SSE Response to DECC Consultation on Possible Models for a Capacity Mechanism

The White Paper published in July 2011 outlined the Government's view that the UK is facing a security of supply challenge over the coming decade, and concluded that a capacity mechanism needs to be introduced to ensure that secure supplies are maintained.

However the details concerning which type of capacity mechanism will be introduced, and how it will be implemented, are yet to be finalised with the Government consulting further on these areas. This response to the consultation provides SSE's views on:

1. The need for a capacity mechanism;
2. The different types of capacity mechanism, with both potential problems and solutions discussed, that are available to Government.
3. The specific consultation questions.

In summary SSE has concluded that:

- A capacity mechanism of some kind will be needed if the UK is to maintain an adequate de-rated capacity margin, and thereby ensure secure electricity supplies.
- A successful capacity mechanism should achieve a desired minimum supply security level by encouraging new capacity to be built and existing capacity to remain on the system. It should also provide the right signals to this capacity to be available at times when it is required i.e. when the system margin is low.
- A market-wide mechanism would be much more effective in achieving this than a targeted mechanism, because it mitigates the risks that generators currently face in the energy market which are preventing investment in sufficient capacity – a targeted mechanism does not do this.
- A market-wide mechanism will be able encourage DSR and non-generation options to be deployed, whilst a targeted mechanism is unlikely to do so.
- A Strategic Reserve will create additional risks for generators in the energy market. Therefore it will not encourage new capacity to be built; or existing capacity to remain on the system
- A market-wide Reliability Option also creates additional risks for generators and will not be effective if implemented in its current form.
- Both a capacity payment and a capacity market, if designed correctly, could be successful capacity mechanism models i.e. they could encourage new build; keep existing plant on the system; and provide the right signals for this plant to be available when needed.
- Of the two, the capacity payment would be a more effective model.

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1. The Need for a Capacity Mechanism

In the 2011 White Paper the Government sets out the context and rationale for introducing a Capacity Mechanism. In short it notes that one of the key challenges to maintaining secure energy supplies is ensuring resource adequacy:

> "*how to ensure there is sufficient reliable and diverse capacity to meet demand, for example during winter anti-cyclonic conditions where demand is high and wind generation low for a number of days*.[1]"

The question is therefore whether the market as it stands can deliver what is needed. Government's analysis suggests that it won't – modelling work illustrates that there will not be enough investment in the firm, flexible capacity needed to maintain an adequate de-rated capacity margin (c. 10%) at the end of the 2010s and into the 2020s.

[1] DECC: 'Planning our electric future: a White Paper for secure, affordable and low carbon electricity', (2011), p. 62.

SSE agrees with this analysis – it believes that whilst the bilateral market has been able to ensure secure supplies in the past, a number of factors mean that under current conditions the necessary investment won't come forward. These include:

1. The risk: reward profile for investments in the bilateral energy market will not provide an investment signal to build an economically efficient level of generation. Effectively the risks are such that generators are likely to build less capacity than customers need. There are several reasons for this the most significant of which is the social nature of electricity reliability i.e. an individual customer cannot contract for a differentiated level of reliability – this a point highlighted in the Consultation and the White Paper[2].

2. Returns for new plant will remain unattractive

Historically the structure and dynamics of the current bilateral market has pushed spark spreads down. Whilst this does not prevent all investment it makes the business case to build unattractive for many generators. The required volume of generation is unlikely to come forward. N.B. Currently spark spreads are particularly low because the UK's capacity margin (c. 20%) is high.

3. Investment in gas going forward is significantly riskier than is has been previously:

Going forward investors in both CCGT's (typically used to run baseload or mid-merit) and OCGT's (typically used to run at peak times), will face the potential problem of 'missing money' from their business cases, making investment riskier and therefore less attractive.

OCGT's rely on high prices (often known as 'scarcity rents') at times of high demand and low supply to cover their long-run marginal costs. With more low marginal cost low carbon plant coming onto the system (i.e. wind and nuclear) these peaks in demand will become more difficult to predict, and more infrequent, making the business case for these plants questionable. Peaks in demand will coincide with peak wind offering generators less opportunity to operate at these times.

In addition this risk of 'missing money' is exacerbated by the possibility of regulatory intervention if prices rise to a point which is deemed politically unacceptable. Therefore even if peaks in demand were predictable there is a risk that the prices needed to provide OCGTs with an adequate return would not be allowed to materialise.

For CCGT's the problem is similar. With more low marginal cost low carbon plant coming onto the system CCGT's will only run when this plant is not running; or to make up the shortfall in the capacity needed to meet demand. They will run less than they do today, making their revenues less predictable and more volatile. With fewer running hours CCGTs will rely more heavily on scarcity rents to make a return. However, as noted above, these rents may not be available due to regulatory intervention to cap prices.

SSE believes some form of capacity mechanism will be needed to rebalance the risk: reward relationship for generation by increasing the certainty associated with capacity value. This rebalancing is needed to ensure that the UK maintains an adequate de-rated capacity margin.

Whilst this will have a cost to consumers it is important to note that a capacity mechanism is not designed to over-reward generators, but rather to change the risk: reward of investments so that additional capacity is made available. Any costs can be kept to a minimum through the efficient design of any mechanism e.g. that it provides an adequate derated capacity margin, and are preferable to the costs that would be incurred if capacity margins were inadequate, and interruptions and periods of sustained high prices became more frequent.

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[2] DECC: 'Planning our electric future: a White Paper for secure, affordable and low carbon electricity', (2011), p. 66.

It should be noted that this is a view not shared by all in the industry, with some arguing that a capacity mechanism is not needed. This argument has been put forward by those who are currently in the process of developing and/or consenting new capacity – this, it is argued, illustrates that there are sufficient incentives for new entrants and that the market can deliver an adequate capacity margin going forward. However it is also these generators that stand to lose the most from the introduction of a capacity mechanism which brings additional capacity into the market.

2. Capacity Mechanism Options

As both the White Paper and the EMR consultation outline there are a number of different capacity mechanism options:

- Capacity Payments
- Capacity Market - Centrally Administered
- Capacity Market - A Reliability Option
- Targeted Resource – A Strategic Reserve

The consultation focuses on the detail of a Strategic Reserve; and Capacity Markets, with a particular focus on the Reliability Option. However this response covers all four main options, as SSE feels it is important to highlight the pros and cons of each approach.

When considering each of these options SSE has looked to answer the fundamental question of: **what is a capacity mechanism designed to do**?

The first, and most obvious, part of the answer is that it is to ensure that there is sufficient capacity built to meet demand i.e. to ensure an adequate de-rated capacity margin. However the second part of the answer is perhaps less obvious: that this capacity must be available when required. Having sufficient capacity on the system is pointless unless it is available at times when it is needed. This would also be a poor deal for consumers who will ultimately finance any capacity mechanism and are paying to ensure that there is generally always sufficient capacity to meet demand.

Therefore a successful capacity mechanism should achieve a desired minimum supply security level by encouraging new capacity to be built and existing capacity to remain on the system. It should also provide the right signals to this capacity to be available at times when it is required i.e. when the system margin is low.

2.1 Market-Wide vs Targeted

The Government analysis suggests that the energy-only market will not be able to encourage investment in the firm, flexible capacity needed to maintain an adequate de-rated capacity margin (c. 10%) at the end of the 2010s and into the 2020s. This is because the risks (outlined above) associated with investing in plant that will operate in the energy-only market are significant. Therefore, in order to fulfil the criteria outlined above and be implemented successfully in the UK, any capacity mechanism must mitigate these risks – without this mitigation there will be insufficient incentive for new plant to come forward; or existing plant to remain on the system.

There has been much debate about whether using a targeted or a market wide mechanism is the most appropriate way forward. SSE continues to believe that a targeted approach would not be appropriate as it does not mitigate the risks experienced by generators in the current (or future) residual market, and therefore would not fulfil the criteria outlined above – indeed a targeted approach could actually jeopardise the security of the UK energy systems (see Section 3 below).

By contrast a market-wide mechanism does mitigate the risks in the energy-only market and would meet the criteria for a successful mechanism. What form this market-wide mechanism would take is more open to debate – SSE believes that both a capacity payment and a capacity market could be implemented successfully, and that of these options a capacity payment would be more effective. This is discussed in greater detail in Section 4.

3. A Strategic Reserve

The fundamental flaw with the Strategic Reserve is that it does not mitigate the risks that generators are currently facing in the energy-only market. Its primary purpose would appear to be to provide capacity for use in exceptional circumstances e.g. extremely high load or situations where energy market plant availability falls outside the expected range.

The existence of the strategic reserve does not change the underlying mismatch of risk and reward in the main energy market, which is where new generation should be expected to operate, other than by providing a route for some existing capacity to exit the market. The likelihood of a new entrant into the energy market covering its investment costs will therefore not change materially.

It is difficult to see how it will encourage the investment required in new generation in this market. Indeed the existence of the Strategic Reserve will add risks into the market, thereby acting as an additional barrier to investment:

- The Government will have an amount of reserve plant on the system. If the despatch price of an SR was set at a level close to a theoretical VOLL e.g. £9000/MWh this would have a limited impact on existing plant on the system. However investors and generators will not believe that Government will never intervene to use the SR because of short-term political pressure. Given the current concerns about high energy prices it is not difficult to imagine a future scenario in which energy prices have risen further and the Government is pressured into releasing the subsidised SR plant into the market.

- The threat of intervention means that generators may therefore consider that the capacity income new plant could expect through scarcity diminishes to zero as the Strategic Reserve would be released at times when prices rose to these levels. This is likely to mean that under most scenarios new investment would not earn enough to cover its ongoing costs never mind repaying its capital. Therefore the SR creates additional political and market risk in an already risky market that is not attracting investment.

- It is difficult to see how this problem can be overcome – primary legislation would not be sufficient as it can be changed, and it is also unlikely that the Secretary of State would not be given powers to intervene in particular situations if an SR was introduced.

- DECCs projections illustrate that leaving the market as it is will lead to underbuild and blackouts. Adding significant political risk, into the already unattractive energy market will simply exacerbate this situation.

- As outlined in Section 2 a number of barriers to investment exist in the current bilateral market. The only way in which the Strategic Reserve could begin to mitigate these problems would be through existing generators moving from the residual energy market to the Strategic Reserve. However this plant would need to be replaced and the problem would be that new build would only come forward if it could get an Strategic Reserve contract because investing in the residual market remained unattractive.

- Both of these consequences – increasing the risks in an already risky market; and creating an attractive alternative for investment - would result in insufficient investment in the energy market. This leads to a slippery slope identified in the consultation in which the SR has to constantly expand to ensure that there is sufficient capacity.

- In theory there would be a point at which prices in the energy market would become extremely attractive to generators, therefore providing a signal to enter this market. However, the existence of the SR volume would imply that these prices would not materialise in practice and their existence is likely to be ignored by investors.

- Also, given the lead time for a project is considerable – currently around 7 years for a new CCGT - the right market signals may come too late for plant to come forward.

- This leaves Government with the risk that the market will underbuild, resulting in the scenario that a capacity mechanism is designed to avoid, namely blackouts.

3.1 SSE Conclusions re: Strategic Reserve
SSE firmly believes that the introduction of a Strategic Reserve would not achieve the outcomes which a capacity mechanism should result in, and has a number of undesirable consequences which could jeopardise the UKs security of supply e.g. through potential underbuild.

In addition it will be extremely difficult for DSR, storage or interconnectors to participate. For example a storage or interconnector investor would not want to limit their ability to use their asset to perhaps one hour a year or less as this would negatively impact on its ability to earn revenue from non-generation services (e.g., acting as load/export as an alternative to constraints).

4. Market Wide Capacity Mechanisms

A market-wide capacity mechanism ideally provides generators and investors with a greater degree of certainty about returns by increasing certainty about the value of capacity. This is achieved by providing generators with an additional payment to the revenue received from the energy market. This payment is effectively replacing the unpredictable scarcity rents which generators would need to receive in the energy-only market in order to make a return.

This mitigates the risks that generators currently face in the energy-only market, and therefore meets the criteria needed for a successful capacity mechanism (see section 2). It encourages new capacity to be built and existing capacity to remain on the system – and can be designed to provide the right signals to this capacity to be available at times when it is required (more detail below).

4.1 Capacity Payments

A Capacity Payment "reimburses all providers through a payment for available capacity, with the level of payment set by a central organisation.[3]" This approach therefore sets a price and lets the market discover the volume of capacity.

There are a number of advantages to such an approach – these include:

- It directly solves the problem that generators are facing in the market by providing increased **certainty and stability** about the level of returns over the long-term.

[3] DECC, op cit, p. 70.

- It is relatively **simple** to introduce, with low transaction costs.
- All players have **equal access** to this payment.
- A long signalled payment has **low regulatory risk**.

However, whilst the White Paper notes that "we recognise that there are other forms of market-wide mechanism, such as those which set price in order to incentivise sufficient volume….and these remain under consideration" there are no questions relating to the capacity payment option in the consultation. This appears to be because Government, in introducing a capacity mechanism, is attempting to achieve a certain capacity margin which it believes will provide system security – and it needs a certain amount of volume in order to reach and maintain this margin.

The question from Government is therefore: *given that we are looking to achieve a volume target, why would we set the price and let the market discover the volume, rather than set a volume and let the market discover the price?*

A number of reasons have been put forward as to why setting the price in this way will not achieve the desired outcomes. These include:

- That payments do not guarantee that targets will be met i.e. the market will build too much or too little;
- That it enables generators to be overpaid thereby increasing costs to consumers; and
- That it doesn't force generators to be available at times when they are needed i.e. when the system is short and prices are high – the times which consumers are paying to be protected from.

However SSE believes that some of these arguments are misleading and others could be resolved through an appropriately designed payment mechanism

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4.1.2 Achieving the Correct Volume:
SSE believes that the current BETTA system of bilateral trading could, given the reduction in risk that a capacity payment would bring, develop the appropriate amount of capacity to meet demand going forward. Generators would not want to oversupply capacity as this would undermine the price of electricity that they would receive in the market, and devalue their capacity payment – therefore generators have an incentive to ensure that the volume of capacity does not go above the market's required margin.

On the opposite side generators would also not wish to undersupply. In the current system capacity is not valued – however once it has been prescribed a value then, as long as there is some available reward in the energy market, new capacity will be built and existing capacity will be incentivised to stay open (as long as it remains competitive with new generation).

In addition it is worth noting that the consequences of setting the price too high in a capacity payment model would not result in overbuild. This is because the price in the energy market will fall as additional capacity comes forward. In a scenario in which the payment is set too low prices in the energy market can partially make the corresponding adjustment upwards. This reduction in income variability increases investor confidence and thereby reduces the risk of underbuild.

SSE therefore believes that generation and supply agents acting together through competitive supply and generation markets are more likely to bring about the "right" level of generation capacity than a central agent, which could face information difficulties which market participants do not have, as well as potentially being subject to "political" biases.

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4.1.3 Avoiding 'Double Payment':
As noted above a concern of some with a capacity payment is that it allows generators to be paid twice for the capacity they are providing: once via the capacity payment, and once via returns from the energy market at times when the system is short and prices are high. Given that a capacity payment is being provided as an alternative to scarcity rents (which generators would normally use to realise the value of capacity) this is an undesirable outcome, and one which could be very costly for the consumer.

However the main reason that a capacity mechanism is under consideration is the recognition that scarcity rents under scenarios where there is an adequate capacity margin will be very rare, and therefore the risk of double payment is low. Therefore an adequately supplied market delivered through a successful capacity mechanism will make periods of scarcity, and therefore double payment, extremely unlikely.

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4.1.4 Delivering Capacity When Needed:
Another criticism levelled at capacity payments is that generators get paid when not required and may not see sufficient incentive to be available when required. We believe that this problem can be mitigated through the introduction of a 'sculpted', rather than a flat, payment. More detail on how this would work is below but, in short, an individual 'pot' of capacity money that a generator could receive each year would be calculated, and the payment would then change to provide the majority of the money to generators at times of system shortage. This would provide an incentive to generators to be available at these times thereby reducing scarcity rent periods through adequate supply. In addition at times of extreme system shortage (this would be determined by the administrator) a penalty could be introduced for those plants which aren't available.

This solution also helps to ensure that capacity is not 'paid twice'. More detail on how a capacity payment model is outlined below.

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4.1.5 A Possible Model
SSE has put together the following model for a capacity payment which it believes could work – however it should be noted that this is designed to promote further discussion and thought on the effectiveness of a capacity payment to ensure security of supply, rather than as a definitive solution:

<u>1. Payment Level</u>

- Each year Government determines the appropriate capacity payment to be made to generators.
- This is done by annually assessing new entry costs, and the likely inframarginal rent for a new entrant.
- Therefore: Capacity Payment = (New Entry Costs – Inframarginal Rent)
- In years when the administrator determines that the inframarginal rent available is sufficient to attract <u>new entry</u> then the capacity payment would drop to zero.
- Generators taking contracts in this year would be protected from any changes in the calculation in subsequent contract years through the provision of the contracts.

<u>2. Contracts</u>

- Contracts of different lengths for this payment would be offered to generators depending on the age of the plant (discussed in more detail in section 4.2.2 below).
- For new plant it would be for its expected economic life (e.g. 15 to 25 years); for existing plant it would be for its residual life (ie economic life less operational years; and for plant that it has exceeded its original economic life then one year contracts could be offered.

- This approach would allow generators to back investment with an appropriately stable medium to long term income stream. It also removes a potential barrier to new entry that would occur if all plants were given long-term contracts.
- **The use of different length contracts with a price model allows Government to have a greater degree of certainty about the volume of capacity it has available over the long-term. In this model Government sets the price and then offers contracts – at this point, Government will understand the volume of generation that it is going to get and for what periods.**

3. Payment Delivery

- Central body would calculate each generator's annual derated capacity 'pot'.
- This could be: Value of MW/ MWh x annualised reliable availability x capacity = Total Pot
- Payments would then be sculpted to provide the majority of this payment at times when the system margin is low, acting as incentive for generators to be available.
- Non-availability at times of system shortage is therefore penalised by low capacity payments – this could be augmented by an additional penalty if plant is not available at times of particularly acute system stress.
- Non-availability of plant that rarely runs would have to be tested through an audit process.
- Money that would have been paid to the generator from its pot is then redistributed at the end of the year to those generators which were available.

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4.1.6 The Cost of a Capacity Payment

Another potential criticism of a capacity payment is that it would be more expensive than alternatives. However this is not necessarily the case. Based on the payment model outlined above SSE has looked at the following scenarios. In each scenario it has been assumed that the market provides the same capacity:

i. Scenario 1: Demand is as the Administrator expected.
ii. Scenario 2: Demand is less than the Administrator expected.
iii. Scenario 3: Demand is more than the Administrator expected.

For each scenario SSE has then calculated the result of a capacity auction based on an exponential capacity vs margin cost relationship; the inframarginal rent a generator might expect to receive given the short run costs of the generation stack; the total income for the generator (sum of inframarginal rent and capacity income); and the total cost to the market (sum of short run costs, inframarginal rent and capacity payments).

		scen 1	scen 2	scen 3	Expected Value
Margin		15%	21%	10%	15%
Auctioned Capacity Payment	£/MWh	3.09	1.99	5.58	3.55
Inframarginal Rent for NE	£/MWh	7.54	6.79	8.79	7.71
Sum with capacity market	£/MWh	10.63	8.78	14.37	11.26
capacity payment	£/MWh	2.78	2.78	2.78	2.78
Sum with Cap payment	£/MWh	10.33	9.58	11.58	10.49
Market Cost Cap Market	£M	8,558	8,138	9,364	8,687
Market Cost Cap Payment	£M	8,496	8,297	8,800	8,531

The table illustrates that a capacity payment is likely to out-turn less expensive than the alternative in most cases although it may be slightly more expensive under certain scenarios.

Setting a price would also give Government some certainty of how much the capacity payment would cost consumers. As outlined above there are unlikely to be runaway costs from overbuild as there are practical factors such as planning and build rates as well as commercial competitive pressures arising in the energy market which will constrain new entry above a certain volume of capacity. Government will therefore have a good idea of what it will cost overall – this is in contrast to a capacity market in which the total costs are only known after the auction has been held given the uncertainty over the market clearing price.

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4.1.7 SSE View on Capacity Payment

A capacity payment approach provides a simple means of supplementing income from the energy only market. It is likely to:

- provide an effective method of encouraging the market to provide the "right" amount of generation investment;
- provide Government with the level of certainty it requires over the volume of capacity that will be available if designed appropriately; and
- provide Government with some certainty about how much ensuring adequate capacity will cost the consumer in total (because the price is known and the volume uncertainty is limited by practical issues).

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4.2 A Centrally Administered Capacity Market

In a Capacity Market the amount of volume which the Government wants to have available is set centrally, and then an auction is held to determine the price which this capacity receives. This setting of volume and allowing the market to determine the price is the main difference between a capacity payment, as outlined above, and a capacity market – many of the other desirable design features (outlined in 4.1 and below) are similar.

SSE believes that a centrally administered capacity market is a simpler mechanism than the reliability option, with none of the problems discussed below. However, whilst a capacity market could meet the criteria for a successful capacity mechanism, there are a number of key issues/ potential problems that need to be carefully considered:

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4.2.1 Achieving the Correct Volume in a Capacity Market

In a centrally administered capacity market Government would set the required de-rated capacity margin, with a central agency setting the required volume and running an auction. However SSE does not think that a central body is better placed to determine the required volume than the market, and the risks of setting the volume incorrectly could be significant.

Setting the volume too high results in overbuild which would dilute returns in the energy market, changing the economics of plant. Setting it too low results in underbuild which leads to scarcity, and correspondingly higher prices. However this risk can partly be mitigated by not auctioning all volume annually (more detail below) and introducing different contract lengths that allow the Government to understand how much volume will be available in a range of different timeframes.

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4.2.2 What Type of Penalty?

Consumers are providing revenue to generators in order to be protected from high prices, and therefore want plant to be available at times when the system is short and prices are rising. Therefore there must be a sufficient penalty/ incentive to be available at these times, and it would need to be stringent enough to ensure this.

This is the same problem discussed above with the capacity payment and therefore the same solution could be used, with the payment sculpted to provide the correct signals. In addition an additional penalty for times of acute system stress could also be introduced.

Payment Delivery

- Central body would calculate each individual generators annual capacity 'pot'.
- This could be: Value of MW/ MWh x annualised reliable availability x capacity = Total Pot
- Payments would then be sculpted to provide the majority of this payment at times when the system is short, acting as incentive for generators to be available.
- Non-availability at times of system shortage is therefore penalised by low capacity payments – this could be augmented by an additional penalty if plant is not available at times of particularly acute system stress.
- Money that would have been paid to the generator from its pot is then redistributed at the end of the year to those generators which were available/ it could potentially be returned to consumers.

Any additional penalty payment would have to be capped, in order for generators to understand and quantify what their liabilities might be. One way in which to cap the penalty would be to either limit it to the total amount of payment received; or to make it proportional to the amount of payment received e.g. double the value.

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4.2.3 Contract Lengths

In the PJM capacity is auctioned annually – this approach ensures that less cost-effective plant which can't compete economically is closed, whilst allowing new entrants to compete. However the problem with this approach is that it provides little long-term certainty for new generation, with investors exposed to their asset becoming stranded in situations where demand drops from one year to the next. There is also a potential upside for plant in that in years when demand rises it will be rewarded to a greater degree, but this is difficult to quantify and does not address the uncertainty that a capacity mechanism is designed to mitigate, especially as this increased price is likely to be moderated by further new entry.

Potential solutions to this problem include:

- Setting a floor price and volume on the market, so that the capacity auction price and volume will never go below a certain level. This provides investors with the necessary reassurances about long-term returns.
- Offering different contract lengths to different plant depending on their 'economic life' rather than holding annual auctions for all capacity. A capacity auction would therefore be held every year, but would be for a proportion, rather than all, capacity.

This would provide the long-term certainty that investors would require to build new capacity by insulating generators against drops in demand, whilst at the same time allowing new entrants to enter the market to compete. In a situation in which all capacity was given long-term contracts new entrants could not compete, but with different contract durations this barrier is removed. It also insulates consumers from increasing capacity prices in future years if demand increases.

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4.2.4 Subsidised Plant

Another potential issue is the introduction of subsidised plant into a capacity market. Subsidised plant e.g. renewables in the UK competing in a capacity auction would distort the price at which the auction cleared driving the price down, and sending the wrong signals to investors. This has been a particular problem in the PJM.

A possible solution is to reduce any level of subsidy from one mechanism e.g. from the RO or the FiT CfD to compensate for the additional payment made through the capacity market. However whether these changes to the level of low carbon support are feasible is questionable and it would also mean that the capacity market would be exposed to changes in other policy areas. An easier, cleaner solution would be to exclude any subsidised plant e.g. that receiving any form of low carbon support from participating in the capacity market (although the central administrator would still need to take account of this capacity in its calculation).

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4.2.5 Encouraging Demand Reduction and Storage

The structure of a Capacity Market means that both primary and secondary capacity markets will be needed for it to work effectively. Providers of capacity will need to reallocate their obligations, generally for short periods of time, because of planned outages and/or unexpected breakdowns in order to avoid having to pay penalty fees. Whilst this could be done through a bilateral contract system i.e. providers negotiate bilateral contracts to ensure they are sufficiently covered, a secondary capacity market would be more effective in encouraging DSR, and ensuring that full capacity cover is provided.

The secondary capacity market, because of its predominantly short-term nature, will allow DSR providers more opportunity to engage with the capacity market thereby allowing these technologies to fully develop. If the Government is serious about promoting the use of DSR then a secondary capacity market should be encouraged.

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4.2.6 Cost

With a centrally administered capacity market the Government doesn't know what the mechanism will cost the consumer in total. This is because the final price is only known once the auction has finished. This is a risk that the Government will have to take on unless it chooses to let the volume of contracts after the contracts prices were in as was the case with NFFO/SRO. However this type of approach, given the Governments desire to achieve a certain level of volume, would appear to be counterproductive.

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4.2.7 SSE View

SSE believes that a centrally administered capacity market could be designed to ensure that the risk: reward profile for generators is changed so that an adequate de-rated capacity margin is achieved; and that plant has sufficient signals to be available when needed. It can also effectively encourage DSR and other non-generation technologies to actively participate in the market.

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4.3 The Reliability Option

As the White Paper notes the proposed Reliability Option mechanism is innovative, with no practical examples to draw from other markets. SSE has found a number of significant design issues that would have to be resolved if the mechanism was to be implemented effectively, and without introducing a number of unintended, and undesirable, consequences.

The main area of concern is the 'clawback' mechanism, which is effectively a two-way contract for difference – the interaction of this with the strike price and the reference market creates a number of interrelated issues:

It would seem logical if a **short-term market** was chosen to index the reference price for a Reliability Option. The main reason for this is that consumers are paying capacity to protect them against short-term price volatility, and using a short-term market enables generators to provide this protection.

However, if the strike price is set at a level at which there is a realistic possibility of it being exceeded then generators will want to trade in the market from which the reference price is taken to protect against basis risk. This will **seriously impact the liquidity of forward markets**.

A potential solution is to is to **set the strike price** at a level which is higher than the short-run marginal costs of the most expensive plant on the system e.g. £2000/MWh – at this level most forward trading will be unaffected as basis risk is minimised. However the full affects that it will have on forward liquidity are difficult to quantify.

The problem with this scenario is that generators are then **exposed to unlimited liabilities**. For example:

i. A 500MW plant has sold its entire capacity in reliability options, at a strike price of £2000/MWh above its variable cost. It has then sold 90% of its output forward at a price of £5/MWh above its variable cost.

ii. The reference price in the short-term market suddenly rises to £9000/MWh for 5 hours. The generator is available and generating at this point and as such pays back the excess money it has earned in the market (9,000-2,000=7,000 x 500MW x 5hrs = £17.5 million).

iii. However it has only earned (50 x 450 x 5 = £12,500) + (9,000 x 50 x 5 = £2,250,000) £2,622,500, leaving it with a total loss of £14,887,500 over a 5 hour period.

A generator would therefore be both available and generating but incurring significant losses. This type of risk makes the scheme extremely unattractive for generators – and it also means that establishing the price at which to bid into the Reliability Option auction is extremely challenging. If the penalty payment is the 'clawback' of income earned when the reference price rises above the strike price it will be impossible to assess what the probability distribution of the penalty payment will be in a reliability market. Therefore, as a generator, it is difficult to judge how much to charge for a Reliability Option. This is exacerbated by the changing distribution of capacity year on year as some plant comes to the end of its contract and others begin theirs – the right price for an Reliability Option one year could therefore be very different in subsequent years.

The Reliability Option therefore results in:

- Unlimited liabilities for generators which are impossible to quantify. This will mean, unless there is an obligation on suppliers to buy the capacity that uptake in the scheme is limited – and if there is an obligation it will be very expensive for consumers; or
- Extremely limited liquidity in the forward markets, with all the resultant problems for electricity suppliers.

4.3.1 SSE View

It is difficult to see how the Reliability Option could be implemented in the way set out in the White Paper. The only way in which the potential difficulties could be mitigated would be to remove the clawback mechanism and set an administrative penalty. However this would turn the mechanism into a centrally administered capacity market.

4.4 SSE Conclusions – Capacity Payment vs Capacity Market
If designed correctly both market-wide mechanisms would mitigate the risks that generators face in the energy-only market, and would therefore meet the criteria for a successful capacity mechanism. Whilst there are a number of design issues with each model that need to resolved SSE do not believe that these are insurmountable, and feels that some of the solutions outlined above could solve these potential problems.

Of the two models SSE has concluded that a Capacity Payment would be more effective than a Capacity Market. In practise the models are similar with many of the design issues and potential solutions common to both, but overall a Payment is a better solution because it:

- Provides Generators with a more certain reward for providing capacity;
- Can provide Government with visibility on the total cost of the mechanism as well as the level of contracted generation (assuming it is appropriately designed); and
- Is more flexible than a Capacity Market in adapting to scenarios in which the payment/ volume is set at the incorrect level. This flexibility is likely to prevent underbuild whilst limiting overbuild.

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5. Responses to Consultation Questions

Q1. Does this table capture all of your concerns with a targeted capacity mechanism? Do you think that the mitigation approach described in the table will be effective?

Q5. How can a strategic Reserve be designed to encourage the cost effective participation of DSR, storage and other forms of non-generation technologies and approaches?

Q7. How would the Strategic Reserve despatch price best be kept independent from short term pressures?

These questions are answered in Section 3 above.

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Q12: How and by whom should capacity in a GB Capacity market be bought and why?
SSE believes that capacity should be purchased by a central institution through an auction process. This is because:

1. Ensuring capacity is a system-wide issue, which is best dealt with through a central body.

2. It reduces overall complexity by ensuring a single strike price and the same contract conditions for all participants.

3. It is cheaper than the alternatives because of reduced transaction costs in secondary markets. The reduced transaction costs, and reduced overall administrative burden that this would place on suppliers, is particularly beneficial for consumers who would ultimately pay for these additional costs through higher bills.

4. It reduces the potential burden on small suppliers which could struggle to manage long-term capacity contracts.

5. Given the complexity and size of the capacity mechanism scheme, it would be sensible to allow the entire administration of the regime to be managed by a central expert body, rather than by suppliers.

6. The experience of capacity markets in the US e.g. PJM illustrates that using a central institution to purchase capacity works well.

If a central body is going to run an auction and spread the cost over suppliers then Elexon is well placed to manage this process. It is involved with the Balancing Market and Settlement Process; governance rules that would only need additions to cover this new role; and it is trusted and understood by investors. They also have access to the full range of data (including confidential market reports).

Q13: What contract durations would you recommend for a Capacity Market?
The duration of contracts for a Capacity Market will depend on how long a plant is willing to offer its capacity for. There will be situations in which a plant will want to have a contract for its entire/ the remainder of its economic life; and situations in which it only wishes to offer it for a portion of this. This is beneficial for Government as it should ensure that it has a mix of reliable, cost-effective capacity on the system.

Implementing a one-size fits all contract regime would therefore be unattractive to both generators and Government, and there therefore needs to be flexibility within the system to allow for different plant to have different contract lengths.

However, in order to provide the right signals for investors in new plant to come forward, and to ensure that older, inefficient plant does not stay on the system longer than is necessary, there should be maximum contract lengths which the Government is willing to offer to different types of plant.

SSE recommends that the maximum length of contract should be for the economic lifetime of the plant. Whilst the exact definition of 'economic life' could be debated it is generally accepted that it is 25 years. On this basis:

- For new plant the contract could be up to the whole life of the plant (e.g. 25 years);
- For older plant the contract could be up to the remaining economic life of the plant; and
- If a plant has come to the end of its economic life but is still running then it could be given up to a one year contract.

There are a number of reasons for adopting this approach.

1. Given the uncertainties of only operating in the market there is a risk that new plant will not come forward if it is only provided with an annual rolling contract. There is too much risk that in the future it would not have its contract renewed, and would therefore be forced to operate in an uncertain and unpredictable market. In addition, by providing it with a contract for life the Government is effectively ensuring that it will have a guaranteed amount of capacity for 20+ years, thereby making the procurement process easier to manage.

2. For existing plant providing it with a contract for the remainder of its economic life will help to ensure that it does not close prematurely; and

3. Whilst plant which has come to the end of its economic life will be less efficient and more expensive to run than new plant, there may well be situations in which it is needed to act as a short-term back-up (providing it is still able to perform this function effectively) to ensure secure supplies. As such allowing this plant to be given an annual contract to perform this role is sensible.

For DSR options which are able to participate in the primary capacity market the length of contract would need to be considered and negotiated depending on the type of demand reduction that was being offered – some providers may want the certainty of long term contracts, whereas others might only want to offer services for short periods. Therefore some flexibility should be allowed for DSR.

This question is also covered in Section 4.2.3

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Q14: How long should the lead time for capacity procurement be? Should there be special arrangements for plants with long construction times?
The Government's assessment that a 4 year window in which to procure the necessary capacity (which is to be determined annually) is too short. Whilst a project which has planning consent could potentially be built in 4 years, projects without consent will need around 6 years. The lead time should therefore be 6 years which would provide sufficient time for new plant to be built if necessary, and for existing plant to be procured as well.

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Q. 15: Should there be a secondary market for capacity? Should there by any restrictions on participants or projects traded?
The structure of a Capacity Market means that both primary and secondary capacity markets will be needed for it to work effectively. In both a reliability market and a centrally controlled market, providers of capacity will need to reallocate their obligations, generally for short periods of time, because of planned outages and/or unexpected breakdowns in order to avoid having to pay penalty fees. Whilst this could be done through a bilateral contract system i.e. providers negotiate bilateral contracts to ensure they are sufficiently covered, a secondary capacity market would be more effective in encouraging DSR, and ensuring that full capacity cover is provided.

The secondary capacity market, because of its predominantly short-term nature, will allow DSR providers more opportunity to engage with the capacity market thereby allowing these technologies to fully develop. If the Government is serious about promoting the use of DSR then a secondary capacity market should be introduced.

However SSE does not believe that the secondary market should include financial players and products initially. Given the new nature of such a market in the short-term it would be sensible to only allow participants who are offering physical capacity to trade.

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Q16: What are the advantages and disadvantages of making a central, administrative determination of (i) the capacity that can be offered into the market by each generator; (ii) the criteria for being available; and (iii) the penalties for non-availability? In outline how would you suggest making these determinations?

This question is answered in Section 4.2 above.

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Q17: How should the reference market for reliability contracts be determined and what would be an appropriate reference market it if is set by the regulator? How could any adverse effects of choosing a particular option be mitigated?

Q18: For a Reliability Market, how should the strike price be determined? If using an indexed strike price, which index should be used?

These questions are answered in Section 4.3 above.

Q19: For a Reliability Market, what level of physical back-up (if any) should be required for reliability contracts, and how much should it be monitored?
As the consultation notes the goal of a Reliability Market is to ensure that:

- Enough generating plants are available to operate and enough DSR/ Storage is enabled; and that
- Generators are producing electricity and DSR/ storage is reducing consumption when needed.

Firstly it is clearly fundamental that any parties which want to provide a reliability contract are credible counterparties i.e. they are able to prove that they will be able to afford penalty payments and/or provide the appropriate amount of capacity.

Given the aims of the Reliability Market it is logical to require providers of reliability contracts to prove that they have/ will have physical backing for the contracts which they are selling. As such SSE does not believe that the 'no physical backing' option outlined in the consultation is desirable as, whilst in theory the financial penalties incurred will provide an incentive for providers to have this capacity available, it may well be cheaper for providers not to do this.

There would therefore be the risk of insufficient capacity on the system at times of need, which would completely undermine the key goals of the Reliability Market outlined above. In addition it would not allow for different contract durations for new and existing plants (which, as noted above, is desirable) because the contract being sold is not actually linked to any physical generation/ demand reduction.

SSE therefore believes that some form of physical backing will need to be introduced, and a 'disappearance ratio' could be used to determine the physical capacity that a contract provider has available. This would be based on forced outage rates and helps to ensure that enough reliable capacity is available in practice; and offers incentives to providers to manage their plant well.

Q. 20: Do you agree that a vertically integrated market potentially raises issues for the effectiveness of a Reliability Market? If so, how should these issues be addressed?
The effect of vertically integrated players on a Reliability Market depends on the method through which capacity is procured. If suppliers contract for capacity through direct bilateral contracts then vertically integrated players will be able to sign reliability contracts between different arms of their businesses – however unless contracts require no physical backing there will be a requirement for the generation arms to ensure that there is sufficient capacity available to meet its contracted requirements.

This problem can be avoided altogether if capacity is procured through central auctions (either by a central body or by suppliers directly). If capacity is procured centrally then the contracts will be between generators and the central contract holder, with the overall costs passed through to suppliers; and if suppliers buy contracts through central auctions then they will be forced to accept the lowest offer, rather than a direct offer from their generation arms.