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Game changers impacting the European energy sector

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Contents

The impact of the US shale gas revolution in Europe

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The US shale gas revolution has seen several EU Member States chase after the “American Shale Gas Dream,” particularly given that shale gas in the US is up to five times cheaper than conventional European gas. The sheer rate of expansion of the shale gas market and its already visible impact on the US economy has shaken up the energy sector. According to an editorial report from *The Wall Street Journal,* gas from shale beds now accounts for more than 25 percent of the US natural gas market, up from just one percent in 2000. Added to this are the hundreds of thousands of jobs this burgeoning industry is said to have created, both directly and indirectly. Shale enthusiasts have also stated that shale gas may have secured US energy needs for the next 100 years.

Despite these attractive assumptions, the topic of shale gas has divided EU Member States into two camps. Critics from countries like France and Bulgaria dismiss it as coming at too high an environmental cost, pointing out that the hydraulic fracturing technology married with horizontal drilling and advanced sensing techniques (or, simply, "fracking") could have unpredictable consequences. On the other hand, supporters such as Poland, Spain, Hungary, Romania and the UK view it as a solution to energy dependency that could lift us out of an impending energy crisis. However, it seems that even countries with ardent government support may not be able to sustain this nascent industry.

United Kingdom

In January 2014, Total became the first oil and gas "major" to invest in UK shale. Total, advised by a team from Dentons' London office, acquired a 40 percent interest in two licenses in the Gainsborough Trough area of the East Midlands, which cover an area of 240 km^2 Island Gas Ltd—a partner in the joint venture company set up for this project—will be the operator of the initial exploration program, with Total taking over operatorship as the project moves towards development.

Onshore oil and gas in the UK, at least in its “unconventional” forms, has so far generally been the preserve of a group of small, specialist companies. This is due to the limited resources to fund test drilling programs for shale and the extensive preparatory work in terms of regulatory clearances and surveys that needs to be completed before drilling can begin. Total’s move shows that there is now enough interest and confidence in the UK shale scene to justify the involvement of companies with sufficient resources to take the more promising prospects to the next stage.

Onshore oil and gas exploration, assessment and production in the UK can only take place with a license under the Petroleum Act 1998, issued by the Department of Energy and Climate Change (DECC). The next round for onshore Petroleum Exploration and Development Licenses (PEDLs) in 2014 will cover, among others, onshore oil and gas exploration and production (including shale gas). The UK Government announced last December that new PEDLs will be subject to greater regulation than before, including enhanced seismic risk analysis / monitoring and a "traffic light" system for controlling operations.

Work commissioned by DECC and published in July 2013 indicates that it will be quite a while before UK shale has an appreciable impact on UK energy prices, and that the impact is likely to be modest. However, the prospect of a UK shale industry also represents in its own right the prospect of economic growth. Estimates of the number of jobs that could be created by UK shale developments vary considerably, but they could be in the tens of thousands. The prospect of additional tax receipts from onshore unconventional gas projects boosting the public finances is also attractive to the UK Treasury as revenue from offshore oil and gas developments dwindles.

As part of its effort to boost investment in shale production, the Treasury detailed proposed "pad allowances" on 19 July 2013, the effect of which would be to reduce the tax rate on a portion of fracking production income from 62 percent to 30 percent, by relieving the 32 percent "supplementary charge." Shale gas would benefit from first-year allowances for capital expenditure and an extended Ring Fence Expenditure Supplement (reflecting the longer payback for shale gas projects). The Finance Bill 2014 will include provisions legislating for this. On 13 January 2014, the Prime Minister also announced that local authorities would be able to keep 100 percent of the business rates from shale developments.

Although an established technology, with onshore shale gas production in the UK going back more than 20 years, fracking is controversial in the UK. Public interest groups and local objectors have targeted the process with anti-shale protests to prevent shale development, particularly in sensitive locations. However, some compelling figures lead to the prediction that "unconventional" onshore oil and gas extraction is likely to play a greater role in the UK energy economy. Estimates of shale gas reserves suggest that it could meet UK gas needs for 50-70 years, assuming a 10-15 percent recovery rate. With this in mind, the UK Government sought to allay these concerns by proposing financial rewards for "host communities". Thus, it has welcomed the Community Engagement Charter launched by the UK Onshore Operator Group (UKOOG) in June 2013. UKOOG proposed that host areas should receive £100,000 per well site at the exploration / appraisal stage and 1 percent of revenues at the production stage, allocated approximately 2/3 to the local community and 1/3 at the county level.

While the search for UK shale gas continues, we have already seen the impact that the US shale revolution has had in the UK. By depressing domestic demand for coal in the US, shale has helped to keep some of the UK's remaining coal-fired power stations supplied with cheap coal and to boost their share of the UK's electricity supply. Also, towards the

end of 2013, Ineos announced that its Grangemouth plant, which had apparently come close to being permanently shut down a few weeks earlier, would start to import ethane derived from US shale gas in 2016.

The potential for successful shale projects exists in many parts of the world and even major oil companies' resources are finite. The UK authorities, at all levels, will need to continue to perform well on shale in order to ensure that the UK receives its fair share of investment in shale projects. There will be more transactions like Total's acquisition of a stake in an existing shale play, but oil companies face a different regulatory environment from the one they are used to if they have been involved in UK offshore projects. They are moving from a world in which DECC regulates almost all aspects of their work under the licensing regime to one in which they have to manage relationships carefully with a range of stakeholders and deal with a number of different authorities, some of which will be very sensitive to local views. It is, however, likely to be some time before any shale project enters the production phase and a number of years before any appreciable amount of shale gas is produced in the UK.

Romania

The Romanian Government is keen to pursue shale gas projects in a bid to address the concerns of energy-intensive industry, such as aluminum, steel and chemical producers, which are perpetually up in arms over high electricity and gas prices. They allege that high energy prices bar them from competing effectively in the market, and as a result these key industry participants have on a number of occasions threatened to relocate outside Romania, triggering massive job losses in the local economy.

To date, four oil concession agreements have been executed in Romania for exploration, development and production: one in Barlad, in eastern Romania, and three in Dobrogea, in the south-east. All of them were granted to a local subsidiary of US oil and gas giant Chevron. Exploration started in October 2013 and was suspended shortly afterwards due to opposition from the local community. Chevron began the exploration process again in February 2014 and was recently granted a second environmental permit to install additional exploration equipment in the concession areas.

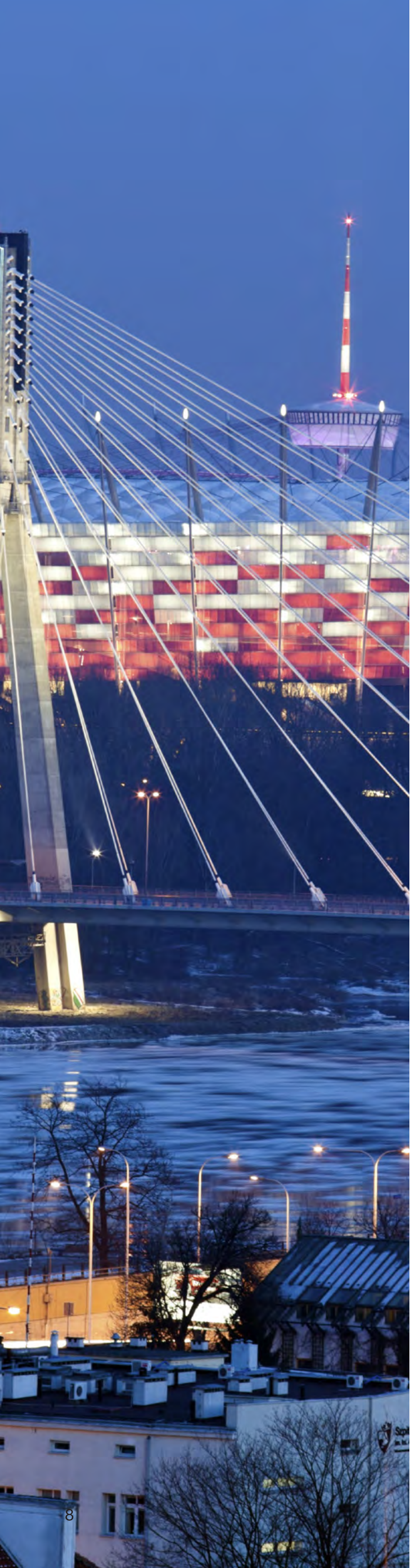
Nevertheless, opposition to shale gas remains active: green NGOs have scheduled regular protest meetings, and they have so far been successful in garnering local community support. In some situations tensions escalated to the point where the Government was obliged to increase the riot police presence and restrict the NGOs' access in shale gas exploration areas, to prevent sabotage of Chevron's drilling equipment.

Experts agree that one of the main reasons for this *"Not In My Back Yard"* approach relates to the fact that local communities receive virtually no direct benefit from shale gas production occurring in those communities. In common with the legal regime in other EU Member States, under Romanian law mineral resources belong to the national public domain and not to private landowners or local communities.

As well as the strain this issue has caused in relations between the Government and its people, it has led to open administrative conflicts between central authorities and local public authorities. In some instances the latter challenged the central agencies' grant of exploration licenses and other permits in court, claiming that shale gas resources do not belong to the State, but in fact belong to the local authorities, arguing that the government should not be allowed to exploit these resources.

This chain of events has led to experts calling for reform of the current Romanian oil and gas legislation, setting up local community funds that would receive part of the royalties paid by the production license holders and distribute the proceeds for the benefit of the local communities. The Government has indicated its readiness to amend the legal framework in the medium term once it has confirmed, through investigative drilling, the existence of viable shale gas deposits.

The current Romanian Petroleum Law is first in line for reform. Although it regulates exploration, development and production activities, it does not make any explicit distinction between conventional and unconventional resources. As noted by the National Agency for Mineral Resources in one of its reports, the specific legislation needed to address the exploration and production of unconventional natural resources (and shale gas in particular) is quite limited, mirroring the relatively restricted exploration activities at present.



Poland

Much like everywhere else, Poland's shale industry is still in its infancy. A full assessment of the scale of Poland's reserves requires more test drilling. However, Poland is believed to have one of the largest shale gas reserves in Europe, with reserves of risked, technically recoverable shale gas estimated at 146 Tcf in four assessed basins. Shale gas potential is being explored by exploration and production companies under 72 unconventional gas exploration concessions. Up until 4 August 2014, 65 exploration drills (including 12 horizontal drills and 27 cases of hydraulic fracturing) have been completed. There is one exploration drill in progress, with another three due to be started shortly. Industry insiders view this relatively low level of activity as a consequence of the unclear legislation governing this sector and the uncertainty of the proposed legislation on the subject.

Initially, the hydrocarbons legislation proposed by the Polish Government involved the mandatory participation of a government-owned entity (National Fossil Fuels Operator) with a minority equity stake in shale gas development projects. However, this gave rise to serious concerns in the industry over the shape of future hydrocarbon regulations. According to industry representatives, these changes, if implemented, could significantly reduce industry investment in shale gas exploration at a time of disillusionment with early well results. In an effort to address these concerns, the Government decided to modify its approach towards shale gas development significantly, by redrafting the proposed hydrocarbons legislation to introduce an incentive scheme for investment in the shale gas industry. The Hydrocarbons Law was signed by the President on 1 August 2014 and awaits publication in the Journal of Laws. The Hydrocarbons Law will come into force on 1 January 2015.

The Hydrocarbons Law also proposes a number of regulations aimed at simplifying the procedure for granting new concessions, reducing the administrative burden, therefore accelerating shale gas exploration and production in Poland. The Hydrocarbons Law proposes one concession only—comprising the exploration and production stage—instead of the separate concessions possible under current law. Any rights acquired under concessions currently in force will be preserved. Companies performing geophysical surveys to examine geological structures will merely be required to notify the competent authority. It will be possible to produce shale gas and explore the rest of the licensed area under the same concession.

The Polish Government has also proposed a dedicated hydrocarbons tax system in separate draft legislation which is currently making its way through Parliament. The State's share of the revenue will come in the form of two new taxes: cash flow tax and royalty tax – not to exceed 40 percent of the gross income of production. Shale gas production will be tax-free until 2020, with the amount of tax on hydrocarbons dependent on profitability.

Ukraine

Ukraine is in crisis, with a new President and a transitional Government pending anticipated elections in the Fall. Nevertheless, a critical focus of the new Government (and the previous regime as well) is increasing energy independence. To that end, over the last couple of years Ukraine has implemented major reforms in its legislation on production sharing agreements specifically to promote shale gas development. Three very public tenders for shale gas development projects took place between 2010 and 2012 in Western and Eastern Ukraine, which were awarded to Shell, Exxon and Chevron. Due to the current crisis with Russia, Exxon has suspended its operations, whereas Shell and Chevron have temporarily halted some of their activities. Regional administrations protested against the potential environmental risks of shale gas exploration, but were eventually placated by changes in legislation that allowed a portion of gas revenues to revert to the relevant local administrations rather than fully to the national government.

Turkey

Inspired by the US shale gas boom, Turkey has begun considering the potential of shale gas to meet its ever-increasing energy demands and to reduce its dependency on imported natural gas. Whether this expectation is realistic or not depends on the findings of the surveys regarding recoverable shale gas resources in Turkey, which are currently at a very early stage.

In June 2013, the US Energy Information Administration released a report which estimates that Dadas Shale (Southeastern Anatolian Basin) and Hamitabat Shale (Thrace Basin) in Turkey contain 163 Tcf of risked shale gas in place with 24 Tcf as the risked, technically recoverable resource. The Turkish Petroleum Corporation (TPAO) conducted early-stage shale gas exploration and drilling activities in cooperation with Shell and Transatlantic Petroleum. According to the media, other companies that are engaged in early-stage exploration activities include ExxonMobil, Anatolia Energy and Valeura Energy.

Exploration and production of shale gas is regulated under the Petroleum Law (Law No. 6491 published in the Official Gazette No. 28647) (the Law) and its accompanying secondary legislation. Although the Law does not have provisions specifically envisaged for shale gas, its definition of "petroleum" is broad enough to include shale gas.

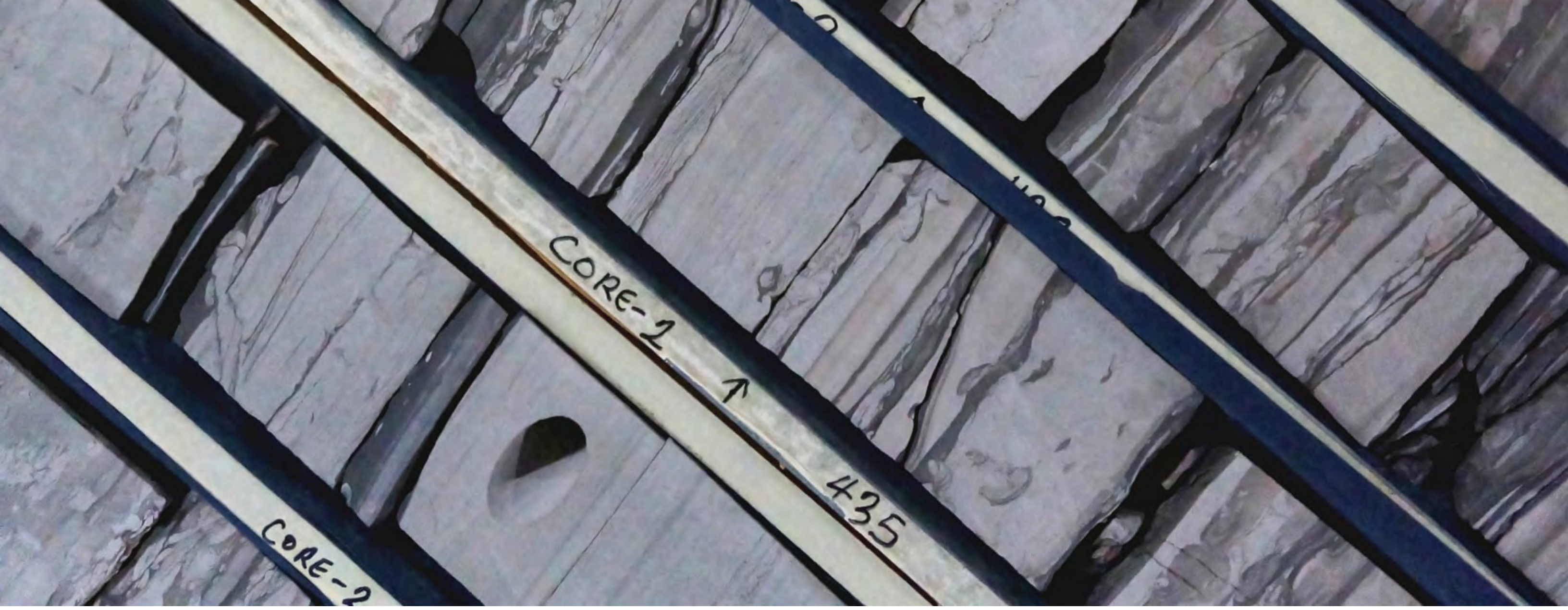
The Law, which entered into force on 11 June 2010, is aimed at liberalizing the petroleum market and incentivizing further investment. The duration of exploration concessions was increased to five years for onshore concessions (with a possible two-year extension) and eight years for territorial waters concessions (with a possible three-year extension). The duration of operation concessions was also increased to 20 years with the potential to extend twice for 10 years. Most of the preferential rights of TPAO existing under the previous Petroleum Law of 1954 were abolished, although TPAO still retains its preferential right for operation.

The Law introduced a clearer and more straightforward method for the calculation of royalties to be paid to the State by the concessionaires. It also provides exemptions from customs duties, levies and stamp tax for equipment imported and supplied locally and facilitates repatriation of capital. It sets forth a general obligation to provide security in the amount of two percent of the total investment amount (one percent for territorial waters) for exploration concession applicants. The Law states that, for unconventional resources (including shale gas), the Ministry of Energy and Natural Resources has the discretion to reduce or completely waive the security payments requirement. Considering that the Council of Ministers resolved to support shale gas exploration studies in its Decree on Approval of Medium Term Program (2014-2016) (Decree No. 2013/5444, published in the Official Gazette No. 28789), the Ministry of Energy and Natural Resources is likely to exercise its discretion regarding security requirements in relation to concessions on shale gas. Despite the improved state of Turkish legislation surrounding the shale gas industry, the need to develop and improve Turkey's legal and technical infrastructure means that shale gas production will not begin before 2020.

Looking ahead

The media's fracking furore has died down, but the impact of the American boom in the shale gas industry has already had an appreciable effect on the European oil and gas landscape. Despite protests from local interest groups, early exploration is well under way in many countries, and the legislative framework is slowly but surely developing. There is still some opposition in certain jurisdictions: France currently has a moratorium on fracking, promised by President Francois Hollande to last at least until the end of his presidential term. In the long run, however, shale gas has the somewhat heady potential of securing energy independence for many countries (including the possibility of Europe freeing itself from its dependency on Russian gas), as well as bolstering the oil and gas industry with the creation of new jobs, and subsequently the economy at large.

Two recent developments may afford a glimpse into the way the shale gas landscape is being moulded in Europe. First, in October 2013, the European Parliament amended the directive regulating environmental impact assessments (EIA) (Directive 2011/29/EU) to ensure that hydraulic fracking is subject to EIAs, preventing conflicts of interest between investors and EIA providers and entitling local communities to challenge exploration and production permits. Second, and more recently, Cuadrilla is submitting planning applications to begin operations in Lancashire, UK, which could start as early as 2015.



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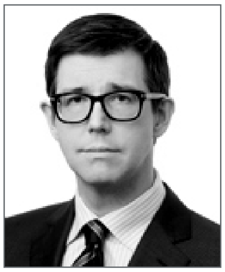

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Renewable energy in Europe

By Mark Cheney, Marc Fornacciari, Tomasz Janas, Charles July, Javier Lasa, Peter Mayer, Claudiu Munteanu-Jipescu and Boris Strauch

Directive 2001/77/EC laid down a framework for the promotion of electricity produced from renewable energy sources (RES) in the European Union. This framework was subsequently strengthened by Directive 2009/28/EC (Renewable Energy Directive) which requires Member States to establish mandatory national targets consistent with an overall EU wide target that by 2020 aims for 20 percent of the energy consumed within the European Union to come from renewable sources.

In January 2014 the Commission proposed in the 2030 Framework that the EU wide target for renewable energy be raised to at least 27 percent by 2030 (45 percent in the case of electricity generated from RES). Note that no new binding national targets are proposed for Member States.

The Renewable Energy Directive also required Member States to grant priority access or guaranteed access to their electricity grids for energy produced from RES.

To date, progress towards meeting the national targets has largely been through the implementation of national support schemes. Member States have implemented a variety of renewable energy support schemes, the most popular being price based schemes such as Feed-in Tariffs (FITs) and Feed-in Premiums (FIPs) and quota based obligations supported by tradable Green Certificates. Because the majority of these schemes are financed through the pass-through of suppliers' costs to end users, as the level of support has increased, the volume of the debate regarding their affordability has risen commensurately.

At the same time, many Member States have reviewed the effectiveness of their renewable energy support instruments and have implemented reforms to their support schemes as they seek to reduce the cost of financing their national renewable energy targets. Most controversially, Spain and Italy have introduced/are proposing retrospective adjustments to their respective support schemes that have resulted in actual/threatened legal action by affected investors.

Consistent with the targets contained in the Renewable Energy Directive, the 2020 strategy and the 2030 Framework, in April 2014 the Commission published revised State Aid Guidelines (Guidelines) setting out the conditions that renewable energy support schemes must meet to be considered compatible with the rules of the internal market.

The Guidelines move renewable energy support schemes towards market-based allocation mechanisms, such as auctions and other

competitive bidding processes and will require the recipients of such support to be subject to market obligations such as balancing (although outsourcing is permitted). With effect from 1 January 2016, generators are expected to sell renewable energy directly in the market and to receive support in the form of a 'top-up' payment above the market price. This would suggest that FITs will no longer be compatible as they insulate generators from market pricing risk unlike FIPs and Green Certificates. Under the Guidelines, projects over 1 MW in size will have to take part in a technology-neutral competitive bidding process (although there will be a transitional period during 2015/2016 where this requirement will be limited to five percent of planned new renewable energy capacity) and technology specific bidding processes are permitted in certain circumstances. Generators will also no longer receive support when electricity prices are negative, a situation that has often arisen in mainland Europe during exceptionally sunny periods.

In addition, the ability of national schemes to exclude participants from other Member States that is allowed under the Renewables Directive was recently called into question in a case referred to the Court of Justice of the EU by the Swedish courts. Ålands Vindkraft, operator of a wind farm in the Åland Islands, applied to participate in the Swedish "green certificate" scheme. Although connected to the Swedish grid, the project was in Finnish territory, and its application was refused on that ground, pursuant to the relevant Swedish law.

The Advocate General, who gave his opinion on the case on 28 January 2014, came to the conclusion that schemes that restrict the availability of subsidy to home-grown renewables, and the provisions of the Renewables Directive that ostensibly permit such restrictions were inconsistent with the EU Treaties' rules on the free movement of goods and did not fall within any of the public interest exceptions that case-law has recognized as capable of overriding the right of free movement. In this case the overriding interest was supposedly the protection of the environment: the promotion of renewable generation reduces greenhouse gas emissions and helps to avoid harmful climate change. But the Advocate General could not see how preventing the import of "foreign" green electricity helped the environment.

The Court's judgment, delivered by the full Grand Chamber of 15 judges, declined to follow the Advocate General in those parts of his reasoning which were more disturbing for the status quo in EU renewable support schemes. The Court agreed that legislation such as the Swedish law is capable of impeding imports of electricity and so is in principle incompatible with the free movement rules. But it found that this restriction could be objectively justified. Without confronting head-on the question of how the overriding interest of environmental protection is served by a restriction on imports, it concluded that the Swedish scheme as a whole served an environmentally beneficial purpose and found that Sweden could legitimately consider that the territorial limitation in its law did not go beyond what was necessary to attain the objective of increasing the production and consumption of green electricity in the EU.

It will be interesting to see whether the restriction of renewable energy support schemes to national projects will survive the move to EU wide targets under the 2030 Framework.

There follows a review of the reforms of the national support schemes of the following Member States: France, Spain, Germany, UK, Poland and Romania.

France

In France, the two main sources of renewable energy are biomass and hydropower. In 2012, energy from RES accounted for 13.4 percent of the gross final energy consumption (16.6 percent in electricity, 16.3 percent in heating and cooling and 7.1 percent in transport).

To date, renewable energy provides 18.6 percent of electricity generation. Hydropower has traditionally been the main source (13.8 percent) followed by wind (2.9 percent) and solar PV (0.8 percent).

According to a report published by RTE, the French electricity transmission system operator, for 2013, the installed hydropower capacity was around 25,400 MW. Meanwhile, the installed wind power capacity grew by 8.4 percent to 8,150 MW and the photovoltaic capacity reached 4,300 MW up 20.9 percent from the previous year. The installed capacity of other sources of renewable energy including biomass was around 1,500 MW.

In order to promote renewable energy, the French Government has put in place two support mechanisms:

- An FIT mechanism under which the legacy operator, *Electricité de France*, has the duty to conclude a power purchase contract with every renewable energy producer that operates a plant meeting certain requirements depending on the renewable energy contemplated; in this case the purchase tariff is determined by ministerial orders. FITs currently apply to the following sectors: hydropower, wind power, photovoltaic, geothermal sources and biomass. The scheme is financed through a compulsory contribution *(contribution au service public de l'électricité)* by all electricity consumers.
- A competitive tendering procedure. Under article L. 311-1 of the energy code, the public authority may launch a tendering procedure if anticipated production capacity fails to meet the objectives of the multi-year plan for electricity production investment. Using this procedure France has carried out an ambitious offshore wind power program off the north and west coasts. The first phase of the program includes the installation of 2,000 MW capacity with the first wind turbines scheduled to be operational by 2017. Several large scale biomass and solar PV projects have also been procured using this procedure.

In May 2014, the French administrative Supreme Court, the *Conseil d'Etat,* ruled that the 2008 FIT Ministerial Order relating to on-shore wind projects should be cancelled as it constituted an unauthorized state aid, since the order had not been notified to the European Commission. After the notification of a new Ministerial Order at the end of 2013, the European Commission issued a decision in March 2014 stating that the French scheme providing support to the production of electricity from on-shore wind installations does indeed constitute state aid, but one that is compatible with EU state aid rules.

In addition, the French Government has recently submitted to parliament a bill on a new national energy model. The draft law aims:

- to reduce by 40 percent greenhouse gas emissions by 2030;
- to reduce by 30 percent the consumption of fossil fuelled energy by 2030;
- to reduce the share of nuclear generation to 50 percent by 2025;
- to increase the share of renewable energy to 32 percent of gross final energy consumption by 2030; and
- to reduce by 50 percent final energy consumption by 2050.

Spain

The renewable energy industry is facing serious challenges in Spain:

Under the current situation where existing renewable energy projects are struggling to service their existing debt, there is little appetite from financial institutions to finance new projects and limited availability of funds to refinance existing projects.

Spain has around 100,000 MW of installed capacity, but its current electricity demand is around only half of that level.

Since 2004 the RES legal regime has been subject to complex regulatory changes. Initially those were designed to shape the regulatory regime, but more recently these have had one goal in mind: to reduce the electricity tariff deficit, as its scale has now become disproportionate (€ 30 billion).

However, cuts and reductions have been insufficient to address the electricity tariff deficit. As a consequence, the Spanish Government from July 2013 to June 2014 has approved regulations reforming the RES sector (Act 24/2013, Royal Decree Law 9/2013, RDL 431/2014, Ministerial Order 1045/2014) The reforms abolish the existing FIT based support system and introduce a new remuneration regime for renewable energy, cogeneration and waste facilities that offers developers a reasonable return on their investment costs (7.4 percent annually, before taxes) across the operational life of the asset and which is retroactive in character.

Return rates are calculated with reference to the average performance in the secondary market of 10-year Spanish Government bonds, plus 300 basis points.

This has led to the cancellation of the incentive for some plants, such as onshore wind farms that became operational before 2005.

The revised support system will see a €1.7 billion reduction in incentives paid to the sector this year, according to the Spanish Government.

Germany

Germany has doubled the renewable share of its total electricity consumption in the past years, reaching a share of the renewable energy production and consumption of 23 percent in 2012. It forecasts an increase by 2025 well ahead of the 50 percent target for 2030, and closing in on official goals of 65 percent in 2040 and 80 percent in 2050.

Some areas are moving faster: in 2010, four German states were 43–52 percent wind powered for the whole year. And in the spring of 2012, half of all German electricity was renewable, nearing Spain's 61 percent record set in April 2012.

In fact, in 2011 the German nuclear shutdown was entirely displaced by year-end, three-fifths due to renewable growth; by mid-2012, the share of nuclear energy in the electricity market had decreased from 22 to 15 percent, mainly as a consequence of shutting down the first eight reactors, whereas the share of renewables had gone up by four percentage points to 22 percent. Efficiency gains cut the total energy used by 5.3 percent, electricity consumption by 1.4 percent, and carbon dioxide emissions by 2.8 percent . Wholesale electricity prices fell 10–15 percent. Germany remained a net exporter of electricity, and during the February 2012 cold snap exported nearly three GW to power-starved France.

However, Germany is reverting to fossil fuels to a certain degree to support the renewable capacity as wind power and solar energy cannot supply base load power on their own after the phase-out of nuclear power.

Germany's grid remained the most reliable in Europe and keeps improving the energy infrastructure to adequately connect industrial sites in south Germany to the windy north.

German policy makers recently worked on making the Renewable Energy Sources Act ready for the future. The revised and amended Act will enter into force on 1 August 2014, with a focus on sticking to the priority connection to the grid, readjusting the feed-in tariff (i.e. reducing it for most sources while mostly keeping up the tariffs for offshore wind), and implementing a pilot tender scheme for PV ground mounted systems.

UK

The UK's deployment of renewable electricity generating technologies (notably wind) has increased significantly in the last few years, but although it is making steady progress towards its 2020 Directive target of delivering 15 percent of energy from RES (in 2012, it had achieved four percent) and—from some perspectives is well placed to meet it—it remains to be seen whether it will do so.

- A significant number of projects, particularly smaller onshore wind sites in England and Wales, fail to obtain development consent. The process for granting consent (or planning permission) is becoming increasingly politicized, and it is almost inevitable in some cases that political decision-makers give greater weight to those who oppose developments that are said to be out of keeping with the landscape. A number of offshore schemes have been refused consent or have been scaled back or discontinued because of the constraints imposed by EU nature conservation legislation (e.g. out of concerns about their impact on bird life).
- There is growing public concern about the cost of subsidies for renewables. This is exacerbated by the fact that over the next few years generating capacity margins in the UK are expected to fall to very low levels and the addition of substantial amounts of intermittent renewable capacity is perceived as contributing to the risk that "the lights will go out", rather than as helping to mitigate it. (Both Government policy and public opinion are ambivalent about biomass / energy from waste, which is for practical purposes the only non-intermittent renewable technology deployable at scale in the UK at present.) At the same time, the form of renewable generation that appears to enjoy the greatest levels of public support—as well as potentially having the greatest potential to add very significant amounts of capacity—is offshore wind, which is also currently one of the most expensive renewable technologies to build.
- The Government is in the process of launching a massive reform of the way that renewables are subsidized, by replacing a Green Certificate scheme (the Renewables Obligation) with a new regime of Contracts for Difference (CfDs, a kind of FIP that provides a guaranteed premium over a reference wholesale electricity price for a fixed period). Reflecting concerns about the cost of renewables and European Commission concerns about the distortions which subsidies bring to the EU single market in electricity (leading to a requirement for many subsidies to be allocated by competitive auction), the new regime offers less certainty about whether and at what level individual projects will be subsidized. Much will depend on whether investors and financiers are prepared to accept these risks. Although the reform program began almost four years ago, many of the key details of the CfD regime are only now being finalized, a few months before it is due to be launched. Moreover, although the generic CfD scheme and specific investment contracts for offshore wind projects have recently received state aid approval from the European Commission, certain large scale biomass projects are still waiting for clearance before they can proceed.

Poland

Over the past 10 years, renewable energy sources (RES) have become an important part of Poland's energy market as evidenced by the dynamic growth in investments in this sector. In particular a large number of wind farms have been established by Polish energy companies and foreign investors entering the Polish market. These dynamics were not jeopardized to any real extent by the economic crisis that now seems to be behind us.

Instead, the brakes are being put on investor enterprise and confidence by the recession on the green certificate market and the Government's reluctance to introduce new rules in the RES sector.

However, now that the Government is going to put new RES legislation before Parliament, this state of insecurity will probably change. In April 2014 the Government approved a long-awaited Bill that sets out new long-term subsidies for renewable energy, aiming to cut costs to consumers and to help the coal-reliant country meet European climate targets. The legislation is expected to be passed in the Fall.

Under the Bill, developers and owners of new renewable facilities can sell energy at auctions at a fixed price that would be guaranteed for 15 years. The proposal would also set a ceiling on the subsidy. Moreover, it would allow renewable electricity producers that are already operating to keep their current subsidies or choose to join the above mentioned auctions on a voluntary basis (subject to the exemptions listed in the Bill). Energy produced from existing facilities will be sold at auctions dedicated to this category of facility and the producer will not be required to go through the pre-qualification process to take part in such auctions, but they will have to provide bank guarantees or deposits of 30 Polish zloty/1 KW installed.

New projects may seek support exclusively via the auction mechanism, with auctions organized and conducted by the Energy Regulator at least once a year (and separate auctions for sources with a capacity up to 1 MW or in excess of 1 MW). The winning bidders shall be those offering the cheapest energy. The price of energy will be determined based on the reference price set by the Minister of Economy at least 60 days before the scheduled date of the auction, in compliance with the rules set out in the Bill on Renewable Energy Sources.

Poland generates around 90 percent of its electricity from coal and must increase renewable energy production to at least 15 percent of the total by 2020 to meet EU rules on carbon emissions. The Polish Government has calculated that by 2020 the cost of its current subsidy system would rise to 7.5-11.5 billion zlotys per year (US$2.5-US$3.8 billion).

Given the above developments, a rapid acceleration of investment in the next few months is expected, as those installations which commence energy generation before the new RES legislation comes into force will have the opportunity to choose their preferred support system – the green certificates system. The final shape of the RES Bill remains uncertain, as following its adoption by the Council of Ministers it must now be passed by Parliament. The RES Bill will also be subject to approval by the European Commission due to the state aid provided for therein.

Romania

Law 220/2008, which originally transposed EU Directive 2009/28/CE, was subsequently improved by amendment Law 139/2010 and Emergency Regulation 88/2011.

In June 2014, Romania reached a total of 4,458 MW of installed RES capacity, of which wind represents 2,616 MW and solar PV capacity 1,208 MW. Of the 1,208 MW of solar PV capacity, 834 MW comes from new photovoltaic capacity installed in 2013. The dramatic growth in the PV facilities installed is seen as a huge success for solar energy, given that PV capacity at the end of 2012 was only 28 MW.

The Government decided to decrease the global RES mandatory quota for 2014 and have wind certificates down to 0.5 per MW until 2017 and to 0.25 per MW starting 2018, from two in 2013 for all wind projects finished after January 2014, while solar PV certificates were decreased to three per MW, from six last year, for all photovoltaic projects finished after 1 January 2014. The measure will only affect projects finished after January 2014, although older projects also faced subsidy cuts after a green certificate suspension was approved in June 2013 suspending one of the two green certificates in the case of wind energy producers and two of the six green certificates in the case of PV energy producers per MWh fed into the grid. The green certificate suspension began on 1 July 2013.

The Government's main aim is to restrain electricity price spikes as a result of the deployment of renewable energies and to respond to pressure from energy-intensive consumers to reduce the costs of RES energy. Thus, subject to European Commission clearance, a number of the 300 energy-intensive consumers will be granted exemptions of up to 85 percent of the cost of green certificates.

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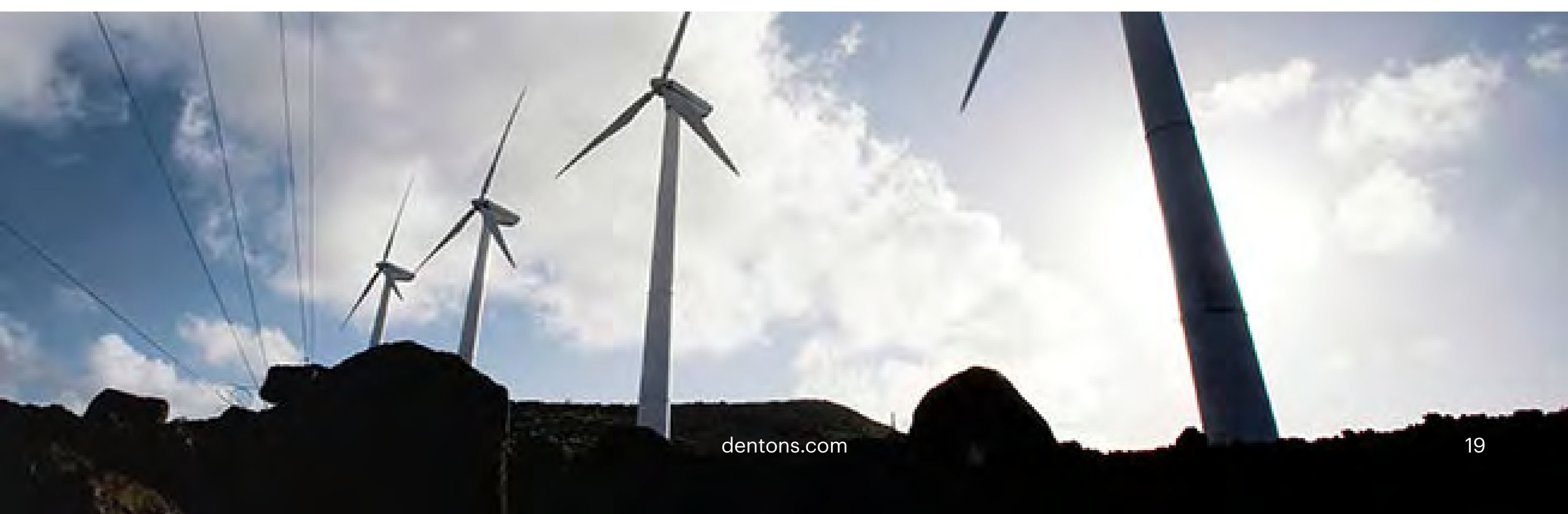


Capacity markets

—A short-term fix for security of supply or a key energy market support mechanism in the transition to a low carbon economy?

By Stuart Caplan, Marc Fornacciari, Charles July and Michał Motylewski

In countries with energy only wholesale power markets, the rise of variable renewable energy production with zero margin costs—and, in some cases priority despatch—is depressing wholesale market prices and displacing marginal thermal power producers which cannot meet their fixed operating costs with reduced operating hours. As a result, an increasing number of conventional power stations are being retired, thereby removing large quantities of firm capacity from the system. At the same time, the variable or intermittent nature of renewable energy requires more firm capacity to be available on a stand-by basis to cover shortfalls in renewable energy production due to weather conditions.

Furthermore, in the EU, US and other developed markets, the impact of environmental regulation such as the Large Combustion Plant Directive and US EPA regulation has hastened the closure or limited the running of coal-fired power stations and this will only be accelerated by the forthcoming application of the EU Industrial Emissions Directive. Moreover, the delay in the commercialization of CCS technology has meant that there has been little or no recent investment in new coal-fired capacity in many EU Member States or in the US. Similarly, several countries, such as Germany, have announced the closure of their nuclear power stations and others, such as the UK, will be unable to commission new nuclear capacity before the scheduled closure of existing capacity. At the same time, the unattractive economics of operation in many EU electricity markets of gas-fired plant relative to coal-fired plant due to higher fuel costs and lower CO2 values has led to the displacement of the former by the latter in the merit order and the withdrawal of considerable amounts of gas-fired capacity, including those with high efficiency and lower CO2 emissions such as newly built CCGT plants.

These factors have led to a marked reduction of investment in replacement conventional power plants such that there is now a perceived risk in many EU Member States of substantially reduced reserve margins so that long-term generation adequacy (i.e. access to sufficient firm generation capacity to meet the highest projected demand) may be jeopardized.

Moreover, increasing levels of intermittent renewable energy production creates an additional requirement for conventional generation plants that are able to operate flexibly in back-up mode, since renewable energy cannot be relied upon as a capacity provider (given imputed firm capacity values in the order of five to ten percent of rated capacity) and therefore can only make a minimal contribution to required reserve margin levels. However, because renewable energy has a high variability, the conventional plant that has to provide the reserve margin must be capable of following a much more volatile and unpredictable demand profile than has previously been required, which calls for more technically competent plant capable of much greater flexible operation in order to provide system stability.

Energy only markets such as those currently operating in Germany and the UK do not incentivize investment in new capacity as they do not explicitly value it, rather compensation for capacity is implicit in the price of energy. For low load factor conventional plant, scarcity prices (i.e. above marginal operating costs) are required to cover fixed costs, but these price spikes have to be sufficiently frequent to attract new investment in new capacity or to prevent existing capacity from leaving the market. Such revenue streams are unpredictable and may also be restricted through market distortions such as capping measures to control the level of price spikes and are therefore unlikely to provide sufficient certainty to encourage investment in the required level of firm capacity to ensure generation adequacy. Accordingly, many countries have turned to capacity payment mechanisms to stabilize wholesale energy prices and to reward investors in firm capacity explicitly through the payment of more certain and more stable revenues over pre-determined periods in the expectation that this will encourage the required levels of investment. The increased certainty of the revenue stream should also lower financing costs for such investment.

Capacity payments are paid in addition to revenues that the generator may earn in the energy market. Logically, wholesale electricity prices should fall due to the removal of the scarcity value from such prices which are now recovered through the capacity market. Notwithstanding the academic theory, experience of the operation of capacity markets in the US shows that claw back and other anti-gaming mechanisms may be required to avoid over compensating generators in circumstances where scarcity market pricing continues despite separate capacity remuneration.

Historically, capacity payment mechanisms have been designed to secure generation adequacy at the lowest cost. This has typically resulted in investment in cheaper, less flexible plant rather than more expensive plant with enhanced operational capacities. Many commentators argue that the design of capacity mechanisms must change so as to incentivize investors to invest or to sustain investment in the more flexible plant that will be required to support the rising share of variable renewable generation. Moreover, in the EU many of the existing capacity mechanisms have been developed on the basis of the needs of the particular national market without regard to their impact on neighboring, interconnected markets. This has led to calls for minimum EU harmonization requirements for capacity mechanisms and their co-ordinated adaptation so as to ensure compatibility with the process of EU market integration in general and the target model of market coupling in particular.

The evolution of national capacity markets raises important questions of EU law, in particular whether a particular capacity payment mechanism may constitute illegal state aid and whether such mechanisms may act as a barrier to free movement of goods and therefore be inconsistent with single market competition rules. Any proposed new capacity mechanism must now meet the European Commission Guidelines on State Aid for Environmental Protection and Energy of April 2014. These Guidelines emphasize demand-side participation and the contribution of capacity providers from other Member States where such capacity can be physically provided and also that the proposed capacity mechanism should not impact negatively on the development of the internal market by undermining the operation of market coupling, including balancing markets, and should not reduce incentives to invest in interconnection capacity.

To date, some 14 EU Member States have in place—or are considering—some form of capacity payment mechanism. There are a number of different designs including short-term targeted strategic reserves, capacity obligations, capacity payments and long-term market wide, volume based capacity auctions. A brief review of some of these arrangements will show that few, if any, address fully the challenges of rising renewable market share or the requirements of EU harmonization.

Under the strategic reserve model a determined amount of capacity is set aside to ensure the required level of generation adequacy—it is effectively a peak load reserve only—and despatched whenever required. The level of payment is set through a competitive tendering process and recovered from network the users. Typically, capacity providers receive the market price for the electricity generated (marginal fuel cost) plus a small premium. It effectively works as a price cap. This is the model used in Germany, Finland, Poland and Sweden. For example, in Poland as of the end of March 2014, the grid operator has procured 830 MW of cold reserve capacity via two consecutive tenders effective from 2016 for a period of two to four years. This is also the model for the recent UK grid operator's proposal for a Supplemental Balancing Reserve for winters 2014/5 and 2015/6. This model has the least distortion on energy markets as it should only operate in peak conditions. Typically, any plant providing this service is excluded from participation in the markets for energy and balancing services. It is straightforward and flexible in duration, although it is mainly purchased on a short term basis through a one or two year ahead tender from a thermal plant that would otherwise close or be mothballed (mothball reserve). However, there is a risk that such capacity would not have been decommissioned but is removed from the energy only market simply because the strategic reserve offers more favorable terms such as firm pricing in contrast to uncertain revenues in the energy only market. It is doubtful whether such a model provides sufficient incentive to investors in new firm capacity of any kind let alone enhanced capability resource.

Another mechanism is the capacity obligation scheme, which is a decentralized arrangement that imposes on suppliers and other market participants an obligation to purchase a certain level of capacity linked to an assessment of their future consumption (three to four years ahead) at peak load in the relevant delivery year. The overall capacity to be contracted in a delivery year is typically higher than the aggregate future expected consumption by a reserve margin set by the regulator or the system operator. The capacity obligation can be met through ownership of plant, contracting with generators or providers of demand response capability and/or purchasing tradable capacity certificates. Contracted generators/demand response operators are required to make the contracted capacity available in periods of shortages or face penalties. Suppliers pay a buyout price or a penalty if insufficient capacity is contracted. The cost of providing the capacity obligation is recovered from customers through retail prices. One of the theoretical advantages of a capacity obligation mechanism is that it offers a market oriented solution and so is less likely to incentivize an over-supply of capacity than centrally procured mechanisms.

France has recently announced such a capacity obligation scheme through Law no. 2010-1488 and Decree no. 2012-1405. Under the French system, which is scheduled to commence in 2016, suppliers are required to meet their capacity obligations by holding a specific amount of capacity certificates that are issued by the system operator based upon data declared by suppliers within the four years prior to the relevant delivery year and following an assessment of the reliability of the declared capacity. The supplier and the system operator enter into a certification agreement regulating the availability of the certified capacity. The system permits the trading of certificates either directly or in a secondary market with the consent of the system operator.

Capacity certificates have a duration of one year. For each year, two deadlines are set; namely, the deadline for the transfer of certificates and the deadline for the collection of certificates. After the first date the system operator calculates any shortfall between the amount of certificates owned and the amount required to meet the supplier's capacity obligation. A shortfall gives rise to an obligation to make a financial contribution to a fund managed by the system operator. If the supplier holds more certificates than required to meet its obligation, it receives a corresponding payment from the fund. Following the second deadline, if a supplier has a shortfall between the amount of certificates owned and the amount required to meet its adjusted capacity obligation (after accounting for any contribution previously paid by that supplier) it is liable to pay a penalty imposed by the French energy regulatory authority (CRE) in an amount not exceeding 120,000€/MW of the capacity shortfall.

Supplier payment shortfalls can be mutualized across several suppliers through the use of certification perimeters under which an agreement is included between the system operator and a creditworthy entity which assumes liability for the capacity obligations of all suppliers within a particular perimeter.

The French capacity market is designed to be compatible with EU market integration, and interconnected capacity located in other Member States will eventually be eligible to participate. It will be interesting to see how the French regulator addresses the concern voiced by several commentators regarding the potential for over-compensation of generators in receipt of capacity payments that could arise as a result of France being connected with energy only markets such as Germany, with a coupled market clearing price that may be driven higher in periods of scarcity by generators not in receipt of capacity payments seeking to secure scarcity rent. Consistent with the European Commission State Aid Guidelines, an affected capacity market may include offset mechanisms to neutralize such risk of windfall profits, but this could complicate the system design significantly.

Capacity payments remain the simplest and most flexible capacity remuneration mechanism. They are typically paid to all generators based on their availability to run and will automatically cease when the required reserve margin is reached. Payments are determined by the regulator, but are not always transparent and are consequently more exposed to regulatory risk. The short term nature of payments (in some jurisdictions these can be determined on an annual basis only) means that they may not be supportive of long term financing for investors. Capacity Payments are used in Ireland, Greece, Italy, Spain and Portugal.

A more complex design is the capacity auction. This is a scheme in which the total required capacity at peak demand is set centrally by the regulator or system operator several years in advance of supply (one to four years) and is procured by a central buyer through a competitive forward auction. The auction disburses to any generator on the system (existing, refurbished or new) as well as demand side operators (demand response, storage and embedded generation) whose bids are accepted (clear the auction) a payment for the firm capacity that they commit to make available to the system operator in the relevant delivery year(s). Failure to meet their contractual commitment results in penalties. The costs of the central buyer are charged to suppliers based on their offtake profile.

As part of its Electricity Market Reform program, the UK announced the introduction of a capacity market in 2014. Features of the UK scheme include a pay-as-clear descending clock auction four years ahead of the delivery year with a secondary year ahead auction to enable adjustments to capacity positions and to permit participation of demand side operators. Participants receive the clearing price set by the marginal bidder; a distinction is made between price takers (existing generation) whose bids are restricted and price makers (new and refurbished generation and demand side operators) whose bids are not. However, there is no restriction on the amount a single bidder can bid into the auction nor on the amount that it can win at the auction, as dilution of market concentration is not one of the objectives of the UK capacity market.

In order to protect consumers from excessive costs, the auction is capped at £75 kW year gross capacity price. This is an administratively set level that reflects a multiple of the Net-CONE (the net cost of new entry – being the gross cost of construction of new open cycle gas turbine plant less expected electricity and ancillary services market earnings, although there has been particular criticism of the underlying assumptions and methodology used to calculate these concepts). The auction is technology neutral and the only ineligible plant is low carbon plant that is in receipt of other forms of financial support, plant that currently participates in the existing short term operating reserve and currently interconnected capacity located in another Member State.

There is no suggestion that more flexible plants will receive a higher price than less capable plants although new build capacity will be offered 15 year capacity agreements with existing capacity being offered rolling one year agreements and three year agreements for refurbished plants. It remains to be seen whether the auction price cap is set sufficiently high to incentivize investors to invest in more flexible new generation CCGTs (which should capture more energy revenues due to their flexibility despite higher capital costs) or whether it will deliver cheaper but less efficient OCGTs. Alternatively, will the major beneficiaries of the capacity payment mechanism be the owners of existing plants or refurbished plants that would otherwise have closed or remained unchanged?

It will be interesting to see the impact of the capacity market on the valuation of existing gas fired plant. Given predicted coal plant retirements (unless these can be postponed through refurbishments funded by capacity payment revenues), capacity prices can be expected to increase in a somewhat predictable manner, and consequently values should firm up. The eligibility of a plant to participate in the capacity market and to capture the clearing price or its ability to access unavailability risk mitigants (see below) should become key drivers in asset valuations of the plant.

Capacity payments will be paid to generators by a settlement body from payments received from licensed suppliers under a supplier levy imposed as a license condition. The settlement body can mutualize any funding shortfall from a particular supplier across all licensed suppliers. The settlement body is not the system operator but a special purpose vehicle that is intended to be bankruptcy remote. It will achieve this objective by only being liable to pay capacity payments when it has collected sufficient funds from the suppliers to make such payments. A similar arrangement has been proposed under the CfD support mechanism, which is part of the same electricity market reform program as the capacity market. However, the current proposal for the capacity market payment mechanism lacks a number of additional protections that were added to the CfD support mechanism at the insistence of financiers. It remains to be seen whether this will adversely impact the bankability of projects supported by a capacity agreement.

Failure to generate when required will result in penalties capped at 200 percent of a generator's monthly capacity payment revenues and 100 percent of annual revenues. This unavailability risk is a much greater concern for new entrants with a single plant or small portfolio than for the vertically integrated generators with large portfolios who can better manage such risk. There is no allowance for planned maintenance or forced outages within the design, and force majeure relief is limited to failures in the power transmission system only. Further, providers of demand side response are particularly sensitive to penalty rates given that there is no limit on the number of incidents that DSR capacity can be required to respond to.

Unavailability risk mitigants include secondary market trading where an outage is foreseeable and the load following nature of the capacity obligation that can reduce the exposure of a single plant operator. Also, over-delivery payments at the negative rate of under-delivery penalties may help to reduce the net exposure of a generator to a single stress event. The Government is encouraging the development of insurance and other financial products to cover such unavailability risk and, if these products emerge, it is likely that financiers will require developers of new build single plant to procure such support, although the cost of such support could render such plant uncompetitive in the

capacity auction relative to existing plant owned by portfolio generators. Several commentators have noted that the treatment of unavailability risk under the capacity market compares unfavorably with the equivalent arrangements under comparable energy infrastructure regimes such as the Offshore Transmission Owners (OFTOs). Again, this may disincentivize investors and funders of conventional plant that rely on a capacity payment revenue stream.

Further, there is no separate change of law mechanism to address supervening regulatory change that was unforeseeable and which occurs between the date of the relevant auction and the relevant delivery year that could render performance uneconomic unless the cost of compliance is reflected in adjusted capacity payments. It is proposed that this concern could be mitigated by "grandfathering" key terms of the capacity agreement by embedding them in the regulations so that they have legislative effect. Clearly, this would not offer any protection if the regulations themselves were subject to change. Failure to address fully these concerns could mean that new entrants will be unable to secure adequate levels of funding to compete with existing plant.

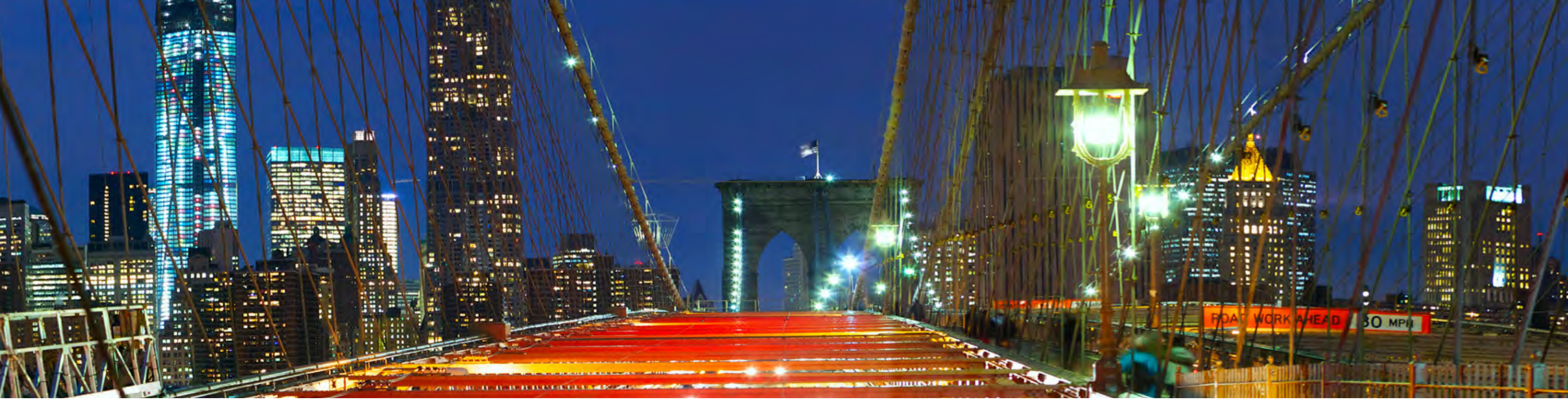
At present interconnected capacity is ineligible to participate in the 2014 capacity auction mainly due to the operation of interconnector capacity rules under the EU Target Model for market coupling. However, the Government is mindful of the importance placed on the participation of interconnected capacity in any consideration by the European Commission of Member States' capacity payment mechanisms for state aid purposes and is committed to finding a solution to this problem. Nevertheless, before cross-border capacity is admitted, further safeguards to the design of the UK capacity market may be required to monitor the actual availability of the capacity resources committed by the foreign provider and to ensure that it will be permitted to make such committed capacity available in circumstances where there are stressed situations either side of the interconnector.

Lessons Learned from US Capacity Markets

In the US, there are six mature organized electricity markets characterized by locational marginal pricing with an independent system operator (ISO) functioning as the market administrator for the clearing price markets (ISO-New England, the New York ISO, PJM Office of Interconnection (Mid-Atlantic states), Mid-Continent ISO (formerly the Midwest ISO), the California ISO and the Electric Reliability Council of Texas). The three north-eastern ISOs have somewhat mature but evolving capacity markets. The lessons learned from these markets can help to avoid repeating mistakes.

US capacity markets used to involve little more than confirmation that each load serving entity (LSE) had sufficient generation under ownership or contract to satisfy peak demand plus reserve margin accompanied by generator dependable capability testing. In the early days of these markets (1998-2003), if there was a surplus, capacity prices tended to plummet because all suppliers would rather have some revenues than become the one that was priced out. In parallel, in times of relative shortage, prices would jump to the penalty an LSE would have to pay if it was deficient – two to three times the all-in cost of a peaking unit. This resulted in a naturally occurring vertical demand curve with prices plummeting with relatively small surplus and prices sky-rocketing in times of slight shortage.

Meanwhile, energy prices following the fallout from the California energy crisis were substantially mitigated. With limited scarcity pricing, and a boom-bust cycle in the capacity markets, there was significant concern that capacity was not being built where and when needed. There was little political will to ease mitigation so as to let energy prices reflect scarcity conditions in more hours and in greater magnitude



than market power mitigation would allow. In order to shore up the revenues and price signals to facilitate new development, restructured capacity markets commenced about ten years ago.

The NYISO was the first to use a demand curve structure. All supply would have to bid into the capacity market. The ISO, subject to the US Federal Energy Regulatory Commission's (FERC) review would determine the price of capacity based on the all-in cost of new entry (CONE) of a peaking unit less the margins the unit could expect from sales of energy and ancillary services to form net CONE. This price was the theoretically economic efficient price when the market had just enough capacity to satisfy peak load plus reserve margin. The ISO would then establish a zero crossing point – an amount of capacity surplus at which the price should be set to zero; and a maximum capacity price at which the prices would be high and level off. With these three points, a linear curve can be formed to guide capacity auctions. All units that bid in below the curve would clear and receive the price at which the amount of supply below the curve crossed the curve.

The demand curve structure sent price signals so that in times of surplus prices would decrease, but not vertically so and in times of shortage, prices would increase without immediately jumping to the penalty level. The demand curve also recognized that there was value in capacity in excess of the installed reserve margin.

All capacity had to participate in the auction. In zones that were import restricted, a certain amount of capacity had to be procured within the zone. Before long, concerns arose that large or critical suppliers in such zones could withhold some of their capacity to ensure prices were higher on the capacity that cleared. In response to this threat, ISOs adopted critical supplier screens and required them to bid into the capacity market as price-takers so they could not withhold. ISO market monitoring units started monitoring for physical and economic withholding as well.

After a period of time, the opposite concern arose – buyer market power or monopsony power. Some large load serving entities that had divested generation to non-affiliated entities were substantial buyers in the ISO capacity auctions. If such buyers entered into power purchase agreements at above market clearing levels they could stimulate new investment even when it was not needed. If the uneconomic entry causes the capacity prices to drop enough, then the load serving entity might pay too much on 1,000 MW, but reap much greater savings on the other 9,000 MW it purchased in the auction.

Uneconomic entry had the effect of causing volatile crashes in capacity prices. In response, FERC required the three eastern ISOs to develop buyer-side mitigation to prevent uneconomic new entry from resulting in artificially low capacity prices. The rules are evolving now. In the NYISO market, a new entrant is subject to a unit-specific net CONE determination by the ISO. If the ISO determines that the unit would clear the ISO's forecast of the capacity market prices, then it would not be mitigated and may bid as a price taker. In contrast, if the ISO determines that the net CONE is above market clearing levels, the unit must bind in to the market with an offer floor.

In PJM, only gas-fired units are subject to buyer side mitigation (a/k/a the Minimum Offer Price Rule or "MOPR"). PJM calculates each new entrant's net CONE which forms an offer floor. If the unit clears an annual capacity auction, then it is not to be mitigated. If the unit's costs result in an offer floor above the clearing price, the unit will not clear the auction, will not receive capacity revenues and will not contribute to lowering capacity prices. This state can continue indefinitely.

Needless to say, there are a number of contentious issues going into the ISO demand curve – assumptions about the reference CT capital structure, cost of capital, margins on energy and ancillary service sales, the slope of the curve, the zero crossing point and other issues. Implementing the capacity markets as structured is in some requests a throwback to ratemaking in a quasi-market context. It is at best regulated competition.

All of these quasi-regulatory patches on patches are a result of energy only price signals that were constrained by supplier side mitigation measures which tended to over-mitigate. Rather than lifting energy mitigation the regulator thought capacity markets with evolving critical supplier mitigation followed by buyer side mitigation and actual offer floors were the way to go.

The capacity markets range from a year-ahead auction market to a three-year ahead market, but each auction produces prices for only one year. The capacity market revenues are not liquidated for any length of time, making the revenue streams less effective to bring down the cost of non-recourse project financing.

In addition to the mitigation of energy prices, over the last decade of capacity markets, the growth of intermittent renewable energy sources has been substantial in some markets. This further reduces energy market revenues which a new CCGT unit may expect. In some instances, energy prices go negative when the wind is blowing and the ISO needs to curtail or back down supply. Negative prices can result in financial obligations for some economic supplies.

Additional flux surrounds evolving rules by which demand response (DR) may participate in the capacity markets. The rules were different for generation and DR. For example, generators must offer supply into the ISO Day-Ahead market in an amount equal to or greater than the amount of capacity which the generator has cleared in the applicable auction. If the generator were not available when needed, its equivalent forced outage rate would suffer, and the amount of capacity it could sell in the future would decrease. In contrast, DR resources were treated as an emergency resource and did not have a day-ahead offer requirement. If DR resources, however, were not available when called in some markets, they would lose half of their capacity revenues on the year, and if they failed to respond a second time, they would lose all capacity revenues on the year.

Other rules affect the incentives for DR resources to participate in the capacity market. For example, there is current litigation over the mandatory response time for DR resources.

On rare occasions, DR suppliers have been found to game the system. Both FERC's Office of Enforcement and ISO market monitoring units have stepped up review of compliance and verification efforts. The potential to lose 50 to 100 percent of the annual capacity revenues by not responding—curtailing load or bringing up on-site generation—is also an incentive to achieve and maintain compliance.

To conclude, capacity markets, once introduced, should not necessarily be regarded as permanent features and in theory should be phased out once generation adequacy can be permanently ensured by the energy market offering a sufficient level of pricing to deliver the appropriate investment incentives. In practice, and based on the US experience, this is unlikely to happen unless the predictability of capacity payment pricing that may be realized under a well-designed capacity market can be replicated in the energy market. Indeed, even if such a level of pricing predictability could be achieved, the pace of phase-out of any capacity payment mechanism needs to be carefully considered, particularly if one of the market design objectives is to stimulate new build plant rather than simply to delay the decommissioning of existing plant. As it is likely that longer duration arrangements will need to be offered to incentivize investors and to ensure the bankability of such arrangements, there should be no suggestion that existing commitments can be prematurely curtailed if the required level of generation adequacy is achieved earlier than anticipated.

In the EU context, a tension exists between national capacity markets that are deploying increasingly sophisticated payment mechanisms to achieve generation adequacy targets and EU regulations that support the development of the internal energy market. The new State Aid Guidelines should ease this tension, although a co-ordinated approach to the introduction of capacity mechanisms by Member States is still required to ensure their compatibility with the process of EU market integration. However, for some Member States, the more pressing requirement to meet security of supply concerns at the national level may overrule such an approach.

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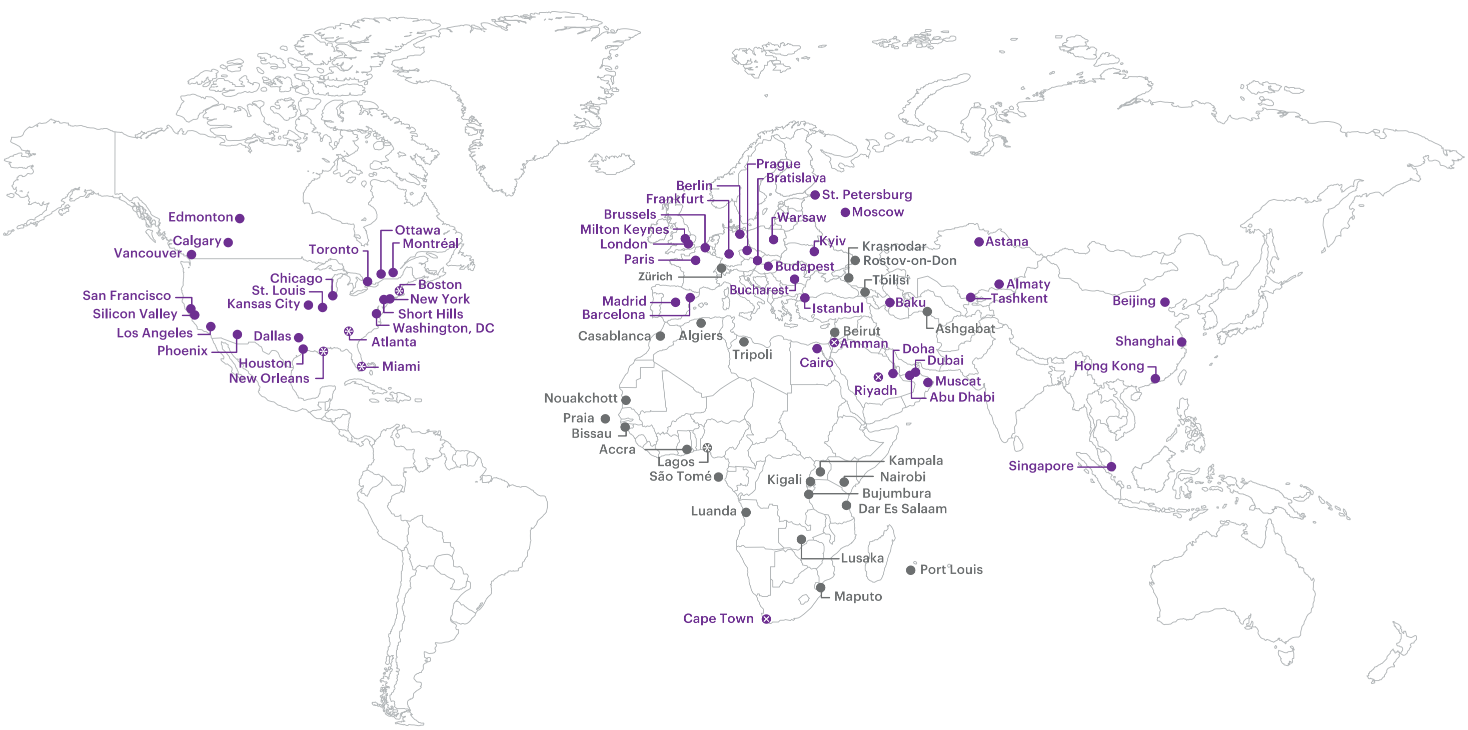

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