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# The US Electricity Industry and the Low-Carbon Transition

Carole MATHIEU

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# Abstract

While the wave of liberalisation produced a fragmented, but now stabilised, industrial landscape, the US power sector is about to undergo another major transformation with the low-carbon transition. Against a background of combined weak demand for electricity, a boom in distributed solar PV power and a decline in the profitability of merchant assets, incumbent stakeholders are currently dealing with further questions about the future of their business models.

Driven as much by market forces as by government support mechanisms, these destabilising factors have an impact, which is still difficult to assess, but the need to control future transformation is already at the heart of debate. In areas where output is priced on the wholesale markets, new tools are being studied to secure compensation for some power stations, with the issue of possible excessive dependency on natural gas in the background. At the same time, an increasing number of states are questioning the design of their support mechanisms for distributed energy.

If net metering, the main support mechanism for distributed solar PV power, has been a resounding success because of its simplicity, it is now criticised because of the problems of covering grid costs and the cross-subsidies it leads to. Although reforms are always difficult to implement, since they involve a conflict of increasingly organised interests, consensus is beginning to emerge regarding the structure of retail sales tariffs. Nevertheless, calls for an assessment of distributed generation according to its actual value for the system are increasing, without any real convergence of views on the methodology to be adopted to date.

Conventional stakeholders are also looking to adapt in order to find growth opportunities where primarily only challenges appear. The diversification of activities is an important lever for transformation, even if the case of NRG Energy illustrates the difficulty in making strategic shifts while maintaining investors' confidence. Changes in the regulatory framework are also being considered, to allow for alignment between the *utilities'* financial interests and the objectives of the low-carbon transition.

More importantly, states such as New York, California, or even Minnesota are engaging in discussion on the optimisation of centralised and distributed resources. The industrial structure in place influences the

approaches adopted locally, particularly with regard to the demarcation between the regulated sphere and activities subject to competition. However, what these initiatives have in common is that they seek to pre-empt and support the changes, *via* a reinforcement of the interface role of distribution grid operators, to eventually promote the emergence of new stable and competitive business models.

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# Introduction

The challenge to the legality of the Clean Power Plan before the courts was no surprise in the United States. This extensive programme aimed at reducing $CO_2$ emissions from power stations currently in operation was indeed unprecedented in both content and form. Since any legislative action about the climate was excluded because of opposition by Congress, these new emission standards were cleverly introduced by the Federal Environmental Protection Agency (EPA) on the instructions of the executive power[1]. The legal battle, led by coal companies and states for which the operation of coal mines still is a major source of jobs and wealth, started right after the plan's publication in the Federal Register on 23 October 2015. It focuses on both the scope of the EPA's mandate and the plan's economic feasibility.

However, the surprise was much greater when the Supreme Court decided on 9 February 2016 to suspend the plan's implementation until the case is heard. Made by five votes to four, this judgement is a serious setback for President Obama, who will leave the White House before the announcement of the final verdict, which should not occur before the end of 2016, or even early 2017. It equally weakens the confidence of the United States' partners, at the time of the first implementation stages of the Paris Agreement. Although nothing says that the plan will finally be buried, the first deadlines will at best be postponed since, according to the original schedule, the states had to submit their plans for complying with the new standards to the EPA by summer 2016.

The question which then arises is whether a failure of the Clean Power Plan is really likely to prevent the low-carbon transition in the United States. The intended reduction, in the region of 32% by 2030 compared to the 2005 levels, is far from insignificant, all the more so since the electric power sector alone represents over one-third of the country's greenhouse gas emissions (EIA, 2015a). On paper, the effort is significant, but this does not necessarily mean that the Clean Power Plan in itself is a revolution for the US electric power sector. A closer look reveals that the transformation is already largely well under way: with coal which is losing in competitiveness in the face of plentiful and cheap domestic gas production,

1. The White House, "Presidential Memorandum – Power Sector Carbon Pollution Standards", 25 June 2013.

and at the same time, with renewable energies, with wind and solar PV power in the lead, experiencing drastic cost reductions, electricity generation is already moving steadily towards a lower carbon intensity. For the period 2005-2014, electricity generation only increased by 1% while, at the same time, $CO_2$ emissions decreased in the region of 15% (EIA, 2015a). In other words, market forces, boosted by the different support mechanisms for renewables and other regulations on air pollutants[2], are already tipping the balance towards the objective set by the Clean Power Plan.

As the 2016 publication of the annual opinion poll conducted by the reference media *Utility Dive* has recently shown, very few leaders of *utilities* are said to be opposed to the Clean Power Plan. On the contrary, two-thirds believe that the emission standards are acceptable or could have even been stricter (Utility Dive, 2016). As ultimate proof of this calm reception of the new plan, the Edison Institute, which represents around 200 private *utilities* serving around 70% of end consumers, has chosen to remain on the side lines of the legal proceedings launched last autumn.

The Clean Power Plan is not causing major concern because it is mainly extending a trend, and above all establishing safeguards against any reversal of the trend. Whether the gas price increases or some renewable energy support mechanisms are challenged here or there, the Clean Power Plan provides stakeholders in the electric power sector with the guarantee that the regulation will take over in all the states, and not only among those which are the most focused on environmental issues. In its absence, the revolution should move forward, but would be more exposed to market fluctuations and the instability of public policies.

Therefore, even without the federal framework, the decarbonisation of the electric power sector is already upsetting the balance in place. Like within the European Union, we can see the pieces of the puzzle begin to fit together, without necessarily an accurate and stable vision of the role that the different stakeholders will have to play. The US electric power sector is also in transition and the implementation of the Clean Power Plan should only support or even accelerate this process. Since the industrial landscape is particularly fragmented, with procedures for opening up to competition varying depending on the states as well as different support policies for renewable energies, there is not one, but several American experiences on the subject. However, everywhere the same major issues arise. What is the

2. See in particular the standards relating to mercury and other toxic gas emissions, the Mercury and Toxic Air Standards, introduced by the Federal Environmental Protection Agency in November 2012.

role and the regulatory model for utilities in the 21st century? What future is there for merchant assets? How can centralised and distributed generation co-exist harmoniously? How can the rise in prosumers be supported without harming the interests of conventional consumers? Or even, how to encourage innovation downstream from the grid, while ensuring the best overall cost-effectiveness of the electricity system?

For the time being, none of these issues have been completely settled. All over the country, there is intense debate, initiatives and other pilot schemes are increasing, as well as back-pedalling. This paper proposes to provide an overview of the transformations at work to try to better outline the new organisational model which the US electricity system could be heading towards.

# The existential crisis of stakeholders in the centralised system

## The organisation of the US electricity system after the liberalisation movement

The US electric power sector is characterised nowadays by a high degree of fragmentation. In the standard system, inherited from the start of the 20th century, electricity is generated, transmitted, distributed, and sold by companies with a monopoly in a given geographical area. The revenue of these entities, commonly called utilities, is determined by the public authorities at a level to cover costs deemed to be efficient and including a rate of return on invested capital which is sufficiently high to justify the investment. There are to date nearly 3,200 utilities, including 210 investor-owned utilities (IOU), 2 009 are owned by the states or municipalities and 9 by the Federal authority, and finally nearly 900 have a co-operative status and are therefore owned by groups of consumers, mainly in rural areas. In addition to the varying shareholder structures, all the utilities no longer fall under the vertically-integrated model. From the end of the 1970s, and particularly with the adoption of the Public Utility Regulatory Policies Act in 1978 which introduced avoided cost pricing methodology for utilities purchasing electricity generated by third parties, competition gradually developed in the generation segment. So, new stakeholders emerged, non-utility generators, whose status was expanded by the Energy Policy Act of 1992. The centralised wholesale markets then took off in the 1990s due to Orders 888 and 889, drawn up by the Federal regulator in 1996, which in particular required the *utilities* to provide free access to the grid and to charge for this transmission service on a non-discriminatory basis. The establishment of regional stakeholders, the Regional Transmission Organizations and Independent System Operators, promoted by Order 2000 issued in 1999 by the FERC, enabled the utilities' transmission grids to be operated by an independent stakeholder across large areas, and this stakeholder also took over the management of the

wholesale market[3]. At the same time, some states decided to open up the retail market to competition, but implementation difficulties and the Californian crisis in 2000-2001 put an end to the reform movement, or even initiated steps backwards. In 2015, in 21 states out of 50, competition was at work in the retail market (Borenstein & Bushnell, 2015).

**Table 1: The five dominant structures for US utilities in terms of shareholders and competitive environment**

| I. Private *Utilities* | II. Public *Utilities* (municipal or co-operative) |
|---|---|
| a. Wholesale market open to competition | a. Wholesale market open to competition ④ |
| i. Retail market open to competition ① | |
| ii. Retail market not open to competition ② | b. Vertically-integrated model and standard generation system ⑤ |
| b. Vertically-integrated model and standard generation system ③ | |

*Source: Ronald Lehr (2013), "Utility and Regulatory Models for the Modern Era", America's Power Plan, Ifri.*

The sector's liberalisation process has achieved varying degrees depending on the states, and the concept of utilities has taken on more blurred boundaries. Some for example, have remained on the fully-regulated, vertically-integrated operator model, while others have delegated management of transmission to a regional operator, only taking on the distribution and owning, or not, deregulated assets. With regard to independent power generators, their share of the total volume of electricity generated in the United States was 35% in 2012, as opposed to 1.6% in 1997 (Borenstein & Bushnell, 2015).

Two decades after the start of the liberalisation process, the industrial landscape now seems stabilised, but the transition to lower carbon generation sources creates new challenges.

3. Regional Transmission Operators and Independant System Operators now cover two-thirds of the United States (RAP, 2015).

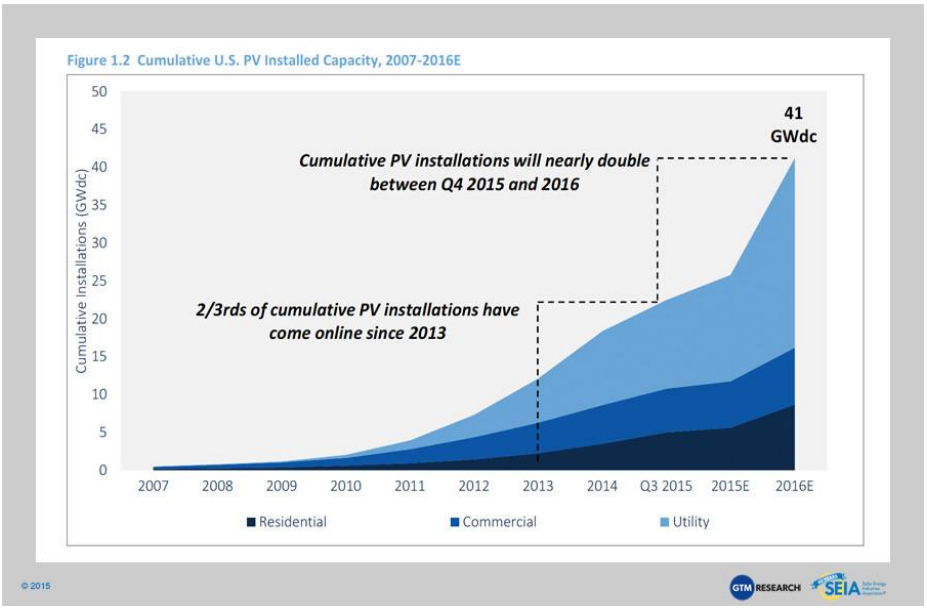
## The threat of a "death spiral" for utilities, from myth to reality

It was really in 2013 that speculation about the future of utilities gained momentum with the publication of a study commissioned by the Edison Institute called "*Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*." Its author, Peter Kind, noted a juxtaposition of trends which threatened to destabilise the centralised utilities model. The first of these trends involved the downturn in electricity consumption. In addition to the slowdown in population growth and the redirection of the economy towards less energy-intensive activities, demand management programmes are in place in 24 states (ACEE, 2015). Finally, it should be noted that increasingly more customers are participating in demand-response programmes, aimed at adapting demand to the electricity supply in real time. There were 9.3 million customers who contributed to such initiatives in 2014 (EIA, 2016a) and their number should continue to grow given the recent decision by the Supreme Court upholding FERC's authority to regulate demand-response in regional wholesale markets, and therefore the principle established in 2012 of compensation at the market price (real time and day-ahead)[4]. As a result of these various changes, electricity consumption has only increased by +1% per year over the last decade and the EIA (2016b) does not envisage a significant increase in the coming years, with only +0.4% in growth predicted for 2016 and +1% for 2017.

The other latest trend characteristic of a more radical break, is the growth of a new category of stakeholders, the prosumers, who have generation capacity, mainly solar PV power, and hence are reducing their dependency on electricity supplied by the grid. This is where the parallel with the wireline telecommunications industry arises. Like the latter, the electricity grid would be bound to gradually lose market share, with the ultimate risk being the winning combination between distributed generation and effective individual storage systems. This time scale remains theoretical at this stage, but the rise of solar PV power in the residential and commercial sectors has been very real since the late 2000s. There are now 784,000 households and businesses which are equipped with solar PV installations (SEIA/GTM, Q3 2015), 40% of which are located in California (EIA, 2015b).

4. Federal Energy Regulatory Commission vs. Electric Power Supply Association, No. 14–840, (25 January 2016).

**Graph 1: Solar capacity installed in the United States for the residential, commercial, and utility-scale sectors**




*Source: SEIA/GTM Research (2015a), "U.S. Solar Market Insight, Q3 2015".*

The momentum is general for solar PV power in the United States. For the three first quarters in 2015, it accounted for 30% of all new installed capacity (SEIA/GTM, 2015). Driven by lower installation costs, which fell by 73% between 2006 and 2015 (SEIA/GTM, 2015), the spread of solar PV power is also supported by various government mechanisms. At federal level, an Investment Tax Credit (or ITC) of 30% has been applied since 2006 to solar PV installations in the residential, commercial, and utility-scale sectors[5]. Sixteen states have also introduced additional tax credits for the residential sector. Finally, more than half of the states (29 states and Washington D.C.) have introduced supply targets for electricity from renewables (Renewable Portfolio Standards or RPS) which the utilities and other suppliers have to comply with by specific dates. Out of these states, five have additionally specified sub-targets specifically for distributed renewable generation (NC Clean Energy Technology Center, 2014).

Finally, it is the compensation mechanisms for electricity injected into the distribution grid which have significantly contributed to making distributed solar PV power competitive. In the United States, the most widespread system is net metering. Introduced for the first time in 1979 in Massachusetts, its main advantage is its simplicity. At the end of a specific

5. Initially, it was anticipated that this credit would expire at the end of 2016. Nevertheless, the budgetary compromise for 2016, passed in December 2015, provides for its extension until 2019 at the current rate of 30%. By 2022, this rate will be reduced to 10%.

period, usually a month, unconsumed output and that injected into the grid is deducted from the quantities taken from the grid and only the residue is paid for by the customer. The prosumer's bill is reduced through this compensation, as a rule carried out on the basis of the retail price, which significantly improves the attractiveness of investing in distributed solar PV power compared to the sole benefit of self-consumption. In addition, net metering provides the owner of the solar PV installation with a tool to cover against the risk of increasing retail sales prices, since part of their supply has a known and stable cost, that of the initial investment[6]. In practical terms, this system only requires a single meter, if it is capable of running in both directions, and the impact on billing remains very legible for the prosumer. On the other hand, it is relatively easy to implement from a political point of view, since it avoids the public authorities having to explicitly grant a subsidy to this type of installation. Due to these many advantages, net metering became more widespread in the 1980-1990s. It is currently in place in 43 states and the Energy Policy Act of 2005 requires its implementation by all government utilities if their customers request it.

Nevertheless, the consensus was broken at the start of the 2010s, when under the combined effect of the lower cost of technology and commercial innovations[7], the volumes affected by this compensation system ceased to be marginal. Distributed solar capacity reached 11 GW across the United States at the end of 2015 and should be increased eightfold by 2030, if the current mechanisms are maintained[8] (Gagnon & Sigrin, 2016). The utilities' fear is that the savings in billing are becoming such that they are threatening their business model. Indeed, the issue is that these prosumers remain connected to the grid to ensure their supply when on-site output is missing or insufficient, and the sizing of the infrastructure, particularly grids, is unchanged since the peak consumption and therefore the maximum transit level is not reduced a priori. The main fault with net metering is it really compensates excess output at the retail price and therefore at a potentially higher level than the actual value for the electricity system. Moreover, the tariff treatment is identical for energy injected and withdrawn when it has different costs depending on whether it is in peak periods or not. In such a situation, it is the other grid users,

6. Or even that of the monthly rent paid to a third-party company owning the installation (solar leasing), or even that of a generation purchasing agreement (power purchase payments) to a third-party company owning the installation.
7. The third-party ownership model, associated with rents or purchasing agreements, covers 60% of the solar PV power market and 90% in the residential segment (GTM/SEIA, 2015b).
8. Among the assumptions made for the baseline scenario developed by NREL are that of a zero carbon price at federal level and that of retaining net metering, with a potential shift towards compensation for excess generation at wholesale price level when the existing caps in terms of capacity are reached.

those who do not have solar PV installations, who must cover the possible loss of earnings for the utilities. The "death spiral" is triggered when these bill increases encourage standard grid users to join this prosumer category. Unchanged fixed costs are spread over an increasingly restricted net consumer base until the standard compensation model for utilities based on electricity sales topples. This outlook is especially worrying as investment needs in the transmission and distribution grids are significant, with an estimated $880 billion for the period 2010-2030 (Brattle Group, 2008). Maintaining a high level of reliability in the electricity grid is an increasingly significant challenge against a background of digitalisation of the economy, increased exposure to extreme weather events, and also the emerging risk of cyber-attacks on infrastructure. However, there has to be full confidence in the covering of costs in order to make these investments, for which the amortisation is spread over several decades. If the investors perceive a regulatory risk, then an increase in the cost of capital would follow, damaging the utilities' investment capacity and thus reinforcing the vicious circle again.

However, three years after the alarm was raised, these same issues are being tackled more calmly. The threat of a substantial erosion of sales has above all been put into perspective. In an extreme scenario, with energy efficiency gains of 2% per year and a market growth in individual solar PV installations of 15% per year, the erosion of electricity sales would only be 10% by 2040 (Nadal & Herndon, 2014). The worry has nevertheless not won over investors, who continue to support the stable returns that utilities provide them with. These are now valued above the average of the last 15 years and in line with the S&P 500, as Peter Kind notes in an update of his 2013 report (Kind, 2015). In other words, there is no market reaction because sales are not experiencing a significant fall and the loss of earnings generated by net metering is now supported by the remaining consumers, and all the more easily as the additional cost is offset by lower fuel prices, particularly gas (Kind, 2015). The long-term risk is not eliminated, as is evidenced by a recent study (Gagnon *et al.*, 2016) which evaluates the technical generation potential of solar PV installations on rooves at 1,432 TWh/year or the equivalent of 39% of annual electricity sales, but it is nevertheless more a question of adapting than the imminent failure of the utilities model.

## The reduced profitability of merchant assets

In terms of market output priced on wholesale markets, the concerns are just as high. In 2015, wholesale electricity prices at major trading hubs on a monthly average basis for on-peak hours were down 27%-37% compared with 2014 (EIA, 2016c). The electricity wholesale markets are following the downward trend observed on the gas market, since it is the gas power stations which set the marginal electricity price for most of the regional markets. However, the gas spot prices traded on Henry Hub averaged at $2.61/MMBtu, which represents the lowest level seen since 1999 (EIA, 2016c). Other factors for the fall may be added, including low growth in demand for electricity, the development of demand-response, and finally the growth in solar and wind energy at a very low marginal generation cost. For 2013, the impact of supply targets for renewables, the RPS, on the wholesale prices was evaluated at between 0 and 0.5 cents per kWh depending on the regions concerned, and is reflected by an annual transfer of wealth from US power generators to consumers that may be up to $1.2 billion (Wiser *et al.*, 2016).

In this context, coal and nuclear assets are highly affected. For 2015, 14GW of coal generation capacity was retired, representing 5% of the entire coal capacity in place at the end of 2014. In addition, retirements announced for 2016 and 2017 affect 10.7GW of additional capacity (EIA, 2016b). Nuclear power, which is not dealing with the same constraints in terms of emissions as coal, is also seeing its profitability decline. In the case of the latest power station closures, that of Kewaunee with a capacity of 556MW, located in Wisconsin and operated by Dominion Resources up until 2013, or even that of Yankee, with a capacity of 604MW, located in Vermont and operated by Entergy up until 2014, the low wholesale price is stated as the main reason. In 2015, Entergy has also announced the early closure of two new nuclear power stations, Pilgrim with a capacity of 728MW, located in Massachusetts and Fitz-Patrick with a capacity of 838MW, located in New York State. In its press release, relating to the closure of Pilgrim, Entergy criticised the faults in the design of the regional electricity market, which prevented a fair valuation of the benefits of nuclear power, namely carbon-free and stable generation, with on-site fuel storage (Entergy, 2015). On the same lines, Exelon announced a possible closure of the Quad Cities nuclear power station in Illinois in the course of 2015, if no reform was introduced to acknowledge the carbon-free characteristic of this generation source.

However, capacity mechanisms intended to compensate available capacity, are in place in all the major regional markets, such as PJM which brings together 13 States in the eastern United States, ISO-NE which covers New England, or even NYISO which covers New York State. They have even usually been subject to reinforcements in recent years, particularly after the intense cold period in the winter of 2013-2014 and the ensuing interruptions in supply. The regional operator, PJM, in particular has updated its model (capacity performance model), by allowing for higher compensation combined with stricter constraints on capacity availability. The first auction including these changes for 2018-2019, has resulted in sales prices 37% higher than those seen in the previous year, 2017-2018. This good news for power generators' revenues, however, may not be sufficient to warrant continuing the activity, because this additional compensation is annual, with no guarantee over the long-term trend, and more fundamentally, because the amounts involved remain marginal. In 2014, the revenue associated with capacity represented less than a fifth of the revenue associated with the wholesale market in the PJM area (RTO Insider, 2015).

In this context, the financial health of independent power generators has seriously deteriorated. 2015 stands out as a terrible year, with a drop in share prices from 30 - 66% for the major power generators, AES, Calpine, Dynergy, NRG and Talen (Kunkel, 2016). At the same time, the utilities present in these deregulated segments are looking to separate their market assets, like NextEra which has decided to sell two gas power stations in Texas, with a total capacity of 3,000 MW. Although gas power stations are competitive nowadays, the transaction is presented by the President of NextEra, Armando Pimentel, as consistent with "the [company's] strategy to reduce market exposure while recycling capital in the portfolio by expanding the assets backing long-term agreements[9]." The utilities are actually seeking to expand their portfolios of regulated assets and favour renewable generation, which benefits from long-term purchase agreements and is therefore not exposed to wholesale market fluctuations. Hence in its investment plan for 2019, NextEra states that $3.5 billion will be dedicated to wind and solar generation assets and that its subsidiary, Florida Power and Light, will spend $7.5 billion modernising its transmission and distribution grid (Market Realist, 2016).

Another strategy consists of trying to convince the regulatory authorities of the need to establish long-term purchase agreements for base

9. NextEra Energy Resources' press release, "NextEra Energy Resources Agrees to Sell Texas Fossil Generating Assets to an Affiliate of Energy Future Holdings", 27 November 2015.

generation which has become uncompetitive on the wholesale markets. Two cases are currently under discussion in Ohio. On the one hand, First Energy is asking the Public Utility Commission of Ohio, PUCO, to approve purchase agreements over 15 years which would cover the generation of two of its coal power stations, one nuclear power station, and its stakes in two other coal generation facilities operated by Ohio Valley Electricity Corporation, OVEC, or a total of 3,300 MW. On the other, American Electric Power, AEP has also proposed similar arrangements for nine of its coal power plants and its stake in another, operated by OVEC, or a total capacity of 3,100 MW. In both cases, the utilities would offer to sell the output contracted in this way on the PJM energy, capacity, and ancillary services markets, and would bill the net costs or gains (difference between the market price and the actual generation cost) to the consumer. The argument put forward to justify such risk transfers is that, in their absence, Ohio would face an excessive dependency on gas. While in this state, gas power stations scarcely represented 1% of electricity generated in 2004, this figure actually rose to about 25% in 2015 (EIA, 2015c). Yet, the reliability of these power stations is in doubt, insofar as their supply depends on possible constraints on the gas network and interruptions cannot be totally excluded, as the polar vortex episode in the winter of 2013-2014 demonstrated, with increases in winter electric bills reaching 80% for residential customers in New York State for example (NYS DPS, 2014). Additionally, First Energy and AEP suggested that the consumer would be the winner in the long term, assuming a future increase in gas prices. In December 2015, both stakeholders reached an agreement with the regulatory authority's services, in both cases for a purchase agreement over eight years, combined with commitments for AEP to deploy solar and wind capacity and to modernise the grid. These statements, which will only be confirmed after approval by PUCO's college, have unleashed a volley of criticism from competing power generators. Exelon and Dynergy in particular have stated that they were able to offer more competitive supplies, with nuclear power supply from Illinois in the case of the first company and building gas power stations in the case of the second one. Furthermore, PJM, the regional grid operator, is launching a study about the implications of such a re-regulation of 6 400 MW on the operation of the regional market and its capacity to attract new investments in the area.

If these measures were to be approved by the Ohio regulator, their legality would very likely be disputed before the federal courts, as was the case for support measures for building new power stations in New Jersey and Maryland. In both these states, the regulators introduced in 2011-2012 contracts for difference, for a period of respectively 15 and 20 years, to ensure stable revenue for the operators of these new power stations,

irrespective of the result of capacity auctions in the PJM area. These arrangements were rejected by the judges in 2013, because of their interference with FERC's exclusive authority on transmission and electricity sales in inter-state trade[10]. In October 2015, the Supreme Court announced that it would decide soon on both cases. In other words, although some states are more clearly demonstrating the will to counter the presumed inadequacies of the regional markets, their local initiatives are perceived as sources of regional inconsistencies and therefore remain exposed to rejection by the federal authorities.

In sum, utilities are afraid for the coverage of the costs of their regulated activities and the power generators pricing their electricity on the markets are struggling to keep their power stations open. In this context, regulatory authorities of the different states are looking for new paradigms which would ensure a more harmonious relationship with the forces of change. The first of the projects involves distributed renewable generation, which the regulators plan to build a favourable regulatory framework for, but also fair from the perspective of other grid users.

10. PPL EnergyPlus, LLC vs. Douglas Nazarian, et al., Civil Action No. MJG-12-1286 (Maryland) (30 September 2013) and PPL EnergyPlus, LLC vs. Robert M. Hanna, et al., Civil Action No. 11-745 (New Jersey) (11 October 2013).

# Distributed solar PV generation: attempts to reform support mechanisms

## Overview of the discussions

Net metering is now under fire from the critics because of the costs transfers which it is likely to introduce. It is when it is combined with a pricing system that is exclusively or largely volumetric (in $/kWh), or even more with an increasing block pricing system designed to charge large consumers more heavily, that the windfall is the greatest[11]. In the third quarter of 2015, 29 states introduced corrective measures or envisaged changes to legislation in place, regarding net metering directly or the design of sales tariffs for the end consumers (NC Clean Energy Technology Center and MCG, Q3 2015).

The debates are particularly difficult, because they are not purely technical, but on the contrary involve more political concepts, such as fairness or consumers' freedom of choice. Supporters of reform point out that disadvantaged households are less likely to be equipped with solar PV installations, for issues of ownership of the roof and access to funding in order to carry out the initial investment. Hence, 49.1 million households with an annual income below $40,000 represent 40% of all US households, but less than 5% are owners of solar PV installations (Mueller & Ronen, 2015). Therefore, cross-subsidies are occurring between these households, for which energy also represents a larger share of the budget, and the wealthiest households.

Nevertheless, the same observation may also be used by the other side, to defend an extension of the support mechanisms for distributed solar PV power and therefore an expansion of these beneficiaries. Furthermore, supporting the prosumers also means supporting consumers' independence with regard to the centralised system, an argument which is receiving attention in a country firmly attached to the concept of personal

11. In the case of California, the actual net average value of savings made by the residential prosumer would be nearly $7,000 higher with the increasing block pricing system, than if a uniform tariff were in place. (Borenstein, 2015).

freedom. This interest in distributed systems is even reinforced by questions about the grid's reliability in extreme climate events. In his last State of the Union Address, President Obama further emphasised that the United States "was taking measures to give home-owners the freedom to generate and store their own energy, something which environmentalists and the Tea Party have given their support to[12]." Indeed, the subject extends beyond the usual boundaries between Democrats and Republicans and creates unprecedented alliances. Debbie Dooley, a Tea Party activist, became known to the general public for her fight for the expansion of residential solar PV power in Georgia, is working to establish a "Green Tea Coalition" with the environmental organisation Sierra Club. This initiative, launched in 2013, has removed some regulatory barriers to the deployment of distributed solar PV power, by allowing for example, the initial investment to be made by a third-party company, and no longer necessarily by the prosumers themselves. In Florida, an equally diverse coalition with the name "Floridians for Solar Choice" is currently looking to obtain a sufficient number of signatures to organise a referendum by popular initiative in late 2016 and to obtain the same arrangements as those adopted in Georgia *via* a constitutional amendment. The challenge is to open up the solar PV power market in Florida, which is currently only 14th across the country in terms of installed capacity (SEIA, 2016), despite particularly favourable sunlight conditions.

More generally, reversing the support mechanisms in place is a complicated exercise when interest groups get organised and make their voices heard. In this respect, it should be noted that the solar PV power industry currently employs 209,000 workers in the United States, including 63% in the residential sector and 15% in the commercial sector. In 2015, 35,052 new jobs were created in this sector, which represents a growth rate 12 times greater than that seen for the entire US economy. Compared to the coal-mining industry, employment in the solar PV power sector is 77% higher (Solar Foundation, 2016). This impact in terms of jobs is one more argument for the solar power lobby, the Solar Energy Industries Association (SEIA), which has greatly expanded its activity in recent years and has just experienced its first great victory, with the extension of the federal tax credit passed at the end of 2015. Beyond these private interests, the prosumers also form influential groups and strongly challenge regulatory changes. Much controversy has emerged in Nevada recently where the regulatory authority, NPUC, wants to reverse the incentives granted to the residential solar PV power market, which between

12. State of the Union Address by President Barack Obama, 12 January 2016.

2013 and 2014 went from 28th to 14th place in the national rankings, before reaching 2nd place in 2015 (Green Tech Media, 8 January 2016). To curb this growth better, the regulator made the decision to gradually reduce, from 1 January 2016, compensation granted as part of net metering, to bring it back down to the level of wholesale prices by 2020 and to increase the monthly service charges for solar PV owners from $12.75 to $38.51 by 2020. The uniqueness of this decision is that it applies to all installations, including 18,000 existing to date, which is likely to call into question the logic of investments decided beforehand. The regulator defends its position by highlighting the need to protect 98% of consumers who, under the old system, had to bear a cost transfer of $16 million per year[13]. However, this abrupt change in the rules of the game has angered the-prosumers who organised demonstrations in Las Vegas in early January 2016, launched five petitions, and also initiated a class action lawsuit against the public operator, Nevada Energy, for having misled consumers about future profits associated with an investment in solar PV installations. Solar panel developers, such as SolarCity, Vivint and Sunrun, immediately announced their withdrawal from Nevada and the dismissal of 650 employees. When asked about this, the three candidates for the Democrat primary, Hillary Clinton, Bernie Sanders and Martin O'Malley, strongly disapproved of this decision, also knowing that the president of the Nevada regulatory authority was previously appointed by the Republican camp. Faced with the scale of the controversy, Nevada Energy presented new options in early February, for example spreading the transition over a longer period (NV Energy, 2016). Therefore, the regulator will have to decide again on the support mechanism in the coming months.

Nevertheless, this episode is unlikely to set a precedent, insofar as retroactive decisions are generally avoided. Even in Hawaii, where the penetration of distributed solar PV power has already reached 20% on some islands (Champley, 2014), the new plan under consideration also provides for a reduction in the amount of credits granted as part of net metering, but only for new installations. But even without making such a radical shift as in Nevada, all states committed to reforming support mechanisms face an increasingly structured opposition, which also causes them turn towards more complex answers.

13. Remarks cited by Green Tech Media, 14 January 2016, "Nevada Regulators Refuse to Back Down on Rate Changes for Rooftop Solar."

## Reforming pricing structures

In the much-feared context of the utilities' compensation model collapsing, much reflection is being given to adjusting the pricing structures for grid electricity. In 2013, the report commissioned by the Edison Institute pointed to the need to move away from the purely volumetric pricing model and to introduce a fixed portion, or to increase this portion in the electricity bill. At the end of 2015, 26 requests of this type were under consideration in 18 states. The average requested increase was 70% and six utilities even asked for an increase greater than 100% (NC Clean Energy Technology Center, Q3 2015). Different formulas have been suggested, including billing a fixed amount per consumer connected to the grid, a total amount according to the maximum subscribed capacity (in $/kW), or even a minimum amount, for example $20 for the first eligible 100 kWh consumed. Some formulas are intended to be applied to all consumers, and others only to prosumers. In all cases they are the subject of particularly lively debate.

Their initial justification is always that the grid costs and other system costs are only reduced if peak consumption itself is reduced. Yet, unless self-consumption is carried out during these peak periods, which is not encouraged as part of simple net metering, then the prosumers are generating the same costs for the grid as in the *ex ante* period. Therefore, increasing the fixed portion of bills would result in giving a fair price to the "insurance" value of the grid.

Nevertheless, increasing this fixed portion at the expense of the variable portion can challenge another objective of the energy policy, which is to promote energy demand management. Low consumption households, which are located in urban areas, in energy-efficient accommodation, or very often, with modest incomes, would be penalised compared to high-consumption households, which are more often located in rural areas and/or have higher incomes (Lazar & Gonzalez, 2015). From this point of view, it is obvious that the regulatory authorities are reluctant to accept the utilities' requests, or at least they only approve increases much lower than those proposed, as was the case recently in Kansas and Missouri (NC Clean Energy Technology, Q3 2015).

Furthermore, some also challenge the initial justification of these requests, insofar as a very limited part of the constituents of the distribution grid is actually sized according to the maximum power associated with the individual consumer. The major part of the costs is really derived from peak demand across the system and not from the individual consumer. By encouraging all consumers to reduce their

individual peak demand, it is not specifically targeting those consuming during system peak load and consequently it is penalising others (Lazar & Gonzalez, 2015). Finally, increasing the fixed portions could also curb the drop in the utilities' revenue, but also reinforce the economic attractiveness of individual storage solutions, and therefore simply encourage consumers to expect this tipping point which would result in them withdrawing totally from the grid (Bronksi *et al.*, 2015). Increasing the fixed component of bills would therefore prevent the utilities from adapting and working now for a smooth and efficient co-existence between centralised and distributed systems.

The challenge is such that even the author of the 2013 report, Peter Kind, now considers that high fixed monthly costs are not a lasting solution to the decline in utilities' revenues (Kind, 2015). Nevertheless, the option which is currently gaining in popularity is variable tariffs over time (time of use tariffs), separating the standard periods from the critical periods (critical peak pricing), or even enabling real-time billing (real time pricing) according to the market prices. In this way, customers are encouraged to move their consumption outside of peak periods and therefore to effectively reduce the costs of the electricity system. This method, so far not very widespread and reserved for large industrial customers or only offered on a voluntary basis, is gaining attention among the utilities (Spiller, 2015).

Furthermore, dynamic pricing is made possible by the massive development of smart grids and meters, which has been encouraged by the Recovery Plan of 2009 and continues to benefit from investment grants from the Department of Energy. In 2013, there were nearly 52 million smart meters installed, including 89% in the residential sector (EIA, 2015d). The initiatives are tending to increase and initial feedback is positive. At the end of a two-year pilot project, the Sacramento Municipal Utility District (SMUD) achieved a shift of 10% in its peak demand, which took place in the summer over the time range 16h-17h, to the standard periods. With these results, the SMUD decided to extend variable tariffs to all of its consumers. The Californian regulatory authority (CPUC) further decided in July 2015 that the three largest utilities in the state, Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric, should also launch pilot projects from 2016 with a view to generalising the scheme by 2019.

In other words, the pricing structure which best seems to balance the objectives to reflect the costs, encourage demand management and reduce the electricity system costs, combines a low fixed component, excluding shared infrastructure costs, and block pricing to allow for higher pricing

per kWh as consumption increases, and finally a price variation over time to reduce peak demand across the system (Lazar & Gonzalez, 2015).

## Setting the price of distributed solar PV power according to its value for the system

The other advantage of deploying smart meters is to enable a closer monitoring of injections of distributed solar PV power into the grid, paving the way for other forms of compensation than those based solely on net metering and retail prices. To calm discussions on the reform of net metering, more regulatory authorities are initiating studies on the actual value of electricity generated by the prosumer at a given time, with a view to deriving compensation in $ / kWh of this value and applying it through smart meters. If the net metering system is retained, then only excess output compared to the site's consumption is compensated at this value. However, the "buy-all, sell-all" model can also be considered, under which the customer purchases all the electricity that they consume at the retail price and sells all of their output at the solar PV power value. So, it closely approximates a feed-in tariff system, with the differences being that it is the value and not the cost of solar PV power which determines the buyback rate and that there are not two, but only one transaction between the prosumer and their supplier, always *via* deduction on the bill. In the latter case, the problem of cross subsidies and coverage of grid costs is resolved and this compensation model is perfectly compliant with the 1978 PURPA legislation which permits utilities to buy electricity from third-party producers only at avoided cost (Taylor *et al.*, 2015). Furthermore, it removes the inconsistency with increasing block pricing which does not interfere with attempts to manage demand. However, precisely because it nevertheless closely approximates the feed-in tariffs, some have suggested that this value-based pricing system would expose the prosumers to taxation on revenue from these sales and could cause them to lose their right to federal investment tax credit (Skadden *et al.*, 2013). Another practical difficulty concerns the legal compatibility between this system and the business model under which solar energy developers own the plant installed on their customers' rooves.

Seeking to evaluate the value of solar PV power empirically is a justified approach, but its implementation is not without difficulties. Indeed, it presumes to accurately identify each of the benefits and costs that distributed solar PV power provides or imposes, and to monetise them. The benefits for the electricity system are the avoided costs, which particularly include energy, capacity, the use of the transmission and distribution grid, and line losses. The costs here can involve possible

investments that need to be carried out on the grid to receive the solar generation. The exercise becomes even more complex when it comes to monetising the environmental benefits of distributed solar PV power, in terms of reducing $CO_2$ emissions and improving air quality, or even the societal benefits in terms of jobs or contribution to the country's energy independence. Consequently, great diversity can be observed in the methods used (Fine *et al.*, 2014) and controversy persists. A new fault line has even appeared between advocates of distributed solar generation and advocates of centralised solar generation. The latter consider that it is the solar PV power stations and not conventional power stations which should act as the reference case. Concurring with this, a study conducted by Brattle Group (2015) at the request of the company, First Solar, which represents 30% of the centralised solar PV power market, has recently shown, from the case of Colorado, that centralised generation was substantially less expensive than distributed solar PV power, while recalling that these power stations allowed "universal access" to solar energy.

In the third quarter in 2015, 12 states published or initiated studies, or even held formal discussions about the actual value of distributed solar energy and net metering policies (NC Clean Energy Technology Center, Q3 2015). To date, however only two specific actions have been identified, one in Austin, Texas, and the other in Minnesota. Austin Energy, the eighth largest utility in Texas, has been applying tariffs based on the value of solar energy for the residential sector since 2012, as part of the buy-all, sell-all system. Initially set at 0.128 $/kWh, the price has been revised annually to take the lower gas prices into account. In 2016, it is 0.109 $/kWh while the standard retail price varies between 0.018 $/kWh (for the first 500 kWh from October to May) and 0.114 $/kWh (for consumption in excess of 2,500 kWh from June to September), with a fixed charge of $10 per month. In Minnesota, a methodology for assessing the value of distributed solar PV power was formally approved by the Department of Trade in 2014. Unlike the example of Austin, the annual review of tariffs only affects new installations. The purchase agreements are signed for a minimum period of 20 years, with a fixed tariff only taking inflation into account. The second major difference with Austin is that the utilities can choose whether or not to apply this methodology to the residential sector. To date, none have made the request. The framework is in place, but there is no concrete implementation of tariffs at the value of solar PV power in Minnesota.

Recently asked to rule on the future of net metering after 2017, the Californian regulatory authority, CPUC, for its part considered that it was too early to envisage introducing value-based tariffs, and that to date, the

practical disadvantages exceeded the theoretical benefits (CPUC, 2016). In reviewing the arguments which were presented against this proposal, one that was retained was the reference to an "administrative burden". This system is in fact based entirely on the regulator's ability to conduct the tariff exercise each year, resisting various pressures, also with a risk of destabilising the sector if the tariffs are too volatile. The idea has been raised of a "loss of control" by the consumer of their own generation to the benefit of the utilities which takes on a more crucial role here. The risk would be of losing one of the key drivers for the development of distributed solar PV power, namely the willingness to self-produce for self-consumption.

By deciding to extend net metering on the basis of the retail price up to 2019, CPUC is confirming that the on-going debate is extremely complex. The alternatives are attractive conceptually, but their actual implementation generates suspicion and controversy equally. The pricing of solar PV power at its actual value will have to be explored further in order to be a credible approach. Finally, it should be noted that a recent study (Taylor *et al.*, 2015) has demonstrated, by studying 50 different locations in the United States, that value-based tariffs of solar PV power which are situated in the price ranges currently under discussion, are generally not sufficient to cover the updated average generation cost (levelized cost) of distributed solar PV power, even including the federal tax credit, therefore requiring the addition of a premium to support development of the sector. Thus, even if the value-based tariffs encourage a more objective a priori assessment of fair compensation to be granted to prosumers, the debate may switch to the amount of the additional premium.

# Embracing change rather than resisting it

Rather than withdraw into a resolutely defensive posture, some conventional stakeholders in the US electric power sector are also open to transformation projects, to finding growth opportunities where initially only challenges appear. This redefinition of the business models is being developed in parallel with reflection on the regulatory framework, always with the idea of promoting new uses, according to a level playing field, and hence moving towards a new effective organisational structure for the US electricity system.

## Diversification of activities and new business models

Determined not to give up their place completely to the solar developers, the utilities are now turning towards supply services downstream of the meter. They can also capitalise on the trust that they have built over a long time with consumers and hope to strengthen this relationship, but also better control the location of installations in order to maximise their benefits for the grid. Some are investing in the residential solar PV power segment through deregulated subsidiaries, as has been the case in Georgia since July 2015 with the creation of Georgia Power Energy Services, a subsidiary of Georgia Power belonging to Southern Co., one of the largest vertically-integrated utilities in the United States. In Arizona, two private utilities, Arizona Public Service (APS) and Tucson Electric Power (TEP) obtained permission from their regulator in 2014 to offer solar PV installations to their residential customers, as part of their regulated activities, to attain their binding target of 15% of electricity generation from renewables by 2025. In the case of APS, the programme is aimed at 10 MW installed capacity at a cost of $28.5 million. The consumers receive a discount on their monthly bill of $30 for the use of their roof for a period of 20 years. In the case of TEP, the programme is aimed at 3.5 MW installed capacity at a cost of $10 million. The contractual terms and conditions are different since here the consumers must pay a lump sum of $250 to be equipped with plant sized according to their electricity consumption, and then they are liable for a fixed amount over 25 years, spread over their

average current bill. This amount is only revised upwards or downwards if electricity consumption increases above or decreases below 15%. These pilot projects are so far restricted to Arizona. The other regulatory authorities are more reserved, fearing to give an undue competitive advantage to the utilities compared to third-party companies.

However, the legitimacy of the utilities to operate in the market segment of community solar is unchallenged due to the administrative complexity of managing this type of projects with multiple participants (Coughlin et al, 2010). In March 2013, 79% of programmes in place were managed by the utilities or by third-parties acting on the utilities' behalf (IREC, 2013). These programmes allow consumers to pool their financial resources to become involved in the development of a single solar PV installation and to directly perceive the benefits *via* reductions in their individual bills. The aim is to democratise access to solar energy, given that 50% of American households and companies are tenants, or do not have sufficient capital, or a suitable roof to install individual solar PV power systems (White House, 2015). A federal initiative was launched in November 2015, the National Community Solar Partnership, in order to share the best practices and hence encourage the deployment of community solar programmes, for the benefit of all consumers and in particular low- and middle-income households. The other great advantage of these programmes is that they can easily be designed in such a way so that the participants bear the total cost of them, without the cross-subsidy issue with non-participants (SEPA, 2013). According to the programmes in place, consumers can either purchase or lease capacity in kilowatts, and then receive discounts on their bills corresponding to the actual or estimated generation of their portion in the installation, or commit to buying a given quantity of electricity at a fixed rate over a long period, for example 20 years. This emerging market, which represented 66 MW at the end of 2014, is growing rapidly. For the period 2014-2020, its average annual growth rate should reach 59% (GTM, 2015).

Diversification of activities is however a difficult strategy to implement, as is shown in the case of NRG Energy. This company is not vertically integrated, but has subsidiaries which operate in the market generation segment, with 49 GW capacity, including 45 GW conventional capacity, and in the segment supplying the deregulated markets, with three million residential and commercial consumers. Under the leadership of its directors, and particularly its CEO, David Crane, the company was positioned at the forefront of the transformation by developing new renewable generation activities and energy services, including distributed solar PV power, recharging networks for electric cars, and connected

houses. The specificity of the NRG strategy was to seize these new opportunities, without seeking to withdraw from conventional generation. Hence in spring 2014, NRG purchased the eighth largest solar developer in the country, Roof Diagnosis Solar, and at the same time, taking over Edison Mission Energy's generation assets, which comprised 8 GW of conventional capacity. However, under pressure from its investors, NRG Energy had to move towards a segmentation of its activities. Since 1 January 2016, the residential and commercial solar PV power, recharging of electric vehicles, and energy management of dwellings have been grouped together in a subsidiary called "GreenCo", for which the parent company's financial support cannot exceed $125 million. On the same date, David Crane was dismissed. Although his strategy was intended to guarantee NRG Energy a lasting existence in a competitive and ever changing world, it was deemed too complex and risky by investors with a more short-term view.

## Aligning the utilities' interests with the low-carbon transition objectives

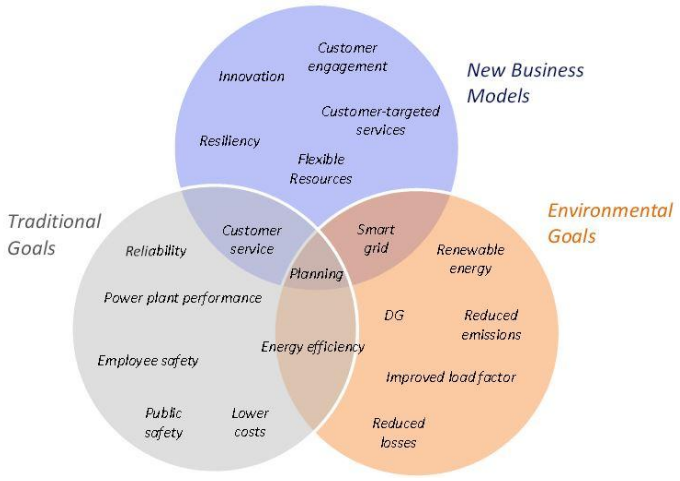
Another adjustment component involves the utilities' compensation model, where they are expected to both maintain a high level of grid reliability, while making infrastructure available which will facilitate new uses, which themselves will then compete with the main activity of distributing electricity to the end consumer. From now on, a new paradigm needs to be thought up which removes this apparent contradiction between the distributor's financial interests and these new uses which are decreasing the quantity of distributed electricity (MIT, 2015).

The first of the reforms consists in decoupling the revenues collected by the utilities from the volumes of electricity sold. The sale prices are adjusted during the pricing period, each year or even at each new billing cycle, to take the actual sales volumes into account and to maintain revenue collected at the level of revenue allowed by the regulated operator. The decoupling may be full, without differentiating the causes of lower sales, or even specifically targeting decreases corresponding to energy-efficiency efforts or to the deployment of distributed resources, insofar as these can actually be measured. Implemented in California since 1982, decoupling is gradually gaining in popularity. In 2015, full decoupling was in place in 15 states and targeted decoupling (lost revenue adjustment mechanisms) in 14 other states (Gilleo *et al.*, 2015).

Once the deterrent effect has been lifted, incentives still need to be developed to interest regulated operators in implementing the low-carbon

transition *via* distributed solutions. The challenge is to break with the standard cost of service regulation model, designed at a time when the utilities mainly had to meet the growing demand by investment decisions in generation and delivery (Whited *et al.*, 2015). In the current context, financial incentives should no longer solely be aimed at reducing operational costs and extending the regulated asset base, but gradually be moving towards achieving predefined public policy objectives. Although so-called incentive legislation, combined with bonus-malus systems, has affected some key areas for a long time, such as infrastructure security and reliability; it is now being extended to energy efficiency and especially to receiving technological changes and opportunities related to distributed resources. The idea is to create new profit opportunities, at a time when conventional sources are drying up, and to make the utilities a driver and not a curb on this low-carbon transition.

**Graph 2: Changing performance criteria under incentive regulation**




*Source: M. Whited, T. Woolf and A. Napoleon, "Utility Performance Incentive Mechanisms: A Handbook for Regulators", Synapse Energy Economics, 2015.*

More than improvements compared to past performances, what is sought now is long-term value creation for the consumer. The difficulty then is not to set too general objectives, the achievement of which could only be measured by subjective judgement, without leading to overly targeted performance criteria which would result in operators becoming disinterested in areas not directly covered (NYS DSP, 2014). As a consequence, although there is consensus on the principle of extending the incentive regulation, it is nevertheless more difficult to agree on the precise items which should be subject to incentives (Lowry & Woolf, 2016). Therefore, their scope tends to be relatively limited. In the case of California, incentives generate less than 1.25% of the allowed revenue for utilities, which is not likely to create a strategic shift (Kind, 2015).

Moreover, incentive regulation would likely be temporary, intended to encourage the utilities to gradually turn towards distributed resources for demand management, generation, or even storage. Once the shift is effective and the distributed resources market has also changed scale, these are opportunities for new services which will form an increasing share of revenue for the utilities. The objective here would be not to compete with third-party companies on the distributed resource market, but to offer ancillary services, that only the distribution grid is able to provide, to facilitate and add value to the distributed supply. As envisaged in New York, market-based earnings could, for example, result from identifying potential customers, analysis of consumption data and grid use, engineering services for the micro-grids, or even charges for using the distribution grid as a platform for linking with consumers (NYS PSC, 2015). However, this model raises two initial objections, expressed in the comments on the recent proposal by the New York regulator. The first comes from third-party companies and consists of noticing that these ancillary services still have a vague scope and that the real challenge involves sharing data on consumption and system use. The second comes from the utilities themselves, which insist on the uncertain nature of this new revenue stream and the low probability that they are a credible alternative to existing tools for covering costs, at least in the short term.

## Optimising resources across the system: a planning issue?

In the on-going debate on the new design of the electricity system, New York State is actually at the forefront. The idea of new sources of revenue for distribution utilities serving as platform operator for the distributed energy system (Distribution System Platform Provider) is part of a larger project called Reforming the Energy Vision, which was launched in 2012 at the initiative of Governor Andrew Cuomo. Its ambition and its specificity mean the whole system has to be rethought, by jointly tackling the major issues of reform such as regulation, retail sales pricing, or even the valuation of distributed resources. The approach is therefore holistic, but also dynamic, to the extent that the reforms must support and promote technological changes, commercial innovations, and changing consumer habits, without prescribing a single and rigid path for change. Given the scale of the task, it is not surprising that six New York utilities, the city of New York, and consumers' associations have recently called on the regulator to slow down, by prioritising the issues and dealing with them in a logical order.

The main issue, about which there is still a lack of common understanding, is the exact scope of the distribution utility's role. Demand management, demand-response, distributed generation, charging of electric vehicles, individual storage or even micro-grids are all resources in terms of energy, capacity, and ancillary services, that could benefit the electricity system as a whole, to a potentially greater extent than conventional investment solutions in infrastructure. The expected gain is expressed in terms of avoided cost for the end consumer, grid reliability, but also carbon footprint. Nevertheless, the evaluation of these alternatives assumes a certain degree of co-ordination which, in the New York approach, would be guaranteed by the utilities acting as platform operators. To the contrary, some advocate for the utilities taking direct control of distributed resources, without partnerships with third-party companies, as a better guarantee of optimisation in terms of location and sizing. 65% of directors of utilities, interviewed by Utility Dive, said they were in favour of direct acquisition of these resources and their inclusion in the regulated asset base (Utility Dive, 2016). Others, at the opposite end, considered that the utilities needed to hand over the operational management of their distribution assets to an independent operator, based on the model previously introduced for the transmission grid, to overcome the conflict of interest between the deployment of these new resources and their traditional sources of profit (Wellinghoff *et al.*, 2015). Finally, a last possibility would be to consider a different role for the utilities depending on the distributed resource involved. In the case of storage for example, the Californian regulator has recently mandated the utilities in its area to achieve a target of 1.325 GW of installed capacity by 2020. They are authorised to acquire these new resources, including downstream of the meter, but may not own more than 50% of storage across each of the three segments, namely transmission, distribution, and downstream of the meter (CPUC, 2013). Furthermore, it should be noted that exceptions to the non-ownership rule of distributed resources by the utilities are also being considered in the New York project, when a demonstration has been made that there is no competitive alternative and that it is a question of meeting a need in the system, or even when this could allow middle- and low-income consumers to benefit from these new resources (NYS DSP, 2014).

Without even settling this debate on the division of roles, the only certainty is that the required optimisation will assume an enhanced planning effort with a double challenge. The first is to identify possible grid reinforcements that will be needed to be carried out to integrate the anticipated levels of distributed generation. So, planning ensures that these reinforcements are no longer handled in a sequential order, as the connection requests flood in, but look for a greater cost-effectiveness with

an overall analysis (Wiedman & Beach, 2014). The second is to assess the potential for use of the distributed resources, with the aim of postponing or avoiding transmission or distribution grid reinforcements. The most advantageous locations may thus be identified, then enabling the utilities to introduce the corresponding incentives. In California, the AB 327 legislation adopted in October 2013, required the large private utilities to introduce distributed resources programmes (Distributed Resources Plans), particularly with a view to accurately identifying the areas where these new resources were likely to provide consumers with the greatest benefit and by providing pilot projects to demonstrate the validity of their conclusions. Presented in the summer of 2015, these plans must be approved by the regulator in March 2016 to subsequently be implemented with a review every two years. They are naturally accompanied by new capital expenditure, estimated for example by Southern California Edison at between $327 and 560 million for the period 2015-2017, and then between $1,405 and 2,585 million for the period 2018-2020. A similar process was followed in New York State, although the dominant feature is less technical and more focused on the transition to the new market model envisaged in the REV initiative. Implementation plans (Distribution Service Implementation Plans) must be published by the utilities in June 2016, at the end of an additional six-month period compared to the initial schedule. They will have to further elaborate the new concepts and specify how the involvement of market stakeholders may be stimulated and what changes this requires from the utilities' point of view.

As in California, the other side of the approach is to test new concepts *via* pilot projects. These include, for example, a digital platform that Con Edison intends to introduce to inform consumers about the demand management levers and to connect them with third-party suppliers likely to activate these levers. This initiative is part of a much larger scale project, the Brooklyn-Queens Demand Management Program, initiated in late 2014 in response to an overload situation. Instead of resorting to a solution in terms of investment in the grid, estimated at $1 billion, the company would set up a demand management programme, with $150 million dedicated to promoting demand-response and energy efficiency in order to reduce peak consumption from 41 MW, and with $50 million dedicated to investments described as "non-conventional", such as the development of large-scale storage capacities and micro-grids for 11 MW. In this way, the investment would be postponed *a minima* from 2017 to 2019. In terms of incentives, the expenses undertaken for this programme are compensated at the usual rate applicable for the asset base, increased by 100 basis points subject to achieving the pre-defined objectives in terms of capacity covered by the programme, to driving the distributed resources market (diversity of

service providers) and cost management, in $/MW, compared to the capital investment solution (NYS DPS, 2014).

There is wide-scale discussion being conducted in different parts of the United States and which sometimes takes different directions depending on the history and interests involved, although the constant is the reinforcement of the interface role of the distribution grid between centralised and distributed resources. The scope of activity of the various stakeholders must gradually be clarified, by cross-checking theoretical debates, technical analysis of integration methods across the grid, and feedback from pilot schemes. No full-fledged model has been stabilised to date, either in California or in New York, but reviews are becoming more widespread, including in the States where the vertically-integrated utilities model is still firmly established. This is particularly the case in Minnesota, with the "e21" initiative driven by the environmental organisation, Great Plains Institute, in co-operation with the utilities, Xcel Energy Minnesota and Minnesota Power, the municipalities and the State, George Washington University and research centres. The threat hanging over the utilities is not of the order of that found in Hawaii or in Arizona, as the retail prices are relatively moderate and there still has not been an explosion in residential solar PV power. However, the "e21" initiative has a proactive approach, intended to pre-empt coming changes with the development of different scenarios. Legislation is already drawing on it, with for example the introduction of performance incentives for Xcel Energy, agreed in June 2015. Like in New York, the approach is holistic and based on dialogue between the various stakeholders, with the difference that the vertically-integrated model serves as a working hypothesis and assumes a more active role by the utilities vis-à-vis consumers. Like ConEdison in New York, Xcel Energy currently proposes to avoid reinforcing a transformer station, which would cost $6 million, by favouring the construction of a new facility combining solar PV power and storage, which would cost $12.5 million, but which would also serve as a pilot project. However, no tender is envisaged here; Xcel would include the investment in its asset base, to ensure full consistency with the regulatory paradigm in place in Minnesota.

# Conclusion

In the United States, it is definitely time for reflection with respect to technological progress, changes in consumers' expectations and the different state support mechanisms for low-carbon transition. For a long time seen as a distant horizon, the tipping point is becoming more concrete for the US electricity industry, although the extent of future shifts is still difficult to evaluate accurately. All the stakeholders, regulated or in competition, which made up the pillars of the centralised electricity system in the 20th century are now facing fundamental questions about the nature of their activities, their revenue streams, and their role within the electricity system.

Without waiting for the possible threat to become clear, the conventional stakeholders are organising their response and are navigating between a purely defensive approach, which mainly consists in ensuring the compensation conditions for distributed generation are not too advantageous, and the willingness to embrace the change, which sometimes implies a commitment in activities which, *a priori*, threatened to cannibalise their traditional business model. The question of market design and of managing the legacy left by the wave of liberalisation in the 1990s very quickly arises. The re-regulation of the generation segment is an approach under debate, even if the regional wholesale markets have just boomed. The competitive model will probably be subject to adjustments and might potentially support a more intrusive regulation, in order to ensure the viability of generation outside of long-term contracts and excluding subsidies, while managing dependency vis-à-vis natural gas. Similarly, downstream management of the electricity system is at the heart of the thinking, with the possibility of entrusting the distribution operators with a more or less active role, but still changing compared to the one they currently have.

Identifying the appropriate design for the 21st century electricity system is a matter of public interest and therefore necessarily involves the legislators and regulatory authorities. The first challenge is to maintain fair conditions of competition between the various stakeholders and to reduce, insofar as possible and desirable, the cross subsidies between different types of grid users. The second challenge is to orchestrate the different low-carbon transition levers to ensure effectiveness across the whole electricity system. It is a question of delimiting the regulated and competitive

environments, but also of sending the relevant signals to the various stakeholders in order to maximise benefits to the system.

Beyond these broad objectives, the reforms are state-based, because they take the history and market structure involved into account. Different formulas are being tested, to get the most out of the existing situation and to promote the most managed transition possible. Nevertheless, these initiatives still have one thing in common, which is their forward-looking nature. Planning exercises are increasing to pre-empt the consequences of the on-going changes, but also above all to envisage the target, in terms of smooth co-existence between conventional and new resources in the electricity system. It is through successive iterations that these various plans will build a complete and accurate view, while progressively translating into regulatory measures and other strategic shifts by the conventional stakeholders. The main benefit of the Clean Power Plan, if it were to be maintained, would be to extend these forward-looking exercises beyond the most progressive States, to supervise the path for lower emissions in the electric power sector and to promote an orderly transition throughout the entire United States.

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