Electricity Market Reform workshop
developing ideas and solutions

Friday 18 February 2011

Key messages

- Need for strong political leadership. Need to maintain cross party support for overall carbon targets and set out vision for decarbonisation of electricity sector. Cross party support attractive to financiers who are nervous following experiences with renewables in other Member States. Certainty over continued support is more important than the level or design of the support mechanism.

- Need for greater transparency around costs, both likely impacts on bills but also cost effectiveness of different policy options. Need for further analysis to enable an assessment of £/tCO₂ saved under the different EMR packages including a realistic EPS.

- Need to get fundamentals right first then introduce policies. EMR too focused on policies and many doubt Ofgem review will result in necessary reforms to wholesale market. DECC should address reforms related to market structure and regulation itself.

- Might need to fundamentally reform the whole market as not much of a market may be left after all the EMR interventions introduced – better to do early if needed? Delegates noted that it wasn’t clear whether EMR is uprooting or just tweaking the market.

- Package includes at least one redundant policy. A range of tools will be needed to address multiple market failures however there appears to be a number of policies addressing similar problems. Incentive mechanisms are not necessarily additive and the interaction between incentives has not been fully explored. Delegates also had a number of reservations around the design of the EPS and the Contract for Difference (CfD).

- Need for prioritisation of policies. The government should not implement four major mechanisms at one time. Government needs to develop a clearly defined long-term implementation roadmap over a long period of time.

- Design the capacity mechanism early? Whilst there may not be an immediate need for a capacity mechanism, designing one early on should allow better decisions to be made. The systems operator may need to be made to take a proactive role in bringing forward new types of demand side projects.

- Need to create institutional capacity and set out responsibilities early on. The current framework is inadequate to implement the EMR package – need for a future consultation on institutional arrangements?

- Need for industrial policy. Whilst government is naturally wary of setting out fixed technology pathways, some minimum commitment to different technologies will be required to stimulate investment and enable supply chains to develop.

- Vital details missing. Government needs to make decisions soon around key details such as who would be the counterparty to low carbon contracts to reduce uncertainty and minimise a potential investment hiatus.

- Cost reduction will be essential to make the package politically stable. The package is designed to increase efficiency in a number of ways, eg by increasing competition across the supply chain and reducing the cost of capital. Need to check the scale of these efficiencies and the assumptions behind them, whether they will be achieved and how benefits/costs are distributed.
Achieving decarbonisation at lowest cost

Presentation: ‘Will the package deliver carbon reductions at lowest cost?’
Meg Gottstein, Regulatory Assistance Project

Meg outlined three ways to save carbon: reduce demand, run existing assets in a carbon efficient way (re-dispatch the existing fleet) and lower the emission profile of new generation. There are then three main types of policies to reduce power sector carbon emissions: carbon pricing, targeted investment support and minimum performance standards – the EMR package contains all three. For every option, Meg stressed the need for consideration of how many tonnes of carbon it will avoid, how much it will cost consumers per tonne and what additional tools are required to get the best results. According to Meg, evidence suggests that putting power markets and carbon pricing together can create high costs of carbon reduction for consumers and that other options such as targeted support for low carbon generators may be more cost effective. She also stressed that for carbon pricing to deliver any real carbon savings, it is essential to use the revenue generated to boost investment in energy efficiency. Meg said that it is essential that the EMR package does not result in carbon ‘lock-in’ that would make decarbonisation impossible or more costly to achieve (because of stranded assets) and that it maximises the participation of demand-side resources.

Following on from Meg’s presentation on the cost effectiveness of different types of policy mechanisms, tables of delegates were asked to think of the advantages and disadvantages of achieving electricity sector decarbonisation through a price signal only or at the other end of the spectrum, through regulation alone.

Why not go for a pure price signal ie carbon floor only?

Advantages included:
- EU-ETS is in place and provides a good base.
- Carbon price signal could be complimented by mechanisms to promote innovation.
- A carbon price path is credible.

Disadvantages included:
- Carbon tax is not legislatively certain as it goes through the Treasury and each year there is a risk of change.

Why not go for regulation only ie Emissions Performance Standard only?

Advantages included:
- An EPS guarantees power sector decarbonisation over a given timescale – hard to predict how market will react to price signals.
- Physical mechanism to deliver physical objectives – the mechanism could be targeted to encourage or discourage particular technologies.
- It demonstrates serious intent on climate change policy and gives a clear sense of travel to an end game. This certainty of outcome would generate confidence and certainty for long term investment (provided the level of EPS is grandfathered at the time investment is made).
- EPS is more legislatively certain than a carbon price.
- Affordability – lower potential risk of creating rents to generators than a carbon price mechanism.
Disadvantages included:
- An EPS could result in problems with security of supply – it may lead to a less diverse portfolio. Need for flexibility given uncertainty around technology developments, e.g. CCS. The use of company wide bubbles, rather than plant bubbles might help increase flexibility.
- Although it may be less expensive than a carbon price only approach, a regulation only approach would also be expensive raising concern over the impact on fuel poverty.
- Regulation goes against the privatisation agenda in the UK electricity sector.
- An EPS would need to be set based on independent analysis and advice but would inevitably be vulnerable to lobbying by industry.
- Putting in EPS now may create problems in other Member States.
- Grandfathering – important going forward to not undermine expectations of investors however hard to balance this with achievement of carbon targets.

Using either solely a price signal or regulation

Problems included:
- They are both sticks. If just use sticks we won’t get the smooth transition we need, risking security of supply – need for carrots and targeted support as well as sticks.
- They do not help to address certain barriers for example the need for additional measures to boost finance on the demand side.
- Neither addresses barriers to entry of new players. Need for additional measures, e.g. to eliminate/reduce offtake risk (the risk that a generator cannot sell the electricity it produces in the market), either by regulating existing players or by introducing a single buyer?

Financing the transition

Presentation: ‘A view from a capital provider’
Chris Rowland, Ecofin Investment Manager

Chris suggested that investors are not well-informed on EMR and there is widespread doubt whether the UK Government will stick to the targets in the EU Directive if the costs appear to be too high as we approach 2020. To reduce this uncertainty now, politicians need to clearly commit to the targets and be more open about the impacts on consumer bills. However Chris also noted that international investors like cross party support for carbon targets in the UK and commitment to grandfathering. He pointed out that there is no new money to invest in projects, instead there needs to be a shift of existing money and a step up in investment from institutional funds. Chris suggested that existing large companies (not necessarily utilities) would play a central role given the fairly risky, fairly low return nature of the investments involved. He questioned the value of a carbon floor price as the carbon price wouldn’t be passed onto the wholesale price as the sector decarbonises (as fossil plant no longer sets the price all the time). In order to encourage investment, Chris outlined three things which must be done: 1) protect expected rates of return of existing capacity, 2) work within the existing industrial structure to minimise disruption, and 3) make returns secure against political intervention now and in the future. He then measured the proposed package against the three objectives and suggested it failed in all three areas. Chris set out a number of ways to reduce these failures for example moving from a CfD to a fixed FIT to avoid distorting wholesale prices.
What features of today's markets stand in the way of new market entry? How can they best be mitigated or removed?

On the supply side, the amount and complexity of regulation is a major barrier to entry for new players. This can be mitigated by introducing centralised administration systems to cope with the RO and FITs, as well as the default risk around measures like the Green Deal.

On the generation side, finance needs to be found for large projects. Delegates debated over whether the same amount of capital will be spread amongst a larger number of players or whether new money will enter the market (see below).

In general, barriers to new entrants include the current structure of the power market with its high levels of vertical integration, a lack of liquidity in the market and a lack of transparency of prices. To address these issues, delegates suggested government may need to force the separation of generation and supply - get rid of vertical integration. A number suggested that the only option may be to revert to a mandatory pool-type system.

Will the proposals attract new sources and type of finance?

Depends on who bears risk? Delegates noted that the consultation paper is unclear over who bears risk so it is unclear whether the proposals will attract new sources and type of finance. If the proposals result in the creation of institutions and arrangements that take away risk from the market then they should result in new sources and types of investment. The current market manages risk through vertical integration which allows companies to manage risk in their own way. If the new arrangement leads to offtake risk being located somewhere else, either through an agency or single buyer, and if FITs or other mechanisms gave price certainty, then the proposals should attract new investments. However, this would reduce the benefits of vertical integration which could potentially reduce investment from existing players.

Replacing the RO unwise? Some delegates suggested that it is hard to see investments occurring without the renewables obligation. The RO provides an incentive for suppliers to invest in renewables and there is a sense that the RO is well understood and investors are comfortable with it. As a result, post-construction refinancing is relatively easy to obtain as well as recycling finance to invest in new projects.

New entrants in the form of small scale renewables? Examples of mechanisms that resulted in new entrants attracting significant finance for small scale renewables are the FIT for solar in Spain and wind in Germany. Belgium has done pre-construction financing on a smaller scale at a slower speed than Spain or Germany. There is a substantial amount of capital available but a limit to the scope and speed at which it can be deployed.

Proposals may not necessarily lead to reduced cost of capital. The bigger issue is pre-construction risk and the cost of capital. DECC’s biggest challenge is to remove risk or reward investors, which in theory would lower costs of capital, however in practice some financiers are sceptical. Financiers suggested that the significant remaining regulatory and political risks counterbalance the benefits of removing wholesale price risk and that the estimates of the reduction in the cost of capital resulting from the EMR package were overstated. Government needs to provide more information on important details such as who would be the counterparty to contracts.
Will the proposals avoid an investment hiatus? What more could be done?

Delegates suggested that without a set of focussed interventions, the proposals will create an investment hiatus. There is an enormous amount of detail to work out which will take significant amounts of government and industry resources; any rational investor would wait to see what the final package looks like and the impact it has on the market before bringing a project forward. There is a perceived political risk associated with investment in new plant because of fears to changes in support levels in the future if the impact on consumer bills is significant.

The hiatus is likely to last through the primary and secondary legislation stages. Investors might get clarity at the primary legislation stage but the hiatus will not end until the details are worked out – this creates a significant problem for supply chain, players and investors.

What could be done?

1. These changes have massive implementation risk. Need to develop a clearly defined roadmap over a long period of time. Government may want to prioritise the four mechanisms as it will not be possible to implement them all at the same time.
2. To maintain stability in investment for renewables, there should be an opt-in for new projects going forward now so they can access either the RO or the new FIT.
3. Other delegates suggested that government should not give projects the option of FIT or RO – simpler to just say one will be implemented and then the other. Giving an option means slower decision making for most companies. There may be credibility problem with a new system being ready in time when you think of the process needed to set prices, allocate contracts, etc.
4. Vintage the RO now – even though there will be date where no more projects are accepted into the RO, it is important that investors get immediate certainty that projects will continue to get the level of support they currently receive. Developers are not then reliant on primary legislation coming through when making near term investment.
5. Some delegates expressed concern that negative prices might undermine existing investments, it is therefore important that the reforms include measures to minimise the risk of negative prices.
6. It is not clear how CCS projects will move from demonstration to having access to the EMR mechanisms – although this problem might be ten years away it does needs to be considered early on (see section on CCS below).

How can we balance supply and demand in a low carbon world?

Will new market mechanisms be needed to balance supply and demand and, if so, when?

Delegates agreed that there will be a need for change regarding capacity mechanisms, but the group split between:

1. Those who thought that the existing National Grid/GBSO mechanisms would evolve naturally as the problems changed (citing National Grid's recent tendering of operating reserve contracts as evidence of this).
2. Those who thought that a more discrete break with current practice would be required by the changing mix of plant on the system (i.e. the prospective increased dominance of intermittent and/or inflexible generating plant).
As to when change would be required, one view expressed was that the design work should start now, specifically because there is currently no pressure on capacity margins - and, therefore, proper thought could be given to a sensible mechanism, rather than having to do something in a panic as and when a real capacity problem emerged.

**Should the mechanism(s) be 'targeted' on the identified margin or operate across the market?**

Any mechanism which started on a targeted basis would inevitably 'creep' towards being a wider-based mechanism. You would need to pay for the bit of capacity you think you need to balance system but recognise that all flexible plant will get a capacity payment.

There was discussion around the carbon impact of a general capacity payment, ie would it not be detrimental if it gave an incentive to keep existing unabated fossil plant open? It was noted this impact should be reduced to some extent as long as the carbon price fed through in the price bid in a competitive tender approach.

**What mechanism(s) would bring forward the most economic adjustments in supply or demand? Do we have the right institutional arrangements for encouraging demand side participation?**

Increasing demand side involvement is likely to be an economic way of balancing supply and demand. As to the question of getting increased demand-side involvement (including storage) in balancing the system, a number of points were made, including:

- some in the group thinking that this would happen naturally, not least as a result of increased prospective returns stemming from the increased price volatility which will result from more low/zero marginal cost plant on the system, and
- others thinking that the System Operator, in particular, would have to play an increased role in facilitating demand-side involvement in balancing – see below.

The group agreed that it is likely that there will need to be increased interconnection with Europe however what is less clear is how it might be funded.

On the supply side, keeping existing plant open is likely to be the most cost effective approach. As long as existing plant can cover its running costs it won’t close. This is a different problem from should you build new plant. If you are building new plant, you have to think of running at base load for 10 years. When we reach the point of building plant to run at 10-15% load factors, then you need a capacity mechanism.

**Who should run the mechanism(s) and/or be the counterparty/ies? Should they be given a remit to encourage new demand side services?**

The System Operator, in particular, would have to play an increased role in facilitating demand-side involvement in balancing - an involvement which could range from simply making more information available to providing aggregation services to providing 'pump-priming' investment to get economic demand schemes off the ground.
How can we ensure investment in low carbon supply?

Will one mechanism work for all technologies?

There could be one high level mechanism but it would have to be significantly redesigned for different technologies and risks. Support for different technologies will need to be linked to different price indexes. The type of support will also depend on the relative maturity of the technology. The different support arrangements may end up sharing a name but look very different though this is not necessarily a problem.

Projects have very different construction period lengths and will therefore need different lengths of visibility of support. Delegates noted the long project time scales of much of the technology involved: you need 3-5 years visibility to get investment in offshore wind and 8 years for nuclear. There is therefore need for an early signal on strike price, which could be negotiated partway through the project cycle. Some delegates questioned whether support should be based on 10 or so years rather than 20 years – as access to finance is typically based on ten year pay backs.

Should support be technology neutral or ring-fenced for specific technology groups? Does Government need to determine technology mix, if so how?

One group suggested that government shouldn’t set out specific targets for each technology but rather an overall target for carbon intensity (like an unregulated falling EPS) maximising flexibility and innovation but providing a clear glide path for industry. The other group said that government does have to determine the mix and in some ways already has by signing up to EU RE targets. It would be useful to the supply chain and development industry for government to set out minimum volume expectations for each technology group. The government may not need to set out the whole picture now however given the many uncertainties involved and can revisit in future.

Institutional needs and allocation of risk: Who should award contracts? Who carries the risk?

Delegates suggested that there may need to be two bodies:

- A body to determine prices and volumes – policy based unit within government.
- A not for profit delivery agency to administer contracts. This must take on risks that the market would overprice.

The body awarding contracts would need to be government backed given the high level of risk involved. However there are a number of innovative options for how government dealt with this risk, eg possibility that they sell debt onto secondary markets or put an obligation on suppliers to buy risk rather than just socialise the cost across consumers.

Delegates considered the challenges involved in moving from a banding review with open volume in 2011 to a tenderable price setting mechanism for fixed volume in 2025. To achieve this, a roadmap would need to be developed with predefined incremental steps to move from evidence-based to tendering and reduce the openness of volume. By the 2020s we would ideally have a tender based scenario that is technology neutral for mature technologies.
Should support levels be based on auctions or on administered prices?

It was noted that the current banding process is fairly amateur and open to manipulation from industry. However this process has resulted in a ROC regime that industry is happy with and which was attracting investment.

It was broadly agreed that open auctions would not be appropriate given the problems with planning for onshore wind and given that offshore wind and nuclear projects have already been allocated sites. In addition CCS is far from being ready to take part in auctions. Auctions could increase barriers to entry and make it hard to finance the early stages of a project as a developer could not be certain of support once the project was completed. However some form of negotiation/tendering process may be appropriate, particularly for more mature technologies.

Should low carbon support contracts be available for long-term demand reduction projects?

Yes great idea in principle and would result in the development of new types of demand side projects. However delegates noted that it would be hard to prove additionality and there would need to be a consideration of any overlap with other demand side policies.

Maximising the growth in renewables

What type of support is needed for mature renewable technologies? How might support for innovative technologies differ?

Support needs to be stable and market-based for mature technologies. It should aim to provide a level playing field. Delegates noted that competition didn’t need to necessarily be at the tariff setting point but should be promoted throughout the supply chain. For example, in recent years a number of turbine manufacturers have entered the UK market which should hopefully result in cost reductions in offshore wind.

Support for innovative technologies needs to be different to that for mature as innovative technologies have both high technology risk and deployment risk. For example, marine needs support for capital expenditure; they need upfront cost of testing and developing new types of technology rather than energy-related payment which would make projects hard to finance. Another example is deep geothermal technology which has potential (albeit on a limited scale) but is hard to finance given the small scale of projects. Innovative renewable technologies need packages based on grants and R&D funding as well as energy-based incentives as the technology matures.

How might fuel price risk be best mitigated for biomass?

There was a general consensus amongst delegates that fuel price risk shouldn’t be removed from biomass. There isn’t a reliable fuel index to reference the contract to and developers are best placed to hedge fuel risks. The main risks surrounding biomass projects related to fuel availability and sustainability issues not price risk. It was also noted that as biomass is used across a number of sectors (food, industry, heat, etc.) as well as power, removing the commodity risk from biomass electricity projects would distort competition. A capacity based payment plus some limited fuel price linked payment might be more appropriate.
Will renewables benefit from a capacity mechanism?

It would depend on the design of the capacity mechanism. Some technologies may benefit, eg hydro, biomass and geothermal (but limited potential). However wind may not benefit and it may not be the best way to incentivise projects. Delegates did note that wind can contribute to balancing through being turned off.

Does an obligation need to be placed on suppliers to buy renewable electricity?

Whilst the proposed CfD removes wholesale price risk, a number of other risks and issues remain that urgently need to be addressed:

- **Basis risk** – intermittent renewables tend to sell electricity below the average market price so would lose out under the proposed CfD which is linked to average wholesale prices.
- **Offtake risk** – delegates noted that whilst independent generators could sell electricity on a power exchange, they could only raise finance for a project if they had a PPA with a supplier. This is particularly important for small players. Whilst the buy-out fund in the renewables obligation gives suppliers some flexibility, delegates felt the mechanism did provide some incentive for suppliers to buy renewable output and were concerned that the proposed CfD could potentially be a step backwards. There was concern that the discount rate suppliers apply to power they purchase from intermittent renewables may increase over time as balancing costs rise as there is a greater penetration of renewables. To reduce the discount rates applied under PPAs (and therefore costs to end consumers) delegates suggested that it was vital that generators are given better access to markets:
  - Ideally through improving market liquidity, or if this is not done, by
  - Introducing an obligation on suppliers to buy renewable output – however it was noted this is far from ideal as further entrenches the vertically integrated model and is a poor substitute to the underlying need to improve market liquidity.
- Delegates also expressed concern over the lack of adequate reference price against which CfDs can be indexed.

Some delegates suggested that these last two problems may only be addressed by significant reform to the wholesale market, eg through the reintroduction of a mandatory pool. A number of delegates questioned whether the Ofgem review would be adequate.

What other barriers need to be addressed?

The problems with the current market structure and high levels of vertical integration were raised as important barriers to new renewable players. One delegate suggested that we need to accept the fact that we are unlikely to get rid of vertical integration but instead need to regulate the existing players so they are made to behave as if they were facing more competition and ensure fair terms for independent generators.

Additional barriers include wider issues around planning, grid connections and charges both on and offshore, and regulatory and political risk (potential for government to change its mind in future if impact on bills is too high). It was noted that the UK is party of a global market – need to see whether UK remains an attractive environment for investment after the reform details are finalised compared to other countries.
From CCS demonstration to deployment

Given that CCS is on the cusp of occurring, should the same mechanism be used to support both the demonstration and deployment phases?

Given the complexity of EMR and long timescales involved, it is unlikely that the demonstration projects will be successfully implemented under the broader EMR process. In addition the New Entrants Reserve (NER) competition is already underway in Europe and is only four years in. It is therefore likely that the first four CCS demonstration projects will have to exist outside of EMR.

The government is buying the first demonstration project through a (competitive) procurement process. Support for future projects will need to be based on how much carbon is stored. There will therefore be a shift from inputs (or gizmos) to outputs. In the early stage the price will be set through strenuous negotiations rather than a competitive process. In future however once the technology has been proven and widely deployed (depending on number of players involved) it should be easier to standardise prices.

Beyond the demo program, delegates would like to see CCS included in EMR and this to be signalled early on, ie support for deployment need to be designed into the EMR now. However, the detailed mechanism for projects beyond the demonstrations doesn’t necessarily need to be designed now. Some delegates suggested that the longer term mechanism might not need to be significantly different to that required for the demonstration projects.

Of the four mechanisms set out in the EMR package, the most important mechanisms for CCS will be FITs and potentially the capacity mechanism rather than the EPS and carbon floor price:

- CCS has a higher marginal cost than other technologies so it will need additional support through a FIT.
- Given that CCS is expected to run at a 50% load factor, capacity payments may also be necessary in future.

What impact does the carbon floor price have on CCS?

It will achieve no new low carbon generation and could drive first CCS plant generation capacity off the grid due to the increased carbon price liability of the unabated portion of the plant. As noted by Chris Rowland above, in the future, carbon price gets dropped out of equation as wholesale price is no longer always set by fossil plant.

On the other hand, a carbon floor price could be one of several forms of incentive that the technology needs. But the UK cannot allow much of a difference to open up between the EU-ETS price and the UK’s carbon floor price otherwise we will have high carbon leakage into the UK, for example a perforation of interconnectors exporting power from CCGT plants on the French coastline into the UK. The UK carbon floor price needs to be within £5-10 of the EU carbon price, to avoid hurting UK industry and incentivising tax avoidance.

What type of FIT may be best for CCS? Will the type of support need to change over time as the technology becomes commercialised?

The operating cost of CCS plant is higher than its competitors so it will end up at the bottom of merit order. A capacity payment will be required, eg if CCS is only expected to run at 50% load factor. As CCS plant has significant operating costs due to fuel use, there needs to be some fuel
commodity element in the FIT. The FIT would need to be structured slightly differently from others to include a security of supply (capacity) element.

**Will CCS benefit from a targeted capacity mechanism?**

At first the capacity payment is likely to mainly reward unabated CCGT. A capacity mechanism could help CCS plant in future but it is likely to be marginal – the heavy lifting is likely to be done through FIT. The need for a capacity payment will depend on extent to which payment under CfDs is purely commodity based or whether it includes a significant capacity element.

**How might an EPS be designed to encourage CCS?**

An EPS is a stick rather than a carrot and won’t on its own encourage new projects. It could however provide an important incentive to retrofit existing plant. An EPS could be designed to reward early movers, by being set at a more generous level at first (assuming grandfathering). The EPS would need to factor in declining load factors to have an effect. However the EPS as currently designed does not help in any of these areas.