

# Energy Regulation in a Low Carbon World

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A chapter for  
Harnessing Renewable Energy  
edited by Boaz Moselle, Jorge Padilla and Richard Schmalensee

4 January 2010

## 1. Introduction

Increasing the use of renewable energy will have significant impacts on the operations of energy utilities – the companies that deliver electricity and gas to consumers using networks of wires and pipes. As discussed in chapter 2, many renewable energy technologies are very different from the traditional large-scale, centralized, technologies that utilities have relied on for over 100 years. Electricity transmission and distribution system operators will have to become used to taking power from many smaller generators, distributed around the system, while larger-scale renewable generators are often sited far away from the major loads. Other renewable electricity may be self-generated by consumers and firms, and electric utilities would then provide a residual service – or perhaps would install and maintain those self-generators. Gas utilities may find that the demand for their product falls significantly, as consumers switch to renewable sources of heat.

If the utilities' operations are changing, should this affect their regulation? Some principles of regulation, such as the need for transparency and stability, will surely remain unchanged. What about the way in which these principles are put into practice? Should the scope of regulation, the activities subject to an economic regulator, be broadened (or narrowed) as the amount of renewable generation grows? Should the regulator's objectives change, or the factors it takes into account when deciding how to achieve those objectives? How are its decisions likely to change?

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\* I would like to thank the editors, Chris Hemsley, Andrew Quinn and participants at the Centre for Competition and Regulation Policy Workshop held at Aston Business School, July 2009, for helpful comments. The views expressed are mine alone. This work was supported by the Birmingham Science City Energy Efficiency and Demand Reduction Project, funded by Advantage West Midlands and the European Regional Development Fund.

The next section of this chapter discusses the scope of economic regulation, and its interaction with energy policy. Section 3 sets out four models of economic regulation for the energy utilities, ranging from the “retail competition” model used in the Nordic countries, the UK and some US states (e.g., Texas), in which only the natural monopoly in delivery (i.e. transmission and distribution) is regulated, through a “wholesale competition” model in which unregulated generators provide power, but the prices paid by (at least some) retail customers are regulated (as in France, Spain and some other US States) and a “single buyer” model in which a regulated entity is responsible for procuring power through competitive tenders (as in some developing countries) to the “integrated firms” model in which regulators have to oversee most of the industry’s value chain (as in those parts of the United States that have not adopted liberalization policies).

Section 4 goes into more detail about how the increase in renewable energy will affect the electricity industry. The fifth section draws out some general implications of these changes for economic regulation, which will apply regardless of the specific model chosen. Section 6 discusses lessons which are specific to the particular tasks facing regulators, which vary according to the regulatory model chosen. Finally, section 7 concludes. While the electricity industry will see the biggest changes, an epilogue discusses possible impacts on the gas industry, and lessons for its regulation.

## 2. The scope of economic regulation and energy policy

What do I mean by economic regulation? I will concentrate on the prices and service standards offered by an industry which is (perceived to contain) a natural monopoly, which are regulated by its government or a government agency. It is thus distinct from competition policy, which applies to industries where competition is believed to be possible, and from health and safety standards and environmental regulation.

Traditionally, the concerns of an economic regulator have been to protect consumers from high prices and to protect investors in the utilities from low prices. This does not mean that consumers and investors have diametrically opposing interests, however. In the short term, it might be possible to reduce the utilities’ prices without ill effects, but in the long term, this is likely to make the companies unsustainable, unable to raise the funds needed to expand or even maintain their

capital equipment. Spiller and Viana Martorell (1996) document what happened when some governments in Latin America reduced electricity prices below the level of long-term viability – the eventual outcome was nationalization. Only when new systems of regulation were created, with sufficient protection for investors, was it possible to re-privatize the companies.

From this perspective, the regulator can be seen as balancing two objectives, both of which are actually in the interests of consumers. First, there is the objective of minimizing the price of energy. Second, the need to give the utility sufficient funds can be seen as contributing towards the objective of ensuring a secure supply of energy. To achieve this objective, it is necessary to go beyond simply providing the utilities with adequate funds (and beyond the scope of regulation), as (for example) the security of supply of imported energy is a concern of foreign policy for many countries. Nonetheless, if the industry's capital stock suffers because the utilities lack resources, the country's security of energy supply will quickly fall.

This emphasis on security of supply may be an unusual way of framing a regulatory issue, but security of supply is a key objective of energy policy for governments. The United States Department of Energy has five strategic themes, the first of which is energy security, defined as “promoting America's energy security through reliable, clean and affordable energy”. The European Union's 2006 Green Paper on Energy set three core objectives: sustainability, competitiveness and security of supply. The UK has four goals for energy policy, including goals related to the environment (“to put the UK on a path to cut our carbon dioxide emissions by some 60% by about 2050, with real progress by 2020”), to security of supply (“to maintain reliable energy supplies”) and to the cost of energy (“to ensure that every home is adequately and affordably heated”) (Department of Trade and Industry, 2003).<sup>1</sup>

Energy policy thus commonly adds a third goal – achieving a low environmental impact – to the two that have (as reinterpreted) traditionally concerned regulators – achieving low prices while ensuring sufficient investment to maintain security of supply. These three goals are often portrayed as the corners of a triangle, since they may often appear to conflict. Diversifying energy sources can increase security of supply, but if it involves raising the share of higher-cost resources, it will act against

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<sup>1</sup> The fourth goal, “to promote competitive markets in the UK and beyond, helping to raise the rate of sustainable economic growth and to improve our productivity” is also related to the price of energy, although I would argue that a competitive market is a means to an end rather than an end in itself.

the objective of keeping prices down. Adding pollution control equipment will reduce environmental impacts and raise prices. In some countries, coal is seen as a more secure primary fuel than oil and gas, but the carbon dioxide (and local pollutant) emissions from burning coal, and hence its environmental impact, are higher. At other times, however, a new development (and particularly a new technology) may further all three goals at once – the introduction of Combined Cycle Gas Turbine generators in the UK in the 1990s raised security of supply by diversifying away from coal (which then dominated the industry’s fuel mix),<sup>2</sup> reduced the environmental impact from sulfur emissions (and also from carbon dioxide, which was not then a priority for environmental policy) and was also cheaper than building coal-fired stations when new investment was required (Newbery, 1999).<sup>3</sup> Increasing the efficiency with which energy is used will tend to reduce the cost and environmental impact of a given level of energy services – that is, heat and light, rather than gas or electricity. This generally leads to lower overall levels of energy consumption, which will increase security of supply by cutting the amount of primary energy required.<sup>4</sup>

### 3. Models of regulation

The way in which an industry is regulated has to reflect its structure. In the past, this did not (in itself) cause any variation in practice, because practically all of the energy utilities were either vertically integrated monopolies or part of a chain of monopolies. We can distinguish several stages – electricity generation (or the production of gas) is the first, followed by high-voltage (or high-pressure) transmission over (potentially) long distances. Distribution at lower voltages or pressures takes the electricity or gas to the consumer, and was traditionally defined to include the sales transaction as well. Full energy liberalization, however, is based on the idea that retailing (called supply

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<sup>2</sup> While an indigenous source of supply would normally be seen as secure, miners’ strikes caused major power cuts in the 1970s and threatened them in 1984-5, and so diversification away from coal reduced the risk of a recurrence.

<sup>3</sup> In practice, much of the new investment was made before additional capacity was actually needed, because market power raised prices and made entry attractive, and may have raised the industry’s costs in the short term.

<sup>4</sup> The demand for energy services is likely to increase because of their lower effective price (the so-called direct rebound effect – as comfort becomes cheaper, people like to be more comfortable) and because the money saved in one area will typically be spent on other goods and services that also consume energy (an indirect effect). Sorrell (2007) reviews the evidence for this and concludes that in developed countries, the direct rebound effect is between 10% and 30% of the energy saving per unit of energy services. The evidence on indirect effects is inconclusive, but they may be quite large (more than 50% of the initially predicted energy saving).

in the UK) can be separated from distribution. Gas utilities might buy their product from oil companies, and some industrial self-generators would sell surplus power to the electricity grid, but the rest of the industry was monopolized. Regulators accordingly concerned themselves with the final prices charged to end consumers, and the intermediate prices used when a regional or national utility sold gas or power to a smaller firm for local distribution.

This started to change once competition was introduced to the energy utilities. Once it was realized that the natural monopoly at the heart of each industry only covers its network, then other companies could be allowed to use that network, whether they were producing energy or selling it to consumers. The first experiments were for limited competition in electricity generation, in the United States, (where the Public Utilities Regulatory Policies Act of 1978 required utilities to buy power from certain kinds of rival generators at their avoided cost of generation) and in Chile, where the 1982 Electricity Act led to the creation of several regional spot markets<sup>5</sup> (Pollitt, 2004). The privatization of the gas industry in Great Britain went further, as independent companies were meant to compete to sell gas to large consumers, and the privatization of electricity included a timetable which would culminate in every consumer in the country having a choice of electricity supplier (retailer). Many other countries followed suit, and the EU adopted a pro-liberalization policy in 1996, and committed itself in 2003 to introducing full retail competition by 2007 at the latest. Despite this commitment, not all Member States have achieved (or perhaps wish to achieve) the same level of competition in practice. Similarly, in the United States, 13 states and the District of Columbia have implemented retail competition and others participate in Regional Transmission Organizations that run organized wholesale markets, but nearly half do not.<sup>6</sup> This means that moves to increase the share of renewable energy need to be studied in the context of a range of regulatory systems.

These systems differ in terms of the activities that the regulators have to carry out. Do they need to regulate the prices paid by consumers? Are there separate prices for

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<sup>5</sup> The prices in these spot markets, and for longer-term sales, were calculated based on estimated marginal costs, rather than from freely submitted price offers.

<sup>6</sup> Source: Energy Information Administration web site, November 2009. The map of Regional Transmission Organizations (which do not map neatly on to state boundaries) shows 20 states with little or no coverage. Even in those states, however, there may be some bilateral trading.

using the network which need to be regulated, or are the costs of the networks simply bundled into the consumers' prices? Are the costs of generation subject to regulation?

For the purposes of this chapter, I will define four different models of regulation, shown in figure 1. The first is that of retail competition. This is the minimalist model of regulation, in which the regulator's activities are largely confined to the natural monopoly of the network of pipes and wires, and the system operation. For this model to work well, there must be effective competition, both in electricity generation or gas production, and in retailing. If retail competition is effective then there is no need to regulate prices to end consumers, since retailers will be forced to set prices close to their costs of buying energy, paying to use the network and dealing with their customers. Similarly, prices in the wholesale market can (in general) be set by the normal processes of competition. The caveat is needed because of the special features of electricity, a non-storable product which must be delivered through a transmission network subject to complicated (and interacting) physical limitations. The demand for electricity is very inelastic in the short term, not just because it cannot be stored but also because most customers do not see the real-time price of power. These features make it possible for even companies with low market shares to exercise market power at particular times, or in particular parts of the country, and so a system of wholesale market monitoring is often needed to ensure that this is not abused. Even so, this market monitoring should be seen as a special form of competition policy, rather than of economic regulation.

Figure 1: Models of regulation

	Generation	Transmission / distribution	Retail
Retail competition	Competitive	Regulated prices	Competitive
Wholesale competition	Competitive	Regulated prices	Regulated prices
Single buyer	Tendered	Regulated	Regulated prices
Integrated firms	Regulated		Regulated prices

The regulator's role under the retail competition model is to ensure that the prices for using the network are appropriate, and that all companies have equal access to it. If the network owner is still integrated into the other stages of the industry, this can be hard to ensure, as there are many ways for an unscrupulous operator to limit its competitors' access to the network.<sup>7</sup> The best solution to this problem is to separate the role of system operator from any commercial user of the network, either by banning network owners from the other stages of the industry, or by creating an independent system operator (ISO) to control the assets owned by companies active in production, generation or retailing. An ISO has the advantage that it can coordinate operations over a wider area than a single company, which will be useful if the historic pattern of asset ownership has created a patchwork of systems that would be inefficiently small if operated separately. At the same time, an ISO may not be as effective in pushing through a program of capital investment in the networks of independent firms as a single network company would be.

It is worth noting that the problem of discrimination between network users has historically been much less important at the distribution level than in transmission. Energy sources (power stations or gas fields) are usually connected to the transmission system rather than to distribution. Even when a (large) power station was connected to the distribution system, it was usually the transmission operators who controlled its ability to operate. At the retail level, it was practically impossible for a distribution system operator to discriminate between customers of different retailers in terms of the quality of energy supply, since all the customers connected to the same segment of the network would receive their supply under the same physical conditions. The regulatory requirements for keeping networks separate have therefore typically been weaker than with transmission, particularly for smaller utilities.<sup>8</sup>

I will call the second model "wholesale competition". This is one in which there is effective competition in generation, based around an active wholesale market, but competition in retailing is limited or non-existent, and so final prices to consumers are

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<sup>7</sup> For example, the network operator might deny access on spurious grounds of system security (i.e., that the network would be vulnerable to failure if power flows from the entrant's area increased), fail to invest in new infrastructure that would facilitate access, or institute a "margin squeeze" through setting excessive prices for ancillary services.

<sup>8</sup> For example the EU's second electricity and gas directives allow Member States the choice of whether to exempt utilities serving fewer than 100,000 customers from the requirements for legal separation between distribution and retailing that are otherwise compulsory (European Commission, 2003a, 2003b).

regulated, as well as the charges for using the networks. This might be a transitional phase – if competition has recently been introduced, and is becoming stronger, but most customers are still with the original incumbent retailers, then some protection can be appropriate.<sup>9</sup> In some EU countries, there is so little competition to serve domestic customers that this transitional phase may appear permanent, even though the market is officially open. It is also possible as a permanent policy to restrict competition to the wholesale market only, if policy-makers are uncertain of the benefits of retail competition and do not wish to incur the transactions costs of implementing it. There need to be enough separate buyers in the wholesale market to avoid a monopsony, but a market covering several regional (or sub-regional) retail monopolies will meet this condition. In the United States, Vermont and West Virginia participate in regional wholesale markets (ISO New England and PJM respectively) without opening their retail markets to competition.

A third model, which has been applied in a number of developing countries, is to have a “single buyer”. This is a regulated entity that is responsible for procuring electricity from generators, but through contracts rather than a wholesale market. The industry may be too small for adequate competition between generators, or policy-makers may distrust the market’s ability to deliver enough capacity, particularly in a system facing high demand growth. The use of long-term contracts is important, since electricity generation has very high sunk costs, and a producer selling to a single organization without the protection of a contract risks being held up for a lower price once their investment is complete. When the European Commission designed a single buyer model, it made it equivalent in its effects to (limited) retail competition, but most countries that actually use this model combine it with monopolies in retailing.

This means that prices to end consumers must be regulated, as with the wholesale competition model. It is likely, however, that there is no longer a need to regulate prices for transmission and distribution, for these may not exist. Generators will have agreed the terms for connecting to the network as part of their long-term contracts, and since these would be agreed before an investment decision is made, they should provide sufficient protection to both parties. If the generators know that they will

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<sup>9</sup> In Great Britain, the incumbent retailers faced price controls when selling to domestic customers until 2002, even though all customers had a choice of retailer by mid-1999. In contrast, price controls for medium-sized commercial and industrial electricity customers were lifted as soon as this market was opened to competition in 1994, in the belief that these buyers were more sophisticated and could protect themselves by shopping around.

have to make payments to use the network, they will seek higher prices from the single buyer.

While there may not be formal prices for using the network, the regulator will still have to oversee its revenue requirements, ensuring that the amount recovered from consumers is reasonable. Figure 1 thus describes this part of the industry as “regulated” without specifying that it has regulated prices. The cost of generation should be kept down by competitive tendering, and then passed through to consumers (just as adequate competition in a wholesale market should keep down the amount that regulated retailers could charge in our second model).

I will call the fourth and final model of regulation one of “integrated firms”. This does not mean that a vertically-integrated monopoly is responsible for every stage of gas or electricity supply. It may well be that there is vertical separation between the utilities responsible for energy production (or import) and transmission, and those responsible for distribution and retailing. The German electricity industry has a three-layer system of “interconnected”, “regional” and “municipal” utilities, with the interconnected utilities owning almost all of the transmission system and much of the generation, but regional and municipal utilities delivering energy to about two-thirds of customers (Schulz, 1995). The model is also compatible with a utility that buys some of its gas or power from third parties, but without the separation implied by a formal “single buyer”. Independent power producers who sell power as their main business would need the protection of a long-term contract, but industrial self-generators with occasional surpluses of power could sell these under short-term deals.

In this model, generation is now regulated, as well as the networks. The regulator must oversee final prices for all consumers, and there may be no intermediate prices to regulate, although if a large utility sells gas or electricity to a smaller one, the regulator may also need to oversee this transaction to ensure that excessive costs are not passed on.

The main challenge for regulators – under any model – is to ensure that prices are high enough for the utility to recover efficiently incurred costs, but not so high that consumers are exploited. The regulator can generally measure what a utility’s costs actually *are* (assuming that competent accountants are available, and with a caveat concerning the cost of capital), but it is a different matter to measure what the costs *could be*. When there is only one firm being regulated, the regulator can only extrapolate from past trends, adjust for predicted changes in the future, commission

efficiency studies from consultants, and perhaps make comparisons with firms in other jurisdictions, hoping that their environment is sufficiently similar to make the comparison valid. When the regulator must deal with several firms, it is possible to make comparisons among them, on the principle of yardstick regulation (Shleifer, 1985). If the firms face sufficiently similar operating environments, then there should be no reason why all firms could not reach the level of the best performers, and their prices should be set to reflect this. Good performers could expect to receive more than the cost of capital, while firms with higher costs would not be able to do so until they cut those costs. In practice, of course, some of the differences in operating environments will be significant, and so regulators will have to adjust for these (Pollitt, 2005; Jamasb and Pollitt, 2007). The difficulty of doing so is why competition, where possible, generally gives better incentives to firms than even the most enlightened regulation.

#### 4. Utilities in a low-carbon world

How will the move to a lower-carbon energy system affect the energy utilities? Many countries (and US States) have adopted targets for renewable energy, and the European Union now has a legally binding target for 2020, that 20% of its final energy consumption shall come from renewable sources, as discussed in chapter 4. Given the resources available for renewable heat and transport, and their costs, the proportion of renewable electricity will need to be well above 20%.

We have been using renewable generation for as long as the electricity supply industry has existed – the world’s first public electricity supply, installed in 1881 in the Surrey village of Godalming, was hydroelectric (Hannah, 1979). A number of countries, both developed and developing, get much or all of their electricity from hydropower. Most developed countries, however, have developed most of their available large-scale hydro resources, prohibiting some potential developments for environmental reasons – though there are opportunities to develop small-scale schemes. Further increases in renewable energy are therefore likely to come largely from burning biomass (including waste) and from wind power. In some countries, solar photovoltaic power may be a sensible option (but not in this author’s northerly, frequently cloudy, home), while others are surrounded by seas containing significant

energy in their currents, tides and waves. Devices to harvest this energy are being developed, but are still mostly at the prototype stage.<sup>10</sup>

Most renewable generation will cost more than conventional alternatives, excluding externalities, unless the price of fossil fuels rises dramatically. In most cases, this is because of high capital costs – several renewable technologies get their “fuel” for free. Biomass generation is the main exception for which fuel costs are a significant part of the whole. Large-scale hydroelectric generation was generally a low-cost energy source, although few sites remain available, and wind turbines at particularly good (windy) locations onshore appeared quite competitive with fossil-fuelled power stations at the high energy and carbon prices of early 2008.

These high costs mean that companies will not be willing to build most types of renewable generators unless they are required to, or are offered financial support. Chapter 8 discusses the various mechanisms that can be used to achieve this.

Table 1: EU electricity generation from renewable sources

	Generation in 2006		Potential for 2020, Green-X model, Least cost scenario	
	TWh	Per cent	TWh	Per cent
Biomass	90	17%	186	14%
Geothermal	6	1%	7	1%
Hydro	344	66%	398	30%
Solar	3	0.1%	62	5%
Marine	1	0%	124	9%
Wind	82	16%	545	41%
	522	100%	1,323	100%

Source: European Commission (2007)

The EU target for renewable energy leads to a wide range of national targets (related to each country’s income and existing level of renewable energy), and the mix of

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<sup>10</sup> An exception is the tidal barrage at La Rance in France, which is effectively a hydroelectric scheme (a very mature technology) built across an estuary rather than an inland river – a similar scheme across the Severn Estuary in the UK could generate 5% of the country’s electricity (DECC, 2009b), at the cost of significant changes to the local ecosystem (and £21 billion).

renewable sources used will obviously vary between countries. Table 1 gives a set of estimates prepared for the European Commission, giving a mix of sources predicted to minimize the cost of meeting the 20% target for renewable energy. The use of biomass and hydroelectricity will increase, but their percentage share of renewable generation would fall. Solar and marine energy would increase from very low levels at present. By far the greatest increase would come from wind generation, which might provide more than one-sixth of Europe's electricity in 2020.<sup>11</sup>

This level of wind generation will lead to significant challenges in dealing with intermittency. Large-scale wind generators only reach full output at wind speeds between around 12 and 25 meters per second, shutting down at higher speeds, and losing power rapidly when the wind is low.<sup>12</sup> A well-sited turbine might have an average output equal to 30% of its rated capacity over the year, but the actual output will vary sharply over time, and meaningful predictions are impossible more than a few days in advance. In regions where clouds are rare, the main factor affecting the output from solar power will be the earth's predictable rotation (although in regions with variable cloud cover, this will have a significant effect on solar output) and tidal energy can be predicted years in advance – but will sometimes be highest at off-peak times. Biomass generators can run when the user chooses, but if these users are households or small businesses with combined heat and power units, they may choose a heat-led operating pattern that does not necessarily produce power at the times it would be most useful for the electricity industry (Hawkes and Leach, 2007).

Intermittent outputs from renewable generators cause two main problems. First, the system operator will need to keep more plant in reserve for times when the level of renewable output suddenly falls. This particularly applies to wind output, since most other renewables are more predictable over the relevant timescales (of a few hours).<sup>13</sup> Gross *et al* (2006) have estimated that these reserves would cost £2 to £3 per MWh of intermittent renewable energy if the UK was to get 20% of its electricity from wind. Note that the system operators always have to keep some plant

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<sup>11</sup> While wind energy would be 41% of renewable generation in this scenario, 43% of electricity generation would be renewable, giving an overall penetration of over 17%.

<sup>12</sup> The range can vary between turbine designs; GE's 3.6 MW offshore wind turbine does not need to cut out until the wind reaches 27 m/s, but needs a speed of 14 m/s to reach full output, whereas its 1.5 MW 1.5xle onshore design can reach full power at a speed of 11.5 m/s, but cuts out after 10 minutes averaging 20 m/s.

<sup>13</sup> Individual photovoltaic units could have volatile outputs on a partly-cloudy day, producing much less when a cloud moves overhead.

in reserve in order to respond instantly if a power station fails, but it has traditionally been sufficient to set this reserve equal to the size of the largest unit running on the system – the worst case for a single failure. If the wind drops over a large area, many separate wind turbines, with a greater collective capacity, could be affected. The level of reserve plant (or demand reduction potential) needed to cover this risk naturally grows with the amount of wind generation, and the system reserve requirement is the greater of that required by wind stations and by conventional plant. The rules of the system (either those of the wholesale market, or the regulation of the system operator, depending on where the responsibility for providing these reserves lies) will have to ensure that these can be paid for.

The second problem is that the wind (or the tide) may not be available at the time of peak electricity demand, which is what determines the total amount of capacity needed on the system. Not all of the capacity of a conventional plant can be counted against this need, as it may be unavailable at the critical time, but it is generally sensible to assume that over 80% will be. The risk that many wind generators will be becalmed at the same time is greater, however, and the effective contribution of a portfolio of wind power stations to ensuring ability to meet peak demand has been estimated at only 20% (or less) of their total capacity.<sup>14</sup> This means that 10GW of additional wind power could only replace 1-2 GW of conventional stations, in terms of planning to meet the peak demand. The energy produced by the wind stations could actually replace the output of around 3.5 GW of conventional plant, if the time of delivery were irrelevant.<sup>15</sup> In other words, between 1.5 GW and 2.5 GW of conventional plant is needed (per 10 GW of wind) because we cannot know whether wind stations will produce when we most want them to. Gross *et al* (2006) predict that this would cost between £3 and £5 per MWh of wind energy in UK conditions. The wider the geographic dispersion of the wind stations, the lower this penalty will be – as long as this dispersion reduces the correlation between their outputs, and there is enough transmission available.

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<sup>14</sup> Gross *et al* (2006) give a range from 19.1% to 26% for Great Britain, if we were to get 20% of our energy from wind – somewhat less than is now planned. The UK government uses a range of 10-20% for the larger quantities expected (House of Lords, 2008b, q 484) and E.ON UK has suggested that the figure should be less than 10% (*ibid*, p. 107).

<sup>15</sup> This assumes that the wind generators have a load factor of 28%, and the conventional generators one of 80%, which is rather low, but produces round numbers in the example – both sets of stations would produce an average output of 2.8 GW.

Note that both of these problems are far less severe in a system with (or connected to) large amounts of hydro generation with reservoir storage. The output from hydro generators can respond inversely to the output from wind, storing energy in the form of water until it is needed. The cost of short-term reserve to cover variations in wind output is very low, since it costs almost nothing to keep a hydro station ready to increase output at short notice. At most hydro stations, the reservoir is not large enough to keep the generator running through the year, and so the system can only provide enough energy (over the year as a whole) if it has more than enough capacity to meet the peak demand. In this context, the risk that a wind generator will not be available at the peak time is less important.

In a system with little hydro generation, the inevitable consequence of increasing the variable output from wind generators is that the output from conventional generators will also tend to be more volatile, except to the extent that demand side response takes up the slack. Sometimes, the output from wind stations will rise at the same time as demand, reducing the increase required from conventional stations, but at other times, demand and renewable outputs will move in opposite directions, increasing the strain on the system. There will also be some stations that are needed for the times when high demand levels coincide with low wind speeds, but do not run very often. It will be important to ensure that these generators can cover their costs.

Demand response can reduce the need for peak capacity, cutting the industry's costs (Borenstein, 2005). Some response can be made without consumers noticing, such as delaying the start of water heaters or refrigerator motors when prices are particularly high (or responding to some other signal, such as system frequency). Some industrial customers have long been used to scheduling energy-intensive processes away from the times when power is most expensive, although this rescheduling is likely to involve some costs. The likely growth of electric vehicles offers a good opportunity to increase the "unnoticed" element of demand response, simply by ensuring that the vehicles mainly charge themselves during low-demand periods overnight, although it will be important to ensure that the vehicle is sufficiently charged by the time it is needed. Electric vehicles have a significant advantage over most other forms of energy storage, in that the battery is needed in any case, and so this kind of use by the electricity industry is essentially a free good. Car batteries could also be discharged when the industry is particularly short of power, but

imposing additional cycles of deep discharging and recharging would shorten the battery's life. Given the cost of batteries, this would be an expensive source of electricity.

Moving on to network issues, in many countries significant investments will be needed to accommodate an increase in renewable generation (Pollitt and Bialek, 2008). Many of the best sites for renewable generators are remote from the centers of demand, and transmission lines will be needed to move the electricity to where it is needed. Most renewable generators are on a much smaller scale than conventional centralized power stations, and so many separate schemes, each with its own grid connection, may be needed to replace a single large conventional station. Since the renewable schemes are generally smaller, their connections will often be to the distribution networks, rather than to the transmission system. This will certainly be the case where self-generation, or community-owned small-scale generation, is concerned.

Connecting large amounts of generation to the distribution networks will require significant changes in their operating practices. Broadly speaking, transmission networks have always been operated to accept two-way flows across every line in the system, but distribution systems have generally been designed to take power in one direction only, from the connection with the transmission system, to the customer.<sup>16</sup> If power always flows in one direction, the design of the system is simpler, and protection equipment against power surges is only needed on one side of the substation it is intended to protect. If power could suddenly flow from a generator located on the customer side of the substation, then extra protection equipment is needed, and it will be necessary to manage the flows on the distribution network in a much more active manner. This requires additional equipment to monitor conditions in real time, and operating practices that respond to them. Local generators and loads may have to change behavior in order to keep power flows within acceptable limits. Greater monitoring, however, can also change those limits. For example, windy conditions allow the heat from power flowing through the network to dissipate more easily, increasing the safe operating limit at the very times when the output from nearby wind farms will be at its greatest (Douglas, 2005).

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<sup>16</sup> Some power stations have been connected at distribution voltages, of course, particularly at the higher voltages close to the transmission system, but on a limited scale compared to the likely growth of distribution-connected renewable generation.

Finally, it is worth mentioning another change that is not directly connected to the growth in renewable energy, but is clearly linked to the move towards a low-carbon energy system. This is the adoption of carbon trading, first in the European Union, and now in parts of the United States.<sup>17</sup> The need to buy permits raises the marginal cost of generation from fossil fuels, even if the generator receives those permits for free.<sup>18</sup> This will tend to raise the wholesale price of power produced by a given capital stock – in a fully competitive market, the price would rise by the price of emissions, multiplied by the carbon content of the marginal plant.

In the longer term, the level and composition of the industry's capital stock may change because of carbon trading. First, if generators receive some permits free of charge, conditional on the existence of a power plant, then the value of those permits can be offset against the cost of keeping the station open. This may allow the station to remain open when its revenues from the electricity market alone would not justify this. This could lead to a market equilibrium with a greater amount of capacity, which would tend to depress the price of power, partly offsetting the impact of the carbon price (Green, 2005).

A more significant change to the capital stock should be that compared to high-carbon power stations, low-carbon generators become relatively more attractive. Natural gas will gain relative to coal, and there is already talk of nuclear power enjoying a renaissance in the US and the UK. Many countries are promoting demonstration schemes for carbon capture and sequestration, and could compel generators to fit it to new plants (and perhaps even to retrofit it to existing ones) once the technology is proven. If the carbon price rose to a sufficiently high level, and was expected to remain there, carbon capture would be economic without government compulsion. The price within the ETS, however, has never reached this level, let alone staying there for long enough to make such investments attractive.

This also applies to renewable generators. If they receive a wholesale price that has been increased by the cost of carbon emissions, this will reduce their need for additional support. Likely levels of carbon prices, however, are unlikely to make most renewable generators competitive with gas-fired or nuclear generators, at least given the costs expected in the UK (Department of Energy and Climate Change, 2009a).

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<sup>17</sup> Federal legislation for a nationwide scheme is being debated at the time of writing (November 2009).

<sup>18</sup> A generator with a surplus of (free) permits still faces the opportunity cost of not selling the spare ones.

## 5. General implications for regulation

How do these trends affect the task of regulation? This section will offer some general implications that are likely to affect regulation across all the stages of the industry. The following section will discuss specific changes that might be needed, in the context of the three tasks (regulating networks, consumer prices, and generation) described in section 3.

First, it is clear that the cost of energy is going to rise – most renewable energy costs more than conventional sources at current fuel prices, even before considering the costs of investment in the networks and changed operating requirements. If fossil fuel prices were to rise significantly, then a move to renewable energy would not lead to a further increase (and might, in extreme cases, reduce costs), but this would be little comfort to energy consumers. The EU has estimated that meeting its 20% target for renewable energy will cost an extra €24-31 billion in 2020, against a predicted energy bill of around €350 billion (European Commission, 2007). This assumes an oil price of \$48/barrel: if the oil price rises to \$78/barrel, energy costs will be much higher, but the additional cost of renewable energy will fall to at most €11 billion, and would be zero in one scenario. Some of these costs may be borne by taxpayers, but the remainder will have to come from energy consumers, and regulators will need to allow the utilities to collect these – as with any other efficiently incurred cost increase. Where parts of the industry have been liberalized, the regulators will not determine prices directly, but regulators who have oversight of these competitive areas must not intervene to suppress necessary increases.

Second, the electricity industry will need a lot of capital investment, both in renewable generation (many technologies are capital intensive) and in changes to the network to accommodate it. This will affect the weight that regulators should place on the different cost components when setting incentives for network companies and for generators, if they are regulated.

A regulated firm's costs can be broken down into its cash operating costs (labor, materials and bought-in services), the return on its new investments, and the return on its existing assets. The firm is assumed able to control both its operating costs and its investment in new assets, but its existing capital stock is, naturally, fixed.

The required return on both new and existing assets depends on the cost of capital, which is affected by the perceived risk of the business.

High-powered incentives to reduce costs will increase the company's risk, since success or failure to do so will feed through to the company's profits. Standard models of financial economies, such as the capital asset pricing model, suggest that diversifiable risks should not affect a company's cost of capital. Nonetheless there are two routes through which the level of incentives might have an impact. First, if the company's profits become more sensitive to the overall state of the economy (and are positively correlated with it), then its beta will rise, increasing the cost of its equity. Second, if favorable tax treatment reduces the cost of debt and a company with risky cash flows has to reduce its gearing, this will increase its weighted average cost of capital.

An optimal regulatory scheme would balance the expected savings from strengthening the incentive on the volume of operating costs, or of investment, against the cost of having to pay a higher expected rate of return. In other words, while it is possible to give the firm very high-powered incentives to reduce both its operating costs and its investment (a pure price cap regime does this), this would be undesirable if it caused too great an increase in the cost of capital. If the industry's cost structure shifts away from operating costs, then optimal regulation would imply paying more attention to the rate of return on capital, and less to the level of operating costs. An increase in the volume of investment will mean that more weight should be placed on incentives for efficient investment than on the impact of a higher cost of capital on payments for existing assets. In other words, incentives for efficient operation might be relaxed, and those for efficient investment should be strengthened.

One way of doing this in practice is to offer the firm a menu of regulatory contracts (Sappington, 1982; Laffont and Tirole, 1993). In the UK, the regulator has given distribution companies such menus for their investments over the next price control period (Pollitt and Bialek, 2008). The regulator uses consultants to assess the necessary level of investment, but the firm can propose a higher base figure. The firm's allowed revenues are then linked to this proposal and its out-turn expenditure. Whatever the out-turn level of expenditure, the firm's revenues are highest if this was the level that it actually proposed, providing an incentive for truthful cost revelation. The allowed revenues increase by less than a unit for each unit increase in the firm's actual expenditure, however, so that the firm has to bear a share of any cost over-run,

and keeps a share of any savings. This provides the incentive to keep actual costs down, and one which is greater, the tougher the target that the firm accepts. Accepting a tough target thus allows the firm the chance to benefit from high-powered incentives. A firm which accepts the regulator's target, and meets this target, will be allowed revenues of more than the amount it spends, which gives a margin of error in case the regulator's target is too tough. Under Ofgem's scheme (which differs from some versions of the menu of contracts approach) the allowed revenues also increase by less than a pound for each pound that the firm proposes to spend above the regulator's target. The greater the firm's proposal, the less revenue the firm will be allowed for any out-turn spending below this proposal.<sup>19</sup> Overall, the scheme gives the firm an incentive to reveal the truth about its expected capital needs, and to keep its costs down, while allowing it to pass part of any genuine over-run on to consumers.

A final general implication is that the number of small electricity generators who wish to inject energy into the network will increase. Any energy producer connected to the network must be subject to the network operator's technical standards and to the industry's commercial arrangements – purely bilateral transactions are impossible in an interconnected system. Energy regulators are often involved in overseeing the details of such standards and arrangements, to ensure that they do not discriminate against particular network users. If we wish to further the development of micro-generation (and the high costs of many micro-generators should be taken into account in that decision), then the regulators will have to ensure that the technical standards are not too onerous, and the commercial arrangements are suitable for non-specialists.

Accommodating these generators will be helped by a variety of so-called smart grid technologies. Traditionally, system operators have had little real-time information on the actual state of the distribution network, which forces them to run it in a relatively conservative manner. More information can be used to increase the allowable power flows. Furthermore, some small-scale generators and loads can be dispatched, responding to instructions based on the state of the system – both the overall balance between generation and demand, and conditions on the local

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<sup>19</sup> If the firm spends more than it proposed, however, it would have been better off to have proposed a higher level of spending.

distribution network. Regulators will have to ensure that companies are rewarded for innovations such as these, and that the boundaries between generation, retailing and networks do not act as barriers. This is potentially a disadvantage of the retail competition model, which sometimes severs the relationship between a customer and their network operator (although in some countries, the customer continues to receive a bill for network services).

The need to give incentives for innovation has emerged as a key theme of the 2008-10 review of network regulation by the British Regulator, Ofgem, “RPI-X@20”.<sup>20</sup> Spending on research and development by the distribution network operators in Great Britain has risen dramatically since a separate revenue stream to fund it was created in 2005 (Ofgem, 2009). One key issue is that spending may have to be incurred well before customers see any benefit from it, and regulators must allow companies to fund this.

## 6. Implications for the regulator’s tasks

While the previous section pointed out some general implications of an increasing share of renewable energy, in this section, I ask how these will change what regulators will need to do. Section 3 set out four organizational models for the industry, and listed the major tasks that the regulators had to undertake: regulating the wires, regulating the amounts received by generators and regulating retail prices.

### 6.1 Regulating the wires

In both the retail and the wholesale competition model, the regulator has to oversee the prices, and other terms, for companies wishing to use the network – in the retail competition model, this is the only area of *ex ante* regulation. This may include the rules of the wholesale market. Hogan discusses these in chapter 6, and I will not repeat that discussion here. Suffice it to say that a liquid multilateral market with prices that reflect the changing state of supply, demand and the transmission system will be far more effective than a bilateral market with prices that ignore the fact that

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<sup>20</sup> Since Great Britain follows the model of retail competition, formal regulation only covers the transmission and distribution networks, and this review does not cover issues related to generation or retailing – even though many network innovations will also affect these sectors. Documents related to the review are available from the regulator’s web site at <http://www.ofgem.gov.uk/Networks/rpix20/Pages/RPIX20.aspx>.

generators in some locations may be unable to get their power to consumers. The transmission system operators already have to undo some trades of this kind to make the European wholesale markets work properly, and the scale of the task will increase with the level of renewable generation.<sup>21</sup>

There are two key aspects to price regulation. One is the average level of prices, and the other is their distribution between customers. As discussed above, the average level of prices is linked to the industry's expected costs, and a key aspect of these is the level of investment. Investment in the electricity networks will need to rise, increasing costs and hence prices. Strong incentives to minimize investment costs might keep prices down, but could jeopardize investment in renewable energy, if insufficient grid capacity is available. For an extreme example, new generators inquiring about connecting to the transmission system in Scotland were told that they might have to wait more than ten years for capacity to become available (House of Lords, 2008a, para 133).

The primary cause of such delays is the long lead time for transmission investment, typically greater than that for generation. In part, this time depends on the process of obtaining planning permission for new transmission lines, which has become a lengthy one in many countries. Sometimes, it will not be possible to develop a line in time to meet an unanticipated need for capacity, and the regulator (and would-be generators) will have to accept this – although reforms to speed the planning process would make this less common.

The impact of this lead time is worsened because it will not always be clear in advance exactly where capacity will be needed, or how much, even if the general requirement is clear. If the network owner is worried that it will be penalized for spending that turns out to be unnecessary, it will not wish to start the detailed investment process until the needs are clear and (preferably) contracts are signed with users. This is likely to impose significant delays, which would be unnecessary in cases where it had earlier become clear that some investment was likely to be required. Regulators should allow companies to recover the cost of making plans, and even seeking planning permission, for new lines which appear likely to be needed, but are later abandoned as circumstances change. To reduce the risk that too many

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<sup>21</sup> This is because many renewable generators will be located far from demand, and their low load factors mean that it would not be economic to build enough transmission capacity to accommodate all their output at the rare times when they are producing at close to full output, leading to an increase in transmission constraints.

unwanted lines are planned, there should be wider consultation on network investment plans. Pollitt (2008) calls for a process of “constructive engagement” already used abroad and in the regulation of UK airports, where users and the airport owner could jointly agree a program of capital investment. Littlechild (2008, and references therein) describes the negotiations used to decide on transmission investments in Chile, where transmission users were able to insist on a cheaper alternative to the line originally proposed by the transmission utility. There needs to be a balance between making a timely start to investment and not authorizing projects with insufficient demand. The California Independent System Operator’s Location Constrained Resource Interconnection Policy requires financial commitments from renewable generators to use at least 60% of a new line’s capacity, but then incorporates the line’s costs in its general transmission tariff.<sup>22</sup> A more prescriptive approach would imply the creation (or empowerment) of some kind of national planning agency to coordinate generation and network investment and act as a “guiding mind”.<sup>23</sup>

It is also important to ensure that the investment needs in the grid are not increased by inflexible procedures. Traditionally, transmission companies have been reluctant to connect generators unless they are certain they can (almost) always accept their output. This is a sensible policy for conventional generators, since (if the investment is desirable) they can expect to be needed to meet peak demand, and preventing them from generating could risk power cuts. Wind generators, in contrast, may not generate at the time of the peak, and if they do, some other stations (which need to be available) will not be running. The transmission system does not need to accept every generator’s output simultaneously, and investment rules need to be altered accordingly. It is important, however, to allocate access to the grid efficiently – something achieved automatically in a wholesale market based on locational marginal prices.

The second aspect of price regulation is the distribution of payments between network users. In particular, how should they vary over time, and over space? A partial answer is that if the wholesale market adopts nodal marginal pricing, then there will be cost-reflective variations over time and space, and these will be passed on to network users. The prices at nodes with net generation are (on average) below those

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<sup>22</sup> I must thank Boaz Moselle for directing me to the relevant part of the California ISO’s web site for this example: <http://www.caiso.com/1816/1816d22953ec0.html>

<sup>23</sup> This term has been used (in this context) in the British review of network regulation, “RPI-X@20”.

with net demand, since the costs of transmission are incurred as power flows from generation to demand nodes. The transmission operator can therefore “buy cheap and sell dear”, retaining the surplus. The problem is that other charges will have to be added, for these net revenues from nodal marginal prices generally recover only a small part of the total cost of transmission – often only around 20 per cent (Perez-Arriaga *et al.*, 1995). It is possible to derive an optimality condition for transmission investment, under which the marginal cost of expanding transmission capacity should just equal the marginal benefit of doing so, which is given by the difference in prices at each end of the line. With constant returns to scale and perfectly divisible capital, this suggests that nodal pricing would completely recover the costs of an optimal system. Perez-Arriaga *et al.* suggest that this result does not hold because of economies of scale and indivisibilities, because it is often sensible to build a line that is currently too large, in order to accommodate future growth, and because changing patterns of generation and demand mean that the inherited transmission system will inevitably be sub-optimal. This suggests that the missing revenue should not be seen as related to identifiable costs of transmission, but as a lump sum that has to be recovered with the minimum of distortion.

Given this, how should the remaining network costs be recovered across time? Should generators (and customers) pay whenever they are sending power to the grid (or taking power from it)? Should they pay based on the maximum cost that they could impose on the grid? Should they pay based on the cost they impose when the load on the grid is heaviest? Given that capital costs form a high proportion of the total, this would argue for some form of peak load pricing, rather than recovering costs evenly over time. Peak load pricing is based on charging users at the time when the load on the grid is heaviest, since capacity built to cope with these times is effectively “free” at times with lower loads.

The issue is that with this kind of peak load pricing, renewable generators would tend to face much lower transmission payments per kW of capacity than conventional generators would, but those payments would be variable over time. In some years, a renewable generator would be able to generate at the time of the system peak, and would be assessed for transmission charges on the basis of this. In other years, the system peak would come when the (local) wind was low, the generator would have little output, and would pay little for transmission. This is unlikely to be politically acceptable, and could also produce perverse incentives not to generate at the system

peak – transmission charges per MW can be an order of magnitude above all but the very highest electricity prices, and if just one or two hours of generation creates a liability to those charges, it will not be worthwhile.<sup>24</sup>

This suggests that transmission charges should be based either on the capacity of a power station, or on the energy it generates over the year, perhaps weighted according to the time of production. If the charges are capacity-related, intermittent renewable generators will pay much more per MWh actually generated than conventional stations able to run at base load. Conventional generators that are needed to meet peak demands, but rarely run at other times, will be in a similar situation. Both may claim this to be discrimination. Furthermore, they will need some revenue source to cover these costs if they are to remain available in a long-term equilibrium. For peaking generators, this is likely to be reflected either in the prices for peak power, or in a capacity market (if one exists). For renewable generators, less able to rely on peak prices or capacity markets, the remainder will have to come from their support scheme. Charging intermittent renewable generators on the basis of their capacity, but adjusted for their relatively low expected output, might be a politically acceptable way of reducing the cost of this – effectively, using a hybrid scheme.

If transmission charges are energy-related, the impact on peak prices and the cost of supporting renewables will be lower – though electricity prices will be slightly higher throughout the year, as generators pass through this additional marginal cost. Furthermore, wholesale prices may not accurately reflect the marginal cost of expanding transmission to accommodate more generation (even with nodal marginal prices, indivisibilities might mean that the system has to be expanded to the point where the price differences at each end of the line are quite low) or wholesale prices may not include any transmission component. In this case, the transmission charges should signal the cost of expanding the system, and capacity-related charges will send a more accurate signal than energy-based ones.

Similar considerations apply to the decision about how network charges should vary over space. The overall system of transmission charges (including transmission-related elements in any wholesale market) should signal the costs of using the transmission system and ensure that the network companies recover their (efficiently

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<sup>24</sup> As an editor pointed out, if this behavior allowed us to avoid building the extra transmission, and we are still able to meet the peak demand, it would be efficient.

incurred) costs (Green, 1997). If other parts of the pricing system send adequate locational signals, so that network charges are purely to recover a lump sum of missing revenue, then a uniform national (or system-wide) charge is appropriate. If generators and customers do not otherwise face charges that reflect the spatial variation in transmission costs, however, then transmission charges should vary over space.

The implications of this may depend on factors specific to each market: in Great Britain, for example, transmission charges are highest in Scotland (which is bad news for wind farms sited there) and lowest in South-West England (which will be good news for marine energy schemes located off the coast of that region). In general, however, it seems likely that renewable generators located in rural areas will face higher transmission charges than conventional generators closer to the loads. Once again, this will affect the cost of supporting renewable energy. The higher the transmission charges paid by the marginal generator (the one whose needs just determine the level of support required), the greater the support it will need. Unless the support scheme separates out and pays each generator's individual transmission charge, this will raise the rents obtained by generators in more favorable locations.

Transmission charges may not in fact have much impact on the locational choices made by renewable generators, who need to choose sites that maximize their output. A one percentage point difference in the load factor achieved by a British wind farm, for example, would largely offset the difference in transmission charges between the north and south of Scotland, or between central England and the South-West.<sup>25</sup> In this case, minimizing the rents obtained by well-sited generators might be more important than sending precise signals. However, the impact on conventional generators must also be taken into account. These have (some) more flexibility to choose their sites, and should be sent signals of transmission costs – either through spatially varying wholesale prices or through transmission charges.

The final issue involved in regulating the wires is how to regulate the transmission system operator, as distinct from the transmission owner. The transmission owner

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<sup>25</sup> These transmission charges vary by around £7 per kW per year, whereas a forward wholesale price for 2010 (at the end of June 2009) was £51.25/MWh, and a renewable generator would also receive Renewables Obligation Certificates that were selling for around £52/MWh (UK Powerfocus, July 2009). A one percentage point change in load factor leads to an increase in output of 88 MWh (for a 1 MW unit), and hence an extra £4.70 per kW per year in income.

receives payments for having built the transmission wires and for keeping them in good repair; the transmission operator is responsible for managing their daily use to move power. Sometimes both functions are combined in a single company, but an independent system operator can be used when it is most effective to run a single market over several transmission owners' grids, or when regulators want to ensure that the grid is operated independently of generation interests, without ordering an integrated company to divest any assets.

The system operator will need to buy operating reserves and (in markets without nodal pricing) will resolve congestion by buying and selling power on either side of a constraint. As the amount of renewable energy increases, so will these costs. This implies that the benefits from giving the system operator strong incentives to control them are likely to rise. It may be difficult to give strong financial incentives, relative to the costs involved, to an independent system operator, for organizations like these have few assets to cushion them against unforeseen events that would lead to a bad out-turn, and hence performance penalties, even in a single year. If significant transmission assets are owned by an independent company which is also the system operator, however, then the revenue stream for these assets provides a suitable cushion against which to strengthen the system operator's incentives.<sup>26</sup> The increase in renewable energy therefore provides an additional argument for establishing independent transmission companies, as opposed to independent system operators.

## 6.2 Regulating generation revenues

In the model of integrated firms, the regulator is responsible for overseeing each stage of the industry's value chain, from generation onwards. It is no longer necessary to oversee a transmission or distribution tariff, since there would be no independent generators or retailers to use it, but the issues surrounding investment in the networks remain. The one simplifying factor is that the regulated firm can coordinate investment in generation and the networks internally, rather than relying on the price mechanism to persuade generators to favor sites that are helpful to the transmission company.

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<sup>26</sup> A state-owned transmission company potentially has the best financial cushion of all, but may well be less receptive to financial incentives than a private-sector organisation.

Against this, the regulator now has some responsibility for the level of investment in generation. As discussed earlier, most forms of renewable generation are good substitutes for conventional generators in providing energy (measured in MWh of power at some point during the year), but are poor at providing capacity (measured in MW of ability to provide electricity when it is really needed). Regulators will have to allow utilities to add renewable generation to their portfolios without retiring many conventional stations. If the conventional fleet is ageing, new build of both renewable and conventional power stations may be needed. The regulator will then have to accept that some of the conventional capacity will rarely be required – it is needed to ensure that peak demand can be met when this coincides with low availability of renewable generators, and this will not happen every year. Too much pressure to demonstrate that reserve stations are “used and useful” will make utilities reluctant to keep this reserve at a suitable level.

Regulators could also face challenges of a different kind if they face a rapid rise in renewable output when conventional capacity was already adequate. In this case, some of that capacity truly would be surplus to requirements. Should the regulator eliminate it from the rate base, so that consumers do not have to pay for assets that they are not using? The regulatory compact adopted in many jurisdictions that have liberalized the energy industries has been to allow utilities to recover the cost of such stranded assets, in the interest of long-term investment incentives. This would also be appropriate in this case, but will increase the apparent cost of renewable energy. With a liberalized wholesale market, the cost of stranded assets is absorbed by their owners, but the risk that something like this would happen should have been taken into account when those owners calculated their cost of capital, which would normally be higher than in a regulated system.

The cost of generation will also be affected by the cost of carbon, in countries with a system of carbon trading. If generators have to buy all their permits, then this will be a cost of business which the regulator should include in their allowable revenues. If generators receive some permits for free, however, then the regulated firm’s revenue requirements should take this into account, muting the increase in price. Politically, this may be an advantage, but it implies that the impact of carbon pricing will have to come entirely from the supply side, rather than from both supply and demand-side responses.

It is worth pointing out that where generation is traded in a wholesale market, regulators are often responsible for market monitoring, even though this is really an aspect of competition policy rather than of economic regulation. Market monitors need to know when to intervene to stop the abuse of market power, which typically manifests itself as high prices. The challenge in electricity markets is that some periods of high prices may be essential if generators are to recover their fixed costs,<sup>27</sup> and market monitors must not intervene to suppress these necessary peaks. A system with a high proportion of intermittent renewable generators may find that the residual load on thermal generators becomes much more uneven, with periods of zero (or negative) marginal costs. If the market is so competitive that prices can only rise above marginal cost and pay for capacity in the few hours when demand is high enough to create scarcity rents, prices at these times will have to be extremely high. An oligopoly with moderate price-cost margins for a larger number of hours might produce a more stable outcome. In either case, the need to differentiate between high and excessive prices, and (perhaps) to respond to political pressure to keep prices down will make the task of the market monitor more demanding.

### 6.3 Regulating Retail Prices

In three of the models described in section 3, the regulator is responsible for overseeing the prices charged to (at least some) energy consumers, either because there is no retail competition (although there may be wholesale competition), or because policy-makers judge that it is not yet sufficiently effective to protect consumers. The combination of regulation and a partially competitive market offers particular challenges, since there is a danger that if the regulator puts too low a cap on the incumbent's prices, then entrants will not be able to win customers and competition will never develop to the point where it becomes self-sustaining (Joskow, 2008).

If regulators wish to develop retail competition and the costs of renewable energy are significant, then it is important that they are shared across customers, regardless of their choice of retailer. If the costs were small, it might be possible to

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<sup>27</sup> The alternative paradigm uses a capacity market to recover generators' fixed costs, sometimes coupled with payments linked to spot prices which should act to restrain those prices (Cramton and Stoft, 2008).

assign them all to the incumbent retailer, on the basis that this would do no more than (partially) offset the advantages of incumbency – a similar approach has (so far) been taken to the cost of universal postal service obligations in most EU countries. The likely excess costs of renewable energy, however, are too great for this approach to be workable. This means that the costs must either be recovered across all energy retailers, or via distribution tariffs (which must also be non-discriminatory across retailers).

One of the standard mechanisms for supporting renewable energy does this automatically. If there is an obligation on all retailers to obtain a set proportion of their power from renewable generators (usually administered by a system of tradable certificates), then this should be neutral across competitors. If a high proportion of the renewable generators able to provide eligible power are integrated with incumbent retailers, then this could form a barrier to entry in retailing;<sup>28</sup> however the rapid increase in renewable energy that most countries are targeting should allow plenty of room for entry in generation to relax this constraint.

The other standard mechanism is to pay renewable generators a feed-in-tariff which offers them a premium price for their power. Some organization has to make these payments, and recoup the cost of doing so. A distribution company might appear to be well-placed to do this. First, most renewable generators will be connected to its system, which gives it the knowledge of which generators are eligible for support, and what they produce. Second, it already bills either consumers or their retailers for distribution services in a non-discriminatory manner, and can add the cost of the feed-in-tariff to these bills. However, in a system with more than one distribution utility, there will almost certainly be a mismatch between each utility's share of renewable energy sources (and hence payments) and energy consumption (and hence receipts). On the basis that the cost of supporting renewable energy should be shared over a wider area, there would need to be side-payments between distributors. This means that the scheme would have to be overseen by a government agency, or the regulator's office, to ensure that the correct payments were made. It might be best for this agency to actually calculate those payments, using information provided by the distribution companies.

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<sup>28</sup> If a high level of integration between retailing and renewable generation extended to the generation sector overall, then the barrier to entry in retailing would be severe. If there are several regional incumbents within a larger market, however, effective competition between them is possible, though not inevitable.

These points also apply in the retail competition model, of course, because that depends on retailers facing similar obligations. They would not apply if there was no retail competition, because then no distortion could arise. In the absence of retail competition, the regulator has more ability to influence which customers actually have to pay for renewable energy. If regulators have a particular duty to protect selected groups of customers, this raises the issue of whether the price rises should be skewed towards others. The problem with this approach is that it can be very difficult to ensure that such help is actually given to those who need it most. Keeping down tariffs for those who use very little electricity may benefit the owners of second homes, for example. Many “fuel poor” households<sup>29</sup> have relatively high energy consumption, often because their homes are poorly insulated.

The distribution of price increases between customer classes is also relevant here: commercial and (particularly) industrial customers facing international competition might claim that they should not be exposed to unnecessary price rises, suggesting that domestic customers should face a high proportion of the support costs. For most industrial and commercial customers, energy costs are not significant – Yago et al (2008) found that a 30 per cent increase in the price of electricity would raise costs by less than one per cent in sectors making up 90 per cent of the UK economy. The remaining sectors will be more affected, however, and some of those are exposed to international competition – particularly aluminum smelting. Should regulators try to design tariffs that will shield such energy-intensive industries from price increases? The general thrust of liberalization policy has been to reduce such political interference in markets (since benefits often go to the best lobbyists rather than the most deserving causes) and align prices to costs.

## 7. Conclusions

The sections above suggest specific ways in which regulators will need to respond if the energy utilities are to absorb large amounts of renewable energy. What about the broader questions set out in the introduction to this chapter?

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<sup>29</sup> In the UK, fuel poor households are defined as those which need to spend more than 10% of their income to achieve acceptable standards of heat and light)

Should regulators' objectives change, or the factors they take into account when deciding how to achieve those objectives? There is no doubt that regulators will have to consider their impact on the environment when making decisions. If they did not, then they would find it hard to justify the investments needed to accommodate renewable electricity generation, for example. Should protecting the environment be seen as an objective to place alongside consumer and producer protection, however, or a constraint on how the regulator goes about its other duties? A mathematical problem can be set up to give the same results, whether environmental protection is included as something to maximize or a constraint that must be met, if the constraint is set at the right level. In the real world, however, regulators would probably have to act in different ways if they were to give environmental protection the same priority as their other duties. We do not want them to damage the environment, but their relative expertise is not in this area, and it would be preferable if economic regulators were not designing environmental policy. My belief is that regulation should continue to prioritize consumer protection and ensuring that firms can finance their activities, but should do so in the light of government environmental policies, and promote their achievement.<sup>30</sup>

Should the scope of regulation be broadened or narrowed? I have argued that the regulators will need to make different decisions on specific issues, but there will be no step changes in the kinds of questions that they must address. The bulk of the evidence so far is that well-designed liberalization programs offer superior performance to the traditional utility model (Joskow, 2008).

Would the growth of renewable energy over-turn this result? Integrated firms can coordinate the development of the network to accommodate renewable generation. The single buyer model allows the policy-maker to choose a mix of low-carbon generators in a coordinated manner to meet its targets. Wholesale market monitoring to guard against the exploitation of market power will be more challenging in an industry with a high proportion of intermittent generation with very low marginal costs. Retail competition may act as a barrier to the development of smart grid technologies which need to coordinate devices for consumers and on the

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<sup>30</sup> In countries where the regulator is constrained to closely follow specific laws, this implies that those laws should give the regulator tasks that achieve these same aims.

network. Competitive models which raise the cost of capital will be more costly for an industry which is becoming more capital-intensive.

These are significant arguments, all suggesting that liberalization will be less successful at dealing with the challenges of renewable energy. I do not believe that they are conclusive, however. The great advantage of competition is that it can allow new entrants to spot opportunities that incumbents have not exploited. If we want many consumers to generate part of their own electricity, then a model in which there is free entry for competing retailers who could provide and maintain generating equipment on the customer's premises could further this. Even though the retail competition model often severs the direct link between the customer and the distribution network operator, it should be possible to find a business model through which retailers (or others) who install a smart grid application on a customer's premises can share in the resulting benefits. Regulators may have to help the industry to develop the essential information protocols and compatibility standards to make this possible, but competitive environments are generally more innovative than monopolies.

As the level of renewable generation increases, of course, less of the market may be truly competitive. Governments may reserve part of the market for renewable generators, either implicitly or explicitly. Other support schemes may be needed to persuade companies to invest in carbon capture and storage or in nuclear power. The danger would be that if the market for unsupported generation became a small rump, competition within it would no longer act as a sufficient discipline on the participating firms, and the prices set there would lose their ability to send meaningful signals.

Helm (2008) has suggested that a "utility" should be created to tender for these stations, financing them in a way that minimized the cost of capital. This is effectively a variant of the "single buyer" model. If there is sufficient competition between developers to win the tenders and build the stations, it might achieve the best of both worlds. The danger, however, is that the single buyer would end up favoring particular technologies which turned out to be unsuccessful, and that there would be no checks and balances to prevent this. It would be better to establish a long-term carbon price and use this to provide incentives for investment in low-carbon generation on the level playing field of a competitive wholesale market. Similarly, efforts to provide a "guiding mind" to coordinate investment in generation and the networks should be based on constructive engagement between the relevant parties,

sharing information on their plans and needs, rather than on prescriptive central planning.

At the same time, competitive models do involve greater risks, and thus a higher cost of capital, than the alternatives. In a more capital-intensive industry, the cost of capital will make a greater contribution to consumer prices, but the importance of choosing an efficient amount of capital will also rise – particularly during a period of high investment, such as most countries are now facing. Again, competitive mechanisms generally lead to better investment decisions than regulatory ones – even when investors have indulged in excessive plant building, this has not been at the cost of electricity consumers.

I therefore conclude that while the detailed decisions that economic regulators need to take will change, and that they will have to take more account of the environment into account as a constraint on what they expect companies to do, the shift to renewable energy will not change the fundamental tasks or nature of economic regulation. We may need to adapt our existing tools, but can continue to use them to build a low-carbon energy system.

#### Epilogue – the natural gas industry

What about the gas industry? There is some scope to replace natural gas with biogas from plant or animal waste, but otherwise, the impact of renewable energy on the gas industry will come from the demand side rather than the supply side. In the medium term, natural gas is likely to be favored over coal as a fuel for electricity generation. This comes both from its lower carbon emissions, and because gas turbines can be more flexible in operation, and better able to respond to intermittent renewable sources, than large coal-fired units. Although the shift to renewables would crowd out fossil fuels, a large enough move away from coal could still cause an increase in gas demand, as could the increased use of (gas-fired) combined heat and power to increase energy efficiency. The first would require large quantities of gas to be delivered to a few sites, while the second would increase the quantity sent to many separate sites around the country. In both cases, additional capacity in the network might be required.

When we come to the growth of renewable energy, however, this could lead to a reduction in end-users' demand for natural gas. The use of renewable heat sources –

biomass and heat pumps<sup>31</sup> – could double as part of the EU’s drive to obtain 20% of its energy from renewable sources, displacing natural gas and other fossil fuels (European Commission, 2007). In the long term, the need to reduce CO2 emissions by 80% or more is likely to be incompatible with burning natural gas without carbon capture, which is likely to be impractical for small-scale heating systems.

Gas industry regulators may thus face the challenging task of managing both growth and decline. If the demand for gas for electricity generation continues to grow, then the issues involved will be similar to those facing electricity networks where more investment is needed. However, the networks involved will mainly be the high-pressure pipelines, delivering large amounts of gas to large generators. If renewable heat (and renewable sources of electricity) reduce the demand for gas by end-users, then the utilities will have to face this, even though the capital (and some operating) costs of their distribution networks will not be declining. This would imply a rising per-unit price, just as the price of natural gas may also be increasing. The process would not be sudden, and a switch to biogas might boost demand, but the potential exists for a vicious circle of rising prices and falling demand. In extremis, regulators (or governments) might need to consider giving gas utilities additional support to ensure that they can still manage their distribution networks safely while reducing sales.

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<sup>31</sup> Heat pumps basically use refrigerator technology in reverse to extract heat from the environment, chilling a fluid so that it is colder than conditions outside (or underground) and can absorb heat from its surroundings. Compressing the fluid then raises its temperature to a point where the heat can be extracted and used. The gross energy delivered by a heat pump can be four times that used for pumping, in which case 75% of the energy delivered would be counted as renewable by the EU.

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