TRANSPOWER

Scheduling, Pricing and Dispatch Software

Model Formulation

Draft adaptations to allow for a market in frequency keeping “regulation” service

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1. INTRODUCTION

This document is a mathematical description of Transpower's "Scheduling, Pricing, and Dispatch" (SPD) software to be used by the New Zealand Electricity Market. It has been presented using a mathematical notation designed to be rigorous but (relatively) easy to follow. There are many alternative expressions which are mathematically equivalent, and will produce the same result in the market. Alternative representations may be more convenient for implementation purposes. Thus the mathematical formulation in this document may not necessarily correspond, in detail, with that implemented by ESCA (the developers of the SPD software). Auditing the software to verify that it is mathematically equivalent will be treated as a separate and subsequent task.

The document is in three parts: the first part provides a glossary to the model components such as sets and variables; in the second part the constraints are defined; and the third part defines pre-processing.

This version has been marked up so as to show the kind of changes which would be required in order to allow development of a market for a frequency keeping "regulation" service. It is thus intended only to facilitate industry discussions, and has no status in relation to the Electricity Governance Rules for the New Zealand electricity market.

Modifications to the text are indicated by change marks, while modified equations are highlighted, thus. The explanations provided are intended to explain the rationale behind the changes, and are not indicative of what might be included in any final formulation document. Reference is made to some minor changes that might be required to the underlying formulation before a frequency keeping market formulation could be built upon it. It is noted that some of those changes might actually align this formulation document better with our understanding of current practice, and/or improve it, even if no frequency keeping market were to be introduced. But these comments should not be interpreted as advocating that such changes should actually be made, since revision of the formulation document to match, or improve, current practice lies outside the present scope.

2. GLOSSARY OF SETS, INDICES, VARIABLES AND PARAMETERS

All variables and parameters are non-negative except where stated. There are no "soft" constraints and associated penalty variables to catch and help identify reasons for infeasible solutions for instances of the model.

The word "scheduled" is used when describing the meaning of some variables. For example, "$Generation_g$ is the MW generation scheduled corresponding to offer $g \in OFFERS$". This is used as a shorthand for "scheduled or dispatched". It includes the concept of generation notionally scheduled to meet metered loads in pricing runs.

2.1. FUNDAMENTAL SETS AND INDICES

2.1.1. Islands

An island is represented by an element of the set *ISLANDS* and is indexed by *i*.

2.1.2. Generation Offers

A generation offer is represented by an element of the set *OFFERS* and is indexed by *g*. The use of the word "offer" does *not* imply this set can contain offers from generator market participants *only*. Non-market participants can also be accommodated within this framework. Only one offer is assumed for each station or unit. Each offer has associated with it an island and a node.

For reserve purposes a subset of *OFFERS* called $ISLANDRISKGENERATORS_i$ is defined. This subset is used to determine the potential risk due to generators in each island. A subset is used because not all offers represent a potential risk. For example, the total generation of a hydro station which is represented by one offer is not a potential risk because it is generally made up of many small units that are not themselves at risk generators.

2.1.3. Purchase Bids

A purchase bid is represented by an element of the set *BIDS* and is indexed by *p*. The use of the word "bid" does *not* imply this set can contain offers from purchaser market participants *only*. The purchase bid is a *gross* bid. That is, it is not *net* of embedded generation. Non-market participants can also be accommodated within this framework. Only one bid per bidder at a node is assumed. Each bid has associated with it an island and a node.

2.1.4. Reserve Offers

A reserve offer from either a generator or interruptible load provider is represented by an element of the set *RESERVEOFFERS* and is indexed by *r*. Like generation offers and purchase bids a reserve offer has associated with it an island and a node. Regulation offers are treated as a sub-set of reserve offers.

2.1.5. AC Nodes

An AC node is represented by an element of the set *ACNODES* and is indexed by *n*. Associated with a node is an island.

There is a subset of *ACNODES* called *REFERENCENODES*. This set contains one and only one node from each island.

2.1.6. HVDC Nodes

An HVDC node is represented by an element of the set *HVDCNODES* and is indexed by *h_n*. Such nodes only connect to HVDC links that have no connection to AC lines. Thus they are only defined for HVDC Pole 1 links.

2.1.7. AC Lines

An undirected AC line is represented by an element of the set *ACLINES* and is indexed by *k*. There is a "conventional" direction for these lines but this does not imply a direction of flow because the "undirected flow" can be positive or negative. However for the purposes of determining losses direction is important. Therefore for each line *k* there are associated forward and backward lines, referred to as directed lines.

A directed line is represented by an element of the set *DIRECTEDACLINES* and is indexed by *q*. The directional nature of lines means it is possible to identify the sending and receiving ends of the line. Functions defined on the set are described below.

2.1.8. HVDC Poles

HVDC Poles are the DC transmission lines from Benmore to Haywards including the submarine cables across the Cook Straight. It is assumed that poles are in pairs and there is only one pair as follows:

$HVDCPoles = \{Pole1, Pole2\}$

2.1.9. HVDC Half Poles

The HVDC Half Poles are the mercury arc valve groups that connect the DC Pole 1 transmission line to the AC systems at Benmore and Haywards.

HVDC Half Poles ={BEN_1A, BEN_1B, HAY_1A, HAY_1B}

2.1.10. HVDC Links

An HVDC link is represented by an element of the set *HVDCLINKS* and is indexed by element *l*. The links are always directional. For each pole and direction and for each half pole and direction there is a unique element in *HVDCLINKS*.

It is assumed that links either connect different islands, or AC and DC nodes within an island.

2.1.11. Reserve Types

A reserve type is represented by an element of the set *RESERVETYPES* and is indexed by element *s*.

RESERVETYPES = {*PLSR*,*TWD*,*IL*}

PLSR is partly loaded spinning reserve which can be provided by any generator. *TWD* is tail water depressed reserve which can only be provided by hydro generators. *IL* is interruptible load which can only be provided by purchasers.

2.1.12. Reserve Classes

A reserve class is represented by an element of the set *RESERVECLASSES* and is indexed by *c*.

RESERVECLASSES = {*Fast*,*Sustained*,*Regulation*}

RAISECLASSES = {Fast,Sustained}

In other words, these are the contingency reserve classes which have been traded in the New Zealand market since inception.

2.1.13. Risk Classes

A risk class is represented by an element of the set $RISKCLASSES_i$ and is indexed by *rc*.

$RISKCLASSES_i = \{DCCE_i, DCECE_i, Manual_i\} \cup ISLANDRISKGENERATORS_i$

$DCCE_i$ indicates the loss of a single HVDC pole. $DCECE_i$ indicates the loss of all HVDC poles. $Manual_i$ indicates an island's minimum risk. These risks apply only to the Fast and Sustained contingency reserve classes. Regulation requirements are specified separately.

2.1.14. Security Measures

A security measure is represented by an element of the set *SECURITY* and is indexed by *v*. The System operator is able to adjust parameters to meet the Electricity Governance Rules Part C.

2.2. DERIVED SETS

Numerous subsets of the fundamental sets are of interest. A subscripted fundamental set represents all elements of the fundamental set having the attribute represented by the subscript.

Examples of derived sets are:

—1. $OFFERS_i$ is the set of all generation offers belonging to island *i*.

—2. $BIDS_n$ is the set of all purchase bids belonging to node *n*.

—3. $ACLINES_n$ is the set of all AC lines connected to node *n*.

—4. $RESERVEOFFERS_{TWD,Fast,i}$ is the set of all *Fast TWD* reserve offers in island *i*.

—5. $HVDCLINKS_{Pole1}$ is the set of *Pole*1 links.

6. *RESERVEOFFERS*$_{PLSRReg\ i}$ is the set of all *regulation* reserve offers from PLSR generators island *i*.[1]

Some combinations of sets and subscripts may not have any useful purpose, or for that matter any meaning whatsoever.

2.3. FUNCTIONS DEFINED ON SETS

For ease of description a number of functions are defined that operate on elements of sets and return either another set or a single element. The following functions are defined:

—1. $k(\cdot)$ where the argument could be a security offer *v* or directed AC line *q* gives the undirected AC line associated with the argument.

—2. $q(v)$ gives the directed AC line *q* of interest in security measure *v*.

—3. $n(v)$ gives the AC node *n* of interest in security measure *v*.

—4. $n(i)$ gives the set of AC nodes *n* located in island *i*.

—5. $g(\cdot)$ where the argument could be a reserve offer *r* or security measure *v* gives the generation offer associated with the argument.

—6. $p(\cdot)$ where the argument could be a reserve offer *r* or security measure *v* gives the purchase bid associated with the argument.

—7. $b(\cdot)$ and $e(\cdot)$ give the beginning and ending AC nodes respectively of a line or link where the argument could be an undirected AC line *k* or a HVDC link *l*. For the undirected AC line the conventional direction of the line is used to determine the beginning and end.

—8. $F(k)$ and $B(k)$ give the forward and backward directed AC lines respectively associated with AC undirected line *k*.

—9. $l(v)$ gives the HVDC link of interest in security measure *v*.

—10. $S_{AC}(n)$ and $R_{AC}(n)$ give the sets of AC directed lines for which *n* is the sending AC node or receiving AC node respectively.

—11. Similarly, $S_{HVDC}(n)$ and $R_{HVDC}(n)$ give the sets of HVDC links for which *n* is the sending AC node or receiving AC node respectively.

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[1] Note that there will almost certainly be no regulation offers from IL or TWD, so *RESERVEOFFERS*$_{PLSRReg\ i}$ = *RESERVEOFFERS*$_{Reg\ I}$

—12. Similarly, $S_{HVDC}(h\_n)$ and $R_{HVDC}(h\_n)$ give the sets of HVDC links for which *h_n* is the sending HVDC node or receiving HVDC node respectively.

—13. $m(i,c,rc)$ gives the mixed security constraint variable *m* corresponding to the *RiskOffset* for island *i*, reserve class *c*, and risk class *rc*.

14. $REG(g)$ gives the regulation offer associated with generation offer *g*.

2.4. GENERATION AND PURCHASES

2.4.1. Parameters

$GenerationOfferBlocks_g$	The number of blocks in generation offer *g*∈ *OFFERS*.
$GenerationOfferMW_{g,j}$	The MW element of the j^{th} block of the offer.
$GenerationOfferPrice_{g,j}$	The price element of the j^{th} block of the offer. *The parameter is unbounded.*
$PurchaseBidBlocks_p$	The number of blocks in purchase bid *p*∈ *BIDS*.
$PurchaseBidMW_{p,j}$	The MW element of the j^{th} block of the bid.
$PurchaseBidPrice_{p,j}$	The price element of the j^{th} block of the bid. *The parameter is unbounded.*

2.4.2. Variables

$Generation_g$	The total MW generation scheduled corresponding to offer *g*∈ *OFFERS*.
$GenerationBlock_{g,j}$	The MW generation corresponding to the j^{th} block of the offer.
$Purchase_p$	The total MW purchase scheduled corresponding to bid *p*∈ *BIDS*.
$PurchaseBlock_{p,j}$	The MW purchase corresponding to the j^{th} block of the bid.

2.5. HVDC TRANSMISSION SYSTEM

2.5.1. Parameters

$HVDCLinkCapacity_l$	The MW capacity of HVDC link *l*∈*HVDCLINKS*.
$HVDCLinkFixedLosses_l$	The fixed losses of the link. The losses attributed to each *link* are half the fixed losses of the *pole*, or *half-pole*, to which the link belongs.
$HVDCBreakpointMWFlow_{l,bp}$	Value of power flow at the break point *bp* of HVDC Link *l*.
$HVDCBreakpointMWLoss_{l,bp}$	Value of variable (no-fixed) loss at the breakpoint *bp* in the loss curve of HVDC Link *l*.

$HVDCBreakpoints_l$	The number of breakpoints in the loss curve of HVDC Link *l*.

2.5.2. Index

bp	Index of the break points from 1 to $HVDCBreakpoints_l$

2.5.3. Variables

$HVDCLinkFlow_l$	The MW flow at the sending end scheduled for HVDC link $l \in HVDCLINKS$.
$HVDCLinkLosses_l$	The MW losses for the link.
$DCNodeNetInjection_{h\_n}$	The MW injection at HVDC node $h\_n \in HVDCNODES$. This is actually set to zero since there are no AC lines connected to HVDC nodes but has been formulated as a variable for consistency with AC nodes.
$Lambda_{l,bp}$	Non-negative weight applied to breakpoint *bp* of HVDC Link *l*.

2.6. AC Transmission System

2.6.1. Parameters

$ACLineCapacity_k$	The MW capacity of AC line $k \in ACLINES$.
$ACLineAdmittance_k$	The admittance of the line. It is really the susceptance but the use of “admittance” seems to be widespread. The admittance of a line is a complex number $G - iB$ where G is the conductance and B is the susceptance. It is the susceptance which is used in the DC power flow calculations.
$ACLineLossBlocks_k$	The number of blocks in the loss curve of the line.
$ACLineLossMW_{k,j}$	The MW element of the j^{th} block of the loss curve.
$ACLineLossFactor_{k,j}$	The loss factor element of the j^{th} block of the loss curve.
$ACLineFixedLosses_k$	The fixed losses of the line.

2.6.2. Variables

$ACNodeNetInjection_n$	The MW injection at node $n \in ACNODES$. *The variable is unbounded.*
$ACNodeAngle_n$	The voltage angle at the node. *The variable is unbounded*

$ACLineFlow_{k}$	The MW flow scheduled for line $k \in ACLINES$. *The variable is unbounded*
$ACLineFlow_{q}^{Directed}$	The MW flow scheduled for directed line $q \in DIRECTEDACLINES$.
$ACLineFlowBlock_{q,j}^{Directed}$	The MW flow corresponding to the j^{th} block of the loss curve.
$ACLineLosses_{q}^{Directed}$	The MW losses for the directed line.
$ACLineLossesBlock_{q,j}^{Directed}$	The MW losses corresponding to the j^{th} block of the loss curve.

2.7. RISK AND RESERVE

A generic reserve offer structure is used. Differentiation between types of reserve is achieved by using the fundamental set *RESERVETYPES* to create subsets of *RESERVEOFFERS*. Contingency r~~R~~eserve is assumed to be freely available while ramping, but joint limits are placed on ramping for regulation and energy dispatch purposes.~~.~~

2.7.1. Parameters

$ReserveOfferBlocks_r$	The number of blocks in reserve offer $r \in RESERVEOFFERS$.
$ReserveOfferProportion_{r,j}$	The incremental MW percentage of the j^{th} block of offer $r \in RESERVEOFFERS_{PLSR}$.
$ReserveOfferPrice_{r,j}$	The price element of the j^{th} block of the offer. *The parameter is unbounded*
$ReserveOfferMaximum_{r,j}$	The maximum MW reserve available from the j^{th} block of the offer.
$ReserveGenerationMaximum_g$	The maximum MW combined generation and reserve capability associated with generation offer $g \in OFFERS$.[2]
$ReserveMaximumFactor_{g,c}$	The factor to adjust the maximum reserve of class $c \in RESERVECLASSES$ associated with generation offer $g \in OFFERS$. At present this defines a common slope defining the trade-off between maximum generation and maximum reserve response to be applied to each offer block for a particular reserve class. If set to 1, then backing off generation by one unit allows one more unit of this reserve class to be supplied. Such a factor may apply to regulation, too, but there is now a three way trade-off between generation, regulation, and each raise reserve class. See 3.4.2.1.
$RegulationMinimum_g$	The minimum generation level below which generator g can not respond to provide regulation under AGC control. $g \in OFFERS$
$RegulationMaximum_g$	The maximum generation level above which generator g can not respond to provide regulation under AGC control. $g \in OFFERS$
$IslandRiskAdjustmentFactor_{i,c,rc}$	The risk adjustment factor for island $i \in ISLANDS$, reserve class $c \in RESERVECLASSES$ and risk class $rc \in RISKCLASSES_i$.
$IslandMinimumRisk_i$	The minimum MW risk level for island $i \in ISLANDS$.

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[2] The reference is made to a generation offer because the maximum capability is advised in a generation offer (Attachment 1 to the Rules). The limit is applied jointly to generation and regulation, plus each class of contingency reserve separately.

$HVDCREGCAP_l$	Absolute cap on HVDC swing capacity for regulation purposes. $l \in HVDCLINKS$
$HVDCREGMAX_l$	Conceptual joint upper bound on HVDC regulation flows for regulation purposes, and energy flows (in the forward conventional direction). This may be set by limits on MW transfer capacity and/or AGC control systems. But the precise computation of the limit will depend on detailed technical investigation of HVDC capability and AGC characteristics, and decisions on such issues as to where, in the HVDC sub-system, flow should be measured and controlled by AGC. $l \in HVDCLINKS$
$HVDCREGMIN_l$	Conceptual joint upper bound on HVDC regulation flows for regulation purposes, and energy flows (in the reverse conventional direction). As above, -the precise computation of the limit will depend on detailed investigations —yet to be conducted. $l \in HVDCLINKS$
$Re\,gSupplyMIN_N$	The minimum regulation requirement which must be met by intra-island s~~i~~upply. $i \in ISLANDS$

2.7.2. Variables

$Reserve_r$	The reserve scheduled corresponding to reserve offer $r \in RESERVEOFFERS$.
$ReserveBlock_{r,j}$	The reserve scheduled corresponding to j^{th} block of the offer.
$IslandRisk_{i,c,rc}$	The MW risk for island $i \in ISLANDS$, reserve class $c \in RESERVECLASSES$ and risk class $rc \in RISKCLASSES_i$. The variable is unrestricted.
$MaxIslandRisk_{i,c}$	The maximum MW risk for island $i \in ISLANDS$, reserve class $c \in RESERVECLASSES$.
$HVDCRec_i$	The total net pre-contingent HVDC flow received at island i. The variable is unrestricted (i.e. negative for export).
$RiskOffset_{i,c,rc}$	The risk offset for island $i \in ISLANDS$, reserve class $c \in RESERVECLASSES$ and risk class $rc \in RISKCLASSES_i$. This is netted off the raw risk and accounts for the effects of HVDC pole rampup, AUFLS, free reserve, and non-compliant generation. The variable is unrestricted. This parameter may be set to zero for the regulation reserve class, or a different calculation may be applied.
$Re\,gSupply_i$	Aggregate regulation supplied by an island $i \in ISLANDS$

$HVDCLinkFlow_l$	Conceptual HVDC flow variable introduced for draft formulation of regulation transfer/sharing on the HVDC link~~v~~. It is related to $HVDCRec_i$ but probably not identical because of the way losses are accounted for in the latter. The precise computation will depend on detailed technical investigation of HVDC capability and AGC characteristics, and decisions on such issues a-s to where, in the HVDC sub-system, flow should be measured and controlled by AGC. $l \in HVDCLINKS$
$HVDC\,Re\,g_l$	Conceptual HVDC regulation swing range variable introduced for draft formulation of regulation transfer/sharing on the HVDC link. As above, -its precise definition will depend on future detailed technical investigations. $l \in HVDCLINKS$

2.7.3. Parameters for pre-processing

$ReserveGenerationMaximum_{g,c}$	The MW combined maximum capability for generation and reserve of class $c \in RESERVECLASSES$ associated with generation offer $g \in OFFERS$. This parameter only serves to indirectly define $ReserveMaximumFactor_{g,c}$, as discussed above. It is not clear why this indirect mode of definition has been adopted, but there is no reason why the same mode can not be applied to regulation.

2.8. SECURITY

The System operator may impose generation, reserve and purchase limits and flow limits on AC and DC transmission equipment for security reasons, using the constraint forms defined in Section 3.5 to meet the requirements of the Grid Operating Security Policy.

2.8.1. Sets

$SECURITY_{GenerationMaximum}$	The set of maximum generation offer security constraints.
$SECURITY_{GenerationMinimum}$	The set of minimum generation offer security constraints.
$SECURITY_{ACLineCapacity}$	The set of all directed AC transmission line flow security constraints.
$SECURITY_{HVDCLinkCapacity}$	The set of HVDC link flow security constraints.
$SECURITY_{GroupACLinesFlow}$	The set of group AC transmission line flow security constraints.
$SECURITY_{GroupACNodesNetInjection}$	The set of all group AC node net injection security constraints.

$SECURITY_{GroupMarketNodes}$	The set of group market node security constraints on generation, purchase and reserve.
$SECURITYACLINESGROUP_v$	The set of AC directed transmission lines used in a group flow security constraint for security measure v.
$SECURITYACNODESGROUP_v$	The set of AC node net injections used in market node group constraint for security measure v.
$SECURITYMARKETPUTNODESGROUP_v$	The set of Purchase offers used in market node group constraint for security measure v
$SECURITYMARKETGENNODESGROUP_v$	The set of Generation offers used in market node group constraint for security measure v
$SECURITYMARKETRESNODESGROUP_v$	The set of Reserve offers used in market node group constraint for security measure v

2.8.2. Parameters

$SecurityGenerationMaximum_v$	The MW generation maximum associated with security measure $v \in SECURITY_{GenerationMaximum}$ imposed on a generation offer by the System operator for security reasons.
$SecurityGenerationMinimum_v$	The MW generation minimum associated with $v \in SECURITY_{GenerationMaximum}$.
$SecurityACLineCapacity_v$	The MW directed AC line capacity associated with $v \in SECURITY_{ACLineCapacity}$.
$SecurityHVDCLinkCapacity_v$	The MW HVDC link capacity associated with $v \in SECURITY_{HVDCLinkCapacity}$.
$SecurityGroupACLinesFlow_v$	The MW maximum total flow of a group of directed AC lines, associated with security measure $v \in SECURITY_{GroupACLinesFlow}$. *The parameter is unbounded.*
$SecurityGroupACLineWeight_q$	The weight associated with directed line $q \in SECURITYACLINESGROUP_v$. *The parameter is unbounded.*
$SecurityGroupACNodesNetInjection_v$	The MW maximum total AC node net injection of a group of AC nodes, associated with security measure $v \in SECURITY_{GroupACNodesNetInjection}$*The parameter is unbounded.*
$SecurityGroupACNodeWeight_n$	The weight associated with AC node $n \in SECURITYACNODESGROUP_v$. *The parameter is unbounded.*
$MarketNodePurWeight_p$	The weight associated with purchase bid $p \in SECURITYMARKETPURNODEGROUP_v$. *The parameter is unbounded.*

$MarketNodeGenWeight_g$	The weight associated with generation offer $g \in SECURITYMARKETGENNODEGROUP_v$. *The parameter is unbounded.*
$MarketNodeResWeight_r$	The weight associated with reserve offer $r \in SECURITYMARKETRESNODEGROUP_v$. *The parameter is unbounded.*
$MarketNodeSecurityLimit_v$	The limit associated with security measure $v \in SECURITY_{GroupMarketNodes}$. *The parameter is unbounded.*

2.9. MIXED CONSTRAINTS.

This facility allows the System operator to impose mixed constraints on any existing variables. It also provides a powerful facility for the creation of new models. Approval for the creation of new mixed constraints is required to go through the consultation process used for rule changes under the Electricity Governance Rules. Such consultation (and subsequent approval) relates to the form of the mixed constraints, and may include specification of permanent conditions with respect to the level of, or relationships between, parameters in the constraint. Other parameters may be adjusted by specified processes. Any formulation constraint involving mixed constraint variables may also be implicitly involved.

2.9.1. Sets

$MIXEDCONSTRAINTS_{Type1}$	The set of all Type 1 mixed constraints. Each constraint, *m*, will normally define one new variable, $MixedConstraintVariable_m$, and can link it to any combination of existing model variables.
$MIXEDCONSTRAINTS_{Type2}$	The set of all Type 2 mixed constraints. Each Type 2 constraint is a group constraint creating links between the new variables created by Type 1 constraints.
$MIXEDVARGROUP_b$	The set of Type 1 mixed constraints whose new variables are linked by Type 2 mixed constraint *b.*
$MIXEDPURNODEGROUP_m$	The set of purchase offers used in Type1 mixed constraint m.
$MIXEDGENNODEGROUP_m$	The set of generation offers used in Type1 mixed constraint m.
$MIXEDRESNODEGROUP_m$	The set of reserve offers used in Type1 mixed constraint m.
$MIXEDDIRACLINEGROUP_m$	The set of AC lines whose flow used in Type1 mixed constraint m.
$MIXEDDIRACLINLOSSGROUP_m$	The set of AC line whose losses are used in Type1 mixed constraint m.
$MIXEDACFIXLOSSGROUP_m$	The set of AC lines whose fixed losses used in Type1 mixed constraint m.
$MIXEDDCLINEGROUP_m$	The set of DC lines whose flow is used in Type1 mixed constraint m
$MIXEDDCLNLOSSGROUP_m$	The set of DC lines whose losses are used in Type1 mixed constraint m
$MIXEDDCFIXLOSSGROUP_m$	The set of DC lines whose fixed are losses used in Type1 mixed constraint m

2.9.2. Parameters

$MixedConstVarWeight1_{m}$	The weight associated with mixed security constraint variable $m \in MIXEDCONSTRAINTS_{Type1}$ *The parameter is unbounded.*
$MixedConstPurWeight_{p,m}$	The weight associated with purchase bid $p \in MIXEDPURNODEGROUP_{m}$. *The parameter is unbounded.*
$MixedConstGenWeight_{g,m}$	The weight associated with generation offer $g \in MIXEDGENNODEGROUP_{m}$. *The parameter is unbounded.*
$MixedConstResWeight_{r,m}$	The weight associated with reserve offer $r \in MIXEDRESNODEGROUP_{m}$. *The parameter is unbounded.*
$MixedConstACLineWeight_{q,m}$	The weight associated with the flow in directed AC line $q \in MIXEDDIRACLINEGROUP_{m}$. *The parameter is unbounded.*
$MixedConstACLineLossWeight_{q,m}$	The weight associated with the variable loss in directed AC line $q \in MIXEDDIRACLINEGROUP_{m}$. *The parameter is unbounded.*
$MixedConstACLineFixedLossWeight_{k,m}$	The weight associated with the fixed loss in undirected AC line *k* $l \in MIXEDACLINEGROUP_{m}$. *The parameter is unbounded.*
$MixedConstDCLinkWeight_{l,m}$	The weight associated with the flow in HVDC link $l \in MIXEDDCLINEGROUP_{m}$. *The parameter is unbounded.*
$MixedConstDCLinkLossWeight_{l,m}$	The weight associated with the variable loss in HVDC link $l \in MIXEDDCLINEGROUP_{m}$. *The parameter is unbounded.*
$MixedConstDCLinkFixedLossWeight_{l,m}$	The weight associated with the fixed loss in HVDC link $l \in MIXEDDCLINEGROUP_{m}$. *The parameter is unbounded.*
$MixedConstraintLimit1_{m}$	The limit associated with mixed security constraint $m \in MIXEDCONSTRAINTS_{Type1}$. *The parameter is unbounded.*
$MixedConstVarWeight2_{m.b}$	The weight associated with mixed security constraint variable $m \in MIXEDVARGROUP_{b}$ in constraint $b \in MIXEDCONSTRAINTS_{Type2}$ *The parameter is unbounded.*
$MixedConstraintLimit2_{b}$	The limit associated with mixed security constraint $b \in MIXEDCONSTRAINTS_{Type2}$. *The parameter is unbounded.*

2.9.3. Variables

$MixedConstraintVariable_m$	Mixed security constraint variable defined by constraint $m \in MIXEDCONSTRAINTS_{Type1}$. The variable is unrestricted.

2.10. RAMPING

A generator has limits on its ability to move from one level of generation to another. Ramping constraints are enforced by constraining the generation level based on energy available over a trading period. The energy based limit is determined by pre-processing.

2.10.1. Parameters for the model determined by the pre-processing

$GenerationMaximum_g^{EnergyBased}$	The constant generation level giving $Energy_g^{Maximum}$ associated with generation offer $g \in OFFERS$ in a trading period. An alternative definition is suggested next.
$GenerationMaximum_g^{TargetBased}$	The maximum generation target level which can be attained by the end of the dispatch interval (or “Trading Period” in the current terminology). This could be a replacement for the above definition, but see discussion in Section 5.3.1.
$GenerationMinimum_g^{EnergyBased}$	The constant generation level giving $Energy_g^{Minimum}$ associated with the offer in a trading period. An alternative definition is suggested next
$GenerationMinimum_g^{TargetBased}$	The minimum generation target level which can be attained by the end of the dispatch interval (or “Trading Period” in the current terminology). This could be a replacement for the above definition, but see discussion in Section 5.3.2.
$RegulationResponseRatio$	The ratio of the interval within which the full MW range of regulation response must be provided, and the dispatch interval.
$MaxJointUpRamp_g$	The maximum MW up ramp which can be expected, for energy dispatch and regulation response combined, within the $RegulationResponseInterval$.
$MaxJointDownRamp_g$	The maximum MW down ramp which can be expected, for energy dispatch and regulation response combined, within the $RegulationResponseInterval$.

2.10.2. Parameters for pre-processing

$RampRate_g^{Up}$	The *ramping up* rate in MW per minute associated with generation offer $g \in OFFERS$.
$RampRate_g^{Down}$	The *ramping down* rate in MW per minute associated with the offer.
$Generation_g^{Start}$	The MW generation level associated with the offer at the start of a trading period.
$TradingPeriodLength$	The length of a trading period in minutes. Arguably, the way in which this parameter is currently employed in the formulation document- is not really appropriate any more, because SPD is being run for "dispatch intervals" which are shorter than the "trading period". We have used the following terminology instead.
$Dispatch\ Interval$ (or $Dispatch\ IntervalLength$, if preferred)	The length of a dispatch interval, in minutes. (Specification of all intervals in seconds, and ramp rates in MW/second would facilitate comparison of "energy" and "reserve/regulation" response rates. But there is no material difference, provided everything is expressed compatibly. Eg "6 second" response = "tenth of a minute" response)
$Regulation\ ResponseInterval$	The period within which the full MW range of regulation response, from the energy dispatch set point to either regulation range limit, must be provided. (Also in minutes, if the length of a dispatch interval is specified in minutes.)

2.10.3. Variables used in the pre-processing

$Generation_g^{Maximum}$	The maximum MW generation level associated with generation offer $g \in OFFERS$.
$Generation_g^{Minimum}$	The minimum MW generation level associated with generation offer $g \in OFFERS$.
$Generation_g^{End,Up}$	The MW generation level associated with the offer at the end of a trading period assuming ramping up at rate $RampRate_g^{Up}$.
$Generation_g^{End,Down}$	The MW generation level associated with the offer at the end of a trading period assuming ramping down at rate $RampRate_g^{Down}$.
$RampTime_g^{Up}$	The time to ramp up to the maximum or the length or the trading period length if this is less.
$RampTime_g^{Down}$	The time to ramp down to the minimum or the trading period length if this is less.
$Energy_g^{Maximum}$	The maximum amount of energy associated with the offer available in the trading period.

$Energy_g^{Minimum}$	The minimum amount of energy associated with the offer available in the trading period.

3. CONSTRAINTS

3.1. GENERATION AND PURCHASES

3.1.1.1. $Generation_{g,j} \le GeneratorOfferMW_{g,j}$

$$j = 1, \ldots GenerationOfferBlocks_g \qquad \forall\, g \in OFFERS\,.$$

3.1.1.2. $$Generation_g = \sum_{j=1}^{GenerationOfferBlocks_g} Generation_{g,j} \quad \forall\, g \in OFFERS\,.$$

3.1.1.3. $Purchase_{p,j} \le PurchaseBidMW_{p,j} \qquad j = 1, \ldots, PurchaseBidBlocks_p$

$$\forall\, p \in BIDS\,.$$

3.1.1.4. $$Purchase_p = \sum_{j=1}^{PurchaseBidBlocks_p} Purchase_{p,j} \quad \forall\, p \in BIDS\,.$$

3.2. HVDC TRANSMISSION

3.2.1.1. $$HVDCLinkFlow_l \le HVDCLinkCapacity_l \quad \forall\, l \in HVDCLINKS\,.$$

3.2.1.2. $$HVDCLinkLosses_l = \sum_{bp=1}^{HVDCBreakpoints_l} HVDCBreakpointMWLosses_{l,bp} \times Lambda_{l,bp}$$

3.2.1.3. $$HVDCLinkFlow_l = \sum_{bp=1}^{HVDCBreakpoints_l} HVDCBreakpointMWFlow_{l,bp} \times Lambda_{l,bp}$$

3.2.1.4. $$\sum_{bp=1}^{HVDCBreakpoints_l} Lambda_{l,bp} = 1$$

3.2.1.5. $$DCNodeNetInjection_{h\_n} = 0 \qquad \forall\, h\_n \in HVDCNODES\,.$$

3.2.1.6. $$\begin{aligned} DCNodeNetInjection_{h\_n} = & - \sum_{l \in S_{HVDC}(h\_n)} HVDCLinkFlow_l \\ & + \sum_{l \in R_{HVDC}(h\_n)} \left(HVDCLinkFlow_l - HVDCLinkLosses_l \right) \\ & - \sum_{l \in HVDCLINKS_{h\_n}} \tfrac{1}{2} \times HVDCLinkFixedLosses_l \end{aligned}$$

$$\forall\, h\_n \in HVDCNODES$$

3.3. AC TRANSMISSION

3.3.1.1. $$ACNodeNetInjection_n = \sum_{q \in S_{AC}(n)} ACLineFlow_q^{Directed} - \sum_{q \in R_{AC}(n)} ACLineFlow_q^{Directed}$$
$$\forall\, n \in ACNODES\ .$$

3.3.1.2. $$\begin{aligned} ACNodeNetInjection_n = & \sum_{g \in OFFERS_n} Generation_g - \sum_{p \in BIDS_n} Purchase_p \\ & - \sum_{l \in S_{HVDC}(n)} HVDCLinkFlow_l \\ & + \sum_{l \in R_{HVDC}(n)} \left(HVDCLinkFlow_l - HVDCLinkLosses_l \right) \\ & - \sum_{l \in HVDCLINKS_n} \tfrac{1}{2} \times HVDCLinkFixedLosses_l \\ & - \sum_{q \in R_{AC}(n)} ACLineLosses_q^{Directed} \\ & - \sum_{k \in ACLINES_n} \tfrac{1}{2} \times ACLineFixedLosses_k \quad \forall\, n \in ACNODES \end{aligned}$$

3.3.1.3. $$ACLineFlow_q^{Directed} \le ACLineCapacity_{k(q)}$$
$$\forall\, q \in DIRECTEDACLINES\ .$$

3.3.1.4. $$ACLineFlow_k = ACLineFlow_{F(k)}^{Directed} - ACLineFlow_{B(k)}^{Directed}$$
$$\forall\, k \in ACLINES\ .$$

3.3.1.5. $$ACLineFlow_k = ACLineAdmittance_k \times \left(ACNodeAngle_{b(k)} - ACNodeAngle_{e(k)} \right)$$
$$\forall\, k \in ACLINES\ .$$

3.3.1.6. $$ACLineFlowBlock_{q.j}^{Directed} \le ACLineLossMW_{k(q)}$$
$$j = 1, \ldots, ACLineLossBlocks_{k(q)}$$
$$\forall\, q \in DIRECTEDACLINES\ .$$

3.3.1.7. $$ACLineFlow_q^{Directed} = \sum_{j=1}^{ACLineLossBlocks_{k(q)}} ACLineFlowBlock_{q,j}^{Directed}$$
$$\forall\, q \in DIRECTEDACLINES\ .$$

3.3.1.8. $$ACLineLossesBlock_{q,j}^{Directed} = ACLineFlowBlock_{q,j}^{Directed} \times ACLineLossFactor_{k(q),j}$$
$$j = 1, \ldots, ACLineLossBlocks_{k(q)}$$
$$\forall\, q \in DIRECTEDACLINES\ .$$

3.3.1.9. $$ACLineLosses_q^{Directed} = \sum_{j=1}^{ACLineLossBlocks_{k(q)}} ACLineLossesBlock_{q,j}^{Directed}$$
$$j = 1, \ldots, ACLineLossBlocks_{k(q)}$$
$$\forall\, q \in DIRECTEDACLINES\ .$$

3.3.1.10. $$ACNodeAngle_n = 0 \quad \forall\, n \in REFERENCENODES.$$

3.4. RISK AND RESERVE

3.4.1. Risk

3.4.1.1.
$$IslandRisk_{i,c,rc} = IslandRiskAdjustmentFactor_{i,c,rc} \times \left(HVDCRec_i - RiskOffset_{i,c,rc}\right)$$

$$\forall\ c \in RAISECLASSES \quad \forall\ i \in ISLANDS \quad \forall\ rc \in \left\{DCCE_i, DCECE_i\right\}$$

This constraint has been modified so as not to apply to regulation in the straw man design, since regulation capacity is not dispatched to cope with loss of the HVDC link. After further investigation, it may well seem desirable to have special calculations of regulation requirements corresponding to particular HVDC states, as in this constraint. But the form of such constraints, if any, will be different from that of 3.4.1.1.

3.4.1.2.
$$HVDCRec_i = HVDCReg + \sum_{n(i)} \left(\begin{array}{l} - \sum_{l \in S_{HVDC}(n)} HVDCLinkFlow_l \\ + \sum_{l \in R_{HVDC}(n)} \left(HVDCLinkFlow_l - HVDCLinkLosses_l\right) \end{array} \right)$$

$$\forall\ i \in ISLANDS$$

Conceptually, the HVDC risk to be covered by reserve in the (energy) receiving island should now include energy transfer, plus maximum regulation swing in that direction. This indicative equation has been modified on the assumption that the maximum regulation swing will equal the HVDC capacity set aside for regulation, *HVDCReg*, irrespective of the balance between "transfer" and "sharing"[3] As with other aspects of this draft formulation, detailed alignment with HVDC states and technological characteristics has not been attempted. [4]

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[3] The formulation assumes a worst case scenario, though, in which that a contingency could occur when regulation flows on the HVDC were at their maximum in that direction. It also assumes that the HVDC capacity set aside for regulation will never be so great as to create a downside risk with respect to HVDC link loss in the (energy) sending island. That could only happen if the regulation range was greater than the energy transfer, and constraints 3.2.4.8&9 will ensue this, provided *HVDCRegMin* is set to some non-negative level, in the planned direction of HVDC energy flow, thus ensuring that regulation swings do not imply a change in HVDC flow direction.

As discussed in Section C.5.4 of Appendix C, this formulation is only intended to ensure that contingency response is sufficient to restore the energy balance to what it was when the HVDC failed, in the worst case. It does not address the issue of restoring the intra-island regulation freeboard to its pre-contingency levels. As discussed in Section C.5.4 of Appendix C the overall effect is probably still an increase in reliability. But Section3.4.2.6 below allows additional constraints to limit each island's reliance on regulation transfer from the other island, if that is considered desirable.

[4] See discussion with respect to 3.4.2.8-10.

3.4.1.3. $$IslandRisk_{i,c,rc} = IslandRiskAdjustmentFactor_{i,c,rc} \times \left(Generation_g - RiskOffset_{i,c,rc}\right) + \sum_{r \in RESERVEOFFERS_{g,c}} Reserve_r$$

$$\forall\ g \in ISLANDRISKGENERATORS_i \quad \forall\ c \in RAISECLASSES$$
$$\forall\ i \in ISLANDS \quad \text{for} \quad rc = g$$

This constraint has been modified so as not to apply to regulation in the straw man design. It relates requirements for raise reserve to the loading of the largest units operating. It probably will not be necessary have a special calculation of regulation requirements corresponding to particular generator loading levels.

3.4.1.4. $$IslandRisk_{i,c,rc} = IslandRiskAdjustmentFactor_{i,c,rc} \times \left(IslandMinimumRisk_i - RiskOffset_{i,c,rc}\right)$$

$$\forall\ c \in RESERVECLASSES \quad \forall\ i \in ISLANDS \quad \text{for } rc = Manual_i$$

This constraint has not been modified, because it is the only one of the *IslandRisk* constraints which needs to apply to regulation, at least for the straw man design. It basically allows the regulation requirement for each island to be set manually.

It might become desirable to add a similar constraint to define an aggregate national regulation requirement, which may be reduced if sharing of regulation duties between islands is enabled. For the straw man design, though, the national risk is just determined by the sum of the island risks above. Section C5.8 of Appendix C suggests that, even if a reduced aggregate national regulation requirement is considered appropriate, it would only apply to regulation dispatches which did not use the full HVDC swing capacity for regulation transfer. Thus that section suggests a formulation in which the reduced aggregate national regulation requirement is implicitly formed, within the LP optimisation, as a weighted sum of the island risks, using a modified form of constraint 3.4.3.6 below.

3.4.1.5. $$RiskOffset_{i,c,rc} = MixedConstraintVariable_{m(i,c,rc)}$$

$$\forall\ c \in RESERVECLASSES \quad \forall\ i \in ISLANDS \quad \forall\ rc \in RISKCLASSES_i$$

This equation has not been changed, because an offset may well be appropriate, depending on the HVDC state etc, as determined by the appropriate *MixedConstraintVariable*.[5] If there is no need to apply an offset to regulation, the offset can be set to zero in the equation.

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[5] But the actual setting of the *MixedConstraintVariable* depends on the mixed constraint set formulation, and has not been addressed

As explained in the next section, we have not considered the detailed linkage of the HVDC regulation sharing model to the technical characteristics of particular HVDC components or configurations. That linkage would have to be determined from detailed technical consideration of the components and configurations involved, and of the way in which they might interact with the final design of the AGC controller. But we expect the linkage to be expressed via modification and/or addition to the existing mixed constraint set, which does not form part of the SPD formulation, per se. For existing reserve classes these linkages impact on the SPD formulation via this constraint 3.4.1.5, setting the corresponding *RiskOffset* variable. We expect that a similar linkage will be required for regulation. But a more complex linkage can not be ruled out.

3.4.2. Reserve

3.4.2.1. $Reserve_{r,j} \le ReserveOfferProportion_{r,j} \times Generation_{g(r)}$
$j = 1,\ldots,ReserveOfferBlocks_r \quad \forall\ r = RESERVEOFFERS_{PLSR}$.

This constraint, which defines the distinctive "fan" shape of reserve offers in the New Zealand market, will apply if regulation offers are included in the set $RESERVEOFFERS_{PLSR}$.. This seems natural, since regulation will mainly, if not exclusively, be supplied by PLSR, that is by partially loaded units. If a "flat" offer form is preferred, this can be achieved by creating a new set for regulation offers, or by just setting $ReserveOfferProportion_{r,j}$ to a very high level for all regulation offer blocks.

Note that these constraints construct a "fan" of offer bands, radiating from the zero generation/reserve point. This was done, in the original formulation, to ensure that the zero generation/reserve point lay within the convex feasible region defined by the LP constraints. In many cases, though, it may be more realistic to have reserve offers radiating from a point further along the generation axis, because reserve can not really be supplied at all at low generation levels.

If constraint 3.4.2.7 was to limit generation to lie above *RegulationMIN*, it may be reasonable to also allow all reserve offers (including those for regulation) to be modified so as to radiate from a point, say *ReserveMIN*, lying somewhere in the range from *generation = zero*, up to *generation= RegulationMIN*. Or, a reserve capability envelope could be super-imposed on the reserve offer structure, cutting the axis at some point such as *ReserveMIN*. Generalisation of the reserve constraints, as such, lies beyond the present scope. But note that, if regulation is treated as a reserve class, then generalisation of the reserve constraint/offer form would also imply generalisation of the regulation constraint/offer form.

3.4.2.2. $Reserve_{r,j} \le ReserveOfferMaximum_{r,j} \quad j = 1,\ldots,ReserveOfferBlocks_r$
$\forall\ r = RESERVEOFFERS$.

3.4.2.3. $Reserve_r = \sum_{j=1}^{ReserveOfferBlocks_r} Reserve_{r,j} \quad \forall\ r \in RESERVEOFFERS$.

3.4.2.4. $$Generation_g + ReserveMaximumFactor_{g,c} \times \sum_{r \in RESERVEOFFERS_{g,c}} Reserve_r$$

$$+ ReserveMaximumFactor_{g,reg} \times \sum_{r \in RESERVEOFFERS_{g,reg}} Reserve_r$$

$$\leq ReserveGenerationMaximum_g$$

$$\forall\ g \in OFFERS \quad \forall\ c \in RAISECLASSES$$

At present, *ReserveMaximumFa~~x~~ctor* defines a common slope determ~~f~~ining the trade-off between maximum generation and maximum reserve response to be applied to each offer block for a particular reserve class. If set to 1, then backing off generation by one unit allows one more unit of this reserve class to be supplied. Such a factor may apply to regulation, too, but there is now a three way trade-off between generation, regulation, and each raise reserve class.

3.4.2.5. $$Reserve_r \leq Purchase_{p(r)} \quad \forall\ r \in RESERVEOFFERS_{IL}.$$

3.4.2.6. $$Generation_g + \sum_{r \in RESERVEOFFERS_{g,reg}} Reserve_r \leq RegulationMaximum_g$$

$$\forall\ g \in OFFERS$$

This constraint has been added to ensure that AGC instructions issued for regulation purposes will not move real-time generator dispatch above the range within which AGC is effective. The constraint is additional to 3.4.2.4, which limits generation, and regulation jointly with each raise reserve class, and is not redundant, unless *ReserveGenerationMaximum* is less than *AGCMaximum*. This seems unlikely, unless a unit is de-rated, in which case pre-processing sets the two limits to be equal.

3.4.2.7. $$Generation_g - \sum_{r \in RESERVEOFFERS_{g,reg}} Reserve_r \geq RegulationMinimum_g$$

$$\forall\ g \in OFFERS$$

This constraint has been added to ensure that AGC instructions issued for regulation purposes will not move real-time generator dispatch below the range within which AGC is effective. The constraint is additional to 3.4.2.1, which also jointly limits generation and regulation over the lower part of the generation range, in accordance with the "fan" offer form. But, since the fan defined by 3.4.2.1 radiates from the zero generation/regulation point, constraint 3.4.2.7 will most likely cut across the rays of that fan, effectively invalidating those offer blocks over the lower part of the potential generation range.

This is not undesirable, and gives greater control over the effective shape of the offer. As noted with respect to 3.4.2.1 an~~d~~ even more flexible offer form could now be proposed, for both regulation and raise reserve, but that development does not constitute part of the straw man design. See discussion and diagrams in Section C2.3 of Appendix C.

Conceptual formulation for HVDC swing limits

3.4.2.8. $HVDCReg \le HVDCREGCAP_l$

$\forall\, l \in HVDCLINKS$.

This explicit cap constraint is required, because there are no implicit limits inherent in the offer block limits as in 3.4.2.1&2.

3.4.2.9. $HVDCLinkFlow_l + HVDCReg \le HVDCREGMAX_l$

$\forall\, l \in HVDCLINKS$.

3.4.2.10. $HVDCLinkFlow_l - HVDCReg \ge HVDCREGMIN_l$

$\forall\, l \in HVDCLINKS$.

These constraints are analogous to 3.4.2.6&7, but for HVDC links, not generation.

As noted in the previous section, we have not considered the detailed linkage of the HVDC regulation sharing model to the technical characteristics of particular HVDC components or configurations. That linkage would have to be determined from detailed technical consideration of the components and configurations involved, and of the way in which they might interact with the final design of the AGC controller. We expect the linkage to be expressed via modification and/or addition to the existing mixed constraint set, which does not form part of the SPD formulation, per se.

Once those linkages haven been determined, the precise form of the above constraints will become clearer. Conceptually, though, the intent is to identify, and eventually optimise, the maximum “swing capacity” of the HVDC. Basically, this is the freeboard available between the dispatched energy flow, denoted here by the variable $HVDCLinkFlow_l$, and the limits within which it is deemed acceptable to vary the HVDC flow, around $HVDCLinkFlow_l$, for regulation purposes.

These limits are denoted here by $HVDCREGMIN_l$ and $HVDCREGMAX_l$, but the calculation of the limits is not addressed. At times they may be physical limits of particular link components, and at others they may be limits imposed by the AGC arrangements. And it may be necessary to compute and/or apply these limits at the pole level, for example. But these are the kind of linkage issues which will have to be addressed by more detailed studies, as explained above.

Among other things, it must be decided where, within the HVDC sub-system, flows are to be (perhaps notionally) measured, limited and controlled. Obviously, the flow sent from one island will not be the same as the flow received in the other island, due to losses. So the limits would be computed differently if applied at one end of the link vs the other. Hence our use of a loosely defined $HVDCLinkFlow_l$ variable, rather than the precise $HVDCRec_i$

variable already calculated by constraint 3.4.1.2 above. This $HVDCRec_i$ measures the aggregate nett flow received in each island, accounting for losses on the incoming flows, and it may well be that it can be used in some of these constraints. But it may be necessary to compute a different aggregate flow measure for regulation transfer purposes, and/or to perform some more detailed computation at the pole level, for example. These details are left for later investigation.

We do note an issue with respect to losses, though. The conceptual formulation given here ignores losses, whereas $HVDCRec_i$, for example accounts for them explicitly. Losses are clearly an issue, and the losses on the base energy flow will impact on the calculation of swing capacity, depending on where it is measured. But it should be recognised the losses on the base energy flow are not really the relevant loss measure when it comes to measuring the effectiveness of regulation transfers.

Those losses will be incurred by the base energy flow, irrespective of any regulation transfer. They will not be greatly affected by regulation activity, because, even if there is an asymmetric nett transfer of regulation from one island to another, regulation activity is supposed to involve essentially symmetric swings around the base energy flow level. Thus the average energy flow level is not expected to change, and nor would the average losses, if the HVDC loss function was linear. Because the HVDC loss function is piece-wise linear, losses may actually change a little. And because it is convex, the direction of change will always be to increase losses.

The effect may not actually be significant, if the extreme limits of HVDC swing are only +/-25MW, as suggested by KEMA, but it could be calculated, perhaps using a probability distribution of expected swings, and the underlying quadratic determining HVDC losses.[6] This increase in losses may be considered a cost of allowing regulation activity on the HVDC, somewhat offsetting the gains from reducing the probability of requiring extreme regulation activity in either island and/or reducing the aggregate national regulation requirement. None of these effects, positive or negative, have been accounted for in the straw man design, and hence in our draft formulation.

What is relevant, from a regulation and AGC perspective, though, is the marginal loss factor applying to swings in the HVDC transfer level. If the marginal loss is 10%, then a swing of 10MW at one end of the link will imply a swing of either 9 MW or 11 MW at the other end.

Note that the applicable marginal loss factor depends entirely on the direction of the underlying energy flow. It does not depend on the direction of the swing. Nor does it depend on the direction of the regulation transfer. Thus, if the direction of energy flow is from South to North, and the marginal loss factor on that flow is 10%. A swing of 10MW in the South Island will correspond to a

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[6] Losses on the extreme limits could be determined within SPD, by applying its piece-wise linear loss representation to variations around the base flow. But note that extreme regulation swings will only occur for a small fraction of the time, and a formula would need to developed to relate these estimates to averages over the entire probability distribution of expected swings.

swing of 9MW in the North Island, irrespective of whether the South Island is providing regulation support to the North Island, or vice versa, and irrespective of whether the swing required, at any particular instant, is to increase or decrease South-North flow.

This marginal loss factor will have to be accounted for by the AGC controller. If necessary it could be set, outside of SPD, based on real time observation of regulation transfer in the preceding dispatch interval. Eventually, it would be desirable to account for the effect within the SPD formulation, but this has not been done in this draft formulation. Preliminary investigation suggests that the effect should be to change the slope of total requirements line shown in Figure C-16 below. But there will also be a related impact on the calculation of the SN and/or NS limits, and these all depend on where, in the HVDC sub-system, flows are notionally measured. Thus the calculation of loss impacts, and refinement of the formulation to deal with them, must also be left for later consideration.

3.4.3. Matching of requirements and availability

3.4.3.1. $IslandRisk_{i,c,rc} \le MaxIslandRisk_{i,c}$

$$\forall\ rc \in RISKCLASSES, c \in RaiseCLASSES, i \in Islands$$

There is only one risk class for regulation and this constraint could be applied, provided $IslandRisk_{i,reg,rc}$ is set appropriately, either to zero, by pre-processing, or to some other level as discussed above.. Thus the change made here to restrict application of this constraint is arguably redundant, along with the alternative form provided below.[7]

3.4.3.2. $MaxIslandRisk_{i,c} \le \sum_{r \in RESERVEOFFERS_{i,c}} Reserve_r \quad \forall\ c \in RESERVECLASSES$

$$\forall\ i \in ISLANDS$$

3.4.3.3. $IslandRisk_{i,reg,MAN} = MaxIslandRisk_{i,reg} \qquad \forall i \in Islands$

As noted above, this constraint is arguably redundant. So long as the manually set $IslandRisk_{i,reg,MAN}$ is the only risk measure applying to regulation, we could just use $IslandRisk_{i,reg,MAN}$, rather than $MaxIslandRisk_{i,reg}$, in the constraints which follow. But the more general form is retained, in case more detailed investigation suggests that some other risk factor needs to be accounted for, perhaps using an adapted version of 3.4.1.1,~~.~~ for example.

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[7] The other change made here corrects an apparent typo in the current formulation, by adding index sets for c and i.

Conceptual formulation for HVDC regulation transfer/sharing

As noted with respect to Section 3.4.2 above, the formulation presented here is still at a conceptual level, because the linkages with actual HVDC/AGC capabilities would be have to be achieved via the mixed constraint set, based on detailed technical studies which would not be appropriate at this stage. We also note that it would be possible, and might eventually be preferred, to develop a completely different style of formulation, based on explicit analysis of South-North and North-South regulation import/export flows. Yet another style of formulation would be based on a representation of extreme regulation flows, as in the FCAS contingency flow analysis built into SPD when it was adapted for the Australian market.

The formulation described here should suffice, on the~~y~~ assumption of a symmetric regulation service. It is based on Figure C-16 from Appendix C, which is reproduced here, for convenience. The reader is referred to Section C5 of Appendix C for an extensive discussion of this diagram, and related issues. But the essential conclusion is that the feasible region for regulation dispatch is limited to the blue line shown, between SN Limit and NS Limit:

- At NS Limit, the South Island is relying as much as possible, given the available HVDC swing capacity, on regulation transfer from the North Island.

- At SN Limit, the North Island is relying as much as possible, given the available HVDC swing capacity, on regulation transfer from the South Island.

These limits are symmetric, because the regulation service is symmetric, and this means that the accessible HVDC swing range is symmetric, too.[8] Note that they are not static, though. "HVDC" i~~o~~n this figure corresponds to the $HVDC\,Reg$ variable, which is limited by constraints 3.4.2.8-10 above. Thus it is influenced by the HVDC configuration etc, which SPD may not be able to control, but also by the underlying HVDC energy flow, which is optimised by SPD.

At times, this may not be limiting, in which case regulation transfer does not have to compete with energy transfer, and the cap in 3.4.2.10 may bind. At other times, though, overall HVDC capacity limits will be tight, and regulation transfer will only be dispatched if this is a more economic use of that capacity than energy transfer. At such times the "HVDC swing range" shown here will contract to the "balance point", and each island must rely entirely on its own resources for regulation, as at present.

At other times, SPD may decide to dispatch regulation at (or near) the balance point, even though there is a wider swing range available, just because regulation offer costs are fairly similar in each island. In that case, the full HVDC swing capacity will still be used, but it will be used to maximise regulation sharing between the islands, rather than to maximise regulation

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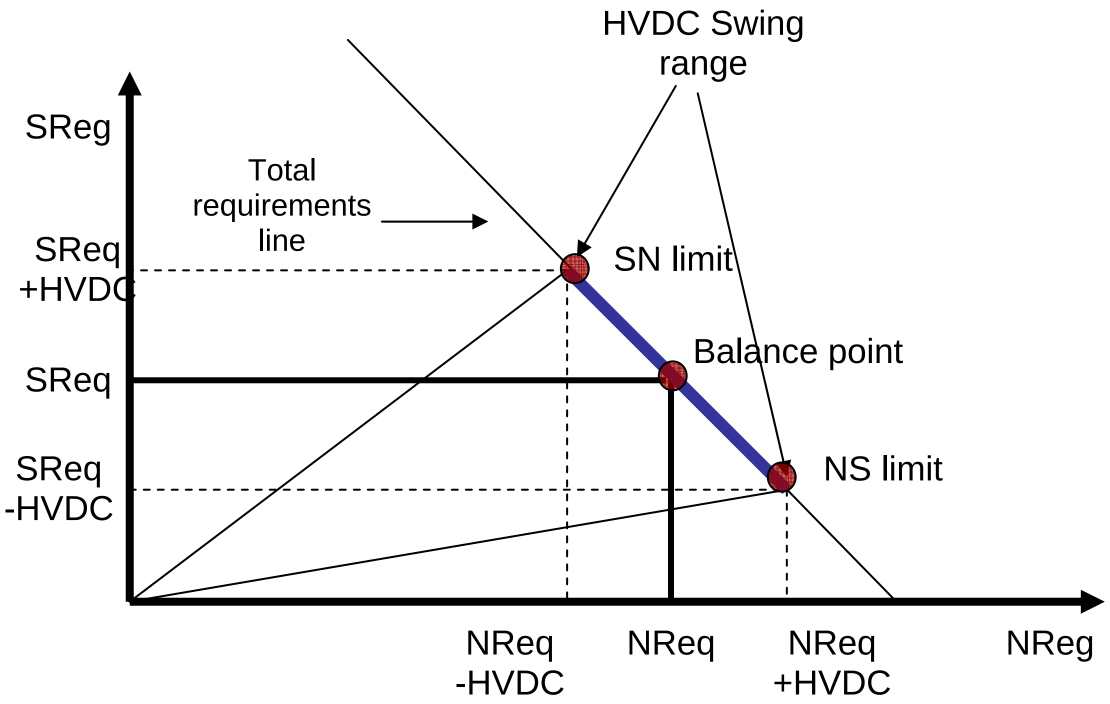
[8] Losses are ignored, as discussed above.

transfer from one island to the other. As discussed in Section 5.7, this could logically lead to a reduction of the aggregate national supply requirement, under those circumstances, but this has not been modelled here.[9] As noted there, though, SPD may not have sufficient motivation to find such solutions, at the cost of possibly limiting energy transfer, unless that advantage is recognised in the formulation. Thus further consideration is recommended.

Figure C-16: Conceptual HVDC formulation



Draft Constraints

3.4.3.4. $$Re\,gSupply_i = \sum_{r \in RESERVEOFFERS_{i,reg}} Reserve_r \qquad \forall i \in Islands$$

This constraint is partly just for notational convenience, since it would be easy to substitute the RHS into other constraints each time the LHS variable is used. But it also provides a constraint ~~on~~for which the shadow price provides a clear measure of the "island regulation supply price", that is the price which should be paid to suppliers of regulation in this island.

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[9] See discussion of Figure C-17 in Section C5.8 of Appendix C.

As noted in Section C5.9 of Appendix C, this "island regulation supply price", may differ from the "island regulation demand price", which is the price that, theoretically, should be paid by a marginal "consumer" of regulation, or causer of regulation requirement in that island. It may also be lower than the island regulation demand price in the island to which this regulation is supplied, on the margin, and which should theoretically be paid by a marginal consumer of regulation, or causer of regulation requirement in that island. Thus the price that should be paid to producers can not necessarily be inferred directly from shadow prices on the other constraints listed below.

3.4.3.5. $MaxIslandRisk_{S,Reg} + MaxIslandRisk_{N,reg} \leq RegSupply_{S} + RegSupply_{N}$

This ensures that the aggregate national supply requirement is met, so that the solution lies on the diagonal "total requirements" line shown in Figure C-16. Note that this ~~is~~ type of formulation is readily generalised to match Figure C-17 of Appendix C, thus allowing a reduction in aggregate national requirement, due to regulation sharing, to be implicitly modelled. That generalised formulation would require two versions of this constraint, each with a non-unity weight on one of the *RegSupply* variables.

Less radically, we have already noted that representation of marginal loss effects may change the slope of this total requirements line, and will also impact on the calculation of the SN and/or NS limits. But these all depend on detailed investigations at some ~~a~~later stage, so refinement of the formulation must be left for later consideration, as above.

3.4.3.6. $MaxIslandRisk_{i,reg} - HVDCReg \leq RegSupply_{i} \quad \forall i \in Islands$

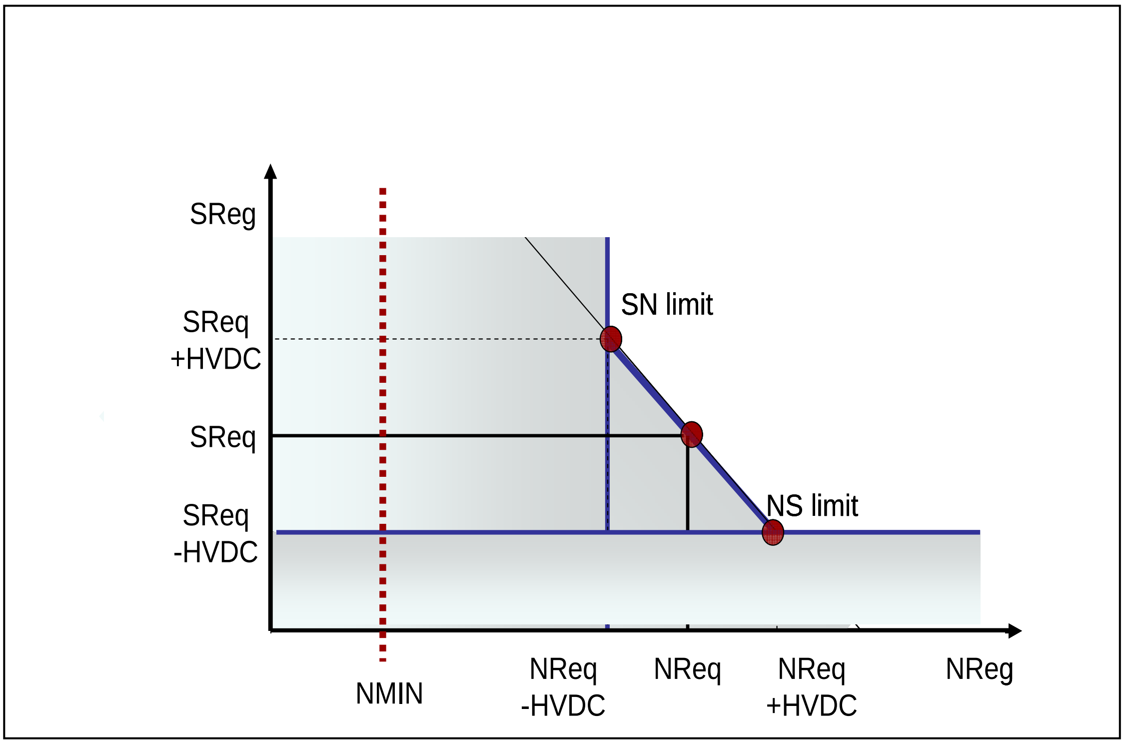
This ensures that the total supply to each island is feasible, in the sense that the imbalance lies within the swing capacity of the HVDC. In terms of Figure C-16, one of these constraints ensures that the solution lies to the right of SN Limit on the diagonal total requirements line defined by constraint 3.4.3.5,~~.~~ while the other ensures that the solution lies to the left of NS Limit, as shown in Figure C16A below. (Solutions not on the diagonal total requirements line will not be preferred because they deliver regulation in excess of requirements, presumably at extra cost)

3.4.3.7. $RegSupplyMIN_{i} \leq RegSupply_{i} \quad \forall i \in Islands$

These constraints ensure that a minimum local supply requirement~~s~~ ~~are~~is met in each island. One of these limits is shown in Figure C-16A, with NMIN indicating $RegSupplyMIN_{N}$. Clearly this limit is redundant, in this case, but it would over-ride 3.4.3.6, if NMIN was set high enough. Similarly for a South Island limit.

Note that, unlike 3.4.3.6, these limits are asymmetric, and may impose a much tighter restriction on "regulation transfer" in one direction than the other. But that does not mean that the final solution implies an asymmetric regulation service. Just as for any other solution lying in the interior of the feasible regulation transfer range, what it means is that the symmetric regulation service dispatched in accordance with this solution will be more balanced~~,~~ between the islands, allowing more moderate participation factors to be adopted, as discussed with respect to the example in Box 2 of Section C5.7 of Appendix C. As noted above, the full HVDC swing capacity is still used in such solutions, but SPD may not have sufficient motivation to find such solutions, unless the advantage of regulation sharing, as opposed to transfer, is recognised in the formulation, which is not the case for this straw man design.

Figure C-16A: Draft HVDC formulation



3.5. SECURITY

3.5.1.1. $Generation_{g(v)} \le SecurityGenerationMaximum_v$
$$\forall\ v \in SECURITY_{GenerationMaximum}.$$

3.5.1.2. $Generation_{g(v)} \ge SecurityGenerationMinimum_v$
$$\forall\ v \in SECURITY_{GenerationMinimum}.$$

3.5.1.3. $ACLineFlow_{q(v)}^{Directed} \le SecurityACLineCapacity_v \quad \forall\ v \in SECURITY_{ACLineCapacity}$

3.5.1.4. $HVDCLinkFlow_{l(v)} \le SecurityHVDCLinkCapacity_v$
$$\forall\ v \in SECURITY_{HVDCLinkCapacity}.$$

3.5.1.5.
$$\sum_{q \in SECURITYACLINESGROUP_v} ACLineFlow_q^{Directed} \times SecurityGroupACLineWeight_q$$
$$\le SecurityGroupACLinesFlow_v \quad \forall\ v \in SECURITY_{GroupACLinesFlow}.$$

3.5.1.6.
$$\sum_{n \in SECURITYACNODESGROUP_v} ACNodeNetInjection_n \times SecurityGroupACNodeWeight_n$$
$$\le SecurityGroupACNodesNetInjection_v$$
$$\forall\ v \in SECURITY_{GroupACNodesNetInjection}.$$

3.5.1.7.
$$\sum_{p \in SECURITYMARKETPURNODEGROUP_v} Purchase_p \times MarketNodePurWeight_p$$
$$+ \sum_{g \in SECURITYMARKETGENNODEGROUP_v} Generation_g \times MarketNodeGenWeight_g$$
$$+ \sum_{r \in SECURITYMARKETRESNODEGROUP_v} \mathrm{Re}\,serve_r \times MarketNodeResWeight_r$$
$$=\le\ge MarketNodeSecurityLimit_v$$
$$\forall\ v \in SECURITY_{GroupMarketNodes}$$

3.6. MIXED CONSTRAINTS

3.6.1.1. $MixedConstraintVariable_m \times MixedConstVarWeight1_m$

$$+ \sum_{p \in MIXEDPURNODEGROUP_m} Purchase_p \times MixedConstPurWeight_{p,m}$$

$$+ \sum_{g \in MIXEDGENNODEGROUP_m} Generation_g \times MixedConstGenWeight_{g,m}$$

$$+ \sum_{r \in MIXEDRESNODEGROUP_m} Reserve_r \times MixedConstResWeight_{r,m}$$

$$+ \sum_{q \in MIXEDDIRACLINEGROUP_m} ACLineFlow_q^{Directed} \times MixedConstACLineWeight_{q,m}$$

$$+ \sum_{q \in MIXEDDIRACLINEGROUP_m} ACLineLosses_q^{Directed} \times MixedConstACLineLossWeight_{q,m}$$

$$+ \sum_{k \in MIXEDACLINEGROUP_m} ACLineFixedLosses_k \times MixedConstACLineFixedLossWeight_{k,m}$$

$$+ \sum_{l \in MIXEDDCLINKGROUP_m} HVDCLinkFlow_l \times MixedConstDCLinkWeight_{l,m}$$

$$+ \sum_{l \in MIXEDDCLINKGROUP_m} HVDCLinkLosses_l \times MixedConstDCLinkLossWeight_{l,m}$$

$$+ \sum_{l \in MIXEDDCLINKGROUP_m} HVDCLinkFixedLosses_l \times MixedConstDCLinkFixedLossWeight_{l,m}$$

$$= \le \ge MixedConstraintLimit1_m$$

$$\forall\ m \in MIXEDCONSTRAINTS_{Type1}$$

3.6.1.2. $$\sum_{m \in MIXEDVARGROUP_b} MixedConstraintVariable_m \times MixedConstVarWeight2_{m,b}$$

$$= \le \ge MixedConstraintLimit2_b$$

$$\forall\ b \in MIXEDCONSTRAINTS_{Type2}$$

3.7. RAMPING

3.7.1.1. $Generation_g \leq GenerationMaximum_g^{TargetBased} \quad \forall\ g \in OFFERS.$

3.7.1.2. $Generation_g \geq GenerationMinimum_g^{TargetBased} \quad \forall\ g \in OFFERS.$

Of themselves, these constraints are innocuous, but the way in which the RHS is calculated, in pre-processing sections 5.3.1&2 makes them inconsistent with the concept of AGC control being used to ramp plant linearly over a dispatch interval. Thus the constraints themselves need not change, but the RHS calculation may need to be reviewed, quite apart from any developments with respect to regulation, and particularly if AGC were to be introduced.

As noted in discussion of Sections 5.3.1&2, we will assume a simpler pre-processing calculation, that produces limits which are consistent with the concept of AGC control being used to ramp plant linearly to a target over a dispatch interval. Thus these limits are also compatible with the discussions in the accompanying paper. We have changed the notation to indicate that we are assuming the RHS limits to be “target based’ rather than “energy based”, as in the status quo.

The following constraints~~t~~ ~~haa~~have~~s~~ been formulated to be consistent with this target based calculation of the generation ramping limits. It need not be created for generators which do not offer regulation, but the $MaxJointRamp_g$ parameter is set by 5.3.4.2 in such a way that the constraint should not be any more limiting than 3.7.1.1 above, even if it is created

3.7.1.3.
$$Reserve_{gREG} + RegulationResponseRatio \times (Generation_g - Generation_g^{start}) \leq MaxJointUpRamp_g \qquad \forall\ g \in OFFERS$$

3.7.1.4.
$$-Reserve_{gREG} + RegulationResponseRatio \times (Generation_g - Generation_g^{start}) \geq MaxJointDownRamp_g \qquad \forall\ g \in OFFERS$$

Note that joint constraints are proposed here on both up and down ramp limits, and that these constraints will also apply no matter whether the generator is ramping up or down for energy dispatch purposes. The Singapore formulation, for example, omits the down-ramp constraint, presumably because down ramping was not thought likely to be a limiting factor But the constraint seems reasonable, since a generator that is ramping down at it maximum rate for energy dispatch purposes surely can not provide any symmetrical regulation response around that ramp rate. If the up and down ramp limits are sufficiently different, it seems possible, that the joint up-ramp constraint could prove binding for a generator that is ramping down in the energy dispatch, or vice versa.

As above, these constraints treat generation as an end-of-period target to be ramped to. Discussion of 5.3.1&2 notes that the current “energy-based” pre-processing formula for ramp limits probably approximates the way in which ramping limits might be set for half-hourly trading intervals, on the assumption that actual dispatch will be re-optimised every 5 minutes~~,~~. Development of joint energy/regulation ramp limits to match these energy based limit calculations may be relevant when considering a formulation to be applied on a half-hourly trading interval basis, knowing that regular re-dispatch will occur within that trading interval. But that is left for later investigation.

3.8. -INTEGER CONSTRAINTS

The Mathematical model presented in this document has a linear objective function. Most of the constraints discussed are also linear and create a convex feasibility region. However the constraints 3.3.1.7 to 3.3.1.10 are used to linearise a non-linear equality constraint, a technique which is really only applicable for convex optimisation problems. However when the effective cost of losses is negative, the solution must be forced to lie in a non-convex feasible region, and this approximation will not produce the correct result.

Apart from that, the constraint 3.3.1.4 defines the unrestricted power flow by two positive variables, each representing a directed power flow. Then the transmission loss is modelled as a function of these directed power flow variables in equation 3.3.1.10. This approach is used to satisfy the market rule requirement to have line losses modelled at the receiving end of the line. When the objective becomes non-convex (globally or locally) this formulation can give circulating branch flows. Similarly, two parallel DC poles can have circulating branch flows in non-convex situations.

A two-stage process will be used to prevent the above-mentioned circulating branch flows and non-physical losses. A pure LP formulation is used first and, when circulating branch flows or non-physical losses are identified in the solution, the problem will be re-solved with “integer constraints” which force the model to choose between the physically feasible alternative solutions.

There are instances where a continuous linear program (LP) formulation can produce solutions that could not be physically implemented. This applies to commitment of HVDC poles in particular directions and also for interconnector transformer limits that depend in an integer fashion on the flow direction, rather than varying continuously with flow as a continuous formulation must assume. In these instances a method must be used to reflect the integer nature of the constraints and allow the optimisation to use the least cost solution.

3.8.1. AC branch integer constraints.

In order to prevent physically infeasible “circulation” on AC lines in the SPD formulation, an integer constraint can be activated to ensure that one of two variables $ACLineFlow_{F(k)}^{Directed}$ or $ACLineFlow_{B(k)}^{Directed}$ $\forall k \in ACLINES$ must be zero, the other can be nonzero. This integer constraint only operates when the existence of non-physical losses is detected in the LP solution. AC branch integer constraints are not applied to lossless AC branches.

3.8.2. Integer constraints to prevent circulating flow between HVDC links.

There can be situations where the SPD solution could schedule the HVDC links to send power in opposite directions, thus effectively recommending circulating power flow between HVDC Pole 1 and Pole 2 and/or between directed lines within poles. This is not a practical outcome and must be prevented to produce a real solution. To prevent this, it is necessary to introduce integer constraints that force all HVDC flows to be in the same direction.

This constraint applies to HVDC links and only operates when the LP solution detects circulating flows between the HVDC links.

3.8.3. Piece-wise linear approximation of HVDC losses (Lambda formulation).

The lambda formulation for the HVDC given in equations 3.2.1.1 to 3.2.1.5 will not, of itself, remove non-physical losses completely. When non-physical losses are detected in the LP solution, integer constraints will be applied to the lambda formulation so as to ensure that at most two adjacent $Lambda_{l,bp}, Lambda_{l,bp+1}$ are greater then zero in the model. The others must be zero. This approach forces the model to interpolate between adjacent breakpoints on the curve, rather than between non-adjacent points which would produce non-physical flow/loss pairs above it.

3.8.4. Integer Constraints for non-continuous limits

When the limits on a set of circuits, transformers, and/or market nodes is dependent on the sign of another variable (indicating a direction of flow, for example), then a decision must be made as to what sign that variable will have, and hence which limits shall apply. Where appropriate an integer optimisation may be used to determine the most appropriate sign, and set limits accordingly. This type of integer formulation may be applied to the Security constraints of Section 3.5, or to the Mixed Constraints of Section 3.6, and will be subject to approval in accordance with the procedures established for constraints in each of those sections. Such integer constraints will effectively force the model to examine an LP solution for each possible constraint limit condition, and then select the lowest cost solution from those options.

3.8.5. Integer variables for AGC range commitment

Integer variables could, in principle, also be used to model commitment of units to their AGC range, within which regulation can be offered. But this is not proposed as part of the initial straw man design.

4. OBJECTIVE FUNCTION

The *NetBenefit* is maximised.

4.1.1.1.
$$NetBenefit = \sum_{p \in BIDS} \sum_{j=1}^{PurchaseBidBlocks_p} Purchase_{p,j} \times PurchaseBidPrice_{p,j} - \sum_{g \in OFFERS} \sum_{j=1}^{GenerationOfferBlocks_g} Generation_{g,j} \times GenerationOfferPrice_{g,j} - \sum_{r \in RESERVEOFFERS} \sum_{j=1}^{ReserveOfferBlocks_r} Reserve_{r,j} \times ReserveOfferPrice_{r,j}$$

5. PRE-PROCESSING

5.1. HVDC TRANSMISSION

The importance and nature of the HVDC link together with its peculiarities requires some pre-processing to better model the HVDC link. This relates to the poles being in and out of service.

5.1.1. Both poles operating

5.1.1.1. This is considered the normal situation.

5.1.2. One or more poles not operating

5.1.2.1. $HVDCLinkCapacity_l = 0 \quad \forall\, l \in HVDCLinks_{POLESOUT}$ where $POLESOUT$ is the set of poles not operating.

5.1.2.2. $HVDCLinkFixedLosses_l = 0 \quad \forall\, l \in HVDCLinks_{POLESOUT}$.

5.2. RESERVE

5.2.1.1.
$$ReserveMaximumFactor_{g,c} = \frac{ReserveGenerationMaximum_g}{ReserveGenerationMaximum_{g,c}}$$

$$\forall\, g \in OFFERS \quad \forall\, c \in RESERVECLASSES.$$

The $ReserveGenerationMaximum_{g,c}$ parameter only serves to indirectly define $ReserveMaximumFactor_{g,c}$. It is not clear why this indirect mode of definition has been adopted in the underlying formulation, but there is no reason why the same mode can not also be applied to regulation.

For the current reserve classes, $ReserveMaximumFactor_{g,c}$ defines a line determining the trade-off between maximum generation from g, and maximum reserve response it can supply in class c. The same line, with this slope cuts across the end of each offer block for the particular reserve class. If the slope is set to -1, then backing off generation by one unit allows one more unit of this reserve class to be supplied. Such a factor may apply to regulation, too, but there is now a three way trade-off between generation, regulation, and each raise reserve class.

Ignoring the interaction with raise reserve, we can think of this trade-off as being defined by a line which intersects the generation axis at $ReserveGenerationMaximum_g$, and intersects the regulation axis at $ReserveGenerationMaximum_{gREG}$.

5.2.1.2.
$$RegulationMaximum_g = MIN\{ReserveGenerationMaximum_g,\ AGCMaximum_g\} \quad \forall\, g \in OFFERS$$

This adjustment is made so as to ensure that if a participant effectively de-rates a unit by offering a *ReserveGenerationMaximum* less than *AGCMaximum*, then SPD will not dispatch regulation –in such a way that the unit could be required to operate above *ReserveGenerationMaximum* at any time during the dispatch interval.

5.3. RAMPING

The following pre-processing is performed for all generation offers $g \in OFFERS$.

5.3.1. Ramping up for energy dispatch purposes

5.3.1.1. $$Generation_g^{Maximum} = \sum_{j=1}^{GenerationOfferBlocks_g} GenerationOfferMW_{g,j}.$$

5.3.1.2. IF

$$Generation_g^{Start} + RampRate_g^{Up} \times TradingPeriodLength > Generation_g^{Maximum}$$

THEN $$RampTime_g^{Up} = \frac{\left(Generation_g^{Maximum} - Generation_g^{Start}\right)}{RampRate_g^{Up}}$$

ELSE $$RampTime_g^{Up} = TradingPeriodLength.$$

5.3.1.3. $$Generation_g^{End,Up} = Generation_g^{Start} + \left(RampRate_g^{Up} \times RampTime_g^{Up}\right).$$

5.3.1.4. $$\begin{aligned} Energy_g^{Maximum} &= \left(Generation_g^{Start} \times RampTime_g^{Up}\right) \\ &+ \tfrac{1}{2} \times \left(Generation_g^{End,Up} - Generation_g^{Start}\right) \times RampTime_g^{Up} \\ &+ Generation_g^{End,Up} \times \left(TradingPeriodLength - RampTime_g^{Up}\right) \end{aligned}$$

5.3.1.5. $$GenerationMaximum_g^{EnergyBased} = \frac{Energy_g^{Maximum}}{TradingPeriodLength}.$$

This generation limit is not actually consistent with that assumed in the discussion in the frequency keeping paper, because it does not correspond to the concept of AGC control being used to ramp plant linearly over a dispatch interval. The formula sets *GenerationMaximum* on the assumption that units can ramp as quickly as possible towards their maximum generation levels then hold those levels, if they are reached within the dispatch interval, until the end of that interval.

We note that these limit calculations were included in the SPD formulation from market start in 1996 (version 2.1.3), but with the caveat that they would not be implemented at that time.[10] We believe that, at the time, this form of limit calculation was intended to represent a view that the generation variable in SPD represents the average rate of energy production over the dispatch interval, rather than a target level to be reached at the end of the dispatch interval. But the calculation seems unrealistic, because it does not match the way in which load ramps, quite apart from any AGC considerations.

---

[10] Since the caveat has now been removed, it seems reasonable to assume that these calculations have been implemented subsequently. But investigation of current practice lies beyond the present scope.

This calculation obviously produces less restrictive limits than a calculation based on linear ramping. -But, leaving aside the possibility of re-dispatch within the dispatch interval, and noting that this same formulation is supposed to apply to 5 minute (re-)dispatch intervals, there are two problems:

- First, to achieve this dispatch outcome under AGC control would require AGC participation factors to be changed part way through the dispatch interval, which we have argued to be undesirable, even if possible; and
- Second, load will not be ramping to match this pattern so, for every unit which is ramped up faster than the rate of change in load, some other unit must be ramped at a slower rate, or even in the opposite direction, to compensate.[11]

It seems possible that this aspect of the current formulation could usefully be reviewed, quite apart from any developments with respect to regulation.[12] Our concern here, though, is merely to note that it would be very difficult to add a frequency keeping market formulation into the underlying formulation in a way which was consistent with ramping limits calculated in this way.

For that purpose, at least, the following simple formula seems more appropriate, to replace all of 5.3.1.2-5[13]:

5.3.1.6.
$$
\begin{aligned}
GenerationMaximum_g^{TargetBased} = MIN\{ & Generation_g^{Maximum}, \\
& Generation_g^{Start} + RampRate_g^{Up} \times TradingPeriodLength\}
\end{aligned}
$$

We will assume that the upper limit on the energy dispatch target is calculated by 5.3.1.6, at least for 5 minute dispatch intervals, with linear ramping to that target for energy dispatch purposes. We then develop compatible calculations for joint energy/regulation ramp limits.–.[14]

---

[11] Of course load will not change linearly, in reality, but that is why we have regulation. It will certainly not change quickly at the beginning of each period, then hold constant until the next period, as this formula implicitly assumes.

[12] As it stands, it probably best approximates the way in which ramping limits might be set for half-hourly trading intervals, on the assumption that actual dispatch will be re-optimised every 5 minutes. But that is probably not the intent, because no mention is made of any alternative formula to be adopted when SPD is re-run for 5 minute dispatch intervals.

[13] Note the change in notation here. Although the LHS still relates to the energy dispatch, it is no longer “energy based” in quite the same way. It is thus referred to as “target based”.

[14] The current 5 minute (re-)dispatch process means that development of joint energy/regulation ramp limits to match (something like) the calculations in the current formulation could conceivably be relevant on a half-hourly basis, but that is left for later investigation. It is not obvious that a 5 minute re-dispatch pattern can be found which would allow all units to simultaneously generate to the energy limit calculated here over the dispatch interval. Even ignoring uncertainty, it is not obvious that a process of myopic optimisation within each re-dispatch interval, could find such a generation pattern, if it does exist. Preliminary investigation suggests that counter-examples can be constructed.

We note that the way in which 5.3.1.1 calculates $Generation_g^{Maximum}$ effectively allows the participant to specify a range within which energy dispatch can occur, in a dynamic fashion, by limiting its offers. The implication is that imposing an upper limit on the AGC range might not materially alter the dispatch situation already assumed by SPD, provided that limit is appropriately linked to the calculation of $Generation_g^{Maximum}$. That linkage could go either way:

- The AGC limit could be accounted for as an upper limit on $Generation_g^{Maximum}$, or

- A participant could indicate an intention to move generation above the AGC range by adjusting offers so that $Generation_g^{Maximum}$ rise above the AGC limit, and this could trigger automatic removal of the regulation offers.[15]

5.3.2. Ramping down for energy dispatch purposes

5.3.2.1. $Generation_g^{Minimum} = \sum_{j=1}^{J} GenerationOfferMW_{g,j}$ where J is the largest

$j \in \{1,\ldots,GenerationOfferBlocks_g$ for which $GenerationOfferPrice_{g,j} \leq 0$.

If $GenerationOfferPrice_{g,j} > 0 \;\; \forall \;\; j = 1,\ldots, GenerationOfferBlocks_g$ then

$Generation_g^{Minimum} = 0$.

5.3.2.2. `IF`

$$Generation_g^{Start} - RampRate_g^{Down} \times TradingPeriodLength < Generation_g^{Minimum}$$

`THEN` $RampTime_g^{Down} = \dfrac{\left(Generation_g^{Start} - Generation_g^{Minimum}\right)}{RampRate_g^{Down}}$

`ELSE` $RampTime_g^{Down} = TradingPeriodLength.$

5.3.2.3. $Generation_g^{End,Down} = Generation_g^{Start} + \left(RampRate_g^{Down} \times RampTime_g^{Down}\right).$

5.3.2.4. $Energy_g^{Minimum} = \left(Generation_g^{End,Down} \times RampTime_g^{Down}\right.$

$$+\tfrac{1}{2} \times \left(Generation_g^{Start} - Generation_g^{End,Down}\right) \times RampTime_g^{Down}.$$

5.3.2.5. $GenerationMinimum_g^{EnergyBased} = \dfrac{Energy_g^{Minimum}}{TradingPeriodLength}$.

---

[15] This seems attractively simple, but note that it means that the SO would not be able to see that more generation capacity could be made available by moving generation outside the AGC range until the participant decided to move into that range.

The discussion above applies equally to ramping down. For 5 minute dispatch intervals, the following simple formula seems more appropriate, to replace all of 5.3.2.2-5.~~:~~ As above, we will assume that the lower limit on the energy dispatch target is calculated by 5.3.2.6, at least for 5 minute dispatch intervals, with linear ramping to that target for energy dispatch purposes.

5.3.2.6.

$$GenerationMinimum_g^{TargetBased} = MAX\{Generation_g^{Minimum}, Generation_g^{Start} - RampRate_g^{Down} \times TradingPeriodLength\}$$

We note that the way in which 5.3.2.1 calculates $Generation_g^{Minimum}$ effectively allows the participant to specify a range within which energy dispatch can occur, in a dynamic fashion, by specifying negative offer bands. This has significant implications for the market design, because it may be taken –to imply that participants can not actually be dispatched at negative prices, unlike the situation in other similar markets.

Resolution of that issue lies beyond the current scope, but the implication is that imposing a lower limit on the AGC range might not materially alter the dispatch situation already assumed by SPD, provided that limit is appropriately linked to the calculation of $Generation_g^{Minimum}$. As above, that linkage could go either way:

- The AGC limit could be accounted for as a lower limit on $Generation_g^{Minimum}$, or
- A participant could indicate an intention to move generation below the AGC range by adjusting offers so that $Generation_g^{Minimum}$ fell below the AGC limit, and this could trigger automatic removal of the regulation offers.

5.3.3. Generation level at the start of a future trading period

To determine energy based ramping limits an instantaneous generation level at the beginning of each trading period is required. For future periods this must be estimated using information from the previous period.

For the purpose of this section parameters and variables from the previous period are indicated by the inclusion of *Previous* as a superscript.

```
5.3.3.1. IF $Generation_g^{Previous} > Generation_g^{Previous,Start}$
THEN $Generation_g^{Start} = \min(2 \times Generation_g^{Previous} - Generation_g^{Previous,Start}, Generation_g^{Previous,Maximum})$
ELSE IF $Generation_g^{Previous} < Generation_g^{Previous,Start}$
THEN $Generation_g^{Start} = \max(2 \times Generation_g^{Previous} - Generation_g^{Previous,Start}, Generation_g^{Previous,Minimum})$
ELSE $Generation_g^{Start} = Generation_g^{Previous,Start}$.
```

This calculation ignores any observation of actual generation, and assumes that ramping will have always occurred in accordance with previous instructions. That would be appropriate for "future periods" in pre-dispatch runs, and the introductory paragraph of this section in the current formulation document seems to say that this formula is only applied in that case. If so, the heading might usefully be changed to reflect this, as above, but the formula does not need to change to account for regulation. Implicitly the formula assumes that generation will not have deviated from the targets dispatched for energy purposes, for any reason, including responses to meet contingency or regulation requirements. That would still be appropriate for future periods in pre-dispatch runs.

There are issues with this calculation, though. Consistent with the calculation in Section 5.3.2 above, it seems to assume that the SPD dispatch variable represents the average rate of energy production across the dispatch interval, rather than the end of period target. We have questioned whether those calculations are actually realistic, but resolution of that issue lies beyond the current scope.

There are other issues, though, relating to the way in which start generation is calculated from real time observations of actual generation, because those observations will sometimes capture units providing responses to meet contingencies, and regularly capture units providing responses to meet regulation requirements. In principle, the situation will be no different with the introduction of a regulation market, because regulation is already provided by some units. So the current approach to setting start generation levels should still work. But that approach is not specified here, so it is difficult to be certain. Arguably, there is a gap in the current formulation here, and a formula or methodology should preferably be provided to cover these situations, irrespective of any regulation market developments. But resolution of that issue lies beyond the current scope.

5.3.4. Joint ramping limits on energy and regulation

We have not proposed joint ramping limits on energy, regulation and reserve, for several reasons:

- A *ReserveResponseRatio* calculated analogously to the RegulationResponseRatio below would be very small for the relatively fast acting reserves traded in the New Zealand market.[16] This means that the ramp rate required to meet energy targets will make very little difference to the effective ramp rate required to deal with a contingency in those time frames.

- This disparity of ramp rates is possible because ramping for these two different purposes employs two different technological approaches, and there may actually be little interaction between them.

- In any case, revision of the reserve market formulation lies outside the present scope.

---

[16] For a half hour dispatch interval the ratios are 0.0033, and 0.033, for fast and sustained reserves, respectively. For a five minute dispatch interval these ratios become 0.02, and 0.2, for fast and sustained reserves. Of these, only the last ratio could be considered significant, but we have not investigated whether it represents an actual physical interaction between sustained contingency response and ramping for regulation and/or energy purposes that should be accounted for.

For regulation purposes, though, we propose the following formula, while noting that, since the ratio is a constant which does not need to be re-calculated before each run, it could just be specified directly via the glossary in Section 2.10.1:[17]

5.3.4.1. $$RegulationResponseRatio = \frac{RegulationResponseInterval}{DispatchInterval}$$

The next formula must be computed for each generator, and sets the maximum MW ramp which can be expected, for energy dispatch and regulation response combined, within the $RegulationResponseInterval$. It assumes that a generator can at least ramp at $RampRateUp^g$, for either energy dispatch or regulation purposes, but may be able to ramp faster for regulation purposes, if so indicated by its regulation offers. It also means that $MaxJointUpRamp_g$ defaults to $RampRateUp^g$ for a generator which offers no regulation. Thus even if a joint ramp limit constraint is created for such a generator, it will not be any more binding than the existing ramp limit constraints, implicitly defined by 3.7.1&2

5.3.4.2. $$MaxJointUpRamp_g = Max\{ \sum_{j \in ReserveOfferBloack_{REG(g)}} ReserveBlockMax_{REG(g),j},\ RampRateUp^g \times RegulationResponseInterval \}$$

A similar formula gives $MaxJointDownRamp_g$:

5.3.4.3. $$MaxJointDownRamp_g = Max\{ \sum_{j \in ReserveOfferBloack_{REG(g)}} ReserveBlockMax_{REG(g),j},\ RampRateDown^g \times RegulationResponseInterval \}$$

---

[17] If the $RegulationResponseInterval$ is set at 5 minutes, the ratio will actually be 1, for a 5 minute dispatch interval. But it will take a different value for dispatch intervals of different length.

5.4. REPLACING BIDS WITH FORECASTS

The system operator may replace purchase bids with load forecasts. For each AC node a forecast is available. This forecast is used to form a dummy purchase bid as described above in the section on non-market participants. For pricing runs the metered load is used in the same way as a forecast to create a dummy purchase bid.

5.5. LOSS APPROXIMATIONS

For each AC line and HVDC link, the variable loss part of the loss curve is approximated by a piecewise linear curve with a pre-determined number of segments. The approximation does not include the fixed losses, which are handled separately (see Constraint 3.3.1.2).

For an AC line or HVDC link the variable MW losses are approximated by $R \times F^2$ where R is the resistance per unit for an AC line, or the HVDC link resistance scaled to allow for using MW instead of current (assuming a constant voltage). F is the MW flow in the line.

A sequence of "breakpoints", MW and loss pairs, define the beginning and end points of the segments making up the approximation. The beginning of the first segment is the (0,0) point and the end of the last segment is at the point defined by the capacity of the line and the loss incurred when the flow is equal to the capacity of the line. The breakpoints are determined by minimising the difference between the approximation and the quadratic curve.

For AC lines, loss factors are derived to define losses for points within the "block" between each pair of breakpoints. The same effect is achieved automatically by the "lambda formulation" used for HVDC links.

6. POST PROCESSING

6.1. ENERGY BUS PRICES[18]

The energy bus price for an AC node is the dual variable value (shadow price) of constraint 3.3.1.2, the energy balance constraint, for that node.

6.2. RESERVE PRICES

The reserve prices are the dual variable values (shadow prices) of constraint 3.4.3.2, the requirement that total reserve cleared by reserve class and island be greater than or equal to the maximum island risk for that class of reserve.

This will now include prices for regulation, as well as fast and sustained reserve, in each island.

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[18] Note that energy bus prices for DC nodes will not be calculated because they relate to conceptual "nodes" internal to the formulation, and are of no relevance to the market.