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PRESERVING ELECTRICITY MARKET EFFICIENCY WHILE CLOSING IRELAND'S CAPACITY GAP*

Seán Lyons, John Fitz Gerald, Niamh McCarthy, Laura Malaguzzi Valeri and Richard S.J. Tol

The public perception of electricity regulation focuses on price outcomes: are prices low or high, rising or falling, stable or volatile. However, the quantity and quality dimensions of electricity services also have important effects on societal welfare. Although electricity is essentially a homogeneous good, the services that deliver it may be differentiated in ways that are significant to users; in particular, by the reliability standard they deliver.[1] Ideally, we should choose the set of market arrangements that will deliver, both now and in the future, the preferred quantity and quality of electricity services at prices that are as low as possible.

Because electrical energy is costly to store and the lead-time for constructing new generation capacity is long in comparison to demand fluctuations, the key decisions affecting quantity and quality of electricity services are the mix and timing of investment in

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[1] Consumers may also differentiate electricity by its source (e.g., carbon-neutral, non-nuclear) but that is not the focus of this paper.

different types of generating plants. The system should have an optimal mix of generating plants available to meet demand fluctuations without excessive risk of outages, and capacity should evolve over time in line with demand growth, all at the lowest practicable cost while maintaining incentives to invest.

In past decades, both the evaluation of appropriate capacity levels and the formulation of the best response to it would have been accomplished through central planning mechanisms (Fitz Gerald *et al.*, 2005, p.57). The central planner would specify a level of capacity (for example, by calculating expected demand plus a reserve margin) thought sufficient to meet a defined standard for system reliability.

In contrast, a core premise of the new All-Island Market[2] is that the regulators should put a mechanism in place that will allow market forces to ensure that adequate capacity is built in an efficient and timely manner. Use of markets, rather than central planning, to deliver the required level of capacity has important advantages; in particular, it should help improve efficiency and lower prices in the long run. However, it also presents challenges for policymakers. Rather than the central planner setting capacity by fiat, investors must be given incentives to build the right sorts of generating plants at the right times and ensure they are available to generate power when needed.

The market's designers have gone to some lengths to create appropriate investment incentives for this purpose. Delivered through a system of administrative "capacity payments", the essence of these incentives is to increase certainty of revenues and allow generators who make plant available at times when capacity margins are relatively tight to earn revenues in such periods that are higher, and in some cases considerably higher, than their short-run costs. The expectation of additional payments at times of scarcity is intended to provide a signal for market participants to ensure that additional capacity is made available when it is required. The overall level of capacity payments is derived administratively from estimates of the tightness of the market and the cost of new peaking capacity.[3]

The performance of such a mechanism in practice depends crucially upon how market participants respond to the incentives it provides. Theory and international regulatory experience emphasise

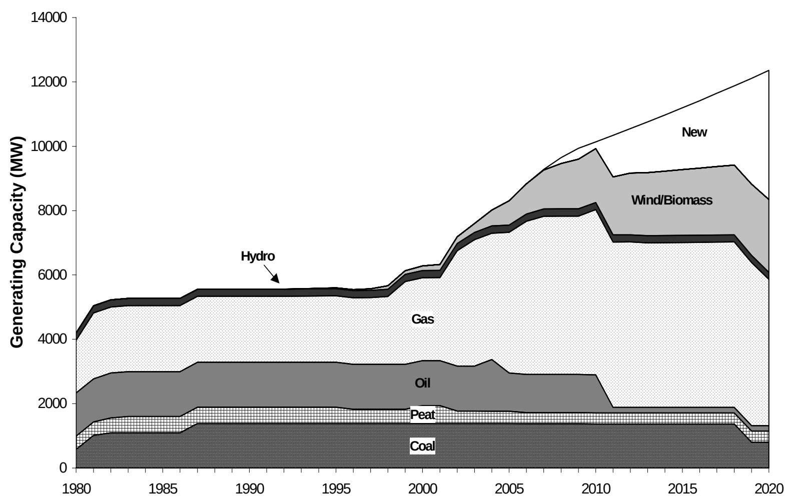
[2] The All-Island market is a single electricity market covering Northern Ireland and the Republic of Ireland, and it is scheduled to go live in November 2007.

[3] Peaking plants display a relatively high variable cost of electricity generation, but fairly low fixed costs. Additionally, they may be switched on and off frequently without excessive cost. Plants suited to such intra-day switching are used to meet demand fluctuations efficiently. On the other hand, base load plants, with relatively high fixed and low variable costs, are optimised for use in a relatively continuous way. Mid-merit plants fall somewhere in between: ideally they produce for several hours, but can be shut down and restarted daily.

the role of credibility as a necessary condition for enabling investment incentives to operate effectively. By credibility, we mean that the state must be in a position to pre-commit that it will not change the rules of the game once irreversible investments are in place. If this sort of credibility is lacking, the market may be subject to under-investment (Blackmon and Zeckhauser, 1992).[4]

This is not merely a theoretical point. Continued increases in demand and planned retirement of old plant imply that significant new electricity generation capacity will be needed over the next seven years (Eirgrid, 2006). Figure 1 below illustrates the extent of future requirements for the All-Island market.

Figure 1: Electricity Generation Capacity in the All-Island Market



Sources: ESRI analysis of generation and transmission adequacy reports published by the System Operator for Northern Ireland and Eirgrid.

Note that the white "New" segment at the top of the chart grows rapidly from 2011 onwards. This represents incremental capacity that will be required to maintain the 2006 level of supply adequacy, allowing for expected demand growth, increases in wind power supply and current plans for plant retirements and introductions.

Indeed, capacity margins are already relatively tight. Forced outages[5] among a small number of ageing generation units could sharply increase the risk of shortages if they were to coincide with peak winter demand (Malaguzzi Valeri and Tol, 2006).

[4] Hold-up problems such as this have been studied extensively in the contracts theory literature. See Schmitz (2001) for a recent survey.

[5] An unscheduled event, such as a technical failure, during which a plant is unable to make all or part of its planned capacity available to the market.

In this paper, we first describe the institutional arrangements used in the SEM to provide capacity incentives and discuss the role of credibility in allowing the market to work. We then examine three important influences on investors' incentives. First, we use a static model of the Single Electricity Market (SEM) to identify the signals the new market will send investors as to the types of generating plant that should be built. Second, we consider the effects of likely future developments in the market, in particular the rapid increase in wind generating capacity. Finally, we analyse some of the sources of risk faced by investors in generating plants, and we suggest that there are important differences in the incidence of the main sources of risk across plant types.

Our static comparison provides ambiguous results as to which sorts of plant should be most attractive to investors. Plant profitability in a relatively small market is likely to be cyclical due to the relatively large size of new plants in comparison to the total market. The growing importance of wind generation in the SEM suggests that the system will need more mid-merit and peaking capacity to help meet system reliability goals in future. We also note that plant retirements planned by the ESB in the next few years are concentrated in the mid-merit segment. Furthermore, peaking and mid-merit plants trading in the SEM should face significantly lower economic, market and credit risks than those faced by base load plants. However, plants that rely heavily on capacity payments are likely to face higher exposure to political and regulatory risk. If such risks are seen as significant, this could have the effect of distorting investors' choices as to which sorts of plant to build, as well as how much investment to commit.

To ensure that there is sufficient investment to meet Ireland's capacity needs and to allow the market to deliver an optimal portfolio of plant types, the SEM must be credible. The third section of the paper refers to direct government intervention in electricity capacity. Recent announcements suggest that this may continue in parallel with the development of the SEM. Such intervention could lead to problems in establishing credibility for the new market.

In the final section, we outline some ways in which the Irish government might support regulatory credibility, increasing societal welfare in the long term.

1. Incentives to Supply Adequate Electricity Generation

In their design for the new SEM, Ireland's two regulators[6] have chosen a mechanism that should allow the market to determine when, where and by whom new generation capacity will be built. The model is not completely devoid of state intervention, as discussed below. However, the logic of this approach is that markets will be better than central planning at building and maintaining generating assets that deliver adequate capacity at least cost. In this section, we discuss the features within the SEM that are intended to ensure that adequate capacity is supplied by the market. While this system may be the best option for Ireland, it presents considerable challenges, especially in the establishment and maintenance of regulatory credibility.

INSTITUTIONAL MEASURES FOR ENSURING THERE IS ADEQUATE CAPACITY

The SEM is an "integrated" market, by which we mean that all physical trading of energy is done through a mandatory pool, and it incorporates a **capacity payments** mechanism. This type of mechanism provides an administratively determined payment for each unit of generating capacity that is made available. Paid for by electricity users, these payments are intended to offset some of the fixed costs of generation, encouraging market participants to offer an efficient level of capacity despite the (parallel) imposition of limitations on wholesale prices.[7] In the SEM the total annual pot of capacity payments is determined in the autumn and is fixed for one calendar year. The pot of capacity payments depends broadly on how tight the market is and on the annual cost of running a best-new-entrant peaking plant. Both these measures are revised once a year.

Several alternative market-based mechanisms are used internationally to provide efficient incentives for supply of electricity generation capacity; De Vries (2007), includes a useful discussion of them. We draw upon his analysis when summarising the main types below:

Energy-only markets allow wholesale prices to vary freely. Periods of scarcity are likely to lead to very high prices, which should act as a signal for potential entrants. However, few jurisdictions are willing to tolerate such extreme price volatility, and the combination of energy-only pricing with price cap measures is likely to lead to under-investment in capacity.[8] Moreover, payoffs to investors in such a market are likely to be highly dependent on

[6] The Commission for Energy Regulation in the Republic of Ireland and the Northern Ireland Authority for Utility Regulation.

[7] In the SEM, prices are limited through bidding principles.

[8] System reliability is thought to have public good characteristics, which implies that it would likely be under-supplied in the absence of state intervention (Joskow, 2006, p.8).

prices in a few peak hours each year, and these are likely to be difficult to forecast.

Strategic Reserve measures take a portion of capacity out of the market and earmark it for use by the system operator when reserve margins are tight. Their effectiveness depends upon the assumptions that the market will replace the assets placed in the strategic reserve and that a central planner can correctly identify the optimal size of the reserve and price at which it should be dispatched.

Operating Reserves Pricing places a similar informational burden on the system operator. In this mechanism, a volume of reserve capacity is purchased in daily auctions, alongside normal operating requirements. Because of the long lead time in building electricity plants, this mechanism may also be vulnerable to investment cycles, as prices signalling scarcity lead to excess entry, followed by periods of underinvestment when prices signal that capacity is adequate.

Capacity Requirements and related models focus on the *volume* of capacity rather than its *price* as in the models we have discussed thus far. Either the system operator or electricity customers (including retail electricity companies and large users) are required to buy sufficient capacity commitments forward to meet expected demand.[9] The certainty provided by these forward purchases is intended to provide an incentive for efficient investment. These models have some attractive theoretical properties, but they rely on the presence of effective competition in the supply of capacity.[10] In a small and concentrated market such as the SEM, a forward capacity auction might be vulnerable to exercise of market power by the largest players.[11]

Although a capacity payments system is probably the most appropriate mechanism for Ireland at present, given that the ESB retains significant market power,[12] it is important to recognise some of its potential shortcomings. First, the system places an important component of price setting in regulators' hands. The level of these capacity payments is based on administrative estimates of the cost of building and maintaining a peaking plant. The incentive properties and the credibility of the SEM are thus dependent upon

[9] Some variants, such as reliability contract models, employ call options rather than forward purchases of capacity. See e.g., De Vries (2007), pp. 27-29.

[10] De Vries (2007) notes that international trade in electricity would erode many of the advantages of a system of capacity payments; because of limited and *de facto* unidirectional interconnection, this problem does not hold for Ireland.

[11] See Malaguzzi Valeri (2006) p. 9, for a discussion of capacity market power problems that have arisen in the PJM system in the United States.

[12] If structural change leads to strengthened competition in the future, this would improve the case for using some form of forward capacity market.

the regulator's ability to set an appropriate level of capacity payments.

Identifying the right level of capacity payments is not easy, and the information provided by market participants on this issue is likely to be one-sided. Both entrants and incumbents have a common interest in arguing for a formula that will provide the highest possible level of payments. Electricity users would prefer the payments (and hence retail prices) to be lower for a given level of capacity, but electricity users do not tend to respond to regulatory consultations.

REGULATORY CREDIBILITY AND PUBLIC OWNERSHIP OF GENERATION ASSETS

There is a second and less direct, but equally important, way in which government actions may affect the capacity payments mechanism. The Irish government retains an influence over a significant proportion of existing capacity through its ownership of the ESB. Public ownership of the largest electricity generation company may give rise to a temptation towards direct intervention in the market. This is partly because the transaction costs associated with direct intervention (e.g. through influence over investment or pricing decisions) may be lower, or more importantly may be perceived to be lower, when the state owns a generator than when it does not.

Why might a government wish to intervene in this way? There are many reasons, but two of the main ones are because the state has a direct stake in the success of the enterprise through the value of its shareholding (which for example might be slated for eventual privatisation), and the government may have conflicting objectives such as maintaining peaceful industrial relations in the short run and maximising long-run consumer welfare. Even if no direct intervention is intended, the government faces an additional hurdle when trying to signal to the markets that it will allow the market to operate without interference (Willig, 1994, pp.157-158; Boycko *et al.*, 1996, p. 318).

One advantage the SEM possesses when trying to establish credibility is its cross-border dimension. Establishing the market on foot of arrangements agreed between two governments and two regulators should make it more difficult for any one party to change the rules for short-term gain. Changing such an arrangement probably involves higher transaction costs than altering the rules within a single jurisdiction. In a related move, the Irish government recently removed issues affecting the SEM from the set of areas on which the Minister may give policy directions to the CER.[13] This change should also serve to increase the credibility of policy related to the market.

In parallel with the development of the SEM, the Commission for Energy Regulation (CER) has announced that structural reforms will be undertaken to improve the effectiveness of competition. Many previous studies have considered models for reducing the ESB's market power in generation by requiring the sale of some of its generating assets (recent contributions include Deloitte & Touche, 2005; McCarthy, 2005, and IPA Consulting *et al.*, 2001). In practice, structural change seems likely to rely not on a regulatory mandate, but on an agreement between the ESB and the CER that the firm will divest up to 30 per cent of its generation capacity before 2010 (CER, 2007).

The recent Energy White Paper also indicates that the government will switch the ownership of transmission assets from the ESB to Eirgrid as a means of "…enhancing competition and transparency and reducing costs" (DCMNR, 2007b, p.48). Such structural changes should reinforce regulatory credibility and strengthen competition in two ways. First, ownership of transmission assets by the generating company could encourage an external perception that that there may be an incentive for subtle forms of qualitative favouritism between the two companies. Transfer of the assets should help remove any such perception. Although conduct regulation is used to prevent favouritism of this kind, the point of structural regulation is to limit the need for conduct regulation while controlling the exercise of market power. Second, to the extent that different levels of risk are associated with the transmission and generation businesses, borrowing costs based on pooled assets could facilitate implicit cross-subsidies to the higher risk business. Transfer of the assets (together with associated debt), should also eliminate this possibility.

The SEM needs to build credibility in order to operate efficiently in the long term, and this task is made more difficult by the absence of a track record for the market, the administrative challenges of setting capacity payments and the scale of state involvement in electricity generation. It may be helped by the pre-commitment associated with its cross-border dimension and by actions taken to reduce concentration and facilitate effective competition.

[13] Ministerial policy directions are permitted under Section 7 of the Energy Regulation Act 1999; the amendment was made in Section 11(d) of the Electricity Regulation (Amendment) (Single Electricity Market) Act 2007.

2. Investment Signals from the SEM

We have earlier noted that Ireland faces a capacity deficit in the medium term. If the SEM performs as designed, it should eliminate this deficit by providing incentives for entry through the signal of high capacity payments at times when the system is under stress. In this section, we ask what sort of plant the SEM's incentives might be expected to attract.

MODELLING OF CAPACITY INVESTMENT OPTIONS

We start with a static comparison of alternative plant types, using a model of economic dispatch for the SEM. This is not intended to be a full project appraisal of the various options, but rather to focus on the main features of the investment decision. The cost of fuel used (at 2006 prices),[14] an estimate of O&M costs and the capital employed by each sort of plant are all taken into account.[15] Carbon prices are assumed to be zero. Plants earn revenue from sales of energy to the market and from capacity payments.[16] Capacity payments have been distributed across the available plant using broad assumptions on availability and assuming no forced outages.

The Irish government has ambitious targets for the share of electricity to be provided by renewable sources in the coming years. On present trends, it seems possible that the market will meet or exceed these targets, principally through the construction of wind generation capacity.[17] Increases in the use of wind generation are included in our modelling, based on projections in Eirgrid (2006).

We have estimated the model for two capacity scenarios: one representing the set of generating plants expected to be available at the start of 2008 and the other as at the end of 2011. We provide more details of the two scenarios below, but the main differences between them relate to the introduction of two new CCGTs, a substantial increase in the amount of wind capacity and planned retirements of other plants by the ESB.

For each scenario, we calculate the short-run return on capital employed (ROCE) by subtracting fuel and O&M costs from total revenue, including capacity payments, and dividing the result by the capital employed.[18] This assumption allows us to make a static comparison between plant types, but it means we are not allowing

[14] Prices were based on IEA averages for the first three quarters of 2006.

[15] However, we abstract from ancillary services and the costs of start-up and ramping up and down generators.

[16] We assume plants bid at fuel cost. This leads to conservative estimates of energy prices, since bids are likely to cover at least some other variable costs.

[17] However, there is also a renewables target for all energy use. Renewables are relatively more expensive in other forms of energy use, particularly transport, so power generation may need to considerably exceed its own target.

[18] Total revenue includes revenue from sales of energy and capacity payments, but omits ancillary services. The inframarginal rent component is also excluded from capacity payments, because it is not clear how it will be applied in the future.

for effects on a plant's profitability of subsequent entry to the market. As we shall see later, such dynamic effects may change this static picture considerably.

Table A below summarises our results for the 2008 scenario. The table compares the return on capital employed that would be earned by a marginal (10MW) new investment in a gas fired CCGT,[19] which is suited to base load generation, compared to a similar investment in a gas fired OCGT,[20] which is better suited to mid-merit or peaking operation.[21] This small increment to capacity is employed as a simplifying device to assist comparison of plant types, abstracting from the "lumpiness" of generation investments. In practice, generation investments have a much higher minimum efficient scale.[22] To provide additional context, the results include estimates of return on capital for existing peaking plant and the (base load) Moneypoint coal plant. For the latter, we provide estimates both at historic cost[23] and assumed replacement cost.

Table A: Marginal Profitability of Different Plant Types under the SEM – 2008 Scenario

Plant Type	Plant Size	Utilisation Rate	Surplus over Operating Costs	Capital Employed	Return on Capital Employed (year 1)
	MW	%	€m	€m	%
New Marginal CCGT	10	91.00	0.614	7.03	8.7
New Marginal OCGT	10	8.20	0.228	4.74	4.8
Existing Peaker	52	0.23	1.670	20.00	8.4
Moneypoint historic	284	91.00	90.400	120.00	75.3
Moneypoint replacement	284	91.00	90.400	200.00	45.2

In the 2008 scenario, system capacity is relatively tight and we estimate the time-weighted average price to be about €64 per MWh. CCGTs have been popular among actual and potential entrants in the past. Under our assumptions, a marginal investment in CCGT capacity would make a return of 8.7 per cent. This figure is slightly higher than the assumed "Best New Entrant" (BNE) cost of capital (7.83 per cent),[24] but it important to note that the returns shown in this table do not include likely revenue from sources omitted from our analysis (ancillary services revenue, the inframarginal rents element of capacity payments, ancillary services revenue and any element of O&M costs included in energy bids). In practice, the full

[19] Combined-cycle gas turbine.

[20] Open-cycle gas turbine.

[21] Recently the regulatory authorities of the SEM have decided that for technical reasons the theoretical best-new-entrant peaking plant will run on distillate oil and not gas (All Island Project, 2007). However, this does not affect our analysis.

[22] For example, a new CCGT would normally generate about 400MW per hour.

[23] We take the €368 million cost of installing flue gas desulphurisation at Moneypoint as the capital value for the historic cost analysis.

[24] All Island Project, 2007, p. 21.

expected return for each plant type should therefore be higher than our estimates.

Moneypoint does better than a marginal CCGT, due to a combination of its low cost fuel (coal), zero assumed price of carbon and the use of historic cost in valuing its capital employed. The use of replacement cost would reduce Moneypoint's estimated return on capital, but we find that the plant would still make a substantial return if the treatment were changed to replacement cost. A change in the price of carbon could adversely affect Moneypoint's profitability; however, given 2006 fuel prices, Moneypoint would still be dispatched unless carbon prices climbed to over €50 per tonne.

Because the capacity payments system is designed to allow an efficient OCGT to make a normal return, we might expect that an incremental investment in this type of plant would receive net revenue close to its required cost of capital. However, as noted above, the returns shown in Table A cannot be directly compared to the BNE cost of capital. We carried out a simple off-model analysis that suggests the apparent shortfall for this plant type compared to the BNE cost of capital is approximately equal to likely revenue from sources not included in our model.

It is important to note that in this scenario the level of demand is high relative to the level of generating capacity in the market. Such scarcity conditions should have a pronounced effect on peakers, which run for more hours than they would if a substantial capacity margin were available. Therefore, the market should (and our model suggests, would) pay oil-fired peaking plants significantly more than their cost of capital under our 2008 assumptions.

Our second static scenario moves the clock forward to 2011 (see Table B below). By this time, we assume, all plant scheduled for withdrawal from the market in Eirgrid's 2007-2013 Generation Adequacy report will have gone. These withdrawals account for over 1,000MW of capacity assumed to be operating in 2007.[25] In addition, we assume that two new 400MW CCGT plants approved for construction by ESB and Bord Gais will have entered the market, along with an additional 1,000MW of wind generation capacity. Annual demand growth is included at the average of the high and low predictions given in the ESRI *Medium-Term Review*.

By 2011, the net effect of generation construction and withdrawals is to substantially widen the margin of available generation over demand. The time-weighted average price is predicted to fall to about €58 per MWh (from €64 on the 2008 scenario).

[25] Great Island is assumed to have closed prior to the 2008 scenario, and steam capacity from Tarbert and Poolbeg is assumed to be closed by 2011.

Table B: Marginal Profitability of Different Plant Types under the SEM – 2011 Scenario

Plant Type	Plant Size	Utilisation Rate	Surplus over Operating Costs	Capital Employed	Return on Capital Employed (year 1)
	MW	%	€m	€m	%
New Marginal CCGT	10	79.0	0.135	7.03	1.9
New Marginal OCGT	10	4.5	0.116	4.74	2.4
Existing Peaker	52	0.0	1.390	20.00	7.0
Moneypoint historic	284	91.0	77.600	120.00	64.7
Moneypoint replacement	284	91.0	77.600	200.00	38.8

The resulting decrease in the profitability of generation affects all plants to some extent, but the predicted impact is relatively limited for plants towards the bottom or top of the merit order. The results reported above for Moneypoint and existing peakers are qualitatively similar to those reported above for 2008.

However, the withdrawal of expensive[26] mid-merit capacity and its replacement by substantial new wind and CCGT capacity has the effect of reducing the predicted ROCE of a new marginal CCGT investment by about 7 percentage points (from 8.7 per cent to 1.9 per cent). The returns on a marginal investment in OCGT capacity fall too, but by less than 3 percentage points (from 4.8 per cent to 2.4 per cent).

The changing relative fortunes of these two plant types appear to reflect the shift in the SEM's plant portfolio away from mid-merit and towards wind and base load capacity. While the utilisation of an incremental OCGT is reduced compared to the 2008 scenario, falling from 8.2 per cent to 4.5 per cent, this change is modest compared to the fall in utilisation of an incremental CCGT (from 91 per cent, which is the maximum level allowed in the model, to 79 per cent). Indeed, older CCGTs are affected still more adversely by the increase in total capacity and changes in the plant portfolio. For example, the 2011 simulation shows Huntstown 1 and Dublin Bay/Synergen running at about half capacity.

Comparing the 2008 and 2011 scenarios illustrates three key points about the SEM. First, plant profitability in a relatively small market is likely to be cyclical. Since increments to capacity tend to be relatively large compared to the size of the market, new plants will tend to depress profitability when they are first brought on stream, at least until demand has time to catch up with the new capacity level. Given that new investment to date has focused on CCGTs, the profitability of older (invariably less efficient) CCGTs is most affected by such increments.

[26] In the sense of high marginal cost.

Second, the unprecedented rise of wind generation, if it continues, seems likely to put pressure on the profitability of CCGTs. This, combined with firm plans for two new CCGTs, suggests that the SEM may be oversupplied with base load capacity in the medium term. Some plants may even be pushed towards the limits of their cycling ability.[27] However, it is not clear whether the rate of growth in wind generation capacity can or will be maintained at this level.

Finally, investments in peaking and mid-merit capacity are likely to be less acutely affected by these changes in the SEM's capacity level and mix. Coal generation will remain profitable unless there is a substantial increase in the carbon price, together with a fall in the relative price of gas to coal.

EFFECTS OF INCREASING THE SHARE OF RENEWABLES IN GENERATION

Beyond the effects we have modelled, the rising share of wind generation has further implications for the maintenance of adequate capacity and for the relative attractiveness of other types of plants on the system.

Because the short- to medium-term availability of electricity generated from wind is constrained by weather conditions, wind plants normally require commitment of other types of plants as backup. In effect, if wind levels drop but demand remains high, other generation assets must be available to take up the slack, sometimes in a relatively short time.

Peaking and mid-merit plants such as OCGTs are generally better suited to a reserve role than CCGTs. As the share of wind on the system rises, the efficient mix of plants should thus also include a rising share of peaking and mid-merit plants relative to base load capacity.[28] The new SEM should facilitate this, because the demand for generation capacity *net of wind power* should become more volatile as the share of wind generation rises. This provides an additional reason that investment in mid-merit and peaking plant should be increasingly attractive over time. The modelling results given above do not include back-up requirements for wind power, so they are likely to underestimate the relative attractiveness of OCGTs.

[27] Switching on and off by a plant is known as cycling. Technical and commercial parameters limit the amount of cycling that is practical for a given type of plant; e.g. if CCGTs cycle too much they may emit excessive levels of NO_x.

[28] However, the relationship is not necessarily equi-proportionate, since the output from wind plants in different parts of the country is not perfectly correlated.

IMPACT OF DIFFERING RISK PROFILES ACROSS PLANT TYPES

The optimal choice of technology for a new plant is sensitive to several uncertain parameters. Some of these parameters are largely exogenous, such as prices of carbon and various fuels. Others are endogenous, such as the extent, type and timing of competing plant entry. Up to now, we have assumed that investors can be certain about the payoffs from generation investments, given expected market structure and demand. In the remainder of this section we relax this assumption.

In particular, how does the exposure of each plant type to various sources of risk affect its attractiveness as an investment? The main risks associated with a new plant investment can be categorised between market and economic risks (e.g. fuel prices, demand growth and volatility, interest rates, labour costs, carbon prices); operational risks (achievable availability levels, unplanned outages); credit risks (depending upon contractual arrangements with energy customers) and political/regulatory risks (stability of the capacity payments system, changes to the Best New Entrant cost assumptions).

To the extent that there are significant differences among the risk profiles of plant types, changes in the perceived magnitude of particular sources of risks may alter different plant types' relative attractiveness.

Given the design of the SEM, base load (e.g. CCGT) investment is likely to be more exposed to market, economic, operational and credit risk, whereas mid-merit or peaking plant investment is more exposed to political and regulatory risk.

To see why, note that each plant type derives its revenue from two sources: sales of energy through the electricity pool and administrative capacity payments, but the relative importance of these two sources varies by plant type. Table C below shows the share of total revenue each plant type is expected to earn from capacity payments, based on our modelling results with (as before) the expected population of generating plants in 2007 and 2011.

Table C: Regulatory Risk Profiles of Different Plant Types under the SEM

	Scenario	Plant Size	Total Revenue	Capacity Payments Revenue	Share of Revenue from Capacity Payments
		MW	€m	€m	%
Marginal CCGT	2008	10	5.50	0.500	8.9
	2011	10	4.40	0.400	9.8
Marginal OCGT	2008	10	1.20	0.500	42.0
	2011	10	0.80	0.400	55.0
Existing Peaker	2008	52	2.70	2.500	93.7
	2011	52	2.30	2.300	100.0
Moneypoint	2008	284	152.90	13.800	9.1
	2011	284	142.40	15.100	8.8

A new CCGT is expected to earn over 90 per cent of its revenue from sales of electricity under the SEM. Generating this energy requires fuel and carbon inputs, an are reduced to the extent that unplanned outages occur or the plant is otherwise unavailable. Credit risk could arise if the plant's output is sold through long-term contracts. Thus a plant of this type has significant exposure to economic, market, operational and credit risks. In contrast, a peaking plant runs only rarely and uses little fuel (and emits little carbon). Because peakers run much less frequently than other plants, they may also be less vulnerable to operational risks. An unplanned outage would be costly for such a plant if it occurred at a time when the plant would have been dispatched (when prices are high), but if the risk of such breakdowns is more evenly distributed over time periods, the plant's revenues should be less vulnerable to unplanned outages than those of plants that run more continuously.

If these were the only risks faced by a plant investment, peaking and mid-merit investments should be more appealing than base load investments if expected rates of return for the former were at least as high and investors were risk averse.

However, the incidence of political and regulatory risk is probably quite different from the risk types discussed so far. In the SEM, the level of capacity payments seems more acutely exposed to political and regulatory decisions than energy revenues are. Through the bidding principles, energy revenues will be limited to a level associated with the variable costs of a marginal plant, and it is hard to see how a regulator could reduce them significantly from such levels. Maintenance of the capacity payments regime, in contrast, relies on political support and on the credibility of administrative decisions about quite technical parameters, in particular assumptions about Best New Entrant costs.

Base load plants like CCGTs and Moneypoint, which in any scenario earn most of their revenues from energy, would be least affected (in relative terms) if capacity payments were to change. A marginal investment in OCGT capacity would feel a substantially stronger effect from changes in capacity payments, with about half of its revenues depending upon the mechanism. Peakers earn almost all of their revenues from capacity payments when there is adequate capacity, but even when capacity is tight (as in our 2008 scenario), the vast majority of their revenues still come from this source.

If the governments or regulators were to intervene in a way that removed or reduced capacity payments after an investor had already built a plant, some of the revenues the investor expected might not materialise. Actual returns would then be lower than those expected at the time of investment. If this risk is material, investors will take it into account when deciding whether, how much and what type of investment to commit.

Taken together, our results on investment incentives suggest that the SEM design will deliver rates of return on new generating capacity that should be sufficient to attract new entry, provided the market arrangements are seen as credible. The mix of plant that it favours is less clear, depending partly on dynamic factors we have not modelled fully here and partly on the strength of regulatory credibility that accompanies it.

In the next section we discuss a second strand of government policy towards electricity market capacity that may also have implications for regulatory credibility and the future development of electricity generation capacity.

3. Direct State Intervention in Electricity Capacity

To achieve the best long-run outcome, the SEM's regulators need to ensure that the capacity mechanism accommodates a set of strategies by all players (incumbents, entrants, government) that will lead to the highest possible societal welfare. These strategies must also be incentive-compatible for each participant. For example, if the mechanism was designed to deliver too little capacity and shortages would result, it would not be credible to assume that government would refrain from intervention.

Although the SEM includes mechanisms that should bring electricity capacity into line with demand, recent policy developments might be interpreted as suggesting a lack of confidence in its speed or efficacy. As we will discuss in the next section, the government and regulators may wish to take actions to counter this impression and thereby reinforce the credibility of the SEM.

Our main source of concern is the Irish government's apparent intention to establish a new parallel capacity acquisition mechanism. In the recent White Paper, the government sets out seven steps it will take to "[ensure] that generation adequacy margins are improved…." Some of these steps are complementary to the SEM, including actions to improve provision of information and site availability. However, two steps may be read as alternatives to the SEM, or at least to anticipate its possible failure to deliver adequate capacity:

- *CER and EirGrid to facilitate and oversee the competitive provision of additional mid-merit/flexible generating plant of at least 240MW over the next 12-18 months to address demand and capacity constraints in the immediate term. This will also contribute to a more balanced power generation portfolio in support of competition and the growth of wind energy on the system;*

- *EirGrid and CER to plan for the undertaking of a fast build option over the next 12 months should this be warranted for*

> *generation security of supply reasons and the ownership and operation of such plant will be awarded by competitive tender.*[29]

While no further details of these planned initiatives were provided, one gets the impression that the government is contemplating a second capacity-setting mechanism to operate alongside the SEM. From the wording used in the White Paper, this might involve construction of a strategic reserve (an option mentioned earlier in this paper).

Whether or not the parallel mechanism is intended to be a strategic reserve or some other way of boosting system capacity, the possibility that it will be employed is likely to affect investor behaviour under the SEM. In particular, investors will place less confidence in the likely future returns available through the SEM if they believe that government might construct alternative capacity, particularly if it is to be remunerated through some separate mechanism.

Suppose, for example, that the new mechanism involved building a significant amount of mid-merit or peaking capacity through a tender process and dispatching these plants outside the SEM (e.g. by the system operator, as in some strategic reserve systems). This could significantly lower the volatility of residual demand for those in the SEM and thereby affect the distribution of capacity payments available through it. Once the new mechanism was in place, the government might also be tempted to put downward pressure on the sum of money made available through the capacity payments mechanism, since the capacity problem would have been "solved".

We do not suggest that this is what the government actually intends to do, but leaving its intentions unclear poses a significant risk to the credibility of the SEM.

A second more general area of concern arises from potential uncertainty over how the government views its role as a shareholder in the ESB, and in particular whether that role may affect its stance towards the SEM capacity mechanism.

We have earlier emphasised that state ownership of significant generating assets places an additional "burden of proof" on the government as it tries to establish regulatory credibility. A variety of measures have been taken that may help address this issue, including establishment of an independent regulator, use of a cross-border basis for the SEM, separation of distribution and generation businesses, and encouragement of the ESB to divest generation capacity and sites. However, credibility will ultimately depend upon

[29] DCMNR (2007b, p. 22).

whether the government is perceived to maintain a firm separation between its roles as owner of the ESB and regulator of the market. Nowhere is this more important than in decisions about construction of capacity, where firms are making commitments to long-term capital investment.

There is a recent example of how perceptions about the state's two roles may become entangled. In January 2007, the Irish government announced that it would permit the ESB to build a new power station at Aghada, Co. Cork (DCMNR, 2007a). This move was long in preparation, and it may well be justified. As the largest generator in the country, it is to be expected that the ESB would wish to continue to invest in capacity, and state support for such investment may be appropriate as long as the competitive playing field is level and the state is investing in the expectation of receiving commercial returns.

However, part of the stated rationale for government approval of the Aghada investment was to help meet an expected shortfall in Ireland's electricity generation capacity from 2009 (DCMNR, 2007a). This gives the impression that the government's decisions as shareholder are linked to its actions on capacity (which under the SEM should be firm-neutral regulatory matters). Even though this particular decision came before activation of the SEM, it might have been better for the announcement to emphasise that future capacity requirements are expected to be met through the incentives provided by the SEM.

4. Implications for Future Policy

There is a valid choice to be made between a centrally planned system and one that relies on market forces to ensure that there is adequate electricity capacity. We consider that the broad model selected for the SEM is the better choice because the market should deliver lower cost supply in the long run, but in principle either approach could deliver adequate capacity.

However, the worst possible outcome would be one in which the state intervenes over time to manage capacity levels, and the fact of this intervention undermines the credibility required to operate a market-based SEM. Lack of competitive investment through the SEM would then provide a rationale for continued state intervention, leading to a high intervention, low competition equilibrium. This might even be worse for electricity users than if the system was based on central planning in the first place. Additional inducements would probably have to be offered to firms providing capacity outside the SEM, and in the presence of barriers to entry, the existence of two mechanisms could offer opportunities for strategic behaviour by those in the market (e.g. potential investors withholding commitments to extract better terms from the state). Moreover, capacity payments would still be paid at a level intended to attract new investment.

Our modelling results suggest that the capacity payments mechanism should be able to provide appropriate signals as to the timing and nature of required capacity. However, the signals the mechanism sends out concerning how much to invest and what types of plant to build are highly sensitive to a range of factors, including the extent of perceived political and regulatory risk, the existing mix of plant in the system (and hence the pattern of withdrawals) and the Best New Entrant cost assumptions.

The regulators may wish to consider what measures may be available to bolster their perceived commitment to the capacity payments mechanism. One option would be to pre-commit to a minimum level of capacity payments, or a fixed schedule, for a number of years – or at least specify a high hurdle for changing the previously announced capacity payments. This could help to reduce market uncertainty about expected revenues from this source, reducing the perceived risk of mid-merit and peaking plant in particular. A related option would be to pre-commit not to change the assumptions made about cost of a Best New Entrant plant for a specified period of time. As well as reducing regulatory risk during the period covered, this would also have the effect of slowing revenue reductions that might otherwise accrue due to technological change. If a highly efficient new technology were introduced, its lower costs would not feed through to capacity payments while the control was in place. This measure could transfer significant benefits from consumers to producers if technology were to advance rapidly, so its effects should be considered carefully before it is applied.

Credibility may be also be adversely affected if government is seen as likely to intervene directly when signals for additional capacity investment are likely to be strong (i.e. when the risk of shortages, and hence levels of capacity payments, are high). We have concerns about the Irish government's apparent intention, mentioned in the White Paper, to establish a new parallel capacity acquisition mechanism. Little detail about these plans has been published to date. If a back-up capacity mechanism is to be established, it is vital that the government signal well in advance the conditions under which it will be activated and explain how its operation will affect those providing capacity through the SEM.

Measures such as these should complement policies directed at facilitating effective competition and encouraging demand-side responsiveness, with the ultimate goal of delivering adequate capacity at least cost.

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