Changes Ahead For California Residential Solar

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Two looming regulatory developments in California will have a significant effect on the residential solar market.

The state is rewriting the rules for net metering, where homeowners who use solar to generate their own electricity can sell any excess electricity to the grid. The rewrite is expected to scale back the benefits of net metering for solar customers.

The current multi-tiered residential rate structure used by investor-owned utilities in the state, which has been an important driver of the economics of solar for high-usage customers, is being re-evaluated and is likely to undergo substantial change or to be superseded by a new structure entirely.

These developments are likely to make California a tougher market for rooftop solar companies. However, the market should still remain viable, and there could even be new opportunities.

Net Metering

California has long supported behind-the-meter residential solar electric generation through net metering, which allows customers to sell surplus solar power back to the utility at the full retail value of the electricity. Net metering was instituted in California in 1996 and has been expanded several times over the years to allow for wider participation and greater benefits.

Under the existing net metering program, the amount of net-metered capacity that can be added for each investor-owned utility is capped at 5% of the utility's aggregate customer peak demand, which is defined as the sum of the maximum peak demands for each customer rather than the maximum demand for the utility as a whole.

When the cap is reached, there will be approximately 5,570 megawatts of installed solar capacity across the systems of the three California investor-owned utilities. At the end of September 2013, Pacific Gas and Electric reported that it had 902 megawatts of net-metered capacity connected to its system, which is the equivalent of 1.87% of the utility's aggregate customer peak demand. / continued page 12

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would be allowed to expire. This would give a boost to solar rooftop companies that retain ownership of systems and lease them or sell electricity from them to homeowners.

The draft bill would also eliminate investment tax credits for solar heating and cooling systems put to business use.

Wind and other projects that qualify for tax credits under current law because they were under construction by December 2013 would be given a deadline to complete the projects. There is none currently. The deadline would be the end of 2016.

PRIVATE EQUITY FUND MONITORING FEES come under fire.

Gregg Polsky, a law professor at the University of North Carolina, took aim at monitoring fees paid to private equity funds by their portfolio companies in an article in *Tax Notes* magazine in early February.

Polsky is representing a whistleblower who has called some such fees to the IRS' attention. The fees are paid under ongoing consulting agreements.

Polsky says either no work is done or the fees exceed what a third party would charge for the same services or they are a percentage of earnings or are paid out to more than one owner in proportion to the ownership interests. The last two features suggest the fees are dividends. Polsky says he and associates examined 229 portfolio companies owned by private equity funds and identified $3.9 billion in questionable monitoring fees paid from 2008 to 2012.

Polsky wrote another article in 2009 criticizing waivers of management fees that he said some private equity funds use to convert ordinary income into capital gains. The IRS is looking into the practice.

A LIKE-KIND EXCHANGE is being litigated.

A predecessor company of Exelon reinvested the proceeds / continued page 13

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San Diego Gas and Electric and Southern California Edison had net-metered capacity of 1.67% and 1.46% of aggregate customer peak demand, respectively.

California's net metering program allows a customer who installs a solar photovoltaic system of one megawatt or less to receive a financial credit for power generated by his or her system and delivered to the utility grid. A typical solar customer will generate more solar power than needed during some parts of the day and less than needed, or none at all, during other parts of the day and throughout the night. The same pattern can arise seasonally, often with the generation of more power than needed during the summer and less than needed during the winter.

Under net metering, customers can send excess power to the grid and use this power as a credit to offset purchases of power from the grid that are made in the same 12-month period.

Two looming regulatory developments in California will affect the residential solar market.

For a customer whose rates are wholly volumetric, meaning that the customer is charged for the kilowatt hours of usage without any fixed charges or demand charges, as is the case for customers of PG&E and SDG&E, this allows the customer to sell power back to the utility at the full retail rate for the power, including all generation, transmission and distribution cost components. Aside from small minimum charges, which are binding only for customers with extremely low net usage, these customers can avoid having to pay electric bills by selling back enough solar power to offset all grid purchases. Customers who generate enough solar power to more than offset all grid purchases can also receive net surplus compensation payments, but at the wholesale rate — rather than retail rate — for the surplus power generation.

Impact of Rates

Net metering has worked hand in hand with residential rate design structures to make solar PV economical for many customers, particularly high-usage customers. Most of California's residential customers have inclining block rates, with prices increasing over two, three or four tiers of rates as usage increases. Net metering is particularly valuable for high-usage customers because it allows them to avoid being pushed into higher tiers and rates.

For example, the January 2014 rates under PG&E's default residential rate schedule were 13¢ per kWh for "baseline" usage, 15¢ per kWh for 100% to 130% of the baseline amount, and more than 32¢ per kWh for usage greater than 130% of baseline amount. In other words, rates for highest levels of energy usage are about two and a half times the rate for the baseline level of usage. (The amount of energy in each tier is linked to the customer's "baseline" usage amount, which is set at 50% to 70% of the average residential electricity usage in the customer's climate zone.)

The steeply inclining block structure greatly increases the value of net metering for high-usage customers, and these customers have represented a significant portion of the market for residential solar in California. Under the January 2014 rates, a high-usage PG&E customer whose solar system reduces electricity consumption from 200% of baseline to 130% of baseline has effectively sold power to the utility at a rate of 32¢ per kWh. By contrast, a low-usage customer whose energy usage without solar PV is at 130% of baseline would sell power to the utility at just 13¢ to 15¢ per kWh.

Customers also have the option to select a time-of-use rate schedule, under which rates are higher during peak periods of the day and during the summer months and lower at night and during other low-usage periods. These rate schedules are usually tiered, meaning that rates vary both by time of consumption and by level of consumption. For customers on time-of-use rate schedules, net metering credits are assigned a value based on the retail cost of power in place at the time of the power generation.

As a result, solar power generated during a summer late afternoon may offset two to three times that amount of winter or nighttime power consumption. For example, under January 2014 rates, one kWh of solar power sent to the PG&E grid between 1 p.m. and 7 p.m. on a summer weekday would earn a credit of 28.7¢, which is the summer peak-period residential time-of-use charge for one kWh of baseline usage. During the summer months between 9 p.m. and 10 a.m., this credit would offset 2.85 kWh of power, since the baseline cost of power is just 10.1¢ per kWh during this interval.

Concerns that the net metering program was shifting costs to customers who do not have solar on their roofs led to legislation requiring a study of net metering's costs and benefits for all ratepayers. AB 2514, enacted in 2012, directed the California Public Utilities Commission to undertake a study "to determine who benefits from, and who bears the economic burden, if any, of, the net energy metering program."

The study was completed in October 2013 by an outside consultant, Energy and Environmental Economics, Inc.

The study found that the level of the net metering subsidy is highly linked to the rate structure and that the utilities' current residential rate structures, with steeply inclining block rates and little or no fixed charges, yield a subsidy of 20¢ per kWh of solar generation.

Critics of the study claim the study does not account for the full benefits that solar PV provides to the grid and overstates the cost-shifting impacts. Despite the criticism, the study is being used to support proposals for changes in the residential rate structures of the three main California utilities.

New Direction

In the fall 2013, the state legislature enacted another bill, AB 327, that will end the current net metering structure in mid-2017 or, if earlier, when net-metered systems reach 5% of a utility's aggregate customer peak demand. AB 327 requires the California Public Utilities Commission to develop a new "standard contract or tariff, which may include net metering" for solar customers, to replace each utility's current net metering structure when the current program expires.

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from sales of two power plants in Illinois in three other power plants in Texas and Georgia in what the company treated as a "like-kind exchange."

The IRS disagreed, and the issues are now in front of the US Tax Court. Exelon filed a petition in January. The IRS says the company owes $517.4 million on the transaction, plus another $6.6 million for the next tax year after the sale.

Ordinarily, anyone selling a project can defer taxes on the gain from sale by using a bank as a "qualified intermediary" to reinvest the sales proceeds in similar property. The proceeds are paid to the bank. The seller then has 45 days to let the bank know where it wants the money reinvested. The reinvestment must be completed within 180 days or, if earlier, the due date for the tax return for the year in which the original projects were sold (including extensions).

The replacement power plant can be a new power plant that the seller is building.

An Exelon subsidiary, Commonwealth Edison, agreed in March 1999 to sell Edison Mission Energy seven base-load power plants and five peaking units as part of utility deregulation in Illinois. Commonwealth Edison was a subsidiary at the time of Unicorn Corporation. Exelon was formed in a merger of Unicorn and PECO Energy Company in October 2000.

Two of the plants were ultimately sold to Edison Mission Energy on December 15, 1999 in a deferred like-kind exchange using State Street Bank as the qualified intermediary. The two plants were Powerton and Collins.

Powerton is a 1,538-megawatt coal-fired power plant in Pekin, Illinois. It sold for $930 million. Collins was 2,698 megawatts and had a dual capacity to run on gas or oil. Mission paid $830 million for it. (The Collins plant shut down in 2004.)

Exelon told State Street on January 28, 2000 where it wanted the sales proceeds reinvested. It directed the bank to reinvest $725 million in unit 1 of the J.K. Spruce power station in San Antonio, Texas. The plant was / continued page 15

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Unlike the current structure, the new net metering structure would not have any cap on participation. However, the new net metering program must ensure that no costs are shifted to non-participating customers. Current net metering customers would be grandfathered under the current system for a period of time that has not yet been determined.

The practical effect of the law is that there will soon be two or possibly three distinct sets of net metering customers: one set that will remain under the current program for an indeterminate period of time, another set that will be put under the new program, and a third set that did not have solar when AB 327 was enacted but installs it before the current net metering program ends and that may be under a different set of grandfathering regulations than pre-AB 327 net metering customers.

To implement AB 327, the California Public Utilities Commission must first determine a schedule to transition from the current net metering program to the future uncapped program as well as the rules for grandfathering existing net-metering customers. The CPUC received a range of proposals for how to structure a transition period and the grandfathering rules.

PG&E and SDG&E both proposed that existing net metering customers with solar systems installed before April 2014 be allowed to remain on the current program through the end of 2023. Net metering customers with systems installed between April 2014 and December 2015 would be allowed to remain on the current program through the end of 2020. Net metering customers with systems installed between January 2016 and June 2017 would be transitioned to a new net metering program that would take effect on July 1, 2017.

SCE proposed that customers who participate in the existing net metering program before July 2017 would be grandfathered in the program through the end of 2023.

The California Solar Energy Industries Association recommended a more extensive grandfathering program that would allow customers who participate in the net metering program before July 2017 to remain under the current program for a minimum of 30 years.

The CPUC is expected to issue a decision on grandfathering rules by March 2014.

The commission has until the end of 2015 to develop the new structure for net metering. AB 327 gives the CPUC wide latitude to determine what should replace the current program. Possibilities include a feed-in tariff that allows customers to sell solar power to the utility at a fixed price or a new net metering program that reduces the amount of power that can be sold back to the utility or reduces the financial credit associated with that power.

In all likelihood, the structure of the new program will depend on the default residential rate structure in place when the program rules are adopted. The commission has a rulemaking underway to re-evaluate the current rate structure.

AB 327 gave the CPUC authority to make radical changes to residential rate design, including reducing the number of rate tiers to two through 2018, eliminating the inclining block rate structure entirely thereafter, and imposing fixed monthly charges of up to $10 per month for non-low-income customers beginning in 2015, with inflation adjustments thereafter.

A CPUC staff proposal released in January 2014 recommends that default residential rates shift from inclining block rates to non-tiered time-of-use rates beginning in 2018, and that until then the CPUC reassess the appropriate time-of-use period definitions — for example, what hours and months should be included in the summer peak rate period — and the rate differentials between time-of-use periods — for example, how much higher the summer peak-period rate should be than the summer off-peak-period rate. The proposal also recommends gradually reducing the number of tiers to two between 2014 and 2018, and greatly reducing the rate differentials between the tiers to just 20% by 2018, at which time the tiered rates would be an optional alternative to the default time-of-use rates. Finally, the staff recommends phasing in a fixed charge that would start at $5 a month and increase to $10 a month by 2018 with future inflation adjustments. The staff proposal does not recommend using minimum bills (instead of fixed charges), but if the CPUC were to adopt minimum bills, it recommends that they should start at $10 per month in 2015 and increase with inflation.

These potentially substantial changes to the residential rate design structure create many unknowns for residential solar developers, as the implications of the changes for the market will depend on the details of the new rate structures.

Potential Effects

There are three areas in which changes in residential rate design could alter the market for residential solar.

One is time-of-use rates or inclining block rates. A shift to non-tiered time-of-use rates (from the current default inclining block rates and optional tiered time-of-use rates) may improve the economics of solar PV for moderate usage residential customers with relatively high shares of energy consumption during peak periods. The extent to which this will be the case will depend on the rate differentials between the peak and non-peak periods and on how much overlap the new time-of-use period definitions retain between the peak time-of-use period and the period of maximum solar generation. These structural time-of-use definitions are likely to differ from those in place in the optional time-of-use rates that are currently available, and how they are structured could significantly support or debilitate the market for residential solar.

For example, the current on-peak period for customers on SDG&E's optional residential time-of-use rate is weekdays from noon to 6 p.m., a period that captures about 35% of the output from solar PV systems in the San Diego area. In January 2014, SDG&E proposed to shift the on-peak period in the winter to weekdays from 5 p.m. to 9 p.m., a period when little solar generation can be expected and, in the summer, to weekdays from 2 p.m. to 9 p.m. These new time-of-use periods would lead to a significant reduction in solar PV generation during the peak periods: less than 10% of the output from solar PV systems would occur in the peak period under SDG&E's proposal instead of about 35% under the current definitions, with the remaining output occurring in the semi-peak period.

If large differentials are maintained between on-peak and semi-peak rates, then this shift could undermine solar PV economics for customers on time-of-use rates. However, changes to time-of-use period definitions may not be quite so detrimental to solar PV economics. For example, the CPUC staff report raised an idea of a split on-peak period that would include both morning hours and late afternoon or evening hours. This structure would offset a portion of the loss of mid-afternoon on-peak hours with the addition of morning on-peak hours, which could include hours of high solar generation.

Another area where change could have an effect is a reduction in the rate differentials for inclining block rates. A reduction in the rate differences between tiers would eliminate the very high upper-tier rates that have been a cornerstone of residential solar economics.

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owned by the local municipal utility, the City Public Service Board known as "CPS," and it entered commercial service in December 1992. The transaction closed on June 2, within the 180-day period.

Exelon directed the bank to spend another $870 million to purchase a 15.1% undivided interest in units 1 and 2 of the Wansley power station and a 30.2% undivided interest in units 1 and 2 of the four-unit Scherer power station from the Municipal Electric Authority of Georgia or "MEAG." The Wansley units were completed in 1976 and 1978. All four Scherer units were completed between 1982 and 1986. The Georgia sales closed on June 9.

Both the Texas and Georgia transactions were structured as SILOs. The IRS does not view SILOs as real purchases. Congress effectively shut down their use (as well as cross-border leases called LILOs) in 2004. The IRS issued a notice in 2005 indicating that it considers SILOs a form of tax shelter called a "listed transaction." It had listed LILOs earlier. The government has won all six litigated LILO and SILO cases to date. A seventh case had a 10-day trial before the US Court of Federal Claims, but the court has not yet released a decision. The facts of the Exelon case may differ materially from those in the other cases.

Rather than buy interests in the power plants outright, an Exelon subsidiary entered into sale-leasebacks with the two municipal utilities. The subsidiary was the lessor. CPS leased back its project for 31.75 years and has an option to repurchase the project at the end of the lease for 101.2% of the amount Exelon paid for the plant. If CPS fails to purchase, then Exelon can require it to find a power contract or a tolling agreement for Exelon with a third party for a term of 9.58 years. CPS paid the Exelon lessor 76.9% of the purchase price for the plant as advance rent six months after the lease started. The advance rent is being treated as a "section 467 loan" and reported by Exelon as income over the lease term.

MEAG leased back the Wansley units for 27.75 years and the

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However, reductions to the upper-tier rates would be done concomitantly with increases in the lower-tier rates, potentially making residential solar economic for lower-usage customers whose rates were too low earlier for the investments to pencil out.

That said, the California Public Utilities Commission has a goal of maintaining a viable and growing residential solar market in California. It is a daunting task, given the competing interests.

Residential rate structures must be designed to balance a number of equity and efficiency concerns that have implications both for solar and non-solar customers. The grandfathering provisions for customers who installed solar before AB 327 became law must be sufficient to provide confidence to customers who are evaluating new solar installations that their investments will not be undermined through future rate design or net metering changes while also satisfying concerns about cost-shifting. The design of time-of-use periods must be done carefully to provide the proper price signals to consumers while at the same time being sensitive to the potentially significant implications for commercial and industrial customers that have structured operations and entered into investments based on the current time-of-use periods. The restructured net metering program must support the residential solar market without increasing rates for non-solar customers.

Given these challenges and complexities, some amount of market disruption is inevitable.

However, there is also opportunity in that new segments of the residential population may be open to solar for the first time with the shift to non-tiered time-of-use pricing.

The retail electricity rate structure and the benefits from net metering are expected to change.

Finally, another area where change would have an effect is the introduction of fixed charges or higher minimum bills. Fixed monthly charges make residential solar less economic because these charges cannot be avoided through net metering. However, the extent of the impact depends on the level of the charge. Furthermore, if a higher minimum monthly bill is used in place of a fixed monthly charge, then the impact is likely to be less significant, particularly for those customers who offset most, but not all, of their electric bills with solar generation and continue to purchase a small amount of power from the utility. Under a fixed charge, these customers would pay the fixed charge in addition to their volumetric charges. Under a minimum bill, the volumetric charges would be credited against the minimum bill amount.

How the net metering program is restructured will also have a significant effect on the long-run viability of residential solar in California. The restructured program is likely to be less generous than the current program. These very important residential rate design and net metering program details have yet to be worked out.

Environmental Update

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ambient air quality standard. The petition says that cross-state pollution from the upwind states contributes significantly to violations of ozone standards in the ozone transport region as a whole — the downwind states are already included in the transport region — and asks EPA to require the upwind states to take steps to reduce their emissions.

EPA must act on the petition within 18 months, but the agency has broad discretion to approve or disapprove the petition. Whether EPA decides to expand the transport region may depend in part on whether CSAPR survives review by the Supreme Court.

In addition to the effort under section 176A, some states and cities have begun taking a more targeted approach to cross-state pollution by filing petitions under section 126 of the Clean Air Act. These petitions ask EPA to find that a particular stationary pollution source or group of such sources emits in violation of the good neighbor provision of the Clean Air Act. If EPA so finds, then the source has just three months to reduce its emissions or shut down.

Greenhouse Gas

The US Supreme Court will also hear arguments in a separate dispute over whether the fact that EPA is required to regulate greenhouse gas emissions from motor vehicles also obligates the agency to regulate such emissions from stationary sources like power plants.

If EPA loses, it could be forced to curb or withdraw current and planned rules imposing limits on greenhouse gas emissions from new and existing power plants and other industry sources, especially coal-fired power plants.

The lawsuit claims that EPA has no authority under the Clean Air Act to require major stationary sources to obtain permits for their greenhouse gas emissions. The Supreme Court let stand earlier a finding by EPA that greenhouse gases like carbon are pollutants that pose a potential threat to human health and the environment and, thus, the agency has the power to act. However, the latest case will test whether the agency only has authority to regulate carbon emissions from motor vehicles or can regulate them more broadly.

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