Frequency Keeping Optimisation

Modelling options

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Version control

Version	Date amended	Comments
1	14 March 2014	
2	31 March 2014	65 MW National FK added

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1 Introduction

1.1 This document is a mathematical description of modification of Transpower's "Scheduling, Pricing, and Dispatch" (SPD) software to optimise energy, reserve and frequency keeping (regulation) markets. This document only present the changes made to current SPD model for this purpose and therefore will not cover the unchanged parts of SPD.

1.2 The modelling options presented in the flowing sections are based on the assumption that frequency keepers are not paid for intra-band constrained on/off.

1.3 In this document, we consider three base models to include frequency keeping markets into SPD optimisation process. The frequency keeping market node constraints are removed in these models.

1.4 The first model (block offer model) is a mixed-integer problem. In this model, frequency keeping providers offer regulation service in block and only one block can be selected from a frequency keeping provider. This regulation offer structure is similar to (more ideal than) current structure. In order to solve this model, a mixed integer model is required. This model can be easily modified to allow multi-blocks cleared from one provider.

1.5 The second model (uniform offer LP model) is a linear problem. In this model, frequency keepers are assumed to have uniform offer ($/MWh). This frequency offer structure is similar to current energy and reserve offer structure. In order to overcome the issue with frequency keeping control min and max, control min/max slopes are introduced to each offer (similar to reserve).

1.6 Model three is a mixed-integer problem (uniform offer MIP model). In this model, frequency keepers are assumed to have uniform offer ($/MWh). Frequency keeping control min/max constraints are applied to the schemes which are selected to provide frequency keeping service.

1.7 All of these models allow frequency keeping service to be shared between islands. Intra-band constrained on/off cost is assumed being removed.

1.8 Table 1 summarises structure, advantages, shortcomings and possible improvements of the three models.

1.9 Table 2 compares the system costs and frequency keeping costs from three different models.

1.10 Section two described the three models in more details. The mathematical formulations of the three models are presented in sections three to six.

Table 1: Regulation optimisation modelling option summary

	Block offer model	Uniform offer LP model	Uniform offer MIP model
General structure	Regulation offered in block ($/block). A regulation scheme can offer multiple blocks of different sizes and prices. No more than one block can be cleared from a regulation scheme. Multiple regulation schemes can be cleared at a time. Actual control min/ max constraints applied for selected regulation schemes. Mixed integer programming required.	Regulation uniformly offered ($/MW). A regulation scheme can offer multiple bands of different sizes and prices. Multiple bands can be cleared from a regulation scheme. Multiple regulation schemes can be cleared at a time. Linearized control min/max constraints applied for selected regulation schemes. Linear programming required.	Regulation uniformly offered ($/MW). A regulation scheme can offer multiple bands of different sizes and prices. Multiple bands can be cleared from a regulation scheme. Multiple regulation schemes can be cleared at a time. Actual control min/max constraints applied for selected regulation schemes. Mixed integer programming required.

	Block offer model	Uniform offer LP model	Uniform offer MIP model
Advantages **Vs.** **Disadvantages**	Regulation offer structure unchanged. Block offer not preferable in dynamically calculated regulation. (over purchase) Optimal solution. But may over-purchase because of block offer. Regulation is paid as it is cost	Regulation offer structure changed. Uniform offer preferable in dynamically calculated regulation. LP optimal solution may not be optimal if control Min/Max constraint violated. Regulation price can be underestimated.	Regulation offer structure changed. Uniform offer preferable in dynamically calculated regulation. Optimal solution. Uniform offers guarantee optimal regulation purchase. Multiple price solutions may occur.

	Block offer model	Uniform offer LP model	Uniform offer MIP model
Notes	Block offer model can replace the current process to pre-select frequency keepers. Block offer model can also be used for final pricing schedule. This model is not preferable for real-time schedule. Hard market node constraints still needed in real time schedule. We can resolve the problem with LP giving regulation solutions is pre-determined.	LP model may be preferable option for real time dispatch but have the issue of under-purchased or underestimated constrained-on cost. One of the operational solutions is to modify the rule so that regulation providers will not get paid for constrained-on/off. However, the issue with control max constraint still exists. Ex: a scheme that has control max much lower than generation max can be selected to provide regulation based on linearized control max constraint. If the linearized control max constraint is bound, this scheme will be constrained off to meet the control max constraint. Therefore, a significant amount of energy is lost from this scheme and need to be supplied from somewhere else. During the energy scarcity period, this will be a critical issue.	Uniform offer model can replace the current process to pre-select frequency keepers. Uniform offer model can also be used for final pricing schedule. This model is not preferable for real-time schedule. Hard market node constraints still needed in real time schedule. We can resolve the problem with LP giving regulation solutions is pre-determined. The regulation marginal price defined by this LP model can be underestimated.

Source: Electricity Authority

Notes: 1.

Table 2: Simulation results

	System Cost (Including Frequency Keeping Cost)				Frequency Keeping Cost Only			
	Island FK	National FK (50 MW)	National FK (65 MW)	National FK (75 MW)	Island FK	National FK (50 MW)	National FK (65 MW)	National FK (75 MW)
Block offer model	$76,660,114	$68,005,719	$70,724,880	$71,725,629	$13,273,093	$5,700,230	$8,248,995	$9,204,826
Uniform offer LP model	$75,740,139	$67,641,864	$69,683,508	$71,141,518	$13,016,972	$5,495,741	$7,458,914	$8,859,399
LP model with constrained-on/off	$77,718,674	$68,292,694	$70,539,277	$72,153,414	$13,016,972	$5,495,741	$7,458,914	$8,859,399
Uniform offer MIP model	$76,435,712	$67,822,712	$69,933,564	$71,442,769	$13,149,712	$5,679,360	$7,678,354	$9,191,665
Current selection process	N/A	N/A	N/A	N/A	$11,810,598	$7,954,552	N/A	N/A

Source: Electricity Authority

Notes:
1. Island FK means NI and SI separately and respectively require 50 and 25 MW of frequency keeping.
2. National FK (50 MW) means there is only one national market for FK with FK requirement of 50 MW. Similarly for National FK (75 MW & 65 MW).
3. Simulation based on historical data from 24 Jun 2013 to 18 Dec 2013.
4. The regulation (frequency keeping) offer data are modified so that a block offer can be equally converted to uniform offer.
5. Modified vSPD model is used for the simulation with FK optimisation part added.
6. The national frequency keeping cost for current process is calculated by removing the SI frequency keeping cost from Island frequency keeping cost. Therefore, this is just the upper bound of national frequency keeping cost.

1.11 When converting historical regulation block offer to uniform offer, we often encounter cases where the average price of the bigger size block is lower than average price of smaller size block. In this case, we need to increase the cost of bigger size block so that its average price is greater than that of the smaller size block. By doing this, we can equally convert block offer to uniform offer.

1.12 For example, a scheme offers regulation in two blocks. The first block offers 10 MW at $100/block. This is equal to $20/MWh in uniform offer. The second block offers 20 MW at $150/block. This is equal to $15/MWh in uniform offer. In order to equally convert block offer to uniform offer, the cost of second block will be adjusted to $200.01/block. The uniform offer will be 10 MW @ $20/MWh for first offer band and 10 MW @ $20.002/MWh.

1.13 Table 3 shows the historical frequency keeping cost from 2009 to 2013. If we assume that national frequency keeping requirement is equal to NI frequency keeping requirement, the frequency keeping cost in SI is the lower bound of saving we could get if national frequency keeping market were in place.

Table 3: Historical frequency keeping cost

[insert caption subheading]

Year	NI	SI	Total
2009	$17,831,765	$2,605,890	$20,437,654
2010	$30,049,306	$5,983,058	$36,032,364
2011	$18,121,427	$4,701,039	$22,822,466
2012	$26,381,455	$16,499,521	$42,880,976
2013	$20,844,089	$12,405,957	$33,250,046

Source: Electricity Authority

Notes: 1.

2 Regulation optimisation modelling options

2.1 Regulation block offer – mixed integer programing model

(a) In this model the regulation is offered in blocks. One regulation scheme can offer multiple blocks of different sizes (MW) and prices ($/block). Frequency keeping providers offer the service in block with the price (cost) in $/block. For each regulation scheme, no more than one block can be selected. Regulation can be provided by multiple schemes at a time. Intra-band constrained on/off cost is removed. This model produces optimal solution.

(b) One of the disadvantages of this model is that mixed integer programming is required because of block offer structure. However, with the small number of frequency keeping providers and enhanced computational power, this model can be solved very quickly.

2.2 Regulation uniform offer – linear programming model

(a) In this model regulation is offered in the form of $/MWh, similarly to energy and reserve.

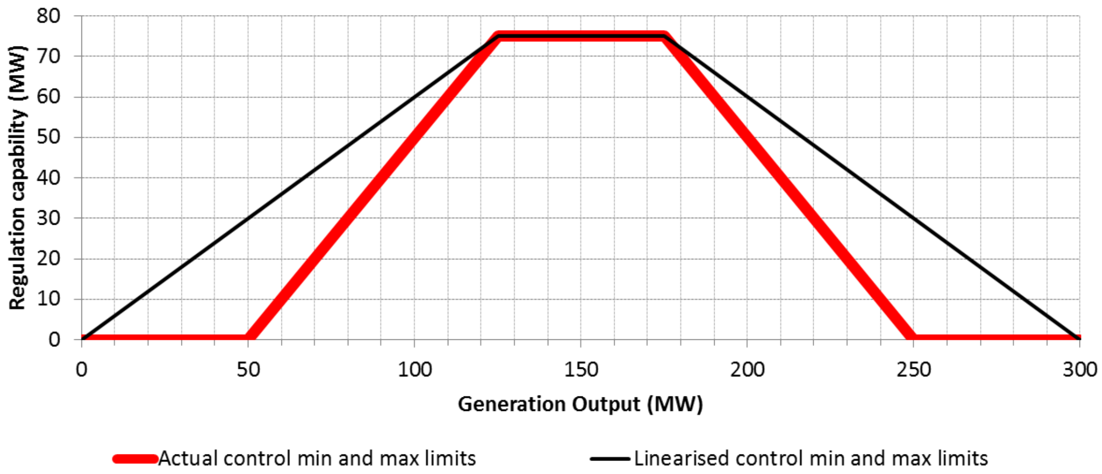
(b) In general, a scheme that is selected to provide regulation is required to have minimum and/or a maximum output limits. The scheme's generation has to be greater than or equal to the minimum limit plus the amount of frequency keeping supplied by the scheme. Similarly, the scheme's generation has to be less than or equal to the maximum limit minus the amount of frequency keeping supplied by the scheme.

(c) If these minimum and maximum limits are equal zero and the plant/scheme's generation capacity respectively, the relationship between generation and frequency keeping is linear and the problem is a straightforward linear programming problem (LP).

(d) In many cases, the minimum is much greater than zero and/or the maximum limit is much less than generation capacity offered. In this situation, the problem becomes a mixed integer linear programming problem (MIP).

(e) In order to solve the problem using LP, the relationship between generation and regulation of a scheme need to be linearized. Let's call this linearized relationship "soft constraint". Figure 1 demonstrates one of the ways to linearize this relationship.

Figure 1 Linearization of control min and max limit of frequency keeping



Source: Electricity Authority

Notes: 2. Generation capacity 300 MW, regulation capacity 75 MW
3. Control min limit 50 MW and control max limit 250 MW

(f) An issue with this approximation is that the amount of frequency keeping supply is overestimated if one of these constraints is binding on either side of the slopes (the black line is always above the red line along the slopes). This means that the regulation provider may be required to constrain on/off its generation output in operation (real time) and the solution is suboptimal. The suboptimal issue gets worse if the control min and/or the gap between control max and generation capacity are larger.

(g) In order to overcome this issue, the following approaches can be considered.

(i) Requesting regulation providers to submit very low price generation offer to meet the minimum generation limit. This approach may help to reduce the occurrence of this issue but does not completely solve the issue with control min limit. Furthermore, this approach does not touch on the control max limit.

(ii) Amending the code so that regulation providers are not paid for constrained-on/off generation to meet regulation control min/max requirements.

(iii) Using MIP to resolving the problem if LP solution violates control min and/or max limits. The MIP problem will be used re-solved with actual control min and max limits being applied for selected frequency keepers. This approach makes sure that control min and max limits are not violated and guarantee the optimal solution but requires mixed integer programming. This approach is described in more details in the following section.

2.3 Regulation uniform offer – mixed integer programing model

(a) In this model regulation is offered in the form of $/MWh, similarly to energy and reserve.

(b) The control min and max limits ("hard constraint") is modelled using mixed integer programming.

(c) A binary variable is introduced in the model so that if a scheme is selected to provide frequency keeping, the actual control min and max limits will be applied for this scheme. For the unselected scheme, frequency keeping offer will be forced to zero and therefore cannot be cleared.

(d) One of the issues with this approach is that it is very likely to have multiple pricing solutions (degeneracy in dual problem). Currently, the frequency keeping requirement is easily predicted, a frequency keeping provider may offer exact amount. If all the offers of this frequency keeping provider are cleared and that is enough to meet the frequency keeping requirement all other offers will be forced to zero. The problem will then have multiple pricing solutions with the extreme price is infeasible price.

(e) This issue can be resolved by reducing the frequency keeping requirement by a very small amount (Ex: If tolerance is 1e-6, we can reduce the frequency keeping requirement by 2e-6). Another option is to add a very small amount (2e-6) to regulation offer MW. This will make sure that the frequency price will be defined by the highest cleared offer price.

(f) This issue may disappear if regulation requirement is dynamically defined based on cleared demand, generation and reserve.

(g) Another solution is to resolve using LP model with fixed regulation and generation min/max constraints applied for the schemes that are selected to provide regulation in MIP model. A problem with the LP resolve is that it may underestimate the regulation price.

3 SETS, PARAMETERS AND VARIABLES

Table 4: SETS

Name	Index	Description
Scheme	s	A group of generators that provide frequency keeping service as a scheme.
Energy Offer	g	Represent offer from generator g.
Reserve Offer	r	Represent reserve offer.
Island	i	Represent island (NI, SI).
Trade Block	k	Represent different band in an offer
Reserve Class	c	Represent different reserve class (6s,60s)

Table 5: PARAMETERS

Name	Description
$RegulationMW_{s,k}$	Maximum MW of frequency offer band k from scheme s.
$RegulationPrice_{s,k}$	Cost of frequency offer band k from scheme s. If block offer → \$/Block; If uniform offer → \$/MWh
$RegulationRequired_i$	Amount of frequency keeping (MW) required in island i
$RegulationSharedMax_i$	Upper limit of frequency keeping (MW) that can be shared through HVDC into island i.
$Capacity_s$	capacity rating of generator g.
$SchemeGenrationCapacity_s$	Total capacity rating of all generators in scheme s.
$RegulationCtrlMin_s$	Minimum generation of frequency keeping provider (scheme) s
$RegulationCtrlMax_s$	Maximum generation of frequency keeping provider (scheme) s
$RegulationCtrlMinSlope_s$	Ratio of maximum frequency keeping and generation. This is used to approximately linearize the FK control min constraint.
$RegulationCtrlMaxSlope_s$	Ratio of maximum frequency keeping and unused but available generation capacity. This is used to approximately linearize the FK control max constraint.

Table 6: VARIABLES

Name	Type	Description
NETBENEFIT	Free	Objective value.
$GENERATION_g$	Positive	Energy cleared from generator g. This is current SPD variable.
$PLORESERVE_{r,c}$	Positive	Total partial load reserve class r cleared from generator g. This is current SPD variable.
$TWORESERVE_{r,c}$	Positive	Total tail-water depressed reserve class r cleared from generator g. This is current SPD variable.
$SCHEMEGENERATION_s$	Positive	Total energy cleared from all generators in scheme s.
$SCHEMERESERVE_{s,c}$	Positive	Total reserve class c cleared from all generators in scheme s.
$REGULATIONBLOCK_{s,k}$	Positive	Frequency keeping cleared from offer block k of scheme s.
$REGULATION_s$	Positive	Total frequency keeping cleared from scheme s.
$REGULATIONHVDC_i$	Positive	Total frequency keeping can be imported through HVDC in to island i.
$BLOCKSELECTED_{s,k}$	Binary	Regulation offer block selected. Only applied in mixed integer model 1
$SCHEMESELECTED_s$	Binary	Regulation scheme selected. Only applied in mixed integer model 3

4 Block frequency keeping offer model

4.1 Revised objective function

$$\mathrm{NETBENEFIT} = \sum_{p \in \mathrm{BIDS}} \sum_{k=1}^{\mathrm{DemandBidBlocks}_p} \mathrm{DEMANDBLOCK}_{p,k} \times \mathrm{DemandBidPrice}_{p,k} -$$
$$\sum_{g \in \mathrm{OFFERS}} \sum_{k=1}^{\mathrm{GenerationOfferBlocks}_g} \mathrm{GENERATIONBLOCK}_{g,k} \times \mathrm{GenerationOfferPrice}_{g,k} -$$
$$\sum_{r \in \mathrm{RESERVEOFFERS}} \sum_{k=1}^{\mathrm{ReserveOfferBlocks}_r} \mathrm{RESERVEBLOCK}_{r,k} \times \mathrm{ReserveOfferPrice}_{r,k} -$$
$$\sum_{s \in \mathrm{REGULATIONOFFERS}} \sum_{k=1}^{\mathrm{RegulationOfferBlocks}_s} 2 \times \mathrm{BLOCKSELECTED}_{s,k} \times \mathrm{RegulationPrice}_{r,k}$$

4.2 Scheme generation calculation

$$\mathrm{SCHEMEGENERATION}_s = \sum_g \mathrm{GENERATION}_g$$
$$\forall g \in \mathrm{Energy\ Offer\ in\ Schemes}$$

4.3 Scheme reserve calculation

$$\mathrm{SCHEMERESERVE}_{s,c} = \sum_r \mathrm{PLORESERVE}_{r,c} + \mathrm{TWORESERVE}_{r,c}$$
$$\forall r \in \mathrm{Reserve\ Offer\ in\ Schemes} \quad \forall c \in \mathrm{Reserve\ Class}$$

4.4 Regulation offer block definition

Maximum only one block is selected from a scheme

$$\sum_{k=1}^{\mathrm{RegulationOfferBlocks}_s} \mathrm{BLOCKSELECTED}_{s,k} \le 1$$
$$\forall s \in \mathrm{Scheme}$$

4.5 Regulation offer definition

$$\mathrm{REGULATION}_s = \sum_{k=1}^{\mathrm{RegulationOfferBlocks}_s} \mathrm{BLOCKSELECTED}_{s,k} \times \mathrm{RegulationMW}_{s,k}$$
$$\forall s \in \mathrm{Scheme}$$

4.6 Regulation Energy and Reserve Maximum

For each reserve class, the sum of regulation, energy and reserve cleared is less than or equal to capacity rating.

$$\mathrm{REGULATION}_s + \mathrm{SCHEMEGENERATION}_s + \mathrm{SCHEMERESERVE}_{s,c} \le \sum_g \mathrm{Capacity}_g$$
$$\forall g \in \mathrm{generators\ in\ Scheme\ s}$$

4.7 Regulation Control Min Definition

$$\text{SCHEMEGENERATION}_s - \text{REGULATION}_s \geq \sum_{k=1}^{\text{RegulationOfferBlocks}_s} \text{BLOCKSELECTED}_{s,k} \times \text{RegulationCtrlMin}_s \quad \forall s \in \text{Scheme}$$

4.8 Regulation Control Max Definition

$$\text{SCHEMEGENERATION}_s + \text{REGULATION}_s \leq \sum_g \text{Capacity}_g + \sum_{k=1}^{\text{RegulationOfferBlocks}_s} \text{BLOCKSELECTED}_{s,k} \times \left(\text{RegulationCtrlMax}_s - \sum_g \text{Capacity}_g\right) \quad \forall g \in \text{generators in Scheme s}$$

4.9 Max regulation imported through HVDC

$$\text{REGULATIONHVDC}_i \leq \text{RegulationSharedMax}_i \quad \forall i \in \text{island}$$

4.10 Available regulation to be shared through HVDC

$$\text{REGULATIONHVDC}_i \leq \sum_{s \in \text{Schemes in island} \neq i} \text{REGULATION}_s \quad \forall i \in \text{island} \quad s \in \text{Schemes in the other island}$$

4.11 Regulation supply balance definition

$$\text{REGULATIONHVDC}_i + \sum_s \text{REGULATION}_s \geq \text{RegulationRequired}_i \quad \forall s \in \text{Scheme in island i}$$

5 Uniform frequency keeping offer LP model

5.1 Revised objective function

$$\text{NETBENEFIT} = \sum_{p \in \text{BIDS}} \sum_{k=1}^{\text{DemandBidBlocks}_p} \text{DEMANDBLOCK}_{p,k} \times \text{DemandBidPrice}_{p,k} - \sum_{g \in \text{OFFERS}} \sum_{k=1}^{\text{GenerationOfferBlocks}_g} \text{GENERATIONBLOCK}_{g,k} \times \text{GenerationOfferPrice}_{g,k} - \sum_{r \in \text{RESERVEOFFERS}} \sum_{k=1}^{\text{ReserveOfferBlocks}_r} \text{RESERVEBLOCK}_{r,k} \times \text{ReserveOfferPrice}_{r,k} - \sum_{s \in \text{REGULATIONOFFERS}} \sum_{k=1}^{\text{RegulationOfferBlocks}_s} \text{REGULATIONBLOCK}_{s,k} \times \text{RegulationPrice}_{r,k}$$

5.2 Scheme generation calculation

$$\text{SCHEMEGENERATION}_s = \sum_g \text{GENERATION}_g$$

$$\forall g \in \text{Energy Offer in Schemes}$$

5.3 Scheme reserve calculation

$$\text{SCHEMERESERVE}_{s,c} = \sum_r \text{PLORESERVE}_{r,c} + \text{TWORESERVE}_{r,c}$$

$$\forall r \in \text{Reserve Offer in Schemes} \quad \forall c \in \text{Reserve Class}$$

5.4 Regulation offer block definition

$$\text{REGULATIONBLOCK}_{s,k} \leq \text{RegulationMW}_{s,k}$$

$$\forall s \in \text{Scheme} \quad \forall k \in \text{Regulation Offer Blocks}$$

5.5 Regulation offer definition

$$\text{REGULATION}_s = \sum_{k=1}^{\text{RegulationOfferBlocks}_s} \text{REGULATIONBLOCK}_{s,k}$$

$$\forall s \in \text{Scheme}$$

5.6 Regulation Energy and Reserve Maximum

For each reserve class, the sum of regulation, energy and reserve cleared is less than or equal to capacity rating.

$$\text{REGULATION}_s + \text{SCHEMEGENERATION}_s + \text{SCHEMERESERVE}_{s,c} \leq \sum_g \text{Capacity}_g$$

$$\forall g \in \text{generators in Scheme s}$$

5.7 Regulation Control Min Definition

$$\text{REGULATION}_s \leq$$
$$\text{RegulationCtrlMinSlope}_s \times \text{SCHEMEGENERATION}_s$$
$$\forall s \in \text{Scheme}$$

5.8 Regulation Control Max Definition

$$\text{REGULATION}_s \leq$$
$$\text{RegulationCtrlMaxSlope}_s \times \left(\text{Capacity}_s - \text{SCHEMEGENERATION}_s\right)$$
$$\forall s \in \text{Scheme}$$

5.9 Max regulation imported through HVDC

$$\text{REGULATIONHVDC}_i \leq \text{RegulationSharedMax}_i$$
$$\forall i \in \text{island}$$

5.10 Available regulation to be shared through HVDC

$$\text{REGULATIONHVDC}_i \leq \sum_{s \in \text{Schemes in island} \neq i} \text{REGULATION}_s$$
$$\forall i \in \text{island} \quad s \in \text{Schemes in the other island}$$

5.11 Regulation supply balance definition

$$\text{REGULATIONHVDC}_i + \sum_s \text{REGULATION}_s \geq \text{RegulationRequired}_i$$
$$\forall s \in \text{Scheme in island i}$$

6 Uniform frequency keeping offer MIP model

6.1 Revised objective function

$$\mathrm{NETBENEFIT} = \sum_{p \in \mathrm{BIDS}} \sum_{k=1}^{\mathrm{DemandBidBlocks}_p} \mathrm{DEMANDBLOCK}_{p,k} \times \mathrm{DemandBidPrice}_{p,k} - \sum_{g \in \mathrm{OFFERS}} \sum_{k=1}^{\mathrm{GenerationOfferBlocks}_g} \mathrm{GENERATIONBLOCK}_{g,k} \times \mathrm{GenerationOfferPrice}_{g,k} - \sum_{r \in \mathrm{RESERVEOFFERS}} \sum_{k=1}^{\mathrm{ReserveOfferBlocks}_r} \mathrm{RESERVEBLOCK}_{r,k} \times \mathrm{ReserveOfferPrice}_{r,k} - \sum_{s \in \mathrm{REGULATIONOFFERS}} \sum_{k=1}^{\mathrm{RegulationOfferBlocks}_s} 2 \times \mathrm{REGULATIONBLOCK}_{s,k} \times \mathrm{RegulationPrice}_{r,k}$$

6.2 Scheme generation calculation

$$\mathrm{SCHEMEGENERATION}_s = \sum_g \mathrm{GENERATION}_g$$

$$\forall g \in \text{Energy Offer in Schemes}$$

6.3 Scheme reserve calculation

$$\mathrm{SCHEMERESERVE}_{s,c} = \sum_r \mathrm{PLORESERVE}_{r,c} + \mathrm{TWORESERVE}_{r,c}$$

$$\forall r \in \text{Reserve Offer in Schemes} \quad \forall c \in \text{Reserve Class}$$

6.4 Regulation offer block definition

$$\mathrm{REGULATIONBLOCK}_{s,k} \le \mathrm{SCHEMESELECTED}_s \times \mathrm{RegulationMW}_{s,k}$$

$$\forall s \in \text{Scheme} \quad \forall k \in \text{Regulation Offer Blocks}$$

6.5 Regulation offer definition

$$\mathrm{REGULATION}_s = \sum_{k=1}^{\mathrm{RegulationOfferBlocks}_s} \mathrm{REGULATIONBLOCK}_{s,k}$$

$$\forall s \in \text{Scheme}$$

6.6 Regulation Energy and Reserve Maximum

For each reserve class, the sum of regulation, energy and reserve cleared is less than or equal to capacity rating.

$$\mathrm{REGULATION}_s + \mathrm{SCHEMEGENERATION}_s + \mathrm{SCHEMERESERVE}_{s,c} \le \sum_g \mathrm{Capacity}_g$$

$$\forall g \in \text{generators in Scheme s}$$

6.7 Regulation Control Min Definition

$$\text{SCHEMEGENERATION}_s - \text{REGULATION}_s$$
$$\geq \text{RegulationCtrlMin}_s \times \text{SCHEMESELECTED}_s$$
$$\forall s \in \text{Scheme}$$

6.8 Regulation Control Max Definition

$$\text{SCHEMEGENERATION}_s + \text{REGULATION}_s$$
$$\leq \sum_g \text{Capacity}_g + \text{SCHEMESELECTED}_s \times \left(\text{RegulationCtrlMax}_s - \sum_g \text{Capacity}_g\right)$$
$$\forall g \in \text{generators in Scheme s}$$

6.9 Max regulation imported through HVDC

$$\text{REGULATIONHVDC}_i \leq \text{RegulationSharedMax}_i$$
$$\forall i \in \text{island}$$

6.10 Available regulation to be shared through HVDC

$$\text{REGULATIONHVDC}_i \leq \sum_{s \in \text{Schemes in island} \neq i} \text{REGULATION}_s$$
$$\forall i \in \text{island} \quad s \in \text{Schemes in the other island}$$

6.11 Regulation supply balance definition

$$\text{REGULATIONHVDC}_i + \sum_s \text{REGULATION}_s \geq \text{RegulationRequired}_i$$
$$\forall s \in \text{Scheme in island i}$$

Appendix A Converting block offer to uniform offer

A.1 Appendix heading 2 is the style to use for the main text in an appendix.

(a) Appendix paragraph (a)

(b) Appendix paragraph (a)

(i) Appendix paragraph (i)

(ii) Appendix paragraph (i)

A.2 Appendix heading 2

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References

Glossary of abbreviations and terms

Authority	Electricity Authority
Act	Electricity Industry Act 2010
Code	Electricity Industry Participation Code 2010
Regulations	Electricity Industry (Enforcement) Regulations 2010