Proposed System Operations Services' Payments & Charges in SEM

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System Operator for Northern Ireland

Contents

1 Introduction

In their role as Transmission System Operators (TSOs) EirGrid and SONI procure a range of services necessary for the secure and economic operation of the respective transmission systems. These services are known as Ancillary Services (AS) in Ireland and System Support Services (SSS) in Northern Ireland. Such services include operating reserve, reactive power and black start which are mainly provided by generators. Some demand customers can provide operating reserve in the form of ‘interruptible load’ such as the Short Term Active Response scheme in Ireland.

In addition to paying for these services the TSOs can levy charges on generators which incentivise proper performance or seek to recover operational costs. Such charges apply to Grid Code performance (currently Northern Ireland only), re-declarations, trips and generator testing.

The structure, treatment and arrangement of System Operations payments and charges are different in Northern Ireland and Ireland. The introduction of the Single Electricity Market (SEM) has provided the opportunity for a review of the mechanisms by which such services are procured and charges levied with the aim of developing harmonised All-Island arrangements.

The harmonisation of the arrangements will:

- Remove any potential distortion caused by differing payment rates and mechanisms;
- Create a common methodology for the provision of services that will apply on an All-Island basis;
- Promote more competitive provision of AS/SSS;
- Encourage more efficient utilisation of these services by the TSOs;
- Ensure that the services are procured and utilised on an efficient, non-discriminatory All Island basis.

This joint TSO consultation document sets out the policy options considered for the efficient procurement of System Operations services and other system operations related payments/charges on an All-Island basis in the SEM, for implementation at some stage post the SEM’s Go-Live date of 1st November 2007.

Comments on this consultation document should be forwarded to the Regulatory Authorities (RAs) by no later than 5:00pm on 21st September 2007, as detailed in the cover note to this document. The policy options considered in this public consultation process will subsequently lead to a decision paper on the matter by the RAs.

Pending the implementation of the new arrangements the existing AS/SSS arrangements and Grid Code performance, re-declaration, trip and generator testing charges will remain in place on the “Go-Live” date of the SEM.

The implementation phase, including the detailed design of arrangements and decisions on appropriate values for the various System Operations services, will begin on completion of this consultation process. This phase may require further consultation on more detailed aspects. The timescales associated with the implementation phase will depend on which arrangements are selected.

1.1 Background

On 3rd March 2006 the TSOs presented a paper to the RAs entitled "Assessment of System Support Services/Ancillary Services Arrangements within the SEM" which recommended that work should commence on harmonising AS/SSS arrangements but, for practical reasons, it was agreed that this was not achievable by "Day 1" of the SEM (also known as the "Go-Live" day). The TSOs were subsequently actioned by the RAs to prepare a paper that would consider options for AS/SSS arrangements in the SEM. This was issued as an RA consultation on 26th July 2006 entitled "Day 1 Proposals for SSS in Northern Ireland and AS, Short Notice Redeclaration Charges and Trip/Fast Wind-down Charges in the RoI"

In the subsequent decision paper published on 29th September 2006, it was stated that the continuation of the existing separate commercial arrangements within each jurisdiction for a limited period was believed to not present a significant distortion to the SEM. On account of this, the RAs allowed the continuation of the existing arrangements for "Day 1" of the SEM subject to minor practical adjustments, pending a full and proper review of arrangements to apply at some stage post the SEM Go-Live date.

This consultation paper by the TSOs is part of the review process. It has been developed by the TSOs and incorporates comments from the RAs, comments from a broad range of industry participants at and following a workshop held on 10th May 2007, and the results of a review of international practice.

1.2 Scope

The scope of this paper includes ancillary services/system support services, Grid Code performance and generator performance incentives and trip and re-declaration charges. Generator testing charges are being considered as part of the SMO revenue submission.

The paper considers each topic under a number of headings:

- Factors influencing the selection of harmonised arrangements.
- Arrangements in similar markets internationally.
- Options and proposals for harmonisation of these arrangements.

Appendix A gives background information such as the role of the services in system operations. Appendix B gives information on the existing procurement guidelines and commercial/contractual arrangements within each jurisdiction; Appendix C provides information on the operating reserve procurement options processes.

1.3 Objectives

The objectives of this paper are to provide options for the harmonisation of Systems Operations services, Grid Code performance incentives and trip and re-declaration charges for the SEM. The options consider what should be procured or charged and how it should be procured or charged. The paper proposes the TSOs' preferred options.

The proposals are supported by a review of the advantages and disadvantages of the proposed and alternative options.

2 Considerations for the Harmonisation of System Operations Services Payments

The TSOs are required to ensure the availability of a range of services necessary for the secure and economic operation of their respective transmission systems. A key consideration is that the services should be categorised according to the service type required and not the technology that provides them.

For any service type identified, the RAs and TSOs must consider if it is necessary or appropriate to apply a financial incentive to ensure the adequate provision of the service for system security. As part of this deliberation an important consideration is whether or not the provision of the particular service is mandatory for generators.

If it is deemed appropriate to incentivise the supply of a particular service, its financial significance should be considered and hence whether it is more appropriate treat it separately for procurement purposes or bundle it into a set of services with one payment.

Another consideration is how the TSOs will procure the service. There are a number of issues to be addressed when considering the procurement.

- In principle each service would be procured through a market mechanism. However the small size of the Irish market would not generally support this.
- The complexity and cost of implementing the procurement option should be commensurate with the cost of the service and the potential benefits.
- The procurement mechanism should promote adequate supply of the service in an operational timeframe and
- Must be practical to calculate and settle.

The payments structure should also be considered in terms of whether there is

- Payment for capability and utilisation
- Rebates for non-performance
- Bonuses for performance above requirements
- Payment rates which change according to time of day/time of year.

The TSOs believe that it is appropriate to continue to incentivise generators to provide some services. It is therefore necessary to recover the costs of the incentivisation. In general the services are of benefit to all consumers. Therefore it is appropriate to treat the cost as a socialised cost and that tariffs should be levied pro rata across all consumers.

Similar issues arise for cost recovery as for those that arise for procurement, for example the recovery mechanism should be practical to calculate and settle. Significant change in this area from the current arrangements would require strong justification. The process should also not distort with other markets such as SEM.

Finally consideration must be given to how to review effectiveness of the implemented procurement and cost recovery arrangements to assess the financial value that is being obtained in following the arrangements.

3 International Review

A review of international markets has been carried out as part of the development of the proposals for System Operations payments and charges in the SEM. The review looked at the markets in Great Britain, New Zealand, Singapore, Tasmania and Cyprus. These markets were selected due to their scale, island nature and/or quality of their power system. One clear lesson learned from this study was that Ireland is different to other markets and, while there are useful comparisons to be made, Ireland currently requires different treatment because of its unique system characteristics.

The review has given a valuable insight into which characteristics of a power system impact on the appropriateness of arrangements for System Operations payments and charges.

The principle factors to consider when selecting a procurement mechanism for system operations services are as follows:

- <u>Generation</u>:

  The mix of generation types is relevant, for example

  - The level of hydro, as this is suited to the provision of ancillary services.
  - A high level of interconnection gives additional sources of ancillary service.
  - High levels of wind require high levels of ancillary services.

  Generation capacity margin is also relevant. A high ratio of dispatchable generation to demand should support competition.
- <u>Market</u>: The scale of the market will influence the complexity of procurement systems. Larger markets require more complex arrangements. The level of competition in the energy market will influence the effectiveness of an ancillary services market system.
- <u>Geographical size</u>: Due to the localised nature of some of the ancillary services, the distance between load and generation affects the criticality of each ancillary service and subsequently the price that it may be appropriate to pay for its provision.

Taking these factors into account it is clear that the SEM is a unique market which does not closely mirror any of the international markets reviewed. For example while Great Britain is similar in its generation mix and generation margins, its electricity market is approximately ten times the size of SEM and this makes complex arrangements necessary and appropriate.

In New Zealand, there is a high level of hydro plant which gives the flexibility required for competitive procurement of ancillary services.

In Singapore the installed capacity is far in excess of the demand. There is a high level of dispatchable generation which supports a good level of competition for the provision of ancillary services. Singapore is also geographically compact which significantly reduces reactive power needs.

Tasmania, although it is an island system, has recently been interconnected via a high capacity 400kV HVDC connection with Australia and participates fully in the Australian market. Tasmania also has very high level of hydro (>95%) which satisfies most of the reactive power needs.

The Cypriot electricity market is in the early stages of liberalisation and is still a fully monopolistic market with one supplier and one generator and is therefore not appropriate for comparison.

None of the systems reviewed have as much wind development as Ireland. High levels of wind will require correspondingly high levels of operating reserve. However, despite the differences, many useful observations can be made from the study of these markets.

3.1 Key Observations

The key observations which came from the review are as follows:

- All of the markets have mandatory requirements on large generators to ensure they have the capability to provide the key ancillary services of operating reserve and reactive power. However, in all markets it is accepted that providers of these services incur a cost (real or opportunity) of provision and as such need to be paid. Furthermore all markets set such payments on a commercial basis.
- All countries have market arrangements for procuring some or all of their ancillary services. The prevalence and effectiveness of ancillary services markets strongly reflects the number of potential providers (in terms of generation companies). Where competition is relatively low then bilateral agreements are more applicable.
- Most of the countries examined have implemented one set of procurement arrangements immediately rather than evolving through a number of stages. The market in Great Britain has evolved since privatisation which has helped with adjustments for changing market structure and behaviour and also with the recognition that the energy market has primacy.

The review also brought up some cautionary notes:

- In Great Britain, when a market was established for frequency regulation, the cost of the service almost doubled.
- Singapore has followed the co-optimised reserve and energy markets of New Zealand but is seeing very high costs and arrangements are under review. A lack of both flexible plant (e.g. hydro) and interconnection is believed to be the main cause of the high costs in Singapore.
- None of the markets have as significant a market share of intermittent wind generation as seen in Ireland (which is continually increasing), which makes their system operation much easier.

- In Great Britain it was recognised that experience of market behaviour and associated system operation issues under the market is required before embarking on the development of ancillary services markets.
- In New Zealand the government has become directly involved in the market to ensure sufficient margin (by building its own 155 MW OCGT). This indicates that the energy/reserve market signals are not driving competition as anticipated.
- The Great Britain market is the only market designed with complex diverse arrangements. Complex arrangements seem to be only appropriate to the large markets.

All the factors mentioned above have been taken into account to support the proposals on future arrangements later in this report. It was deemed to be useful to also consider each of the services individually. Some of the observations made for each individual service are given below.

3.2 Reserve

The following characteristics of Reserve have been noted:

- New Zealand, Tasmania and Singapore all co-optimise reserve with the energy markets. In the case of Tasmania and New Zealand this is facilitated by the large amounts of hydro which makes such an approach practical. Singapore have copied the New Zealand/Tasmania arrangements which, although does not satisfactorily fit with the generation mix in Singapore, functions due to the high plant margin, high relative reserve levels needed and the relative large size of generation units compared to island demand.
- Great Britain has a mixture of market arrangement and non-tendered bilateral contracts for procurement of reserve. This is to give the TSO flexibility in obtaining the necessary types of reserve needed by the system at most economic cost by facilitating market forces where competition is high and controlling information and cost mechanisms where competition is low which should minimise cost.
- GB has started to see an increasing focus on reserve due to the emergence of increasing amounts of wind generation on the network. There is much less wind generation in GB than in Ireland, where there is likely to be a more significant issue on managing reserve and procuring necessary services economically.
- Cyprus has only bilateral agreements for reserve, which reflects the monopoly nature of its generator.
- A mixture of “causer pays” and socialisation of the reserve costs is being used in different markets.

3.3 Reactive Power:

The following characteristics of reactive power have been noted:

- In all markets, there is a mandatory requirement for generators to have the capability to provide a defined level of reactive power which is enforced by the relevant technical Grid or Network Code. However, also in all markets the utilisation of reactive power is procured commercially with generators paid for the service, reflecting the value to the System Operator and/or opportunity cost of the generator.
- The importance of reactive power is will vary depending on the size of the island (and thus network) and the location of generation and demand (thus nature of power flows).
- In particular, reactive power is of low importance for smaller scale markets where network sizes are accordingly small with the distance of power flows being relatively small. Singapore is sufficiently geographically small and has relatively collocated generation and demand that reactive power requirements are minimal and thus costs equally minimal.
- However for larger scale islands, especially with longer network routes and/or geographical disparity of generation sites and demand centres, reactive power can be a more important service. This is the case in both GB and particularly New Zealand which have very long network routes.

3.4 Black Start

The following characteristics of black start have been noted:

- In most island markets, there are bilateral contracts for provision of black start. This is due to the need for the TSO to specify and/or control the location of such service providers.
- Accordingly black start is typically compensated by the System Operator paying, on an annuitised basis, the capital costs for construction of the black start facility. Typically utilisation including any testing is not paid for under contract if the black start facility can recover this via the wholesale market (e.g. coordinate the test in a way which allows market selling). Furthermore typically a black start facility is free to participate in the energy market if the owner feels it economic to do so.
- The exception in this study is Singapore which procures black start via a regular auction. This is due to the small island nature of Singapore, the fact that installed capacity exceeds the system demand and the coincidence of generation/load which means that localised network considerations are not important but also the presence of more than sufficient black start capable generation units which provides natural competition for service provision.
- Black start is a relatively small proportion of Ancillary Services costs. As an example in the GB market it accounts for about 4% of costs.

4 Proposed Harmonised Arrangements

4.1 Bundling versus Unbundling

There are two options for the payment mechanism to generators. This could be either a single payment for all incentivised services (bundling), paid at appropriate intervals, or could be an individual payments for each service (unbundling).

There are advantages to unbundling. The advantages are that it:

- Gives greater transparency as to what is being purchased, and can help avoid cross-subsidisation between different services;
- Can result in more effective use of ancillary service resources, since different providers can supply different amounts of each service, rather than required quantities of a bundle of services.
- Facilitates competition in certain services where provision is high relative to the requirements.

Proposed Change
It is proposed that for the reasons outlined above and in the interest of a harmonised market that an unbundled approach be taken.

4.2 Operating Reserve

Operating reserve is required to ensure secure and reliable operation of power systems. It is mandatory for generators to provide the service in accordance with the harmonised Grid Code. The fundamental role of operating reserve is to ensure sufficient capable capacity is available in operational timeframes to react to events affecting generation, demand and/or the transmission system. (A more detailed explanation of operating reserve is given in the Appendix.)

The capacity must be sufficiently flexible and controllable to be useful as operating reserve. For this reason not all generation capacity is available to provide operating reserve. Operating reserve on the Irish system is typically provided by interconnection, interruptible load (e.g. the STAR scheme in Ireland), pump storage and mid-merit gas turbines.

Due to the small scale of the Irish system, there needs to be a heavy emphasis on the provision of operating reserve. The TSOs are further aware that, as levels of intermittent generation increase, operating reserve requirements will increase. The TSOs therefore propose that the provision of operating reserve should continue to be directly incentivised through an individual payment mechanism. This allows the TSOs to give clear signals to the market of the demand for operating reserve.

In addition a stand alone incentivisation scheme aligns with the SEM's capacity payment mechanism which specifically excludes AS revenue. The TSOs strongly recommend that incentivisation continues through payments based on regulatory-approved rates.

4.2.1 Incentive Requirement

The provision of operating reserve is one of the most significant services that must be provided to the power system. In order to ensure sufficient levels, the TSOs incentivise the provision of operating reserve. This is consistent with international practice. The TSOs propose that incentivisation is continued.

The provision of capacity and the provision of reserve are fundamentally different. Incentivisation of reserve provision, in particular in the Irish market with limited interconnection and significant amounts of wind, is intended to encourage response within the required operating timeframes. Capacity payments are concerned with encouraging the capacity to exist rather than incentivising favourable response times. Therefore the signals to encourage these two separate characteristics need to be separate.

The example of the UK- Wales pool and the fact it paid for both reserve and capacity separately is worth keeping in mind

4.2.2 Stand-alone Procurement Arrangements for Operating Reserve

The provision of operating reserve currently costs approximately €25M in total for both transmission systems combined. Given the magnitude of the payment, it is appropriate and efficient to consider operating reserve as a separate individual service with separate procurement mechanisms and also possible cost recovery mechanisms rather than bundled together with all other system operation services.

Appendix C gives further detail on the options for procurement of operating reserve.

4.2.3 Options for Procurement of Operating Reserve Service

The TSOs propose a regulated approach for the procurement of the operating reserve service. In reaching this conclusion, the TSO considered several options for the procurement of operating reserves as follows:

- Regulated
- Annual tender
- Annual tender, daily market schedule for reserve
- Daily reserve market

In considering the various options, the TSOs have looked at international practice and participant opinion and believe that the regulated approach is best suited at present to the Irish market. The other options considered here would fundamentally put at risk the provision of this essential service.

4.2.3.1 Regulated Approach

The rates of payment would be set, most likely calculated by TSOs, and then approved by the RAs on an annual basis. Payment would be on an availability basis, since generators are already paid via constraints payments for being scheduled down (or up) to provide reserve, and interruptible loads should not incur additional costs through being scheduled. There would be with-held payments or penalties for not providing the required reserve. Both generators and demand customers would be encouraged to provide reserve.

Advantages:

- Matches the Irish markets key design parameters and unique characteristics
- Similar to the current approach
- Simple to administer
- Fits with current market design
- Understood and accepted by participants

It may be difficult to decide what the payment rates should be, given potentially diverse sources of reserve, however in Ireland where the primary source of reserve is from generators a flat rate across all provides simplicity for management while still delivering the service.

4.2.3.2 Annual Tender

This approach does not suit the current Irish market. The reason for this is its limited number of providers in the market at this time. A tender would either increase the payments or cause the reserve requirements not to be met by the market place.

A tender process may well work in the future for the market and is likely to be the next step from a regulated approach.

Advantages:

- Moves to a more market based approach whereby price is driven by market forces.
- If the tender process is competitive (i.e. where there is a high level of competition in the market) then the required amount of reserve is purchased in a cost effective way.
- Open to new innovative reserve providers who have clear information on the standards and prices they will need to meet to enter the reserve market

Disadvantages

- There is uncertainty as to how the market will react. Prices may increase if there are not enough existing and potential new providers.
- Significant price increases may require the RAs to determine a reserve price cap, effectively resulting in the regulated solution in any case. This has occurred in other markets.
- May required some systems development work to provide the reserve settlement, although existing settlement/finance systems may be able to be configured.
- Reserve scheduling costs still bundled up with the constraint costs in the SEM, which makes the costs of providing reserves less transparent, and makes it harder to allocate those costs in a way that gives incentives to increase performance.
- Not as flexible for providers as a daily reserve market – they are committed to providing reserve for the whole year at the same price, which may create some risks for them.

4.2.3.3 Annual tender/daily market approach

This approach does not suit the current Irish market for the same reason as given for the basic annual tender approach.

Advantages

- The approach should develop competitive price provided the market is capable and is encouraged to compete effectively/rigorously for the provision of the service
- More flexible for providers as they can offer different levels of reserve on different days provided they are Grid Code compliant.

Disadvantages

- If there are not enough existing reserve providers and potential new providers the prices may go to the RA-set reserve price cap, effectively resulting in the regulated solution in any case.
- Both the development of additional systems and the management of the arrangements, which would be resource intensive, would increase costs close to or above the cost benefits that the approach would bring itself.

4.2.3.4 Daily reserve market approach

This approach does not suit the current Irish market for the same reason as the basic annual tender approach and annual tender/daily market approach.

Advantages

- Similar to annual tender/daily market approach. However this approach would bring a more competitive price provided there is a very high level of competition and generators and demand customers are capable and willing to provide the service.

Disadvantages

- If there are not enough existing reserve providers and potential new providers the prices may go to the RA set reserve price cap, effectively resulting in the regulated solution in any case.
- Requires the most systems development work. As well as the SEM adaptation, there will need to be changes to the SEM participant interfaces, extending them to include reserve offers. Participants who wanted to offer reserve would need to develop systems or arrange for a data processing entity to enter offers for them. Both this development process and the management of the arrangements would be expensive.

Proposal

It is proposed that a regulated approach be used as the current market has limited providers (and associated risk of price increase as dominant players would be in strong positions) and as there is the possibility of a tendered approach not delivering the required reserve. In addition, having reviewed international practice, it is felt that the SEM conditions are unique as they currently stand and a regulatory approach is best suited. As the SEM develops, and particularly as wind is integrated further, other approaches may become suitable and more apparent. Therefore the TSOs suggest that the provision of reserve is closely monitored and the incentivisation level and mechanisms are regularly reviewed for appropriateness of the effective approach against other approaches.

4.2.4 Cost Recovery for TSOs

The cost of the procurement of operating reserve from providers in the SEM must be recovered through some fair and transparent mechanism. There are options for cost recovery from the simple to the complex.

- Operating reserve benefits all electricity users and is difficult to allocate to specific users. The most simple cost recovery option would be to allocate the cost as part of transmission tariff proportionally on all customers.
- Some users require higher levels of reserve. A more complex option would be to allocate the cost of operating reserve to users based on level of use. For example, regulating reserve (or the portion of the primary reserve used for regulation) would be allocated to loads – either on a MWh basis, or consistent with other transmission charges. The remaining reserve charges would be allocated to generators.
    - It is important to give the right signals to generators when operating and considering investment in new plant. However, as operating reserve revenue is small compared to other SEM revenue, it is unlikely that cost of operating reserve would be a significant concern for a new investor.
    - The operating reserve requirement is calculated based on the largest unit operating at the given time. This is analogous to the condition whereby a runway's length is calculated based on the largest airplane using it. The "runway" formula imposes higher costs on larger users. This "runway" formula is a common way of allocating reserve costs based on generator size. By implementing this formula, a signal would be sent into the market as to the preferred unit size on the system.
    - This could be adjusted where a generator unit is undergoing testing, so this generator bears more of the reserve costs when under test.
    - Potentially it could also be modified based on the historical performance of a generation unit – units with forced outages could be charged more than reliable units, providing incentives for reliability.
- Regulating reserve could be levied on demand customers and intermittent generation. The remaining reserve charges could be allocated to generators as above.

Proposal
The TSOs do not have a strong preference for cost recovery. There are many combinations once there is a move from simple proportionally levying on all customers. Should there be a move from the simple levying approach, the cost of the day to day administration would have to be taken into account. In terms of implementation and administration socialisation is the simplest approach.

4.3 Reactive Power

The adequate provision of reactive power is essential in power systems in order to ensure secure and reliable operation of power systems and avoid voltage collapse. It is mandatory service provided by generators in accordance with the harmonised Grid Code.

4.3.1 Incentive Requirement

The provision of reactive power is one of the most significant services generators must provide to the power system. In order to ensure performance, the TSOs incentivise the provision of reactive power through procurement arrangements. This is consistent with international practice. The TSOs propose that incentivisation is continued.

4.3.2 Stand-alone Procurement Arrangements for Reactive Power

The provision of reactive power currently cost just under €15M in the existing transmission systems. Given the magnitude of the payment, it is appropriate and efficient to consider operating reserve as a separate individual service with separate procurement and possibly cost recovery mechanisms rather than bundled together with all other system operation services.

4.3.3 Option for Procurement of Reactive Power Service

Reactive power has fewer options, because it is more location specific. Some of the options are:

- Regulated approach with fixed payment rates (as detailed for reserve)
- Negotiated contracts with specific providers, with regulatory approval.
- A combination of the two, with contracts covering specific requirements beyond the mandatory levels.
- A complementary approach to the above options is that the incentivisation of the provision of reactive power in the longer term should reflect transmission system development planning. Reactive power needs can also be met by transmission infrastructure such as capacitor banks or static var compensators. In developing the transmission system, the TSOs should take account of where reactive power payments are high and seek to reduce them by installing appropriate transmission equipment.

Proposal

It is proposed that a regulated approach be used as in the current market with limited providers and with the possibility of a tendered approach not delivering the required service a regulated approach is best. Grid planning which takes account of reactive power payments will complement this approach.

4.3.4 Cost Recovery for TSOs

In terms of who should pay for this ancillary service, we should consider who causes the need for the service and whether it is realistic to try to give incentives for them to change their behaviour. This applies to long run investment timeframes as well as on a day to day basis. If this is not realistic, for example because it is not possible to effectively allocate costs to the causing party, then the costs may just be spread across participants in some way.

Options:

- A simple allocation to consumers, either on a MWh basis or consistent with other transmission charges.
- If specific arrangements are in place to measure/estimate power factors for consumers then some cost recovery could be allocated on this basis

Proposal

The TSOs do not have a strong preference for cost recovery. There are many combinations once there is a move from simple proportionally levying on all customers. Should there be a move from the simple levying approach, the cost of the day to day administration would have to be taken into account. In terms of implementation and administration socialisation is the simplest approach.

4.4 Black Start

The black start service is required to restore power systems in the event of a blackout. Currently generators are paid for black start based on regulatory-approved rates.

4.4.1 Incentive Requirement

The provision of the black start service is not mandatory in Ireland. However the service is essential and therefore generators who provide the service must be adequately incentivised. The payment rates for the black start service should reflect the additional capital cost of additional generator equipment and should be bound in long term contracts.

4.4.2 Stand-alone Procurement Arrangements for Black Start

Again as black start is not mandatory, it would be difficult to bundle it with the incentivisation payments for other mandatory services. Therefore a stand alone procurement arrangement is required for the black start service. Two separate rates could apply – one for providing the service immediately and a second for installing minimum equipment that would provide for the service in the future if required.

4.4.3 Options for Procurement of Black Start Service

Option 1: Regulatory-approved rates with tender (tendered on a regional basis as new providers are required)

- Under this methodology when new black start requirements are identified, a tender is held in the required region and a rate is agreed with the successful tender. The rates are approved by the RA.

Option 2: Negotiated contracts with regulatory approval

- This would involve direct engagement by the TSO with an identified appropriate black start site and a provider in a particular region. The RA's would approve the final negotiated rates and provider. This option may work particularly well during the development of the connection offers for new generators.

Option 3: Connection requirement depending on TSO need

- This would involve inserting a clause into the connection agreement that requires all those signing up to the connection agreement to have black start capability. However in practice the TSO would tell the applicant at an early stage of the development of the connection offer if that site should be/should not be required to have the capability. The rate would then be directly negotiated.

Proposal
Option 2 is proposed to ensure that adequate services are available on an ongoing basis. Option 1 is also proposed in the short-term.

4.4.4 Cost Recovery for TSOs

All users benefit from this service, so the black start service should be levied on all consumers. A cost of the service could be allocated to consumers on a MWh basis or consistent with other transmission charges.

5 Performance Incentives

Grid Code performance is particularly important for small transmission systems. Failure of generators to perform up to the standards set out in the Grid Code cost the power system. The end consumer effectively pays for non-performance through higher constraint costs. Where a generator is non-compliant it means another generator will likely see instructed imbalances to pick up for the other generators non performance resulting in constraint costs. At present, there are a large number of generator performance derogations in Ireland. The provision of appropriate incentives could encourage better performance, reduce derogations and ultimately reduce costs.

At present it is clear from the number of existing derogations that there are not enough incentives to perform as required by the Grid Code in Ireland. Existing arrangements in Northern Ireland go some way to incentivise performance by including minimum load capabilities, minimum on time, minimum off time, governor droop capability and loading/deloading rates in the System Support Services payment. There is no equivalent in Ireland.

Appropriate performance incentives will help the TSOs in minimising constraint payments. There is significant scope for the TSOs to better ensure performance of generators in relation to the Grid Code concerning AS/SSS. The overriding principle for the development of additional performance incentives in Ireland is that there is no increase in cost to the electricity consumer.

Currently the only penalty measure in Ireland is an extreme one. Generators must comply or be removed from the system. The threat of disconnection from the system is too severe and would have too great an impact on SEM than the non-performance merits.

Alternative incentive mechanisms are required to encourage improved Grid Code performance and remove deliberate excursions from the Grid Code.

Ways to manage Grid Code performance:

Preferred methods

- Current Northern Ireland arrangements: Where the generators declare, or SONI identify, a deterioration (or reduced flexibility) in characteristics, there is a reduction (rebate) of the SSSA payment which the generators receive. Formulae exist in the existing contractual arrangements which calculate the amount of the rebate during these periods of reduced performance. These formulae take account of a range of factors such as timing and scale of deviation from the original stated level.
- Linking grid code performance with the capacity payments, so that non-performance would be penalised by a reduction in capacity payments. The TSOs would notify the SMO of non-performance and the SMO would adjust the settlement amounts.
- The performance incentivisation mechanism could be activated once a situation is found during system operation which proves a generator is not performing adequately. A penalty/reduced payment could be applied until a formal test is carried out which proves that the generator has made adjustment to ensure adequate performance.

Possible alternative methods

- A simple schedule of penalties for types of non-performance, imposed under the Grid Code. The TSO would decide non-performance has occurred and impose the penalties. Penalty funds received could be rebated off transmission tariffs.
- A simple schedule of penalties for types of non-performance, imposed under the connection agreements, if this is legally permissible. The TSO would decide non-performance has occurred and impose the penalties. Penalty funds received would be rebated off transmission tariffs.
- Case by case penalties for non-performance under the Grid Code (or connection agreements). This might involve an assessment of the costs caused by the non-performance.
- Make some other payment for grid code performance that could then be reduced for non-performance – the same arrangement as in Northern Ireland at present. Obviously this could be an extra cost if a consequent reduction in payments to generators is not made elsewhere, probably to capacity payments, in which case this option looks similar to the one above.
- Withhold AS payments for those who are non compliant.
- Reward those who move away form their derogated level of performance and penalise those who stay at a derogated level for more than a predetermined period of time
- Make Generators pay upfront for derogations. System modelling could develop the cost to the system of the derogations. The generator would pay the cost upfront before the derogation is awarded. The modelling would come under significant

scrutiny and debate as it sets the cost and therefore may not be practical to implement.

There would also need to be some kind of review or appeal process.

Proposal
The TSOs propose to use a scheme of withholding AS payments coupled with a penalty mechanism which will take the form of an amount charged to the unit which is a multiple of the rate paid for performance (similar to the Ireland WPDRS incentivisation penalties), the exact details can be agreed during the implementation of the harmonised market.

6 Trip & Re-Declaration Charges

Where a generator suffers a forced outage, both the generator and TSOs are technically and financially affected. The main financial effect for the generator is that it loses energy revenue and capacity payments under the T&SC. However, the generator has also imposed additional costs on the relevant TSO, since the TSO will re-dispatch to replace the generator, incurring increased constraint costs. Therefore it is appropriate to levy charges based on the tripping of a generator. The T&S Code does not address this charge and therefore new arrangements need to be developed.

6.1.1 TSO Proposed option for applying Trip & Re-declaration Charges

- Current arrangements: Specific calculation based on size of generation change and rate of generation change.

6.1.2 Options for applying Trip & Re-Declaration Charges

The options below should be considered along with the options in the performance incentives section. It may be appropriate to unify the Trip & Re-Declaration charges mechanisms with the incentivisation scheme.

- Rather than a specific calculation, a standard charge could be levied on generators. This would probably be a regulated amount calculated to match the relevant constraint costs over a year.
- Forced outages could be treated as a category of non-performance in the Grid Code performance regime, with different penalties depending on whether the event is classified as a trip or a re-declaration.
- There could be a modification to the arrangements for uninstructed imbalances in the T&SC to penalise participants for trips and re-declarations, with a higher rate of penalty applying for trips.
- In the current T&SC design the ex-post availability of the unit is reduced to zero, and the forced outage is not counted as an uninstructed imbalance, which could

otherwise provide a strong incentive on the participant. Future modifications to the T&SC might look at counting the forced outage as an uninstructed deviation. This would also entail systems development in the SEM systems and the TSO's systems.

- Consider the interaction of forced outages and spinning reserve charges. If the generators are paying for the costs of spinning reserve, an argument could be made that they are already paying at least some of the costs for protection from outages – similar to an insurance scheme. However spinning reserve typically pays for the costs of scheduling reserve, not necessarily the costs associated with the activation of the reserve. In any case, to provide incentives for the generators not to trip, the spinning reserve cost recovery could be modified to charge more to unreliable generators.

7 Other Issues

A number of related issues arise from the harmonisation of the operational service in addition to those discussed above. These are discussed here.

7.1 Rules V Agreements

In the short to medium term, it is proposed that agreements arrangements are kept. In the medium to long term, rules should be considered.

A rules based approach could be more transparent, and might be simpler to administer if there were a lot of contracts.

Agreements potentially allow more flexibility in contracting for different services at different locations, whereas a rules based approach would need to be more specific about defining standard services that are required. If it is possible to define a standard commodity and standard arrangements for dealing with it, then a rules based approach will work. If not, then individual contracts are probably better.

Even with an agreements based approach it would be desirable to keep the agreements as similar as possible, to avoid discrimination and to simplify management of the contracts.

A rules based approach would need some way to bind the participants and the TSOs to abide by the rules. However a contract based approach would also likely need to consider whether the RAs could force an ancillary services provider to enter into a contract with terms determined by the RAs. In both cases licences could be the vehicle used for this. A rule based approach would need a document to place the rules in. The Grid Code is a technical document and therefore it would not be an appropriate location. The Trading & Settlement Code sets out the rules for the SEM. Given that the intention is to keep ancillary services separate to the SEM, it would not be an appropriate location either. The most favourable location would be a new ancillary services code.

Any new Ancillary Services Code would need to be mentioned in the appropriate modified licences.

Proposal
It is proposed that in the short to medium term that agreements are used to secure system services. However in the long term as more entrants into the scheme, a rules based approach will be more attractive and will help reduce administrative burden.

7.2 Incentivisation of the TSOs

The TSOs recognise that it is appropriate to incentivise them to economically procure ancillary services. An incentivisation scheme is currently in place in Great Britain. However the TSOs believe that ancillary services should not be treated in isolation and that any incentive scheme developed should be developed taking into account the TSOs' entire business. The TSOs further believe that in order to develop incentives for ancillary services, that the industry must first gain experience of operating both the SEM and the other system operations services' payment and charges mechanisms.

7.3 Technology Harmonisation

Monitoring of generator reserve performance (and trips by EirGrid) in Northern Ireland and Ireland is currently based on different data acquisition technologies. SONI use event recorders which have a relatively high resolution whereas EirGrid use SCADA which has relatively low resolution. If generator reserve monitoring is to be performed in a consistent manner then monitoring technologies need to be aligned. This is an issue for the implementation stage. However, the following options for harmonisation present themselves:

- Convert SONI event recorder data to a lower resolution SCADA format.
- EirGrid install event recorders at all generating stations.
- SONI and EirGrid install new, identical, event recorders at all stations

There is a cost associated with each of these options.

8 Conclusions

8.1 Proposals

8.1.1 Operating Reserve & Reactive Power

The TSOs believe that the best way forward for System Operations payments and charges in the SEM is to continue with the regulated rate approach for both operating reserve and reactive power. The TSOs propose to report on a regular basis any change in the system services market and including whether other approaches such as a tendered or market based approach would be appropriate.

8.1.2 Black Start

For the black start service, a combination of a tendered approach with regulatory approved rates for existing generators and regulatory-approved negotiated contracts for new generators is recommended.

8.1.3 Unbundling of services

An unbundling of services would bring transparency, efficient use of capabilities of the generation mix and promote competition. Unbundling should be a feature of successful harmonised arrangements.

8.1.4 Grid Code performance

In terms of Grid Code performance the more cost based penal system in Northern Ireland is seen as desirable and hence the move towards this system. It is recommended that in the short to medium term that agreements are used to secure system services.

8.1.5 Proposed option for applying Trip & Re-declaration Charges

Trip & Re-declaration charges should be based on a specific calculation which is a function of the size of generation change and rate of generation change.

8.2 Next Steps

Comments on this consultation document should be forwarded to the RAs by no later than 5:00pm on 21st September 2007, as detailed in the cover note to this document. The TSOs are seeking to confirm from the consultation process that their recommendations are suitable. The TSOs are interested in understanding the generator and demand customer perspectives on the issues and recommendations discussed in the paper.

The policy options considered in this public consultation process will subsequently lead to a decision paper on the matter by the RAs. The decision paper will outline policy for the harmonised treatment of AS/SSS as well as other system operations related charges/payments as discussed in this paper.

The implementation phase will begin once the harmonised arrangements have been selected. The timescale for the implementation phase will depend on which arrangements have been selected and the ease with which they can be incorporated into existing systems. This phase is likely to require further consultation on more detailed aspects. The work on the development of systems to settle and monitor harmonised system services and the work on deciding a value for the rates to be applied to the system serves will take place during the implementation phase which is expected to run throughout 2008.

Appendix A: System Operation Services Technical Summary

This section gives a brief explanation of the main system operation services procured by the TSOs.

A.1 Operating Reserve

In addition to dispatching generators to supply energy to match demand, the TSO will schedule additional generating capacity to provide operating reserve (OR). Operating reserves are used to respond to sudden outages of generating plants or transmission lines that are providing supplies of energy to meet demand in real time. The OR sources must be capable of reacting sufficiently quickly to maintain the frequency, voltage and stability parameters of the network within acceptable ranges. OR typically consists of 'spinning reserves' which can be fully ramped up to supply a specified rate of electric energy production in less than 10 minutes and 'non-spinning reserves' which can be fully ramped up to supply energy over a slightly longer time frame of up to around 30 minutes. Primary, Secondary, Tertiary 1, Tertiary 2 and Replacement reserve are examples of OR and are defined by the ramp up limits. OR can be sourced from any location on the power system to cover for loss of generation. Additional generation is also scheduled to provide continuous frequency regulation (aka regulating reserve or automatic generation control) to stabilise network frequency in response to small instantaneous variations in demand and generation. OR is the largest of the ancillary services.

A.2 Reactive Power

The adequate provision of reactive power is essential in power systems in order to ensure secure and reliable operation of power systems. Reactive power is tightly related to bus voltages throughout a power network, and hence reactive power services have a significant effect on system security. Insufficient reactive power supply can result in voltage collapse – such as those occurring in Canada-US and Sweden in 2003. The US-Canada Power System Outage Task Force states in its report that insufficient reactive power was an issue in the August 2003 blackout, and recommended strengthening the reactive power and voltage control practices. There is a key restriction associated with RP which is that it cannot be transferred over large distances. Therefore the provision of RP is confined to local markets.

A.3 Black Start

Black start units are generators capable of being started and synchronized without the support of the power grid. They are needed in the event of widespread power black out. Selecting black start generators is, to a degree, location dependent given that black start generators must be electrically other generators to re-build the system. The black start units must also have sufficient capacity and ramping capability to be able to provide the restart power required by the other units. The system operator will determine how many units within the control area must have black start capability, where they are to be located, and how to use them in the event of a blackout.

A.4 Other Main Services

There are many more capabilities that TSOs require of generators in order to effectively operate the transmission system. These are specified in the Grid Code. Among the more important are:

- Minimum load capabilities,
- Minimum on time,
- Minimum off time (which combines with minimum on time to effectively set a Maximum number of starts in a 24hr period)
- Governor droop capability
- Loading/deloading rates

Appendix B: Existing Arrangements

When discussing Ancillary Services (AS) arrangements in the Ireland and System Support Services (SSS) in Northern Ireland, it is important to note the differences in the scope of these services as defined by each TSO. In the Ireland, operating reserve, reactive power and black start are defined as AS. In Northern Ireland, as well as operating reserve and reactive power, SSS also include minimum load capabilities, maximum number of starts in a 24hr period, minimum on time, governor droop capability and loading/deloading rates. In Northern Ireland black start capability is a grid code connection condition. The following sections summarise the existing AS/SSS arrangements for each TSO.

B.1 SONI’s System Support Services

The independent generator in Northern Ireland (CPS CCGT) is contracted to provide SSS through a bi-lateral System Support Service Agreements (SSSA) with SONI.

For Power Procurement Business (PPB) steam plant, the PPB GUA’s (Generator Unit Agreements) provide SSS in the same physical terms as the SSSA. The PPB GUA payments are commercially different to SSSA payments due to the differences in PPB plant availability payments. At present SONI pays PPB for SSS based on the SSSA payment mechanism (see below) although a SONI / PPB SSSA does not exist.

All steam units get paid at the same SSS availability credit of £0.50/MW/h for the following services: operating reserve, reactive power, minimum load capabilities, maximum number of starts in a 24hr period, minimum on time, governor droop capability and loading/deloading rates. The SSS availability credit is derived from a yearly average value of £0.50/MW/h, weighted for time of year and time of day. Failure to provide any of these services or a declared inflexibility will result in a reduction of the SSS availability credit and possible rebate payments from the generator to SONI.

For example, a 400MW unit with 90% availability will receive (£0.50/MW/h x 400MW x 8760hrs x 90%) £1,576,800 annually in respect of SSS payments (assuming no rebates apply).

OCGTs in Northern Ireland are under PPB contract and receive an availability payment from SONI part based on successful starts of up to £5.2/MW/h (scaled by availability). The OCGTs SSS are subject to GUA conditions but an SSSA levy is not paid by SONI.

Generators are monitored for the provision of these services against their technical characteristics set out in their connection agreement.

An overview of the flow of payments for SSS from demand customers to generators is summarised in Figure 1.

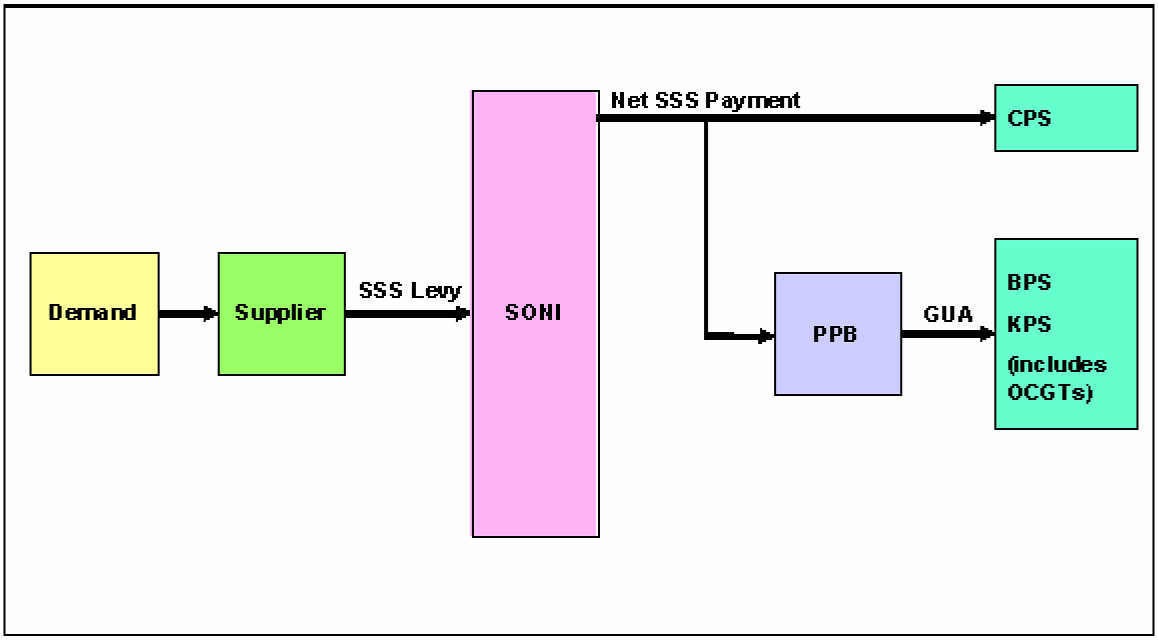

Figure 1 Overview of SSS Money Flow in Northern Ireland

B.2 EirGrid's Ancillary Services

Generators in the Ireland are offered bi-lateral contracts with EirGrid for the provision of AS. These contracts, which are approved by the CER, set out the technical characteristics of the generator and the commercial arrangements by which EirGrid pays the generator for delivery of services and rebates the generator for failure to provide services.

Three Ancillary Services are contracted by EirGrid; these are operating reserve, reactive power and black start. Operating reserve and reactive power services are mandatory with minimum technical standards set out in the Grid Code. Black start is a service which is contracted for as required by EirGrid.

EirGrid also contracts directly with approximately 40 commercial/industrial customers for the provision of an interruptible load service. Interruptible load contributes towards EirGrid's operating reserve requirements.

The payment rates for the provision of AS are approved by the CER and published annually in EirGrid's 'Ancillary Services Statement of Payments'. Payment rates for operating reserve range between €1.91/MWh and €1.19/MWh for the different reserve categories. The total payment for each category of reserve in each trading period is capped at EirGrid's operational requirements in that period. If, because of generator loading conditions, more reserve is available than required, then the payment rate is scaled to limit the payment to the cap for that period. Payments for reactive power are calculated based on by availability and utilisation. The figures are €0.152/Mvarh for availability and €1.28/Mvarh for utilisation. Currently the rates are the same for leading and lagging reactive power. Black start payments range from €7.34/h to €74.68/h.

AS payments are made directly from EirGrid to generators or to PES in the case of Edenderry Power Ltd. as Edenderry have nominated PES as their agent. Payments are also made directly to demand customers for IL service. EirGrid recovers the cost of AS from demand customers through the TUoS tariff.

An overview of the flow of payments for AS from demand customers to generators is summarised in Figure 2.

Approximately one third of EirGrid's operating reserve AS payments are made to ESBPG's Turlough Hill pumped storage station as its technical characteristics mean that it can provide significant quantities of operating reserve.

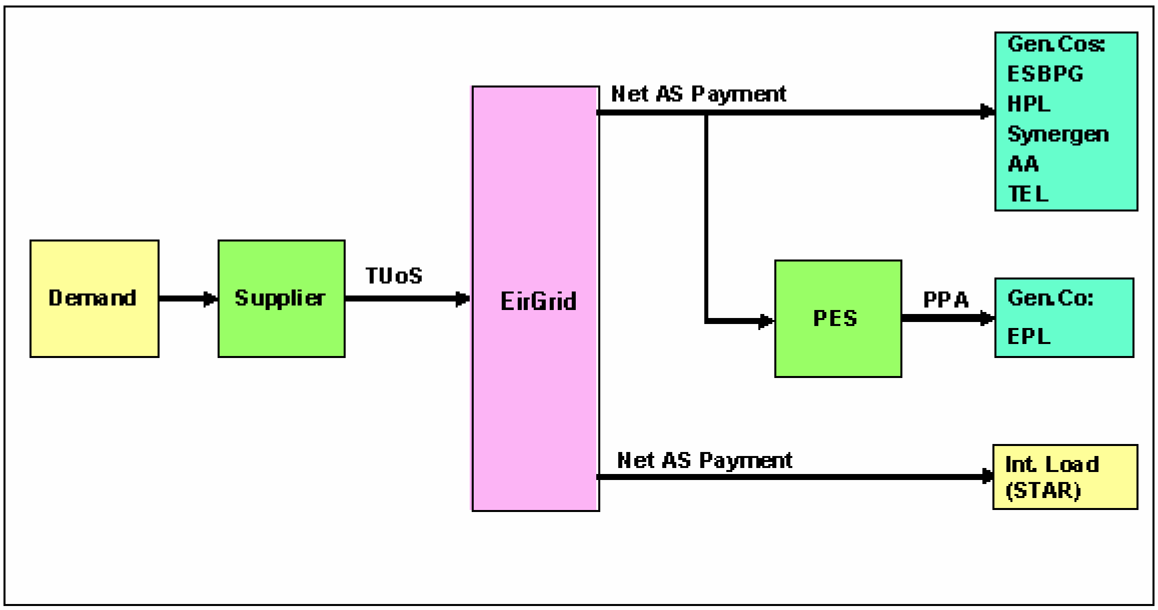

Figure 2 Overview of AS Money Flow in Ireland

Appendix C: Operating Reserve Procurement Options Processes

This appendix outlines possible processes behind the some of the procurement options identified in the paper. Operating Reserve is the only service included in this appendix as it has more procurement options that the other services discussed. The possible processes for other services are a subset of those expanded on below. The appendix is for background discussion only.

C.1 Operating Reserve

Operating Reserve has a number of procurement options as discussed in the paper. This section gives a brief introduction into processes which might be followed for each of the procurement options discussed.

C.1.1 Regulated Rates

The rates of payment would be set, most likely calculated by TSOs, and then approved by the RAs, probably on an annual basis. Generators would be required to provide services under the Grid Codes. Payment would be on an availability basis, since generators are already paid for being scheduled down (or up) to provide reserve, and interruptible loads should not incur additional costs through being scheduled. There would be with-held payments or penalties for not providing the required reserve

C.1.2 Annual Tender

- The TSOs would run a tender process annually for provision of reserves in the following year.
  - o As an alternative, there could be shorter term contracts, say for a month, or a season. However the additional administration burden may not be worthwhile. The advantage of more frequent tenders is that unexpected events can be handled. For example, following an unexpected major outage of a TSO-contracted plant. However the rules governing an annual tender process should be flexible enough to allow for an ad-hoc incremental tender where necessary.
  - o The TSOs could also contract for a longer time period than a year. This obviously has some administrative cost savings in that the annual auction is not needed. And it might be more attractive to a reserve provider to have a longer term contract to underpin capital expenditure associated with the equipment needed to provide the reserve. However, against this the TSOs need to be very careful about locking up the reserve market for long periods of time, thus preventing new lower cost sources of reserve from entering.

  An annual process is probably a good compromise.
- There would be a separate tender for each class of reserve. This would be simplest to administer, since the TSO would be able to do a simple comparison within each class. However theoretically it might lead to problems if a provider is accepted in one class but not in adjacent classes, potentially giving the TSO a harder time scheduling the reserve in practice.

- A tender may not be worthwhile where there are not enough potential providers. A good future process might be to run a simple expression of interest process prior to the tender which determines if the tender should be held or if the TSO should just negotiate with the small group of providers.
- The RAs might set a price cap for reserve, which would provide an upper limit to the prices in tender offers. However care would need to be taken that this was not too low and resulted in a shortfall of reserve being offered.
- Prior to the tender, potential providers would have to be certified as able to provide a given quantity of the reserve class. The certification process could be as simple or complete as seems justified – it might be as simple as assessing the provider's historical performance, assessing new equipment or as complex as a specific test programme. However the standards should be consistent across providers.
- Tender offers would specify the resource providing the reserve, which could be an individual plant or a portfolio – especially in the case of an aggregator combining small interruptible loads.
- The Tender offers might specify limits as to how and when the TSO can use the resource – e.g. interruptible loads might specify maximum interruption duration, or maximum number of activations in a year. And provisions would be made for scheduled maintenance etc. There would need to be compensation if the TSO uses the equipment beyond the terms of the contract. This will help ensure providers still cooperate when TSO really needs them.
- The TSOs would determine the results of the tender by accepting tendered resources until the reserve requirement in that class is met. The reserve price would be set by the last tender accepted – marginal cost pricing.
- The accepted providers' equipment would need to be kept up to the required standard, and there would be arrangements for tests, penalties etc
- The relevant TSO would be able to schedule the accepted providers' resources for reserve, and provider would have to be prepared to respond when required.
- The reserve and energy dispatch could be co-optimised within the TSO scheduling and dispatch process, giving efficient scheduling of reserve resources.
- Under this option the SMO market schedules would not include reserve, and reserve providers would not receive half-hourly reserve payments, since constraint payments cover this, at least for generators. Instead a payment for availability should be made, most likely calculated on a daily basis, and perhaps settled monthly. This implies that potential reserve providers would bid a daily price for reserve availability into the annual tender for each resource.
- This annual process could be rules based, or contract based, with contracts entered into annually on the basis of a successful tender offer.

C.1.3 Annual tender/Daily Market Approach

- Similar to the annual tender approach, except that a daily market schedule for reserve is produced.
- The TSOs (or potentially another party – see discussion in general section) would run a tender process annually for provision of reserves in the following year.
- There would be a separate tender for each class of reserve. This would be simplest to administer, since the TSO could do a simple comparison within each class.
- The same arrangements for expressions of interest, certification, price caps etc would apply to the tenders. Participants would have different reserve capabilities in

each reserve class, and these capabilities would form part of the unit registration data.

- However, unlike the annual process, the TSO would accept all tenders as reserve providers, and these providers could then be scheduled on any given day.
- Scheduling of the reserve resources would be similar to the annual tender process above.
- However the SEM under the T&SC would be modified to use a similar energy-reserve co-optimisation as is used by the TSO schedulers.
- The reserve requirements in each class would be calculated dynamically based on the units dispatched and potentially other constraints identified by the TSOs (e.g. flows across certain lines).
- There could be reserve requirements for the whole island, or separate reserve requirements for different locations, or a combination of the two
- If required the reserve providers could be allocated to certain groups, for example based on past performance in providing reserve, or locational issues.
- Units registered to provide reserve would each have a market reserve schedule, in the same way generators and demand side units now have an energy schedule. Reserve prices would be calculated in each half-hour Trading Period for each reserve class. Providers of reserve that were scheduled for reserve in that Trading Period would receive the relevant price for the reserve scheduled in each reserve class, settled on the same schedule as energy transactions. This implies that potential reserve providers would bid a half-hourly price for reserve scheduling into the annual tender for each resource, and these half-hourly offer prices would be used throughout the year to schedule reserve in each half-hour. Note that there would be no payment for units that were simply scheduled to run at less than their capacity but not scheduled specifically to provide reserve.
- If the market schedules did take account of energy-reserve co-optimisation, then this would result in lower constraint costs for the TSOs, since the market and dispatch schedules would more closely resemble each other. Instead there would be explicit payments to the reserve providers in each half-hour that they were scheduled to provide reserve.
- Compared with the current SEM design, the portion of constraint costs that relate to reserve scheduling would be separated from the remaining network constraints. Instead of having to provide an incentive regime for the TSO's for procurement and scheduling of reserves, the reserve market would provide the incentives for efficient reserve provision.
- This annual/daily process could be rules based, or contract based, with contracts entered into annually on the basis of a successful tender offer.

C.1.4 Daily Reserve Market Approach

- Would include several markets, one for each class of reserve
- Providers' equipment would need to be up to the required standard, rules would need to allow for tests, penalties etc. There would be an annual certification/recertification type process. Participants would have different reserve capabilities in each reserve class, and these capabilities would form part of the unit registration data.

- Participants who had qualified to provide reserves would offer reserve each day, using the same timeframe as the energy market. Most likely they would use extensions of the current SMO-participant interfaces.
- In the same way as the previous option, the SEM under the T&SC would be modified to use a similar energy-reserve co-optimisation as is used by the TSO schedulers. The reserve requirements in each class would be calculated dynamically as described above, including any locational requirements.
- As described above, units registered to provide reserve would each have a market reserve schedule, and reserve prices paid to those scheduled would be calculated in each half-hour Trading Period for each reserve class.
- This would obviously require more sophisticated systems. While much of the previously described annual tender approaches could be manual business processes, the daily market realistically would need to be automated, so modifications would need to be made to bidding interfaces, market clearing logic, settlement systems and reports.
- An option would be to accept offers less frequently, say once a week. But once the decision is made to opt for a frequently repeated process and to set up the corresponding IT infrastructure (principally the facility for providers to easily submit reserve offers) there seems to be little reason not to match the energy trading timetable.
- The frequency of the market in this option probably means that a rules based approach would be best – similar to the energy market arrangements. Although the reserve market arrangements could be in a separate code of their own, it probably makes more sense to piggy-back them onto the T&SC by adding new sections in the reserve market processes.

Glossary

Term	Name
AS	Ancillary Services
CCGT	Combined Cycle Gas Turbine
CER	Commission for Energy Regulation (Ireland)
CPS	Coolkeeragh Power Station
ESBPG	ESB Power Generation
GUA	Generator Unit Agreement
IL	Interruptible Load
OCGT	Open Cycle Gas Turbine
OR	Operating Reserve
PES	Public Electricity Supply
PPA	Power Purchase Agreements
PPB	Power Procurement Business
RA	Regulatory Authority
RP	Reactive Power
SEM	Single Electricity Market
SONI	System Operator Northern Ireland
SSS	System Support Services
SSSA	System Support Services Agreement
T&SC	Trading & Settlement Code