, the requirements for installments and carryforwards must still be met in order to claim such credits for the 2014 tax year and beyond.

Hawaii. Hawaii’s Department of Taxation recently proposed administrative rules governing the renewable energy technologies income tax credit. Such proposed rules added additional definitions to the temporary rules, requirements to claim the credit and allocation systems used by multiple or mixed use properties.

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6. *Id.* at 7284.5(c).

7. La. RIB 13-026 (Sept. 24, 2013).

8. N.Y. Advisory Opinion No. 1120607A (Sept. 9, 2013).

9. *Id.*

10. *Id.*

11. N.C. Dept. of Rev., Notice, Sept. 18, 2013.

12. *Id.*

13. See N.C. Gen. Stat. § 105-129.161(c).

Why End-Users Are Investing (Big) In Distributed Generation

Julia E. Sullivan, George D. (Chip) Cannon Jr., David K. Burton, Scott D. Johnson and John M. White

The term “distributed generation” generally refers to small-scale generating facilities installed on an end-user’s side of the utility meter and interconnected to the utility’s low-voltage distribution system. Distributed generation usually is designed to meet an end-user’s on-site energy needs, often with power generated from solar, wind or biogas resources or cogeneration technology. While each distributed generation investment is unique and requires careful, fact-specific due diligence, we identify below some of the potential benefits and challenges for commercial and industrial end-users who invest in distributed generation assets.

Self-Generation Was First Developed Under PURPA

Electricity in the United States traditionally has been produced by large generating plants which can cost \$1 billion or more to design and build. These plants offer economies of scale, but tend to be located far from end-use customers. Thus, extensive—and costly—transmission and distribution infrastructure is needed in order to deliver the output to end-users.

Congress began encouraging an alternative power delivery model in 1978, when it passed the Public Utility Regulatory Policies Act of 1978 (PURPA).¹ Among other things, PURPA requires certain utilities to enter into agreements to purchase power from qualifying renewable energy or cogeneration facilities, known as “Qualifying Facilities” or “QFs.” Many QFs are owned by large industrial or commercial end-users and, under the statute, they can sell their excess power to the public utility. To date, PURPA is estimated to have brought online about 71 GW of non-utility power.²

Investment in Distributed Generation Has Surged

In a survey by Ernst & Young, a third of the corporations surveyed reported plans to increase their amount of self-

generated power over the next five years.³ Examples of distributed generation include rooftop solar photovoltaic units, wind generating units, combined heat and power units (also known as cogeneration) and biomass generators that can be fueled with waste gas or industrial and agricultural by-products. Much of the recent increase in distributed generation is being driven by “big-box” retailers and other commercial and industrial businesses that now generate a significant portion of their own electricity with solar panels installed on their large, flat roofs.

Distributed Generation Has Potentially Significant Economic Benefits

Because they are located at the site where the energy is needed, distributed generation assets do not require expensive transmission and distribution infrastructure to deliver their power and do not experience the associated transmission and distribution losses. Relative to utility-scale assets, distributed generation enjoys a comparatively simple permitting and development process and lower operation and maintenance expenses. These savings can make a big difference in the bottom line. For example, one source estimates that the Kroger Company’s installation of on-site wind turbines, solar panels and biogas facilities at certain of its locations will reduce the grocery retailer’s power supply costs by \$160 million per year.⁴ These kinds of savings can give companies in energy-intensive industries—particularly manufacturing—a critical competitive edge. Because most distributed generation is unaffected by the price of fuel, these assets also can provide a physical hedge against potentially volatile and unpredictable utility rates, thereby reducing the end-user’s total risk profile.

“Net metering” laws that have been passed by all but a handful of states can further improve the economics of distributed generation by allowing end-users to sell excess energy onto

3. Ernst & Young, Renewable Energy Country Attractiveness Indices – Billion-Dollar Corporations Prioritize Energy Mix Strategy 4 (Issue 33, May 2012), available at [http://www.ey.com/Publication/vwLUAssets/Renewable_energy_country_attractiveness_indices_-_Issue_33/\\$FILE/EY_RECAI_issue_33.pdf](http://www.ey.com/Publication/vwLUAssets/Renewable_energy_country_attractiveness_indices_-_Issue_33/$FILE/EY_RECAI_issue_33.pdf).

4. Rebecca Smith & Cassandra Sweet, “Companies Unplug from Grid, Delivering a Jolt to Utilities,” *Wall St. J.*, Sept. 18, 2013, at A1.

1. 16 U.S.C. § 824(a)(3) (2012).

2. Peter Maloney, “PURPA: Still Generating Electricity, But With A Few Worms In The Mix,” *The Barrel* (Oct. 9, 2012, 2:08 PM), http://blogs.platts.com/2012/10/09/purpa_today.



the grid. According to the Database of State Incentives for Renewables & Efficiency, 43 states, the District of Columbia and three U.S. territories have net metering policies in place.⁵ Under these laws, when a customer's power demand is less than the output of its on-site generating facilities—which is common for some customers given the intra-day changes in their energy usage and the nature of intermittent energy resources such as wind and solar—the customer's utility meter will "run backward," resulting in a credit on the customer's utility bill. States structure their net metering programs differently, with some states, such as New Jersey, paying the customer as much as the full retail value of the power delivered to the utility's system.⁶ Other states use the wholesale rate utilities pay to large power producers.⁷ Limits on the types

5. Database of State Incentives for Renewables & Efficiency, Net Metering, (July 2013), http://www.dsireusa.org/documents/summarymaps/net_metering_map.pdf. The "holdouts" include Alabama, Mississippi, South Dakota and Tennessee, while Idaho, South Carolina and Texas have voluntary utility programs only. *Id.*

6. New Jersey Board of Public Utilities, New Jersey's Clean Energy Program – Net Metering and Interconnection, <http://www.njcleanenergy.com/renewable-energy/programs/net-metering-and-interconnection> (last visited Dec. 9, 2013).

7. U.S. Energy Information Administration, *Policies for Compensating Behind-the-Meter Generation Vary by State*, Today In Energy (May 9, 2012), <http://www.eia.gov/todayinenergy/detail.cfm?id=6190>.

of facilities eligible for net metering and the total amount of power that can be exported to the grid also may apply. In general, net metering programs can increase the attractiveness of investing in distributed generation by helping customers defray the cost of the investment.

Owners of on-site generation also may receive compensation for participating in load management programs or wholesale markets for capacity, energy, or ancillary services. For example, in the wholesale power market administered by PJM Interconnection, L.L.C. (PJM), the independent grid operator for the Mid-Atlantic region, an end-user with on-site generation can participate in "demand response" programs. Under these programs, PJM pays end-users to turn on their on-site generation—thus reducing their demand for power from the regional grid—during system emergencies or when prices are very high. PJM also allows distributed generation resources to make wholesale sales in its organized energy and capacity markets.

If the distributed generation asset uses renewable energy technology, the owner may be able to sell renewable energy credits (RECs) as a separate product. RECs are a tradable commodity representing a claim to the environmental benefits associated with the generation of power from renewable



resources.⁸ The REC market is highly decentralized and includes mandatory state programs⁹ as well as voluntary programs such as the U.S. Environmental Protection Agency's (EPA) Green Power Partnership.¹⁰ The owner of a distributed renewable generation asset can either use the RECs it generates, thereby reducing its own carbon footprint, or sell the RECs to a utility that is subject to a renewable portfolio standard or to another company that elects to participate in a voluntary program. Because the economic value of RECs can change over time as public policies change and the supply and demand of RECs varies through the operation of market forces, the long-term value of RECs is highly uncertain.¹¹

8. See, e.g., U.S. Environmental Protection Agency, Renewable Energy Certificates, <http://www.epa.gov/greenpower/gpmarket/rec.htm> (last updated Oct. 16, 2012).

9. Twenty-nine states and the District of Columbia have implemented renewable portfolio standards, which require utilities to serve their customers with a fixed percentage or amount of power coming from renewable resources. Eight additional states have "renewable portfolio goals." Database of State Incentives for Renewables & Efficiency, Renewable Portfolio Standards (March 2013), http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

10. U.S. Environmental Protection Agency, Green Power Partnership, <http://www.epa.gov/greenpower> (last updated Dec. 9, 2013). There currently is no federal renewable portfolio standard.

11. U.S. Department of Energy, Renewable Energy Certificates—REC Prices, <http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5> (last updated Oct. 2, 2013).

While the opportunities to create economic value by investing in distributed generation are significant, careful analysis of economic factors, including the local utility's rate structure, is essential. Most distributed generation can serve part, but not all, of the end-user's load. To the extent that the distributed generation asset produces intermittent power (e.g., solar or wind), the end-user must remain connected to the grid for back up power. The potential long-term cost of utility standby service and back up power should be carefully analyzed as part of the economic decision to invest in a distributed generation asset.

Distributed Generation Helps Companies "Go Green"

Many companies view distributed renewable generation as an opportunity to improve their bottom line while bolstering their image with environmentally conscious consumers who prefer to buy products produced by companies that share their commitment to carbon reduction.¹² Google and Apple, for example, have publicized a goal of powering 100 percent of their operations with power from renewable resources.¹³

12. See, e.g., Joe Manget et al., Capturing the Green Advantage for Consumer Companies 16-17 (January 2009), available at <http://www.bcg.com/documents/file15407.pdf>.

13. Google, Inc., Renewable Energy, <http://www.google.com/green/energy> (last visited Dec. 9, 2013); Apple Inc., Environmental Progress, <http://www.apple.com/environment/progress> (last visited Dec. 9, 2013).

These companies and many others recognize and embrace the tangible and intangible value associated with renewable energy. Programs such as EPA's Green Power Partnership, a voluntary program that encourages organizations to use "green" power as a way to reduce the environmental impacts associated with conventional electricity, foster companies' differentiation from their non-partner competitors and lend credibility to their efforts.¹⁴

Distributed Generation May Improve the Reliability of Electric Service

Distributed generation is an especially attractive option for industrial or commercial customers that require a continuous power source. The effects of "Superstorm" Sandy and other major weather events underscore the vulnerability of transmission and distribution systems to major disruptions. While generators survived Sandy relatively unscathed, the vast transmission and distribution system that connects them did not. Millions of utility customers lost power during the storm, some for lengthy periods. For some commercial or industrial customers, such disruption can be catastrophic. Recent experience with storm-related outages also highlights the vulnerability of the bulk power system to terror attacks, cybersecurity deficiencies, and simple vandalism.

Certain types of distributed generation facilities can provide a continuous source of backup power independent of the vulnerable transmission and distribution system.¹⁵ For some customers, this benefit alone may be worth the investment in distributed generation.¹⁶ Cogeneration, often used by hospitals and universities, is an especially attractive type of distributed generation for providing backup power. When Sandy hit the South Oaks hospital and nursing home on Long Island kept power flowing using a cogeneration resource located on-site.¹⁷ As the storm threatened the Long Island Power Authority system, the hospital isolated itself from the grid and brought

its plant online.¹⁸ Similarly, a 40 MW cogeneration facility located on-site at Co-Op City, a large housing cooperative in the Bronx, kept power flowing to its schools, shopping centers and more than 14,000 apartments during and after the storm, as much of the rest of New York City went dark.¹⁹ As these examples demonstrate, distributed generation can not only save customers money, but also can bolster reliability during emergency events.

It May Be Possible to Shift Operational Responsibility for Distributed Generation to a Third Party

Owning and operating a power generation asset is outside the core competency of most end-users, and this lack of expertise can create a disincentive to invest in distributed generation. One option is for the end-user to lease a portion of its site, such as a rooftop, to a project developer who will own and operate the distributed generation asset and sell the output to the end-user. According to the U.S. Energy Information Administration, 23 states and the District of Columbia currently have retail choice programs (an increase of six states since 2010) that allow end-use customers to buy electricity from competitive retail suppliers.²⁰ In states that do not permit retail choice, innovative project structures and consultation with the utility and state regulators may be required in order to achieve the end-user's commercial objectives.

There Are a Number of Financing Options for Distributed Generation

Despite the potential benefits of distributed generation, financing can be a major obstacle. Up-front costs of building distributed generation, while decreasing for some technologies, can be high, with the appurtenant benefits and return on investment spread out over time. In addition, some commercial properties might not qualify for financing, and some potential end-users may prefer to not have the associated debt on their balance sheets. However, a variety of

14. E.g., U.S. Environmental Protection Agency, *Green Power Partnership – Join Us*, <http://www.epa.gov/greenpower/join/index.htm> (last updated Nov. 4, 2013).

15. The benefits of particular types of distributed generation during certain types of disruptions depend, of course, on the circumstances. For example, a solar-powered facility would not be useful during a major, but short-term, weather-related disruption, whereas a fuel cell or energy storage device would be. Likewise, a cogeneration facility that depends on regular fuel deliveries that might themselves require the electric power system could be useless in a long-term outage situation, whereas a solar or wind facility would not be similarly affected.

16. See, e.g., Wendy Koch, "Post Sandy, U.S. Pushes Microgrids for Backup Power," *USA Today*, Oct. 31, 2013, available at <http://www.usatoday.com/story/news/nation/2013/10/31/microgrids-increase-post-sandy/3305379>.

17. *Id.*

18. *Cogeneration (CHP) Plants Keep the Lights on for Thousands During Sandy*, Energy Concepts, <http://nrg-concepts.com/cogeneration-chp-plants-keep-the-lights-on-for-thousands-during-sandy> (last visited Dec. 9, 2013).

19. William Pentland, "Lessons from Where the Lights Stayed on During Sandy," *Forbes* (Oct. 31, 2012, 5:21 PM), <http://www.forbes.com/sites/williampentland/2012/10/31/where-the-lights-stayed-on-during-hurricane-sandy>.

20. U.S. Energy Information Administration, *Electricity Monthly Update for September 2013* (Nov. 22, 2013), <http://www.eia.gov/electricity/monthly/update> (after Dec. 20, 2013, access the update for September 2013 in the "Previous Issues" collection); U.S. Energy Information Administration, *State Electric Retail Choice Programs Are Popular with Commercial and Industrial Customers*, *Today in Energy Blog* (May 14, 2012), <http://www.eia.gov/today-in-energy/detail.cfm?id=6250#>.

ownership structures and financing alternatives are available that can resolve some of these challenges.

For example, the California Public Utilities Commission (CPUC) recently approved a pilot program intended to help attract private capital for investment in distributed generation projects for industrial and commercial customers.²¹ That program allows nonresidential utility customers to repay third-party lenders for financing the costs of distributed generation through the customer's utility bill, a financing mechanism called "on-bill repayment." By bundling repayment of the third-party loan with the customer's energy costs on its utility bill and allowing for the termination of service for nonpayment, the CPUC hopes to reduce events of loan default or delinquency, thus attracting new private capital and lowering borrowing costs for distributed generation projects.

Many other states have implemented Property Assessed Clean Energy (PACE) programs that help both residential and commercial entities finance distributed generation and other energy efficiency initiatives.²² These programs help finance those activities through a tax assessment added to a building's existing property tax bill. PACE programs typically provide up-front, competitive, fixed-rate financing for eligible projects, with repayment of the loan through a tax obligation that attaches to the property. That tax obligation transfers with the property, so investors benefit from lower default rates and a lower cost of capital. The intent of the PACE programs is that the customer's savings on its monthly utility bill would exceed the increase in its property tax obligation.

Financing options are heavily influenced by the federal tax benefits available for solar projects. These benefits include a 30 percent investment tax credit and five-year accelerated depreciation.²³ For projects that are operational after 2016, the 30 percent investment tax credit is scheduled to decline to only 10 percent.²⁴ The optimal federal financing option depends on the tax status of the end-user. For instance, government and non-profit end-users are not permitted to claim the investment tax credit or accelerated depreciation. Therefore, these types of entities typically would prefer a power purchase agreement (PPA), as such a structure will permit the owner/financier to claim the investment tax credits and accelerated

depreciation. In contrast, a lease structure involving such an end-user would result in disqualification of the investment tax credit and accelerated depreciation for the owner/financier. The fundamental difference between a PPA and a lease is that in a lease the end-user pays a fixed monthly rent regardless of the energy generated. Thus, in a lease, the efficiencies or inefficiencies of the solar project accrue to the end-user. In contrast, in a PPA the end-user pays based on the kilowatt hours generated, so the efficiencies or inefficiencies accrue to the owner/financier.

If the end-user is a corporation, it can either own the solar project itself and claim the tax benefits or enter into a PPA or lease. Ownership is generally attractive when the corporation has a significant tax appetite. If the corporation has minimal tax appetite or is in need of a financing solution, it can consider either a lease or a PPA; either of those would permit the owner/financier to claim the tax benefits and accordingly lower the rent or rate it charges the end-user.

Many states also provide tax benefits for solar projects. The state tax benefits vary widely in terms of types and amounts. States with particularly generous tax benefits include Hawaii and North Carolina.²⁵

Conclusion

Each investment is unique and requires careful, fact-specific due diligence. A well-structured investment in distributed generation can create opportunities for end-users to lower energy bills, reduce energy price volatility, earn tax benefits, improve electric service reliability and create product differentiation through environmentally conscious decision-making.

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21. *Application of Pac. Gas & Elec. Co. for Approval of 2013-2014 Energy Efficiency Programs & Budget, et al.*, Decision No. 13-09-044, Decision Implementing 2013-2014 Energy Efficiency Financing Pilot Programs, issued Sept. 20, 2013, CPUC Case Nos. 12-07-001, et al.

22. *PACE Programs*, PaceNow, <http://pacenow.org/pace-programs> (last visited Dec. 9, 2013).

23. 26 U.S.C. § 48 (2012).

24. *Id.*

25. See, e.g., Haw. Rev. Stat. § 235-12.5 (2012) (providing for a 35 percent tax credit for solar energy systems).



An Analysis of U.S. Energy Policy Objectives: Green and Brown Power Options Examined

By David K. Burton

As the nation's population and economic activity increase, so does its need for electricity. Today's technology provides the nation with choices beyond fossil fuels. Below the policy rationales for alternative sources of electricity are explained. Then the widely available technologies for green and brown power are evaluated against the rationales for alternative energy.

Electricity generation is estimated to contribute 38 percent of American carbon dioxide emissions. The second largest contributor is transportation at 27 percent with 41 percent of that contribution coming from passenger cars. As the generation of electricity is the largest contributor, it is the focus of the discussion below.

Policy Rationales for Green Electricity

There are three typical policy rationales provided to justify the higher cost of green electricity. The first is "climate change." The idea of climate change is that carbon dioxide and other greenhouse gasses from fossil fuel emissions are either causing the earth's atmosphere to warm or are otherwise causing a change in the oceans and associated weather patterns.

Even to a non-scientist, merely observing changes in recent climate patterns suggests that the climate is changing. These changes include the melting of ice that has permitted ships during summer months to use an arctic passage that prior to 2009 was impassable by commercial vessels; the increase in severe weather like Hurricanes Sandy and Irene in 2011 and 2012 in the Northeast; and rising oceans eating away at coast lines. National Geographic predicts that by the end of this century coastal areas such as Miami Beach will be underwater. Many scientists believe these changes to be caused by the emission of carbon dioxide and related pollutants into the atmosphere; certainly as such emissions have increased with industrial development, so have these changes in the climate.

The second rationale is "energy independence." One aspect of this rationale is that as energy is the lifeblood of the American economy, the nation should not be dependent on other nations for it. A second aspect is that the world's largest oil deposits are in the Middle East, which has a history of instability and strife, and the second largest deposits are in Russia, which has a history of being geopolitical competitor of the U.S. Finally, importing oil contributes to the American trade deficit, which weakens our economy and fills the coffers of countries that often are not governed by democratic principles.

An Analysis of U.S. Energy Policy Objectives

The third rationale is health and welfare. This rationale comes in several flavors. The first flavor relates to pulmonary disease and other illnesses as reflected in a 2009 quote from the Environmental Protection Agency: “increases in ground-level ozone pollution [are] linked to asthma and other respiratory illnesses.” The Chinese have recognized this reality as they recently banned the construction of coal-fired power plants in Beijing, Shanghai and Guangzhou in order to limit air pollution.

The second is that developed nations will be able to address the rising oceans by investing in civil engineering improvements that will protect their coastal communities, while developing nations will lack the resources to make such investments. Thus, the use of alternative energy resources helps reduce the risk of immeasurable damage to coastal regions in the developing world.

The final flavor is described as one of “equity” by the United Nations. It has asserted that developed countries that benefited the most from the industrial revolution (and the associated increase in the use of fossil fuels) should change their behavior to address fossil fuel emissions, rather than asking developing nations whose peoples are just starting to benefit from energy generated from fossil fuels to curtail their economic ascendancy.

America’s Choices for Electricity Production

To generate incremental energy, America has effectively six choices: nuclear, coal, natural gas, wind, solar and hydro. They each have different cost benefit analyses and different levels of feasibility.

No new nuclear plant in the U.S. has started construction in the last 40 years. After the Fukushima nuclear disaster in Japan, many analysts believe it would be impossible to obtain the permits necessary to construct a new nuclear plant in the United States. In 2011, the nation’s 65 nuclear power plants provided over 19 percent of its electricity generation. As those plants are decommissioned due to age and/or safety concerns, that power will need to be replaced by another source.

Similarly, there are no realistic plans to build new coal-fired plants in the U.S. This is due to environmental regulations and opposition from the public due to health and environmental concerns. For instance, President Obama has instructed the EPA to issue regulations that would require newly constructed coal-fired plants to use expensive carbon capture and sequestration technology. Coal currently provides approximately 36 percent of the nation’s electricity. Some existing plants are being shuttered due to their inability to operate profitably while complying with environmental

regulations. Like nuclear, the power from those plants will need to be replaced by another source.

New natural gas-fired plants are being built, and the shale gas revolution has created an abundance of American natural gas. Economists have asserted that the availability of such natural gas is enabling America to more quickly recover from the great recession than European nations have. Infrastructure that had been constructed to import liquefied natural gas is now being reconfigured to export it. Today, natural gas is approximately twice as expensive as coal per Btu of energy produced. The cost to construct highly efficient combined cycle natural gas plant is approximately a dollar per Watt of electric generation capacity. A combined cycle plant generates electricity from a turbine fueled by natural gas and a steam turbine fueled by waste heat from the gas turbine. A single cycle gas fired plant only has the steam turbine and costs approximately 30 percent less to construct than a combined cycle plant.

Recently, more new electric generation capacity was added by new wind farms than by new natural gas-fired power plants. The construction of a wind farm is approximately twice as expensive as the construction of a combined cycle natural gas plant: approximately two dollars per Watt of electric generation capacity. However, once the plant is constructed, the wind is free (in contrast to natural gas).

A problem with wind is that the dense population areas that require more electricity are generally on the East and West Coasts, while the wind blows the strongest and most consistently in states like South Dakota that are far from the coasts. And currently the infrastructure to economically transmit electricity from the middle of the nation to the coasts does not exist. Further, there is currently no good way to increase the rates paid by California customers to fund the construction of transmission lines in South Dakota to bring wind energy to homes and businesses in California.

Rooftop solar power avoids the challenges of transmission that confront wind: the electricity created by rooftop solar is used by the building the solar panels are installed on and the excess is sold to the local utility in an arrangement known as net metering. The sun, like the wind, is a free resource, but the construction of each Watt of rooftop solar electric generation capacity costs two to three times as much as wind.

Utility-scale solar projects cost less than rooftop solar to construct due to economies of scale; however, the most efficient areas to build them are places that are flat and sunny: the desert. And desert regions are often far from energy hungry population centers; thus, similar transmission challenges arise as in wind. The construction of each Watt of

utility-scale solar electric generation capacity costs one and a half to two times as much as wind.

Occasionally a new hydroelectric dam is built in the U.S., but they are relatively rare. First, there is a limit on the number of suitable locations. Second, it is difficult to obtain approval to build them due to concern about the fish population and other ecosystem consequences.

Comparing the Options to the Objectives

In the first section, three objectives were outlined: mitigating climate change, achieving energy independence and improving the health and welfare of people here and abroad.

The generation of electricity is the largest contributor to carbon dioxide emissions in the U.S. Almost none of the feedstock for generation of electricity comes from abroad. The U.S. has substantial coal deposits, so it exports more coal than it imports. Further, the shale gas revolution has resulted in an abundance of natural gas here. Little uranium is being imported for the nation's nuclear power plant fleet. Thus, the nation's electric generation capacity is not dependent on imports, so there is no need for energy independence to be a factor in the electric generation equation. (America does import some petroleum for cars and other modes of transportation. Further, some buildings and residences are heated with oil that may be imported. In addition, the energy needs of military units stationed abroad raise true security problems that have placed the Pentagon on the cutting edge of the green energy movement.)

If the sole policy focus is climate change, wind, solar, hydro and nuclear are all viable options. Natural gas power plants are approximately twice as clean as their coal-fired cousins and technological improvements have made today's natural gas plants cleaner than those constructed in past decades. Currently, the nation is for the most part only constructing wind, relatively clean and efficient natural gas and solar power plants. Thus, the nation in terms of the construction of new electric generation capacity should be given high marks with respect to mitigating climate change.

However, the growth in wind and solar over the last five years has been supported by tax credits. The tax credit for wind lapsed last year and the tax credit for solar declines by two-thirds after 2016. If these tax credits are not extended, the nation's climate change marks for electricity generation will likely be much lower in future years.

The National Renewable Energy Laboratory recently estimated that in the Western U.S. wind and solar will be competitive with natural gas without the tax credits by 2025. The investment bank

Lazard recently published a report concluding that the cost of energy generated by wind and utility scale solar had declined 50 percent in the last four years. Given that the oil and gas industry has received tax benefits and other government subsidies for over a century, another 11 years of wind and solar tax credits is a drop in the bucket. Further, the tax breaks would appear to be a prudent investment for the nation given the gains in efficiency that wind and solar have made in the last four years.

In terms of health and welfare, the leading options are solar and wind. Hydro is arguably a good option, if one believes the ecological consequences are appropriately mitigated. The examples of the nuclear disasters in Fukushima and Chernobyl would suggest that nuclear power is inconsistent with health and welfare policy objectives; however, France generates the majority of its electricity from nuclear plants and France has never had a nuclear disaster. At the moment, the whole nuclear power debate in the context of constructing new generation is almost irrelevant as the low price of natural gas has undercut the commercial motivation for building new nuclear power plants.

The final question is how are these choices and policy rationales reflected in national policy? The unfortunate answer is that there is no coherent national energy policy. The closest Congress has come is the tax credits referenced for wind and solar, but they have always been enacted with a sunset date that prevents investors from engaging in long-range planning. In addition, Congress also provides tax benefits to the oil, gas and coal industries, and those benefits do not have a sunset date. Thus, Congress is driving with one foot on the gas and one foot on the brake.

A first step toward a coherent national energy policy would be agreement with respect to the relevant facts. This would require an acknowledgment that a concern about dependence on energy imports is not a justification for wind, solar, hydro or nuclear power because the nation does not import meaningful levels of natural gas or coal. On the other side of the table, it would require acknowledgment that climate change is a real concern and that alternative energy technologies are the most viable means to mitigate it.

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U.S. Solar M&A Market Update

By Elliot Hinds

The following is a high-level update on some notable trends in the solar M&A market as reported in two recent solar M&A market sessions in which Akin partner Elliot Hinds was a presenter—Solar M&A Webinar on November 19, 2013 (with Carl Weatherly-White of Lightbeam, formerly with K Road, Alex Ellis of SunEdison and Tarik Bolat of Renewable Energy Trust) and Solar M & A Market Issues at the Renewable Energy Law symposium in San Diego on January 26, 2014 (with Dirk Mueller of Farella Braun and Martel).

*While there was an approximately 20 percent increase in the number of transactions in 2013, deal sizes from a monetary perspective actually decreased (roughly from an average size of \$24M in 2012 to \$17M through Q3 2013).

*Market consolidation is widely recognized phenomenon in the solar industry and will continue to be major dynamic of the solar M&A market in 2014. Some of the most prevalent types of transactions are the sales of mid-stage to late-stage development pipelines to utilities, manufacturers and developers and investors who have adequate and/or lower cost of capital (including various types of Asian investors). Projects at these stages typically require significant deposits especially

for interconnection and power purchase agreements, and therefore this tends to be a barrier to further development by many parties. The well-known limitations in access to affordable development capital for early/mid stage projects continues to drive acquisitions of development stage projects, at stages when developers have less leverage.

*Increased interest in shovel-ready projects results from utilities seeking to replace coal and nuclear facilities that are facing environmental compliance pressures and costs and solar projects becoming an acceptable investment for institutional investors seeking yield. Rather than build and transfer, more parties are drawn to the value of owning solar assets for the long term.

*The yieldco phenomenon is not only happening at the utility scale, but smaller and medium-sized funds are being formed with the same strategy in mind for groups of smaller solar projects.

*There is a healthy pull and tug in the large utility scale solar project space resulting in large manufacturers and utilities



becoming even more dominant acquirers and owners of utility scale projects, both operating and in development.

*A number of factors influence this dynamic including flat to low load growth in the U.S., low natural gas prices and lower PPA prices and lower number of PPA awards. In fact the slowdown in PPA awards and prices has led to significantly increased valuations of utility scale projects, as demonstrated by the NRG Yield and Pattern Energy IPOs. However, those high valuations make the utility scale projects less appealing for investors with high hurdle returns.

*Many developers have been withdrawing from the utility scale market in favor of smaller projects (sub 20 MWs) which tend to have lower carrying costs and fewer environmental and other developmental hurdles that lead to delay. The large utility projects that hit the market invariably go to the bidder with the lowest cost of capital. This has left the large-scale utility solar market to manufacturers, driven by their desire to place their product, and utilities opportunistically putting their low cost of capital to work.

*Considerable interest remains in acquiring uncontracted assets especially at the commercial and small-scale utility level. This is a reflection of the maturity of the solar market in general where investors see the inherent value of the asset and have adopted sensible sensitivity cases, discount and financing rates and other tools that are quite familiar in other more seasoned aspects of the power market. Furthermore, the increased presence of acquirers with power marketing groups has taken away some of the fear of merchant deals.

*Sellers of development projects are not necessarily receiving development cost reimbursement at the M&A closing or carrying costs until the reimbursement occurs, which is happening more frequently at commencement of construction. However, carrying costs for development or other invested

capital are most often provided in joint venture or other strategic alliance arrangements, as opposed to individual M&A transactions.

*Milestone and earn-out payments of purchase price are dominant and are expected to remain dominant in 2014, especially in development stage M&A deals. There continue to be a variety of earn-out measurements, most notably PPA price, project capacity and resale price.

*For projects being sold in the development stage, milestone payments of the purchase price continue to dominate but these tend to be all-or-nothing deals. In other words, it is quite rare to have deals with buy-back rights where projects fail to meet milestones within a specified period of time. Sellers appear to have become more selective, favoring buyers that have a demonstrated ability to complete projects.

*Where an earn-out of a development stage project is determined by the ultimate resale value of the completed project, the calculation of resale value comes into sharper focus in the negotiation. This is particularly the case where the manufacturer's business plan is to buy, build and transfer. However, any deal involving a construction agreement and a purchase agreement should be carefully evaluated because shifts of allocation to the purchase price versus the construction contract price can affect other deal terms such as indemnification caps and liquidated damages (which are calculated on the basis of overall contract price) as well as tax treatment and the overall cash flow in the transaction. In addition, the EPC scope should be evaluated to exclude cost items that are not reflective of value such as late stage development costs (e.g., mitigation land), utility interconnection work, certain taxes and financing costs.

*Sellers pay for less than optimal design and engineering work. M&A deals increasingly feature price adjustments and/or reimbursements for capacity or output changes, which historically would be associated as a risk of the contractor or project owner, rather than the developer.

*An interesting by-product of the smaller size and larger deal volume is more of a corporate style approach to due diligence especially in portfolio development deals. Parties are approaching risk assessment in portfolio development deals from the perspective of critical flaws rather than an expectation of flawless projects. This approach is the natural result if one assumes a failure rate in a development pipeline.

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Will Residential Solar Debt Financing Eclipse The Third-Party Ownership Model?

By Daniel P. Sinaiko

The residential solar market arrived in 2008. That year SolarCity and Morgan Stanley closed the first residential tax equity portfolio financing in the United States. The financing was backed by a portfolio of customer leases, whereby SolarCity owned the solar equipment and leased it to the energy consumer. This “third-party ownership” (TPO) structure was critical to the success of the SolarCity financing model for two reasons: first, by leasing the equipment to the end user, it enabled customers to go solar for little or no up-front cost; second, it enabled a financial investor to own the equipment and thereby capture the tax credits that facilitate tax equity financing.

Since that initial financing, the residential solar sector has experienced robust growth. No fewer than six residential solar installation finance companies have been built around the TPO model. SolarCity, SunRun, OneRoof, Sungevity and others have collectively closed over \$3 billion in project financings. SolarCity recently completed the first distributed generation installer initial public offering and asset-backed securitization transactions. Installed cost has fallen from over \$8.40 per watt in 2008 to near \$5.00 per watt. Net metering policies have been expanded to 40 states and the District of Columbia. Renewable energy credit (REC) markets have opened in 29 states, including New Jersey, Massachusetts, New York and Pennsylvania. These advances have largely been achieved on the back of the TPO model that supported the first tax equity transaction back in 2008.

Amidst the cacophony of TPO backed residential solar, a new voice is emerging. In 2013 the residential solar lending market surfaced as a viable alternative to TPO. Sales organizations like Sungage and commercial banks like Admiral’s Bank are deploying debt products that are shifting industry focus away from TPO. This pivot, if it is not yet a sea change, is being caused by numerous market factors, some seeds sown by the success of the TPO model, and others endemic to the shortcomings of the TPO model.



A Victim of Its Own Success?

The achievements of the TPO model have ripened the market for residential solar debt products. Residential solar has effectively reduced installed costs, created a favorable policy environment and made the sector credible.

- **Cost Reduction.** The remarkable decrease in the installed cost of residential solar systems has driven the robust market penetration of residential solar in the last five years. Since 2008 the installed cost of solar has fallen by almost 40 percent. This is due in part to equipment vendors aggressively slashing cost and margin, but it is also due to process improvements achieved in large part by TPO proponents. Reduced installation costs (a) make tax credits, which are based on installed system cost, a smaller piece of the value puzzle, compared to the value of energy and RECs, and (b) due to lower per system tax credits, increase the number of customer installations required to achieve a portfolio of sufficient aggregate value to merit a financing.
- **Policy Improvements.** High unemployment and increased climactic volatility have led state and local governments to undertake policy initiatives designed to

cultivate the green economy locally. From net metering programs to renewable energy certificate markets, solar developers have created a favorable policy environment for residential solar installation. All of these benefits have facilitated the deployment of residential photovoltaic generation, be it through leases and PPAs or customer ownership.

- **Industry Gravitas.** The over \$3 billion in solar financings that have closed since 2008 has given the concept of solar finance credibility. The first five years of TPO residential solar have established a strong asset class. In 2012 Clean Power Finance reported that default rates in residential solar portfolios were lower than those of AAA bonds. Consequently, residential solar now looks ripe for institutional investment.

A Different Mousetrap

As impressive as the rising tide of residential solar has been, the TPO model has not overcome all the financing challenges it faces. The TPO model presents significant advantages to end users:

- Low up-front customer costs
- Ability to capture the value of equipment depreciation

- Energy price certainty.

At the same time, TPO integrators have struggled with a number of issues, including:

- A shortage of tax equity financing sources
- A high cost of tax equity capital
- Limited ability to lever tax financing structures
- Ability to pass on REC value to customers
- Home sale liquidity
- Familiarity and simplicity
- Financier system priority.

Third-party debt financing may present an opportunity to overcome some of these difficulties. End-users, developers and financing providers take a different view on which structure best addresses these issues. The following summary analyzes whether a TPO or debt structure is better suited to resolve a particular residential solar finance challenge from the perspective of end-users, developers and financiers (or whether that party is neutral to the issue):

| ISSUE | END-USER PREFERRED | DEVELOPER PREFERRED | FINANCIER PREFERRED |
|-------------------------------|--------------------|---------------------|---------------------|
| Universe of Finance Sources | Debt | Debt | Neutral |
| Finance Cost | Debt | Debt | Neutral |
| Up-Front Cost | TPO | Debt | Neutral |
| Levered Tax Credit Absorption | Debt | Debt | Neutral |
| Depreciation Absorption | TPO | TPO | TPO |
| REC Ownership | Debt | TPO | TPO |
| Energy Price Certainty | Debt | Neutral | Neutral |
| Home Sale Liquidity | Debt | Debt | Debt |
| Residual Ownership | Debt | Neutral | TPO |
| Familiarity/Simplicity | Debt | Debt | Debt |
| Financier Priority | Debt | Debt | Debt |



- **Financing Sources.** The growth of residential solar through the TPO model has not been unbridled. No factor has limited residential solar deployment more than the availability of tax equity investment, and the consequence short supply has on cost. This investment is predicated on the existence of taxable income. For a time, this need was alleviated by “1603 cash grants,” which were offered in lieu of tax credits under the American Recovery and Reinvestment Act. Even at its most robust, the bench of residential tax equity investors has never run deeper than a dozen providers. Given the extensive universe of asset-based lenders who need no offsetting tax liability, the market for debt finance on solar is potentially much larger.
- **Financing Costs.** Residential solar issuers have made it worth the while of willing tax credit investors. At times, after-tax yields for tax investors have been as high as the mid-teens (though it is lower now). Even as the cost of capital trends lower, the rates being offered by solar lenders are more favorable, with published rates as low as 6 percent. At some point, the lower cost of capital associated with debt financing, coupled with the end user’s ability to retain solar tax credits and residual value, becomes more economically compelling than the customer’s ability to defer cost and monetize depreciation.
- **Up-Front Cost.** In a TPO structure, a customer has the opportunity to defer all up-front cost associated with going solar. There are “zero down” debt products in the market, though, at a minimum, the homeowner must be prepared to finance or advance the value associated with the investment tax credit.
- **Levered Tax Credit Absorption.** The ability of the TPO model to defer end-user cost is compelling, but these costs must land somewhere for the system to be built. Perhaps 50 percent of the value of a solar project can be funded tax credit and depreciation monetization. However, due to inability of lenders and tax investors to agree on their relative priority in a default, developers have been unable to create levered residential tax equity structures. Consequently, the developer winds up carrying the up-front costs in the TPO model. Recently, some developers have been able to mitigate this risk through back-levered portfolio financing, though the cost of back-levered debt is materially higher than an asset backed loan. By contrast, the entire cost of a system can be removed from a developer’s balance sheet through customer debt financing. Further, this structure obviates the need to monetize tax credits, as the owner-end user may claim them.
- **Depreciation Absorption.** Consumer debt financing solves the issue of levered tax credit absorption effectively, though it is an imperfect solution. Unlike a consumer, a company in the business of leasing

equipment to end users may take a tax deduction for the depreciation associated with the equipment. Thus customer debt financing strands value associated with the depreciation of the system that a TPO provider might be able to monetize. One way to view the relative economic superiority of debt and TPO models is evaluating whether the interest rate spread between debt and tax equity structures outweighs the value of equipment depreciation.

- **REC Ownership.** An additional benefit for end users that comes with customer system ownership is REC ownership. In jurisdictions with renewable portfolio standards, each MWh of energy that is generated by a solar system creates a REC for the owner of the system. A typical home may consume 11 MWhs per year, perhaps half of which might be cost-effectively generated by a rooftop solar system. In the TPO system, RECs are typically reserved by the third-party owner. Moreover, developers and tax investors have historically been hesitant to pass the value of speculative residential RECs on to end users in the form of lower lease or PPA payments. Debt financing enables the customer to own the system and the RECs it produces. As the REC markets mature, REC ownership will be a bigger piece of the value puzzle.
- **Energy Price Certainty.** Going solar is often seen as a way for end users to hedge against rising electricity costs. This is partly true in TPO structures. Zero down leases and PPAs will typically have rent/price escalators in the range of 2-4 percent annually. The escalator can be “bought down” with a down payment, though a down payment partly undercuts one of the major selling points for the TPO model. Fixed rate solar loans will ensure that the cost of the end user’s solar power remains fixed for the entire term of the loan (until the loan is repaid, at which point solar energy cost drops to zero).
- **Home Sale Liquidity.** Most homeowners will live in their homes for between five and seven years. What happens to the solar contract when the owner moves? In the case of a lease or power purchase agreement, the end user must either transfer the lease obligations to the new owner or make a buyout payment (which may include penalties for tax implications if the buyout occurs in the first five years). Will the presence of leased equipment, which may someday be removed, impair the value of the home? Can the lease or power purchase agreement be assigned? Uncertainty around these issues may result in discomfort about home sale liquidity for end-users.
- **Residual Ownership.** While the TPO model creates short-term benefits for a homeowner by reducing the cost of electric from lease signing, TPO customers build no equity in the systems that benefit them. End-users that debt finance their systems may have higher up-front costs, but, unlike TPO customers, they own the system when the financing is repaid. How important ownership is to a solar energy consumer is debatable — regardless, the all-in cost of ownership associated with debt financing is likely to be lower than that of TPO financing.
- **Customer Comfort.** Another factor that has limited penetration of the TPO model is the perceived complexity of a lease or power purchase agreement. Consumers are very familiar and comfortable with car or mortgage loans that can be paid off at virtually any time. A solar lease is similar to an auto lease, though those products have their proponents and detractors. Whether perceived or actual, homeowners may have less comfort with a lease or power purchase agreement as a financing vehicle than a loan.
- **Financier Priority.** One final concern tax investors harbor that lenders may not is how their interest in financed solar systems can coexist with the rights of senior mortgage lenders. To the extent a lender makes a secured loan, the liens of a mortgage lender attach to collateral fixtures. If a solar system is deemed a fixture to a mortgaged home, a tax investor could find that its interest in the system is subordinated to the rights of the mortgagee. Solar lenders have no such problems, as the Uniform Commercial Code, which has been adopted in every state, will permit a purchase money lender’s interest in a fixture to prime senior liens with an appropriate and timely filing. While the low solar default rate has made this more of an academic issue for tax equity financiers, it is not an issue that solar lenders have to worry about.

What’s Next?

Whether debt products will change the course of residential solar finance remains to be seen. With low up-front costs, strong market penetration and many purveyors, the tried and true TPO model promises to remain preeminent in the short run. Nonetheless, debt products are gaining ground on the establishment. If they don’t change the paradigm of solar finance, they have at least opened the discussion on the best value proposition for consumers.

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