QUARTERLY SYSTEM OPERATOR AND SYSTEM PERFORMANCE REPORT

FOR THE ELECTRICITY AUTHORITY

Transpower New Zealand Limited

July to September 2017

Keeping the energy flowing




TRANSPOWER

Report Purpose

This report is Transpower's review of its performance as system operator for Q1 (July to September) 2017, in accordance with clause 3.14 of the Electricity Industry Participation Code 2010 (the Code).

As this is the final self-review report of the quarter, additional information is included as per SOSPA clause 12.3. This includes performance against the performance metrics in the year to date, and actions taken in regards to the system operator business plan, statutory objective work plan, participant survey responses, and any remedial plan agreed under clause 14.1 (i). A summary of technical advisory services for the quarter is also provided.

A detailed system performance report (Code obligated) is provided for the information of the Electricity Authority (Authority).

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Commentary

This section highlights successful management of significant events and operational issues by the system operator. It provides additional commentary (not Code or SOSPA required) relating to aspects of system operator performance or system performance. The remainder of the report provides supporting detail (which is Code or SOSPA required) in two sections:

- System operator performance, and
- System performance.

We hosted four new Authority Board members with a tour of Haywards and NCCW during August. This was followed by the regular Authority SOC (System Operations Committee) meeting at Transpower House. Discussion included review of dry year policies, the South Australian blackout findings and review of the SO capital plan.

System operator performance

1 Compliance

July

The system operator reported no breaches of the Code in July.

August

Three breaches were reported in August, two were manual errors related to Special Protection Scheme rating changes during outages, the other was an error in notification timeframe sent to a participant.

September

In September Transpower as system operator reported two breaches of the Code:

- In July an outage at Matahina was modelled incorrectly causing an incorrect zero price to be generated for the Matahina Grid Exit Point. A participant claimed a pricing error and the input was changed to resolve the error, resulting in no market impact.
- In August a planned outage of Bunnythorpe transformers coincided with an unplanned outage of Mangahao generation, requiring market system constraints to be applied in real time. While adjusting the constraints to match system conditions a co-ordinator mistakenly made an incorrect adjustment, which caused an error in pricing. Transpower claimed the pricing error and resolved the issue, again preventing a market impact.

Appendix A shows instances where the system operator has applied discretion under 13.70 of the Code.

2 Market design and system enhancement project updates

Progress against in-flight market design and service enhancement projects is included below along with details of any variances from the current Capex Plan.

Efficient Procurement of Extended Reserves

Majority of the project is on hold pending the recommendation on options from the Authority board. In the meantime, Transpower continues to support the Authority with input and options assessment.

Transpower continues to work on the capital component of this work to make changes to the Reserve Management Tool (RMT) and developing a tool to support extended reserves block data collection. The approved capital project underway deviates from the current Capex Plan with an increased approved capital cost (approved $525k against Capex Plan of $195k). Although the approved completion date currently aligns with the Capex Plan, this is now at risk given the delays in confirming direction and options.

Real Time Pricing

A consultation paper on the real time pricing proposal to determine and publish final process for the spot market in real-time was released in August and two industry workshops were held (Auckland and Wellington). The consultation period was extended by two weeks to ensure industry has adequate time to consider the proposal.

We continued to work with the Authority, providing advice throughout the consultation process. Planning commenced for the next phase which will refine the requirements, confirm the solution and develop the capital business case. Time and cost of this work aligns with the current Capex Plan.

EDF Phase III

This project will replace the aging inter-party dispatch interfaces with new interfaces able to be supported and to enable new dispatch products in the future. The Authority approved Transpower proceeding with the project and the internal business case was approved. Start-up of the capital project has now commenced. Time and cost of this work aligns with the current Capex Plan.

Sensitivity Schedules

The Sensitivity Schedules initiative was developed following industry feedback where there was a desire to obtain price sensitivity information based on variability of the forward looking forecast schedules. Analysis has been completed demonstrating a positive net benefit. This initiative was originally intended to be a ‘service enhancement’ however, there has been synergies identified with the Load Forecast Improvement project now being established by the Authority. This ‘service enhancement’ project has now been put on hold, with the scope being migrated across to the Load Forecast Improvement ‘market design’ project. Although time and cost of this work align with the current Capex Plan, this project will now be aligned with the Load Forecast Improvement project and therefore will be removed from the Capex Plan.

3 Performance metrics

The following dashboard shows system operator performance against the performance metrics for the financial year during Q1 as required by SOSPA 12.3 (a). Overall the system operator are exceeding performance metric targets to date; taking into account the fact that some metrics are unable to be measured this early in the year.

TRANSPOWER — SO Service Dashboard — Sep-17

CRITICAL SUCCESS FACTORS	MONTHLY PERFORMANCE			YTD PERFORMANCE
	Trend	% of Monthly Baseline	Monthly Actual	YTD Progress vs. Baseline Target
Our customers are informed and satisfied		-100% 0% 100% 200%	0%	0% 20% 40% 60% 80% 100% 120% Baseline target is 100%, 500% YTD
We maintain Code compliance and meet our contract obligations		-100% 0% 100% 200%	125%	0% 20% 40% 60% 80% 100% 120% Baseline target is 100%, 105% YTD
We deliver projects successfully		-100% 0% 100% 200%	-	0% 20% 40% 60% 80% 100% 120% Baseline target is 100%, X% YTD
We are committed to optimal real time operation		-100% 0% 100% 200%	113%	0% 20% 40% 60% 80% 100% 120% Baseline target is 100%, 113% YTD
Our people are engaged and competent		-100% 0% 100% 200%	-	0% 20% 40% 60% 80% 100% 120% Baseline target is 100%, X% YTD
Our tools and technologies are fit for purpose		-100% 0% 100% 200%	97.93%	0% 20% 40% 60% 80% 100% 120% Baseline target is 100%, 98.09% YTD

How to read this dashboard:

YTD PERFORMANCE

YTD Progress vs Baseline target

0% 20% 40% 60% 80% 100% 120%

- Shows year-to-date progress vs. baseline as %
- RAG criteria are the same for all metrics

<80% | 80%<95% | >95%

MONTHLY PERFORMANCE

Trend | % of Monthly Target | Monthly Actual

-100% 0% 100% 200% 2

% completed compared to monthly baseline (in this case 2 completed v. 2 planned this month)

Monthly trend based on monthly actual

4 Actions taken

The following table contains a full list of actions taken during Q1 regarding the system operator business plan, statutory objective work plan, participant survey responses and any remedial plan, as required by SOSPA 12.3 (b).

Item of interest	Actions taken
(i) To give effect to the **system operator business plan**:	• Completed Solar PV investigation project reports • Delivered draft SO Service Capex Plan and Roadmap • Delivered SO Annual-Self Review and Assessment • Completed scoping and literature review for Energy Storage Systems • Approved Tighter Grid Management Roadmap and commenced development of Special Protection Scheme management enhancements • Collaborated with Grid and ICT to complete SCADA/EMS Lifecycle Refresh
(ii) To comply with the **statutory objective work plan**:	**Policy and procedure alignment with CRE** Over this period 24 documents have been checked against CRE. **Review of SOSFIP** Commenced analysis of treatment of contingent storage. This will inform the extent of any changes required to the SOSFIP. **Review of the Security Policy – Interconnecting transformers** The Review will commence in Quarter 2. **Review performance metrics and implement performance dashboard** Implemented performance dashboard on 11 August.
(iii) In response to participant responses to any **participant survey**:	N/A – Participant survey is yet to occur.
(iv) To comply with any **remedial plan** agreed by the parties under SOSPA 14.1 (i):	N/A – No remedial plan in place.

5 Cost-of-services reporting

The feasibility study into implementing annual cost-of-services reporting to the Authority is required in financial year 2 (SOSPA 12.6 refers). We completed our investigation of the feasibility of cost of service reporting and presented our findings to the Authority in early September. We are awaiting feedback from the Authority.

6 Technical advisory hours and services

The following table provides the technical advisory hours for Q1 and a summary of technical advisory services to which those hours related (SOSPA 12.3 (d) refers).

TAS Statement of Work (SOW)	Status	Hours worked during Q1
TAS SOW 65 – Assessment of implementing the load aggregator participant type and block demand dispatch	In Progress	11.50
TAS SOW 66 – Investigation of potential reforms of voltage support ancillary service	Closed	12.50
TAS SOW 69 – RTP Consultation Support	In Progress	54.00
TAS SOW 70 – EPER: Project Support September 2017	In Progress	30.50
Total hours		**108.50**

7 Separation of Transpower roles

As system operator, Transpower has not been materially affected by any other role or capacity Transpower has under the Code or under any agreement.

System performance

8 Operational and system events

July

The combination of the dry winter and a severe cold weather event set three new power system records. There were two power system events, one related to severe weather.

On 13 July, the heavy snow event on the central plateau of the North Island resulted in outages on the 110 kV central North Island network with a loss of service to Ohakune, National Park for part of the day and a longer one day sustained loss of supply to Mataroa. Total load lost was 9 MW. The extended outage at Mataroa was due to limited access to identify the cause of the loss and then to repair broken conductors. The impact of the outages was mitigated by significant damage with the local distribution networks supplied from these GXP's.

There was a 25 MW loss of supply to parts of Nelson on 13 July when Stoke Transformer T6 tripped. The local distribution network back fed the lost demand until full supply from Stoke was available.

August

Pole 3 was taken out of service for three hours on 3 August for urgent maintenance. Pole 2 remained in operation, though with monopole operation the national frequency sharing and market arrangements were unavailable and transfers restricted to 500MW north (slightly less, south). No material operational issues arose during the outage.

Several short notice outages of Islington (ISL) bus sections were required on 28-29 August due to a number of stuck disconnectors on the 220 kV bus. These outages were well managed by coordinators who were required to plan for unusual disconnector configurations (i.e. buses tied via disconnectors).

September

A major loss of SCADA control capability occurred on 16 September. Market dispatch continued normally but no SCADA indications or control actions were available for a little over two and a half hours. A response team was quickly established to understand and correct the problem and a full incident review is underway.

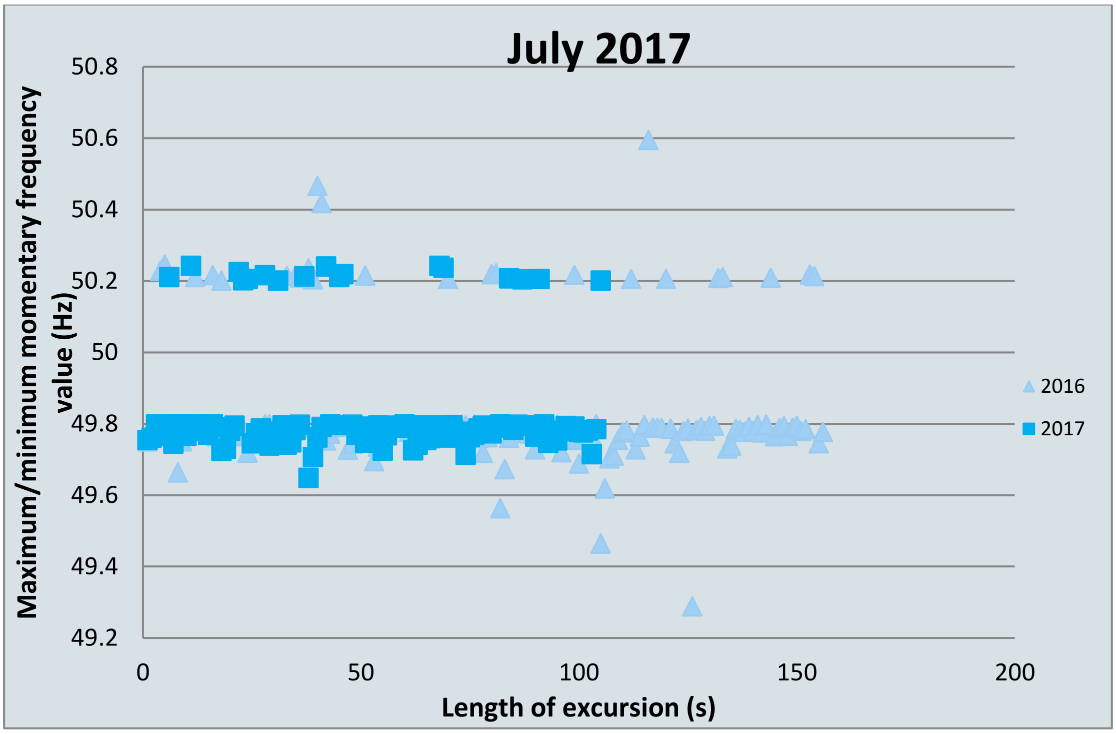
Two minor loss of supply events occurred during September:

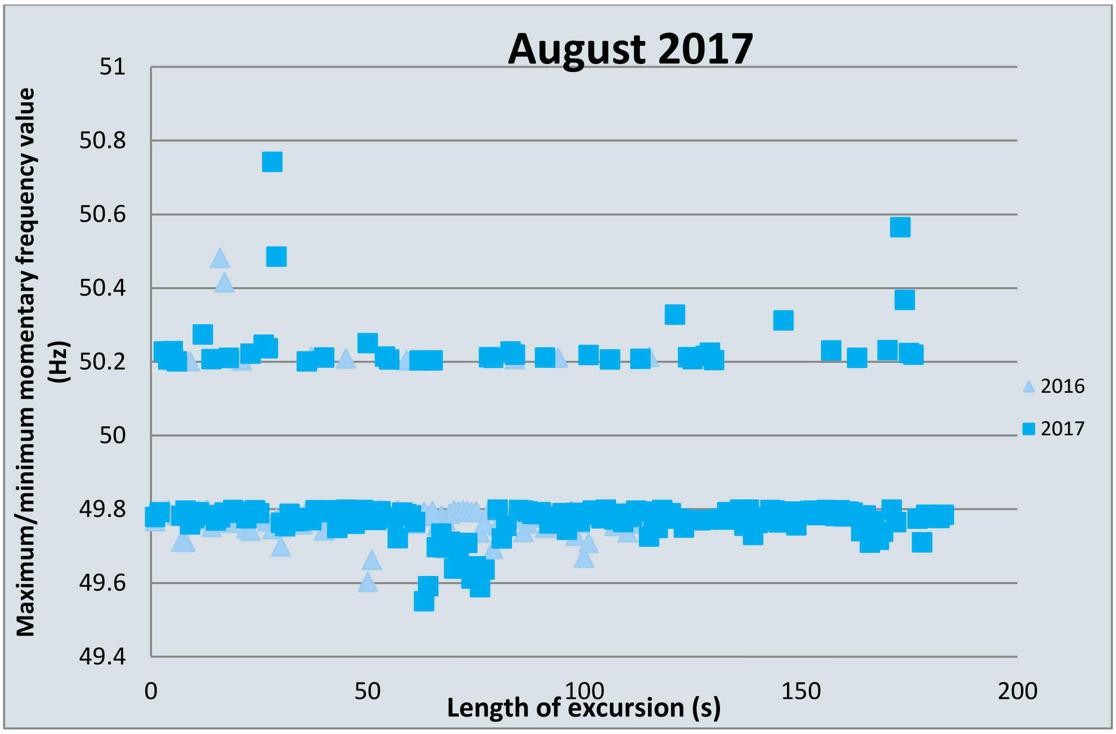
- On 11 September the Fernhill 110 kV bus tripped resulting in the loss of 38 MW. Restoration was interrupted by a further trip, with a successful restore commencing around half an hour later. Impacts were limited by Unison's ability to supply via Whakatu.
- The second was on 20 September when Stoke T6 and 33 kV bus B1 tripped, shedding 36 MW. Customer service was quickly resumed by supply through other Network Tasman feeders.

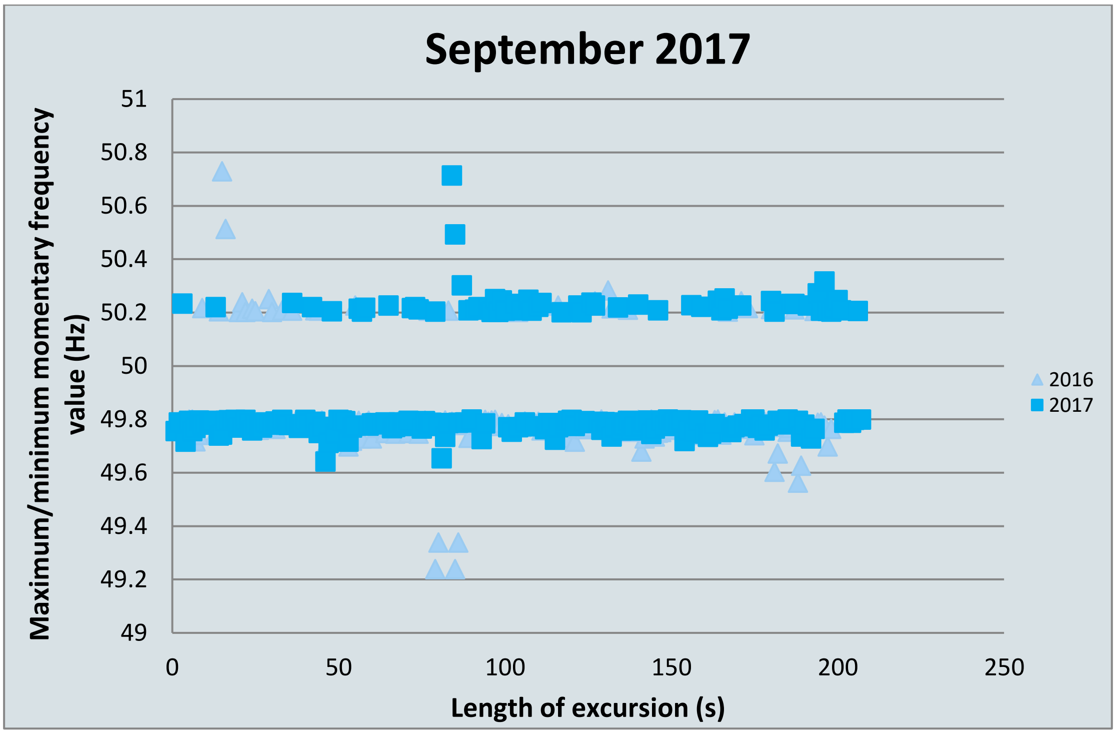
9 Frequency fluctuations

9.1 Maintain frequency in normal band and recover quickly from a fluctuation

The following charts show the maximum or minimum frequency reached and length of each frequency excursion outside the normal band (49.8 to 50.2 Hz) during the reporting period.




August 2017
Maximum/minimum momentary frequency value (Hz)
51
50.8
50.6
50.4
50.2
50
49.8
49.6
49.4
0
50
100
150
200
Length of excursion (s)
2016
2017


September 2017
Maximum/minimum momentary frequency value (Hz)
51
50.8
50.6
50.4
50.2
50
49.8
49.6
49.4
49.2
49
0
50
100
150
200
250
Length of excursion (s)
2016
2017

9.2 Maintain frequency and limit rate occurrences during momentary fluctuations

The tables below show the total number of momentary fluctuations outside the frequency normal band, recorded in each island, for each month over the last 12 months and the 12 month cumulative totals, grouped by frequency band.

North Island

Frequency Band	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Annual rate
55.00 > Freq >= 53.75													
53.75 > Freq >= 52.00													
52.00 > Freq >= 51.25													
51.25 > Freq >= 50.50													
50.50 > Freq >= 50.20	25	29	24	22	11	10	8	16	22	6	22	31	**226**
50.20 > Freq > 49.80													
49.80 >= Freq > 49.50	68	70	42	45	30	52	55	59	42	52	92	89	**696**
49.50 >= Freq > 48.75	1		1	2		1			3				**8**
48.75 >= Freq > 48.00													
48.00 >= Freq > 47.00													
47.00 >= Freq > 45.00													

South Island

Frequency Band	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Annual rate
55.00 > Freq >= 53.75													
53.75 > Freq >= 52.00						1							**1**
52.00 > Freq >= 51.25													
51.25 > Freq >= 50.50	1		1	1	1	1	1	1	1		2	1	**11**
50.50 > Freq >= 50.20	8	16	8	12	9	7	16	18	28	11	17	28	**178**
50.20 > Freq > 49.80													
49.80 >= Freq > 49.50	17	31	17	22	19	27	29	33	45	36	50	58	**384**
49.50 >= Freq > 48.75		1							3				**4**
48.75 >= Freq > 48.00						1							**1**
48.00 >= Freq > 47.00						1							**1**
47.00 >= Freq > 45.00													

Note: Frequency excursions for March include simultaneous over-frequencies and under-frequencies that occurred when the South Island was split into two electrical islands on 2 March.

9.3 Manage time error and eliminate time error once per day

There were no time error violations in the reporting period.

10 Voltage management

Grid voltages momentarily exceeded the Code voltage ranges at Dobson, Kumara, and Greymouth on 25 September at 05:28 following the tripping of the Kikiwa Static Synchronous Compensator STC2. The Dobson inter-connecting transformers were tapped to restore voltages to within the Grid Owner's limits agreed with customers. This is currently under investigation by Transpower as Grid Owner as part of an internal investigation process.

11 Security notices

The following table shows the number of Warning Notices, Grid Emergency Notices and Customer Advice Notices issued over the last 12 months.

Notices issued	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17
Demand Allocation Notice	-	-	-	-	-	-	-	-	-	-	-	-
Grid Emergency Notice	2	-	-	-	4	1	1	1	-	-	1	-
Warning Notice	-	-	-	-	-	-	-	-	-	-	-	2
Customer Advice Notice	12	26	7	11	7	24	10	16	23	2	6	6

12 Grid emergencies

The following table shows grid emergencies declared by the system operator from July to September.

Date	Time	Summary Details	Island
July		None.	
08-Aug-17	19:30	A Grid Emergency was declared to allow the Arapuni 110 kV split to be closed following the tripping of 220 kV Atiamuri-Whakamaru Circuit 1.	N
September		None.	

13 Security of supply

The security of supply situation has continued to improve since returning to 'Normal' status at the end of July. Above average inflows in August and September saw overall hydro storage increase from 64% of average at the start of August, to 88% at the start of September. Current hydro storage levels were at 121% of average as at 1 October.

Over the last four weeks the contribution of hydro to the generation mix has continued to rise, with thermal generation falling. This signals an end to the dry-winter generation behaviour.

14 Ancillary services

The tender process is underway and covers frequency keeping, instantaneous reserve and black start contracts for the North Island.

Two market participants in the North Island are looking to offer reserves. Assessment of the test results and how these would be modelled are on-going.

Refer Appendix B for Ancillary Services Graphs.

Appendix A: Discretion

July

Event Date & Time	Event Description
3/7/2017 5:51:00 PM	WGN0331. In-period update to offered IL capability.
12/7/2017 8:19:40 PM	WHI2201 WHI0. To ensure secure solution. RTD alternating between WHI being dispatched on, then off, solution infeasible without WHI when dispatched on, takes 10 minutes to start.
13/7/2017 10:17:45 AM	WHI2201 WHI0. NI Load still rising and 10MW minimum required.
31/7/2017 8:22:23 PM	WHI2201 WHI0. Required for Secure Dispatch due to RTD oscillations.
31/7/2017 8:41:34 PM	WHI2201 WHI0. Required for Secure Dispatch due to RTD oscillations.

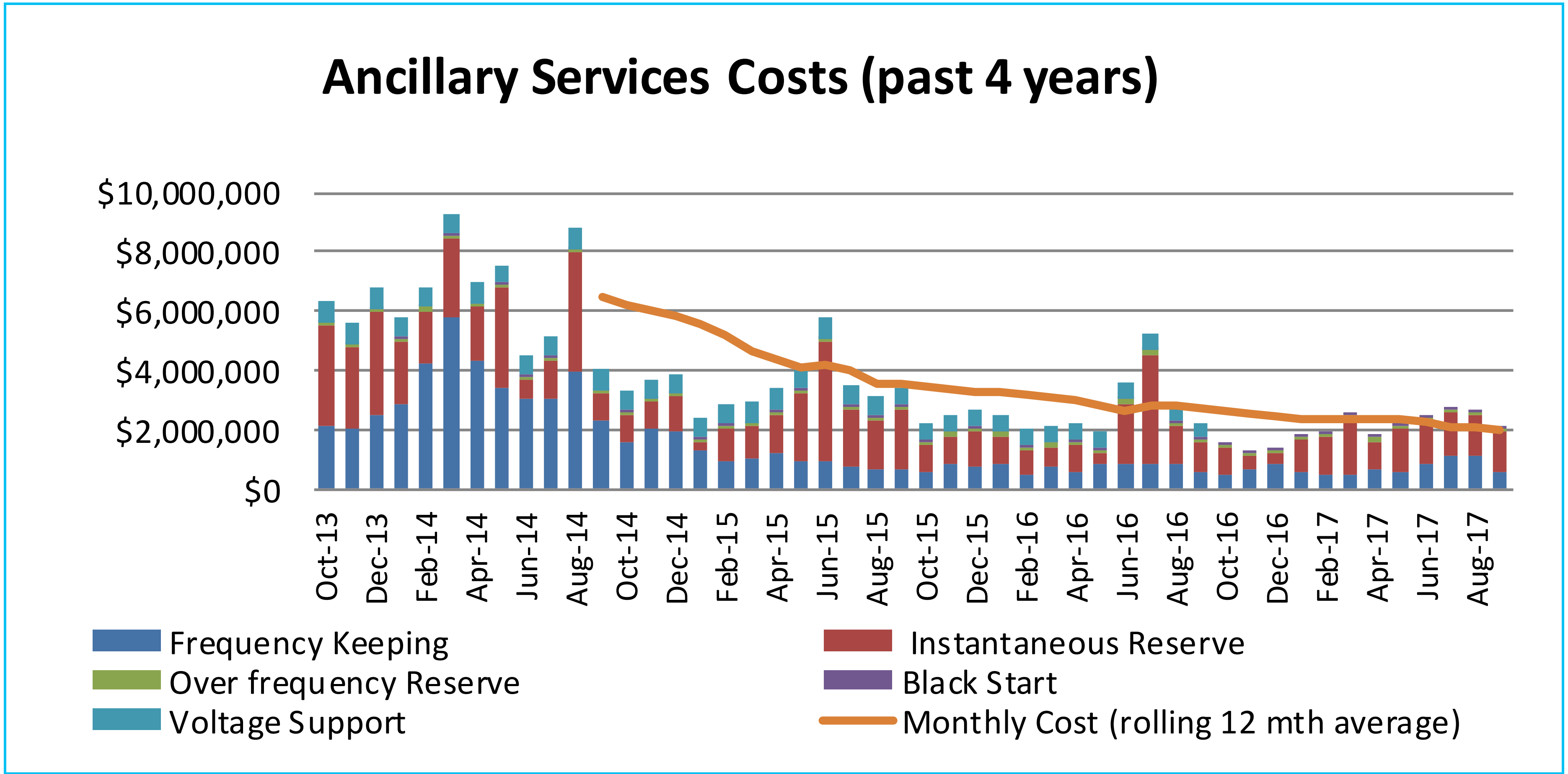
August

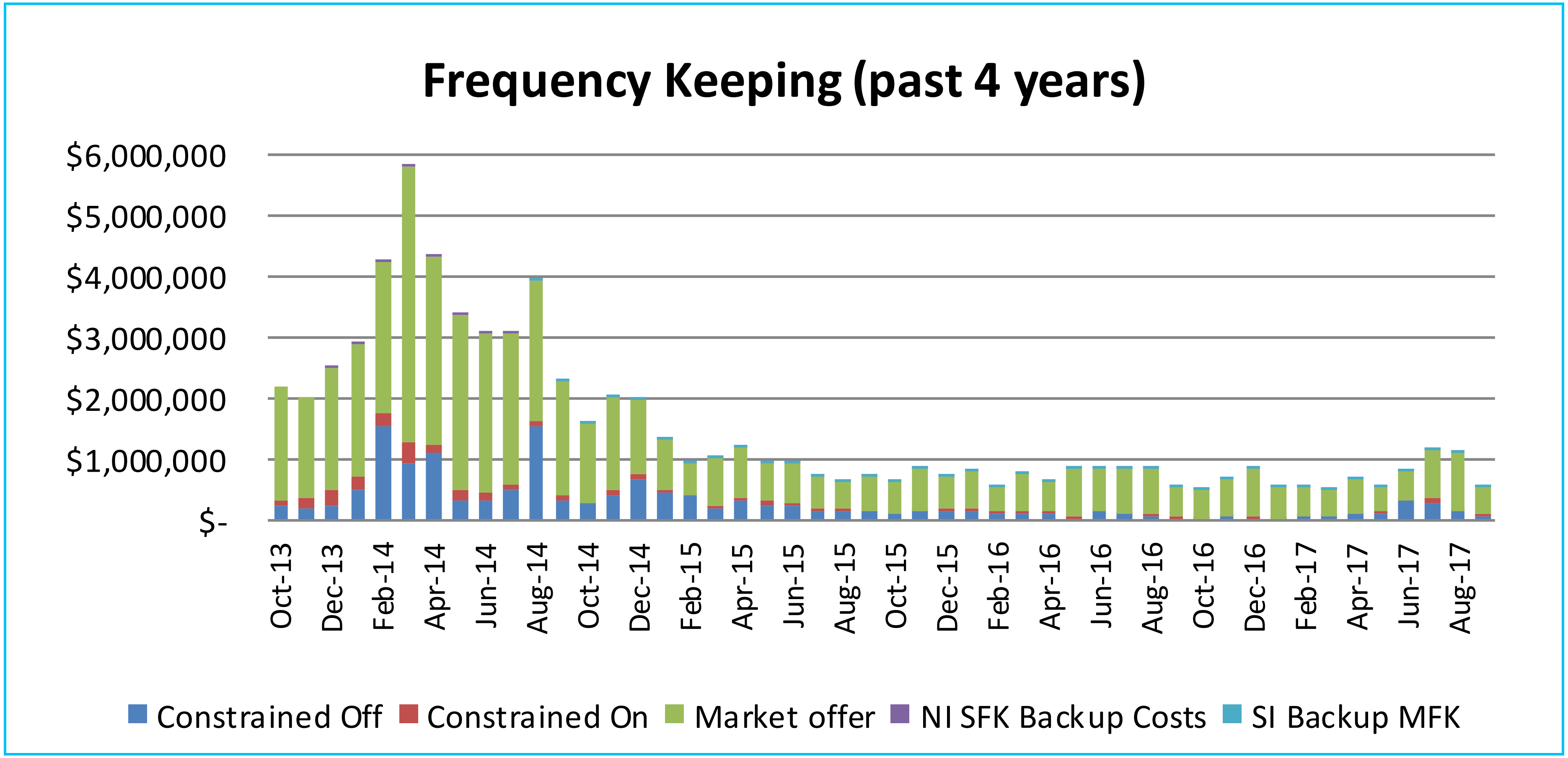
Event Date & Time	Event Description
8/8/2017 1:30:23 AM	MAN2201 MAN0. Restoration of emergency potline - Line 3.
15/8/2017 6:40:26 PM	WGN0331. In-period update to offered capability.
16/8/2017 3:57:43 AM	MKE1101 MKE1. Tripped, caused by system event. In-period update to offered capability.
23/8/2017 7:36:44 AM	WHI2201 WHI0. Required for system security of supply for the morning peak.
30/8/2017 11:50:28 AM	MAN2201 MAN0. Line 2 185MW extended potline return.

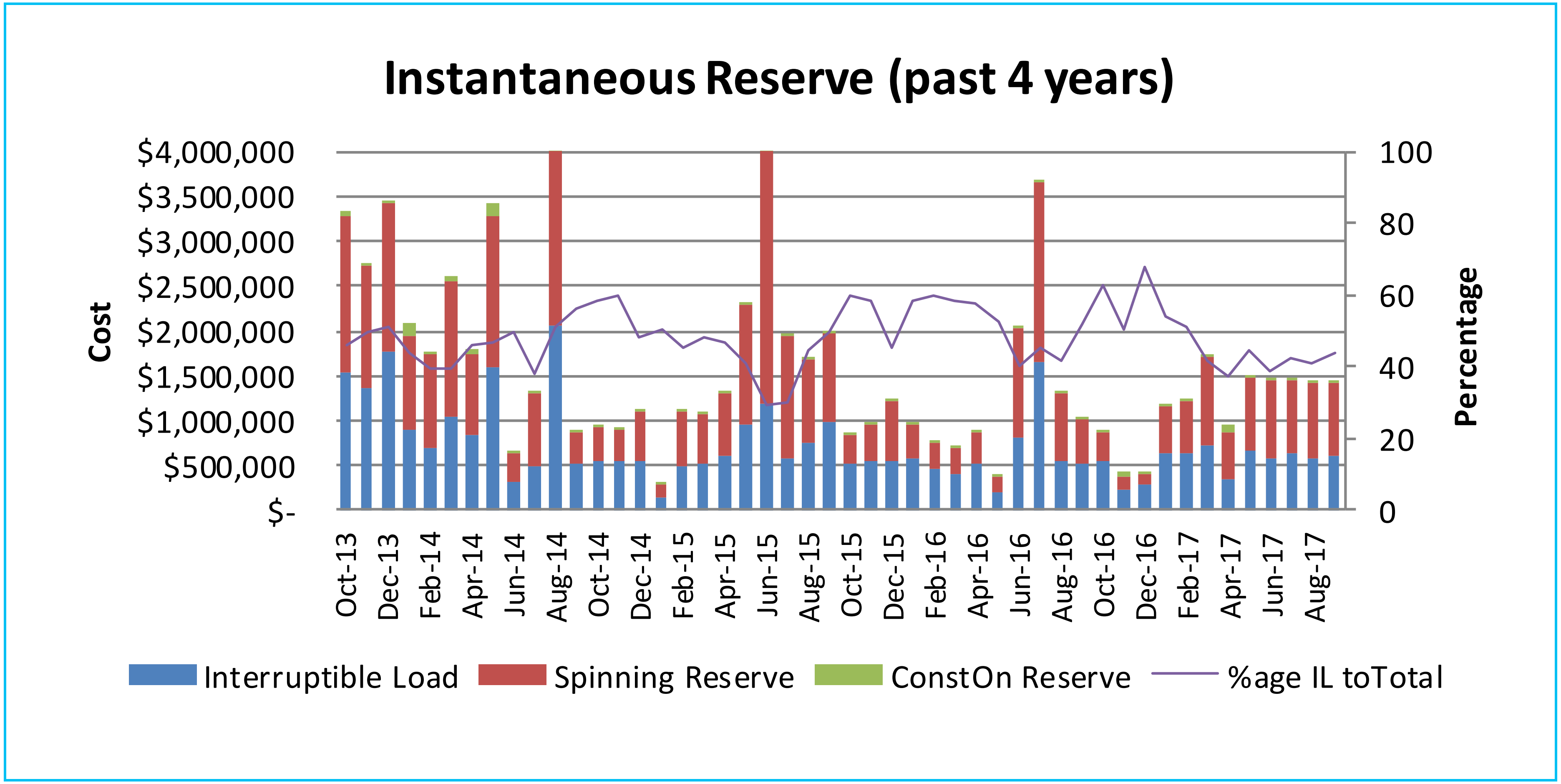
September

Event Date & Time	Event Description
6/9/2017 7:57:51 PM	MKE1101 MKE1. Tripped off due to system event. Energy Co-ordinator called NOVA Trader to advise that the Dispatcher Discretion will run through to 20:30 and after that they will need to connect or use some other market mechanism if they are unable to comply.
6/9/2017 9:34:25 PM	MKE1101 MKE1. Lightning caused circuit to trip.
11/9/2017 9:56:38 AM	TUI1101 TUI0. Real-time contingency violation of Redclyffe-Tuai 1 or 2, Fernhill bus fault.
14/9/2017 11:58:37 AM	MAN2201 MAN0. Extended potline restoration.
25/9/2017 8:39:16 AM	MAN2201 MAN0. Extended potline restoration.

Appendix B: Ancillary Services Graphs




Frequency Keeping (past 4 years)
$6,000,000
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000
$-
Oct-13
Dec-13
Feb-14
Apr-14
Jun-14
Aug-14
Oct-14
Dec-14
Feb-15
Apr-15
Jun-15
Aug-15
Oct-15
Dec-15
Feb-16
Apr-16
Jun-16
Aug-16
Oct-16
Dec-16
Feb-17
Apr-17
Jun-17
Aug-17
Constrained Off
Constrained On
Market offer
NI SFK Backup Costs
SI Backup MFK


Instantaneous Reserve (past 4 years)
Cost
$4,000,000
$3,500,000
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$-
100
80
60
40
20
0
Percentage
Oct-13
Dec-13
Feb-14
Apr-14
Jun-14
Aug-14
Oct-14
Dec-14
Feb-15
Apr-15
Jun-15
Aug-15
Oct-15
Dec-15
Feb-16
Apr-16
Jun-16
Aug-16
Oct-16
Dec-16
Feb-17
Apr-17
Jun-17
Aug-17
Interruptible Load
Spinning Reserve
ConstOn Reserve
%age IL toTotal