CRA Insights: Energy

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Investing under regulatory uncertainty

Finding the new equilibrium

The investment challenge

In the past, assessing the prospects for generation investment was relatively straightforward. Given an assumed loss of load expectation, analysts would take projections of technology costs, commodity prices, plant retirements and system demand to model a path for power prices that would bring the market back into an equilibrium in which supply excesses or deficiencies had been eliminated. But now with government as the dominant "participant" in power generation, supporting out-of-the money low carbon investments, and the energy market failing to provide effective price signals, this old investment paradigm no longer works.

Moreover, the solution is not as simple as incorporating a carbon reduction goal to act as a constraint on forward price and capacity projections. This is in part because of additional complexities that have been introduced to the power markets, such as new generating technologies, the changing role of the consumer and the consequent requirements placed on the system operator to bring supply and demand into balance. Investors now need a more comprehensive approach to power sector projections. This requires the combination of policy analysis (for which "Brexit" is yet another major uncertainty) with the assessment of the economic factors that drive outcomes, not just within but across multiple markets that make up the industry supply chain.

New investment support and market mechanisms have not resolved uncertainties

The Government's position as the dominant participant in power generation is highlighted in Table 1. Since 2012, out of some 26GW of new capacity that have been contracted for or commissioned, some 25GW have been with the direct support of government through Contracts for Differences, the Renewables Obligation and the Capacity Market. This figure is still in excess of 20GW if plant with Capacity Market agreements are excluded.

The Levy Control Framework, that was intended to provide a guide and set a constraint on the rate of progress of government support, has been breached and an over spend of £1.5 billion is now expected in 2020/21.

As a result, at least in part, the Contracts for Differences auction planned for the end of 2015 was postponed. It is now widely expected to occur before the end of 2016 (which will further increase the Levy Control over spend), but no new date for the auction has been announced. The scope and rules for this auction are also unclear to developers and investors who are trying to bring new projects to an appropriate state of readiness. The removal of Levy Exemption Certificates, the reduction of subsidies for small solar and the cancellation of the Carbon Capture and Storage competition have further compounded uncertainties around the Government's strategy for low carbon generation investment.

Table 1: New capacity contracted and/or commissioned in Great Britain since 2012

Technology	EMR		RO/Merchant		Total CfD/RO	Total
	Total CfD	Capacity Market (De-rated)	RO Since 2012	Non-contracted New builds		
Nuclear (HPC)	3,200				3,200	3,200
Onshore wind	749		3,426		4,175	4,175
Offshore wind	4,346		2,376		6,722	6,722
Solar PV	72		4,827		4,899	4,899
Other renewables	1,521		610	65	2,130	2,195
Distributed generation		2,073			2,073	2,073
CCGT		-		910	-	910
DSR		1,433			1,433	1,433
Total	**9,888**	**3,506**	**11,239**	**975**	**24,632**	**25,607**

Source: CRA analysis

At the same time, the recent introduction of a capacity market for fossil-fired generation has had only limited success in resolving uncertainties for investors seeking to project revenue streams. The Capacity Market was established to provide an additional source of revenue to complement energy market revenues where prices have become depressed and difficult to project due to the growing influence of renewables. But clearing prices in the two capacity market auctions that have so far taken place have been well below initial expectations and below what is required to support large-scale, transmission connected generation.

Investing under regulatory uncertainty

The future is by definition uncertain, and investors customarily evaluate the impact of such uncertainty on their potential investments. Standard techniques principally involve extrapolation from historic analysis and estimation on the basis of an understood "market model". However, in the case of regulatory uncertainty, there is not always a clear precedent and the "market model" may itself be subject to fundamental change.

This leaves investors needing to develop and test market projections by reference to:

- *Policy objectives.* Regulated market mechanisms - on which investors may rely for revenues - that do not deliver outcomes consistent with policy objectives are likely to be reviewed and

modified in order to “improve” the design of the mechanism. However, the relative weight placed on competing objectives may change over time. For example, Brexit will change policy perspectives on such goals as security of supply and affordability.

- *Policy constraints*. There are numerous constraints that in practice affect the achievability and timing of the pursuit of policy objectives and associated regulatory reforms. These may be political and linked to different UK or EU-wide initiatives.
- *Underlying market economics*. Most importantly, investments that are not supported by an underlying economic advantage are inevitably more vulnerable than others.

The dependence of policy objectives and constraints on underlying market economics cannot be over-emphasised. This is highlighted by some of the distortions to, or restrictions on, economic efficiency arising from some of the regulatory mechanisms and market arrangements currently under review. Investors concerned with regulatory uncertainty need to pay close attention not just to the “big picture” of the regulatory direction of travel but also to the likely implications of these distortions. Regulatory changes to address distortions or restrictions on economic efficiency can have large impacts on investment decisions.

Current market arrangements and sources of inefficiency

The complexity and interrelated nature of markets and regulated mechanisms is evident through some changes and issues now being considered by government, industry and policymakers in relation to distortions associated with embedded benefits, locational incentives, the capacity market and network charges.

Incentives for distributed generation from embedded benefits

In the last two capacity auctions, over 2GW of new small scale diesel and gas-fired generation have secured a capacity contract (in most cases lasting 14 or 15 years). These generating sets are typically less than 50MW and are connected to the distribution network. As such, not only are they exempt from some transmission costs levied on larger generators, but can also benefit from sharing with suppliers or large industrials the mitigation of the demand-side network charges of National Grid. However, there is no similar benefit available to appropriately located, large generators directly connected to the transmission network. This is discussed further in *CRA Insights: Energy*, “**Why is the missing money, still missing?**”

Locational incentives

After a two-year investigation into GB’s energy markets, one of the most fundamental recommendations of the Competition and Markets Authority (CMA) is that wholesale prices should reflect the differential costs of transporting power to different locations. The CMA finds that “the current system of uniform charging for transmission losses creates a system of cross-subsidisation

that distorts competition between generators and is likely to have both short- and long-run effects on generation and demand".[1]

The CMA has not recommended the introduction of locational clearing prices to reflect network congestion because of possible adverse effects on contract market liquidity, but has recommended introducing locational charging for transmission losses in GB. Given the transmission charging arrangements in GB, this issue is linked to the review of embedded benefits.

Further capacity market developments

While the CMA did not consider the possibility of regionally differentiated prices in the Capacity Market, similar markets in the East Coast of the US have procedures for assigning higher capacity prices to generators located in constrained areas. This is intended to incentivize the optimal location of generation investment and reduce transmission costs. A similar approach may be required in GB to the extent that locational incentives in transmission network charges are considered insufficient.

In any event, international experience suggests that the rules and methods for implementing capacity markets are constantly evolving. Based on the evolution of the US capacity markets, we would expect further review of the GB capacity market to focus on the following.

- *Estimation of net CONE*. The estimation of the net Cost of New Entry (CONE) is important because it impacts the slope of the demand curve and, as such, the market clearing price. Net CONE should reflect the expected costs of building the marginal generation asset, minus any expected revenues from the energy and ancillary services market. Net CONE for the GB Capacity Market auction was set at £49/kW at the 2015 auction on the basis of a CCGT and has not been revised since. Our analysis suggests, however, that the energy and ancillary services revenues implied by the gross-net CONE differential are generally inconsistent with the market's expectations of energy prices (as reflected in the futures curve).
- *De-rating of generating units.* At present all generating units of the same technology type are equally de-rated. This does not allow for differential unit performance resulting from differences in age or maintenance expenditure.
- *Interconnectors*. Interconnectors may offer capacity in the Capacity Market auction. However, the financial performance of GB's new interconnectors is also underpinned by a regulatory regime that places a floor under revenues to cover operating and debt service costs. This reduces the financial risk exposure for investors in interconnectors relative to other sources of power.
- *Contract term.* The capacity market discriminates between new, refurbishing and existing capacity by offering different length of agreements to each category of plant. However, the service and performance obligations that are procured are the same for each category of

[1] Competition & Markets Authority. *Energy Market Investigation. Summary of Final Report.* 24 June, 2016

plant. Capacity contracts for new plant in the US can benefit, at most, from a 7-year contract, compared to a 15-year contract in GB.

Incentives for on-site generation from consumer network charges

The recent increases in network and policy support costs have encouraged consumers to become producers as well as consumers – in other words "prosumers". This is because distribution network charges and policy-support costs, which are in the first instance borne by suppliers, are largely recovered through charges based on energy consumption. This incentivises the prosumer to reduce metered consumption (and with it the associated liability for such charges) by investing in on-site generation. Feed-in tariffs and other "embedded benefits" also act as an additional incentive for investment.

However, network costs and policy support costs are, in practice, mostly fixed in the short-term and invariant to changes in consumption. Thus, prosumers that remain connected to the network—which brings with it the benefit of access to back-up sources of supply—and at the same time limit their exposure to consumption-based network charges, may not be meeting their share of the associated cost. Consequently, the prosumer may at present be encouraged to invest in distributed generation, when in practice from a system perspective such on-site generation has not reached parity with other forms of generation investment.

Providing for contract adaptation

Of course, long-term contracts that are available to low carbon generators and in the Capacity Market do not just provide cover against deficiencies in market revenues. They also provide some degree of protection from the regulatory uncertainties discussed in this paper. However, where these contracts interact with regulated market mechanisms that may be subject to uncertain reform and change, then there is some continuing risk exposure for investors. This arises for example in the determination of a reference price for Contracts for Differences.

This risk is at present mitigated by extensive change in law provisions and dispute resolution procedures. However, these tend to be complex and potentially burdensome to implement which increases prospective costs for investors. There is near certainty that qualifying changes will occur to a greater or lesser extent over the life of a long-term power contract given the frequency with which such changes have occurred to date. Consequently. It may be appropriate for some long-term contracts to include a "fall-back purchase agreement" that is less dependent on market arrangements, as well as a change in law safety-net.

Conclusions: Implications for investors

Investment in GB generation has recently been encouraged by the introduction of new market mechanisms in the form of auctions for renewable Contracts for Differences and for capacity agreements available in the Capacity Market. However, even with the additional revenues that these market mechanisms provide, investors still need to contend with substantial and ongoing regulatory uncertainty. The uncertainty concerns not just shifting policy objectives and constraints, but also how increasingly complex market arrangements (including new elements introduced to meet specific

policy objectives) will be developed to deliver efficient outcomes. Generation investment must cover the full range of generation from centrally connected plant to generating capacity behind consumers' meters, with varied operational capabilities and performance.

This means that potential investors, assessing the scope and potential impact of regulatory uncertainty, should set as priorities:

- *Whole system market modelling and analysis*. Given the interrelated nature of the current market arrangements and the underlying economics that determines efficient investment, it is necessary to take an all-inclusive approach to market modelling. This means taking into account the competing cost structures for generation across all the main sources of demand and the consequential impact of outcomes in one market segment on other market segments.
- *Engagement with government and regulators*. With so many potential areas for further market reform, it is clear that close engagement with government and regulators is an important means of risk mitigation for many investors. This is particularly important following the recent referendum on EU membership; negotiations with the EU and the development of new UK regulations will draw on industry views on how best to shape the future of investment in the GB electricity market. Some initial comments have focussed on the specific requirements of the EU single energy market. In practice, developing a Brexit negotiation strategy will inevitably turn from these specific requirements to a consideration of the overall effectiveness of UK energy policy – and how this may or may not be constrained by the single market.
- *Contract adaptability*. Investors should aim for contract terms that provide for adaptation to future regulatory and legal changes, while not leading to onerous procedures or the need for dispute resolution.

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