Solar Power and the Spanish Lesson

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Pain in Spain

In Spain, when the rain isn't falling mainly on the plain, about 5,000 distributed generation (DG) facilities, mostly solar photovoltaics (PV) on residential and small commercial rooftops, kick in to provide from 30–40 per cent of their owners' electricity supply requirements, with the balance drawn from their local utility.[1] This relatively large installed base of solar capacity is a result of the country's generous incentives for renewable DG. But in 2013 this favorable climate changed radically. Spanish authorities, struggling to close a "tariff deficit," meaning the gap between the cost of running the country's electric system and the revenue it brings in, required all DG owners to register their systems and imposed a per kilowatt-hour fee on electricity generated by DG systems. The fee alone is reported to be higher than the wholesale price that Spanish electric utilities pay gas-fired power plants, and has completely altered the economics of DG systems in that country. In most cases, system owners found that the payback period for their investments in solar PV had more than doubled overnight. Adding insult to injury, the government also imposed stratospheric fines for failing to register one's system or pay the fee. The top range of the fine, €30 million, is the same amount that a nuclear plant in Spain would pay as a penalty for leaking radioactive material that endangered public safety. Many DG owners are simply removing or abandoning their solar DG equipment rather than pay the fee or risk the fine.

While the fees and penalties in Spain are certainly draconian, the rationale used by the Spanish Government and utilities to justify these impositions—a "tariff deficit"—is the same one that American utilities are using now to slow the growth of DG, namely, that customers who generate their own power must help cover the fixed and operating costs of an electric grid that they still need when the sun doesn't shine. The response of solar energy developers and system owners generally is that the government and utilities have at best failed to take into consideration the benefits DG provides in alleviating strain on the grid during peak times, and at worst are trying to squelch the competition to cement their monopoly position. On January 27, 2014, the Arizona Corporation Commission opened a proceeding to investigate the value and cost of DG and net metering.[2]

This may not sound like a big battle, but it represents the next major controversy affecting the future of electric utilities: How can extensive renewable DG capacity, and in particular solar PV on residential and small commercial structures, be integrated with the existing electric utility grid, and what will be its impact on the fundamental business model under which utilities have operated for more than a century? It is no exaggeration to say that leaders of traditional electric utilities view DG not merely as a "new normal," but rather as an existential threat.

Over the past decade, we've witnessed the internet pull the foundations out from beneath many different industries, from bookselling and publishing to newspapers and retailing generally. Ten years ago the CLECs (competitive local exchange carriers) fought major court battles to enable their land lines to compete with AT&T's. Wireless and smart phones have since eclipsed them both. Ten or fifteen years from now, the typical residence could have a geo-thermal unit in the basement for heating and cooling, solar PV on the roof and out in the backyard a generator to supplement these two fired by cheap natural gas obtained from fracking the nation's abundant shale deposits. The owner of such a house will not long remain a customer of the electric utility. Few industries have an allergy to change stronger than that of traditional electric utilities and, for them, this scenario is a nightmare from which they would like to awaken.

Widespread adoption of solar DG is no longer considered decades away, and in some markets substantial solar DG penetration is only years away. CNBC reported recently that in the United States in 2013 a new solar generating system was installed every four minutes.[3] Indeed, the City of Lancaster, California recently mandated the installation of solar DG on all new homes within its jurisdiction.[4] What was true of calculators and computers is proving equally true of solar panels, namely quality and power are improving, and prices, though still not cheap, have come down considerably. Throw in a few advances such as a practical and reasonably priced energy storage technology, and these factors will convert our current top-down framework in which large, centrally controlled generating stations serve a mass-market load into a bottom-up model in which a mass of small generating stations serve themselves.

Regulators and politicians join the fray

Nor is the timing of this battle particularly auspicious for the utilities. Tensions between federal and state regulators, on one hand, and monopoly electric utilities, on the other,

[1] "Spaniards Gird for Fee on Solar Power" *Wall Street Journal*, October 21, 2013.
[2] Arizona Corporation Commission Docket No. E-00000J-14-0023, January 27, 2014.
[3] "Power play: Utilities want solar users to pay up" January 9, 2014, available at: *http://www.cnbc.com/id/101319945* [Accessed January 28, 2014].
[4] *http://www.planningreport.com/2014/01/24/lancaster-california-s-mayor-rex-parris-leads-city-become-first-mandate-residential-solar* [Accessed February 1, 2014.]

are likely to get worse before they get better through a resolution that accommodates the legitimate interests of both sides.

State regulators generally view renewable DG positively because it increases the resilience of the grid to the impacts of climate change. New York is a case in point. After taking the Hurricane Irene left hook in 2011, followed by the Superstorm Sandy right uppercut in 2012, New York was on the ropes, grid-wise. Beyond the physical devastation, parts of metropolitan New York City—Gotham itself—were without power for weeks, and the incumbent electric utilities found themselves short on replacement equipment essential to restore service. As a direct consequence, New York's Governor Cuomo has on several occasions questioned whether public utilities should hold their monopoly franchises in perpetuity. Stating that these franchises were not "guaranteed by the Old Testament",[5] he suggested that New York's public utilities laws be amended to provide that the franchise would be held only for a period of years, after which the incumbent's performance would be reviewed and evaluated, and the franchise put out for auction among competitors. Given that governors are generally "big picture" people, we may excuse Mr Cuomo for not elaborating the mechanics of how his proposal might work. It may be unprecedented. What is more important is that the political leader of a key business and commercial state has raised this issue so forcefully and so bluntly. His proposals reflect the impact climate change has had on public utilities' traditional power to dominate the political debate over their franchises.

On February 20, 2014, the New York Public Service Commission adopted a two-year rate plan with Consolidated Edison, New York City's electric utility, that includes a commitment by ConEdison to invest $1 billion over a four-year period to harden and make more resilient its electric system, as well as its natural gas and steam systems.[6]

DG costs and payback periods

DG is one response to the effects of climate change on the grid. But there are a number of issues to consider before we begin comparing rooftop solar PV to iPhones in terms of breadth of adoption.

Costs vary by location and system, but with rebates, tax refunds and other incentives available on residential and small commercial solar energy systems, the final cost of a solar PV system to a home-owner should range from $3–$5 per watt, so that for a 4kW system a customer can expect to pay from $12,000–$20,000. While that is less than it was only a few years ago, it still represents a major purchasing decision for most households. In addition, the payback period can range from eight to 15 years. While that's roughly comparable to the average length of stay for family home-ownership, a family is likely to be several years into that stay before considering the acquisition of a solar PV system, and therefore it has to compare the payback period to the length of time that they expect to remain in the home. Solar generating installations have not been commonplace in prior years in many jurisdictions, and so a home-owner may not be confident that he will "get that money back" when the home is sold. Solar DG financing alternatives attempt to deal with that precise issue.

DG financing alternatives

To address these issues, solar energy companies have come up with at least two alternatives to a straight purchase that can involve little or no money down from the home-owner.

The first is a straight lease of the equipment from the solar energy developer, with the home-owner putting little or no money down. We'll assume that the home-owner will use the zero-down option as that scenario is likely to be of most concern to incumbent electric utilities. The reduction in the home-owner's monthly electricity bill is intended to exceed the monthly lease payments.

First, some of the good points for the home-owner based on a review of a typical solar lease from a leading solar developer:

- no money down and a guaranteed annual kilowatt-hour volume of generation;
- the lease provides for a guaranteed price per kilowatt-hour, and in the event of a shortfall in the annual volume, the home-owner is compensated for that difference at this rate (whether this guaranteed price reflects only a commodity supply charge or in addition takes account of avoided utility delivery services charges is not known, and may be subject to negotiation);
- the solar energy developer does not place a lien on the real property of the home-owner, which is a significant difference from the PACE (property assessed clean energy) model. Under PACE, the development cost of the DG facility is paid off through an increment in the owner's real property taxes, and in most states the lien of real property taxes primes any other lien, including the mortgage The Federal Housing Finance Authority (FHFA) has objected to priming liens to secure indebtedness incurred to install PACE DG facilities in homes with mortgages securitised by FannieMae.[7] This opposition has slowed the progress of the PACE as a DG financing vehicle. The solar energy

[5] *Platt's Energy Economist* (No.378) April 1, 2013, p.13.
[6] *http://www3.dps.ny.gov/pscweb/WebFileRoom.nsf/PressReleases?OpenForm&Count=5000* [Accessed March 3, 2014].
[7] Federal Register, available at: *https://federalregister.gov/a/2012-1345* [January 28, 2014].

developer will presumably still file a UCC fixture financing statement to evidence its interest in the equipment; and

- the solar energy developer, as lessor, undertakes to insure the solar DG facility against loss or damage.

The customer pays all sales and use taxes, and all tax credits, incentives, rebates and renewable energy certificates (RECs) go to the solar energy developer. But the home-owner has the account with the utility, and therefore would get the benefit of net metering, if available.

There also are some disadvantages which the home-owner has to evaluate when considering the installation of solar DG facilities under a zero-down lease. Because the solar energy developer's costs are front-end loaded and some anticipated tax benefits accrue only over time, the developer needs to make sure that the lease will be in force for a minimum term so that it can recoup its investment, take its profit and obtain the full range of expected tax benefits and incentives that attend placing this equipment in service. Whether that is a five-year, 10-year or other term is case-specific and subject to negotiation. The larger point is that the developer's minimum lease term may conflict with the home-owner's expected or actual length of stay in the home. The zero-down lease provides a few alternatives for a home-owner who sells the home before the scheduled expiration of the DG lease:

1. the home-owner can move the solar DG facility to the new home at the home-owner's expense;
2. if the purchaser of the home wants to continue with the system and passes credit approval, the solar energy developer will allow the purchaser to assume the lease;
3. if the buyer of the property wants to assume the lease but does not pass credit approval, the lease suggests that the home-owner add the cost of the renewable DG facility to the purchase price of the home, and then pay down the lease discounted to a present value as described further below. In this case the buyer of the home does not make any further payments under the lease, but must abide by the other lease terms; or
4. prepay the lease for its remaining term, with payments discounted to present value, plus the net after-tax lost value to the developer from loss of the investment tax credit and accelerated depreciation on the system over five years. If the solar panels are to be removed, that's done at the home-owner's expense.

Alternative 1 sounds reasonable, unless the seller is moving to an apartment, condominium or other residence for which such a transfer is not practical.

Alternatives 3 and 4 above amount to the same thing. The language in Alternative 3 presupposes that the seller lists the solar DG system as an exclusion in the real property sales contract but offers it for purchase at a separately stated price. That is likely to put the seller at a disadvantage in bargaining power because, even if the buyer wants a solar DG system he can reject the seller's separate offer, compel the seller to remove it at the seller's expense, and then have the latest model DG system installed under a new zero-down lease. Plus, in this way the buyer avoids paying a lump sum out-of-pocket for a fixture that is already part of the real property. A more realistic assessment of the house sale scenario leads to the conclusion that Alternative 3 merely restates the home-owner's obligation to prepay the lease, albeit with a recommendation that that be effected with a portion of the proceeds of sale. In most cases, proceeds of sale will be the only source of funds in an amount sufficient to prepay the lease, which is why Alternatives 3 and 4 are in the end indistinguishable. There is nothing impossible in any of this, but the home-owner has to recognise that if the prepayment of the lease is large enough, it may affect other plans, such as the acquisition of a new residence.

In the current low interest rate environment, discounting the future lease payments to present value may not yield much benefit. If the owner's projected future stay in the house is shorter than the lease or power-purchase agreement (PPA) term, there is a risk that netting the lease prepayment obligation against aggregate power savings through termination will leave the owner in a negative position.

The second developer-driven financing alternative is a PPA between the home-owner and the solar energy company. Under the PPA model, the home-owner pays a per kilowatt-hour price for energy generated by the DG facility, and that price is ideally lower than the utility's bundled service price. Thus, the more electricity put out by the home solar DG system, the more the home-owner saves.

For a solar energy developer of residential and small commercial installations one disadvantage of the PPA compared to the lease structure is that payments under the PPA are less predictable. Both provide receivables, and the savings should be comparable as far as the home-owner is concerned, but the regularity of payments under the lease can better facilitate the securitisation of those lease assets, and those securities can then be sold to raise capital with which to fund yet more installations. In this connection, it's worthwhile to note that Goldman Sachs agreed to provide $500 million in financing to developer Solar City.[8] The Goldman Sachs/solar developer connection has probably not escaped the attention of the utilities.

Another issue that will affect both the lease and PPA structure is the low price level in current electricity markets, at least in Illinois. Fixed forward commodity supply prices in the Midwest wholesale market for calendar years up to 2017 have been in the range of \$31–\$35 per megawatt-hour for most of 2013. Low natural gas prices and a slack economy chiefly account for these price levels. With regard to customers taking bundled supply and delivery service from the utility, in Illinois the prices that they pay for electricity supply are determined through laddered electricity supply procurement events (i.e. auctions for approximately one third of requirements) run by the Illinois Power Agency (IPA) on behalf of the state's two main investor owned utilities, Commonwealth Edison and Ameren. Illinois has a competitive retail electricity market, and during the past few years many Illinois cities and towns, including Chicago, have approved municipal electricity aggregation referenda, meaning that all of the electric utility accounts in the town are switched to a competitive supplier (apart from those who expressly opt out), and so far these have been at rates that are lower than those charged by the utility. Home-owners contemplating the acquisition of a solar DG system need to consider the impact of current low market prices on the value proposition of solar DG leases and PPA's because the benchmark against which savings are measured is that much lower. Simply stated, if the electricity prices customers are paying are already low, then from a pure price viewpoint the home-owner has to weigh whether the amount to be saved on electricity supply under a solar DG lease or PPA, even with a zero-down option and net metering, is enough to justify assuming the obligations that arise on the back end of the lease.

As for the utilities themselves, Duke Energy in North Carolina proposed a programme in which Duke itself would install and own rooftop solar panels at customer sites. The DG installation would reduce the customer's bills (and demands on Duke's system) by the amount of energy generated. Despite opposition arguments that this would just be an extension of the utility's monopoly, the North Carolina Utilities Commission approved the plan in 2013, subject to some limitations, including a cap of 10MW in aggregate nameplate capacity and a maximum of 425 installations.

Renewable Energy Certificates

In Illinois, the IPA is tasked with procuring both conventional and renewable electricity on behalf of the state's investor owned utilities, ComEd and Ameren. Under recent amendments to its enabling act, 0.75 per cent of the renewables that the IPA is required to obtain on behalf of the utilities for the planning year ending June 1, 2014 are to be sourced from renewable DG facilities of less than 25kW in nameplate capacity. Due to a quirk in the Illinois renewable portfolio standard (RPS) law, though, the IPA has not made any substantial purchases of RECs, and has estimated that it will not be procuring RECs until at least 2018. Attempts to fix this flaw in the statute during the 2013 Illinois legislative session were unsuccessful. Thus, to the extent that REC sales comprise part of the economic benefits of the solar DG lease or PPA, the actual operation of a state's RPS must be considered.

The same is true of net metering if the parties are relying on that as one of the economic benefits. Current Illinois law caps net metered accounts at five percent of the utility's load for the preceding planning year, which runs from June 1 to May 31. Eligibility for net metering is determined on a first-come, first-served basis. While a zero-down lease is one way to broaden the installed base of solar DG among residential and small commercial customers, under current Illinois law, net metering is not available on a mass-market basis. For net metering in other states, a solar energy developer will need to check both state by state and tariff by tariff to determine the terms and conditions on which it is available, and, if net metering is rationed as in Illinois, whether any volume cap remains available.

The utilities fight back

Having made known their opposition to unbridled expansion of solar DG, which they believe low-cost or no-cost installations would likely foster, utilities have tried different tactics to slow the growth of this energy sector.

Solar DG developers as utilities

Perhaps the most developed tactic for utilities seeking to control the spread of solar DG is trying to have the solar DG developer as either lessor under a lease or seller under a PPA classified as a "public utility" under state law. A common feature of being an electric public utility is having an exclusive service territory. As a general proposition, subject to some minor exceptions, no one else can sell electricity to end-users within that territory. This is evident under the historic electric public utility model, which contemplated a single vertically integrated generation-transmission-distribution system serving native load. If an incumbent electric utility can persuade the state utility regulator to view a solar DG developer operating under either a PPA or a solar DG lease as a public utility, that would effectively shut down solar DG development.

[8] "Goldman Sachs to Finance \$500 Million for SolarCity Roofs", Bloomberg News, May 16, 2013, available at: *http://www.bloomberg.com/news/2013-05-16/goldman-sachs-to-finance-500-million-in-solarcity-roofs.html* [January 28, 2014].

This was tried in Iowa in 2013 in the case of *SZ Enterprises, LLC d/b/a Eagle Point Solar v Iowa Utilities Board*.[9] In that case, the developer Eagle Point filed with the Iowa Utilities Board a petition for a declaratory order that, based on the facts in the petition, Eagle Point was not a "public utility" under the Iowa public utilities statute.

In its petition, Eagle Point described the transaction in which it proposed to engage. Eagle Point would be generating electricity from facilities of which it retained ownership and would be selling it to an end user, so the argument that it might be a public utility had at least some plausibility. In Eagle Point's specific project, it was going to install an on-site solar PV system on a building owned by the City of Dubuque. The city would enter into a PPA with Eagle Point pursuant to which it would purchase all of the output of the solar DG system, which would be installed on the city's side of the meter. The building would remain connected to the distribution system of Interstate Power and Light (IPL) and it was contemplated that the DG facility would provide only a portion of the building's electricity supply requirements. The city would continue to purchase most of its electricity supply from IPL. The Iowa Utilities Board concluded that Eagle Point would be a public utility.

However, on appeal, the Polk County, Iowa District Court reversed the board's determination. According to the court, the principal question for Eagle Point was not just whether the entity wished to sell to every member of the public without discrimination, but whether those sales are of a type to "clothe the operation with a public interest". The court noted that the renewable energy equipment would be on the customer's side of the meter, the customer would still be connected as an IPL customer and would still be purchasing power and energy from the public utility. The court rejected as artificial the board's implicit distinction between behind the meter generation equipment owned by a customer and the same equipment owned by a third party, even though the end result is the same. In the court's view, the board's analysis elevated the form of the financing method over the substance of the transaction. That the customer chose to finance a renewable energy system through a PPA rather than through a loan or lease did not in the court's view change the essential character of Eagle Point's proposed transaction.

The court added that a third-party renewable energy developer is not a natural monopoly and lacks market power, and that there is substantial competition between such developers. Further, customers are free to negotiate individual prices and terms of service with them. Under the facts and circumstances of this case, the Iowa District Court concluded that Eagle Point was not monopolizing and did not intend to monopolize the IPL territory with a public service commodity, and therefore reversed the board's finding that Eagle Point was a public utility.

The Iowa statute under consideration in *Eagle Point* also contained a definition of "electric utility" which was potentially broader than the term "public utility," and the board argued that Eagle Point fit into this category. While the court rejected this argument, it illustrates why the public utilities laws of each state have to be reviewed with care in order to determine the scope of entities regulated by the state's public utilities commission.

Resale and redistribution

Another potential tactic for utilities seeking to slow the growth of solar DG development in their service territories is to seek to prohibit a solar DG lease or PPA as a resale or redistribution of electricity. Generally, these restrictions are quite common, and may be found either in the utility's tariffs, the public utility commission regulations, or both.

Leases and PPAs should not be considered resales or redistributions of electricity because the solar developer is not reselling electricity originally produced by the utility. Rather, the electricity is independently generated by the equipment that is the subject of the PPA or solar DG lease. That said, the resale and redistribution provisions of tariffs and regulations must be reviewed to determine whether their scope is broader than usual.

Conclusion

Residential and small commercial solar DG definitely has the potential to expand, and this will reduce demand for service by the utility. The availability of zero-down financing alternatives will enable many customers who would otherwise not be able to afford these facilities to install them. But even zero-down financing is not an unalloyed good. The home-owner must consider potential back-end costs, particularly if a sale of the home were to occur prior to the scheduled termination of the lease or PPA. Likewise, if RECs or net metering is intended to be part of the overall financing package, both the regulatory regime of the state and its actual operation must be carefully reviewed to determine whether these are in fact available. Solar developers must also advert to the possibility that utilities will continue to try to slow things down, or even, as in the case of Spain, try to impose additional costs on the industry to achieve what they consider a leveling of the playing field.

[9] *SZ Enterprises, LLC d/b/a Eagle Point Solar v Iowa Utilities Board* (Case No.CVCV 009166) March 29, 2013 Iowa District Court.