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ELECTRICITY: RENEWABLES AND SMART GRIDS

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FOREWORD

This document comprises proceedings in the original languages of a Roundtable, Electricity: Renewables and Smart Grids, held by the Competition Committee (Working Party No. 2 on Competition and Regulation) in February 2010.

It is published under the responsibility of the Secretary General of the OECD to bring information on this topic to the attention of a wider audience.

This compilation is one of a series of publications entitled "Competition Policy Roundtables".

PRÉFACE

Ce document rassemble la documentation dans la langue d'origine dans laquelle elle a été soumise, relative à une table ronde, Electricité : Energies Renouvelables et Réseaux Intelligents, qui s'est tenue en février 2010 dans le cadre du Comité de la concurrence (Groupe de Travail No. 2 sur la Concurrence et la Réglementation).

Il est publié sous la responsabilité du Secrétaire général de l'OCDE, afin de porter à la connaissance d'un large public les éléments d'information qui ont été réunis à cette occasion.

Cette compilation fait partie de la série intitulée "Les tables rondes sur la politique de la concurrence".

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EXECUTIVE SUMMARY

By the Secretariat

(1) *Many OECD countries have adopted targets for the share of electrical energy that will be produced from renewable energy sources by the year 2020. In addition to general mechanisms which increase the price of greenhouse gas emissions such as carbon taxes or cap-and-trade schemes, many OECD countries have introduced specific programs to encourage investment in renewable generation capacity. These programs include, in particular, renewable purchasing obligations on electricity retailers, and/or a guaranteed price or a guaranteed premium for renewable producers.*

Most countries reported that they have implemented specific schemes to encourage investment in renewable technology. These schemes can take many forms, including capital grants or tax breaks (such as exemption from other levies), but most countries reported the implementation of a renewable purchasing obligation on energy retailers or a guaranteed price (a “feed-in” tariff) or a guaranteed premium over the wholesale price for renewable producers. The former approach sets the volume (or the share) of renewable generation required and allows the price premium for renewable generation to adjust to achieve that volume in the most efficient manner; the latter approach sets the price (or the premium) for renewable generation and allows the volume to adjust.

Those countries which fix the required quantity of renewable generation typically do so by placing an obligation on electricity suppliers to purchase a proportion of their energy requirements from renewable sources - known as a Renewables Obligation or Renewable Portfolio Standard. This creates a demand for renewable generation over-and-above the demand for conventional generation, for which electricity suppliers are prepared to pay a premium. Generation from renewable sources produce renewable “certificates” which can be traded between market players or on power exchanges and which are submitted to the government as proof of satisfaction of a renewable obligation. This approach ensures that a given renewable target is met using the most efficient renewable technology.

Many countries also or instead pay a fixed price or a fixed premium or bonus (over the wholesale price for electricity) to renewables producers. The fixed price or premium may vary from one renewable technology to another (e.g., it is typically higher for solar generation), may vary by time of day, and is usually updated annually. This fixed price for renewable generation is also known as a “feed-in” tariff. Often, in order to provide the certainty necessary for investment, there are limits on the extent to which the government can change the feed-in tariff or renewables premium from one year to the next. (In a few cases, such as Bulgaria, the government enters into long-term 15-25 year power purchase contracts with renewable producers).

Several countries have had some difficulty setting these tariffs at an appropriate level to yield an efficient mix of renewable generation. This has particularly been a problem in the case of solar generation. For example, Spain found that “there has been excessive investment in some technologies in Spain” and “the investment incentives could have been too strong”. The renewables regulation was revised in 2008, allowing for the progressive reduction of tariffs and premiums. Potentially excessive investment in solar generation has also been experienced in France and the Czech Republic (where installed photovoltaic

capacity increased by 25 times in 18 months). The Czech regulator is seeking the power to reduce the regulated purchase price for solar generation by more than the current limit of 5 per cent per annum.

In most cases, the cost of these schemes to encourage investment in renewables is passed back onto electricity consumers, pushing up retail prices. The Czech Republic observed that the main factor influencing the growth of prices in 2010 is the significant growth of the cost of covering the support for renewable generation, including about 240 GWh of high-cost solar generation.

For member countries of the European Union, these forms of encouragement to investment in renewable electricity generation typically fall under the EU rules on state aid (and, in particular, the guidelines on State Aid for Environmental Protection). The EU emphasised in its submission that, amongst other things, the aid (a) must be necessary to ensure the viability of the renewable sources concerned and should not result in overcompensation for renewable energy; (b) should be designed in such a way as to not dissuade renewable energy producers from becoming more competitive; (c) should not create barriers to entry for eligible generators; and (d) should not distort the operation of the electricity supply market. There are also specific rules governing the provision of operating aid. In Hungary, some combined heat and power (CHP) generating units are eligible for renewable subsidies. The Hungarian submission to this roundtable noted that some of these CHP units – especially the larger ones – could be viable when competing on the wholesale electricity market, raising the possibility that subsidies for these units could at times constitute a breach of EC state aid rules.

Not all OECD countries have explicit policies for subsidising investment in renewable generation. In New Zealand, investment in generation is undertaken in response to competitive market signals - there are no renewables purchasing obligations or feed-in tariffs (although the government has established an Emissions Trading Scheme which will improve the cost effectiveness of renewable generation relative to thermal generation). The recent Electricity Market Review in New Zealand recommended the development of pricing guidelines and principles to guide the purchase of the output of small-scale distributed generation by retailers, but there was no recommendation to implement subsidies or feed-in tariffs for distributed generation. Even without direct subsidies New Zealand has experienced some investment in renewables, particularly in geothermal and wind generation, raising the question of whether subsidies are needed when an emission trading scheme exists.

(2) *The increasing penetration of renewable generation capacity raises a number of issues for the electricity supply network such as: upgrading and reinforcing the main backbone network in response to changing power flows; (b) managing the congestion that arises on the transmission and distribution network in response to new renewable generation. In many cases this investment in transmission and distribution would be carried out by vertically separated and regulated transmission and distribution businesses, raising the issue of how to incentivise regulated businesses to carry out the needed upgrades.*

In many cases the best locations for investment in renewable generation are far from the existing transmission and distribution networks. In these cases exploiting the renewable resources may require substantial investment in new transmission or distribution assets. This raises the issue of who should pay for such network augmentation. One common approach requires new generation facilities to pay for the cost of construction of new transmission assets to connect back to the existing transmission grid. However, generators may feel that if they have paid for certain assets they should have a degree of control over how those assets are used and may attempt to deny access to those assets to rival generating firms. In Australia, a project known as “scale efficient network extensions” is exploring how to share the cost of transmission connection assets between developers and consumers. In New Zealand the Electricity Commission aims to identify geographic areas in which there is likely interest from developers of renewable generation to

ensure that transmission investment by the regulated transmission owner to those areas are correctly sized from the outset.

A related issue is the need for upgrades or reinforcement to the existing shared networks. In the UK, under the previous policy, generators were not able to connect to the shared network until National Grid had carried out the necessary reinforcements. However, with a substantial amount of renewable generation being planned, especially in the north, a backload of connection requests developed, which reached 60 GW of capacity and resulted in connection dates forecast out to 2023. In 2010 the UK developed a new connection policy under which generators can connect to the shared network as soon as their connection assets are completed, with the costs of any resulting congestion essentially shared across all market participants.

It is not always economic to build transmission and distribution networks so as to eliminate all congestion, especially in the short-run. In many countries, substantial investment in renewable generation capacity has given rise to periodic congestion on the transmission network which must be managed, particularly in those networks with regional or zonal pricing (such as the UK) rather than nodal pricing (such as New Zealand). In the UK the substantial investment in renewable generation capacity in Scotland has given rise to constraints on the transmission network and concerns about the exercise of market power. The UK writes that "innovative contracts have been increasingly used to balance output, such as inter-trips and capped generation contracts, which can deliver substantial savings over the traditional approach of managing constraints through the balancing mechanism". The Netherlands, also, has been forced to introduce a congestion management system due to constraints arising from distributed generation units associated with greenhouses, particularly in the west. As in the UK, the costs of this congestion management system are spread across all users.

One challenge is how to incentivise regulated transmission and distribution networks to provide the necessary upgrades. In the Netherlands, the growth in distributed generation has led to capacity problems for some distribution businesses. Distribution businesses in the Netherlands are regulated using yardstick regulation that rewards the businesses for increasing various measures of output (such as service quality or quantity) but does not currently reward the businesses for accommodating distributed generation. Concerns have been expressed that this will limit the growth of distributed generation and adversely affect the ability of the Netherlands to reach its emissions targets. The Dutch regulator is proposing to introduce an "output category" for distributed generation which would allow a distribution business to increase its revenue in line with the volume of distributed generation it serves.

(3) *The output of many sources of renewable generation (particularly wind, solar, and wave generation) is variable, dependent on the weather, and cannot be easily controlled. But electricity supply and demand must be kept in balance at all times. The increasing penetration of these intermittent generation sources raises the question of how to maintain balance of supply and demand when renewable supply varies.*

Unlike conventional generation technologies such as coal, gas, nuclear, the level of production of some of these new renewable energy sources – such as wind, wave and solar generation – cannot be directly controlled by the network operator and instead depends on factors such as the weather. The balance between electricity production and consumption must be maintained minute by minute. As penetration of wind and solar generation increases there is likely to be an increasing demand for mechanisms which facilitate supply/demand balancing. The more limited the ability of existing generation to supply those balancing services (that is, to ramp up and down in response to changing wind generation), the more limited the ability of the network to accommodate intermittent generation. The power system in Bulgaria is only able to accommodate intermittent generation with a penetration up to 20 per cent of the currently installed capacity, but applications have been submitted for 12,000 MW of renewable generation

capacity which not only exceeds this recommended level by several times but also exceeds the capacity of the network itself (10,000 MW). In Hungary, concerns about the ability of the existing system to accommodate intermittent generation led to the government placing a limit of 330 MW (later extended to 740 MW) on wind generation capacity.

Accommodation of large volumes of intermittent generation will require an increase in the network's ability to provide balancing services. Some balancing will be provided by flexible conventional generating plant, such as gas-fired plant. the Bulgarian submission notes, for example, that for each 100 MW of intermittent generation installed 60 MW of conventional generation will be needed for balancing. Some of this balancing can also be provided by demand-side response or distributed generation or storage. To the extent that "smart grid" infrastructure can facilitate the provision of demand-side response or distributed generation or storage, it facilitates the increasing penetration of renewable generation.

In some cases, current market arrangements implicitly assume that generation is largely controllable. In this case there may be implicit discrimination against wind and other intermittent generation. For example, market rules which require generators to specify their output a day in advance of actual dispatch, coupled with strong penalties for generating more or less than the target, may act as a barrier to entry by wind generators. On the other hand, wind and other intermittent generation may impose increased balancing costs on the system. In order to preserve a level playing field between generation technologies, these increased costs should be passed back to the intermittent generators which give rise to these costs.

(4) Historically, electricity was typically produced centrally by large generating units, often powered by fossil fuels, and transported in one direction to customers who were able to consume as much as they liked at a single time-averaged retail price. That paradigm is being eroded, in part because of smart grids. The term "smart grid" refers to a cluster of innovations in metering and communications which allow for more distributed and small-scale generation, more efficient customer consumption decisions, and more efficient and higher utilisation of network resources.

A variety of pressures are putting the traditional approach to electricity production and distribution under close scrutiny, including: (a) the need to accommodate a large amount of inherently intermittent renewable generating capacity in order to meet greenhouse gas emissions targets; (b) the need to accommodate a large amount of small-scale, distributed energy generation and storage facilities such as roof-top solar installations, or plug-in electric vehicles; and (c) pressure to improve the utilisation of network resources by shifting consumption decisions over time.

In the past the first two of these pressures may have been met by simply building more network assets. However, increasing costs of construction, especially in congested areas, and public pressure on electricity bills has led to pressure to achieve smarter use of existing resources, through a cluster of innovations collectively known as the "smart grid". The innovations involved in the provision of a smart grid include (a) more sophisticated metering technologies which allow for time-of-use and two-way metering of electricity flows; (b) communications networks to allow for two-way flow of information between electricity producers, consumers and electricity system operators; and (c) the development of appliances and devices which are able to respond autonomously to price signals or instructions from the network operator. Many of these technologies already exist and have been in place for many years in the control of the high-voltage transmission network and the associated producers and consumers. The primary impact of the smart grid concept will be in the extension of these technologies to distribution businesses and the associated distributed generation and smaller consumers.

The U.S. submission, quoting the Electric Power Research Initiative, describes a smart grid as the "overlaying of a unified communications and control system on the existing power delivery infrastructure to provide the right information to the right entity … at the right time to take the right action" and as a

result "it is a system that optimizes power supply and delivery, minimizes losses, is self-healing, and enables next-generation energy efficiency and demand response applications". The IEA defines the smart grid as the use of digital technology on electricity networks to monitor and manage the transport of electricity from the point of generation to the point of consumption, in a way which optimizes asset utilisation, minimises operating costs, and minimises environmental impact while maintaining system reliability, resilience and stability.

A smart grid would allow two-way information flows – including information on the current state of the electricity market to end-users and information on end-user consumption and demand patterns back to network operators. In principle, customer generation and consumption decisions could respond to signals in the wholesale market either indirectly through a response to the wholesale price, or directly through arrangements with the local electricity supplier. For example, the local electricity supplier might have the power to adjust the setting on air-conditioning in response to conditions in the wholesale market, or to control certain appliances – such as dryers or dishwashers – to operate at off-peak times. The customer might be permitted to charge the batteries of an electric vehicle at off-peak times and sell some of that power back to the grid at peak times.

The penetration of smart metering infrastructure varies greatly across OECD countries. In almost all OECD countries the largest electricity consumers make use of sophisticated meters. A few countries – such as Italy – already have widespread roll-out of advanced metering infrastructure to all households. Many countries have small-scale or trial roll-out of smart meters to all households in a small area. Other than these exceptions, smart meters have not yet achieved significant penetration in most OECD countries. Most small electricity consumers remain on simple contracts under which they pay a single flat rate or a simple peak/off-peak tariff for electricity. In the EU, the 3rd liberalisation package specifies the objective that, subject to a cost-benefit analysis to be carried out in the next three years, 80 per cent of households should have a smart meter installed by 2020.

The roll out of smart metering is not cheap. One submission noted that 8.6 billion GBP of investment will be required to replace the 47 million gas and electricity meters in the UK alone. There is a question as to who should be responsible for the investments necessary for the transition to a smart grid and what incentives they will face. Much of that investment will need to be carried out by regulated distribution businesses that do not necessarily directly benefit from these investments. In the Netherlands, which uses yardstick regulation for distribution businesses, investment in smart grid infrastructure may yield benefits (such as the enhanced ability to incorporate intermittent distributed generation, or the possibility for new value-adding tariff structures) that are not related to productive efficiency and that cannot easily be captured by the distribution business. The Dutch regulator has consulted on the need for an "innovation incentive" in the regulatory regime. Another issue is that, under the yardstick framework, even if major new investment is required by a distribution business, this cannot be reflected in a higher revenue stream until the next regulatory period. The Dutch regulator is considering extending the class of investments that classify as "substantial and exceptional", in which case the distribution business can start to recover the costs during the regulatory period.

(5) One of the primary objectives of smart grids is to increase the responsiveness of consumers to wholesale electricity market conditions – in particular, by reducing consumer demand (or increasing distributed generation) at times when the supply/demand balance in the wholesale market is tight.

A number of countries are experimenting with different forms of tariffs to determine the approaches that are most effective and the most acceptable to consumers. Some forms of demand-side response (such as "interruptible" contracts for large consumers) have been around for many years and do not require new technological or market innovations. Other forms of demand-side response, such as time-of-use pricing,

require more sophisticated metering infrastructure which, in the past, was limited to the largest electricity consumers. The roll-out of advanced metering infrastructure to smaller customers allows more widespread use of retail tariffs which respond either to the time of day or to the wholesale electricity price. In turn, it is expected that, once retail customers are exposed to a time-varying price for electricity, customers will seek out ways to shift their consumption across time – for example, through appliances whose consumption varies with the retail price for electricity (such as a dryer which only turns on at low-price times), or devices controlled directly by the electricity supplier (such as adjustments to the thermostat setting on air-conditioners), or small-scale generation or storage devices (such as batteries in electric vehicles) which can be drawn on at peak times.

Shifting electricity consumption away from peak periods has many potential efficiency benefits. An electricity supply industry must have sufficient spare capacity – in generation, transmission, and distribution to handle all but the very highest peak demand times. If the peak demand exceeds average demand by a large margin, the electricity industry must incur substantial cost, maintaining a large volume of capacity (including, generation, transmission, and distribution capacity) in reserve for the purpose of meeting peaks that are few and far between. In California, a reduction in peak demand of 15-20 per cent would allow a reduction of 5-10,000 MW in peak capacity.

In addition, wholesale electricity markets tend to be prone to the exercise of market power. Importantly, an increase in demand responsiveness significantly reduces the scope for the exercise of market power. As FERC has recently stated, demand response "can provide competitive pressure to reduce wholesale electric prices, increase awareness of energy usage, provide for more efficient operation of markets, mitigate market power, enhance reliability, and, in combination with certain new technologies, support the use of renewable energy resources and distributed generation".

Although some forms of time-of-use pricing have been around for many years, ideally customers would face so-called "dynamic pricing" which varies with conditions in the electricity system. One form of dynamic pricing is so-called "critical peak pricing" which allows the electricity utility to designate up to a certain number of hours per year as "super-peak" with a particularly higher retail price, provided they give the retail customers 24 hours notice of the period within which the super-peak prices will apply. Trial studies of time-of-use and dynamic pricing tend to show that the response of small customers to time-of-use pricing is relatively modest. These studies typically show a reduction in consumption in peak periods of roughly 10-20 per cent relative to customers on fixed prices. Studies show that introducing automatic devices – such as smart thermostats – significantly enhanced the price responsiveness of customers.

Dynamic and time-of-use pricing schemes do not necessarily reduce electricity consumption overall – as customers may increase their usage in low-cost off-peak periods by more than they curtail their usage in high-cost peak periods.

Changes to tariff arrangements raise issues of consumer expectations and perceptions of fairness. Existing customers have a long history of purchases in electricity-consuming appliances and lifestyle habits which affect their future consumption decisions. Customers are typically wary of new pricing schemes under which their total bill could rise significantly or in ways that are partly out of their control. Trials show that customers are more willing to take up schemes under which, rather than being penalised for increasing consumption, they are rewarded for reducing consumption below a target level. However this can create strategic incentives to manipulate their consumption in a way that increases their target level.

(6) *These electricity industry developments – the increasing penetration of renewables and the transition to smart grids – may give rise to competition policy issues. Primary among these competition policy issues are (a) issues concerning discriminatory access to networks; and (b) the establishment of standards in metering services.*

Several OECD countries have vertically separated the transmission and distribution infrastructure from the potentially competitive generation and retailing segments. Such vertical separation eliminates the incentive on the network owner to discriminate in favour of his or her own affiliates in the generation or retailing sectors. However, in many OECD countries the network owner also participates in the generation or retailing sectors. In this case, the network owner may be reluctant to connect a rival if doing so results in a loss of sales to its own affiliate. This reluctance to connect could manifest itself in delays in completing connection arrangements, failure to make necessary upgrades or reinforcement, reserving capacity for its own affiliates, favouring its own generation affiliates in the dispatch process, and so on. The U.S. warns against these risks: "both regulators and enforcers should be aware that incumbent electricity firms may be able to impede entry of not only generation sources but also of new technologies that have the potential to facilitate new forms of competition. To address this possibility, competition authorities should evaluate whether such efforts reflect legitimate business purposes of an effort to exclude competition on the merits".

The French submission explicitly raises the possibility that in the event the network owner invests in renewable generation (either directly or through an affiliate), it might be tempted to discriminate against independent or third-party renewable generators. The submission points to the requirements of the 2nd and 3rd liberalisation packages of the EU, which require legal and functional separation of generation and transmission and which forbid discrimination in users of the network, particularly with respect to connection to the network. The French submission notes that the potential for such discrimination is kept under close watch by the regulatory authorities.

Many countries are in the process, or have plans to roll out smart meters to all households (often in both electricity and gas) in the near future. One key issue is what features or functionality these smart meters should have and who should decide? Should customers have a choice of smart meter provider, or should they accept the meter provided by their electricity supplier? Will a customer need to purchase a new meter if it changes electricity supplier? Should there be a requirement for inter-operability of different metering infrastructure with different devices? In New Zealand there have been cases in the past where an existing advanced meter has been replaced by a new advanced meter when a customer changes retailer. The submission notes that this should only occur in the future where there is a technical requirement to replace or upgrade the functionality of a meter installation and not due to impeded access to information or incompatibility of data formats across retailers.

Competition authorities have expressed concerns about the possibility for proprietary standards in meters to be an obstacle to the development of retail competition. The U.S. writes that "the DOJ and FTC's experience with standard-setting bodies is … there is a risk in such technology-heavy markets that incumbents will try to influence the vote of a standards-setting organization to ensure that rival technologies will be viewed as unsafe, suspect, or otherwise disfavoured. …. Going forward, standard setting will play a crucially important role in creating smart meters and smart devices that can successfully connect to each other and to the broader network. … Experience teaches that this is a particularly important realm for antitrust and regulatory vigilance. Notably, standard-setting organizations should insist on openness regarding existing intellectual property rights to prevent hold-up, take care that the standards are not so onerous as to prevent entry, and seek to ensure that standardized technology is advanced enough to allow maximal use of expanding technological opportunities".

Many national and international organisations are pursuing the development of standards for metering infrastructure, including the EU, the (U.S.) National Institute of Standards and Technology, the

International Organisation for Standardisation (ISO), and the International Electrotechnical Commission (IEC).

Submissions also mentioned concerns regarding data privacy and security issues. The French submission noted that the 3rd EU liberalisation package allows all customers to have access to all the collected data on their electricity consumption and to have that information communicated to any supplier which they have authorised.

Increasing volumes of renewable generation and the transition to smart grid technologies both have the potential to change the electricity industry. These changes may include enhanced competition as small-scale generators compete with existing generators and demand-side responsiveness mitigates existing market power. Competition authorities have a role to play in ensuring that desired policy objectives are achieved in a manner which is competitive and technologically neutral, that barriers to the entry of new firms are minimal, and that dominant players do not use that dominance to restrict the growth of competition in existing services or any new services that may emerge.

SYNTHÈSE

Par le Secrétariat

(1) Un grand nombre de pays de l'OCDE se sont fixé des objectifs concernant la proportion d'électricité qui sera produite avec des énergies renouvelables à l'horizon 2020. Outre des mécanismes généraux qui relèvent les prix des émissions de gaz à effet de serre comme les taxes sur le carbone ou les systèmes d'échanges de quotas d'émissions, les pays de l'OCDE ont souvent mis en place des programmes spécifiques pour favoriser les investissements dans la production d'électricité renouvelable. Ces programmes comportent notamment l'obligation pour les détaillants d'acheter de l'électricité renouvelable et/ou un prix ou une prime garantis pour les producteurs de cette électricité.

La plupart des pays ont indiqué qu'ils avaient mis en place des mécanismes spécifiques afin d'encourager les investissements dans les énergies renouvelables. Ces mécanismes peuvent prendre des formes très diverses et notamment se traduire par des subventions en capital ou des allégements fiscaux (par exemple, l'exemption de certains prélèvements). Toutefois, une majorité des pays a imposé aux détaillants l'obligation d'acheter de l'électricité renouvelable et fixé un prix garanti (le tarif d'achat) ou encore accordé une prime en sus du prix de gros aux producteurs d'électricité renouvelable. La première méthode consiste à définir le volume (ou la proportion) d'électricité renouvelable nécessaire et à laisser la prime accordée à ce type de production s'ajuster de façon à atteindre le plus efficacement possible la proportion fixée ; dans le deuxième cas, on fixe le prix (ou la prime) de la production d'électricité renouvelable et on laisse le volume s'ajuster.

En règle générale, les pays qui fixent une quantité obligatoire d'électricité renouvelable imposent aux fournisseurs d'électricité de se procurer un pourcentage donné de leurs besoins énergétiques sous forme renouvelable. Cela crée une demande d'électricité renouvelable supérieure à la demande d'électricité produite dans des centrales classiques que, de surcoût, les fournisseurs d'électricité sont prêts à payer plus cher. La production d'électricité renouvelable entraîne la création de certificats verts, qui peuvent être échangés entre acteurs de marché ou sur des bourses d'électricité et qui sont remis aux administrations publiques comme preuve de respect de l'obligation d'achat. Cette méthode garantit que l'objectif fixé pour l'électricité renouvelable est atteint avec la technologie la plus efficace.

En plus ou à la place de ce système, nombre de pays payent un prix ou une prime fixe (venant s'ajouter au prix de gros de l'électricité) aux producteurs d'électricité renouvelable. Ce prix ou cette prime peuvent dépendre du type d'énergie renouvelable concerné (ils sont en général plus élevés pour la production solaire) et du moment de la journée ; de plus, ils sont généralement revus tous les ans. Le prix fixé pour la production d'électricité renouvelable est également appelé tarif d'achat. Souvent, le souci de créer des conditions propices à l'investissement limite les possibilités de modifier d'une année sur l'autre les tarifs d'achat ou la prime aux énergies renouvelables. (Dans un petit nombre de cas, par exemple en Bulgarie, l'État signe des contrats d'achat à long terme (15-25 ans) avec les producteurs d'électricité renouvelable).

Plusieurs pays ont eu quelque difficulté à déterminer les tarifs qui permettent de parvenir à une répartition satisfaisante entre les différentes formes d'énergie renouvelable. Le problème s'est notamment

posé pour la production solaire. Ainsi, l'Espagne a estimé que « l'investissement dans certaines technologies avait été excessif dans le pays » et que « les incitations à investir avaient peut-être été trop fortes. » La réglementation sur les énergies renouvelables y a été revue en 2008, ce qui s'est traduit par une baisse progressive des tarifs et des primes. La France et la République tchèque (dans ce dernier pays, la puissance photovoltaïque installée a été multipliée par 25 en 18 mois) ont probablement aussi surinvesti dans l'énergie solaire. Le régulateur tchèque souhaite être autorisé à abaisser le tarif d'achat réglementé de la production solaire davantage que le pourcentage actuel fixé à 5 % par an.

Dans la plupart des cas, le coût de ces mécanismes destinés à favoriser les investissements dans les énergies renouvelables est répercuté sur le consommateur d'électricité, ce qui se fait monter les prix de détail. La République tchèque a observé que la hausse des prix en 2010 tient principalement à l'augmentation notable du coût du soutien apporté aux énergies renouvelables, notamment à une capacité de production solaire très chère avoisinant 240 GWh.

Pour les pays membres de l'Union européenne, ces incitations à investir dans la production d'électricité renouvelable relèvent habituellement des règles européennes sur les aides d'État (et, en particulier, de l'encadrement des aides d'État pour la protection de l'environnement). Dans sa contribution, l'UE a souligné, que l'aide a) doit être nécessaire pour assurer la viabilité des sources renouvelables concernées et ne doit pas trop avantager les énergies renouvelables ; b) doit être conçue de façon à ne pas dissuader les producteurs de ces énergies d'améliorer leur compétitivité ; c) ne doit pas créer de barrières à l'entrée pour les producteurs susceptibles de bénéficier de cette aide ; d) ne doit pas perturber le fonctionnement du marché de l'électricité. Par ailleurs, l'octroi d'aides au fonctionnement obéit aussi à des règles spécifiques. En Hongrie, certaines unités de cogénération peuvent bénéficier des subventions destinées aux énergies renouvelables. Le document présenté par la Hongrie relevait que certaines de ces centrales de cogénération — surtout les plus grandes — pourraient être viables si elles devaient affronter la concurrence sur le marché de gros de l'électricité, ce qui pose la question de savoir si l'octroi de subventions à ces unités constitue dans certains cas une violation des règles européennes sur les aides d'État.

Certains pays de l'OCDE ne subventionnent pas les investissements dans la production d'électricité renouvelable. En Nouvelle-Zélande, ce sont des signaux favorables du marché qui sont à l'origine de ce type d'investissement, car il n'existe ni obligation ni tarif d'achat d'électricité renouvelable (cela étant, l'État a mis en place un système d'échange de quotas d'émissions de CO_2 qui va contribuer à améliorer la rentabilité de la production d'électricité renouvelable par rapport à celle de la production thermique). L'étude du marché de l'électricité récemment menée dans le pays recommandait d'établir des orientations et principes de tarification afin d'aider les détaillants à acheter l'électricité produite par des unités décentralisées de petite taille, mais ne suggérait pas d'instaurer des subventions ou des tarifs d'achat pour la production décentralisée. Même sans subventions directes, on a investi dans les énergies renouvelables en Nouvelle-Zélande, notamment dans la production géothermique et éolienne, ce qui pose la question de savoir si ces subventions sont nécessaires lorsqu'il existe un système d'échange de quotas d'émissions de CO_2.

(2) L'augmentation des capacités de production d'électricité renouvelable pose des problèmes pour le réseau électrique, notamment : nécessité de mettre à niveau et de renforcer le réseau en raison des modifications des transits d'électricité ; gestion des congestions sur les réseaux de transport et de distribution que provoque la production d'électricité renouvelable. Souvent, ces investissements dans le transport et la distribution seront le fait d'entreprises de transport et de distribution réglementées et verticalement séparées, ce qui pose la question de savoir comment inciter des entreprises réglementées à effectuer les mises à niveau nécessaires.

Bien souvent, les meilleurs emplacements pour investir dans la production d'électricité renouvelable sont éloignés des réseaux de transport et de distribution existants. L'exploitation des énergies renouvelables peut, dans ce cas, exiger des investissements substantiels dans de nouvelles infrastructures de transport ou de distribution. Se pose alors la question de savoir qui doit payer la facture de ce renforcement du réseau. Une des méthodes fréquemment employées consiste à imposer aux nouvelles installations de production de financer la construction des actifs de transport qui les raccorderont au réseau de transport existant. Cependant, les producteurs peuvent estimer que, s'ils ont financé des infrastructures, ils ont leur mot à dire sur la façon dont ces actifs sont utilisés et parfois même tenteront d'en refuser l'accès à des concurrents. En Australie, un projet baptisé « Étendre efficacement le réseau » examine comment partager le coût des infrastructures de raccordement entre leurs promoteurs et les consommateurs. En Nouvelle-Zélande, l'Electricity Commission cherche à recenser les zones géographiques auxquels les promoteurs de centrales renouvelables sont susceptibles de s'intéresser afin de s'assurer que les investissements que le propriétaire du réseau de transport réglementé y a consentis sont correctement dimensionnés dès le départ.

Il est également nécessaire de mettre à niveau ou de renforcer les réseaux existants. Au Royaume-Uni, en vertu de dispositions aujourd'hui abandonnées, les producteurs ne pouvaient être raccordés au réseau tant que National Grid n'avait pas effectué les renforcements nécessaires. Or, comme des investissements importants ont été lancés dans la production d'électricité renouvelable, surtout dans le nord du pays, les demandes de raccordement non satisfaites se sont accumulées et représentent aujourd'hui 60 GW de sorte que les dates de raccordement prévues s'étalent jusqu'en 2023. En 2010, le Royaume-Uni a adopté de nouveaux principes de raccordement, en vertu desquels les producteurs peuvent êtres raccordés au réseau dès que les installations de raccordement sont prêtes. Les coûts liés aux congestions qui en résultent sont, pour l'essentiel, partagés entre tous les opérateurs intervenants sur le marché.

Il n'est pas toujours rentable, surtout à court terme, de construire des réseaux de transport et de distribution pour éliminer toutes les congestions. Dans nombre de pays, les investissements substantiels consentis dans des moyens de production renouvelables ont entraîné des congestions périodiques du réseau de transport, congestion qu'il faut gérer, surtout sur les réseaux où l'on pratique une tarification régionale ou zonale (comme au Royaume-Uni) et non nodale (comme en Nouvelle-Zélande). Au Royaume-Uni, les investissements importants effectués en Écosse dans des moyens de production renouvelables ont créé des contraintes sur le réseau de transport et fait redouter l'exercice de pouvoir de marché. Le Royaume-Uni écrit que « des contrats d'un genre nouveau sont de plus en plus utilisés pour équilibrer la production. Parmi ces contrats, on peut citer les contrats d'effacement prévoyant des délestages et ou un plafonnement des volumes de production participant à l'ajustement qui permettent de réaliser des économies par rapport à la méthode classique qui consiste à gérer les contraintes en ayant recours au mécanisme traditionnel d'ajustement ». Les Pays-Bas ont également été contraints de mettre en place un dispositif de gestion des congestions en raison des contraintes qui résultent de l'existence, principalement dans l'ouest du pays, d'unités de production décentralisées associées à des serres. Comme au Royaume-Uni, le coût de ce dispositif est réparti entre tous les utilisateurs du réseau.

L'un des défis à relever est de trouver comment inciter des gestionnaires des réseaux de transport et de distribution d'électricité à effectuer les mises à niveau nécessaires. Aux Pays-Bas, avec l'essor de la

production décentralisée, certaines entreprises de distribution ont rencontré des problèmes de capacité. Dans ce pays, les entreprises de distribution sont soumises à un étalonnage concurrentiel qui récompense les distributeurs qui ont amélioré divers aspects de leur activité (comme la qualité de service ou la quantité) mais, à l'heure actuelle, ne récompense pas les entreprises qui prennent en charge la production décentralisée. D'aucuns redoutent que ce dispositif ne freine l'essor de la production décentralisée et ait un effet défavorable sur la capacité des Pays-Bas d'atteindre leurs objectifs d'émissions. L'autorité de régulation néerlandaise propose d'instaurer une « catégorie de production » correspondant à la production décentralisée qui permettrait à une entreprise de distribution d'augmenter ses recettes en fonction du volume de production décentralisée qu'elle fournit à ses clients.

(3) Pour bon nombre de modes de production d'électricité renouvelable (notamment pour la production éolienne, solaire ou houlomotrice), la quantité d'électricité produite est variable, dépend des conditions météorologiques et ne peut être facilement maîtrisée. Or l'offre et la demande d'électricité doivent être égales en permanence. L'essor de cette production intermittente pose la question de savoir comment maintenir l'équilibre entre l'offre et la demande alors que la production renouvelable n'est pas constante.

Contrairement aux techniques de production classiques -centrales à charbon et à gaz ou centrales nucléaires- avec certaines énergies renouvelables, comme l'énergie éolienne, houlomotrice ou solaire, la production ne peut pas être directement contrôlée par le gestionnaire de réseau, car elle dépend de facteurs tels que les conditions météorologiques. Or la production et la consommation d'électricité doivent être constamment en équilibre. Sachant que les productions éolienne et solaire augmentent, on devrait avoir besoin de plus en plus de mécanismes qui facilitent l'équilibrage de l'offre et de la demande. Moins les moyens de production existants seront capables d'assurer cet équilibre (c'est-à-dire d'augmenter ou de diminuer rapidement leur production pour s'adapter aux variations de la production éolienne), moins le réseau sera capable d'intégrer la production intermittente. En Bulgarie, le système électrique n'est capable de gérer la production intermittente que si celle-ci représente au maximum 20 % de la puissance actuellement installée. Or les demandes déposées pour produire de l'électricité renouvelable représentent, au total, 12 GW, ce qui non seulement est égal à plusieurs fois le niveau recommandé mais dépasse également la capacité du réseau lui-même (10 GW). En Hongrie, des inquiétudes concernant la capacité du système existant d'absorber la production intermittente ont conduit l'État à fixer une limite de 330 MW (ultérieurement portée à 740 MW) à la production éolienne.

Afin de pouvoir gérer une importante production intermittente, les gestionnaires de réseau devront mettre en place davantage de services d'ajustement. Une partie de l'ajustement sera assurée par des installations classiques ayant une grande souplesse de fonctionnement, par exemple des unités à gaz. Le document présenté par la Bulgarie relève que 100 MW de puissance installée intermittente exigent 60 MW de puissance installée classique pour l'ajustement. L'effacement de la demande ou les moyens de production ou de stockage décentralisés peuvent également contribuer à l'ajustement. Dans la mesure où les infrastructures de réseau évoluées facilitent l'effacement de la demande ou l'utilisation de moyens de production ou de stockage décentralisés, elles participent aussi à l'essor de l'électricité verte.

Dans certains cas, le fonctionnement actuel du marché repose implicitement sur l'hypothèse que l'on peut maîtriser l'essentiel de la production. Si c'est le cas, la production éolienne et d'autres productions intermittentes risquent d'être automatiquement désavantagées. Ainsi, les règles du marché qui imposent aux producteurs d'indiquer quel sera leur volume de production 24 h à l'avance et qui sont assorties de lourdes pénalités si la production est supérieure ou inférieure à la quantité annoncée peuvent constituer des barrières à l'entrée pour les producteurs éoliens. Cela étant, la production éolienne et les autres productions intermittentes peuvent renchérir les coûts d'ajustement du système électrique. Afin que tous les modes de production soient sur un pied d'égalité, il conviendrait de répercuter la hausse de ces coûts sur les producteurs intermittents qui en sont responsables.

(4) *Jusqu'à une date récente, l'électricité était en général produite par de grandes unités centralisées brûlant des combustibles fossiles, puis transportée à destination des clients qui pouvaient en consommer autant qu'ils le désiraient à un prix de détail unique établi en calculant une moyenne dans le temps. Ce modèle est aujourd'hui remis en cause, notamment depuis l'apparition des réseaux intelligents. Le terme « réseau intelligent » fait référence à un ensemble d'innovations dans le domaine du comptage et des communications, qui permettent de gérer des unités de production plus petites et plus décentralisées, permettent aux clients de consommer leur électricité plus efficacement et favorisent une utilisation plus efficace et plus intense des réseaux.*

Plusieurs contraintes poussent à une remise en cause de la méthode classique de production et de distribution de l'électricité, notamment : a) la nécessité d'intégrer de nombreux moyens de production renouvelable, par essence intermittente, afin d'atteindre les objectifs fixés pour les émissions de gaz à effet de serre ; b) la nécessité de prendre en charge de nombreux moyens de production ou de stockage décentralisés de petite taille, comme les panneaux photovoltaïques de toit ou les véhicules électriques rechargeables ; c) la volonté de mieux utiliser les ressources des réseaux par des reports de consommation.

Jusqu'à présent, on pouvait gérer les deux premières contraintes en construisant davantage d'infrastructures de réseau, mais la hausse des coûts de construction, surtout dans les zones congestionnées, et le refus du public de voir sa facture s'alourdir poussent à une utilisation plus fine des capacités existantes en s'appuyant sur un ensemble d'innovations que l'on rassemble sous l'expression « réseau intelligent ». Parmi ces innovations, on peut citer : a) des techniques de comptage plus évoluées qui permettent un comptage horosaisonnier et bidirectionnel des transits d'électricité ; b) des réseaux de communication qui permettent l'échange de flux d'informations bidirectionnels entre les producteurs d'électricité, les consommateurs et les gestionnaires de réseau ; c) la mise au point d'appareils et de dispositifs capables de réagir de façon autonome à des signaux-prix ou à des instructions données par le gestionnaire de réseau. Bon nombre de ces techniques existent déjà et sont déjà utilisées depuis longtemps pour la conduite du réseau de transport haute tension ou chez les producteurs et consommateurs. L'idée maîtresse des réseaux intelligents est d'appliquer ces techniques aux entreprises de distribution ainsi qu'aux producteurs décentralisés et aux petits consommateurs qui sont raccordés à leur réseau.

Le document présenté par les États-Unis, citant l'Electric Power Research Institute, décrit le réseau intelligent comme «la superposition d'un système unifié de communications et de contrôle et d'un réseau électrique de sorte que la bonne information soit transmise à la bonne entité […] au bon moment et que la décision prise soit la bonne » et, donc, comme « un système qui gère au mieux la production et la desserte de l'électricité, réduit les pertes au minimum, est autocicatrisant et peut intégrer la prochaine génération de solutions pour améliorer l'efficacité énergétique ou gérer les effacements de la demande ». L'AIE de son côté définit le réseau intelligent comme le fait d'appliquer des technologies numériques aux réseaux électriques afin de suivre et de gérer le transport de l'électricité depuis le lieu de production jusqu'au lieu de consommation d'une manière qui exploite au mieux les infrastructures, réduit au minimum les charges d'exploitation et l'impact sur l'environnement tout en assurant la fiabilité, la robustesse et la stabilité du système électrique.

Dans un réseau intelligent, les flux d'informations pourront être bidirectionnels : les informations sur l'état du marché seront transmises en temps réel au consommateur final et, inversement, l'état de la consommation et les profils de la demande seront communiqués aux gestionnaires de réseau. En principe, la décision du client de fournir ou de consommer de l'électricité pourrait être fonction des signaux du marché de gros, indirectement, s'il s'agit de s'adapter au prix de gros, ou immédiatement s'il peut être automatiquement déconnecté ou connecté aux termes d'accords passés avec le fournisseur local d'électricité. Ce fournisseur local peut, par exemple, être autorisé à modifier le réglage de la climatisation en fonction de l'état du marché de gros ou à piloter certains appareils — comme les sèche-linge ou les lave-vaisselle — de sorte qu'ils ne fonctionnent qu'aux heures creuses. Le client pourrait être autorisé à

charger les batteries d'un véhicule électrique aux heures creuses et, en période de pointe, à revendre aux gestionnaires de réseau une partie de cette électricité stockée.

Le nombre d'infrastructures de comptage intelligent qui ont été installées varie considérablement suivant les pays de l'OCDE. Presque partout les grands consommateurs disposent de systèmes de comptage avancés. Par contre, rares sont les pays, comme l'Italie, qui ont déjà déployé à grande échelle des infrastructures de comptage évolué pour tous les ménages. L'installation à petite échelle ou à titre expérimental de compteurs intelligents dans tous les foyers d'une zone restreinte est pratiquée par de nombreux pays. Si l'on exclut ces exemples isolés, on dénombre peu de compteurs intelligents dans la plupart des pays de l'OCDE. Les petits consommateurs d'électricité ont en majorité souscrit des contrats simples, en vertu desquels ils paient un tarif unique pour l'électricité, voire un simple tarif ou un tarif double (heures creuses/heures pleines). Dans l'UE, le troisième paquet de libéralisation fixe l'objectif suivant : sous réserve de l'analyse coûts-bénéfices qui sera effectuée dans les trois prochaines années, 80 % des ménages devront disposer d'un compteur intelligent à l'horizon 2020.

Le déploiement de compteurs intelligents a un coût. Un des documents remis observait qu'il faudrait investir 8.6 milliards GBP pour remplacer les 47 millions de compteurs électriques ou à gaz installés au Royaume-Uni. La question se pose de savoir qui doit engager les investissements nécessaires pour mettre en place des réseaux intelligents et quelles seront les incitations à le faire. L'essentiel de ces investissements devra être consenti par des entreprises de distribution réglementées qui n'ont pas la certitude d'en bénéficier directement. Aux Pays-Bas, où les entreprises de distribution sont soumises à un étalonnage concurrentiel, investir dans des infrastructures de réseau intelligentes peut présenter des avantages (capacité accrue d'intégrer des productions décentralisées intermittentes ou possibilité de mettre en place de nouveaux systèmes tarifaires innovants) qui ne concernent pas l'efficience productive et dont ne peuvent pas profiter les distributeurs. L'autorité de régulation néerlandaise a engagé des consultations concernant l'intégration « d'incitations à innover » au cadre réglementaire. L'étalonnage concurrentiel pose un autre problème qui tient au fait que, même si une entreprise de distribution doit consentir des investissements importants, ces derniers ne peuvent entraîner une augmentation des recettes avant le prochain réexamen des règles tarifaires. L'autorité néerlandaise envisage d'élargir la catégorie des investissements qualifiés « d'importants et d'exceptionnels », ce qui permettrait aux entreprises de distribution de commencer intégrer les investissements engagés dans les tarifs avant que ceux-ci ne soient réexaminés par l'autorité de régulation.

(5) L'une des finalités des réseaux intelligents est de rendre les consommateurs plus réactifs à la situation du marché de gros de l'électricité, notamment en réduisant leur demande (ou en augmentant la production décentralisée) lorsque l'équilibre entre l'offre et la demande est difficile à atteindre sur le marché de gros.

Plusieurs pays expérimentent des systèmes tarifaires différents afin de trouver celui qui est le plus efficace et le plus acceptable pour les consommateurs. Certaines formes maîtrise de la demande (comme les contrats interruptibles pour les gros consommateurs) existent depuis de nombreuses années et ne nécessitent pas d'innovations techniques ou commerciales. D'autres, comme la tarification horosaisonnière, exigent des infrastructures de comptage plus évoluées qui, autrefois, étaient réservées aux très gros consommateurs d'électricité. Le déploiement de telles infrastructures chez les petits consommateurs facilite l'instauration de tarifs de détail qui varient soit en fonction de l'heure, soit en fonction du prix de gros de l'électricité. Lorsque le prix de détail de l'électricité fluctuera en fonction du moment de la journée, les consommateurs devraient être incité à déplacer leur consommation dans le temps, par exemple en utilisant des appareils consommant en fonction du prix de détail de l'électricité (des sèche-linge qui ne démarrent que lorsque le prix est bas), des dispositifs pilotés directement par le fournisseur d'électricité (et qui, par exemple, modifient le réglage du thermostat sur les climatiseurs) ou de

petits moyens de production ou de stockage (comme des batteries de véhicules électriques) qui peuvent être mobilisés en période de pointe.

Effacer une partie de la demande d'électricité en période de pointe présente de nombreux avantages en termes d'efficience. Un système électrique doit disposer d'une réserve suffisante (production, transport et distribution) pour pouvoir faire face à toute les situations sauf les périodes d'extrême pointe. Si la demande de pointe est bien supérieure à la demande moyenne, les entreprises d'électricité doivent engager de lourdes dépenses pour conserver les importantes réserves (que ce soit pour la production, le transport ou la distribution) qui leur permettront de faire face à de rares pointes espacées. En Californie, un effacement de 15 à 20 % de la demande de pointe permettrait une diminution de la puissance nécessaire en pointe comprise entre 5 000 et 10 000 MW.

En outre, sur les marchés de gros de l'électricité l'exercice de pouvoir de marché est chose courante. Or, une augmentation la maîtrise de la demande contribue à réduire sensiblement la possibilité d'exercer ce pouvoir. Comme l'a récemment fait observer la FERC, la maîtrise de la demande « peut, en accentuant la pression concurrentielle, faire baisser les prix de gros de l'électricité mais aussi attirer l'attention des consommateurs sur l'usage qu'ils font de l'énergie, contribuer à un meilleur fonctionnement des marchés, atténuer les pouvoirs de marché, améliorer la fiabilité et, associé à certaines techniques nouvelles, favoriser le recours à des sources renouvelables et à une production décentralisée ».

Diverses formules de tarification horosaisonnière existent depuis de nombreuses années, mais l'idéal serait que les clients disposent d'une tarification dite dynamique, avec un prix de l'électricité qui varie en fonction de l'état du système électrique. La « tarification des pointes critiques » est une catégorie de tarification dynamique. Elle permet à l'entreprise d'électricité de définir un certain nombre d'heures par an (pendant lesquelles le tarif de détail est beaucoup plus élevé) comme appartenant à l'« extrême pointe », d'en avertir le client domestique 24 heures avant. Les expérimentations menées sur la tarification horosaisonnière et sur la tarification dynamique révèlent une faible réactivité des petits consommateurs à la tarification horosaisonnière. Elles montrent en général une baisse de consommation aux heures de pointe d'environ 10 à 20 % par rapport aux consommateurs dont le tarif est fixe. Elles révèlent également que l'installation de dispositifs automatiques — comme les thermostats intelligents — sensibilisent davantage les consommateurs aux prix.

Les tarifications dynamique et horosaisonnière n'entraînent pas nécessairement une baisse de la consommation globale d'électricité, car les clients peuvent consommer pendant les heures creuses (où le prix est bas) davantage qu'ils ne réduisent leur consommation en période de pointe (où le prix est élevé).

Les changements de système tarifaire posent la question de la perception de l'équité et des attentes des consommateurs. Les consommateurs actuels ont depuis longtemps l'habitude d'acheter des appareils gourmands en électricité et ont adopté un style de vie qui a une incidence sur leur future consommation d'électricité. En général, ils se méfient de nouveaux systèmes tarifaires qui peuvent entraîner une hausse notable de leur facture totale ou une hausse qu'ils ne pourraient pas complètement maîtriser. Les expérimentations effectuées montrent qu'ils sont davantage disposés à adopter une tarification pour laquelle, plutôt que d'être pénalisés en cas d'augmentation de la consommation, ils sont récompensés lorsque leur consommation passe en-dessous d'un seuil prédéfini. Cela étant, ce type de tarification peut les inciter à modifier leur consommation de telle sorte que ce seuil soit relevé.

(6) *Ces évolutions du secteur de l'électricité — essor des énergies renouvelables et transition vers les réseaux intelligents — peuvent soulever des problèmes propre à la politique de concurrence. Parmi ceux-ci, les plus importants concernent a) l'accès discriminatoire aux réseaux ; b) l'instauration de normes de comptage.*

Plusieurs pays de l'OCDE ont séparé verticalement les infrastructures de transport et de distribution des secteurs de la production et de la vente au détail, qui peuvent être ouverts à la concurrence. Cette séparation verticale dissuade le propriétaire du réseau d'opérer une discrimination en faveur de ses filiales qui produisent de l'électricité ou la vendent au détail. Néanmoins, dans bon nombre de pays de l'OCDE, le propriétaire du réseau est également producteur et détaillant. Dans ces pays, il peut être réticent à raccorder au réseau un concurrent si cela risque de provoquer une baisse de chiffre d'affaires de sa propre filiale. Cette réticence peut se traduire par des délais de raccordement excessifs, par le fait de ne pas effectuer les mises à niveau ou les renforcements nécessaires, de réserver de la capacité à ses propres filiales, d'appeler de préférence les centrales qui leur appartiennent, etc. Les États-Unis mettent en garde contre ce risque : « les autorités de régulation et de contrôle doivent être conscientes que les opérateurs historiques sont en mesure de refuser l'accès non seulement à des moyens de production mais aussi à de nouvelles technologies capables de facilité l'apparition de formes de concurrence inédites. Pour empêcher cela, les autorités de la concurrence doivent examiner au cas par cas si ces actions sont justifiables ou trahissent une volonté d'évincer la concurrence. »

Le document soumis par la France évoque la possibilité qu'un propriétaire de réseau qui investit dans la production d'électricité renouvelable (soit directement soit au travers d'une filiale) soit tenté d'opérer une discrimination au détriment d'autres producteurs d'électricité renouvelable, que ces producteurs soient ou non indépendants. Ce document fait état des dispositions des deuxième et troisième paquets de libéralisation européens, qui imposent la séparation fonctionnelle et juridique des activités de production et de transport et interdisent toute discrimination à l'égard des utilisateurs du réseau, notamment pour le raccordement au réseau. Il relève également que les autorités de régulation surveillent de près les éventuels problèmes de discrimination.

Bon nombre de pays sont en train de déployer des compteurs évolués dans tous les foyers (souvent, pour le gaz comme pour l'électricité) ou envisagent de le faire dans un proche avenir. Il s'agit alors de savoir quelles doivent être les caractéristiques et les fonctionnalités de ces compteurs et qui doit en décider. Les clients doivent-ils pouvoir le fabricant de compteur ou doivent-ils accepter le compteur qui leur est remis par leur fournisseur d'électricité ? Un client sera-t-il obligé d'acheter un nouveau compteur s'il change de fournisseur d'électricité ? Doit-il y avoir une obligation d'interopérabilité entre les différentes infrastructures de comptage équipées de différents compteurs ? En Nouvelle-Zélande, il est déjà arrivé qu'un client ayant changé de détaillant soit obligé de remplacer son compteur intelligent par un nouveau compteur. On note, dans la contribution de ce pays, que cette situation ne devrait se reproduire que si le remplacement ou la mise à niveau des fonctionnalités d'un compteur s'impose techniquement et non parce l'accès à l'information est entravé ou parce que les formats de données adoptés par les détaillants sont incompatibles.

Les autorités de la concurrence ont fait savoir qu'elles redoutent que les normes constructeurs pour les compteurs ne fassent obstacle à la concurrence sur le marché de détail. Les États-Unis indiquent que « l'expérience du ministère de la Justice et de la FTC en matière d'organismes de normalisation montre […] qu'il existe un risque, sur des marchés où les technologies jouent un rôle très important, que les opérateurs historiques tentent d'influencer le vote de ces organismes afin de s'assurer que les technologies concurrentes soient jugées peu fiables, suspectes ou pénalisées de toute autre manière. […] Ultérieurement, la normalisation devrait jouer un rôle essentiel à la mise au au point de compteurs et de systèmes intelligents, capables de se connecter les uns aux autres et ainsi qu'au réseau d'électricité. […] L'expérience nous enseigne que cette question doit faire l'objet d'une surveillance attentive de la part des

autorités de régulation et de la concurrence. Les organismes de normalisation doivent notamment exiger la transparence concernant les droits de propriété intellectuelle existants afin d'éviter les stratégies de «hold-up», veiller à ce que les normes ne soient pas d'une complexité excessive interdisant l'accès aux nouveaux entrants et s'assurer la technologie normalisée soit suffisamment mûre pour que toutes ses possibilités techniques puissent être exploitées. »

De nombreux organismes nationaux et internationaux sont en train de mettre au point des normes pour les infrastructures de comptage, notamment l'UE, le National Institute of Standards and Technology (États-Unis), l'Organisation internationale de normalisation (ISO) et la Commission électrotechnique internationale (CEI).

Les documents présentés font également part de certaines inquiétudes concernant les questions de confidentialité et de sécurité des données. Le document de la France relève que le troisième paquet de libéralisation européen autorise tous les clients à avoir accès à toutes les données recueillies sur leur consommation d'électricité et à les transmettre au fournisseur qu'ils auront autorisés.

La production croissante d'électricité renouvelable et la transition vers les réseaux intelligents sont susceptibles de provoquer des transformations dans le secteur de l'électricité, notamment une concurrence accrue si de petits producteurs entrent en compétition avec des électriciens déjà présents et si la gestion de la demande atténue le pouvoir de marché actuel de certains opérateurs. Dans ce contexte, les autorités de la concurrence ont un rôle à jouer : elles doivent s'assurer que les objectifs visés sont atteints en préservant la concurrence et en respectant la neutralité technologique, que les barrières à l'entrée pour les nouvelles entreprises sont réduites au minimum et que certains acteurs ne se servent pas de leur position dominante pour freiner la concurrence dans les services existants ou dans les nouveaux services qui pourraient voir le jour.

ISSUES PAPER

1. Introduction

New challenges for competition policy will arise from ongoing technological and production changes in the electricity sector. This issues paper describes selected changes and identifies related competition policy questions.

Three notable trends in technology for electricity production are the focus of the paper. These are:

- The increasing rollout of non-hydro renewable like wind and solar generation;
- The development and rollout of new metering and grid technologies; and
- Increased customer provision of electricity, e.g. from small-scale distributed generation.

These changes are important and timely because they impact climate change policy. There is a broad consensus that greenhouse gases need to be limited, as evidenced by the Kyoto Treaty, the Copenhagen Accord of December 2009[1], the Stern Review[2] and initiatives to cut greenhouse gases at the national, regional and local level.[3] As the source of 24% of greenhouse gases,[4] the electricity sector may be subject to substantial shifts in policy that affect the retail costs of electricity, customer use of electricity and the mix of sources chosen for generation.

The technological and policy developments could dramatically alter the structure of electricity markets by expanding the set of suppliers, increasing the extent to which demand declines during periods of scarcity and increasing reliance on non-traditional electricity generators.

In the future, generation using renewable sources is expected to grow. Increased production from renewable sources such as wind and solar creates a challenge for maintaining network quality, because

1 See http://unfccc.int/resource/docs/2009/cop15/eng/l07.pdf.

2 Stern (2007) urges regulators to "innovate in response to the challenge of integrating these [low-carbon] technologies to exploit their potential, and unlock the resultant opportunities that arise from shifting the generation mix away from centralised sources."

3 The UK has set a long-term target of cutting carbon emission by 60% by 2050. (Neuhoff, Cust and Keats-Martinez (2008). The Stern Review provides an economic analysis of climate change. (See http://www.hm-treasury.gov.uk/sternreview_summary.htm)

4 See Stern (2007). The Executive Summary states: "The consequences of taking no action to abate greenhouse gases could be severe." "Under a BAU [business as usual] scenario, the stock of greenhouse gases could more than treble by the end of the century, giving at least a 50% risk of exceeding 5°C global average temperature change during the following decades. This would take humans into unknown territory. An illustration of the scale of such an increase is that we are now only around 5°C warmer than in the last ice age." (p. iv) For a critique, see Mandelsohn (2008) who argues that the economic content of the report is minimal.

these sources are non-dispatchable: the generation sources cannot be turned on at will.[5] One of the best ways to address sudden shortfalls in output will be through increased demand response and small-scale supply response. New metering and grid technology is available and, in some cases, being installed, that can narrowly record customer electricity usage by time period – allowing time-of-use pricing – and permit contributions to the electricity grid from small generators, potentially including households. These new metering and grid technologies are referred to as "smart grid" technologies. This paper focuses on competition policy questions that may arise from changes in the technology of generation and usage of electricity.

Competition policy questions will develop in many different ways. For example:

- Special regulatory treatment of renewable energy, with trading of permits or requirements for distributors to purchase a minimum percentage of electricity from renewable sources, may create new pockets of market power for renewable energy suppliers. Existing renewable capacity may be entirely needed to meet a regulatory obligation, enabling managers of that capacity to extract high prices for the electricity produced.[6] This situation may at times justify market definitions for supply of electricity that are limited to renewable or narrower categories.

- Current systems for competitive determination of dispatching order are often based on bidding a day in advance by electricity suppliers. Day-in-advance bidding places wind at a significant disadvantage to other forms of generation, because wind levels can be predicted with relative accuracy a few hours in advance, but much less accurately one day in advance. Policy changes may be needed to permit wind bidding shortly in advance of delivery.

- Regulations may distort competitive outcomes by giving undue competitive advantages to some forms of electricity generation, such as solar, that are very costly compared to other forms of low-carbon generation.

- Incumbents may have incentives to ensure that standards serve as a barrier to entry because the new technologies and policies may enhance ability and willingness of customers to find new contractual arrangements that reduce incumbent profits. Standards set for new technologies may restrict ability of competitors to incumbents to contract with, deliver to and receive from their desired trading partners.

- Access to the grid for small-scale suppliers is not assured. This will raise a classic access pricing problem, as with larger generators. Clear technical and contractual rules will be essential to limit the ability of the purchaser to exercise monopsony power.

The analysis in this note will suggest the following points:

- Economic principles should govern the development of new technologies rather than simplistic pro-renewable rules or pro-smart grid rules. If the issue of concern is cutting greenhouse gases, the solution is not to adopt low-carbon-production (such as solar) at any cost. Pricing greenhouse gas emissions will lead to the most efficient reduction in output of such gases;

5 For the purpose of this paper, renewable sources include wind, solar, wave, tidal, hydro, geothermal and combustible renewable. For the purpose of this paper, variable renewable sources are a more limited collection that is restricted to: wind, solar, tidal and wave energy.

6 Price may be "high" in comparison to the price determined through an open bidding process to supply electricity, with no preferential treatment for certain sources.

- Clear, reasonable standards are needed for next-generation electricity meters;
- Regulation needs to allow creative, unpredicted actions by intermediaries or consumers;
- Intermittent production by wind and other renewable generation may require new system rules for bidding, guaranteed delivery and permissible sources; and
- In many countries, wind and solar production are best exploited in areas where transmission capacity is low. Exploiting such sources would require substantial new investment in transmission capacity.

Since many of the technological developments discussed here are long-term and not yet widespread, practical policy experience is lacking. To the extent that best practice is suggested, the best practice is provisional and subject to revision in light of experience.

This issues paper proceeds as follows: Section 2 identifies and provides evidence about important new developments. Section 3 identifies competition policy questions that may result from these developments. Section 4 concludes.

2. New developments

Prior to discussing the new developments, it is worth taking stock of key facts about the electricity sector that affect its market structure. We will then consider evidence and predictions about evolving new generation technologies, suggesting that despite their small market penetration at the moment, these generation technologies may grow significantly in the future. Increasing production from wind and solar sources can have deleterious impacts on network quality, absent better demand or supply response. For enhancing demand response, the paper will consider impacts of new electricity meter technologies. Finally, the question of supply response from customers will be addressed. These discussions are a prerequisite to identifying potential competition policy challenges in the electricity sector.

2.1 Basic facts

Electricity markets have a number of features that create challenges for liberalisation and competition policy. These include:

- Highly inelastic demand;
- Absence of real time price signals for customers;
- Absence of storage;
- Need to maintain system in constant balance of supply and demand;
- Constrained supply;
- Little demand response to changed wholesale prices;
- High variability in demand over the course of the day and year; and
- Opportunity for pockets of market power to emerge.

The inelastic demand combined with the constrained supply and absence of storage results in spot market peak electricity prices that are 100-200 times higher than the base prices.[7] These factors need to be taken into account in the design of electricity market structures, including the relationship of system operators with generators and grid owners, the decision rule for deciding on which generators will be called on to produce electricity ("dispatched"), decisions about which transmission capacity to add or upgrade and decisions on how to interconnect networks.

The electricity generation sites that are selected for dispatch will vary depending on the alternatives available and their relative costs. Electricity is generated from a variety of different sources. Some of them use fuel, such as coal, gas and nuclear, while others do not, such as wind, hydro and solar. The mix of sources varies substantially from one country to another. For example, even though 84% of electricity produced in 2007 came from fuel-based generation, Norway generates 98% of its electricity from hydro.[8] Table 1 shows how the sources of electricity vary across OECD countries, measured in GigaWatt-hours (GWh). While "low carbon" sources represent more than 80% of production in Iceland, Norway, Switzerland, Sweden and France, the overall percentage of wind (1.4%) and solar (less than 0.1%) are small. In some countries, wind has achieved much larger penetration than the average. These include Denmark, Spain, Portugal, Ireland and Germany where wind accounts, respectively, for 18.3%, 9.2%, 8.5%, 6.9% and 6.2% of total electricity output. The countries with the largest ouput from solar are Germany, the United States and Spain. In all cases, solar electricity output is less than 1.0% of total output.

7 See Brennan (2004), p. 121.

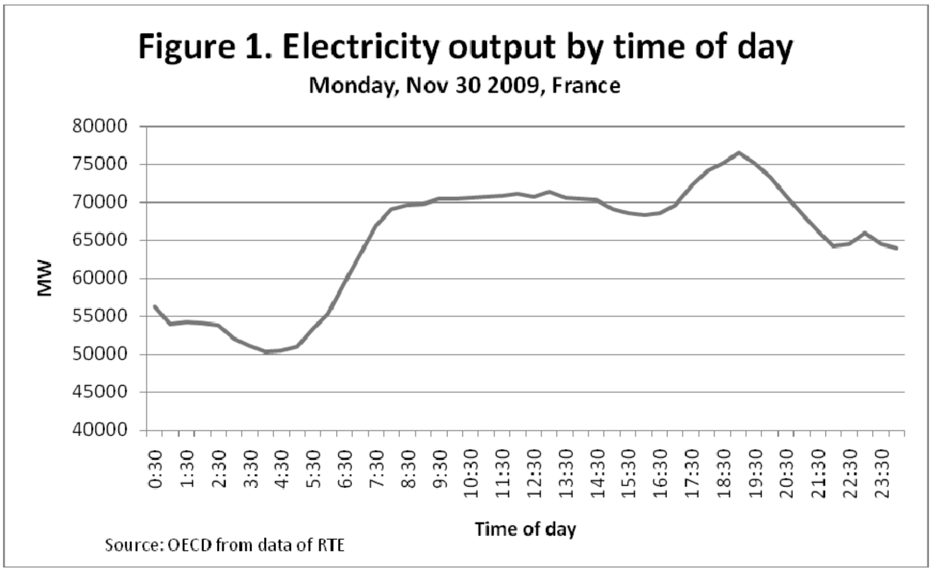
8 Generation costs account for more than the majority of electricity costs. For example, the EIA estimates that generation accounts for 67% of the average cost of electricity, distribution accounts for 26% and transmission 7%. (EIA (2009), Table A8)

Table 1. Source of electricity by OECD country, 2007 GWh

Country	Fossil	Combustible renewables and waste	Nuclear	Hydro	Geo-thermal	Solar	Wind / tide / wave / other	Total	Low carbon % of total	Wind/ solar
Australia	235,589	2,031		14,724		10	2,611	254,965	6.8%	1.0%
Austria	18,743	4,150		38,485	3	17	2,032	63,430	63.9%	3.2%
Belgium	34,526	3,641	48,227	1,683		6	737	88,820	57.0%	0.8%
Canada	166,295	8,455	93,492	368,518		26	3,055	639,841	72.7%	0.5%
Czech Republic	58,172	1,203	26,172	2,523		2	126	88,198	32.7%	0.1%
Denmark	28,092	3,859		28		2	7,173	39,154	18.4%	18.3%
Finland	32,974	10,099	23,423	14,177		4	572	81,249	47.0%	0.7%
France	56,347	5,514	439,730	63,662		16	4,571	569,840	89.1%	0.8%
Germany	394,558	30,762	140,534	28,458		3,075	39,713	637,100	33.2%	6.7%
Greece	58,092	209		3,376		1	1,818	63,496	8.2%	2.9%
Hungary	23,254	1,709	14,677	210			110	39,960	37.5%	0.3%
Iceland	2	2		8,394	3,579			11,977	100.0%	0.0%
Ireland	25,120	132		1,016			1,958	28,226	10.5%	6.9%
Italy	257,790	6,954		38,482	5,569	38	5,055	313,888	15.7%	1.6%
Japan	756,951	23,019	263,832	84,234	3,043	8	2,624	1,133,711	31.2%	0.2%
Korea	278,246	573	142,937	5,042		71	448	427,317	34.8%	0.1%
Luxembourg	2,895	103		919		21	64	4,002	25.1%	2.1%
Mexico	209,427	2,656	10,421	27,276	7,404	9	262	257,455	17.6%	0.1%
Netherlands	89,719	5,566	4,200	107		36	3,613	103,241	7.7%	3.5%
New Zealand	15,110	777		23,516	3,458		984	43,845	63.8%	2.2%
Norway	901	443		135,052			1,075	137,471	99.0%	0.8%
Poland	152,997	2,890		2,939			522	159,348	2.2%	0.3%
Portugal	30,392	2,150		10,449	201	24	4,037	47,253	31.1%	8.6%
Slovak Republic	7,550	499	15,334	4,615			58	28,056	71.3%	0.2%
Spain	185,406	3,635	55,103	30,807		508	27,833	303,292	37.7%	9.3%
Sweden	3,606	10,656	66,969	66,188			1,430	148,849	90.4%	1.0%
Switzerland	936	2,309	27,925	36,737		27	16	67,950	95.2%	0.1%
Turkey	154,982	214		35,851	156		355	191,558	19.0%	0.2%
United Kingdom	307,487	11,395	63,028	8,948		11	5,274	396,143	19.5%	1.3%
United States	3,111,787	71,653	836,634	275,545	16,798	689	35,750	4,348,856	26.8%	0.8%
TOTAL	6,697,946	217,258	2,272,638	1,331,961	40,211	4,601	153,876	10,718,491	35.5%	1.5%

Source: IEA, Energy Statistics of OECD Countries, 2009

One reason that electricity generation sources are mixed is that there is substantial temporal variation in demand for electricity, meaning that some generation sources are likely to be used with high frequency (for base load) and some are likely to be used during peak times. Electricity demand varies substantially across the course of the day. Figure 1 illustrates how demand varies with time of day in one country (France). The peak usage on a day is 50% higher than lowest usage. Similarly, across the course of the year, there are substantial variations. In France, for example, peak winter usage is almost 50% higher than low summer usage.[9] These figures illustrate the fact that electricity demand exhibits substantial seasonal and daily variation. This in turn means that the number and type of generating facilities that are active varies with the day and season. This variation yields the need for a market structure that can deliver highly variable output at a reasonable overall cost.



The general principle underlying the determination of which plants produce power at different times is their underlying cost of production.[10] Figure 2 illustrates how costs of production have been estimated to vary for different technologies. (NEA, IEA & OECD (2005))[11] These figures present point estimates as the center of a range. A supply curve based on costs can be drawn that determines which technologies or production would operate at difference volumes of output. The "baseload" is typically carried by the less expensive technologies, while the more expensive technologies would be used for supplying at the peak load. If the peak load exceeds total capacity of the system, wholesale prices for electricity in a liberalised market can rise dramatically until demand is reduced sufficiently to equalise demand and supply. As the demand increases, the cost of producing the marginal unit of electricity generally rises.

9 In some electricity markets, such as those with hot summers and high levels of air conditioning, the seasonal variation may be reversed, with summer electricity output being higher than that in the winter.

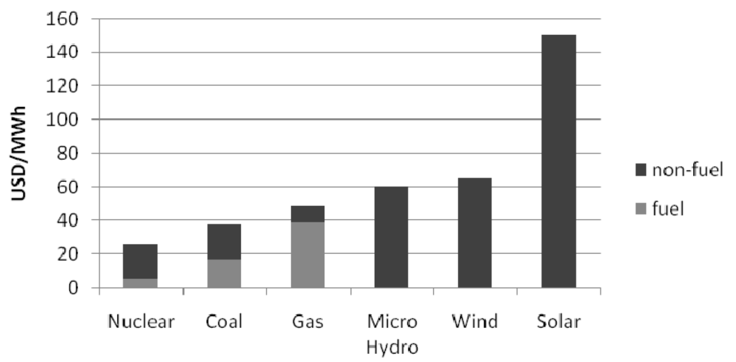
10 In liberalised markets with excess capacity, the cost of production (including return on capital) will generally be closely related to the price that bidders offer to produce electricity.

11 Large scale hydropower is not included in these estimates. Its costs can likely fall below the cost of coal-based production.

The cost of a technology depends very much on how it is regulated. Carbon permits, for example, significantly raise the cost of coal and gas generation compared to other technologies, and can change their position in the order of dispatch.[12]

One point that emerges clearly from Figure 2 is that solar power is by far the most expensive generation technology listed. Photovoltaic solar is considerably more expensive than the concentrated solar figures reported here, with a cost ranging from $350-680 per MWh. The production, installation and operation costs of solar facilities are very high, per MWh, compared to other outputs. In some countries, there are guaranteed purchase programs for solar-generated power that result in payments for production of solar power that are 10-100 times the market price of electricity at a given time, with a built-in right to connect at the "feed-in" tarriff rate even at low-price times. Tarriffs that build in subsidies will result in substantial economic inefficiency, particularly if applied on a large scale.

Figure 2. Relative Power Generation Costs



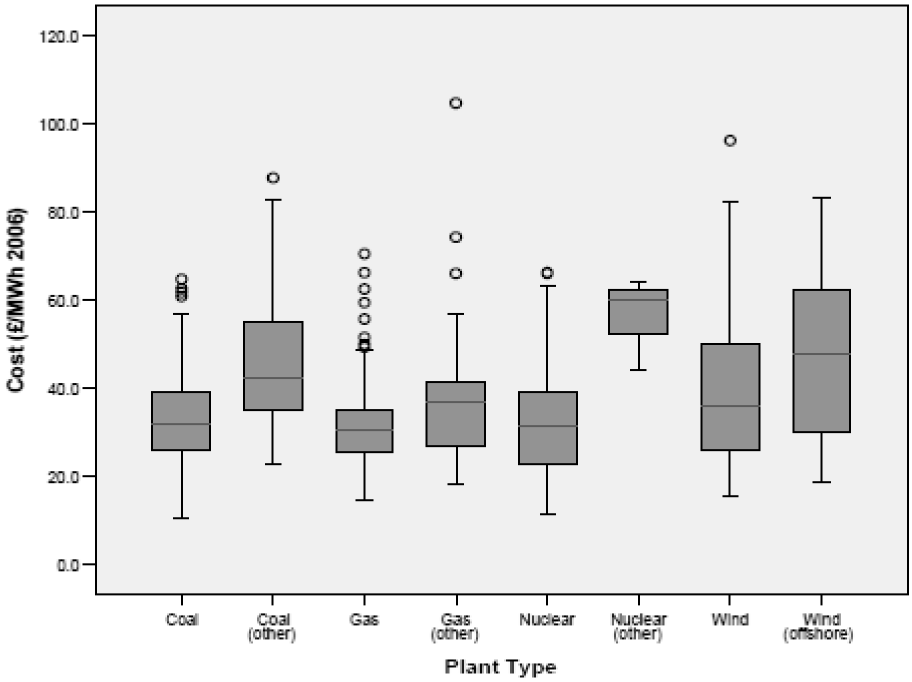
Source: author estimates from NEA, IEA & OECD (2005)

The point estimates reported are actual central tendencies within a range. A recent estimate by the UK's Energy Research Centre shows that the range even for each mode of production can be broad, as shown in Figures 3 and 4. In the figures, the box for each category represents the central 50% of cost estimates (GBP per MWh) and the wide horizontal line in the middle of the box shows the median. The narrow horizontal lines represent the highest and lowest values, excluding outliers, which are shown by small circles. Figure 3 shows the range of costs for the main production technologies. There is a clear tendency for coal, gas and nuclear generation to be the lower cost technologies out of those considered.[13] Figure 4 shows the estimated range of costs of wind generation in different countries, showing that wind can be much lower cost in some locations than others, emphasising the importance of regional factors in determining likely success of wind generation.

12 The order of generating costs (from low to high) could change dramatically depending on the greenhouse gas regulatory regime in force. Tolley and Jones (2004) suggest that coal cost could rise to 83-91 USD/MWh and gas could rise to 58-68 USD/MWh. The IEA's *World Energy Outlook 2008* includes a 30 USD/tone CO2 value in its cost estimations for Europe in 2015 and 2030 and wind becomes cheaper than coal per MWh (p.151). The dispatch order of technologies, by effective cost, would then change to nuclear, wind, micro hydro, gas/coal.

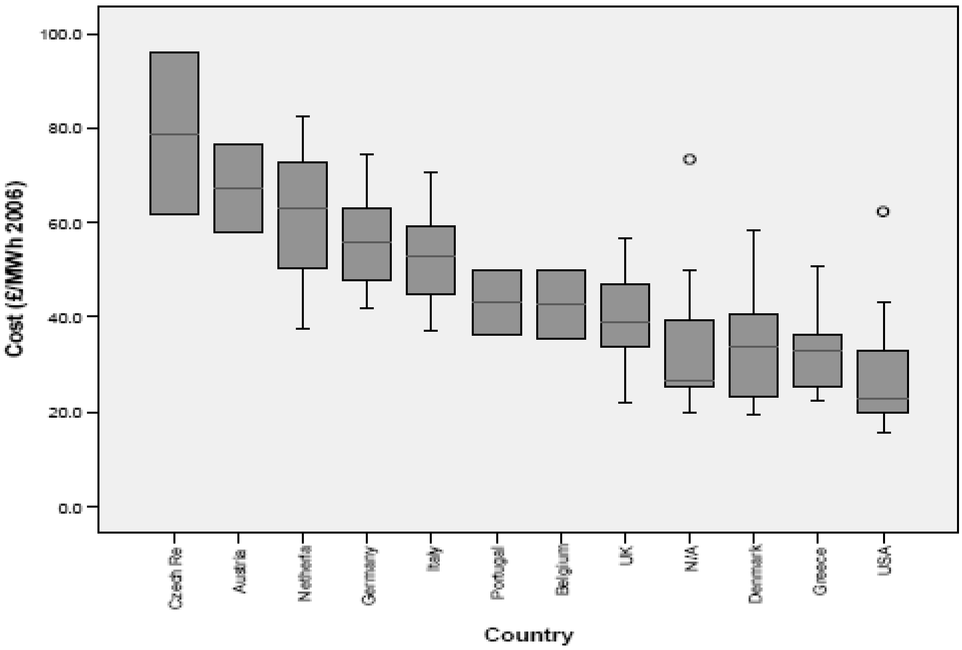
13 Note that hydro power is missing.

Figure 3. Cost ranges for predominant technologies



Source: Heptonstall (2007)

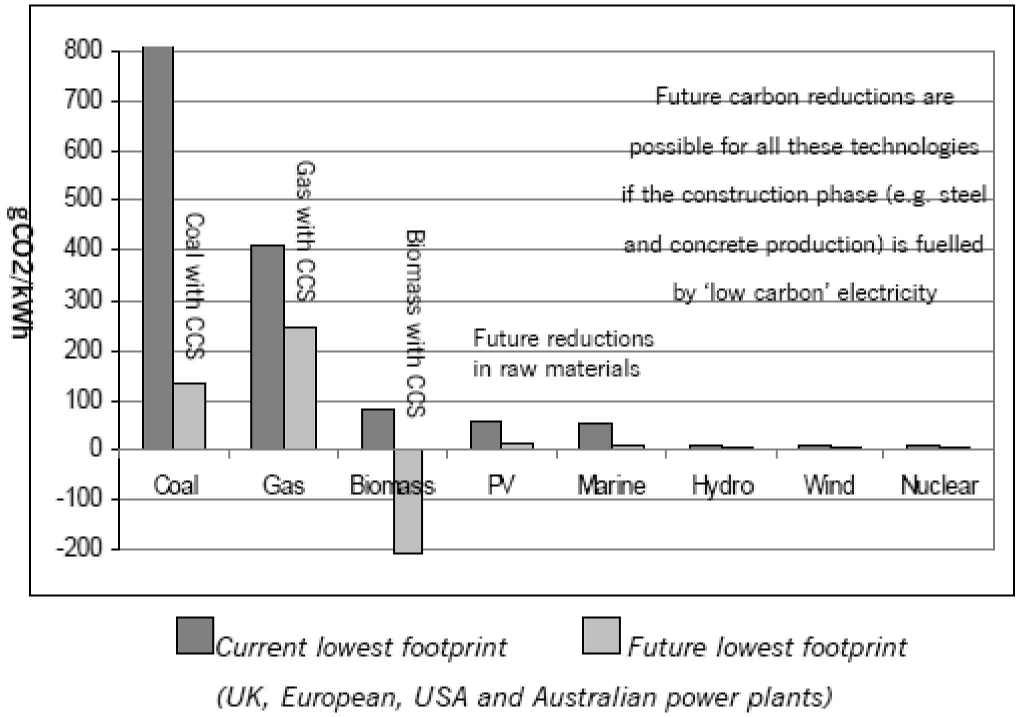
Figure 4. Cost ranges for wind by country



Source: Heptonstall (2007)

Carbon dioxide emissions differ significantly by generation source. In particular, coal and gas are two of the lowest cost technologies[14] but among the highest emitters of carbon dioxide per unit of electricity produced, as suggested by Figure 5. This is the reason why many policies designed to reduce greenhouse gas emissions, such as tradable carbon emission rights or carbon taxes would be expected to have a disproportionately large effect in raising the net costs of coal and gas generation. It is important to note that with carbon capture and storage (CCS) technologies in place, coal and gas emit much lower levels of greenhouse gases, with coal becoming a noticeably smaller source of emissions than gas.

Figure 5. Current and future carbon footprints



Source: Parliamentary Office of Science and Technology (2006)

The carbon dioxide outputs from generation are one of the main sources that is driving public policy to focus on renewable generation, such as wind and solar power.

Key points to emerge from this section are:

- Current levels of output from non-hydro renewable are very small (under 2%).
- Electricity demand varies substantially over the course of the day and year in predictable ways.
- Wind and solar currently each account for a small proportion of total output, but wind provides 23 times more output than solar, as of 2007.
- Wind is a dramatically lower-cost production source compared to solar.

14 They are low cost when excluding externality costs, which are not the focus of this paper.

- Changes in regulation (e.g., carbon taxes) may substantially change the order in which different sources are called for production, as can changes in fuel costs.

2.2 Predictions of renewable growth

Currently, renewable generation account for about 16% of OECD electricity output (Calculations from Table 1),[15] but the amount from wind and solar is less than 2% of OECD output. Given their small share of output, why should wind and solar be a focus of this current work? The reason is that output from renewable sources is expected to grow significantly in the future. This growth would occur in part as a continuation of past trends and in part as a result of government policy actions (such as fixed cap emission credits) that promote low-carbon renewables. In fact, despite their small share of generation, wind and solar are both growing rapidly. Based on the economics of each, wind is likely to grow much larger than solar. Growth in solar is based largely on implicit subsidies through extremely high tarriffs paid for solar-produced electricity.

Tables 2 and 3 show recent annual electricity output, measured in GigaWatt-hours, from wind, wave and other generation (table 2) and solar (table 3).[16] Wind and wave production of electricity increased by 41 times between 1990 and 2008. Between 2000 and 2008, the annual growth rate was 25%. Solar production of electricity increased by 12 times between 1990 and 2008. Between 2000 and 2008, the annual growth rate for solar power has been 36 %. Both wind and solar have had dramatically higher growth rates than electricity production as a whole, with growth of 1.5% in the OECD over the same time period.

Table 2. Development of wind, wave and other generation in OECD: 1990-2008 GWh

Country	1990	2000	2006	2007	2008
Australia		58	1,713	2,611	3,285
Austria		67	1,770	2,032	2,005
Belgium	7	16	622	737	871
Canada	26	296	2,531	3,055	3,053
Czech Republic			50	126	246
Denmark	610	4,280	6,108	7,173	6,928
Finland		78	584	572	602
France	571	650	2,708	4,571	6,223
Germany	71	9,352	30,710	39,713	40,400
Greece	2	451	1,699	1,818	1,661
Hungary			43	110	205
Iceland					
Ireland		244	1,622	1,958	2,410
Italy	2	1,349	3,998	5,055	7,355
Japan		109	2,210	2,624	2,919
Korea		17	313	448	429
Luxembourg		27	58	64	61
Mexico	1	19	59	262	255
Netherlands	56	1,077	2,880	3,613	4,407
New Zealand		120	669	984	1,107
Norway	136	115	768	1,075	1,092
Poland		5	256	522	833

15 Renewable is defined as: hydro, combustible renewable, geothermal, solar, wind and wave.

16 2008 figures are estimates.

Portugal	1	168	2,925	4,037	5,733
Slovak Republic			56	58	56
Spain	14	4,727	23,626	27,833	31,832
Sweden	6	457	987	1,430	1,974
Switzerland		3	15	16	16
Turkey		33	127	355	797
United Kingdom	9	947	4,225	5,274	7,111
United States	3,066	5,650	27,874	35,750	53,203
TOTAL	4,578	30,315	121,206	153,876	187,069

Source: IEA, Energy Statistics of OECD countries 2009.

Table 3. Development of solar generation in OECD: 1990-2008 GWh

Country	1990	2000	2006	2007	2008e
Australia		1	9	10	10
Austria		3	15	17	17
Belgium			2	6	40
Canada		16	21	26	26
Czech Republic			1	2	13
Denmark		1	2	2	2
Finland		2	3	4	4
France		5	12	16	36
Germany	1	60	2,220	3,075	4,000
Greece			1	1	5
Hungary					
Iceland					
Ireland					
Italy	4	18	35	38	200
Japan	1	2	6	8	12
Korea	1	5	31	71	264
Luxembourg			21	21	20
Mexico	1	7	10	9	9
Netherlands		8	35	36	38
New Zealand					
Norway					
Poland					
Portugal	1	1	5	24	38
Slovak Republic					
Spain	6	18	119	508	2,492
Sweden					
Switzerland	1	11	23	27	27
Turkey					
United Kingdom		1	11	11	14
United States	666	529	565	689	933
TOTAL	682	688	3,147	4,601	8,200

Source: IEA, Energy Statistics of OECD countries 2009.

Renewable sources of energy (such as wind, solar, hydro or wave) are increasingly promoted by public policy. In the European Union, the Renewable Energy Directive,[17] agreed in December 2008, establishes a 20 % renewable energy target by 2020 for Europe. The European Commission stated that 12% of the EU electricity demand is expected to come from wind to meet this target, up from 4% in 2008. According to the European Wind Energy Association (EWEA) "2008 was the first year in which more new wind energy capacity was installed in the EU than any other electricity generating capacity. 23.8 GW of new capacity was installed, of which 8.5 GW (36%) was wind and 6.9 GW (29%) was gas. (EWEA (2009a), p. 16) Jurisdictions give incentives for the production of renewable energy that include guaranteed system purchases at prices that both exceed cost of investment and, often, exceed costs of alternative, traditional and controllable forms of generation. In many cases, the prices offered for this energy are even higher for distributed renewable energy product (i.e., energy produced by small consumers) than for mass-produced renewable energy. Carbon taxes give good wind sites a production cost advantage over gas or coal, for example.

These trends apply at the worldwide level, according to the IEA *World Energy Outlook 2008*. The *Outlook* states, "World renewables-based electricity generation — mostly hydro and wind power— is projected to more than double over the *Outlook* period, its share of total electricity output rising from 18% in 2006 to 23% in 2030." (IEA (2008) p. 159) The levels of investment implied by these statistics are large. According to the IEA, "Total cumulative investment in renewable energy supply in 2007-2030 amounts to $5.5 trillion (in year 2007 dollars). The greater part of this investment is for electricity generation. Renewables account for just under half of the total projected investment in electricity generation." (IEA (2008) p. 159)

In review substantial growth is expected from wind and, potentially, solar electricity generation through 2030. At times, the economic basis for a regulatory preference for increased renewable generation, particularly solar, is difficult to identify. Nonetheless, assuming this growth continues, it will present new regulatory challenges, especially because electricity networks have not historically been based on variable, non-dispatchable sources of energy.

2.3 Implications of renewable growth for network stability

From the perspective of network management, variable renewable sources of energy such as wind and solar power are challenging because they generate a flow that cannot consistently be dispatched in response to demand. A solar or wind generator has output that can vary dramatically depending on time of day and atmospheric conditions. Meanwhile, the consumption profile in many countries is becoming considerably more "peaky" due to the increased installation of air conditioning. These issues can present problems for maintaining the minute-by-minute balance between supply and demand that is needed to keep a network in equilibrium (and avoid blackouts or surges).

The European Wind Energy Association (EWEA) states "Wind power is sometimes incorrectly described as an intermittent energy source. This is misleading because, on a power system level, wind power does not start and stop at irregular intervals, which is the meaning of intermittent. Wind is a technology of variable output."[18] (EWEA 2005) The claim that wind is not intermittent at the system level

17 Directive 2009/28/EC. of the European Parliament and the Council of 23 April, 2009 on the promotion of the use of energy from renewable sources. OJ L140, 5.6.2009, pp.16-62.

18 The EWEA notes: "It is sometimes incorrectly expressed that wind energy is inherently unreliable because it is variable. Electricity systems – supply and demand - are inherently highly variable, and are influenced by a large number of planned and unplanned factors. The changing weather makes millions of people switch on and off heating, lighting, e.g. a sudden thunderstorm. Millions of people in Europe switch on and off equipment that demands instant power - lights, TVs, computers. Power stations, equipment and transmission lines break down on an irregular basis, or are affected by extremes of weather such as

requires further substantiation and may depend on local or regional weather patterns. For example, some of the hottest days in some countries, and those that would require highest peak power, are days in which there is little wind.[19] But at the individual wind farm level, the claim is certainly false. Since wind generators will bid their capacity individually, there is a challenge to ensuring that the bids can be appropriately resourced and do not result in system disruption when a wind farm that has no wind purchases electricity from a reserve elsewhere.

A report by the Electric Power Research Institute (2008) states that "There are two aspects to resolving the intermittency issue. One is the development of more powerful and accurate wind energy forecasting systems, both regional -and plant- specific, to allow more precise estimates of same-day and next-day hourly fluctuations in wind speed and resultant energy generation potential. The second aspect is utilising real-time and forecasted wind information to better integrate wind with the dispatch of other generation and demand-side options to provide frequency control and system stability. Inasmuch as a Smart Grid would provide the capability to dispatch ancillary services to balance intermittent wind resources, it is reasonable to attribute a portion of wind resource penetration to the emergence of a Smart Grid infrastructure." (p. 9-2) Pollitt and Bialek (2009) suggest "Future networks will require more active management, as the intermittency of renewable energy requires increased network management….The uncertainty of the timing, volume and location of new renewable also makes planning of network development more difficult than in the past and has implications for regulation."

"Wind power is variable in output but the variability can be predicted to a great extent. This does not mean that variability has no effect on system operation. It does, especially in systems where wind power meets a large share of the electricity demand." (EWEA 2005) Wind predictions are much more accurate a few hours in advance than they are a day in advance. In liberalised energy markets, this means, for example, that day-ahead bidding markets are likely to penalise a wind farm compared to markets that allow bidding just a few hours in advance.

"However as the amount of wind energy in the electricity grid increases, new challenges emerge. Initially built for traditional power sources, the grid is not yet fully adapted to the foreseen levels of wind energy, and nor are the ways in which it is designed and operated. So far, adaptation has been slowed by planning and administrative barriers, lack of public acceptance, insufficient economic incentives for network operators and investors to undertake transmission projects…and a generally fragmented approach by the main stakeholders." (EWEA (2009b) p. 16)

Wind sites that are close together have highly positively correlated output, while those that are more distant, but in the same region, have less correlated (but still positively correlated) outputs. This correlation means that at times of low output in one site, there is more likely to be low outputs in other wind sites. The question then arises, when designing an energy network to achieve high reliability, how much capacity of total maximum capacity should be allocated to renewable. "Under a worst case scenario, renewable would deliver energy to a network but not provide capacity on the network, due to the variability of output resulting in low generation during high-demand periods. The availability of solar energy in the UK provides a good example of such a relationship, as its availability during times of high electricity demand has been shown to be effectively zero, resulting in no offset of conventional capacity (UKERC (2006)."

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drought, which particularly impacts hydro and nuclear energy. Trees fall on power lines, or are iced up and cause sudden interruptions of supply. The system operators need to balance out planned and unplanned changes in constantly changing supply and demand in order to maintain the system's integrity." (EWEA 2005

19 Wolak (OECD presentation) notes that, during a July 2006 heat storm in California, on July 24 the demand in the California ISO control area hit a 1 in 50 year peak of 50,200 MW, but wind generation was only operating at 5% of its capacity.

(Sinden, 2009, p. 151) Sinden suggests that when wind power accounts for 10% of total generation, an appropriate capacity credit for wind power may be about 25% of its capacity while when wind power is 25% of total generation, the appropriate capacity credit would fall, due to the increased uncertainty of whether the network would be able to achieve full output, to 20%. (Sinden (2009, p. 152)

Box 1. Wind power in Denmark and other European countries

This box describes some of the experiences with wind power in Europe according to the European Wind Energy Association (EWEA) suggesting that large amounts of wind energy can be integrated into an electricity network, providing the appropriate operating and regulatory conditions are present.

> "In Denmark, the country in the world with the highest penetration of wind power, 21% of total consumption was met with wind power in 2004. In the west-Denmark transmission system, which is not connected to the eastern part of the country, some 25% of electricity demand is met by wind power in a normal wind year and, on some occasions, the wind has been able to cover 100% of instantaneous demand. The integration of large amounts of wind power is often dismissed as impossible and many grid operators are reluctant to make changes in long established procedures to accommodate wind power. In Denmark, the grid operator was initially sceptical about how much wind power the system could cope with. The attitude of many grid operators to wind power can best be illustrated by the following quote from Eltra, the TSO [transmission system operator] in west-Denmark, at the presentation of its annual report.
>
> *"Since the end of 1999 - so in just three years - wind power capacity in the Jutland-Fyn system has increased from 1,110 MW to 2,400 MW…Seven or eight years ago, we said that the electricity system could not function if wind power increased above 500 MW. Now we are handling almost five times as much. And I would like to tell the Government and the Parliament that we are ready to handle even more, but it requires that we are allowed to use the right tools to manage the system".*
>
> "In the western Energinet (formerly Eltra's) supply area, wind energy covers some 25% of electricity demand in a normal wind year and it is not a technical problem to handle more – it is a regulatory issue. The tools for managing more wind power in the system are developed and grid operators should be allowed to use them. Ultimately, experience with wind power in the areas of Spain, Denmark, and Germany that have large amounts of wind power in the system shows that the question as to whether there is an upper limit for renewable penetration into the existing grids will be an economic and regulatory rather than a technical issue.
>
> "In those areas of Europe where wind power development is still in its initial stage, many lessons can be learned from Denmark, Germany and Spain. However, it is important that stakeholders, policy makers and regulators in those emerging markets realise that the issues that TSOs in those three countries are faced with will not become an issue until much larger amounts of wind power are connected to the national grids." (EWEA (2005) p. 10)

From a competition perspective new forms of generation can lower concentration and enable more efficient generation profiles. But they could add opportunities for a small number of suppliers to charge extremely high prices when peaks of demand coincide with troughs in renewable generation.

Regulations for grid operation and TSO play a large role in determining how well wind or solar power can be integrated into an electricity network. Network regulations in most countries have been designed with non-variable generation in mind. Regulations may have the effect of excluding wind or adding unnecessary costs to the provision of wind power. These regulations are, in essence, a type of access rule. Such regulations may need to be changed in order to allow broad penetration of wind generation, while maintaining safe, stable and reliable networks.

Increased demand response would help to address the increased supply variability from introduction of wind and solar power.

2.4 Demand-side response

Network quality may suffer from increased use of variable renewable generation.[20] But the unpredicted increase or decrease in generation from one source can be accommodated not only by changing generation from other sources[21] but also from a demand response. For example, if electricity generation falls because of lower-than-predicted wind speeds, a demand response would consist of lowering demanded electricity in order to maintain a balance of demand and supply. Demand response means a reduction in customer consumption of electricity from the expected level in response to a signal, such as a price change or a message sent to the customer. There are two kinds of demand response: one that is dispatchable and one that is not dispatchable.

- *Dispatchable demand response.* When a company is able to send a message that either directly controls consumer appliances such as air conditions and can turn them off or has agreements with customers for them to reduce demand when the company faces certain reliability or economic signals, the demand response is considered "dispatchable."

- *Non-dispatchable demand response*. Non-dispatchable demand response occurs in response to price signals and gives the customer the ability to decide exactly how to change demand, if at all. For example, if customers reduce their consumption in response to a higher electricity price, that is a demand response, but one that is not dispatched.[22]

In principle, dispatchable and non-dispatchable demand response should be largely equivalent. In one case, the change in consumption is based on a long term contract (with a price feature); in the other, the change in consumption is driven by a variation in price without a contractual obligation for customers to response. But given that both short-run and long-run price elasticity of demand is negative, as discussed below, an increase in electricity price at any given time should be accompanied by a decrease in consumption from the expected level.

Programs are already in place in many countries, particularly for dispatchable demand response. An indication of selected countries with demand response programs is provided by Table 4.

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20 According to simulations by Crosswinds for congestion challenges in Europe, "Wind power prediction errors have an impact on the hourly cross-border power flow. The results of the simulations indicate that most of the time the deviations between the actual and predicted power flow fall within some 20 % of line capacity. Obviously, for some cross-border connections this can increase the severity of congestion. The simulations for 2015 show a limited impact of installed wind power capacity scenarios on the cross-border power flows uncertainty level. Nonetheless, the results indicate that the effect of wind generation forecast errors should be taken up in large scale integration studies." (EWEA 2009b, p. 80)

21 Immediate supply response can include dispatching reserve capacity like hydro or pump storage.

22 Demand response can equally result in lower prices leading to higher consumption. Many consumers who face a basic demand response system, like time of day pricing with a prime time and night-time rate, substitute demand from one part of the day to another, such as for an electrically powered water heater.

Table 4. Demand response programs in select countries

Country	Experience
Italy	-With about 90% penetration of new meters, Italy has highest penetration of advanced meters among European countries. -Interruptible programs are applied only to very large industries. -Time-of-use rates are available.
Spain	-Large customers are already covered by direct load control mechanisms when physical imbalances are in place. -Time-of-use pricing in practice. -Consideration of introducing spot market for load curtailment with participants paid the sport market price when they are curtailed.
United Kingdom	-Industral and large commercial customers can agree to time-of-use and interruptible contracts. -About 4.5 million customers use multi-rate energy tarriffs, like low night-time pricing. -A pilot project with about 10,000 households participated in billing trials. -Study for Department of Business, Enterprise and Regulatory Reform shows negative net present value from roll-out of 'smart enabled' meters.
United States	-Most operators are regional and many have industrial and large commercial customer interruptible contracts. -Among U.S. states, Georgia has longest experience with innovative pricing, with about 1/3 of ouput covered by variable pricing. -Demand response became official policy in 2005 with the Energy Policy Act of 2005

Source: Torriti, Hassan and Leach (forthcoming) + author.

Dispatchable and non-dispatchable response will be discussed sequentially.

2.4.1 Command and control demand reduction (dispatchable)

System operators generally have direct control over turning on or off electricity plants connected to the distribution network. This direct control is necessary to maintain balance. The need for the quantity of electricity generated and consumed to exactly match combined with a limited ability to store electricity has led to competition concerns at lower levels of concentration than in many other industries, particularly for meeting peak load.

In order to ensure that demand does not exceed supply, many electricity network controllers (or intermediaries who aggregate load) have contracts with large customers or collections of medium-sized customers that offer lower price in return for controllability: the ability for the controller to demand a reduction or halt in electricity usage at the companies at times of peak usage. These contracts are relatively common in many countries. While they do not necessarily involve real-time price signals to the end user, the controller's decision about when to reduce or stop electricity consumption at a given customer will likely be based on price and demand considerations.

While attractive in principle, at times, command-and-control reductions are difficult to achieve. For example, at the beginning of the electricity shortages in California in 2000-2001, large customers who had enrolled for curtailable demand programs were called upon to reduce their demand repeatedly. "The programs successfully enrolled large numbers of customers, representing approximately 5% of system peak demand. In 2000, the interruptible rate[23] and direct load control programs [of two operators] had load

[23] "Customers electing to receive service on an interruptible rate schedule agreed to reduce their demand to a Firm Service Level (FSL) when called upon by the utility during system emergency conditions, for a limited number of hours per year (100-150 hours, depending on the utility). In exchange, these customers

curtailment potential of ~2,400 MW and 300 MW respectively. Prior to 2000, the programs were seldom used and viewed as an "insurance policy" as California had comfortable capacity reserves. During 2000, the utilities' load management programs provided significant reliability benefits and helped avert rotating outages on several occasions….Throughout the final eight months of 2000, customers in the interruptible program were asked to curtail load on 23 occasions, and provided up to 2,200 MW of load reduction (CAISO, 2001a). During this period, the utility interruptible programs were instrumental in avoiding blackouts on at least five occasions…." The customers covered under curtailable demand programs were able to leave the program. "After the experience of 2000, a number of customers left the curtailable demand program. Customers representing 20% of the load reduction potential in PG&E's program and 55% in SCE's program opted out by summer 2001, stripping the total potential load of the program down to approximately 1,200 MW (CPUC, 2001b; Wallenrod, 2001)." (Goldman et al. (2007)) One lesson for regulation is that allowing customers to change contract types in the midst of an electricity shortage can derail demand control mechanisms. Given that supply shortages can last for periods of more than a year, as in California, 12-month contracts may be too short to guarantee that sufficient supply will remain within the program. Even if contractual options are well designed, it may be difficult to enforce such contracts in response to political demands to protect customers.

Command and control demand response systems can provide substantial demand reductions. In the long run, direct communication with consumers through mechanisms such as real-time pricing may be more successful, as discussed next.

2.4.2 Price signals (non-dispatchable)

Price signals can serve as an effective form of demand response, by ensuring that real-time costs of system operation are reflected in the costs customers face.

Historically, customer pricing has followed very stable patterns, with either a fixed price per kilowatt hour or a fixed peak and off-peak price. While retail prices, notably for households, have followed a stable approach, wholesale prices change from day to day and hour to hour -- or even more frequently. In times of relative scarcity, wholesale prices can increase substantially. While industrial users may face highly variable prices that reflect wholesale price changes, many customers do not perceive this wholesale price variability.

The generally limited relationship between costs (as represented by wholesale prices) and hourly demand is a curious leftover from the state-controlled command-and-control era of electricity production. At peak periods, customers face a price that is less than the cost of the electricity they use. This encourages excess electricity usage at peak periods.

The limited relationship between much retail pricing and wholesale costs has the advantage of creating a simple billing system, stable cost expectations (for the customer) and predictable demand (for the system operator). But it has the disadvantage of discouraging innovative forms of demand management. It is not expected that consumers would actively manage their use of electricity over the course of the day. But they could govern automated processes that determine when machines run. A few of the forms of automated management that might evolve are:

- Air conditioners that adjust the room temperature up during periods of peak price (thus drawing less electricity at such times)

received significant rate discounts (~15%) on the demand charges for their "non-firm" load (i.e., the load above their FSL)." Goldman et al. (2007).

- Machines that turn on (such as dishwashers) when electricity is at a low price.
- Centrally controlled electrical operations for a household (e.g., by a computerised control panel and Wi-Fi communication with devices) that turns devices on or off or reduces electricity demand at peak times, to substitute the demand towards other times.

Because of the absence of a financial incentive for many consumers to better manage their costs, many innovations that would help reduce electricity usage at peak periods and substitute some usage towards non-peak periods are either not made or not installed.

This situation of having prices that systematically do not reflect real costs is an economic oddity. In other markets, retail prices serve to equilibrate demand and supply. Consumers respond to high prices by lowering their demand (price elasticity of demand) and supplies are increased in response to higher prices. Price signals can equilibrate markets even when prices evolve in a continual fashion, as they do with stock markets.

Introducing real-time pricing in electricity markets would be one method to ensure that customers take more account of the costs of the electricity they use and the benefits they derive from it.[24] Demand responsiveness can be achieved through other means than direct real-time pricing of customer use. Similar results can be achieved if utilities compensate customers for reducing their use or allow customers to resell power to others (in which case, a third party is paying them to reduce their use).

Demand response programs are not free. To the extent that responses are lower for some customers (e.g., residential) than others (commercial) and investment per kW-hour saved may be much cheaper for large customers than smaller ones, it may be worth focusing programs on those customers who will be most responsive. Box 2 explains why focusing on large customers alone may deliver the majority of benefits from demand response, even if large customers account for only 1/3 or less of energy use. The Box shows why adding other customers has a lower marginal impact because of the steep slopes of the supply and demand curves for electricity. Nonetheless, many programs of demand response are being expanded.

Box 2. Demand response: where does the benefit come from?

Figure 6 illustrates the impact of demand responsiveness on electricity prices and quantity. In this illustration, the supply curve is initially very flat and then becomes steeper, as more expensive generation technologies are added. It suddenly becomes steep as maximum capacity is reached. The capacity constraints are near binding because when all available generators are running and congestion prevents importing further electricity from neighbouring areas, supply is very difficult to increase.

The lines indicated by D show different states of demand. When demand does not respond to price at all (for example, because there is a fixed retail price for all electricity customers), the demand curve is vertical: completely inelastic. This is indicated in the figure by line D_0. As pricing and demand management programs are introduced, demand becomes increasingly less vertical. Demand curve D_1 shows a possible curve when large customers are covered by real-time pricing. Demand has a negative slope, indicating that in response to higher prices there is lower demand. When even more customers are covered by real-time pricing or substitutes for it, demand responds more to

24 Borenstein (2007) states that one area of concern about real-time pricing is the "possible volatility of costs to the end-use customer. This is often expressed as concern about the cost the customer would face for electricity consumer during an hour in which prices hit an extreme spike, such as $10,000 /MWh. Borenstein finds that, for 1142 large industrial customers, "simple heding strategies can eliminate more than 80% of the bill volatility that would otherwise occur."

price, as indicated by demand curve D_2. In this curve, both large customers and others are subject to real-time pricing or other demand management methods.

In summary, the three demand curves of Figure 6 illustrate:

D_0: inelastic demand

D_1: elastic large customer demand, inelastic household/small customer demand

D_2: elastic large customer demand, elastic household/small customer demand

The equilibrium of supply and demand is met at a different point for each demand curve. When the demand curve is vertical, as in D_0, the quantity produced is 65 and the price is 680 EUR/MWh.

When a small amount of demand response is introduced, as in D_1, the price falls 41%, to 400 EUR/MWh, even though the quantity reduction is about 8%.

The further introduction of demand elasticity (for example, from expanding real-time pricing to households) further changes the slope of the demand curve to D_2, and reduces prices a further 20% to 320 EUR/MWh with a quantity reduction of about 3%.

The key point is that, for the curves illustrated here (and perhaps for realistic situations) most of the improvement from demand responsiveness comes from enhancing demand responsiveness of the easiest target group, large customers. Graphically, the benefit from adding small customers, like households, is shown by areas C-B. Area A is a benefit that occurs in both cases. Prior to implementing a roll-out of smart meters, the case for the investment needs study.[25] Factors to be considered in such a study would include not only the cost of rolling out smart meters and the direct benefits to consumers shown through the demand curves in Figure 6, but also the indirect benefits from externalities, such as reduced CO_2 output in response to smart metering and the wind power it enables.[26]

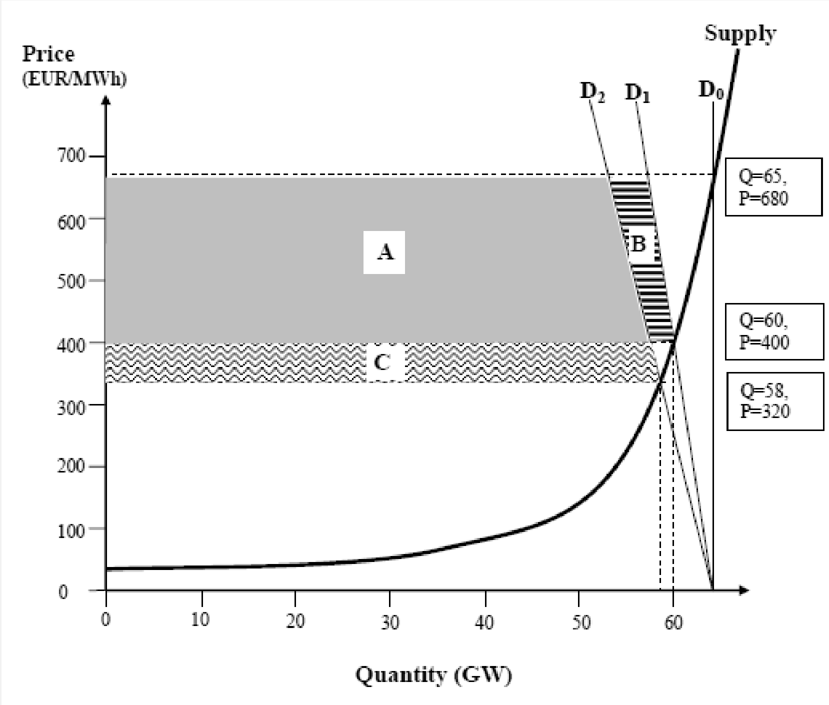
Borenstein (2005) suggests that the benefits of real-time pricing will only amount to about a 5% reduction in the electricity bill, smaller than might have been expected.[27]

25 Brennan (2004) states “Policies to promote real-time metering require more than showing benefits from more timely responses to variations in cost. They require positive externalities to imply that too few meters would be installed through private transactions.” Estimates of the benefits from more active electricity demand include GAO (2004), Walter *et al*. (2004) and Borenstein and Holland (2005).

26 Real-time pricing will not necessarily reduce CO_2 output. Real-time pricing will lower prices. Some studies (e.g., the Gridwise study in the Olympic peninsula described below) find an increase in overall electricity usage with real-time pricing (in this case by 4%). See Holland and Mansur (2008) who suggest that real-time pricing would reduce pollutants and CO_2 when peak demand is oil fired rather than hydroelectric but otherwise would likely increase pollutants, though by a small percentage.

27 “…in an electric system that must always stand ready to meet all demand at the retail price, the cost of a constant-price structure is the need to hold substantial capacity that is hardly ever used. But utilities optimize by building "peaker plants" for this purpose, capacity that has low capital cost and high operating cost. The social cost of holding idle capacity of this form turns out to be not as great as one might think.” (Borenstein, 2009)

Figure 6. Effects of increasing demand response



Developing more capable demand-side responses could be particularly important if, as Kwoka (2008) suggests, barriers to entry in electricity generation are significant and if insufficient generation capacity is being constructed. EIA[28] notes that the reserve margin is expected to fall to 5.1% in the ERCOT (U.S.) region, 7.5% in the MRO (U.S.) and 8.0% in the NPCC (U.S.). That is, absent an increase in investment, notably for baseload capacity, in a number of areas of the U.S. shortages are likely to develop in the medium term.

2.4.3 Smart grid

The new "smart-grid" collection of technologies and devices can help to promote real-time demand elasticity and distributed production of electricity by moving the electricity network towards a two-way model of communication with constant updating of price and usage information. Smart grids could improve the capacity of electricity networks to operate with renewable technologies that are variable in output. They make technically feasible:

- Real time price differentiation over time and location, to incentivise customer reduction of demand or shifting of electricity time of use;
- Remote control of electrical devices, allowing consumers or electricity suppliers to curtail or shift their time of use in response to market signals;
- Injection of electricity into the grid by consumers / embedded producers, for example from small-scale wind or solar generation;

28 Electric Power Annual 2006, Table 3.3.

- Real-time billing and payment mechanisms that keep track of electricity time of use and production over time, and allow this to be communicated remotely;

- Tracking both customer draw of electricity from the grid and customer input into the grid from customer-owned generation.

For the current purposes, this collection of technologies will be referred to as "smart-grid" technologies. Installing smart-grid technologies would be a major investment but could transform existing electricity networks to enable two-way flows of information.

This technology is not yet widely installed in most countries and standards are increasingly being developed. Smart grids are expected to be rolled out in the near or medium future in a number of markets, particularly those which benefit from strong government support for smart-grid initiatives. The standards for smart grids and the regulations (or case law) that govern the customer-retailer-distributor-generator-dispatcher interfaces will have a dramatic impact on the nature of electricity markets in the future.

Smart grid technology has the potential to help maintain the necessary balance between output and consumption of electricity when renewable generation is used, because :

- Smart grids can make the demand side respond in real time to changes in supply conditions, reducing peak demand; and

- Smart grids can change the demand-supply balance by activating distributed generation by small customers, increasing peak supply.

Empirical evidence shows that the potential economic impacts of smoothing electricity demand are non-trivial. Faruqi and Sergici (2009) survey 15 recent experiments of dynamic electricity pricing, finding that households respond to higher prices by lowering usage. The magnitude of the response depends on factors such as whether there is central air conditioning in a home and whether thermostats can be controlled remotely. Time-of-use rates induce a drop in peak consumption of 3-6%, critical peak pricing tarriffs induce a drop in peak consumption of 13-20% and the presence of smart technologies, such as smart thermostats, is associated with a decline in critical peak demand of 27-44%. Kiesling (2009) examines studies between 2003 and 2006, reporting estimates of residential own-price elasticity for electricity that range from -0.035 to -0.17. These are small own-price elasticity numbers compared to most sectors. But given that peak prices can be 100-200 times off-peak rates,[29] these small elasticities can still have substantial effects on quantity demanded.

Box 3. GridWise Olympic Peninsula Demonstration Project

Many demonstration projects have occurred to test the impacts of introducing real-time or similar pricing mechanisms with residential customers. This box describes one recent project.

In the Olympic Peninsula of Washington state, in the U.S., 130 households with both broadband and electric heating participated in a project that lasted from April 2006 to March 2007. The households all began with broadband connections and electric heating and received a programmable controlling thermostat with a user interface that could be programmed in response to price signals if desired. Appliances such as water heaters were installed with controller chips that allowed them to receive price signals and change their behaviour in response to these signals.

29 See Brennan (2004), p. 121.

Three pricing options were given to households:

- A fixed-price contract;
- A time-of-use contract with a variable CCP component that was callable in periods of tight capacity; and
- A real-time pricing contract that would reflect wholesale prices in five-minute increments.

A number of preliminary results have been established:

- For the real-time pricing group, peak consumption decreased by about 15-17% relative to what the peak would have been with fixed pricing. Overall energy consumption increased by 4% (a reflection of lower prices in many periods of the day from real-time pricing).
- For the time-of-use group, the own-price elasticity of demand was (-0.17) based on hourly data. The overall reduction in usage was 20% compared to the fixed price group.

(For more details, see Hammerstron *et al*. (2007) and Kiesling (2009).)

Smart grids have the potential to:

- Increase elasticity of demand, particularly through the introduction of smart-controlled devices;
- Access a new and important storage medium (car batteries);
- Create flexible supply response through customer generation and calls on storage; and
- Provide real-time price signals both for changing demand and changing supply.

Smart grids may make electricity markets more competitive while at the same time ensuring that electricity networks are sufficiently flexible to address unreliable supply patterns from renewable generation sources like wind and solar power.

The challenge with smart metering is that installation of the meters is expensive and residential customer interest is typically low. For example, in the U.S. state of Maryland, when given a choice, 2% of residential consumers have chosen to move away from fixed cost plans while 94% of large customers have done so. (Brennan, 2008) If these figures are typical, they suggest that broad efforts to increase small customer participation in the electricity market will not succeed in attracting customer interest or active decision making. It is possible that consumers do not want to make the investment to manage their electricity usage. Alternatively, it is possible that consumers will change to becoming active managers once price incentives become real, as with telecom services.

2.5 Unconventional supply-side response

In addition to demand response as a method to mitigate variable output of renewable electricity sources, new forms of supply response are expected to develop. Smart grids can permit distributed generation.[30] Customers will increasingly install solar and in some cases wind generation in the future.

30 "Distributed energy resource systems are small-scale power generation technologies (typically in the range of 3 kW to 10,000 kW) used to provide an alternative to or an enhancement of the traditional electric

These customers could potentially use the electricity themselves. In systems that permit distributed generation input into the grid, the customers could also sell excess capacity into the grid.[31] Standards have been developed to permit such sales into the grid.

While most customers do not currently have significant supply resources, there is a new type of supply that could become very significant with time, though the approach is still unproven. This would involve using the batteries of plug-in hybrid electric vehicles (PHEVs) as a source of reserve electricity capacity. EPRI (2008) p.9-4. Batteries could charge during periods of base load (at night, for example, when other uses are low) and serve as a source of power when demand is higher and the cars are not in use. Widespread adoption of PHEVs with improved batteries connected to the electricity system could also see significant increases in aggregate electricity demand and significant new load at off-peak periods.[32] Some scenarios suggest that this incremental capacity could have dramatic effects if widely adopted and connected to the grid. Distributed generation and storage could offer incremental capacity for the power grid while reducing the need for large, commercial capital investments in possibly inefficient peak-load generation capacity. One jurisdiction has already passed legislation requiring the electricity system operator to purchase electricity from car batteries. "The bill, which is the first of its kind in the world, requires electric utilities to compensate owners of electric cars for electricity sent back to the grid at the same rate they pay for electricity to charge the battery."[33] The practical barriers to dispatching PHEV power into the grid are significant.

3. Competition policy questions

Increasing adoption of variable renewable generation and smart grid technologies could increase efficiency and mitigate highly inelastic demand. The adoption also raises a number of competition policy questions. Because of their novelty, these questions have been little studied. One of the purposes of this roundtable is to bring these questions to the fore and narrow them for discussion purposes. The topics cover many different areas and do not claim completeness. This section is primarily designed to present questions rather than to develop background or suggest answers.

The answers of governments or others (such as Independent System Operators (ISOs)) can have major impacts on investment. Designing regulatory incentives to promote efficient investment is a key objective of electricity market oversight. Pollit and Bialek (2009) suggest the need for "new thinking in the determination and regulation of required network investments, particularly the use of user engagement and competitive tendering. Consideration needs to be given to the locational signals inherent in current transmission and distribution pricing structures and whether these need to be changed. Ownership unbundling of distribution from the rest of the electricity system is an issue whose time will come." Competition policy will be affected by these investment considerations.

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power system." (See Wikipedia, Distributed Generation, accessed Jan 25, 2010, at http://en.wikipedia.org/wiki/Distributed_generation.)

31 The USA Federal Energy Policy Act of 2005 calls for state utility commissions to consider certain standards for electric utilities. Section 1254 of the act states: "Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources With Electric Power Systems, as they may be amended from time to time."

32 Since cars are normally parked 95% of the time, PHEVs could provide highly flexible draws of electricity since they only need to charge 30% of the day in expected use. (See Plug-in Hybrid FAQ at Climate Progress.org, http://climateprogress.org/2008/07/11/plug-in-hybrid-faq/)

33 http://www.udel.edu/V2G/ . The legislation is Delaware Senate Bill 153(2009) .

Topics include:

- Market definition;
- Standards for smart meters;
- Rules on market participation;
- Demand participation;
- Information availability rules;
- Access to the transmission grid;
- Bidding and dispatch; and
- Monopsony purchasers of electricity.

These will be discussed sequentially. These topics are important because market power in electricity markets can have substantial effects.[34] Regulators, system operators and competition authorities have an important role to play in preventing the creation and exercise of such market power.

3.1 Market definition

The expansion of renewable sources of energy is largely a result of government regulations. One type of regulation with an expansionary effect is the establishment of a target. In Australia, the Mandatory Renewable Energy Target has been supported by cross-regional trade in Renewable Energy Certificates. The introduction of such specific regulation for one type of energy has led the Australian competition authority (ACCC) to determine that relevant markets for mergers include "A national market for the supply of Renewable Energy Certificates. This market would need to be treated as a national market given the cross-regional trade in RECs, under the MRET scheme."[35] In a number of similar cases, the ACCC decided acquisitions of renewable assets were unlikely to substantially less competition, despite increasing concentration in the renewable energy electricity market, because of small increments of growth from the merger and rapid sectoral growth due to government policy. Cases like these suggest that special regulations for renewable electricity sources may lead to narrow definitions of electricity markets with respect to renewables.

- **Do regulations limit the extent to which non-renewable sources of energy can compete with renewable sources of energy?**
- **If so, is a renewable electricity market a reasonable market definition?**

The geographic reach of such markets could be international in nature, to the extent that credits are tradeable across borders and within a region (e.g., the European Union.)

34 See Borenstein and Bushnell (1999), Johnsen, Verma and Wolfram (1999), Wolfram (1999) and Borenstein, Bushnell and Wolak (2002) for papers on market power in electricity markets in Norway, the U.K. and the U.S..

35 For example, International Power & Mitsui Ltd – proposed acquisition of Queensland wind energy assets, reference 30140, 16th November 2007.

3.2 Standards

Electricity networks and generation facilities are long-lived investments, with lives between 30-60 years. Changes in the regulation of such long-lived networks are often incremental in the short-term, but could be dramatic and unpredictable in the long-run. Installing a meter that serves the immediate needs of electricity retailers may lead to the installation of hard-wired technology that cannot adapt well to future market institutions and regulations. Meter technology changes are unlikely to occur frequently. Yet technological and organisational innovations are likely to continue at a fast pace, including the type and activities of market competitors. It is desirable to ensure that standards are developed that would allow for many potential uses rather than only limited uses. The U.S. Federal Energy Regulatory Commission (FERC, 2009) notes that "advanced metering infrastructure will be encouraged by improving and expanding interoperability, open standards for communications protocols and meter data reporting standards. Development of these standards would enable the development of new technologies, such as smart appliances, to support broader application of demand response programs and dynamic pricing. Congress recognised the need for such standards in EISA 2007, granting the FERC authority to approve standards developed through the NIST consensus process." (pp. 70-71)

Incumbent electricity retailers may not find it in their interest to install smart meters that are flexible, to the extent that such meters:

- Cost more than simple, inflexible hardware based meters;
- Reduce their control over the end-customer; and
- Enhance potential competition in the future.

Kiesling (2009) emphasises the importance of ensuring that "institutions have the capacity to adapt to unknown and changing conditions." (p. 39) One part of ensuring that institutions and market solutions can adapt is to avoid unnecessary technological limitations on interactions.

- **Would incumbents have an interest to ensure standards do not promote increased competition?**
- **What competition policy issues are present for smart meter standards?**
- **Can regulation impose a requirement for enhanced meters?**

3.3 Rules on market participation

Demand response is a product that could, potentially, be sold in competition with wholesale electricity. Small demand responses could be "aggregated" and "sold" back into the wholesale marketplace by entities other than traditional utility suppliers. The electricity system operator for Melbourne selected an aggregator of demand response in a recent open contest. Regulators or independent system operators may stop the development of such entities through rules that effectively exclude demand response as a product that can be bid into a market.[36] Rules may require market bidders to be generators, for example, which would rule out suppliers of "demand reduction" or battery storage providers.

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36 Allowing bids on demand response requires the ability to measure the response, notably the difference between expected demand and actual demand, so that the response is verifiable. Estimating expected demand for a particular customer can be challenging. An appropriate standard for such measurements needs to be identified.

More troubling is the point that paying for demand response requires an estimate of expected demand absent the response. Wolak (2006) suggests that, in an experiment in Anaheim California, for days that are not peaking days, usage by a group of customers facing real-time pricing was higher than for customers who were in the control group. Wolak noted the result was "consistent with the incentive that treatment group customers have to increase their reference level in order to obtain a higher rebate during the CPP days."[37] The experimental design made it profitable for customers to increase their non-peak consumption in order to have a higher reference level of usage that would allow higher payment for reducing demand below the reference level. In short, under at least one seemingly reasonable system design, gaming the demand response system can occur, leading to excessive payments to customers who reduce demand and increased usage above the level that would have occurred with simple real-time pricing.

- **Should demand response be sold into the system planning market, like generation?**

- **If so, how can demand responses be identified to avoid gaming of the system by participants? (Gaming could occur, for example, if a site creates an expectation of high use without actually being a net high use consumer)**

- **Can small customers purchase from one or more retailers and sell generation capacity to one or more (potentially different) intermediaries?**

3.4 Demand participation

Demand response was discussed extensively in Section 2. Making demand response work well requires not only appropriate equipment but appropriate contractual schemes. Contractual schemes can be based on either dispatchable methods, such as centralised command and control rules or on non-dispatchable methods, such as flexible, real-time pricing. Transmission and system operators can effectively reduce the role of demand response by not allowing demand response resources to be bid for providing network services, such as resolving energy imbalance.

In a recent rulemaking procedure, the Federal Energy Regulatory Commission of the U.S. determined that each ISO or Regional Transmission Operator (RTO) must "accept bids from demand response resources, on a basis comparable to any other resources, for ancillary services that are acquired in a competitive bidding process."[38] The Commission required "demand resources that are technically capable of providing the ancillary service within the response time requirement, and that meet reasonable requirements adopted by the RTO or ISO as to size, telemetry, metering and bidding, be eligible to bid to supply energy imbalance, spinning reserves, supplemental reserves, reactive and voltage control, and regulation and frequency response."[39]

The success of demand participation depends very much on the extent to which peak demand would be curtailed by use of these demand participation schemes. That is, what percentage of peak demand or total electricity usage is covered by different contractual schemes? Questions that are thus important, in practice, for determining success of demand response include:

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37 This is also consistent with those treatment customers increasing consumption in lower-priced periods than under the average price they faced before the experiment, and that the control group still faces.

38 Federal Energy Regulatory Commission (2008) p.27.

39 Federal Energy Regulatory Commission (2008), p.28.

- **How common are contracts that allow the electricity network operator to temporarily "shut down" small-scale or large-scale electricity users at peak periods, helping it to adapt to the potentially limited ability of renewable generation to provide electricity?**

- **How common is flexible pricing that can change on a daily and hourly basis?**

- **Are ISO's and transmission operators required to accept demand response bids?**

3.5 Information availability

A number of new intermediaries may arise in the future. These might include:

- Small demand aggregators;

- Distributed generation aggregators;

- Battery response aggregators; and

- Usage insurers (who provide insurance to customers of real-time pricing that their bills will not be excessive).

This list is not intended to be complete, but should give a sense of the new business niches that will arise with extended real-time pricing.

In order for these new intermediaries to emerge, design products and make contracts with customers, they will need information about customer usage patterns (e.g., for demand reduction) or capabilities (e.g., do they have car battery capacity) If such information is only available to their retailer, the retailers will have a substantial, unearned advantage over other providers in developing products using their customers.

- **Who controls the information about smart-grid capacities of different customers?**

- **Does the dispatch operator have access to smart-grid customer information? Does anyone (other than the dispatch operator) have access to smart-grid information?**

- **Is there a price for access to such information?**

3.6 Access and transmission

Gaining appropriate access to the transmission grid could create challenges for renewable generators and other sources of supply for several reasons.

First, many of the strongest sources of renewable energy do not have good transmission network connections. Therefore, extensions to the transmission network would be required which are time consuming and costly. Absence of good network connections is already a reason being used for reducing sizes of planned windfarms.[40]

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[40] Mesa Power, for example, cancelled orders to purchase wind turbines from GE for a project in the Texas panhandle, alleging a lack of transmission capacity. (Bloomberg, Jan 13, 2009, "GE Says Pickens' Mesa Cuts Wind Turbine Order in Half".)

Second, transmission grid owners are also sometimes generators and may prefer to reduce competition by delaying connections or not aggressively seeking and obtaining permission to extend transmission networks.

Third, transmission grid and ISO rules about “quality” of delivered electricity could have a strong impact on the ability of variable output providers to contribute electricity to the network. If wind farms are required to input exactly the amount of energy they bid into the system at exactly the bid times at the exact node where they bid, they may have difficulty.[41]

- **On what basis are connection costs calculated and allocated?**

- **Do incumbent generators have the ability and incentive to limit transmission capacity of renewable generators? If so, how can these incentives be changed? Do they have incentives to construct new transmission capacity for renewable generation?**

- **Are some electricity companies able to exercise monopsony power in the purchase of renewable electricity? Can such purchasers foreclose new producers to the benefit of their own generation?**

3.7 Bidding and dispatch

An electricity system operator in a liberalised market typically uses bidding to decide dispatching order of generation. This bidding process also determines the marginal price of relevance for customers.

Bidding design rules can affect the viability of variable energy providers. Currently, many bidding systems in which an ISO compares bids from alternative generators are conducted on a day-ahead basis. Wind-based energy can be much better predicted when there is short lead time between the prediction and the period of usage. For example, predictions made 3 hours before production is promised are considerably more accurate than those made a day before the wind energy is produced. Therefore, if bidding rules for ISOs involve day-ahead bidding (as opposed to short-advance bidding) wind will be disadvantaged.[42]

- **Do bidding rules disadvantage variable generation compared to other forms of generation?**

- **If so, can rules be changed in a way that works well for variable generation without penalizing traditional generation?**

- **Do rules that permit a renewable source of generation to connect to the network and deliver energy at any time create undue benefits to renewable energy and excessive costs to users?**

3.8 Monoposony power

A system operator or retailer may have exclusivity over relations with their consuming customers who also deliver small-scale or distributed generation. When a buyer has exclusive ability to purchase a product, the buyer is referred to as a monopsonist. Such a buyer can take advantage of its market power to determine prices in a way that is most profitable to the buyer. Situations can arise in which the system would benefit from additional production, but the monopsonist offers an insufficient amount to the small-

41 For details on the problems that can arise with access, see OECD (2004) Access and pricing in telecommunications.

42 In contrast, other generators who need to plan human resources in advance may face difficulties from short-notice bidding that is ongoing during a day.

scale providers to convince them to generate. Many of the same problems with monopolists are reflected in monopsonies.

- **Are there monopsony (single buyer) issues for the purchase of customer-generated electricity? For example, have any rules been developed for such purchases?**

- **Are customers allowed to purchase from one entity and sell to another? If so, might there be arbitrage issues, particularly if they are allowed to purchase at a regulated low price and sell at a (high) market price.**

- **Are fixed prices for purchases a good option to avoid market power of the buyer?**

- **How might monoposony power issues be resolved?**

4. Conclusion

In summary, the classic competition policy problems in the electricity market arise from features of the existing system that include:

- Highly inelastic demand;

- Absence of real time price signals for customers;

- Absence of storage;

- Need to maintain system in constant balance of supply and demand; and

- Constrained supply

Dramatic change is expected in electricity markets over the next two decades that may alleviate some of the market power that exists. The potential expansion of renewable generation, the presence of higher capacity storage options along with the introduction of real-time price signals may change all the features above except the need to maintain a system in constant balance of supply and demand. One result is that competition concerns may become less acute in this sector than they have been in the past.

As the movement towards a more decentralised network with increased renewable output progresses, a number of new competition policy challenges are likely to arise while the traditional market power concerns retreat. Key topics of concern in the future may include:

- Market definition;

- Standards;

- Rules on market participation;

- Rules for demand participation;

- Information availability;

- Access and transmission;

- Bidding and dispatch rules; and
- Monopsony power.

This paper identifies some of the main questions that arise in relation to these topics. Policies that address these topics will undergo a substantial evolution in the coming years. A government role in policy development may be desirable, especially to the extent that incumbents' incentives are to design standards and institutional structures that reduce competition and ensure high revenues for themselves. If the policies are well developed, the acuteness of market power problems in the electricity sector may decline. But ensuring that the policies achieve this objective will be an ongoing challenge, particularly to the extent that market power concerns are overshadowed by the pursuit of a low-carbon goal of policy.

Increasingly electricity networks will feature more decentralised co-ordination. The institutional and trading structures of the future that would enable such co-ordination are difficult to predict. Kiesling (2009) recommends "humility" in overseeing the development of decentralisation. Ostrom (2005) suggests "we need to…be better facilitators of building adaptive institutional design – in contrast to presuming we are the experts who can devise the optimal design to solve a complex problem." (p. 254)

Achieving appropriate institutional design and interconnection rules will be a challenge. Key points from this paper are:

- Economic principles should govern the development of new technologies rather than simplistic pro-renewable rules or pro-smart grid rules. If the issue of concern is cutting greenhouse gases, the solution is not to adopt low-carbon production (such as solar) at any cost. Pricing greenhouse gas emissions will lead to the most efficient reduction in output of such gases;
- Clear, reasonable standards are needed for next-generation electricity meters;
- Regulation needs to allow creative, unpredicted actions by intermediaries or consumers;
- Intermittent production by wind and other renewable generation may require new system rules for bidding, guaranteed delivery and permissible sources; and
- In many countries, wind and solar production are best exploited in areas where transmission capacity is low. Exploiting such sources would require substantial new investment in transmission capacity.

The challenges are considerable, not only for competition policy but more generally for both the government and the private sector. Addressing these challenges will require ongoing technical review and regulatory action at a sub-national, national and international level.

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NOTE POUR DISCUSSION

1. Introduction

Les évolutions actuelles des technologies et des conditions de production dans le secteur de l'électricité annoncent de nouveaux défis pour la politique de la concurrence. La présente note de réflexion en décrit quelques-unes ainsi que les questions qu'elles posent concernant la politique de la concurrence.

Trois grandes tendances des technologies de production d'électricité seront examinées :

- exploitation croissante des énergies renouvelables, hors hydraulique, telles que les énergies éolienne et solaire ;
- développement et déploiement de nouvelles technologies de compteurs et de réseaux ;
- contribution accrue du client à la fourniture d'électricité, par exemple, grâce à la petite production répartie.

Ces évolutions sont importantes et opportunes car elles ont un impact sur les politiques en matière de changement climatique. Il est aujourd'hui largement admis que les rejets de gaz à effet de serre doivent être limités. En témoignent le Protocole de Kyoto, l'Accord de Copenhague de décembre 2009[1], le rapport Stern[2] et les diverses initiatives de réduction des émissions de gaz à effet de serre lancées aux plans national, régional et local[3]. A l'origine de 24 % de ces émissions[4], l'industrie électrique pourrait connaître des changements de politique radicaux susceptibles de se répercuter sur les prix de détail, le mode de consommation de l'électricité ainsi que la nature du parc de production.

Les évolutions technologiques et stratégiques pourraient radicalement changer la structure des marchés de l'électricité en élargissant l'éventail des fournisseurs, en amplifiant les baisses de la demande

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1 Voir http://unfccc.int/resource/docs/2009/cop15/eng/l07.pdf.

2 Stern (2007) appelle les autorités de régulation à « innover, face au défi posé par l'intégration de technologies [à faibles émissions de carbone], de façon à en exploiter le potentiel et à profiter des possibilités offertes par un parc de production moins centralisé. »

3 Le Royaume-Uni s'est fixé comme objectif à long terme de réduire ses rejets de carbone de 60 % d'ici 2050 (Neuhoff, Cust et Keats-Martinez, 2008). Le rapport Stern propose une analyse économique du changement climatique (voir http://www.hm-treasury.gov.uk/sternreview_summary.htm).

4 Voir Stern (2007), dont le résumé indique que « les conséquences de la non réduction des émissions de gaz à effet de serre pourraient être graves ». « Avec un scénario d'inaction (BAU), le stock de gaz à effet de serre pourrait plus que tripler d'ici la fin du siècle, donnant au moins un risque de 50 % de voir la température moyenne du globe varier de plus de 5 °C au cours des décennies suivantes. Cette évolution mènerait l'humanité en territoire inconnu. Pour illustrer l'ampleur de cette hausse, rappelons que la température actuelle ne dépasse que de 5°C la température de la terre à la dernière période glaciaire » (page iv). Pour une critique, voir Mandelsohn (2008) qui reproche au rapport son contenu économique minimal.

lors des hausses de prix pour cause de pénurie et en augmentant la dépendance vis-à-vis des producteurs d'électricité non traditionnels.

L'électricité renouvelable devrait occuper une place de plus en plus importante à l'avenir. La part croissante des énergies renouvelables, notamment éolienne et solaire, est un défi pour le maintien de la qualité du réseau, car cette production n'est pas "dispatchable", ou appelable, c'est-à-dire que ces installations ne peuvent pas être démarrées à volonté[5]. Pour pallier les baisses de production soudaines, l'une des meilleures méthodes consistera à recourir davantage à la gestion de la demande et à la production à petite échelle. Grâce aux nouvelles technologies de comptage et de réseau mises au point, et parfois déjà installées, on peut mesurer avec précision la consommation d'électricité par périodes – donc appliquer des tarifications horosaisonnières – et envisager l'alimentation du réseau par de petites unités de production, y compris, un jour, les ménages. Ces nouvelles technologies de comptage et de réseau sont des technologies de réseaux "intelligents". La présente note de réflexion examine les questions que pourraient soulever ces changements de technologies de production et de modes de consommation pour la politique de la concurrence.

Ces questions sont de nature diverse. A titre d'exemple :

- Les régimes réglementaires spéciaux dont bénéficient les énergies renouvelables, avec la mise en place de systèmes d'échanges de permis ou l'obligation faite aux distributeurs d'acheter un pourcentage minimum de l'électricité renouvelable, pourraient créer de nouvelles niches de pouvoir de marché pour les fournisseurs d'énergies renouvelables. Si les capacités existantes de production d'électricité renouvelable sont être toutes nécessaires pour satisfaire à une obligation réglementaire, les propriétaires de ces installations ont les moyens de vendre leur électricité à des prix élevés[6]. Cette situation justifiera parfois de définir des marchés de la fourniture d'électricité limités à la catégorie des énergies renouvelables, voire à des sous-catégories.

- Les systèmes actuels employés pour établir l'ordre économique d'appel des groupes de production reposent généralement sur des enchères organisées la veille pour le lendemain. Ces enchères désavantagent fortement l'énergie éolienne car les prévisions de vent, si elles sont relativement précises à quelques heures d'écart, sont beaucoup moins sûres une journée plus tôt. Des changements de politique pourraient être nécessaires pour permettre aux producteurs éoliens de présenter une offre peu de temps avant l'heure de fourniture de l'électricité.

- Les réglementations peuvent perturber les effets de la concurrence en accordant un avantage concurrentiel excessif à certaines formes de production d'électricité, telles que la production solaire, très coûteuses par rapport à d'autres technologies à faibles émissions de carbone.

- Les nouvelles technologies et politiques pourraient renforcer la capacité et la volonté des clients de souscrire de nouveaux types de contrats, susceptibles de réduire les bénéfices des opérateurs historiques. De ce fait, ces derniers pourraient être incités à tout mettre en œuvre pour que les normes servent de barrières à l'entrée sur le marché. Ces nouvelles normes technologiques pourraient limiter la capacité des concurrents des opérateurs historiques de passer des contrats

5 Dans le contexte de ce document, on appelle énergies renouvelables l'ensemble des énergies éolienne, solaire, houlomotrice, marémotrice, hydraulique et géothermique ainsi que la biomasse, et on appelle énergies renouvelables intermittentes le sous-ensemble des énergies éolienne, solaire, houlomotrice et marémotrice.

6 Les prix peuvent être « élevés » par rapport aux prix résultant d'enchères ouvertes, en l'absence de régime préférentiel accordé à certaines sources.

avec les partenaires commerciaux de leur choix, de leur livrer de l'électricité ou d'en recevoir d'eux.

- L'accès des petits producteurs au réseau n'est pas assuré. Comme dans le cas des plus gros producteurs, le problème qui se pose est celui de la tarification de l'accès. Il sera indispensable de fixer des règles techniques et contractuelles claires pour limiter la capacité de l'acheteur d'exercer un pouvoir de monopsone.

L'analyse présentée dans cette note de réflexion met en avant les points suivants :

- Le développement des nouvelles technologies doit être régi par des principes économiques, non des règles simplistes favorisant les énergies renouvelables ou es réseaux intelligents. Si le problème est bien de réduire les émissions de gaz à effet de serre, la solution ne consiste pas à mettre en œuvre des technologies de production peu émettrices de carbone (telle que le solaire) à n'importe quel coût. C'est en fixant le prix des émissions de gaz à effet de serre qu'on les réduira de la façon la plus efficiente.

- Les compteurs de la nouvelle génération doivent faire l'objet de normes claires et raisonnables.

- La réglementation doit laisser place à l'inventivité et aux actions imprévues des intermédiaires ou des consommateurs.

- La variabilité de la production d'électricité renouvelable, et notamment éolienne, pourrait exiger de modifier les règles concernant les enchères, la puissance garantie et les sources autorisées.

- Dans de nombreux pays, les meilleurs sites pour exploiter les énergies éolienne et solaire se trouvent dans des zones où la capacité de transport est faible. L'exploitation de ces énergies nécessiterait donc de nouveaux investissements substantiels dans les réseaux de transport.

Puisque la plupart des évolutions technologiques évoquées ici concernent le long terme et ne sont pas encore appliquées à grande échelle, on manque d'expérience de l'action politique concrète. Dans la mesure où l'on serait amené à suggérer de meilleures pratiques, ces dernières seraient provisoires et appelées à être révisées à la lumière de l'expérience acquise.

La présente note de réflexion est structurée comme suit : la section 2 décrit les évolutions récentes importantes, exemples à l'appui. La section 3 recense les questions que pourraient soulever ces évolutions pour la politique de la concurrence. La section 4 présente les conclusions.

2. Évolutions récentes

Avant de dresser un panorama des dernières évolutions du marché de l'électricité, il convient de rappeler quels sont les principaux déterminants de sa structure. Nous étudierons ensuite certains éléments et prévisions qui suggèrent que, malgré leur faible taux de pénétration actuel, les nouvelles technologies de production pourraient connaître un essor considérable. L'augmentation de la production d'électricité éolienne et solaire peut avoir des effets négatifs sur la qualité du réseau si l'on ne parvient pas à une meilleure gestion de la demande ou de l'offre. S'agissant de la gestion de la demande, cette note de réflexion examine l'impact des nouvelles technologies de comptage de l'électricité. L'offre d'électricité par les clients est ensuite étudiée. Ces analyses sont indispensables pour identifier les éventuels défis à relever en matière de politique de la concurrence dans le secteur de l'électricité.

2.1 Caractéristiques fondamentales

Certaines caractéristiques des marchés de l'électricité peuvent présenter des difficultés pour la politique de libéralisation et de la concurrence. Ces caractéristiques sont notamment les suivantes :

- demande très inélastique ;
- absence de signaux de prix transmis en temps réel aux clients ;
- impossibilité de stocker l'électricité ;
- nécessité de maintenir en permanence l'équilibre entre l'offre et la demande ;
- offre contrainte ;
- faible réaction de la demande aux variations des prix de gros ;
- forte variabilité de la demande au cours de la journée et au cours de l'année ;
- possibilités d'émergence de niches de pouvoir de marché.

Du fait de l'inélasticité de la demande, à laquelle viennent s'ajouter les contraintes sur l'offre et l'absence de stockage, les prix de l'électricité sur le marché spot aux heures de pointe sont 100 à 200 fois plus élevés que les prix en base[7]. Il importe de prendre en compte ces facteurs quand on conçoit les structures du marché de l'électricité, en particulier les relations entre les gestionnaires de réseaux et les producteurs, les propriétaires de réseaux et les autres acteurs du marché, la règle appliquée pour déterminer les installations qui seront appelées (dont la production sera injectée sur le réseau), ou encore les décisions concernant les capacités de transport à ajouter ou à rénover ou le mode d'interconnexion des réseaux.

Les centrales électriques qui seront appelées sont choisies en fonction des autres solutions et de leurs coûts relatifs. L'électricité est produite avec des sources d'énergie diverses, qui peuvent être des combustibles –dans le cas des centrales nucléaires ou des centrales à charbon ou à gaz – ou d'autres formes d'énergie, dans celui des centrales éoliennes, hydrauliques ou solaires. Le dosage des différentes sources est très différent d'un pays à un autre. A titre d'exemple 84 % de l'électricité produite en 2007 provenait de centrales brûlant des combustibles, mais 98 % de l'électricité norvégienne est hydraulique[8]. Ces différences entre États membres de l'OCDE se retrouvent dans le tableau 1 qui indique le nombre de gigawattheures (GWh) produits par pays et par source d'énergie. Bien que les centrales « peu émettrices de carbone » comptent pour plus de 80 % de la production en Islande, en Norvège, en Suisse, en Suède et en France, les pourcentages globaux de l'éolien (1.4 %) et du solaire (moins de 0.1 %) sont faibles. Dans certains pays, la part de marché de l'éolien est bien supérieure à la moyenne dans la zone OCDE. C'est le cas au Danemark, en Espagne, au Portugal, en Irlande et en Allemagne, où les centrales éoliennes fournissent respectivement 18.3 %, 9.2 %, 8.5 %, 6.9 % et 6.2 % de la production totale d'électricité. Les pays où la production solaire est la plus forte sont l'Allemagne, les États-Unis et l'Espagne. Dans tous les cas, cependant, le solaire équivaut à moins de 1.0 % de la production totale.

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7 Voir Brennan (2004), p. 121.

8 La production représente plus de la moitié des coûts de l'électricité. Selon une estimation de l'AIE, la production, la distribution et le transport représentent respectivement 67%, 26% et 7% du coût moyen de l'électricité (AIE, 2009, tableau A8).

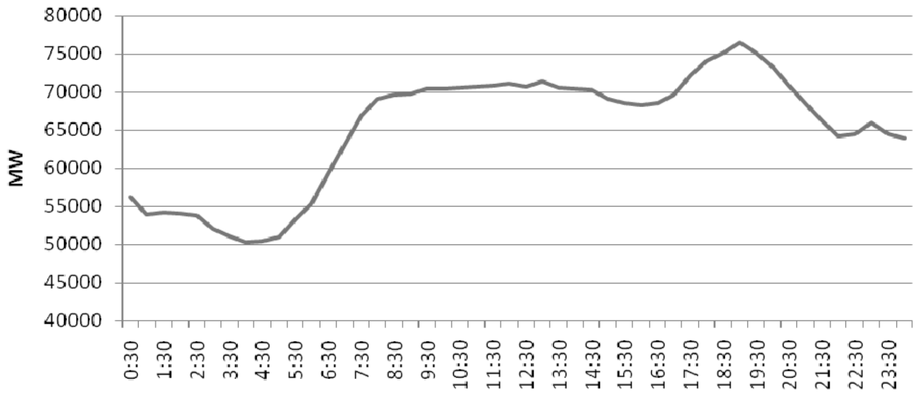
Tableau 1. Production d'électricité dans les pays de l'OCDE par source d'énergie, 2007, GWh

Pays	Combustibles fossiles	Energies renouvelables combustibles et déchets	Nucléaire	Hydraulique	Géothermie	Solaire	Éolien, marée, vagues, autres	Total	Faibles émissions de carbone, % du total	Éolien/ solaire
Australie	235 589	2 031		14 724		10	2 611	254 965	6.8%	1.0%
Autriche	18 743	4 150		38 485	3	17	2 032	63 430	63.9%	3.2%
Belgique	34 526	3 641	48 227	1 683		6	737	88 820	57.0%	0.8%
Canada	166 295	8 455	93 492	368 518		26	3 055	639 841	72.7%	0.5%
République tchèque	58 172	1 203	26 172	2 523		2	126	88 198	32.7%	0.1%
Danemark	28 092	3 859		28		2	7 173	39 154	18.4%	18.3%
Finlande	32 974	10 099	23 423	14 177		4	572	81 249	47.0%	0.7%
France	56 347	5 514	439 730	63 662		16	4 571	569 840	89.1%	0.8%
Allemagne	394 558	30 762	140 534	28 458		3 075	39 713	637 100	33.2%	6.7%
Grèce	58 092	209		3 376		1	1 818	63 496	8.2%	2.9%
Hongrie	23 254	1 709	14 677	210			110	39 960	37.5%	0.3%
Islande	2	2		8 394	3 579			11 977	100.0%	0.0%
Irlande	25 120	132		1 016			1 958	28 226	10.5%	6.9%
Italie	257 790	6 954		38 482	5 569	38	5 055	313 888	15.7%	1.6%
Japon	756 951	23 019	263 832	84 234	3 043	8	2 624	1 133 711	31.2%	0.2%
Corée	278 246	573	142 937	5 042		71	448	427 317	34.8%	0.1%
Luxembourg	2 895	103		919		21	64	4 002	25.1%	2.1%
Mexique	209 427	2 656	10 421	27 276	7 404	9	262	257 455	17.6%	0.1%
Pays-Bas	89 719	5 566	4 200	107		36	3 613	103 241	7.7%	3.5%
Nouvelle-Zélande	15 110	777		23 516	3 458		984	43 845	63.8%	2.2%
Norvège	901	443		135 052			1 075	137 471	99.0%	0.8%
Pologne	152 997	2 890		2 939			522	159 348	2.2%	0.3%
Portugal	30 392	2 150		10 449	201	24	4 037	47 253	31.1%	8.6%
République slovaque	7 550	499	15 334	4 615			58	28 056	71.3%	0.2%
Espagne	185 406	3 635	55 103	30 807		508	27 833	303 292	37.7%	9.3%
Suède	3 606	10 656	66 969	66 188			1 430	148 849	90.4%	1.0%
Suisse	936	2 309	27 925	36 737		27	16	67 950	95.2%	0.1%
Turquie	154 982	214		35 851	156		355	191 558	19.0%	0.2%
Royaume-Uni	307 487	11 395	63 028	8 948		11	5 274	396 143	19.5%	1.3%
Etats-Unis	3 111 787	71 653	836 634	275 545	16 798	689	35 750	4 348 856	26.8%	0.8%
TOTAL	6 697 946	217 258	2 272 638	1 331 961	40 211	4 601	153 876	10 718 491	35.5%	1.5%

Source : AIE, Statistiques de l'énergie des pays de l'OCDE, 2009

La diversité des sources d'énergie employées s'explique par la variabilité importante de la demande au fil du temps, qui signifie que certaines énergies seront utilisées fréquemment (production en base), tandis que d'autres ne le seront qu'aux heures de pointe. La demande d'électricité varie substantiellement sur une période de 24 heures, comme l'illustre la figure 1 qui représente l'évolution de la demande pendant une journée en France. La consommation de pointe est supérieure de 50 % à la consommation minimale. La demande d'électricité varie aussi pendant l'année. En France, par exemple, la pointe de consommation hivernale est supérieure de près de 50 % au minimum de la consommation estivale[9]. Ces chiffres montrent l'ampleur de la variabilité journalière et saisonnière de la demande d'électricité. Cette variabilité se répercute sur le nombre et le type de centrales en fonctionnement, qui fluctuent, eux aussi, au cours de la journée et au fil des saisons, et exige de mettre en place une structure du marché qui permette la fourniture d'une puissance très irrégulière à un coût global raisonnable.

Figure 1. Production électrique en fonction de l'heure - lundi 30 novembre 2009, France



Source : OCDE d'après des données de RTE

Pour déterminer à quel moment quelle centrale doit produire de l'électricité, on part des coûts de production[10]. La figure 2 compare les coûts de production estimés des diverses technologies (AEN, AIE et OCDE, 2005)[11]. Les chiffres indiqués sont des estimations ponctuelles, c'est-à-dire les valeurs médianes des séries de valeurs calculées. Ces coûts permettent de tracer une courbe de l'offre qui donne les techniques ou modes de production utilisables en fonction de la quantité d'électricité à produire. Les technologies les moins coûteuses sont généralement affectées à la production en base, tandis que les plus coûteuses fournissent la puissance de pointe. Si la charge de pointe dépasse la puissance installée totale du système, les prix de gros sur un marché libéralisé de l'électricité peuvent s'envoler tant que la demande n'a pas suffisamment baissé pour s'aligner sur l'offre. Quand la demande augmente, le coût de production du kWh marginal croît lui aussi le plus souvent.

La réglementation a une incidence notable sur le coût d'une technologie. L'imposition des permis d'émissions de carbone, par exemple, fait que les coûts de production dans les centrales à gaz ou à charbon

9 Sur certains marchés de l'électricité, notamment dans les régions aux étés très chauds où l'usage des climatiseurs est important, la variation saisonnière peut être inversée, c'est-à-dire que la consommation d'électricité est plus importante en été qu'en hiver.

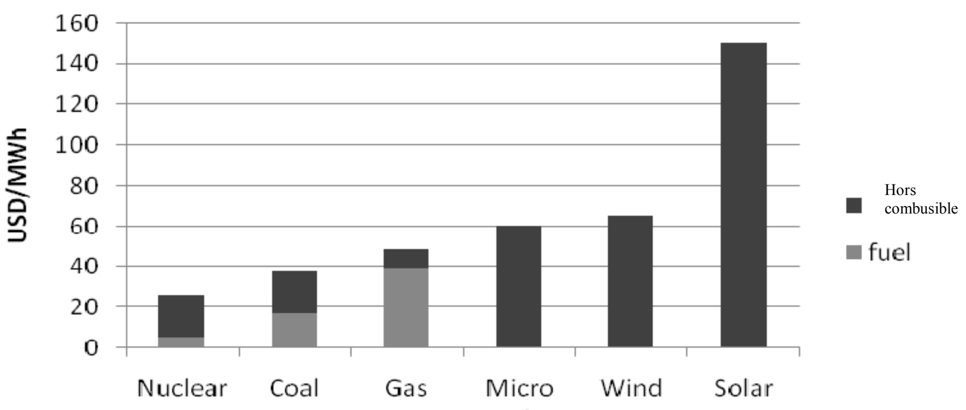
10 Sur les marchés libéralisés surcapacitaires, les coûts de production (rendement du capital investi inclus) seront en général étroitement liés aux prix proposés aux enchères pour produire l'électricité.

11 Les coûts de la grande hydraulique ne sont inclus dans ces estimations. Ils sont certainement inférieurs à ceux des centrales à charbon.

sont beaucoup plus élevés que dans d'autres types de centrales, ce qui peut modifier l'ordre d'appel des installations[12].

Comme le montre clairement la figure 2, l'énergie solaire est de loin la technique de production la plus chère. Avec des coûts variant de 350 à 680 USD/MWh, le solaire photovoltaïque, revient beaucoup plus cher que le solaire thermique représenté sur la figure. Les coûts, rapportés au MWh, de production, d'installation et d'exploitation des centrales solaires sont très élevés par rapport à ceux d'autres centrales. Dans certains pays, qui ont adopté des programmes garantissant l'achat de l'électricité solaire, les prix d'achat de cette électricité sont 10 à 100 fois supérieurs aux prix du marché à un moment donné, et les producteurs sont en droit d'injecter de l'électricité sur le réseau au tarif incitatif, même en période de bas prix. Les tarifs subventionnés entraîneront des inefficacités économiques substantielles, en particulier s'ils sont appliqués à grande échelle.

Figure 2. Comparaison des coûts de production de l'électricité



Source : estimations de l'auteur, d'après des données de l'AEN, de l'AIE et de l'OCDE (2005)

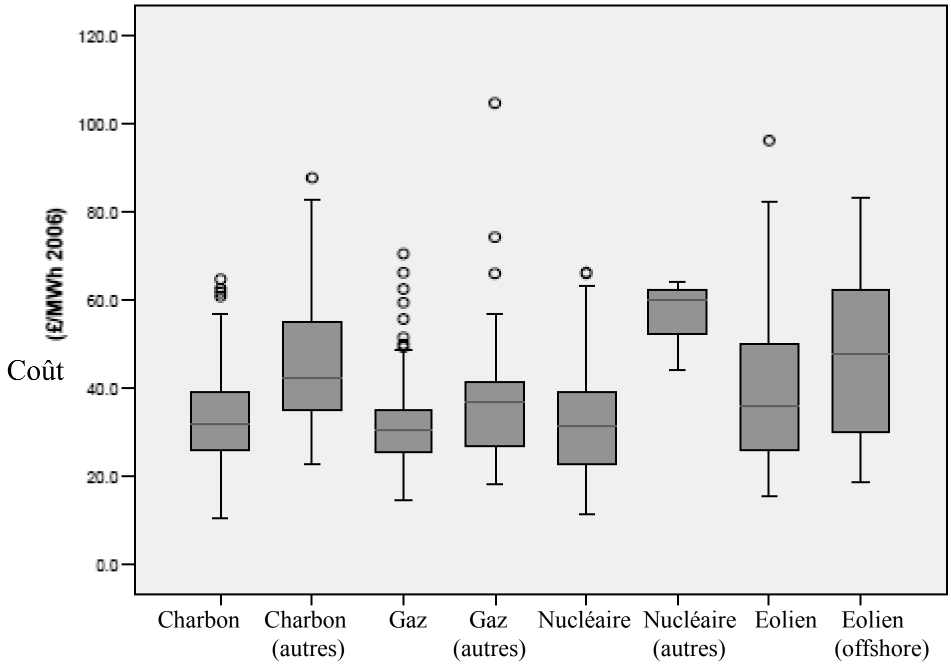
Les estimations ponctuelles rapportées ici sont en fait les tendances médianes d'une série de valeurs. Une estimation récente du *UK Energy Research Centre* montre, voir Figures 3 et 4, que l'intervalle de variation peut être important même pour un seul mode de production. Chaque boîte représentée sur les figures 3 et 4 correspond (les valeurs sont exprimées en GBP par MWh) à l'écart interquartile (série obtenue après élimination des 25% de valeurs les plus faibles et des 25% de valeurs les plus fortes), la ligne horizontale longue située dans la boîte donne la médiane, et les lignes horizontales courtes indiquent les valeurs maximale et minimale de la série, obtenues après exclusion des valeurs aberrantes représentées par les cercles. En observant la figure 3, qui présente les séries de coûts obtenues pour les principales technologies de production, on constate que les centrales à charbon et à gaz et les centrales nucléaires sont assurément les moins chères des technologies considérées[13]. La figure 4, qui présente l'intervalle de

12 Suivant la réglementation en vigueur en matière de réduction des gaz à effet de serre, l'ordre d'arrivée des différentes centrales dans le classement des coûts de production (par ordre croissant) pourrait radicalement changer. D'après Tolley et Jones (2004), les coûts des centrales à charbon et à gaz pourraient atteindre respectivement 83-91 USD/MWh et 58-68 USD/MWh. Dans le *World Energy Outlook 2008*, l'AIE applique une valeur de 30 USD/tonne de CO_2 pour estimer les coûts en Europe en 2015 et 2030, et le coût par MWh des centrales éoliennes devient inférieur à celui des centrales à charbon (p. 151). L'ordre d'apple des centrales, déterminé en fonction du coût effectif des technologies, deviendrait donc : nucléaire, éolien, micro-hydraulique, gaz/charbon.

13 On notera que l'hydraulique n'est pas pris en compte.

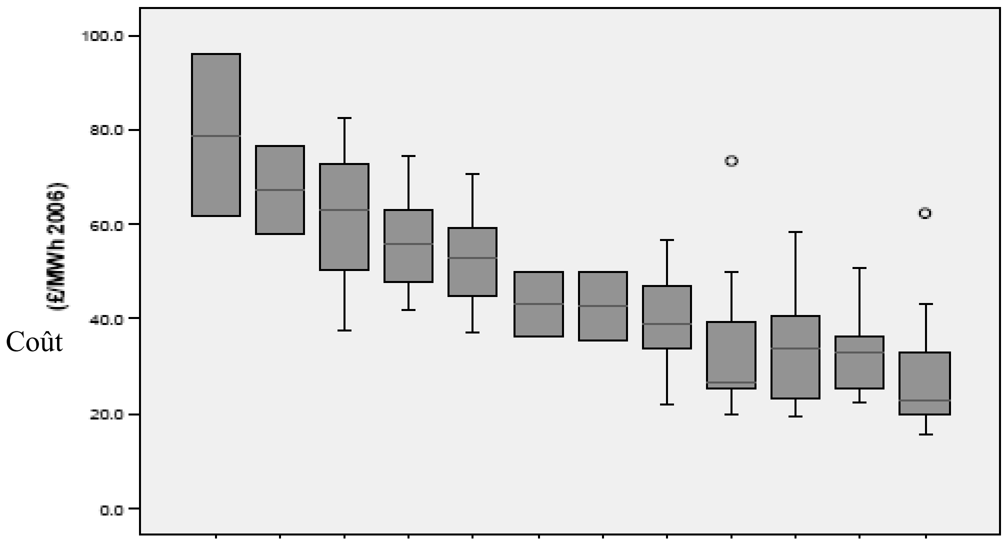
variation des coûts de la production éolienne dans plusieurs pays, révèle que ce mode de production est beaucoup moins coûteux dans certaines régions que dans d'autres, d'où l'importance du facteur géographique quand on cherche à évaluer les chances de succès d'une centrale éolienne.

Figure 3. Intervalle de variation des coûts des technologies prédominantes



Source : Heptonstall (2007)

Figure 4. Intervalles de variation des coûts de la production éolienne dans plusieurs pays



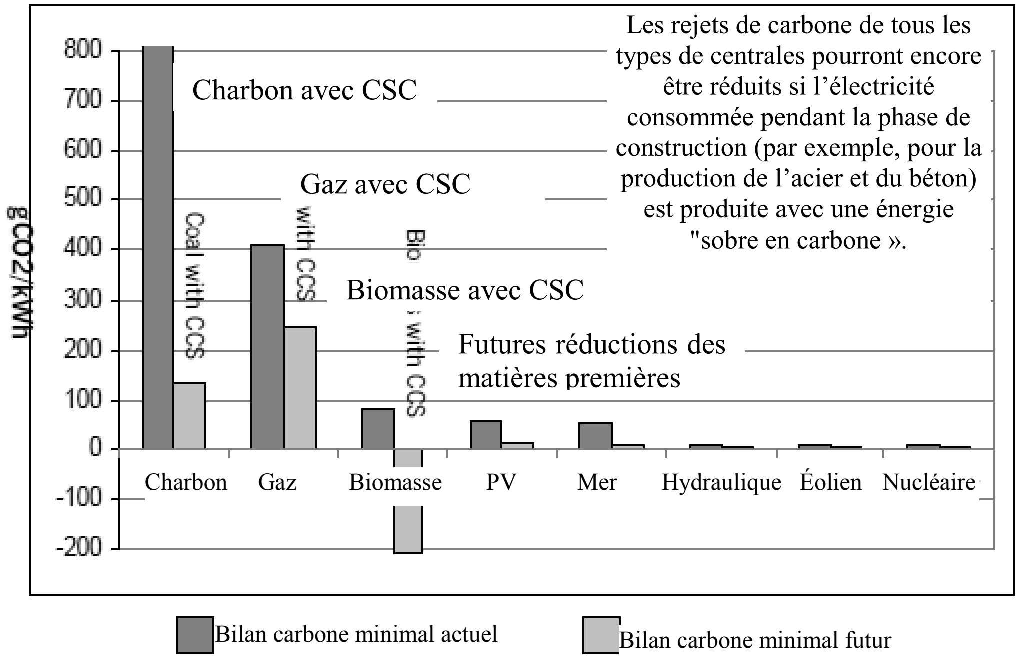
Pays dans l'ordre du diagramme : République tchèque, Autriche, Pays-Bas, Allemagne, Italie, Portugal, Belgique, Royaume-Uni, N/A, Danemark, Grèce, États-Unis

Pays

Source: Heptonstall (2007)

Les émissions de dioxyde de carbone sont également très différentes selon les sources. Comme l'illustre la figure 5, les centrales à charbon et à gaz figurent parmi les techniques les moins coûteuses[14] mais aussi les plus polluantes, en termes de volume de CO_2 rejeté par unité d'électricité produite. C'est la raison pour laquelle de nombreuses politiques visant à réduire les émissions de gaz à effet de serre, au moyen de systèmes d'échanges de quotas d'émissions ou de taxes sur le carbone par exemple, devraient avoir pour effet d'augmenter de façon disproportionnée les coûts nets de la production d'électricité dans des centrales à charbon ou à gaz. Il importe de noter que les technologies de captage et de stockage du carbone (CSC) permettent de réduire fortement les rejets de gaz à effet de serre des centrales à charbon et des centrales à gaz, et que les premières deviennent alors moins polluantes que les secondes.

Figure 5. Bilans carbone actuels et futurs



(Centrales britanniques, européennes, américaines et australiennes)

Source : Parliamentary Office of Science and Technology (2006)

Les volumes de dioxyde de carbone rejetés par les centrales électriques sont l'une des principales raisons pour lesquelles les politiques publiques mettent aujourd'hui l'accent sur les énergies renouvelables, telles que l'éolien et le solaire.

Les principaux enseignements de cette section sont les suivants :

- La part actuelle de l'électricité renouvelable, hors hydraulique, est très faible (moins de 2 %).
- La demande d'électricité varie fortement au cours d'une journée et au cours d'une année, mais de façon prévisible.

14 Ces technologies sont peu coûteuses quand on exclut les coûts des externalités, qui n'entrent pas dans le cadre de ce document.

- Les productions éolienne et solaire représentent toutes deux un très faible pourcentage de la production totale d'électricité mais, en 2007, la quantité d'électricité éolienne était 23 fois supérieure à la production solaire.
- Les coûts de production de l'électricité éolienne sont nettement inférieurs à ceux de l'électricité solaire.
- L'évolution de la réglementation (taxes sur le carbone, par exemple), tout comme les fluctuations des prix des combustibles, pourrait substantiellement modifier l'ordre d'appel des moyens de production d'électricité.

2.2 Prévisions de croissance des énergies renouvelables

A l'heure actuelle, l'électricité renouvelable représente environ 16 % de l'électricité produite par les pays de l'OCDE (calcul effectué à partir des données du tableau 1)[15], mais l'éolien et le solaire ne dépassent pas la barre des 2 %. Étant donné ce faible chiffre, pourquoi axer la présente note de réflexion autour de ces deux sources d'énergie ? Tout simplement parce qu'elles devraient acquérir une importance considérable à l'avenir. Leur croissance devrait être le prolongement des tendances passées mais aussi le résultat de l'action publique (plafonds fixes de crédits d'émissions, par exemple) visant à promouvoir les énergies renouvelables peu émettrices de carbone. De fait, malgré leur faible part de marché actuelle, l'énergie éolienne et l'énergie solaire connaissent un essor rapide. L'analyse économique laisse à penser que la première devrait progresser beaucoup plus fortement. La progression de la seconde est largement due aux subventions implicites accordées via les tarifs d'achat très élevés de l'électricité solaire.

Les tableaux suivants indiquent la production annuelle récente, en gigawattheures (GWh), des centrales éoliennes, houlomotrices et autres (tableau 2), et solaires (tableau 3)[16]. La production des centrales éoliennes et houlomotrices a été multipliée par 41 entre 1990 et 2008. Le taux de croissance annuel moyen était de 25 % entre 2000 et 2008. La production électrique des centrales solaires à été multipliée par 12 entre 1990 et 2008, et le taux de croissance annuel moyen était de 36 % entre 2000 et 2008. Les taux de croissance annuels des énergies éolienne et solaire sont donc très supérieurs à celui de la production totale d'électricité, égal à 1.5 % dans la zone de l'OCDE au cours de la même période.

Tableau 2. Évolution de la production éolienne, houlomotrice et autres dans la zone de l'OCDE : 1990-2008, GWh

Pays	1990	2000	2006	2007	2008
Australie		58	1 713	2 611	3 285
Autriche		67	1 770	2 032	2 005
Belgique	7	16	622	737	871
Canada	26	296	2 531	3 055	3 053
République tchèque			50	126	246
Danemark	610	4 280	6 108	7 173	6 928
Finlande		78	584	572	602
France	571	650	2 708	4 571	6 223
Allemagne	71	9 352	30 710	39 713	40 400
Grèce	2	451	1 699	1 818	1 661
Hongrie			43	110	205

15 Les énergies renouvelables sont les énergies hydraulique, les énergies renouvelables combustibles et les énergies géothermique, solaire, éolienne et houlomotrice.

16 Les chiffres indiqués pour 2008 sont des estimations.

Islande					
Irlande		244	1 622	1 958	2 410
Italie	2	1 349	3 998	5 055	7 355
Japon		109	2 210	2 624	2 919
Corée		17	313	448	429
Luxembourg		27	58	64	61
Mexique	1	19	59	262	255
Pays-Bas	56	1 077	2 880	3 613	4 407
Nouvelle-Zélande		120	669	984	1 107
Norvège	136	115	768	1,075	1,092
Pologne		5	256	522	833
Portugal	1	168	2 925	4 037	5 733
République slovaque			56	58	56
Espagne	14	4 727	23 626	27 833	31 832
Suède	6	457	987	1 430	1 974
Suisse		3	15	16	16
Turquie		33	127	355	797
Royaume-Uni	9	947	4 225	5 274	7 111
États-Unis	3 066	5 650	27 874	35 750	53 203
TOTAL	4 578	30 315	121 206	153 876	187 069

Source : AIE, Statistiques de l'énergie des pays de l'OCDE, 2009.

Tableau 3. Évolution de la production solaire dans la zone de l'OCDE, 1990-2008, GWh

Pays	1990	2000	2006	2007	2008e
Australie		1	9	10	10
Autriche		3	15	17	17
Belgique			2	6	40
Canada		16	21	26	26
République tchèque			1	2	13
Danemark		1	2	2	2
Finlande		2	3	4	4
France		5	12	16	36
Allemagne	1	60	2 220	3 075	4 000
Grèce			1	1	5
Hongrie					
Islande					
Irlande					
Italie	4	18	35	38	200
Japon	1	2	6	8	12
Corée	1	5	31	71	264
Luxembourg			21	21	20
Mexique	1	7	10	9	9
Pays-Bas		8	35	36	38
Nouvelle-Zélande					
Norvège					
Pologne					
Portugal	1	1	5	24	38
République slovaque					
Espagne	6	18	119	508	2 492
Suède					

Suisse	1	11	23	27	27
Turquie					
Royaume-Uni		1	11	11	14
États-Unis	666	529	565	689	933
TOTAL	682	688	3 147	4 601	8 200

Source : AIE, Statistiques de l'énergie des pays de l'OCDE, 2009.

Les sources d'énergies renouvelables (telles que les énergies éolienne, solaire, hydraulique et houlomotrice) sont de plus en plus encouragées par l'action publique. Dans l'Union européenne, la directive sur les énergies renouvelables[17], adoptée en décembre 2008, fixe à 20 % le pourcentage des énergies renouvelables dans la consommation totale de l'UE en 2020. La Commission européenne a déclaré que 12 % de la demande d'électricité européenne doit être satisfaite grâce à la production éolienne, contre 4 % seulement en 2008. Selon l'European Wind Energy Association, « En 2008, pour la première fois, on a installé dans l'Union européenne plus de capacité de production éolienne que d'autres formes de production : les nouvelles centrales totalisent 23.8 GW, dont 8.5 GW (36 %) pour les centrales éoliennes et 6.9 GW (29 %) pour les centrales thermiques à gaz » (EWEA, 2009a, p. 16). Les pays favorisent le développement des énergies renouvelables par le biais d'incitations telles que des garanties d'achat à des prix supérieurs aux coûts d'investissement et, souvent, aux coûts d'autres modes de production traditionnels et contrôlables. Souvent, les tarifs d'achat de cette énergie sont même plus élevés s'il s'agit de production décentralisée (production des petits consommateurs) que de centrales puissantes. Les taxes sur le carbone confèrent aux bons sites éoliens un avantage sur le gaz et le charbon en termes de coûts de production.

Selon l'AIE, ces tendances s'observent dans le monde entier. Dans le *World Energy Outlook 2008*, l'agence affirme que « la production mondiale d'électricité renouvelable – hydroélectricité et électricité éolienne, principalement – devrait plus que doubler au cours de la période étudiée et son pourcentage de la production totale passer de 18 % en 2006 à 23 % en 2030 » (AIE, 2008, p. 159). Les investissement qu'impliquent ces statistiques sont importants. Toujours selon l'AIE : « Le montant total cumulé des investissements dans les énergies renouvelables entre 2007 et 2030 s'élève à 5 500 milliards d'USD (en USD de 2007) et le gros de ces investissements est destiné à la production d'électricité. La production d'électricité renouvelable devrait attirer près de la moitié du total des investissements destinés à la production d'électricité. » (AIE, 2008, p. 159)

Pour résumer, on s'attend à un essor important de la production d'électricité éolienne, et potentiellement solaire, jusqu'en 2030. Il est parfois difficile d'identifier les raisons économiques pour lesquelles la réglementation privilégie la production renouvelable, en particulier solaire. Quoi qu'il en soit, à supposer que cette croissance se poursuive, elle présentera de nouveaux défis réglementaires, notamment parce que les réseaux électriques ne sont pas traditionnellement alimentés par des centrales à la production intermittente, non dispatchable.

2.3 Conséquences de la croissance des énergies renouvelables sur la stabilité des réseaux

Du point de vue de la gestion des réseaux, les énergies renouvelables intermittentes telles que l'éolien et le solaire présentent des difficultés car l'électricité qu'elles fournissent ne peut pas être dispatchée de façon régulière pour répondre à la demande. La production d'une centrale solaire ou éolienne peut varier brutalement en fonction de l'heure ou des conditions atmosphériques. Parallèlement, la courbe de la consommation possède de plus en plus de pointes en raison de l'usage plus fréquent de la climatisation. A

[17] Directive 2009/28/CE du Parlement européen et du Conseil du 23 avril 2009 relative à la promotion de l'utilisation de l'énergie produite à partir de sources renouvelables. JO L 140 du 5.6.2009, p. 16-62.

cause de ces facteurs, il est de plus en plus difficile de maintenir, minute par minute, l'équilibre entre l'offre et la demande nécessaire au bon fonctionnement du réseau (sans panne générale ni surtension).

L'European Wind Energy Association explique que « l'énergie éolienne est parfois considérée à tort comme intermittente. C'est un qualificatif trompeur car à l'échelle du système les éoliennes ne sont pas démarrées ou arrêtées à intervalles irréguliers, ce que signifie le terme d'intermittence. En fait, les centrales éoliennes sont à production variable »[18] (EWEA, 2005). Dire qu'au niveau du système l'éolien n'est pas intermittent doit être étayé. D'ailleurs la justesse de cette affirmation pourrait dépendre des régimes météorologiques locaux ou régionaux. Par exemple, dans certains pays, les journées les plus chaudes, donc celles qui nécessitent une production d'électricité maximale, sont aussi des journées pendant lesquelles il y a peu de vent[19]. A l'échelle d'une unique ferme éolienne, l'affirmation est assurément fausse. Comme les producteurs éoliens mettront leur production aux enchères de manière individuelle, il pourrait être difficile de s'assurer que ces enchères s'appuient sur des ressources suffisantes et que le système ne risque pas d'être perturbé si une ferme éolienne achète de l'électricité produite ailleurs lorsqu'il n'y a pas de vent.

Un rapport de l'Electric Power Research Institute (2008) établit qu'il existe « deux angles d'attaque pour résoudre le problème de l'intermittence. D'une part, il s'agit de concevoir des systèmes de prévision de vent plus puissants et plus précis, applicables au niveau d'une région et d'une centrale, pour obtenir des estimations plus fines des variations horaires, pour la journée en cours et le lendemain, de la vitesse du vent et de la production d'énergie possible. D'autre part, il faut, en s'appuyant sur les observations et les prévisions de vent, mieux intégrer l'éolien à l'utilisation des autres modes de production et solutions de gestion de la demande d'énergie lorsqu'il s'agit d'assurer la stabilité du système et le réglage de la fréquence. Dans la mesure où un réseau intelligent permettrait de recourir aux services système pour équilibrer les ressources éoliennes intermittentes, il est raisonnable d'imputer une part de la pénétration de l'éolien sur le marché à l'émergence d'infrastructures de réseaux intelligentes » (p. 9-2). Pollitt et Bialek (2009) suggèrent : « Les futurs réseaux devront être gérés de façon plus active puisque la variabilité des énergies renouvelables le nécessite. (…) L'incertitude quant aux moment, au volume et au lieu de production d'électricité renouvelable complique également la planification du développement des réseaux et a des conséquences pour la réglementation. »

« La production des centrales éoliennes est variable, mais cette variabilité peut être prévue dans une large mesure, ce qui ne veut pas dire, pour autant, qu'elle n'a aucun effet sur l'exploitation du système. Elle en a un, en particulier quand l'éolien satisfait une forte proportion de la demande » (EWEA, 2005). Les prévisions de vent sont beaucoup plus précises à quelques heures qu'à vingt-quatre heures. Autrement dit, sur les marchés de l'énergie libéralisés, les enchères sont pénalisantes pour les éoliennes si elles ont lieu la veille pour le lendemain plutôt que quelques heures à l'avance seulement.

18 Selon l'EWEA : « Il est parfois dit à tort que l'énergie éolienne est non fiable par nature car variable. Or, les systèmes électriques – du côté de l'offre comme de la demande – sont fondamentalement variables et soumis à un grand nombre de facteurs, prévus et imprévus. Du fait des variations météorologiques, des millions de gens allument ou éteignent leurs appareils de chauffage, d'éclairage, etc., par exemple en cas d'orage soudain. En Europe, des millions de personnes allument ou éteignent des appareils nécessitant une alimentation immédiate – lampes, téléviseurs, ordinateurs. Les centrales, les équipements et les lignes de transport tombent en panne à intervalles irréguliers, ou pâtissent de conditions météorologiques extrêmes telles que la sécheresse qui touche durement les centrales hydrauliques et nucléaires. Des arbres s'abattent sur les lignes à haute tension, le gel provoque des coupures de courant soudaines. Pour maintenir l'intégrité du système, le gestionnaire de réseau doit équilibre les variations, prévues et imprévues, d'une offre et d'une demande constamment fluctuantes. » (EWEA, 2005)

19 Wolak (communication OCDE) indique que le 24 juillet 2006, lors d'une vague de chaleur ayant frappé la Californie, la demande dans la zone de réglage du *California Independant System Operator* a atteint le pic, observé une fois tous les cinquante ans seulement, de 50 200 MW, mais que la production éolienne ne fonctionnait qu'à 5 % de sa puissance à ce moment-là.

« Cependant, à mesure que la proportion d'électricité éolienne injectée sur le réseau augmente, de nouveaux problèmes apparaissent. Initialement conçu pour les centrales électriques classiques, le réseau n'est pas encore totalement adapté aux niveaux de puissance prévus pour l'éolien, pas plus que ne le sont sa conception et son exploitation. Jusqu'à présent, l'adaptation a été ralentie par des problèmes de planification, des obstacles administratifs, le manque d'adhésion du public, l'insuffisance des incitations économiques offertes aux gestionnaires de réseaux et aux investisseurs pour qu'ils entreprennent des projets concernant les réseaux de transport (…) et des démarches parcellaires des principales parties prenantes » (EWEA, 2009b, p. 16).

Les niveaux de production des sites éoliens d'une même région sont étroitement corrélés si les sites sont proches les uns des autres, et le sont moins (tout en le restant) si les sites sont plus éloignés. Cette interdépendance signifie que, si la production d'un site est faible, la production des autres sites sera sans doute limitée elle aussi. La question se pose donc, quand on conçoit un réseau dont on attend un haut niveau de fiabilité, de savoir quelle part de la puissance totale maximale attribuer aux énergies renouvelables. « Dans le pire des cas, les centrales qui exploitent des énergies renouvelables injectent de l'électricité sur le réseau sans pour autant contribuer à augmenter la capacité de ce réseau, parce qu'elles ne produisent pas assez pendant les pointes du fait de la variabilité de leur production. La disponibilité de l'énergie solaire au Royaume-Uni en est un bon exemple : il a été démontré que la production des centrales solaires en période de forte demande est nulle, donc qu'elle ne peut pas venir au secours des moyens de production classiques (UKERC, 2006) » (Sinden, 2009, p. 151). Toujours selon Sinden, si l'éolien assure 10 % de la production, on peut lui accorder un crédit d'environ 25% de la capacité, tandis que s'il représente 25 % de la production totale il faut ramener ce crédit à 20%, du fait des incertitudes accrues concernant la possibilité pour le réseau de fournir la totalité de l'électricité prévue (Sinden, 2009, p. 152).

Encadré 1. L'éolien au Danemark et dans d'autres pays européens

Cet encadré présente des exemples d'exploitation de l'énergie éolienne en Europe tels que rapportés par l'European Wind Energy Association (EWEA). Selon ces informations, un fort pourcentage d'éolien pourrait être intégré aux réseaux électriques, sous réserve que les conditions réglementaires et opérationnelles appropriées existent.

« Au Danemark, le pays du monde où la part de marché de l'éolien est la plus élevée, cette énergie a permis de satisfaire 21 % de la demande totale en 2004. Sur le réseau de transport de l'ouest du pays, qui n'est pas connecté à celui de la partie orientale, l'électricité éolienne satisfait environ 25 % de la demande annuelle d'électricité dans des conditions de vent normales et, dans certains cas, elle a pu couvrir 100 % de la demande instantanée. L'intégration d'une forte composante éolienne est souvent jugée impossible, et de nombreux gestionnaires de réseaux rechignent à modifier des procédures établies de longue date pour les adapter à l'éolien. Le gestionnaire danois était initialement sceptique quant à la puissance éolienne que le système pouvait absorber. Les propos qu'Eltra, gestionnaire du réseau de transport de l'ouest du Danemark, a tenus à l'occasion de la présentation de son rapport annuel illustrent on ne peut mieux l'attitude de la plupart des gestionnaires de réseaux vis-à-vis de l'éolien :

« Depuis la fin de 1999 – donc en tout juste trois ans – la puissance installée éolienne du système Jutland-Fyn est passée de 1110 à 2400 MW. (...) Il y a sept ou huit ans, nous avions déclaré que le système électrique ne pouvait pas fonctionner si l'éolien dépassait la barre des 500 MW. Aujourd'hui, nous gérons près de 5 fois cette puissance. J'aimerais dire au gouvernement et au Parlement que nous sommes prêts à en gérer encore plus, à condition d'être autorisés à utiliser les bons outils de gestion du système. »

Dans la zone de desserte occidentale d'Energinet (anciennement d'Eltra), l'électricité éolienne satisfait environ 25 % de la demande annuelle d'électricité, dans des conditions de vent normales, et sa gestion n'est plus un problème technique – mais un problème réglementaire. Les outils permettant de gérer une capacité de production éolienne plus importante sont développés, et les gestionnaires de réseaux devraient être autorisés à les utiliser. En définitive, l'expérience de l'éolien des zones espagnoles, danoises et allemandes qui ont une forte composante éolienne révèle que la question de la puissance renouvelable maximale qu'il est possible

d'introduire dans les systèmes électriques existants ne sera pas une question d'ordre technique, mais une question d'ordre économique et réglementaire.

Les pays d'Europe où le développement de l'éolien est encore balbutiant pourraient tirer de nombreux enseignements des expériences danoise, allemande et espagnole. Cependant, il importe que les parties prenantes, les décideurs et les autorités de régulation de ces marchés émergents comprennent que les situations nouvelles auxquelles doivent faire face les gestionnaires de réseaux de transport de ces pays ne deviendront pas un problème tant que la puissance éolienne raccordée aux réseaux électriques n'a pas atteint un niveau beaucoup plus important » (EWEA, 2005, p. 10).

Du point de vue de la concurrence, l'introduction de nouveaux modes de production peut limiter les phénomènes de concentration, donc favoriser des schémas de production plus efficients. Mais elle pourrait offrir à un petit nombre de fournisseurs la possibilité de facturer des prix extrêmement élevés lorsque les pointes de demande coïncident avec les creux de la production renouvelable.

La réglementation applicable à l'exploitation des réseaux électriques et l'activité des gestionnaires de réseaux de transport (GRT) détermine largement les possibilités d'intégrer des moyens de production éoliens ou solaires à un réseau électrique. Dans la plupart des pays, cette réglementation a été établie dans l'optique d'une production d'électricité non intermittente. Elle pourrait donc avoir pour effet d'exclure la production éolienne ou d'en augmenter ses coûts de façon non nécessaire. Par essence, elle constitue une forme de règle d'accès au marché. Il pourrait être nécessaire de la modifier pour favoriser une pénétration plus importante de l'éolien sans compromettre la sûreté, la stabilité et la fiabilité des réseaux.

Une meilleure gestion de la demande serait également un moyen de gérer la variabilité accrue de l'offre que l'intégration de moyens de production éoliens et solaires entraîne.

2.4 Gestion de la demande

La qualité du réseau pourrait pâtir de l'augmentation de la production intermittente des centrales fonctionnant avec des énergies renouvelables[20]. Mais le basculement sur un autre moyen de production[21] n'est pas le seul recours possible pour compenser une hausse ou une baisse de production inattendue. Gérer la demande en est un autre. Par exemple, si la production d'électricité chute parce que la vitesse du vent est plus faible que prévu, on peut rééquilibrer l'offre et la demande en réduisant la demande. Il s'agit, en d'autres termes, d'inciter le client moins consommer que prévu, en réponse à un signal qui peut être un changement de prix ou un message. Il existe deux types de gestion de la demande : l'effacement piloté ou et l'effacement volontaire.

- *Effacement piloté* : L'entreprise d'électricité peut directement piloter les appareils des consommateurs, par exemple les climatiseurs, et les arrêter, le cas échéant. Cette entreprise peut

20 Selon Crosswinds, qui a effectué des simulations pour étudier le problème de la congestion en Europe : « Les erreurs de prévision de la production éolienne pourraient avoir un impact sur les transits transfrontaliers horaires. Les résultats des simulations montrent que les écarts entre les transits réels et prévus avoisinent le plus souvent 20 % de la capacité de transit des lignes. A l'évidence, une telle situation agraverait les risques de congestion de certaines liaisons transfrontalières. Les simulations effectuées pour 2015 indiquent que les différents scénarios de la puissance installée éolienne ont un impact limité sur les incertitudes relatives au transits transfrontaliers. Néanmoins, les résultats montrent que les effets des erreurs de prévision de la production éolienne devraient être pris en compte dans les études d'intégration à grande échelle » (EWEA, 2009b, p. 80).

21 La gestion immédiate de l'offre peut consister à utiliser une capacité de réserve, par exemple production hydroélectrique classique ou pompage-turbinage.

aussi avoir conclu des accords avec ses clients pour qu'ils réduisent leur consommation lorsqu'elle reçoit certains signaux concernant la fiabilité ou la rentabilité du réseau.

- *Effacement volontaire* : Le client réagit à des signaux de prix et peut décider de modifier ou non sa demande et la façon de le faire. Par exemple, si les clients réduisent leur consommation parce que le prix de l'électricité est plus élevé, ils s'effacent volontairement[22].

En principe, il n'existe pas de grandes différences entre ces deux formes d'effacement. La modification de consommation est, dans un cas, requise par un contrat à long terme (avec incitation tarifaire) et, dans l'autre cas, motivée par une variation de prix sans obligation contractuelle pour le client. Mais comme l'élasticité-prix de la demande est négative à court et à long terme, comme on va le voir, une hausse du prix de l'électricité à tout moment devrait s'accompagner d'une baisse de la consommation par rapport à son niveau prévu.

Des programmes existent déjà dans de nombreux pays, en particulier pour favoriser l'effacement piloté. Le tableau 4 décrit la situation dans quelques pays où des programmes d'effacement de la demande ont été mis en place.

Tableau 4. Programmes d'effacement de la demande dans quelques pays

Pays	Expérience
Italie	- L'Italie est le pays européen où les compteurs avancés sont le mieux implantés puisqu'ils représentent près de 90 % de la totalité. - Les programmes d'effacement ne s'appliquent qu'aux très grandes entreprises manufacturières. - Existence de tarifs horosaisonniers.
Espagne	- Les gros consommateurs sont déjà soumis à des mécanismes de gestion directe de la charge quand des déséquilibres physiques apparaissent. - Application de tarifs hororsaisonniers. - Le pays envisage de créer un marché spot de l'effacement où les participants seraient payés le prix spot quand ils s'effacent.
Royaume-Uni	- Les clients industriels et les gros consommateurs du tertiaire peuvent négocier des contrats avec effacement ou des tarifs horosaisonniers. - Près de 4.5 millions de clients bénéficient d'un tarif multiple, par exemple d'un tarif spécial pour la nuit. - Quelque 10 000 ménages ont participé à des essais de facturation dans le cadre d'un projet pilote. - Une étude réalisée pour le ministère des Affaires économiques, des entreprises et de la réforme réglementaire donne une valeur actualisée nette négative pour le déploiement de compteurs « intelligents ».
Etats-Unis	- La plupart des opérateurs sont régionaux et beaucoup ont négocié des contrats d'effacement avec leurs clients industriels et leurs gros consommateurs du tertiaire. - La Géorgie est l'État qui possède la plus longue expérience en matière de systèmes de tarification innovants. Aujourd'hui, un tiers de l'électricité produite est vendue suivant un barème de tarifs variables. - La gestion de la demande est officiellement entrée dans la loi en 2005, avec le vote de l'Energy Policy Act.

Source : Torriti, Hassan et Leach (à paraître) + auteur.

22 La gestion de la demande peut aussi prendre la forme d'une hausse de la consommation suite à une baisse des prix. De nombreux clients qui ont adhéré à un système de gestion de la demande volontaire, tel qu'une tarification horaire comprenant un tarif heures pleines et un tarif heures creuses, choisissent de reporter une partie de leur consommation (fonctionnement d'un chauffe-eau électrique, par exemple) d'un moment de la journée à un autre.

Les deux principes de l'effacement piloté et de l'effacement volontaire seront examinés l'un après l'autre.

2.4.1 Effacement piloté

Les gestionnaires de réseau peuvent généralement contrôler directement la mise en service ou l'arrêt des centrales connectées au réseau de transport. Ce moyen de contrôle direct est nécessaire pour maintenir l'équilibre du réseau. Comme les quantités d'électricité produites et consommées doivent toujours être égales et qu'il est très difficile de stocker l'électricité, les problèmes de concurrence se posent à des niveaux de concentration plus bas que dans d'autres secteurs, en particulier lorsqu'il s'agit de satisfaire la demande de pointe.

Pour garantir l'alignement de la demande sur l'offre, de nombreux gestionnaires de réseau (ou intermédiaires chargés de regrouper le scharges) ont négocié avec de gros consommateurs ou des groupes de consommateurs moyens des contrats prévoyant la vente d'électricité à un tarif avantageux contre la possibilité pour le gestionnaire de contrôler la consommation du client : ainsi, en période de pointe, le gestionnaire peut imposer une réduction de la consommation ou un effacement. Ces contrats existent dans de nombreux pays. S'ils n'impliquent pas nécessairement la transmission des signaux de prix aux utilisateurs finals, le gestionnaire aura néanmoins tendance à prendre la décision de réduire ou d'interrompre la consommation d'un client donné en fonction de considérations liées à la demande et aux prix.

Cet effacement piloté est séduisant en principe, mais parfois difficile à mettre en œuvre. Lorsque les premières pénuries d'électricité sont apparues en Californie en 2000-2001, les gros clients qui avaient opté pour des programmes avec effacement ont été appelés à réduire leur consommation de façon répétée. « Les programmes, auxquels avaient adhéré un grand nombre de clients, représentaient à peu près 5 % de la demande de pointe. En 2000, les programmes d'effacement[23] et de contrôle direct de la charge (de deux opérateurs) correspondaient à une capacité d'effacement d'environ 2400 MW et 300 MW, respectivement. Avant 2000, ils étaient rarement utilisés. Comme la Californie disposait de réserves de puissance importantes, ils étaient considérés comme une « police d'assurance ». Pendant l'année 2000, les programmes de gestion de la charge des compagnies d'électricité ont largement contribué à la fiabilité du réseau et ont permis d'éviter des coupures tournantes à plusieurs reprises. (…) Les 8 derniers mois de l'année 2000, les clients qui avaient souscrit des contrats d'effacement se sont vus demander 23 fois de réduire leur consommation, et ont ainsi libéré jusqu'à 2200 MW (CAISO, 2001a). Au cours de cette période, les programmes d'effacement ont permis d'éviter l'écroulement du réseau à 5 reprises au moins. (…) » Les clients ayant souscrit des contrats d'effacement ont pu quitter le programme. « Après l'expérience de 2000, un certain nombre de clients ont abandonné le programme d'effacement. A l'été 2001, des clients représentant 20% du potentiel de réduction de la charge du programme de PG&E et 55 % de celui du programme de SCE avaient choisi de changer de contrat, entraînant un recul de la capacité d'effacement totale à environ 1200 MW (CPUC, 2001b ; Wallenrod, 2001) » (Glodman et al., 2007). Cette expérience a ainsi démontré que le fait d'autoriser les clients à modifier leur contrat pendant une pénurie d'électricité peut dérégler les mécanismes de maîtrise de la demande. Attendu que les pénuries de l'offre peuvent durer plus d'un an, comme en Californie, des contrats de 12 mois paraissent trop courts pour garantir la participation d'une offre suffisante au programme d'effacement. Même si les options

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[23] « Les clients ayant souscrit un contrat avec effacement ont accepté de réduire leur consommation jusqu'à un niveau de puissance garanti, sur demande de leur compagnie d'électricité en cas d'urgence, pendant un nombre limité d'heures par an (100 à 150 selon le fournisseur). En échange, ils ont bénéficié d'importantes baisses de tarif (~15 %) sur leur consommation « non garantie » (au dessus du niveau garanti) » Goldman et al. (2007).

contractuelles sont bien conçues, il pourrait s'avérer difficile d'appliquer les clauses de ces contrats du fait des exigences politiques de protection des consommateurs.

Les systèmes d'effacement piloté peuvent substantiellement réduire la demande. A long terme, la communication directe avec les consommateurs, via des mécanismes tels que la tarification en temps réel, pourrait être plus avantageuse, comme nous allons le voir.

2.4.2 Signaux de prix (effacement volontaire)

Les signaux de prix sont un moyen efficient de stimuler la gestion de la demande, puisqu'ils visent à aligner les coûts que doivent payer les consommateurs sur les coûts d'exploitation du système en temps réel.

Jusqu'à présent, les tarifs appliqués ont toujours été très stables et ont pris la forme soit d'un tarif unique par kilowattheure, soit d'un double tarif pour les heures pleines et les heures creuses. Tandis que les prix de détail, ceux que payent la clientèle résidentielle notamment, sont stables, les prix de gros varient d'un jour à l'autre et d'une heure à l'autre – voire plus souvent encore. Quand l'électricité est relativement rare, les prix de gros augmentent substantiellement. Si les industriels peuvent avoir à payer des prix très variables qui reflètent les fluctuations des prix de gros, la plupart des consommateurs ne perçoivent pas cette variabilité des prix.

La relation, en général ténue, entre les coûts (représentés par les prix de gros) et la demande horaire est un curieux vestige du temps où la production d'électricité était réglementée et aux mains de l'État. En période de pointe, les clients paient un prix inférieur au coût de l'électricité qu'ils consomment, ce qui favorise une surconsommation à ces périodes.

Cette quasi-déconnexion entre les prix de détail et les prix de gros a l'avantage de simplifier le système de facturation et de stabiliser les prévisions des coûts (pour les consommateurs) et de la demande (pour les gestionnaires de réseaux). Mais elle a l'inconvénient de décourager les formes innovantes de gestion de la demande. Il est peu probable que les clients gèrent activement leur consommation au fil de la journée. Mais ils pourraient programmer des dispositifs automatisés pilotant le fonctionnement des appareils. Ce principe d'automatisation de la gestion pourrait prendre les formes suivantes :

- le réglage des climatiseurs à une température plus élevée pendant les périodes de pointe (d'où une baisse de la consommation d'électricité pendant ces périodes) ;
- la mise en route de certains appareils (lave-vaisselle, par exemple) quand le prix de l'électricité est bas ;
- une centrale de gestion des appareils électriques chez les particuliers (par exemple, par panneau de commande informatisé et communication sans fil avec les appareils), qui mette sous/hors tension ou commande une baisse de la consommation pendant les périodes de pointe, afin de reporter la consommation sur d'autres périodes.

Du fait de l'absence d'incitation financière de nature à encourager une forte proportion de consommateurs à mieux gérer leurs coûts, de nombreuses innovations qui permettraient de réduire la demande d'électricité en période de pointe et d'en reporter une partie sur les périodes creuses ne sont pas pas installées ou ne voient tout simplement pas le jour.

Cette déconnexion systématique entre prix et les coûts réels est une bizarrerie économique. Sur d'autres marchés, les prix de détail contribuent à l'équilibre entre l'offre et la demande. Quand les prix sont

plus élevés, les clients répondent en réduisant leur demande (élasticité-prix de la demande), et les fournisseurs répondent en augmentant leur offre. Les signaux de prix peuvent équilibrer les marchés même quand les prix varient en continu, comme ils le font sur les marchés boursiers.

La mise en place, sur les marchés de l'électricité, d'une tarification en temps réel serait un moyen de s'assurer que les clients tiennent davantage compte des coûts de l'électricité qu'ils consomment et des avantages qu'ils en retirent[24]. Mais la réactivité des clients peut être encouragée par d'autres méthodes que la tarification en temps réel de l'électricité consommée : les électriciens peuvent indemniser les clients qui réduisent leur consommation, ou autoriser des clients à revendre la puissance électrique qu'ils ne consomment pas (ce qui revient à dire qu'un tiers les paie pour qu'ils réduisent leur consommation).

Les programmes d'effacement de la demande ne sont pas gratuits. Dans la mesure où l'effacement d'une clientèle (résidentielle, par exemple) a davantage d'effet que celui d'une autre (entreprises) et où l'investissement par kWh économisé serait inférieur pour les gros consommateurs, il pourrait être intéressant de destiner ce type de contrats à la clientèle dont le comportement a le plus d'effet sur la courbe de charge. L'encadré 2 explique pourquoi une approche axée sur les seuls gros clients pourrait générer la majorité des bénéfices, même si ces clients représentent au plus un tiers de la consommation totale d'énergie : du fait de la raideur des pentes des courbes de l'offre et de la demande, l'ajout d'autres clients a un impact marginal plus faible. Pourtant, l'extension des programmes d'effacement de la demande est très fréquente en ce moment.

Encadré 2. Effacement de la demande : d'où viennent les bénéfices ?

La figure 6 illustre l'impact de la gestion de la demande aux prix et aux volumes de l'électricité. La courbe de l'offre augmente d'abord très lentement puis rapidement, avec l'ajout de technologies de production plus coûteuses. La pente devient très raide lorsque l'on atteint la capacité maximale. Or ces contraintes sont pour ainsi dire insurmontables, car il est très difficile d'augmenter l'offre quand toutes les centrales disponibles sont en fonctionnement et que la congestion empêche d'importer de l'électricité de régions voisines.

Les droites notées D correspondent à différents états de la demande. Quand la demande ne réagit pas du tout au prix (par exemple, prix de détail fixe pour tous les consommateurs), la droite est verticale, c'est-à-dire totalement inélastique, c'est le cas de figure représenté par la droite D_0. Plus l'on met en place des programmes tarifaires et de gestion de la demande, plus la droite oblique. La droite D_1 illustre l'état possible de la demande quand les gros clients sont soumis à une tarification en temps réel. La pente est négative, car l'augmentation des prix fait baisser la demande. Si le nombre de clients soumis à la tarification en temps réel ou à des mesures de substitution, la demande réagit d'autant plus aux prix, comme l'illustre la droite D_2. Dans ce cas, les gros clients et les autres sont soumis à un système de tarification en temps réel ou à d'autres méthodes de gestion de la demande.

Pour résumer, les trois courbes de la demande illustrées à la figure 6 sont les suivantes :

D_0 – demande inélastique ;

D_1 – demande élastique pour les gros clients, inélastique pour le secteur résidentiel et les petits consommateurs ;

D_2– demande élastique pour les gros clients, élastique pour le secteur résidentiel et les petits consommateurs.

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24 Selon Borenstein (2007), l'un des sujets d'inquiétude concernant la tarification en temps réel est le « risque de volatilité du prix payé par le consommateur final ». Cet argument est souvent cité en rapport avec les coûts que devrait payer le consommateur à une heure où le prix atteindrait un pic extrême, par exemple 10 000 USD/MWh. Borenstein montre que, pour 1142 gros clients industriels, « des stratégies de couverture simples permettent de se prémunir contre plus de 80 % de la volatilité des prix ».

L'équilibre entre l'offre et la demande est atteint à des points différents selon la courbe de la demande. Quand la courbe de la demande est la droite verticale D_0, la puissance fournie est de 65 GW et le prix est de 680 EUR/MWh.

Quand on introduit un petit pourcentage de gestion de la demande, comme illustré par la droite D_1, le prix chute de 41 % à 400 EUR/MWh, alors que la puissance ne diminue que de 8 %.

Si l'élasticité de la demande augmente encore (extension de la tarification en temps réel au secteur résidentiel, par exemple), la droite de la demande devient la droite D_2, et le prix baisse encore de 20 % à 320 EUR/MWh pour une réduction de la puissance d'environ 3 %.

Le point à retenir est donc que, pour les courbes illustrées ici (et peut-être dans des situations plus réalistes), la majeure partie de la gestion de la demande est obtenue du groupe le plus facile à cibler, c'est-à-dire des gros consommateurs. Les bénéfices de l'ajout des petits consommateurs tels que les ménages sont graphiquement représentés par les aires B et C. L'aire A correspond aux bénéfices générés dans tous les cas. Avant de déployer des compteurs intelligents, il faut donc étudier les avantages de ces investissements[25]. Les facteurs à considérer dans le cadre d'une telle étude seraient non seulement les coûts de déploiement des compteurs intelligents et les bénéfices directs pour les consommateurs représentés par les courbes de la demande de la figure 6, mais aussi les bénéfices indirects générés par les externalités, comme la diminution des rejets de CO_2 après l'installation de compteurs intelligents, ou l'accroissement de la capacité de production éolienne ainsi rendue possible[26].

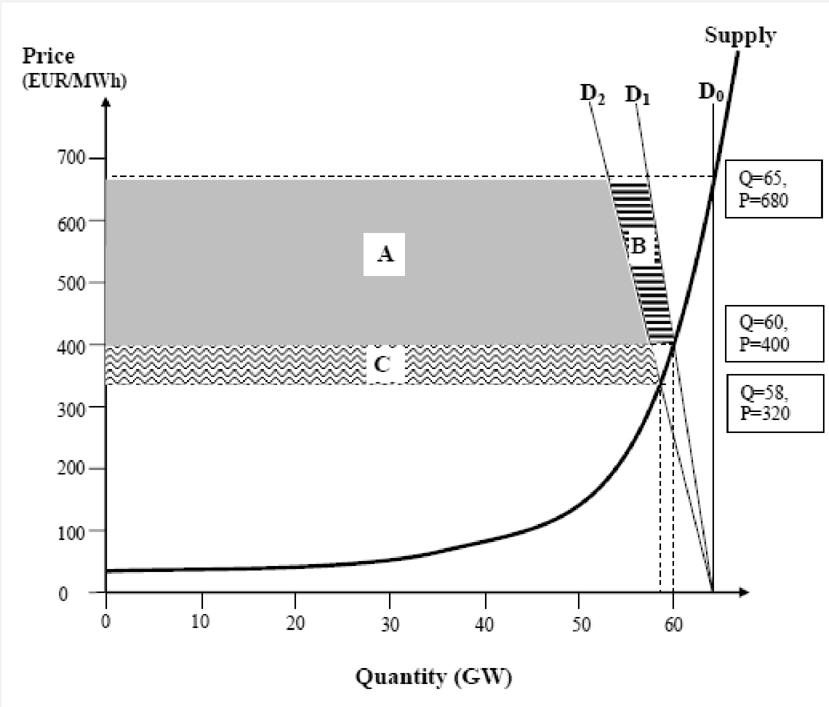
Selon Borenstein (2005), la tarification en temps réel n'abaissera que de 5 % le coût de l'électricité, soit moins que ce que l'on aurait pu espérer[27].

25 Selon Brennan (2004), « les politiques visant à promouvoir le comptage en temps réel ne doivent pas seulement démontrer l'intérêt d'une réponse plus rapide aux variations des coûts. Il faut qu'il existe des externalités positives suggérant que les transactions privées ne permettraient pas d'installer suffisamment de compteurs ». Les bénéfices d'une réactivité accrue de la demande ont été estimés notamment par le GAO (2004), Walter *et al*. (2004) et Borenstein et Holland (2005).

26 La tarification en temps réel n'induira pas nécessairement une réduction des émissions de CO_2. Elle entraînera une baisse des prix. Certaines études (par exemple, projet *Gridwise Olympic Peninsula* décrit plus loin) montrent que la tarification en temps réel peut déboucher sur une augmentation de la consommation totale d'électricité (dans ce cas, de 4 %). Voir Holland et Mansur (2008) : selon leur analyse, la tarification en temps réel réduirait les concentrations de polluants et de CO_2 là où la demande de pointe est satisfaite par des centrales thermiques au fioul plutôt que par des centrales hydrauliques, mais elle les aggraverait, bien que dans de faibles proportions, dans le cas contraire.

27 « … dans un système électrique qui doit toujours être prêt à satisfaire l'intégralité de la demande au prix de détail, le coût d'une structure de prix constante équivaut à la nécessité de conserver une capacité importante mais rarement utilisée. Pour optimiser leur production, les électriciens construisent des « centrales de pointe » aux coûts en capital faibles mais aux coûts d'exploitation élevés. Le coût social du maintien en service de cette capacité sous-exploitée est finalement plus faible qu'on pourrait croire » (Borenstein, 2009).

Figure 6. Effets d'une augmentation de la gestion de la demande



Légende du graphique : Price = Prix ; Supply = Offre ; Quantity = Puissance

La gestion de la demande peut se révéler particulièrement important si, comme le suggère Kwoka (2008), il existe d'importantes barrières à l'entrée du marché de la production d'électricité s et si l'on ne construit pas suffisamment de moyens de production. Selon l'EIA[28], la marge de réserve devrait tomber à respectivement 5.1 %, 7.5 % et 8.0 % dans les zones d'intervention de l'ERCOT, de la MRO et du NPCC (États-Unis). Autrement dit, si les investissements, notamment dans les centrales en base, n'augmentent pas, des pénuries sont susceptibles d'apparaître à moyen terme dans plusieurs régions des États-Unis.

2.4.3 Réseaux intelligents

En transformant les réseaux électriques en systèmes de communication bidirectionnels avec actualisation permanente des informations sur les prix et la consommation, les nouveaux outils et technologies dits « de réseaux intelligents » peuvent favoriser l'élasticité de la demande en temps réel et la décentralisation de la production d'électricité. Grâce à ces nouveaux outils et technologies, les réseaux seraient mieux à même de gérer l'électricité renouvelable, et notamment la production variable de certaines centrales. Deviennent ainsi techniquement réalisables :

- la différentiation des prix en temps réel en fonction du lieu et de l'heure, pour inciter les clients à réduire leur demande ou à consommer de l'électricité à d'autres moments ;
- la télécommande des appareils électriques, pour que les clients ou les fournisseurs puissent s'effacer ou reporter une partie de leur consommation en réponse aux signaux du marché ;

28 Electric Power Annual 2006, tableau 3.3.

- l'injection d'électricité dans le réseau par les consommateurs ou les producteurs possédant par exemple des petites unités de production solaire ou éolienne ;

- des mécanismes de facturation et de paiement en temps réel, qui permettent de suivre les profils de consommation ou de production au cours du temps, et de communiquer ces informations à distance ;

- des dispositifs mesurant les quantités d'électricité soutirées du réseau par les clients, mais aussi injectées dans le réseau par les unités de production des clients.

Dans le contexte de ce document, toutes ces technologies seront appelées « technologies de réseaux intelligents ». Leur déploiement nécessiterait des investissements considérables, mais pourrait transformer les réseaux électriques existants et permettre la communication bidirectionnelle.

Ces technologies ne sont pas encore très utilisées dans la plupart des pays, mais l'élaboration des normes s'intensifie. Les réseaux intelligents devraient être déployés à court ou à moyen terme sur un certain nombre de marchés, en particulier dans les pays dont les pouvoirs publics soutiennent le plus activement les projets de réseaux intelligents. Les normes élaborées pour ces réseaux et les réglementations (ou la jurisprudence) qui régissent les interfaces entre clients, détaillants, distributeurs, producteurs, et dispatcheurs auront un impact déterminant sur la nature des marchés de l'électricité de demain.

Les technologies de réseaux intelligents peuvent contribuer à maintenir l'équilibre nécessaire entre la production et la consommation d'électricité quand on utiliser des énergies renouvelables, et cela pour les raisons suivantes :

- avec les réseaux intelligents, la demande peut réagir en temps réel aux modifications de l'offre, de qui permet d'écrêter les pointes de la demande ;

- les réseaux intelligents peuvent modifier le rapport entre l'offre et la demande en activant la production décentralisée de petits consommateurs contribuant pour augmenter l'offre de pointe.

Les données empiriques montrent que le lissage de la demande d'électricité peut avoir d'importantes répercussions sur le plan économique. Faruqi et Sergici (2009) ont étudié 15 récentes expériences de tarification dynamique et constatent que les ménages réagissent à une hausse des prix en réduisant leur consommation. L'amplitude de la réaction dépend de plusieurs facteurs, notamment l'existence ou non dans le logement d'un système central de climatisation ou de thermostats télécommandés. L'application de tarifs horosaisonniers induit une baisse de 3 à 6 % de la demande en période de pointe, l'application du tarif de pointe critique provoque un recul de 13 à 20 % de cette même demande et le déploiement des nouvelles technologies, thermostats intelligents par exemple, fait chuter de 27 à 44 % la demande lors des pointes critiques. Après examen d'études menées entre 2003 et 2006, Kiesling (2009) rapporte que les estimations de l'élasticité-prix de la demande des clients résidentiels se situent entre -0.035 et -0.17. Ces chiffres sont plutôt faibles si on les compare à ceux de la plupart des autres secteurs. Mais comme les prix aux heures de pointe ont parfois 100 à 200 fois supérieurs aux prix aux heures creuses[29], ces petites élasticités peuvent néanmoins avoir un impact important sur la quantité d'électricité demandée.

29 Voir Brennan (2004), p. 121.

Encadré 3. Projet de démonstration GridWise Olympic Peninsula

De nombreux projets de démonstration ont été réalisés pour tester l'impact de la tarification en temps réel ou de mécanismes similaires sur les clients résidentiels. Cet encadré décrit un projet récent.

Dans l'Olympic Peninsula de l'État de Washington, aux États-Unis, 130 foyers équipés du haut débit et d'un chauffage électrique ont participé à une étude entre avril 2006 et mars 2007. Au début du projet, toutes les habitations étaient équipées de connexions haut débit et d'appareils de chauffage électrique. Les ménages ont reçu un thermostat de contrôle doté d'une interface utilisateur qu'ils pouvaient programmer, s'ils le souhaitaient, en réponse aux signaux de prix. Ont aussi été installés des appareils, tels que des chauffe-eau, dotés de puces de commande permettant la réception des signaux de prix et la modification du mode d'utilisation en réponse à ces signaux.

Trois options de tarification ont été proposées aux ménages :

- simple tarif ;
- contrat à tarif horosaisonnier avec pointe critique variable appelable en période de pointe ;
- contrat à tarif en temps réel reflétant les prix de gros par tranches de cinq minutes.

Un certain nombre de résultats préliminaires ont été obtenus :

- Dans le groupe ayant souscrit des contrats à tarif en temps réel, la consommation de pointe a diminué de 15 à 17 % par rapport la valeur qu'elle aurait atteint avec un prix fixe. La consommation d'énergie totale a néanmoins augmenté de 4 % (une manifestation du fait que le tarif en temps réel multiplie les périodes de la journée où les prix sont bas).

- Dans le groupe ayant souscrit des contrats à tarifs horosaisonniers, l'élasticité-prix directe de la demande, calculée à partir de données horaires, était égale à -0.17. La consommation totale était inférieure de 20 % à celle du groupe qui avait opté pour un simple tarif.

Pour plus d'information, voir Hammerstron *et al*. (2007) et Kiesling (2009).

Les possibilités offertes par les réseaux intelligents sont les suivantes :

- augmentation de l'élasticité de la demande, en particulier grâce au déploiement d'appareils intelligents ;

- accès à un nouveau et important moyen de stockage (batteries de voiture) ;

- souplesse de la gestion de l'offre grâce aux unités de production des clients et au recours au stockage ;

- signaux de prix en temps réel permettant d'influer sur la demande et sur l'offre.

Grâce aux réseaux intelligents, les marchés de l'électricité pourraient être plus concurrentiels. Dans le même temps, les réseaux électriques seraient suffisamment soupes pour s'adapter aux profils de production variable des centrales fonctionnant avec des énergies renouvelables, comme l'éolien et le solaire.

S'agissant des compteurs intelligents, les difficultés viennent du fait que leur installation coûte cher et que les clients résidentiels s'y intéressent, en général, peu. Dans l'État américain du Maryland, par exemple, 2 % des clients résidentiels ont choisi de renoncer au simple tarif tandis que 94 % des gros clients

ont fait ce choix (Brennan, 2008). Si ces chiffres sont représentatifs, ils suggèrent que les efforts entrepris pour inciter les petits consommateurs à participer au marché de l'électricité ne réussiront pas à susciter leur intérêt ou à les inciter à prendre leur sort en mains. Il est possible que la clientèle ne souhaite pas investir dans la gestion de sa consommation d'électricité. Mais elle pourrait aussi changer de comportement et gérer activement sa consommation quand les incitations de prix seront réelles, comme cela s'est produit sur le marché des télécommunications.

2.5 Mécanismes non conventionnels de gestion de l'offre

Pour compenser la variabilité de la production d'électricité renouvelable, on devrait pouvoir utiliser, outre la gestion de la demande, de nouvelles formes de gestion de l'offre. En effet, les réseaux intelligents permettent d'envisager une production répartie[30]. A l'avenir, les clients installeront de plus en plus souvent des unités de production solaire voire, dans certains cas, éolienne. Ils pourront consommer eux-mêmes l'électricité produite. Mais, dans les systèmes où cette production décentralisée peut être injectée sur le réseau, ils vendre la puissance excédentaire produite[31]. Des normes ont été élaborées pour permettre cette vente d'électricité au réseau.

Si, pour l'instant, la plupart des clients ne possèdent pas de moyens de production importants, un nouveau type d'offre pourrait jouer un rôle primordial avec le temps, quoique l'approche n'ait pas encore fait ses preuves. Il s'agirait d'utiliser les batteries des véhicules hybrides rechargeables (VHR) comme réserve de production d'électricité (voir EPRI, 2008, p. 9-4). Les batteries pourraient être chargées pendant les périodes de production en base (la nuit, par exemple, quand la consommation est faible) et servir de source d'électricité quand la demande est plus forte et que le véhicule n'est pas utilisé. La généralisation des VHR à batteries perfectionnées et leur branchement au réseau pourrait aussi entraîner une augmentation substantielle de la demande d'électricité cumulée et donc une forte hausse de la charge en période creuse[32]. Certains scénarios suggèrent que cette capacité supplémentaire pourrait avoir un impact majeur si elle était raccordée au réseau et que la solution se généralisait. La production et le stockage décentralisés pourraient offrir une capacité supplémentaire au réseau tout en limitant la nécessité d'entreprendre des investissements lourds dans des moyens de production de pointe peu efficients. L'un des États américains a déjà voté une loi exigeant des entreprises d'électricité qu'elles achètent l'électricité produite par les batteries des véhicules. « Première de ce genre dans le monde, cette loi exige des électriciens qu'ils paient aux propriétaires de véhicules électriques qui injectent de l'électricité sur le réseau le prix qu'eux-mêmes ont payés pour charger la batterie de leur véhicule. »[33] Cependant, en pratique, il existe de nombreux obstacles au dispatching de l'électricité des VHR sur le réseau.

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30 « On apelle production répartie la production d'électricité dans des installations de petite puissance (de 3 kW à 10 000 kW en général) employées comme solution de remplacement ou amélioration des systèmes électriques traditionnels. » (Voir Wikipedia, « Distributed Generation », accès le 25 janvier 2010 à l'adresse http://en.wikipedia.org/wiki/Distributed_generation.)

31 Le Federal Energy Policy Act de 2005 appelle les State Utility Commissions à réfléchir à certaines normes en matière de production d'électricité. La section 1254 de la loi stipule : « Il devra être proposé des services d'interconnexion en se fondant sur la collection de normes de l'Institute of Electrical and Electronics Engineers (IEEE) 1547 intitulées "IEEE Standard 1547 for Interconnecting Distributed Resources With Electric Power System" et susceptibles d'être modifiées. »

32 Comme les véhicules restent garés 95 % du temps et que les VHR n'ont besoin d'être chargés que pendant 30 % de la journée en utilisation normale, leurs horaires de consommation pourraient être très souples (voir article « Plug-in Hybrid FAQ » sur le site de Climate Progress à l'adresse http://climateprogress.org/2008/07/11/plug-in-hybrid-faq/).

33 http://www.udel.edu/V2G/. La loi est la Delaware Senate Bill 153(2009).

3. Politique de la concurrence

Le recours accru à la production d'électricité renouvelable et aux technologies des réseaux intelligents pourrait améliorer l'efficience et limiter l'inélasticité de la demande. Mais cette évolution soulève aussi un certain nombre de questions de politique de la concurrence qui, parce qu'elles ne se posent que depuis peu, ont jusqu'à présent été peu étudiées. L'un des objectifs de la table ronde est de mettre en lumière ces questions et de les préciser pour les besoins de la discussion. Les sujets couverts sont très divers et ne prétendent pas à l'exhaustivité. Cette section vise avant tout à présenter les questions plutôt qu'à détailler leur contexte ou proposer des réponses.

Les réponses des pouvoirs publics ou d'autres acteurs tels que les gestionnaires de réseau indépendants (ISO) peuvent avoir un impact majeur sur l'investissement. L'un des objectifs fondamentaux de la surveillance des marchés de l'électricité doit être de concevoir des incitations réglementaires favorisant des investissements efficients. Selon Pollit et Bialek (2009) il faudra éventuellement « repenser la façon de déterminer et de réglementer les investissements nécessaires dans les réseaux, en particulier l'implication des utilisateurs et le recours aux appels d'offres concurrentiels. Il importe de tenir compte des signaux locaux inhérents aux structures de prix actuelles du transport et de la distribution, et de se demander si ces structures doivent être modifiées. La séparation entre la propriété des actifs de la distribution et celle du reste du système est une question qu'il faudra traiter en temps voulu. » La politique de la concurrence sera affectée par ces considérations relatives aux investissements.

Les sujets abordés sont les suivants :

- définition du marché ;
- normes applicables aux compteurs intelligents ;
- règles de participation au marché ;
- participation de la demande ;
- règles sur la disponibilité des informations ;
- accès au réseau de transport ;
- enchères et dispatching ;
- acheteurs d'électricité en situation de monopsone.

Les sujets seront traités dans l'ordre. Il s'agit de points importants car les effets des pouvoirs de marché peuvent être substantiels sur les marchés de l'électricité[34]. Les autorités de régulation, les opérateurs et les autorités de la concurrence ont un rôle important à jouer pour prévenir l'apparition et l'exercice de ces pouvoirs de marché.

[34] Voir Borenstein et Bushnell (1999), Johnsen, Verma et Wolfram (1999), Wolfram (1999) et Borenstein, Bushnell et Wolak (2002) pour des articles sur les pouvoirs de marché en Norvège, au Royaume-Uni et aux États-Unis.

3.1 Définition du marché

L'essor des sources d'énergies renouvelables est, dans une large mesure, un effet des réglementations publiques et, notamment, du fait que certains pays se sont fixés des objectifs chiffrés à atteindre. En Australie, le Mandatory Renewable Energy Target (MRET) a été soutenu par des échanges transrégionaux de certificats d'énergies renouvelables (CER). La mise en œuvre d'une réglementation spécifique à un type d'énergie a conduit la Commission australienne de la concurrence et de la consommation (ACCC) à imposer que les marchés à prendre en compte pour les fusions comprennent « un marché national de l'offre de certificats d'énergie renouvelable. Ce marché devrait être considéré comme un marché national, étant donné les échanges transrégionaux de CER réalisés en application du MRET »[35]. Dans un certain nombre de cas similaires, l'ACCC a décidé que les acquisitions d'actifs de production d'électricité renouvelable étaient peu susceptibles de freiner la concurrence, malgré la concentration croissante du marché de l'électricité renouvelable, en raison de la faible croissance résultant des fusions et de l'essor rapide du secteur favorisé par les politiques publiques. Des cas comme celui-là suggèrent que les réglementations spéciales établies pour les sources d'électricité renouvelable pourraient déboucher sur des définitions restreintes des marchés de l'électricité quand on s'intéresse aux énergies renouvelables.

- **Les réglementations restreignent-elles les possibilités des sources d'énergie non renouvelables de concurrencer les sources d'énergie renouvelables ?**

- **Si oui, peut on raisonnablement définir un marché comme étant celui de l'électricité renouvelable ?**

L'étendue géographique de ces marchés pourrait être internationale si les entreprises de différents pays peuvent s'échanger les crédits à l'intérieur d'une même région (Union européenne, par exemple).

3.2 Normes

Les réseaux et les centrales électriques sont des investissements à long terme, dont la durée de vie va généralement de 30 à 60 ans. Les modifications des dispositions qui réglementent des actifs à si longue durée de vie se font souvent progressivement à court terme, mais pourrait être radicales et imprévisibles à long terme. L'installation de compteurs répondant aux besoins immédiats des détaillants d'électricité pourrait entraîner le déploiement d'une technologie câblée difficilement adaptables aux futures institutions et réglementations du marché. Il est peu probable que les technologies de compteurs changent souvent. Pourtant, les innovations technologiques et organisationnelles, et notamment les types de concurrents et leurs activités, devraient continuer d'aller bon train. Il convient de veiller à élaborer des normes qui autorisent de multiples usages potentiels plutôt que quelques usages limités. Aux États-Unis, la Federal Energy Regulatory Commission (FERC, 2009) note que « la mise en place d'une infrastructure de compteurs avancés sera favorisée par l'amélioration et le développement de l'interopérabilité, des normes ouvertes applicables aux protocoles de communication et de normes sur la relève des compteurs. Ces normes favoriseraient la mise au point de nouvelles technologies, d'appareils intelligents par exemple, qui permettraient à leur tour de généraliser les programmes d'effacement de la demande et les systèmes de tarification dynamique. Le Congrès était conscient de la nécessité d'établir ces normes dans la loi EISA 2007, et a chargé la FERC d'approuver les normes élaborées par la procédure de consensus du NIST » (p. 70-71).

Les détaillants d'électricité historiques pourraient ne pas trouver dans leur intérêt d'installer des compteurs intelligents à tarif multiple dans la mesure où ces compteurs :

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35 Par exemple, International Power & Mitsui Ltd – proposed acquisition of Queensland wind energy assets, référence 30140, 16 novembre 2007.

- coûteraient plus cher que les compteurs simples ;
- réduiraient leur contrôle sur les utilisateurs finals ;
- favoriseraient la concurrence ultérieurement.

Kiesling (2009) souligne qu'il est important de vérifier que « les institutions ont la capacité de s'adapter à des conditions inconnues et changeantes » (p. 39). Pour s'assurer de l'adaptabilité des institutions et des solutions de marché, il importe notamment d'éviter les contraintes ou interactions technologiques inutiles.

- **Les opérateurs historiques ont-ils intérêt à faire en sorte que les normes ne favorisent pas un renforcement de la concurrence ?**
- **Quels problèmes les normes sur les compteurs intelligents doivent-elles résoudre en matière de politique de la concurrence ?**
- **La réglementation peut-elle imposer des compteurs avancés ?**

3.3 Règles de participation au marché

L'énergie effacée est un produit qui pourrait venir concurrencer l'électricité en gros sur le marché. Des petites quantités d'énergie effacées pourraient être agrégées et revendues sur le marché de gros par d'autres entités que les fournisseurs d'électricité traditionnels. Lors d'une mise en concurrence ouverte, le gestionnaire du réseau électrique de Melbourne a ainsi récemment sélectionné un prestataire d'effacements. Les autorités de régulation ou les gestionnaires de réseau indépendants peuvent empêcher l'essor de ces entités en instaurant des règles qui excluent l'énergie effacée des produits qui peuvent être mis aux enchères sur un marché[36]. Ces règles pourraient exiger des enchérisseurs qu'ils soient des producteurs, par exemple, ce qui exclurait les fournisseurs d'énergie effacée ou stockée en batterie.

Plus problématique est le fait que, pour payer l'énergie effacée, il faut savoir quelle aurait été la demande en l'absence d'effacement. Selon Wolak (2006), on a pu constater, lors d'une expérimentation réalisée en dehors des jours de pointe à Anaheim, en Californie, que la consommation d'un groupe de clients soumis à une tarification en temps réel était plus élevée que celle des clients du groupe témoin. Wolak note que le résultat « concorde avec le fait que les clients appartenant au groupe auquel était appliquée la tarification en temps réel sont incités à augmenter leur niveau de référence pour obtenir un meilleur rabais les jours de pointes critiques»[37]. Dans les conditions de l'expérience, il était avantageux pour ces clients d'augmenter leur consommation en période creuse et de voir ainsi leur consommation de référence augmenter, pour gagner ensuite davantage en réduisant leur demande. En résumé, dans le cas d'au moins un système pourtant apparemment raisonnable, les clients peuvent abuser du mécanisme d'effacement. Au bout du compte, les clients qui réduisent leur demande sont trop bien rémunérés et la consommation dépasse le niveau qu'on aurait observé avec une tarification en temps réel simple.

- **L'énergie effacée doit-elle être vendue, comme la production, sur le marché ?**

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36 Pour que l'énergie effacée puisse être mise aux enchères, il faut d'abord pouvoir la mesurer pour lavérifier; et notamment la différence entre la demande prévue et la demande réelle. Il peut être difficile d'estimer la future demande d'un client spécifique. Ce type de mesure doit faire l'objet d'une norme appropriée.

37 Ce résultat concorde aussi avec le comportement des clients de ce groupe qui augmentent leur consommation lorsque les tarifs sont inférieurs aux tarifs moyens auxquels ils étaient soumis avant l'expérience, et que payent toujours les membres du groupe témoin.

- **Si oui, comment quantifier cette énergie pour éviter les abus ? (Il y a abus si, par exemple, un site donne l'impression erronée qu'il consomme beaucoup d'électricité alors qu'il n'est pas un gros consommateur net.)**

- **Est-il possible que des petits consommateurs achètent de l'électricité à un ou plusieurs détaillants et et vendent l'électricité qu'ils produisent à un ou plusieurs intermédiaires (éventuellement différents) ?**

3.4 Participation de la demande

La section 2 décrit longuement le principe de l'effacement de la demande. Pour que ce mécanisme fonctionne bien, il faut non seulement des matériels appropriés, mais aussi des contrats adaptés. Ces contrats peuvent se fonder sur des mécanismes pilotés ou volontaires, tels que systèmes de tarification multiple en temps réel. Les gestionnaires de réseaux de transport peuvent effectivement limiter le rôle de l'effacement en refusant que cette énergie soit mise aux enchères sur les marchés des services système, par exemple pour résorber les déséquilibres entre production et consommation.

Lors d'une récente procédure, la Federal Energy Regulatory Commission américaine a décidé que chaque gestionnaire de réseau indépendant ou de réseau de transport régional (RTO) doit « accepter les enchères portant sur de l'énergie effacée, sur une base comparable à celle de toute autre ressource, pour les services systemes acquis dans le cadre d'un processus d'enchères concurrentielles »[38]. La commission a également exigé que « l'énergie effaçable techniquement capable d'assurer le service système dans le délai imparti et qui satisfait aux exigences raisonnables fixées par les gestionnaires de réseau indépendant ou régional concernant la quantité, la télérelève, le comptage et la mise aux enchères, puisse être mise aux enchères pour assurer l'ajustement, la réserve tournante, les réserves supplémentaires, le réglage de la tension et de la puissance réactive, et les réglages primaire et secondaire de la fréquence ».[39]

Le succès de la participation de la demande au marché dépend très largement de l'amplitude de la réduction de la demande qui peut ainsi être obtenue. Autrement dit, quel pourcentage de la demande de pointe ou de la consommation totale d'électricité serait effectivement couvert par ces régimes contractuels ? Pour déterminer le succès potentiel des programmes d'effacement, il convient de se poser les questions suivantes, importantes dans la pratique :

- **Existe-t-il déjà beaucoup de contrats qui autorisent les gestionnaires de réseau à interrompre temporairement la desserte de petits ou gros consommateurs d'électricité pendant les périodes de pointe, afin d'adapter la demande à la capacité potentiellement limitée des centrales de production d'électricité renouvelable ?**

- **Des tarifs variables en fonction de la journée ou de l'heure, sont-ils déjà souvent appliqués ?**

- **Les gestionnaires de réseau ont-ils l'obligation d'accepter les offres d'énergie effacée aux enchères ?**

3.5 Disponibilité des informations

Un certain nombre de nouveaux intermédiaires pourraient faire leur appararition à l'avenir, notamment :

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38 Federal Energy Regulatory Commission (2008) p.27.

39 Federal Energy Regulatory Commission (2008), p.28.

- des intermédiaires regroupant plusieurs petites consommations ;
- des intérmédiaires regroupant les productions réparties ;
- des intermédiaires regroupant l'énergie stockée en batterie ;
- des assureurs (qui fourniraient aux clients soumis à des tarifs en temps réel l'assurance que leurs factures ne seront pas excessives).

Cette liste n'est pas exhaustive. Elle vise uniquement à donner une idée des nouvelles niches qui se créront si la tarification en temps réel se généralise.

Pour que ces nouveaux intermédiaires puissent émerger, concevoir des produits et signer des contrats avec des clients, ils devront avoir accès aux informations concernant les schémas de consommation (par exemple, pour l'effacement) ou de production (par exemple, pour le stockage en batterie) des clients. Si les détaillants sont les seuls à posséder ces informations, ils pourraient bénéficier d'un avantage indû substantiel sur les autres fournisseurs pour la conception de nouveaux produits pour leurs clients.

- **Qui détient les informations concernant les technologies de réseaux intelligents dont sont équipés les différents clients ?**
- **Le centre de conduite du réseau a-t-il accès aux informations sur les clients d'un réseau intelligent ? Qui (en dehors du centre de conduite) a accès aux informations données par le réseau intelligent ?**
- **L'accès à ces informations a-t-il un prix ?**

3.6 Accès au réseau de transport

L'accès au réseau de transport des producteurs d'électricité renouvelable ou d'autres types de producteurs pourrait se révéler problématique et cela pour plusieurs raisons.

Premièrement, un grand nombre d'unités de production d'électricité renouvelable ne disposent pas de connexions satisfaisantes au réseau de transport. Il faudrait donc développer le réseau de transport, ce qui est long et coûteux. L'absence de connexions efficaces est déjà l'une des raisons pour lesquelles on envisage de réduire la puissance des fermes éoliennes prévues. [40]

Deuxièmement, les propriétaires de réseaux de transport sont aussi parfois des producteurs d'électricité. Ils pourraient donc chercher à limiter la concurrence en retardant l'installation des connexions requises ou en s'abstenant de réclamer et d'obtenir les autorisations d'extension des réseaux.

Troisièmement, les règles des gestionnaires de réseaux concernant la « qualité » de l'électricité fournie pourraient avoir d'importantes répercussions sur la capacité des propriétaires de centrales à production variable d'injecter de l'électricité dans le réseau. Par exemple, les fermes éoliennes pourraient

[40] A titre d'exemple, la société Mesa Power a annulé les commandes d'aérogénérateurs qu'elle avait passées auprès de GE pour un projet dans le Texas Panhandle, au motif que la capacité de transport était insuffisante. (Bloomberg, 13janvier 2009, « GE Says Pickens' Mesa Cuts Wind Turbine Order in Half ».)

avoir des difficultés à injecter la quantité exacte d'énergie qu'elles ont mise aux enchères à un moment précis et un nœud précis[41].

- **Sur quelle base les coûts de connexion sont-ils calculés et alloués ?**

- **Les producteurs historiques sont-ils en mesure ou incités à limiter la capacité de transport des producteurs d'électricité renouvelable ? Si oui, comment modifier ces incitations ? Sont-ils incités à construire des ouvrages de transport pour les unités de production d'électricité renouvelable ?**

- **Certains électriciens bénéficient-ils d'un pouvoir de monopsone lorsqu'ils achètent de l'électricité renouvelable ? Ces acheteurs peuvent-ils barrer la route aux nouveaux producteurs au bénéfice de leur propre production ?**

3.7 Enchères et dispatching

Sur un marché libéralisé, le gestionnaire du réseau a généralement recours à un système d'enchères pour décider de l'ordre d'appel des groupes de production (ou dispatching). Ce processus d'enchères détermine également le prix marginal facturé aux clients.

Les règles d'organisation des enchères peuvent avoir une incidence sur la viabilité des fournisseurs d'électricité intermittente. A l'heure actuelle, bon nombre d'enchères organisées par des gestionnaires de réseau indépendants pour comparer les offres de plusieurs producteurs ont lieu de la veille pour le lendemain. Or, les prévisions de la production éolienne sont beaucoup plus précises si elles sont effectuées peu de temps avant la période de consommation. Par exemple, les prévisions faites 3 heures avant la production sont beaucoup plus sûres que les prévisions à 24 heures. Par conséquent, si les enchères des gestionnaires de réseaux se tiennent avec un jour d'avance (par opposition à quelques heures seulement), les producteurs éoliens seront défavorisés.[42]

- **Les règles d'enchères désavantagent-elles la production variable par rapport aux autres types de production ?**

- **Si oui, peut on modifier ces règles pour les adapter à une production variable sans pour autant pénaliser la production traditionnelle ?**

- **Les règles qui permettent aux producteurs d'électricité renouvelable de se raccorder au réseau et de fournir de l'énergie à tout moment favorisent-elles indûment les énergies renouvelables à de coûts excessifs pour les utilisateurs ?**

3.8 Pouvoir de monopsone

Un gestionnaire de réseau ou un détaillant d'électricité pourrait avoir l'exclusivité des relations avec les consommateurs qu'il dessert et qui produisent également de l'électricité à petite échelle ou dans des unités décentralisées. Quand un acheteur a l'exclusivité de l'achat d'un produit, on dit qu'il est

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41 Pour plus d'information sur les problèmes d'accès au réseau, voir OCDE, Tarification de l'accès dans le secteur des télécommunications (2004).

42 A l'inverse, les producteurs qui doivent planifier les ressources humaines dont ils ont besoin pourraient être mis en difficulté par des enchères à court terme organisées tout au long de la journée.

monopsoniste. Un tel acheteur peut tirer parti de son pouvoir de marché pour fixer les prix de la manière qui lui est la plus avantageuse. Alors qu'il serait bon d'augmenter la production, il peut arriver que le monopsoniste offre trop peu aux petits fournisseurs pour les convaincre de produire de l'électricité. Beaucoup des problèmes observés en cas de monopole se retrouvent dans les situations de monopsone.

- **Existe-t-il un risque de monopsone (acheteur unique) concernant l'achat de l'électricité produite par les clients ? A-t-on, par exemple, établi des règles pour organiser ces achats ?**
- **Les clients ont-ils le droit d'acheter à un fournisseur et de vendre à un autre ? Si oui, pourrait-il y avoir des problèmes d'arbitrage, en particulier s'il leur est possible d'acheter l'électricité à un prix réglementé (bas) et de la vendre au prix du marché (élevé) ?**
- **Le fait de fixer des prix d'achat est-il une bonne solution pour limiter le pouvoir de marché de l'acheteur ?**
- **Comment résoudre les problèmes liés au pouvoir de monopsone ?**

4. Conclusion

Pour résumer, les problèmes classiques de politique de la concurrence que l'on rencontre sur le marché de l'électricité sont dus à certaines caractéristiques du système en place, parmi lesquelles :

- demande très inélastique ;
- absence de signaux de prix transmis en temps réel aux clients ;
- impossibilité de stocker l'électricité ;
- nécessité de maintenir en permanence l'équilibre entre l'offre et la demande ;
- offre contrainte.

Les marchés de l'électricité devraient radicalement changer au cours des deux prochaines décennies, et ces changements devraient modérer certains pouvoirs de marché existants. L'expansion potentielle des énergies renouvelables, la présence d'options de stockage de plus grande puissance et l'introduction des signaux de prix en temps réel pourraient avoir une incidence sur toutes les caractéristiques susmentionnées, à l'exception de la nécessité de maintenir un équilibre constant entre l'offre et la demande. Par conséquence, les menaces pour la concurrence dans le secteur de l'électricité pourraient être moins vives qu'elles ne l'ont été par le passé.

Lorsque le système de production transport sera moins centralisé avec l'essor de la production d'électricité renouvelable, de nouveaux problèmes se poseront pour la politique de la concurrence, tandis que les préoccupations traditionnelles liées aux pouvoirs de marché s'estomperont. Les principales questions qui se poseront à l'avenir pourraient s'articuler autour des points suivants :

- définition des marchés ;
- normalisation ;
- règles de participation au marché ;

- règles de participation de la demande ;
- disponibilité des informations ;
- accès aux réseaux de transport ;
- enchères et dispatching ;
- pouvoir de monopsone.

Cette note de réflexion identifie les grandes questions qui se posent concernant ces points. Les politiques en la matière évolueront de façon notable dans les années à venir. L'intervention des pouvoirs publics pourrait être souhaitable, en particulier dans la mesure où les opérateurs historiques ont intérêt à concevoir des normes et des structures institutionnelles qui limitent la concurrence et leur garantissent des revenus élevés. Avec des politiques bien élaborées, l'importance des problèmes de pouvoir de marché dans le secteur de l'électricité devrait décliner. Mais il sera toujours difficile de vérifier que les politiques mises en place permettent d'atteindre cet objectif d'autant que ces questions de pouvoir de marché seront éclipsées par le souci de réduire les émissions de carbone.

De plus en plus, la coordination des réseaux électriques sera décentralisée. Les futures structures institutionnelles et commerciales qui faciliteraient cette coordination sont difficiles à prévoir. Kiesling (2009) recommande l'« humilité » à ceux qui devront surveiller l'évolution de cette décentralisation. Selon Ostrom (2005) : « nous devons (…) davantage nous efforcer de faciliter l'élaboration d'un montage institutionnel adaptatif – plutôt que de penser que nous sommes des spécialistes capables de concevoir un système optimal permettant de résoudre un problème complexe » (p. 254).

Il sera difficile de concevoir un cadre institutionnel et des règles d'interconnexion adaptés. Les principales conclusions de cette note de réflexion sont les suivantes :

- Le développement des nouvelles technologies doit être régi par des principes économiques, non des règles simplistes favorisant les énergies renouvelables ou es réseaux intelligents. Si le problème est bien de réduire les émissions de gaz à effet de serre, la solution ne consiste pas à mettre en œuvre des technologies de production peu émettrices de carbone (telle que le solaire) à n'importe quel coût. C'est en fixant le prix des émissions de gaz à effet de serre qu'on les réduira de la façon la plus efficiente.
- Les compteurs de la nouvelle génération doivent faire l'objet de normes claires et raisonnables.
- La réglementation doit laisser place à l'inventivité et aux actions imprévues des intermédiaires ou des consommateurs.
- La variabilité de la production d'électricité renouvelable, et notamment éolienne, pourrait exiger de modifier les règles concernant les enchères, la puissance garantie et les sources autorisées.
- Dans de nombreux pays, les meilleurs sites pour exploiter les énergies éolienne et solaire se trouvent dans des zones où la capacité de transport est faible. L'exploitation de ces énergies nécessiterait donc de nouveaux investissements substantiels dans les réseaux de transport.

Les pouvoirs publics et le secteur privé devront relever des défis considérables, et pas seulement en matière de politique de la concurrence. Pour relever ces défis, il s'agira d'associer expertises techniques en continu et actions réglementaires aux niveaux infranational, national et international.

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CZECH REPUBLIC

1. Introduction

The submission of the Czech Competition Authority (hereinafter referred to as the "Authority") for the discussion on regulation and competition issues related to "smart grid technologies" and renewable energy source is divided into two parts. The first part analyses the national legislation and forms of regulating this area in the Czech Republic (hereinafter referred to as the "CR"). The analysis focuses primarily on the definition of renewable energy sources (hereinafter referred to as "RES"), conditions related to RES power producers' connection to the power distribution system, or pricing of electricity generated by RES. In addition, the submission points out some selected problems related to RES power generation.

The second part of the contribution answers individual questions asked in the source material. However, the note on the smart grid technology in the contribution is only marginal due to the lack of direct experience with its use in the CR.

In recent years, the CR saw a marked growth of RES power share. The most significant growth of all RES types is achieved especially by photovoltaic plants. The development of installed photovoltaic output increased almost 25 times in the last one and half a year. However, this source of energy is not the cheapest variant of power generation. Although the anticipated photovoltaic power generation share is expected to be about 7 % in 2010 (from all RES types), the anticipated photovoltaic share in end user tariff creation is about 40 % (out of the overall contribution for the RES).

Major investments in new smart grid technologies started only in 2009. For example, ČEZ[1] prepares smart technology testing and implementation in the distribution network as part of the FutureMotion – Energy of Tomorrow project.

2. Regulatory framework

In the CR, the RES area is specifically regulated by the Act on the promotion of electricity production from renewable energy sources,[2] implementing relevant community legislation.[3] In particular, the Act:

- defines what sources can be regarded as RES;
- regulates methods of support for RES power generation; and

1 ČEZ is the leading Czech power producer, dealer and supplier in the CR, and is majority-owned by the state.

2 Act No. 180/2005 Coll. on the promotion of electricity production from renewable energy sources, amending certain acts.

3 Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market.

- regulates the method of RES power pricing.

Apart from this fundamental legal norm, generally applicable regulations regulating Czech power generation apply to the RES area. In particular, it is the Energy Act[4] that regulates business conditions, public administration execution and regulation in energy sectors. Furthermore, there are other laws and implementing regulations that set the rules for power market organizing, conditions of connecting to the Transmission System (hereinafter referred to as the "TS") or Distribution System (hereinafter referred to as the "DS"), details of technical data measurement and reporting, TS and DS operating rules etc.

2.1 State Energy Agency

The State Energy Agency is competent to control over compliance with the Act on the promotion of the use of energy from renewable sources and the Energy Act. The State Energy Agency is a public agency subordinated to the Ministry of Industry and Trade.

2.2 Energy Regulatory Office

Prices of electricity generated from RES are regulated by the Energy Regulatory Office (hereinafter referred to as the "ERO") as a general power generation regulator. Among other things, the task of the ERO is to support the creation and maintenance of conditions for competition in energy sector, promotion of RES using and protection of consumer interests. The ERO also decides about license granting, amendment or cancellation, decides disputes when contracts between market participants are not concluded, or decides disputes over access to electricity distribution systems, all in relation to RES as well. The ERO therefore also decides disputes over RES electricity purchase.

2.3 Definition of renewable sources

It is regulated in the CR by the Act on the promotion of the use of energy from renewable sources. Renewable sources mean *renewable non-fossil natural energy sources, i.e. wind energy, solar energy, geothermal energy, water energy, soil energy, energy of the air, biomass energy, landfill gas energy, energy of sewage treatment plant and energy of biogases*.

2.4 Obligation to connect

The TS operator or DS operators are obliged to connect preferably the RES electricity producer's facility in order to transmit or distribute RES electricity within areas where they operate their systems, if conditions stipulated by law are met. In the event of multiple connection options, this obligation to connect falls upon that DS operator who has the lowest connection costs. Exempt from this obligation are situations where lack of capacity of distribution equipment can be documented, or if safe DS operation would be endangered as a result of additional RES facility connection.

2.5 Support for RES electricity generation

It takes two alternative forms in the CR: mandatory purchase and the so called green bonus. The subsidy amount is determined depending on the RES type and installed output of the plant. The RES power producer may select the type of support, i.e. whether they offer the power produced for mandatory purchase for the minimum price set by the ERO, or whether they ask for the green bonus. The main criterion for the RES electricity producer's selection between the two support types is the total price they

4 Act No. 458/2000 Coll. on business conditions and public administration in the energy sectors and on the modification of some acts, as amended.

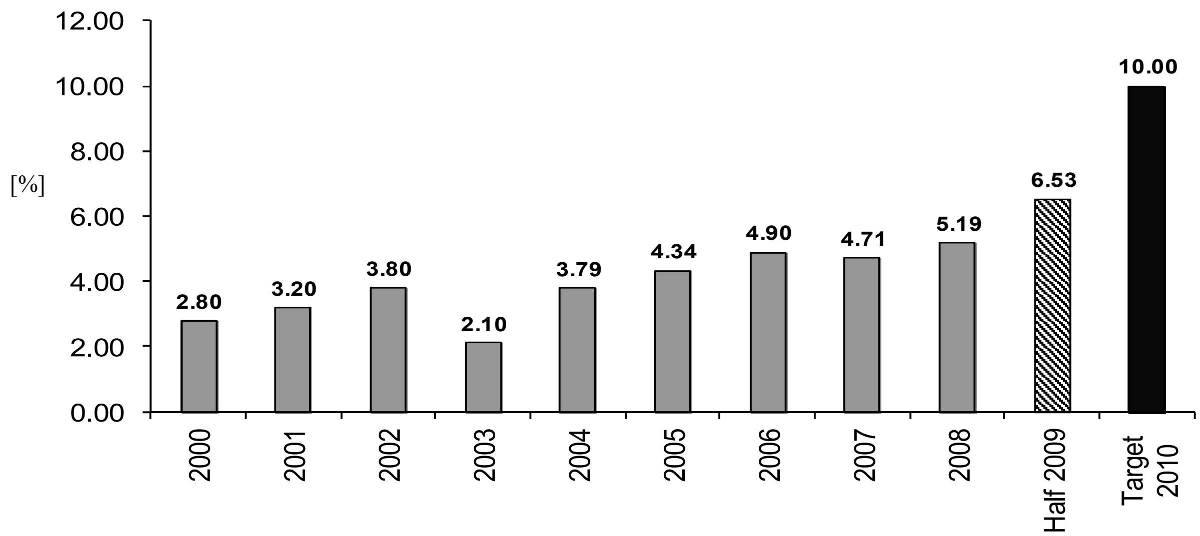
gain for the RES electricity. So it depends whether a specific RES electricity producer has the possibility to negotiate better price conditions with a specific customer than those they get for the mandatory purchase. The producer who offered electricity for mandatory purchase must sign a contract with the relevant regional DS or TS operator. If the RES electricity producer does not offer this power for mandatory purchase, and sells it on the electricity market, the relevant regional DS or TS operator is obliged to pay the producer the green bonus for this electricity, an addition to the market price the fixed amount of which is also set by the ERO. The selection made may be changed at the earliest a year after the RES electricity producer made a binding choice of the two options and started to use it. The option may be changed always as of 1 January of the following calendar year.

As part of the price regulation, the ERO sets RES electricity purchase prices always for one calendar year ahead, separately for each renewable source type and green bonus. The purchase prices are set as minimum prices, and green bonuses are set as fixed prices. Basic criteria for fixing RES electricity prices and green bonuses are laid down in Section 6 of the Act on the promotion of the use of energy from renewable sources. The ERO must make the prices attractive enough to be able to meet the set target of the RES electricity production to total electricity consumption ratio. When setting the green bonuses, the ERO also considers the increased rate of risk of RES electricity use on the electricity market.[5] The present legislation[6] does not allow the ERO to decrease the purchase prices of electricity from these sources by more than 5 % a year (cf. Section III.4. *Photovoltaic power plants* below).

3. Renewable sources of electricity

The RES electricity production develops hastily in the CR, which is evidenced by the ever growing development of the RES electricity production share.

RES electricity production ratio in the CR



Source: ERO

5 A detailed analysis of the criteria that the ERO takes into consideration is provided in the implementing regulation No. 475/2005 Coll.

6 Cf. Section 6, paragraph 4 of the Act on the promotion of the use of energy from renewable sources.

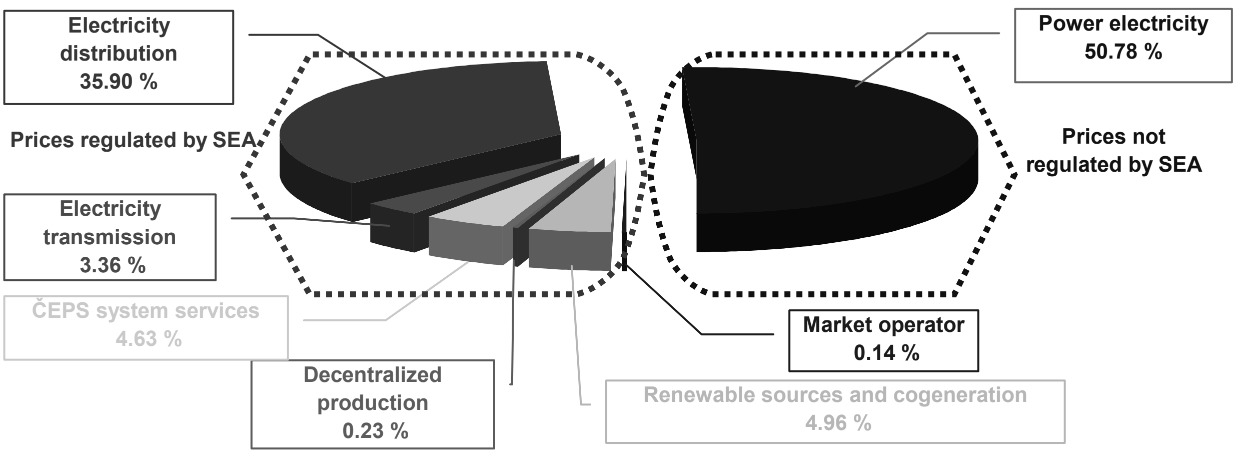
3.1 Major RES types in the CR

At present, about 179.4 MW is installed in wind power generation in the CR, and 124.4 MW in sources generating power from photovoltaic panels.[7] These are the most preferred technologies that will also see the most considerable increase in installed output in the years to come. The TS and DS operators file applications for connection of photovoltaic panels of about 16,000 MW. In the CR, requests for capacity reservation for RES total to about 23,000 MW. To give an idea and compare: about 18,000 MW have currently been installed in the CR in all technologies producing electricity. The requested amount of RES connections therefore even exceeds the total installed output within the territory of the CR. This scope of installed output spread is not feasible in the foreseeable future, not only with regard to the financial exigency of this investment, but also with regard to the legal, technical and other obstacles hindering from building a *de facto* brand new TS and DS.

3.2 Structure of electricity price for Czech consumers

In the environment of the Czech liberalized market,[8] the final price for power supply to customers consists of two basic parts. The first part comprises regulated items determined by the ERO. These items include, among others, the power distribution price, or a payment covering additional costs related to the support for the RES electricity production. The ERO sets the regulation so that companies providing power transmission and distribution could only gain such revenues that cover the cost of necessary maintenance and investment, and provide customers with a reliable supply through their networks. The second part of the final price is the payment for power electricity itself, set by the specific trader in electricity, which is not regulated since 1 January 2006. For a better orientation, the share of each component of price for the total power supply for the Household category of customers is shown in the diagram below:

Percentage of each household power supply price component in 2010 (excl. tax)



Source: ERO

7 Source: ERO; October 2009.

8 The Czech electricity market liberalization conditions are regulated in the first place by Act No. 458/2000 Coll. on business conditions and public administration in the energy sectors and on the amendment of some acts, as amended.

3.3 Impacts of RES power production support on Czech electricity prices

The main factor influencing the growth of prices regulated by the ERO in 2010 is the significant year-on-year growth of the contribution for covering the support for the RES electricity production. The dramatic increase in costs connected with the support in 2010 is caused by the expected volume of electricity generated by photovoltaic plants of about 240 GWh, which will bring about costs of almost CZK 2.8 billion. The increase in the cost of support for electricity production from environmentally-responsible sources has an impact on the uniform state-wide contribution from customers to cover this support. Currently, the contribution is CZK 166.34 per MWh, which is more than three times as much as the figure for 2009. Almost CZK 7 billion is spent for RES alone. And although the ERO employed the maximum decrease rate provided for by the present legislation, the purchase price of electricity from photovoltaic plants is now almost CZK 13 per kWh. The market electricity price is currently about CZK 2 per kWh.

If the contribution for the supported sources remained at the 2009 level, the regulated components would grow, at the low voltage level, for example, by about 3 % (considering the inflation). However the actual growth in total regulated prices at the low voltage level ranges between 10 and 16 % in 2010. The consequence of this growth in total regulated prices (forming about 50 % of the total price for power supply to end consumers) in 2010 is the decrease in the final price for power supply to end consumers only by about 3 %, in spite of the fact that the prices for power electricity dropped by about 15 % in 2010.

That is also why the ERO, as a price regulator, enforces breaking through the maximum five-percent limit permitting the annual decrease of the electricity purchase price. An amendment to the Act on the promotion of the use of energy from renewable sources is prepared. If passed, the ERO would have a tool at their disposal for a more significant decrease in solar electricity purchase prices.

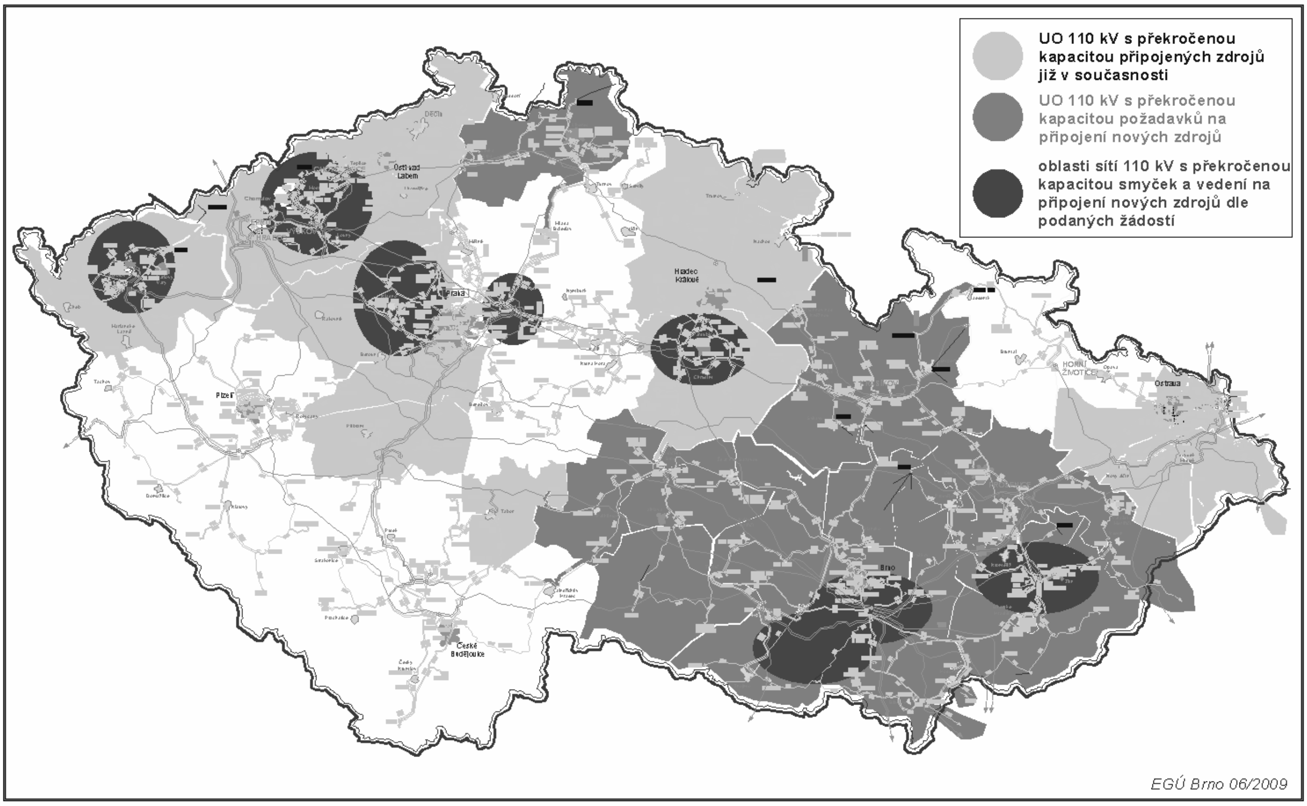
3.4 Photovoltaic power plants

As mentioned above, photovoltaic electricity production sees the greatest growth. It is caused by the fact that there has been an enormous decrease in the purchase costs of building such plant – the price of solar panels for electricity production has dropped to a half. In connection with more and more powerful solar panels, the payback period of the solar power plant investment is considerably shorter, five years in some cases. Still, electricity purchase prices are guaranteed for 15 years in the CR, which was the original estimate of investment payback period. The law does not allow the ERO to reduce RES electricity purchase prices by more than 5 % year, though. Thanks to these "generous" and long-term guaranteed electricity purchase prices, photovoltaic plant operators have a secure long-term gain today.

The big growth in requests for RES power plant connection brings about to TS or DS operators higher demands for the development of these networks, specifically in respect of their capacity increase. The time necessary for network (line structure) building and empowering varies from 12 to 15 years in the CR. The reason for this long execution time is the complicated approval process. Connection payments and fees (consumers, producers) are defined by the implementing regulation.[9] The electricity producer pays for the source connection itself and also pays a certain amount for the given TS/DS operator's network building or empowering. The amount paid by the producer covers only a part of the network operators' costs connected to this operation (about 10 to 20 % of the total cost). The expected network operators' investment costs related to the already issued positive opinions on RES connection have reached about CZK 25 billion.

9 Public Notice No. 51/2006 Coll. on conditions for connection to grids.

At present, there are some areas in the CR where the capacity for new source connection to the network is limited or already depleted. These areas in the CR are documented by the picture below.



UO 110 kV kde požadavky na připojení nových zdrojů přesahují volnou kapacitu sítí včetně vedení 110 kV

Yellow: 110 kV areas where the capacity for source connection has been exceeded already
Orange: 110 kV areas where requests for new source connection have exceeded the capacity
Brown: 110 kV areas where the capacity of loops and lines for new source connection has been exceeded according to requests received
110 kV areas where requests for new source connection exceed the free network capacity including 110 kV lines

3.5 Photovoltaic plants – speculations

Another problem that occurs in connection with the state-guaranteed photovoltaic plant electricity purchase is speculations. These consist in the legal option to reserve TS or DS capacity for electricity generated by a photovoltaic plant already at the time of intent, although the intent is quite unrealistic. Only a simple documentation is needed in the CR to make DS operators book the capacity for the new photovoltaic plant. Because of the higher price, dozens of fields throughout the CR transform into potential solar parks, although there is a little chance to build a plant there. In this way, the capacity for other power plant connection is entirely blocked in the CR.

In South Moravia alone, which is a sought-after region because of the more frequent and intensive sunshine, the DS operator receives about a thousand applications for solar power plant connection. But “only” 425 plants have been connected since the beginning of the year. Still this is an extreme development. According to the ERO data, the whole CR had 1,214 solar power plants at the beginning of 2009, and 2,900 as at 1 October 2009.

This reason also leads to the effort to modify the existing legislation that will require a higher source investor's responsibility for capacity reservation, for example through an advance payment for connection, and investor's duty to inform the network operator about the progress of the source preparation project.

3.6 RES and the Authority

As part of its competence, the Authority encountered RES power plant operators' complaints. The reason for these complaints was disagreement with the purchase price set by the ERO or contractually agreed with the DS operator. In addition, the Authority dealt with complaints concerning declining their request for power plant connection to the DS. The Authority explained the claimants the system of purchase price setting in detail as well as the legal procedure that the ERO uses for setting these prices. In the case of a decline to connect a new source to the DS, no breach of competition rules has been found following investigation by the State Energy Agency pursuant to the Energy Act. The reasons for declining to connect the applicant were objectively justifiable (the DS operator did not have sufficient capacity of the DS operated by them). Therefore, the Authority did not initiate or carry on any administrative proceeding regarding RES for potential breach of competition rules.

3.7 Conclusion

The Authority fully respects the government's effort to support the use of RES by granting subsidies for RES power production. It is an implementation of the government's interest in electric energy source diversification and environmental protection enhancement, in addition to the interest in protection and support of competition. To meet these goals, however, it is necessary to choose tools that are, if possible, neutral from the competition protection point of view, and have as little negative effect on prices as possible. According to the Authority, the support for RES electricity overly contributes to the jump in final electricity prices for consumers, even at the time of the deep drop in non-renewable source energy prices. The Authority also believes that the situation when speculative TS and DS capacity blocking is enabled, howbeit unintentionally, is negative in terms of competition. The non-existence of TS and DS capacity may have a negative effect on the entry of new electricity producers, both those who would like to offer RES electricity at a cheaper price (e.g. thanks to new technologies), and those who would generate electricity from non-renewable sources but more effectively. This may really limit the potential for development of competition on power markets.

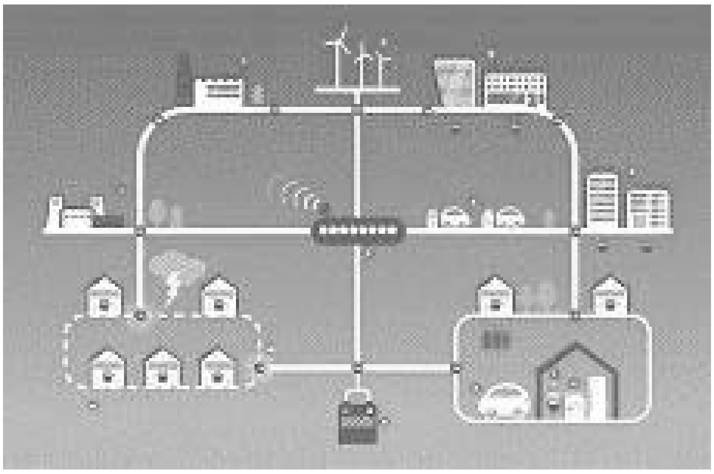
4. Smart grids

The "smart distribution network" technology (hereinafter referred to as the "smart grids") has not fully reached the phase of commercial use, although it is in an advanced development stage. The only active element in the CR that perhaps can be referred to as smart grids is the use of remote collective consumption control system for switching electric hot service water heating, accumulation electricity and direct heating electricity.

4.1 Implementation of intelligent solutions

The efforts for a more ecological, effective and economic electricity production and transmission escalate in the CR. Example: the ČEZ project (FutureMotion) that focuses over a long term on testing intelligent meters, new automation elements in the distribution network, connection of diverse power plants to the network and charging stations for electric cars in the future. The town of Vrchlabí was chosen for testing these state-of-the-art energy elements and should become the first region employing smart grids

east of Germany. The long-term project called Smart Region now begins its first stage.[10] The aim of the project in Vrchlabí is to test how various new technologies may work together in a small location: smart household metering systems, a higher number of local production source including renewable sources, charging stations, combined electricity and heat power plants. The aim is to test at a lower scale how intelligent networks can connect and control many elements to the benefit of customers and the entire network.[11]



In the future and with a long-term horizon, intelligent networks or Smart Grids are supposed to provide the whole CR with such benefits as a better consumption peak regulation, faster electricity supply recovery after power failures, or even the so called island operation that would, if an important line is broken, ensure that smaller regions are switched over right to local production sources with a balanced electricity consumption and supply balance in the tested region.

4.2 Support for electric mobility

One of the features of the future power engineering transformation will be motor transport "electrification". The concept of electric mobility offers a comprehensive solution to support electric car development, including the necessary infrastructure. The key players in this concept are battery manufacturers, electric car manufacturers, users, and municipalities as well as the state (they provide benefits to the electric car development) and electricity distributors. Nevertheless, new technology implementation will be complicated and long-lasting.

5. Specific topics for the issues discussed regarding renewable sources of electricity

5.1 Wholesale pricing

5.1.1 How often are the prices regulated?

The ERO sets RES electricity purchase prices and green bonus prices always once per calendar year. The RES electricity producer may choose one of these supports provided by law. If the producer chooses

[10] Vrchlabí thus joins Western Europe and USA regions where such testing is taking place, such as the city of Boulder in Colorado, USA, Malaga in Spain, Amsterdam in the Netherlands, or Mannheim in Germany. Other lower-scale projects are ongoing in Greece or Denmark, for example.

[11] Source: ČEZ.

the RES electricity purchase price regime, these prices are set by the ERO as minimum prices. In the green bonus regime, the RES electricity producer signs a contract with another entity (trader, electricity producer) for the price negotiated between the two parties. Added to this price is the legal green bonus set by the ERO as a fixed amount. Like the green bonuses, the purchase prices are paid by end consumers as a regulated price component contained in the price for the overall electricity supply.

5.1.2 Are there different prices for small-scale production and large-scale production?

Rather than the production scale, the amount of support is influenced by the date of putting the RES power plant into operation or RES power plant reconstruction. The price differentiation with regard to the installed output is only used in solar electricity generation (photovoltaic technology).

5.1.3 How are the prices set for small-scale and large-scale producers?

The basic rules for RES electricity pricing are defined directly by the Act on the promotion of the use of energy from renewable sources. When setting the purchase prices and green bonuses, the ERO proceeds from different costs of each equipment type acquisition, connection and operation, including their development over time. In general, the prices are set to ensure a 15-year payback period for typical installations for the specific RES type. The system is conceived in the manner allowing the producer to get the following amount from the purchase prices: a) reasonable return on capital employed over the electricity plant service life; and b) non-negative amount of the net present value of cashflow after tax for the entire electricity plant service life.

5.1.4 How large is the subsidy for different forms of renewable production, if there is any subsidy?

The subsidy changes every year depending on the level of purchase prices for each RES type, and the level of estimated electricity market price in the given calendar year.

5.1.5 Are there any competitive distortions that have been alleged as a result of renewable pricing policies?

In general, legal conditions for the use of RES electricity or pricing distort the market as these sources would never be employed on the market without the support. This is not only the result of price setup but also the result of the effort to promote electricity production from environmentally friendly sources. Therefore, this distortion is in favour of the climate protection and consistent increase in RES share of primary energy source consumption.

5.1.6 How common is flexible, time-of-day pricing to electricity customers?

There are many customers in the CR with accumulation and direct-heating appliances. That is why a double-tariff system was introduced in the past, alternating low-price and high-price zones during the day. Switching is done by means of collective remote control.

5.1.7 How do you induce customers to use more expensive energy sources?

This issue is not relevant in the Czech conditions. All costs are collectively dissolved in the regulated tariff for distribution so the customer does not distinguish that the RES supplies more expensive electricity than the classic sources.

5.1.8 How do you change consumer incentives?

This issue is not relevant in the CR with regard to the chosen mechanism of RES electricity production support. Nevertheless, ČEZ have introduced a product called Green Energy (hereinafter referred to as the "GE") as early as 2006. Through this product ČEZ guarantees to the customer that the sold amount of electricity will not be higher than the amount produced or purchased from RES. Technically it is impossible to ensure that electricity consumed by the customer is electricity produced solely from RES. The GE price is then slightly higher than the conventional electricity price – but the increase is only 10 hellers per kWh. The GE should rather be used for marketing purposes and as an incentive of customer interest in ecological behaviour; signing up for GE consumption is rather a sign of green thinking. ČEZ intends to reinvest the funds gathered for the GE in the RES support.

5.1.9 Can types of meters and access to data change incentives?

In general, they may change incentives, but in some respects this may only have a short-time, passing effect.

5.2 Investment

5.2.1 If wholesale prices for renewable energy yield an excessively high return on investment, they may lead to excessive investment in renewable technologies generally or distributed energy in particular. Is there any evidence of excessive investment and distortion in production arising from such investment?

Yes, there is an evidence of excessive investment in the CR due to the considerable state-guaranteed returns. Specifically, the example of photovoltaic plants in the CR in 2009 and 2010 was mentioned above.

5.2.2 How do you encourage investment in renewable energy due to lack of assurance of transmission and, similarly, encourage investment in transmission absent renewable generators?

The operation, not investment support is regarded as the main support in the CR. The main obstacle to the faster infrastructure development is the lengthy approval processes related to the new electricity transmission and distribution equipment construction or reconstruction aimed at increasing the capacity of operated networks.

5.2.3 Is investment to extend or build transmission mandated?

In principle it is. Among other things, the applicable legislation lays down the duty to ensure TS or DS innovation and development on the network operators. The TS and DS operators are also obliged to connect to the electricity grid everyone's facility and provide electricity transmission or enable electricity distribution to everyone who applies for it and meets the conditions for connection and business conditions laid down by the TS or DS operation rules, except for cases of demonstrable lack of transmission or distribution equipment capacity, or if reliable TS or DS operation would be endangered. In addition, the TS and DS operators have to provide all electricity market traders with non-disadvantaging conditions for connecting their equipment to the TS and DS and electricity transmission or distribution through the TS or DS.

5.2.4 Who pays for new transmission?

The greater part of investment costs related to the building of new or reconstructed networks is paid by end consumers in the total price for electricity supply. The TS or DS operator's costs that were spent expediently for TS or DS modification in response to the applicant's request for connecting their generator

are recognized by the ERO when setting the regulated part of the price for transmission or distribution. If the plant is to be connected to the TS, the applicant pays the take-off line to the connection point to the full extent. The share of RES electricity producers in the payment for transmission cost is about 10 – 20 % of the total cost related to the network building.

5.3 Output plans and minimum purchases

5.3.1 What are the current output requirements for renewable energy sources?

The condition is provided by law. The aim is to reach a 10% share of RES electricity production in the gross domestic electricity consumption in the CR in 2010.

5.3.2 What sources are classified as "renewable"?

The classification is provided by the Act on the promotion of the use of energy from renewable sources, and is based on the definition used in the European Communities legislation.[12] Renewable sources mean in the CR *renewable non-fossil natural energy sources, i.e. wind energy, solar energy, geothermal energy, water energy, soil energy, energy of the air, biomass energy, landfill gas energy, energy of sewage treatment plant and energy of biogases*.

5.3.3 Do government or operators have plans to increase renewable generation in the future? If so, what are these plans?

Yes, the plans do exist. The requirement follows the national 13% RES energy quota on gross domestic energy consumption in 2020. The target is given by Directive 2009/28/EC.[13]

5.3.4 Are there minimum purchase/output requirements for renewables? How are these put into operation?

There are no such requirements in the CR. The CR does not apply support in the form of marketable certificate quota fulfilling.

5.3.5 Who has the responsibility for adopting renewable sources (the system operator, independent distribution companies, etc.)?

The primary responsibility is borne by the Czech government, whose task is to create such conditions for investors that they invest sufficiently in RES. The ERO plays the key role in providing the support and setting purchase prices and related conditions. Within the area of their operation, TS or DS operators are obliged to preferably connect RES producer's equipment to the TS or DS, if the electricity producer applies for it. The duty to connect the RES electricity producer's facility rests on that DS operator where connection costs are lowest, except for cases of demonstrable lack of distribution facility capacity, or if reliable DS operation would be endangered.

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12 Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market.

13 Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

5.3.6 How do minimum purchase plans tie into transmission capacity?

There were no problems with transmission capacities until 2008. In 2009, with regard to the dramatic development of photovoltaic sources, all distribution capacity was completely exhausted in many places. This problem is going to escalate in 2010.

5.3.7 Is there a mechanism for trading renewable energy credits? If so, how does that function?

There is no mechanism for trading renewable energy credits in the CR. The CR employs the system of fixed prices and green bonuses (bonus in addition to the market price).

5.4 Connection to the grid

5.4.1 Are connection rules for renewable electricity suppliers clear and transparent?

Czech rules for RES electricity producer connecting are clear and transparent. They are specified by the Act on the promotion of the use of renewable sources, regulating the TS or DS operator's duty to connect the RES electricity production equipment and enumerating conditions for exemption from this obligation. These policies are then specified in more detail in the secondary legislation.[14] Technical details of the connection are also described in the Rules for TS and DS Operators approved by the ERO.

5.4.2 How long do renewable generators need to wait to get connected?

The time depends on specific conditions. If the DS and the TS is sufficiently sized at the required connection point, the applicant receives a positive opinion on the application for connection from the network operator within 30 days from lodging the application. Following the receipt of the positive opinion from the DS or TS operator, the applicant has to sign a contract of connection to the TS or DS. When these conditions are fulfilled, the source may be connected practically at once. If there is no capacity at the point in question, either a different connection point is recommended to the RES electricity producer or the application is declined. In such case, the applicant has to wait until the network capacity is increased.

5.4.3 On what basis are connection costs calculated and allocated?

Connection prices are set by the ERO in a legal regulation. The pricing is calculated on the basis of analyses and findings that are primarily based on the observation of actually incurred connection-related costs.

5.4.4 Do incumbent generators have incentives to limit transmission capacity of renewable generators? If so, how can these incentives be changed?

Network operators that are distinguished from electricity producers or traders in the CR, are obliged to renovate and extend the networks. They get the cost of network development back from end users who pay the price for electricity.

5.5 Dispatch in response to demand

5.5.1 A commonly cited challenge with renewable generation is that production often depends on external forces that cannot be controlled by the operator. For example, wind power depends on

[14] Such as Public Notice No. 51/2006 Coll. on conditions for connection to grids.

the presence of appropriate atmospheric conditions. What efforts are being made to increase the ability to dispatch renewable energy resources in response to demand?

In general, TS or DS operators are obliged to guarantee the connected electricity source capacity reservation to the amount of its installed output. This means that the capacity is reserved even at times when the source does not produce (shutdowns, failures). For RES, the capacity is reserved to 100 % of installed output even in the case the source does not produce due to atmospheric conditions (no wind, no sunshine). At present, there is no system of compensation for RES electricity production reductions in the CR. When the RES penetration in the CR is negligible, it is not necessary to reduce (regulate output) RES production. It is estimated that a RES production regulation system will be introduced in the future to maintain a secure and reliable electricity grid operation even with a high RES penetration in the CR. This concept will lead to the optimisation of cost for end customers.

5.5.2 How common are contracts that allow the electricity network operator to temporarily "shut down" small-scale or large-scale electricity users at peak periods, helping it to adapt to the potentially limited ability of renewable generation to provide electricity?

In the CR, any consumer limitation is only allowed in emergency situations, when secure and reliable operation of the electricity grid is endangered.

5.5.3 How common is flexible pricing that can change on a daily and hourly basis?

In general, electricity prices change every hour on the wholesale market. As regards end consumers, daily, monthly, annual or multiannual prices are applied. Tariffs offered by electricity traders than allow choosing double-tariff rates. The low and high tariffs are then switched through the collective remote control system during the day. As the electricity price is lower for the customer when the low tariff applies, building heating or hot water heating appliances are switched on at the customer at that time.

5.6 Vertical and horizontal issues

5.6.1 Do generating companies own both renewable and non-renewable plants?

They do, the legislation does not forbid this.

5.6.2 Can such generators create bundles of renewable and non-renewable plant output?

Yes, Czech electricity generators can create such output bundles.

FRANCE

Une énergie renouvelable est une énergie dont la source se régénère au moins aussi rapidement qu'elle est consommée. Le pétrole est une source d'énergie qui se régénère. Néanmoins, sa consommation est bien supérieure au rythme de cette régénération : il ne s'agit donc pas d'une énergie renouvelable. Bien souvent, les énergies renouvelables sont issues de phénomènes naturels : énergie solaire, éolienne, marémotrice, géothermique, etc.

L'une des grandes caractéristiques de l'électricité est qu'elle n'est pas stockable, du moins pas en grande quantité. Il se pose en conséquence le problème de son transport à partir des sites de production, qui sont bien souvent disséminés, d'une part, et de sa distribution, d'autre part.

De manière générale, l'économie de l'électricité est une économie de réseau, qui soulève à ce titre d'intéressantes problématiques de concurrence, au premier rang desquelles figurent les questions d'accès aux infrastructures et de rémunération de leur usage.

Les énergies renouvelables soulèvent en outre des problématiques spécifiques à chaque source d'énergie. L'une d'entre elles provient du fait que l'électricité d'origine solaire ou éolienne, par exemple, ne peut pas encore être produite à des prix compétitifs par rapport aux sources plus classiques d'énergie telles que le pétrole, le gaz ou l'énergie nucléaire.

Pour encourager le développement des énergies renouvelables non-compétitives et disséminées, de nombreux Gouvernements ont instauré des politiques publiques de subvention fiscale et d'obligation d'achat, par lesquelles les gestionnaires de réseaux de transport ou de distribution, ou les fournisseurs, sont non seulement tenus de raccorder au réseau les producteurs, mais encore d'acheter l'électricité produite à un prix réglementé qui est généralement fixé à un niveau incitatif, et ce quelle que soit la taille des producteurs.

Le surcoût généré au niveau des gestionnaires de réseaux par ces obligations incitatives est souvent répercuté sur l'ensemble de la collectivité des clients d'électricité, qui en assure donc le financement indirect.

De telles incitations ont vocation à soutenir le développement du marché jusqu'à ce que les avancées technologiques permettent de ramener le coût de production du mégawatt-heure d'électricité renouvelable à des niveaux comparables à celui des sources classiques. La question du montant optimal de subvention de la production d'électricité d'origine renouvelable peut être posée.

Par ailleurs, les réseaux de distribution et de transport d'électricité sont des monopoles naturels en raison du caractère non dupliquable des infrastructures associées. En France, une filiale d'EDF, RTE (Réseau de Transport d'Electricité) possède le monopole de la gestion des infrastructures de transport tandis que les réseaux de distribution sont concédés par les communes soit à ErDF (Electricité Réseau Distribution France), autre filiale d'EDF, soit gérés en régie municipale, c'est-à-dire directement par les communes ; ce dernier cas de figure se rencontre sur environ 5 % du territoire national.

Ces réseaux en monopole constituent des points de passage obligés lors d'un projet dans le domaine des énergies renouvelables, puisque l'obligation de rachat de l'électricité ne peut s'appliquer qu'à partir du moment où l'installation renouvelable est raccordée au réseau.

Or, en l'absence de régulation du secteur, il se peut que les gestionnaires de réseaux procèdent de manière discriminatoire au raccordement des producteurs indépendants d'électricité d'origine renouvelable.

Une première raison possible pour un tel comportement peut être que ces gestionnaires considèrent que le raccordement de petits sites de production d'électricité d'origine renouvelable est peu rentable en raison de leur taille limitée, ce qui revient à estimer que les compensations accordées par l'Etat sont insuffisantes.

Une autre raison possible pour un refus ou des délais exagérés de raccordement peut être que des entreprises liées aux gestionnaires de réseaux (entreprise-mère, filiales), voire les gestionnaires de réseaux eux-mêmes, développent également des activités dans le domaine des énergies renouvelables. Dans ce cas, le gestionnaire de réseau peut être tenté de favoriser sa propre production par rapport à des productions indépendantes, par exemple en raccordant de manière prioritaire et plus rapidement ses propres installations. C'est pour remédier à ce risque que le deuxième paquet de libéralisation du marché intérieur du gaz et de l'électricité a mis en place des dispositions pour garantir la séparation fonctionnelle, comptable et juridique des activités de production et de gestion des réseaux. Il interdit par ailleurs tout traitement discriminatoire des utilisateurs de la part des gestionnaires de réseaux, notamment en ce qui concerne le raccordement des utilisateurs à leurs réseaux. Ces dispositions viennent d'être rendus beaucoup plus rigoureuses dans le cadre du troisième paquet. Elles ont été transposées en droit français et le respect de ces dispositions par les gestionnaires de réseaux fait l'objet d'un contrôle attentif de la part des pouvoirs publics (Etat et autorité de régulation).

Des abus de monopole ne peuvent cependant pas être exclus a priori et appellent la vigilance des autorités de concurrence comme des autorités de régulation sectorielles. Pour cette raison, les autorités de régulation sectorielles peuvent généralement être saisies des litiges découlant des procédures de raccordement et rendre des décisions contraignantes. L'autorité de régulation française dispose ainsi d'un comité de règlement des différends et des sanctions.

Pour éviter une éventuelle distorsion de concurrence trop importante du marché en faveur des énergies renouvelables, les tarifs de rachat font régulièrement l'objet d'une réévaluation par l'Etat. Ainsi, la France a notamment pris le 12 janvier 2010 un arrêté supprimant une « niche tarifaire », qui risquait de conduire à des phénomènes de spéculation sur les installations photovoltaïques.

Les compteurs ou réseaux intelligents (smart meters ou smart grids) sont une autre thématique d'actualité dans le secteur de l'énergie.

Les compteurs intelligents permettront au fournisseur d'électricité comme au consommateur de connaître en temps réel ou presque la consommation réelle de ce dernier, et donc de formuler des offres plus variées car mieux adaptées au profil de consommation. A terme, ces dispositifs permettront le développement d'offres adaptées au profil de consommation.

Un des enjeux concurrentiels liés aux compteurs intelligents est l'accès aux données de comptage, caractéristiques de la consommation des utilisateurs, qui sont des données commerciales sensibles à la fois pour le consommateur, et pour son fournisseur en titre.

La future réglementation communautaire en matière d'électricité et de gaz naturel (le « troisième paquet » de directives communautaires relatives au développement du marché de l'électricité et du gaz

naturel) prévoit déjà que le consommateur devra pouvoir disposer sans frais de l'ensemble de ses données de consommation et pouvoir les transmettre à tout fournisseur qu'il aura expressément autorisé. Au-delà de ces obligations d'information, le troisième paquet fixe également un objectif concernant le déploiement des compteurs intelligents d'ici 2020 : en fonction des résultats d'une étude coûts-bénéfices qui devra être menée dans un période de trois ans après l'entrée en vigueur, les compteurs devront ensuite être déployés sous 10 ans. 80 pour cent de ces installations devront être effectuées d'ici 2020.

Cette disposition est de nature à fluidifier la concurrence entre fournisseurs, en permettant aux fournisseurs ou aux propriétaires du compteur (s'il s'agit du gestionnaire de réseau de distribution), d'avoir accès aux données de consommation que le client souhaite communiquer aux fournisseurs concurrents susceptibles de formuler une offre plus avantageuse basée sur la consommation réelle.

Il convient de noter que la multiplication des possibilités d'heures creuses et de tarifs associés incitera les consommateurs à adopter de bonnes pratiques environnementales/d'économie d'énergie.

Une expérimentation d'envergure de déploiement de compteurs évolués a été lancée en France par ErDF.

Un enjeu concurrentiel potentiel concerne le processus de mise en place de ces réseaux et compteurs intelligents. Une vigilance des autorités est nécessaire pour s'assurer que les choix technologiques des gestionnaires de réseaux soient neutres au regard des différents acteurs. Dans cette optique, la mise en place de procédures transparentes de concertation et de mise en œuvre, telles qu'elles sont pratiquées en France par la CRE et par ERDF, est une bonne pratique qu'il est possible de recommander.

GREECE

1. Introduction

The introduction of competition in the electricity market in Greece is progressing at a rather moderate speed. The incumbent electricity utility, Public Power Corporation (PPC SA) besides being the owner of both Transmission and Distribution networks, still has above 95 % of the market in both competitive sectors (generation and supply).

There is no formal demand side participation in the wholesale market in Greece. The demand's involvement in the market is minimal and may only be affected indirectly, through the minimisation of the use of electricity by a limited number of industrial customers during peak hours, when the price of electricity is high. Nevertheless, although these measures do reveal some elasticity of the consumers to the high prices during peak hours, in general they are considered as adequacy-of-supply measures.

At the end of 2008, apart from PPC SA, supply licenses had been granted to 37 other companies. None of these companies are affiliated to the Transmission System Operator (TSO) or Distribution System Operator (DSO) businesses. It should be noted that, until recently, independent suppliers were mainly active in trading rather than in retail supply.

Despite the procedures being in place for supplier switching, there has been minimal competition in the retail market due to the following factors:

- Regulated retail tariffs have not been cost reflective and contain cross-subsidies between the different tariff groups.
- Due to the market dominance of PPC, there is lack of information on consumer characteristics, including typical load profiles.
- Consumers are still not fully aware of their freedom of choice of supplier.
- End-user retail tariffs until very recently (October 2009) were bundled, i.e. not separated by activity.
- There is no independent Distribution System Operator (currently PPC SA acts as DSO) and no Distribution Code (although there is a draft version which went through public consultation in 2008).
- The revision of the Supply Code, which will introduce more favourable switching conditions for consumers, is pending.
- Details of the regulations governing the Supplier of Last Resort have not yet been finalised.

The Renewable Energy sector is rather developed (mainly hydro units, including units with large reservoirs, photovoltaics, and wind energy). Concerning smart grid issues (smart metering, etc) one must

admit that no significant capabilities exist on the network and the relevant discussion may be considered as being at its very early stages in Greece. A more detailed analysis concerning RES in Greece and smart grids follows below.

2. Renewable sources of electricity

2.1 Wholesale pricing

- Feed-in tariffs for RES in Greece are usually regulated once a year.

- There are different prices for small scale PV (photovoltaics) and large-scale PV. There is no specific documentation according to which the prices are set. Prices are initially set by Law. After that, they are yearly updated (almost always increased) through Ministerial Decree following an "opinion" granted by the Regulatory Authority.

- A subsidy is provided for the investment cost, and this is in the order of 40% of the initial investment.

- Feed-in tariffs vary for the different forms of RES. Current tariff levels do not equally support all RES forms (eg. tariffs for biomass are considered rather low, whereas tariffs for wind and - PV) could be characterised generally as rather "generous"). Of course, this is partially attributed to the cost of each RES form, i.e. more support is given for RES which are closer to being competitive to conventional generation, so as better to utilise the available funds.

- Flexible time-of-day pricing is not common in Greece (see below, for High and Medium Voltage customers). Residential customers (Low voltage) have only the option of a "night-tariff".

- There is no specific administrative or market measure to induce customers to use more expensive energy sources.

- It is perceived that changing the type of meter of residential customers and by providing to them more data concerning the cost of their consumption will change their attitude.

2.2 Investment

- Although, as already mentioned, tariffs for wind and PV are rather "generous", there is no excessive investment and distortion in production from RES in Greece, as yet.

- Transmission network capacity today is not the limiting factor for RES in Greece: according to the Hellenic Transmission System Operator (HTSO), the interconnected system (i.e. not including non-connected islands) could accept energy injection from intermittent RES generation above 7,000 MW by the year 2012-13; it is the overall system balance which constitutes a more binding constraint, i.e. in the order of 5,500 MW of intermittent RES (mainly wind) by year 2012-13. However, currently installed intermittent RES generation in the interconnected system does not exceed 1000 MW, and the rate of new installations is in the order of 200 MW/yr. It is expected that this rate will increase due to forthcoming legislation.

- Investment to extend or build transmission is planned by the Hellenic TSO, according to projected needs over a 5-yr horizon. The HTSO's plan is approved on a yearly basis by the Minister (following an opinion by the Regulator). The HTSO has the mandate of implementing the approved plan. The incumbent electricity utility, PPC, being the owner of the transmission

system, is primarily responsible for building new lines. The HTSO has also the capacity to build new lines by assigning such projects to 3rd parties.

- New transmission is finally paid by electricity consumers (regulated transmission tariffs in the electricity bill).

2.3 *Output plans and minimum purchases*

- The following are classified as RES:
  - wind energy
  - solar energy
  - wave energy
  - tidal energy
  - geothermal energy
  - hydraulic energy
  - energy from biomass & biofuels (landfill gas, sewage treatment plant gas, etc.)
- The Government has plans to increase renewable generation up to 40% of total electricity consumption by the year 2020.
- There are no minimum purchase/output requirements for RES.
- There is no mechanism in place for trading renewable energy credits.

2.4 *Connection to the grid*

- Connection rules are rather clear. There are still some issues to resolve such as transferring the ownership of the connection assets (equipment + land) to the Transmission System owner (i.e. the PPC).
- RES generators currently may wait long for being connected. The reason for this is that the HTSO "reserves" network capacity is at a very early stage of the licensing process. Thus, projects with long delays in environmental licensing still have reserved transmission capacity; this results in hindering subsequent applications from being processed in cases with limited transmission capacity.
- Connection costs are calculated on the basis of unit costs suggested by the HTSO and approved by the Minister (following an opinion by the Regulator).
- The incumbent generator (PPC), being also primarily responsible for building new capacity, may in some cases have incentives to limit transmission capacity of RES generators.

2.5 Dispatch in response to demand

For the time being, the installed capacity of RES in the interconnected system is not at levels high enough to justify efforts to adapt load demand to RES generation.

2.6 Vertical and horizontal issues

- Generation companies own both RES and conventional plans.
- Bundles of RES and non-RES output are not allowed by current market operation rules.
- All RES generation is dispatched to and absorbed on a priority basis by the wholesale market (mandatory pool). Thus, there is no possibility to exercise any monopsony power.

3. Smart grids

3.1 Status of adoption and demand response

- *Smart grid adoption:* Currently, no elements exist on the network that could be characterised as "smart grid" capabilities and there is no relevant discussion. A couple of small scale pilot projects have been deployed by the Distribution Company (Distribution Network Operator - DNO) to evaluate broadband communication over power lines. Results are pending.
- *Demand response:* There is no permanent active demand response system in place. Basic (passive) demand side management is promoted through the incumbent supplier tariffs for: a) large (High Voltage) industrial customers, whose tariffs include price differentiation between predetermined periods of low, intermediate and high system demand, b) Medium Voltage customers (industrial and commercial), who are given some incentive to reduce demand during mid-day periods of high system demand, c) Low Voltage customers (including residential), to whom more simple tariff options (daytime and night-time tariffs) are available.
- *Smart metering:* Electronic interval (hourly) metering capability exists for high voltage (large industrial) and medium voltage customers, representing in total approx. 35% of peak demand; however real time price information relay to these customers through the metering or network infrastructure is not supported.
- *Customer benefits from reduced demand:* Apart from benefits through the incumbent retailer tariffs, distribution network customers, regardless of their retailer, currently enjoy a reduction in distribution network charges by shifting their demand to periods of low system demand.
- *Demand response products in wholesale markets:* Market design foresees the submission of price-related power requests by load representatives, however this option is not active at the moment. Moreover, only a relatively small number of retailers are currently competing with the incumbent retailer and demand response product offering to their customers is yet to be seen.

3.2 Standards

The risk of network development coming second to or being affected by the interests of the incumbent retailer to minimise exposure to competition is naturally present to a certain degree and is exacerbated by insufficient unbundling. Regulatory involvement in the network planning process is in any case necessary.

3.3 Ownership

Network infrastructure, including metering devices, is owned by the Distribution Company. As far as "smart grid" technology is concerned, it seems reasonable to design and standardise certain "core" communication functions of the network, enabling development and use of a variety of end-user communication and control devices. This should make provision of such devices possible by the DNO and the retailers, as well as through the relevant marketplace. In all cases, the customer should have the option to obtain ownership of infrastructure installed "beyond the meter".

3.4 Information

There are currently no "smart grid" customer capabilities.

3.5 Monopsony buyer

Small-scale, non-centrally dispatched generation (mainly RES and small Combined Heat and Power - CHP) is absorbed on a priority basis and remunerated according to regulated prices (feed-in tariffs, refer to Q.1 above).

3.6 Revenue reduction incentives

Exposure to high wholesale prices and a capacity assurance mechanism, which obliges retailers to contract capacity in proportion to their customers' demand during periods of high system load, are considered effective incentives for retailers to develop and provide demand response products and solutions to their customers.

HUNGARY

The scope of this contribution is limited to renewable electricity since Hungary hardly has experience so far regarding smart grids.

1. Wholesale pricing

Prices offered for electricity generated by renewables are sometimes regulated. How often are the prices regulated? Are there different prices for small-scale production and large-scale production? How are the prices set for small-scale and large-scale producers? How large is the subsidy for different forms of renewable production, if there is any subsidy? Are there any competitive distortions that have been alleged as a result of renewable pricing policies? How common is flexible, time-of-day pricing to electricity customers? How do you induce customers to use more expensive energy sources? How do you change consumer incentives? Can types of meters and access to data change incentives?

Hungary has been promoting renewable based electricity (RES-E) investments and generation efficiency (combined heat and power generation (CHP)) since 2003 via a feed-in tariff scheme. The system is called Mandatory Power Purchase regime (MPP), which now basically consists of a guaranteed feed-in-tariff paid by the Transmission System Operator (TSO) to the eligible power plants for a certain period of time to cover the costs of their investments and an allocation mechanism, which distributes the MPP electricity among all consumers and fully covers the associated costs of the TSO.

The TSO is mandated to purchase any electricity produced by the eligible plants. The MPP encompasses not only renewable plants but waste combustion plants and cogeneration plants (CHPs) as well. The reasoning behind the participation of CHPs is based on their high efficiency rates. Those CHP plants that start commercial operation before 31 December 2010 are eligible to participate in the MPP regime.

The feed-in tariff is determined by a government decree, however the maximum price is set by the Electricity Act. The tariff is different according to production scale, resource type and time-of-day – however the differentiation is not really effective. The decree defines three time-zones: peak, off-peak and "deep off-peak". For the new power plants generating renewable electricity there are four price categories:

All plants smaller than 20 MW and using renewable resources

- except:
  - wind energy
  - solar energy
  - water energy over 5 MW

Solar energy below 20 MW (no time-zones, but the average price is about the same as in category (a))

(c) All plants between 20 – 50 MW and using renewable resources

- also
  - water energy between 5 – 20 MW
  - plants with older parts (i.e. already running before starting to produce electricity from renewable resources)
- except wind energy

(d) New wind energy capacities (below 50 MW) can be attained on tenders, the price is based on the bids on the tenders

The TSO allocates the electricity traders, universal service providers and electricity importers the MPP electricity, proportionate to their traded quantities (which will be passed on to the final consumers). They pay for the MPP electricity via a separate fee (called MPP fee), while the consumers' payment for the MPP electricity is included in the retail price. Thus, there is neither need nor scope for consumer incentives to facilitate RES-E consumption because consumers do not have choice as MPP electricity – including RES-E production – is allocated by the TSO.

A renewable or a waste combustion plant or a CHP is eligible for the MPP tariff when the regulator accepts its request based on the fulfilment of a few conditions regarding efficiency and the utilization of the by-product heat (CHPs are encouraged to sell the heat for district heating). Then it determines the amount of electricity eligible for MPP and computes the time needed for the return of investment. So the participation in the MPP regime is limited in time.

The subsidy (a transfer from consumers to generators through the TSO) provided by the MPP regime is the difference between the feed-in tariff and the market price. Thus, the size of the subsidy also depends on the production scale and the resource type. Moreover, it is different in time (apart from the time-zones), as the guaranteed feed-in tariff does not reflect market price changes. For example, during the current recession demand and accordingly market prices fell significantly but the guaranteed price remained unchanged, so the size of the subsidy increased.[1] The total subsidy paid for MPP electricity in the first half of 2009 was app. 43 billion HUF (app. 148 million euros).[2]

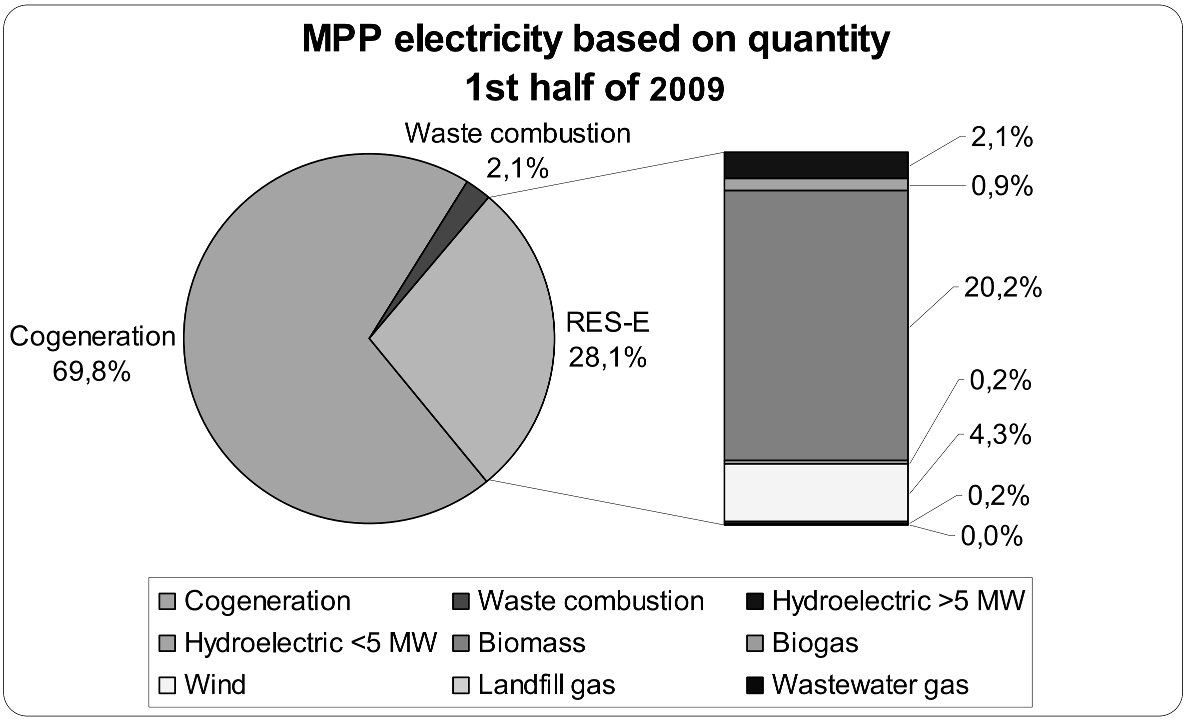
As mentioned before, the MPP regime subsidizes not only real renewables but also certain CHPs which use natural gas as their primary energy source. This implies a two-fold problem. First, the guaranteed off-take obligation at higher prices withdraws these CHPs from the electricity wholesale market resulting in fewer market participants and in less competition. Second, the high volumes sold by these CHPs in the MPP regime at higher than market prices inevitably drive up electricity retail prices. The share of CHPs among power producers eligible for MPP accounted for around 70% in 2009, while in the same year the volume of electricity generated in the MPP regime altogether reached as much as 20% of Hungary's total production. This means that around 15% of the domestic electricity generation is produced

[1] In the first half of 2009 the average subsidy was 11.87 HUF/kWh compared to the 10.59 HUF/kWh in the first half of 2008, which is a 12% increase. However, because of the depreciation of the HUF during the crisis it was 4,09 and 4,17 eurocents respectively.

[2] More details can be found in the Appendix.

by CHPs that are not operating under real market conditions. According to the view of some energy market experts the operation of many CHPs– mainly the larger ones – currently subsidized via the MPP regime could be viable by competing on the electricity market. If this was the case then one could not exclude the possibility that the participation of competitive CHPs in the MPP regime might constitute illegal state-aid under EC law.

The share of the different energy sources subsidized by the MPP regime is shown in the following figure.



2. Investment

If wholesale prices for renewable energy yield an excessively high return on investment, they may lead to excessive investment in renewable technologies generally or distributed energy in particular. Is there any evidence of excessive investment and distortion in production arising from such investment? How do you encourage investment in renewable energy due to lack of assurance of transmission and, similarly, encourage investment in transmission absent renewable generators? Is investment to extend or build transmission mandated? Who pays for new transmission?

Feed-in tariffs for renewable energy do yield an extraordinary high return on investment for certain technologies (e.g. wind), whereas for other technologies investments do not pay back with the current feed-in level (e.g. geothermal). However, if excessive investment is defined by Hungary's commitment (as an EU member state) to raise the RES proportion to 13% by 2020 then it is far from excessive since in 2007 renewables (mainly biomass) accounted for 6% of total consumption.

Because of the apparent high intention for investments, there was some fear of excessive wind generation that could cause system stability problems, thus balancing market problems. The regulator tackled this fear by implementing a quota system maximizing (in 330 MW – app. 3,4% of Hungary's total production capacity) the wind generation capacity eligible for the MPP regime. This system triggered

substantial speculation on the tender allocating the quotas, so in the end a significant part of the quotas was purchased by agents who did not intend to build any wind generation and planned to sell their quotas later.

The Hungarian Energy Office has carried out detailed studies and extended the wind generation quota with another 410 MW (app. 4,2% of Hungary's total production capacity). This will be allocated on a tender too.

Currently Hungary's main source of renewable energy is biomass: 70 percent of all renewables. The significant share of biomass is due to the fact that it is the cheapest renewable technology in Hungary, and also to the dominant role of co-firing power plants (which operated on coal basis before). There are some studies showing that this might be excessive compared to sustainable input availability.

However, regarding geothermal energy investments (the geographical characteristics of Hungary are exceptionally favourable for this type of energy) it is quite the opposite. The viable technology using geothermal energy is cogeneration, so these investments would need to access district heating markets. However, each of these local markets has a single district heating provider (owned by the local government), which usually enters in long term purchasing agreements to cover all of its demand, which constitutes a significant obstacle for geothermal investors planning to enter the market. In result, although, geothermal energy has economic potential, there has not been significant investments taken place so far.

3. Output plans and minimum purchases

What are the current output requirements for renewable energy sources? What sources are classified as "renewable". Do government or operators have plans to increase renewable generation in the future? If so, what are these plans? Are there minimum purchase/output requirements for renewables? How are these put into operation? Who has the responsibility for adopting renewable sources (the system operator, independent distribution companies, etc.)? How do minimum purchase plans tie into transmission capacity? Is there a mechanism for trading renewable energy credits? If so, how does that function?

In Hungary the Electricity Act classifies all non-fossil and non-nuclear based energy as "renewable". Thus, the definition of "renewable" encompasses solar, wind, geothermal, hydro, biomass and any kind of biogas based energy. Nevertheless, as mentioned before, the MPP regime subsidizes not only renewable electricity production but cogeneration as well.

Since 2008 eligible power plants have been required to provide a schedule a month ahead (which can be altered one day earlier). There is a penalty fee if a plant deviated from its schedule. The allowed deviation from the schedule is set by the government decree (5% for all eligible plants except wind, for which it is 30%).

The government has to increase RES, according to the EC commitment. There are several forms of promotion of RES besides MPP, like tax exemption for biofuels, investment subsidies from EU funds. However, besides the MPP regime there is no scope for renewable energy credits.

MPP is different in the case of household power plants where not the TSO but the universal service providers are obliged to take off the produced electricity. Household power plants are mainly (99%) based on solar energy. Their number is increasing, however their share in the total electricity production is still negligible.

4. Connection to the grid

Are connection rules for renewable electricity suppliers clear and transparent? How long do renewable generators need to wait to get connected? On what basis are connection costs calculated and allocated? Do incumbent generators have incentives to limit transmission capacity of renewable generators? If so, how can these incentives be changed?

The Distribution Grid Code contains the detailed technical rules of the connection of renewables and household power plants to the distribution network (mainly these power plants connected to the distribution network). The Code is publicly available on the websites of the distribution companies. According to the legislation these power plants have to pay 50% of the connection fee, the remaining part is paid by the distribution company.

5. Dispatch in response to demand

A commonly cited challenge with renewable generation is that production often depends on external forces that cannot be controlled by the operator. For example, wind power depends on the presence of appropriate atmospheric conditions. What efforts are being made to increase the ability to dispatch renewable energy resources in response to demand? How common are contracts that allow the electricity network operator to temporarily "shut down" small-scale or large-scale electricity users at peak periods, helping it to adapt to the potentially limited ability of renewable generation to provide electricity? How common is flexible pricing that can change on a daily and hourly basis?

Currently there are no incentives to dispatch eligible plants in response to demand because the feed-in tariffs are always higher than the balancing market prices. However, the feed-in tariffs are different according to the time-zones, which is an incentive, although not that flexible. The TSO and the Hungarian Energy Office try to find new ways to include MPP plants in the balancing market. The TSO will be empowered to shut down wind energy capacities if needed. The compensation rules are not fully elaborated yet.

Regulations enable users to offer balancing energy to the market but it is rare in practice. Probably the rules of participation in the demand side management are too complex for the industrial customers, the technical conditions (capacity, gradient, duration, etc.) can be fulfilled only by a few of them; moreover the regulator feels that the customers lack information and interest in participation.

6. Vertical and horizontal issues

Do generating companies own both renewable and non-renewable plants? Can such generators create bundles of renewable and non-renewable plant output? Are some electricity companies able to exercise monopsony power in the purchase of renewable electricity? Can such purchasers foreclose new producers to the benefit of their own generation?

Some smaller scale acquisitions have taken place in the industry: conventional incumbents (earlier not involved in RES-E production in Hungary) have acquired some previously independent renewable based capacities. Nevertheless, it is not clear if these developments are indicative as for future market structure (e.g. whether RES-E production will represent a sort of new entry or rather it will be present through the diversified portfolio of conventional incumbents. These acquisitions were under the merger control threshold therefore the GVH did not deal with them in detail.

APPENDIX

MPP electricity and subsidies in the first half of 2008 and first half of 2009 in HUF

	Purchased electricity			Subsidy			Average subsidy	
	2008/I	*2009/I*	*Change*	*2008/I*	*2009/I*	*Change*	*2008/I*	*2009/I*
	GWh		*%*	*million HUF*		*%*	*HUF/kWh*	
Renewables total	808,2	1 013	25%	8 312	11 474	38%	10,28	11,33
Out of:								
Hydroelectric >5 MW	71	75,4	6%					
Hydroelectric <5 MW	24	33,2	38%	254	380	49%	10,61	11,44
Biomass	608,9	729,9	20%	6 861	8 958	31%	**11,27**	**12,27**
Biogas	9,4	8,9	-6%	102	103	1%	10,81	11,56
Wind	86,7	156,4	80%	1 003	1 926	92%	**11,57**	**12,31**
Landfill gas	7,4	7,6	4%	80	90	13%	10,88	11,83
Wastewater gas	0,9	1,5	65%	11	18	67%	**11,3**	11,43
Waste combustion	15,7	75,1	379%	110	538	390%	7	7,16
Cogeneration	2 264	2 520,30	11%	24 625	30 906	26%	10,88	**12,26**
Total	3 153,70	3 615,30	15%	33 408	42 918	28%	10,59	11,87

*The three largest average subsidies are emphasised

MPP electricity and subsidies in the first half of 2008 and first half of 2009 in Euros

	Purchased electricity			Subsidy			Average subsidy	
	2008/I	*2009/I*	*Change*	*2008/I*	*2009/I*	*Change*	*2008/I*	*2009/I*
	GWh		*%*	*thousand euros*		*%*	*eurocents/kWh*	
Renewables total	808,2	1 013	25%	32 762	39 532	21%	4,05	3,90
Out of:								
Hydroelectric >5 MW	71	75,4	6%					
Hydroelectric <5 MW	24	33,2	38%	1 001	1 309	31%	4,18	3,94
Biomass	608,9	729,9	20%	27 043	30 863	14%	4,44	4,23
Biogas	9,4	8,9	-6%	402	355	-12%	4,26	3,98
Wind	86,7	156,4	80%	3 953	6 636	68%	4,56	4,24
Landfill gas	7,4	7,6	4%	315	310	-2%	4,29	4,08
Wastewater gas	0,9	1,5	65%	43	62	43%	4,45	3,94
Waste combustion	15,7	75,1	379%	434	1 854	328%	2,76	2,47
Cogeneration	2 264	2 520,30	11%	97 060	106 481	10%	4,29	4,22
Total	3 153,70	3 615,30	15%	131 678	147 867	12%	4,17	4,09

* The apparent contradiction between the trends in the figures in HUF and in euro is due to the significant depreciation of the HUF.

JAPAN

1. Renewable sources of electricity

1.1 Wholesale pricing

1.1.1 Prices offered for electricity generated by renewables are sometimes regulated. How often are the prices regulated? Are there different prices for small-scale production and large-scale production?

The Ministry of Economy, Trade and Industry (METI) launched the "New Purchase System for Solar Power-Generated Electricity" (feed-in tariff, FIT) in November 2009. Under this system, electricity utilities are obliged to purchase excess electricity generated by photovoltaic power generation system (covering systems with a capacity of less than 500kW) remaining after self consumption at a purchase price roughly twice the conventional rates. Also, expenses associated with power purchase are paid by all electricity customers. Specifically, obligation fees named "Solar Power Surcharge" are added on electricity charges in proportion to the volume of electricity consumption.

METI revises the FIT purchase price every year. Also, wholesale prices for portions that exceed a specified scale and period are determined, regardless of the type of power resource, in accordance with the Electricity Business Act. All rates other than the above are unregulated and set by the market.

In addition, Japan Electric Power Exchange (JEPX) started the Wholesaling of Green Electricity, etc. in November 2008 on a trial basis.

1.1.2 How are the prices set for small-scale and large-scale producers?

In fiscal 2009, METI set aside a budget of approx. 112.7 billion yen for the introduction of photovoltaic, wind and biomass power generation, heat utilization and other renewables. (Breakdown: Beginning of fiscal 2009: 70.8 billion yen/After supplementation in fiscal 2009 (after returns): 41.9 billion yen)

1.1.3 How large is the subsidy for different forms of renewable production, if there is any subsidy? Are there any competitive distortions that have been alleged as a result of renewable pricing policies?

We are not aware of any discussion to that effect.

1.1.4 How common is flexible, time-of-day pricing to electricity customers?

All electricity utilities offer a range of time-of-day rate options for daytime, nighttime, etc. for both large-scale and small-scale customers.

1.1.5 How do you induce customers to use more expensive energy sources? How do you change consumer incentives?

The system does not offer incentives for electricity customers that would favor power suppliers with a greater capacity to utilize renewable energies.

On the other hand, Japan employs the Renewable Portfolio Standard (RPS) system, which mandates electricity utilities to use a specified amount of electricity from renewable energies.

1.1.6 Can types of meters and access to data change incentives?

Electricity utilities are required to use a meter that has passed the official examination in accordance with Measurement Act. The government, however, sets no regulation on the type of meters to be employed.

1.2 Investment

1.2.1 If wholesale prices for renewable energy yield an excessively high return on investment, they may lead to excessive investment in renewable technologies generally or distributed energy in particular. Is there any evidence of excessive investment and distortion in production arising from such investment?

We are not aware of any evidence to that effect.

1.2.2 How do you encourage investment in renewable energy due to lack of assurance of transmission and, similarly, encourage investment in transmission absent renewable generators? Is investment to extend or build transmission mandated?

N/A.

1.2.3 Who pays for new transmission?

Regarding the extension or development of transmission facilities, electricity utilities in charge of management of transmission/distribution networks in the area in question examine possibilities for system reinforcement if and when they are not able to sustain supply reliability. While investment to extend or develop transmission facilities is not mandatory, electricity utilities are under the obligation to ensure stable supply of electricity. In the case of new transmission facilities, the party who builds a new power generation facility pays all the cost.

1.3 Output plans and minimum purchases

1.3.1 What are the current output requirements for renewable energy sources?

At present, there are no requirements on output of renewable energy based power generation.

1.3.2 What sources are classified as "renewable".

"Renewable energy sources" are defined in enforcement ordinance of the Act on the Promotion of the Use of Nonfossil Energy Sources and Effective Use of Fossil Energy Materials by Energy Suppliers (Act No. 222 of August 27, 2009) as follows (Renewable energy sources):

- Photovoltaics

- Wind
- Hydro
- Geothermal
- Solar heat
- Atmospheric and other heat sources in nature (excluding geothermal and solar heat)
- Biomass (organic matter derived from plants and animals that can be utilized as energy sources (excluding crude oil, petroleum gas, flammable natural gas, coal and coal-derived fuels (including byproducts obtained in coal production that are used for combustion)))

1.3.3 Do government or operators have plans to increase renewable generation in the future? If so, what are these plans?

In its manifesto, the Democratic Party of Japan (DPJ), the current party in power, sets as one of its targets: "Increase the ratio of renewable energy to total primary energy supply to around 10 percent by 2020."

1.3.4 Are there minimum purchase/output requirements for renewables? How are these put into operation?

In Japan, the Act on Special Measures concerning New Energy Use by Electricity Utilities (RPS Act), promulgated in 2002, mandates electricity utilities to use, at a minimum, a specified amount of electricity from new energy or other renewables. Under the RPS Act, the government sets, every four years, the "usage target" for eight years and allots the obligation amount according to the volume of electricity supplied by the respective utility. The "usage target" is determined after comprehensively examining the trends of energy, global environmental problems and other factors, status of new energy introduction, moves in the development of new energy technology, prospects for cost reduction, volume of feasible introduction and international progress in the field.

For new and other renewable energies mandated under the RPS Act, which entail high power generation cost, the eventual cost burden is passed on to customers in the form of electricity cost while electricity utilities make an effort to streamline their acquisition operations.

1.3.5 Who has the responsibility for adopting renewable sources (the system operator, independent distribution companies, etc.)?

The government operates the RPS system to promote the introduction of renewable energy. Private operators are looking to expand the utilization of renewable energies including wind power generation under this system.

1.3.6 How do minimum purchase plans tie into transmission capacity?

At this time, introduction obligations under the RPS Act are not determined in combination with transmission capacity.

1.3.7 Is there a mechanism for trading renewable energy credits? If so, how does that function?

In Japan, the "Act on Special Measures concerning New Energy Use by Electricity Utilities" (RPS Act), promulgated in 2002, mandates electricity utilities to use, at a minimum, a specified amount of electricity from new energy and other renewables. The obligated parties under the RPS Act may seek to meet their obligations by purchasing "Renewable Energy Certificates (New Energy Certificates)" from other utilities, in addition to conducting new energy based power generation or purchasing new energy-based electricity.

The "Renewable Energy Certificates" are equivalent to their value in new energy, etc. that can be traded among utilities apart from electricity.

Also, the private sector has a mechanism called "Green Power Certification System." Under this system, electricity generated by photovoltaic, wind, hydro, geothermal and biomass power (green power) is split into electricity and "added environmental value" and added environmental values are converted into a certificate that can be traded. By purchasing the certificates, electricity customers can assume that the power they use is green.

1.4 Connection to the grid

1.4.1 Are connection rules for renewable electricity suppliers clear and transparent? How long do renewable generators need to wait to get connected?

Rules for system interconnection (http://www.escj.or.jp/English/index.html) are clear and highly transparent. In principle, electricity utilities in charge of management of transmission/distribution networks in the area in question conduct an interconnection examination and inform the interconnection applicant of the result of the examination within three months.

1.4.2 On what basis are connection costs calculated and allocated?

The constructions cost of power supply lines is calculated according to the "Ministerial Ordinance on Coverage of Payment for Power Supply Lines" and paid by the power producer.

1.4.3 Do incumbent generators have incentives to limit transmission capacity of renewable generators? If so, how can these incentives be changed?

In the case of wind power generation, electricity utilities in charge of management of transmission/distribution networks in the area in question limit the volume of power generated from wind in the interconnection due to the difficulty of adjusting supply and demand to variable output prevalent in wind power generation.

Electricity utilities in charge of management of transmission/distribution networks in the area in question do not impose any limit on hydro- and geothermal generated power in the interconnection.

1.5 Dispatch in response to demand

1.5.1 A commonly cited challenge with renewable generation is that production often depends on external forces that cannot be controlled by the operator. For example, wind power depends on the presence of appropriate atmospheric conditions. What efforts are being made to increase the ability to dispatch renewable energy resources in response to demand?

Examinations are underway by governmental study groups and public-private councils on the construction of “smart grids,” a system of power transmission/distribution that can help promote effective supply-demand balance using telecommunications technology and realize stable power supply. Its implementation in the form of demonstration projects is currently being planned.

Also underway are demonstration projects to install storage batteries at wind power generation facilities and to level the unstable output of photovoltaic power generation, as well as development of technology for improved storage battery performance, among others.

1.5.2 How common are contracts that allow the electricity network operator to temporarily “shut down” small-scale or large-scale electricity users at peak periods, helping it to adapt to the potentially limited ability of renewable generation to provide electricity?

Electricity utilities adopt a contract with some large-scale customers in which low electricity rates are applied on condition that power supply is suspended at times of peak demand. The purpose of the contract, however, is not to support the introduction of renewable energy but to ensure stable power supply.

1.5.3 How common is flexible pricing that can change on a daily and hourly basis?

All electricity utilities provide time-of-day rate options for peak shifts and peak cuts by employing a meter that combines the meter with clock. The default is normal rates but customers may select time-of-day option.

1.6 Vertical and horizontal issues

1.6.1 Do generating companies own both renewable and non-renewable plants? Can such generators create bundles of renewable and non-renewable plant output?

Many electricity utilities own power plants based on renewable energy and non renewable energy. Also, these utilities supply electricity by making good use of renewable and non renewable energies in a combined manner, partly to deal with the enhanced need to respond to global warming.

For fulfilment of the obligations of the RPS system, electricity utilities accept supply from new power suppliers. The Japan Fair Trade Commission and METI have compiled ‘Guidelines for Proper Power Electric Trade,’ which is not only for the renewable energy trade, to secure proper trade in electricity market, and by this guideline the government has been keeping the new supplier not to be eliminated from the market.

Additionally, under the “New Purchase System for Solar Power-Generated Electricity,” which started in November 2009, electricity utilities are mandated to purchase excess electricity generated by photovoltaic power generation systems remaining after self consumption at a purchase price roughly twice the conventional rates. This purchase obligation is assumed by general electricity utilities stipulated in the Electricity Business Act.

1.6.2 Are some electricity companies able to exercise monopsony power in the purchase of renewable electricity? Can such purchasers foreclose new producers to the benefit to their own generation?

N/A.

2. Smart grid

(NOTE: not all countries have experience with smart grids. If your country has no smart grid experience, please respond to renewables questions (above) and respond to questions below only as seems appropriate.)

2.1 Status of adoption and demand response

2.1.1 What is the status of smart grid adoption in your country? Are large customers (e.g., factories) tied in to a peak-demand response system?

In Japan, as the result of continuing efforts to build advanced transmission/distribution networks by utilizing information technology to date, the ratio of automation of the networks is higher than other jurisdictions, thus, the reliability on electricity supply has been kept in high level. Also, electricity utilities adopt a contract with some large-scale customers in which low electricity rates are applied on condition that power supply is suspended at times of peak demand.

2.1.2 What is the extent of "smart metering" whereby customers can see and respond to real time to price changes? What evidence exists of their potential effects in your jurisdiction?

Although there is no set definition of "smart metering," the Japanese government's Council for Regulatory Reform has drafted a proposal, which seeks to "pursue the reform of all mechanisms triggered by the introduction of smart metering beyond mere computerization of electricity measurement and sophistication of functions; for example, the system of two-way communications among meter operators that is generated as a consequence, improved operations at electricity utilities and diversification of customer services." The government currently provides support to demonstration tests on energy conservation and load leveling effects realized through the implementation of real-time billing programs.

2.1.3 How do you ensure that customers would benefit from reducing their demand?

Customers enjoy the benefits of reducing their demand in the form of lower electricity bills.

2.1.4 Who receives the monetary benefit of system cost reductions from demand reductions?

Parts of the monetary benefit of system cost reduction are fed back to customers in the form of lower electricity unit rates.

2.1.5 How do you choose a benchmark for measuring demand "reduction"?

Retail companies (electricity utilities) employ their respective techniques to estimate demand fluctuations and load leveling effects.

2.1.6 Is demand response a product that can be sold in competition with wholesale electricity? Can small demand responses be "aggregated" and "sold" back into the wholesale marketplace by any entities other than traditional utility suppliers?

In Japan, the nature of demand response is recognized as being different from that of wholesale electricity. For this reason, competition with wholesale electricity or sale on the wholesale market is not taken into assumption.

2.2 Standards

How are standards being determined for smart-grid elements? Are there any competition policy issuess that have surfaced for such standards? Would incumbents have an interest to ensure standards do not promote increased competition? Is there a risk that standards or devices are being devised in an inflexible way that will prevent future adaptation of the network to new standards, technologies and competitors to existing utilities?

International standards for smart-grid elements are, as in other technologies, determined by discussions among stakeholders, where related parties are convened to discuss and formulate standards. These processes are undertaken by international standardization agencies such as International Standardization Organization (ISO) and International Electrotechnical Commission (IEC) in the global setting, by forums attended by businesses in the respective technology fields in the private sector, and by governmental institutions in the case of national standards. In this regard, problems associated with competitive policy are judged based on 'Guidelines on Standardization and Patent Pool Arrangements' (June 2005 Japan Fair Trade Commission).[1]

Conducts pose the regal issues with the Antimonopoly Act (AMA) in the 'Guidelines on Standardization and Patent Pool Arrangements'

Although the standardization of specifications determines the functions or performances of the products with specifications, by accepting compatibility among the new products it enables speedy commercialization and expansion of demand and this contributes to greater consumer convenience. As such, standardization of specifications by competitors is not assumed to pose legal issues with the AMA.

However if the activity restricts competition in related markets or threatens to impede fair competition with restrictions as follows it poses the regal issues with the AMA.

- Restrict prices of new products with specifications

  Competitors in the activity jointly fix prices, quota outputs, limit marketing activities etc of their new products with specifications. (Unreasonable restraint of trade, etc)

- Restrict development of alternative specifications

  Competitors in the activity mutually restrict, without due cause, the development alternative specifications or adopt alternative specifications to produce and distribute products with them.(Note 4) (Unreasonable restraint of trade, dealing on restrictive terms etc)

- Unreasonably extend the scope of specifications

1 http://www.jftc.go.jp/e-page/legislation/ama/Patent_Pool.pdf.

Competitors in the activity jointly extend the scope of specifications when doing so is not necessary to ensure compatibility among their products, but only to mutually restrict competition in developing new products. (Unreasonable restraint of trade, etc)

- Unreasonably exclude technical proposals from competitors

  Competitors deliberately, without due cause, prevent technical proposals by a specific competitor from being adopted in the development or improvement of the technologies for specifications.(Private monopolization, discriminatory treatment in a concerted activity, etc)

- Exclusion of competitors from the activities

  Competitors deliberately exclude specific competitors from the activity in a case in which the competitors are largely not involved in developing and distributing the products with the specifications and do not participate in the activity, and are at risk of being excluded from the market. (Private monopolization, etc)

2.3 Ownership

Who owns smart-grid elements (e.g. smart meters)? The customer? Electricity distribution network operator? Electricity retailer? If a customer switches from one provider of electricity to another, must equipment be changed?

In Japan, electricity utilities serve as both electricity network operators and retailers. Electricity utilities own transmission/distribution networks including smart grids (No comment on the latter part of the question).

2.4 Monopsony buyer

Are there monopsony (single buyer) issues for the purchase of customer-generated electricity? For example, a system operator may have no regulations over how it sets prices for on-demand electricity produced through distributed generation. Have any rules been developed for such purchases? If not, how might monoposony power issues be resolved? Does the wholesale market structure eliminate or reduce the benefits of real-time pricing?

Electricity generated by customers can be sold to PPS (power producer and supplier), etc. in addition to general electricity utilities. However, general electricity utilities are under an obligation to purchase excess electricity generated by photovoltaic power generation systems installed at ordinary households, etc. in accordance with FIT (feed-in tariff). Large-scale power producers may also sell their electricity to JEPX.

The government does not impose any regulation on selling price of electricity (unless it meets certain requirements in period/scale to be regarded as wholesale supply). Electricity utilities are under an obligation to purchase excess electricity generated by PV facilities at a uniform price in accordance with FIT. The government reviews the tariff price every year for the year in which the facility was installed.

Regarding selling price of electricity in the unregulated wholesale market, it is possible to set variable prices for different time-of-day.

NETHERLANDS

1. Summary

This paper will discuss the relationship between the regulatory framework for energy networks and the development of smart grids. We will show that, provided externalities can be internalized by additional regulatory measures, the regulatory framework in principle does not hinder innovation. As an example of such regulatory measures, we show the case of distributed generation (DG) in the Netherlands. The paper will posit that the introduction of DG has led to a first step in the development of smart grids by the DSOs.

This paper will furthermore look at the experiences with smart metering in the Netherlands, with an emphasis on privacy issues and the roll-out of smart meters. The smart meter is expected to be an important aspect of a future smart grid and to be beneficial to customers. A smart meter can offer the customer enhanced insight in their energy usage and allow service providers to offer new services to the customers. In this sense, network innovation is paramount for the continued innovation at a customer level.

2. Introduction

To reduce the emission of greenhouse gasses and to enhance security of supply in Europe, the European Union has set specific targets for 2020[1]: cutting greenhouse gases by at least 20% of 1990 levels, increasing use of renewables to 20% of total energy and improving energy efficiency by 20%. These targets cover the sustainability and part of the security of supply objectives[2] of the three core objectives in implementing a European energy policy[3]. The third objective is competitiveness: to support the development of a truly competitive internal energy market.

One of the expected contributors to the above-mentioned objectives is DG. DG refers to both Renewable Energy Sources (RES, e.g. wind) and Combined Heat and Power (CHP) connected to the distribution grid[4]. DG can contribute in different ways[5], for example by reducing network losses[6], by

1 ‘Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions - 20 20 by 2020 - Europe's climate change opportunity’, COM(2008) 30 final, January 23rd, 2008.

2 It is expected that the 2020 targets contribute to security of supply, but for energy security also specific measures have been formulated, see e.g. COM(2007) 1 final (full reference in footnote 3).

3 ‘Communication from the Commission to the European Council and the European Parliament – An energy policy for Europe’, COM(2007) 1 final, January 10th, 2007.

4 In the Netherlands, the NMa has defined DG as production connected to a voltage level lower than 110 kV (‘Position paper on Distributed Generation’, May 2004, in Dutch: ‘*Standpuntendocument Decentrale Opwekking*’).

5 For a more extensive list, see e.g. ‘Position paper on Smart Grids – A CEER Public Consultation Paper’, E09-EQS-30-04, December 9th, 2009.

6 Scheepers, M.J.J., Bauknecht, D., Jansen, J.C., Joode, J. de, Gómez, T., Pudjianto, D., Ropenus, S., Strbac, G., ‘Regulatory Improvements for Effective Integration of Distributed Generation into Electricity Distribution Networks’, ECN-E--07-083, November 16th, 2007.

diversifying the supply side of the energy chain and by raising awareness of consumers by enabling them to become (small) producers.

The Netherlands has seen a rapid growth in DG, from 31% of installed power in 1999 to 41% in 2008[7]. In 2008, 10 GW of installed power is DG, of which 7.5 GW is CHP and 2.2 GW is RES (wind). The large share of CHP in DG is mainly due to the intensive use of CHP in greenhouses. In order to deal with the growing significance of DG, DSOs have to deal with a growing volatility in load as well as with a growing supply of electricity to their grid.

In principle, DSOs have two technological options to tackle this development. The first one is extending the grid, making the grid sufficiently large to facilitate both peak demand and peak supply to the grid. The other option is to use the existing grid more efficiently by using IT-technology and giving incentives to both producers and consumers to respond to the tightness of the network. The latter option is viewed to have positive effects, both for the DSOs as for energy producers and consumers.

One of the current questions facing the NMa with regard to the regulation of DSOs is, whether the current regulatory framework is neutral towards the two technological options. This is not the case if there are externalities associated with grid extension. As an example of externalities in grid extension, this paper will examine the case of DG in the Netherlands. Congestion due to DG can be solved in an innovative way, which provides a first step towards balancing on distribution level (opposed to balancing only on transmission level) and the development of a smart grid. An important component of such a smart grid is the smart meter. This paper will provide an overview of the Netherlands' experience with roll-out and privacy issues of smart meters.

3. Smart-grid challenges to regulation[8]

The Dutch regulatory framework for energy networks can be characterized as output-oriented regulation, in which the focus is on outcome parameters as total revenues and the reliability of the supply of energy. Regarding the distribution networks, total revenues are set by an efficiency factor at the efficient cost level (the yardstick), calculated as the average of the costs of all DSOs at the end of the regulatory period. The yardstick includes both capital and operational costs, so that DSOs are free to allocate the total revenues among these costs.

An important characteristic of this yardstick method is that the NMa, acting in its role as regulator, does not intervene in management decisions of DSOs. This is because the DSOs have far more knowledge concerning efficient network management than the regulators have. The well-known problem of information asymmetry between regulator and the DSO is solved by giving the DSO the freedom as well as the incentives to choose the optimal technical solution for its specific situation.

Another argument behind giving DSOs the freedom of operation stems from the fact that neither the regulator nor the DSOs know ex-ante what technique will be the most efficient one. When each DSO is able to make its own choice concerning technology, the benefits of a decentralized organization come to

7 Source: Statistics Netherlands (CBS), November 2nd, 2005.

8 This section is partly based on Mulder, M., 'Which challenges do smart grids pose to regulation?', in Auger, J.-F., Bouma, J.J., and Künneke, R. (eds.), Internationalization of Infrastructures: Proceedings of the 12th Annual International Conference on the Economics of Infrastructures, Delft, 2009.

the fore[9]. This means that there is a higher chance that the best technique will be chosen ex-post by at least one of the DSOs.

If all DSOs would make comparable investments in smart grids, all the costs of a smart grid would enter into the yardstick and the revenues of the DSOs would increase by the costs of the smart grids. However, if only some of the DSOs would make these costs, the yardstick would only rise by the share of these DSOs in the total industry and these DSOs would only be partially compensated. So, uncertainty over the investment behaviour of other DSOs creates uncertainty for prospective DSOs considering making an investment.

If some DSOs believe that investing in smart grids is the optimal approach, while others are more sceptical about the efficiency of such an investment, the efficiency of the investments is unclear ex-ante. If the investments turn out to be efficient, DSOs who have chosen this technology will, at a later stage, reap the benefits, while others, those who were hesitant to invest in the uncertain technology, will then have higher costs. In this sense, the regulation effectively deals with investments with uncertain benefits, albeit that a certain time lag will occur.

However, the regulatory framework might hamper investments in smart grids if these investments create externalities, that is, if other participants (e.g. producers or consumers) benefit from the investments without sufficiently rewarding the DSO who invests. In such a case of positive externalities, the DSOs would not invest enough. This might be the case when a new technology creates new products (such as energy-saving services or charging options for electric cars) for which no tariff products have been defined by the regulator. This externality is solved if the regulator defines appropriate product categories.

Recently, the NMa has consulted the stakeholders on the need for an innovation incentive[10], as for example employed in the UK[11]. In their responses, some stakeholders argued that yardstick competition does not work as well as a properly-functioning market, because by innovation DSOs can only increase their efficiency and not create additional value (and raise their tariffs) or diversify to other market segments[12]. Moreover, it is argued that yardstick competition works well for innovations that raise efficiency, but not for system innovations in which fundamental changes to the way DSOs work are necessary[13]. System innovations are envisaged by some stakeholders in the transition towards a sustainable energy system.

In the stakeholders' responses, DSOs have also identified a more general perceived barrier to innovation of the regulatory framework, namely that the recovery of costs of investments above the yardstick level cannot start until the following regulatory period. Currently, the NMa is investigating if it is possible to widen the class of extension investments of DSOs that classify as substantial and exceptional, in which case a DSO can start to recover the costs within the regulatory period[14]. Recently, part of an

9 See e.g. Kay, J., 'The Truth About Markets: Why Some Nations Are Rich but Most Remain Poor', Penguin, 2004.

10 'Consultation on innovation', NMa, October 16th, 2009, in Dutch: '*Consultatie over innovatie*'.

11 See e.g. Scott, J., Vaessen, P., Verheij, F., 'Reflections on Smart Grids of the Future', KEMA Consulting under the authority of the Ministry of Economic Affairs, March 11th, 2008.

12 'Reaction to consultation document', Eindhoven University of Technology, November 3rd, 2009, in Dutch: '*Reactie op consultatiedocument*'.

13 'Reaction to consultation document on innovation', ECN and KEMA, November 11th, 2009, in Dutch: '*Reactie op consultatiedocument over innovatie*'.

14 Section 41b(2) of the Dutch Electricity Act in conjunction with the 'Policy Rule regarding Substantial Investments, NMa, July 25th, 2005, in Dutch: '*Beleidsregel Aanmerkelijke Investeringen*'.

extension investment for the integration of wind energy in the southwest of the Netherlands has been classified as substantial and exceptional[15].

4. Experiences with distributed generation in the Netherlands

DSOs are obliged by law to provide access to the system to whomever asks for it[16]. Access can only be refused if the DSO lacks the necessary capacity and can substantiate such a refusal[17]. Some DSOs claim that in case of failure of one component, they still have to be able to provide transport (N-1 criterion), though by law this is only applicable for networks of 110 kV and higher[18]. Even then, the NMa has taken the viewpoint[19] that in case of congestion it is sufficient to realize the N-1 criterion in an operational sense and not necessarily in a design sense.

The growth in DG has led to capacity problems for some DSOs, as the design of the distribution network is aimed at centralised production and local consumption, and not at dispersed production. One of the main issues in connecting DG to the net is the way in which DSOs can internalize the costs for capacity extension in the network[20]. There is currently no transport fee for producers, which means that producers, both central generation and DG, only pay connection fees (to cover shallow network costs) and no fee to cover deep network costs for extension of capacity.

Capacity problems can limit the growth of DG and might thus have an averse effect on reaching 2020 targets and the development of a more competitive supply side (see paragraph 0). In the next regulatory period (from 2011), the NMa is considering to solve this problem by introducing a product category for generation[21]. A DSO then produces output for the costs induced by generation, which gives a better estimate of the DSO's efficiency[22]. In this way, a DSO is able to recover the costs incurred by generation.

Without a transport fee for generation, growth in DG is only covered in the following regulatory period, which can lead to financeability issues for a DSO[23]. Moreover, without such a fee, consumers will

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15 'Decision on determining network tariffs electricity under Section 41c, paragraphs 1 and 2 of the Dutch Electricity Act 1998 and amendment of the calculation volumes under Section 41a, paragraph 2 of the Dutch Electricity Act, as of January 1st, 2010 for DELTA Netwerkbedrijf N.V', NMa, December 17th, 2009, in Dutch: '*Besluit tot vaststelling van de nettarieven elektriciteit ingevolge art. 41c, 1e en 2e lid van de Elektriciteitswet 1998 en wijziging van de rekenvolumina ingevolge art. 41a, 2e lid van de Elektriciteitswet 1998 per 1 januari 2010 voor DELTA Netwerkbedrijf B.V.*'.

16 Section 24(1) of the Dutch Electricity Act.

17 Section 24(2) of the Dutch Electricity Act.

18 Section 31(12) of the Dutch Electricity Act.

19 'Vision document on Capacity Shortage', NMa, 2008, in Dutch: '*Visiedocument Transportschaarste*'.

20 Though this paper deals with electricity networks, we would like to stress the similarities with gas distribution. There is a strong development in biogas production in the Netherlands, which is expected to lead to capacity problems in the distribution networks. A way of solving this is to develop a separate raw biogas-infrastructure and upgrade the biogas to biogas with natural gas quality at a central point connected to the transmission network or use some form of congestion management (possibly with storage), as will be discussed for electricity.

21 This can be seen as a partial solution for an externality as discussed in paragraph 13. The full solution would be a transport fee for generation, see paragraph 19.

22 If there is no output category for generation, a DSO that makes costs for generation will appear inefficient.

23 Financeability issues can also be avoided if the extension investments can be classified as substantial and exceptional, see paragraph 15.

pay for DG in their region, which is not justified. Both issues can be solved by introducing a transport fee for generation, which, to avoid unjustified unequal competitive conditions, should also apply for central generation. Note that the introduction of such a tariff might influence competition conditions between countries.

As mentioned in paragraph 4, there are two main solutions to the capacity problems, which negatively affect competition, due to DG. One is to extend the network by installing extra cables and transformers. The second is to use the network more smartly. One response to the consultation on innovation states that the use of smart solutions for future capacity problems can save significant amounts on future investments[13]. In the Netherlands, some smart solutions have already been developed for the capacity problems induced by DG.

In Westland, a region in the western part of the Netherlands and an area with a high concentration of CHP-units in greenhouses, electricity production during peak hours is so high, that electricity is exported to the transmission network[24]. Due to capacity limitations at the connection point to the transmission network, not all electricity can always be exported. To still be able to connect new CHP-units, the DSO uses, in co-operation with the TSO, a system of congestion management[25].

Congestion management means that after the day-ahead market has closed, some parties[26] will be asked not to deliver the electricity sold during times of peak load and in this way stay below the level of available capacity limitations. At the same time the TSO will ask a producer outside the congested region to deliver more electricity than sold, in order to maintain the balance between supply and demand. The costs of this system[27] are socialized in the transport fee[28].

This system of congestion management is often seen as a temporary solution while new capacity is being built. However, it can also be seen as a first step towards an energy market in which electricity is balanced on a regional level. To maintain the integrity of the distribution network, a system should then be in place that makes it possible to disconnect, or downscale both production and consumption in a smart way. For such a system, it is envisaged that smart meters are required. This would assist in the creation of a level playing field for all energy users and a market-based system in which consumption and production are driven by price.

Smart meters can provide the DSO with the data to balance the distribution network by supply-side and demand-side management. Moreover, smart meters can provide consumers greater insight into their energy consumption, and might thus ultimately lead to energy savings. Such transparency also enables consumers to make more informed choices, which stimulates competition in the industry. An important prerequisite is the development of new services (by e.g. the energy supplier) and the engagement of the

24 In this case, the penetration level of DG leads to an increase of network losses, compare with paragraph 0.

25 At the moment, this system is not explicitly covered in the Dutch Electricity Act. In proposed changes to this act, which are expected to come into force July 2010, additional rules for congestion management are included, as e.g. an obligation to report the use of congestion management in a certain region to the NMa (new section 24a(2)) and priority treatment of transport of renewable energy sources (new section 24a(3) and 24a(5)).

26 The producers that have the highest variable costs, reflected in the prices willing to pay not to produce, are asked not to produce in the case of congestion.

27 The costs are mainly due to differences in the (lower) price for not producing and the (higher) price of additional production in other regions.

28 This means that consumers pay for this system, as there is at the moment no transport fee (see paragraph 19).

consumer in the process of development of and the roll-out of smart meters. Below we describe the Netherlands' experiences with this process.

5. Experiences with smart metering in the Netherlands

In the Netherlands, the metering market was liberalised in 2000, resulting in free metering tariffs and freedom of choice regarding metering companies. Between 2000 and 2006, the metering tariff increased by 83% in total. After publication of this increase by the NMa in 2006, the Minister of Economic Affairs decided to regulate the metering tariffs to prevent further unjustified increases. Since 2007, the metering tariff for electricity meters[29] has been a regulated tariff, based on the average metering tariff of 2005 plus inflation. Despite some uncertainties in the socio-economic business models, the roll-out of smart metering is based on a flat-fee migration to smart meters.

In the Netherlands, a smart meter is defined as a meter that can be accessed remotely. Metering data can be gathered either wireless or via Power Line Carrier (PLC) by the DSO. The so-called *Nederlandse Technische Afspraak* 8130 (NTA 8130)[30] contains a detailed technical specification which all smart meters in the Netherlands must comply with. With the liberalisation in the retail market as a higher objective and with new views on the role of metering in the overall market structure, new market roles around smart metering and detailed specifications of the roll-out are described in the 'Bill on improving the market system for small consumers' (in Dutch: '*Wetsvoorstel verbetering kleinverbruikersmarkt elektriciteit en gas*').

This bill proposes a mandatory minimum of bi-monthly metering data collection. The user may grant permission for a higher frequency to a third party (most likely, but not limited to, the supplier) at extra costs. The bill also stipulates that the DSO will become the exclusive owner of meters and will be responsible for roll-out and installation. The DSO will collect the metering data and make them available to the supplier. The supplier will be responsible for retrieving the metering data from the DSO and for transferring the data into official metering data for the invoicing of customers.

The combination of remote metering access by DSOs and a mandatory roll-out for consumers, as described in the bill, resulted in early 2009 in public debates concerning privacy. The result of these debates is that the bill is currently being revised and that the mandatory roll-out will change to a voluntary roll-out. The revision of the bill has caused a delay in the start of a nationwide roll-out, which will not take place before 2011. It is however generally expected that the Netherlands will meet the criteria[31] of smart metering as described by the third package of legislative proposals for Europe's electricity and gas markets[32].

Due to the current delay in the ratification of the bill several DSOs have initiated pilot projects. Because of these pilots, some 3-5% of Dutch households currently have a smart meter. Until the start of the voluntary roll-out, this percentage is likely to only gradually increase. Only newly-built houses, households that need meter replacement and households that are willing to pay for smart meter installation will be

29 Due to legal-technical reasons it is currently not possible to regulate gas meters. This will change when the 'Bill on improving the market system for small consumers' (see paragraph 26) becomes effective.

30 This standard is owned by NEN, the Dutch Normalisation Institute.

31 An important criterion is that, if roll-out of smart meters is assessed positively, at least 80 % of consumers shall be equipped with intelligent metering systems by 2020.

32 Annex I, Article 2 of the Directives 2009/72/EC and 2009/73/EC of the European Parliament and of the Council, 13-07-2009.

provided with a smart meter. As in several other countries, the role of the meter is expected to change following broad-scale introduction of the meters.

6. Concluding Remarks

We have shown that, in theory, the regulatory framework is not hindering the development of smart grids, provided that externalities can be internalized by additional regulatory measures. We have shown that externalities existed in network extension for DG and that the NMa has created product categories to allow the DSOs to internalize the benefits of network extension. We have argued that the case of DG has led to the development of smart grids (congestion management) by the DSOs and that, in the future, DSOs may become increasingly responsible for balancing the distribution network.

An important component of such a smart grid is thought to be the smart meter, which allows the DSO to balance the demand-side and supply-side, and allows service providers (e.g. energy suppliers) to offer new services to customers. In this sense, network innovation is paramount for the continued innovation at a customer level. We have discussed the case of smart metering in the Netherlands, with an emphasis on privacy issues and the roll-out of smart meters. We have shown that these issues have led to a delay in the process of rolling out smart grids, but that it is expected that the Netherlands will meet the criteria of smart metering as described by third package stipulations.

NEW ZEALAND

1. Background to the New Zealand Electricity Industry

The electricity industry has four main components:

- Generation (competitive);
- Transmission (the high voltage grid known as the national grid) (regulated);
- Distribution (local lines companies) (regulated); and
- Retail (competitive).

Approximately 60 percent of New Zealand's electricity is generated by hydro stations, with the balance from geothermal stations, gas, coal and oil-fired thermal stations, bio-mass plants and wind farms.

The sale of generation at the wholesale level is co-ordinated through a half hourly traded market, which operates as a pool. The pool is administered and governed by the sector regulator, the Electricity Commission. Prices in the wholesale market are determined by market bids and offers, and are not capped in any way. The market is characterised by locational marginal pricing, or nodal pricing. The market therefore clears bids and offers at over 200 nodes around the country on the national high voltage transmission grid.

Transpower (a state owned company) owns and operates the national high voltage transmission grid. It is both the Asset Owner and the System Operator.

There are 29 local distribution lines companies connected to the national grid. For the most part, distributors sell their services to retailers who provide a bundled "delivered electricity" service to end consumers, although some distribution companies contract directly with connected consumers. Most end-consumers are connected to the local distribution networks, but a small number of large industrial consumers are directly connected to the national high voltage grid.

The Electricity Industry Reform Act (EIRA) 1998 required full ownership separation between lines and energy (generation and retail) businesses. Since the introduction of the Act, however, amendments have allowed lines businesses to own some generation and to sell the output from those stations. Recent decisions following a Ministerial Review of the electricity industry include further relaxation of these rules to permit lines businesses to retail electricity and construct new generation (subject to some restrictions, such as corporate separation).

There is a high degree of vertical integration between generators and retailers of electricity. There are five large generator/retailer companies that have about 97% of the retail market share.

There are no generation subsidies in New Zealand, for any type of generation. However, there are a number of areas where renewable generation is facilitated:

- The government has established the Marine Energy Deployment Fund, and is administered by the Energy Efficiency and Conservation Authority, a government agency. The fund provides grants to deploy devices in the New Zealand marine environment to provide information and practical experience. Grants will be made in four rounds, from 2008 to 2012, from a total fund of $8 million. More information regarding this fund can be found at: http://www.eeca.govt.nz/node/1300;

- A National Policy Statement on Renewable Generation is being developed to assist decision makers (local councils in the first instance) to weigh up the benefits of renewable generation with local environmental effects, when making decisions regarding the granting of resource, or planning, consents;

- The Energy Efficiency and Conservation Authority is working with local councils regarding the effects of small scale distributed generation, in order to inform the resource / planning consenting process; and

- The government has established an Emissions Trading Scheme, which will ultimately improve the cost effectiveness of renewable generation relative to thermal generation.

In September 2008, the government placed a 10 year moratorium over investment in new base-load fossil-fuelled thermal electricity generation. Exemptions were available where the non-renewable generation was necessary to ensure security of supply. Other measures included providing some regulatory preference to renewable energy sources, such as permitting lines companies to invest in renewable generation. This moratorium was revoked in December 2009, following the change in government.

Smart meters are being rolled out currently in New Zealand. The roll-out is not regulated; retailers are contracting with metering companies to install smart meters for commercial purposes. Another driver is that the rules relating to metering require household meters to be certified by 1 April 2015. That is, these meters need to be tested and certified, or else replaced, by this date. Many companies are choosing to replace meters, and gain the benefits of automated meter reading offered by smart meters, along with the ability to provide smart tariffs.

While the smart meter roll-out is not currently regulated, the Electricity Commission published guidelines for advanced metering infrastructure in early 2008.

2. Renewable sources of electricity

2.1 Wholesale pricing

2.1.1 Prices offered of electricity generated by renewables are sometimes regulated. How often are prices regulated?

Delivered electricity prices, charged to the consumer by the retailer, are not regulated in New Zealand. Prices for high voltage transmission, and for local distribution, are regulated. These regulated lines charges are ultimately paid by end-consumers, whether they are directly billed by the lines company, or whether these costs are passed on by the retailer.

2.1.2 Are there different prices for small-scale production and for large scale production?

Generation in New Zealand, relative to this question, can be differentiated between that connected to the national transmission grid and that connected to the local distribution networks. Generation connected

to the national transmission grid must sell its power into the spot market, the half hourly pool. These sales may be hedged through the purchase and sale of electricity forward contracts. Apart from location differences arising from losses and constraints on the high voltage transmission system (New Zealand has locational marginal prices, or nodal prices) all generation sold into the wholesale market receives the spot price. Distributed generation, connected to local distribution networks, are also ultimately required to be sold into the wholesale market. A distributed generator may either sell directly to the half-hourly wholesale market, or may sell to another party under bi-lateral contracts, but that party must then sell to the wholesale market. When sold to the wholesale market distributed generation receives the nodal price for the node that the distributed generation is electrically connected to.

2.1.3 How large is the subsidy for different forms of renewable production, if there is any subsidy?

There are no generation subsidies in New Zealand.

2.1.4 Are there any competitive distortions that have been alleged as a result of renewable pricing policies?

All generation in the half-hourly wholesale market receives the same price, apart from locational differences resulting from losses and constraints on the transmission system.

2.1.5 How common is flexible, time-of-day pricing to electricity customers?

Generators selling into the spot wholesale market receive half hourly prices as set within the pool. Off-take customers that are directly connected to the transmission system also pay the half hourly price, although they can hedge this by buying forward electricity contracts. Retailers (who are also, for the most part, the generators), pay the half hourly price in the wholesale market although they can also hedge for this by having an internal transfer cost where they are vertically integrated, or buying forward electricity contracts form other generators. The retailers' customers for the most part receive a fixed price / variable volume hedge. Under such a hedge prices do not vary with the spot market, but retailers can change the hedge price to end-consumers at reasonably short notice. Some retailers offer a day/night tariff option to household consumers where the distributor provides this cost differential (not all distributors offer day/night tariffs as the uptake has been so limited). Three retailers currently offer time of day pricing to mass market customers, however this is only within certain geographic areas at this stage and this does require advanced metering to be available.

2.1.6 How do you induce customers to use more expensive energy sources?

There is no such inducement in New Zealand

2.1.7 How do you change consumer incentives?

New Zealand relies on the market model to send optimal price signals to consumers. However the Electricity Commission is exploring ways in which this signal can be passed through more effectively to end consumers. For example, the Electricity Commission is exploring the option of 'dispatchable demand', where interruptible load can be scheduled into the half hourly pool, as a replacement for generation.

2.1.8 Can types of meters and access to data change incentives?

Trials are being conducted both here and internationally to test this question. Results from New Zealand trials are not yet available.

2.2 Investment

2.2.1 If wholesale prices for renewable energy yield an excessively high return on investment, they may lead to excessive investment in renewable technologies generally or distributed energy in particular. Is there any evidence of excessive investment and distortion in production arising from such investment?

Apart from locational signals, all generation selling into the wholesale market receives the same price. As such, renewables do not receive a higher price compared to other types of generation, so investment signals arising from the electricity market cannot be thought of as distorting incentives between different types of generation. It should be noted that the market price for electricity in New Zealand is not high enough to support all kinds of renewable generation, at the current level of costs for those generation types. This situation leads to some parts of the industry calling for feed-in-tariffs, however such tariffs are not planned in the New Zealand in the medium term.

2.2.2 How do you encourage investment in renewable energy due to lack of assurance of transmission and, similarly, encourage investment in transmission absent renewable generators? Is investment to extend or build transmission mandated? Who pays for new transmission?

New investment in transmission is planned for by the transmission company, Transpower, and must pass the Grid Investment Test (GIT). The GIT is a cost-benefit analysis, which determines whether or not the benefits of a new transmission investment outweigh the costs. For projects which are required to meet technical reliability and security requirements (i.e. N-1 or similar), the preferred option must minimise the costs, or have the lowest negative NPV compared to alternatives, under the GIT. Transmission investment which is required to allow new generation to connect, or to relieve congestion, is generally considered to be an "economic investment project" (although such projects can also provide reliability benefits). Such projects must have a positive NPV, and to have the largest positive NPV compared to alternatives, in order to pass the GIT.

At present the sector regulator, the Electricity Commission, sets the GIT and checks its application, prior to approving an investment project. The GIT looks at the need for new transmission for a period going forward 20 years. If this test finds a project for new transmission capacity – to allow the connection of more generation or to relieve congestion created by more generation – is economic (has a positive NPV, and the highest NPV compared to alternatives), then investment to create that increased transmission capacity will be approved. There does not need to be a signed connection contract between a new generating plant and the transmission company in order to gain approval for the increase in transmission capacity. However new generation projects, or plans for new generation projects, need to be fairly certain in order to trigger new investment in transmission. The Electricity Commission is undertaking a work-stream entitled "Transmission to Enable Renewables", which aims to identify areas in New Zealand which are rich in renewable fuel (e.g. wind, geothermal). This is intended to "pool" the interest from renewable developers in a region, so that a new transmission investment is sufficient to cover the needs of a number of renewable generation development projects, not just one.

Approval of the transmission investment project by the Electricity Commission means the cost of that project can go into the Transpower's regulated revenue requirement, which is recovered from directly connected parties, or transmission customers. The Electricity Commission has approved a methodology for the allocation of the revenue requirement to transmission customers. That methodology makes a distinction between connection and interconnection assets. Connection assets are those assets dedicated to one or more users, required to gain physical access to the interconnected grid. The interconnected grid is the meshed assets that transport electricity from one point to another. The methodology used to define connection assets is known as 'deep connection'.

Generators pay these 'deep connection' charges, for connection assets relevant to their generation plant, but they do not pay anything in contribution to the interconnection assets. Distribution companies pay both deep connection charges for connection assets required to connect them to the interconnected grid, and they also pay for their share of interconnection charges. Interconnection charges are allocated amongst distributors and direct customers using a 'postage stamp' methodology, using peak demand (MW) as an allocator. That is, the costs associated with all interconnection assets are charged to distributors and direct connects at the same rate per MW, throughout the country. The transmission pricing methodology is currently under review, but at this stage a preferred alternative methodology has not been indentified. Distributors pass on their transmission charges, along with the costs of their own distribution assets, to customers connected directly to their distribution grid.

As outlined above the GIT regulates new investment in the interconnected grid. Transmission capacity to generators is not firm, so that if there is congestion, generation is ramped back, starting with generation with the highest offer. This is calculated as part of the market clearing solution in the half hourly pool. There is no compensation paid if generation is required to be ramped back due to transmission congestion.

As the generator pays deep connected charges, it is incentivised to connect where the grid already exists, to minimise its costs. If a new generator connects in an area where the interconnected grid is already congested, congestion will worsen. In this case the transmission company, Transpower, may apply the GIT to ascertain whether investment in transmission to relieve the congestion will be economic. However, if such transmission investment is not considered economic under the GIT, Transpower cannot invest in order to alleviate the congestion, and generation in the area might not be able to operate at full output.

2.3 Output plans and minimum purchases

2.3.1 What are the current output requirements for renewable energy sources? Are there minimum purchase/output requirements for renewables? How are these put into operation? Who has responsibility for adopting renewable sources? How do minimum purchase plans tie into transmission capacity? Is there a mechanism for trading renewable energy credits? If so how does that function?

There are no output requirements or minimum purchase plans in New Zealand. There are no quotas etc for renewable energy. There is an aspiration that 90% of electricity generation will come from renewable sources by 2025 in the New Zealand Energy Strategy. This strategy is currently under review. There are no renewable energy credits in New Zealand.

Note that in 2008, 65% of electricity generated came from renewable sources. This was lower than in previous years due to low hydro inflows leading to reduced hydroelectric generation. As a comparison, 73% of generation came from renewables in 2004, which was a reasonably wet year.

2.3.2 What sources are classified as "renewable"?

For the purposes of government statistics, "renewables" generally include: hydro; geothermal; wind; bioenergy, solar energy and marine energy, among others.

2.3.3 Do government or operators have plans to increase renewable generation in the future? If so, what are these plans?

Generation is developed in response to competitive market signals; as such there are no regulated plans for generation development in New Zealand. However, in measuring the level of security margins in New Zealand going forward, the Electricity Commission collected data from developers regarding their

plans to build new generation. The data in the table below is taken from the Electricity Commission's base case, and includes projects that are committed, or have high or medium probability of occurring.

Table 1. New generation assumptions in the baseline scenario (committed, high and medium probability)

	Installed operational capacity, mw (as at 2008)	New build as a % of 2008 operational capacity	Type of new build as a % of all new build until end 2014
Total operational installed capacity, 2008	9380		
Total forecast new capacity to end 2014	1379	14.7	
Forecast new capacity to end 2014 – all renewables	869	9.3	63
Forecast new capacity to end 2014 – hydro	50	0.5	3.6
Forecast new capacity to end 2014 – wind	464	4.9	33.6
Forecast new capacity to end 2014 – geothermal	355	3.8	25.7

2.4 Connection to the grid:

2.4.1 Are connection rules for renewable electricity suppliers clear and transparent?

Technical connection requirements for renewable generators are the same as those for conventional generation. Exemptions to requirements can be granted to all types of generation, however generators who are granted exemptions may face a higher allocation of ancillary service costs.

2.4.2 How long do renewable generators need to wait to get connected?

Generators that are to be connected to the Grid may connect once Transpower is satisfied the generator meets the connection requirements, subject to any exemptions, and once connection assets are in place. Connecting a new generator may create greater congestion on the interconnected grid, however as transmission access is not firm, a generator will not be refused connection for this reason, nor will connection be delayed for this reason.

Generators that are to be connected to a local distribution network may connect once the network owner is satisfied the generator meets the distributor's connection requirements. Connecting a new generator may require investment within the distributor's network and generators may be charged all or part of this investment.

2.4.3 On what basis are connection costs calculated and allocated?

For connection to the national transmission grid, connection assets are identified using a deep connection methodology. Asset values are derived using depreciated historical cost plus other overheads according to the overall Transmission Pricing Methodology. Connection assets are allocated solely to the parties connected by those assets. If more than one generator is using the same connection assets, the costs are allocated between parties using the proportion of a party's anytime maximum injection to the sum of the anytime maximum injections at that location.

For connection to local distribution networks, connection assets are identified by the distributor using the distributors' own methodology. Regulations exist to assist this connection process at the distribution level.

2.4.4 Do incumbent generators have incentives to limit transmission capacity of renewable generators? If so, how can these incentives be changed?

Transmission capacity for generators is non-firm. If congestion on the interconnected grid occurs, generators with the highest offers will be constrained back first. If generators have the same offer, they will be pro-rata'ed back. Levels of generation dispatch around constraints are calculated within the wholesale market pool.

Renewable generation tends to have a marginal cost of zero; therefore its offer price is usually low compared to thermal generation. Often renewables must run (the alternative is to spill "fuel", either hydro or wind), in which case they have an offer price very close to zero. As such it is usually generation with a higher short-run marginal cost that is constrained off first when constraints in the transmission system occur.

2.5 Dispatch in response to demand

2.5.1 What efforts are being made to increase the ability to dispatch renewable energy resources in response to demand?

The Electricity Commission in conjunction with the System Operator has investigated the issues with integrating intermittent generation into the operation of the power system. The investigation has resulted in a series of ongoing work-streams:

- To look at technical standards to protect the power system and also give investors more certainty (e.g. fault ride through);
- Specification and quantities procured of ancillary services such as frequency keeping and instantaneous reserve;
- To modify pre-dispatch and dispatch processes to support more intermittent generation (e.g. forecasting and information provision); and
- To integrate intermittent generation into ancillary service cost allocations.

Note that New Zealand also has significant existing hydro and geothermal renewable resources, which will be impacted on by the consideration of the dispatch of intermittent generation such as wind.

2.5.2 How common are contracts that allow the electricity network operator to temporarily 'shut down' small-scale or large-scale electricity users at peak periods, helping it to adapt to the potentially limited ability of renewable generation to provide electricity?

As part of the "N-1" operating security standard, to cover the largest single unplanned generation failure at each point of time in the market, both spinning reserve from generators and interruptible load can be offered into the 'instantaneous reserves' market. Reserves offered into this market need to be able to respond to an under-frequency event within 6 to 60 seconds. In New Zealand, some domestic hot water cylinders are on frequency sensitive relays, a system called 'ripple control'. Load connected to this system can usually respond within the time frame required by the instantaneous reserves market. Hot water

cylinders that are controlled by ripple control that is not frequency sensitive can also be remotely turned off by distributors should there be an emergency requirement to do so.

Any addition, as part of their connection requirements, distributors are required to provide blocks of load (AUFLS – automated under-frequency load shedding) that can be interrupted should frequency drop to pre-specified levels. These are not contracts but connection requirements.

Load under the two mechanisms above can be interrupted should there be an unplanned shortfall in overall generation, or due to unplanned transmission outages, in real time.

Prior to real time, if the System Operator calculates that N-1 cannot be maintained in the near future, it will shed load in order to allow N-1 to be reached. Again, this is in response to a shortfall in total generation, or local grid conditions.

There are no contracts or other arrangements in place to shed load specifically in the event that, for example the wind stops blowing. If the drop in wind causes a situation where N-1 cannot be maintained, then load may be shed using the mechanisms described above.

2.5.3 How common is flexible pricing that can change on a daily and hourly basis?

The wholesale market pool clears on a half hourly basis. Direct connect customers, and some larger local network connected customers face half hourly prices for the un-hedged portion of their load.

Some medium to large businesses have time of use meters that allow them to respond to price signals.

Time of use prices are not at all common for household consumers, although three retailers already offer time of use prices and there are also some pilot studies testing the response to smart tariffs, enabled by smart meters at the household level.

2.6 Vertical and horizontal issues

2.6.1 Do generating companies own both renewable and non-renewable plants? Can such generators create bundles of renewable and non-renewable plant output?

Yes, generating companies do own both types of generation. Of the five main generating companies in New Zealand, all own at least some renewable generation (including hydro). One company has only renewable generation in its portfolio, as it owns the majority of the hydro power stations in the South Island and some wind farms.

As the New Zealand electricity market is a pool, with forward hedges being financial only, all generators essentially offer a portfolio of generation to the spot market. This could be considered a ‘bundle’.

2.6.2 Are some electricity companies able to exercise monopsony power in the purchase of renewable electricity? Can purchasers foreclose new producers to the benefit of their own generation?

Vertical integration exists to a significant extent between generation and retail. Nearly all, if not all, companies interested in building new (large) generation to be connected to the national transmission grid are existing “generator-retailers”. These companies therefore do not buy renewable generation off independent power producers at the transmission level.

At the local distribution level, however, there may be a number of independent power producers, from manufacturing plant using heat and steam which can also be used for power production (co-generation), to local hydro operations on farms, to solar panels on household roofs. A person with a small-scale distributed generation plant needs to obtain an agreement with a retailer to buy net output. In most instances, the retailer with whom the person has a supply contract will also have the reciprocal contract to purchase any surplus power from that person. Most consumers have the choice of at least four retailers.

3. Smart grids

3.1 Status of adoption and demand response

3.1.1 What is the status of smart grid adoption in your country? Are large customers (e.g. factories) tied into a peak-demand response system? What is the extent of "smart metering" whereby customers can see and respond to real time price changes? What evidence exists of their potential effects in your jurisdiction? How do you ensure that customers would benefit from reducing their demand? Who receives the monetary benefit of system cost reductions from demand reductions? How do you choose a benchmark for measuring demand 'reduction'?. Is demand response a product that can be sold in competition with wholesale electricity? Can small demand responses be aggregated and sold back into the wholesale marketplace by any entities other than traditional utility suppliers?

Current demand response programmes are outlined above. One additional program is the development of a "grid support contract" by Transpower. The grid support contract enables load aggregators (who can be entities other than either retailers or distributors) to contract with sources of interruptible load, to be activated at times of transmission system peak, and to on-sell this capacity to Transpower in order to defer investment in transmission assets. The practical detail relating to the grid support contract has been trialled and proven. Currently, money provided for the trial has been used to pay for investments (load controller project) required to co-ordinate demand responses in the upper South Island. This has proved effective in flattening the peaks in this region, deferring transmission investment. The load controller is estimated to have reduced load at peak by 30 megawatts during winter.

Larger customers with half hour meters are charged peak demand and critical peak demand transmission and distribution charges. These may be at preset periods or maybe co-incident with national grid constraint times, but do provide a direct financial incentive for larger customers to control electricity demand.

Medium industrial and some commercial customers have had 'smart meters' or time of use meters for some time, and can respond to half hourly price signals in real time. Currently, if there is enough demand reduction, then all demand-side participants should benefit from demand reduction as this will either lower the wholesale price, or prevent that price from being as high as it would have been without the demand reduction. This causes scope for some demand-side participants to 'free ride' on the demand reduction activities of other participants.

Mass market customers already have controllable thermal storage load (hot water cylinders, storage heaters' etc) controlled by the distributor that a customer is connected to via ripple injection/receiver (or ripple control) systems[1]. This controllable load is used to reduce peak demand on the transmission grid and local networks either at times of constraint due to demand for electricity, or during periods of maintenance.

[1] Details of ripple systems can be found in Existing Capability Working Panel study on the Electricity Commissions web site.

Customers are charged less in distribution charges if they provide controllable load in the ripple control system.

3.2 Standards

3.2.1 How are standards being determined for smart grid elements? Are there any competition policy issues that have surfaced for such standards? Would incumbents have an interest to ensure standards do not promote increased competition? Is there a risk that standards or devices are being devised in an inflexible way that will prevent future adaptation of the network to new standards, technologies and competitors to existing utilities?

Any applicable standards for smart grid developed internationally would be considered for adoption within New Zealand.

The Electricity Commission is developing regulation around certain elements of advanced meters and advanced metering infrastructure (operation, information, and access to information from advanced meters).

The Electricity Commission is also about to embark on a project, with industry, to agree information exchange protocols and data formats for information available from the back office of advanced metering systems. Open access at the meter level is regarded as a significant security risk. Also as New Zealand has competitive metering supply, any distributor's network could have a number of different manufactures and versions of meters installed.

The Electricity Commission has recommended to the Minister of Energy that once this work with industry is complete, that regulations be developed in the area of information exchange protocols and metering infrastructure. This is to facilitate

- The effective operation of networks;
- The effective settlement of generation and purchase volumes of electricity;
- Multi user facility of the metering infrastructure (eg water and gas);
- Switching of retailers; and
- To prevent competition issues arising.

3.3 Ownership

3.3.1 Who owns smart grid elements (e.g. smart meters)? If a customer switches form one provider of electricity to another, must equipment be changed?

There are a number of different elements that act as an information source to smart grids, advanced meters are only one of these.

The predominant information source is the distributors own SCADA system to provide instantaneous real time information on the distributors system such as switch positions, loadings, voltage, disturbances, constraints etc.

Remote switching of distribution networks is not common in New Zealand except on major feeders or loads. The development of self healing networks and installation of remote switching may require significant investment by distributors that would only be carried out should there be a cost benefit to do so.

Advanced meters could provide either historic or real time information to smart grid systems on individual points of connection. Real time information has costs associated with it, and to date no distributors have seen a benefit in paying for this service.

Currently, meter companies are separate entities from electricity distributors and retailers, although some advanced metering companies are subsidiaries of electricity distributors and retailers. However, it is in the financial interest of metering companies to ensure all retailers can use their services or their asset will be displaced. This competitive pressure ensures that systems offered will meet the minimum requirements of users. There have already been cases, prior to the Electricity Commission issuing its guidelines, where an existing advanced meter has been replaced by a new advanced meter, when a new retailer took over a customer. This should only occur going forward where there is a technical requirement to replace or upgrade the functionality of a meter installation and not due to impeded access to information or incompatibility of data formats across retailers. Retailers and metering companies are now entering agreements with each other to prevent this being a cause for a meter being replaced. Switching of customers between retailers does not cause a change in meter unless an upgrade to functionality is required.

Further, the Electricity Commission is developing regulation that

- Requires all users of a meter to be consulted prior to a meter change; and
- Making ownership and some details of metering installations transparent by integrating meter owners into the Registry that records attributes necessary for settlement for every point of connection to local and embedded networks.

3.4 Information

3.4.1 Who controls the information about smart-grid capacities of different customers? The database used may contain important information to different potential purchasers and sellers of electricity. Does the dispatch operator have access to smart-grid information? Does anyone (other than the dispatch operator) have access to smart-grid information? Is there a price for such access?

The System Operator (Transpower) will have real time information available for customers and generators where these are direct connections to the national transmission grid. This includes the connection point of local networks to the national transmission grid. Where a generator is connected to a local distribution network the System Operator will only have access to real time information in the case of a generator above 10MW.

Where the customer connection is to a local distribution network, only the distributor or their authorised agent will have access to capacity information on different customers.

Due to the competitive nature of meter provision in New Zealand, access to advanced metering information is made at the back office system, where appropriate security and authorisation processes can be put in place. This also allows appropriate revolving encryption on the communications link between the meter and the back office software.

Smart grid operators may access some but not all information from the advanced meter back office (e.g. there is no need for them to have access to load aggregator information, gas or water information), but will have access to all of the network information that they collect from their own SCADA system.

3.5 Monopsony buyer

3.5.1 Are there monopsony (single buyer) issues for the purchase of customer-generated electricity? For example, a system operator may have no regulations over how it sets prices for on-demand electricity produced through distributed generation. Have any rules been developed for such purchases? If not, how might monopsony power issues be resolved? Does the wholesale market structure eliminate or reduce the benefits of real-time pricing?

The price paid for electricity from distributed generation will be determined by the nodal pricing at the node the generator is electrically connected to, and commercial negotiation for hedges that the generator may offer to purchasers.

The recent Electricity Market Review considered measures to encourage small-scale generation[2]. The review team recommended that the Electricity Commission develop mandatory terms and conditions (including pricing guidelines and principles) for the purchase by retailers of power from small-scale distributed generation, which would assist in reducing transaction costs for individual investors in small-scale distributed generation. The team did not, however, consider that there was a case for mandating subsidies from retailers by way of tariffs for purchased distributed generation (for example, "feed-in" tariffs).

Relevant papers and more detail from the review (including submissions) are available at: www.med.govt.nz/electricity-market-review.

3.6 Revenue reduction incentives

3.6.1 Does the market structure of the electricity system provide stakeholders with the ability and incentive to invest in smart-grid technologies that may reduce revenues due to efficiency measures?

It is not clear at this stage whether this was the case or not.

The Commerce Commission, in its regulation of lines businesses, is required to promote incentives, and avoid imposing disincentives, for investment in energy efficiency and demand-side management, and to reduce energy losses;

Due to time constraints, and the complexity involved in accounting for such mechanisms, the Commission has not implemented any in its recent work to reset the default price path for lines businesses. However, it does consider that there are potential initiatives available to lines businesses to influence energy efficiency and related outcomes that may be consistent with the purpose of Part 4 of the Commerce Act.

2 It should be noted that the Rules already facilitate the trading of distributed generation, which is as easily switched and trade as is consumption, and the Electricity Commission has also provided a service provider for small generators to use to provide Registry functions.

NORWAY

1. Introduction

Expenditures on electricity constitute a significant part of the household's budget in Norway. Each person consumes about 7000 kWh electricity each year and this constitutes about 75 per cent of the total energy consumption[1]. A well functioning competitive electricity market is therefore of significant importance for the consumers. Introduction of smart metering with two-way communication between the end-user and the grid company will reduce operation costs and have positive implications for both the distribution system operators (DSO), suppliers and the consumers. Increased frequency of meter reading will also provide more efficient pricing of capacity and contribute to higher value for flexible producers.

Smart meters are an essential part of the development of smart grids called for by the increased flexibility and need for coordination associated with increased local and renewable production and more flexible consumption.

However, due to the high penetration of hydro production with flexible and relatively dispersed production, the need for coordination through relatively automated system operations is nothing new in Norway. To a large extent the Norwegian transmission grids already perform many of the tasks associated with smart grids. The focus of this note will therefore be on smart metering.

The Norwegian Water Resources and Energy Directorate (NVE) is responsible for the regulation of the energy sector and as such for the deployment of smart meters and, through the regulation of the transmission system operators (TSO) and the DSOs, also for the development of smart grids.

The concept of smart grids, including smart metering, decentralised production, smart houses etc., will contribute to increased diversification with regards to the type of products offered and the type of market players participating in the electricity market. Given the right regulatory framework this will provide more competition and also a more effective market.

2. Status for smart metering

NVE has during the last years made several requests for comments regarding regulation of the introduction of smart metering. The regulation process has been postponed until autumn 2010, mainly pending the establishment of standards for smart metering in Europe. The provisional deadline to complete the installation of smart grids in Norway is 2016.

The governments in the Nordic countries recently renewed and further broadened their commitment to create a thoroughly integrated Nordic energy market. NordREG[2] is, in cooperation with the market participants, mandated to present a road map for the development of a common Nordic retail market by 2015. The cooperation between the Nordic countries already facilitates a set of prioritised transmission

1 Source: Statistics Norway (SSB), www.ssb.no.

2 NordREG is a cooperative organization for Nordic regulatory authorities in the energy field.

investments along with a more efficient handling of bottlenecks through so called market splitting[3] of the Swedish and Finnish markets, which will strengthen the function of the common Nordic wholesale marked.

In Norway, smart meters are so far mainly installed in housing cooperatives and companies. In these cases, the grid company gets accurate information about the consumption, but the end-user still pays the average monthly price and not a price reflecting the price when the electricity was used.

The use of smart meters in Norway is still very limited and most end-users report their consumption to the grid company every second month. In these cases, neither the grid company nor the end-user has information about which day or hour the electricity has been consumed. Consequently, most end-users do not have incentives to reduce the consumption in periods with high prices since they pay the same price independently of when it is consumed.

A number of companies have contracts implying that they can shift their consumption to periods when the prices are low. This (applies) however to a minor part of the market, and a significant expansion of smart meters that will allow end-users to respond to changes in the price of electricity, is vital to get an efficient use of the transmission capacity.

3. Standards for the smart grid elements

The choice of standards for smart grid elements is of great importance. NVE states that the economic benefit from smart grids depends on inter alia, that more efficient energy consumption is realised. According to NVE, these benefits will not be materialized without efficient competition between different suppliers of services to the end-user, as well as between suppliers of meter and communication equipment and between suppliers of the connected IT systems. An important premise for efficient competition is the establishment of standards in the different interface regarding smart grids.

The Norwegian Competition Authority is of the opinion that the standards should be open and non-proprietory to prevent the grid owner from abusing its position. As long as no international standards specifying requirements to smart grid metering systems exist, it is not possible to make a complete official requirement. However, it is stated by the NVE that it will be a requirement in Norway that it should be possible to connect external equipment to the meters from other suppliers than the electricity supplier.

4. Ownership and information

With respect to information about consumption, NVE's starting point is that the individual end-user owns data about self consumption and that the grid company must have approval from the end-user to communicate the data to any third parties.

Regarding the communication channel between the owner of the grid and the end-user, some market players are of the opinion that only the grid company should be allowed to use this communication channel to avoid any use for commercial purposes. However from a competition point of view, it is important that access to the communication channel is made on a neutral and non-discriminatory basis.

Information to the end-user about prices and consumption is vital to obtain an efficient market for electricity. The Norwegian Competition Authority's opinion is that it should be an obligation to make the

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3 With market splitting one power exchange ensures the right cross-border power flow by establishing production surpluses in the power exchange's low-price areas, and production deficits in the power exchange's high-price areas. Source: www.nordpoolspot.com.

price and consumption data easily available for the end-users, either through communication and information through a computer/the internet or through a display containing the relevant information. This is crucial for the end-users' possibility to adjust their consumption and thereby contribute to increased competition.

With smart metering and real time reading on an hourly basis, the end-users will have the possibility to reduce their consumption in high price hours. It is therefore important that the end-users have access to information about both their consumption and the prices in real time, and ultimately that this results in actual real-time price differentiation.

This information might contribute to increased consciousness among the end-users about prices and consumption and will be positive both from a competition and environmental perspective. However, realization of these positive effects conditions that consumers pay a price based on the time when the energy was consumed and not a predefined consumption profile.

As a final remark, the Norwegian Competition Authority would like to underline that increased consciousness among end-users about prices and usage are also important with respect to the climate challenge. The Norwegian Competition Authority's view is that increased transparency and consciousness regarding energy costs among end-users will contribute to a more effective utilisation of scarce energy resources and thereby be of significance for the achievement of climate policy objectives.

SPAIN

1. Wholesale pricing

1.1 Prices offered for electricity generated by renewables are sometimes regulated. How often are the prices regulated? Are there different prices for small-scale production and large-scale production? How are the prices set for small-scale and large-scale producers? How large is the subsidy for different forms of renewable production, if there is any subsidy?

The current Spanish system to promote the generation of renewable energy (RE) is based on a "feed-in tariff" with certain specific characteristics. RE generators must choose between selling energy in the daily market at market prices plus a price premium (the most common option), or get a regulated tariff, which is annually determined by the government. The latter option is limited to plants with a capacity below 50 MW. These incentives are kept until power targets for each technology are reached. If the goal is achieved new tariffs are introduced, as it has happened in the case of photovoltaic energy.

Both, price premiums and regulated tariffs are set by Royal Decree on the basis of different technologies' costs, the degree of participation in demand, and their impact on the technical and financial management system. These premiums and tariffs are fixed attending to the type of facility (technologies), the age of equipment, and the power of the plants. They are higher in less mature technologies, also in the first 25, 20 or 15 years of the facility's life (depending on technology) and in facilities with less power capacity.

Price premiums are reviewed annually and increased by the CPI-X, where X is equal to 0.25 until 2012, and equal to 0.5 in 2013 and onwards. There are maximum and minimum values for the premiums which change depending on the technology. This way, a cap and a floor are established .

1.2 Are there any competitive distortions that have been alleged as a result of renewable pricing policies?

The electrical energy produced by renewable sources is offered in the electricity daily market at a price equal to zero. Therefore, this energy is placed ahead of offers from other technologies which could be expelled from the daily market if the demand is low and the generation of renewable power is high.

This could be happening in the Spanish market, affecting technologies such as the combined cycle. Despite being competitive, these technologies could be being expelled from the market in certain slots, because the nuclear and renewable energy would preferentially meet the demand.

1.3 How common is flexible, time-of-day pricing to electricity customers?

Any small end-user (less than 10 kW) can choose a time-of-day pricing with a lower price for off-peak hours. However, the majority of them still do not pick this option. Wholesalers design more complex deals for industrial customers. Moreover, heavy users can go directly to any of the 24 daily markets to acquire energy.

Currently, there are pilot projects in several Spanish cities, for smart meters connected to telecommunication networks.

1.4 How do you induce customers to use more expensive green energy sources? How do you change consumer incentives? Can types of meters and access to data change incentives?

The Spanish system does not allow the option of green energy for the consumer. Part of the electric energy consumed comes from this kind, but energy pricing is independent of the energy source generating it. End-users could choose to pay more for green power through bilateral contracts with renewable generators or through the acquisition of RECS[1] certificates. There were attempts by operators to sell "green power" but failed to convince consumers.

2. Investment

2.1 If wholesale prices for renewable energy yield an excessively high return on investment, they may lead to excessive investment in renewable technologies generally or distributed energy in particular. Is there any evidence of excessive investment and distortion in production arising from such investment?

The system of "feed-in tariff" has proved itself much more efficient in terms of investment promotion than others, as those based on tradable green certificates. In Spain, the results, in terms of expansion of the power generated from renewable energy sources, has been very positive, especially in wind power and, in recent years, in photovoltaic. However, certain areas have suffered from overinvestment. Although it is difficult to determine when there is an overinvestment process, the evolution of installed photovoltaic power since 2007 (see table below), and its comparison with government forecasts, leads to the conclusion that there has been excessive investment in some technologies in Spain. The investment incentives could have too strong.

Structure and evolution of the installed power of special regime by technologies (MW)

	2004	2005	2006	2007	2008	%08/07
Renewable	11.004	12.780	14.545	17.636	21.921	24,3
Hydraulic	1.638	1.767	1.869	1.924	1.979	2,9
Wind	8.479	10.055	11.542	14.107	15.874	12,5
Other renewable	888	958	1.133	1.605	4.069	153,6
Biomass	484	527	572	601	639	6,3
Industrial solid waste	170	170	188	188	188	0,1
MSW	213	224	258	258	258	0,0
Solar	20	36	116	558	2.984	435,0
Non-renewable	6.502	6.665	6.824	6.899	7.132	3,4
Waste heat	89	89	89	89	89	0,0
Coal	69	69	69	69	69	0.0
Diesel heat	1.340	1.340	1.340	1.341	1.341	0,0
Coal	210	210	210	210	210	0,0
Diesel fuel	4.795	4.958	5.117	5.191	5.424	4.5
Total	17.506	19.444	21.369	24.534	29.053	18,4

Source: REE, "Spanish electric system 2008".

[1] The Renewable Energy Certificate System provides quality certificates which ensure the generated energy comes from a renewable source.

Effectiveness indicator for the promotion of wind power

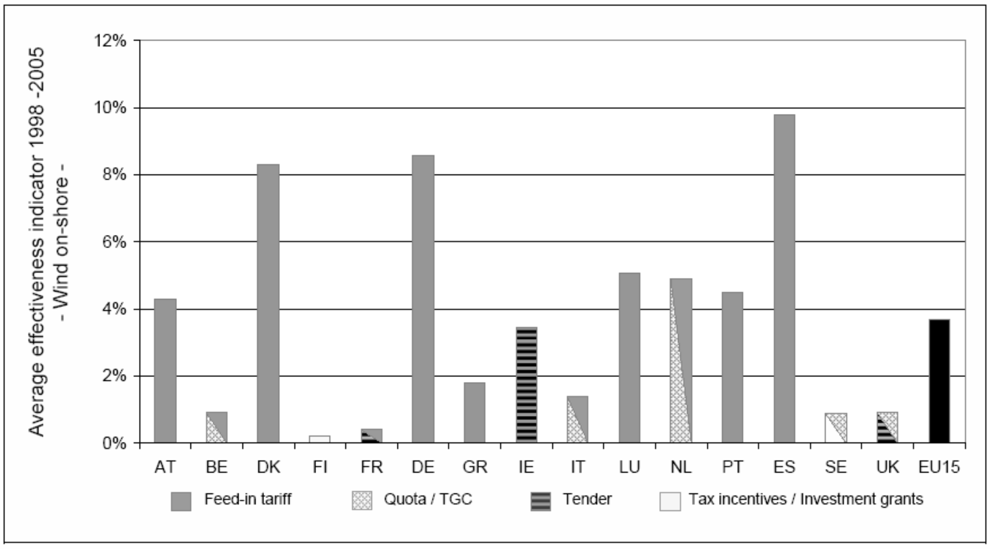


Figure 3 Effectiveness indicator for wind onshore electricity in the period 1998-2005 in the EU-15 showing the relevant policy schemes during this period

Source: "On the success of policy strategies for the promotion of electricity from renewable energy sources in the eu" (2006). Anne Held, Reinhard Haas, Mario Ragwitz.

In the Spanish system, incentives for the installation of renewable energy capacity are limited. When reaching 85% of the expected installed power level for a technology, the Ministry of Industry sets a deadline for registration of new plants eligible for the tariffs in force and establishes a new legal framework, changing incentives, and sometimes, taking the opportunity to correct deficiencies in the regulatory framework.

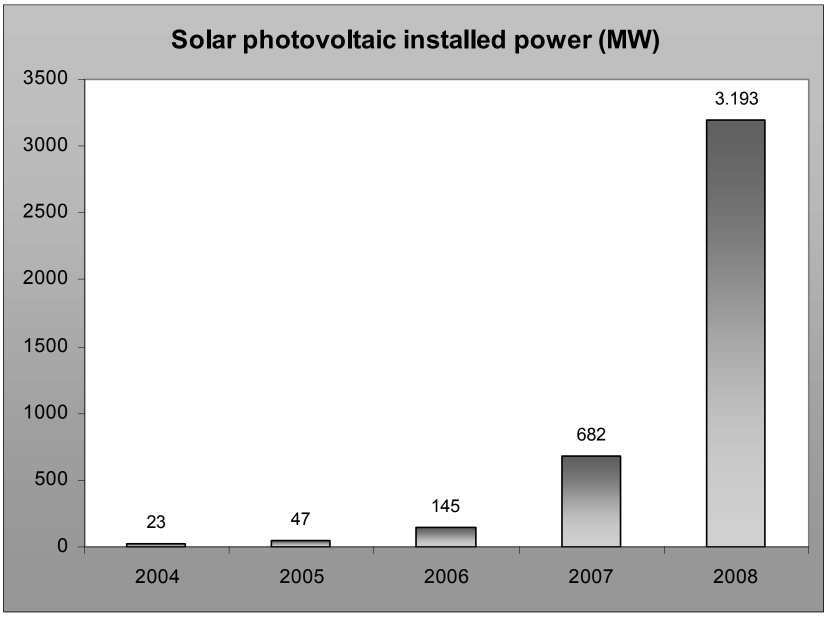
This procedure had to be launched in September 2007 in the field of photovoltaic energy, because the planned objectives had been achieved well in advance over the forecasts. It was considered that this overinvestment could generate an extra cost of € 335M in 2008, which would require an increase of 1.3% in the 2008[2] electric tariff.

These estimations fell short and the extra cost has been higher than expected due to the high pace of investment in this technology. The evolution of investments in this technology, in the period 2004-2008, is reflected in the table below:

Solar Photovoltaic Facilities

Year	Installed power (MW)	Sold energy	Number of facilities	Total Revenue (Thousands of €)	Average Price Total Revenue (cent €/kWh)	Matching Premium (thousands of €)
2004	23	18	3.233	6.791	36,741	6.144
2005	47	41	5.328	16.402	39,908	13.990
2006	145	107	9.722	45.543	42,748	39.821
2007	682	493	19.977	214.034	3,383	193.361
2008	3.193	2.320	48.580	1.052.908	45,306	903.994

2 Source: CNE, Report 30/2008 on the proposed RD 1578/2008.



The regulation was revised in 2008. The new regulation allows the progressive reduction of tariffs and premiums in a very flexible way so as to adapt the system to the costs reduction obtained in less mature technologies.

Furthermore a new registration system for RE pre-allocation has been set up. It is mandatory to register in order to have access to the economic incentives for RE. The system allows to program future changes in tariffs. This will prevent transition problems from one call to another, since it would be possible to know, well in advance, the applications for future generation capacity in different technologies. Once the decision to invest is made, and after acquiring the necessary licenses, the investor is able to register. This way, the collection of existing incentives is ensured, which limits the uncertainty and encourages investment.

2.2 Who pays for new transmission?

Red Electrica Española (REE), the Spanish monopolist in the transportation network and system operator, and the distribution companies, are obliged to allow the access of new facilities to its network, provided that they have capacity available. In general, the new generator is responsible for the costs.

3. Output plans and minimum purchases

3.1 What sources are classified as "renewable"?

Renewable energies are classified into 8 groups and 13 subgroups:

- Solar (photovoltaic and thermal)
- Wind (onshore and offshore)
- Geothermal, tide, ocean thermal, wave, etc...
- Small hydro (less than 10 MW)

- Hydraulics (10 to 50 MW)
- Biomass (energy crops, agricultural waste and gardens, and forest harvesting)
- Biomass from manure, bio fuels and biogas (three subgroups)
- Biomass from industrial plants (agricultural sector, forestry and paper industry).

3.2 Does government or operators have plans to increase renewable generation in the future? If so, what are these plans?

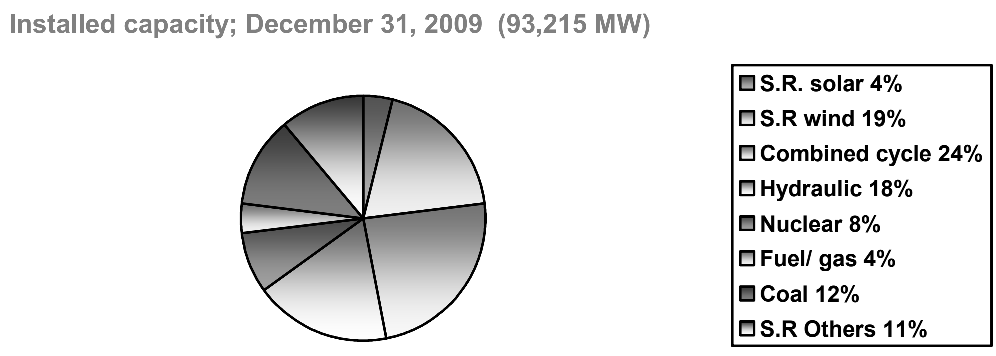
The objectives of the current Renewable Energy Plan are as follows:

1998- 2010 Plan (revised in 2005)

	1998	2006	2010
Biomass and biogas	69	527	2274
Wind Power	884	11100	20155
Solar photovoltaic	1	77	371
S. Thermoelectricity	0	0	500
Hydro <50 MW	1249	1740	2200
Municipal solid waste	104	261	261

(MW)
Source: CNE, Report 3/2007

Currently, a new Plan for Renewables for the perios 2011 to 2020 is being prepared, of which there is already an advance in compliance with 2009/28/CE Directive. This new plan provides a contribution of renewable energy to gross final energy consumption by 22.7% in 2020. The expected contribution of renewable energy to gross electricity generation is 42.3% in 2020. The distribution of installed power by technology that now exists, is shown in the chart:



S.R: Special Regime.
Source: Preview of the Report "Spanish electrical system 2009" REE

3.3 Are there minimum purchase/output requirements for renewables? How are these put into operation?

Renewables offer all the power generated in the daily market at a price equal to zero. So it is very unusual not to sell all the energy produced. There are no output requirements beyond the market deals..

3.4 How do minimum purchase plans tie into transmission capacity?

Once the daily trading session has been celebrated and once the executions of the national bilateral contracts are received, the system operator (REE) evaluates the technical viability of the program to ensure the safety and reliability of supply in the transport network. If the result does not respect the maximum capacity of exchange between electrical systems or safety requirements, REE modifies the allocation of energy realised by the daily market. Renewables are also submitted to this system as another source of generation.

3.5 Is there a mechanism for trading renewable energy credits? If so, how does that function?

No, the Spanish system is a "feed-in tariff".

4. Connection to the grid

4.1 Are connection rules for renewable electricity suppliers clear and transparent? How long do renewable generators need to wait to get connected?

The regulation of the connection of new generation facilities does not provide differential treatment to renewable generators. Any request follows the provisions of RD 1955/2000. The rule is clear and specifies the procedure to follow.

The right of access may be restricted only by the lack of capacity, which could be based only on criteria of safety, regularity or quality of supplies. The request is routed to the operator of the distribution network in the area, including the necessary information to determine whether there is enough capacity or not. In absence of conflict, the dealer must decide the application within 15 days.

If the new plant will cause significant increases in energy flows (in any case, when the installation has more capacity than 50MW), or if it will affect the safety or the quality of supply, REE must deal with the application in two months.

Potential conflicts are resolved in front of the regulator. Once granted authorization access, the connection procedure should be resolved within 6 months.

All these procedures should be made with the sufficient time for proper commissioning of the amenities and at least two months before it, including the conditioning of equipment or others that establish the rules.

Actually, a Royal Decree of access and connection to the electricity network of special treatment facilities, including renewables, is in development process. The project unifies access and connection arrangements.

4.2 On what basis are connection costs calculated and allocated?

The costs of connecting facilities and the costs of strengthening and expanding the existing network corresponds to the new generator, provided that these costs are not included in the network planning.

5. Dispatch in response to demand

5.1 A commonly cited challenge with renewable generation is that production often depends on external forces that cannot be controlled by the operator. For example, wind power depends on

the presence of appropriate atmospheric conditions. What efforts are being made to increase the ability to dispatch renewable energy resources in response to demand?

First, when the generators go to the market must make a production forecast. There are penalties for any deviation. Moreover, the system operator has set up a control centre of the Special Regime (CECRE) to optimize the integration of ER without compromising the system security. It is addressed primarily to anticipate and mitigate the impact on the system arising from sudden falls in production of wind power.

5.2 How common is flexible pricing that can change on a daily and hourly basis?

The market price is determined through the interaction of supply and demand in the 24 wholesale daily markets, taking into account the technical restrictions, intraday market and real-time operations. However, most of the domestic consumers pay a constant rate independent of the pool price and the time of consumption.

6. Vertical and horizontal issues

6.1 Do generating companies own both renewable and non-renewable plants?

The large Spanish electricity companies have a significant capacity of renewable energy. Iberdrola Renewables has 5200MW of installed capacity in Spain, Endesa has 2791MW (Spain and Portugal), EUFER (which is owned by Enel and Gas Natural Group) has1065MW and EON 228MW.

6.2 Are some electricity companies able to exercise monopsony power in the purchase of renewable electricity? Can such purchasers foreclose new producers to the benefit for their own generation?

It seems impossible, since the electricity market does not allow to choose a particular primary source.

UNITED KINGDOM

1. Executive Summary

This paper describes existing regulation on smart grid and renewable energy sources in the UK. The purpose of such regulations is to encourage investment and increased use of renewable energy sources as well as more efficient use of energy in the UK. In particular, such regulation is designed to counteract the high cost, market failures, and barriers which constrain renewable electricity development and investment, and to help achieve the UK's renewable energy and greenhouse gas emission targets.

This is done in a number of ways, for example by imposing Renewable Obligations (RO), which provide an obligation on licensed electricity suppliers to produce a specified number of Renewable Obligation Certificates, or else require them to pay a penalty for any shortfall. It would be extremely costly (in administrative terms) to set the level of subsidy at exactly the right level for every renewables installation, and therefore one can expect there to be some rents for renewables generators/ electricity suppliers under the RO.

In addition, changes to the UK planning system, investment in the grid and other actions described in the Renewable Energy Strategy are designed to encourage investment.

Smart Meters, which allow for suppliers to differentiate their products and which make consumers more aware of usage and efficiency of energy are likely to enable change in how energy is consumed however one has to be careful about the benefits that meters on their own can achieve. The UK Department for Energy and Climate Change DECC considers that the changes achievable could be significant but only if they are accompanied by carefully designed policies. This paper describes such policies and how they are being implemented in the UK.

2. Renewable sources of electricity: wholesale pricing and regulation of pricing

Prices for electricity generated in the UK are not typically regulated. In respect of the UK's wholesale power market, the price of electricity is typically determined by the costs of generating electricity from the plant which balances supply and demand – the *marginal* plant.

Currently, the *marginal* plant, is run on fossil fuels, and therefore the prices of fossil fuels are the major determinant of wholesale electricity prices. Wholesale electricity prices in the UK are therefore not determined by the size of the plant but by the short-run marginal costs of the 'marginal kilowatt-hour' needed to balance supply and demand. The possible exception to this is the 'export tariff', which is due to be introduced in April 2010, and which sets the price that small scale electricity generators will receive for selling their renewable electricity to the grid.

2.1 Subsidies for renewable electricity suppliers

Wholesale prices on their own are not high enough to generate a sufficient return in order to encourage investment in renewable electricity in the UK. For this reason, the Renewables Obligation (RO) and the exemption from the Climate Change Levy provide subsidies for renewable electricity so as to

counteract the high cost, market failures, and barriers which constrain renewable electricity development and investment. Such subsidies additionally help meet the UK's renewable energy and greenhouse gas emission targets.

Under the RO, electricity suppliers are obliged to buy a set proportion of renewable electricity, or are else required to pay a fine on any shortfall. This set proportion of renewable electricity is increased each year, in a line of 'fixed targets' (see paragraphs 25 to 27 below for a detailed description on ROs). The actual renewable generation has not exceeded the level of the fixed targets yet, which may arguably indicate an absence of 'excessive' investment in renewables.

It would be impossible (or extremely costly in administrative terms) to set the level of subsidy at exactly the right level for every renewables installation. Hence, there are some rents for renewables generators/ electricity suppliers under the RO. Changes have been made to improve the efficiency of the RO, such as the introduction of banding (tailored support levels for five different classification of renewable electricity technologies), and moving to a 'headroom only' approach (see for example the RES Impact Assessment for the centralized electricity sector available at: http://decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/res/res.aspx).

2.2 Time of Use tariffs and smart meters

Time of Use (ToU) tariffs are not very common in the UK. In fact, without smart meters – for which roll- out will not properly commence before mid-2012 – it is technically very difficult for an energy supplier to offer the service in the UK.

It is expected that the use of ToU tariffs will become more common once smart meters are rolled-out in the UK, which will allow suppliers to differentiate their products by reference to efficiency. Smart Meters are therefore likely to make consumers more aware of usage and efficiency, however they are likely to have only a marginal effect on the types of energy sources consumed.

The DECC considers that Smart Meters can enable change in consumption behaviours but one has to be careful about the benefits that meters on their own can achieve. The DECC considers that the changes achievable could be large but only if they are accompanied by carefully designed policies. A meter on its own is unlikely to have any significant effect on changes in which energy is consumed.

3. Investment: encouraging investment

Investment in renewable energy generation in the UK is encouraged through the financial incentives described above, namely the RO and the exemption from the Climate Change Levy. In addition, changes to the UK planning system, investment in the grid and other actions described in the Renewable Energy Strategy are designed to encourage investment.

The RO bands are set in accordance with information on costs and revenues, including cost of capital and returns needed to incentivise investment.

In April 2010 the UK government will be introducing Feed in Tariffs for small-scale renewable energy generation (less than 5MW) which is intended to incentivise microgeneration and smaller scale community and industrial renewable electricity projects. The tariff levels have been set to achieve a rate of return to investors of between [ ] which evidence suggests is necessary to compensate for the higher risk and uncertainty associated with these small-scale renewable energy generation projects.

Independent regulator and transmission owners are generally concerned about the potential risk of building transmission assets without full assurances provided by multiple small renewable electricity

generators. In March 2009, following a joint report chaired by DECC and Ofgem together with the Electricity Networks Strategy Group, recommended £5 billion worth of additional transmission investment to accommodate **likely** renewable generation in the run-up to 2020.

Transmission investment is typically agreed between Ofgem and the transmission owners as part of the Transmission Price Control Reviews that take place every five years. Following the joint report, Ofgem is authorising anticipatory an exception to accommodate investment in transmission by the transmission owners outside of the normal Transmission Price Control Review investment plans that take place every five years so as to facilitate the achievement of the UK's renewable energy targets.

Capital investment in the transmission network is recovered through the standard transmission charges paid by all electricity generators and suppliers, which are ultimately reflected in consumers' electricity bills.

4. Output plans and minimum purchases

For 2009/10 the level of the RO has been set at 0.111 Renewables Obligation Certificates (ROCs) per MWh for England, Wales and Scotland, and 0.0427 ROCs per MWh for Northern Ireland. This corresponds roughly to 11.1% and 4.2% renewable electricity.[1]

The renewable sources eligible for support under the RO are set out in Table 1 below:

Table 1: Renewable sources eligible for support under the Renewables Obligation

•	Electricity generated from landfill gas
•	Electricity generated from sewage gas
•	Co-firing of biomass
•	Onshore wind
•	Hydro-electric
•	Co-firing of energy crops
•	Energy from waste with CHP
•	Geopressure
•	Co-firing of biomass with CHP
•	Standard gasification
•	Standard pyrolysis
•	Offshore wind
•	Dedicated biomass
•	Co-firing of energy crops with CHP
•	Wave

1 With the introduction of 'banding' in the Renewables Obligation from April 2009, 1 ROC no longer always corresponds to 1 MWh of renewable electricity. For example, 1 ROC for onshore wind still corresponds to 1 MWh, but 1 ROC for offshore wind for new stations since April 2009 corresponds to 2/3 of a MWh and 1 ROC for co-firing of biomass with fossil fuel for new station since April 2009 corresponds to 4 MWh of electricity.

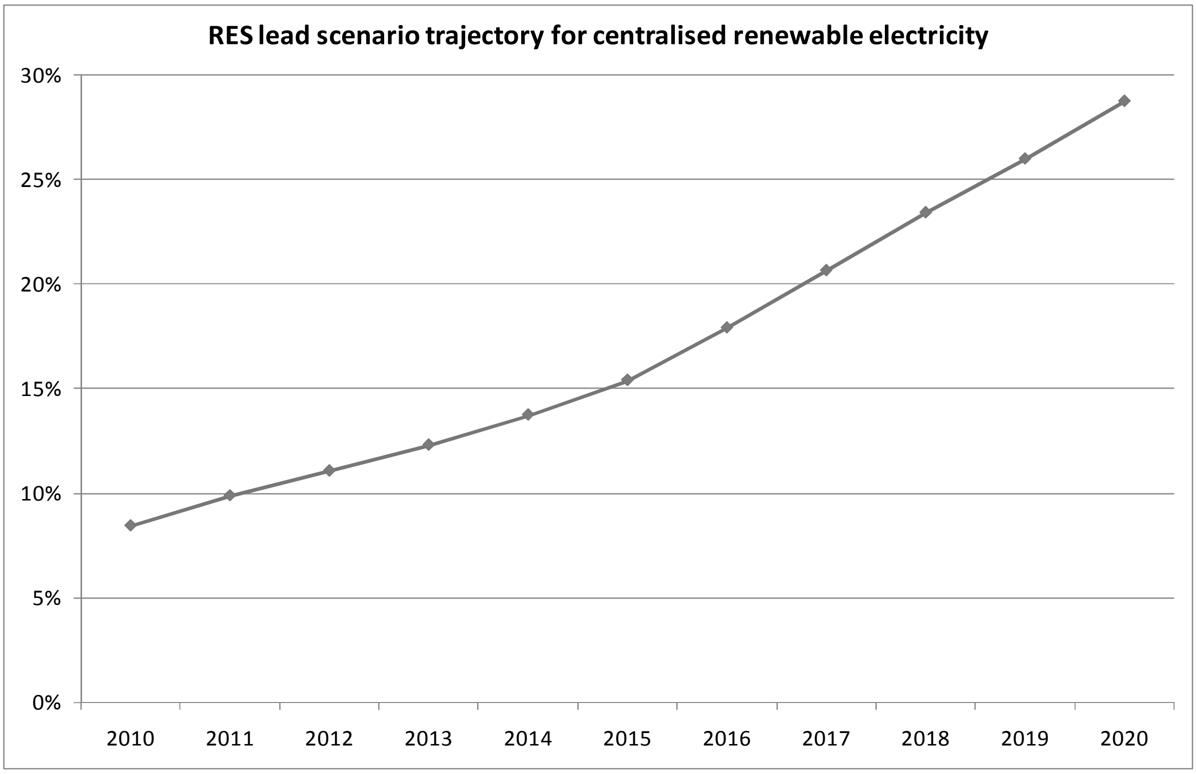
- Tidal-stream
- Advanced gasification
- Advanced pyrolysis
- AD
- Dedicated energy crops

- Dedicated biomass with CHP
- Dedicated energy crops with CHP
- Solar photovoltaic
- Geothermal
- Tidal impoundment – tidal barrage
- Tidal impoundment – tidal lagoon

The technology definitions are set out on the following website: http://www.opsi.gov.uk/si/si2009/uksi_20090785_en_10#sch2-pt2.

In order to meet the UK's 2020 renewable energy target of 15%, it is estimated that around 30% of renewable electricity will need to come from renewable sources (mostly from large scale generation, but with contributions from small-scale electricity).

The Renewable Energy Strategy (RES) of July 2009 sets out the UK government's plans to achieve this ambitious degree of expansion of renewable electricity which is described in the diagram below.

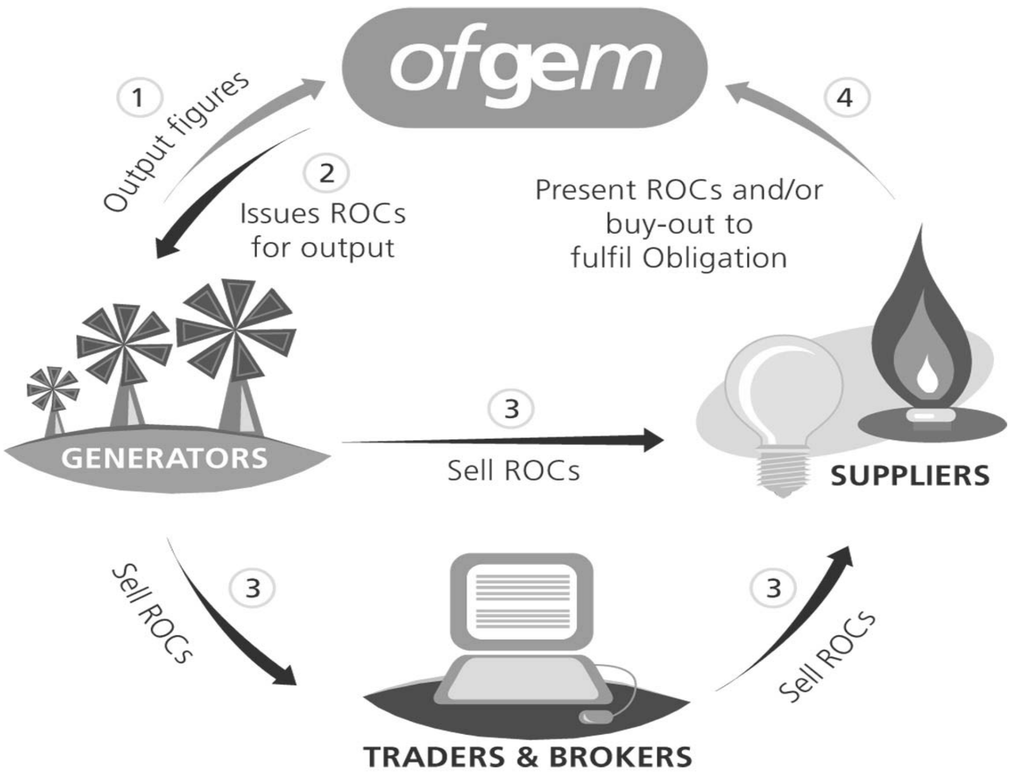


The private sector has considerable plans for expansion of renewable energy. There are currently 2.9GW of renewable energy in construction, 8.4GW awaiting construction and a further 10GW in planning.

The minimum purchase system for electricity is the RO. Its working, including the trading of ROCs, is explained in the textbox and subsequent diagram below:

Box 1. Renewables Obligation

- The RO works by placing an obligation on licensed electricity suppliers to produce a specified number of ROCs per MWh which increases annually, or else pay a penalty for any shortfall.
- The obligation for 2009/10 is 9.7% currently rising to 15.4% in 2015/16 unless the UK has moved to headroom.
- The RO is administered by Ofgem who issues Renewables Obligation Certificates (ROCs) to renewable electricity generators. Generators receive different numbers of ROCs depending on the technology.
- Generators sell their ROCs to suppliers or traders which allows them to receive a premium in addition to their electricity. ROCs can be sold with or without the associated electricity.
- Suppliers present ROCs to Ofgem to satisfy their obligation. Where they do not present sufficient ROCs they have to pay a penalty known as the 'buy-out' price. This is set at £37.19/MWh for 2009/10 (and linked to RPI).
- Money from the 'buy-out' fund is recycled to suppliers who present ROCs on a pro-rata basis.



From April 2010 the UK is also due to introduce feed-in tariffs as an alternative choice to the RO subsidy for small-scale generators in certain renewable technologies on installations less than 5MW in size.

Transition to the feed-in tariffs will be compulsory for microgenerators under 50kW in size in the relevant technologies.

Under the feed-in tariff system, electricity suppliers will be obliged to purchase (often in the form of lower electricity bills) electricity exported to grid at the level of the ‘export tariff’, and pay small-scale generators a generation tariff for all their generation, whether used on or off site.

The responsibility for adopting renewable sources falls to the UK government in terms of its statutory commitment to the 2020 renewables target. Government places/will place an obligation on electricity suppliers to buy electricity from renewable sources from small-scale generators under the feed-in tariffs, and from the generally larger-scale generators under the RO. Where this obligation is not met, a ‘buy-out’ price must be paid.

5. Connection to the grid: connection costs and rules

The DECC considers that connection rules are understood by new generators, whether renewable or not. The connection involves an application to the transmission system operator (SO), who in turn gives the new generator an estimated connection date based on the local works and reinforcements needed to the grid to accommodate the new generator.

Because of the substantial wider reinforcements required for the connection of the substantial amount of renewable generation being planned, a ‘connection queue’ developed during 2008/09 that reached 60GW of new capacity with connection dates going as far as 2023.

As a result, Ofgem approved a new interim grid access connection model based on connecting new generators as soon as local works were completed and managing the likely constraints, whilst wider reinforcements took place. The UK government is currently consulting on a new grid access model to be introduced on an enduring basis from June 2010.

Currently, local works to connect the new generator to the grid are paid for by the generator requiring the connection. The new generator is also required to put up securities to cover transmission reinforcement work being carried out, but these are netted off against transmission network charges following connection to the grid (and are therefore effectively socialised across all generators and suppliers).

Incumbent generators do not have incentives to limit transmission capacity of renewable generators because of the system for transmission described above.

6. Dispatch in response to demand

The practice of ‘shutting down’ electricity users at peak periods in order to help adapt to potentially limited ability of renewable generation has not led to potential problems in the UK. In fact, the opposite is true. Contracts that allow for a balance of output have allowed the UK to make substantial savings over the traditional approach of managing constraints through the balancing mechanisms.

Increasingly, at times of high renewable output, the transmission network is constrained and constraint costs are incurred as a result of having to reduce the electricity output of conventional generators to accommodate renewable output. This is particularly the case in Scotland, which has a high proportion of renewable generation compared to the rest of the country (a proportion expected to increase substantially in the short to medium term). Scotland is traditionally an electricity exporting zone and has inadequate transmission capacity to England and Wales.

As a result, innovative contracts have been increasingly used to balance output, such as intertrips and capped generation contracts, which can deliver substantial savings over the traditional approach of managing constraints through the balancing mechanism.

7. Vertical and horizontal issues

In the UK generating companies own both renewable and non-renewable plants.

In the UK generators sell their output to suppliers and the system operator either on the market or through commercial contracts. As renewables generation have low short run marginal costs of generation and therefore are placed low in the merit order of generation, one would expect them to provide baseload electricity and thus for generators to be able to sell their electricity through the market or contract accordingly.

Suppliers are able to make a commercial decision as to the mix of electricity (renewables or non-renewables) they wish to purchase.

Currently, over half of the renewable generation in the UK is by the major power producers[2]. Over the next decade following the UK's implementation of the RES, there is going to be a significant increase in the construction of renewable plants in the UK. By current estimation, the most significant investment in renewable infrastructure is being undertaken by the big six major producers. Due to the current structure of the UK electricity supply, with several large suppliers acting in the market, the DECC would not expect companies to be able to exercise monopsony power in the purchase of renewable electricity.

Currently there are six major players in the UK generator market and smaller independent companies. Given this market structure, it is unlikely that purchasers would be able to foreclose new producers to benefit their own generation and if this were to occur it would suggest collusion on part of the producers.

Going forward, the current market structure suggests that this is also unlikely in the future. However, given that the market is continuously changing, the DECC considers that any prediction about the future state of the market is purely conjecture.

8. Status of adoption and demand response

The development of smart grid adoption within the UK is at an early stage. The UK government published a paper 'Smart Grids- The Opportunity' on 2nd December along with an industry vision for Smart Grids.

The industry group Electricity Networks Strategy Group (ENSG) is currently developing a routemap for the implementation of Smart Grids.

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2 Major power producers at the end of 2008 were; AES Electric Ltd., Baglan Generation Ltd., Barking Power Ltd., British Energy plc., Centrica Energy, Coolkeeragh ESB Ltd., Corby Power Ltd., Coryton Energy Company Ltd., Derwent Cogeneration Ltd., Drax Power Ltd., EDF Energy plc., E.On UK plc., Energy Power Resources, Gaz De France, GDP Suez Teesside Power Ltd., Immingham CHP, International Power Mitsui, Magnox Electric Ltd., Premier Power Ltd., RGS Energy Ltd, Rocksavage Power Company Ltd., RWE Npower plc., Scottish Power plc., Scottish and Southern Energy plc., Seabank Power Ltd., SELCHP Ltd., Spalding Energy Company Ltd., Uskmouth Power Company, Western Power Generation Ltd, Airtricity, Cumbria Wind Farms, Fred Olsen, HG Capital, Renewable Energy Systems, Vattenfall Wind Power.

Smart Meters, both electric and gas, will be rolled out to all households by 2020. The functionality and communications infrastructure are still in the specification stage. It will be important to ensure these specifications enable the development of a Smart Grid rather than close of the benefits that a Smart Grid can deliver. The transmission, distribution, suppliers and generators will need to work together to ensure the benefits are fed through to the consumer.

More active demand response facilities will ensure the need for less peaking plants to be built which will enable suppliers to develop time of use tariffs for customers. Time of use tariffs will help ensure bills do not rise substantially, allowing for the increased use of renewable power sources. The DECC would envisage more energy supply companies to come into the market to provide the services of selling energy to customers. Each smart meter fitted in a new home will be accompanied by a visual display unit which will allow consumers to benefit by reducing their demand at peak times. There have been some small demonstration projects on Smart Grids carried out in the UK some examples of which are below in Table 2:

Table 2: Projects on Smart Grids carried out in the UK

Skegness, Lincolnshire	Due to the connection of both onshore and offshore wind, Skegness generates more electricity than it requires. Exporting the power to the local town of Boston would, using traditional solutions, require reinforcement of the existing lines. Instead, dynamic line rating technology monitors the weather conditions in real time and dynamically assesses the line rating, increasing the capacity of the existing lines without the need for physical reinforcement.
Orkney	An innovative Active Network Management (ANM) scheme has provided the basis for the connection of multiple new renewable generators, which are managed to meet network constraints at several monitoring locations on the Orkney network in real time. The deployment of ANM and the accompanying commercial arrangements are a quicker and cheaper alternative to network reinforcement to connect more renewable generation to the Orkney network. The technical and commercial aspects of this work are repeatable and are applicable to many existing distribution networks.
Martham, Norfolk	An advanced network voltage control system has been installed to enable the connection of additional wind farms to an existing MV network. The system fine-tunes the substation source voltage according to the output of the generators, so preventing voltage-rise issues. A Lithium Ion battery storage system is now being installed which will mitigate the intermittency of the wind farm output and enable further distributed generation to be connected. The technology has wide potential application to rural MV networks.
Isle of Wight	The Isle of Wight is currently the location of a pilot scheme to evaluate the performance of next generation network automation to automatically reconfigure the network into isolatable sections. It is evaluating both the overhead and underground plant functionality and how they can interact on mixed networks. Using 'intelligent' auto-reclosers there is no restriction imposed by protection discrimination – this being achieved using a high -speed radio link with banks of auto-reclosers having the same protection settings. These auto-reclosers will detect the faulted section, reclose for transient faults, isolate permanent faults and reconfigure the network. The control engineer would only see permanent faults. Real time load management and network constraints will allow the load management to be automated easing issues associated with Distributed Generation and load growth.

9. Standards

The ENSG in its routemap is looking at the best way to develop standards for the Smart Grid. Within the ENSG group they have included manufacturers of appliances to ensure their product development can understand the elements a Smart Grid will need. The need for the transmission operators and Distributor Network operators to be involved in helping to specify the functionality of Smart Meters and the communications infrastructure for these is also paramount. The industry is also working closely with the EU taskforce on Smart Grids which will also be looking at developing some European standards.

10. Ownership

Following the UK government's response to the consultation on Smart Meters it has been decided that the Electricity retailer will be responsible for installing and owning Smart Meters. There will be a separate company set up who will be responsible for the handling of the communication fed in from Smart Meters. The DNOs and TOs will own their own elements of the Smart Grid. The consumer will not need to change equipment when they change supplier.

11. Information

As discussed above, the information that is fed through from Smart Meters will be run by a different company who will then feed this information back to retailers and distributors.

12. Monopsony buyer: regulations on setting price for on-demand electricity produced through distributed generation

There will be set prices for power produced through distributed generation. These will consist of differing prices depending on the technology used for producing the power taking account of the cost for producing this power.

13. Revenue reduction incentives

The incentives mechanism for encouraging investment in Smart Grid and reduction of revenues is still be looked at. The regulator Ofgem has made available £500 million for investment through their Low Carbon Networks Fund for DNOs to invest in Innovative technology which is likely to include demonstration projects for Smart Grids.

UNITED STATES

1. Introduction

Smart Grid technologies and advances in renewable electricity generation have the capacity to reshape the United States markets for electric power. The U.S. response to the global economic crisis includes a significant investment in these new technologies,[1] promising to accelerate the pace of these already burgeoning innovations. Such technological leaps have the potential to alter not only the business models of existing firms, but also to enable entry by new firms -- and new *kinds* of firms -- previously unknown in the industry.

This paper discusses how these new technologies might change the competitive status quo for American consumers and some of the competition policy issues that this new environment can raise. These include a variety of steps that firms with market power might take to try to limit or delay new entry or the possible dislocations that can arise from wide-scale deployment of the newest technology. In this environment, both antitrust enforcers and regulators need to be mindful of the incentives of incumbent firms. If experience with other industries that underwent similar transformations is a guide, competition agencies should be prepared to take appropriate enforcement action to guard against anticompetitive practices that thwart new entry. Through competition advocacy, competition agencies may also be able to assist regulators in the design of policies that will maximize the competitive potential of smart grid technologies to benefit consumers.

This paper proceeds in three parts. First, it explains what is meant by smart grid technology and discusses how smart grid technology and renewable resources might alter the market for electric power. Second, it identifies U.S. programs to support smart grid technology and renewable energy, including provisions from the American Recovery and Reinvestment Act of 2009.[2] Third, it discusses the role antitrust enforcement might play in this context and suggests opportunities for competition advocacy by competition agencies. The paper concludes by identifying areas that may benefit from further research.

2. Understanding the smart grid and its effects

Understanding the competitive concerns that could accompany a transition to smart grid technology requires an understanding of what is meant by “smart grid” and how it interacts with the use of renewable generation resources. In general, the term “smart grid” refers to the layering of a telecommunications system on top of the existing power grid. This layering of communications would not only improve operations of the existing network, but also likely would lead to the development of sensors, data measurement tools, control systems, and other devices that have the potential to radically change the competitive landscape of electricity markets. In particular, smart grid technology makes use of two-way information sharing between system administrators and various generation, transmission, and distribution sites throughout the system.[3] In the words of the Electric Power Research Initiative, a smart grid is the

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1 *See* http://www.oe.energy.gov/american_recovery_reinvestment_act.htm.

2 American Recovery and Reinvestment Act of 2009, Pub. L. 111-5 (2009).

3 *See* ELECTRIC POWER RESEARCH INITIATIVE, THE GREEN GRID 1-1 (2008).

"overlaying of a unified communications and control system on the existing power delivery infrastructure to provide the right information to the right entity . . . at the right time to take the right action."[4] As a result, "it is a system that optimizes power supply and delivery, minimizes losses, is self-healing, and enables next-generation energy efficiency and demand response applications."[5]

To simplify matters, smart grid technology can be divided into two broad categories. First, it can refer to the use of advanced metering and other technological measures to more accurately monitor, respond to, and affect customer usage. Because these technologies typically require installations at the user end of the wire -- that is, on the lower-voltage, final distribution portion of the supply chain -- regulatory requirements in this realm in the United States are typically subject to the jurisdiction of the several states in the United States.[6] Second, the smart grid concept can refer to infrastructure modernization initiatives that are designed to improve the information sharing capabilities and responsiveness of the broader transmission (or even distribution) systems. Because these networks (particularly, the transmission ones) are higher-voltage, interstate systems, they are usually subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).[7] This paper will discuss each category of smart grid technology in turn.

2.1 Advanced metering, demand response, and distributed generation

One major set of smart grid initiatives involves the installation of smart meters at the end of the distribution system. Large-scale industrial customers have begun using such meters, seeking to identify strategies for conserving their electricity usage and saving costs in the process. Such meters can be used to obtain real-time price information from utilities and to allow utilities to get specific information about how much electricity particular consumers are using rather than just the amount of general demand. As these technologies become more sophisticated, they can be connected to major home and industrial appliances, allowing them to be programmed for use only when electricity rates are low or even allowing utilities to control them -- for a fee or in exchange for reduced electricity rates -- during periods when demand is extremely high relative to supply. A few utilities currently use meters that are "smart enough" to allow some of their customers to take advantage of strategies like time-of-day pricing or other forms of more nuanced measurement than a mere tally of the number of kilowatt hours used each month. But increasing the penetration of the most innovative and "smartest" meters, with their two-way, digital communications capability, would enable a much broader set of programs that might vastly alter the shape of electricity markets.

The principal impact of smart meters is to better enable the set of changes collectively known as "demand response." Because there is no efficient way as yet to store large amounts of electricity, generation must constantly be matched with consumption. At the same time, short run demand for electricity is extremely inelastic. Consumers may not be aware of when electricity is most expensive and when it is cheapest; at least in the short run, they therefore may use all the electricity necessary to meet their preferences. This means that utilities must constantly monitor demand and must have generating capacity ready for very large peaks -- sometimes called "needle peaks" -- even if they occur infrequently.[8] This "peaking" generation is typically older, costlier, and more harmful to the environment. Indeed, a

4 *Id.*

5 *Id.*

6 FERC also plays a role in this area pursuant to the Energy Independence and Security Act of 2007, 42 U.S.C. §§ 17001-17386 (2007).

7 The states are primarily responsible for many siting issues.

8 Approximately 10% of California's generation capacity is used less than .65% of the time annually. *See* ELECTRICITY ADVISORY COMMITTEE, SMART GRID: ENABLER OF THE NEW ENERGY ECONOMY 7 (2008).

significant portion of electricity costs comes from maintaining rarely used excess capacity for the purpose of meeting peaks that are few and far between.

With respect to smart meters, the use of "demand response" can take at least four important forms. First, simply exposing end users to more real-time prices often will be sufficient to cause them to refrain from using high-energy appliances when prices are high, deferring their use to less costly times of the day.[9] Because smart meters with digital displays or connections to cellular phones and home computers can communicate this kind of real-time pricing information to customers, they have the capacity to introduce significantly more short-run elasticity into the demand for electric power. In the longer run, smart metering technology could lead to increases in demand elasticity as consumers invest in technologies that preserve convenience but shift consumption to off-peak demand periods. For example, smart meters could even be linked to appliances that would tailor their own peak usage to electricity costs -- say, a dryer that is told when electric power is cheap and is turned on automatically at that time. Similarly, with efficient price signals, consumers may decide to invest in distributed generation that can further increase demand response by such consumers.

Second, many studies indicate that simply exposing consumers to information about their energy usage is sufficient to cause them to consume less power overall.[10] Reflecting this development, a number of diverse players, including information companies like Google, are interested in assisting consumers by tracking their electricity usage and enabling them to better manage their overall demand.[11] Third, smart meters that are connected to appliances could be linked to the utility company, which could – for example, in exchange for discounted rates -- turn off certain non-essential devices to save power during peak demand periods and thereby avoid the possibility of "brownouts."[12] Moreover, because utility control over demand during peaks is essentially a substitute for installing new peaking generation (or new transmission), firms capable of pooling this kind of demand response could bid it into reserve capacity markets, provide a form of competition (*i.e.*, an alternative to new generation and/or transmission), and reduce the need to maintain environmentally and economically costly generation reserves. Finally, smart meters that operate in conjunction with recharging systems for electric vehicles of the future could help channel this new demand into off-peak periods and potentially facilitate access to the energy stored in vehicle batteries for system reserves (provided, of course, that such technologies continue to develop and are practical to implement).

In sum, demand response strategies that use smart meters (or even "smart enough" meters) have the potential to improve the functioning of competitive electricity markets. As FERC recently stated, demand response "can provide competitive pressure to reduce wholesale electric prices, increase awareness of energy usage, provide for more efficient operation of markets, mitigate market power, enhance reliability,

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9 *See, e.g.*, PACIFIC NORTHWEST NATIONAL LABORATORY, PACIFIC NORTHWEST GRIDWISE TESTBED DEMONSTRATION PROJECTS (2007); *see also* DEMAND RESPONSE AND SMART GRID COALITION, TIME-BASED PRICING FOR RESIDENTIAL CUSTOMERS: QUESTIONS & ANSWERS (2007), *available at* http://www.smartgridnews.com/artman/uploads/1/Time-Based_Pricing_for_Residential_Customers.pdf.

10 Although there is significant research remaining to be done on the designs that best promote consumer awareness and reaction to price and usage information, diverse studies do indicate that consumers who receive information about high levels of consumption do choose to consume less energy. *See, e.g.*, CASS SUNSTEIN & RICHARD THALER, NUDGE 193-194 (2009) (describing Southern California Edison Ambient Orb project); http://sites.energetics.com/madri/pdfs/ChartwellHydroOneMonitoringProgram.pdf (describing Hydro One pilot program with PowerCost Monitor).

11 http://www.google.org/powermeter.

12 *See, e.g.*, Dan Charles, *Renewables Test IQ of Grid*, SCIENCE 172-175 (Apr. 2009).

and, in combination with certain new technologies, support the use of renewable energy resources and distributed generation."[13]

Smart grids, through both demand response and other capabilities, also have the capacity to facilitate better integration of renewable energy sources and other new generation technologies into the system. The increasing reliance on renewable energy sources, such as wind and solar, introduces greater variability into the supply chain. This is because, unlike traditional fossil fuel generation, wind and solar generators cannot balance increased demand by burning more fuel, *i.e.,* their output is dependent on variable weather conditions.[14] Smart grids could potentially offset such variation with demand response or could allow system operators to balance them more rapidly with calls on less expensive reserve generators, making large-scale renewable generation both easier and more cost-effective.[15] The two-way communications capabilities of smart grid technology also facilitate competition in electricity generation by allowing for greater use of "distributed generation" and "distributed storage," where multiple, small-scale generation and storage sites – such as rooftop solar panels or plug-in hybrid vehicles -- can sell electricity back to the grid.[16] Significantly, this has the capacity to introduce an entirely new competitor into the market for electric generation -- namely, the consumer.

2.2 Infrastructure improvement

The other important segment of smart grid initiatives is the modernization and expansion of the existing transmission system. This interstate system of long-distance, high-voltage wires is the principal system to which most large-scale generation resources (both traditional and renewable) are connected. It is often analogized to the interstate highway system -- a series of higher-volume, longer-distance pathways carrying traffic to lower-volume, local streets -- except that the engineering complexities of electricity require every "highway" in the system to be kept in constant balance. Notably, improving the communications network along the grid allows it to balance itself automatically – and much more quickly -- by enabling the system to carry much less reserve capacity to balance unexpected drops or surges in supply. It also allows the grid to "heal" itself by automatically detecting failures and thus allows the grid to respond better to emergencies. Significantly, smart grid technology offers the opportunity to address the special demands placed on the system by some forms of renewable resources whose output can be more variable.[17] In general, a smarter transmission system will be able to get much greater use out of existing generation and transmission capacity, making the operation and continued maintenance of the grid less costly.

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13 FED. ENERGY REGULATORY COMM'N, THE STRATEGIC PLAN: FY 2009–2014, at 8 (2009), *available at* http://www.ferc.gov/about/strat-docs/FY-09-14-strat-plan-print.pdf.

14 *See* Charles, *supra* note 9, at 172-175.

15 *Id.*; *see also Trade Winds*, THE ECONOMIST (Jun. 21, 2008) at 6-12.

16 *See, e.g.*, Dep't of Energy, The Potential Benefits of Distributed Generation and the Rate-Related Issues That May Impede Its Expansion at 6, *available at http://www.oe.energy.gov/DocumentsandMedia/1817_Report_-final.pdf* (explaining that the viability of distributed generation depends on state implementation of "provisions that promote smart metering, time-based rates . . . demand response, net metering, and fossil fuel generation efficiency.").

17 *See* David Talbot, *Lifeline for Renewable Power*, TECH. REV. (Jan./Feb. 2009) at 41-47, *available at* http://www.technologyreview.com/energy/21747/ (describing German experience and major challenges facing the U.S. grid).

3. U.S. Smart Grid and Renewable Investment

As part of the response to the global financial crisis, the United States invested in infrastructure spending in the American Recovery and Reinvestment Act (ARRA).[18] Notably, the Act allocated $16.8 billion for efficiency and renewable programs and another $4.5 for grid modernization.[19] In addition to these investments, the government has established various programs to foster progress in these areas. These include, for example, the Federal Smart Grid Task Force established under Title XIII of the Energy Independence and Security Act of 2007,[20] and a number of efforts by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy.[21] These programs create grant and loan opportunities for businesses interested in investing in smart grid and renewable technologies. These government incentives – which represent environmental, security, and economic priorities – may foster even faster growth in these already burgeoning sectors.[22]

In 2008, the Department of Energy released an exhaustive report chronicling the various policy steps that state and federal entities had taken to encourage the growth of smart grid technology.[23] For present purposes, it is sufficient to say that federal programs range from requiring deployment of advanced metering in federal buildings[24] to requirements for planning, reports, or smart grid demonstration projects.[25] Meanwhile, in conjunction with federal direction, some states have enacted standards requiring time-based metering,[26] and the National Institute of Standards and Technology is in the process of developing standards for interoperability of smart grid technologies.[27] Together with the recent financial appropriations, these and other programs help to structure and create the incentives for major investment in smart grid technology.

On the renewables side, many U.S. states have recently enacted guidelines that require utilities to provide a fixed percentage of their total load from renewable resources (generally from 10-30 percent).[28] The U.S. Congress is considering proposals for a similar federal requirement.[29] In many of these "RPS programs," states provide for renewable energy credits or certificates called "RECs," which are not energy purchases as such, but rather "tradable commodity certificate[s] representing the environmental aspect of

18 Pub.L. 111-5, Feb. 17, 2009, 123 Stat. 115 (2009).

19 *See* http://www.energy.gov/recovery.htm.

20 Pub.L. 110-140, 121 Stat. 1492 (2007).

21 *See* http://www.eere.energy.gov.htm.

22 *See* FEDERAL ENERGY REGULATORY COMMISSION, ASSESSMENT OF DEMAND RESPONSE AND ADVANCED METERING (2008); *see also* http://apps1.eere.energy.gov/news/news_detail.cfm/news_id=12209 (noting major increases in utility investment in smart grid technology).

23 *See* NATIONAL COUNCIL ON ELECTRICITY POLICY, DEMAND RESPONSE AND SMART METERING POLICY ACTIONS SINCE THE ENERGY POLICY ACT OF 2005: A SUMMARY FOR STATE OFFICIALS (2008).

24 *Id.* at 3.

25 *Id.* at 4-10.

26 *Id.*

27 *Id.* at 5-6.

28 29 states and the District of Columbia have set RPS targets; another 5 states have set non-binding targets. *See* RYAN WISER & GALEN BARBOSE, STATE OF THE STATES: UPDATE ON RPS POLICIES AND PROGRESS 6 (Nov. 18, 2009).

29 *See* American Clean Energy Leadership Act of 2009, S. 1462, 111th Cong. (2009); American Clean Energy and Security Act of 2009, H.R. 2454, 111th Cong. (2009).

electricity generated by renewable energy."[30] Due in significant part to RPS programs, the development of renewable sources of energy generation are growing rapidly with, for example, wind-powered generation constituting 42 percent of all new generation built in the United States in 2008 (according to the American Wind Energy Association).[31] As noted above, the development of smart grid technology can operate in tandem with an increased reliance on renewable energy sources and facilitate its use.

Moreover, as described above, the advent of large-scale, distant, renewable generation itself creates pressure for grid modernization. This is because a more modern grid would be able to compensate for these variable resources by balancing out rapid drops in generation with calls on other resources (including demand response), rather than by requiring the wind farm or solar plant to have its own conventional fuel generation (or energy storage devices) to offset such dips.[32] Thus, the policy initiatives in favor of renewables and smart grid technology work together to create significant incentives for modernizing and transforming the business of electricity generation, transmission, and delivery.

4. Antitrust enforcement and competition advocacy

The incentives that face today's market participants are complex and may vary widely depending on local market characteristics. These characteristics include the relevant regulatory framework, the availability of installed generation capacity, the integration of generators and distributors, the types of fuels and generators available, and the shape and frequency of load peaks. Indeed, it is impossible to determine in the abstract whether incumbent firms will be better or worse off in the wake of the deployment of smart grid technology. It is quite possible, moreover, that different firms will react to incentives facing them in different ways, employing a variety of different strategies. Many utilities, recognizing that smart grid technologies can provide significant cost savings, already are experimenting with smart metering initiatives, time-of-day and real-time pricing, and other programs using demand management to reduce costly peaks. On the other hand, because of the potential of this new technology to disrupt their existing business models, some incumbent firms may resist the deployment of this technology. Given the potential significance of this technology, policymakers are likely to be interested in evaluating the reasons for resistance to its adoption.

4.1 Antitrust experience in electricity and related markets

Appreciation of the potential role of antitrust *vis-à-vis* smart grid technology can be aided by an evaluation of how the U.S. antitrust agencies have addressed analogous markets. Notably, antitrust enforcement played an important role in ensuring open access to competing electricity providers in the past. Consider, for example, the seminal case *Otter Tail Power Company v. United States*.[33] In that case, the Supreme Court held that Otter Tail had violated the Sherman Act by refusing to sell wholesale power or to wheel power from another source to a municipal power system that sought to compete with Otter Tail in the retail electricity market. In particular, the Court concluded that Otter Tail had monopoly power in retail sales of electric power in its service area and that it had used its dominance in transmission to foreclose potential competition for retail sales. Although the FERC has since taken the lead in ensuring

30 SECTION OF ANTITRUST LAW, AM. BAR ASS'N, ENERGY ANTITRUST HANDBOOK 251 (2d ed. 2009).

31 AMERICAN WIND ENERGY ASSOCIATION, WINDPOWER OUTLOOK 2009, at 1 (2009), *available at* http://awea.org/pubs/documents/outlook_2009.pdf.

32 *Id.*

33 *Otter Tail Power Company v. United States*, 410 U.S. 366 (1973).

open access to facilities by regulation,[34] the courts have historically played an important role in enforcing antitrust claims based on a denial of access.[35] Although each market is structured differently – both within and outside the United States – both regulators and enforcers should be aware that incumbent electricity firms may be able to impede entry of not only generation sources but also of new technologies that have the potential to facilitate new forms of competition. To address this possibility, competition authorities should evaluate whether such efforts reflect legitimate business purposes or an effort to exclude competition on the merits.

The technological changes in the telecommunications industry and the landmark case of *U.S. v. AT&T* may also be relevant to the emerging technological developments in the smart grid environment.[36] In that case, the Justice Department focused on the efforts of AT&T to protect its legacy business model from would-be rivals in the equipment manufacturing and long distance markets. In both markets, AT&T used its control over the interface to the telephone network to forestall competition and the emergence of new technologies.[37] Without an antitrust remedy, AT&T's refusal to open its interfaces to new technologies produced by competitors would have slowed the deployment of new equipment, including modems. An incumbent's use of its control over existing networks and interfaces to exclude competitors is hardly unique to AT&T. Indeed, the DOJ's case against *Microsoft* involved similar interoperability concerns.[38]

The DOJ and FTC's experience with standard-setting bodies is also highly relevant in this context. As in the *Allied Tube* case, there is a risk in such technology-heavy markets that incumbents will try to influence the vote of a standards setting organization to ensure that rival technologies will be viewed as unsafe, suspect, or otherwise disfavored.[39] As the Supreme Court recognized, such standards can make all the difference in whether rivals will be able to compete with existing technology.[40] Going forward, standard setting will play a crucially important role in creating smart meters and smart devices that can successfully connect to each other and to the broader network.

In the smart grid context, government regulators will take the lead in cultivating and endorsing the relevant standards. Even so, experience teaches that this is a particularly important realm for antitrust and regulatory vigilance. Notably, standard setting organizations should insist on openness regarding existing intellectual property rights to prevent hold-up,[41] take care that the standards are not so onerous as to

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34 *See* FERC Order No. 888, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21,540 (May 10, 1996).

35 *See, e.g.*, City of Vernon v. So. California Edison Co., 955 F.2d 1361 (9th Cir. 1992), *cert. denied*, 506 U.S. 908 (1992); City of Anaheim v. So. California Edison Co., 955 F.2d 1373 (9th Cir. 1992), *cert. denied*, 506 U.S. 908 (1992); City of Malden v. Union Elec. Co., 887 F.2d 157 (8th Cir. 1989).

36 *United States v. AT&T Co*., 552 F. Supp. 131, 224 (D.D.C. 1982), aff'd sub nom. *Maryland v. United States*, 460 U.S. 1001 (1983).

37 Philip J. Weiser, Deputy Assistant Attorney General, Antitrust Division, U.S. Department of Justice, INNOVATION, ENTREPRENEURSHIP AND THE INFORMATION AGE, Remarks as Prepared for Silicon Flatirons Center Digital Broadband Migration Conference: Examining the Internet's Ecosystem, University of Colorado at Boulder, January 31, 2010, *available at* http://www.justice.gov/atr/public/speeches/254806.htm.

38 *See United States v. Microsoft,* 84 F. Supp. 2d 9 (1999).

39 *Allied Tube & Conduit Corp. v. Indian Head, Inc.*, 486 U.S. 492 (1988); *see also* Philip J. Weiser, *Regulating Interoperability, available at* http://papers.ssrn.com/so13/papers.cfm13abstract_id=1344828.

40 *Id.*

41 Philip J. Weiser, *Making the World Safe for Standard Setting* (March 13, 2008), *available at* http://papers.ssrn.com/so13/papers.cfm?abstract_id=100342.

prevent entry, and seek to ensure that standardized technology is advanced enough to allow maximal use of expanding technological opportunities. Indeed, the U.S. Department of Commerce's National Institute of Standards and Technology (NIST) is already doing important work in this area.[42] Given their experience in this area, antitrust authorities can be particularly effective advocates in these endeavors.

4.2 The role for competition advocacy

Competition agencies may have a similarly important role to play in the competition advocacy arena. In particular, in designing effective regulatory polices with respect to smart meters and demand response, there are a number of specific kinds of possible behavior to which regulators and antitrust enforcers should be sensitive. Incumbents may have much to lose from efficient demand response, and they may try to use regulatory actions to limit deployment of smart meters and residential-scale demand response by, for example:

- Resisting deployment of smart meter technology;
- Supporting deployment of less sophisticated, proprietary, or closed architecture equipment so that access to information is difficult and expensive;
- Supporting imposition of utility-type regulation on new entrants to raise their costs and discourage entry; and
- Supporting strict and inflexible interconnection criteria for variable resources, like rooftop solar.

Similarly, regulators and antitrust enforcers should be sensitive to the following types of behavior with respect to infrastructure modernization:

- Refusing to update grids, even when it makes economic sense to do so, in order to foreclose entry by renewable generation sources;
- Attempting to convince regulatory bodies to force inordinate costs for connection and modernization onto new entrants, including renewable generation; and
- Other attempts to raise costly barriers to entry for new generation (or limit it entirely), including attempts to foreclose renewable resources from capacity markets and attempts to impose excessive charges for backup power on customers with distributed generation.

To be sure, not every one of these types of actions is necessarily harmful to competition, unwarranted, or unjustified. There are undoubtedly substantial costs involved in the coming technological transition and incumbent firms may have legitimate concerns about whether the benefits of a transition to a new generation of technology outweigh the costs of that transition, particularly when environmental and other social costs have not fully been internalized in price. This question makes it all the more important for

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images/stories/file/iprstrust/Making%20the%20World%20Safe%20for%20Standard%20Setting.pdf. For an example of how standard setting processes can enable patent holders to engage in holdup-type behavior, *see Rambus Inc. v. Infineon Techs. AG*, 318 F.3d 1081, 1100-01 (Fed. Cir. 2003).

42 Under the Energy Independence and Security Act of 2007, NIST is assigned "primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of Smart Grid devices and systems." 42 U.S.C. §1305 (2007). NIST has already published a framework and roadmap for smart grid interoperability standards, *available at* http://www.nist.gov/public_affairs/releases/smartgrid_interoperability_final.pdf.

regulators to be able to carefully and intelligently evaluate the incentives of firms and consider the claims of those who comment on their proposals. Antitrust agencies may be particularly well-equipped to assist in this endeavor. Given their institutional expertise, antitrust enforcers can help highlight for regulators the positive dynamic effects of increased competition in the face of competing arguments about its ultimate economic impact.

4.3 Areas for further research

Because smart grid technology and widespread integration of renewable generation resources are both still nascent, much remains to be learned about optimal implementation, best industry practices, key regulatory issues, and the incentives of entrants and incumbents. This is itself an important point for enforcers and regulators: where the technology – and experience with it – is still developing, any governmental approach must be flexible and subject to revision so that it can accommodate creative and unexpected advances by consumers, producers, and new entrants. In other words, regulation should take a dynamic view of the market and endeavor to find approaches that facilitate technological change, experimentation, and the possibility of disruptive business models that defy the classic approaches of incumbents. As the technology evolves, the following issues merit further evaluation and study.

4.3.1 How smart is smart enough?

Many of the programs and initiatives described above might be capable of implementation with meters that are less advanced – and, perhaps, less costly – than the latest technology. It merits investigation whether there are less expensive alternatives that could provide nearly equal benefits. At the same time, existing firms may have incentives to deploy second-best technology that provides essential benefits to themselves without enabling entry by newer players. What appear to be the most essential technologies? Do existing firms have incentives to deploy them? Do others? Does the existing regulatory structure spread the costs of technological investment in ways that provide incentives for that investment when it is or could be socially beneficial? If not, what regulatory design would do so? What are the experiences of other countries in these areas?

4.3.2 How will consumers respond?

Energy markets, like many others, implicate questions of human behavior. The issue is not only whether certain programs create incentives for consumers to conserve energy and save money, but also whether those incentives are salient so that consumers actually act on them. Which technologies best enable consumer response? How have consumers actually responded to test and pilot programs in various jurisdictions? Do programs that enable utilities to control home appliances work best because they are automatic or do consumers find this option unpalatable? What kind of grid architecture will best enable consumers to find and make the choices that they would themselves regard as welfare maximizing?

4.3.3 What investment structures work best?

Many of the possible benefits of smart grid technology lie with consumers, but consumers may be unwilling or unable to make large, up-front investments to realize these benefits, especially where the benefits will come only if others do the same. Are consumers likely to invest in smart grid technologies? Under what conditions? Are incumbents or entrants better poised to make initial investments? What regulatory changes would be necessary to provide the right incentives for initial investment? To the extent that smart grid technologies facilitate non-economic goals such as environmental conservation or electric reliability, should governments be expected to invest? What have been the results where governments have done so?

5. Conclusion

Smart grid technology continues to develop and is only in its incipient stages. Utility regulators still have a lot to learn about this technology, how it will work, and what regulatory strategies are optimal in this area. As regulators proceed to encourage the development and adoption of this technology, it is important that they are mindful of the relevant competition policy issues that it raises. Similarly, for antitrust enforcers, the development of new technologies and the potential blocking position of incumbent monopolists - as evidenced in the *Otter Tail* and *AT&T* cases - raise concerns that merit attention as well.

EUROPEAN UNION

1. Introduction

Support to renewable energy sources in the European Union (EU) is one of the instruments used to achieve the ambitious environmental targets of having at least 20% reduction in greenhouse gas emissions by 2020 compared to 1990 and a binding target of a 20 % share of renewable energies in overall EU energy consumption by 2020.

One of the main tools which EU member states can use to achieve these targets and address environmental concerns is the correct application of the polluter pays principle. Regulation or market based instruments should ensure that costs of environmental protection are internalised by companies and reflected in the final price of their products. If pollution becomes a real economic cost, companies will tend to maximise their profits by reducing this cost component and therefore pollution. In addition, if polluting goods are more expensive, demand will adjust towards less polluting sectors offering cheaper and more environmentally friendly goods and services. It is widely accepted however, that environmental costs have not been internalised for a long time.

To address the problem of negative externalities governments may use regulation to ensure companies meet certain environmental standards or to introduce market based instruments (for example taxes, charges or emission trading systems) to ensure companies pay for their pollution.

Another option open to EU member states is the possibility of state aid (public subsidies). State intervention may be justified in order to give companies an incentive to increase investment in and viability of environmental protection. State aid can also be directed to relieve firms from the financial burden of enforcing a stricter overall environmental policy.

2. State aid for renewable energy sources

The high cost of production of some types of renewable energy does not allow companies to charge competitive prices on the market and thus creates a market-access barrier for renewable energy. Therefore, public subsidies to renewable energy sources can be justified if the cost of production of renewable energy is higher than the market price for conventional energy and if there is no mandatory EU wide standard concerning the share of energy from renewable sources for individual undertakings.

There is a great range of instruments governments can use to subsidise renewable electricity. These can be divided between investment aid, including capital grants, tax exemptions or reductions on the purchase of goods, and operating aid in the form of price subsidies, green certificates, tender schemes and tax exemptions or reductions on the production of renewable energy.

In overall terms, operating aid – support per MWh- for renewable electricity is far more important than investment aid in creating incentives for companies to initiate or increase production of renewable electricity. Operating aid can be provided using market-based instruments that fix a quantity of renewable electricity to be produced or instruments that fix a price to be paid for renewable electricity. Quantity fixing can be done by quota obligations, where EU member states impose an obligation on consumers,

suppliers or producers to source a certain percentage of their electricity from renewable energy; sale of green certificates, which prove the renewable source of the electricity; or tenders for the provision of a certain amount of electricity from a certain technology source, where the bidding should ensure the cheapest offer is accepted. More frequently used instruments are those that fix a price to be paid for renewable electricity. They include the introduction of feed-in tariffs and premiums or tax reductions and tax exemptions.

All support measures to renewable energy sources developed and to be implemented in EU member states, insofar as they constitute state aid in the meaning of Article 107 of the EU Treaty, have to comply with the EC law on state aid and in particular with the rules of the Community Guidelines on State Aid for Environmental Protection.[1]

State aid must be necessary to ensure the viability of the renewable energy sources concerned. EU member states have to demonstrate that without public support the renewable energy sources in question cannot compete with conventional or cheaper renewable technologies. It must be acknowledged here that due to technological developments in the field of renewable energy and to gradually increasing internalisation of environmental costs the difference in production costs has been shrinking over the past years for some technologies, thus reducing the need for public support.

State aid cannot result in overcompensation for renewable energy and member states need to ensure that the revenues of the generators do not exceed the costs of production and a reasonable benefit for a given technology over a given period of time, since the production costs for such technologies usually decline when technology matures.

Public support should be designed in such as way that it does not dissuade renewable energy producers from becoming more competitive. State aid should provide an incentive for generators to increase efficiency in terms of volumes (MWh), price mechanisms should not overcompensate well developed forms of renewable generation and emerging technologies should receive the additional support required to encourage investment.

In addition, state aid should not create barriers to entry for eligible generators or distort the operation of the electricity supply market.

According to the rules of the Community Guidelines on State Aid for Environmental Protection EU member states can grant both investment and operational aid in order to support the energy production from renewable sources.

For investment aid EU member states can cover up to 80% (100% if the aid is granted in a genuinely competitive bidding process) of the extra investment costs the aid beneficiary has to bear as compared with investment costs needed for a conventional power plant or a conventional heating system with the same capacity in terms of the effective production of energy. Any operating benefits and costs during the first five years of the life of this investment must be taken into account while calculating the extra investment costs.

	Aid intensity for renewable energy sources	*Aid intensity for renewable energy sources granted in competitive bid*
Small enterprise	80%	100%
Medium-sized enterprise	70%	100%
Large enterprise	60%	100%

1 OJ C 82, 1.4.2008, p.20.

For investment aid not exceeding EUR 7.5 million per undertaking per investment project EU member states may grant aid to cover extra investment costs without taking account of operating benefits and operating costs. In that case the aid intensities are 45% for large enterprises, 55% for medium enterprises and 65% for small enterprises[2].

Operating aid for the production of renewable energy may be justified in order to cover the difference between the cost of producing energy from renewable energy sources and the market price of the form of energy concerned. That applies to the production of renewable energy for the purposes of subsequently selling it on the market as well as for the purposes of the undertaking's own consumption. EU member states have four options to grant operating aid for renewable energy production.

- Option 1: Member states may compensate up to 100% of the difference between the cost of producing energy from renewable sources, including depreciation of extra investments for environmental protection, and the market price of the form of energy concerned. The aid may also cover a normal return on capital. Operating aid may then be granted until the plant has been fully depreciated according to normal accounting rules. Any investment aid granted to the undertaking in question in respect of the new plant must be deducted from the production costs[3].

- Option 2: EU member states may also support renewable energy sources by using market mechanisms such as green certificates or tenders. These market mechanisms allow all renewable energy producers to benefit indirectly from guaranteed demand for their energy, at a price above the market price for conventional power. The price of these green certificates will be determined by supply and demand[4].

- Option 3: Operating aid may cover the extra production costs without taking into account potential investment aid. The aid must not exceed 100 % of the extra costs in the first year but must have fallen in a linear fashion to zero by the end of the fifth year. In the case of aid which does not decrease gradually, the aid intensity must not exceed 50 % of the extra costs for a period of 5 years[5].

- Option 4: Operating aid may be granted to new plants producing renewable energy on the basis of calculation of the external costs avoided. The external costs avoided represent a monetary quantification of the additional socio-environmental damage that society would experience if the same quantity of energy were produced by a production plant operating with conventional forms of energy. They will be calculated on the basis of the difference between, on the one hand, the external costs produced and not paid by renewable energy producers and, on the other hand, the external costs produced and not paid by non-renewable energy producers.

3. Conclusion

Increased use of renewable energy sources is an environmental priority for the EU and the EU law on State aid is of particular relevance as regards national support schemes for the promotion of renewable energy sources. It has been acknowledged that public subsidies to renewable energy sources can not only successfully influence firms' choices of production methods so that they switch to greener electricity but also contribute to the creation of a long term competitive market for renewable electricity. The EU State

2 See Art 23 of the General Block Exemption Regulation, OJ L 214, 9.8.2008, p. 3.

3 See Commission Decision in case nr N 47/2008.

4 See Commission Decision in case nr N 414/2008.

5 See Commission Decision in case nr N 669/2008.

aid control policy safeguards that only subsidies, which contribute to increased environmental protection without unduly distorting competition between companies and trade between EU member states are introduced in EU member states.

BULGARIA

1. General information

The encouragement of the use of renewable sources of energy in general, and of renewable sources of electricity in particular, is a relatively new policy in Bulgaria, which is directly related to the fact of Bulgaria being EU Member State. Bulgaria has implemented in its national legislation the provisions of Directive 2001/77/EC of the European Parliament and the European Council for the promotion of electricity produced from renewable energy sources (RES) in the internal electricity market. In 2009 the EU adopted a wide-ranging package on climate change, which focuses on three main areas: emissions cuts, renewables and energy efficiency. As regards the renewable energy sources, Directive 2009/28/EC of the European Parliament and of the Council set the goal of increasing renewable energy's share in EU market to 20% by 2020 (with 2005 being taken as a basis year for comparison). Under the Directive, the target goal to be achieved by Bulgaria in 2020 is 16% share of RES in the total energy consumption.

The main national legal acts regulating the use of renewable energy sources are:

- Energy Act;
- Renewable and Alternative Energy Sources and Biofuels Act;
- Energy Efficiency Act.

By virtue of § 1 of the Supplementary provisions of the Renewable and Alternative Energy Sources and Biofuels Act, the renewable energy sources are defined as *non-fossil energy sources which contain solar, wind, water and geothermal energy, including wave energy and tidal energy, which renew themselves without any visible depletion when used, as well as residual thermal energy, energy from biomass and energy from industrial and municipal waste.*

The law defines also the alternative energy sources as hydrogen, waste products from technological processes, etc.

Bulgarian government estimates that by 2020 the biggest potential in Bulgaria for generation of renewable energy (including biofuels) have the following renewable energy sources:

- biomass – 34 %
- hydro energy – 29%.
- solar energy - 9%
- liquid fuels - 8%
- geothermal and solar energy - 7%

- biogas - 6%

These laws create the legal framework for the encouragement of the use of renewable sources for production of electricity, setting the following instruments for the achievement of the target goal of 16% share of RES in the total energy consumption in 2020:

- Interconnection with priority with a set deadline to the transmission/distribution network of each producer of RES generated electricity. The deadline for connection is set to not later than the date the producer has declared as a date of actual start of work of the plant;

- Guaranteed period (under long term contracts) of mandatory purchase of the electricity, produced by new power plants, using RES. The guaranteed period is set to 25 years for the electricity, produced from geothermal and solar energy, and to 15 years-for the electricity, produced by water electricity plants with installed power under 10 MW or from other renewable energy sources. The starting date of the duration of the long term contracts are set as follows-after re-negotiation, but not later than as of 31st March 2009 for the existing producers, and as of the date of the actual start of the production, but not later than as 31st December 2015 for the new producers;

- Preferential prices for new power plants, using RES, with the exception of water electricity plants with installed power over 10 MW;

- Issuing of “certificate of origin” for the electricity, produced from RES. The certificate is issued by the State Energy and Water Regulatory Commission (SEWRC), on the basis of which the regulator issues “green certificate”;

- Simplified procedures for issuing the necessary permits for small RES projects or for decentralized installations for production of energy from RES.

The main traditional renewable source of electricity in Bulgaria was and continues to be the hydro energy. Out of the total amount of electricity, generated by RES in 2008, the share of big hydroelectric plants is 85,9%, the share of small hydroelectric plants amounts to 11,7%, and the share of wind electric plants is 2,4%[1].

In 2004 the first wind electricity plants started production of electricity and their installed power and production show significant increase.

Installed power and production of electricity by the wind power plants in Bulgaria

Year	Installed capacity MW	Production GWh
2005	7,5	4,5
2006	25,5	19,8
2007	40,7	46,8
2008	112,6	122,2
2009[2]	285	138,8

1 The data was announced by the National Electric Company during a conference in November 2009 on the use of RES.

2 The data for the first nine months of 2009 and is not final. The source of the data is the Ministry of Economy, Energy and Tourism.

The share of solar installations in the production of electricity from RES is still insignificant, due to the climate in Bulgaria and the significantly higher price of the equipment needed as compared to the other RES technologies. This technology, however, attracts considerable interest on the side of the business and show steady increase in the RES sector.

In the end of 2009, Bulgaria adopted and published its forecast for development of the renewable energy until 2020, as required by Directive 2009/28/EC. The forecast shows, that the total technical potential for production of energy from renewable sources in Bulgaria is about 4500 ktoe per year, with the highest share of the hydro energy (~31%) and biomass (~36%)[3]. The geographic position of the country determines a relatively small share of the wind generate energy (~7.5%) and the energy from sea ties and waves.

2. Pricing and Interconnection

The prices of the renewable energy sources in Bulgaria are preferential and subject to regulation. Large-scale water power plants with installed power over 10 MW are excluded from the preferential pricing. The energy and utilities regulator in Bulgaria, the State Energy and Water Regulatory Commission (SEWRC), is the competent authority, which determines the prices of the electricity for the regulated electricity market, incl. the prices of the electricity from renewable energy sources.

The wholesale price of the electricity from RES is set once a year by the energy regulator. This price is different for the different RES (wind, solar, water energy, etc.) and it is determined on the basis of the 80% of the average price of the final suppliers for the previous calendar year plus additions, set by the energy regulator depending on the source energy (the price for the electricity, generated by photovoltaic power plants, is the highest).

The preferential prices for the electricity, produced from RES, differ not only depending on the technology used, but also on the size (installed power) of the plant.

Preferential wholesale prices (without VAT) of electricity from RES for 2009[4]

Type of generating facility	Price (in BGN per MWh)
Water plants with installed power up to 5 MW	105
Wind plants working effectively up to full 2250 hours per year	189
Wind plants working effectively more than full 2250 hours per year	172
Photovoltaic plants with installed power up to 5 KW	823
Photovoltaic plants with installed power up above 5 KW	755
Plants, working with biomass (waste wood) with installed power up to 5 MW	217
Plants, working with biomass (solid agricultural waste) with installed power up to 5 MW	166
Plants, working with biomass (energy agricultural plants) with installed power up to 5 MW	187

For reference purposes only, the regulated prices (per MW) of the electricity, produced from other sources of energy) are: 12 BGN (electricity from Kozloduy Atomic Plant) and 41-76 BGN (electricity from coal or gas).

3 The production of fuels from RES is also included in the forecast document, which impacts the shares of the RES for the production of electricity. The source of the data is the Ministry of Economy, Energy and Tourism (http://www.mee.government.bg/doc_vop/RESforecast291209.doc).

4 Source: State Energy and Water Regulatory Commission

The electricity from RES is subject to mandatory purchase by the transmission/distribution companies. The legal provisions, stipulating that the interconnection to the network is to be made at the nearest possible access point to the grid, determine whether the interconnection will be made to transmission or distribution network.

The costs for the interconnection to the network are not part of the wholesale preferential price of electricity from RES. The producers of RES generated electricity pay only the direct costs for the interconnection. Any reconstruction or extension of the network, which might become necessary due to the connection of new RES electricity producers, is to be borne by the transmission/distribution companies. These costs however, are eligible costs to be included by the transmission/distribution companies in their investment plans, which are subject to approval by the energy regulator. After being approved by the energy regulator, these costs influence the price for transmission/distribution.

The preferential regulated price for RES generated electricity is determined by 31st of March each year and it is valid for the whole year. Any change in the price that might occur during the year is taken into account when the price is set for the next calendar year.

The price for the use of "green energy" is invoiced and paid by all consumers (households, SMEs, big undertakings) and by all electricity trading companies for the part of the electricity for export.

Art. 20, para 2 of the Renewable and Alternative Energy Sources and Biofuels Act stipulate that rules for putting in place a market mechanism for promoting generation of electric and thermal power from renewable energy sources shall be stipulated by a special law.

Differentiated pricing of the electricity, depending on the period of consumption, is available for the consumers of electricity both on the regulated and the liberalized electricity market. Households and small businesses buy electricity at a regulated price, while the big industrial consumers buy electricity at the liberalized market on the basis of contracts, in which differentiated hourly pricing is included. For business consumers, using medium and high voltage electricity, three tariffs are available-peak, night and day tariffs.

Two tariffs for the regulated price of electricity for the households and small businesses (connected to low voltage networks) are used in Bulgaria-day and night tariffs, with the price of the night tariff being lower.

The existence of differentiated price tariffs induces consumers to avoid peak hours of electricity consumption.

The consumer incentives to use "green energy" and pay more for it however, are related directly to the level of income of Bulgarian households, according to the data, announced in January 2010 by the Center for the Study of Democracy (CSD), an interdisciplinary public policy institute. The CSD made a research of the consumers' attitudes on using clearer, yet more expensive energy sources. Only 13% of Bulgarian households are willing to pay extra for clean energy. Of those 82.5% would only bear a modest increase in their electricity bills – with up to 10%. Willingness to pay a 'green energy premium' is directly linked to the level of income. Low income households support cheaper although 'dirtier' energy[5]. The study of the CSD suggests that Bulgarian government should elaborate a programme to introduce economic stimuli, while at the same time performing public campaigns to convince people and businesses on the benefits of the RES.

5 Source: Center for the Study of Democracy - http://www.csd.bg/artShow.php?id=9963.

According to the minister of environment and waters, at the moment Bulgarian government is not in the position to offer financial incentives for investments by the households and public institutions. As for the future, there are some possibilities to use for that purpose the green investments scheme, under which the money, coming from the sale of emissions, might be accumulated in a special fund for financing of roof solar installations. Another possibility, which could be explored, is to use financing under the EU funds after the year 2013.

Some opportunities for the business to receive grant financing for developing RES projects are available in Bulgaria. These opportunities are usually part of grant schemes, financed by the European Union, the European Bank for Reconstruction and Development, the Netherlands, the Japanese government, etc., which generally aim at protecting environment and encouraging energy efficiency measures.

Bulgarian Commission on Protection of Competition has not dealt with cases, related to the RES market(s) and alleging possible infringements of competition rules.

3. Investment and Dispatch in response to demand

As already discussed under the previous point, investments in RES generated electricity facilities attract big interest on the side of the business, as these investments are strongly supported by the government policy for encouraging renewables and for achieving the target goal for Bulgaria under Directive 2009/28/EC. The legislative package of incentives for new RES, consisting of combination of guaranteed long-term (15 to 25 years) purchase of electricity at a preferential price, which is 2 to 5 times higher than the price of the electricity, produced by conventional energy sources, and guaranteed connection to the network, led to some problems for the electricity sector in Bulgaria. These problems evoked a public discussion in December 2009 and the debate is still continuing. The problems, as reported in the media, could be summarized as follows:

- ***Ecological problems*** - Some of the RES installations (especially wind and photovoltaic parks) are constructed in traditional agricultural areas, or close to areas, which are protected as natural habitats of rare birds or plants. According to the data, announced by the Ministry of Environment and Waters, until the end of 2009, the ministry has issued 900 permissions for hydroelectric plants, which covers the total water potential of Bulgaria, but new applications for such plans continue to be submitted. The ministry has issued also 800 permissions for wind parks, and another 177 projects have applied for permission, some of them being large-scale;

- ***Technical problems*** - Applications for new RES electricity installations have already been submitted. These projects envisage to have installed power of 12 000 MW, which endangers the functioning of the transmission and distribution systems. From a technical point of view, in order to ensure the stability of the electricity system, the share of the RES facilities should not exceed 20% of the total energy production. The generated electricity from RES (the installations already functioning, the approved RES projects and the above-mentioned new applications for additional ones) amounts to 12000 MW, which not only exceeds several times the recommended 20% of the total capacity of the transmission network, but the capacity of the network itself (10000 MW). In addition, in order to compensate the dependence of the renewable generation on the presence of appropriate atmospheric conditions and to ensure the stable work of the electricity system, new facilities, generating electricity from conventional sources, should be erected. According to the publicly announced opinion of experts from the Bulgarian system operator, the specific work regime of wind and solar installations, for example (their highest production capacity is before or after peak daily hours) necessitate the system to have a buffer of additional traditional generating installations equaling 60% of the RES installed power;

- ***Economic and social problems*** – The companies, producing electricity from RES, enjoy long-term guaranteed preferential prices, which are significantly higher than the prices of the electricity, produced from conventional sources.

The public discussion on how to achieve the 2020 target goal of 16% share of RES in a way, which is economically efficient, environment friendly and socially oriented is still ongoing and it will be the basis for some legislative amendments in the regulation of RES, which are expected to take place in 2010.

As regards the possibility for the electricity network operator to temporarily “shut down” small-scale or large-scale electricity users at peak periods, helping it to adapt to the potentially limited ability of renewable generation to provide electricity, the Commission on Protection of Competition has no information on such practices.

According to publicly announced opinions by experts from the Bulgarian system operator, the daily and seasonal fluctuations in the amount of the electricity produced by RES, as well as some technical problems for the system caused by the work of some RES electricity plant (mainly the wind plants), require that the system operator to ask for changes of the work regime (frequent lowering and increasing of produced amount of electricity) of the conventional electric plants in order to balance the load of the whole system.

RUSSIA

1. Renewable sources of energy

Development of and increase of the share of renewable sources of electricity in the energy production has been officially declared as one of the priorities of the state energy policy in Russia. On January 1, 2009 the Government of the Russian Federation issued a Resolution No. 1-r on the Basic directions of the state policy on increasing electricity energy effectiveness on the basis of renewable sources of energy until 2020. This document determines aims and principles for the use of renewable sources of energy, contains target indices of energy volume generated by the renewable sources of energy and of its consumption, as well as measures to be taken to achieve these indices.

The more comprehensive document was adopted on November 12, 2009, which is a Resolution of the Government of the Russian Federation No. 1715-r "On energy strategy of Russia until 2030". This strategy sets new landmarks for the development of energy sectors within the frameworks of transition of the Russian economy to the innovative development that is envisaged by the Concept of long-term social and economic development of the Russian Federation until 2020 (adopted by the Resolution of the Government of the Russian Federation No. 1662-r of 17.11.2008).

Increase of energy effectiveness basing on the usage of renewable sources of energy, necessary for stable long-term energy supply of the Russian economy provides for penetration of innovative high-end technologies and equipment into the energy sector that is directly related to the international obligations of the Russian Federation concerning reduction of emission of greenhouse gases.

Technical resource of the renewable sources of energy (except for the hydroelectric power), with wind and solar power dominating, is estimated as not less than 4,5 bln tones of standard fuel per year, which exceeds the consumption volume of all fuel and energy resources in Russia in 4 times. The economic potential of the renewable sources of energy depends on existing economic situation, price, presence and quality of fossil fuels, as well as on regional peculiarities.

The Basic directions of the state policy on increasing electricity energy effectiveness on the basis of renewable sources of energy until 2020 set a target to increase the relative volume of production and consumption of renewable sources energy from 0,5 % till 4,5%.

To achieve this goal it is necessary to put into operation a number of generating units (wind stations, tidal power stations, geothermal power stations, thermoelectric power station, etc.) with a total installed capacity of up to 25 gWt. The layout of allocation of such generating units on the territory of the Russian Federation should be adopted in accordance with the allocation of productive forces, perspectives of social and economic development and resource base.

In order to ensure level-playing field for the producers of energy with the use of renewable sources of energy and fossil fuels it is envisaged to:

- establish and regularly specify figure and periods of validity of extra charge that is added to the equilibrium price on the wholesale energy market to determine the price for energy produced by the qualified generating units using renewable sources of energy;
- establish obligation for the players of wholesale energy market to acquire the determined volume of energy produced by generating units using renewable sources of energy;
- undertake actions to improve legal regime for using natural resources to build and maintain energy generating units using renewable sources of energy.

Presently the legal regulations are being elaborated to determine the sequence of application of the above mentioned extra charge to the price of the wholesale energy market.

There are no special rules for connection to the renewable energy suppliers. General rules of non-discriminatory access to the services on transmission of energy and mechanisms of technological connections to electric networks are being used.

Price for connection is set by the tariff regulating authorities.

Monitoring of development of production of renewable sources of energy is executed by the Ministry of Energy of the Russian Federation.

2. Vertical and horizontal issues

Energy companies can own generating units using renewable sources of energy observing the requirements on prohibition of combination by the group of persons and affiliated persons of competitive and naturally monopolistic types of activity in the energy on the territory of one price area of the wholesale energy market.

BIAC

1. Introduction

The Business and Advisory Committee (BIAC) to the OECD appreciates the opportunity to submit these comments to the OECD Competition Committee WP2 for its roundtable on renewable energy and smart grids and the new challenges those phenomena pose for competition policy.

To help meet increasing electricity demand in a sustainable way, the growing integration of renewable energy technologies to the grid, and the challenges this involves, will need to be given due consideration. While they will not entirely replace conventional power sources in the near future, renewable energy, such as hydroelectric, biomass, wind, and geothermal energy, has a role to play by increasing electricity supply and by reducing overall GHG emissions. The integration of renewable energies to the grid would help realise the potential of renewable energy sources and would contribute to lowering GHG emissions while boosting energy efficiency. BIAC outlines in this paper various considerations that need to be taken into account in designing and implementing grids that can accommodate increasing use of renewable energy technologies.

Recent years have witnessed dramatic innovation in technology associated with electricity networks. At the same time, large-scale renewable sources of energy (RES) and small-scale distributed generation (DG) has grown. The promotion of RES has become a key public policy goal in many countries. In Europe, this is espoused in the EU's Climate Change Package. If realised, these ambitions, could imply that 20—30% of electricity generated will be from RES facilities.

Transmission networks and network technology play a key role in delivering increased RES generated electricity. Most RES – generated electricity is highly volatile – given that it is subject to varying climatic and atmospheric conditions. This has major implications for the future design and operation of transmission (high voltage) as well as distribution (low voltage) networks, including how the necessary investments in these networks are to be incentivised and financed. At the same time the potential to improve network capacity use and to link electricity demand and supply in real time has to be harnassed. It is widely believed that the collection of technologies referred to as 'smart-grid technologies' can offer the potential to change the interfaces between customer-retailer-generator-dispatcher-network owner/operator in the future. At the same time, the standards to be set for these new technologies and the regulations governing their introduction and use could have a dramatic impact on the nature of electricity (and indeed gas) markets in the future.

BIAC notes that in many, if not all OECD jurisdictions, electricity markets have undergone significant structural change in the last two decades as result of both privatisation and liberalisation strategies. Many countries have privatised their generation and retail sectors. Many countries have introduced so-called “unbundling” or functional separation requirements for vertically integrated companies, so that access to transmission/distribution networks for competing supplies of electricity can be guaranteed on fair and non-discriminatory terms. Unbundling or functional separation takes a variety of forms and may range from full or ownership unbundling requirements –so that key transmission (or distribution) assets are transferred to independent legal entities (TSOs or DSOs) who have no legal or commercial relationship with supply or trading functions in a vertically integrated company. Some

jurisdictions only require legal unbundling, however – i.e. the creation of a separate legal entity to run the network while others may only require accountancy unbundling.

Incumbent electricity (and gas) companies – public or private – have seen many of their traditional privileges and obligations removed. Exclusive rights to import/export electricity, to generate electricity, and to supply certain categories of consumer have gradually been phased out. In the EU, the follow-up to the Commission's 2007 Sector Inquiry has had far-reaching consequences for the legality of long-term contracts between generators and customer/users, although the EC Commission does, to some extent, acknowledge that long term contracts may be necessary to underpin investments in new transmission and generation capacity.

Extensive sector–specific regulation has accompanied – if not driven – the changing market structures. Regulation is primarily focussed on network use – given their natural monopoly characteristics – and on the tariffs and conditions for connection and access to the networks. In general, the generation/trading functions are not subject to extensive ex ante regulation. Competition policy plays a key role here. The retail sector, however, is still closely regulated in order to maximise consumer protection, and to a certain extent, to promote active "switching" by consumers to new suppliers.

It follows that this market or sector is one in which regulatory frameworks and regulatory incentives and disincentives are crucial. Getting the regulatory framework to be a "smart" framework is key. An increasingly predictable and transparent regulatory regime will be necessary for the much-needed investment in restructuring grids. BIAC calls on policy makers to consult closely with the private sector on new energy policy reforms, and emphasises that policy reforms must not inhibit innovation, obstruct competition, or undermine investment.

Against the backdrop of the extensive sector-specific regulation that now typifies this sector, competition law and policy principles and norms would seem - at first sight- to play a secondary role, although they are of undoubted importance. That said, as new issues arise in these markets and in so far as specific regulation is not (yet) in place, adherence to competition law principles – and to the objectives of competition policy - are of vital importance. Furthermore, suitable regulatory frameworks should always acknowledge and address actual as well as potential competition concerns in order to ensure the coherence of public policies. Among the many relevant points, the following are in BIAC's view particularly relevant.

While BIAC supports the promotion of RES, it identifies four main potential concerns. First, there is a risk that the promotion of RES as a key policy objective threatens the role of economic analysis. The second concern is that the application of the standard tools and concepts of anti-trust policy to conventional fuel markets is already complex and there seems as yet little understanding of how a "state-sponsored shift" towards RES can further complicate this analysis. A third concern is of a procedural nature and relates to the need for appropriate guarantees for confidentiality in information flows. Finally, BIAC would like to draw attention to the potential for distortive effects as a result of ill-equipped national support measures for RES.

2. The promotion and treatment of RES as a key policy objective should not threaten the role of proper economic analysis

A first fundamental BIAC concern is that even if the promotion of RES is a key public policy objective, this should not threaten or eliminate the role of proper economic analysis in applying new norms or assessing the conduct of market players – whether ex ante or ex post. The following four points seem particularly relevant.

- Recognise the ongoing importance of a clear analytical framework for the application of competition law: as sector-specific regulation in this sector seeks to achieve a number of public policy objectives (sustainability, security of supply, competitiveness) that are not necessarily aligned with the objectives of competition policy, it is particularly important to ensure that courts, antitrust agencies and other parties continue to apply a clear analytical framework based on the long term benefits of consumers. Generally, if the competition analysis of business conduct necessitates taking into account non-economic variables or requires solving trade-offs for which economic analysis is ill-equipped or ambiguous, the economic accuracy of decisions becomes uncertain, and so does judicial review. BIAC believes that particularly in the EU competition rules should not be used to promote policy objectives that do not belong to those traditionally pursued by EU competition law. Pursuant to recital 9 of Regulation 1/2003 articles 81 and 82 EC (now 101 and 102 TEUF) serve to protect competition on the market. Those provisions do not serve to promote environmental objectives, unless these objectives translate into benefits for consumers. See in this respect paragraph 42 of the Article 81(3) EC Guidelines.

- Proper identification and trade-off between short and long term effects, including efficiencies: BIAC believes that there is a risk that – given the rapid developments in this sector and the associated uncertainty on future market developments and -structures- the antitrust analysis will be skewed towards an analysis of static, current effects (efficiencies and costs) that fails to appreciate dynamic efficiencies, as well as potential harm to competition. Therefore, when applying provisions of competition law BIAC favours an approach that allows for explicitly factoring in innovation-related claims. Traditional generation technologies are relatively mature and stable, whereas many RES technologies (off-shore wind, solar, CSS) are experiencing high rates of innovation. There is a clear need to take innovation and dynamic innovation into account, especially in the area of dominance.

- Proper evaluation of incentives brought about by ex-ante regulation: BIAC notes that ex-ante regulation may have a profound effect on market conduct and the incentives of market participants. As a result, a careful analysis of the practical means, as well as the financial incentives that market operators have, at their disposal should form an integral part of any ex-post evaluation of business practices under competition law (and indeed in any ex ante merger evaluation processes).

- Take account of the interrelationship between financial and physical markets: the significance of energy markets as trading place for financial products should not be overlooked. BIAC believes it is important to take account of the fact that energy markets are increasingly market places for trading in physical as well as financial products, such as Guarantees of Origin or Energy Certificates. As a result, externalities in one market may impact market conduct in other markets. Spill-over effects from physical into financial markets should be addressed.

3. The application of conventional tools and concepts of antitrust policy is especially complex in the area of RES

The second concern is that the application of the standard tools of anti-trust policy to conventional fuel markets is already complex and there seems as yet little understanding of how a ‘state-sponsored shift’ towards RES can further complicate this analysis. BIAC submits that particularly the following seven points merit attention.

3.1 Careful application of market definition, market power and other key concepts in competition law

BIAC notes that the expansion of RES, the evolutionary nature of the sector and the accompanying sector specific regulation imposes exceptionally strict requirements on the application of conventional competition law concepts. False positive findings of antitrust liability may particularly result from incorrectly and over-narrowly defining the temporal and geographical dimension of the relevant market.

BIAC specifically draws attention to the challenges surrounding the application of conventional competition law concepts to completely new market settings, such as the "markets" for renewable energy. The main difficulty comes from the fact that conventional economic concepts, such as "relevant market" or "market power" must be applied in completely new market settings and antitrust agencies must fight anti-competitive practices without always being able to firmly rely on past case law, an intimate knowledge of the market or even definite insights from economic theory.

The problem raised by the definition of the relevant market for the purposes of assessing the abuse of a dominant position is only one of such examples. The definition of the relevant geographic market is complicated by the fact that these markets may be consistently moving in the new liberalized context, for instance because of the development of regional exchanges and market coupling initiatives in electricity or a structural reduction in long-term reservations of gas import capacity. State sponsored support for RES producers complicates this further, especially if RES is given favourable wholesale market access. The problem of defining the relevant product market is particularly complex. The emphasis on the definition of the relevant market already causes several problems for antitrust authorities for instance in the conventional generation market where market power might be exercised – temporarily- by non-dominant pivotal suppliers or by the dominant incumbent through portfolio effects. The impact of RES alongside conventional energy generation needs to be carefully thought through.

The case of abuse of dominance in generation is a good example of the limitations of economic theory itself for antitrust purposes. Economic analysis gives few useful insights for the enforcement of Art 82 EC in individual cases as the different strategies used to exercise market power are complex. Tracking abuse of market power in the generation market requires highly assumption-specific oligopoly modelling yielding results which may be too uncertain to firmly ground policy actions. It is sometimes similarly argued that the insights derived from these models on how market power is (or will be) exercised are too rough to base enforcement action on. From a practical point of view, it will indeed be difficult for antitrust authorities to differentiate between the exercise of market power and legitimate scarcity rents.

Overall, the main problem primarily lies in the speculative nature of economic analysis which might not provide straightforward answers to novel questions. Economic analysis suggests that antitrust enforcement is complex and requires a careful consideration of the market context in which the practices examined occur. A strong willingness to use the antitrust laws to fix the shortcomings of sector-specific regulation might thus lead to over-enforcement in a sector that may be especially vulnerable for disincentives in relation to investments in new generation equipment.

3.2 Awareness of geographical market fragmentation

Restrictive national policies which limit access of foreign RES to their markets could, if not properly taken into account, also distort market definition processes.: The promotion of nationally produced RES to the exclusion of imports may have repercussions for other (EC) policies. For instance, territorial restrictions under national renewable energy support schemes may raise concerns under the EC free movement provisions. Similarly, national support schemes may give rise to state aid concerns. See also below, Section V.

3.3 Proper interpretation of the signalling function of prices

As a result of national support regimes or sector specific legislation, prices may not be cost- related or market driven. For instance, feed-in tariffs have been used to support very extensive renewable power generation investment programmes. As those tariffs are not market driven, they are in contrast to "conventional market prices", no reliable indicator for e.g. market power.

3.4 Take account of the position of large industrial users and potential monopsony issues

The analysis of business conduct involving large industrial energy users that export back to the grid may be complex in light of their dual role as users and suppliers of electricity and possible monopsony (and resulting fair compensation) issues that these firms may face. BIAC also notes that the price charged for energy to large users, in particular as a result of compulsory renewable energy quotas, represents a major cost-factor and may therefore have an impact on their international competitive position. Addressing potential monopsony power over electricity purchasing for customer-produced electricity is not only an important issue for regulators and antitrust authorities, but also offers opportunities for efficiencies. The TSO/DSOs are in effect the monopoly purchasers of excess energy exported to their grids by large users. Too often, energy intensive customers/CHP plant operators are confronted with the choice to either supply or export excess capacity and pay a penalty, or not to produce at all, and obtain some compensation. In contrast, RES producers may however be allowed to produce and export excess at no cost – and are not required to shut down (because this may be technically impossible). This seems discriminatory as well as economically inefficient. BIAC takes the position that any system of regional balancing to maximise the efficient use of the local networks should ensure fair rewards to all concerned.

3.5 Market entry and participation

BIAC notes that market entry and participation rules, including access terms and rules of prices and bidding and despatch rules will be crucially important in the future environment. This applies both to sector regulation and the application of competition law. These issues may involve a detailed analysis of the position of non-traditional utility suppliers and the possible emergence of intermediaries, aggregators and other new parties. BIAC notes that there is an inherent possibility that general provisions of competition law will be relied on to secure (additional) market access and advocates a strict application of general principles of competition law in this respect. Indeed, what matters in these cases is whether access to grids and to ancillary services, such as balancing power and system services, will increase the long-term economic efficiency in general; the position of individual market participants is in of secondary interest only. In other words it should not be forgotten that competition policy is directed to maintaining healthy competition – and not to protecting particular competitors.

3.6 A well-defined evaluation of vertical and conglomerate effects

BIAC notes that it is likely that industry participants will increasingly be active on multiple horizontally and vertically related "markets." In particular, it can be expected that energy suppliers will have combined renewable and conventional portfolios. It is important to take account of these activities as they may have an impact on the incentives of firms to enter into pro- or anticompetitive conduct.

3.7 Take account of the interrelationship between different levels of the market

The future market structure in energy markets will likely be characterised by the existence of market participants that are (simultaneously) active on different levels of the market. It is important to take account of this phenomenon when reviewing business conduct under competition law provisions.

4. Procedural concerns: RES and smart grids prompt the need to ensure guarantees for confidential information flows

Thirdly, the design and construction of smart grids gives rise to a great number of complex issues. Smart grids will have the potential to continuously communicate with each customer/ generator connected to it. The presence of smart meters would support the potential for two-way communication. BIAC is supportive of this development, but notes that many issues remain unanswered. Key issues are likely to be who owns/installs these meters – should this be a ' market' subject to competitive tendering and light-handed regulation? Or should TSOs/DSOs have exclusive rights to install and maintain such meters? Is this necessary to achieve a rapid roll-out of the technology? If so, should closer regulation be required? This in turn raises important questions about ownership of data and information and who should have access to those data. BIAC notes that this debate should not be limited to data produced or stored in the meters: an equally important aspect of smart grid management is congestion management.

The generation of (customer and supplier) data and the communication of these data prompt the following additional observations. Under the "Third Package" TSOs shall publish relevant data on aggregated forecasts and actual demand, on availability and actual use of generation and load assets, on availability and use of the networks, and on balancing and reserve capacity. Particularly in concentrated markets there is a risk that such data may facilitate anticompetitive collusion. Thus, while transparency may improve marketing functioning by creating a level playing field and enhance trust in markets, it may also deteriorate market functioning by facilitating anticompetitive practices. BIAC is of the opinion that companies should be adequately shielded from any antitrust liability in the event of communication of data pursuant to the Third Package rules.

5. The potential for distortive effects as a result of state intervention / public policy support for RES

BIAC's fourth concern relates to the effects that state intervention and public policy may have. In particular in the EU, governments are allowed and do in fact use a range of instruments to support RES, including investment aid, capital grants, tax exemptions, or reductions on the purchase of goods and operating aid in the form of price subsidies, green certificates, tender schemes and tax exemptions and reductions on the production of renewable energy.

BIAC is concerned that, despite the – as such laudable- objective of stimulating renewable energy, state intervention and support may have distortive effects in the market place. In this respect BIAC believes first that (i) sufficient policy attention should be given to the implications of the different types of national support for solar, wind, etc, for the wider dynamics of competitive energy markets, (ii) regulators should ascertain whether certain forms or methods of public support can be considered less distortive in the short or longer term, or whether better alternatives be devised and (iii) pay sufficient attention to the "accumulation" of preferential rights and privileges for RES – production. For example, a RES generator may receive a fixed price, or "green bonus", as well as lower connection tariffs, and priority grid access. Grid tariffs may also be adjusted. In particular many countries do not require RES generators to bear 'balancing costs' – i.e. the costs incurred by the TSO for maintaining the network in balance despite fluctuations in supply and demand. BIAC takes the view that although state support measures may generate short-term efficiencies, or help to achieve environmental standards, this should not be at the expense of long-term efficiency considerations.

BIAC also notes that the leadership role, which the EU asserts in tackling climate change and setting targets for renewable energy consumption - the '20-20'20- targets - could become unrealistic, if policymakers fail to adopt more market-based mechanisms to help achieve those targets. It is an anomaly in an increasingly integrated European wholesale energy market to perpetuate national support schemes

and hence contribute to continued geographical market fragmentation. BIAC is concerned that efficiency gains and technological progress cannot be realised optimally across the EU, if renewable energy markets remain sheltered and split according to national boundaries. In this respect, it is noted that a number of companies have recently lodged complaints with the Commission about territorial restrictions under national RES support schemes. The Commission also opened proceedings against several Member States for failing to recognise green certificates of origin of renewable energy generated in other Member States. BIAC is supportive of measures leading to mutual compatibility of national support mechanisms and, more ambitious, the accommodation of trade flows across national borders.

In this respect BIAC notes that current national schemes diverge widely; the UK, Sweden, Poland and Belgium apply Green Certificates/ renewable portfolio standards; while feed-in tariffs have been used to support extensive renewable power generation investment programmes in Denmark, Germany and Spain. The network operating companies, into whose grid windmill operators “feed” their “green” power, pay the feed-in tariff. Feed-in tariffs are however not target driven and the schemes typically place no limits on the amount of capacity installed, since any plant that qualifies as renewable under the scheme is eligible for the tariff. It is argued that his method has achieved volume growth in renewable electricity generation at the price of cost-effectiveness, especially in Germany, where no market adjustment is normally made to the tariff payable and no re-dispatch by the grid operator is allowed. In exceptional cases the energy production by renewable energy generators may give rise to (non-commercial) energy flows, non-transparent network congestion and false price signals, that may cause distortions in the European wholesale power market, especially on a cross-border basis.

Hence, players in the industry are arguing for an eventual uniform market-based support scheme at European level, which reflects this reality and would allow (i) competition between different mature technologies and locations of renewable power generation, in order to optimise efficiency, create wider choices and minimize overall cost, (ii) competition between generators and suppliers of both conventional and renewable electricity across Europe on a level playing field, (iii) continuing liquidity in cross-border wholesale power markets and (iv) a well functioning and transparent new European market for instruments evidencing renewable output, probably as Guarantees of Origin (a “financial” product, hereafter “GoO”). BIAC agrees with this position and takes the view that, where possible and practical, these market-based alternatives are preferable.

The creation of a specific market at EU level for GoOs offers the potential advantage that (i) new renewable generation investments are triggered by the market in a more natural and economically rational way, rather than artificially only by national authorities, (ii) the market price of the EU-wide GoO will reflect the incremental cost of additional renewable production in a given technology and (iii) the impact of the EU renewable consumption target on the end consumer power price is harmonized and overall reduced, since investors and technologies are competing on a level playing field over a much wider geographical market.

6. Conclusions

Renewable energy sources have a significant role to play by increasing electricity supply and by reducing overall GHG emissions.

An increasingly predictable and transparent regulatory regime will be necessary for the much-needed investment in restructuring electricity grids. BIAC calls on policy makers to consult closely with the private sector on new energy policy reforms, and emphasises that policy reforms must not inhibit innovation, obstruct competition, or undermine investment.

Even if the promotion of RES is a key public policy objective, this should not compromise the role of proper economic analysis in applying new norms or assessing the conduct of market players – whether ex ante or ex post.

Competition rules should not be used to promote policy objectives that do not belong to those traditionally pursued by competition law and the use of the antitrust laws to fix the shortcomings of sector-specific regulation might lead to over-enforcement in a sector that may be especially vulnerable for disincentives in relation to investments in new generation equipment.

The application of standard tools of anti-trust policy (such as the "relevant market" and "market power") to conventional fuel markets is already complex and a 'state-sponsored shift' towards RES can further complicate this analysis. Particular attention should be given to the still nationally fragmented nature of energy markets, large industrial users, monopsony issues, market entry, non-horizontal effects and the significance of energy markets as trading place for financial products.

Companies should be shielded from antitrust liability in connection with the supply and communication of (customer and supplier) data required by smart grid technologies.

BIAC is concerned that, despite the - as such laudable - objective of stimulating renewable energy, state intervention and support may have distortive effects in the market place. Long-term efficiency considerations should not suffer as a result of state support measures that may concentrate on short-term efficiencies. Where possible and practical, uniform market-based support scheme at European level are preferable.

ANNEX

CONSIDERATIONS FOR ACCOMMODATING RENEWABLE ENERGY TECHNOLOGIES TO THE GRID

THOUGHT-STARTER

FEBRUARY 2010

1. Introduction

The IEA estimates that, unless new policies are put in place, world electricity demand will grow at an annual rate of 2.5% from 2007 to 2030, which would be met to a large extent by increasing energy production from coal[1]. In this scenario, however, greenhouse gas (GHG) emissions would rise by approximately 1.5% per year, possibly resulting in a 6ºC increase in global average temperature and "irreparable damage to the planet"[2].

To help meet increasing electricity demand in a sustainable way, the growing integration of renewable energy technologies to the grid, and the challenges this involves, will need to be given due consideration. While they will not replace conventional power sources in the near future, renewable energy, such as hydroelectric, biomass, wind, and geothermal energy, has a role to play by increasing electricity supply and by reducing overall GHG energy emissions. The advantages of integration of renewable energies to the grid would help realise the potential of renewable energy sources and would contribute to lowering GHG emissions while boosting energy efficiency.

In designing and implementing a grid that can accommodate increasing use of renewable energy technologies, BIAC outlines in this paper various considerations that need to be taken into account, such as investment costs, energy security and regulatory issues.

2. Investment Requirements

Creating grids that hold enough flexibility to accommodate variable energy inputs from certain renewable energy sources would entail significant investment costs. In terms of connecting grids to renewable energy sources, such as offshore wind farms, tidal energy locations or solar energy sites, investment will be necessary for the transmission and distribution lines from these often geographically-dispersed sites. Investment will also be needed to upgrade the existing grids with the necessary hi-tech devices and sensors to be able to respond to variable inputs from renewable energy sources.

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1 International Energy Agency (IEA), World Energy Outlook 2009.

2 Ibid.

In the United States alone, for example, the introduction of additional infrastructure, whether smart or not, could require investment totalling as much as USD 1.5 trillion between 2010 and 2030[3], and that figure does not include the customers' share in paying for new technology outlays. Even in a country such as the United Kingdom, which has a far smaller land area, smaller population and much higher average population density than the United States, a significant sum of £4.7 billion by 2020 will be necessary for new investment in transmission lines (both maintenance and expansion), while a further £8.6 billion will be necessary to simply replace the current 47 million gas and electricity meters in the country[4].

While returns in the long-term may be high, policies for smart grid deployment in countries should carefully consider how to strategically finance the investment costs, particularly in the context of the current economic crisis (and thus reduced credit and liquidity). At the same time, sound analysis is needed on the expected economic returns on investment in smart grids and infrastructure for integrating renewable energies. Integrating renewable energies into the grid should make increasing use of public-private partnerships (PPPs) where possible, in order to encourage investment.

3. Security of Electricity Supply

Presently, the electric grid is tailored for the use of conventional, consistent power sources. The challenge with several renewable energies is their reliance on variable natural phenomena, such as wind and sunlight, which results in variable voltage input. Updates to the grid must therefore be able to accommodate inconsistent energy inputs, and it will be important to line up conventional base-load generating capacity and more peak power plants for use during periods of reduced inputs from renewable energy sources. At the same time, affordable and effective power storage mechanisms should be employed to capture any excess production. Ensuring that the grid has capacity to accommodate the varying input from renewable energies will require significant restructuring, improved forecasting of energy production, and mathematical models to predict grid behaviour with higher integration of renewable energies.

We can also expect to see a rise in small-scale energy production from renewable energy sources at local levels, potentially adding thousands of generating sources to electrical grids. Grids must therefore be able to continuously calculate increasingly complex and variable supply and demand to ensure reliable and secure electricity supply on a scalable, real-time and per-need basis. Moreover, due to the computerised nature of a smart grid, the potential for technical disruption, or even sabotage, should be addressed in development.

4. Regulatory Challenges

An increasingly predictable and transparent regulatory regime will be necessary for the much-needed investment in restructuring grids. BIAC calls on policy makers to consult closely with the private sector on new energy policy reforms, and emphasises that policy reforms must not inhibit innovation, obstruct competition, or undermine investment.

It will thus be important to achieve greater policy coherence and consistency between all levels of government in cases where grids span more than one provincial or national jurisdiction, thus facilitating investment and expansion by the industry. This becomes particularly relevant in the case of integrating

3 US Department of Energy, "The Smart Grid: An Introduction" (2009): http://www.oe.energy.gov/SmartGridIntroduction.htm and the Brattle Group (2009): http://www.brattle.com/_documents/UploadLibrary/Upload767.pdf

4 UK Department of Energy and Climate Change, "Smart Grids: The Opportunity" (2009): http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/network/smart_grid/smart_grid.aspx

often geographically-remote renewable energy sources, such as offshore wind farms or tidal energy, where long-distance transmission lines could potentially cross several regional or national boundaries.

Administrative simplification will also play an important role, as currently it is often highly time-consuming and difficult in many countries to seek rights-of-way and to gain regulatory approvals for new transmission lines. Administrative obstacles for siting and permitting would therefore need to be addressed to ensure that grid updates are implemented as effectively and efficiently as possible.

Furthermore, public opposition to new transmission and distribution lines in remote, local and pristine areas can make it difficult to build much-needed new infrastructure. Policy makers at national and local levels should do more to help inform the public and garner public support for new transmission lines and installation of renewable energy technologies.

Policy makers should also help to support further research and development for the integration of renewable energies into the grid. For example, it would be valuable to carry out data collection and analysis to help understand in practice the impacts of increasing integration of renewable energies into the grid. At the same time, research into enhanced forecasting techniques would be useful. Furthermore, the demand-side of grid integration practices and burden-sharing require further consideration, as well as the further analysis into the potential environmental benefits to be reaped by implementation of smart grids.

5. Conclusion

BIAC is supportive of restructuring energy grids in cost-effective ways to improve energy security and address climate change by greater integration of renewable energy technologies, where appropriate. Consultation with the private sector will be fundamental to the success of this endeavour.

In our view, the OECD and IEA have key roles to play in informing the upgrading of electricity grids. They hold several comparative advantages vis-à-vis other international organisations, including close cooperation with BIAC and other stakeholders, a whole-economy perspective, and a wealth of technical and economic expertise to help guide policy makers.

We therefore encourage more OECD and IEA analysis into issues surrounding the integration of renewable energies into the grid. It would be particularly useful to examine the costs and benefits associated with increasing integration of renewable energies, as well as further research into modelling and forecasting. The OECD and IEA can also work to provide guidance to policy makers on such issues to ensure policy coherence and administrative simplification for a sound investment environment. BIAC looks forward to providing input to OECD and IEA activities on these issues where possible.

SUMMARY OF DISCUSSION

The Chairman (Alberto Heimler) acknowledged the broad consensus among the countries present – that CO_2 emissions need to be curtailed and electricity production made cleaner with respect to the environment. The development of the smart grid will make this easier in two ways:

- By allowing greater responsiveness of consumer demand to wholesale prices;
- By accommodating dispersed or distributed generation resources – especially in renewable sources.

Government policies in OECD countries are aggressively encouraging the development of renewable generation resources through, for example, subsidies and requirements to purchase a share of energy requirements from renewable sources. These policies may not encourage the use of the most efficient renewable sources and may encourage over-investment in renewables.

The roundtable will address the following questions:

- Is the development of the smart grid a natural or endogenous investment by electricity network operators or should it be mandated by some form of regulation?
- Will electricity consumption respond to changes in prices? If not, how can demand fluctuation be smoothed with price signals?
- Are the renewable energy sources efficiently priced? The greater the volume of renewable resources in the market the greater the significance of any competition-distorting subsidies.

1. Smart Grids

The first speaker was David Elzinga from the Energy Technology Policy Division of the IEA. He spoke about the work of the IEA developing a smart grids “roadmap” for use at the G20 meeting in Korea in November 2010.

Regarding the definition of a smart grid: it relates to the use of digital technology on electricity networks to monitor and manage the transport of electricity – from the point of generation of electricity to the point of consumption – both conventional base load generation and intermittent renewable generation. On the demand side, smart grids are needed to coordinate demand side management and demand response in a way that optimizes asset utilisation, minimises operating costs and minimises environmental impact while maintaining system reliability, resilience and stability.

Achieving an adequate reduction of CO_2 emissions will require a technological revolution. If we are to achieve the target emissions reductions by 2050 no single technology will provide the full solution. The IEA’s Energy Technology Perspectives document (2008) forecasts that to achieve the required emissions reductions by 2050, 36 per cent of the forecast emissions reductions will be from energy efficiency, 21 per

cent from the use of renewables and 19 per cent from Carbon Capture and Storage (CCS). Both energy efficiency and renewables will require smart grid technology to be used in an optimal way.

Forecasts prepared by the IEA under the scenario of meeting the target level of CO_2 concentration of 450 parts per million, show that by 2050 the make-up of electricity generation is expected to be quite different, particularly in the growth of non-dispatchable renewable energy. By 2050 transportation is forecast to make up 10 per cent of electricity demand. Transportation services require large amounts of electricity at certain times – further exacerbating the problem of managing the grid.

There are several benefits from a move to smart grids – such as opportunities to increase power reliability and power quality, together with increased energy efficiency through peak load reduction. In addition smart grids are a key enabling technology for environmental and conservation benefits through electrification of transportation and the integration of renewable energy sources. There is also scope (although more study is required) for reducing the costs of energy to the end customer.

Public policy and regulatory arrangements are the largest barriers to the emergence of smart grids. Fragmentation of the electricity industry has made coordination more difficult and has made it harder for some parties to gain access to the financial benefits that can arise from changes to the system. Furthermore, some aspects of the use of smart grids may not be palatable to consumers if not handled correctly. Some further R&D is required. To an even greater extent there is a need for large-scale deployment and demonstration to show what the technology is capable of delivering. There may be a need to establish standards for safety or inter-operability.

The goals for the IEA are to assist member countries to develop a common understanding and vision for smart grids, to quantify the costs and benefits, to develop policy recommendations, and to understand the benefits of smart grids for developing countries.

The Chairman noted that Italy is unique among OECD member countries in that it has rolled out smart meters to more than 90 per cent of households. Interestingly, the primary motivation was not the introduction of flexible (time-of-use) prices but the elimination of fraud.

Mr Lo Schiavo (Italian electricity regulator) acknowledged that Italy has already installed 30 million smart meters – one of just three European countries with material penetration of smart meters. Roll-out plans have been decided in some countries and are under discussion in others, due to the EU Directive in the Third Energy Package.

The installation of smart meters started in 2000, first as an initiative of ENEL. In 2006 the regulator compelled all other distributors to provide a smart metering system.

In terms of the experience with smart meters:

- Estimated bills have been almost completely eliminated. In the past 5 out of 6 bills per year were estimated – this figure is now less than ten per cent.
- The smart meters allow for a minimum level of service in the case of non-payment and, when payment is made, allows for very fast reconnection.
- Switching customers is easier, enhancing competition.
- Smart meters allow time-of-use metering which means higher cost-reflectivity.

- Detection of theft of electricity is easier (but this was not the only driver).

The cost of these smart meters was allowed for in the form of a higher “X” factor in the price cap for the distribution businesses, resulting in an increase in charges of 2 euros per customer per year which, in the light of the benefits listed above, was considered reasonable.

In terms of demand response: Demand participation is allowed in the wholesale day-ahead market but the quantity of demand response is still limited – less than 1 per cent of demand bids, in part due to the existence of interruptibility contracts with large consumers. However, in Italy all households and small business customers face a contract which limits their maximum power consumption. The typical household contract is 3 kW. This limit on power consumption is a strong tool for energy efficiency. In fact the average Italian household has an annual energy consumption of 2.7 MWh/year, which is amongst the lowest in Europe. There is a phase-in for time-of-use metering, starting with higher voltage customers who had hourly metering by the end of 2005, extended to higher-consumption low voltage customers by the end of 2009, and metering in 3 bands for all low voltage customers to be completed by the end of 2011.

A two-band tariff is being introduced for all household customers (the meters record consumption in 3 bands but the universal service tariff will be in 2 bands): peak hour consumption (weekdays 8 am – 7 pm) and off-peak (the rest of the time). Consumers are encouraged to move their consumption to evenings, nights and weekends. To encourage this, the Italian regulator would like to see the limit on power consumption increased from 3 to 4.5 kW during off-peak hours. Italy is also proposing to introduce smart metering in gas over a period of 6-7 years.

The Chairman noted that Norway has a programme which will complete the roll-out of smart meters by 2016. According to the competition authority, the final consumer should have the right to choose its own meter rather than being forced to purchase the meter from the electricity company. In addition the competition authority suggests that the smart meters should provide information on not only the quantity consumed, but also the total amount spent on electricity. The Chairman asked whether this advice has been accepted by the regulator or the electricity companies.

The delegate from Norway replied that the situation is as follows: In the case of large end-users with consumption over 100 MWh per year, grid companies are obliged to provide smart meters with the ability to meter electricity use hourly. For these users information about their consumption and the price they are to pay is available on the invoice but not on the display of the meter. In the case of smaller end-users (with less than 100 MWh per year), grid companies have no obligation to provide smart meters. The industry is generally positive about providing users access to information on prices and their own consumption, but there is a debate about whether this should be through the Internet or on a display on the meter itself. The responsible government agency, the Norwegian Water Resources and Energy Directorate has required that this information be at least available through the Internet. The competition authority is exploring whether having access to that information on the meter display would increase transparency of the electricity market and heighten consciousness of energy costs among end-users.

The Czech Republic reported on a planned smart-grid experiment carried out by ČEPS, the largest generating company in the Czech Republic. ČEPS is in the process of selecting a smart meter supplier for this experiment. A town has been chosen on the basis of its strategic location for wind and solar generation. In addition, the town has implemented a responsible environmental policy and has a long-term strategy to improve the share of renewables in its energy consumption. The aim of the project is to test all the elements of a smart grid – smart meters, distributed generation including renewable sources, charging stations, and combined electricity and heat. The project is still in its initial stages.

Professor Frank Wolak (Stanford University) drew a distinction between dynamic pricing and time-of-use-pricing. Time-of-use pricing refers to tariffs which change with the time of day, but the relationship between the price and time is fixed and determined in advance. Under dynamic pricing, prices vary with real time system conditions; in other words when the price is high in the wholesale market, the price is high in the retail market. Dynamic pricing gives consumers the ability to alter consumption on the basis of real time system conditions – this allows the system operator to better manage resources in real time and allows for better control of the exercise market power, which is a significant problem in wholesale electricity markets. In the U.S., there are some time-of-use-pricing programmes that have been in place for a very long time. The current challenge is to implement dynamic pricing – that is, prices that respond to the system conditions. This requires, amongst other things, the ability to measure the customer's consumption on at least an hourly basis, which requires an interval meter on the customer's premises.

The traditional approach to demand response has been to administratively set a baseline of consumption and then to pay customers who are willing to reduce consumption relative to this baseline. This approach has various problems. One problem is that customers have an incentive to make the administratively-set baseline as high as possible. Another problem is that the supplier of this service has an incentive to look for customers who would normally be consuming less than the baseline during peak demand periods. These customers do not actually have to respond to real-time prices, the curtailment service provider simply offers in to the market the demand response during the period when the customer is likely to be consuming less than the baseline anyway.

The goal of dynamic pricing is to treat generation symmetrically with load – in particular, the default price that load pays should be the wholesale price, just as the default price paid to generators is the wholesale price. The trick is then allowing customers to effectively choose different kinds of products to hedge that real-time price risk. In the traditional vertically-integrated regime, the vertically-integrated utility was a kind of insurance provider for electricity – allowing retail customers to pay the average price per kWh and supplying all they required at that price. This will always be a problem in a liberalized industry since there is no guarantee that any fixed retail price will cover the cost of purchasing an undetermined (and potentially unlimited) quantity of electricity in the wholesale market. This was a problem in California where the incumbent utilities were required to sell to end-users at a fixed default price while wholesale prices were climbing.

How should we pass through the real-time wholesale price to consumers? The standard economists' response that customers will figure it out does not excite regulators. Customers should be able to benefit by reducing their consumption at times when the price is high, and increasing consumption in those hours when the price is low – perhaps not even reducing their overall consumption, but reducing their total bill. Protecting customers from volatile wholesale prices is not costless – since it eliminates the incentive for customers to shift their consumption from times of high demand – increasing the capacity required in the system, which must be paid for by all customers.

Another big rationale for increasing the demand responsiveness in the market is the increasing intermittency resulting from an increased share of renewables. California has a renewable portfolio standard target of 20 per cent by 2010 and the legislature is trying to increase that to 33 per cent by 2020.

The problem with intermittent energy sources is that they may not be present when needed. In California, when the record system peak load was reached on July 24, 2006 only 5 per cent of the installed wind capacity was operating. On this day, as it is the case for most other days, most of the wind generation occurred in the middle of the night whereas the peak demand occurred in the middle of the day. In addition, California policy AB32, which is proposing to introduce a cap-and-trade carbon scheme to establish a carbon price, will result in even higher prices during the day (when carbon emissions are higher) and even lower prices at night.

The load duration curve for California shows us that a 15-20 per cent reduction in peak demand (which is in the realm of what has been achieved in real time pricing studies) will allow a reduction in 10,000 to 5,000 megawatts of peak capacity on the system.

There is a roll-out of hourly meters for all customers in California, to be implemented by the end of 2011 (large electricity users already have hourly meters). The big challenge is coming up with a politically-acceptable form of real-time pricing. The first complaint of consumers is that they will need to stay home to monitor the meter to make decisions as to when to reduce their consumption.

One possible solution is Critical Peak Pricing (CPP). Under this approach, consumers are notified that a fixed block of hours on the following day will be priced at a higher price. The customer receives notice on a day-ahead basis that 4-6 hours of the following day will be charged a higher price. Typically there is a maximum numbers of critical peak days that a retailer can declare during the summer months to avoid price-responsiveness fatigue on the part of customers.

The problem with this form of peak-load pricing is that because it allows the retailer to charge a higher price during CPP events, the retailer has an incentive to make use of the maximum number of days of declared “critical peak” whether or not there is a true need for customers to reduce their consumption. An alternative is to have a critical peak rebate under which the customer is paid for reducing his/her consumption at declared critical-peak times. Customers favour this approach because they cannot be made worse off than the baseline fixed price, because if they fail to reduce their consumption during CPP events, they only lose the rebate. This approach aligns the incentives of the retailer with the customer – so that the retailer only declares critical peak days when the wholesale price is forecast to be particularly high. In the Anaheim study it was found that the critical-peak-with-rebate mechanism resulted in a reduction of consumption of 13 per cent in the treatment group relative to the control group.

A subsequent study in Washington, D.C. examined a number of related issues as follows: First, does the price response differ for customers in the critical peak pricing scheme (which guarantees a higher price for a block of hours) compared to an hourly pricing scheme (under which the price could go high for periods as short as one hour). Second, is there a difference in response when customers are paid a rebate to reduce their consumption than when they are required to pay an equivalent penalty for increasing their consumption? Third, what is the effect of smart thermostats which automatically reduce consumption during high price or critical peak events?

In regards to hourly pricing versus critical peak pricing, there seemed to be no less response to hourly pricing than to critical peak pricing. The simplest explanation for this is that hourly prices tend to be clustered (usually there is a sustained period of high prices during the peak, exactly mirroring the high price that would be faced under critical peak pricing). In regard to a critical peak rebate versus a critical peak surcharge, the experiments showed that the critical peak rebate resulted in an effect which was only one-half to one-third of the effect with the surcharge. It appears that the fear of being punished for not responding motivated people more than the fear of not being paid a rebate. The smart thermostats significantly enhanced the price responsiveness of customers, particularly for customers with both electric air-conditioning and heating in their houses.

California is considering introducing the critical peak rebate scheme as a default – this may not result in the same price response as a critical peak surcharge scheme.

In response to a question from the Chairman, Professor Wolak agreed that the participants on the various dynamic pricing programs knew they were taking part in an experiment and may have adjusted their behaviour accordingly. But he emphasized that the participants were randomized into the two groups and those in the control group did not know they were in the control group. In addition, customers did not

have the ability to make any long-run responses to the critical-peak pricing such as invest in technologies that would allow them to shift their loads. The results are consistent with experiments in other jurisdictions which show demand response in the range of 10-20 per cent. The key thing is that the demand response is being targeted to just 10 to 20 critical peak hours a year – sufficient to lop the top off the load-duration.

The Netherlands raised an issue that arises due to the form of the regulation of distribution networks. In the Netherlands, the regulatory framework for energy networks uses a yardstick approach. The yardstick is formed by averaging the costs of all distribution operators for a given set of outputs. This is then used to set the revenues for each distribution business for three years. Problems can arise however, if investment in smart grids is recognized as a cost, but there is no corresponding observed increased output measure. This might be the case if a new technology creates products (such as energy-savings services or charging options for electric cars) for which no tariff products have been defined by the regulator. In the absence of a new product category, a distribution business which invests in a smart grid so that its costs are above the average will be penalized.

Another related problem relates to congestion. The growth in distributed generation has led to capacity problems for some distribution networks. New generators in the Netherlands only pay connection fees (shallow connection costs) and are not required to contribute to network upgrade costs. Distribution businesses will be reluctant to incur upgrade costs to relieve congestion if this is not reflected in a higher revenue allowance. One possible solution is to define an output or product category for generation – so that the costs incurred to connect new generation are better reflected in a distribution network's efficiency measure. Another solution is to introduce a "transport fee".

The transport fee has certain advantages: in the absence of the fee, consumers in a region must pay all of the costs of additional distributed generation connections, even if the benefits are spread over the country as a whole. A transport fee will also signal to generators the costs of their location decisions – i.e., the fees will be cost-orientated which is in line with the EU guidelines for electricity markets. Finally, the transport fee causes generators to internalize the upgrade costs.

One of the issues with the transport fee is that it does not necessarily provide an incentive for an operator to reduce congestion in a smart way using, say, advanced information and communication technologies rather than installing wires and transformers. The NMa is considering whether or not a separate incentive for network innovation is necessary.

A delegate from the UK observed that there will be a large need for reinforcement of the existing grid to accommodate renewable generation in the UK over the next 15 years. A lot of the renewable generation investment is occurring in Scotland whereas the largest loads are in the South. A queue of 60 GW of capacity has built up over 4 years waiting for connection to the transmission grid.

As a result, Ofgem has approved an interim grid access connection model under which generators are connected as soon as local works are completed while managing the likely constraints until wider grid reinforcements take place. This allows renewables to get on the grid more quickly to meet the renewables targets. The UK government is currently consulting on a new grid access model to be introduced on an enduring basis from June 2010.

The UK is carrying out a review at the moment on how the energy markets should be regulated in the light of the need for smart grid and renewables, and whether, under the current regulatory framework, the target for renewables will be reached. Conclusions (on matters such as whether there is a need to change the regulatory framework or the role for state intervention) are expected to be announced in March 2010.

Professor Leigh Hancher (Tilburg University) discussed the European energy regulatory framework. Energy market liberalization in Europe has been a three-step process. The so-called ‘Third Package’ of regulation has just been introduced and should be implemented within the 27 countries of the EU by March 2011.

The basic message in the third package is to reinforce unbundling. Transmission operators should be structurally separated from generation supply. Regulators get increased power at the national level and there is a gradual transfer of regulatory power to the European level. The objective is not just to liberalize 27 individual markets but also to promote cross-border trade. The third package also focuses on investment and the fact that a massive amount of investment is needed to make the transition to a low carbon economy. Consumer protection and data protection are also strengthened.

The parallel Climate Change Package also resulted in a number of very important initiatives being adopted at EU level, including the famous 20-20-20 Goals: by 2020 a reduction in energy consumption by 20% and an increased renewable use by 20%. These targets will ultimately be reviewed to see if they should be extended to 2050. There is also the introduction of a European-wide emission trading scheme and a carbon capture system.

The European authorities could be said to be riding two horses simultaneously. One could say that the whole purpose of liberalization of electricity markets has been to remove or limit state interference in Europe’s energy markets: promoting liquid wholesale markets, promoting choice, promoting switching between suppliers. On the other hand, the Climate Change Package suggests an opposing tendency: binding targets, and state intervention perhaps restricting choice, restricting competition as well as restricting trade, and many would add distorting the emergent wholesale markets throughout Europe.

The Third Package allows member states to intervene to promote the roll-out of smart grids by declaring these investments to be public service obligations. The existence of public service obligations has, in the past, been used as an excuse to give a company certain exclusive rights - as a sort of quid pro quo for performing various public service obligations. This raises the issues of a possible clash between liberalization efforts and the need for public service obligations to promote the Climate Change Package.

There is a concern that the renewable energy directive will result in uneven burden sharing across the member states since some member states have more potential to switch to renewables than others. The Commission was asked to consider using more market-like mechanisms to achieve the binding targets, but although there are joint targets and various ways of exchanging so-called guarantees of origin for green energy, there is not yet an EU-wide market for renewable certificates; this was rejected by a majority of the member states. This is seen by many as the major limitation on the scope for market-like techniques to achieve renewable energy targets in the future.

State aid plays a very important role in the environmental field and in promoting renewables generally. There are quite generous environmental aid guidelines which allow member states to grant subsidies or aid to various projects or types of projects. These guidelines are very generous towards renewable energy forms, because they allow operating aid to cover the daily operational costs of producing renewable energy and they give renewable energy production a higher ‘age intensity’ to allow faster penetration of renewables. There are many ways for member states to promote renewables without contravening state aid rules. For example, state action that does not provide money but imposes minimum prices or minimum quotas on consumers does not amount to a transfer of resources in state aid terms. For example in Belgium the Belgian government has required grid operators to give priority dispatch to solar energy. This is a state mandate with no funding involved, which therefore does not fall under the state aid rules.

Environmental aid is now one of the largest areas of subsidization (after regional aid which has always been the biggest form of aid in the EU). Environmental aid now constitutes approximately 24% of total horizontal aid, covering all sectors. Sweden provides the most environmental aid, with 86%, the average for EU-12 being 6%. There are large differences across the member states.

Moving on to smart grids, one of the interesting issues is how to get network owners to innovate. One of the consequences of privatization is that funding for research and development within network companies has basically dried up. There have been attempts by some transmission system operators to set up cross-border R&D initiatives, but this has not yielded many results. There is now greater interest in exploring how monopoly networks will be incentivized to innovate.

One of the issues facing regulators seeking to make the transition to a low-carbon or carbon-free economy is that most consumers and transmission system operators are not confronted with a significant and credible carbon price. Network companies expect to be able to pass on these costs, so they do not have any particular incentive to innovate. Even if waiting causes these costs to rise considerably they can still expect to pass on these costs at an even later stage.

When it comes to promoting innovation three questions have to be answered: At what stage should "government stimulus" be applied? Who or what should be eligible? And how much state support is required? Can we construct some kind of regulatory models that will limit government support to a transitional period?

Three possible options have been raised in the UK in the context of the RPI-X@20 initiative: (a) targeting specific types of innovation considered desirable; (b) a competition for new ideas where different parties are invited to come up with different solutions; and (c) ex post offers of prices or rewards for successful investments. Of these, ex ante provision of funds for research results in significantly less risk for the regulated firm than a system of ex post rewards.

The Chairman asked France about the rules regarding structural separation. The third package requires functional separation of networks from generation. The OECD Recommendation on Structural Separation views structural separation more favourably than functional separation. In some countries wind resources are located in regions with few consumers. Would a vertically-integrated company have the same incentive to invest in the network to accommodate this new source of energy as a vertically separated company?

France responded that as far back as the Second Package of electricity and gas reforms there were rules requiring the functional, accounting and legal separation of generation and network activities. These requirements have been strengthened in the Third Package. The effectiveness of these provisions is assured by both the competition authorities and the sectoral regulators. In this context, it is not advisable to opt for ownership separation. There are synergies between these different activities that justify maintaining the historic link between the various entities. Watertight separation could lead to a less efficient system and would ultimately harm consumers. Finally, the development of renewable energy should not lead to increased overall consumption but rather to a partial replacement of fossil fuels. Thus it should not require a higher density network, which would necessitate reorganization. For France, the measures set out in the Third Package are sufficient to prevent abuse of monopoly and thereby establish an optimal development of the networks.

After the Chairman opened the floor to general questions Mr Lo Schiavo emphasized that it is important not just to look at short term elasticity. In Italy, for example, consumers are not expected to react very much to time-of-use prices. However appliance manufacturers are expected to respond to design new

products that make intelligent consumption decisions, shifting consumption to low price hours. Technology is the tool for modifying consumption patterns rather than changes in consumer behaviour.

Regulators should not just focus on the risk-averseness of network companies. Regulators can introduce forms of incentive regulation that induce desirable behaviour with rewards and penalties. A quality-of-service incentive scheme in Italy, for example, has had good results. The central message of the ERGEG document (that was circulated in the roundtable) is that incentive regulation can help induce network companies to identify and experiment with solutions for smart grids. Tariff regulation is not only about cost cutting. It is also about promoting value, quality and innovation in the future. It is up to regulators to create mechanisms for rewarding long-term innovation. The ERGEG paper sets out some ideas.

Frank Wolak emphasized that although technology may result in larger changes to consumption patterns than changes in consumer behaviour, customers must still be exposed to the dynamic tariff in order to have an incentive to invest in the technology in the first place. They will not choose the responsive smart technology if there are no cost savings from doing so.

The Chairman asked the EU why they did not simply adopt a "polluter-pays" principle – imposing charges on carbon emissions and allowing the market to respond in the most efficient manner.

The delegate from the European Union agreed that the polluter-pays principle is an important tool to encouraging greener electricity production and it has been put into effect in the EU through the European trading system for greenhouse gases (which puts a price on CO_2 emissions). However, at the same time, experience has shown that environmental costs have not been internalized to a sufficiently high degree. So a number of EU member states have chosen to address national emissions targets through the use of state aid.

There are 2 types of state aid: investment aid and operating aid. In some circumstances certain types of aids are more efficient and more appropriate than in other cases. The EU has sought to leave the choice of the most appropriate tool to the member states provided there is no over-compensation – that is provided the revenues do not exceed the cost plus a reasonable benefit. The EU state aid control policy aims to ensure that only those subsidies are introduced which contribute to increased environmental protection without unduly distorting competition in the member states.

Turning to Bulgaria, the Chairman asked whether the extent of the subsidies for renewables will not result in over-investment in renewable energy sources.

Bulgaria replied that the current share of renewables in energy production is far below the target share of 16% which is Bulgaria's binding target under the EU's Third Package directive. As a result, Bulgarian legislation provides for some incentives for renewables: First, companies that produce energy from renewable resources are allowed priority in interconnection with the transmission and distribution networks. Second, there is a guaranteed period of 25 years for mandatory renewables purchasing contracts with distributors of electricity. Third, there is preferential pricing for new power plants that use renewable energy sources. These preferential prices are not subsidies they are prices subject to regulation by the national electricity regulator in the energy market.

In the case of Spain, the Chairman noted that there has been a significant problem of over-investment in solar energy relative to wind energy since 2007. Would it be better simply to include the social cost of pollution in the price for conventional electricity?

Spain replied that there are two types of feed-in tariffs for renewable energy in Spain. Renewable energy generators can either sell the energy at market prices plus a premium or obtain a fixed tariff. This

last option is only available for small generators, so the first option is more common. Both the premium and the tariff are regulated by the government. They are set with the aim of increasing private investment in renewable energies in conformity with the targets stipulated in the government's multiannual plans for each type of renewable technology.

This system does raise some competition concerns. It would be desirable that the regulated premium and tariffs reflected in some way the long run social costs of conventional energies or alternatively the long run social benefits of renewable energies. The competition authority in Spain has not studied this issue in depth yet. We do have the experience with photovoltaic energy where these investment incentives were reviewed by the government once it was clear that the investment targets for this technology were to be achieved ahead of schedule.

The Chairman observed another competition concern in the wholesale energy market is that preferential access for renewable energies in this market might displace other sources of energy from the market regardless of their efficiency, especially when demand is low and/or when renewable energy generation is high. This could be seen as unfair particularly where these other conventional energies include in the bidding prices the real social costs of the technologies they use for generation. This can also be viewed as a competition issue.

Russia sees several possible ways to increase the share of renewable energy sources to its target of 4.5% by 2020: the creation of a special regulatory framework for renewable generating companies; reduction of barriers to entry (for example, through a reduction in license or documentation requirements, or by improving the ease of access to the transmission networks); financial incentives such as special tax treatment; or a reduction in fees. These are new issues for Russia which will have to be considered carefully so as to not distort competition in the electricity market.

The Chairman noted that Hungary has a mandatory purchasing regime for renewable energy sources at a guaranteed fixed tariff (known as the "feed-in" tariff). Is this tariff set up so as to cover the cost of the most efficient renewable technology? Is Hungary concerned about over-investment in the less efficient renewable energy sources? Does this approach exclude renewables from the entire wholesale market?

Hungary acknowledged that there is a mandatory purchasing regime for renewables in Hungary with a guaranteed fixed feed-in tariff. This scheme favours the less costly technologies (there is not enough compensation to induce investment in the more expensive solar technologies).

On the other hand, some experts in Hungary are concerned about over-investment in Combined Heat and Power (CHP) generation which uses natural gas and is also subsidized under this scheme. Some experts say that these generators could operate profitably on the market without any subsidies. It is difficult to say why these generators are encompassed in this feed-in tariff scheme.

Paul Wilczek from the European Wind Electricity Association raised the issue of grid connection requirements (called 'grid codes' in Europe or 'connection conditions' in the U.S.) which defines the set of technical rules which each party has to fulfil to be connected to a public electricity system.

These grid codes have developed independently in member states. One aspect of a grid code is the so-called "fault ride-through requirements". As an example, the fault ride-through requirements for Italy, France, and Germany are quite different in shape and content and in the extent to which they are negotiable. It is not clear to a wind farm developer, manufacturer or even a system operator what has to be done to connect a wind farm to the electricity network. The grid code documents are not homogenous, documents are often scattered, not available in one simple format, and often not available in translation.

This imposes extra costs of both wind farm and system operators and, in the end, for the electricity consumers.

Solving the issues related to grid code harmonization is essential to reach the 2020 renewable targets in Europe in a cost effective way. Reaching these targets will be quite a lot more expensive if we do not overcome some of these grid connection shortcomings. To give some idea of the scale of the issue, by the end of 2009 the EU has about 75 GW installed wind capacity. To fulfil the 2020 targets will require around 230-250 GW installed capacity. EWEA forecasts a total of 400 GW by 2030, with 150 GW of this offshore.

When wind penetration was very low the connection requirements could be less sophisticated. The few turbines that existed could just switch off in the event of a system fault. With increasing levels of penetration transmission system operators (TSOs) have required more sophisticated response of wind turbines regarding voltage and frequency control, and fault-ride-through capability. The problem is not so much for the manufacturers to meet these requirements – the problem is understanding exactly what are the requirements, what requirements wind power plants can fulfil, and asymmetrical requirements as regards conventional power generation.

The EWEA believes that with a certain level of harmonization of grid connection requirements the main shortcomings could be overcome. Over time such a harmonization process will likely bring down the number of grid connection requirements and reduce the need to revise new grid codes. The EWEA has been working for 3 years on a harmonization exercise and has decided to propose a two step approach:

- Structural harmonization: aimed at establishing a common template for setting out grid connection requirements using clearly defined terms.

- Technical harmonization: adapting existing national grid codes to the common template, to be performed gradually where it is technically possible.

EWEA has published a Generic Grid Code format in December 2009 and has been in contact with the newly established European organization for transmission system operators, ENTSO-E, and with European regulators (both through ERGEG and a new agency, the Agency for the Cooperation of Energy Regulators, ACER). Under the Third Package of reforms these organizations are required to publish a network code for grid connections.

The overall objective when talking about harmonizing grid code requirements is facilitating the economic and efficient connection of the targeted renewable energy sources capacity for 2020 and beyond.

An interesting development is an inter-governmental initiative to establish a North Sea grid. Economically it makes no sense to connect all the offshore wind farms radially, connection by connection. But, an offshore grid with HVDC cables would have the possibility to plug in the offshore wind farms into substations out in the sea. This would allow not only the grid connection for wind farms but would also create a trans-national grid which is urgently needed.

In response to a question about who should pay for the cost of “deep” grid reinforcement (as opposed to just the connection costs), Mr Wilzcek commented that the European transmission grid is outdated and requires significant investment to achieve a truly integrated market. The renewables are just the drivers that are bringing these problems out in the open. Any refurbishment of the grid will benefit other sources of electricity as well and further enhance security of supply and the creation of an internal energy market in Europe.

New Zealand pointed out that the wholesale electricity pricing regime in New Zealand treats all types of generation equally, whether it is wind, hydro or fossil-fuel powered – that is all generation receives the same wholesale market spot price adjusted only for the local losses and constraints.

Yet in New Zealand wind generation accounts for 5 per cent of the total generation capacity and growing. There are a number of factors that have contributed to make wind in certain locations an economical form of generation in New Zealand, including the following:

- The availability of new hydro sites: New Zealand has a well developed network of hydro electric generation plants with – depending on the rainfall – 65-75% of New Zealand's electricity coming from hydro generation. It is becoming increasingly difficult to identify commercially viable sites for new hydro facilities which would pass the New Zealand national resource management process as an approved use of the land or water.

- The availability of wind: New Zealand is fortunate to be placed in the latitudes known as the "Roaring 40's" which are typified by high average wind speeds. This, combined with a relatively low population density has enabled generators to identify sites which allow the exploitation of economies of scale and plant capacity factors which are the envy of wind farms around the world. For example, the West Wind wind farm just outside Wellington, is a 142 megawatt wind farm with a forecast 47% capacity factor – significantly above international averages.

- The risk of getting it wrong: Although the amount of wind that hits New Zealand is very important it is also important to know that the design and siting are critical for wind farm efficiency. In New Zealand wind farm developers know that if they construct their farm in a less than optimum place they might not get the adequate return on the investment that they are expecting. As a result, the best generators and wind farm developers have invested heavily in developing real in-house expertise in wind farm design modelling and analysis. They now have the confidence to know that they can identify the sites they think are suitable for efficient wind farm development.

Wind farm developers in New Zealand generally believe that, even without subsidies, there is significant economically viable wind resource remaining available in the country whereas that is not the case for hydro. The Electricity Commission of New Zealand forecasts that about one third of the new generation built between 2010 and 2014 will be wind. The planned introduction of an emission trading scheme in New Zealand should also help by improving the relative cost effectiveness of the renewable generation.

The delegate from BIAC noted that its submission highlighted the potential for distortive effects resulting from differing forms of state intervention – particularly in Europe – intended to promote renewables. BIAC argues that there should be a more uniform subsidy scheme that removes some of the distorting effects of differing measures across different countries.

BIAC agreed that, in principle, the approach suggested by the Chairman (where consumers simply pay the full price for electricity including environmental damage) would indeed seem more attractive at first glance than a partly harmonized subsidies scheme. A more uniform subsidies scheme on the European level was recommended as a first step because that seems to be a practical, pragmatic and feasible way forward.

The Chairman invited the United States to suggest some answers to the list of questions set out in the conclusion of its submission, such as: what regulatory changes are necessary to provide the right incentives for investment in renewable energy sources? And: to the extent that smart grid technologies facilitate non-

economic goals such as environmental conservation and electricity system reliability, should governments be ready to invest?

A delegate from the United States responded first to the question on the role for government investment. As set out in the U.S. submission, the U.S. government has initiated a number of investments in renewable energy and much of it (4.5 billion USD) is earmarked investment in smart grids. There are more details in the U.S. submission.

As to what regulatory changes should be made, the delegate stated that policymakers are still learning from research (such as that carried out by Frank Wolak) as to how best to incentivise consumers and businesses to make the necessary upgrades and to initiate projects in the smart grid area. If potential competitors or actual competitors were to want to engage in some sort of collaboration or joint venture, this would be considered under the existing FTC/DoJ collaboration guidelines. The issue of harmonization of grid codes that has been raised is an example of standard setting. The U.S. submission discusses some of the competition issues related to standard setting.

Luca Lo Schiavo (Italy) noted that in Italy there is a complex system of incentives for renewable generation. The regulatory authority has already signalled formally to the parliament that some of these incentives can be too generous – especially for rooftop solar installation. There is a risk that the benefits of this investment will not exceed the cost.

He went on to discuss issues with wind generation. At present in some European countries (including Italy) wind plants are not subject to balance charges. Balance charges are the extra charges that arise in the event the real production of the plant is different from the targeted or scheduled level of production. This decision was made due to the difficulty of forecasting wind conditions. But over time the technology for forecasting wind production has improved. Wind generators should be required to pay balancing charges, as is the case in some other European countries.

In Italy one solution could be to progressively introduce a form of regulation which ensures that wind producers have the right incentives to accurately forecast wind strength - so far without introducing balancing charges (but this could be envisaged for the near future). Also, with increasing wind penetration the capability of the reserve markets must be improved. There is currently no mechanism for intra-day exchange of reserve capability in real time. This could be improved thanks to IT technology. Reserve capability could be moved from one state to another. Of course this requires network reinforcement which is a major focus for European regulators and among them the Italian regulator.

In response to a question about gate closure times (6 hours versus 24 hours) Luca Lo Schiavo pointed to a consultation paper on wind integration (available on the website www.energyregulators.eu). There is a high variability of gate closure times across European member states. But he again emphasized the importance of balance charges: if there is no balance charge there is no difference between 24 h, 8 h and 6 h. The real question is how to make the wind producer more responsible for the balancing costs they produce. Where balancing charges are applied to wind plants, the gate closure time should generally be reduced in order to avoid undue discrimination against wind plant that cannot forecast production more than a few hours in advance.

Paul Wilczek agreed that in the absence of cross-border balancing markets there will be large costs associated with integrating large amounts of wind energy into the electricity market. On the issue of gate closure times: any wind farm operator would be comfortable bearing balancing costs provided the gate closure times are appropriate, i.e. as close to real time as possible. As long as the balancing costs are transparent and represent the true and fair costs of balancing, a move towards imposing balancing costs on wind generators is a reasonable step forward.

Prof Leigh Hancher observed that it has been virtually impossible to achieve harmonization of gate closure times across the EU. In regards to the cross-border balancing markets – there is no competition because the TSOs are not willing to allow cross border trade except between themselves. They are not keen to see other suppliers in to the cross-border balancing market.

David Elzinga (IEA) responded to a question from the Chairman regarding whether it would be simpler and preferable to use taxes and charges to reflect the full costs of existing conventional generation technologies rather than to subsidise specific generation technologies. In general the IEA supports the use of charges which internalize these external costs, but believes that politically the public is not ready to accept this approach at this point. For this reason the IEA remains supportive of technology-specific interventions/subsidies. Even in situations where overheated markets have been created, for instance in the case of the solar market in Spain, such experiences yield data points that help design more appropriate interventions in other markets around various technologies. We cannot wait for political and social acceptance for charges to be imposed on conventional generation if we want to meet our 2050 goals.

The Chairman concluded the roundtable with the following points:

- Smart meters and dynamic pricing go hand-in-hand. One cannot ensure customers take account of the costs of scarcity in the electricity industry without dynamic pricing which requires smart meters.

- Proprietary separation of network ownership from generation and retailing creates its own issues for investment in smart grids – as it may require coordination between the network and retailing sectors. This is an issue that should be taken up again in the discussion on the Recommendation on Structural Separation.

- Imposing taxes and charges on polluters is politically very difficult and technically very difficult to implement. However subsidies should be more neutral than they are today especially as the penetration of renewable energy sources increases. To improve the functioning of markets it would be better to introduce a bidding mechanism instead of feed-in tariffs that exclude renewables from competition and from the electricity wholesale market mechanisms.

- Finally, there is the issue of integration of different national markets. There was a discussion on this issue with respect to the balancing market and the integration of renewables in Europe but the issue extends to all OECD countries. The degree of trade in electricity across national boundaries is limited. In order to increase the share of renewable energy in production there will need to be stronger integration of electricity markets which implies more integration of transmission networks.

COMPTE RENDU DE LA DISCUSSION

Le Président (Alberto Heimler) constate que la nécessité de réduire les émissions de CO_2 et de rendre la production d'électricité moins néfaste pour l'environnement fait l'objet d'un large consensus parmi les pays présents. Le développement des réseaux intelligents facilitera la prise en compte de ces contraintes de deux manières :

- en permettant une plus grande adaptation de la demande des consommateurs aux fluctuations des prix de gros ;
- en intégrant les moyens de production dispersés ou décentralisés, notamment ceux qui exploitent des énergies renouvelables.

Dans les pays de l'OCDE, les politiques gouvernementales favorisent fortement le développement de moyens de production renouvelables, notamment par le biais de subventions et de l'obligation d'acheter une partie des besoins en énergie sous forme d'énergie renouvelable. Ces politiques peuvent ne pas favoriser les énergies renouvelables les plus efficaces et entraîner un surinvestissement dans les énergies renouvelables.

La table ronde abordera les questions suivantes :

- Le développement des réseaux intelligents est-il un investissement naturel ou endogène pour les gestionnaires de réseaux électriques ou doit-il être imposé par une forme de réglementation ?
- La consommation d'électricité évoluera-t-elle en fonction des prix ? Si la réponse est non, comment lisser les variations de la demande grâce à des signaux-prix ?
- Les énergies renouvelables sont-elles au prix d'efficience ? Plus la quantité d'énergie renouvelable disponible sur le marché est grande plus l'effet des subventions qui faussent la concurrence est important.

1. Réseaux intelligents

Le premier intervenant est David Elzinga, qui travaille à la division des politiques de technologie de l'énergie de l'AIE. Il évoque les travaux de l'AIE visant à définir une feuille de route « Réseaux intelligents » en vue de la réunion du G20 en Corée en novembre 2010.

Définition du réseau intelligent : un réseau intelligent applique des technologies numériques aux réseaux électriques afin de suivre et de gérer le transport de l'électricité, — depuis son lieu de production, avec des moyens de production en base classiques mais aussi des énergies renouvelables, jusqu'à son lieu de consommation. Du côté de la demande, il est nécessaire de disposer de réseaux intelligents afin de coordonner la maîtrise de la demande d'énergie et l'effacement de façon à optimiser l'utilisation des actifs, réduire au minimum les charges d'exploitation et l'impact sur l'environnement tout en préservant la fiabilité, la résilience et la stabilité du système électrique.

Pour parvenir à réduire suffisamment les émissions de CO_2, une révolution technologique sera nécessaire. Aucune technologie ne permettra à elle seule d'atteindre les objectifs de réduction d'émissions fixés pour 2050. *Energy Technology Perspectives 2008*, un document établi par l'AIE, estime que, pour atteindre l'objectif fixé en 2050, 36 % des réductions d'émissions devront résulter d'une amélioration de l'efficacité énergétique, 21 % du recours aux énergies renouvelables et 19 % du captage et du stockage du CO_2 (CSC). L'efficacité énergétique et les énergies renouvelables nécessiteront une utilisation optimale des réseaux intelligents.

Les prévisions établies par l'AIE pour le scénario dans lequel l'objectif de concentration du CO_2 est de 450 parties par million montrent qu'en 2050, la répartition des modes de production d'électricité devrait être assez différente, notamment en raison de l'essor des énergies renouvelables non dispatchables. On prévoit que, en 2050 les transports représenteront 10 % de la demande d'électricité. Les services de transport ont besoin, à certains moments, de grandes quantités d'électricité, ce qui aggrave les problèmes de gestion du réseau.

Les réseaux intelligents présentent plusieurs avantages, notamment la possibilité d'améliorer la fiabilité et la qualité de la fourniture d'électricité ainsi que l'efficacité énergétique grâce à une réduction des pointes de consommation. Parce qu'ils favorisent l'électrification des véhicules et l'intégration des sources d'énergie renouvelables, ils permettent de surcroît des avancées en termes de qualité de l'environnement et de préservation des ressources. Ils seraient également un moyen de réduire la facture énergétique du client final (même si des études complémentaires sont nécessaires pour confirmer ce point).

Les politiques publiques et les dispositions réglementaires actuelles constituent le principal obstacle à l'essor des réseaux intelligents. L'éclatement du secteur de l'électricité a rendu la coordination plus complexe et fait qu'il est plus difficile pour certaines parties prenantes de tirer des avantages financiers d'une amélioration du système. De plus, certains aspects des réseaux intelligents risquent de ne pas être du goût des consommateurs s'ils ne sont pas traités correctement. Des études et recherches complémentaires sont nécessaires. Qui plus est, il faudra procéder à un déploiement et des démonstrations à grande échelle pour connaître les véritables possibilités de cette technologie. Il sera peut-être nécessaire aussi de définir des normes de sécurité et d'interopérabilité.

L'AIE entend aider ses pays membres à dégager une compréhension et une vision commune des réseaux intelligents, à en quantifier les coûts et bénéfices, à élaborer des recommandations et à évaluer les avantages des réseaux intelligents pour les pays en développement.

Le Président souligne que l'Italie est le seul pays membre de l'OCDE à avoir installé des compteurs intelligents dans plus de 90 % des habitations. Il est intéressant de relever que la motivation première de cette opération n'était pas la mise en place de tarifs variables (horosaisonniers) mais la lutte contre la fraude.

M. Lo Schiavo (autorité italienne de régulation de l'électricité) confirme que l'Italie a déjà installé 30 millions de compteurs intelligents, ce qui en fait l'un des trois seuls pays européens où ces compteurs sont une réalité concrète. D'autres pays ont arrêté ou examinent des projets de déploiement en raison de la directive européenne inscrite dans le troisième paquet énergie.

L'installation de compteurs intelligents a débuté en 2000, au départ à l'initiative d'ENEL. En 2006, le régulateur a contraint tous les autres distributeurs à fournir à leurs clients un dispositif de comptage évolué.

De l'expérience acquise avec ces compteurs intelligents on retiendra que :

- Les factures estimatives ont été presque complètement supprimées. Auparavant, cinq des six factures annuelles étaient des estimations. Aujourd'hui, les factures estimatives représentent moins de 10 % de l'ensemble des factures.

- Les compteurs intelligents permettent de mettre en place un niveau de service minimal en cas d'impayés et, une fois les arriérés acquittés, de reconnecter très rapidement le client.

- Il est plus facile pour les clients de changer de fournisseur, ce qui renforce la concurrence.

- Les compteurs intelligents permettent une tarification horosaisonnière et, de ce fait, les tarifs reflètent mieux les coûts.

- Il est plus facile de détecter les vols d'électricité (mais ce n'est pas la seule raison qui a motivé l'installation de ces compteurs).

Le surcoût engendré par ces compteurs a été pris en charge en augmentant le facteur X qui intervient dans le calcul du prix plafond fixé pour les prestations des distributeurs. Il en est résulté une hausse des tarifs de deux euros par client et par an, ce qui, au vu des bénéfices énumérés ci-dessus, a été jugé raisonnable.

S'agissant de l'effacement : les capacités d'effacement peuvent s'échanger sur le marché spot mais restent limitées (moins de 1 % des offres, en partie en raison de l'existence de contrats interruptibles conclus avec les gros consommateurs). Cela dit, en Italie, la consommation d'électricité de tous les clients particuliers et toutes les petites entreprises est limitée par contrat. Pour les ménages, la puissance maximale souscrite est en général de 3 kW. Cette limite à la consommation d'électricité est un puissant facteur d'efficacité énergétique. De fait, la consommation d'électricité annuelle de la clientèle domestique italienne s'élève en moyenne de 2.7 MWh/an, ce qui en fait une des plus basses d'Europe. Une introduction progressive du comptage multitarif est en cours : la clientèle haute tension bénéficie d'un comptage multitarif depuis fin 2005 ; fin 2009, cette mesure a été étendue à tous les clients basse tension dont la consommation est élevée ; d'ici fin 2011, tous les clients basse tension devraient disposer d'un comptage triple tarif.

Un tarif double est actuellement mis en place pour toute la clientèle résidentielle (les compteurs enregistrent la consommation en trois postes horaires, mais le tarif universel sera un tarif double) : il distingue heures pleines (8 h-20 h du lundi au vendredi) et heures creuses (le reste du temps). Les clients sont incités à consommer l'électricité de préférence le soir, la nuit et le week-end. À cette fin, l'autorité de régulation italienne souhaiterait que la puissance maximale passe de 3 à 4.5 kW pendant les heures creuses. L'Italie envisage également d'introduire en six à sept ans un système de comptage intelligent du gaz.

Le Président relève que la Norvège a adopté un programme qui prévoit le déploiement de compteurs intelligents chez tous les clients à l'horizon 2016. Selon l'autorité de la concurrence, le consommateur final devra pouvoir choisir son compteur et ne pas être contraint d'acheter le compteur proposé par la compagnie d'électricité. Cette autorité a proposé par ailleurs que les compteurs intelligents informent non seulement sur les quantités consommées mais aussi sur la somme totale dépensée en électricité. Le Président demande si cette suggestion a été acceptée par le régulateur ou par les compagnies d'électricité.

Le délégué de la Norvège décrit la situation suivante : aux clients consommant plus de 100 MWh par an, les gestionnaires de réseaux sont tenus de fournir des compteurs intelligents qui soient capables à mesurer la consommation électrique toutes les heures. En effet, pour ces clients, la consommation et le montant à payer figurent sur leur facture mais non sur le cadran du compteur. Les gestionnaires de réseaux ne sont pas obligés de fournir des compteurs intelligents aux plus petits consommateurs (consommant

moins de 100 MWh par an). D'une manière générale, les entreprises du secteur sont favorables à l'idée de fournir aux clients des informations sur les prix et sur leur consommation d'électricité, mais la question de savoir si ces informations doivent être disponibles sur Internet ou sur le compteur lui-même fait débat. L'administration chargée de cette question, la Direction nationale des ressources en eau et de l'énergie, a exigé que ces informations soient au moins disponibles sur Internet. L'autorité de régulation enquête actuellement pour savoir si le fait d'afficher ces informations sur le compteur accroîtrait la transparence du marché de l'électricité et rendrait les utilisateurs plus conscients du coût de l'énergie.

La République tchèque fait état d'un projet d'expérimentation de compteurs intelligents lancé par ČEPS, le plus gros producteur d'électricité du pays. ČEPS est en train de sélectionner un fournisseur de compteurs intelligents pour cette expérimentation. Une ville a été choisie pour sa situation stratégique en termes de production éolienne et photovoltaïque. Cette ville a mis en place une politique environnementale responsable et s'est dotée d'une stratégie à long terme pour augmenter la part des énergies renouvelables dans sa consommation d'énergie. L'objectif de ce projet est de tester tous les éléments d'un réseau intelligents : compteurs intelligents, production décentralisée exploitant notamment les énergies renouvelables, bornes de chargement et production combinée de chaleur et d'électricité. Le projet n'en est qu'à ses débuts.

Le professeur Frank Wolak (université Stanford) opère une distinction entre tarification dynamique et tarification horosaisonnière. Dans le cas de la tarification horosaisonnière, les tarifs varient en fonction de l'heure de la journée mais la relation entre le prix et l'heure est fixe et connue à l'avance. En cas de tarification dynamique, les prix varient en temps réel ; en d'autres termes, lorsque le prix est élevé sur le marché de gros, il l'est également sur le marché de détail. La tarification dynamique donne aux consommateurs la possibilité de modifier leur consommation en fonction de la situation, ce qui permet au gestionnaire de réseau de mieux gérer les moyens dont il dispose en temps réel et de surveiller les cas d'exercice de pouvoir de marché, qui posent actuellement un problème important sur les marchés de gros de l'électricité. Aux États-Unis, la tarification horosaisonnière existe dans certains cas depuis très longtemps. Le défi actuel est de mettre en place une tarification dynamique, c'est-à-dire de faire en sorte que les prix fluctuent en fonction de l'évolution des conditions de fonctionnement du système. Cela impose notamment de pouvoir mesurer la consommation du client toutes les heures au minimum, et donc l'installation d'un compteur à courbe de charge chez le client.

En matière d'effacement, l'approche classique, c'est que l'administration définisse une consommation de référence puis de rémunérer les clients désireux d'abaisser leur consommation en dessous de ce niveau de référence. Cette approche présente plusieurs inconvénients. Tout d'abord, les consommateurs ont intérêt à faire monter le plus possible le niveau de référence. Ensuite, l'agrégateur d'effacement a intérêt à chercher des clients qui normalement consomment moins que le niveau de référence pendant les périodes de pointe. En fait, ces clients n'ont pas besoin d'adapter leur consommation l'évolution des prix en temps réel et l'agrégateur se contente de proposer au marché des capacités d'effacement pendant la période où le client consommera sans doute moins que le niveau de référence.

L'objectif de la tarification dynamique est de traiter symétriquement production et demande. En particulier, le prix par défaut payé par les clients finals devrait être le prix de gros, tout comme le prix par défaut payé aux producteurs est le prix de gros. La solution consiste alors à permettre aux clients de choisir différents types de produit afin de couvrir ce risque de fluctuation des prix en temps réel. Lorsque les entreprises d'électricité étaient verticalement intégrées, elles offraient une sorte d'assurance sur l'électricité, en permettant aux clients particuliers de payer un prix moyen du kWh et en fournissant toute la quantité demandée à ce prix. Dans un secteur libéralisé, cela posera toujours un problème étant donné que rien ne garantit qu'un prix de détail fixe couvrira le coût d'achat d'un volume indéterminé (et potentiellement illimité) d'électricité sur le marché de gros. C'est ce qui s'est passé en Californie lorsque

les électriciens historiques ont été contraints de vendre de l'électricité aux consommateurs finals à un prix par défaut fixe alors que les prix de gros augmentaient.

Comment répercuter sur les consommateurs des prix de gros qui évoluent en permanence ? La réponse classique des économistes, à savoir que les clients y veilleront, ne satisfait pas les autorités de régulation. Les clients devraient pouvoir bénéficier de ce mécanisme en réduisant leur consommation lorsque les prix sont élevés et en augmentant leur consommation lorsque les prix sont bas : ils ne diminueront peut-être pas leur consommation globale, mais allégeront leur facture. Protéger les clients contre la volatilité des prix de gros a un coût : étant donné que, dans ce cas, les clients ne sont plus incités à diminuer leur consommation aux heures de pointe, il faut accroître les capacités du système et cette augmentation doit être financée par tous les consommateurs.

Autre raison majeure de rendre la demande plus sensible à la situation du marché est la part croissante de la production intermittente, qui résulte de l'essor des énergies renouvelables. La Californie vise une la proportion des énergies renouvelables dans la production d'électricité totale de 20 % en 2010; le législateur s'efforce de la porter à 33 % à l'horizon 2020.

Les sources d'énergie intermittentes présentent un inconvénient : elles ne sont pas toujours disponibles lorsqu'on en a besoin. En Californie, lorsque la demande a atteint un niveau-record, le 24 juillet 2006, seuls 5 % de la puissance éolienne installée étaient mobilisables. Ce jour-là, comme c'est le cas la plupart du temps, la majeure partie de l'électricité éolienne a été produite au milieu de la nuit, alors que la pointe de consommation a eu lieu au milieu de la journée. De plus, en Californie, la loi AB32, qui prévoit de mettre en place un système d'échange de quotas d'émissions de CO_2 afin d'établir un prix du CO_2, va entraîner une hausse des prix au cours de la journée (lorsque les émissions de CO_2 sont élevées) et une baisse la nuit.

La monotone de charge de la Californie montre qu'un écrêtement de 15 à 20 % de la demande de pointe (ce qui correspond au résultat obtenu par les études sur la tarification en temps réel) permettra d'abaisser de 5 000 à 10 000 mégawatts la puissance indispensable pendant les pointes.

En Californie, des compteurs à postes horaires doivent être installés chez tous les clients d'ici la fin 2011 (les gros consommateurs d'électricité disposent déjà de ce type de compteurs). La grande difficulté consiste à trouver une forme de tarification en temps réel qui soit politiquement acceptable. Les consommateurs se sont plaints essentiellement d'avoir à rester chez eux pour surveiller le compteur afin de décider quand limiter leur consommation.

Une solution possible est la tarification des pointes critiques. Pour ce type de tarification, les consommateurs sont avisés que, pendant un nombre fixe (4 à 6) d'heures le lendemain, l'électricité leur sera facturée à un prix plus élevé. En général, il y a un nombre maximal de jours de pointe qu'un détaillant peut déclarer pendant les mois d'été, afin d'éviter que, par lassitude, les clients ne réagissent plus aux hausses de prix.

Ce type de tarification pose un problème : comme elle autorise le détaillant à facturer un prix plus élevé les jours de pointe critique, ce dernier a intérêt à déclarer le maximum possible de jours de pointe, qu'il soit ou non nécessaire que les clients réduisent leur consommation ces jours-là. Une autre solution consiste à accorder une remise au client les jours de pointe critique : l'utilisateur reçoit de l'argent s'il réduit sa consommation aux heures de pointe critique déclarées. Les clients préfèrent cette solution car, dans ce cas, ils ne paieront pas plus cher que le tarif de référence, étant donné que, s'ils omettent de réduire leur consommation aux heures de pointe, ils ne perdront que la remise. Cette démarche fait coïncider les incitations destinées au détaillant et celles du client, de telle sorte que le détaillant ne déclare jours de pointe que des jours où le prix de gros risque d'être particulièrement élevé. L'étude menée à Anaheim a

montré que le mécanisme prévoyant une remise les jours de pointe a permis d'abaisser de 13 % la consommation du groupe expérimental par rapport à celle du groupe témoin.

Une étude ultérieure, effectuée à Washington, a permis d'étudier les questions connexes suivantes : la réaction du client à l'évolution des prix est-elle la même s'il est soumis à une tarification avec des pointes critiques (le prix est plus élevé pendant plusieurs heures) ou à une tarification horaire (le prix peut augmenter sur une durée aussi courte qu'une heure) ? La réaction des clients est-elle la même s'ils bénéficient d'une remise lorsqu'ils réduisent leur consommation ou s'ils doivent payer un supplément lorsque leur consommation augmente ? Enfin, quel est l'effet des thermostats intelligents, qui diminuent automatiquement la consommation lorsque le prix est élevé ou lors des pointes critiques ?

Pour ce qui est de la tarification horaire et la tarification des pointes critiques, la réaction des clients semble identique. L'explication la plus simple à ce phénomène est que le tarif horaire est souvent le même pendant plusieurs heures consécutives (on observe, en général, une période prolongée pendant laquelle les prix sont élevés lors des pointes, prix qui correspondent exactement à ceux qui seraient appliqués aux pointes critiques). Pour ce qui est de la différence entre remise et supplément en cas de pointe critique, l'expérience montre que la remise produit un effet qui représente entre la moitié et le tiers de l'effet du supplément. Il apparaît que la peur d'être sanctionné pour n'avoir pas réagi est plus incitative que la peur de ne pas bénéficier d'une remise. Enfin, si un thermostat intelligent est installé, le client réagit davantage aux variations de prix, surtout s'il dispose à la fois d'une climatisation électrique et du chauffage électrique.

La Californie envisage d'introduire les remises accordées pour effacement lors des pointes critiques dans tous les contrats. La réaction des clients aux variations de prix risque de ne pas être la même qu'avec le supplément appliqué aux pointes critiques.

En réponse à une question du Président, le professeur Wolak convient que les personnes qui ont participé aux diverses études sur la tarification dynamique savaient qu'il s'agissait d'une expérience et pouvaient avoir adapté leur comportement en conséquence. Il souligne néanmoins que les participants ont été répartis aléatoirement en deux groupes et que les membres du groupe témoin ignoraient qu'ils en faisaient partie. En outre, ils n'avaient pas la possibilité de s'adapter à la tarification heures de pointe en adoptant des solutions à long terme et, notamment, ne pouvaient investir dans des technologies leur permettant de différer leur consommation. Les résultats sont conformes à ceux d'expériences menées dans d'autres États, expériences qui montrent un effacement dans une proportion qui varie de 10 à 20 %. Le point essentiel est que l'on ne cherche un effacement que 10 à 20 heures de pointe critique par an, ce qui est suffisant pour écrêter la courbe de charge.

Les Pays-Bas soulèvent un problème qui résulte du mode de régulation des réseaux de distribution. Dans ce pays, la réglementation des réseaux électriques se fonde sur un étalonnage concurrentiel. L'étalon est calculé en prenant la moyenne des coûts payés par tous les distributeurs pour un ensemble particulier de produits. Cet étalon est utilisé pour fixer les recettes de tous les distributeurs pour une durée de trois ans. Cependant, un problème se pose si un investissement dans les réseaux intelligents, qui a un coût, ne se traduit pas par une amélioration observée de la mesure. C'est le cas par exemple d'une nouvelle technologie qui donne naissance à des produits (par exemple, des services permettant des économies d'énergie ou des solutions de rechargement pour véhicules électriques) pour lesquels le régulateur n'a pas encore établi des tarifs. Si ce dernier ne crée pas une nouvelle catégorie de produits, le distributeur qui aura investi dans les réseaux intelligents, à des coûts supérieures à la moyenne, sera pénalisé.

Une autre difficulté connexe concerne les congestions. L'essor de la production décentralisée d'électricité a créé des problèmes de capacité sur certains réseaux de distribution. Aux Pays-Bas, les nouveaux producteurs ne paient que le prix du raccordement (coût partiel) et ne sont pas tenus de participer

aux coûts de mise à niveau du réseau. Les entreprises de distribution seront réticentes à supporter les charges de mise à niveau nécessaires pour éviter les congestions si elles n'obtiennent pas en échange de pouvoir bénéficier d'une hausse de leurs recettes. Une solution possible serait de définir une catégorie de produit pour la production, de sorte que les charges supportées pour raccorder de nouvelles unités de production se retrouvent dans la mesure de l'efficacité du réseau de distribution. Une autre solution consiste à instaurer un tarif d'utilisation du réseau de transport.

Ce tarif d'utilisation du réseau présente plusieurs avantages : en son absence, les consommateurs d'une région donnée doivent assumer l'ensemble des coûts de raccordement des nouvelles unités de production décentralisées même si le pays tout entier bénéfice de ces raccordements. Un tarif d'utilisation du réseau révèlera également aux producteurs le coût qui résulte du choix de leurs sites de production. Autrement dit, le tarif sera fonction des coûts, ce qui va dans le sens des lignes directrices relatives aux marchés de l'électricité définies au niveau européen. Enfin, un tarif d'utilisation du réseau encourage les producteurs à internaliser les coûts de mise à niveau.

Un des problèmes posés par le tarif d'utilisation du réseau est qu'il n'incite pas nécessairement un opérateur à décongestionner le réseau d'une manière intelligente, par exemple, en ayant recours à des technologies avancées d'information et de communication plutôt qu'en installant des câbles électriques et des transformateurs. À l'heure actuelle, la NMa a entrepris de déterminer s'il est nécessaire de mettre en place un mécanisme d'incitation distinct pour favoriser les innovations sur le réseau.

Un délégué du Royaume-Uni observe que le réseau britannique devra être considérablement renforcé dans les 15 prochaines années afin d'y intégrer les énergies renouvelables. Une bonne partie des investissements dans la production d'électricité renouvelable concernent l'Écosse alors que l'électricité est majoritairement consommée dans le sud du pays. En quatre ans, des unités de production de 60 GW ont été construites mais ne sont toujours pas raccordées au réseau de transport.

Pour cette raison, l'Ofgem a approuvé une procédure temporaire d'accès au réseau, en vertu de laquelle les producteurs sont raccordés dès que les installations locales sont prêtes, tout en gérant les contraintes tant que le réseau n'a pas été renforcé. Cette solution permet d'intégrer plus rapidement les énergies renouvelables au réseau et ainsi d'atteindre plus vite les objectifs fixés pour ce type d'énergie. Le gouvernement britannique a engagé des consultations relatives à une nouvelle procédure d'accès au réseau, qui devrait être mise en place pour longtemps à partir de juin 2010.

Le Royaume-Uni examine en ce moment comment les marchés de l'énergie devraient être réglementés si l'on développe des réseaux intelligents et que l'on intègre aux réseaux les énergies renouvelables et vérifie si, dans le cadre réglementaire actuel, les objectifs fixés pour les énergies renouvelables seront tenus. Ses conclusions (sur des questions comme la nécessité éventuelle de modifier le cadre réglementaire ou sur l'intervention de l'État) sont attendues pour mars 2010.

M. Leigh Hancher (université de Tilburg) expose le cadre réglementaire européen de l'énergie. En Europe, la libéralisation des marchés de l'énergie s'est déroulée en trois étapes. Le troisième paquet de réglementation vient d'être adopté et doit être transposé dans les 27 pays de l'UE d'ici mars 2011.

L'idée maîtresse du troisième paquet, c'est de renforcer la séparation des activités. Les gestionnaires de réseaux de transport doivent être structurellement distincts des producteurs d'électricité. À l'échelle nationale, les autorités de régulation voient leurs compétences accrues et il y a un transfert progressif du pouvoir de réglementer vers des organismes européens. L'objectif n'est pas seulement de libéraliser 27 marchés individuels, il s'agit aussi de favoriser les échanges transfrontaliers. Le troisième paquet se concentre également sur les investissements et sur le fait qu'il faut procéder à des investissements massifs

pour assurer la transition vers une économie sobre en carbone. Enfin, la protection des consommateurs et des données est également renforcée.

En parallèle, le paquet énergie et climat a également s'est traduit par l'adoption de plusieurs initiatives très importantes au niveau européen, notamment le fameux objectif 20-20-20 : d'ici 2020, une réduction de la consommation d'énergie de 20 % assortie d'une augmentation de l'utilisation des énergies renouvelables de 20 %. À terme, ces objectifs seront revus afin de décider s'ils doivent être prolongés jusqu'en 2050. Il est également prévu de mettre en place un système d'échange de quotas d'émissions de CO_2 au niveau européen et de développer les systèmes de captage du carbone.

On pourrait penser que les autorités européennes courent deux lièvres à la fois. On pourrait dire que la libéralisation des marchés de l'électricité a eu pour unique objectif de faire cesser ou de limiter l'ingérence des États sur les marchés de l'énergie d'Europe en favorisant la liquidité des marchés de gros, la liberté de choix du consommateur, les changements de fournisseurs. À l'inverse, le paquet énergie et climat semble aller dans une direction opposée : objectifs contraignants et intervention des États, qui pourraient restreindre les choix, la concurrence et les échanges et, ajouteraient certains, pourraient perturber le fonctionnement des marchés de gros récemment créés dans toute l'Europe.

Le troisième paquet autorise les États membres à intervenir pour promouvoir le déploiement des réseaux intelligents en déclarant ces investissements comme des obligations de service public. Dans le passé, les obligations de service public ont servi de prétexte pour octroyer à des entreprises certains droits exclusifs en échange de l'exécution de diverses missions de service public. Cela pose le problème d'un éventuel conflit entre les efforts de libéralisation et les obligations de service public nécessaires à la mise en œuvre du paquet énergie et climat.

Certains redoutent que la directive relative aux énergies renouvelables ne fasse pas porter l'effort sur tous les États membres d'une manière équitable, puisque certains pays ont plus de possibilités de les développer que d'autres. Il avait été demandé à la Commission de privilégier la mise en place de mécanismes obéissant davantage à une logique de marché pour atteindre les objectifs contraignants. Or, même s'il y a des objectifs communs et plusieurs moyens d'échanger des garanties d'origine pour les énergies renouvelables, il n'existe pas encore de marché européen des certificats verts, car cette idée a été rejetée par une majorité d'États membres. Nombreux sont ceux qui estiment que ce point constitue le principal obstacle à l'adoption de mécanismes de marché pour atteindre les objectifs de production d'électricité renouvelable.

Les aides d'État jouent un rôle très important en matière d'environnement et de promotion des énergies renouvelables, d'une manière générale. Des lignes directrices généreuses en matière d'aides d'État destinées à la protection de l'environnement autorisent les États membres à octroyer des subventions ou des aides à divers projets ou types de projet. Pour les énergies renouvelables, ces lignes directrices sont très généreuses car elles autorisent des aides au fonctionnement couvrant les coûts au jour le jour de la production d'électricité et, de plus, favorisent davantage les modes de production exploitant les énergies renouvelables afin d'en accélérer le développement. Les États membres disposent de nombreux moyens de promouvoir les énergies renouvelables sans contrevenir aux règles sur les aides d'État. À titre d'exemple, un État qui ne verse pas d'argent mais impose des prix ou des quotas minimaux aux consommateurs n'effectue pas un transfert de ressources au sens des aides d'État. Ainsi, en Belgique, le gouvernement a imposé aux gestionnaires de réseau d'appeler en priorité l'électricité solaire. Cette obligation légale ne suppose pas de financement et échappe donc pas aux règles sur les aides d'État.

L'environnement est aujourd'hui l'un des domaines les plus subventionnés (après les régions qui ont toujours été les grandes bénéficiaires des aides dans l'UE). Les aides destinées à la protection de l'environnement représentent aujourd'hui à peu près 24 % de l'ensemble des aides horizontales et couvrent

tous les secteurs. Ce chiffre atteint 86 % en Suède, qui est le pays qui octroie le plus d'aides destinées à protéger l'environnement, la moyenne pour les 12 pays entrés récemment dans l'UE étant de 6 %. Dans ce domaine, il y a donc de grandes différences entre les États membres.

Pour ce qui est des réseaux intelligents, il s'agit notamment de trouver comment inciter les propriétaires de réseaux à innover. La privatisation a eu pour conséquence en particulier le tarissement des budgets de R-D chez les gestionnaires de réseau. Certains gestionnaires de réseaux de transport ont bien essayé de lancer des programmes de R&D internationaux, mais sans grands résultats. Aujourd'hui, la question de savoir comment des réseaux monopolistiques peuvent être incités à innover suscite davantage d'intérêt.

L'un des problèmes auxquels sont confrontés les régulateurs qui cherchent à assurer la transition vers une économie sobre en carbone ou sans carbone tient au fait que la plupart des consommateurs et des gestionnaires de réseau de transport ne paient par pour le CO_2 un prix significatif et crédible. Les gestionnaires de réseaux pensent pouvoir répercuter ce coût sur leurs clients et ne sont donc pas incités à innover. Même si l'immobilisme conduit à une hausse considérable de ces coûts, ils peuvent toujours espérer la répercuter ultérieurement.

Pour ce qui est des moyens de favoriser l'innovation, il faut répondre à quatre questions : à quel stade l'Etat doit-il donner un coup de pouce ? Qui ou quelle activité doit être concerné ? Quelle doit être l'ampleur du soutien de l'État ? Pouvons-nous concevoir un modèle de régulation qui limite dans le temps le soutien de l'État ?

Au Royaume-Uni, dans le cadre de l'initiative RPI-X@20, trois solutions envisageables ont été présentées : a) cibler certains types spécifiques d'innovations jugées souhaitables ; b) organiser une compétition afin de faire émerger des idées nouvelles en insistant sur la diversité des solutions à proposer ; c) proposer des offres de prix ou des récompenses a posteriori en cas d'investissements réussis. Parmi ces solutions, le financement préalable de la recherche présente, pour une entreprise réglementée, un risque beaucoup moins élevé qu'un mécanisme de récompenses a posteriori.

Le Président interroge la France sur les règles relatives à la séparation structurelle. Le troisième paquet impose une séparation fonctionnelle entre les réseaux et la production. La recommandation de l'OCDE concernant la séparation structurelle dans les secteurs réglementés privilégie la séparation structurelle par rapport à la séparation fonctionnelle. Dans certains pays, les gisements de vent se situent dans des régions où il y a peu de clients. Est-ce qu'une entreprise verticalement intégrée aura autant intérêt à investir dans le réseau pour intégrer cette nouvelle source d'énergie qu'une entreprise verticalement séparée ?

La France répond que le deuxième paquet de libéralisation du marché intérieur du gaz et de l'électricité imposait déjà la séparation fonctionnelle, comptable et juridique des activités de production et de réseau. Ces dispositions ont été renforcées dans le cadre du troisième paquet. Le respect de ces obligations est contrôlé à la fois par l'autorité de la concurrence et par l'autorité de régulation sectorielle. Dans ces conditions, il n'est pas souhaitable d'opter pour la séparation patrimoniale. Entre ces différentes activités, il existe des synergies qui justifient le maintien du lien historique entre les différentes entités. Une séparation radicale pourrait nuire à l'efficacité du système et serait, au bout du compte, préjudiciable au consommateur. Enfin, le développement des énergies renouvelables ne doit pas conduire à une augmentation de la consommation globale mais plutôt à un remplacement partiel des combustibles fossiles. Par conséquent, il ne doit pas imposer une densification du réseau, ce qui nécessiterait une réorganisation. Pour la France, les mesures figurant dans le troisième paquet suffisent à prévenir les abus de position dominante des monopoles et à favoriser un développement optimal du réseau.

Le Président ayant décidé de passer aux questions d'ordre général, **M. Lo Sciavo** souligne qu'il importe de ne pas s'intéresser seulement à l'élasticité à court terme. En Italie, par exemple, on ne s'attend pas à ce que les consommateurs réagissent beaucoup à une tarification horosaisonnière. En revanche, on pense que les fabricants d'appareils ménagers s'adapteront en concevant de nouveaux produits évolués, qui consommeront de l'électricité aux heures où le tarif est bas. Ce sont les technologies et non un changement de comportement des consommateurs qui modifieront les schémas de consommation.

Les régulateurs ne devraient pas seulement s'intéresser à l'aversion pour le risque des gestionnaires de réseau. Ils ont la possibilité d'instaurer des formes de réglementation incitative qui induisent le comportement souhaité grâce à un système de récompenses et à de sanctions. En Italie, par exemple, un mécanisme d'incitation destiné à améliorer la qualité de service a donné de bons résultats. L'idée maîtresse du document de l'ERGEG (que tous les participants à la table ronde ont pu consulter), c'est qu'une réglementation incitative peut conduire les entreprises de réseau à trouver et à expérimenter des solutions intelligentes. La tarification n'a pas pour unique objectif de réduire les coûts. Elle doit également favoriser la qualité, l'innovation et produire de la valeur. C'est aux autorités de régulation qu'il revient de concevoir des mécanismes qui récompensent l'innovation à long terme. À cet égard, le document de l'ERGEG avance quelques idées.

Frank Wolak souligne que, même si la technologie doit davantage modifier les schémas de consommation que l'évolution du comportement des consommateurs, il faut néanmoins que l'on impose une tarification dynamique aux consommateurs pour qu'ils soient incités à investir dans cette technologie. Ils n'investiront pas dans des appareils intelligents si ces derniers ne leur permettent pas de faire des économies.

Le Président demande au représentant de l'UE pourquoi l'Union n'a pas simplement adopté le principe pollueur-payeur, c'est-à-dire fait payer les émissions de CO_2 et laissé le marché s'y adapter de la manière la plus efficace possible.

Le délégué de l'Union européenne convient que le principe pollueur-payeur favorise grandement la production d'une électricité verte et qu'il a été mis en œuvre dans l'UE au travers du système d'échange de quotas d'émissions de gaz à effet de serre (qui fixe le prix des émissions de CO_2). Cependant, l'expérience a montré que les coûts environnementaux n'avaient pas été suffisamment internalisés. Par conséquent, plusieurs États membres ont décidé d'atteindre leurs objectifs nationaux d'émissions en ayant recours à des aides d'État.

Deux types d'aides d'État existent : les aides à l'investissement et les aides au fonctionnement. Suivant les cas, certains types d'aides sont plus efficaces et mieux adaptés que d'autres. L'UE a souhaité laisser le choix de l'outil le mieux adapté aux États membres à condition qu'il n'y ait pas de surcompensation, c'est-à-dire que les recettes ne soient pas supérieures à la somme des charges et d'un bénéfice raisonnable. En matière d'aides d'État, la stratégie de contrôle de l'UE consiste à vérifier que les subventions versées ne servent qu'à protéger l'environnement et ne faussent pas la concurrence au sein des États membres.

Se tournant vers la Bulgarie, le Président demande si le montant des subventions octroyées en faveur des énergies renouvelables ne risque pas d'entraîner un surinvestissement dans les énergies renouvelables.

La Bulgarie répond que la part actuelle des énergies renouvelables dans la production d'énergie est bien inférieure à 16 %, qui est l'objectif contraignant fixé à la Bulgarie par la directive européenne incluse dans le troisième paquet. C'est pourquoi, la législation bulgare prévoit des incitations afin de favoriser les énergies renouvelables. Tout d'abord, les entreprises qui utilisent des énergies renouvelables pour produire de l'électricité sont raccordées en priorité aux réseaux de transport et de distribution. Ensuite, les

distributeurs sont obligés d'acheter de l'électricité solaire et géothermique dans le cadre de contrats d'une durée minimale de 25 ans. Enfin, les centrales électriques nouvelles qui exploitent des énergies renouvelables bénéficient de tarifs préférentiels. Ces tarifs préférentiels ne constituent pas une subvention, ils sont soumis à la réglementation du marché de l'énergie par l'autorité nationale de régulation de l'électricité.

Le Président relève que l'Espagne, a fortement surinvesti dans le solaire par rapport à l'éolien depuis 2007. Ne serait-il pas plus simple d'intégrer au prix de l'électricité produite dans des centrales classiques les coûts de la pollution pour la collectivité ?

L'Espagne répond qu'il existe deux types de tarifs d'achat des énergies renouvelables dans le pays. Les producteurs d'électricité renouvelable peuvent soit vendre l'énergie au prix du marché plus une prime soit obtenir un tarif fixe. Cette deuxième possibilité n'est offerte qu'aux petits producteurs ; la première solution est donc la plus courante. La prime et le tarif sont tous deux réglementés. Leur montant est déterminé en fonction d'un objectif : augmenter les investissements privés dans les énergies renouvelables selon une proportion conforme aux objectifs fixés par le gouvernement dans des plans pluriannuels établis pour chaque énergie renouvelable.

Ce mode de fonctionnement ne pose pas de problème de concurrence. Il serait souhaitable que la prime et les tarifs réglementés reflètent peu ou prou les coûts à long terme des énergies classiques supportés par la collectivité ou, inversement, les avantages à long terme des énergies renouvelables pour la société. En Espagne, l'autorité de la concurrence n'a pas encore approfondi cette question. Le pays a acquis une solide expérience de l'énergie photovoltaïque, un domaine où les incitations à investir ont été revues par le gouvernement dès qu'il est apparu clairement que les objectifs d'investissement seraient atteints avant la date prévue.

Le Président évoque un autre problème de concurrence sur le marché de gros de l'énergie : en accordant un accès préférentiel à ce marché aux énergies renouvelables on risque d'en éjecter d'autres énergies néanmoins rentables, surtout si la demande est faible et/ou si la production renouvelable est élevée. Cette attitude pourrait être jugée injuste surtout si le montant de l'enchère pour une énergie classique inclut le coût réel pour la collectivité des techniques utilisées pour produire l'énergie en question. Ce point peut également être considéré comme un problème de concurrence.

La Russie estime qu'elle dispose de plusieurs moyens d'augmenter la part des énergies renouvelables et de la porter à l'objectif de 4.5 % fixé pour 2020 : instauration d'un cadre réglementaire spécifique pour les producteurs d'énergies renouvelables ; réduction des barrières à l'entrée (par exemple en assouplissant les exigences en matière d'autorisations ou de documentation ou en facilitant l'accès aux réseaux de transport) ; des incitations financières, par exemple un régime fiscal spécifique ; une diminution des redevances et contributions. En Russie, ces questions se posent depuis peu et devront être examinées attentivement si l'on ne veut pas fausser la concurrence sur le marché de l'électricité.

Le Président relève que la Hongrie a instauré une obligation d'achat de la production des installations renouvelables à un tarif fixe garanti. Ce tarif d'achat est-il calculé en fonction des coûts des énergies renouvelables les plus rentables ? La Hongrie craint-elle un surinvestissement dans les énergies renouvelables les moins rentables ? Cette démarche les exclue-t-elle complètement du marché de gros ?

La Hongrie confirme qu'elle a établi un système d'achat obligatoire à un tarif fixe et garanti pour les énergies renouvelables. Ce système favorise les technologies les moins coûteuses (la compensation n'est pas suffisante pour inciter à investir dans les technologies solaires, plus coûteuses).

Par contre, en Hongrie, certains experts s'inquiètent d'un surinvestissement dans la production combinée de chaleur et d'électricité (cogénération), qui consomme du gaz naturel et bénéficie également de subventions au titre du système d'achat. Certains spécialistes sont d'avis que ce type de production peut être rentable même sans subvention. Il est difficile d'expliquer pourquoi la cogénération bénéficie du système.

Paul Wilczek (Association européenne de l'énergie éolienne) soulève le problème des règles de raccordement au réseau (énoncées dans les codes de réseau en Europe et les règles de raccordement aux Etats-Unis) qui définissent les règles techniques que toute entité doit respecter pour être raccordée à un système électrique public.

Ces codes de réseau ont été mis au point de manière indépendante dans les différents États membres. L'une des caractéristiques d'un code de réseau, ce sont les exigences de tenue aux creux de tension. À titre d'exemple, ces exigences sont très différentes en Italie, en France et en Allemagne pour ce qui est de la forme, du contenu ou du périmètre de ce qui est négociable. Un promoteur ou un constructeur de ferme éolienne, ou même un gestionnaire de réseau ne sait pas précisément ce qu'il faut faire pour raccorder un parc éolien au réseau électrique. Les documents qui constituent un code de réseau ne sont pas homogène ; ils sont souvent épars, ne sont pas disponibles dans un format simple et unique ; ils sont rarement traduits. Cela induit des coûts supplémentaires pour les fermes éoliennes, les gestionnaires de réseau et, *in fine*, pour les consommateurs d'électricité.

Il est essentiel de résoudre les problèmes d'harmonisation des codes de réseau si l'Europe veut, sans dépense excessive, atteindre les objectifs fixés pour 2020 en matière d'énergies renouvelables. Ces objectifs seront beaucoup plus coûteux à respecter si l'on ne parvient pas à surmonter certains problèmes de raccordement au réseau. Pour donner une idée de l'ampleur du problème, rappelons que, fin 2009, la puissance éolienne installée en Europe était de 75 GW. Pour que se concrétisent les objectifs de 2020, la puissance installée devra avoisiner 230-250 GW. L'EWEA prévoit une puissance installée totale de 400 GW à l'horizon 2030, dont 150 GW en mer.

Lorsque l'éolien était très peu développé, les règles de raccordement pouvaient être moins élaborées. Les quelques éoliennes raccordées au réseau pouvaient tout simplement être arrêtées en cas de défaut sur le réseau. Depuis l'essor de cette technique, les gestionnaires de réseau de transport (GRT) exigent que les éoliennes participent davantage au réglage de la tension et de la fréquence et de plus qu'elles soient moins sensibles aux creux de tension. Le problème n'est pas que les constructeurs remplissent ces exigences mais qu'ils les comprennent précisément et qu'ils déterminent celles auxquelles peuvent satisfaire les centrales éoliennes et ainsi que les obligations plus contraignantes auxquelles est soumise la production classique d'électricité.

L'EWEA pense qu'à un certain niveau d'harmonisation des règles de raccordement au réseau, les principaux problèmes pourront être surmontés. À terme, cette harmonisation devrait entraîner une diminution du nombre de règles de raccordement et rendre moins nécessaire la révision des nouveaux codes de réseau. L'EWEA travaille à cette harmonisation depuis trois ans et a proposé d'adopter une démarche en deux étapes :

- Une harmonisation structurelle : elle vise à définir un modèle commun pour énoncer les règles de raccordement au réseau en utilisant une terminologie clairement définie.

- Une harmonisation technique : elle consiste à adapter les codes de réseau existants au modèle commun ; elle sera effectuée progressivement en fonction des possibilités techniques.

L'EWEA a publié un modèle général de code de réseau en décembre 2009 et a pris contact avec le réseau européen des gestionnaires de réseau de transport d'électricité récemment créé, le REGRT-E, et avec les autorités de régulation européennes (l'ERGEG et un nouvel organisme, l'Agence de coopération des régulateurs de l'énergie, l'ACER). En vertu du troisième paquet de réformes, ces organismes sont tenus de publier un code de réseau portant sur les raccordements.

En matière d'harmonisation des codes de réseaux, l'objectif global est de permettre un raccordement efficace et rentable des centrales renouvelables qui doivent être installées d'ici 2020 et au-delà.

L'initiative intergouvernementale visant à créer un réseau électrique en mer du Nord est une démarche intéressante. Économiquement, cela n'a pas de sens de raccorder un à un en antenne tous les parcs éoliens offshore. En revanche, un réseau en mer constitué de câbles HTCC permettrait de raccorder les parcs éoliens à un poste de transformation en mer. Cela permettrait non seulement de raccorder des parcs éoliens au réseau, mais aussi de créer le un réseau international tant attendu.

En réponse à la question de savoir qui doit payer les coûts d'un renforcement « en profondeur » du réseau (par opposition aux simples coûts de raccordement), M. Wilzcek fait valoir que le réseau de transport européen a vieilli et doit faire l'objet d'investissements importants afin que le marché soit réellement intégré. Les énergies renouvelables ne font que porter les problèmes au grand jour. La mise à niveau du réseau profitera aussi à d'autres modes de production d'électricité, améliorera la sécurité de l'approvisionnement et favorisera la création d'un marché intérieur de l'énergie en Europe.

La Nouvelle-Zélande souligne que, dans ce pays, les tarifs de gros de l'électricité ne distinguent pas entre les modes de production - éolien, hydraulique ou combustibles fossiles. En d'autres termes, le prix spot sur le marché de gros est le même quel que soit le mode de production, après ajustement pour tenir compte des pertes et des contraintes locales.

Or, en Nouvelle-Zélande, l'électricité éolienne représente 5 % de la puissance installée totale, et ce chiffre continue à augmenter. Le fait que l'énergie éolienne soit un mode de production rentable dans certains endroits du pays s'explique par plusieurs facteurs, notamment :

- L'existence de nouveaux sites où installer des centrales hydrauliques : en Nouvelle-Zélande, le réseau de centrales hydrauliques est bien développé ; il produit 65 à 75 % — suivant les précipitations — de l'électricité du pays. Or il devient de plus en plus difficile de trouver, pour de nouvelles installations hydrauliques, des emplacements économiquement viables qui remplissent les conditions fixées au niveau national en matière d'utilisation des sols ou de l'eau.

- Le potentiel éolien : la Nouvelle-Zélande a la chance de se situer dans les quarantièmes rugissants, latitudes qui se caractérisent par des vitesses moyennes de vent élevées. Cette caractéristique, conjuguée au fait que la densité de population est relativement faible, a permis aux producteurs de trouver des emplacements où ils peuvent tout à la fois réaliser des économies d'échelle et obtenir des facteurs de charge qui feraient rêver les exploitants de parcs éoliens du monde entier. Ainsi West Wind, située en périphérie de Wellington, est un parc éolien de 142 mégawatts dont le facteur de charge prévu atteint 47 %,, un chiffre bien supérieur à la moyenne mondiale.

- Le risque d'erreur : même si la quantité de vent qui balaye la Nouvelle-Zélande est très grande, il ne faut pas oublier que la conception et choix de l'emplacement influent ont une grande influence sur le rendement énergétique d'une ferme éolienne. En Nouvelle-Zélande, les promoteurs de parcs éoliens savent que s'ils construisent un parc sur un site qui n'est pas optimal, ils risquent de ne pas obtenir le retour sur investissement attendu. C'est pourquoi les meilleurs producteurs et

promoteurs de centrales éoliennes ont lourdement investi afin de disposer d'une expertise interne réelle de la modélisation et de l'analyse de la conception d'un parc éolien. Ils savent maintenant choisir avec certitude des sites adaptés à la construction d'une centrale éolienne.

En Nouvelle-Zélande, les promoteurs de fermes éoliennes estiment en général que, même en l'absence de subventions, le pays dispose d'un important potentiel éolien économiquement viable, ce qui n'est pas le cas de l'énergie hydraulique. L'*Electricity Commission of New Zealand* prévoit qu'environ un tiers des nouvelles unités de production construites entre 2010 et 2014 seront des parcs éoliens. La mise en place prévue d'un système d'échange de quotas d'émissions de CO_2 devrait également contribuer à améliorer la rentabilité de la production d'électricité renouvelable par rapport aux autres modes de production d'électricité.

Le délégué du BIAC observe que sa contribution insiste sur les distorsions de la concurrence que peuvent entraîner les différentes formes d'intervention de l'État — surtout en Europe — destinées à promouvoir les énergies renouvelables. Pour le BIAC, il devrait y avoir un mécanisme de subvention plus uniforme, ce qui éliminerait certaines distorsions de la concurrence résultant des mesures différentes adoptées suivant les pays.

Le BIAC convient que, en principe, la démarche proposée par le Président (selon laquelle les consommateurs doivent payer pour l'électricité un prix qui tienne compte des atteintes à l'environnement) est, de prime abord, bien plus séduisante qu'un mécanisme de subvention partiellement harmonisé. S'il préconise de mettre en place un mécanisme de subventions plus uniforme à l'échelle européenne, dans un premier temps, c'est que cette démarche lui semble un moyen pratique, concret et réalisable d'avancer.

Le Président invite les États-Unis à proposer quelques réponses à la liste de questions qui figure dans la conclusion du document qu'ils ont soumis, dont notamment : quelles sont les modifications de la réglementation à opérer afin de disposer d'incitations propices aux investissements dans les énergies renouvelables ? Et, dans la mesure où les technologies des réseaux intelligents permettent d'atteindre des objectifs non rentables, comme la protection de l'environnement ou la fiabilité du système électrique, les États devraient-ils être prêts à investir ?

Un délégué des États-Unis répond tout d'abord à la question portant sur le rôle des investissements publics. Comme indiqué dans le document soumis par les États-Unis, le gouvernement américain a engagé plusieurs investissements dans les énergies renouvelables, dont la plus grande partie (4.5 milliards USD) est consacrée aux réseaux intelligents. Pour plus de détails, se référer au document présenté par les États-Unis.

Pour ce qui est des changements à apporter à la réglementation, ce délégué note que les responsables continuent de tirer des enseignements des recherches (comme celles effectuées par Frank Wolak) qui visent à déterminer quel est le meilleur moyen d'inciter les consommateurs et les entreprises à effectuer les mises à niveau nécessaires et à entreprendre des projets dans le domaine des réseaux intelligents. Toute initiative par laquelle des concurrents potentiels ou réels envisageraient de collaborer ou de s'associer d'une manière ou d'une autre serait examinée dans le cadre des directives conjointes FTC/ministère de la Justice en matière de collaboration. La question de l'harmonisation des codes de réseau qui a été évoquée constitue un exemple de normalisation. Le document soumis par les États-Unis examine certains problèmes que pose la normalisation en termes de concurrence.

Luca Lo Schiavo (Italie) observe que l'Italie a mis en place un système complexe d'incitations en faveur des énergies renouvelables. L'autorité de régulation a déjà indiqué officiellement au Parlement que certaines de ces incitations pouvaient être trop généreuses, notamment pour les toitures photovoltaïques. Il y a un risque que les bénéfices de ce type d'investissements soient inférieurs aux coûts.

Il passe ensuite à des aspects particuliers de l'énergie éolienne. Aujourd'hui, dans certains pays européens (y compris l'Italie), les centrales éoliennes ne sont pas redevables des charges d'ajustement. Les charges d'ajustement sont les charges supplémentaires qui sont dues si la production réelle de la centrale est différente du niveau prévu. Cette décision a été prise en raison de la difficulté qu'il y a à prévoir les conditions de vent. Or, au fil des ans, les techniques de prévision de la production éolienne se sont améliorées. Les producteurs éoliens devraient donc désormais être tenus de payer des charges d'ajustement, comme c'est le cas dans certains pays européens.

En Italie, une solution possible serait de mettre en place progressivement une réglementation qui permette aux producteurs éoliens de disposer des incitations ad hoc pour prévoir avec précision la force du vent, sans toutefois instaurer à ce stade des charges d'ajustement (celles-ci pourraient être envisagées dans un proche avenir). Par ailleurs, en raison de l'essor de l'éolien, il faut augmenter les capacités du marché des réserves, ce que permettraient les technologies de l'information. Les réserves d'un État pourraient ainsi être exploitées dans un autre. Bien sûr, des renforcements de réseaux s'imposeraient, un objectif prioritaire des autorités de régulation européennes, et notamment du régulateur italien.

En réponse à une question sur les heures de clôture des guichets (6 heures ou 24 heures à l'avance), Luca Lo Schiavo signale un document mis en consultation qui porte sur l'intégration de l'énergie éolienne (disponible sur www.energy-regulators.eu). Les heures de fermeture des guichets sont extrêmement variables au sein de l'Union européenne. Mais M. Lo Schiavo revient sur l'importance des charges d'ajustement : en l'absence ces telles charges, peu importe que les guichets ferment 24 h, 8 h ou 6 h à l'avance. La vraie question est de rendre les producteurs davantage responsable des charges d'ajustement qu'ils génèrent. Si l'on facture les charges d'ajustement aux centrales éoliennes, il faut en général réduire l'écart entre heure de fermeture des guichets et production d'électricité afin que ce type de centrales ne soient pas désavantagées par rapport aux autres, étant donné qu'elles ne peuvent faire des prévisions de production que quelques heures à l'avance.

Paul Wilczek est également d'avis que, en l'absence de marchés d'ajustement internationaux, l'intégration de grandes quantités d'énergie éolienne sur le marché de l'électricité se traduirait par des coûts élevés. Sur la question des heures de clôture des guichets : tout producteur éolien sera disposé à payer les charges d'ajustement si les heures de clôture sont adaptées, c'est-à-dire aussi près que possible du temps réel. Dès lors que les charges d'ajustement sont transparentes et reflètent fidèlement les coûts, il est raisonnable de décider de les imposer aux producteurs éoliens.

M. Leigh Hancher observe qu'il est pratiquement impossible de parvenir à une harmonisation des heures de clôture des guichets au sein de l'UE. Pour ce qui est des marchés d'ajustement internationaux, il n'y a pas de concurrence car les GRT ne souhaitent pas autoriser les échanges internationaux, sauf pour ce qui les concerne. Ils ne tiennent pas à ce que d'autres fournisseurs viennent les concurrencer sur le marché international de l'ajustement.

David Elzinga (AIE) répond à une question du Président sur le fait de savoir s'il ne serait pas plus simple et préférable d'avoir recours à des taxes et à des charges pour refléter le coût réel des modes de production classiques de l'électricité plutôt que de subventionner des modes de production spécifiques. En général, l'AIE encourage le recours à des charges qui internalisent les coûts externes, mais estime que, sur un plan politique, le public n'est pas encore prêt à accepter cette idée. C'est pourquoi l'AIE continue d'être favorable à des subventions/interventions ciblant des technologies spécifiques. Même les cas de surchauffe du marché, celui de l'énergie solaire en Espagne, par exemple, fournissent des informations qui permettent d'imaginer des interventions mieux conçues sur d'autres marchés autour de diverses technologies. Nous ne pouvons pas attendre que le fait d'imposer des charges sur la production classique d'électricité soit acceptable socialement et politiquement si nous voulons atteindre les objectifs que nous nous sommes fixés pour 2050.

Le Président conclut la table ronde par les points suivants :

- Les compteurs intelligents et la tarification dynamique vont de pair. Les clients ne pourront pas tenir compte de la rareté dans le secteur de l'électricité en l'absence de tarification dynamique, tarification qui impose d'installer des compteurs intelligents.

- La séparation de la propriété du réseau, d'une part, et de la production et de la vente au détail, d'autre part, engendre des problèmes spécifiques pour ce qui est des investissements dans les réseaux intelligents, car ceux-ci peuvent nécessiter une coordination entre le réseau et la vente au détail. Il conviendrait d'aborder à nouveau cette question lors des discussions sur la recommandation concernant la séparation structurelle.

- Sur un plan politique et technique, il est très difficile d'imposer aux pollueurs de payer des taxes ou des charges. Néanmoins, les subventions devraient être plus neutres qu'elles ne le sont aujourd'hui d'autant que la part de marché des énergies renouvelables augmente. Pour améliorer le fonctionnement des marchés, il serait préférable d'instaurer un mécanisme d'enchères à la place des tarifs d'achat qui évitent aux énergies renouvelables la concurrence et les excluent du marché de gros de l'électricité.

- Enfin, se pose le problème de l'intégration de marchés nationaux indépendants. La question a été abordée du point de vue du marché de l'ajustement et de l'intégration des énergies renouvelables en Europe, mais le problème se pose à tous les pays de l'OCDE. Le volume des échanges d'électricité transfrontaliers reste limité. Si l'on veut augmenter la part des énergies renouvelables dans la production, il sera nécessaire d'intégrer davantage les marchés de l'électricité, ce qui suppose une meilleure intégration des réseaux de transport.