AUFLS event 12 November 2013

Market performance enquiry

05 May 2015

Version control

Version	Date amended	Comments
1.0	2 October 14	1st draft to Authority Board
2.0	28 November 2014	2nd Draft revised post system operator review and comments
3.0	28 December 2014	Revisions post legal review
4.0	14 January 2015	Further revisions
5.0	20 April 2015	Final revisions following the Security and Reliability Council presentation of and discussion on the Enquiry Report

Market Performance enquiries, reviews and investigations

The Authority may carry out an enquiry, review or investigation as a result of monitoring the industry or the market, or at the request of an external party. The Minister may also ask or direct the Authority to look into an issue.

An enquiry, review or investigation looks at the circumstances giving rise to an out of the ordinary event, including the actions of participants. An enquiry, review or investigation may result in suggestions for Code amendments, market facilitation measures, or in a finding that no further action is needed. In all of these cases the Authority usually publishes a report of its findings.

At the same time as it carries out a market performance enquiry, investigation or review, the Authority's compliance team may investigate whether there has been a breach of the Code, Act or Regulations. The two processes may run concurrently, but may not be completed at the same time.

Enquiries, reviews and investigations represent three stages in an escalating process, with increased effort and significance attached to each one.

Market Performance Enquiry (Stage I): At the first stage, the Authority carries out low-cost ad hoc analysis using existing data and resources. The purpose of an enquiry is to better understand circumstances, observed through routine monitoring, that appear to require closer inspection. The Authority would not usually announce it is carrying out an enquiry.

If the results of the enquiry show that the circumstances are unlikely to have any implications for the Authority's statutory objective: competitive, reliable and efficient operation of the electricity industry, the Authority is unlikely to take further action. The Authority publishes the results of its enquiry only if the matter is likely to be of interest to industry participants.

Market Performance Review (Stage II): The Authority will initiate a review if, at the end of a Stage 1 enquiry, it does not have enough information to understand the issue but it appears to be significant for the competitive, reliable or efficient operation of the electricity industry. The Authority makes relatively informal requests for information 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 there was a high level of stakeholder or media interest.

Market Performance Investigation (Stage III): At this stage, the Authority may exercise statutory information-gathering powers under section 46 of the Electricity Industry Act to acquire the information it needs to investigate an issue in depth. The Authority would generally announce early in the process that it is undertaking an investigation and indicate when it expects to complete the work. The Authority generally publishes reports of Stage III investigations.

1 Executive summary

1.1 On 12 November 2013 Transpower undertook an HVDC commissioning test of Pole 3 which involved deliberately causing a fault in the AC power system north of Haywards while the HVDC was running northwards at high power. This test caused equipment at Benmore to trip leading to a rapid decrease in HVDC flow and the first stage of North Island Automatic Under Frequency Load Shedding (AUFLS). This resulted in 401 MW of lost load, and fast instantaneous reserve was also activated. Transpower was found to be the causer of the event. The Authority initiated an enquiry to consider issues relating and contributing to the 12 November 2013 AUFLS activation event.

1.2 This enquiry has focused on the obligations of the system operator under the Code and in particular with Technical Code A, and any amendments that may be required to the Code to reduce the risks of similar events occurring in the future. It is important to note that a review of the actions of the grid owner and its suppliers is not within the scope of this enquiry other than where it has relevance to the actions taken by the system operator. The enquiry identified and considered three specific areas of concern:

(a) the system operator's role and responsibilities in assessing risks arising from modifications to the assets

(b) how the system operator identified and challenged key assumptions relied upon during the testing

(c) the appropriateness of the limited levels of reserves cover for high power testing.

1.3 On concern (a) the Authority concluded that the system operator was entitled to rely on the information provided by the grid owner. Clause 8.4 of the Code allows the system operator to rely on the assets and information provided by the asset owner.

1.4 On concern (b) the Authority's considers that, when assessing the risks of a proposed test plan, the system operator would have been expected to have questioned the grid owner's assumptions that the high power tests were similar to the low power tests and through this challenge may have identified, eliminated or mitigated the risk that led to the event of 12 November 2013.

1.5 On concern (c) the Authority sought, and was provided with, further information from the system operator on its ability to procure additional fast instantaneous reserves. The information confirmed that, under tests at high power transfers, full reserve cover could not be obtained at a reasonable cost.

1.6 The enquiry has found that, whilst it is appropriate that the Code does not specify detailed procedures for the system operator's agreement to test plans and commissioning plans, an appropriate standard should apply when agreement is being made to test plans and commissioning plans. Amending the Code and Technical Code to apply the reasonable and prudent operator (RPO) obligation to the system operator when agreeing to test plans and commissioning plans should achieve this objective.

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2 Introduction

2.1 On 12 November 2013 the first stage of North Island Automatic Under Frequency Load Shedding (AUFLS) was activated resulting in the loss of electricity supply to consumers. The total loss of load due to the AUFLS activation was 401 MW – this was in addition to the fast instantaneous reserves that were also activated.

2.2 Transpower identified that the AUFLS activation was caused by a secondary contingent event that occurred following a high power test conducted during commissioning of Pole 3 of the High Voltage Direct Current (HVDC) interconnector.

2.3 Subsequent to the event, Transpower has provided information, relevant reports and supporting documentation to the Electricity Authority (the Authority). Transpower and the Authority have met to discuss the event and the Authority has sought clarification and further information and has asked a number of questions related to the event.

2.4 The scope of the Authority's enquiry has focused on the actions taken by the system operator in approving and managing the Pole 3 commissioning tests. The objective of the enquiry is:

(a) to establish how the Code requirements were applied for the HVDC high power test

(b) to determine if improvements can be made to the management of commissioning tests

(c) to determine if amendments are required to the Code.

2.5 The Authority has considered the reports, information and responses provided by Transpower and has concluded its enquiry into the AUFLS activation event.

2.6 This enquiry report considers issues relating to, and contributing factors for, the 12 November 2013 AUFLS activation event.

3 Cause of the event

3.1 The Test Plan agreed by the grid owner and system operator included live on-site testing of the performance of Pole 3 at low, medium and high power levels. Following the completion of low and medium power testing the system operator approved the grid owner's request to undertake a sequence of tests at high power levels.

3.2 On 12 November 2013, three high power tests were scheduled, the second of which was to test the HVDC bi-pole stability (or 'ride-through' capability) during a phase-to-phase fault on the nearby HVAC network. The test involved physically creating a phase-to-phase fault by short-circuiting two of the phase conductors on the 220 kV HAY-BPE circuit 1 at a time coincident with a high level of HVDC northward transfer.

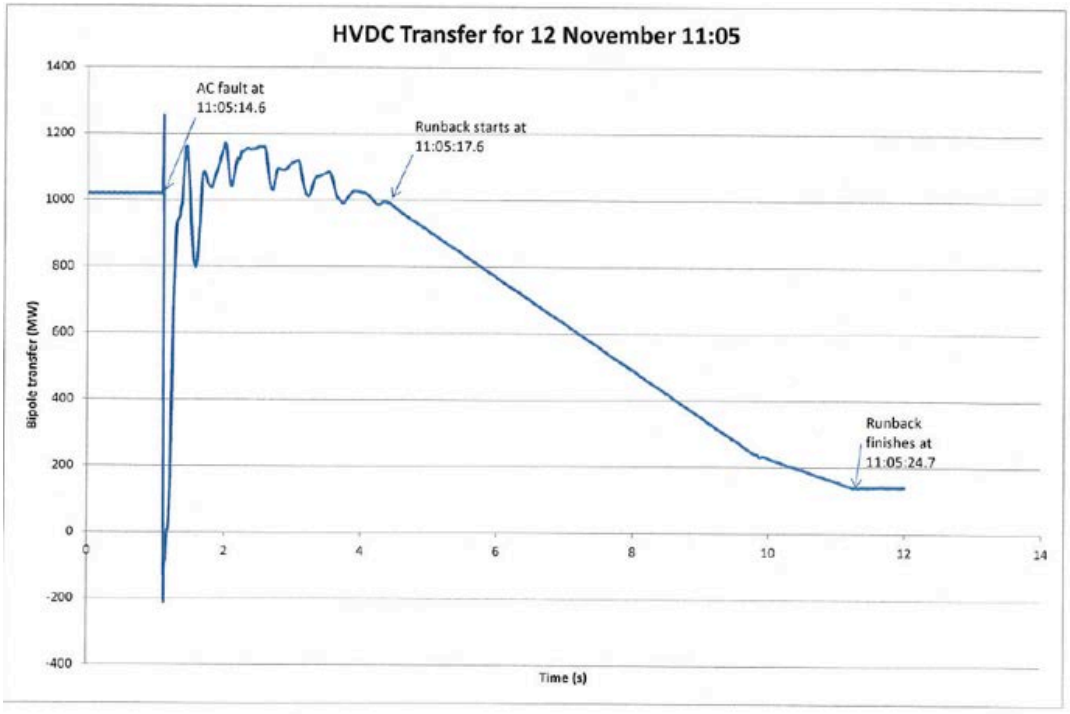
3.3 At the time of the test, the HVDC northwards transfer was approximately 1000 MW. The test phase-to-phase fault resulted in the interruption of the HVDC

transfer for approximately one tenth of a second before transfer resumed following subsequent fault clearance. During the test, a consequential but brief transient increase in 220 kV AC system voltage occurred at Benmore. The transient increase had been predicted and was expected to occur under high load testing. During off site testing in 2012 it was identified that modifications to the control response for transient overvoltage events were required to manage overvoltage during HVDC bipole trip events (as distinct from events occurring on the 220kV AC system). This change–which was made by the lead contractor Siemens–is discussed in paragraph 4.2.

3.4 Under the later high power testing, as expected, the transient increase in 220 kV AC system voltage occurred. However, the modification made earlier by Siemens unintentionally sent a signal to the filter[1] protection system, this caused the simultaneous tripping of three of the five filter banks at Benmore.

3.5 The capacity of the two remaining in-service filter banks was insufficient to support the high level of HVDC transfer and an automatic reduction in the HVDC transfer was triggered. As can be seen in Figure 1, this action reduced the level of northwards transfer from 1018 MW to 140 MW over a period of 7.1 seconds. This significant runback resulted in a reduction of the system frequency in the North Island and an increase in the South Island.

Figure 1: HVDC transfer



3.6 In the North Island, the fast instantaneous reserves cover available was insufficient to cover the large runback in HVDC transfer and avoid the system

[1] The filters are a network of resistors, inductors and capacitors tuned to filter out harmonic frequencies so that just the 50Hz fundamental current is left.

frequency reducing below the threshold frequency of 47.8 Hz, at which frequency the first stage of AUFLS relays were triggered. This resulted in the disconnection of 401MW of load in the North Island and arrested the further fall of North Island system frequency. Since this arrested the decline of system frequency, the second stage of AUFLS, configured to trip at 47.5 Hz, did not activate.

4 Contributing factors

4.1 Information provided by Transpower has established that the three Benmore filter banks should not have tripped during this event. Subsequent enquiry has concluded that the three filter banks tripped due to the control logic at Benmore sending an unintended trip signal to the filter banks.

4.2 The following contributing factors have been identified from reviews of relevant documents provided by Transpower and following subsequent discussions between the Authority and Transpower:

(a) in 2012 Siemens modified the HVDC transient overvoltage protection system with the intention of sending a signal to the station control system if overvoltage above a set point occurred. Unintentionally, the as-built modification also meant that a trip signal was generated and sent to the three filters at Benmore when the overvoltage occurred during the November 2013 event

(b) simulation testing failed to expose the unintended protection system signal that caused the trip signal to be sent to the filter banks

(c) Transpower states that both it and Siemens had identified the unintended protection system signal in previous on-site testing but had not identified the potential for it to cause the consequential tripping of three filter banks – a single filter had tripped as a result of the earlier test

(d) the grid owner assumed that the earlier completed low and medium power transfer tests had established that there was no secondary risk to Pole 3 for fault ride through and voltage disturbances during high power testing

(e) for the high power test there was insufficient fast instantaneous reserves dispatched in the North Island to provide cover for more than a 650 – 750 MW runback, meaning that any unexpected runback in HVDC transfer above that range would lead to a significant reduction in North Island system frequency and a consequential tripping of at least the first stage of the North Island AUFLS relays.

4.3 Based on information provided to it by the grid owner, the system operator undertook assessments and concluded that the high power tests could proceed. This is further discussed from paragraph 7.3 [Assessment of modification risk].

4.4 It is important to note that the Pole 3 project was approved as an economic investment under the Grid Investment Test (GIT). Therefore delays in testing and commissioning are unlikely to have had implications for the security and reliability of the electricity.

5 Requirements for test plans

5.1 Technical Code A of Schedule 8.3 defines obligations for asset owners and the technical standards for assets, to enable the system operator to plan and comply, with its principal performance obligations. Amongst other things, Technical Code A sets out the information that an asset owner is required to provide to the system operator. These requirements include that the asset owner:

(a) meets any other reasonable requirements of the system operator, identified during planning studies, which are required for the system operator to plan to comply, or to comply, with its principal performance obligations[2]

(b) provides the system operator with an asset capability statement in the form from time to time published by the system operator for each asset that is proposed to be connected, or is connected to, or forms part of the grid[3]

(c) agree a test plan with the system operator when they intend to conduct any tests on their assets while connected to the system, and when the tests may impact on the system operator's ability to comply with its Principal Performance Objectives (PPOs).[4] The test plan must contain sufficient information to enable the system operator to plan to comply, and to comply, with the principal performance obligations;

(d) provide a commissioning or test plan[5]

(e) contact the system operator for advice if the asset owner is unsure whether the commissioning or connection of an asset may impact on the system operator's ability to plan to comply, and to comply, with the principal performance obligations[6]

5.2 Technical Code A requires that the asset capability statement provided by the asset owner to the system operator must include *all information reasonably requested by the system operator so as to allow the system operator to determine the limitations in the operation of the asset that the system operator needs to know for the safe and efficient operation of the grid.*[7]

5.3 Technical Code A also requires that the information provided by an asset owner to the system operator is *updated and reissued as information and design development progresses through the study, design, manufacture, testing and commissioning phases.*[8]

5.4 Clause 8.4 of the Code states that the system operator may rely on the assets and information provided by an asset owner and may assume that asset owners are complying with their asset owner performance obligations (AOPO) and the Technical Codes and/or a valid dispensation or equivalence arrangement.

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[2] Code, clause 2(1)(c) of Technical Code A of Schedule 8.3.

[3] Code, clause 2(2) of Technical Code A of Schedule 8.3.

[4] Code, clause 2(2)(b) of Technical Code A of Schedule 8.3

[5] Code, clause 2(6) of Technical Code A of Schedule 8.3

[6] Code, clause 2(6)(c) of Technical Code A of Schedule 8.3

[7] Code, clause 2(5)(a) of Technical Code A of Schedule 8.3

[8] Code, clause 2(5)(c) of Technical Code A of Schedule 8.3

5.5 Clause 9 of Technical Code A states that:

> *the system operator is not, by reason of any such review or lack of review, responsible for strength, adequacy of design or capacity of an asset. In undertaking a review, the system operator is not responsible for any consequence of a failure of an asset due to inadequate design.*

5.6 Technical Code A places the responsibility on the asset owner to provide sufficient information on asset capability to enable the system operator to assess the potential impact on its ability to meet its PPO.

5.7 It follows that to comply with its obligation to agree to test plans, the system operator would fully consider all information provided by the asset owner and identify, request and obtain any additional information that it reasonably required. A key aspect of system operator's agreement to test plans is its assessment of the identification, analysis and management of risks that could impact on its ability to meet its PPOs. It would be expected that both the system operator and the asset owner meet good electricity industry practice (GEIP) standards when developing and implementing test plans. For risk management, AS/NZS ISO 31000:2009[9] provides a standard generally referred to and used in the New Zealand electricity industry. This enquiry uses ISO 31000:2009 as a benchmark against which to measure the system operator's performance.

6 How the system operator managed HVDC testing

6.1 The system operator has provided the Authority with details and descriptions of its approach to the overall HVDC project testing and commissioning. This section provides the Authority's summary of the steps in the system operator's approach relevant to the Code requirements. When developing its views the Authority has referred to and relied upon the system operator's 13 December 2013 report and the Due Diligence Engineers' Review report of 4 February 2013.

6.2 The Authority has reviewed documentation provided by the system operator and is generally satisfied that the management framework implemented for the HVDC Pole 3 testing and commissioning meets the Code requirements. The framework included the requirement to obtain and assess an Asset Capability Statement, Commissioning Plan and Test Plans. There is an important and clear distinction between these two sets of information:

(a) Asset Capability Statements provide information of the physical characteristics of the assets and how they will operate under defined conditions

(b) Commissioning and Test plans set out the procedures that will be followed when undertaking the testing and commissioning of those assets when they are connected to the system.

6.3 When assessing an Asset Capability Statement, the system operator is primarily focused on consideration of the implications for the security of the system under normal operation when the assets are fully commissioned. In this regard the

[9] ISBN 978-1-86975-127-2 http://www.iso.org/iso/home/standards/iso31000.htm

asset owner is required to provide accurate information on the capability of its assets that the system operator can rely on.

6.4 When undertaking an assessment of a Commissioning and Test plan, the system operator considers the appropriateness of the plans proposed by the asset owner and identifies any concerns regarding risks to the system during these special conditions. The system operator can seek further information from the asset owner to address any concerns identified. In other words, the system operator is responsible for asking for the information it needs to carry out its assessment of system risks, and the asset owner is responsible for providing that information. For risks that have significant consequences, such as a test that could not be covered by reserves, with the potential of causing a significant AUFLs event, the system operator would be expected to carry out a comprehensive risk assessment of the proposed Commissioning and Test plans.

system operator's management of risk during high power testing

6.5 On 15 February 2013 the grid owner (Pole 3 Project) released its HVDC Pole 3 Commissioning Risk Assessment.[10] This included risk assessments for the low, medium and high power tests for Pole 3. The version control for the assessment report indicates that there was interaction with the system operator and account taken of the system operator's views in the discussion that would have occurred around this time.

6.6 Despite the planning, interaction and risk assessments, the defect in the implementation of the Siemens modification was not known by the grid owner or the system operator and the potential for a three filter tripping event was not identified by the grid owner or the system operator.

6.7 Following its review of relevant circumstances, the Authority considers that there are issues likely to have contributed to the failure to identify this particular risk. These issues are discussed below.

6.8 Given the significant risks and complexity of the HVDC project, the system operator gave consideration to the management of risks prior to commencing commissioning. With particular reference to the high power testing, the grid owner states that it recognised the need for the system operator to understand:

> *the asset capabilities of the new Pole 3 and Pole 3 tools and associated equipment, and the likely system impacts;*
>
> *the nature of the expected tests required to commission the assets (from an asset owner's and the system operator's perspectives);*
>
> *the impact of the expected tests on the power system and any market impacts.*[11]

6.9 A system operator Response Team (SORTed) was formed to:

> *(amongst other things) interact with the Pole 3 project team to manage and oversee all of the system operator commissioning, testing and review processes*.[12]

[10] Annex A1 HVDC Pole 3 Commissioning Risk Assessment Issue 4

[11] system operator 12 December 2013 report section 2.3.3

6.10 During the second half of 2012 the system operator introduced a number of initiatives to prepare for the HVDC commissioning programme. This included a workshop at which the top three risks were assessed as being:

> *excessive workload pressure on system operator staff, leading to poor decision making or team discontent;*
>
> *real time shift team communications. This was the risk of poor communications of operational requirements (including test activities) arising from different shift personnel being involved in NCC operations during testing. The potential consequences included modelling risk failures, lack of appreciation of test plan actions and expected outcomes etc.;*
>
> *loss of supply to participants (i.e. operation of AUFLS).*[13]

6.11 Included in the management actions initiated to handle the risks identified were:

a) an AUFLS audit and the AUFLS Pole 3 ready project and

b) inclusion of the system operator's Investigations engineers in the development of test plans to ensure that the system operator understood the impact of proposed tests.

6.12 An independent external review of the system operator's approach to the commissioning programme was undertaken by r2a Due Diligence Engineers (r2a) with a final report issued in February 2013. The r2a report[14] recommended (amongst other things) that the system operator should document a quality control process and framework that it would apply to the Pole 3 commissioning and testing.

6.13 The r2a review finding included the following:

> *It was recognised that some of the commissioning tests will provide for secondary extended contingent events. The available precautions for such events are not as certain as for secondary contingent events and greater care will be required due to the unknown nature as to how the system will behave. That is, there is little room for error.*[15]

6.14 For the HVDC commissioning and testing, the system operator adopted a standardised approach it has previously used when commissioning generators. This approach changes the management of secondary risk from a Contingent Event to an Extended Contingent Event once all system operator-relevant tests to prove resilience to risk of trip are satisfied.[16]

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[12] system operator 12 December 2013 report section 2.3.7

[13] system operator 12 December 2013 report section 2.3.8

[14] r2a Pole 3 Commissioning Due Diligence Review to the system operator December 2012

[15] r2a review report section 6.4

[16] system operator 13 December report section 2.1

6.15

6.16 The following table details this approach.

Risk	Definition
Secondary Contingent Event	Under which it is assumed a generator undergoing commissioning will trip if an under frequency event occurs.
Secondary Extended Contingent Event	Under which is it assumed that a generator undergoing commissioning will probably not trip for an under frequency event. Given the small risk of a trip during an under frequency event, load shedding (AUFLS) is relied on to protect the power system from collapse.

Source: system operator

6.17 For the high power tests, the fast instantaneous reserves available to the system operator were insufficient to manage an HVDC runback when transfers were in excess of 750MW. On 12 November 2013 tests were carried out at transfer levels slightly in excess of 1000 MW. As the system operator had assessed the risk of an event as being low, for the high power test, the HVDC was treated as a secondary extended contingent event and, in accordance with the policy outlined above, AUFLS resources would be relied upon if a secondary event were to occur.

6.18 The potential consequences of a secondary event occurring during the 12 November 2013 tests were well understood by the system operator and had been considered and identified in its planning, in workshops (including weekly test plan workshops) and in the r2a review. The system operator's 13 December report includes the following discussion on the commissioning workshops:

> *The system operator took a 'back to basics' approach to the commissioning process and test requirements. A series of workshops examined all individual control loops forming part of the HVDC control system. The HVDC project team was present to explain the purpose of each loop.*
>
> *The workshops allowed the system operator to identify those loops which had the potential to react adversely to system disturbances, and thus require the HVDC to be a secondary (CE) risk when operating on the power system (until proven resilient).*
>
> *Tests were identified which would demonstrate the risk did not exist. These tests, when performed and the results analysed, would allow transition of the HVDC (firstly the Pole 3 controls in the first phase of testing and then the Pole 2 controls in the second phase) from secondary CE risk to secondary ECE risk.*

6.19 The Commissioning Risk Assessment is consistent and well aligned with the staged approach to Pole 3 testing described in the grid owner's December report.[17] The assessment document sets out the three stage approach adopted where low and medium power tests would be used to demonstrate the resilience of Pole 3 providing sufficient confidence to accept the risks inherent in the high power tests. The grid owner and the system operator agreed a series of

[17] Automatic under frequency load shedding event 12 Nov 2013. Transpower New Zealand Section 6

prerequisite tests that had to be passed at low and medium power levels before high power level tests could proceed.

6.20 It is clear from the documents the Authority has assessed that the system operator had appropriately identified the risks and consequences of a secondary contingent event occurring during the high power tests. It is clear that the system operator had put in place an adequate platform that allowed for the exchange of information and views with the grid owner and provided clear opportunities for the system operator to raise concerns.

7 Issues identified

7.1 During the enquiry the Authority identified three specific areas of concern:

(a) the system operator's role and responsibilities for assessing risks arising from modifications to the assets

(b) how the system operator identified and challenged key assumptions relied upon during testing

(c) the appropriateness of the limited levels of reserves cover for high power testing.

7.2 Each of the issues are discussed in the following subsections.

Assessment of modification risk

7.3 During testing and commissioning of transmission assets, risks of a subsequent failure generally increase when modifications are made during the testing period. This is particularly the case when modifications are made following the completion of a sequence of tests. When this occurs, it may be necessary to repeat the earlier tests as the initial results may not be relevant after the modifications have been made.

7.4 In particular, modifications to complex protection systems can have unintended consequences. This is recognised in the Pole 3 Commissioning Plan where it sets out how onsite modifications are to be handled.[18]

> *During system testing changes may be required to control and protection systems to optimise performance for system conditions, or as a corrective action to achieve test acceptance. Where a change is required, the change control procedure shall be followed. Any changes or modifications will be jointly discussed and agreed between Siemens and the Transpower P3 Project Representatives. The Transpower P3 Project will seek advice from the Transpower system operator for any change.*
>
> *In assessing a change the following is to be considered:*
>
> *(a) Prior to implementation providing evidence the change has the required outcome through offline testing or similar means.*
>
> *(b) Regression testing requirements are to be confirmed if it is assessed that the change may impact on other functionality or invalidate any*

[18] New Zealand Inter Island Pole 3 Project HVDC Pole 3 Project Commissioning Plan Version 3 Section 2.7

previously run tests. Any regression tests will comprise of a selected number of repeat tests. The exact type and number of regression tests will be agreed between Siemens and Transpower with the final confirmation being provided by the On-Site Test Lead (P3 sign off person). This regression testing may be carried out as an on-site test or on the Customer Simulator environment. The environment selection of the tests and test environment is to be discussed with Siemens and approved by Transpower.

(c) Revised documentation and supporting information shall be provided by Siemens prior to the change being implemented.

7.5 It is beyond the scope of this enquiry to consider if appropriate post-modification tests were undertaken following the 2012 offsite protection modifications, and if they were, why the issue had not been identified and corrected. The Authority notes that the grid owner's report states that:

The factory acceptance tests included both functional performance tests (FPT) and dynamic performance tests (DPT). These tests proved correct functioning of the controls, logic and performance of the overall interconnected New Zealand AC and HVDC system, ensuring:

a. contractual obligations under the contract were achieved

b. dynamic performance relevant to system security was correct

c. protection functions operated correctly and met performance requirements

d. performance at design boundaries was achieved.

The AC protection systems were not integrated within the FPT and DPT factory acceptance testing environment in Germany. This is not practicable nor usual practice. The testing of the AC protections followed Transpower's standard approach for the commissioning of any protection system, including other AC filters.[19]

7.6 However, it is concerning that, for whatever reason, the output signal produced by a modification to a protection system had not or could not have been checked to make sure that its output signal would have no unintended trip consequences.

7.7 The Commissioning Plan procedure for the testing and approval of modifications to protection systems made during on-site commissioning had to take into account advice from the system operator. It would be expected that the system operator would require sufficient testing to ensure that protection signals did not trip unintended equipment. The Authority understands that the system operator did not have the same level of engagement for modifications made in the factory.

7.8 On the basis that the system operator did not have knowledge of the factory-made protection system modifications, it did not have the knowledge with which to form questions or challenges relating to the tests to be undertaken.

[19] Appendix A: Response to Electricity Authority questions Question 5

7.9 Clause 8.4 of the Code allows the system operator to rely on the assets and information provided by the asset owner. It follows that the system operator would rely on the information provided.

7.10 The Authority considers that the system operator, having no knowledge of the factory-made modifications, had to rely on the information provided by the grid owner.

7.11 The incorrect control settings applied to the AC filter protection had led to an earlier filter trip event on the 28 September 2014 and Siemens had investigated the problem and proposed a 'fix' for the problem. The system operator has informed the Authority that:

> *input from Siemens on the event of 28th September including a proposed fix was obtained on 2 November 2013. Based on Transpower's initial review of the proposal the cause of this issue was not clear and additional work was required to confirm that this proposal would resolve the defect. During the week the response was obtained, priorities were focused in parallel on resolving defects that were required to be implemented during the bipole outage from the 8th to 10th November and managing the tests being run at site. Because of this workload and other priorities the final assessment of this defect and associated fix were not actioned prior to 12th November.*
>
> *In relation to the setting of priorities, highest priority was given to issues that were considered to have potential to lead to some type of unwanted event or those that were pre-requisites to be resolved prior to the next tests being carried out.*[20]

7.12 The system operator has also confirmed that, had the proposed fix been implemented prior to the high power tests, this would have prevented the 12th November filter trip and subsequent AUFLs event. The system operator also confirmed to the Authority that the only critical component, other than multiple filter tripping, that could trip the whole HVDC is the towers, which carry the transmission lines.

7.13 The Authority's view is that understanding the issue with the filters should have been identified as a priority for the system operator because:

(a) the high powered test couldn't be covered by reserves and had to rely on AUFLS

(b) a filter tripping issue had been observed on a previous test but the fix for this had not been implemented

(c) loss of the filters was known to be one of the two events that would lead to a bipole trip.

7.14 Part of understanding this issue should have been to challenge the assumptions that underpinned the asset owner's risk assessment of the HVDC's anticipated performance during the high powered test.

[20] Email 25 November Dan Twig to Doug Watt [incorporating advice from the grid owner]

Challenging assumptions

7.15 The Authority considers that when assessing test and commissioning plans to GEIP standards the system operator would be expected to challenge the assumptions of an asset owner particularly where these assumptions were relied upon during high-risk tests with significant potential consequences. AS/NZS ISO 31000 requires that, when analysing risk, *the confidence in determination of the level of risk and its sensitivity to preconditions and assumptions should be considered.*[21]

7.16 Whilst the method for reviewing assumptions may not be set out in detail in the Testing and Commissioning Plans, it is expected that such a risk assessment would be undertaken in the application and considered by the system operator prior to agreement with test plans. In the event, the documentation reviewed does not indicate that this happened at the right time in the process.

7.17 In mid-2012 the system operator raised concerns and sought assurances from the grid owner regarding secondary risk of an HVDC trip. The system operator sought assurance that:

> *there are no points in the operating envelope where the HVDC response will significantly deviate from the modelled response.*[22]

7.18 The grid owner in its Commissioning Risk Assessment Report made a critical assumption that there was no secondary risk to Pole 3 during the high power testing. The basis for this assumption was that system ride-through for frequency and voltage disturbances had been established by tests at lower transfer levels and through model validation.[23] The Commission Assessment Report states that:

> *This off-site testing when combined with a carefully sequenced site commissioning process and 'low risk' live AC/DC system testing at low and mid-range power transfers provides a high degree of confidence regarding performance. Accordingly a very high degree of certainty can be provided that any meaningful secondary trip risks will not be introduced by the new Pole 3 HVDC control systems at high (i.e. above 350 MW) power transfer levels.*

7.19 The higher transient increase in 220 kV AC system voltage at high power testing that exposed the filter protection logic error and led to the 12 November AUFLS event, meant that this assumption was actually incorrect and that the low and medium power tests could not be relied upon to provide full confidence in the integrity of the high power tests.

7.20 There were factors that should have been taken into account when assessing the potential risks for high power tests. It was known that the AC system voltage at Benmore would rise under the high power tests and that this effect was known and expected by the grid owner prior to the test. It was also known that a defect in the filter protection system had previously led to a filter tripping incident, that this defect had not been repaired and that a multiple filter tripping could cause a bipole trip and consequent AUFLS event.

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[21] AS/NZS 31000 2009 section 5.4.3

[22] HVDC Pole 3 Commissioning Risk Assessment Appendix A

[23] HVDC Pole 3 Commissioning Risk Assessment Section 9.5.4

7.21 Whilst the grid owner is responsible for the ability of its assets including the accuracy of the information submitted to the system operator, the Authority's view is that, when assessing test and commissioning plans, the system operator, when assessing risk, would have challenged the grid owner's assumptions and conclusions and drilled into the differences between the lower and high power tests. If the system operator had done this, the assumed potential for a three-filter trip may have been reassessed, risks of filter protection issues identified and increased priority given to the implementation of the proposed 'fix'. Applying an alternative focus on the differences between the lower and high power tests could have provided valuable perspectives on the potential areas of additional risk.

7.22 The system operator and grid owner have stated views that, had a challenge of the assumptions been undertaken, the underlying protection fault would not have been discovered. The system operator restated this view in its letter to the Security and Reliability Council discussed at its meeting on 20 March 2015[24] when the findings of this Enquiry were discussed. In its letter, the system operator said that; *while true that installation of a fix for the September issue would have prevented the AUFLS event, neither party involved in assessing the earlier event considered it could lead to the events of 12th November 2013.*

7.23 Subsequently in an email to the Authority, the system operator provided the following insight into the approach it took when agreeing to the test plan:

> *For the test which resulted in the AUFLS event Siemens was represented at all relevant meetings and had opportunity to raise any concerns regarding the nature and circumstances of the test; no objection was raised.*
>
> *If Siemens had any reason to believe the filter fix (to the September event) was needed to be in place before high power testing was carried out there was every opportunity for company representatives to have make their views known and advise against testing until the fix was implemented. No such advice or opinion was offered.*[25]

7.24 Given what was known about the potential risk of a multiple filter trip and the consequences of reliance on AUFLS for such an event, the Authority remains of the view that the system operator could have taken a more proactive role in questioning the assumptions on which the grid owner and Siemen's positions were based. Key questions that could have been asked include:

(a) What are the likely scenarios that could lead to a bi-pole trip event?

(b) Have there been any earlier problems with components that could lead to a bi-pole trip?

(c) If there have been earlier problems, has the defects been corrected and tested?

(d) If the defects have not been corrected, what is the basis for assuming that the risk probability of proceeding with the test has not changed?

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[24] Letter from John Clarke to the SRC dated 10 March 2015

[25] Email John Clarke to Doug Watt 26 March 2015

(e) Are the assumptions for proceeding with the test reasonable given the consequences to consumers or can the test be deferred until the defect has been fixed?

7.25 Had these questions been asked and answered it is possible that the system operator's understanding of the potential risks and consequences of the test would have changed, even if the underlying specific defect could not have been identified. This could have led to a deferral of the high power test pending resolution of the protection logic defect.

7.26 The Security and Reliability Council advised that the system operator could communicate the risk to relevant/interested parties when AUFLS was being relied upon during testing in order to broaden the ownership/acceptance of the risk. The Security and Reliability Council considered value could be gained from the opportunity for affected parties to question the basis for agreeing to the test. Currently, under the Code, the Authority's expectation is that the system operator would ask and document responses to these questions when agreeing to test plans.

7.27 Throughout this enquiry, the system operator has maintained that *it did strongly challenge the grid owner's views regarding testing and the degree of reliance placed on earlier testing to indicate performance in subsequent high power testing*[26]. On the basis of the documentation provided and the system operator's response to questions, the Authority has not been convinced that this occurred.

7.28 Specifically, the fix for the September issue would have prevented the November AUFLS event but *neither party involved in assessing the earlier event considered it could lead to the events of 12th November 2013*[27]. On the basis of the documentation provided to the Authority it appears that the system operator accepted this and assumed that there was a low risk of trip and therefore the test could proceed. Given that the cause of the earlier filter trip had not been resolved, the Authority considers that there was good reason to rigorously question how the parties had reached the conclusion (which AUFLS event proved incorrect) that the defect could not cause a multiple filter trip. Until this had been established, it would have been prudent to defer the test.

Reserves cover for high power testing

7.29 In its December 2012 report the system operator stated that as available reserve cover was limited to 650 – 750 MW it was not possible to cover the secondary contingency for high power testing. The report provides the following explanation:

> *The 12 November failure occurred after a test with northwards transfer of 1000 MW. To cover the Bi-pole as a contingent event risk would have required procurement of at least 900 MW of fast instantaneous reserve (FIR), assuming availability of generator net free reserves of around 100 MW. Actual reserves available are always reduced by plant unavailability and other factors. For a subsequent 1200 MW north flow test on 26*

[26] Letter from John Clarke to the SRC dated 10 March 2015

[27] Letter from John Clarke to the SRC dated 10 March 2015

November, all available North Island reserves were contracted and a peak of only 566 MW of FIR was achieved.

7.30 The Authority sought, and was provided with, further information from the system operator on its ability to procure additional fast instantaneous reserves. The Authority accepts that under tests at high power transfers, full reserve cover could not be obtained at a reasonable cost. Accordingly, reliance on AUFLS was consistent with the Authority's expectation of the system operator.

8 Could the AUFLS event have been avoided?

8.1 As discussed in section 6, the system operator established a framework for the management of Pole 3 connection, testing and commissioning. The framework included the required components set out in Technical Code A including assessment of:

(a) Asset Capability Statement

(b) Test plans and test plan process

(c) Project Commissioning Plan

(d) Communication plan for staged AC and DC fault tests

(e) Risk assessment and management (including secondary risk considerations)

(f) Management reporting

(g) Weekly test workshops.

8.2 The framework included a clear systematic approach including periodic reviews with the system operator and the grid owner's Pole 3 project team.

8.3 The Authority found that the framework established by the system operator had been subjected to external independent review and is consistent with what the Authority would expect. In particular, the framework was found to align with the risk management framework and process set out in AS/NZS ISO 31000:2009.

8.4 It is important to note that in addition to the finding on the appropriateness of the framework, the application of the framework also needs to be considered. In other words, the framework may be fit for purpose but it may not have been appropriately applied in practice. The key points to consider are:

(a) could the framework have been in any way applied differently and prevented the 12 November 2013 AUFLS activation and, if so

(b) is it reasonable to expect this to have been done?

8.5 Answering the first question requires consideration of the sufficiency of the information provided by the grid owner to the system operator and any additional information that the system operator could/should have reasonably requested.

8.6 The Authority considers that reliance on the results of low and medium power tests without identifying and assessing the differences between these tests was an error. Whilst ultimately it was the grid owner that placed reliance on the assumption and provided guidance to the system operator on this basis, if this

assumption had been questioned when reviewing and agreeing to the test plan, there is a possibility that the AUFLS event could have been avoided.

9 Improvements that may avoid future events

9.1 Whilst it may be several decades before an HVDC project of an equivalent size and complexity is again undertaken in New Zealand, the key findings of this enquiry are pertinent to other projects. In particular, the management and testing of modifications to protection systems can potentially be improved to avoid unintended trippings. Other recent events have been associated with protection issues and a focus on improving the review and testing of design and installation is desirable.

9.2 The Authority acknowledges the preparation and planning that the system operator undertook for the testing and commissioning of Pole 3. The 12 November 2013 event and AUFLS activation were extremely unfortunate, considering the diligence that had been applied to planning for the tests.

9.3 With hindsight, it is possible to see events and actions through a different lens. A key lesson from this enquiry is that critical conclusions made by asset owners (and the assumptions they are based on) must be identified and rigorously challenged when agreeing to test and commissioning plans.

9.4 In discussions, the system operator has explained that challenges and discussion did occur in various meetings with the grid owner. However, the Authority's view is that there is insufficient evidence to conclude that there was appropriate formality and rigour in this process. The Authority encourages the system operator to consider how it can address this when assessing test plans in the future.

9.5 The Security and Reliability Council noted at its meeting of 20 March 2015 that valuable lessons had been learned in terms of risk management and the documentation of processes. The Authority agrees with this view.

10 Should the Code be amended?

10.1 Part 8 of the Code contains specific requirements that an asset owner, wishing to connect to and operate on the transmission system, must provide information to the system operator. The system operator is responsible for assessing the information and agreeing to the test and commissioning plans that allow connection and operation.

10.2 The Authority considers that the responsibility and liability for the provision of asset capability and accurate information (including test and commissioning plans) correctly lies with the asset owner.

10.3 The Code provides for the system operator to submit requests to asset owners for additional information that it considers to be necessary to undertake an assessment. The system operator relies on the information provided to it. The Code does not set out how the system operator should assess the information provided by asset owners or what additional information the system operator should request.

10.4 The Authority considers that the Code adequately provides for the system operator to identify and request all information required to ensure that it can meet its PPOs.

10.5 As discussed in section 5 the system operator and asset owner are required to agree to the test plan submitted by the asset owner. The Code does not specify procedures for the system operator's assessments. The Authority considers that this is appropriate because the assets, technical issues and conditions are highly situation-specific and the system operator will necessarily apply wide-ranging technical judgements when agreeing to test plans.

10.6 However, assessments undertaken by the system operator must be technically robust, to meet the requirement of what would be expected of a reasonable and prudent operator (RPO) and be in accordance with GEIP. The Code currently applies the RPO obligation to specific requirements that do not include the agreement of test and commissioning plans.

10.7 For system risks that have high consequences, the Authority considers that the Code correctly requires the system operator to assess and agree to test and commissioning plans. However, in order to meet this obligation the system operator would be expected to undertake appropriate levels of risk assessment in accordance with GEIP and that this would include the challenging of assumptions in test plans. The Authority considers that the Code is not sufficiently clear on the standard that should be applied when agreeing to test and commissioning plans.

10.8 This enquiry has not identified any Code amendments that would have avoided the 12 November 2013 or potential future AUFLS activations. And the Authority considers it inappropriate for the Code to specify detailed procedures for the system operator's agreement to test and commissioning plans. However, the Authority considers that an appropriate standard should be required for the system operator's agreement to test and commissioning plans. Amending the Code and Technical Code to apply the RPO obligation to the system operator when agreeing to test plans would achieve this objective.

Glossary of abbreviations and terms

AC	Alternating Current
AOPO	Asset Owner Performance Obligations
AUFLS	Automatic Under Frequency Load Shedding
Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
DC	Direct current
GIT	Grid Investment Test
GEIP	Good Electricity Industry Practice
HAY-BPE	Haywards to Bunnythorpe (refers to a transmission circuit or circuits)
HVDC	High Voltage Direct Current
Hz	Hertz (unit of frequency)
kV	Kilovolts, 1000 volt
MW	Megawatt
MWh	Megawatt hour
PPO	The system operator's Principal Performance Objectives
RPO	Reasonable and prudent operator
r2a	r2a Due Diligence Engineers
SO	system operator
SORT	system operator Response Team