Integrated Single Electricity Market (I-SEM)

Financial Transmission Rights

Consultation Paper

SEM-15-061

8 September 2015

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1 EXECUTIVE SUMMARY

The purpose of this consultation paper is to set out for consideration by stakeholders the alternative means through which cross border hedging may take place. This involves explaining the operation of FTRs and how they may be used to facilitate cross border market access and hedging of market price differences.

It sets out the two types of FTR (Options and Obligations) that may be adopted and considers their advantages and disadvantages in terms of market efficiency. The paper also sets out for consideration questions of implementation, including the potential for separate products on each interconnection and issues affecting FTR payouts. Finally the paper discusses options for the FTR auctioning platform.

Five questions are posed to market participants, which are:

1. Which offers the greater benefit to the I-SEM/GB market: FTR Options or FTR Obligations?

2. What arrangements would be preferred: one FTR between the I-SEM and GB or one FTR per interconnector?

3. Should any of the following be discounted from the FTR product payouts?
   - Interconnector transmission losses;
   - Ramping constrains;
   - Curtailment risks

4. What are the important issues to be considered in deciding on the development of an auction platform?

5. What is the preferred approach in relation to the establishment of the I-SEM FTR auction platform?

Minded to decisions

Minded to decision 1: In relation to the type of FTR, The SEMC is not presenting a 'minded to' view on the question of the most appropriate type of FTR. The arguments in favour and against each type of FTR are relatively balanced and prior to assessing the views from market participants the SEMC feels that it would be premature to indicate a minded to decision.

Minded to decision 2: In relation to the question of having one FTR product auctioned between the I-SEM and GB border as opposed to one FTR product per interconnector, the SEMC considers that the additional complexity and cost involved in providing a single FTR product is not justified by the potential benefits and it is therefore minded to support the sale of FTRs by interconnector.

Minded to decision 3: With regard to whether losses and ramping should be discounted from the FTR payout, the SEMC considers that the inclusion of losses in the FTR payout when the IC owners have no control over these losses would not be an appropriate allocation of risk and are therefore minded to include a discount for losses in the FTR pay out. On the other hand ramping is a constraint over which some control is possible and the SEMC is therefore minded that the FTR payout should not be discounted for ramping constraints.

Minded to decision 4: Finally, with regard to the allocation platform for FTRs, the Regulatory Authorities are working alongside the TSOs and Interconnector owners to establish the most efficient means of implementing the auctioning platform. At this stage no minded to decision will be indicated. Nevertheless, the SEM is seeking views from market participants in terms of the criteria to be employed in the decision making in relation to this topic.

The structure of the paper is as follows:

Section 1 is an Executive summary setting out the purpose of the paper, consultation questions and minded to decisions.

Section 2 sets out the policy background to the paper including development of the Forward Capacity Allocation Guideline.

Section 3 sets out the types of hedging instruments that are available and in particular how spatial hedging instruments in the shape of FTR Options and FTR Obligations might work. The characteristics of each are explained including the facility for netting provided by FTR Obligations.

Section 4 sets out the arguments for and against the availability of a single FTR product sold on the I-SEM-GB border and the provision of separate FTR products by each interconnector.

Section 5 discusses the implications of including the operational characteristics of each interconnector in the FTR product, which would require separate FTRs for each interconnector. These operational constraints include losses on the interconnector, ramping constraints and risks of unplanned outages and curtailment.

Section 6 discusses development of an auction platform for FTRs.

Section 7 summarises the consultation process.

Appendix A explains the implementation process for FTRs and its relationship with the development of the Forward Capacity Allocation Guideline at the European level.

2 POLICY BACKGROUND

As set out in the high level design decision paper, the philosophy of the I-SEM is characterised by a number of features including, inter alia, the following:

- Preference for a competitive approach that is in the interests of consumers
- Access to all I-SEM market places for participants of all sizes and technologies and
- Liquid trading of financial forward contracts for effective hedging of short term prices.

In light of these characteristics, the RAs overall intention within the Forwards and Liquidity workstream is to develop policies that will fulfil a number of objectives including the following:

- Facilitate effective risk management:
  - to allow suppliers to manage risks associated with power purchase costs and to facilitate offering long-term fixed prices to end-use customers
  - to facilitate management of price and volume risk associated with variable spot market prices
  - to allow non-vertically integrated entrants to participate on the same terms as vertically integrated incumbent firms by enabling them to effectively hedge their positions and
  - Ensure transaction costs are minimised allowing participants to manage the administrative cost of trading activity.
- Facilitate the provision of long term price signals
- Ensure spot markets are liquid
- Be consistent with the other elements of the I-SEM design and
- Be consistent with the development of the reference price for CfDs.

The 'minded to' policy proposals and consultation questions on cross border transmission rights have been developed with reference to the following objectives, which are consistent with the overall I-SEM philosophy and objectives of the Forward and Liquidity workstream set out above:

- promote efficient use of cross-zonal transmission
- promote competition within I-SEM and between zones
- be compatible with market power mitigation measures and

  provide adequate return for existing assets and appropriate signals for future cross-border investment.

Additionally, it is necessary to fully comply with EU requirements, notably the Capacity Allocation and Congestion Management Regulation (CACM Regulation), which was adopted on 25th July 2015, and, more particularly, the developing Forward Capacity Allocation Guideline (FCA). The FCA Guideline will mandate the detailed rules of forward capacity allocation to be delivered through a Harmonised Access Rules (HAR) document that will have region-specific annexes. The current HAR is a pilot project and therefore voluntary but it is in an advanced stage of development by ENTSO-E.

It should be noted that the version of the FCA NC published on the ENTSO-E website continues to undergo change and options presented in this paper will necessarily comply with the final version of the FCA Guideline.[1]

[1] The latest draft of the European Commission FCA Guideline dated 10 June 2015 can be accessed through the following page:
http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/European-network-code/Joint-European-Stakeholder-Group/

3 FTR TYPE – OPTIONS vs. OBLIGATIONS

There will be two types of forward hedging instruments in the I-SEM:

- Temporal
- Spatial.

Generators and suppliers require temporal hedging tools to protect against unanticipated movements in underlying prices over time[2]. This is of particular importance to suppliers who will have signed fixed price contracts with consumers and therefore need to lock in the costs of power purchases to fulfil those retail contracts. The decision on the High Level Design of the I-SEM established that temporal hedging in the I-SEM will be achieved purely by financial contracts or contracts for difference (CfDs).

Spatial hedging is used when a party is selling from one market area to another. For instance, a market participant with a supply business in the I-SEM which wishes to buy power in the GB market in order to serve demand in the I-SEM would be exposed to the price differential between the two markets. Spatial hedging instruments provide price protection when accessing additional markets. Figure 1 below shows a stylised representation of prices over a period of time between the I-SEM and GB markets with a supplier in I-SEM and generator in GB, who will purchase and sell respectively into the power exchanges in their market.

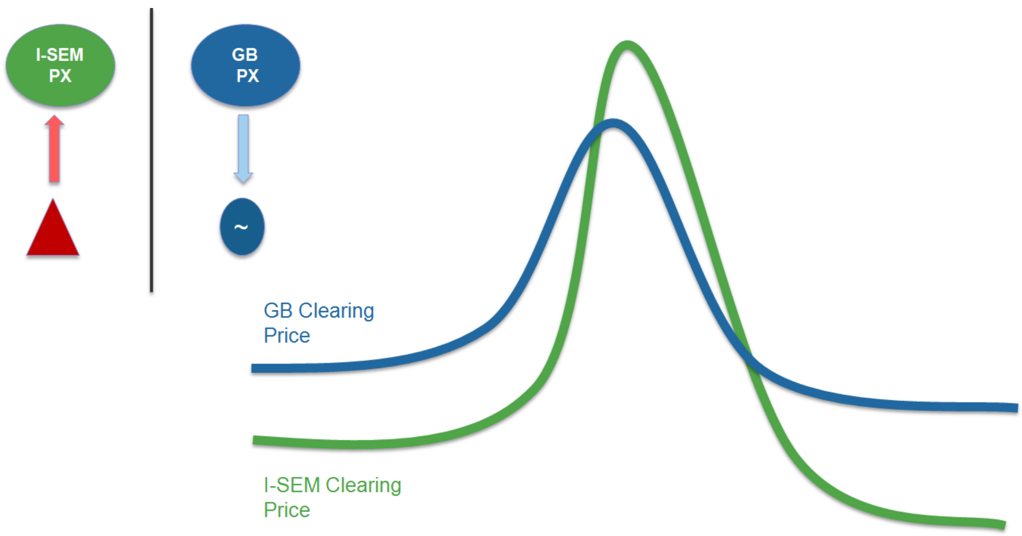

Figure 1

[2] Short-term hedging against on-the-day price volatility is also needed but these CfD-type products are not fundamental to forward markets.

ENTSO-E defines three categories of cross-border transmission risk hedging product: Physical Transmission Rights (PTRs), Financial Transmission Rights (FTRs) and Contracts for Differences (CfDs) (ENTSO-E Transmission risk hedging products – an ENTOE-E educational paper 20.06.2012). Financial Transmission Rights are further distinguished between Options and Obligations. Since the SEMC has already determined in the High Level Design Decision that FTRs will be adopted in I-SEM, the remainder of this paper discusses FTR Options and FTR Obligations.

For the I-SEM design, FTRs will allow market participants to choose exposure to the GB day-ahead market instead of the I-SEM market. In pricing a bid to purchase transmission rights, each party will be making a forecast of price difference exposure over the life of the transmission product being bid for. It therefore follows that the price of transmission rights at auction will approach the market clearing valuation of price differences. For transmission rights to attain a non-zero valuation there will be an expectation of a difference in clearing prices between interconnected markets for at least some of the time.

For the Interconnector Owners, there are revenues and liabilities in each direction of flow as follows:

- Revenue collected from congestion whenever there is a price difference in the direction of flow; this is collected on MWh flowed with the revenue coming from buying and selling the energy for this flow in each of the coupled markets that have utilised the physical capacity.
- Revenue from the FTR auctions per MW sold, which, in an efficient market, should fully offset:
- Liabilities per MW whenever there is a positive price difference between the day-ahead coupled markets either side of the border for which FTRs have been sold. With FTR obligations, revenue will be received by the Interconnector owners per MW whenever there is a negative price difference between the day ahead coupled markets on each side of the border for which FTRs have been sold.

3.1 FTR OPTIONS

The FTR Option purchaser is buying a right to be paid the price difference between adjacent markets in the direction for which the option was purchased, provided that the price difference is favourable. The price difference is determined as the difference in the clearing prices of the day-ahead auctions in the two coupled markets[3]. As the holder of an FTR option has the right to collect the price difference and not the obligation to do so, the price difference is only paid out if it is positive in the direction concerned and there is no obligation on the holder to pay to the provider in case of a negative price difference. Figure 2 below illustrates the stage at which the FTR Option would be exercised, with the shaded area representing the option payout to the FTR holder that is the positive price difference between the I-SEM and GB markets (GB price – I-SEM price). In this case the supplier purchasing the FTR would ensure that it incurs only the GB market clearing price when the I-SEM price is higher.

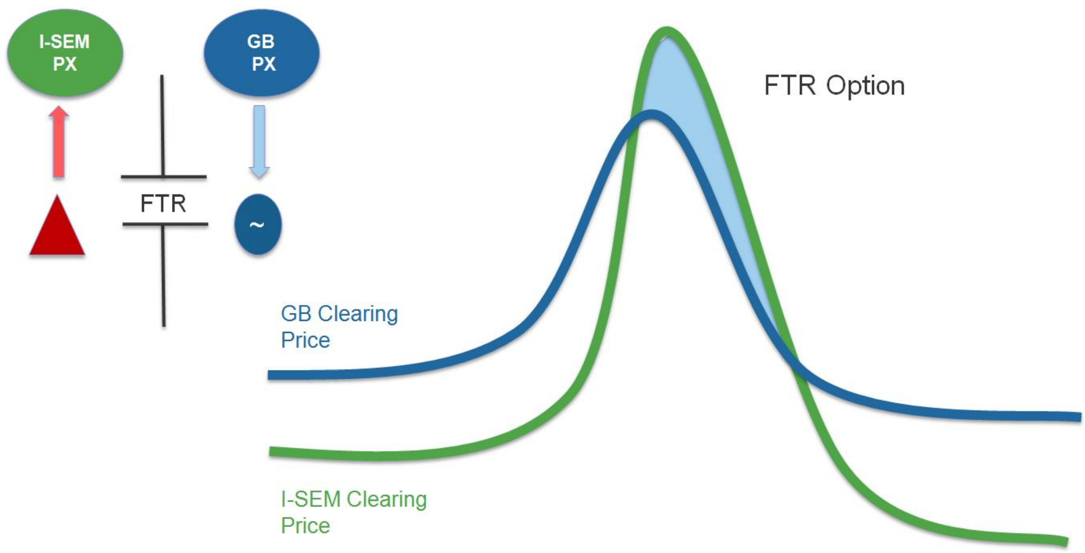

Figure 2

A party bidding for FTR Options in a particular direction will price the possibility of earning revenue whenever prices in the destination market are higher than prices in the originating market. Unlike with nominated PTRs, the bidder is effectively guaranteed being paid that price difference without having physically flowed energy. An FTR Option is therefore similar to a PTR with use it or sell it (UIOSI) in which flows which are not nominated are auctioned and the holder receives a remuneration equal to the day ahead price spread.

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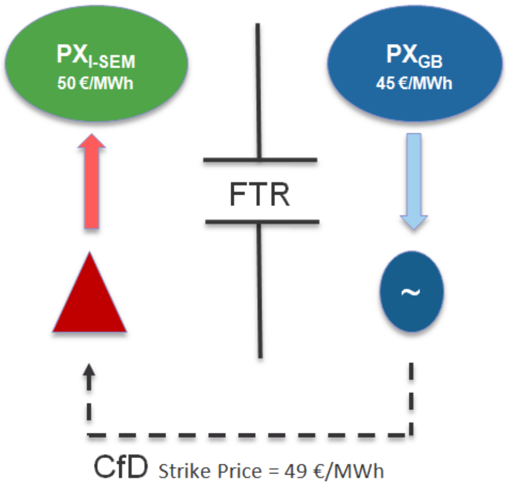
[3] The actual calculation of the price difference will depend on the treatment of losses and ramping, which is discussed in Section 5.1

In the example below (Figure 3), a supplier in the I-SEM signs a two-way CfD with a generator in GB. The CfD has a volume of 100 MWh, the GB PX Day Ahead clearing price is the reference and the strike price is 49 €/MWh. In this case if the reference price for the CfD was a Day Ahead clearing price of €55 the purchaser would pay €5,500 (100MWh*€55) which would be offset by receipt of €600 from the CfD counterparty (100MWh* (€55-€49)). Similarly a Day Ahead price of €45 would incur a cost to the purchaser of €4,500 plus the contract difference payment of €400 ((€49-€45)*100MWh). (The cost of the FTR is excluded from these examples.)



$ISEM \quad SUPPLIER \quad POSITION$

$CfD = (49-45)*-100 = -400$

$FTR = (50-45)*100 = 500$

$ISEM_{PX} = -100*50 = -5{,}000$

$NET\_POSITION = -400+500-5{,}000 = -4{,}900$

$GB \quad GENERATOR \quad POSITION$

$CfD = (49-45)*100 = 400$

$GB_{PX} = 100*45 = 4{,}500$

$NET\_POSITION = 400+4{,}500 = 4{,}900$

Figure 3

The Figure above shows the combined use of temporal and spatial hedging. It illustrates that a supplier in the I-SEM would be able to access the GB CfDs market and sell electricity to the I-SEM consumers at the strike price achieved in a CfD with a GB generator. At present in GB the main route to market is through physical bilateral contracts; the example above is illustrative of the general approach adopted with exposure to power exchange prices being purely voluntary. Although perhaps less convenient, a GB generator or any other party could offer a physical bilateral contract in the GB market (at the 49 €/MWh of the example) and this could then be sold into the GB power exchange (receiving the PX price of 45 €/MWh). This could be represented as:

ISEM SUPPLIER POSITION

*Bilateral physical contract (in GB market) = 49 * -100 = -4,900*
*GB_{PX} = 100*45= 4,500*
*FTR = (50-45)*100 = 500*
*$ISEM_{PX}$ = -100*50= -5,000*
NET_POSITION = -4,900 +500 -5,000 + 4,500 = -4,900

GB GENERATOR POSITION
*Bilateral physical contract = 49 * 100 = 4,900*

Therefore, a CfD market in GB is not vital; all that is required is sufficient liquidity in GB forward markets.

3.2 FTR OBLIGATIONS

FTR Obligations operate in a very similar fashion to FTR Options; they are a financial product based on the payout of price differentials between coupled markets. However, FTR Obligations differ from FTR Options in one crucial aspect; while they pay out to the holder when the price spread is favourable, the holder must pay out to the Interconnector (IC) when the price spread is in the opposite direction. Figure 4 below illustrates the stage at which the FTR Obligation would generate a payment or liability for the market participant. The red shaded area represents the Obligation payout by the FTR holder that is the positive price difference between the GB and I-SEM markets (I-SEM price – GB price) In this case the supplier purchasing the FTR would ensure that it always incurs the GB market clearing price.

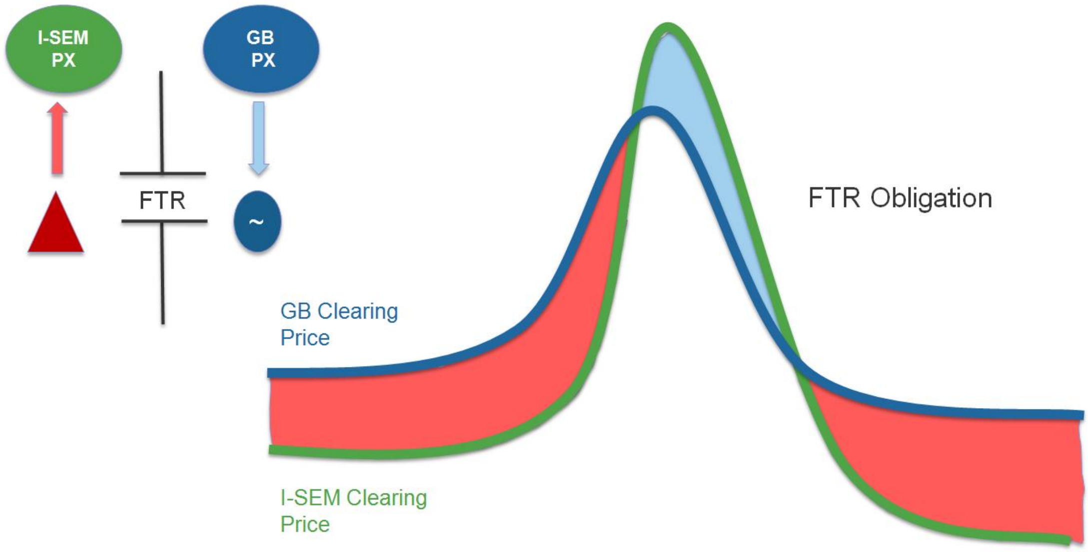


Figure 4

FTR Obligations are considered to be a perfect hedge product as a holder can expect to exactly offset price differences between markets. If the holder has a product fixing temporal price differences in one market then, by purchasing an FTR Obligation, the holder will be completely hedged when trading in an adjacent market.

FTR Obligations have an additional attribute. Because the hedge is in both price directions through the FTR Obligation, the Interconnector Owner is in a position to net-off sales of FTR Obligations by selling an equivalent amount of FTRs in the opposite direction of flow without increasing financial exposure. This is known as netting and potentially allows the IC owner to make available an additional transmission right in the main direction for every FTR Obligation sold in the opposite direction, knowing that a payout in one direction will be exactly offset by the liability of an FTR Obligation holder in the opposite direction to pay out to the IC owner.

To illustrate the netting capabilities of FTR Obligations, Figure 5 below shows a generator in the I-SEM with a contract of 500MW with a load in GB and equivalently a generator in GB with contract with a load in the I-SEM of 1000MW. The Available Transmission Capacity (ATC) of the interconnector is 500MW in both directions. Assuming that the optimum dispatch corresponds to the contractual positions of the two generators i.e. generator in the I-SEM produces 500MW and the generator in GB produces 1000MW to meet an aggregate demand of 1500MW (Load in the I-SEM is 1000MW and Load in GB is 500MW). The resulting 500MW interconnector power flow does not violate the ATC limitation since the injections and withdrawals of the market participants are netted.

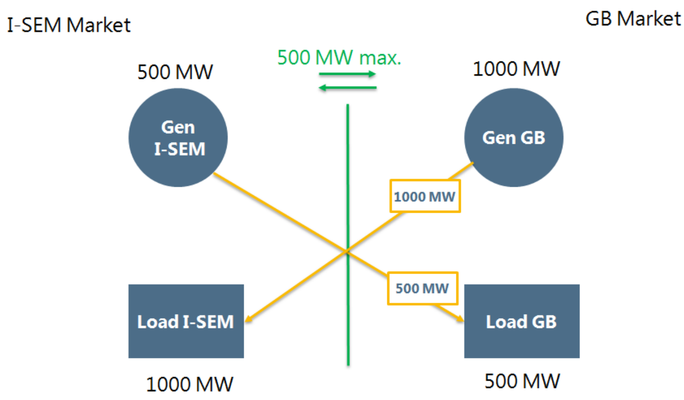


Figure 5: Crossing cross-border clearing paths

If both generators (from I-SEM and GB) were to seek hedges for their cross border transactions, then the Interconnector owner would be in position to offer 1500MW of FTR Obligations but only 500 of FTR Options. There is no limit to the amount of FTR Obligation that can be sold as long as there are interested parties willing to buy Obligations in the opposite direction and the net position does not exceed the ATC limitation. This is because of the netting effect between negative and positive payouts in each trading period. In relation to the FTRs Options, the Interconnector owner will always be limited to the ATC of the interconnector as there is no netting effect on the FTR payouts.

However, it must also be considered that over the period for which any set of FTR Obligations are held, there will only be an opposite flow FTR Obligations purchased if there is no market consensus on average prices in a market, because no one is going to buy an FTR Obligation from an expected higher price market towards an expected lower price market by which they would anticipate losing money. Additionally, if there is no general expectation of price differences between markets then spatial hedges are unnecessary.

3.3 TEMPORAL AND SPATIAL HEDGING - NUMERICAL EXAMPLE

Let us assume an I-SEM supplier owns a generation asset in the GB market which he wants to use to meet I-SEM demand. For his demand in the I-SEM he has a need to procure 100 MW during the day (hours 7-22) and 50 MW during the night (hours 1-6 and 23-24). This example would also work for an I-SEM supplier buying a physical contract in GB to meet I-SEM demand. Let us assume perfect foresight on expected prices for I-SEM and GB day ahead spot-markets. The expected prices during daytime are €60 and €50 and during night-time €10 and €20 for I-SEM and GB respectively. This is summarised in Table 1 below.

	hours	# hours	MW/h	spot price	
				I-SEM	GB
Day	7-22	16	100	60.00	50.00
Night	1-6, 22-24	8	50	10.00	20.00

Table 1: I-SEM and GB spot-market profile with I-SEM supplier contract profile

Without physical access to the I-SEM/GB border with the facility to physically nominate flow over the interconnector the parties will participate in the day ahead auction within their own markets and seek to lock in the market price in the adjacent market through purchase of an FTR. This will mean for example that the I-SEM supplier will buy its power in the I-SEM at the I-SEM price and with purchase of an FTR in the direction of the I-SEM will receive the difference in price between the I-SEM and GB markets, effectively paying the GB price. Similarly the GB generator will sell into the GB market in order to take the GB market price. The purchase of an FTR must therefore be concluded by a sell to the GB spot market and a buy from the I-SEM spot market for the supplier and generator to avail of the price in the GB market. For the I-SEM supplier Table 2 below shows the trade results on both DAMs.

hour	Volume (MW)	DAM price I-SEM (€/MW)	GB (€/MW)	DAM trade results (€) I-SEM (buy)	GB (sell)	total
1	50	10	20	-500	1000	500
2	50	10	20	-500	1000	500
3	50	10	20	-500	1000	500
4	50	10	20	-500	1000	500
5	50	10	20	-500	1000	500
6	50	10	20	-500	1000	500
7	100	60	50	-6000	5000	-1000
8	100	60	50	-6000	5000	-1000
9	100	60	50	-6000	5000	-1000
10	100	60	50	-6000	5000	-1000
11	100	60	50	-6000	5000	-1000
12	100	60	50	-6000	5000	-1000
13	100	60	50	-6000	5000	-1000
14	100	60	50	-6000	5000	-1000
15	100	60	50	-6000	5000	-1000
16	100	60	50	-6000	5000	-1000
17	100	60	50	-6000	5000	-1000
18	100	60	50	-6000	5000	-1000
19	100	60	50	-6000	5000	-1000
20	100	60	50	-6000	5000	-1000
21	100	60	50	-6000	5000	-1000
22	100	60	50	-6000	5000	-1000
23	50	10	20	-500	1000	500
24	50	10	20	-500	1000	500
Total	2000			-100000	88000	-12000

Table 2: DAM trade results for physical bilateral contract profile

We derive from this table an average price of €100,000/2,000 = €50/MWh in I-SEM and an average price of €88,000/2,000 = €44/MWh in the GB market. This means that with every MWh supplied in the I-SEM, the I-SEM supplier would have an imbalance in revenue achieved in the GB market and payments to the I-SEM PX of €6/MWh on average. As the table shows, he loses a total of €12,000.

The following table shows the value of the different FTR products, Options and Obligations, for the given market profile.

hour	DAM prices (€/MW)		price spread(€)		Value of FTR option (€/MW)		Value of FTR obligation (€/MW)	
	I-SEM	GB	GB →I-SEM	I-SEM →GB	GB→I-SEM	I-SEM→GB	GB→I-SEM	I-SEM→GB
1	10	20	-10	10	0	10	-10	10
2	10	20	-10	10	0	10	-10	10
3	10	20	-10	10	0	10	-10	10
4	10	20	-10	10	0	10	-10	10
5	10	20	-10	10	0	10	-10	10
6	10	20	-10	10	0	10	-10	10
7	60	50	10	-10	10	0	10	-10
8	60	50	10	-10	10	0	10	-10
9	60	50	10	-10	10	0	10	-10
10	60	50	10	-10	10	0	10	-10
11	60	50	10	-10	10	0	10	-10
12	60	50	10	-10	10	0	10	-10
13	60	50	10	-10	10	0	10	-10
14	60	50	10	-10	10	0	10	-10
15	60	50	10	-10	10	0	10	-10
16	60	50	10	-10	10	0	10	-10
17	60	50	10	-10	10	0	10	-10
18	60	50	10	-10	10	0	10	-10
19	60	50	10	-10	10	0	10	-10
20	60	50	10	-10	10	0	10	-10
21	60	50	10	-10	10	0	10	-10
22	60	50	10	-10	10	0	10	-10
23	10	20	-10	10	0	10	-10	10
24	10	20	-10	10	0	10	-10	10
Total value per day (€/MW)					160	80	80	-80

Table 3: Value of FTR Options and Obligations for given market profile

If we use the values at the bottom of this table, we can derive that with 100 MW of FTRs in the direction (GB→I-SEM), the I-SEM FTR holder will receive €16,000 with FTR Options (=100*€160) and €8,000 (=100*€80) with FTR Obligations. With a daily loss on the DAM trade of €6,000, this means a net gain on his contract of €10,000 per day with 100 MW of FTR Options and a net gain of €2000 per day with 100 MW of FTR Obligations.

This example uses a profile of demand that is a realistic position of a supplier but it should be noted the benefits of the FTR are essentially derived from price spread and that therefore, even when seeking to hedge base load energy, similar results would be found.

From Table 3 we can also derive pay-outs for different volumes of FTRs per product. In Table 4 below we see a copy of the bottom line of Table 3 for the pay-out on 1 MW of FTRs in the first line. The pay-outs for other values are simply derived from this by multiplication.

TRs	FTR Options		FTR Obligations	
(MW)	GB→I-SEM	I-SEM→GB	GB→I-SEM	I-SEM→GB
1	160	80	80	-80
50	8,000	4,000	4,000	-4,000
75	12,000	6,000	6,000	-6,000
100	16,000	8,000	8,000	-8,000
125	20,000	10,000	10,000	-10,000
150	24,000	12,000	12,000	-12,000
200	32,000	16,000	16,000	-16,000

Table 4: Pay-out on given market profile for different volumes of different FTR products

From this table, we can conclude that, for the price profile utilised, the I-SEM supplier can buy a complete spatial hedge with only 75 MW of FTR Options in the contract direction but needs 150 MW of FTR Obligations for an equivalent hedge. Thus, given this expected price profile, FTR Options should achieve a higher price than Obligations at auction.

As already noted, these results, although affected by the profile of demand, are essentially a result of the profile of price spreads. FTR Obligations could also provide spatial hedging if the instrument became a time-of-day product (e.g. separate FTRs covering night-time, daytime and peak). If time-of-day FTRs were to be considered useful then the following considerations would arise:

- Are there time-of-day forward energy contracts to match the FTRs?
- What is the implication on liquidity in the energy markets from the splitting of forward products?
- What is the implication for liquidity in secondary markets for FTRs from the same market fragmentation?
- Would the same incentives for netting arise with time-of-day FTR Obligations?

3.4 FINAL CONSIDERATIONS

From the perspective of an FTR holder, Options would always have a positive value – the holder would never have to pay out if the price difference is negative. This may assist with liquidity in the FTR auction by encouraging traders to participate who do not have an underlying energy trade to hedge. Options would also require less credit cover – only sufficient to pay the auction price for the FTR with no need to provide credit cover for a payout under the FTR. On the other hand, FTR Options would, in general, be more expensive to purchase than an FTR obligation as its payouts are always positive.

From the perspective of a FTR holder, Obligations In general would cost less to purchase per MW than the corresponding FTR option. In pricing at auction, buyers will price in the probability of a net payout on price spreads with both FTR Options and FTR Obligations but with the latter must also price in the risk of an uncapped liability arising from negative price spreads, which may be caused by unpredictable events; this would not be a fundamental problem for parties needing to hedge a supply or generation position because they could offset any such price shocks with a matching forward energy contract that would face the same price shock in the opposite direction. This may mean however that non-physical parties would not be attracted to such a market, which would impact on liquidity. Therefore, the net auction clearing price for FTR Obligations would be lower than for an FTR option, and could be zero (with the auction failing to clear where the value to many is less than zero).

On the other hand, FTR Obligations would require buyers to post higher levels of credit cover than for FTR Options. With FTR Obligations the holder has potential liabilities that are uncapped, which therefore poses an additional credit risk for IC owners. This may make FTR Obligations difficult to trade in secondary markets because any purchaser in that secondary market would need to post credit cover to the IC owner. This can be mitigated if FTR Obligations are traded across an exchange in the secondary market because the IC owners would be protected by an exchange's credit cover rules.

Obligations have the advantage of potentially increasing the volume of FTRs that can be sold by the Interconnector owner above and beyond the ATC of the interconnector. This is due to the netting effect of simultaneous acquisition of transmission rights in opposite directions on the interconnector. Thus Obligations might increase the liquidity in the forward market as they increase the available hedging opportunities available for cross border transactions, dependent on demand for FTR Obligations in the opposite direction to the dominant flow.

The table below sets out the main attributes of the two types of FTR and the advantages and disadvantages of each

Attribute	FTR Option	FTR Obligation
Main attributes	Sold at auction by interconnector provider for a defined period of time (year, quarter, etc.); auction sets clearing price for holders of product.	
	FTR Option bought from A→B pays out the price spread per MW between markets whenever price in day ahead market B is above price in market A (but pays nothing when price in market B is below that in market A).	FTR Obligation bought from A→B pays out the price spread per MW between markets whenever price in day ahead market B is above price in market A but holder pays out price spread to provider whenever price in market B is below price in market A.
Coverage of price spread risk	Effective hedge: covers holder against any adverse price spread exposure. No downside risk if congestion changes direction.	Perfect hedge: holder indifferent to changes in direction of benefit to a holder that is trying to hedge a buy/sell energy contract.
Hedging efficiency	Depending on market price spread profiles, it is possible to hedge a financial position with fewer FTRs than the actual MW of energy contracted. (If pattern of congestion is predictable and noticeably different between time periods).	Depending on market profiles, more than 1 MW of FTR per average MW of contract may be needed to completely cover the financial position of the contract. (Assuming time of day FTR product not available)
Liquidity of product	Usable as a speculative instrument, increasing potential demand.	More appropriate to physical traders than to asset-less speculators due to negative value risk. Netting may increase availability in the primary market. The need for the holder to provider credit cover against negative price spreads could limit secondary trading although trading on formal exchanges could improve this position.
Netting	Not commercially feasible to provide.	Providers can increase availability of FTRs in the dominant direction to the extent that parties are willing to purchase FTRs in the opposite direction; this is reliant on there being no consensus as to net price spreads between markets.
Cost at auction	Options would always have positive value therefore higher prices should be achieved at auction.	Lower net price due to likely lower net payout than FTR Options and due to uncapped risk of negative price spreads to

Attribute	FTR Option	FTR Obligation
		the holder.
Credit cover	Lower requirement (all payouts are by creditworthy providers).	Buyers will need to pay providers when spreads are negative so must provide credit cover against this possibility. The cost of cover is increased due to potential for price shocks.
Price shock risk	Holder hedged against unpredicted large price spreads. Provider hedged through congestion revenues.	Uncapped risk of unpredicted adverse price spreads for the holder, but only if there is no underlining energy contract that offsets this position. Provider hedged through congestion revenues.

Table 5: Summary of advantages and disadvantages of FTR Options and FTR Obligations

The attributes of FTR Options and Obligations confer relative advantages and disadvantages that are partly dependent on the particular role performed by the market participant.

The IC owner will be principally concerned with revenue adequacy. Both Options and Obligations provide effective hedging opportunities to market participants which will generate demand for the product sold by the interconnector owner.

FTR Options will be favoured in so far as they have a higher value to the holder because they involve no risk of a negative pay out. If they are favoured by asset less traders this will also increase demand for FTRs. In so far as liquidity is thereby increased through secondary trading this may also increase demand in the primary market.

On the other hand the payout by the IC owner with Options is always either zero or positive and no revenue is received for flows in the opposite direction as is the case with FTR Obligations. In so far as Obligations allow netting and an increase in the number of FTRs that can be sold this will increase IC revenue which may offset their lower individual value. The necessity to buy more Obligations to hedge a given price exposure will also increase demand for this product. This necessity would arise where the FTR was not split and sold on a time of day basis. Obligations will also however increase credit risk to the IC owner although may be addressed by a clearing house so reducing its risk.

For market participants seeking to hedge cross-border trades, while Options provide an efficient hedge Obligations provide a perfect hedge. FTR Options will be more expensive because there is no risk of a negative pay out if the flow on the interconnector is against the direction of the FTR purchased, but this cost may be offset by the need to purchase less to hedge a given volume of MW. FTR Options are less risky for a holder who does not have an underlying energy transaction which may be attractive to asset less traders whose presence in the market may increase liquidity and price discovery to the benefit of physical traders.

FTR Obligations will be less expensive to purchase but will involve increased risk of payouts including through negative price shocks, which will require posting of collateral. As noted above this may be mitigated by a clearing house function. However, this reflects FTR risk only and the overall financial risk can be neutralised by the underlying energy contract hedged against a particular market price. In so far as netting would become a feature of the sale of FTR Obligations the volume available for purchase may be increased.

3.5 MINDED TO DECISION AND CONSULTATION QUESTION

The Regulatory Authorities have not taken a view on which type of FTR better meets the SEM objectives and are not presenting a 'minded to' view on the question of the most appropriate type of FTR. It is recognised that there are theoretical advantages to both types and that these will be affected by the concrete circumstances of the I-SEM. Market participants' perception of the efficacy of each instrument is an important consideration that it wishes to take into account before moving from a neutral position on the balance of advantages and disadvantages afforded by the two types of FTR.

Consultation Question 1: Which offers the greater benefit to the I-SEM/GB market: FTR Options or FTR Obligations?

4 FTRs PER INTERCONNECTOR OR PER BORDER

4.1 RATIONALE FOR A SINGLE BORDER FTR OR FTRs PER INTERCONNECTOR

Currently the two interconnectors between SEM and GB markets – East-West Interconnector and Moyle Interconnector separately auction PTR capacity.

In transitioning to the I-SEM market, a further aspect of FTR design that needs to be addressed is whether a single FTR product should be auctioned for the border, i.e., the combined capacity would be auctioned together, or whether separate FTRs would be auctioned for each interconnector.

Each of the current interconnectors could be described as semi-merchant with part of their revenues covered from subventions from specific onshore transmission tariff payers in Northern Ireland (Moyle interconnector) and Ireland (East-West interconnector) with a distinct and separate business case and different operating characteristics. They currently sell distinct and separate PTR products although a common auction platform is used. The products auctioned on each vary by time period, e.g., monthly, annual products etc. and the auctions take place at different times.

With FTRs, the payout is based on market price differentials between coupled markets in the day ahead. This means that the FTR payout need not have a relationship to physical characteristics such as power flow. Unless there is inclusion of losses and ramping adjustments within the FTR payout, the payout per MW sold and hence the market value of the FTR at auction on each interconnector will be the same (unless the perceived probability of curtailment may differ between interconnectors).

This means that a single FTR product could be sold on the GB - I-SEM border and allocation of auction revenues could be split between interconnectors in proportion to the MW made available by each interconnector for each auction.

With FTRs per interconnector, price spread correction to take losses into account will depend on the loss factor and the market price on the sending side. As the second parameter varies per hour this will either require a different ex-post correction each day or require an ex-ante forecast and an ex-post correction at each FTR auction.

With interconnector business cases being different due to differences in technical characteristics and operational constraints, revenue adequacy risks are also different. Loss factors incur a price spread even with no congestion and thus no congestion income. Differences in loss factors between interconnectors may incur price spreads just enough to generate congestion income on one interconnector (with a lower loss factor) but not on the other.

Ramping constraints may induce negative or reduced congestion income in ramping constrained hours but differently by interconnector when different ramping constraints apply.

Apart from technical characteristics ramping constraints may also be imposed by the interconnected system on either side due to system stability or disproportionate system balancing costs. With each difference in operational constraints the business case differs. This can be viewed as an argument to treat the FTR products supplied by each interconnector separately or as an argument to separate the business cases on the provider side of the FTR auction only.

Unplanned outages will also differ per interconnector, creating different firmness risks accordingly. When an unplanned outage occurs on an interconnector after the day-ahead firmness deadline that interconnector must guarantee full physical firmness until the end of the next day.

This could be done through countertrade (in the intraday market or through specific contracts with generators and/or suppliers) and would eventually be done by the system balancing operator, incurring imbalance charges.[4] Where this still generates congestion income as if unavailability did not occur (because the market coupling result will not be undone and the congestion rents still collected from the market coupling), countertrade costs or imbalance charges - also known as firmness costs - will apply until curtailment becomes effective from the second day after.

For the FTRs, full price spread has also to be paid out until curtailment becomes effective. After that, curtailed capacity must still be remunerated with the full price spread until the total congestion income for that calendar month is exhausted. The only exception occurs with force majeure where curtailment only requires initial price paid to be remunerated.

[4] Current licence conditions restrict countertrading and contracting.

Losses and ramping constraints impact interconnector revenues differently by interconnector. The effect of losses on price spread in relation to congestion income is different according to the loss factor and can be allocated per interconnector. The effect of ramping constraints is not directly on the price spread (although ramping constraints will contribute occasionally to broaden such spreads) but on the congestion income. While negative congestion incomes are easy to detect it is not possible to exactly determine the reduced congestion income due to ramping constraints.

From a TSO/Interconnector owner perspective a separation in liabilities for FTR provision may be preferred. This relates especially to firmness costs. Sharing of these liabilities would require an agreement between the Interconnector owners while also being compatible with the FCA. Separate liabilities however do not necessarily imply that FTRs must be sold per interconnector.

When the FTRs are auctioned on a per interconnector basis each interconnector would have its own business with the auction office independent from the other interconnector and there is no need to agree on separation of auction income, pay-out obligations and curtailment caps between providers or sharing of curtailment caps towards the FTR holders. This could shorten implementation time but may delay development of a single harmonised product.

The rationale for FTRs on a border basis and not per interconnector is that the price spread to be hedged is on the border and not different per interconnector. On the other hand a reason to sell FTRs separately by interconnector is differences in potential curtailments for which the market may prefer one interconnector above the other.

It may be argued that an efficient market for FTRs may result from a single transparent and simple product on the border, which will be reflected in a better price for the FTR product. For this reason, revenue adequacy risk measures from operational constraints in the FTR product definitions may be avoided.

On the provider side revenue adequacy risk measures from operational constraints can be split or shared, depending on the preference of the providers.

Under the new firmness regime imposed by the CACM Regulation and FCA, there are no revenue adequacy risks from unplanned outages as any costs to maintain allocated rights that cannot be curtailed must be remunerated through network tariffs in a timely manner and payout obligations for curtailed rights are capped to the congestion income. However, as the curtailed capacities will differ per interconnector FTR pay-out liabilities must be kept separate per interconnector although this can be accounted for in the auction arrangements. FTR pay-out limitations from curtailment can be shared by the FTR holders and also accounted for in the auction arrangements.

From a market participant perspective there may be little advantage to separation of curtailment risks by interconnector as this would lead by definition to separate products and an auction per interconnector. Liquidity would be split and hedging may become less efficient.

With liquidity split efficient hedging may be considered more complicated as the value of the products will be different according to a difference in curtailment expectations while the spread between the two markets will be the same. Therefore, the issue for interconnector users is whether they prefer to be exposed to the cap on compensation for curtailment at a single interconnector point or whether it is preferable for this risk to be socialised across both interconnectors.

4.2 SUMMARY OF ADVANTAGES AND DISADVANTAGES

A summary of the advantages and disadvantages of the two approaches are summarised below.

FTR PER INTERCONNECTOR	
Advantages	Disadvantages
Supports greater product diversity – each interconnector could offer different products, as they do today	Liquidity would be split across the two interconnectors (though this occurs today). Auctioning of FTRs per interconnector may split the liquidity that may exist on the border and therefore increase the risk of pricing and market power issues
Simpler to implement – no revenue sharing arrangements between interconnector owners required;	More complex for market participants to bid in multiple auctions

FTR PER INTERCONNECTOR	
easier to accommodate losses and ramping being included in FTR	
More easily adaptable to changes in bidding zone configurations, or construction of new interconnectors	
SINGLE FTR PER BORDER	
Advantages	Disadvantages
Concentrates liquidity into one auction; same price for FTRs on both interconnectors	Would require a revenue sharing agreement between interconnector owners to account for different characteristics of the interconnectors, e.g., ramping, losses if included, firmness/availability
Simpler for market participants	Less ability to offer product diversity to market participants, compared to today
	Not future proofed with regard to any bidding zone changes in either SEM or GB
	Not future proofed with regard to the construction of new interconnector on the SEM/GB border, as a new revenue sharing arrangement would need to be negotiated

Table 6: Summary of advantages and disadvantages of FTRs per interconnector and a single FTR per border

4.3 MINDED TO DECISION AND CONSULTATION QUESTION

Having different products being sold by each interconnector would be in keeping with current arrangements and to some extent simpler to implement as it would not require revenue sharing arrangements between interconnector owners. It would maintain existing agreements regarding staggering of auction dates to ensure bidders are not compelled to bid in both auctions simultaneously (and risk acquiring twice as many transmission rights as they need).

Having distinct products would also accommodate any eventual changes in zone configuration in GB or I-SEM. On the other hand, liquidity would be split across the two interconnectors (though this occurs today) and therefore increases the risk to pricing. In addition market participants would have an additional variable to deal with when seeking cross border price hedging (which is what market participants require).

Having a single FTR product on the I-SEM/GB border would concentrate liquidity into one auction and the same price for FTRs should apply to both interconnectors, which would make the cross border hedging process simpler for market participants.

For interconnector providers, having a single product would potentially require an auction revenue and FTR payout sharing agreement between interconnector owners to account for the different curtailment risks of the interconnectors (and the consequent risk of payout capping, although payout could be dealt with once it occurred and might not need ex ante apportionment of revenues to take this into account). It might also require a congestion rent sharing agreement to cover ramping, losses and firmness. It should be noted that, in reality, the calculations and processes with regard to congestion rents would be identical regardless of whether the FTRs were sold as a single product or separate ones. It would also require any new interconnector to adhere to the same revenue sharing agreement, which may prove an obstacle to new entry.

The SEMC consider that the additional complexity and cost involved in the collaboration of the interconnector owners providing a single FTR product is not justified by the potential benefits that might accrue from a single product.

The SEMC are persuaded that there is greater flexibility and choice for FTR users and any potential new providers if separate products are provided at each interconnector and that this outweighs any potential loss of liquidity and increased complexity for FTR users. It is considered that the continuation of existing arrangements in this respect would facilitate the objectives of introducing Financial Transmission Rights. It is therefore minded to support the sale of FTRs by interconnector.

Consultation question 2: What arrangement would be preferred: one FTR between the I-SEM and GB or one FTR per Interconnector?

5 FTR PRODUCT DEFINITION

The FTR product definition can include the operational characteristics of interconnection. The inclusion of such characteristics will change the risk profile of market participants buying the FTRs and the interconnector owners who are selling FTRs. The following operational characteristics and risks could be considered in the design of the FTR product:

- Interconnector losses
- Ramping constraints
- Curtailment.

Buyers and sellers of cross border energy will have to be able to hedge the cost of losses, along with hedging energy costs (via CfDs) and congestion (via FTRs).

When the FTR product definition is corrected for operational characteristics it leads automatically to a different product per interconnector as the operational constraints are reflected in the properties of the FTR and their price.

5.1 INTERCONNECTOR LOSSES

Physical losses mean that more generation needs to be injected into one end of an interconnector than is delivered at the other end. Losses increase the cost of meeting demand and since they are based on a percentage of the cost of energy at the sending end, the cost of losses varies along with the energy price.

This is accounted for in market coupling by the price in the exporting market being lower than the price in the importing market; in the border between GB and I-SEM, this would be as follows:

- No flow: prices equal in both markets
- Flow on Moyle only: price in receiving market is 1.8% - 5% higher than in sending market
- Flow on both interconnectors: price in receiving market at least 5% higher than in sending market.

If FTR payouts do not take account of loss factors then the payout for FTRs on each interconnector would be the actual price spread. If FTR payouts take account of losses then the price spread for FTR payouts on the Moyle Interconnector would be:

$$\text{price spread}_{\text{unadjusted}} - (\text{price in receiving market} * 1.8\%)$$

and the price spread for FTR payouts on the East-West Interconnector would be:

$$\text{price spread}_{\text{unadjusted}} - (\text{price in receiving market} * 5\%)$$

Loss factors are different per interconnector (Moyle: 1.8%, East-West: 5%) and so therefore are the price spread thresholds at which each interconnector starts collecting congestion rents. If the price spread for FTR pay-out is not corrected for the loss factor (i.e. losses are not included in the payout) each interconnector will have a different ratio of FTR pay-out obligation versus congestion income per unit of FTR product sold.

Market coupling between I-SEM and GB will establish the flows that have to be injected or withdrawn at each end of each interconnector by the shipper concerned. When losses are included in the market coupling, the flows differ with the losses incurred between sending end and receiving end flows. From the clearing and settlement of the respective volumes in each market with the power exchange(s) concerned, the interconnector shipper cashes out the congestion rents: sending end volume * price on sending end – receiving end volume * price on receiving end.

The flows on a border resulting from market coupling can be different per interconnector as a consequence of different technical characteristics - such as losses, ramping constraints and available capacities. The collected congestion rents can therefore also be different per interconnector.

The table below illustrates how different loss factors on Moyle and East-West would collect different congestion rents from the market coupling, where both have an equal ramping constraint of 300 MW/h and an equal 500 MW of available capacity. In this synthetic example of day-ahead prices, where Moyle has a loss factor of 1.8% and East-West of 5%, Moyle receives a total congestion rent of 13,583 whereas East-West only receives 9,350.

DA-result									
Price				Moyle			East-West		
GB	I-SEM	Spread	rel. diff.	GB	I-SEM	CR	GB	I-SEM	CR
54	64	-10	15.6%	500	-491	4,424	500	-475	3,400
56	67	-11	16.4%	500	-491	4,897	300	-285	2,295
63	59	4	6.3%	200	-196	-1,012	0	0	0
67	64	3	4.5%	-100	102	183	0	0	0
60	62	-2	3.2%	200	-196	177	200	-190	-220
54	65	-11	16.9%	500	-491	4,915	500	-475	3,875
						13,583			9,350

Table 7: Synthetic example of optimal prices and flows from DA allocation with resulting CRs

When loss factors are taken into account in the day-ahead market coupling the costs of the losses are already paid for by all the users of the day-ahead market power exchanges through a delta in the local market prices (negative in exporting market, positive in importing market). When price spreads for FTR pay-out are corrected for the loss factors FTR holders also pay for these losses where they are not causing them and have no control over them, although this will affect their pricing of the FTR. If FTR payouts include losses, i.e., market participants are able to hedge the cost of losses on an interconnector by buying a FTR, the IC will be responsible for paying out the price difference between the two bidding zones, when the price difference arises due to losses, even though there was no flow on the interconnector on which to collect revenue. Hence, the IC will be relying on the auction revenues to cover the expected payout for losses.

- The auction price of the FTR would be higher as it would also provide a hedge against the price difference caused by losses.
- The IC owners would be at risk that auction revenues would not cover the additional price difference caused by losses that they would need to pay out.
- Interconnector users would have to purchase fewer FTRs in order to be fully financially hedged (in general terms, if the users must cover the losses element of the price spread then they could do so by buying additional FTRs – 1.8% more FTRs in the case of Moyle and 5% more in the case of East-West – and would recover the additional cost by bidding lower in the auctions).

FTR PAYOUT ON MARKET SPREAD (NOT DISCOUNTED FOR LOSSES)	
Advantages	Disadvantages
Holder hedges full price spread – more effective hedging instrument.	Increased auction revenue adequacy risk to IC owner of payout of price spreads due to losses.
More straightforward product may encourage asset-less traders and also secondary liquidity.	IC owner will pay out on price differences when due to losses when there is no flow on which to collect congestion rent.
FTR purchasers not responsible for losses so should not have payout discounted for being incurred	FTR purchasers may pay higher auction price per MW.

Table 8: Summary of advantages and disadvantages FTR payout based on market price spread (excluding discount for losses)

5.2 RAMPING

Ramping constraints on each interconnector are the combined result of system ramping constraints and technical maximum ramp rates on the interconnector. The risk presented by ramping constraints can be attributed to the FTR holder or IC owner.

I. Ramping constraints causing adverse flow

Adverse flows are flows on an interconnector from a high to a low price area. Adverse flows diverge market prices and cause negative congestion rents. Figure 6 below illustrates a situation in which negative congestion rents prevent the IC owner from receiving congestion rent while still being exposed to the payment for FTRs based on the price difference between the coupled markets. As both have a negative welfare effect (less consumer and producer surplus due to diverging market prices, negative congestion rents) the welfare optimizing objective function of the market coupling would only allow adverse flows to meet ramping constraints when there is sufficient welfare compensation effect in adjacent hours. As marginal congestion rents are equal to the marginal welfare benefits of the market coupling (both are equal to the price spread in the direction of the flow, i.e. price in import market minus price in export market), optimality conditions of the market coupling ensure that ramping constraints can never cause an overall negative congestion rent over the whole day.

Figure 6 shows an example of an adverse flow caused by a ramping constraint. Moyle and EWIC together have a joint capacity of 1000 MW (Moyle is currently operating on half of its normal capacity 500 MW. The full capacity should be restored by 2016). There is a switch in price spread from I-SEM to GB from hour t to t+1 and back from hour t+1 to hour t+2. The joint ramping constraint on Moyle and EWIC is 600 MW/h, i.e. the flow on both interconnectors together cannot change more than 600 MW from hour to hour. During hour t and hour t+2 maximum flow would go in the direction of the GB market, collecting congestion rents of €10,000 for each hour. In hour t+1, price spread changes direction and an optimal flow, not constrained by ramping, would be 1000 MW in the direction of I-SEM. As the ramping constraint limits change of flow to 600 MW, the flow in hour t+1 cannot change direction and is minimized to 400 MW of adverse flow. The total congestion rent collected over all three hours is maximized while respecting the ramping constraint to €16,000, where it would have been €30,000 (=1,000*3*(€50-€40)) without the ramping constraint.

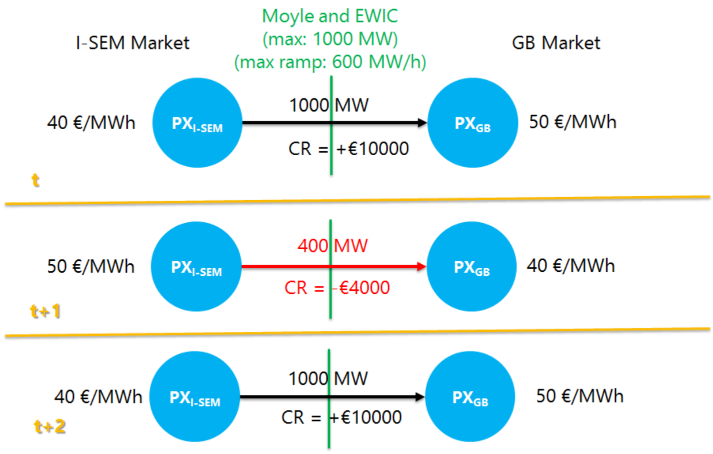


Figure 6: Adverse flow caused by ramping constraint

II. Ramping constraint causing reduced flow

Reduced flows caused by ramping constraints are flows that go from high to low price area but that are smaller than the available capacity. The interconnector flow is constrained because of the ramping limit but not because of available capacity.

Continuing with the example before, let us change prices in t+1 and t+2 to €40 and €45 for I-SEM and €42 and €40 for GB respectively. Figure 7 shows the optimal flow results in this case. Flow in t+1 is reduced from t at max ramp rate to create a maximum non-adverse flow in t+2. The congestion rent over all the hours, respecting the ramping constraint, is maximized to €11,800, where it would have been €17,000 (=1,000*((€50-€40) + (€42-€40) + (€45-€40)) without ramping constraint.[5]

[5] Similarly, avoiding an adverse flow in t+1 and imposing the ramping constraint only on t+2 when the relative prices of the two markets reverse would yield a congestion rent of only €10,000 (1,000*((€50-€40) +(€42-€40)) + (400*€-5)

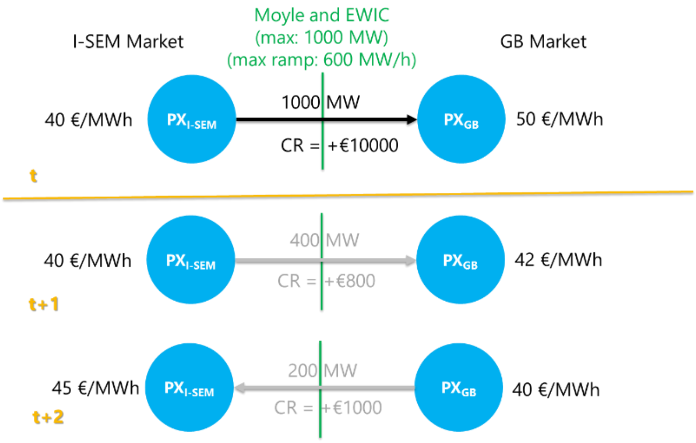


Figure 7: Reduced flows caused by ramping constraints

When ramping constraints are taken into account in day-ahead market coupling the costs of these constraints are already paid for by all the participants of the day-ahead market power exchanges through the resulting limitations in price convergence (higher price spreads during ramping constrained hours). When price spreads for FTR pay-out are corrected for the ramping constraints FTR holders pay also for these constraints when they are not causing them and have no control on them, although this will affect the value and price of the FTR.

Correction of the FTR price spread to take into account reduced congestion income due to ramping constraints will require an ex-post correction each day (as the effects will vary per day) or require an ex-ante forecast and an ex-post correction at each FTR auction.

Ramping constraints arise from technical limitations of the interconnector and of the grids to which it is connected. Constraints on the system to which the interconnector is joined are relatively larger than the ramping constraints of the interconnector itself. These constraints are not controllable by the FTR purchaser or by the IC owner and are managed by the TSO. The question that arises in relation to FTRs involves the allocation of risk, which party is best in position to manage it, and whether the constraints that are imposed should be paid by the FTR purchaser or the Interconnector owner.

The table below summarises the advantages and disadvantages of the attribution of risk to the various parties.

RISK ALLOCATED TO FTR HOLDER (FTR PAYOUT DISCOUNTED)	
Advantages	Disadvantages
Risk can be allocated directly by discounting FTR pay out.	FTR holder not responsible for ramping curtailment risk and has no means of controlling it.
FTR purchaser can factor ramping curtailment risk into FTR auction price offered.	Inclusion of discount on FTR payout reduces the value of the FTR to the holder and potential efficiency of hedging opportunity.
	Transparency of FTR product reduced by process for reducing FTR payout.
RISK ALLOCATED TO IC OWNER (FTR PAYOUT NOT DISCOUNTED)	
Advantages	Disadvantages
FTR payout is more straightforward and transparent. May favour purchase by asset-less traders and increase secondary trading	IC owner not responsible for most significant ramping curtailment risk and has no means of controlling it.
Exclusion of discount on FTR payout increases the value of the FTR to the holder and potential efficiency of hedging opportunity.	IC owner exposed to risk of revenue shortfall due to payout of market spread exceeding congestion rent received.

Table 9: Summary of advantages and disadvantages of allocation of ramping curtailment to FTR holder and Interconnect owner

5.3 UNPLANNED OUTAGES/CURTAILMENT

According to Article 70 of the CACM Regulation, if physical unavailability occurs after the day-ahead firmness deadline, (which must be proposed by all TSOs in Europe in accordance with Article 69 of the CACM Regulation), the capacities allocated to the Interconnector shipper resulting from market coupling on each side of the border must be guaranteed by the TSOs. Therefore, the shipper should still collect the resulting congestion rents from the market coupling price spreads and pay these to the interconnector owner. However, if the same (interconnector) entity is accountable for these TSO and shipper responsibilities, re-dispatch costs, countertrade trade costs or imbalance charges would apply in order to keep the resulting physical net positions of the Shipper and this could outbalance the congestion rents.

According to the current version of the draft FCA Guideline drafted by the European Commission dated 10 June 2015[6], if physical unavailability were to occur before the day-ahead firmness deadline, curtailment of long term transmission rights is allowed, subject to remuneration to the holder limited to a cap equal to the calendar month[7] congestion income. This cap is currently defined in Article 59.2.b of the draft HAR as the congestion income from the daily allocations plus the income from allocation of Long Term Transmission Rights in the month of curtailment.

An exception occurs in case of Force Majeure, in which case TSOs are allowed to curtail long term transmission rights with only the initial price paid by the FTR purchaser as remuneration.

While, in the case of DC interconnectors, curtailment gives the FTR provider the right to cap the remuneration of the FTR holders at the total calendar month congestion income, revenue adequacy risk is not so limited after the day ahead firmness deadline, i.e. during the day of operation and the next day (at most). During this period, congestion rents will still be collected but firmness costs arise due to the obligation to keep the physical net position resulting from market coupling. These firmness costs are however eligible to be included in the transmission tariffs or through other compensation mechanisms, subject to approval by Regulatory Authorities provided they are reasonable, efficient and proportionate.

When the FTR product definition is corrected for firmness costs this leads automatically to a different product per interconnector as the firmness costs will be different.

Summary

Whereas FTR results per unit of product sold are in principle the same for all interconnectors on a bidding zone border, congestion rents and firmness costs from day-ahead market coupling may be different per unit of capacity on each interconnector due to differences in loss factor, ramping constraints and unplanned capacity outages. The correction of FTR payouts to reflect particular technical characteristics of each interconnector such as losses, ramping rates and firmness costs would lead to the auctioning of different products across Moyle and EWIC.

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[6] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/European-network-code/Joint-European-Stakeholder-Group/

[7] For DC interconnectors. For AC interconnectors the cap is equal to the calendar year congestion income.

If the FTRs holder is not exposed to reduction of their payouts due to the technical characteristics of each interconnector, then the FTRs should achieve higher prices in the auctions and this higher price should, in theory, compensate the IC owners for the potential imbalance between congestion revenues (which are constrained by the technical characteristics of each IC) and liabilities against FTR holders.

5.4 MINDED TO DECISION AND CONSULTATION QUESTION

The RAs consider that the inclusion of losses in the FTR payout when the IC owners have no control over these losses would not be an appropriate allocation of risk. Evaluation of the effect of losses can best be taken into account through the price offered at auction by purchasers of FTRs. For the interconnector owner a lower price for the FTR may be offset by reduced liability for pay out on the market spread. It therefore is minded to include a discount for losses in the FTR pay out.

On the other hand ramping is an operational constraint over which some control by the IC owners/TSOs is possible but which is not possible for purchasers of FTRs. Exclusion of ramping constraints on FTR payout will incentivise maximum interconnector availability. The RAs therefore have a minded to view that the effect of ramping constraints should not be included in the FTR payout and that this pay out should not therefore be discounted on this account.

This minded to decision is subject to the final text of the FCA Guideline. Presently, there is an ongoing debate among member states, ACER, EC and ENTSO-E on whether losses and ramping should or should not be discounted from FTR payouts. The SEMC is seeking views on a preferred approach to the treatment of losses and ramping constraints in the event the FCA Regulation does not specify a specific approach.

The impact of curtailment on the FTR product is defined through the EC FCA Guideline, which provides that curtailment of cross-zonal capacity shall be subject to firmness provisions that set out the compensation payable to FTR holders given the particular timing and circumstances under which curtailment arises. The SEM Committee is not minded to seek to depart from these provisions as they exist in the current version of the Guideline and no minded to decision in relation to curtailment is therefore proposed in this consultation.

Consultation Question 3: Should any of the following be discounted from the FTR product payouts?

- Interconnector transmission losses;
- Ramping constrains;
- Curtailment risks

6 AUCTION PLATFORM

Three alternatives for the auction provider were introduced in the discussion paper (SEM-15-010). The suggested alternatives may be different in timing of implementation, implementation costs, operational costs and transition costs towards the single allocation platform. This section summarises the three alternatives and expectations with respect to their differences.

Another aspect to be considered is that FTR Options are included in the current early implementation HAR but FTR Obligations have not yet been incorporated, although provision for them is currently required by the FCA. There are clearly additional challenges with an FTR Obligation product that has bi-directional payment, with a more complex settlement system and more stringent credit assurance arrangements placed on market participants. However a clearing house for settlement would assist with credit assurance and would also make secondary trading of FTR Obligations easier.

In the context of the FCA, a Single Allocation Platform (SAP) for all long term transmission rights will need to be implemented within a short time after its entry into force. However it is unlikely that the SAP will be delivered by the time the first FTR auction for I-SEM is planned to take place (i.e. March 2017). For this reason, the Regulatory Authorities (RAs) need to consider alternatives for the interim period.

Adopt the local/SEM allocation platform

The first option is to alter the current SEM IC allocation platform to incorporate FTRs. An advantage in this case would be that the product can be more easily shaped to local needs, including FTR Obligations, which would reduce implementation time (at least in terms of procurement and approvals). On the other hand implementation costs would be high because of the significant changes that will need to be made and the costs are completely born from local implementation. Risks of stranded costs and new implementation costs to move to the required single allocation platform at a later stage arise with this alternative.

FUIN Platform

There is an initiative underway for a High Voltage Direct Current (HVDC) interconnector platform involving interconnector owners in the France-UK-Ireland-the Netherlands (FUIN) region. This HVDC platform would facilitate early compliance with the HAR for currently operating interconnectors (BritNed, IFA, Moyle and East West Interconnector). Interconnector owners have expressed a preference for this solution.

It is anticipated that implementation costs with this option would be lower than the local solution as the costs will be shared across a greater number of interconnectors. There may be greater implementation risk compared to the local solution, with more stakeholders involved in the project. It is not envisaged that this platform will cater for FTR Obligations as part of early implementation of the HAR. If this platform is not designated a SAP as outlined in the FCA there may also be risks of stranded costs and new implementation costs to move to the designated SAP at a later stage.

Joint Allocation Office (JAO)

ENTSO-E is striving for early implementation of the FCA and the HAR and it is understood that the Joint Allocation Office (JAO)[8] will be auctioning FTRs in the first half of 2016. The JAO is open for other TSOs, who can join by becoming shareholders of the JAO or just by using its services. The JAO platform is seen by European stakeholders such as ENTSO-E, ACER and European Commission as a project leading to the SAP.

Like the option for the FUIN platform the JAO platform is expected to cater for FTR Options only as part of early implementation of the HAR but will be required to cater for Obligations in order to fulfil the requirements of the SAP under the FCA. The implementation costs for SEM-GB interconnectors involved in joining this platform should in principle be the lowest of all three options. On the other hand the risk of getting the necessary system requirements in place in time and gaining agreement with existing members will be the greatest of the three options outlined. If JAO is designated the SAP under the FCA then this option will involve no stranded costs.

Out of the three options discussed here this platform is the one that is at the most advanced stage of development. The SEM interconnector owners have informed the RAs that the FUIN regional TSOs and interconnector owners have considered the option of joining the JAO platform but that the solution of the JAO appears to be High Voltage Alternating Current (HVAC) focused and lacks the capability to address FUIN regional specificities in advance of target go-live in early 2016 for HAR compliant capacity auctions by BritNed and IFA.

6.1 MINDED TO DECISION AND CONSULTATION QUESTION

The SEMC does not have a minded to decision in relation to the determination of the allocation platform to be used in the I-SEM. Instead the RAs will work alongside Interconnector owners and TSOs to establish the most efficient alternative. The RAs

[8] JAO is a merger of the European CASC and CAO allocation platforms made up of 20 TSOs from 17 countries which will carry out auctions on 27 borders within Europe.

will keep market participants abreast of developments on this front as more information becomes available.

However, the SEMC would seek views from market participants on the criteria for decision making in relation to the I-SEM FTRs auction platform and whether there is any initial preference for one of the three approaches outlined.

Consultation question 4: What are the important issues to be considered in deciding on the development of an auction platform?

Consultation Question 5: What is the preferred approach in relation to the establishment of the I-SEM FTR auction platform?

7 SUMMARY OF CONSULTATION

The five questions posed in the Consultation paper are set out as follows:

1. Which offers the greater benefit to the I-SEM/GB market: FTR Options or FTR Obligations?
2. What arrangements would be preferred: one FTR between the I-SEM and GB or one FTR per interconnector?
3. Should any of the following be discounted from the FTR product payouts?
    - Interconnector transmission losses;
    - Ramping constrains;
    - Curtailment risks
4. What are the important issues to be considered in deciding on the development of an auction platform?
5. What is the preferred approach in relation to the establishment of the I-SEM FTR auctioning platform?

The SEM Committee has taken minded to decisions on (2) and (3) above as follows:

2. The SEM Committee is minded to support the sale of FTRs by interconnector.
3. The SEM Committee is minded that the FTR payout is discounted for losses. It considers that ramping constraints should not be discounted from the FTR payouts. The SEM Committee does not seek to move from the EC FCA Guideline, which provides that curtailment of cross-zonal capacity shall be subject to firmness provisions which set out the compensation payable to FTR holders. No minded to decision in relation to curtailment is therefore proposed in this consultation.

Specific views are sought from stakeholders on the questions above, which should be received by 17:00 on 19 October 2015.Responses should be sent to James Curtin (jcurtin@cer.ie) and Joe Craig (joe.craig@uregni.gov.uk).

James Curtin	**Joe Craig**
Commission for Energy Regulation	Utility Regulator
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Please note that the SEM Committee intends to publish all responses unless marked confidential.

APPENDIX A - POLICY IMPLEMENTATION PROCESS

Implementing the policy on cross border transmission rights is expected to require Moyle and EWIC to propose amendments to their access rules, which are subject to licensing requirements in SEM and GB. These rules will be underpinned by European guidelines which are currently under final stages of development. The following paragraphs will outline the process and current timeframe for the RAs' implementation.

As part of the EU's Third Energy package a number of regulations (guidelines) have been developed to assist in the creation of a single European electricity market (EU target model). These include the Capacity Allocation and Congestion Management Regulation, the Forward Capacity Allocation (FCA), and Electricity Balancing (EB) which relate to energy trading.

The FCA establishes the high level requirements and principles for the type and quantity of long term transmission rights. As a European regulation it will supersede existing national arrangements and will apply directly to EU Member States without being transposed into national laws or regulatory frameworks.

The FCA has been submitted to comitology and is being reviewed by EU member states. It is expected that the representatives of the member states will vote on this in late 2015. If approved, the FCA will then be subject to the scrutiny of the EU parliament, which could take around 6 months, before being published in the official journal of the EU. After 20 days it will then become law. Within this timeline therefore it may come into force in the middle of 2016.

ENTSO-E (European Network of Transmission System Operators for Electricity), supported by the Agency for the Cooperation of Energy Regulators (ACER), have decided to begin early implementation of the FCA in order to contribute to faster delivery of the single European electricity market. One of the means of achieving this is via the development of an early version of the harmonised allocation rules (HAR), which will set out the terms and conditions for the allocation of long term transmission rights for PTRs with UIOSI and FTR Options. The HAR that was consulted upon in February 2015 by ENTSO-E is voluntary allowing sufficient time for those seeking early adoption in 2016 to proceed towards implementation. Consultation on binding harmonised rules required under the FCA will be carried out when the Guideline formally enters into force.

The HAR contains most of the detailed rules that are not explicitly set out in the FCA (article 51). It is a single set of European contractual arrangements (but with regional annexes to cover local specificities) for long term cross zonal capacity allocation, which are to be sold through explicit auctions. The FCA (article 52) requires all TSOs to draft the HAR binding rules within a set period of time (the latest draft states 6 months) after it comes into force. This will then be submitted to European National Regulatory Authorities (ENRAs) for approval, who have 6 months to approve. This timeline would result in a HAR approved in the middle of 2017.

The TSOs in each capacity calculation region[9] are required to jointly develop proposals for the design of long term transmission rights (LTTR) on each bidding zone border within 6 months of the FCA coming into force (article 31). This will include the type of LTTR, the allocation timeframe, the form of product and the bidding zone border covered. This will be submitted to the ENRAs for approval, who have another 6 months to approve. This results in the type of LTTR being approved by the middle of 2017.

A further requirement of the draft FCA (article 48) is that there is a single allocation platform for the auctioning of long term transmission rights across EU borders. Article 49 requires all TSOs to submit a common set of requirements for the single platform to all ENRAs within a set period of time (the latest draft states 3 months) after it comes into force. Following ENRA approval (who have 6 months), TSOs are required to have the platform operational within a specific timeframe (12 months in the latest draft). Compliance with this timeline would require the platform to come into operation in early 2018.

It should be noted that the timelines indicated are based on the current draft of the FCA[10] and that earlier drafts developed by ENTOS-E have had longer timelines for the implementation of the HAR and the single allocation platform. The above timelines could therefore be subject to change.

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[9] As established under article 15 of the guideline on capacity allocation and congestion management (CACM).

[10] European Commission version from 10 June 2015.

Early implementation of the (voluntary) HAR, prior to the entry into force of the FCA, has meant that an early draft was submitted to ENRAs in July 2015. Approval is expected to take 3 months and following this, auctions for long term transmission rights are expected to take place across most of Europe for 2016 using this version of the HAR. This HAR also contains a set of annexes that include a set of border specific amendments to the main text. In the case of the SEM-GB border, which applies to the Moyle and East West Interconnectors, the annex will state that the HAR will only come into force for capacity utilised after I-SEM go live date. For capacity sold for use up to this date the local access rules will apply. Early implementation of the HAR that will meet the date for I-SEM go-live will require transitional/regional platform solutions in advance of the single allocation platform.

The current interconnector access rules and existing auction platform will need to be altered to facilitate the introduction of Financial Transmission Rights (FTRs) in I-SEM. SEM and GB Regulatory approval is required for the Access Rules and Charging Methodology Statements of the Moyle Interconnector and the East West Interconnector as a condition of their respective licences.

The Moyle interconnector seeks approval from UR[11] and Ofgem[12] and the East West Interconnector seeks it from the CER[13] and Ofgem.[14] Interconnector access rules were determined to be a SEM matter in January 2011 and the relevant functions of the CER and UR are now exercised by the SEM Committee. The charging methodology statements are also submitted to the RAs for approval, who issue their approval within 3 months of submission.

The go live date for I-SEM is October 2017 and interconnector capacity will need to be auctioned in advance of this date. The auctioning of interconnector capacity also interacts with other work streams within I-SEM, such as the first auction for reliability options, where interconnector capacity would facilitate cross border bidding in the capacity mechanism. The current working assumption is that the first interconnector capacity auction is to be sold at least 3 months in advance of the first I-SEM auctions for reliability options, expected to take place in June 2017. This would require the first I-SEM FTR auction to take place in March 2017 at the latest.

The above timelines leave the SEM-GB interconnectors with a number of options when it comes to the provision of an auction platform for FTRs:

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[11] Condition 17 of the Moyle Interconnector Licence. The UR has the power to approve Access Rules for the Moyle Interconnector under Condition 17, paragraph 4 of the Moyle Interconnector Licence.
[12] Condition 10 and 11a of EWIC's Interconnector Operator Licence granted by Ofgem.
[13] Condition 20 of EWIC's Interconnector Operator Licence granted on 7 October 2011 and the CER approves the Access Rules under Article 34A(1) of the Electricity Regulation Act (1999).
[14] Condition 10 and 11a of EWIC's Interconnector Operator Licence granted by Ofgem.

1) Build/adopt a local platform for SEM-GB interconnector capacity auctions
2) Join an FUIN[15] group of DC interconnectors in building a regional platform
3) Join the Joint Allocation Office[16] (JAO) platform, (which is the main allocation platform for TSOs with AC interconnection on continental Europe).

A further consideration to be taken into account is that the draft of the HAR used for early implementation does not include any provision for FTR Obligations. If the SEM Committee decides to opt for FTR Obligations for the commencement of I-SEM, this will require additional time and resources to draft a version of the HAR catering for Obligations; seeking agreement with and commitment from all other European TSOs and ENRAs to commence work on HAR for FTR Obligations and incorporate this into the allocation platform solution. This also has implications for the development/selection of a platform to auction transmission rights. At present the regional and JAO options outlined above are not expected to cater for FTR Obligations as part of the HAR early implementation. However the FCA Guideline includes provision for Obligations so that both HAR for Obligations and an auction platform that caters for them are required by the FCA.

[15] France-UK-Ireland-The Netherlands (FUIN).
[16] A merger of the European CASC and CAO allocation platforms in use in significant parts of Europe.