Rental calculations for Financial Transmission Rights

Market performance enquiry

23 October 2014

Market Performance enquiries, reviews and investigations

An enquiry, review or investigation could be triggered as a result of monitoring by the Electricity Authority or an external party. The Minister may also request or direct the Authority to look into an issue. Likely outcomes of enquiries, reviews or investigations are suggestions for Code amendments, market facilitation measures, or a finding that no further action is needed. A report is typically published in all cases.

A three-stage process is followed when undertaking enquiries, reviews or investigations. An escalating level of effort and significance attaches to the three stages.

Market Performance Enquiry (Stage I): At the first stage, routine monitoring results in the identification of circumstances that require closer inspection. This stage may entail the design of low-cost ad hoc analysis using existing data and resources to better characterise and understand what has been observed. The Authority would not usually announce it is carrying out this work.

This stage may result in no further action being taken if the enquiry is unlikely to have any implications for the competitive, reliable and efficient operation of the electricity industry. In this case, the Authority publishes its enquiry only if the matter is likely to be of interest to industry participants.

Market Performance Review (Stage II): A second stage of investigation occurs if there is insufficient information available to understand the issue and it could be significant for the competitive, reliable or efficient operation of the electricity industry. Relatively informal requests for information are made to relevant service providers and industry participants. There is typically a period of iterative information-gathering and analysis. The Authority would usually publish the results of these reviews but would not announce it is undertaking this work unless a high level of stakeholder or media interest was evident.

Market Performance Investigation (Stage III): The Authority may exercise statutory information-gathering powers under section 46 of the Act to acquire the information it needs to fully investigate an issue. The Authority would generally announce early in the process that it is undertaking the investigation and indicate when it expects to complete the work. Draft reports will go to the Board of the Authority for publication approval.

Executive summary

The market for Financial Transmission Rights (FTR) in New Zealand went live in May 2013 with two FTR hubs – Benmore and Otahuhu, with the first FTR auction in June 2013. FTR rental allocation results are available from July 2013, the first FTR period to be auctioned. In May 2014, the Electricity Authority (Authority) agreed to expand the FTR market to five hubs, and the FTR manager is in the process of developing its systems for this change. As part of its function to monitor the FTR Market, the Authority recently upgraded its FTR rental calculation tool to accommodate the additional three FTR hubs. While testing this upgrade, it was discovered that the results from the tool differed from the results published by the FTR manager.

It was not expected that the tool developed by the Authority would yield precisely the same results as the FTR manager due to rounding of some of the input data, particularly final pricing data. However, the differences the Authority uncovered were potentially substantial although to date have had no material impact. The FTR manager has taken a conservative approach in making available for auction much less capacity than actually exists. Consequently, the FTR account has been more than adequate and the differences in the size of the account have had no impact on auction participants.

Examination of two discrepancies has yielded the following explanations:

1. The FTR manager has calculated the HVDC rental in a manner not intended by the Authority when drafting the Code. Instead of using only the HVDC variable loss, the FTR manager has used the sum of variable and fixed losses in the calculation of the HVDC rental. The amount of the HVDC rental allocated to the FTR account has therefore been underestimated. The Authority has already initiated a process with the FTR manager that will see the intended approach implemented by the FTR manager.
2. The calculation of the constraint excess amount to be paid into the FTR account arising from branch group constraints that involve branch flows with flows in the opposite direction to the conventional direction is incorrect. The impact of this discrepancy is potentially substantive, although to date the actual errors have been immaterial. The FTR manager has investigated and agrees with the Authority's assessment. The FTR manager has initiated a change request to correct this calculation.

In addition, the Authority has some concerns regarding three further issues:

1. Based on the data provided to the Authority by the FTR manager, it appears that the FTR injection at the Otahuhu (OTA) hub is allocated to three different nodes: OTA2201, OTA2202 and OTA2203. The Authority maintains this is incorrect and that the OTA injection should be allocated to node OTA2201 only. The financial implication of this is not large but it should nonetheless be resolved, not least because doing so is straightforward. The FTR manager has investigated and agrees with the Authority's assessment. The FTR manager has initiated a change request to correct this allocation.
2. For a given injection pattern, the branch participation loading calculated by the FTR manager is not the same as the result calculated by the Authority. More specifically, the branch participation loading results are very close for branches close to the Benmore hub but increasingly divergent for the branches close to the Otahuhu hub. The FTR manager has investigated and believes this issue is related to the OTA hub allocation issue. The FTR manager believes that the change request to correct the OTA hub allocation issue will also correct the participation loading issue. The Authority has requested further information from the testing of this change request to confirm and is waiting for this response before continuing its enquiry into this matter.
3. The marginal loss factor of an AC line may not be calculated accurately when the scheduled flow on the line is exactly equal to MW capacity of the first loss block or to the total MW capacity of the first

and second loss blocks. This is because the scheduled flows reported in the final pricing data are rounded to three decimal places while the loss block capacity may be specified with greater precision. This is a relatively minor technical issue that cannot easily be put right without significant disruption and costs, as the change is required to be applied to the market system (SPD) operated by the system operator. Any change to the SPD output to increase the number of decimal places will have consequential impacts on all participants and downstream systems that use the SPD output that will require testing and potential enhancement to manage the additional precision. The Authority will not pursue a change to SPD, as any improvements in the accuracy will be immaterial.

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1 Introduction

1.1 A market for Financial Transmission Rights (FTR) was established in New Zealand in 2013. During the development phase of the FTR market, an FTR user group was formed. This group requested that the Electricity Authority (Authority) develop a tool to calculate the amount of loss and constraint excesses to be paid into the FTR account (i.e. FTR rentals) based on a given injection pattern. To meet this need, the Authority augmented its vSPD model with a module that enabled FTR rentals to be calculated for a given injection pattern. Although this added functionality is available as an option within the standard vSPD model, for the sake of clarity throughout this paper, we shall refer to it as the vSPD FTR rental tool.

1.2 The vSPD FTR rental tool was initially developed to estimate FTR rentals based on Schedule 14.6 of the Electricity Industry Participation Code 2010 (Code). Instead of using a matrix of lossless shift factors to determine branch and constraint participation loadings, this tool determines branch and constraint participation loading by solving an energy-only, lossless scheduling, pricing and dispatch model. Configuring the model with a given generation pattern at the source node and a given load pattern at the sink node mimics the energy injection and offtake for each of the given FTR injection patterns.

1.3 The FTR market went live in May 2013 with two FTR hubs – Benmore and Otahuhu, with the first FTR auction in June 2013. FTR rental allocation results are available from July 2013, the first FTR period to be auctioned.

1.4 In May 2014, the Authority agreed to expand the FTR market to five hubs. The FTR manager is in the process of developing its systems for this change.

1.5 As part of its function to monitor the FTR market, the Authority recently further enhanced its vSPD FTR rental tool to accommodate three additional FTR hubs, bringing the total number of hubs to five. During the testing phase of this initiative, the simulated results were compared with the actual historical results generated by the FTR manager. These tests revealed that the results produced by the vSPD FTR rental tool were different from those published by the FTR manager.[1]

1.6 In June 2014 the Authority launched a Market Performance enquiry into these discrepancies. A draft report was shared with the FTR manager in September 2014. Two meetings with the FTR manager subsequently occurred. The Authority is now satisfied that steps are being undertaken by the FTR manager to correct the discrepancies uncovered by the Market Performance enquiry and documented in the September 2014 draft report.

1.7 The remainder of this paper presents the analysis undertaken as part of the Market Performance enquiry and describes the steps currently underway to correct the discrepancies. The enquiry identified two discrepancies, as well as three minor issues of concern. All five of these matters, the two discrepancies and the three minor issues, arise with the current two hub arrangement as well as the five hub enhancement, the testing of which led to the Market Performance enquiry.

1.8 To set the scene, Table 1 through Table 4 summarise the FTR rental results obtained from the vSPD FTR rental tool and the FTRClearing website. The differences between the two sets of results are highlighted in Table 3 and Table 4. The report then continues, beginning with section 2, to analyse the causes of these differences. The analysis was based on data taken from final pricing cases files and data provided by the FTR manager. The FTR manager provided data on

[1] See https://www.ftrclearing.co.nz for the FTR manager's published results.

branch participation loading, branch assigned capacity, constraint participation loading, and constraint assigned capacity.

Table 1: FTR rentals estimated using the vSPD FTR rental tool, dollars
First four months of 2014

	January	February	March	April
AC branch FTR rental	-	-	-	-
AC branch group constraint FTR rental	42,226.72	9,641.31	1,142.00	10,550.04
AC branch loss FTR rental	1,280,629.15	1,101,550.07	106,455.62	706,056.40
HVDC FTR rental	2,017,497.10	1,091,321.43	266,361.84	244,053.29
Total FTR rental	3,340,352.97	2,202,512.81	373,959.46	960,659.73

Source: Electricity Authority

Notes:
1. AC branch FTR rental means loss and constraint excess generated by AC line limits.
2. AC branch group constraint FTR rental means loss and constraint excess generated by binding branch constraints.
3. AC branch loss FTR rental means loss and constraint excess generated by AC line loss curve blocks.
4. HVDC FTR rental means HVDC loss and constraint excess.

Table 2: FTR rentals published on the FTRClearing website, dollars
First four months of 2014

	January	February	March	April
AC branch FTR rental	-	-	-	-
AC branch group constraint FTR rental	23,927.35	378.81	1,141.96	10,549.41
AC branch loss FTR rental	1,278,445.82	1,104,254.46	105,309.61	705,534.49
HVDC FTR rental	1,883,734.64	870,505.79	116,150.65	187,112.70
Total FTR rental	3,186,107.81	1,975,139.06	222,602.22	903,196.60

Source: https://www.ftrclearing.co.nz

Table 3: Difference between vSPD FTR rental tool and the FTRClearing website, dollars
First four months of 2014

	January	February	March	April
AC branch FTR rental	-	-	-	-
AC branch group constraint FTR rental	18,299.37	9,262.50	0.04	0.63
AC branch loss FTR rental	2,183.33	-2,704.39	1,146.01	521.91
HVDC FTR rental	133,762.46	220,815.64	150,211.19	56,940.59
Total FTR rental	154,245.16	227,373.75	151,357.24	57,463.13

Source: Electricity Authority

Table 4: Relative difference between vSPD FTR rental tool and the FTRClearing website, percent
First four months of 2014

	January	February	March	April
AC branch FTR rental	-	-	-	-
AC branch group constraint FTR rental	76.5	2,445.2	0.0	0.0
AC branch loss FTR rental	0.2	-0.2	1.1	0.1
HVDC FTR rental	7.1	25.4	129.3	30.4
Total FTR rental	4.8	11.5	68.0	6.4

Source: Electricity Authority
Notes: 1. Difference (Table 3) as a percent of FTRClearing (Table 2).

1.9 The four tables above show that the FTR rentals calculated by the FTR manager are always lower than the FTR rentals calculated using the Authority's tool. Additional analysis by the Market Analytics team at the Authority revealed the following:

(a) The calculation of the HVDC loss and constraint excess by the FTR manager was not undertaken as intended by the Authority when drafting the Code.

(b) The FTR manager's calculation of the loss and constraint excess generated when branch group constraints are binding is incorrect under certain conditions.

1.10 Three further issues were uncovered during the enquiry. They are each discussed later in the report and relate to the following:

(a) The allocation of injection and offtake quantities to nodes at hubs.

(b) The method for calculating branch participation loading.

(c) The determination of marginal AC losses.

2 Calculation of HVDC FTR rentals

2.1 Schedule 14.6, clause 9 of the Code states that the HVDC loss and constraint excess to be paid into the FTR account for each trading period of the relevant billing period must be calculated in accordance with the following formula:

$$\max\left(\begin{array}{l} 0, \sum_{n(NI)} \text{price}_n \times \left(\begin{array}{l} \sum_{l \in R_{HVDC}(n)} \left(\text{HVDCLinkFlow}_l - \text{HVDCLinkLosses}_l\right) \\ - \sum_{l \in S_{HVDC}(n)} \text{HVDCLinkFlow}_l \end{array}\right) \\ + \sum_{n(SI)} \text{price}_n \times \left(\begin{array}{l} \sum_{l \in R_{HVDC}(n)} \left(\text{HVDCLinkFlow}_l - \text{HVDCLinkLosses}_l\right) \\ - \sum_{l \in S_{HVDC}(n)} \text{HVDCLinkFlow}_l \end{array}\right) \end{array}\right) \div 2 \qquad (1)$$

where:

Price_n	denotes the energy price at AC node n
n(NI)	denotes the set of North Island AC nodes to which any HVDC links are connected
n(SI)	denotes the set of South Island AC nodes to which any HVDC links are connected
HVDCLinkFlow_l	denotes the MW flow at the sending end scheduled for HVDC link l
HVDCLinkLosses_l	denotes the variable MW losses for HVDC link l
$S_{HVDC}(n)$	denotes the set of HVDC links for which n is the sending AC node
$R_{HVDC}(n)$	denotes the set of HVDC links for which n is the receiving AC node.

2.2 The intention of the Authority when drafting the Code was to use only the HVDC variable loss component when calculating HVDC FTR rentals. This component varies as a function of the current flowing through the HVDC equipment and the equipment's resistance, and does not include any fixed loss aspects. However, the FTR manager interpreted the Code to mean that the *sum* of the variable and fixed loss components should be applied in the formula.

2.3 The HVDC rental is calculated independently of the FTR flow pattern. Based on final pricing data, the Authority calculated the HVDC rental according to the formula from Schedule 14.6, clause 9 for every month for which rentals are published on the FTRClearing website. The results in Table 5 reveal that the monthly HVDC rental data from the FTRClearing website is consistently lower than the intended HVDC rental.

2.4 The underestimate shown in Table 5 is the amount calculated as intended by the Authority less the amount as calculated by the FTR manager using the total HVDC loss. The total amount shown in Table 5 covers 13 months.

Table 5: HVDC loss and constraint excess calculations
Dollars

Month	As intended by the Authority	As interpreted by the FTR manager	Underestimate
Jul 2013	1,165,378.35	1,053,883.93	111,494.42
Aug 2013	4,155,462.75	4,097,167.98	58,294.77
Sep 2013	1,338,503.59	1,285,227.92	53,275.67
Oct 2013	4,234,613.40	4,183,630.67	50,982.73
Nov 2013	4,350,506.53	4,283,969.14	66,537.39
Dec 2013	3,152,316.88	3,052,844.77	99,472.11
Jan 2014	2,017,489.88	1,883,734.64	133,755.24
Feb 2014	1,091,308.37	870,505.79	220,802.58
Mar 2014	266,355.20	116,150.65	150,204.55
Apr 2014	243,957.59	187,075.59	56,882.00
May 2014	2,791,862.21	2,703,006.75	88,855.46
Jun 2014	1,051,895.38	944,075.26	107,820.12
Jul 2014	1,309,647.11	1,186,298.80	123,348.31
Aug 2014	1,900,560.49	1,750,617.83	149,942.66
Total	**29,069,857.73**	**27,598,189.72**	**1,471,668.01**

Source: Electricity Authority

2.5 The Authority and the FTR manager have agreed that the language used in the Code may lead to ambiguity that in turn enables different interpretations to be taken. Nevertheless, the Authority has requested that the FTR manager modify its systems to ensure that the HVDC rental is calculated in the manner intended by the Authority when drafting the Code. The FTR manager is currently implementing this change as approved by the Authority (Request For Change number: FM CR-011).

3 Calculation of binding branch constraint FTR rentals

3.1 Branch group constraints in the scheduling, pricing and dispatch (SPD) model are typically formulated as presented below in equation (2). Schedule 14.6, clause 7(3) of the Code states that the FTR manager must determine a constraint participation loading in accordance with the formula shown in equation (3).

3.2 An analysis of the data provided to the Authority by the FTR manager led the Authority to estimate that the FTR manager must have applied equation (4) when determining a constraint participation loading. The FTR manager has confirmed that this is the case. The implication of this discrepancy is that the FTR manager's calculation is undertaken differently from the approach prescribed in the Code.

$$\sum_{k} \mathrm{weight}_{k,v} \times \mathrm{ACLineFlow}_{k} \le \mathrm{RHS}_{v} \tag{2}$$

$$\max\left(\sum_{k \in \mathrm{ACLineGroup}_v} \sum_{h \in \mathrm{Hubs}} \mathrm{weight}_{k,v} \times \mathrm{SF}_{k,h} \times \mathrm{Inj}_{h,p} : p \in 1,..P \right) \tag{3}$$

$$\max\left(\sum_{k \in \mathrm{ACLineGroup}_v} \left(\mathrm{abs}\left(\mathrm{weight}_{k,v}\right) \times \left(\sum_{h \in \mathrm{Hubs}} \mathrm{SF}_{k,h} \times \mathrm{Inj}_{h,p} \right)\right)\right) : p \in 1,..P \tag{4}$$

where:

RHS_v	denotes the limit applied to constraint v
$\mathrm{ACLineFlow}_k$	denotes the flow scheduled for AC line k relative to the conventional direction
$\mathrm{weight}_{k,v}$	denotes the weight associated with AC line k in constraint v
$\mathrm{SF}_{k,h}$	denotes the shift factor relating flows on AC line k to injections at hub h
$\mathrm{Inj}_{h,p}$	denotes the positive or negative hub injection at hub h in FTR injection pattern p taken from the set of P balanced extreme FTR injection patterns.

3.3 If the scheduled flows on the AC lines involved in a constraint are either all positive or all negative, the two candidate formulae, equation (3) and equation (4), produce the same result. However, if some of the scheduled flows are positive while others are negative, the formula implemented by the FTR manager, equation (4), will produce an incorrect result.

3.4 The following actual case from 11 February 2014 demonstrates this. According to the final pricing data, the branch group constraint ATI_OHK.1__THI_WKM1.1__THIWKM1*__ATI__LN was binding in trading period 18 on 11 February 2014. This constraint relates to two AC line flows as follows:

$$\left(0.683 \times \mathrm{Flow}_{\mathrm{THI\_WKM1.1}}\right) + \left(-1.205 \times \mathrm{Flow}_{\mathrm{ATI\_OHK.1}}\right) \le 440 \text{ MW} \tag{5}$$

3.5 Table 6 illustrates the magnitude of the error in the size of the loss and constraint excess arising from the FTR manager's incorrect constraint participation loading calculation in trading period 18 on 11 February 2014. The loss and constraint excess generated by the binding constraint should have been $9,640.06 whereas the FTR manager calculated it to be $378.81. This situation is not contrived; it occurs frequently.

Table 6: Loss and constraint excess generated by binding constraint, 11 February 2014
ATI_OHK.1__THI_WKM1.1__THIWKM1*__ATI__LN constraint in trading period 18

Branch	Weight	Final pricing flow, MW	FTR flow (MW) pattern 1 $SF_{k,h}$ x $Inj_{h,p1}$	FTR flow (MW) pattern 2 $SF_{k,h}$ x $Inj_{h,p2}$	FTR flow (MW) applied by FTR Manager	Correct FTR flow, MW
ATI_OHK.1	-1.205	-211.329	-75.706	69.152	-69.099	-75.706
THI_WKM1.1	0.683	271.374	122.377	-111.782	-111.853	122.377
Constraint RHS, MW		440.000	Participation loading, MW		6.869	174.792
Shadow price, $/MWh		110.30	Constraint FTR rental, $		378.81	9,640.06

Source: Electricity Authority

3.6 It is possible that the incorrect calculation of the loss and constraint excess generated by *mixed* constraints may be in error by a similar magnitude to that just demonstrated for *branch* constraints. While mixed constraints are not currently employed in SPD, Schedule 14.6 of the Code continues to accommodate their use.

3.7 Subsequent to the September discussions between the Authority and the FTR manager, the FTR manager has committed to modify its systems so as to implement equation (3) (Request For Change number: FM CR-012).

4 Injection/offtake allocation and the calculation of branch participation loading

Allocation of injection and offtake quantities to nodes at hubs

4.1 Based on the data provided to the Authority by the FTR manager, the Authority was able to determine that the injection and offtake applied to the Otahuhu (OTA) hub for the purpose of calculating branch participation loadings has been proportionally distributed across three nodes – OTA2201, OTA2202 and OTA2203. It should be allocated solely to the settlement node OTA2201 according to the hub definitions documented in the FTR allocation plan.[2] The FTR manager has agreed to correct this as part of the aforementioned change request, FM CR-012.

Calculation of branch participation loading

4.2 The Authority remains unable to replicate the FTR manager's published FTR rentals, even after applying the incorrect allocation used by the FTR manager noted previously in paragraph 4.1. Using the vSPD FTR rental tool, the Authority has applied the same injection patterns as the FTR manager appears to be using (see Table 7, note 4), yet the branch participation loading results still do not match.

2 See, for example, FTR allocation plan 2012 at https://www.ftr.co.nz/policies.

4.3 As previously noted, the Authority's the vSPD FTR rental tool takes a different approach to calculating the branch participation loading to that adopted by the FTR manager. Specifically, the Authority exploits the readily available mathematical formulation inherent in SPD/vSPD. But that is not the only method of the calculating the branch participation loading for a given injection or offtake pattern. In order to resolve the differences noted above in paragraph 4.2, the Market Analytics team has used a scientific programming language to develop a computer routine to precisely replicate the approach described in schedule 14.6 of the Code.[3] This routine uses the shift factor approach implemented by the FTR manager. However, the Authority is still unable to produce the same results as the FTR manager. Yet the two approaches formulated and tested by the Authority, the vSPD FTR rental tool and the Python-based script, give identical results to each other.

4.4 Table 7 compares the FTR flows calculated using the Authority's tools and different injection patterns with the result from the FTR manager's data. Since the two tools developed by Authority produce exactly the same result, only one set of Authority results for each injection pattern is presented in Table 7.

Table 7: FTR flow for the balanced extreme FTR injection of 750MW from OTA to BEN

Data based on trading period 1, 1 February 2014

Branch name	From bus	To bus	Authority tools with correct pattern	Authority tools with FTR manager's pattern	FTR manager's data
HEN_OTA.1	19	71	0.54	0.104	0.087
OTA_SWN.1	70	31	0.422	0.081	0.068
OTA_T4.T4	70	66	17.113	17.252	16.734
OTA_T2.T2	70	67	10.57	10.655	10.311
OTA_TIE4.1	70	71	185.889	35.743	30.015
OTA_TIE5.1	70	71	111.578	21.454	15.007
OTA_TIE3.1	70	72	20.295	220.133	240.080
OTA_PAK3.1	70	91	77.473	77.816	71.336
DRY_OTA1.2	70	96	102.872	102.713	102.488
OTA_WKM1.1	70	195	60.929	60.914	60.872
OTA_WKM2.1	70	195	61.004	60.989	60.941
OTA_T3.T3	70	754	0.059	0.011	0.010
OTA_T5.T5	70	754	0.059	0.011	0.010

3 A Python script was developed, as the routine involves little more than straightforward matrix manipulation.

Branch name	From bus	To bus	Authority tools with correct pattern	Authority tools with FTR manager's pattern	FTR manager’s data
OTA_PEN5.1	71	57	18.687	21.991	16.562
OTA_PAK4.1	71	91	76.433	82.002	75.221
HLY_OTA2.2	71	95	101.951	102.169	102.118
OTA_PEN6.1	72	57	20.295	10.757	30.704
OHW_OTA1.1	151	70	-101.737	-101.603	-101.504
OHW_OTA2.1	151	71	-100.936	-101.140	-101.208

Source: Electricity Authority

Notes:
1. Only branches connected to OTA are shown.
2. The OTA2201 node is mapped to bus 70, the OTA2202 node is mapped to bus 72, and the OTA2203 node is mapped to bus 71.
3. Correct pattern means 750MW injected at OTA2201 and 750MW taken off at BEN2201.
4. FTR manager's injection pattern means 709.376MW injected at OTA2201, 209.376MW taken off at OTA2202, 250MW injected at OTA2203, and 750MW taken off at BEN2201.

4.5 The calculation of branch participation loadings is straightforward. However, the Authority and the FTR manager have been unable to reconcile the findings described above. For example, the FTR manager does not agree that the injection and offtake applied to the Otahuhu hub for the purpose of calculating branch participation loadings has been incorrectly proportionally distributed across three nodes. Rather, the FTR manager maintains it is has incorrectly distributed the injection and offtake equally across the three nodes.

4.6 The FTR manager will implement the correct allocation as described in change request FM CR-012, and then investigate this matter further before responding again to the Authority.

4.7 By correcting the allocation of injection and offtake at Otahuhu, the FTR manager may also address the unresolved issue with the branch participation loading calculations. Until such time as the corrections have been implemented, the Authority is unable to be completely satisfied on this matter.

5 Marginal loss factor

5.1 Schedule 14.6, clause 9(5) of the Code states that the amount of the loss and constraint excess generated by each AC line loss curve block must be calculated in accordance with the formula in equation (6).

$$\min(\text{ACLineFlowBlock}_{k,j}, \text{AssignedCapacity}_{k,j}) \times \text{ReceivingEndPrice}_{k} \times \left(\text{ACLineLossFactor}_{k,\text{marg}} - \text{ACLineLossFactor}_{k,j}\right) \div 2 \quad (6)$$

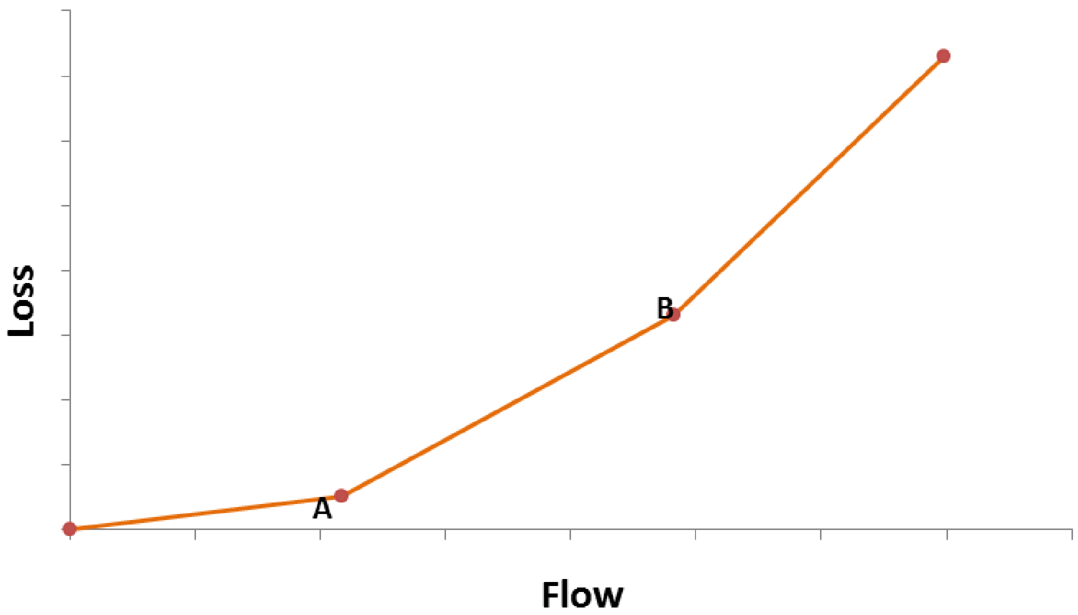
where:

$\text{ACLineLossFactor}_{k,marg}$ is marginal loss factor of AC line k = $\min(\text{ACLineLossFactor}_{k,j})$ for which $\text{ACLineFlowBlock}_{k,j} < \text{ACLineLossMW}_{k,j}$

$ACLineFlowBlock_{k,j}$	is the MW flow on the j[th] block of the loss curve of AC line k in the direction of scheduled positive flow, assuming that loss curve block are utilised in order from lowest to highest loss factor, in each direction
$AssignedCapacity_{k,j}$	is the assigned capacity of the j[th] block of AC line k
$ReceivingEndPricet_{k}$	is the nodal energy price at the receiving end of the scheduled flow on AC line k
$ACLineLossFactor_{k,j}$	is the loss factor of the j[th] block of the loss curve of AC line k
$ACLineLossMW_{k,j}$	is the MW capacity of the j[th] block of the loss curve of AC line k

5.2 Figure 1 presents a typical loss curve of an AC line which has three loss blocks.

Figure 1: Typical AC line loss curve with three loss blocks



Source: Electricity Authority

5.3 It is not unusual to have an AC line flow scheduled exactly at point A or B on the loss curve. In cases where the scheduled AC flow is at point A or B, the marginal loss factor is equal to the loss factor of the second or third loss block, respectively, i.e. the block to the right of the corner point.

5.4 In SPD, the MW capacity of point A (denoted $ACLineLossMW_{k,1}$) of AC line k which has three loss blocks is calculated as $Capacity_k$ * 0.3101 where $Capacity_k$ is the capacity of the line. If $Capacity_k$ is an integer multiple of 10, the resulting value of $ACLineLossMW_{k,1}$ will have no more than three decimal places. Otherwise the resulting value of $ACLineLossMW_{k,1}$ will have more than three decimal places. For example, if an AC line has capacity of 69.81MW and a scheduled flow of 21.648081MW exactly coinciding with point A on the loss curve, the marginal loss factor of this line should be equal to the loss factor of the second block, not the loss factor associated with the first block.

5.5 However, because the scheduled flows reported by SPD are rounded to three decimal places, the scheduled flow entered into the FTR rental calculation becomes 21.648MW. As this is less than the capacity of the first loss block (21.648081MW), the marginal loss applied for this AC line will be equal to the loss factor of the first loss block. The amount of the loss and constraint excess associated with this line will be underestimated.

5.6 In another example, an AC line has a capacity of 69.88MW and a scheduled flow of 21.6697MW at some infinitesimally small distance to the left of point A on the loss curve. The marginal loss factor of this line should be equal to the loss factor of the first block. Because the scheduled flows are rounded to three decimal places, the scheduled flow entered into the FTR rental calculation becomes 21.670MW. Since this is greater than the capacity of the first loss block (21.669788MW), the marginal loss applied to this AC line will be equal to the loss factor of the second loss block. In this case the amount of the loss and constraint excess will be overestimated.

5.7 This particular issue has only a minor impact on the calculation of the amount of loss and constraint excess. It is a minor technical problem and to correct it would require a costly change and audit of the SPD software. Rather than implementing a software change, the Authority intends to round off scheduled flows reported by vSPD to three decimal places, as is the case with SPD.

6 Summary

6.1 The Authority has identified two discrepancies and three minor issues of concern regarding the calculation of the amount of loss and constraint excess available to be paid into the FTR account.

6.2 First, the calculation of the loss and constraint excess amount generated by the HVDC is not as intended by the Authority when drafting the Code. The FTR manager is addressing this.

6.3 Second, the Authority has determined that the calculation of the amount of loss and constraint excess generated by binding branch group constraints is incorrect if the constraint involves branch flows with a direction that is opposite to the conventional direction. The FTR manager is correcting this.

6.4 Finally, the Authority has highlighted three issues of concern related to the calculation of branch participation loadings and the calculation of marginal loss factors. The FTR manager is correcting the allocation of injection and offtake at the Otahuhu node. This may address the calculation of branch participation loadings. The Authority will verify this once FM CR-012 has been implemented. The minor precision issue with the calculation of marginal loss factors will not be corrected as to do so would require a change to SPD. Rather than implementing a software change, the Authority will round reported flows from vSPD to align with what occurs in SPD.

Glossary of abbreviations and terms

AC	Alternating current
Act	Electricity Industry Act 2010
Authority	Electricity Authority
BEN	Benmore
Code	Electricity Industry Participation Code 2010
FTR	Financial transmission rights
HVDC	High voltage direct current
OTA	Otahuhu
Regulations	Electricity Industry (Enforcement) Regulations 2010
SPD	Scheduling, pricing and dispatch
vSPD	Vectorised scheduling, pricing and dispatch