

**PLANNED OUTAGE COORDINATION PROCESS (POCP)  
INDUSTRY REVIEW  
MEETING MINUTES FOR 5<sup>th</sup> APRIL 2006**

**ATTENDEES:**

Mark Pearce (Chair)  
Rick Liew (Contact)  
Greg Salmon (Meridian)  
James Denham (Genesis)  
Tim Dobbs (Mighty River)  
Brendan Olsen (Grid Owner)  
Ray Basher (Grid Owner)  
Greg Spence (System Operator)  
Alan Jenkins (ENA)  
Richard Clark (RedSpider)  
Stephanie Wenman (Project Manager)

**APOLOGIES:**

Chris Sadler (Vector)  
Richard Spearman (Trustpower)  
Grant Tuffery (System Operator)

**MINUTES**

1. The Review Team noted that Richard Smith had resigned from Trustpower, and would be replaced in the Review Team by Richard Spearman.
2. The minutes of the previous meeting were noted and accepted.
3. The action points from the previous meeting were reviewed. In response to the SO action point from Para. 9 of the previous minutes, Greg Spence tabled a draft paper "SO Response to POCP Issues" (Appendix A), and presented a brief summary of the paper (Appendix B). Following discussion of the paper and the presentation, it was agreed:
  - That **Greg Spence** would amend the POCP Users Guide to explain the point in the SO assessment process at which the Assessment Status of an outage would typically be added or changed.
  - That **Greg Spence** would investigate the feasibility of linking a named constraint directly to a specified outage, and report back the outcome of this.
  - That **Greg Spence** would investigate the possibility of adding additional information to the current Assessment Status of "Assessed". Specifically, that the Assessed status could be flagged to indicate where the previous year's occurrence of a specified outage had required either a constraint or "other action".
  - That **Greg Spence** would also investigate the possibility of adding other SO assessment information within the POCP database, and the relative timeliness of adding any such information.
  - That **Greg Spence** would develop an overall proposal encompassing all of the above action points, discuss the potential impacts of his proposal on the POCP database with Richard Clark, and report this back to the next meeting of the Review Team.
4. The Review Team noted that other action points from the previous meeting had been completed and there were no further issues arising.

5. The Review Team further discussed the issue of “The timeliness of information provided by asset owners, and of the System Operator assessment of the information”. The Team noted that although the current situation was not perfect, the issue had been fully discussed by the Review Team, and SO information included in the relevant presentation material. The action points in Para 3. above had resulted from the discussion, and it was agreed that beyond finalising the above action points at the next meeting, and the intended consideration of routine operational outage coordination meetings, this issue has now been closed by the Review Team.
6. The Review Team further discussed the issue of “The certainty and variability of outage plans”. The Team noted that there was already a good level of communication between the System Operator, the Grid Owner and other Asset Owners, which helped to manage the level of change to notified outages. There was some discussion of the “churn rate” as noted in Appendix A. The Team noted that a certain level of churn was inevitable, and also desirable in response to market and weather factors. The Team accepted that the churn rate may create planning issues, but these should be minimized by the action points noted in Para. 3 above. It was agreed that this issue would now be closed by the Review Team.
7. Discussion then turned to the issue of “The role of POCP in identifying, communicating and mitigating the impacts of outages, including pricing outcomes”. The Review Team noted the following points:
  - The current constraint indicator on Assessed outages, and the proposed additional flags showing the previous year’s action for a specific outage, can be used to identify situations where a pricing or security risk may exist.
  - Any further attempt to forecast price impacts based on POCP data can only second guess market action as determined by bids and offers. This would not result in any reliable price forecasting information, as no one organisation is in a position to estimate pricing outcomes. Additionally, external factors such as weather have a significant affect on the actual pricing outcome.
  - The Review Team considered that it was not part of the role of the POCP to identify possible pricing outcomes, and accordingly agreed to take no further action on this issue.
8. The Review Team had further discussion on the issue of “POCP and the Operational Communications Rules change, and associated issues”. It was agreed that the Review Team would write to the Electricity Commission to express their views on this issue. **Mark Pearce** to draft a letter incorporating the points noted during discussion. The draft letter will be sent to all Review Team members for review. **All Review Team members** are to provide a response on the draft letter. **Mark Pearce** will then finalise the letter and forward to the EC on behalf of the Review Team.
9. The current POCP Business Rules were reviewed and following action points noted:
  - Business Rule 5 to be updated to reflect that Technical Code D has been altered to remove the provision relating to confidential information.
  - Business Rule 6 to be updated to state the current information requirements, status codes etc as per the current POCP database.
  - Business Rule 7 to be updated to remove reference to the Common Quality Obligations.

**Stephanie Wenman** to update the Business Rules and provide a revised draft to the next meeting.

The Team also discussed the possibility of an additional Business Rule to specify the frequency, format and minimum quality of data loaded into the POCP database. This will be further considered at the next meeting.

**Stephanie Wenman** to ensure that ongoing Business Rules issues are included in the discussion on governance at the next meeting (see below).

10. The Review Team then discussed the need for regular POCP governance meetings, and regular outage planning coordination meetings. It was noted that outage planning coordination meetings could have implications in relation to information disclosure and competition law. Also that while it would be desirable to hold these sort of meetings at similar times, it was likely that there would be different organisational reps at each of the governance and planning meetings. Action points arising were:

- **Ray Basher and Brendan Olsen** to consider what could be practically achieved through regular coordination meetings, and report back to the next meeting;
- **Mark Pearce** to seek advice on the possible issues relating to information disclosure and competition law, and report back to the next meeting.
- **Review Team members** to further consider POCP governance issues at the next meeting.

11. Richard Clark from RedSpider then joined the meeting for discussion on the issues of “The sustainability of the existing database”, “Need for additional information fields in the database”, and “Focus on users and useability”. Key points noted/action points arising from this discussion were:

- Part of the ongoing governance responsibility will be to regularly review the POCP database, and to ensure it is still fit for purpose.
- The database is capable of handling the current load, and any “cosmetic changes”.
- The need for any immediate significant enhancement or redevelopment of the database will be discussed at the next meeting, after the System Operator has reported back as per the action points in Para 3. above.
- Should it be decided not to redevelop the database in the immediate future, it should be noted that this is likely to be required in the medium term, and that appropriate funding will need to be secured for the redevelopment.
- **All Review Team members** to advise Richard Clark of name and contact details for a nominated POCP technical contact from their organisation.
- **Richard Clark** then to produce a “technical update” for distribution to all nominated contacts.
- **Richard Clark** to investigate bug fixes/possible enhancements relating to:
  - Linkages between outages;
  - Comments fields;
  - Confirmation messaging;
  - Displayed Assessment Status of historical outages.
- **Richard Clark** to report back progress on these issues to the next meeting.
- **Stephanie Wenman** to ensure that ongoing database management issues are included in the discussion on governance at the next meeting.
- **All Review Team members** to consider if there are any other enhancements or fixes they want made to the POCP database, including any specific items/descriptions they want to use in filtering information. These should be advised to Richard Clark ASAP. **Richard** to then analyse the requests, consider the potential impact on the database, discuss as required with Greg Spence, and then report back to the next meeting on the best way to achieve the user requests, and any resulting recommendations for specific actions/responsibilities.

12. It was noted that the Review Team has yet to address the issue of “Stakeholder Management”.
13. The next meeting of the Review Team will be held on Wed 3 May, from 9.30 – 4.00 at Transpower House.

Stephanie Wenman  
POCP Review Project Manager

## **Planned Outage Co-ordination Process (POCP) Industry Review**

### **System Operator Response to Issues Raised At 8 March Meeting**

**Plan:** 1. *a detailed scheme, method, etc., for attaining an objective.* 2. *a proposed, usually tentative idea for doing something.* –O.E.D. 1982.

#### **Purpose**

In response to the issues raised in the first industry POCP review workshop on 8 March 2006, this paper summarises the current planning process from the SO perspective. As noted in the minutes of the 8 March meeting the specific issues of interest are:

- Preparation of the Grid Owners annual plan and addition of other outages.
- Assessment time frame of Generator outages.
- Planning resource requirements.
- Assessment lead times
- The role of regional forums

#### **Outage Planning Process Overview**

There are a number of planning processes operating over a 12 month period which delivers overall co-ordination of outages within the industry.

These processes begin 12 months out from real-time with the assessment and notification of the Grid Owners annual plan. In this process the Grid Owner consults with the System Operator, Generators and Connected Parties to co-ordinate and schedule outages for the most appropriate time over the coming 12 months. Many Generators also notify their outage plan over a 12 month period.

The other end of the spectrum is the 4 week ahead Security Assessment process where the System Operator is confirming all necessary outage arrangements are in place, and preparing the SO tool set for real-time operation.

Between these processes there is the Annual Plan additional outage window request process, where if additional outage windows are required by the Grid Owner beyond 9 weeks from real-time, an assessment is done to identify an appropriate outage window. This process is typically used for large projects.

There is also the 6-9 week Security Planning process where detailed outage requirements are developed and confirmed in with the Grid Owner prior to the outage request being confirmed in POCP.

Within the System Operator group there is the equivalent of 7 full time Operations Planning Engineers allocated to these outage planning processes, plus one team leader.

In summary the planning processes are time based as follows:

**Annual Plan Assessment Process (up to 12 months)**

The Grid Owner develops an Annual Plan of outages in February each year which covers the coming 12 months from July onwards.

In assembling the Annual Plan the Grid Owner consults with Generators, connected parties and the System Operator to ensure there are no conflicting outage requests within the plan. Once the plan is confirmed it is published to POCP which usually occurs in March each year.

**Additional Window Assessment Process (9 weeks–12 months)**

Where the Grid Owner identifies the need for additional outage windows in the Annual Plan after it has been published, the GO will request a one off assessment be done to confirm the proposed outage will not create a conflict with the existing planned outages. They may alternatively request the System Operator to identify a suitable outage window which will allow the work to be done with minimum impact to the system. These one off requests are typically made for large projects.

**Security Planning Process (6-9 weeks)**

The 6-9 week Security Planning process uses the outage information listed in POCP, and focuses on determining the detailed arrangements that are required to ensure security standards are maintained during an outage. These arrangements can include,

- building constraints.
- determining load management levels
- determining minimum generation levels where non-market generation is concerned
- determining grid reconfiguration options
- determining protection change requirements or use of special protection schemes

As with the Annual Plan and Additional Window request processes, the Generation outages listed in POCP for part of the assessment in this 6-9 week process. As part of this process generator outages are also assessed for impact on overall energy availability. That is the assessment looks at the submitted generation outages, to identify any conflicting outages which could result in insufficient generation plant being available to meet energy and reserve requirements. Completion of this process is signified through outages being selected to assessed in POCP.

**Security Assessment Process (0-4 weeks)**

The 0-4 week Security Assessment process focuses on ensuring the necessary arrangements identified from the 6-9 week process are in place, and confirming security standards will be met. The activities for this process include:

- assembling the relevant constraints into “bundles”
- uploading the System Operator and market tool sets with the necessary information
- issuing market notifications via CAN's

- preparing information for the control room operators (The Grid Plan)
- co-ordination of switching plans with the Regional Operating Centres

Within the 0-4 week timeframe, the assessment of typically 30% of outages is completed between 2-4 weeks out from realtime, with the remaining 70% being completed between 0-2 weeks from realtime.

Approximate planning statistics are:

- 350 outage notifications per month
- 10 transmission outages per 1 generation outage

Of the 3500 assessments for the last year less than 10 were notified as potential EGR security issues.

### **Variability of Outage Plans.** (refer figure 1.)

Typically there are around 3,500 transmission outages and 350 generation outages notified through POCP within any 12 month period.

The Grid Owner submits a 12 month annual outage plan for the coming financial year in May each year. Prior to submitting the plan the GO consults with connected parties and the System Operator to determine the most appropriate timing for an outage. The plan is based on planned maintenance activities and projects that are committed at the time of forming the plan. Generators also enter many of their planned outages up to 12 months in advance of real-time.

Both Generator and Grid Owner outages are added as the year progresses in response to new projects, additional maintenance requirements, and fault response. Additional outages can be added anywhere from real-time, in response to a fault situation, to 12 months out.

As well as submitting new outages, existing outages can be rescheduled. This can be due to changes in system conditions, contractor availability, revised project timelines, generator or transmission availability during the outage period, or other connected party requirements.

The current change rate for outages within the 0-9 week timeframe is approx 6% per week.

Current statistics show that:

- Within any 9 week period there are typically 700 individual outage requests that need assessing. This is an average of 78 outages per week.
- For a 6% change rate per week, of the 78 outages lodged for the 4<sup>th</sup> week out from real-time, 24% of those outages will have been changed by the time they become real-time.
- Of the outages lodged for the 9<sup>th</sup> week from real-time, 46% of those outages will go through to real-time without being changed.

To maintain a lead time of 4 weeks in the 6-9 week Security Planning process ie:each week assessing all new and changed outages within that time frame requires the assessment of 93 outages per week. Of those 93 outages, 15 will need to be re-assessed the following week.

### **Impact of other factors**

As well as Generation and Transmission outage requests being changed, there are a number of other factors which impact heavily on the planning process.

#### **Outage numbers.**

As assets age, the need for routine maintenance outages increases. In conjunction with this comes an increase in the number of project outages required to replace/upgrade ageing assets.

#### **Outage complexity**

As the number of outages increases, the number of concurrent or simultaneous generation and transmission outages also increases. This creates significant additional work through assessing the impact of multiple outages, and determining the arrangements that will be required to maintain security standards.

#### **Regulatory requirements**

With the introduction of the EGR's the SO is required to meet higher standards for post contingent voltage during outages, which often requires certain arrangements to be made. These arrangements might include, load management plans being agreed with distributors, or higher levels of generator availability being agreed with local generation. Where these measures are unavailable, often agreements with connected parties for lower levels of post contingent voltage are required, along with a revised asset capability offer from the respective asset owner, which allows assets to be operated at a lower post contingent voltage. Determining these additional arrangements places increased resource drain and time pressure on the overall planning process.

#### **System conditions**

System load growth is of the order of approx 2.5%. Simple outages that one year ago did not require detailed assessment, may now need to be assessed for post contingent equipment loading, or post contingent voltage violations or voltage instability. Any necessary mitigating measures then need to be agreed and documented in preparation for real-time operation.

### **Timeliness of assessment information.**

Advice of the assessment being completed is notified in POCP through having the outage status changed from Confirmed or Tentative, to Assessed.

For generation outages not assessed in the Annual Plan, or Additional Window request processes, this occurs in the Security Planning process 6-9 weeks out from real-time. Similarly for transmission outages not assessed previously, the status is set to Being Assessed once the Security Planning process begins 6-9 weeks out from real-time. The outage is then marked as Assessed once any necessary mitigating arrangements have been confirmed, which occurs in the Security Assessment process 0-4 weeks out from real-time. Where an outage requires constraints to be applied to ensure security standards are maintained, the status is set to Assessed (C) to note a constraint is required.

Where a potential security risk is identified, the assessment status is set to Potential EGR issue, an assessment form is attached to the outage explaining the security risk. An email notification is then sent to the respective asset owners notifying them of the situation.

Notification of a potential EGR issue has always triggered an appropriate response by the effected asset owners. There have been no instances in the three year history of POCP where notification of a potential EGR security issue has been disregarded or ignored by an asset owner.

### **Regional Security Forums.**

Under the original POCP business rules the System Operators role in relation to the POCP process was envisaged to be that of “facilitator”. Hosting the outage information, and notifying the industry of situations where some form of intervention is required, allows participants to make their own decisions with respect to managing asset outages.

For some situations, the System Operator will move from it's role of facilitator, to being a co-ordinator, to ensure sufficient measures are in place to maintain security standards. Recent examples of this are the Upper NI Summer Security working group, and the Upper SI Summer Transmission upgrade forum.

Where the Upper NI forum was concerned, the generator and transmission outage information contained in POCP allowed the working group to assess the consequence of particular forced outages, and arrange the necessary mitigation measures to be put in place should they occur. The System Operator acted as co-ordinator to ensure participants were fully informed and that the situation was resolved.

In the case of the Upper SI Transmission upgrade program, close coordination of outage timing, load management, and generator availability was required across a large number of parties, to ensure security standards would be maintained. Providing notification of the detailed outage requirements through POCP allowed the SO to co-ordinate the outage requirements across multiple parties in a transparent and impartial manner.

Although the regional forum approach is very successful, it is resource intensive for all parties involved. Therefore this approach is only adopted where a specific issue is identified, and it's resolution would not be dealt with effectively by the planning process. The proposed 2006 System Operators's policy statement (currently out for consultation) sets out the possible criteria for convening a Regional Forum.

## **Summary**

The increasing demands from higher levels of regulatory compliance, load growth, the number and complexity of outages all add to the effort required to plan for outages.

The increased number of outages occurring on a tighter grid, result in many outages having a higher sensitivity to changing system conditions. System variables such as natural demand variation, changes in hydrology/generation availability, and forced outages. As such outage arrangements often cannot be confirmed until system conditions become more certain i.e. 2 – 4 weeks out from real-time. This then leads to more outage related decisions being made closer to real-time.

At the beginning of the POCP forum review, the following main points were identified for review. In the context of the information provided, forum members need to consider the following:

- Should POCP provide detailed assessment information for situations other than when PPO's may be at risk. If so what would be the overall net benefit, and to who? What information would be provided? Would the current process and database need to be altered/enhanced, and what additional resource would be required.
- Is the timeliness of notification of PPO security issues sufficient? If not what would be considered appropriate, what net benefits would be gained and what process or resource changes would be required.
- Does the variation of outage plans create issues for POCP users? If greater certainty was required what process or rule changes would be required, and what implications would this have.

In the context of the existing process & tools, it is unlikely that the deployment of additional resource alone would deliver a step change in providing enhanced planning information further in advance of real-time.

If the POCP forum wanted to enhance the process with a more central and active role for the System Operator in assessing and co-ordinating outages, changes would be required in the structure of the process and the regulations pertaining to the management of asset owners outage plans. The tools, process and technology used in the planning process would also need to be reviewed.

The POCP forum should carefully define the scope of the review. Issues that may be perceived regarding the timing of Grid Owner Outages may be dealt with in the forthcoming consultation process on the Benchmark agreements under Part F of the EGR's. One of the proposals is to place additional obligations on the Grid Owner in demonstrating its outage timing is at least cost to the industry. These rule changes are outside of the scope this review forum and Technical code D.

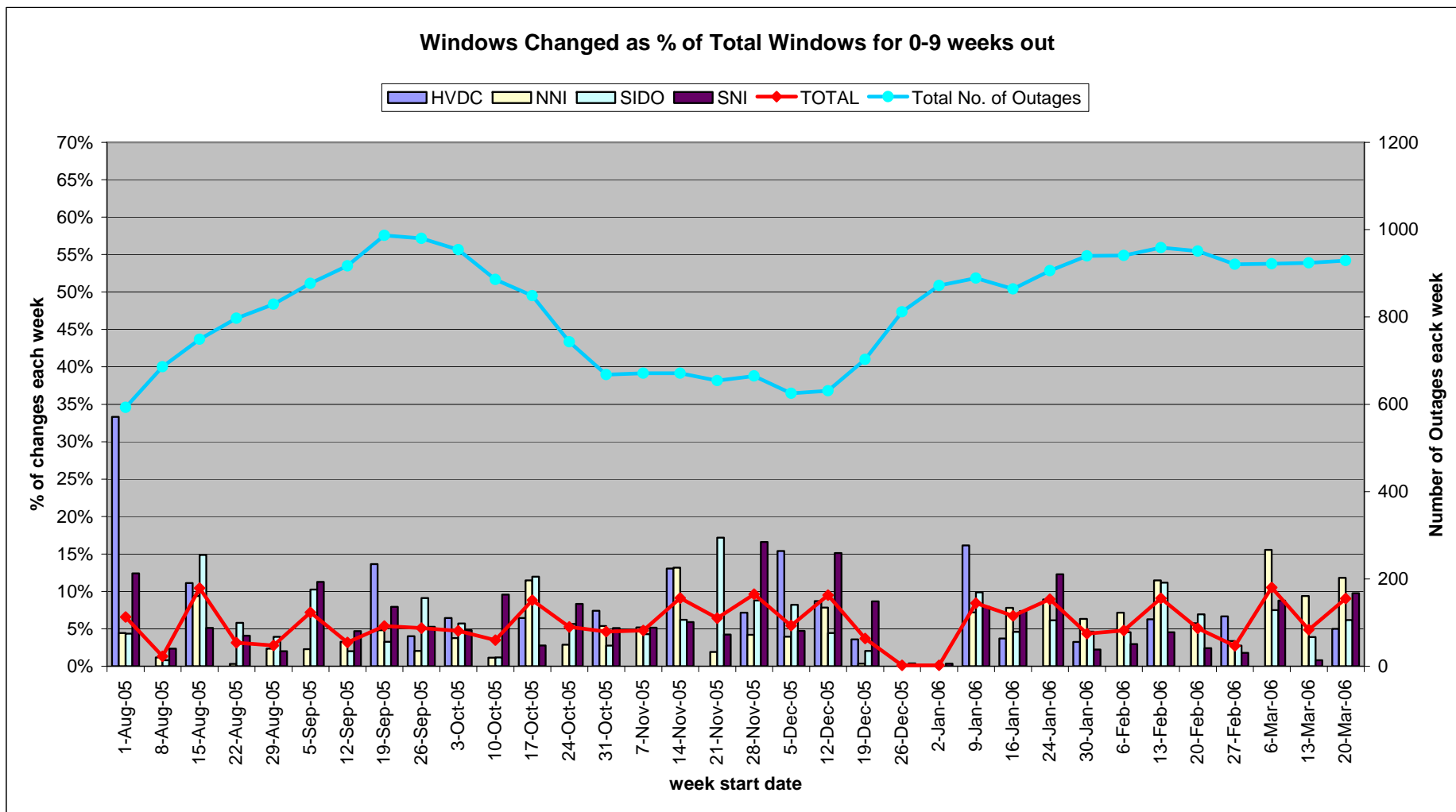


Figure 1. Outage changes 0-9 week summary.

# Planned Outage Co-ordination Process Forum

## Planning Process Overview

4 April 2006



# Planning Process Review

- Process overview
- Outage plan variability & other factors
- Timeliness of assessment information
- Regional security forums
- Summary



# Process Overview

- Four discreet planning processes
  - Annual Plan.
    - Submitted in Feb/Mar for 12 months
    - Input from Generators, Connected Parties & System Operator.
    - High level co-ordination
  - Additional Annual Plan Outage Windows
    - Additional outages as required 9 weeks-12 months
    - One-off assessment. Large projects.
  - Security Planning Process
    - Weekly routine. 6-9 weeks.
    - Detailed planning
    - Energy balance
  - Security Assessment Process
    - Weekly routine. 0-4 weeks.
    - Confirming outage arrangements
    - Preparing real-time operations



# Process Overview -statistics

- Full time equivalents of 7 Operations Planning Engineers
- Typically 3500 -4000 outages pa. ~350 outages per month. ~80 outages per week
- Transmission to Generation ratio 10:1
- Churn rate 0-9 weeks 6% per week
- Typically ~10 Potential EGR security issues pa. (0.3%)

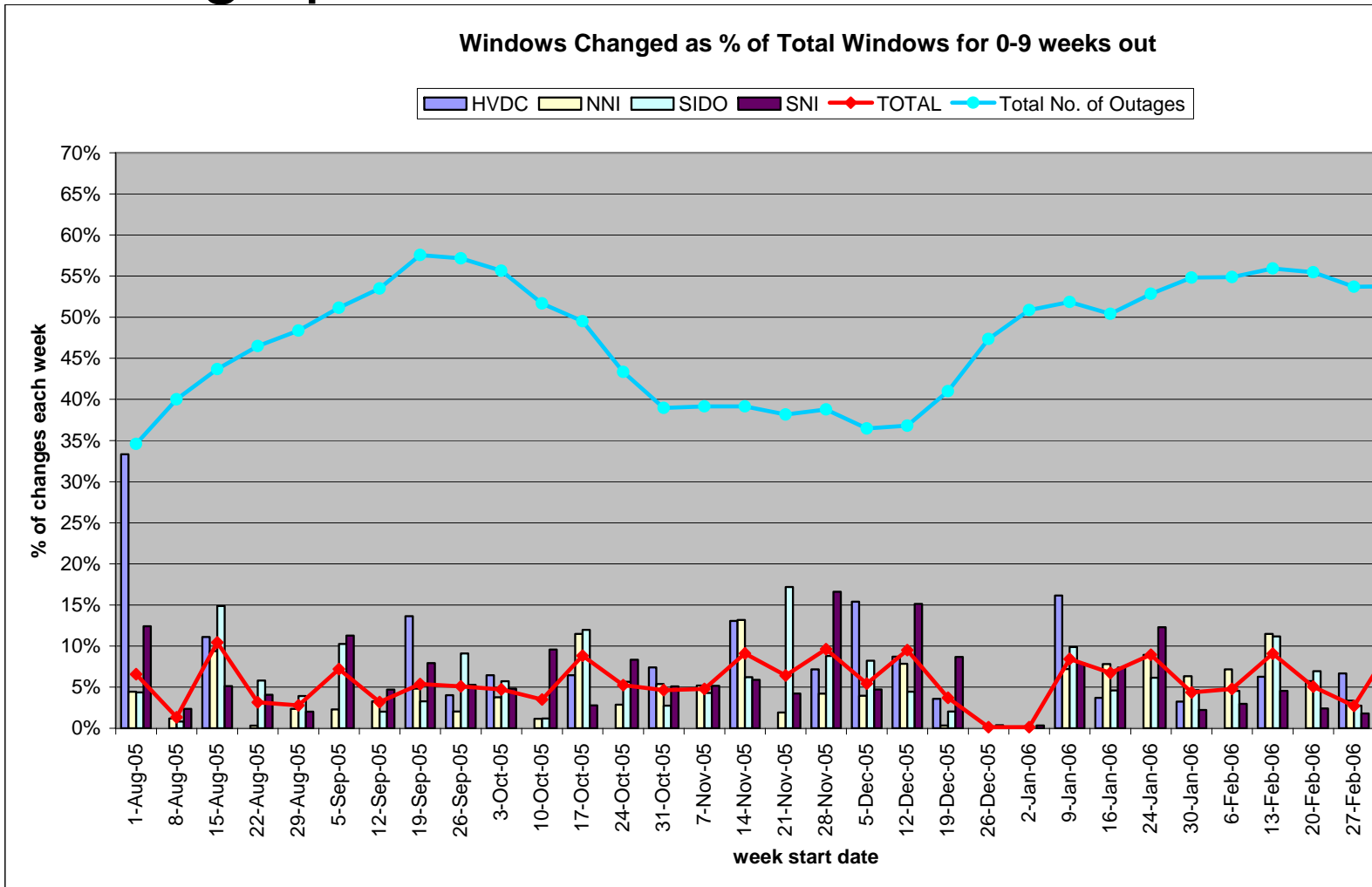


# Outage plan variation & other influences

- 12 month average churn rate 0-9 weeks 6% per week
  - Transmission stats only -unlikely to be influenced by generation due to 10:1 ratio.
  - Caused by a range of variables
    - changes in system conditions
    - contractor and resource availability
    - revised project timelines
    - altered generator or transmission availability
    - connected party requirements
  
- Tighter system & complex conditions
  - Increased number of outages –projects and maintenance
  - Increased complexity –multiple/concurrent outages
  - Increased regulatory requirements
  - Ongoing load growth



# Outage plan variation & other influences



# Timeliness of assessment information

- High level assessment Annual Plan process
  - Co-ordinated with effected parties
  - Conflicts resolved prior to publication
- Additional window requests
  - One-off assessment
  - High level or detailed as required
  - Conflicts resolved prior to publication
- Detailed planning begins 6-9 week process.
  - Conflicting outages
  - Energy balance assessment
  - Detailed outage requirements
- Confirming detailed arrangements and preparing real-time tools 0-4 week process
  - Confirming arrangements in place
  - Assembling constraint bundles
  - Providing market notifications (CAN's)
  - Preparing information for control centres (Grid Plans)
  - Co-ordinating Regional Operating Centre switching plans



# Regional Security Forums

- Change in SO role from Facilitator to Co-ordinator
  - Identified security risk situations
  - Multiple parties involved
  - POCP provides impartial & transparent process
- Successful approach to managing specific issues
  - Upper NI Summer / Winter
  - Upper SI TTU program
- Draft Policy Statement defines criteria for convening forums.



# Summary of Issues

- Changing environment
  - Interdependency of parties
  - Increased number of outages, complexity, difficulty, & re-planning of outages
  - Uncertain system conditions beyond the short term (0-10 weeks)
- Enhanced level of performance or step change required?
  - Additional resource unlikely to provide solution
  - Process redesign / Technology change
  - Increased regulatory requirements on outage plans (part F changes)

