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Appendix 2 Market Rules Reporting Requirements

1.1 Summary of Requirements

Clause 2.16.11 of the Market Rules sets out a requirement for the Report to the Minister to report on the effectiveness of the market in dealing with the matters identified in clauses 2.16.9 and 2.16.10 of the Market Rules.[1] In addition, clause 2.16.12 of the Market Rules sets out further requirements for the Report to the Minister. These requirements are set out in Table 1 below, together with a reference to where the analysis can be found in this report.

Table 1 Reporting requirements under the Market Rules

Market Rule clause	Market Rule reporting requirement	See report section
2.16.9 (a)	Monitoring of Ancillary Services Contracts	App 2 sec 1.6
2.16.9 (b)	Monitoring of inappropriate and anomalous market behaviour	App 2 sec 1.13
2.16.9 (c)	Monitoring of market design problems or inefficiencies	Exec Summary
2.16.9 (d)	Monitoring of problems with the structure of the market	Exec Summary
2.16.10 (a)	Effectiveness of the Market Rule change process and Procedure change process	App 2 sec 1.9
2.16.10 (b)	Effectiveness of the compliance monitoring and enforcement measures in the Market Rules and Regulations	App 2 sec 1.12
2.16.10 (c)	Effectiveness of the IMO in carrying out its functions under the Regulations, the Market Rules and Market Procedures	App 2 sec 1.7
2.16.10 (d)	Effectiveness of System Management in carrying out its functions under the Regulations, the Market Rules and Market Procedures	App 2 sec 1.8
2.16.12 (a)	Summary and analysis of the Market Surveillance Data Catalogue	Table 2
2.16.12 (b)	Effectiveness of the market	Exec Summary
2.16.12 (b) i.	Effectiveness of the Reserve Capacity market	Exec Summary
2.16.12 (b) ii.	Effectiveness of the market for Bilateral Contracts for capacity and energy	App 2 sec 1.3
2.16.12 (b) iii.	Effectiveness of the Short Term Energy Market	App 2 sec 1.4
2.16.12 (b) iv.	Effectiveness of Balancing	Exec Summary
2.16.12 (b) v.	Effectiveness of the dispatch process	App 2 sec 1.10
2.16.12 (b) vi.	Effectiveness of planning processes	App 2 sec 1.11
2.16.12 (b) vii.	Effectiveness of the administration of the market, including the Market Rule change process	Exec Summary
2.16.12 (b) viii.	Effectiveness of the Ancillary Services	Exec Summary

[1] Pursuant to clause 2.16.11 of the Market Rules, the report must be produced at least annually, or more frequently where the Authority considers that the WEM is not effectively meeting the Wholesale Market Objectives.

Market Rule clause	Market Rule reporting requirement	See report section
2.16.12 (c)	Assessment of any specific events, behaviour or matters that impacted on the effectiveness of the market	Exec Summary
2.16.12 (d)	Any recommended measures to increase the effectiveness of the market in meeting the Wholesale Market Objectives to be considered by the Minister	Exec Summary

As set out above, clause 2.16.12 (a) requires a summary of the information and data compiled by the IMO and the Authority under clause 2.16.1. These requirements are set out in Table 2 below, together with a reference to where the information and data can be found in this report.

Table 2 MSDC data and analysis requirements under the Market Rules

Market Rule clause	Market Rule reporting requirement	See report section
2.16.2(a)	The number of Market Generators and Market Customers in the market	Table 7
2.16.2(b)	The number of participants in each Reserve Capacity Auction	n/a
2.16.2(c)	Clearing prices in each Reserve Capacity Auction and STEM Auctions	Figures 3, 4
2.16.2(d)	LFAS Submissions	Figures 21, 22
2.16.2(dA)	All Reserve Capacity Auction offers	n/a
2.16.2(f)	All STEM Offers and STEM Bids, including both quantity and price terms	Figures 27-67
2.16.2(gA)	All Fuel Declarations	Table 5
2.16.2(gB)	All Availability Declarations	Figure 68
2.16.2(gC)	All Ancillary Service Declarations	Figure 69
2.16.2(h)	Any substantial variations in STEM Offer and STEM Bid prices or quantities relative to recent past behaviour	Figures 27-67
2.16.2(hB)	The information in clause 7A.2.18(c) (i.e., any information as to whether a Facility was not able to comply with a Dispatch Instruction from System Management and the reasons for that non-compliance)	App 2 sec 1.10
2.16.2(j)	The frequency and nature of Dispatch Instructions and Operating Instructions to Market Participants	App 2 sec 1.10
2.16.2(k)	The number and frequency of outages of Scheduled Generators and Non-Scheduled Generators, and Market Participants' compliance with the outage scheduling process	App 2 sec 1.2
2.16.2(l)	The performance of Market Participants with Reserve Capacity Obligations in meeting their obligations	App 2 sec 1.2
2.16.2(m)	Details of Ancillary Service Contracts that System Management enters into	App 2 1.6
2.16.2(n)	All LFAS Prices	Figure 20
2.16.2(o)	The number of Rule Change Proposals received, and details of Rule Change Proposals that the IMO has decided not to progress under clause 2.5.6	Table 4
2.16.2(p)	Such other items of information as the IMO considers relevant to the functions of the IMO and the Economic Regulation Authority under this clause 2.16.	-
2.16.4(a)	Where applicable, calculation of the means and standard deviations of values in the Market Surveillance Data Catalogue	-
2.16.4(b)	Monthly, quarterly and annual moving averages of prices for the STEM Auctions, the Balancing Market and the LFAS Market	Figures 3,4,12,13,20
2.16.4(c)	Statistical analysis of the volatility of prices in the STEM Auctions, the Balancing Market and the LFAS Market	Figures 5,6,16,17,23-26
2.16.4(cA)	Any consistent or significant variations between the Fuel Declarations, Availability Declarations, and Ancillary Service	App 2 sec 1.13

Market Rule clause	Market Rule reporting requirement	See report section
	Declarations for, and the actual operation of, a Market Participant facility in real-time	
2.16.4(d)	The proportion of time the prices in the STEM Auctions and through Balancing are at each Energy Price Limit	Figures 7,8,18,19
2.16.4(e)	Correlation between capacity offered into the STEM Auctions and the incidence of high prices	App 2 sec 1.4
2.16.4(f)	Correlation between capacity offered into and made available in the Balancing Market and the incidence of high prices	App 2 sec 1.5
2.16.4(fA)	Correlation between capacity offered into and made available in the LFAS Market and the incidence of high prices	App 2 sec 1.6
2.16.4(g)	Exploration of the key determinants for high prices in the STEM, in Balancing, in the Balancing Market and in the LFAS Market, including determining correlations or other statistical analysis between explanatory factors that the IMO considers relevant and price movements	App 2 sec 1.4, 1.5, 1.6
2.16.4(h)	Such other analysis as the IMO considers appropriate or is requested of the IMO by the Economic Regulation Authority	-

1.2 Reserve Capacity Mechanism

The Reserve Capacity Mechanism (**RCM**) has been in operation since 2005. The primary objective of the RCM is to ensure that there is sufficient generation and DSM capacity to meet system reliability and adequacy requirements.

The Authority notes that there has been sufficient capacity secured under the RCM to meet forecast capacity requirements, with the number of Capacity Credits[2] assigned to participants exceeding the Reserve Capacity Requirement (**RCR**) in each of the Capacity Years since its inception.

Performance in meeting Reserve Capacity obligations

The performance of Market Participants with Reserve Capacity obligations is assessed by comparing the quantity of a Facility's Forced Outages and Planned Outages to the maximum generating capacity of the Facility, as registered by the IMO.

Table 3 below sets out, for each Facility, the average across all Trading Intervals of the capacity subject to outages, relative to the Facility's maximum generating capacity, for four periods i.e., the 2010/11 through 2013/14 Capacity Years.

In the previous Reporting Period, the most notable Forced Outage rates were recorded by the four Vinalco Muja facilities. The Forced Outage rates for these facilities were 99.5 per cent for Muja G1 and Muja G2, 50.2 per cent for Muja G3, and 38.2 per cent for Muja G4. All four facilities had much lower Forced Outage rates in the current Reporting Period, with Muja G1 dropping to 46.4 per cent, Muja G2 down to 35.3 per cent, Muja G3 with a reduced Forced Outage rate of 4.8 per cent, and Muja G4 with 5.2 per cent. Only one other facility had a Forced Outage rate higher than 10 per cent and that was Alcoa's Wagerup facility which had a forced outage rate of 25.6 per cent, up from 3.2 per cent in the previous period.

Out of Synergy's 16 facilities with generating capacity greater than 100 MW, seven had lower Planned Outage rates than the previous Reporting Period. The most notable improvement was seen in the Muja G5 facility (decreasing from 33.2 per cent in 2012/13 to 2.3 per cent in 2013/14) and the Muja G6 facility (decreasing from 23.5 per cent in 2012/13 to 3.7 per cent in 2013/14). On the other hand the most notable increases in Planned Outage rates were from the Kemerton GT12 facility (increasing from 1.3 per cent in 2012/13 to 16 per cent in 2013/14) and the Muja G7 facility (increasing from 4.3 per cent in 2012/13 to 24.4 per cent in 2013/14). For Synergy's remaining generation (i.e. those with generating capacity less than 100 MW), five out of the 17 facilities displayed a deterioration in their Planned Outage rates.

Alinta's four facilities with generating capacity greater than 100 MW all had a higher planned outage rate in the current period compared to the previous period, with their Pinjarra U1 (16.1 per cent) and Pinjarra U2 (12.9 per cent) facilities both having planned outage rates higher than 10 per cent. Out of the remaining six IPP facilities with generating capacity greater than 100 MW, only Griffin Power's BW2 Bluewaters G1 facility had a higher planned outage rate than the previous period, with a planned outage rate of 10.9 per cent. No other IPP facility had a planned outage rate greater than 10 per cent.

[2] The RCM is built around the concept of a Capacity Credit, which is a notional unit of one megawatt (MW) of Certified Reserve Capacity provided by a generator or DSM provider. Capacity Credits have value and can be traded either bilaterally between Market Participants or with the IMO. In return for receiving Capacity Credits, generators are required to offer their capacity into the market at all times (unless undergoing scheduled maintenance on a Planned Outage).

Table 3 Ratio of quantities subject to outages to maximum generating capacity (1 October 2010 to 30 September 2014)

Participant	Resource Name	Max Gen (MW) 2010/11 Cap Year	Forced 2010/11 Cap Year	Planned 2010/11 Cap Year	Max Gen (MW) 2011/12 Cap Year	Forced 2011/12 Cap Year	Planned 2011/12 Cap Year	Max Gen (MW) 2012/13 Cap Year	Forced 2012/13 Cap Year	Planned 2012/13 Cap Year	Max Gen (MW) 2013/14 Cap Year	Forced 2013/14 Cap Year	Planned 2013/14 Cap Year
Alcoa	ALCOA_WGP	25.0	5.1%	10.3%	25.0	4.1%	29.5%	25.0	3.2%	21.6%	25.0	25.6%	9.9%
Alinta	ALINTA_PNJ_U1	145.0	0.2%	14.0%	145.0	0.1%	4.3%	145.0	0.0%	6.1%	143.0	0.5%	16.1%
Alinta	ALINTA_PNJ_U2	145.0	0.1%	7.0%	145.0	0.2%	11.6%	145.0	0.3%	1.7%	143.0	0.3%	12.9%
Alinta	ALINTA_WGP_AGG	380.0	0.0%	0.8%									
Alinta	ALINTA_WGP_GT	190.0	1.3%	1.8%	190.0	0.0%	2.1%	190.0	0.4%	2.5%	190.0	0.0%	7.6%
Alinta	ALINTA_WGP_U2	190.0	0.0%	2.9%	190.0	0.4%	1.7%	190.0	1.2%	3.3%	190.0	0.8%	7.0%
Alinta	ALINTA_WWF				89.1	0.0%		89.1	0.0%		89.1	0.0%	0.0%
Blair Fox Pty Ltd	BLAIRFOX_KARAFIN_WF1							5.0			5.0		
Blair Fox Pty Ltd	BLAIRFOX_WESTHILLS_WF3							5.0			5.0		
Denmark Community	DCWL_DENMARK_WF1							1.4			1.4		
EDWF Manager	EDWFMAN_WF1	80.0	0.0%	0.0%	80.0		0.0%	80.0	0.3%	0.0%	80.0	0.0%	0.1%
Goldfields Power	PRK_AG	68.0	1.4%	6.1%	68.0		0.5%	68.0		0.3%	68.0	0.1%	0.2%
Greenough River	GREENOUGH_RIVER_PV1							10.0			10.0	0.2%	0.2%
Griffin Power	BW1_BLUEWATERS_G2	217.0	1.2%	10.1%	217.0	5.8%	14.2%	217.0	2.3%	12.5%	217.0	1.9%	8.0%
Griffin Power 2	BW2_BLUEWATERS_G1	217.0	2.4%	8.7%	217.0	1.6%	4.5%	217.0	0.2%	8.7%	217.0	1.1%	10.9%
COLLGAR	INVESTEC_COLLGAR_WF1				200.0	0.1%		206.0	0.0%	0.3%	206.0	0.0%	0.1%
Landfill Gas & Power	CANNING_MELVILLE	3.0	0.0%	0.0%	1.2			1.0			1.0		
Landfill Gas & Power	RED_HILL	3.3	0.0%	0.0%	4.0			3.8			3.8		
Landfill Gas & Power	KALAMUNDA_SG							1.3			1.3		
Landfill Gas & Power	TAMALA_PARK	4.5	0.0%	0.0%	5.0			4.8			4.8		
Merredin Energy	NAMKKN_MERR_SG1							82.0	1.4%	4.5%	82.0	0.5%	2.5%
Mt Barker Power	SKYFRM_MTBARKER_WF1							2.4			2.4		
Mount Heron	MHPS							1.4			1.4		
Mumbida Wind Farm	MWF_MUMBIDA_WF1							55.0			55.0		
NewGen Neerabup	NEWGEN_NEERABUP_GT1	342.0	0.0%	6.0%	342.0	0.1%	2.7%	342.0	0.0%	6.1%	342.0	0.0%	1.5%
NewGen Kwinana	NEWGEN_KWINANA_CCG1	324.0	0.9%	2.3%	324.0	0.2%	15.5%	324.0	0.3%	4.5%	324.0	0.7%	2.3%
Perth Energy	ATLAS							1.1			1.1		
Perth Energy	ROCKINGHAM							4.0			4.0		
Perth Energy	SOUTH_CARDUP							3.4			3.4		
Western Energy	PENERGY_KWINANA_GT1	116.0	0.1%	0.2%	116.0	1.9%	3.2%	116.0	0.3%	2.4%	116.0	0.0%	1.6%
Southern Cross	STHRNCRS_EG	23.0	0.0%	0.0%	23.0	0.7%	1.4%	23.0	3.0%	2.8%	23.0		

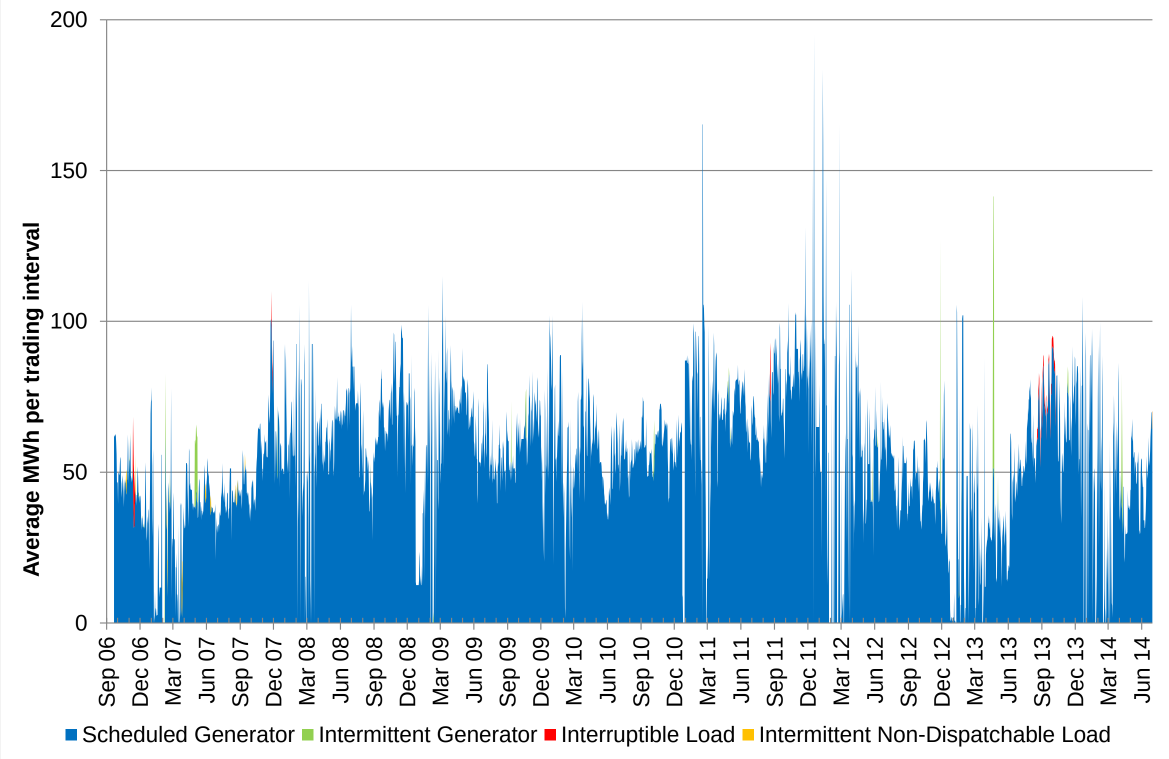
Participant	Resource Name	Max Gen (MW) 2010/11 Cap Year	Forced 2010/11 Cap Year	Planned 2010/11 Cap Year	Max Gen (MW) 2011/12 Cap Year	Forced 2011/12 Cap Year	Planned 2011/12 Cap Year	Max Gen (MW) 2012/13 Cap Year	Forced 2012/13 Cap Year	Planned 2012/13 Cap Year	Max Gen (MW) 2013/14 Cap Year	Forced 2013/14 Cap Year	Planned 2013/14 Cap Year
TESLA	TESLA_GERALDTON_G1				9.9		0.5%	9.9		27.4%	9.9		0.9%
TESLA	TESLA_KEMERTON_G1							9.9		9.1%	9.9		1.2%
TESLA	TESLA_NORTHAM_G1							9.9		4.7%	9.9		1.2%
TESLA	TESLA_PICTON_G1				9.9	0.3%	3.6%	9.9		1.6%	9.9		1.9%
Tiwest	TIWEST_COG1	37.7	1.2%	3.1%	36.0	0.1%	3.7%	39.7	1.2%	2.1%	39.7	7.0%	7.9%
Synergy	ALBANY_WF1	21.6	0.0%	0.2%	21.6		0.0%	21.6		0.0%	21.6		
Synergy	COCKBURN_CCG1	236.6	0.0%	17.5%	236.6	1.0%	4.8%	236.6	0.2%	2.8%	236.6	0.5%	9.4%
Synergy	COLLIE_G1	318.0	0.6%	14.7%	318.0	3.6%	11.7%	318.0	0.2%	9.0%	318.0	2.2%	7.1%
Synergy	GERALDTON_GT1	20.8	0.4%	0.3%	20.8	0.0%	4.2%	20.8	0.9%	11.4%	20.8		2.3%
Synergy	GRASMERE_WF1				13.8		0.0%	13.8		0.1%	13.8		
Synergy	KALBARRI_WF1							1.6			1.6		
Synergy	KEMERTON_GT11	154.0	0.0%	4.2%	154.0	0.1%	3.2%	154.0	0.0%	13.1%	154.0		0.9%
Synergy	KEMERTON_GT12	154.0	0.0%	15.7%	154.0		0.1%	154.0	0.5%	1.3%	154.0	0.2%	16.0%
Synergy	KWINANA_G1	111.5	5.2%	9.7%									
Synergy	KWINANA_G2	111.5	4.9%	16.9%									
Synergy	KWINANA_G5	177.0	0.0%	53.6%	177.0	0.4%	23.0%	180.0	8.4%	3.0%	180.0	2.7%	7.5%
Synergy	KWINANA_G6	177.0	2.5%	49.6%	177.0	1.4%	25.9%	184.0	2.3%	24.0%	184.0	2.1%	5.4%
Synergy	KWINANA_GT1	20.8	0.0%	21.9%	20.8		2.0%	20.8	0.1%	19.5%	20.8	1.2%	6.0%
Synergy	KWINANA_GT2				100.1	0.1%		100.1	2.5%	12.0%	100.1	1.1%	19.8%
Synergy	KWINANA_GT3				100.1	0.1%		100.1	3.8%	12.6%	100.1	4.4%	12.0%
Synergy	MUJA_G5	185.0	15.8%	18.7%	185.0	0.5%	13.9%	195.7	1.2%	33.2%	195.7	2.5%	2.3%
Synergy	MUJA_G6	185.0	0.4%	20.5%	185.0	4.1%	40.3%	190.8	1.0%	23.5%	190.8	5.4%	3.7%
Synergy	MUJA_G7	211.0	0.0%	42.9%	211.0	0.1%	5.5%	211.0	2.7%	4.3%	211.0	0.3%	24.4%
Synergy	MUJA_G8	211.0	1.9%	18.5%	211.0	0.4%	15.2%	211.0	4.5%	6.6%	211.0	0.5%	9.5%
Synergy	MUNGARRA_GT1	37.2	0.0%	5.4%	37.2	1.9%	0.4%	37.2		8.9%	37.2	0.7%	22.4%
Synergy	MUNGARRA_GT2	37.2	0.1%	0.7%	37.2	0.2%	6.4%	37.2	0.1%	1.6%	37.2	0.6%	7.6%
Synergy	MUNGARRA_GT3	38.2	1.5%	10.9%	38.2	0.0%	0.5%	38.2	1.1%	17.1%	38.2	1.4%	0.7%
Synergy	PINJAR_GT1	37.2	0.0%	7.4%	37.2	0.0%	0.1%	37.2	0.0%	5.3%	37.2		0.2%
Synergy	PINJAR_GT10	116.0	0.4%	10.4%	116.0	0.5%	27.9%	116.0	0.3%	21.7%	116.0	0.7%	21.8%
Synergy	PINJAR_GT11	123.0	0.1%	49.3%	123.0	0.1%	19.9%	123.0	0.2%	10.7%	123.0	0.2%	5.2%
Synergy	PINJAR_GT2	37.2	0.2%	5.2%	37.2		1.4%	37.2		9.6%	37.2	0.5%	0.2%
Synergy	PINJAR_GT3	38.2	0.3%	0.1%	38.2		12.7%	38.2		0.2%	38.2	0.0%	7.3%

Participant	Resource Name	Max Gen (MW) 2010/11 Cap Year	Forced 2010/11 Cap Year	Planned 2010/11 Cap Year	Max Gen (MW) 2011/12 Cap Year	Forced 2011/12 Cap Year	Planned 2011/12 Cap Year	Max Gen (MW) 2012/13 Cap Year	Forced 2012/13 Cap Year	Planned 2012/13 Cap Year	Max Gen (MW) 2013/14 Cap Year	Forced 2013/14 Cap Year	Planned 2013/14 Cap Year
Synergy	PINJAR_GT4	38.2	0.0%	1.7%	38.2		6.7%	38.2	0.2%	0.2%	38.2	0.2%	7.2%
Synergy	PINJAR_GT5	38.2	0.4%	7.8%	38.2	1.0%	1.0%	38.2		6.0%	38.2	0.0%	0.2%
Synergy	PINJAR_GT7	38.2	0.1%	0.2%	38.2	0.4%	5.9%	38.2	0.0%	0.3%	38.2	0.0%	9.8%
Synergy	PINJAR_GT9	116.0	0.0%	27.3%	116.0	0.1%	16.7%	116.0	0.2%	5.9%	116.0		6.3%
Synergy	PPP_KCP_EG1	85.7	0.0%	4.7%	85.7	0.0%	0.5%	85.7	0.9%	8.8%	85.7	0.1%	5.6%
Synergy	WORSLEY_COGEN_COG1	116.4	1.8%	17.1%	116.4		3.5%	116.4	0.5%	2.7%	116.4	0.1%	6.7%
Synergy	WEST_KALGOORLIE_GT2	38.2	0.1%	4.3%	38.2	1.0%	0.1%	38.2	0.2%	18.5%	38.2	2.2%	0.2%
Synergy	WEST_KALGOORLIE_GT3	24.6	0.0%	3.5%	24.6		19.7%	24.6	1.2%	5.5%	24.6	0.2%	0.2%
Vinalco Energy	MUJA_G1							55.0	99.5%		55.0	46.4%	3.8%
Vinalco Energy	MUJA_G2							55.0	99.5%		55.0	35.3%	0.3%
Vinalco Energy	MUJA_G3							55.0	50.2%	6.1%	55.0	4.8%	8.9%
Vinalco Energy	MUJA_G4							55.0	38.2%	11.4%	55.0	5.2%	1.8%
Waste Gas	HENDERSON_RENEWABLE_IG1	3.2	0.0%	0.0%	3.0	0.2%		3.0	0.2%		3.0		

*A Capacity Year starts 1 October and ends 30 September the following year. The Maximum Generating Capacity of each facility was sourced from the IMO's website. Planned and Forced Outages include full and partial ex-post outages for each facility for the Reporting Period. Blanks in the above table for some facilities denote that there are no Outages to be reported.

Figure **1** below illustrates the quantity of Planned Outages.

Figure 1 **Quantity of energy subject to Planned Outage (cumulative daily average MWh per Trading Interval)**



The average amount on Planned Outage was higher for each month of the current period compared to the corresponding month in the previous Reporting Period.

In particular, December 2013 had a much larger average per trading interval (75 MWh), compared to December 2012 (29 MWh). November 2013 also had a noticeable increase on average planned outage per trading interval compared to November 2012, increasing from 43 MWh to 70 MWh per trading interval. March 2014 had an average of 46 MW of Planned Outage per trading interval, up from 25 MW in March 2013.

Synergy's Collie G1 facility had the largest amount of planned outages across the first six months of the current period, comprising 14.4 per cent of the total planned outages during this period. There was a significant increase in planned outage for this facility compared to the same six month period of 2012, from a total of 1,226 trading intervals (representing a total of 181,529 MW) in the July 2012 to December 2012 period, to 2,939 trading intervals (a total of 860,791 MW) in the July 2013 to December 2013 period. This represented being on planned outage for 33 per cent of intervals across these months.

Synergy's Muja G5 and Pinjar GT10 also each contributed to over 10 per cent of the total planned outages for the July 2013 to December 2013 period. During this period, Muja G5 was on planned outage for 47.3 per cent of the time, whilst the Pinjar GT10 unit was on planned outage for 77.5 per cent of the time.

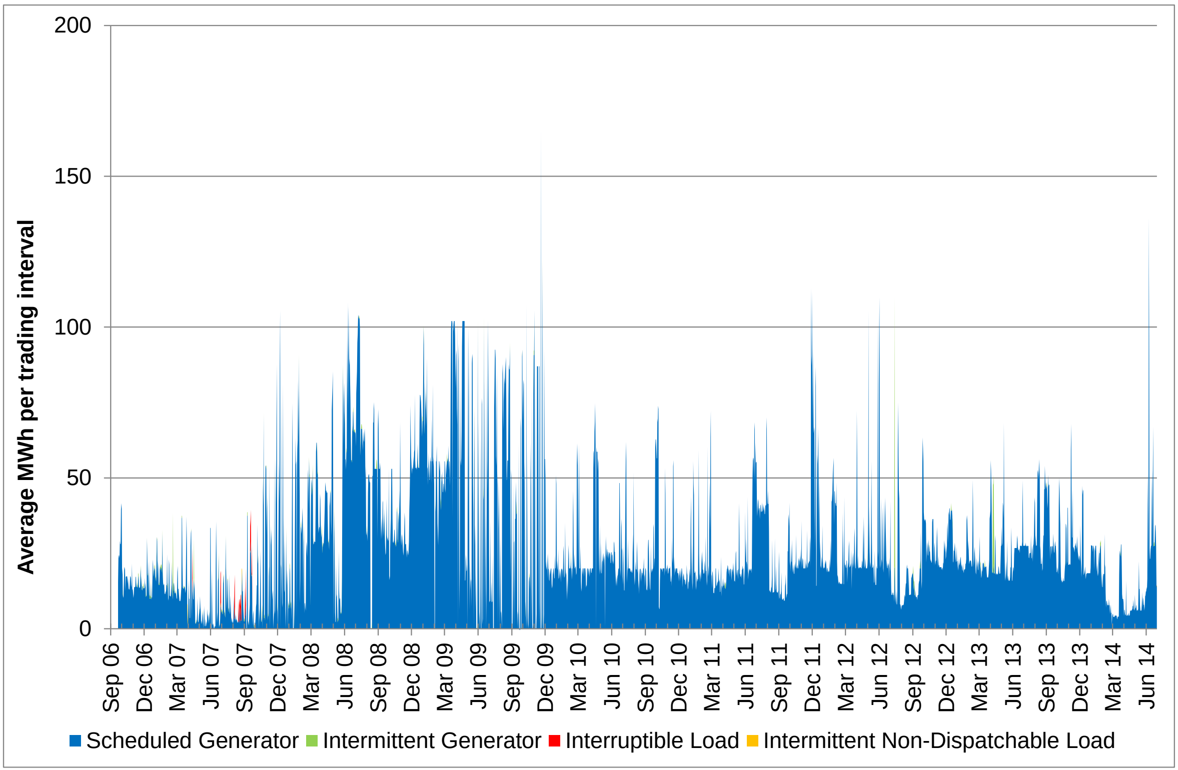
In the second half of the current Reporting Period, Synergy's Kwinana GT2 facility had the highest quantity of Planned Outages, both in terms of frequency and quantity. In the January 2014 to June 2014 period, 258,211 MW of Planned Outages were recorded for this facility, up from 182,378 MW through the January 2013 to June 2013 period.

Alinta's Pinjar U1 and U2 facilities had large increases in Planned Outages in the January to June 2014 period, compared to the January to June 2013 period, as did Synergy's Kwinana G5 and Kemerton GT12 facilities.

Planned Outages for Synergy's Muja G5 and Muja G8 dropped markedly in the January to June 2014 period compared to the corresponding period of 2013. Planned Outages for Muja G5 dropped from 459,408 MW to 64,740 MW, whilst for Muja G8, the total Planned Outages decreased from 299,277 MW to 38,380 MW. No Planned Outages were recorded for NewGen's Neerabup_GT1 facility in the first six months of 2014, compared to 315,695 MW across the same period in 2013.

Figure 2 below illustrates the quantity of Forced Outages.

Figure 2 Quantity of energy subject to Forced Outage (cumulative daily average MWh per Trading Interval)



Across the current Reporting Period, there were 16 days where the average amount of Forced Outage exceeded 50 MWh per trading interval, down from 18 days in the previous Reporting Period.

There was a decrease by 20 per cent on the total number of Forced Outages for the July 2013 to December 2013 period, compared to the July 2012 to December 2012 period. The total amount of MW on Forced Outage decreased by 11 per cent (from a total of 1,672,257 MW to 1,487,412 MW) across these time frames.

Muja G1 and Muja G2 dominated the Forced Outage rates in the July 2013 to December 2013 period, comprising almost 60 per cent of all Forced Outage amounts. Kwinana G5 was on Forced Outage for a lower number of trading intervals in the July 2013 to December 2013 period (2068 intervals) than the July 2012 to December 2012 period (3166 intervals), however the total amount of Forced Outage increased (from 128,530 MW in the 2012 period to 137,153 MW in the 2013 period). Muja G5 did not have any Forced Outages in the July 2012 to December 2012 period, however it had over 50,000 MW of Forced Outages in the

July 2013 to December 2013 period. Tiwest COG1 had a large jump in Forced Outages, from 2036 MW in the July 2012 to December 2012 period, to 35,349 MW in the July 2013 to December 2013 period.

In the January to June 2014 period, the months February through May all saw a lower level of Forced Outages per trading interval compared to the February to May months of 2013. The month with the highest quantity of Forced Outages per trading interval was June 2014, which also had the highest increase in the quantity of Forced Outages in 2014 compared to June 2013. January 2014 also had an increase in Forced Outage quantity per trading interval compared to January 2013, however the increase was less than 1 MWh per trading interval.

For the second half of the current Reporting Period, Vinalco's Muja G1 and Muja G2 facilities were once again the facilities with the highest amounts of Forced Outages. Synergy's Kwinana G6 had the third highest amount of Forced Outages for the first six months of 2014, however the amount of Forced Outages was much lower than the amount recorded for the facility in the corresponding months of 2013.

1.3 Bilateral Contracts for capacity and energy

Bilateral Contracts are confidential to the contracting parties. The market is informed through informal and individually formed market intelligence. The formal information is received by the IMO at the time of settlement by way of STEM submissions for energy, and Capacity Credit Allocation submissions for Reserve Capacity. In both cases, only the quantities are provided to the IMO. Other terms in the contracts such as price, length of the contracts and other conditions are known only to the contracting parties.

Bilateral Contracts in capacity and energy, separately or combined, play an important role in supporting new investments. This tends to happen for the larger investments requiring outside financing, giving the financiers greater cash flow certainties. The challenge is the lack of depth in the Bilateral Contract market in the WEM, given the concentrated market structure.

This lack of depth in the Bilateral Contract market may have contributed to the composition of new capacity coming into the market in recent Reserve Capacity Cycles. Smaller capacity additions are relatively easier to bring about than larger capacity additions that require larger borrowings and the support of a bilateral contract for risk mitigation purposes.

1.4 Short Term Energy Market

The STEM is a day-ahead market where a Market Participant can trade energy around its bilateral position.

Short Term Energy Market Clearing Prices

STEM Clearing Prices are summarised separately for Peak Trading Intervals (occurring between 8 am and 10 pm) and Off-Peak Trading Intervals (occurring between 10 pm and 8 am).

Figure 3 and Figure 4 illustrate, respectively, average daily peak and off-peak STEM Clearing Prices for each Trading Day from 21 September 2006 (market commencement) up to 30 June 2014, as well as 30-day, 90-day and annual moving average prices.

Figure 3 **Daily Average STEM Clearing Prices (Peak Trading Intervals)**

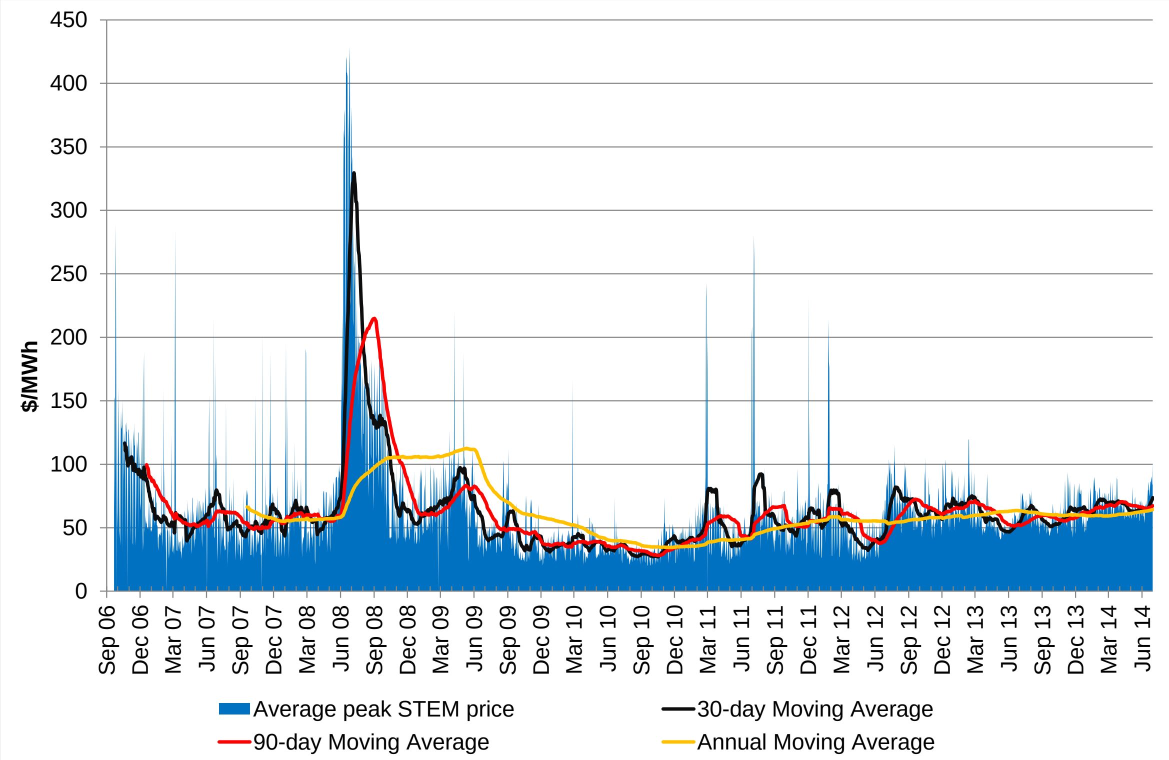
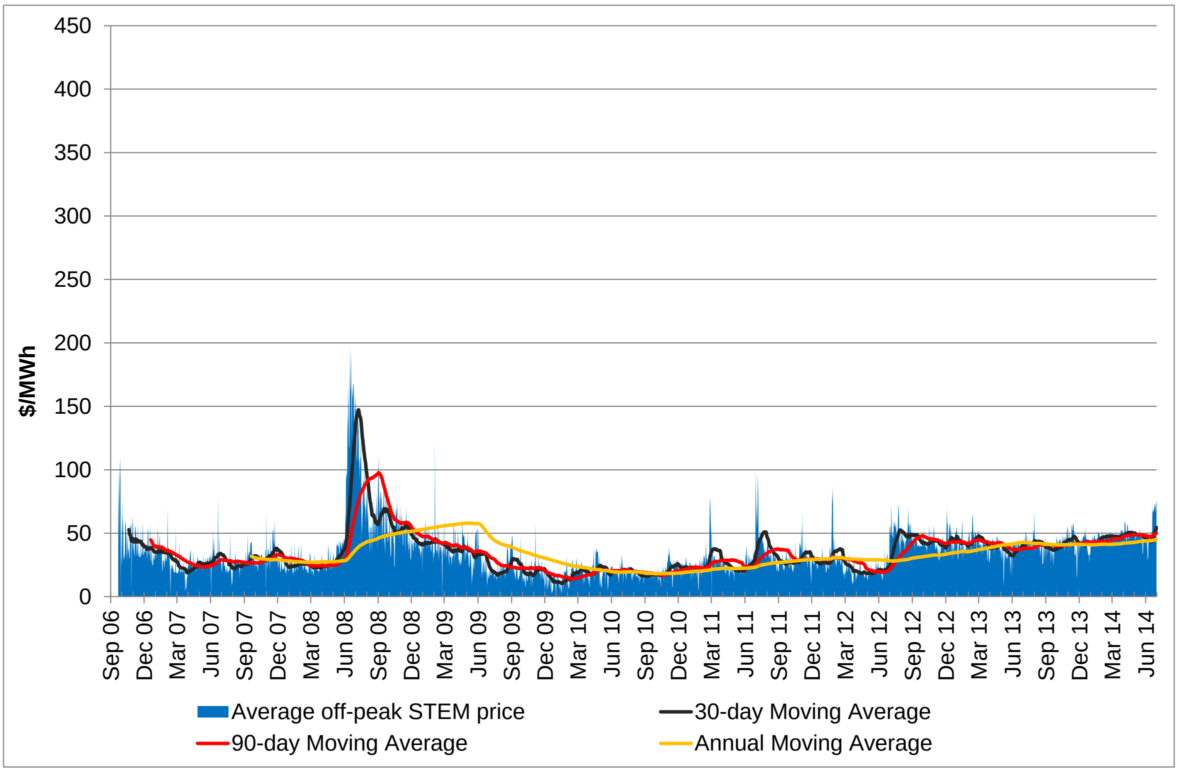


Figure 4 **Daily Average STEM Clearing Prices (Off-Peak Trading Intervals)**



Following a period of high prices immediately after market commencement, STEM Clearing Prices were relatively stable in 2007 and 2008, prior to the Varanus Island incident (which occurred in June 2008).[3] Following the incident and the subsequent curtailment of gas supplies, prices increased significantly, peaking at a daily average in excess of $400/MWh during Peak Trading Intervals, and a daily average of close to $200/MWh during Off-Peak Trading Intervals. The average peak and off-peak prices have been at lower levels each Reporting Period since that event in June 2008.

The introduction of the Carbon Tax in July 2012 was largely responsible for the increase in the average clearing price for both the peak and the off-peak periods. The average clearing prices from July 2012 onwards have been relatively stable.

Volatility of Short Term Energy Market Clearing Prices

Figure 5 and Figure 6 show the mean and standard deviation (as well as maxima and minima), by month, of STEM Clearing Prices for Peak and Off-Peak Trading Intervals, from market commencement up to 30 June 2014.

Peak STEM Clearing Prices were relatively consistent during the current Reporting Period on a month by month basis. The most volatile month was November 2013, with April 2014 being the least volatile month and one of the lowest volatile months for Peak periods since market commencement. In the current Reporting Period, Off-peak STEM Clearing Prices were the most volatile during June 2014. The Authority notes that the volatility in peak and off-peak STEM Clearing Prices has generally reduced compared to the previous Reporting Period.

[3] The incident was caused by the rupture of a corroded pipeline and subsequent explosion at a processing plant on Varanus Island on 3 June 2008. The plant, operated by Apache Energy, which normally supplied a third of the State's gas, was shut down for almost two months while a detailed engineering investigation and major repairs were carried out. Gas supply from the plant was partially resumed in late August 2008. By mid-October 2008, gas production was running at two-thirds of normal capacity, with 85 per cent of full output restored by December 2008.

Figure 5 **Summary statistics for STEM Clearing Prices in Peak Trading Intervals (per calendar month)**

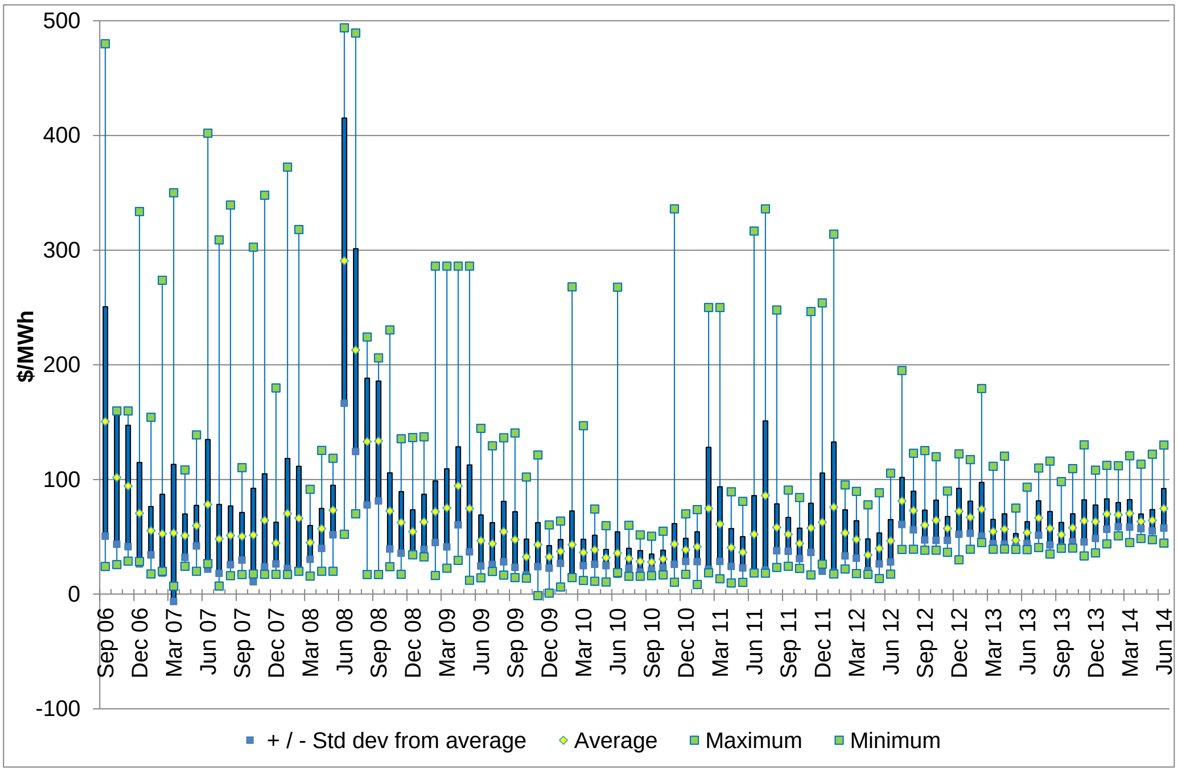
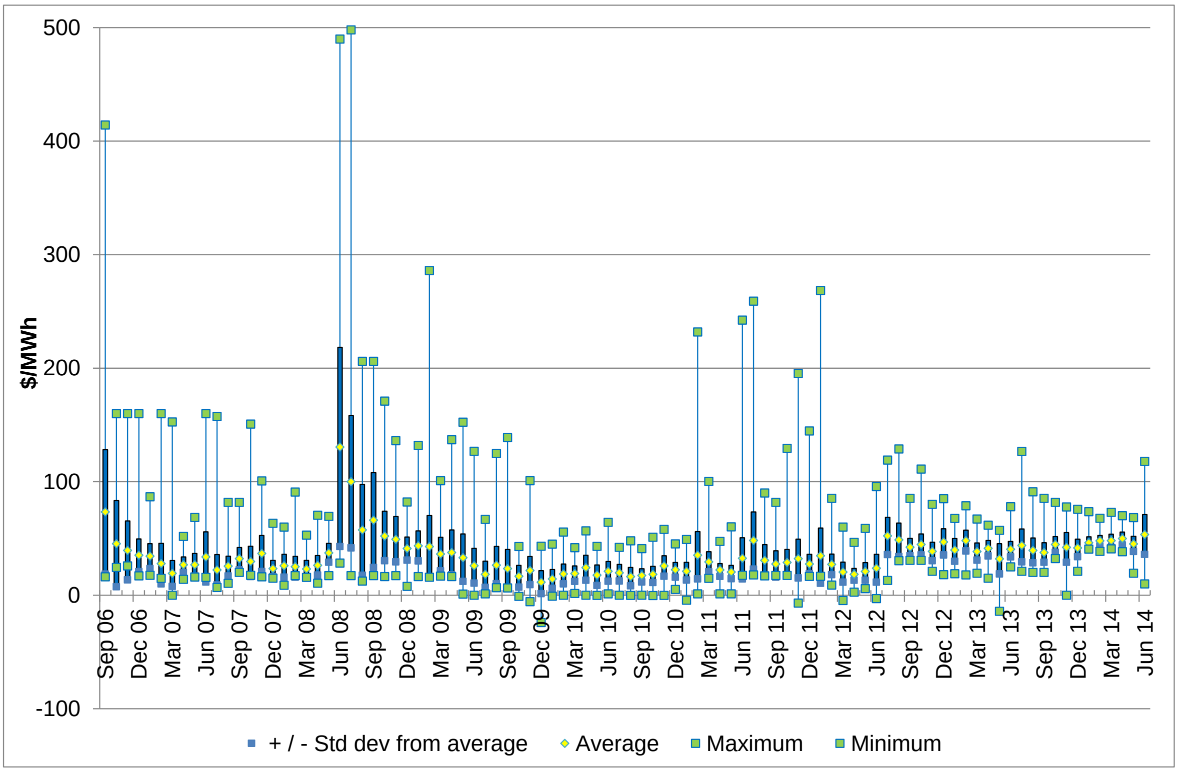


Figure 6 **Summary statistics for STEM Clearing Prices in Off-Peak Trading Intervals (per calendar month)**



High prices in the Short Term Energy Market

Figure 7 and Figure 8 illustrate the proportion of peak and off-peak Trading Intervals during which STEM Clearing Prices were at the Maximum STEM Price and Alternative Maximum STEM Price.

Since 2008, the highest incidence of both off-peak and peak STEM Clearing Prices reaching the Maximum STEM Price occurred between June and September 2008, which coincided with the Varanus Island incident. STEM Clearing Prices also reached the Maximum STEM Price during Peak Trading Intervals between March 2009 and May 2009, and during three Peak Trading Intervals, twice on 3 November 2010 and once on 6 July 2011. In the current Reporting Period STEM Clearing Prices did not reach the Maximum STEM Price, as was also the case in the previous Reporting Period.

STEM Clearing Prices only reached the Alternative Maximum STEM Price during Peak Trading Intervals in September 2006 and June 2007. Since then, STEM Clearing Prices have not reached the Alternative Maximum STEM Price.

Figure 7 Proportion of Trading Intervals STEM Clearing Prices at Maximum STEM Price (per calendar month)

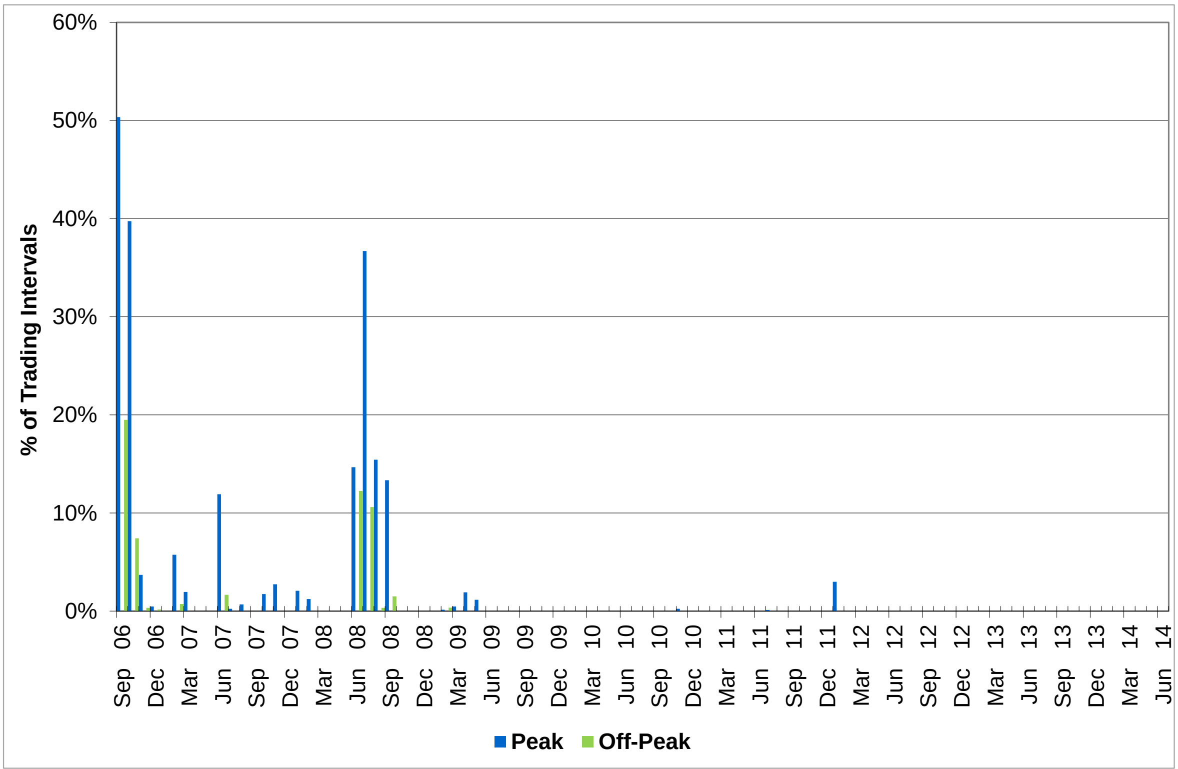
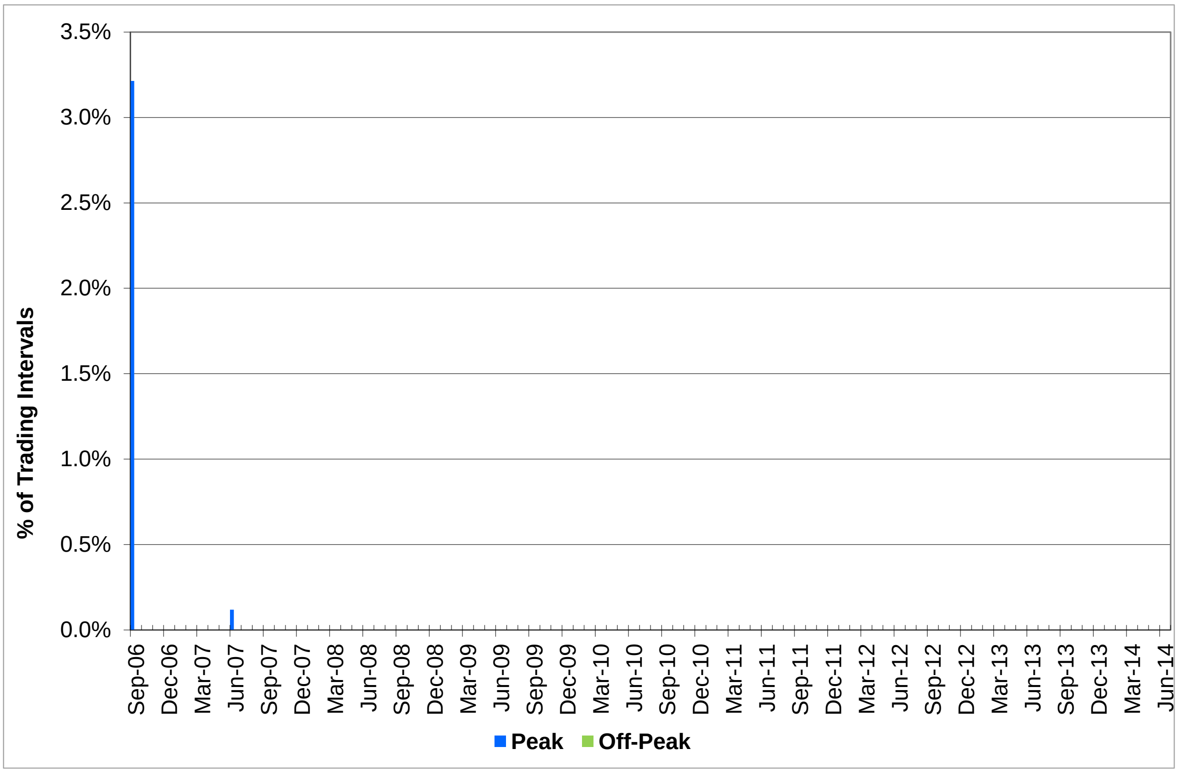


Figure 8 Proportion of Trading Intervals STEM Clearing Prices at Alternative Maximum STEM Price (per calendar month)



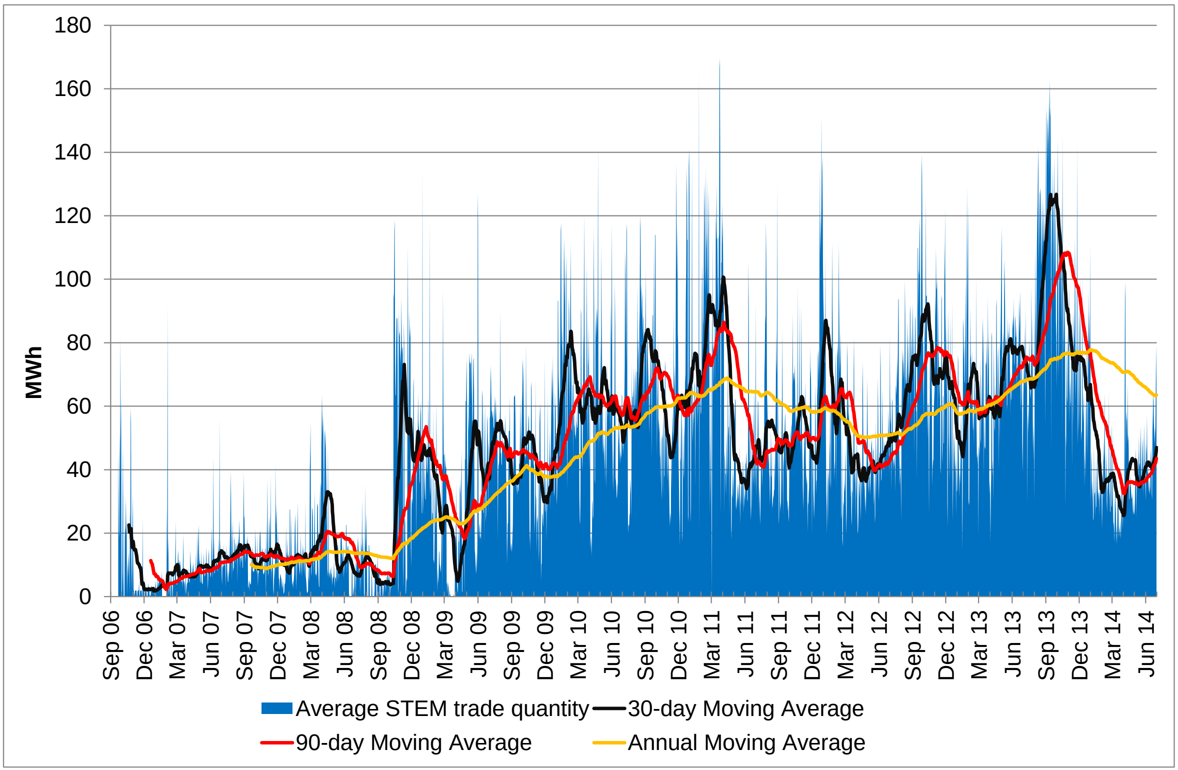
Clause 2.16.4(e) of the Market Rules requires the IMO to calculate the correlation between capacity offered into STEM Auctions and the incidence of high prices. In previous Reports to the Minister the Authority highlighted that a simple correlation between capacity and prices will fail to capture other factors that can influence STEM Clearing Prices, such as bidding behaviour and demand conditions, and that more detailed analysis was required to understand the key determinants of high prices in the STEM. For these reasons, correlations between STEM Clearing Prices and quantities offered are not included in this report.

As required under 2.16.4(g), the IMO investigates high price incidents observed in the STEM to identify the key drivers and whether any further action is required. The results from this analysis are provided to the Authority and discussed at the regular surveillance meeting held between the two organisations.

Short Term Energy Market traded quantities

Figure 9 shows average daily STEM Clearing Quantities for each Trading Day from 21 September 2006 (market commencement) to the end of the current Reporting Period (30 June 2014), as well as 30-day, 90-day and annual moving average quantities.

Figure 9 Average Daily STEM Clearing Quantities



The increased activity in the STEM in the last six months of 2013 was largely due to Synergy selling large quantities of energy in the STEM to Verve Energy. The daily average traded quantity reduced in the first six months of 2014 due to the ending of the Vesting Contract and the removal of the need for Synergy to sell over nominated quantities in the STEM.

Figure 10 and Figure 11 show the daily average volume bought and sold in the STEM, respectively, for all Market Participants, from market commencement to 30 June 2014.

The major buyer in the STEM in the current Reporting Period was Synergy, followed by ERM Power Retail, Southern Cross Energy and Griffin Power 2. Synergy was the largest STEM seller, followed by Alinta Sales and Griffin Power 2.

Figure 10 Daily average quantities bought in the STEM (MWh)

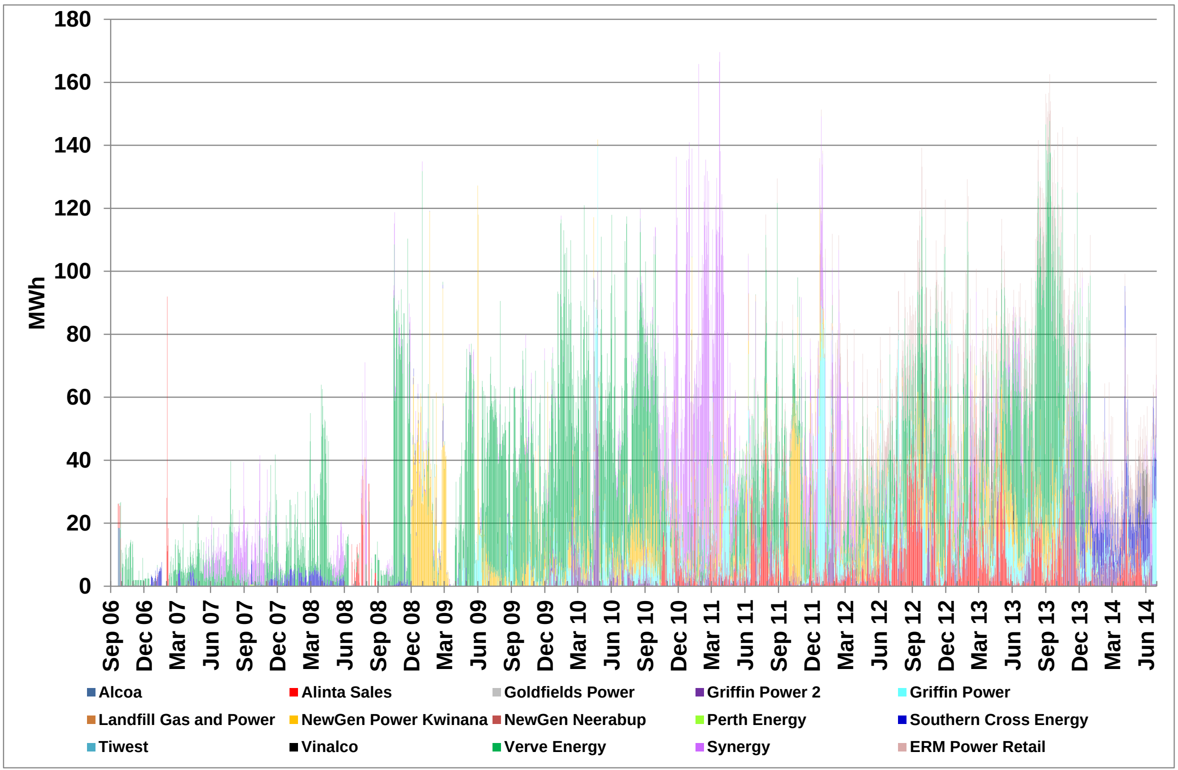
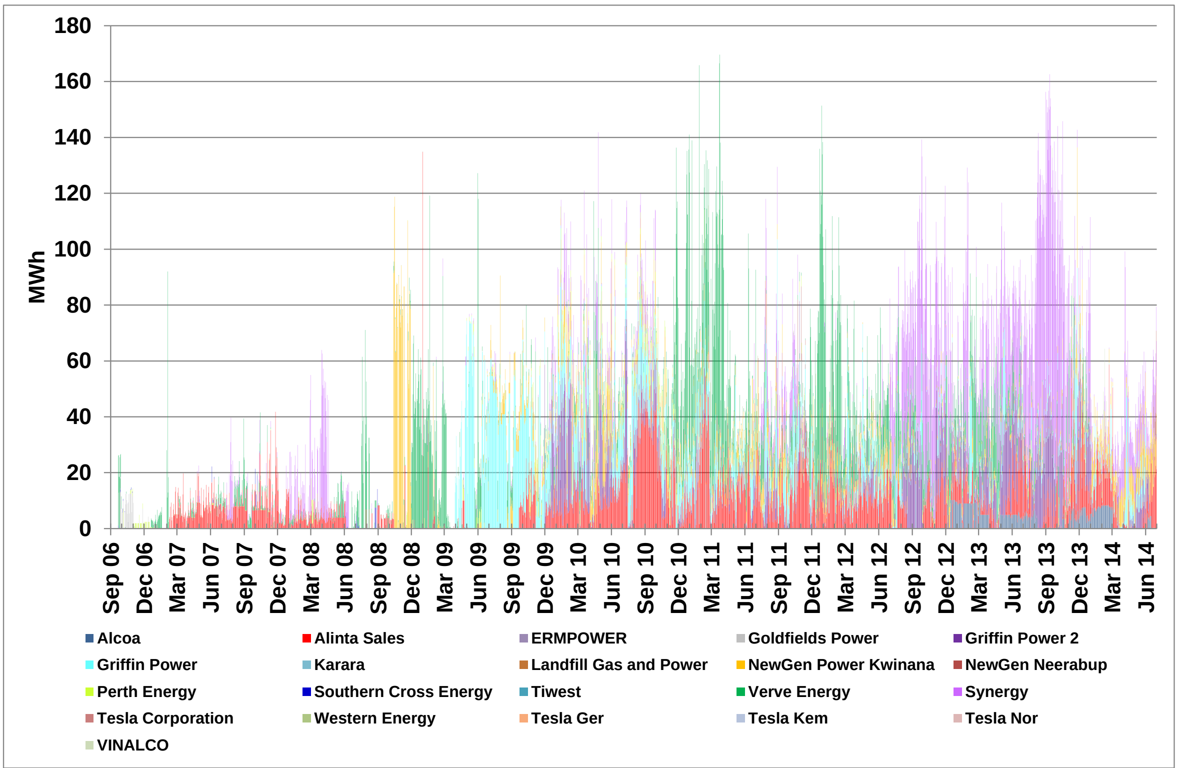


Figure 11 Daily average quantities sold in the STEM (MWh)



1.5 Balancing

Energy Balancing refers to the process for meeting supply and consumption deviations from contracted bilateral and STEM positions in each Trading Interval. The new competitive balancing market introduced on 1 July 2012 has enabled all generators to offer balancing services. Balancing facilities are defined as Market Generators' (other than Synergy's) scheduled and non-scheduled generating facilities.

Balancing offers are required to be submitted for all generators, apart from those on an approved planned outage or forced outage. Balancing offers include the quantity and price at which a Market Participant is willing to be dispatched. Prices offered must be within the Price Cap (i.e. between the maximum and minimum STEM price) and must not be in excess of the Market Participant's reasonable expectation of its Short Run Marginal Cost (**SRMC**) when such behaviour relates to market power. Market Participants are able to revise their offers up to two hours prior to the Trading Interval commencing, to reflect changes in market conditions.

Under the new Balancing Market, Synergy has continued to be able to offer its facilities on a portfolio basis and is treated as a single Balancing Facility. Synergy is able to offer its portfolio in 35 tranches and IPP's can offer 10 tranches for each scheduled generating facility. Intermittent generating units can only be offered as a single tranche and offers include price and an estimate of output. Synergy is also able to offer a facility on a stand-alone basis, consistent with IPP's, but to date, has not.

The IMO uses the balancing offer submissions to develop the Balancing Merit Order (**BMO**) that is ultimately used to determine which facilities are dispatched by System Management.

Any deviation Market Participants are required to make from their Net Contract Position (**NCP**) is treated as a Balancing Market transaction. Market Participants are paid the Final Balancing Price on their Metered Balancing Quantities (**MBQ**), i.e. the difference between actual generation or load, and their NCP. This differs from the NEM where settlement is based on total generation and load.

Balancing prices

Figure 12 and Figure 13 illustrate average daily peak and off-peak period Balancing Prices (respectively) for each Trading Day, from market commencement to 30 June 2014.

Figure 12 Daily Average Balancing prices (Peak Trading Intervals, $/MWh)

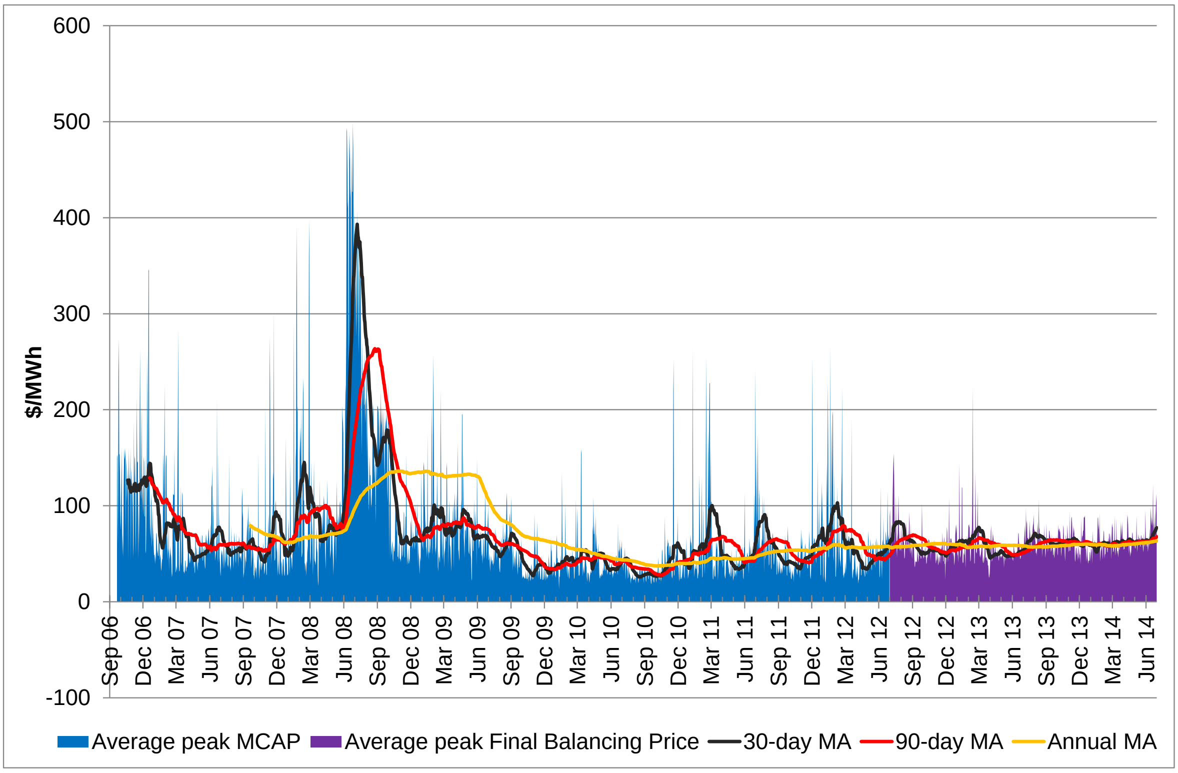
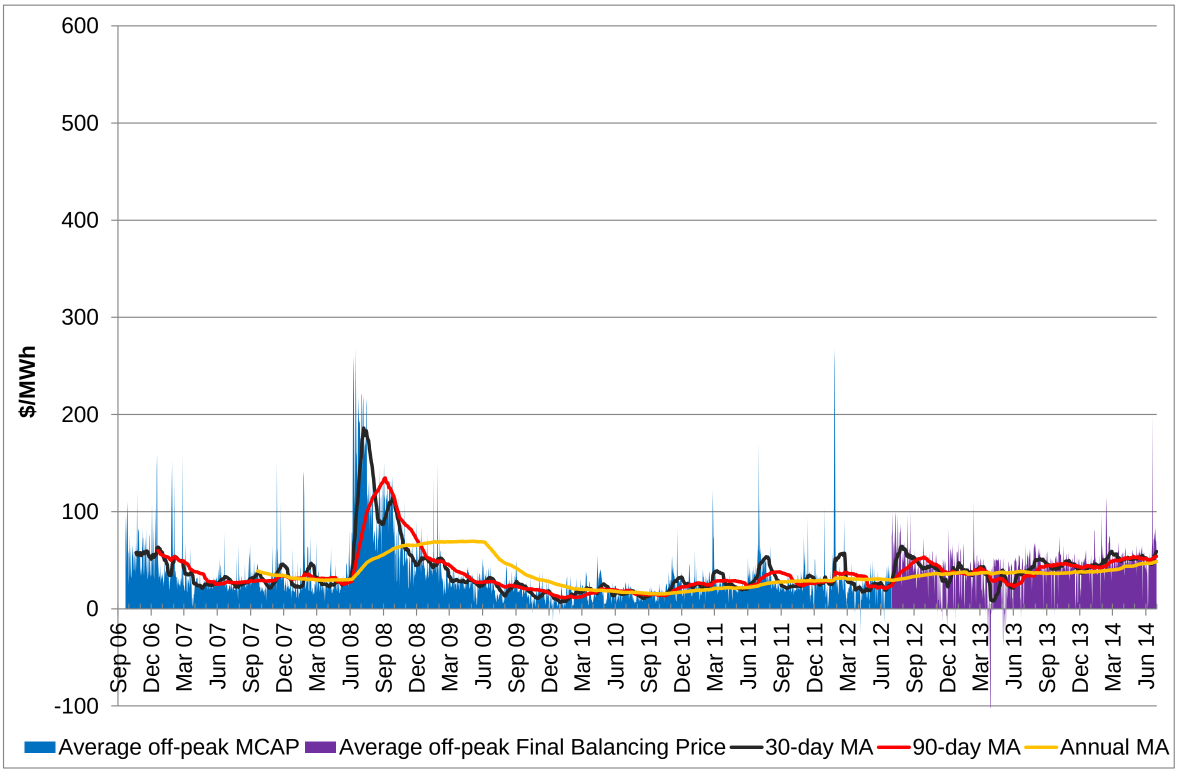


Figure 13 Daily Average Balancing prices (Off-Peak Trading Intervals, $/MWh)



Following a period of high prices immediately after market commencement, both Peak and Off-Peak Balancing prices were relatively stable until June 2008, when the Varanus Island incident occurred. Following that event, and the subsequent curtailment of gas supplies, Balancing prices increased significantly in June 2008 and remained at elevated levels for a number of months. Balancing prices have returned to lower levels since that time, with average prices at or below those experienced before the 2008 Varanus Island incident. The Annual Moving Average for the Off-Peak Balancing price has gradually increased since the later months of 2010.

Daily Average Peak Balancing prices moved in a smoother band during the current Reporting Period compared to the previous Reporting Period, indicated by a flatter 30 day moving average for the current Reporting Period. There was a limited number of spikes in price during the current Reporting Period when compared to previous periods. The Balancing Market cleared at the maximum STEM price on four occasions in Peak intervals during the current Reporting Period, compared to 16 in the previous Reporting Period.

Figure 14 shows Peak Balancing Prices since commencement of the new Balancing Market in 2012. The frequency of prices above $300/MWh was much lower through the July and August period of 2013 compared to the same period in 2012. A cluster of higher prices around the $125/MWh mark is evident for the July to September 2012 and 2013 periods. There was a noticeable drop in prices above $300/MWh during the summer months of the current Reporting Period compared to the previous Reporting Period. Higher Peak Balancing prices in June 2014 compared to June 2013 is notable from this chart.

Figure 15 compares Off-Peak Balancing prices from 1 July 2012 to 30 June 2014. Figure 15 shows that average off-peak Balancing prices were noticeably higher in June 2014. Prices reached the Maximum STEM price on only one occasion which was on 20 June 2014.

The Authority notes a much lower incidence of negative prices in Off-peak periods in the current Reporting Period compared to the previous Reporting Period. The previous Reporting Period had 678 instances of negative prices in off peak periods (representing approximately 9.3 per cent of Off Peak Trading Intervals), compared to 196 in the current Reporting Period (representing approximately 2.7 per cent of Off Peak Trading Intervals).

Figure 14 Peak Trading Intervals Final Balancing Prices (1 July 2012 to 30 June 2014)

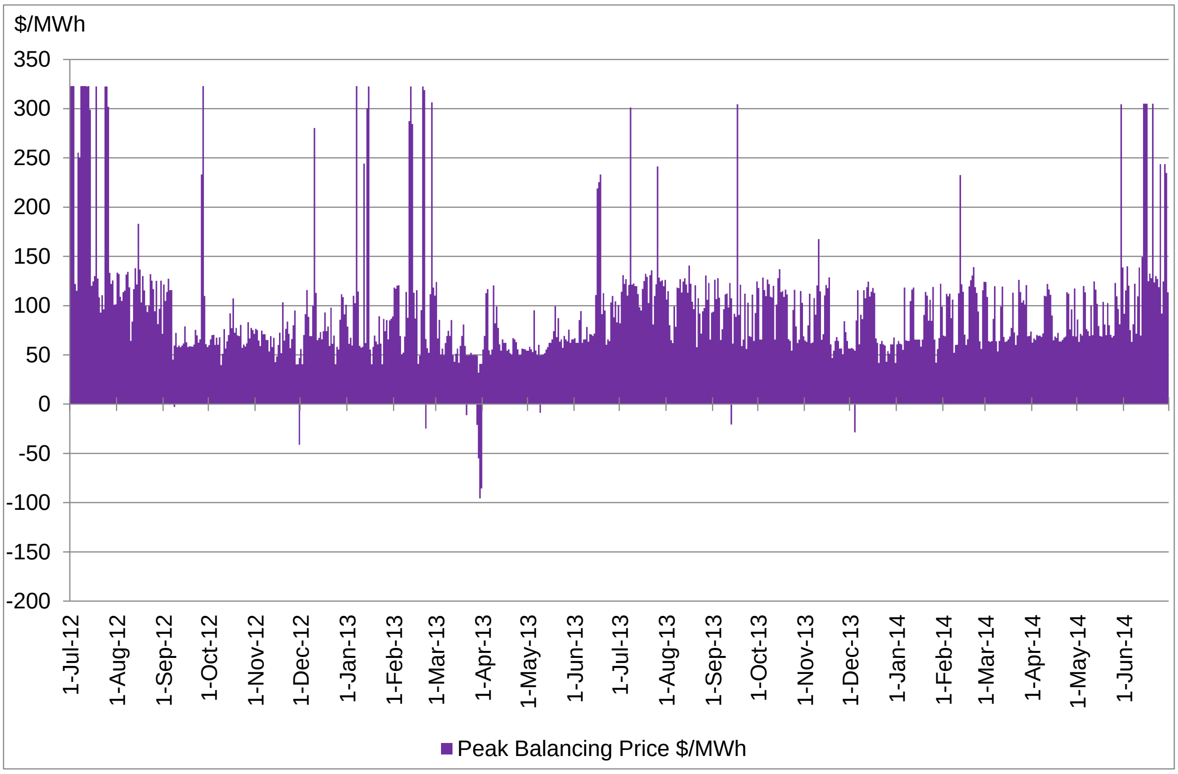
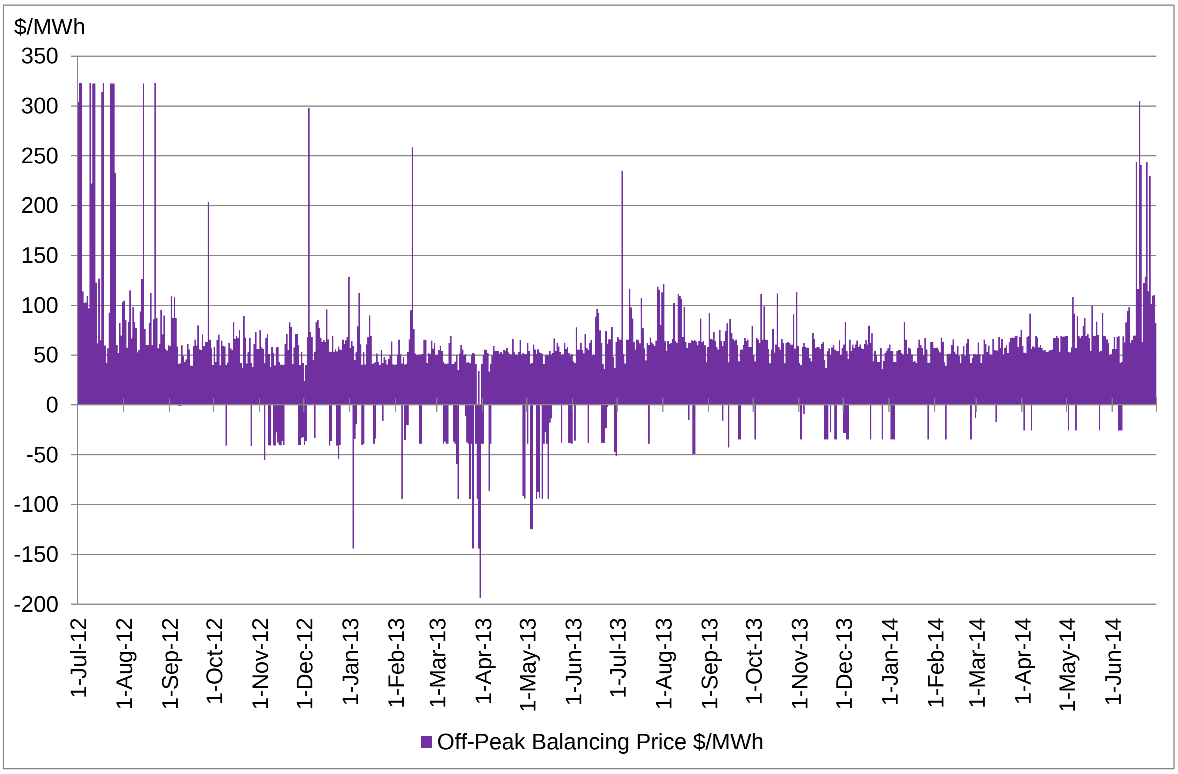


Figure 15 Off-Peak Trading Intervals Final Balancing Prices (1 July 2012 to 30 June 2014)



Volatility of Balancing prices

Volatility in Balancing prices is more accurately analysed by determining means and standard deviations. The means and standard deviations (as well as the maxima and minima) from market commencement to 30 June 2014 of MCAP/ Final Balancing prices are illustrated in Figure 16 and Figure 17.

Figure 16 Summary statistics for MCAP/ Final Balancing Price during Peak Trading Intervals (per calendar month)

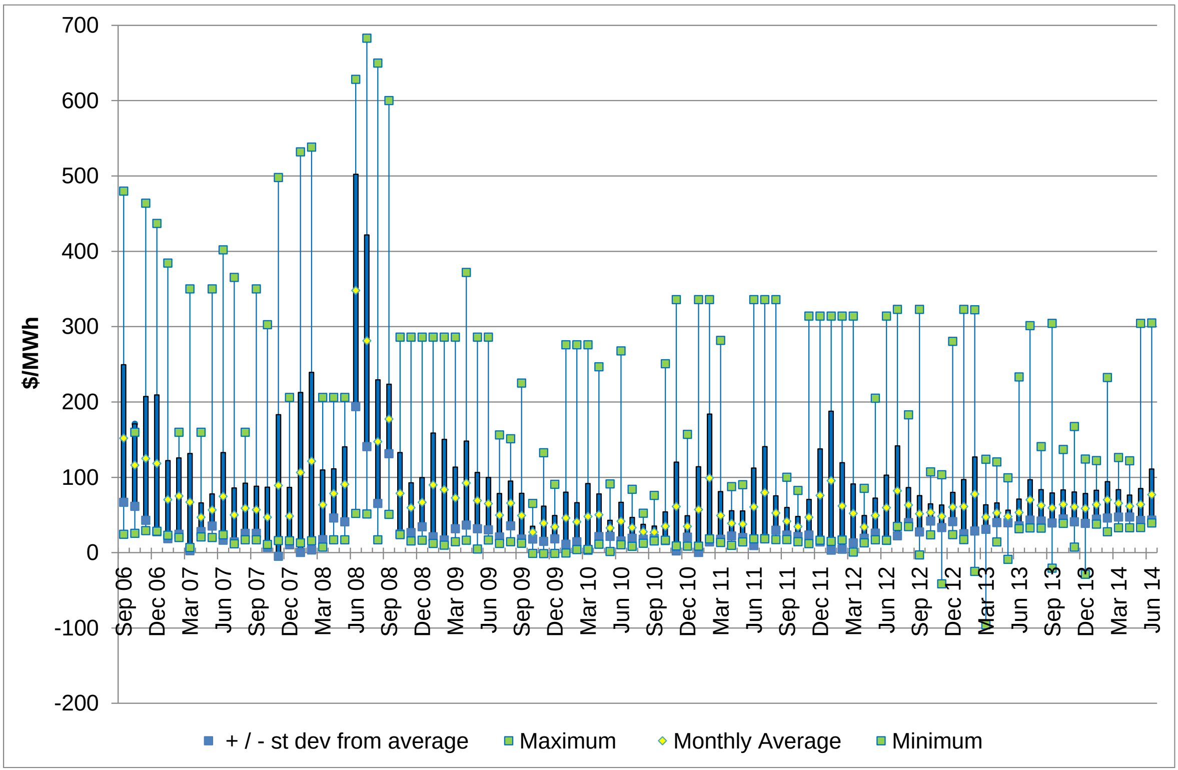
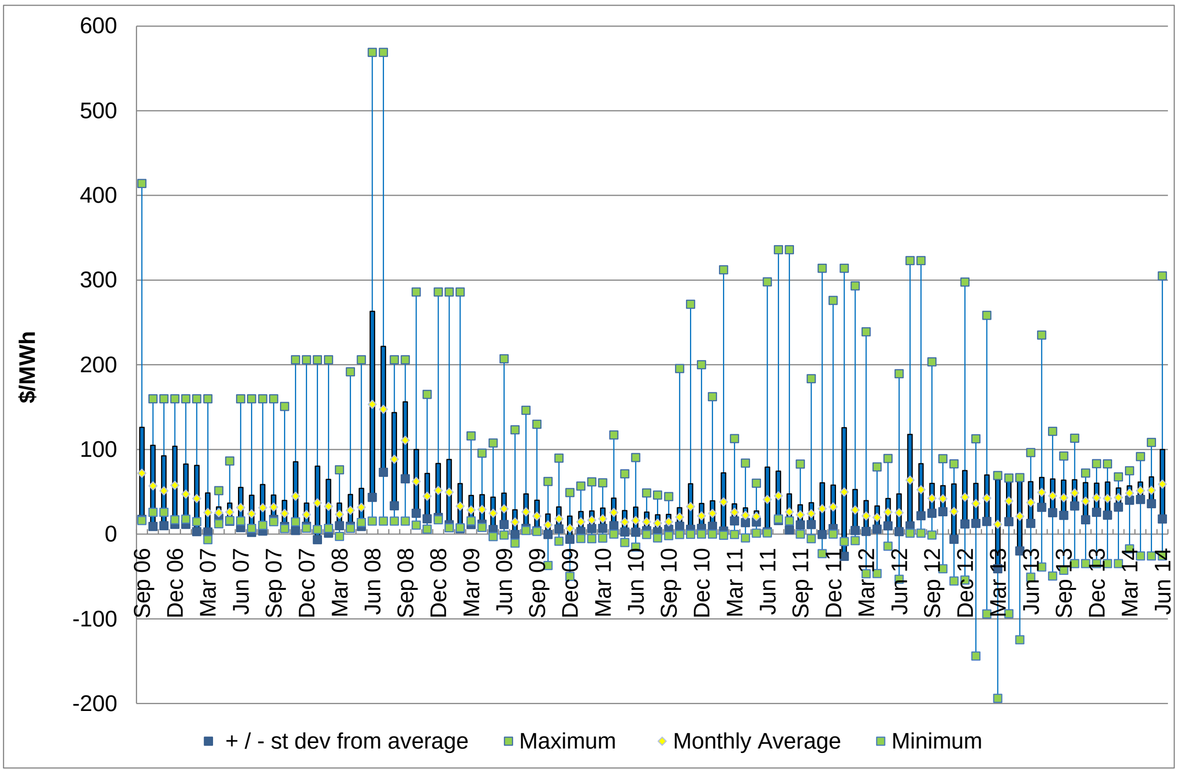


Figure 17 Summary statistics for MCAP/ Final Balancing Price during Off-Peak Trading Intervals (per calendar month)



Prices reached over $300/MWh in Peak trading intervals in July 2013, September 2013, May 2014 and June 2014 during the current Reporting Period. June 2014 was the most volatile month during the current Reporting Period for both peak and off-peak trading intervals, with the volatility during June off-peak intervals being noticeably larger than the other months of the period. This is discussed further below.

The price spikes throughout the period tended to occur in situations where: a) there were a large number of outages; b) there was a large deviation between forecast and final load; and c) there was a large deviation between forecast and final non-scheduled generation.

Whilst not necessarily being considered as “high,” there were 1,023 instances of prices clearing over $100/MWh in the current Reporting Period, compared to 613 instances in the previous Reporting Period. A significant number of these instances took place in June 2014 (206 clearing prices above $100/MWh).

In June 2014, there were a large number of prices clearing over $100/MWh (46) that took place in Off Peak periods in the Balancing Market. This included one instance of 16 consecutive Off Peak intervals on 19 June where the price was over $100/MWh, with 14 of these intervals over $243/MWh. There were no instances of clearing prices over $100/MWh in Off-peak periods during June 2013.

Loads and outages for June 2014 were higher than those in 2013. The average daily load per interval in June 2014 was larger than June 2013 for every day from 8 June to the end of the month. In the last week of June, the load was, on average, higher by 150 MW per Trading Interval. In addition, there was a higher level of baseload outage in June 2014 compared with June 2013, with the discrepancy again being larger in the last week of the month.

The maximum Balancing clearing price occurred in June 2014, where on five instances the Maximum STEM price was reached. An example of one of these instances took place during the 5:30pm trading interval on 20 June 2014. Final generation ended up 87 MW higher than the forecast level of generation half an hour before the start of the Trading Interval and intermittent generation was lower than forecast. The result was a need for an additional 100 MW of generation. Furthermore, there were 862 MW of outages during this Trading Interval, including approximately 534 MW of baseload capacity.

High Balancing prices

Figure 18 illustrates the proportion of Peak Trading Intervals and Off-Peak Trading Intervals during which MCAP/ Final Balancing prices were at the Maximum STEM Price. This shows that MCAPs were regularly at the Maximum STEM Price during Peak Trading Intervals in the summer months of the first years of the market, and also from June 2008 to September 2008 during the Varanus Island interruption.

In the current Reporting Period, the Final Balancing Price reached the Maximum STEM price on four instances during Peak Trading Intervals and on one occasion during Off-Peak Trading Intervals.

Figure 18 Proportion of Trading Intervals Final Balancing Price/MCAPs at Maximum STEM Price (per calendar month)

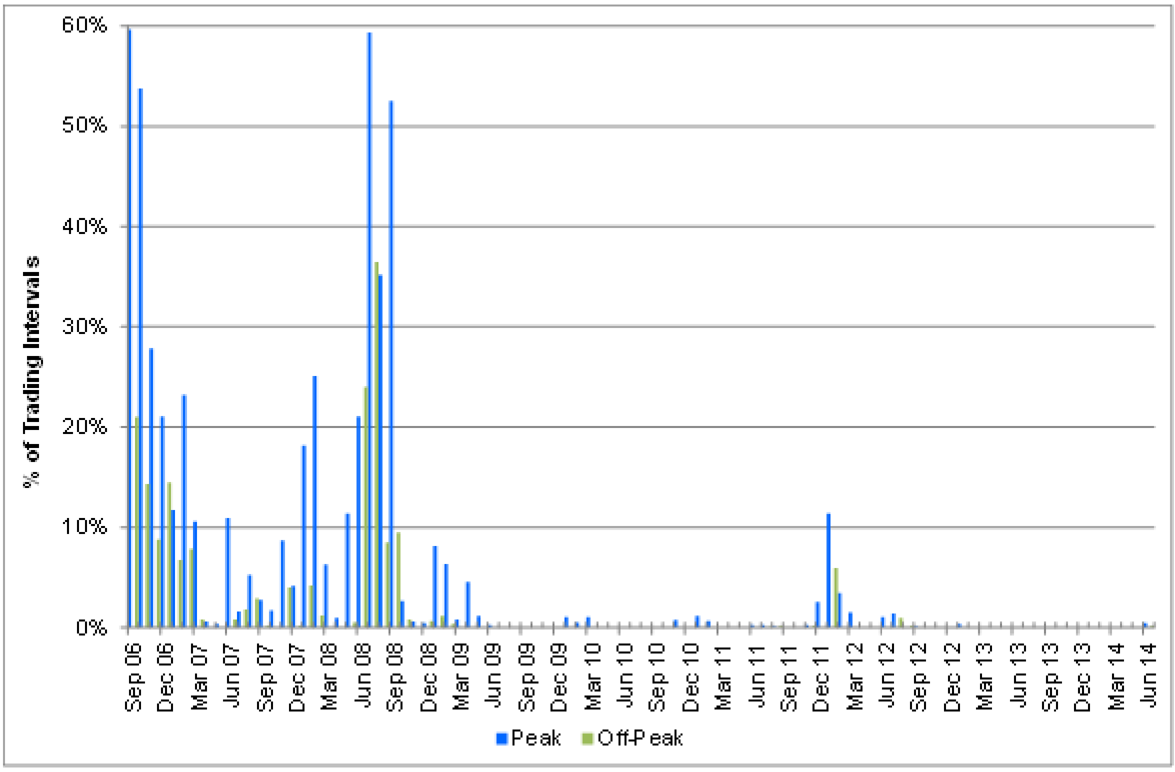
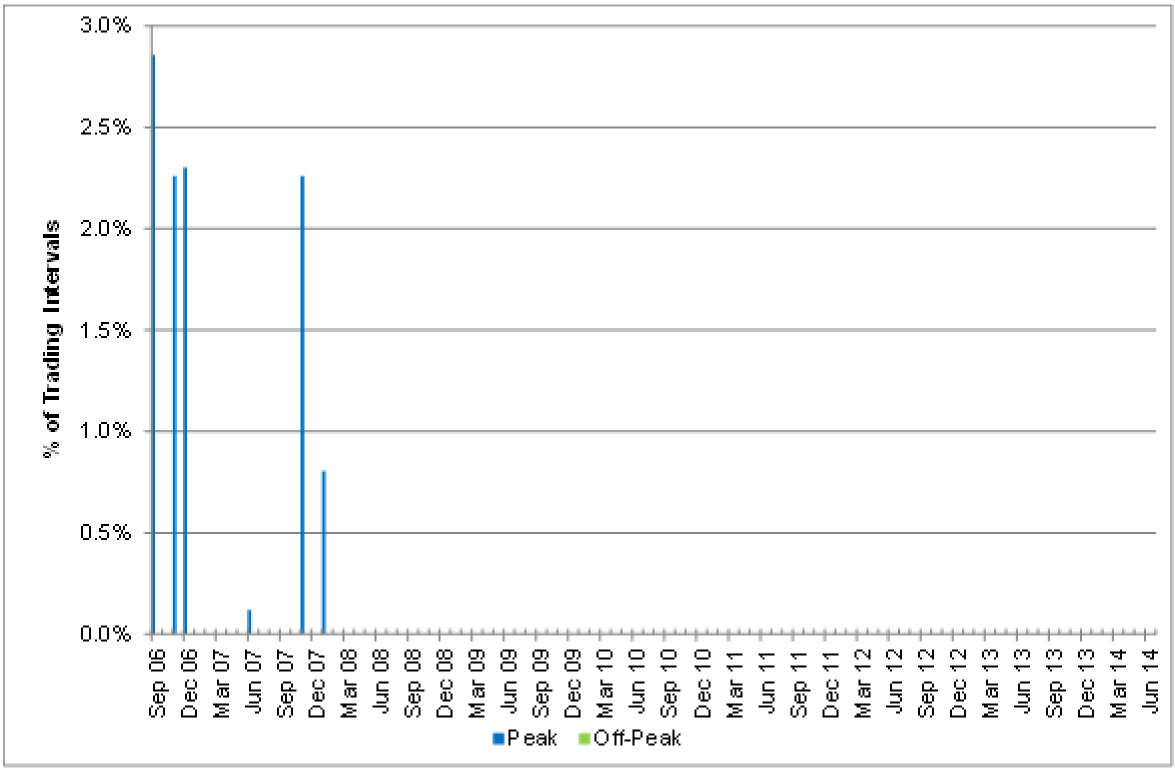


Figure 19 illustrates the proportion of peak and off-peak periods during which MCAPs were at the Alternative Maximum STEM Price. As was the case in the previous Reporting Period, there were no instances of the Final Balancing Price reaching the Alternative Maximum STEM Price in the current Reporting Period. The last time the MCAP reached the Alternative Maximum STEM Price was in January 2008.

Figure 19 Proportion of Trading Intervals Final Balancing Prices/MCAP at Alternative Maximum STEM Price (per calendar month)



Clause 2.16.4(f) of the Market Rules requires the IMO to calculate the correlation between capacity offered into Balancing and the incidence of high prices. In previous Reports to the Minister the Authority highlighted that a simple correlation between capacity and prices will fail to capture other factors that can influence prices, such as bidding behaviour and demand conditions, and that more detailed analysis was required to understand the key determinants of high prices. For these reasons, correlations between Balancing Prices and quantities offered are not included in this report.

As required under 2.16.4(g), the IMO investigates high price incidents observed in Balancing to identify the key drivers and whether any further action is required. The results from this analysis are provided to the Authority and discussed at the regular surveillance meeting held between the two organisations.

1.6 Ancillary Services

Ancillary Services are required to maintain power system security and reliability through the control of key technical characteristics, such as frequency and voltage, which ensures that electricity supplies are of an acceptable quality.[4] There are five defined types of Ancillary Services applicable in the SWIS, which are Spinning Reserve, Load Following, System Restart, Load Rejection Reserve and Dispatch Support services.[5] System Management is required to estimate the technical requirements for Ancillary Services, based upon standards set out in the Market Rules. Pursuant to its obligations under clause 3.11.11 of

[4] The Technical Rules for the South West Interconnected Network is the basis for the setting of operating parameters in WEM.

[5] These Ancillary Services are defined in section 3.9 of the Market Rules.

the Market Rules, System Management must prepare a report each year, which comprises three parts:

- the quantities of each of the Ancillary Services provided in the preceding year, including Ancillary Services provided under Ancillary Service Contracts, and the adequacy of these quantities;
- the total cost of each of the categories of Ancillary Services provided, including Ancillary Services provided under Ancillary Service Contracts, in the preceding year; and
- the Ancillary Service requirements for the coming year and the Ancillary Services plan to meet those requirements.

At the time of preparing this report to the Minister, the 2014 Ancillary Services report and plan had not been approved by the IMO.

Spinning Reserve

Synergy has been the sole default provider of the Spinning Reserve Ancillary Service[6] since market commencement. Synergy receives a payment from the market, which is calculated as the Balancing price multiplied by a margin value that is determined by the Authority under the Market Rules.[7] The Spinning Reserve Ancillary Service cost is recovered from Market Generators. Synergy, besides being the provider, is also responsible for a large portion of the Spinning Reserve Ancillary Service cost.

As per Market Rule 3.10.2, System Management has estimated that the maximum Spinning Reserve level that may be required is 70 per cent of the quantity of the largest contingency, which is the Collie power station. This gives a maximum Spinning Reserve level of 240 MW. The Spinning Reserve service can be provided by such facilities as synchronised generation and interruptible loads.[8]

System Restart

System Management requires at least three generating stations to provide System Restart Ancillary Services[9]. These generators should be situated at different locations so as to reduce the risk of system restart failure. As a result, System Management would prefer to have restart capability in the three electrical sub networks including the North Metropolitan, South Metropolitan and South Country.

System Management has obtained three System Restart services for the 2014/15 period. These services will be provided by Synergy's gas turbines at Kwinana and Pinjar, as well as Perth Energy's Kwinana GT1 facility. System Management intends to initiate a

[6] Spinning Reserve is reserve that is synchronised to the system that can respond almost immediately and provide frequency or voltage support for a short duration.

[7] The margin values are determined for each financial year. For the 2013/14 financial year, these values were set at 15 per cent for Margin-Off Peak and 14 per cent for Margin Peak (without carbon price) which covers Synergy's costs for the provision of spinning reserve ancillary service.

[8] For 2014/15, an additional two sources of Spinning Reserve have been obtained, being 13 MW supplied by Simcoa's interruptible load and 13 MW supplied by Bluewaters Power Station. An existing 42 MW of Spinning Reserve is provided by interruptible load from one market participant, with the remaining Spinning Reserve requirement to be supplied by synchronising additional Synergy generators.

[9] System Restart Ancillary Services are provided by generators capable of starting up without the need to use power from the power system and are also able to energise the power system to enable other generators to be started up.

procurement process for the System Restart services required from 1 July 2016, when the current contracts for System Restart services end.

No System Restart service was used in the 2013/14 period.

Payments for these System Restart contracts are collected via the R value of the Cost_LR parameter,[10] defined in the Market Rules. Under clause 3.13.3C of the Market Rules, the Authority is responsible for determining the Cost_LR parameter. The Authority published its determination on the Cost_LR parameter for the 2013/14, 2014/15 and 2015/16 financial years in March 2013.[11]

Load Rejection Reserve

The Load Rejection Reserve service[12] is determined by the extent of load lost during a network fault. The requirement is set to maintain system frequency below 51.0 Hz, returned to less than 50.5 Hz within two minutes, and then returning to the 49.8 Hz to 50.2 Hz range within fifteen minutes. The current quantity is 120 MW and is based on the size of the load reductions that have occurred in the past during network fault events.

The L value of the Cost_LR parameter provides for compensation of the cost associated with the provision of this service. The value has been set at nil since market commencement, and has been set at this value for the 2013/14, 2014/15 and 2015/16 financial years.

Dispatch Support

Synergy's facilities at Mungarra, West Kalgoorlie and Geraldton are currently contracted to supply Dispatch Support Ancillary Services.

Load Following

Clause 3.10.1 of the Market Rules specifies the criterion for determining the level of LFAS[13]. The LFAS requirement is based on a level sufficient to maintain system frequency between 49.80 Hz and 50.20 Hz for at least 99.9% of each month. Historically the system frequency has been achieved for 99.97 per cent of the time, beating the adequacy requirement of maintaining frequency for 99 per cent of the time.

A competitive LFAS market was introduced on 1 July 2012. Prior to that date, Synergy was the sole provider and remained so until February 2013, when the first offer of service from NewGen was accepted in the new competitive LFAS market. Synergy and NewGen receive a payment from the market for the provision of LFAS. Market Customers and Intermittent Generators share the payment of LFAS costs.

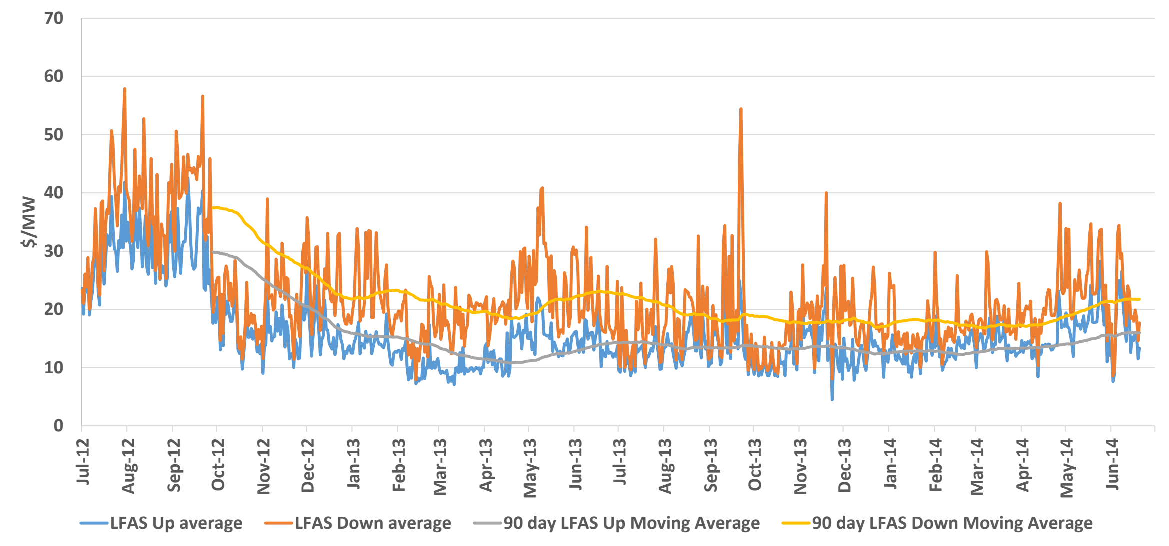
[10] The Cost_LR parameter covers the payment to a Market Generator for the costs of providing the Load Rejection Reserve and System Restart Ancillary Services, and specific Dispatch Support Ancillary Services.

[11] The R values determined by the Authority are $42,315 per month for the 2013/14 financial year, $43,373 per month for the 2014/15 financial year and $44,457 per month for the 2015/16 financial year. See http://www.erawa.com.au/cproot/11212/2/20130318%20-%20Determination%20of%20the%20Ancillary%20Service%20Cost_LR%20Parameter.pdf

[12] In providing Load Rejection Ancillary Services, generators shut down quickly in the event of lost load, such as when a transmission line trips, in order to keep the power system stable.

[13] Generators providing LFAS are run in a manner that allows for the generators' output to be rapidly changed to balance real-time fluctuations between load and generation.

Figure 20 **Average LFAS Up and Down Prices (1 July 2012 to 30 June 2014)**



Of the current total LFAS requirement of 72 MW (both Up and Down), NewGen is only able to provide 30 MW, which it generally offers as two tranches of 15 MWs, at different price bands.

Across the current Reporting Period, the average LFAS Down price of $18.53/MW was lower than the average LFAS Down price for the previous Reporting Period of $25.37/MW. Similarly for LFAS Up, the current Reporting Period average price of $13.72/MW was lower than the previous reporting average price of $17.87/MW. The lower prices took place in both Peak and Off-Peak trading intervals.

Aside from February and March 2014, the average LFAS Down price for each month of the current Reporting Period was lower than the corresponding months in the previous Reporting Period. February through to May saw higher current Reporting Period prices for LFAS Up compared to the previous Reporting Period, but lower prices occurred across the remaining months.

There was a noticeable jump in the LFAS Down average price in the middle of September 2013, where the LFAS Down price reached a maximum of $106.78/MW on 21 September 2013, and where the LFAS Down clearing price cleared above $60/MW in 18 trading intervals on this day. A similar peak in LFAS Down prices occurred around the same time in 2012, however that was before Synergy had introduced the HEGTs at Kwinana to provide LFAS.

In these trading intervals on 21 September 2013, Synergy was the participant that set the price and there was a jump in the offer price for LFAS made by Synergy in these intervals compared to the surrounding trading intervals. These higher offer prices, and subsequent clearing prices, coincided with instances of the Forecast Balancing price being negative. During such instances it is likely that a participant will find it unattractive to be operating in the energy market, as its costs will not be covered by what it can make in the Balancing Market. These costs include not only the SRMC of the facility, but also the start-up costs that would be incurred in getting the facility up and running. Thus, the LFAS offer prices would include an allowance for the shortfall between the Forecast Balancing price and the SRMC, as well as any start-up costs incurred.

Offer prices for LFAS should be based on the incremental SRMC in providing the ancillary service. In instances where the Forecast Balancing price is close to the SRMC of the facility (or on a relatively flat portion of the SRMC curve), the incremental change will be close to zero.

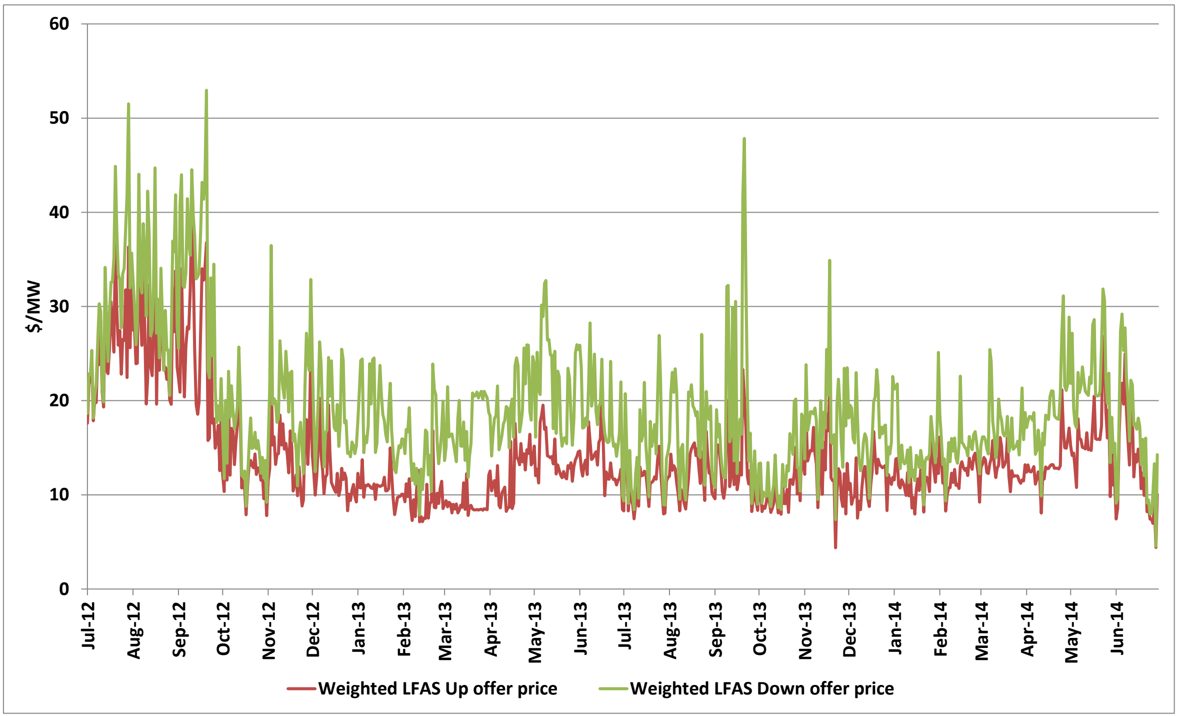
A similar result took place in November 2013, where the LFAS Down price reached a maximum of $115.76/MW on 19 November 2013, and the clearing price was higher than $60/MW in eleven consecutive intervals on this day, including nine consecutive intervals where the clearing price was higher than $100/MW. The Forecast Balancing price for each of the eleven trading intervals clearing above $60/MW was negative.

In trading intervals where the Forecast Balancing price is high (e.g., approaching the maximum STEM price), it is also likely that LFAS prices will be higher than LFAS prices during trading intervals where the Forecast Balancing price is low but positive. As the Forecast Balancing price increases beyond the SRMC of the facility, there will be an opportunity cost to consider because the facility will miss out on providing energy at high prices in the Balancing Market. An example of this took place on 19 June 2014, where several off-peak trading intervals had a Forecast Balancing price greater than $243/MWh and the corresponding LFAS Down prices for these intervals were around the $40/MW mark. Whilst this price is not as high as the prices above $100/MW incurred during the period of negative Forecast Balancing prices, it is a relatively high price for LFAS.

The Authority has noted issues resulting from Synergy bidding as a portfolio, rather than on a facility by facility basis, in previous reports to the Minister. This bidding practice also has an implication for the LFAS market, with transparency lacking as to which facility is providing LFAS. Difficulties therefore exist with comparing facility SRMCs with Forecast Balancing prices, in order to determine likely LFAS offer prices.

The Authority notes the continual work between System Management and the IMO to reduce the cost of providing LFAS. The Authority also notes the lack of competition in the current LFAS market as a driver of higher costs in this market.

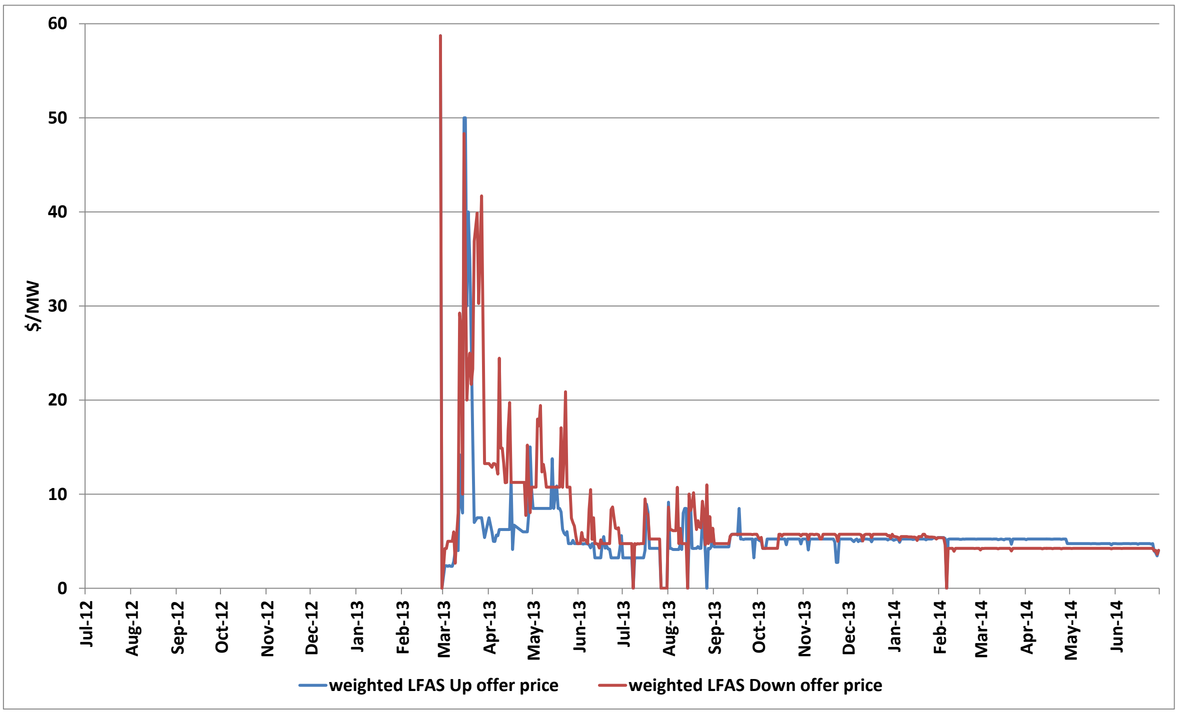
Figure 21 Synergy's daily weighted average LFAS Up offer price and LFAS Down offer price



Synergy is required under the Market Rules (Market Rule 7B.2.5) to provide offers for total LFAS volumes required by the market. In other words, based on the current requirement of 72 MW, Synergy is required to offer at least 72 MW into the LFAS market.

As shown in Figure 23, prices offered since early 2013 have followed a broadly similar pattern during 2013 and 2014.

Figure 22 NewGen's daily weighted average LFAS Up offer price and LFAS Down offer price



NewGen made its first offer into the LFAS market on 27 February 2013. Unlike Synergy, NewGen does not provide offers in every Trading Interval and is not able to offer the full amount of LFAS required by the market (as noted earlier, it can provide up to 30 MW).

As seen in Figure 22, the average prices that were offered by NewGen for both LFAS Up and LFAS Down tended to decline over time. There was very little variability in the weighted LFAS Up and LFAS Down offer price provided by NewGen during the current Reporting Period, with a weighted average offer price of $5.01/MW for LFAS Up and $5.08/MW for LFAS Down. The highest daily average LFAS Down price submitted by NewGen was $11/MW, which took place on 27 August 2013. From the start of September 2013 until the end of the current Reporting Period in June 2014, the range of daily average LFAS Down offer prices for NewGen was between $4.25/MW and $5.75/MW.

Figure 23 LFAS Up Peak Summary Statistics

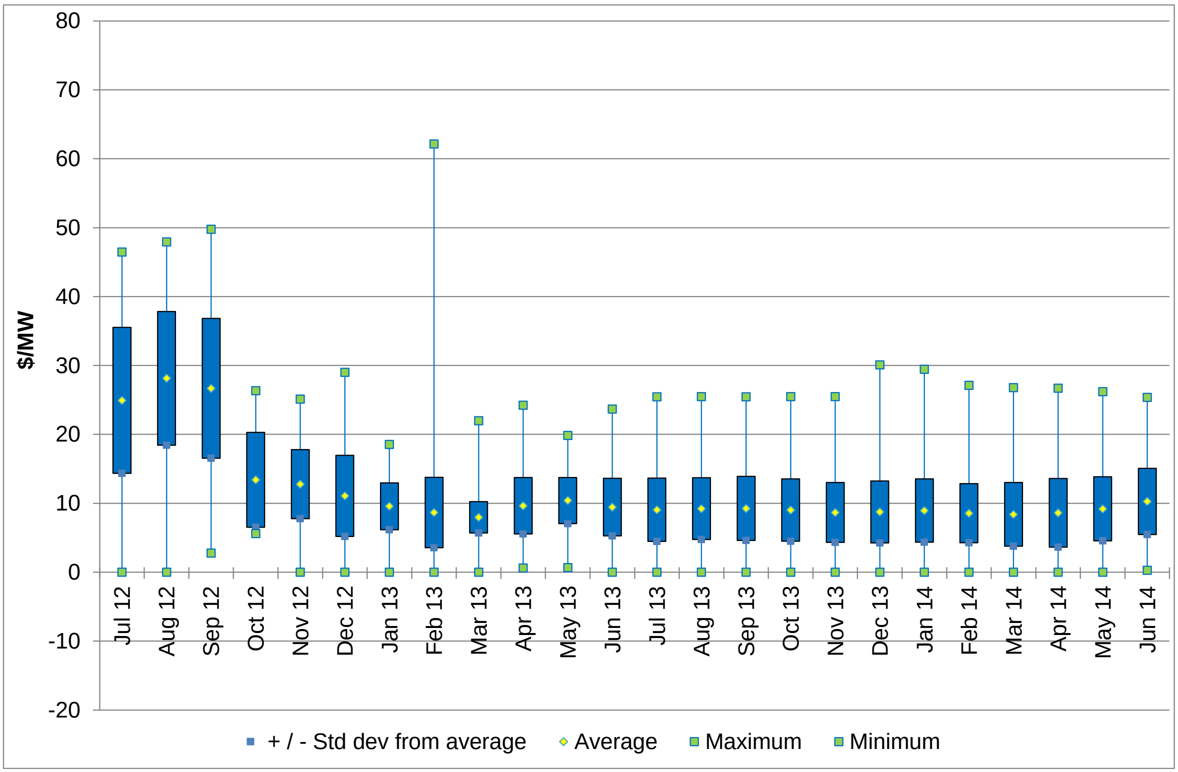


Figure 24 LFAS Down Peak Summary Statistics

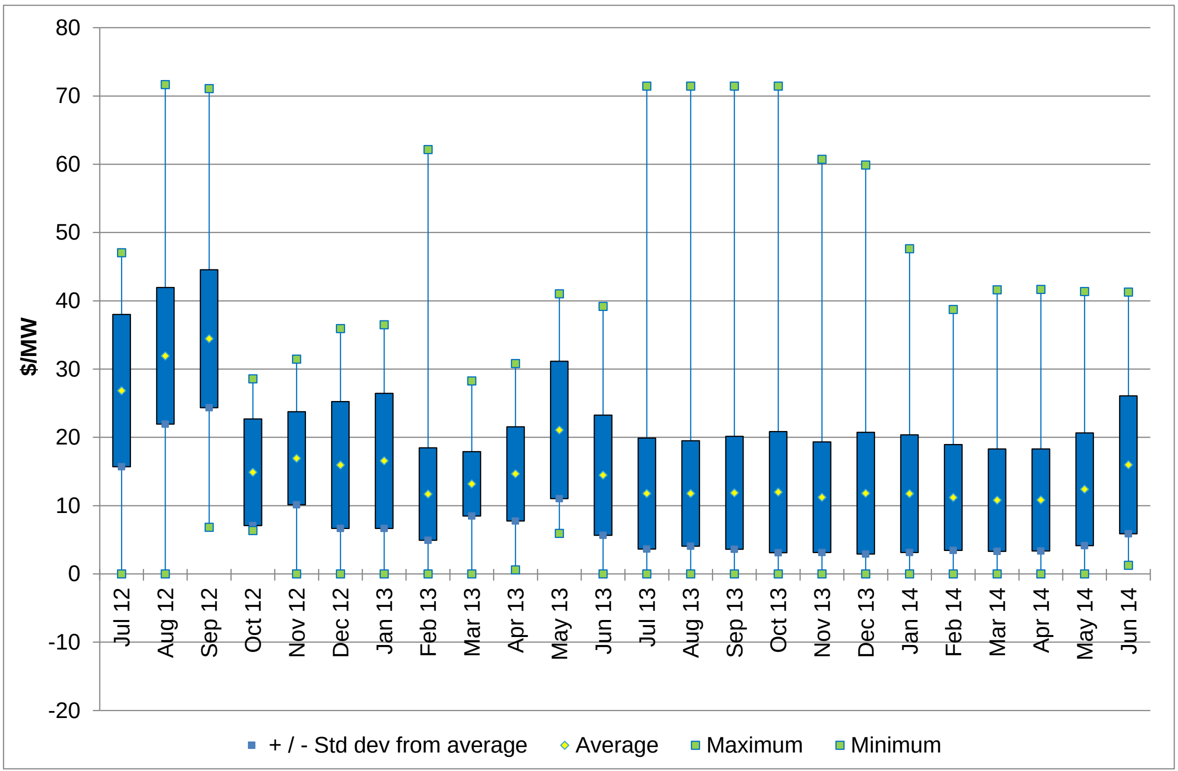


Figure 25 LFAS Up Off Peak Summary Statistics

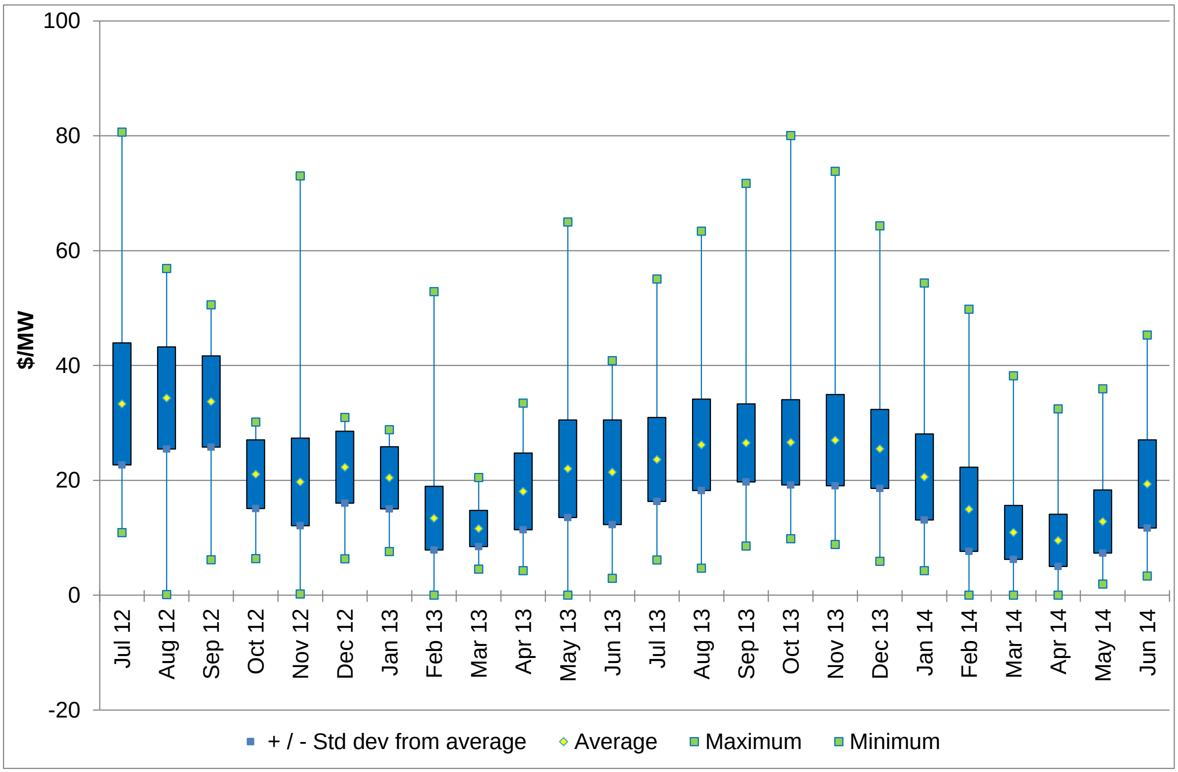
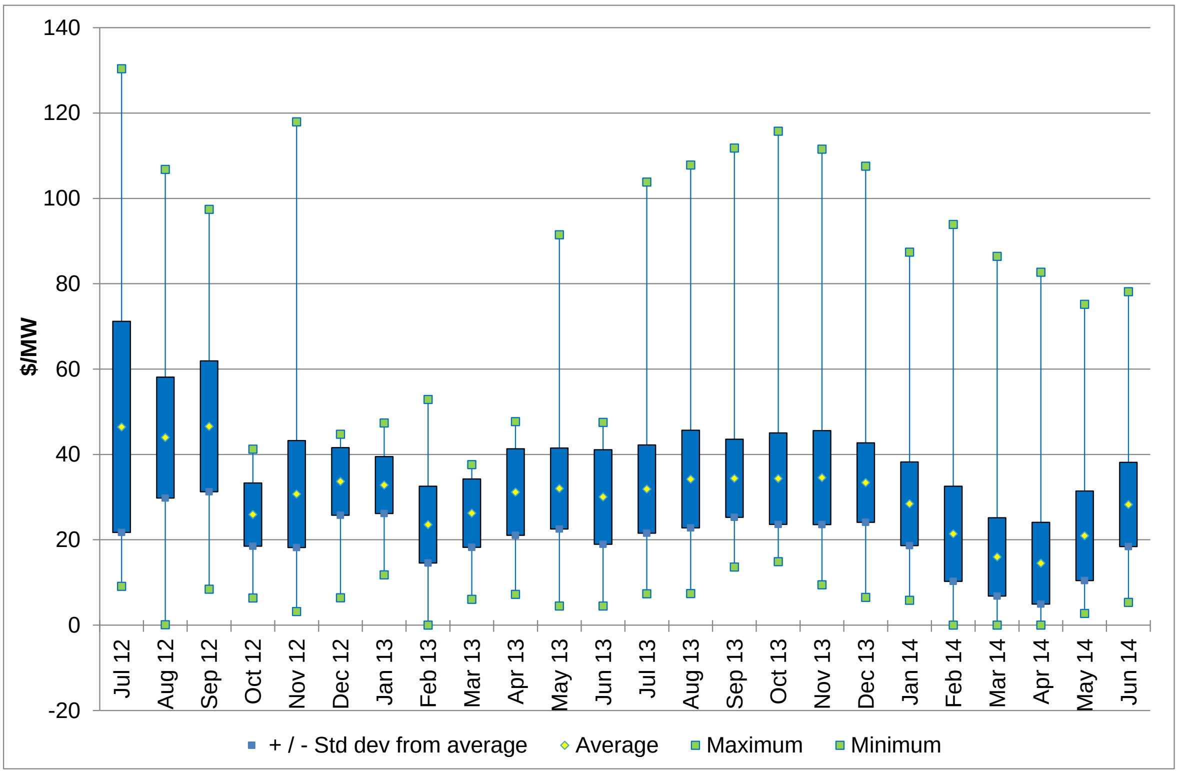


Figure 26 LFAS Down Off Peak Summary Statistics



Clause 2.16.4(fA) of the Market Rules requires the IMO to calculate the correlation between capacity offered into LFAS and the incidence of high prices. In previous Reports to the Minister the Authority highlighted that a simple correlation between capacity and prices will fail to capture other factors that can influence prices, such as bidding behaviour and demand conditions, and that more detailed analysis was required to understand the key determinants of high prices. For these reasons, correlations between LFAS Prices and quantities offered are not included in this report.

As required under 2.16.4(g), the IMO investigates high price incidents observed in LFAS to identify the key drivers and whether any further action is required. The results from this analysis are provided to the Authority and discussed at the regular surveillance meeting held between the two organisations.

1.7 The effectiveness of the Independent Market Operator in carrying out its functions

Clause 2.1.2 of the Market Rules provides that the functions of the IMO are:

- to administer the Market Rules;
- to operate the Reserve Capacity Mechanism, the STEM, the LFAS Market, and the Balancing Market;
- to settle such transactions as it is required to under the Market Rules;
- to carry out a Long Term PASA study and to publish the Statement of Opportunities Report;
- to do anything that the IMO determines to be conducive or incidental to the performance of the IMO's functions;
- to process applications for participation, and for the registration, deregistration and transfer of facilities;
- to release information required to be released by the Market Rules;
- to publish information required to be published by the Market Rules;
- to develop amendments to the Market Rules and replacements for them;
- to develop Market Procedures, and amendments and replacements for them, where required by the Market Rules;
- to make available copies of the Market Rules and Market Procedures, as are in force at the relevant time;
- to monitor other Rule Participants' compliance with the Market Rules, to investigate potential breaches of the Market Rules, and if thought appropriate, initiate enforcement action under the Regulations and the Market Rules;
- to support the Authority in its market surveillance role, including providing any market related information required by the Authority;
- to support the Authority in its role of monitoring market effectiveness, including providing any market related information required by the Authority; and
- to carry out any other functions conferred, and perform any obligations imposed, on it under the Market Rules.

Clause 2.14.3 of the Market Rules sets out the requirements for the audit of the IMO. It stipulates that the IMO must ensure that the Market Auditor carries out the audits of such matters as the IMO considers appropriate, which must include:

a) the compliance of the IMO's internal procedures and business processes with the Market Rules;

b) the IMO's compliance with the Market Rules and Market Procedures; and

c) the IMO's market software systems and processes for software management.

PA Consulting's 2014 audit report on the compliance of the IMO's internal processes and procedures with the Market Rules, and the IMO's compliance with the Market Rules and Market Procedures (**Audit Report**) distinguishes between material and non-material breaches. Breaches are classified as 'material' if they do not comply with the Market Rules and may affect decisions made by Market Participants, affect the outcome of the market, or otherwise affect the financial position of one or more Rule Participants. Non-material breaches are classified as such, if they do not comply with the wording of the Market Rules but do comply with their intention; or they do not comply with the Market Rules but are not likely to affect decisions made by Market Participants, affect the outcome of the market, or otherwise affect the financial position of one or more Rule Participants.

In PA Consulting's 2014 Audit Report, material breaches of clause 4.12.4(c)(v) were the only material breaches noted. Clause 4.12.4 (c)(v) specifies that for Interruptible Loads, Demand Side Programmes and Dispatchable Loads, the Reserve Capacity Obligation Quantity (**RCOQ**) will equal zero for Trading Intervals that fall outside of the periods when they can be dispatched, which must include the period between noon and 8:00 PM on all business days. The IMO should have calculated the RCOQ to be zero, as per the terms of Demand Side Programme contracts under 4.12.4(c)(v), and, due to a software defect, did so on business days, but not on non-business days from January 2013 to November 2013.

This breach impacted two Demand Side Programmes between May 2013 and November 2013, whereby the IMO collected $26,000 more in refunds from the Demand Side Programmes than it should have. This refund excess has since been returned by the IMO to the affected participants, and a patch that corrects the software defect has been implemented.

The remaining breaches identified by PA consulting were non-material. A number of multiple breaches of clauses 4.27.1 and 9.4.7 were technical in nature, in that the IMO were compliant with the intent of the rules, and it is the wording of the rules that requires changing[14]. PA consulting noted that, with a few exceptions,[15] the IMO had not breached obligations identified as non-compliance incidents in the previous year's audit, and that the IMO had been proactive in self-reporting instances of non-compliance and actively managing remedial actions to address any incidents at senior management level.

[14] Clause 4.27.1 requires that the IMO monitor the total availability of capacity in the SWIS on a daily basis so that they can implement clause 4.27.2, which requires the IMO to assess on a monthly basis, the number of days in the preceding months that SWIS capacity fell below particular thresholds as defined by this rule. However, the IMO monitors SWIS capacity on a monthly basis, implementing both clause 4.27.1 and 4.27.2 through a monthly software (Wholesale Electricity Market Systems; WEMS) event. Clause 9.4.7 requires that the IMO confirm, by telephone, receipt of a Capacity credit Allocation submission from a Market Participant within 30 minutes of receiving the submission. However, the IMO uses an automated confirmation system which is more efficient.

[15] Including Market Rules 2.5.8 (where the Minister is required to be notified of changes to protected provisions) and 2.34.8 (relating to the timeframe for the IMO notifying the Rule Participant of its acceptance or rejection of changes in Standing Data), both of which were self-reported by the IMO.

PA consulting observed a notable improvement in the quality of controls used by the IMO to manage non-compliance risk. Of note were uses of an alerts system notifying IMO staff of impending deadlines and market events/incidents, and issue and project tracking software; an improvement in obligation coverage and quality of the IMO's internal procedures relative to previous audits; and the continued use of electronic procedures to document work instructions, mitigating the risk of human error in undertaking complex multi-step processes.

PA consulting noted that this year's audit involved a comprehensive review of all IMO Internal Procedures against all relevant obligations in the Market Rules and related Market Procedures (where relevant). On the basis of this review, PA Consulting observed that there was a significant improvement in the coverage and quality of the IMO's internal procedures.

In its Audit Report of Compliance of the IMO's market software systems and processes for software management, PA Consulting observed two non-material incidents of non-compliance, i.e., one where the IMO's release process was not followed,[16] and another where a settlement system release was not independently certified prior to implementation.[17] PA Consulting also observed one rule change that was still yet to be reflected in production software, however this had not affected market outcomes, as the IMO manually performed the affected calculations where necessary.[18]

PA Consulting considered that the IMO had continued to improve its software management processes, with particular improvements in the Software Configuration Management Plan document, and an increased level of automation in the WEMS build and release process. PA Consulting also noted that the IMO had taken the opportunity afforded by the upcoming major settlement system release to significantly improve the Settlement system change, test and release processes.

PA Consulting did not observe anything that caused it to believe that the IMO's processes for software management are not compliant with the Market Rules, in all material respects.

The Authority is generally satisfied with the IMO's performance in effectively carrying out its functions prescribed in the Market Rules and Market Procedures.

1.8 Effectiveness of System Management in carrying out its functions

Clause 2.2.1 of the Market Rules provides that System Management has the function of operating the SWIS in a secure and reliable manner. The other functions of System Management in relation to the WEM are:

- to procure adequate Ancillary Services where Synergy cannot meet the Ancillary Service Requirements;

[16] This instance of non-compliance was with Market Rule 2.36.1(c) and related to post implementation verification release testing that was completed significantly after the release i.e., it was less timely than PA Consulting considered appropriate.

[17] This instance of non-compliance was with Market Rule 2.36.1(d) and specifically related to a change to WEMS database code that was implemented without independent certification of its correctness.

[18] RC_2010_22, which alters the calculation of capacity refunds for partially commissioned intermittent generators under Market Rule 4.26.1A(a)(ivA), is still yet to be reflected in production software.

- to assist the IMO in the processing of applications for participation and for the registration, de-registration and transfer of facilities;
- to develop Market Procedures, and amendments and replacements for them, where required by the Market Rules;
- to release information required to be released by the Market Rules;
- to monitor Rule Participants' compliance with Market Rules relating to dispatch and Power System Security and Power System Reliability; and
- to carry out any other functions or responsibilities conferred, and perform any obligations imposed, on it under the Market Rules.

Clause 2.14.6 of the Market Rules sets out the requirements for the audit of System Management. It stipulates that in accordance with the Monitoring Protocol, the IMO must at least annually, and may more frequently, where it reasonably considers that System Management may not be complying with the Market Rules and Market Procedures:

a) require System Management to demonstrate compliance with the Market Rules and Market Procedures by providing such records as are required to be kept under these Market Rules or any Market Procedure; or

b) subject System Management to an audit by the Market Auditor to verify compliance with the Market Rules and Market Procedures.

PA Consulting were again utilised by the IMO to undertake this function, and considered areas that had changed or should have changed since the annual audit undertaken in the previous year.

PA consulting identified four material breaches in two particularly important areas of non-compliance. For example, two material breaches related to Market Rule 7B.3.6 under which System Management must use facilities for LFAS in accordance with the selection information provided by the IMO. On each of 24 January 2014 and 11 March 2014, System Management implemented market dispatch in a manner that was not in accordance with the LFAS merit order for one interval, resulting in Participants providing different amounts of LFAS than they otherwise would have, and thus affecting market settlement payments. PA consulting noted that System Management does not have the tools in place to allow easy and systematic identification of such breaches and considered that further analysis and tools would greatly improve market transparency and likely identify further areas for improvement.

Additionally, two material breaches related to developing and publishing critical market information, and in particular to dispatch advisories being provided either late or not at all. System Management was found to be materially non-compliant with Market Rules 7.11.3, 7.11.5(d) and 7.11.6, which respectively require that System Management release a Dispatch Advisory:

- as soon as practicable after System Management becomes aware of a situation requiring the release of a Dispatch Advisory;
- in the event or anticipation of significant outages of generation transmission or customer equipment; and
- comprising particular information, such as the date and time of the dispatch advisory, and any actions System management plans to take in response to the situation, among other things.

PA Consulting noted that System Management's role as the sole provider of near-real-time information to Market Participants means that if it does not provide information, or provides it late, participants will not have a full set of information on which to base their market decisions. PA Consulting considered that the current dispatch advisory mechanism may not be the most efficient way to provide information to the market and recommended an investigation of alternate approaches to more effectively share System Management's view of likely future dispatch.

System Management was also found to be materially non-compliant with Market Rule 7A.3.15, which requires that System Management provides the IMO with a forecast of the Relevant Dispatch Quantity (**RDQ**) for each future Trading Interval in the Balancing Horizon, and updates the forecasts each time it has new information on which to determine these quantities.[19] Whilst System Management has a range of information available to it to assess the likely load,[20] the forecast provided to the IMO for use in its Balancing Forecast is produced by System Management's Metrix Load forecasting tool, which is also used in the Real-time dispatch engine that produces automatic electronic dispatch instructions to generation facilities.

The Metrix load forecast does not, however, always represent System Management's best estimate of the future RDQ, which is actually arrived at using a combination of load forecast tool outputs with similar past day profiles. PA consulting noted that this issue was raised in its previous audit, though the use of alternate forecasts is lower than in the previous year, due to improved performance of the Metrix tool, which was employed 98.5 percent of the time in the current audit period, compared to 93 percent of the time in the previous audit period.

Nevertheless, PA consulting considered that this breach was material, as the purpose of the IMO's Balancing forecast is to provide Market Generators with information upon which to assess whether to make (or update) a Balancing Submission and, as such, a more accurate forecast could influence participants to make different decisions in the market.

In relation to this, PA Consulting noted that System Management has not yet built functionality to publish this forecast to the market due to a number of issues, though PA Consulting believes that these issues can be resolved and more transparent information can be provided to the market.

PA Consulting also noted a number of developments that it considered did not relate directly to compliance with market rules, but that increased the general potential for non-compliance. These included:

- the need for System Management to articulate a long term strategy for automated systems for planning, scheduling and dispatch, and define a robust Service Level Agreement for system support, including target response and resolution times, to ensure that the critical real-time nature of the systems is embedded in support processes;

[19] System Management is not required to update the forecasts provided to the IMO more than once per Trading Interval. Also under Market Rule 7A.3.15, System Management may provide a forecast of the EOI Quantity for Non-Scheduled Generators, with each determined in accordance with the Power System Operation Procedure.

[20] This includes the output of two load forecasting tools, the ability to plot similar past days against the current load, and the ability to take a combination of the various inputs to arrive at the load forecast they think is the most likely to eventuate.

- System Management and Networks are still working through the process of defining how parties interact across the ring fence and in some areas, the appropriate level of oversight and authority to be exercised by System Management;
- System Management has made only minimal progress on improving and reorganising internal procedures, and in some areas has moved backwards, with ownership and governance of control room procedures currently unclear; and
- System Management staffing levels for real time activities are low compared to other System operators, particularly overnight.

Apart from these main findings, PA Consulting did not observe anything else that caused it to believe that System Management had not been compliant with the Market Rules and market procedures in all material respects. PA Consulting considered that System Management's compliance self-reporting practices still appeared robust, with staff proactively notifying potential compliance issues, though not all issues were noted by staff.

The Authority is generally satisfied with System Management's performance in effectively carrying out its functions prescribed in the Market Rules and Market Procedures. However, as identified in PA Consulting's report, there are a number of areas where improvements can be made.

1.9 Rule Change Process and the Procedure Change Process

Under clause 2.5 of the Market Rules, any person, including the IMO may formulate a Rule Change Proposal by completing a Rule Change Proposal form. The IMO may subject a Rule Change Proposal to the Fast Track Rule Change Process or the Standard Rule Change Process.[21] The Fast Track Rule Change Process takes about one month, while the Standard Rule Change Process takes six months or longer.

Information on Market Rule changes that have commenced, been rejected or are under development is available on the IMO's website. Table 4 provides a summary of the IMO's progression of Rule Change Proposals, from the commencement of the formal Rule Change process in December 2006 up until June 2014.

[21] Refer to clause 2.6 of the Market Rules for the Fast Track Rule Change Process and clause 2.7 for the Standard Rule Change Process.

Table 4 Progression of Rule Change Proposals since market commencement

Date range	Received	Commenced	Not progressed	Rejected	Under development
15 December 2006 and 31 July 2007	9	9[22]	-	-	-
1 August 2007 and 31 July 2008	36	36[23]	-	-	-
1 August 2008 and 31 July 2009	37	24[24]	-	3	10
1 August 2009 and 31 July 2010	19	15[25]	2	1	1
1 August 2010 and 31 July 2011	29	25[26]	2	-	2
1 August 2011 and 30 June 2012	13	10[27]	-	1	2
1 July 2012 and 30 June 2013	23	19[28]	-	2	2
1 July 2013 and 30 June 2014	12	7[29]	-	1	4

1.10 Dispatch process

In the new competitive Balancing Market that was introduced on 1 July 2012, Market Participants provide balancing submissions for each Trading Interval, specifying prices at which their facilities may be dispatched and by how much. The IMO uses these prices to construct the Balancing Merit Order (**BMO**), used by System Management for real time dispatch.

System Management uses the most recent BMO to determine and issue dispatch instructions to generators, to meet the expected demand trend during the Trading Interval. System Management may only depart from the BMO if it is necessary to maintain system security and reliability, and it may issue Dispatch Instructions to Demand Side Programmes or Dispatchable Loads if necessary.

The introduction of the new Balancing Market, has necessarily significantly increased the number of dispatch instructions.[30] System Management publishes a quarterly status report setting out the number and type of Dispatch Instructions issued, together with details of any non-compliance by Market Participants.[31] The Authority has not replicated that information in this report.

[22] As at the end of the 2007 calendar year.

[23] All of which have commenced.

[24] As at the time the 2009 Report to the Minister was released.

[25] As at the time the 2010 Report to the Minister was released.

[26] As at the time the 2011 Report to the Minister was released.

[27] As at the time the 2012 Report to the Minister was released.

[28] As at the time the 2013 Report to the Minister was released.

[29] As at the time the 2014 Report to the Minister was released.

[30] Prior to the new Balancing Market being introduced, Dispatch Instructions were generally only required if there was an unexpected change from IPP Resource Plans as Verve Energy was the default provider for all balancing energy.

[31] See reports published on IMO website http://www.imowa.com.au/home/electricity/market-information/system-management-reports

1.11 Planning processes

The planning processes consist of the following:

- long term planning, which is conducted annually;
- medium term planning, which is undertaken each month; and
- short term planning, which is carried out each week.

Each of the above planning processes involves a forecasting study, also known as the Projected Assessment of System Adequacy (**PASA**).

The Long Term PASA is undertaken by the IMO in order to determine the Reserve Capacity Target for each year in the ten-year period of the Long Term PASA Study Horizon. The results are presented in the IMO's Statement of Opportunities report, which is published on the IMO's website each year.[32]

System Management is required to undertake the Short Term PASA and the Medium Term PASA.[33]

Long Term PASA

As set out in the Executive Summary, the Authority considers that there are inherent difficulties with the IMO having sole responsibility for the long term demand forecasts, and considers it is likely to result in an overly pessimistic forecast of demand, and conservative estimate of the capacity requirement.

Medium Term PASA

System Management must carry out a Medium Term PASA study by the 15th day of each month and provide it to the IMO for publication on the Market website. Under clause 3.16 of the Market Rules, this study must consider each week of a three year planning horizon, starting from the month following the month in which the Medium Term PASA study is performed.

The Medium Term PASA study provides assistance to System Management with respect to:

- setting Ancillary Service Requirements over the year;
- outage planning for Registered Facilities; and
- assessing the availability of Facilities providing Capacity Credits, and the availability of other capacity.

Short Term PASA

Under clause 3.17 of the Market Rules, the Short Term PASA study must consider each six-hour period of a three week planning horizon (the Short Term PASA Planning Horizon).

[32] A report prepared in accordance with clause 4.5.13 presenting the results of the Long Term PASA study.

[33] The Short Term PASA is conducted in accordance with clause 3.17 of the Market Rules, while the Medium Term PASA is conducted in accordance with clause 3.16 of the Market Rules.

System Management must carry out a Short Term PASA study every Thursday and provides the results to the IMO for publication on the Market website.

The Short Term PASA assists System Management in assessing:

- the availability of capacity holding Capacity Credits in each six-hour period during the Short Term PASA Planning Horizon;
- the setting of Ancillary Service Requirements in each six-hour period during the Short Term PASA Planning Horizon; and
- final approvals of Planned Outages.

The Authority notes that the implementation of the new competitive Balancing Market has provided Market Participants with more dynamic, close to real time, information that compliments the weekly Short Term PASA.

System Management also publishes Dispatch Advisories to all Market Participants to advise them of significant changes to market conditions to enable them to adjust their bids accordingly.

As noted in PA Consulting’s report, there are a number of areas where the information provided by System Management to the market could be improved.

1.12 Compliance monitoring and enforcement measures in the Market Rules and Regulations

Compliance monitoring and enforcement requirements are defined under clauses 2.13 to 2.16 of the Market Rules, with specific obligations placed on the IMO, System Management and the Authority.

Compliance monitoring and enforcement measures undertaken by the IMO

Clause 2.13.2 of the Market Rules provides that the IMO must monitor other Rule Participants’ behaviour for compliance with the Market Rules and Market Procedures, in accordance with the Monitoring Protocol. The IMO is required to investigate potential breaches of the Market Rules and take enforcement action where appropriate, which can include applying to the Electricity Review Board (**ERB**) for fines or other orders. Under clause 2.15.3, the Monitoring Protocol must specify:

- the IMO’s monitoring processes for assessing compliance by Rule Participants with the Market Rules and Market Procedures;
- a process for System Management to demonstrate compliance with the Market Rules, Market Procedures and audit processes, where the IMO requires such demonstration or an audit;
- a process for Rule Participants to report alleged breaches of the Market Rules and Market Procedures;
- processes for investigating alleged breaches;
- guidelines for the IMO when issuing warnings about alleged breaches to Rule Participants; and

- the procedure for bringing proceedings in respect of specified Market Rule breaches before the ERB.

The IMO has been producing biannual reports on enforcement action taken to the ERB pursuant to clause 2.13.26 of the Market Rules. During the period 21 September 2013 to 20 September 2014 no new proceedings were brought before the ERB by the IMO.[34]

The Authority notes that the IMO's compliance team has continued to actively monitor the major Market Generators' bidding behaviour since commencement of the new Balancing and LFAS markets. The Authority is of the view that the IMO's compliance team has been effective in identifying and analysing potential anomalous behaviour and outcomes in the new Balancing and LFAS markets thus far.

The IMO's compliance with the Market Rules is audited once a year by the Market Auditor.[35] Pursuant to the Market Rules, the IMO requires that System Management either demonstrate compliance with the Market Rules and Market Procedures or undergo an audit by the Market Auditor. Each year since market commencement, System Management has elected to undergo an audit by the Market Auditor.

Compliance monitoring and enforcement measures undertaken by System Management

Clause 2.13.6 of the Market Rules provides that System Management must monitor Rule Participants' behaviour for compliance with the provisions of the Market Rules referred to in clause 2.13.9 of the Market Rules,[36] and the Power System Operation Procedures developed by System Management. System Management must report any alleged breaches of the provisions of the Market Rules referred to in clause 2.13.9 of the Market Rules or the Power System Operation Procedures to the IMO, in accordance with the Monitoring and Reporting Protocol.[37]

For example, clause 2.13.9 of the Market Rules requires System Management to monitor Rule Participants for breaches of clause 7.7.6(b) of the Market Rules, which states that a Market Participant must confirm receipt of the Dispatch Instruction or Operating Instruction and advise if it cannot comply, or cannot fully comply, with the Dispatch Instruction or Operating Instruction.

[34] IMO website, six-monthly compliance reports September 2013 to March 2014, and March 2014 to September 2014, http://www.imowa.com.au/six-monthly-compliance-reports

[35] The Market Auditor is an auditor appointed by the IMO to conduct at least annual audits of: the compliance of the IMO's internal procedures and business processes with the Market Rules; the IMO's compliance with the Market Rules and Market Procedures; and the IMO's market software systems and processes for software management. In addition, the Market Rules require that the IMO must at least annually require System Management to demonstrate compliance with the Market Rules and Market Procedures by providing such records as are required to be kept under the Market Rules or any Market Procedures, or subject System Management to an audit by the Market Auditor to verify compliance with the Market Rules and Market Procedures. In accordance with this requirement, the IMO has subjected System Management to an annual audit by the Market Auditor each year since market commencement.

[36] Pursuant to clause 2.13.9 of the Market Rules, System Management must monitor Rule Participants for breaches of clauses 3.4.6 and 3.4.8; clauses 3.5.8 and 3.5.10; clauses 3.6.5 and 3.6.6B; clauses 3.16.4, 3.16.7 and 3.16.8A; clauses 3.17.5 and 3.17.6; clause 3.18.2(f); clauses 3.21A.2, 3.21A.12, and 3.21A.13(a); clauses 3.21B.1 and 3.21B.2; clause 4.10.2, where System Management is instructed by the IMO under clause 4.25.13; clause 7.2.5; clause 7.5.5; clause 7.7.6(b); clauses 7.10.1, 7.10.3 and 7.10.6A; and clause 7.11.7.

[37] IMO website, Power System Operation Procedure: Monitoring and Reporting Protocol, http://www.imowa.com.au/docs/default-source/rules/system-management/ppcl0012/ppcl0012_final_proposed_amended_procedure.pdf?sfvrsn=2

Clause 2.13.9 of the Market Rules requires System Management to monitor Market Participants' compliance with Dispatch Instructions and Operating Instructions.[38] A Market Participant must comply with the most recently issued Dispatch Instruction, Operating Instruction or Dispatch Order applicable to the Registered Facility for the Trading Interval. A Market Participant must inform System Management as soon as practicable where it cannot comply or fully comply with a Dispatch Instruction or an Operating Instruction. A Market Participant must also comply with a request made under clause 7.10.5(c) by System Management for an explanation for deviations in a manner that is not within the Tolerance Range determined under the Market Rules.

Clause 2.13.9 also requires System Management to monitor Market Participants' and Network Operators' compliance with directions that System Management issues in any Dispatch Advisory under clause 7.11.6(f) or directions under clause 7.11.6B.[39]

As part of System Management's reporting obligations, under clause 7.12.1 of the Market Rules, System Management must provide a report once every three months on the performance of the market with respect to the dispatch process.[40] This report must include details of:

- the incidence and extent of issuance of Operating and Dispatch Instructions;
- the incidence and extent of non-compliance with Operating and Dispatch Instructions;
- the incidence and reasons for the issuance of Dispatch Instructions to Balancing Facilities Out of Merit, including for the purposes of clause 7.12.1, issuing Dispatch Orders to the Balancing Portfolio in accordance with clause 7.6.2;
- the incidence and extend of transmission constraints;
- the incidence and extent of shortfalls in Ancillary Services, involuntary curtailment of load, High Risk Operating States and Emergency Operating States, together with:
    - a summary of the circumstances that caused each such incident; and
    - a summary of the actions that System Management took in response to the incident in each case.
- the incidence and reasons for the selection and use of LFAS Facilities under clause 7B.3.8.

System Management has fulfilled this requirement under the Market Rules, and has produced four status reports on the performance of the market with respect to the dispatch process covering the period from 1 July 2013 to 30 June 2014 during this Reporting Period.

Each year since market commencement, System Management has been subject to an audit by the Market Auditor, pursuant to the Market Rules.

Compliance monitoring undertaken by the Authority

Pursuant to clause 2.16.9 of the Market Rules, the Authority, with the assistance of the IMO, must monitor the Ancillary Service Contracts that System Management enters into, and the criteria and process that System Management uses to procure Ancillary Services from other

[38] Clause 7.10.1, 7.10.3, and 7.10.6A of the Market Rules.

[39] Clause 7.11.7 of the Market Rules.

[40] See the IMO website, http://www.imowa.com.au/system_management_reports

persons; inappropriate and anomalous market behaviour; market design problems or inefficiencies; and problems with the structure of the market.

In relation to inappropriate and anomalous market behaviour, the Authority must monitor whether:

- prices offered by a Market Generator in its Portfolio Supply Curve reflect the Market Generator's reasonable expectation of the SRMC of generating the relevant electricity;
- prices offered by a Market Generator in its Balancing Submission exceed the Market Generator's reasonable expectation of the SRMC of generating the relevant electricity; and
- prices offered by a Market Generator in its LFAS Submission exceed the Market Generator's reasonable expectation of the incremental change in SRMC incurred by the LFAS Facility in providing the relevant LFAS.

If, upon an investigation,[41] the Authority determines the above to be the case, the Authority must request that the IMO refer the matter to the ERB for a civil penalty to be imposed on the relevant Market Participant.[42]

The Authority and the IMO have utilised a SRMC modelling tool to assist in the monitoring of prices offered by a Market Generator in its Portfolio Supply Curve to assess whether these prices reflect the Market Generator's reasonable expectation of the SRMC of generating the relevant electricity. The Authority has issued information requests to Market Generators that have the potential to exercise market power, for the necessary data and information as inputs into the SRMC model. The IMO manages the operation of the SRMC model, which involves reviewing the modelled results in order to determine whether the prices submitted with Market Generators' Portfolio Supply Curves reflect the reasonable expectation of the SRMC of generating the relevant electricity. The Authority and the IMO regularly review the results of this modelling.

The Authority and the IMO have incorporated the Balancing and LFAS markets into the SRMC modelling tool, in order to assist in the monitoring of prices offered by Market Generators in these markets. In addition, the Authority and the IMO have also been reviewing bidding behaviour by Market Generators and prices that are offered by Market Generators in their Balancing and LFAS submissions, in order to assess whether these prices exceed the Market Generator's reasonable expectation of the SRMC of generating the relevant electricity, and the incremental change in SRMC incurred by the LFAS Facility, respectively. The Authority and the IMO liaise on a regular basis in relation to these reviews and are continuing to refine this process.

The Authority is currently undertaking a formal investigation into pricing behaviour by Vinalco Energy.

[41] Clause 2.16.9E of the Market Rules.

[42] Clause 2.16.9H of the Market Rules.

1.13 Inappropriate and anomalous market behaviour

The Authority, with the assistance of the IMO, is continuing its observation of the behaviour of participants in the new competitive Balancing market and LFAS market, as well as in the STEM. The behaviour of participants is being actively monitored to ensure generators offer their electricity at prices that are reflective of their expected SRMC for generating the electricity.[43] As noted above, the Authority is currently undertaking a formal investigation into pricing behaviour by Vinalco Energy.

No significant issues have been identified in relation to the MSDC surveillance items.

[43] Refer to clause 2.16.9 of the Market Rules for details.

Appendix 3 MSDC – Additional Charts

Figure 27 **Daily average quantity of STEM Offers (cumulative MWh per Trading Interval)**

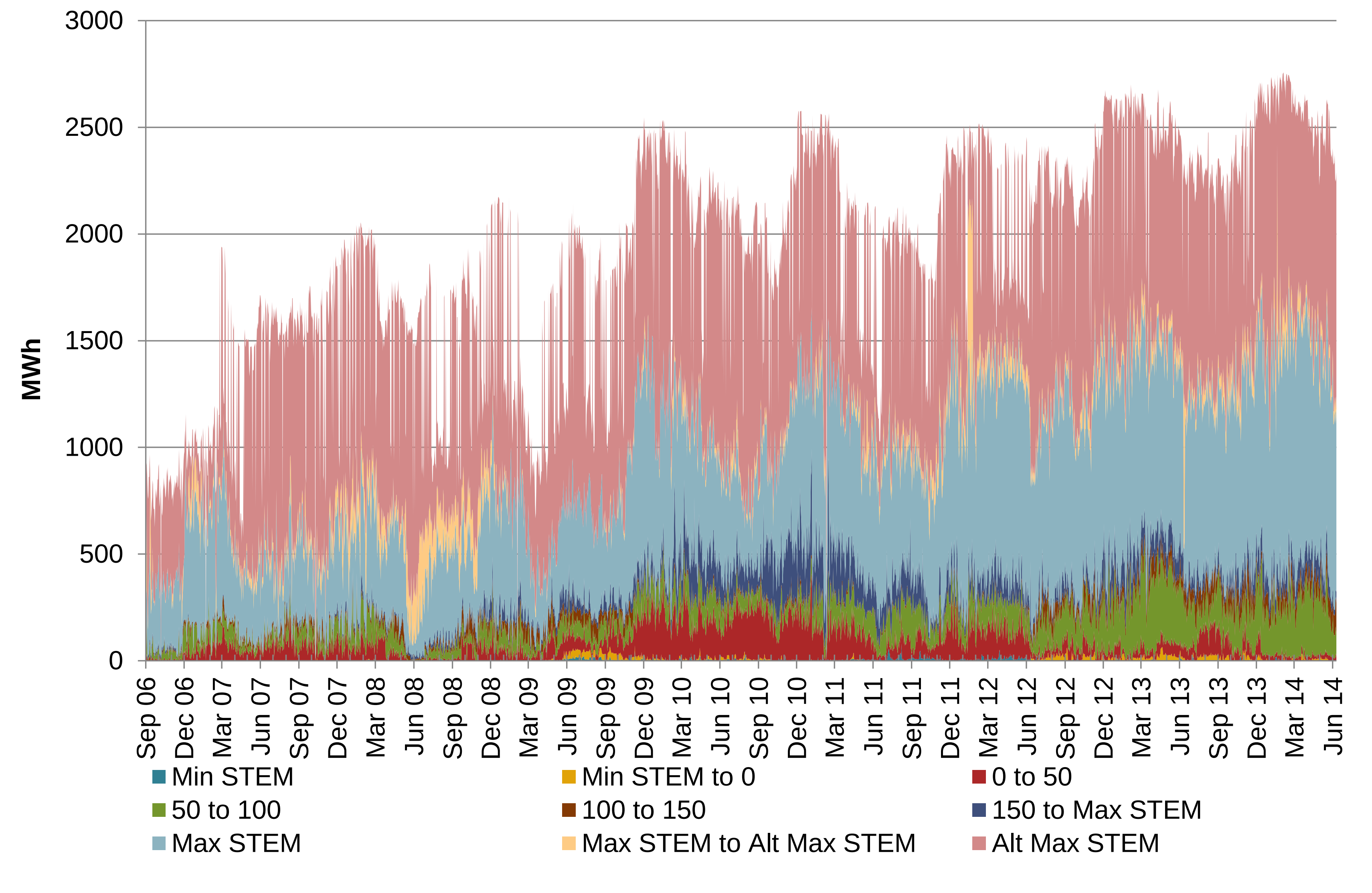


Figure 28 Alcoa's daily average STEM Offers (cumulative MWh per Trading Interval)

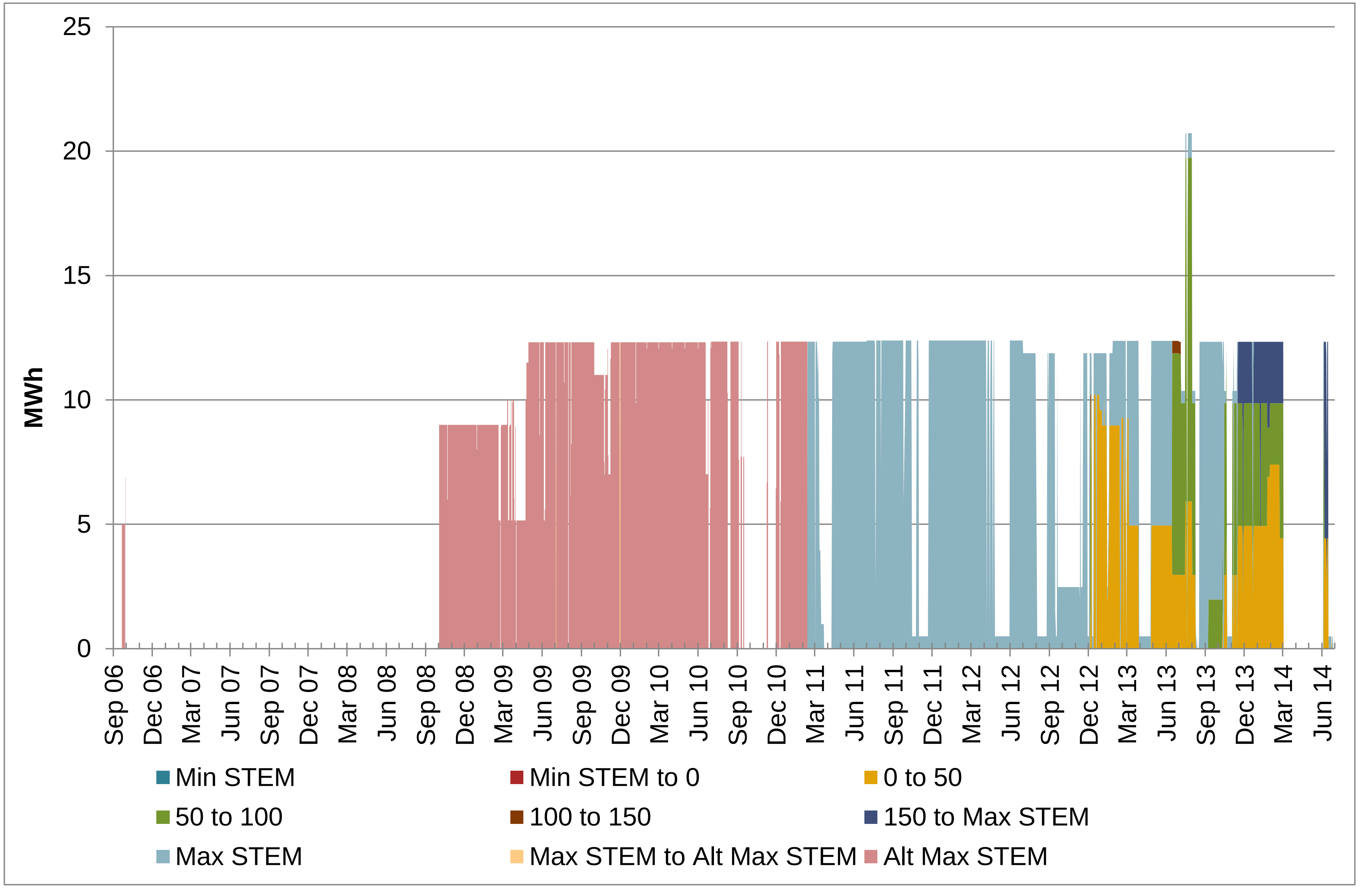


Figure 29 **Alinta's daily average STEM Offers (cumulative MWh per Trading Interval)**

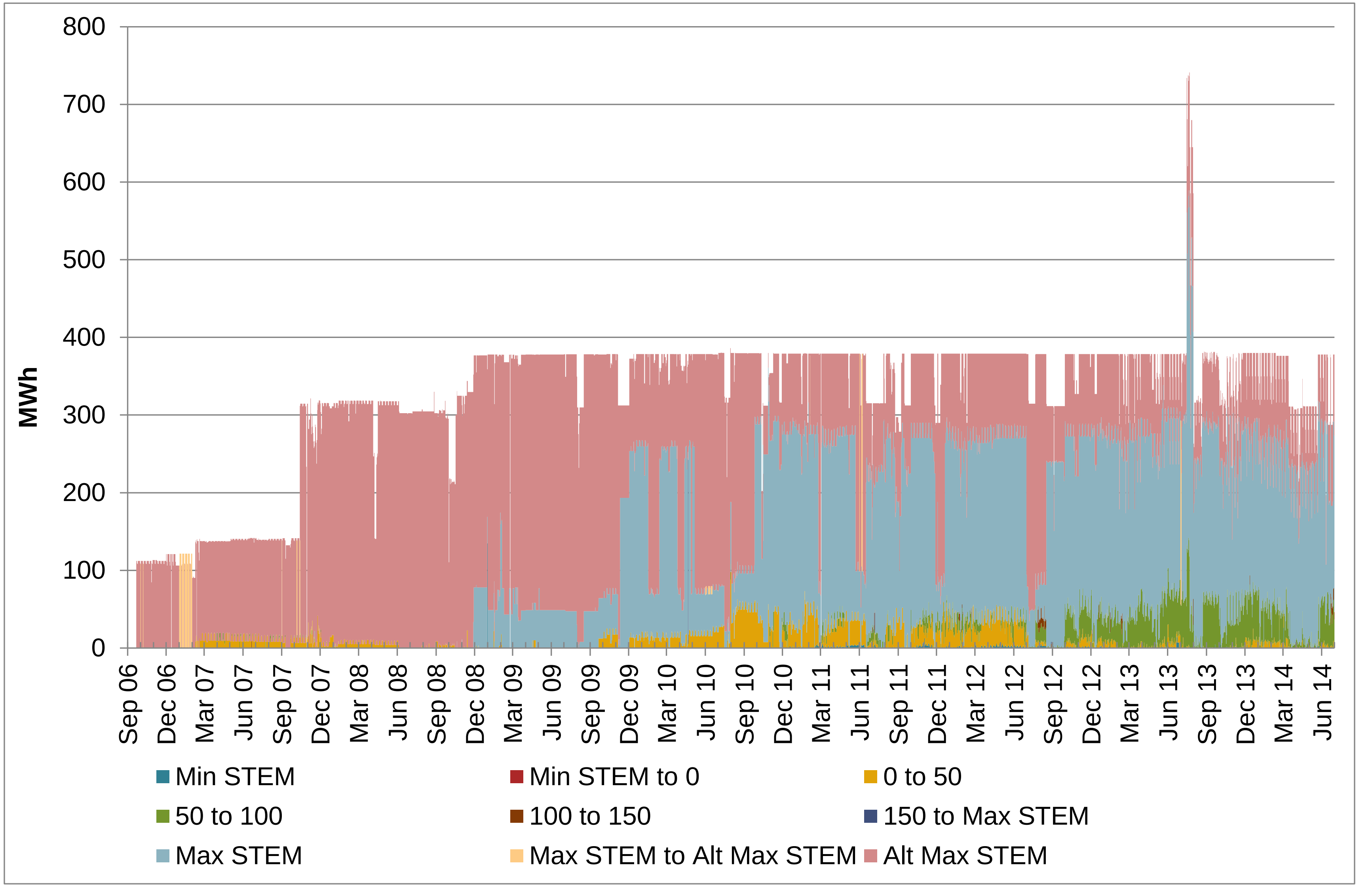


Figure 30 ERM Power's daily average STEM Offers (cumulative MWh per Trading Interval)

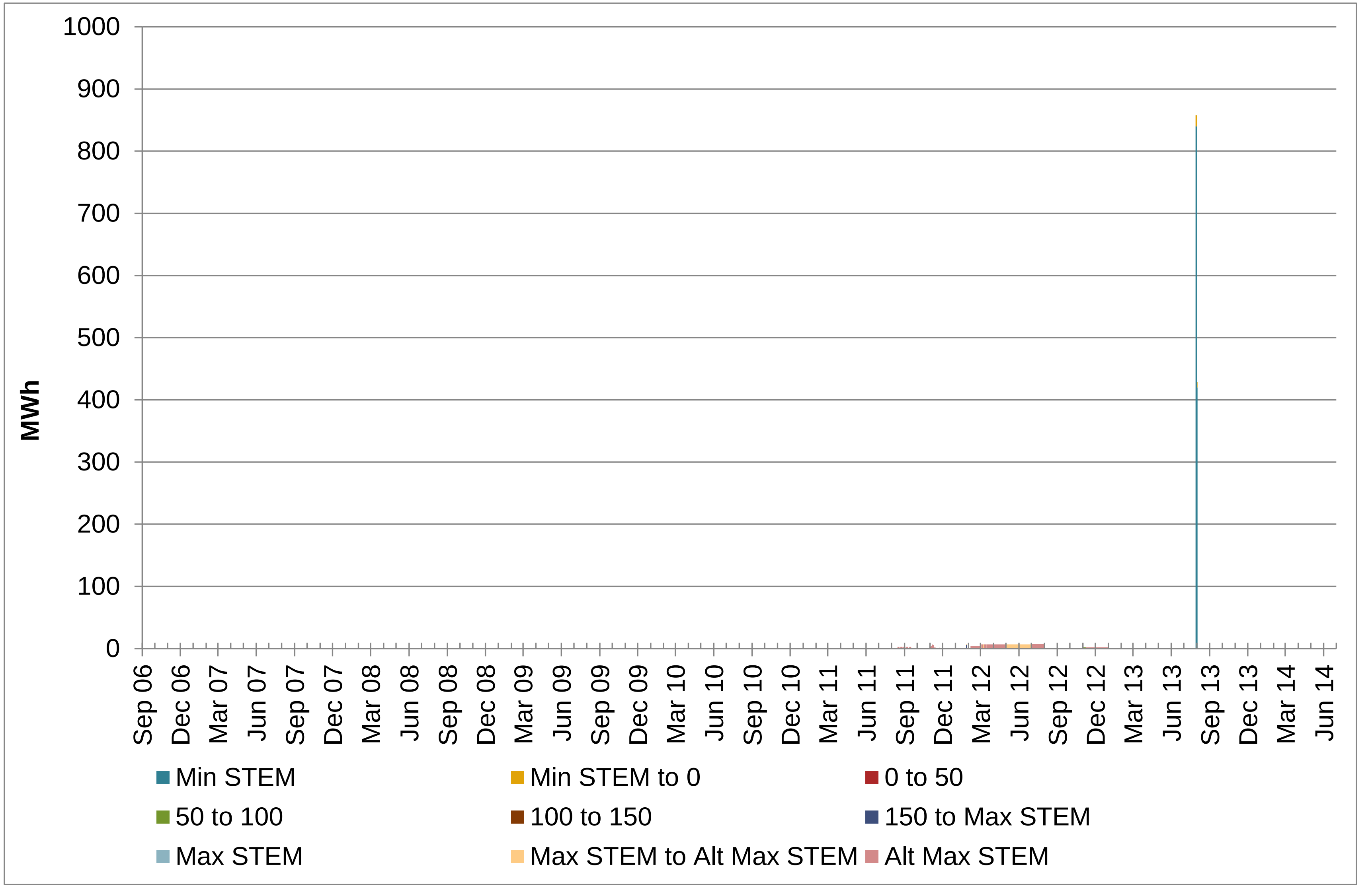


Figure 31 Goldfields Power's daily average STEM Offers (cumulative MWh per Trading Interval)

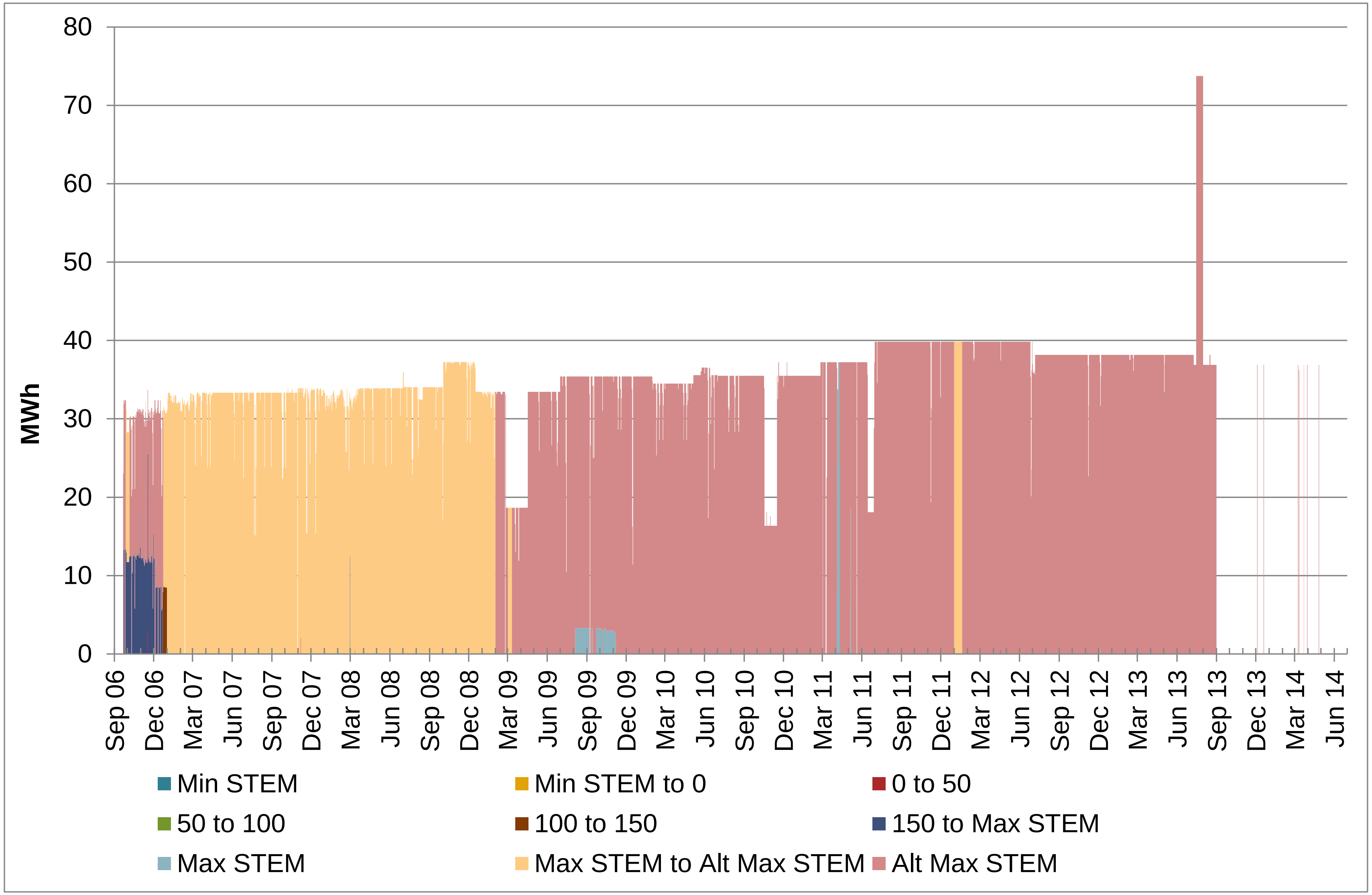


Figure 32 **Griffin Power's daily average STEM Offers (cumulative MWh per Trading Interval)**

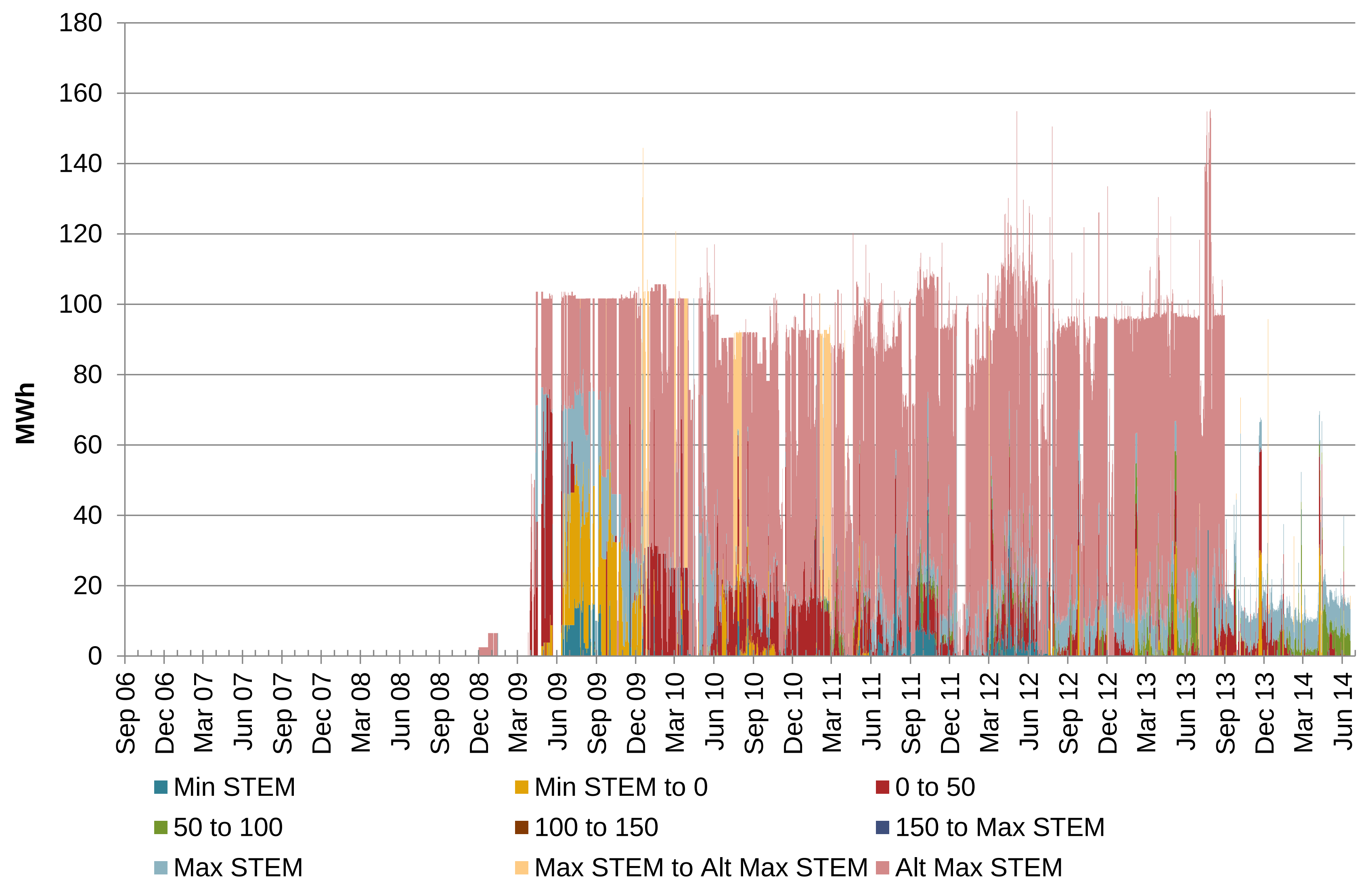


Figure 33 Griffin Power 2's daily average STEM Offers (cumulative MWh per Trading Interval)

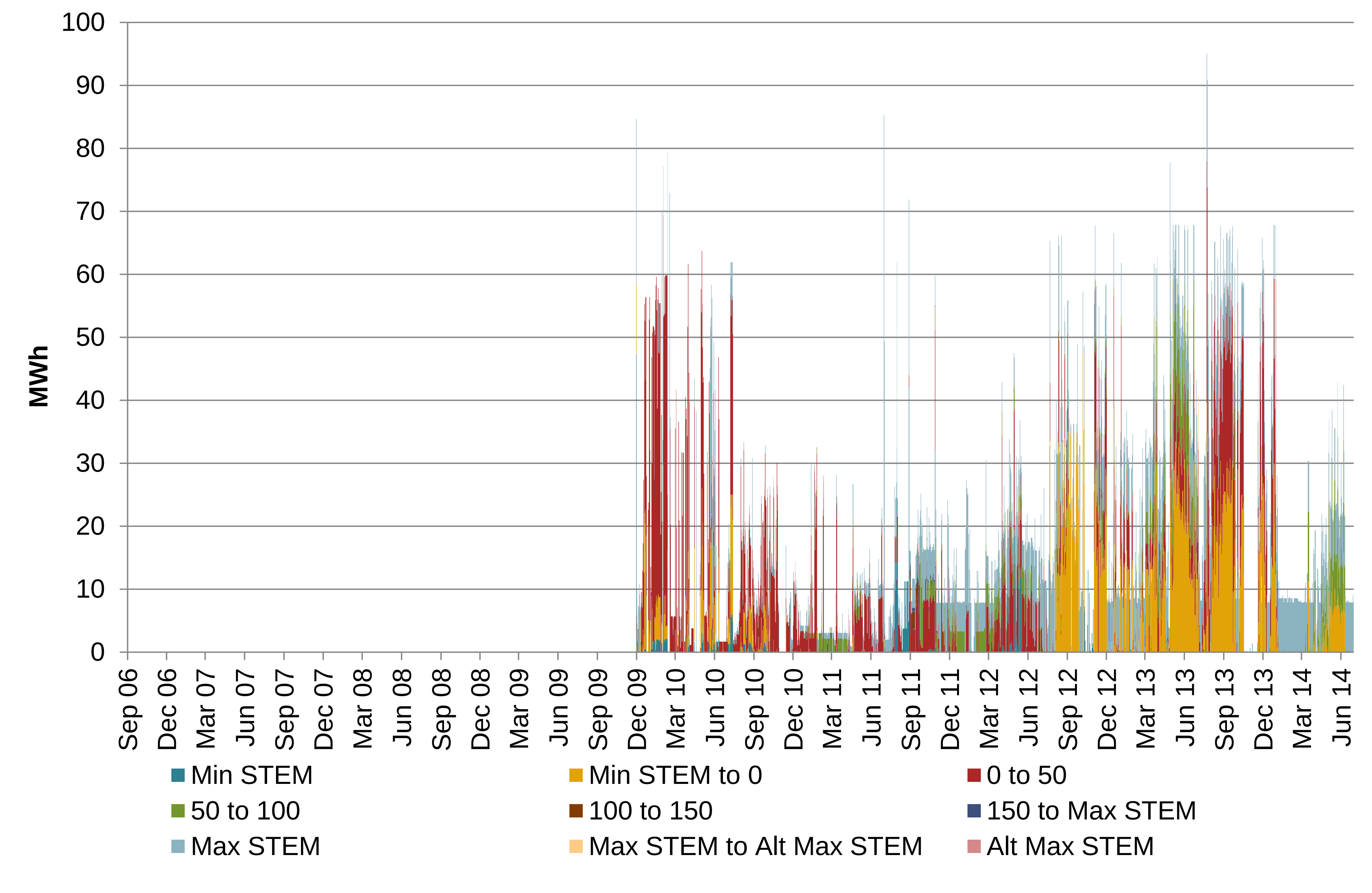


Figure 34 Karara's daily average STEM Offers (cumulative MWh per Trading Interval)

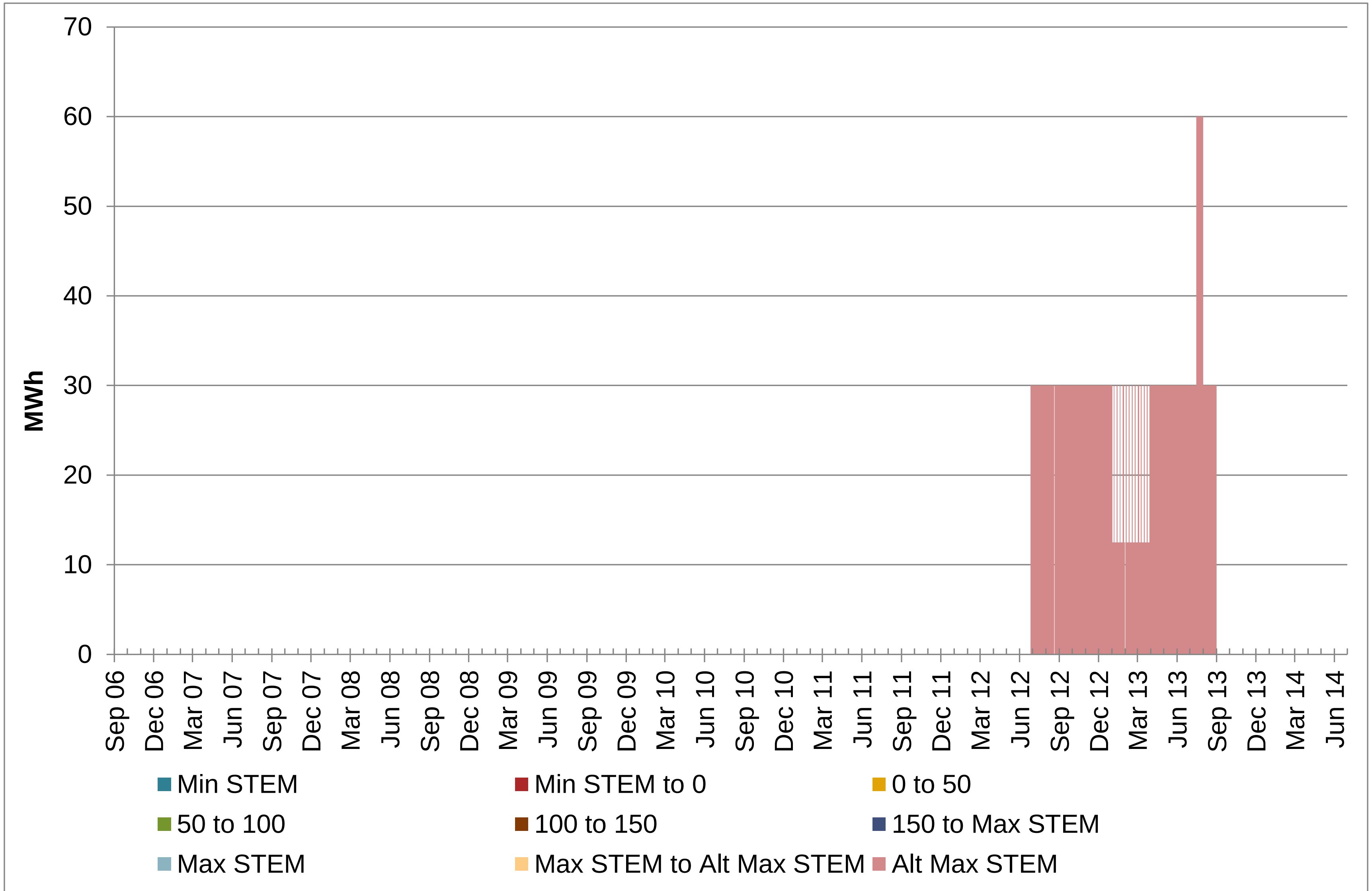


Figure 35 Landfill Gas and Power's daily average STEM Offers (cumulative MWh per Trading Interval)

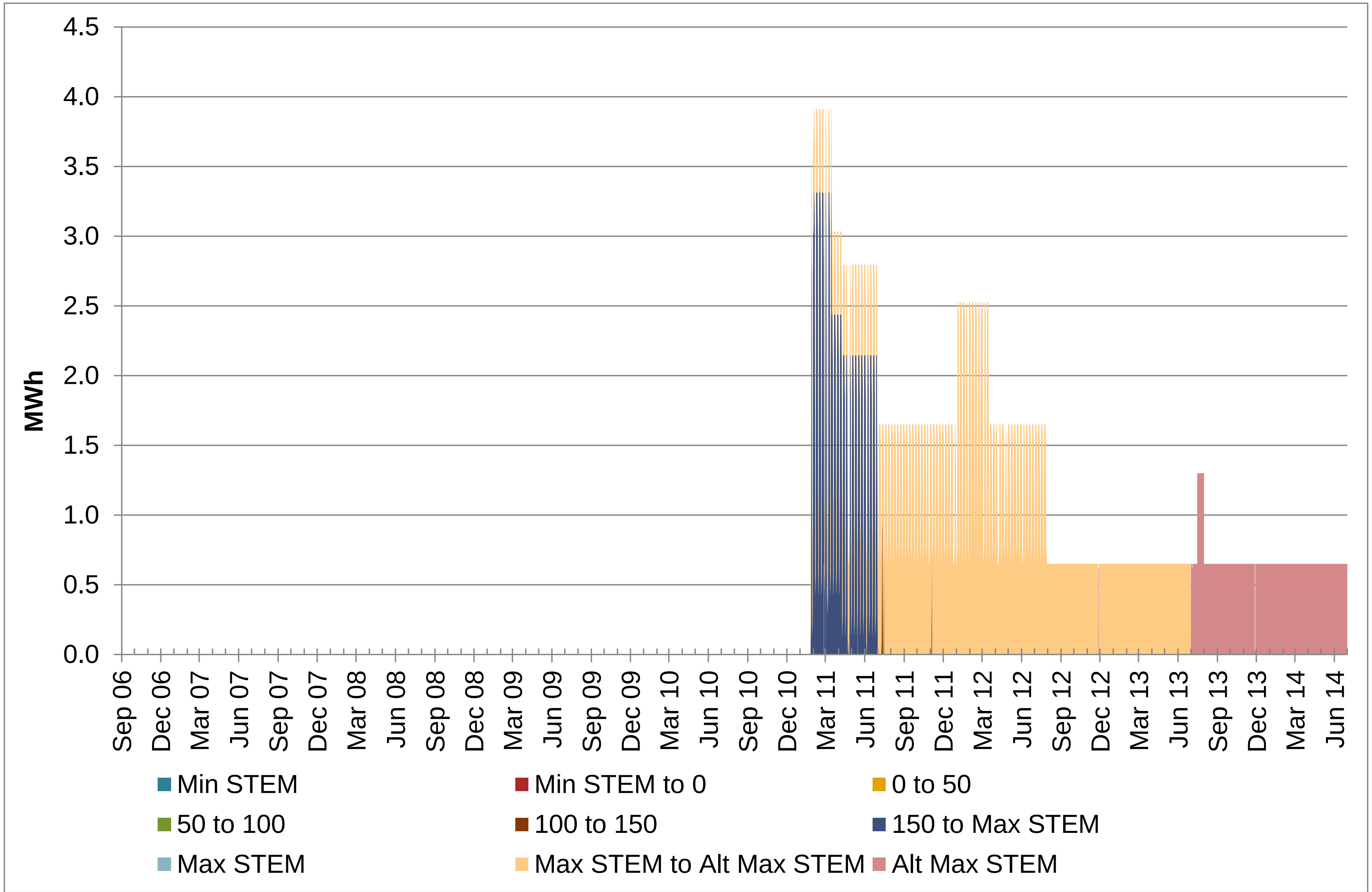


Figure 36 **Merredin daily average STEM Offers (cumulative MWh per Trading Interval)**

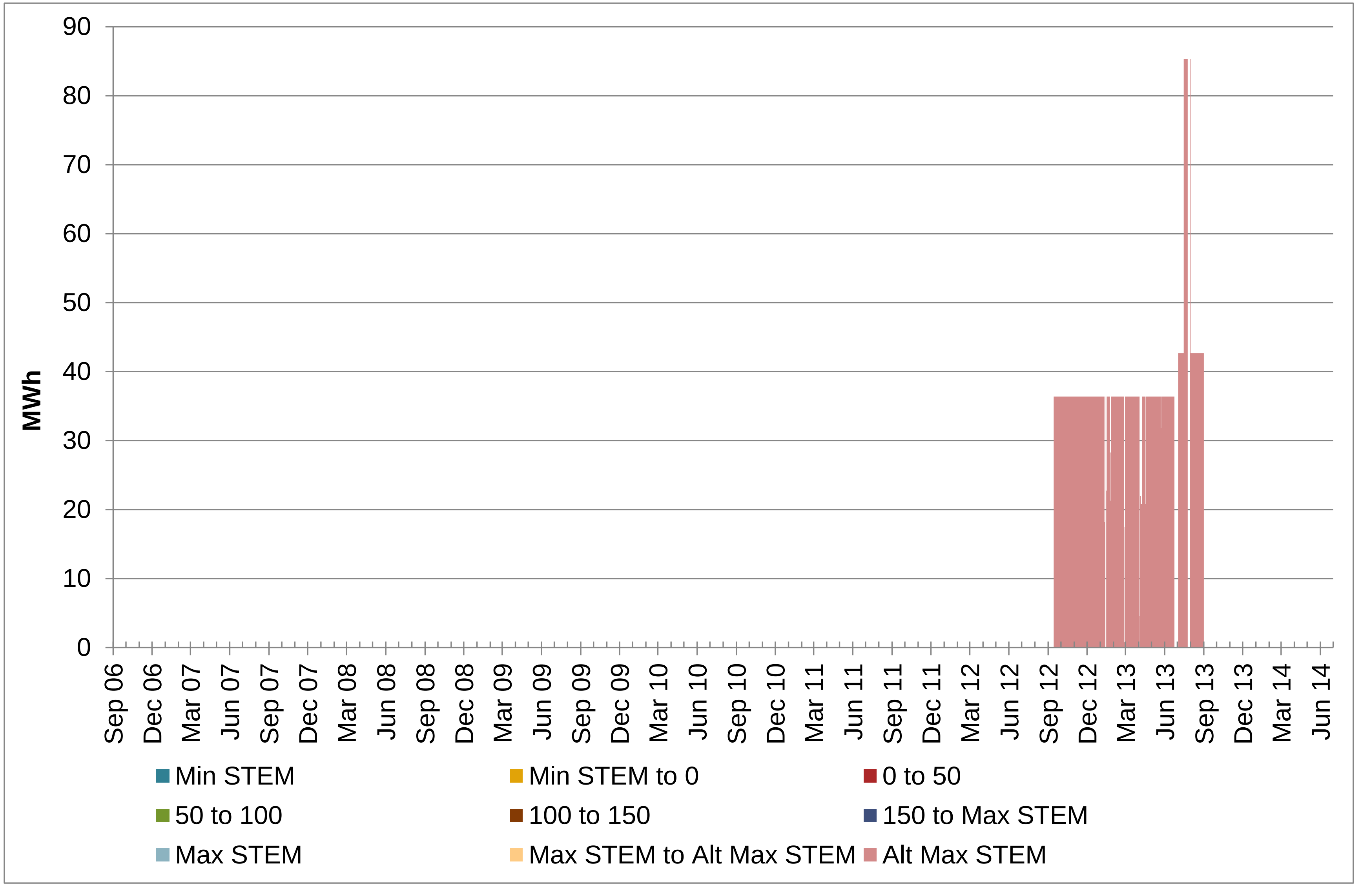


Figure 37 NewGen Power Kwinana's daily average STEM Offers (cumulative MWh per Trading Interval)

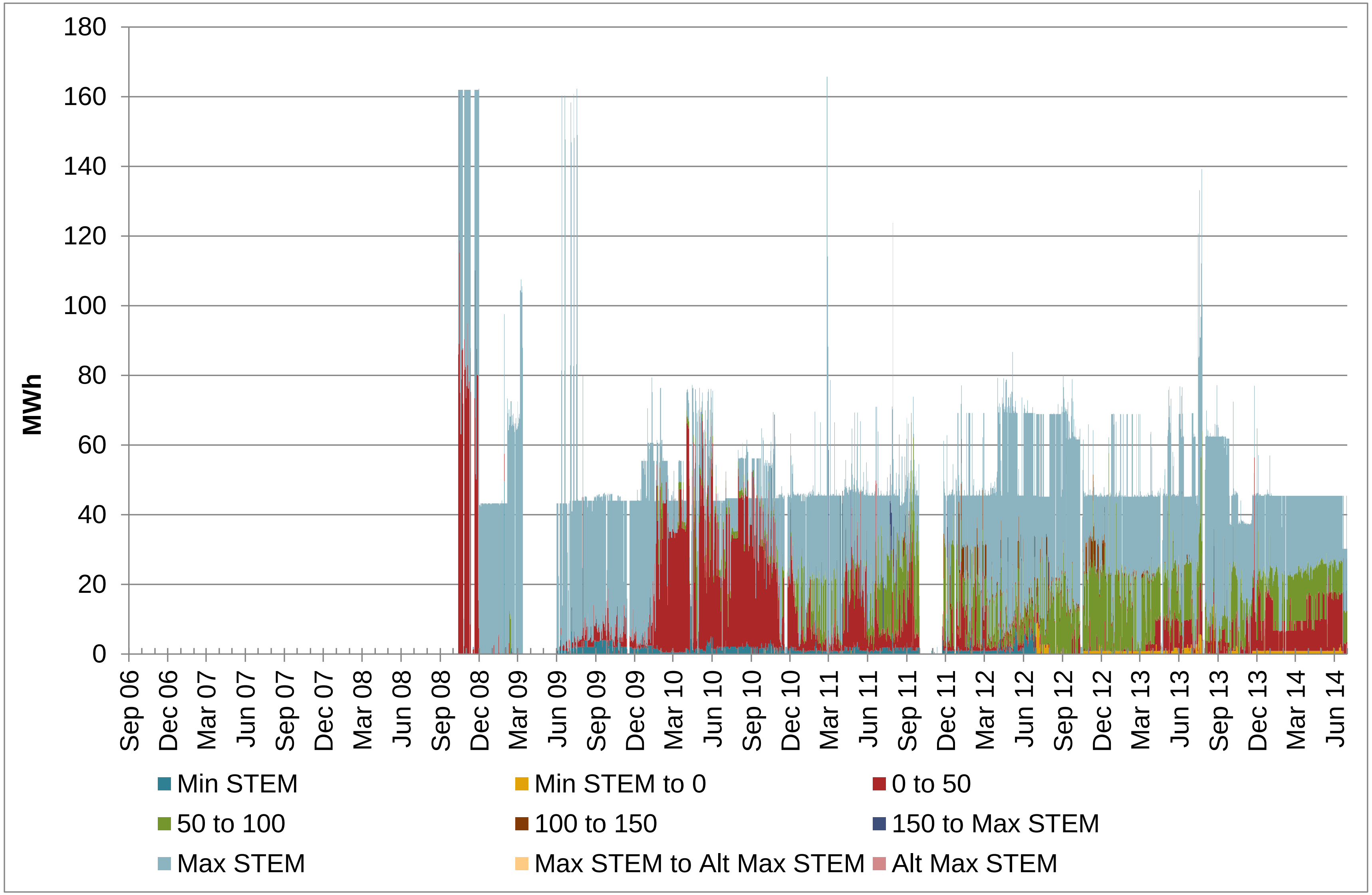


Figure 38 NewGen Neerabup's daily average STEM Offers (cumulative MWh per Trading Interval)

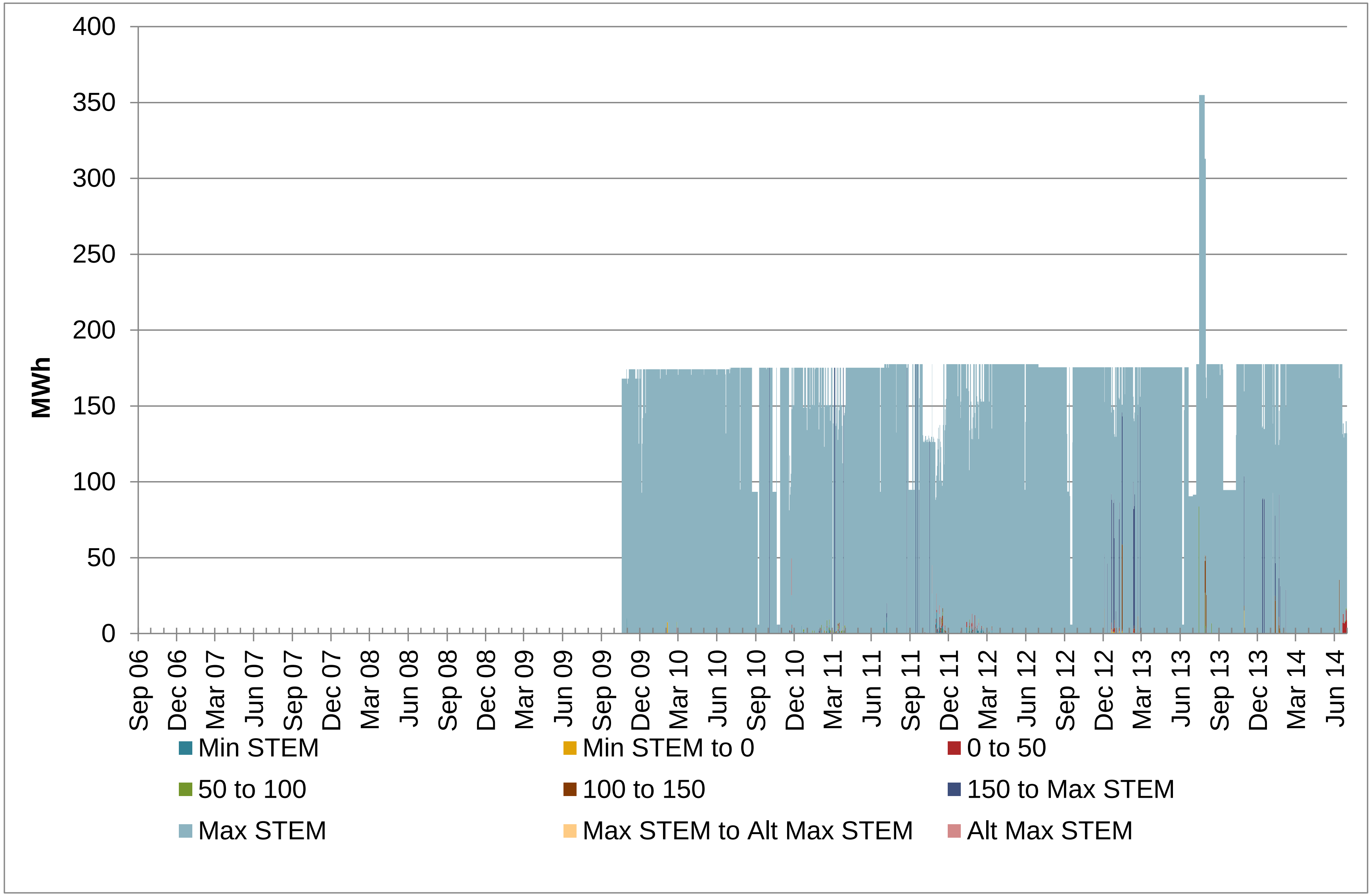


Figure 39 Perth Energy's daily average STEM Offers (cumulative MWh per Trading Interval)

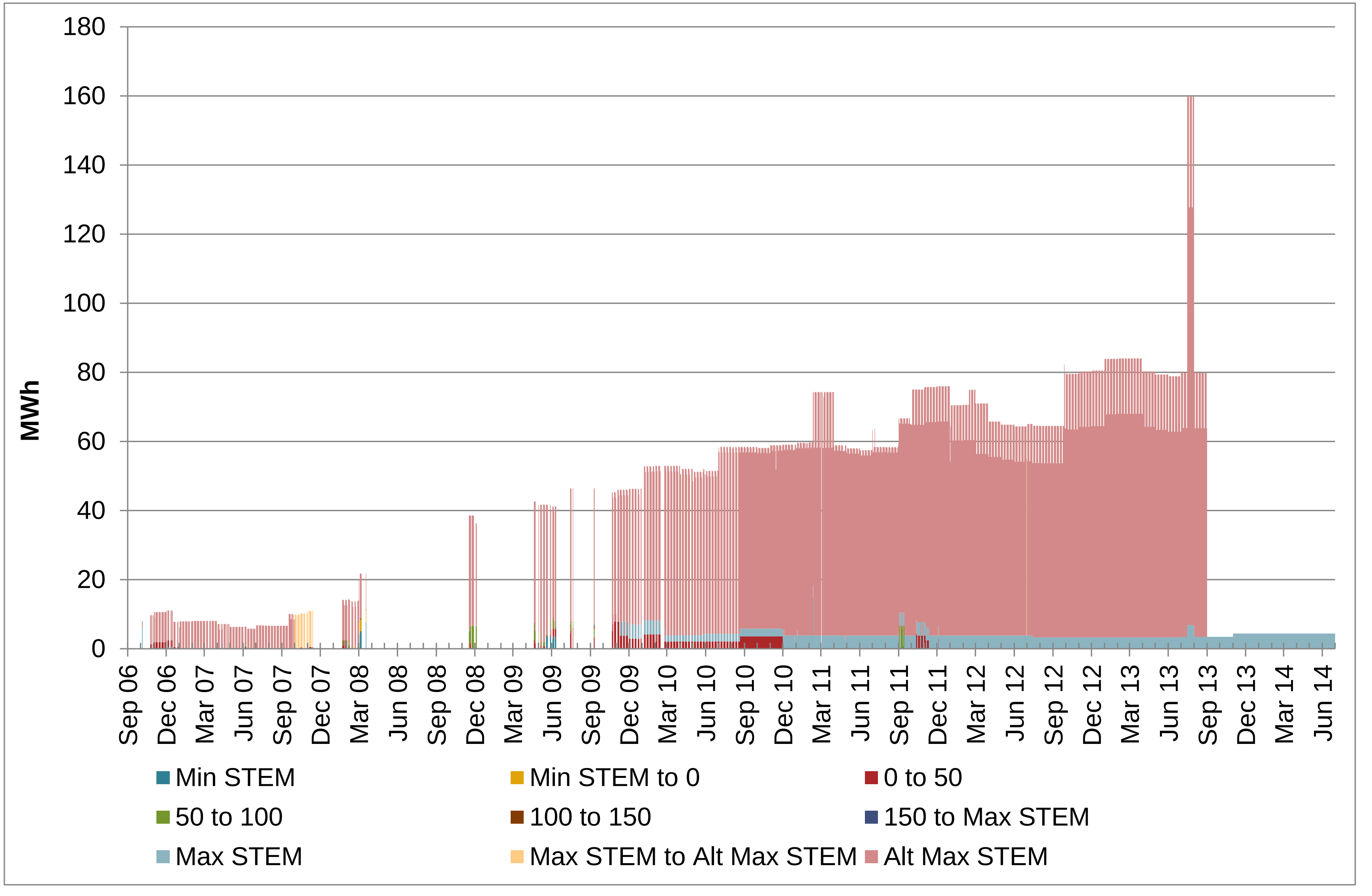


Figure 40 Southern Cross Energy's daily average STEM Offers (cumulative MWh per Trading Interval)

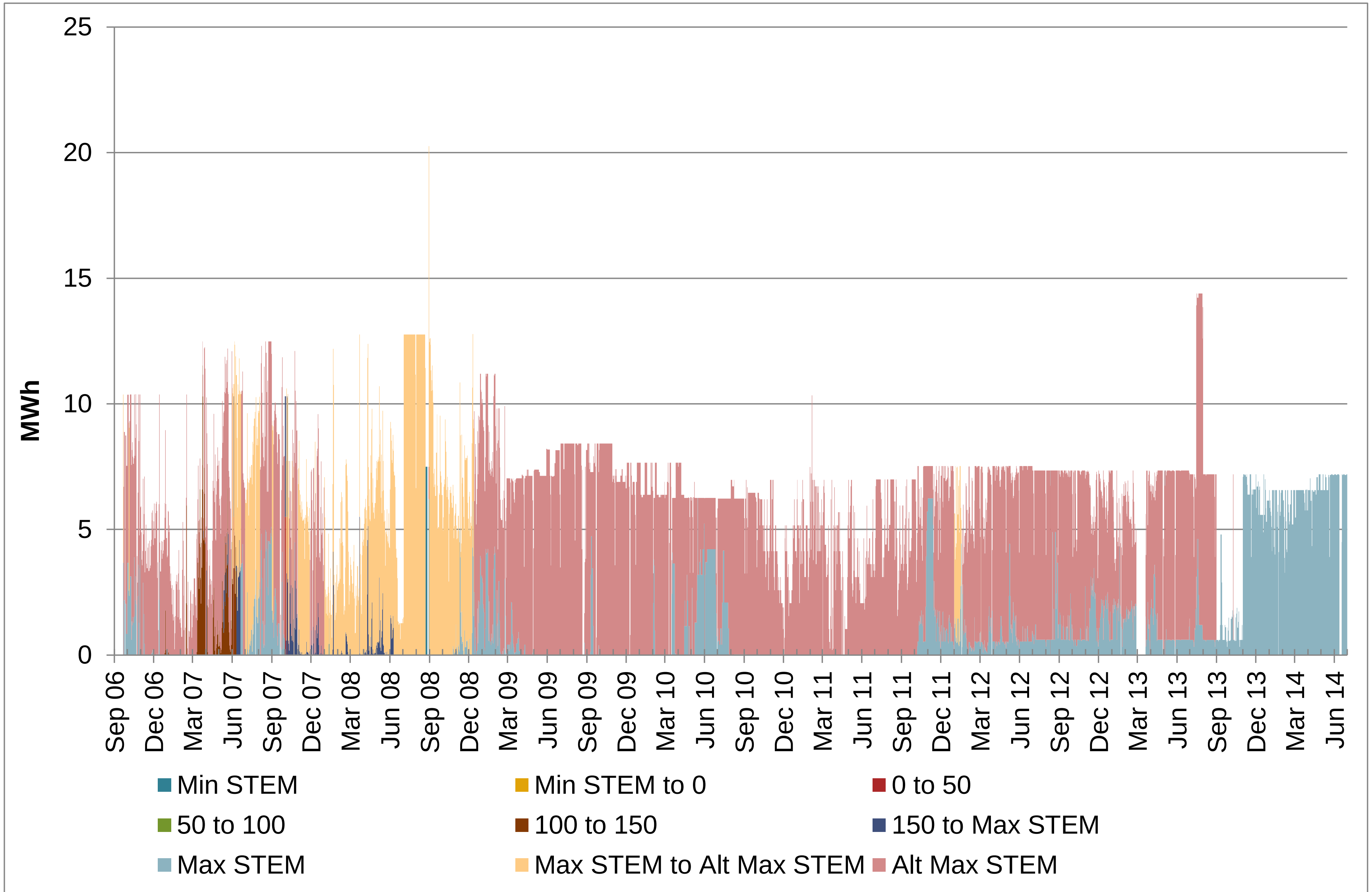


Figure 41 **Tiwest's daily average STEM Offers (cumulative MWh per Trading Interval)**

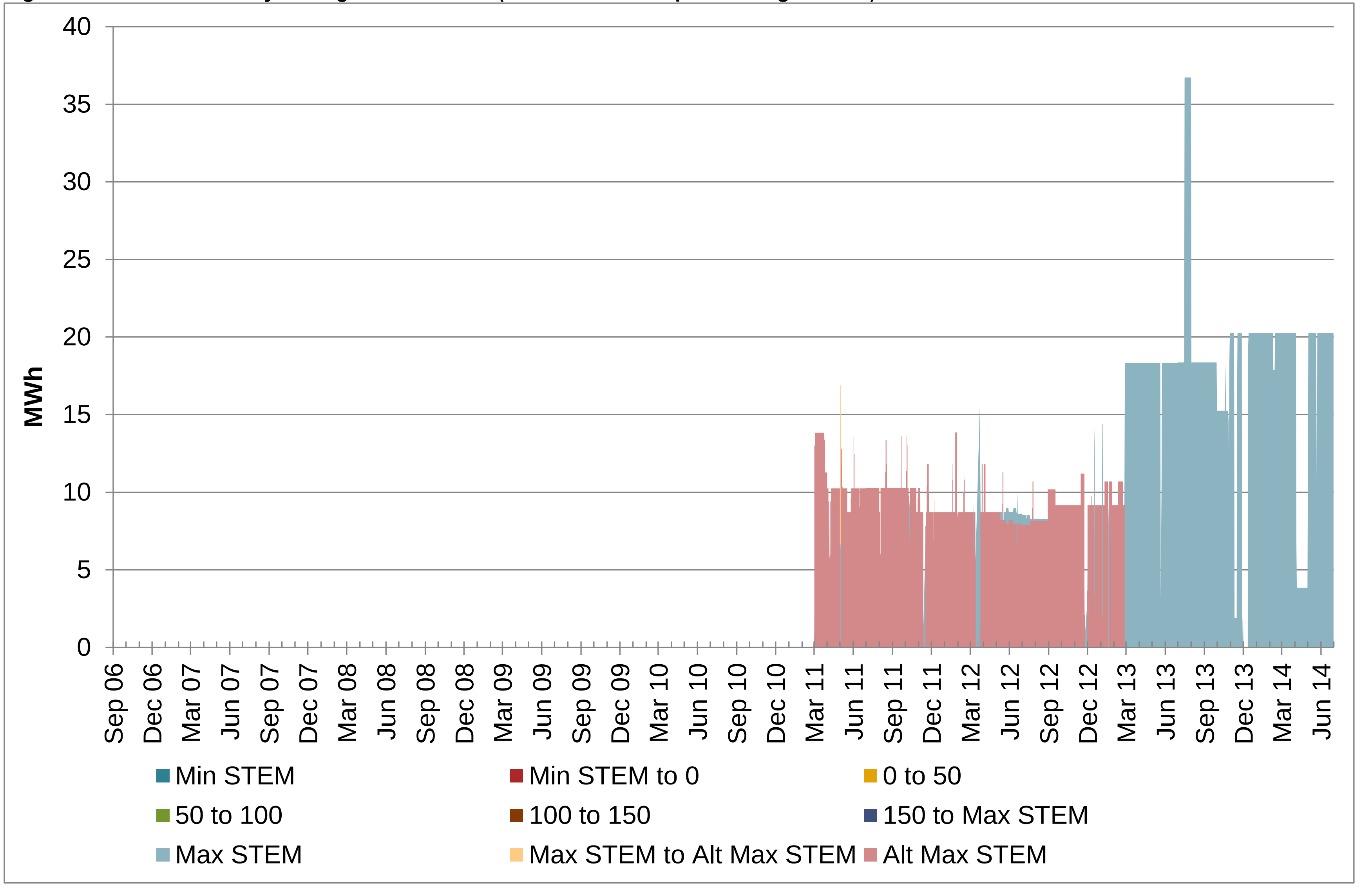


Figure 42 Tesla Management's daily average STEM Offers (cumulative MWh per Trading Interval)

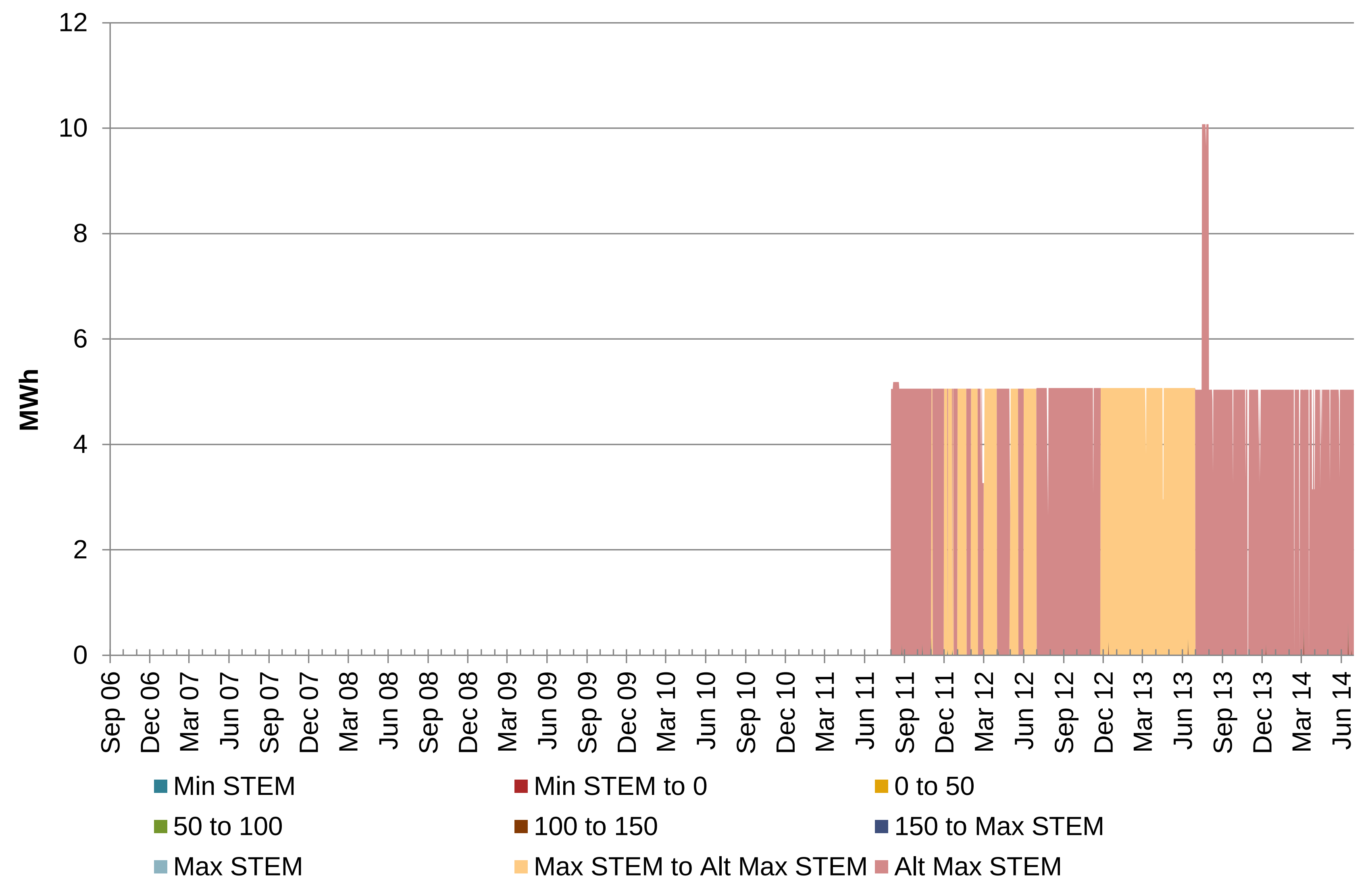


Figure 43 Tesla Geraldton's daily average STEM Offers (cumulative MWh per Trading Interval)

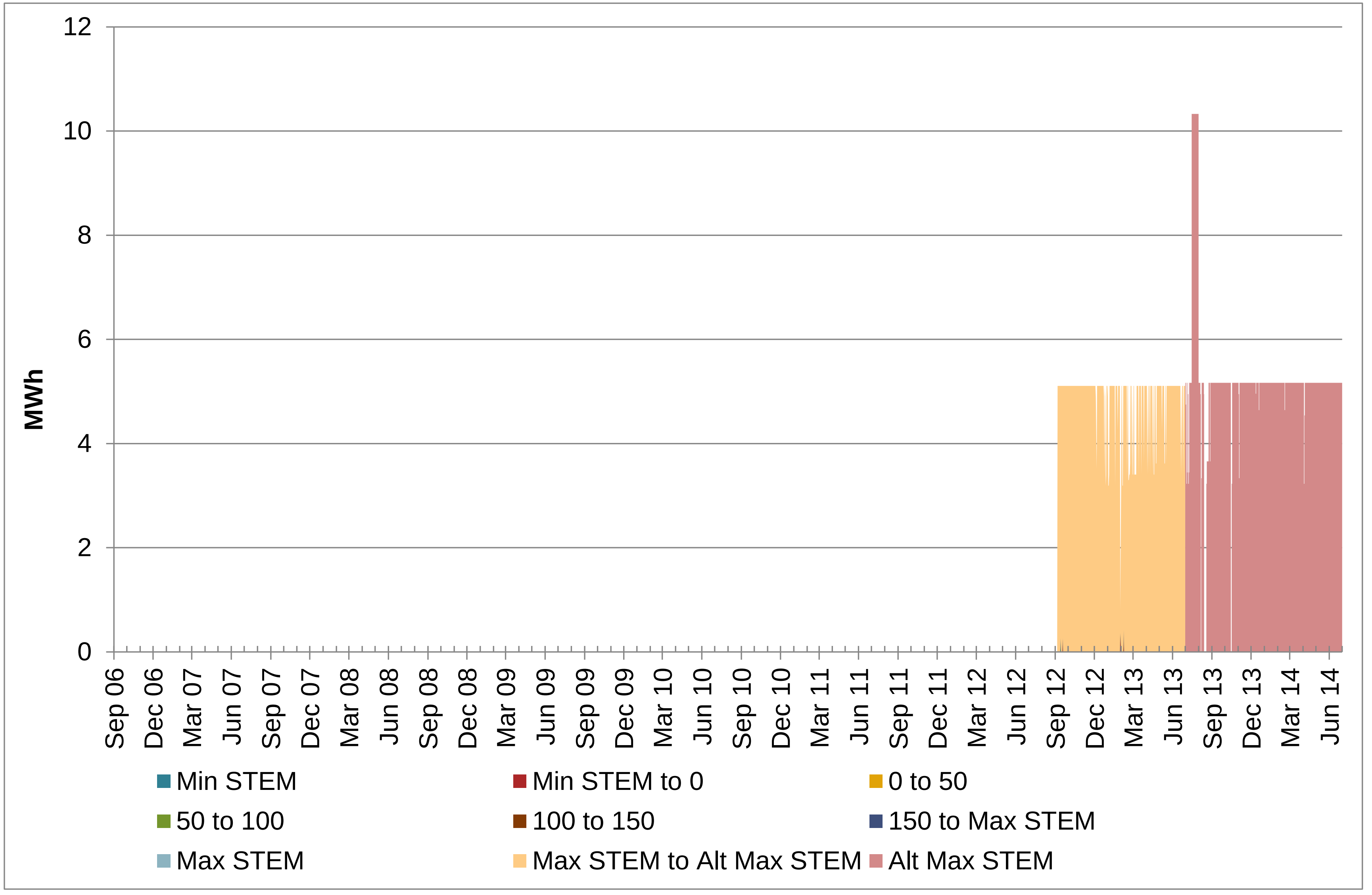


Figure 44 Tesla Kemerton's daily average STEM Offers (cumulative MWh per Trading Interval)

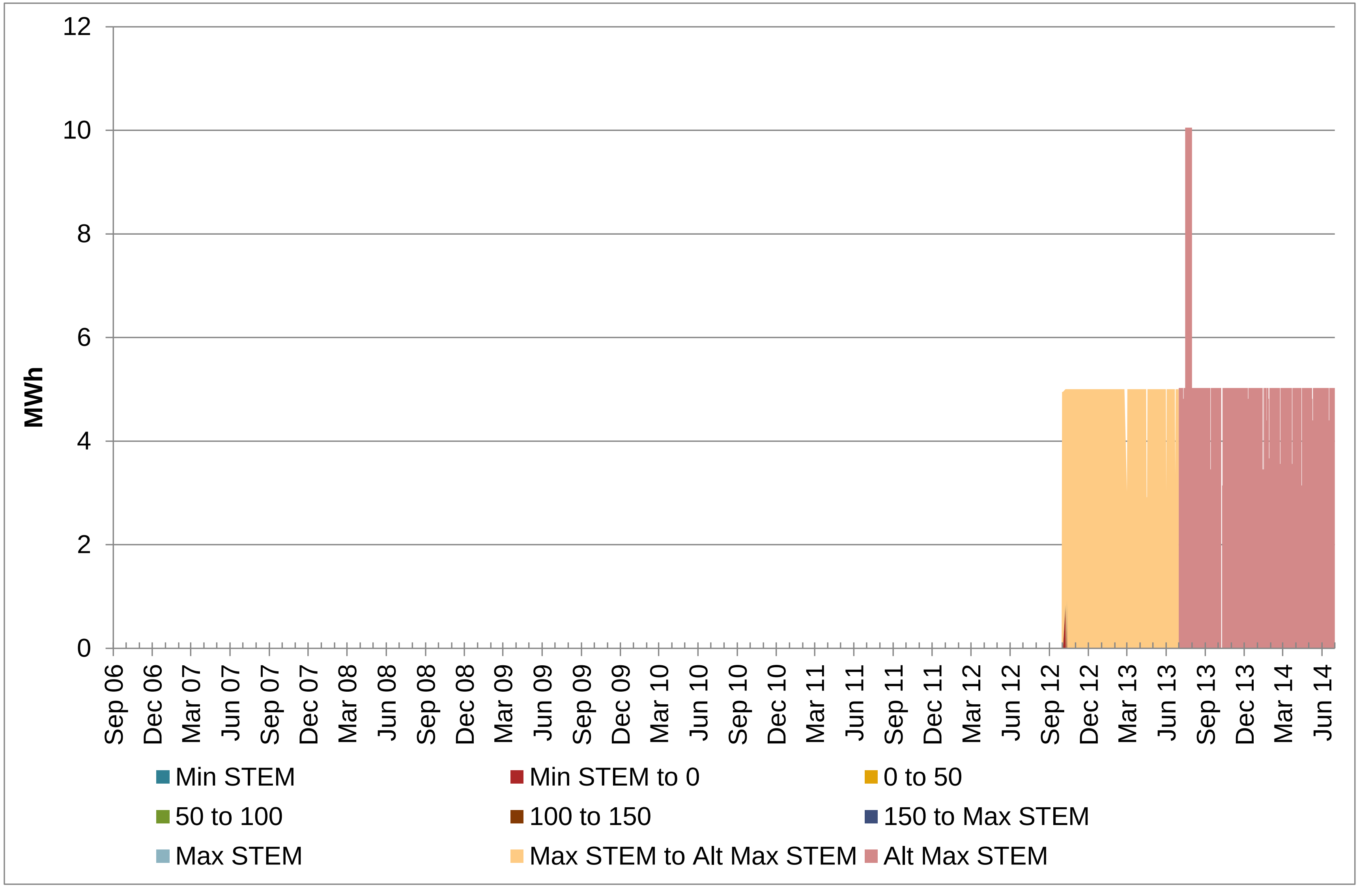


Figure 45 Tesla Northam's daily average STEM Offers (cumulative MWh per Trading Interval)

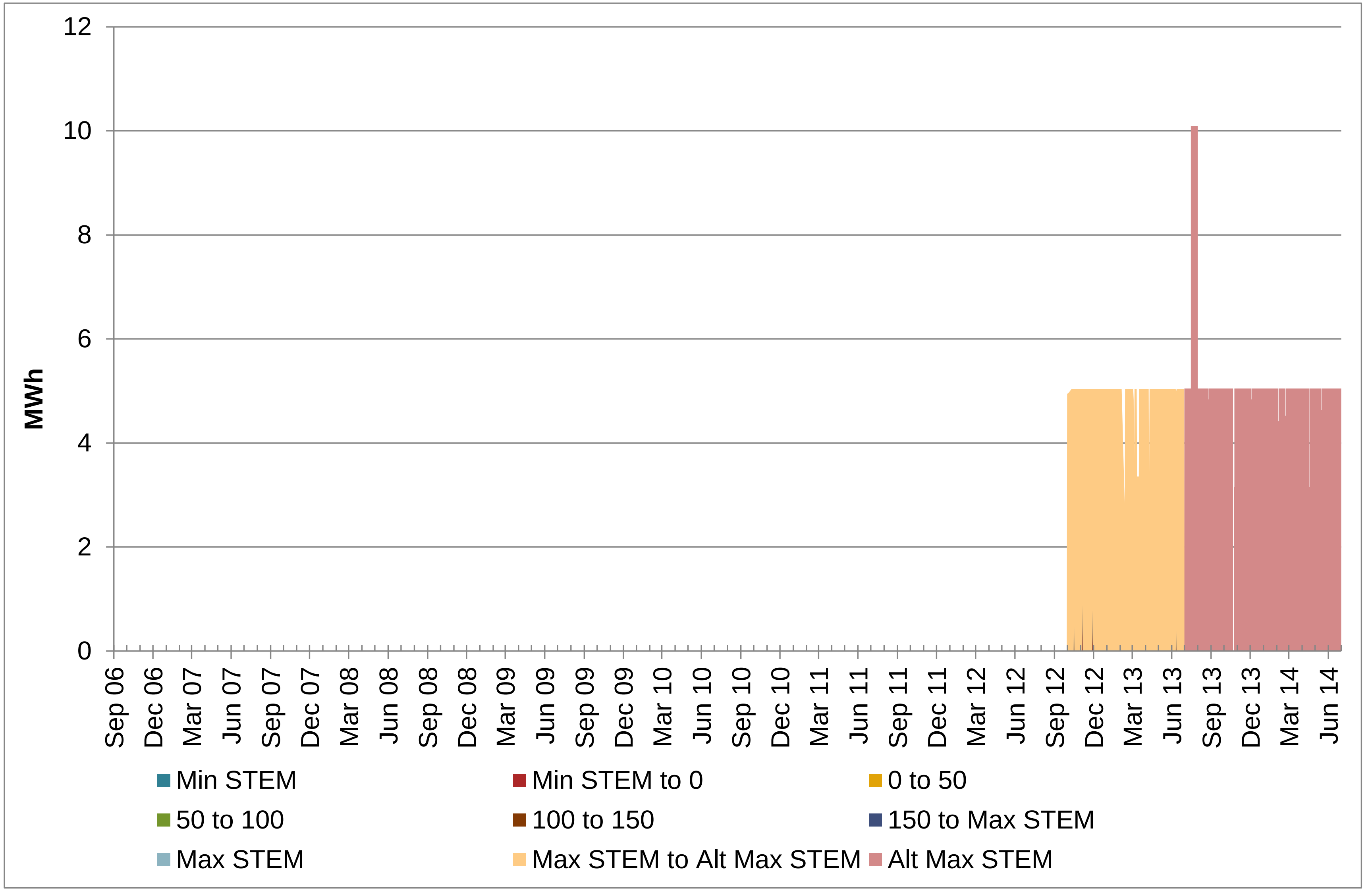


Figure 46 Western Energy's daily average STEM Offers (cumulative MWh per Trading Interval)

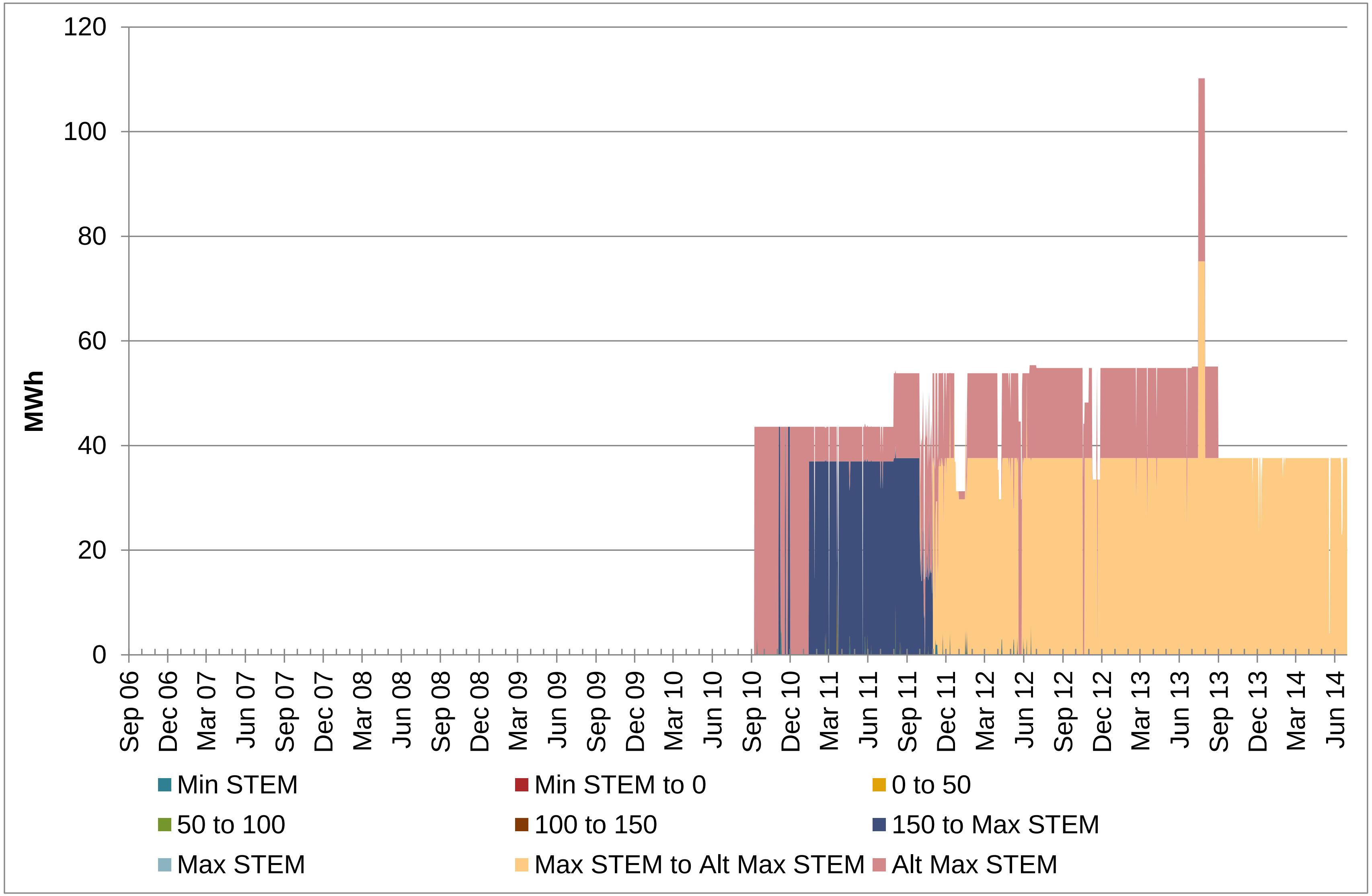


Figure 47 Synergy's daily average STEM Offers (cumulative MWh per Trading Interval)

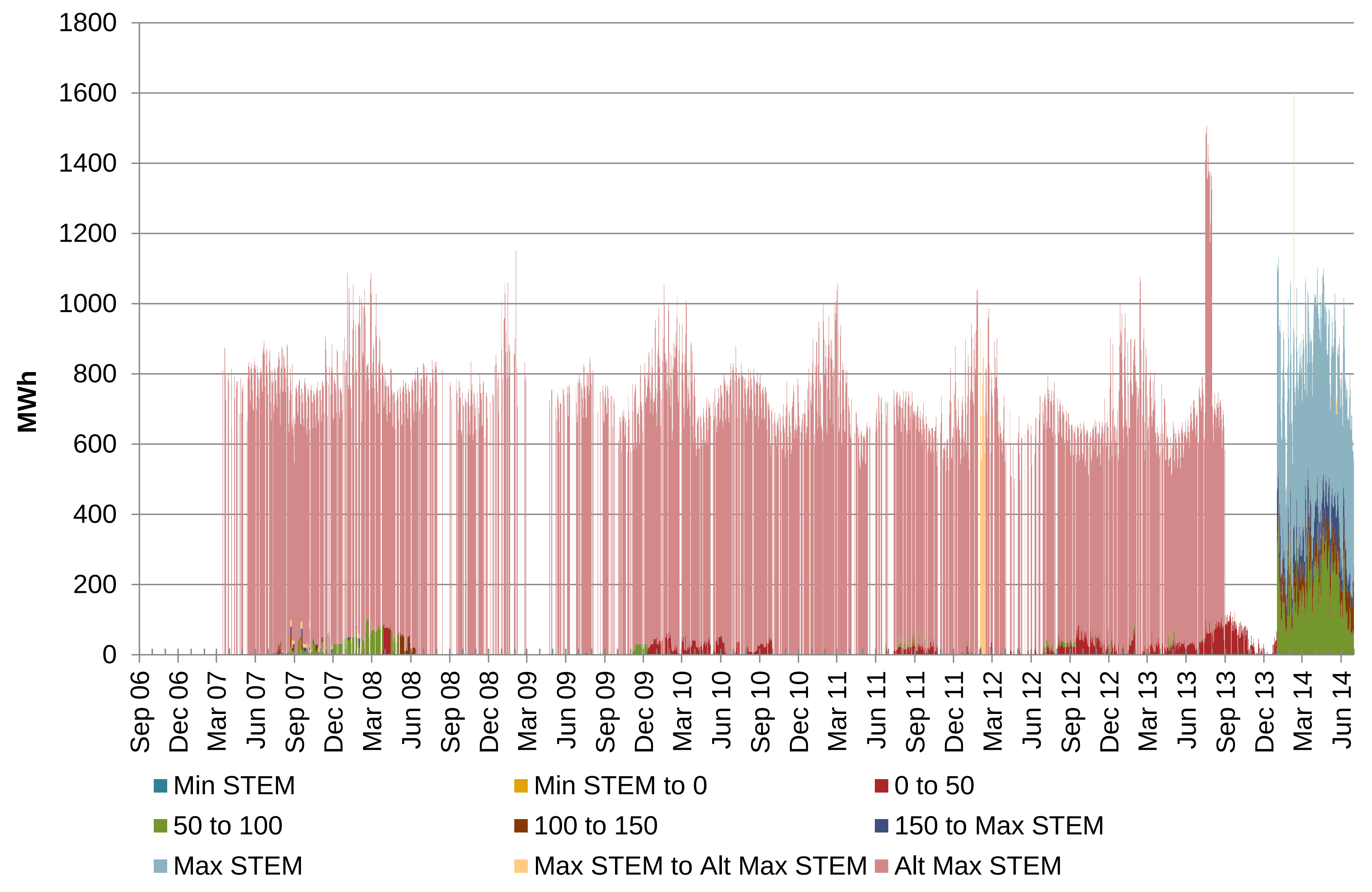


Figure 48 Verve Energy's daily average STEM Offers (cumulative MWh per Trading Interval)

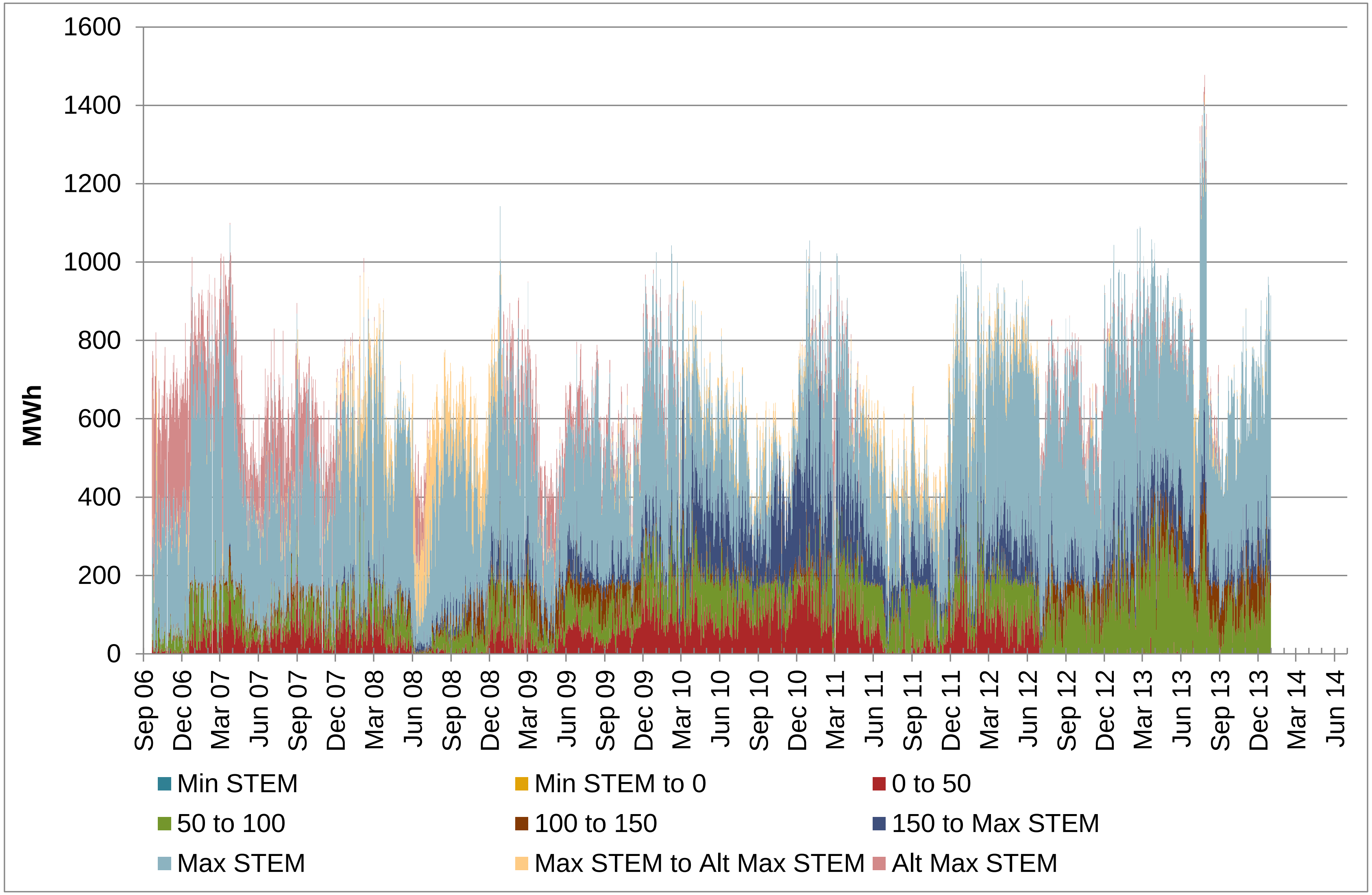


Figure 49 Vinalco's daily average STEM Offers (cumulative MWh per Trading Interval)

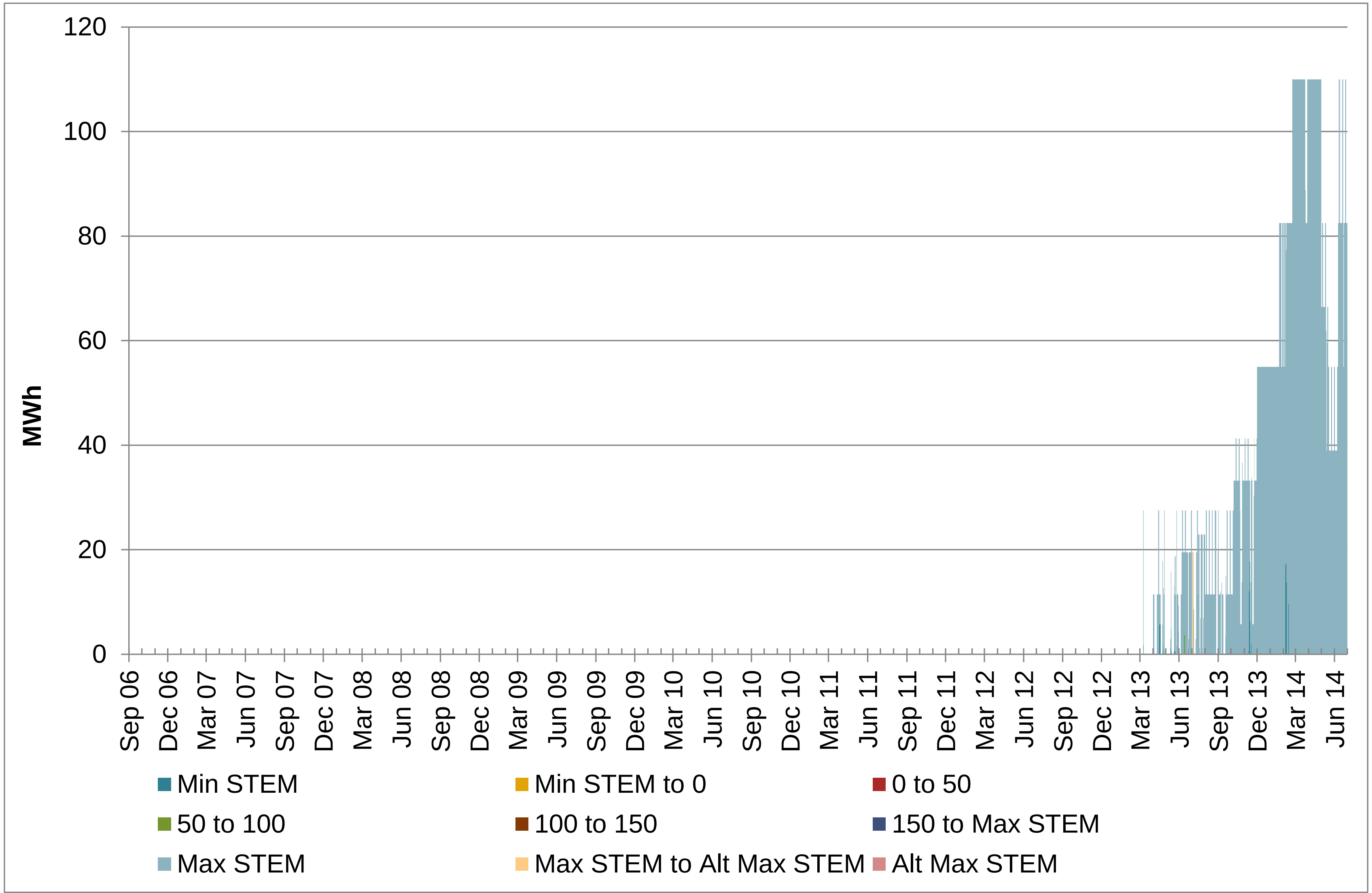


Figure 50 **Daily average quantity of STEM Bids (MWh per Trading Interval)**

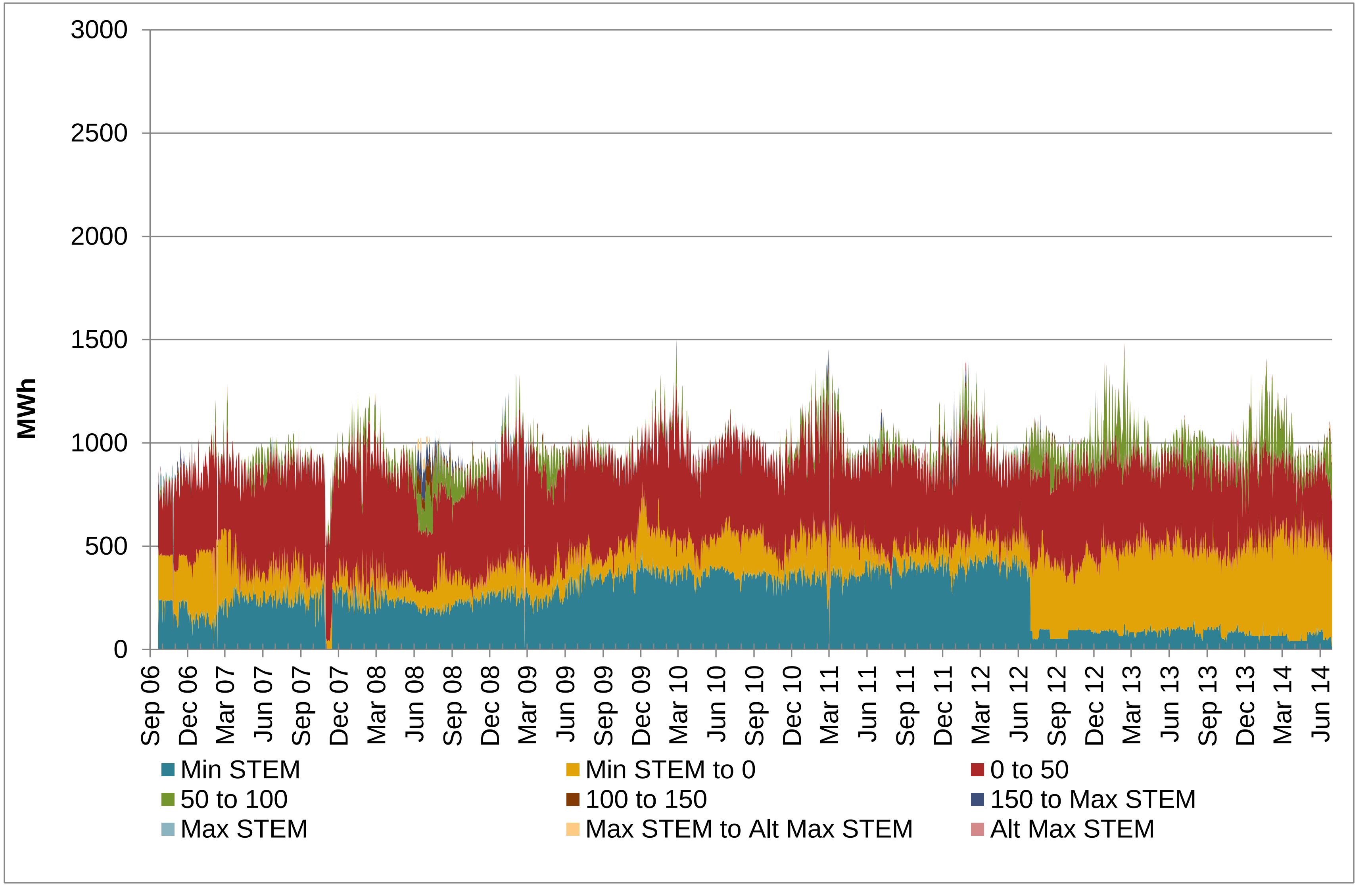


Figure 51 Alcoa's daily average STEM Bids (cumulative MWh per Trading Interval)

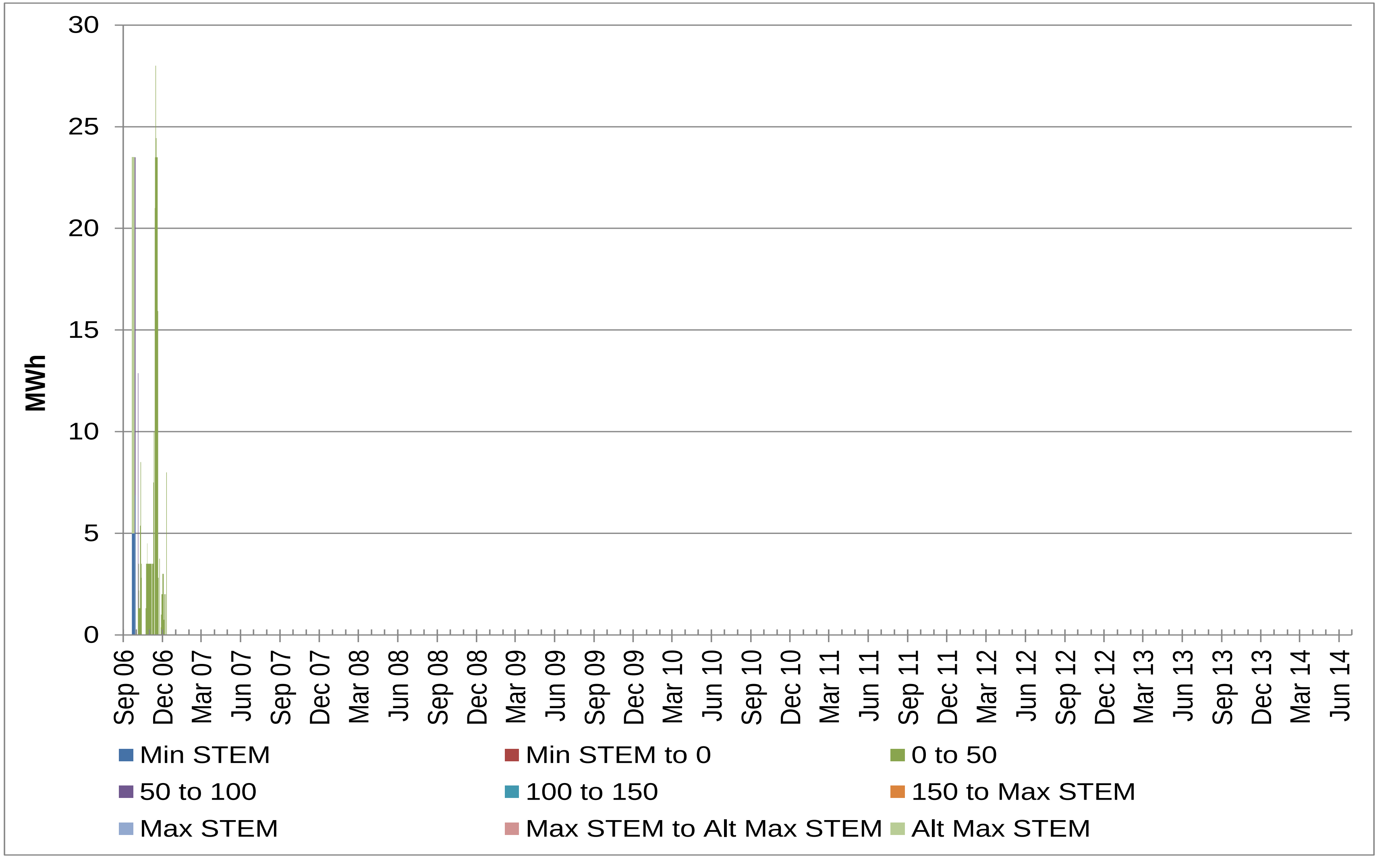


Figure 52 **Alinta's daily average STEM Bids (cumulative MWh per Trading Interval)**

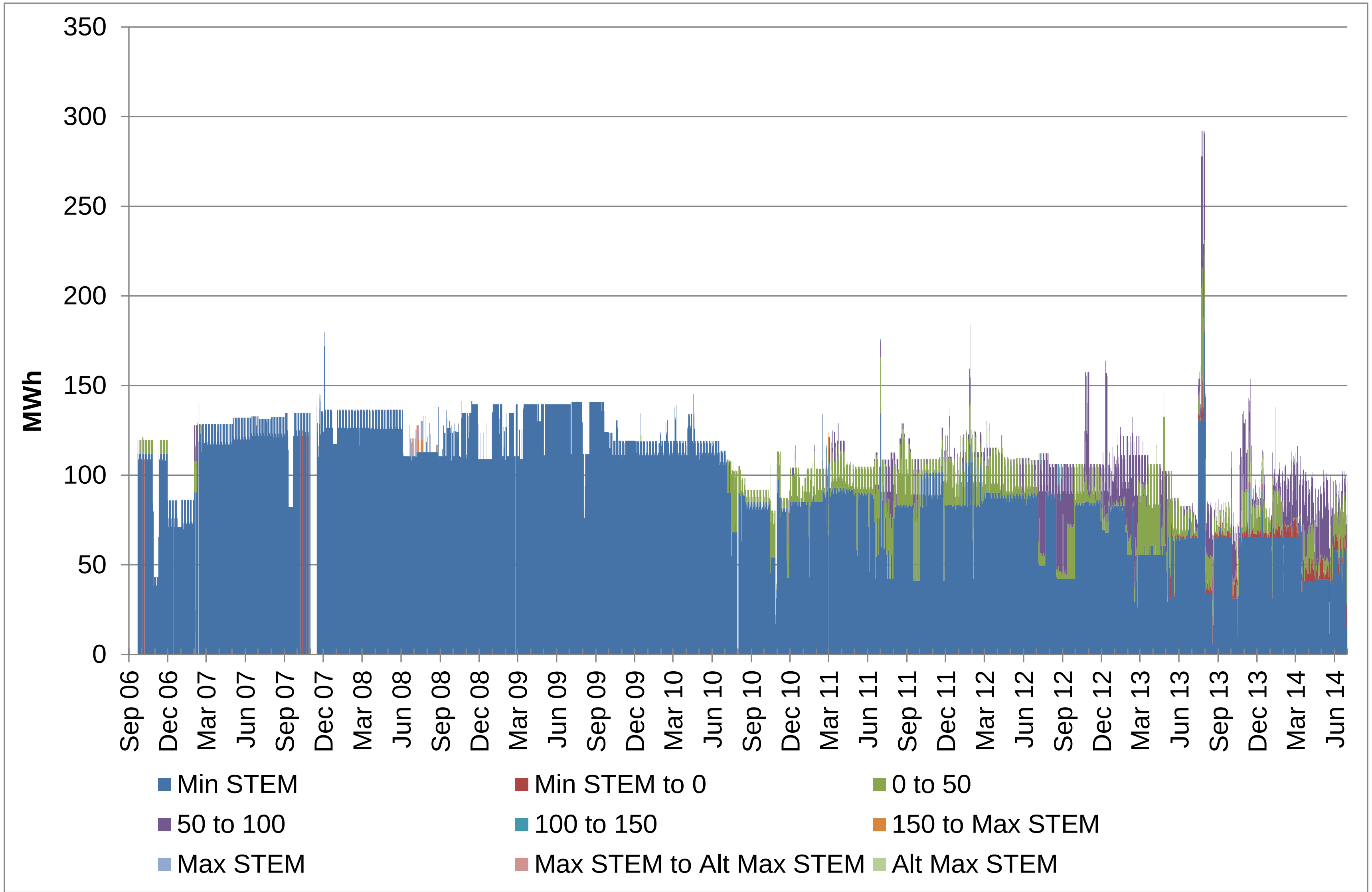


Figure 53 ERM Power's daily average STEM Bids (cumulative MWh per Trading Interval)

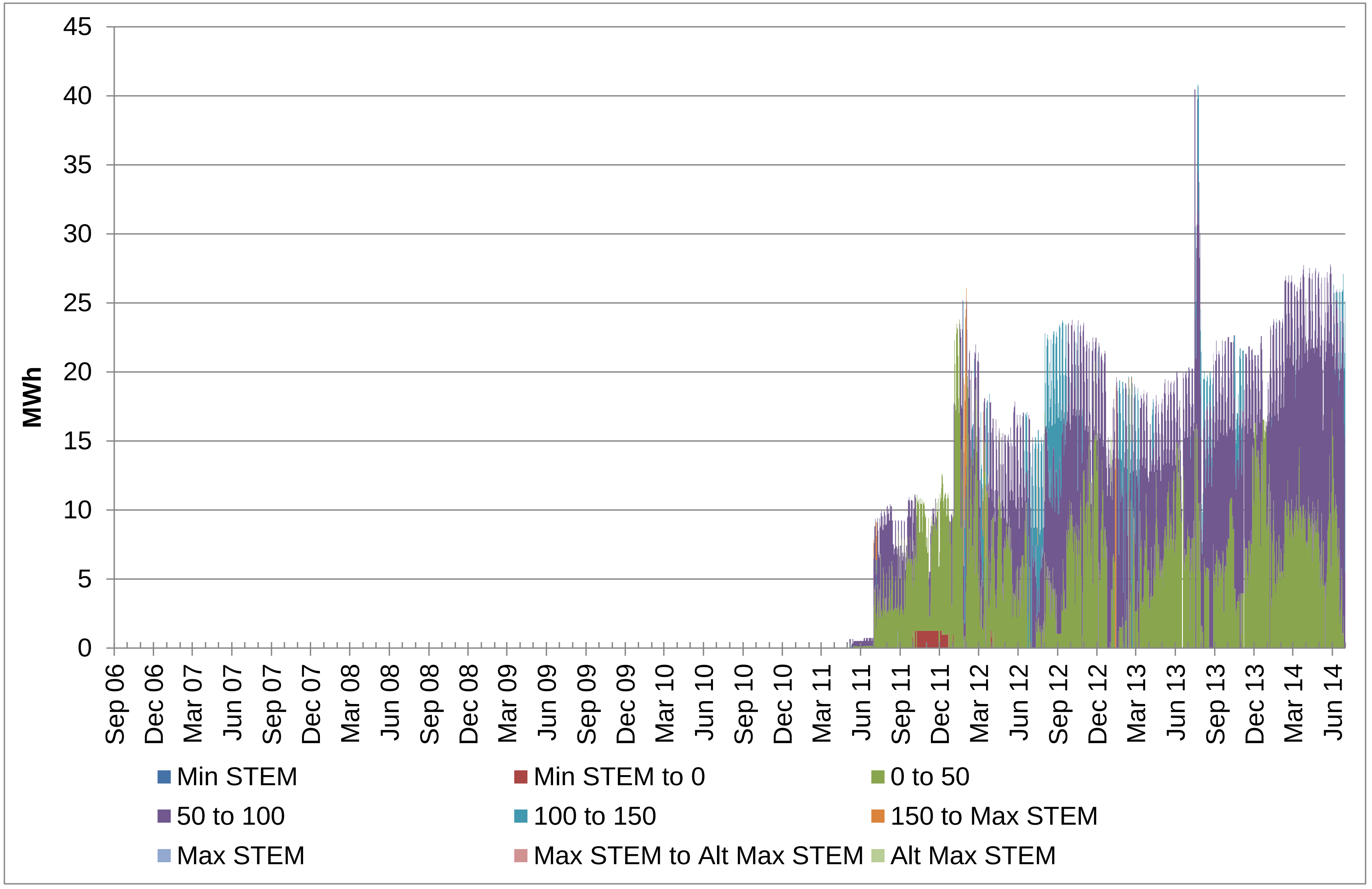


Figure 54 Goldfields Power's daily average STEM Bids (cumulative MWh per Trading Interval)

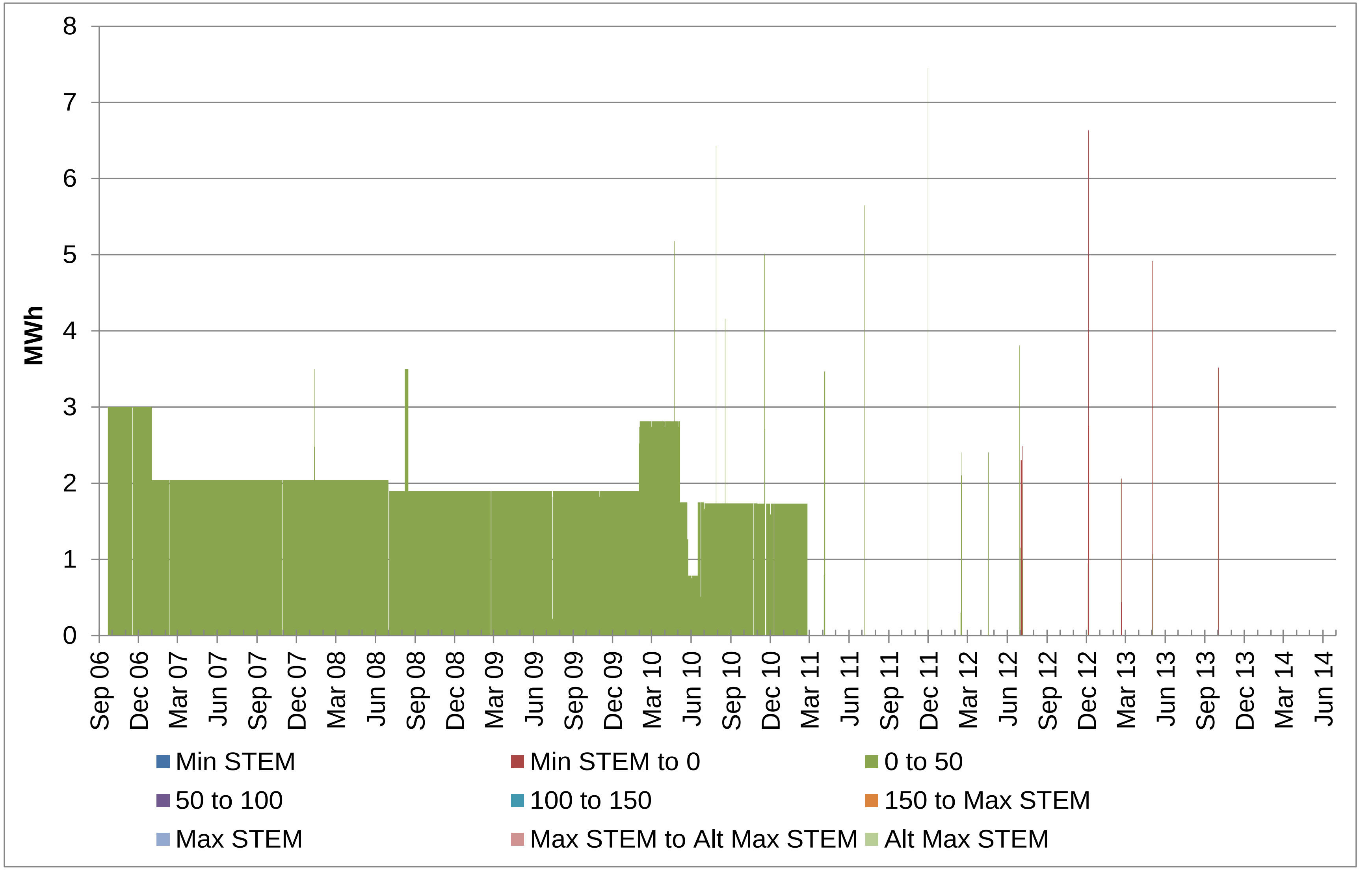


Figure 55 Griffin Power's daily average STEM Bids (cumulative MWh per Trading Interval)

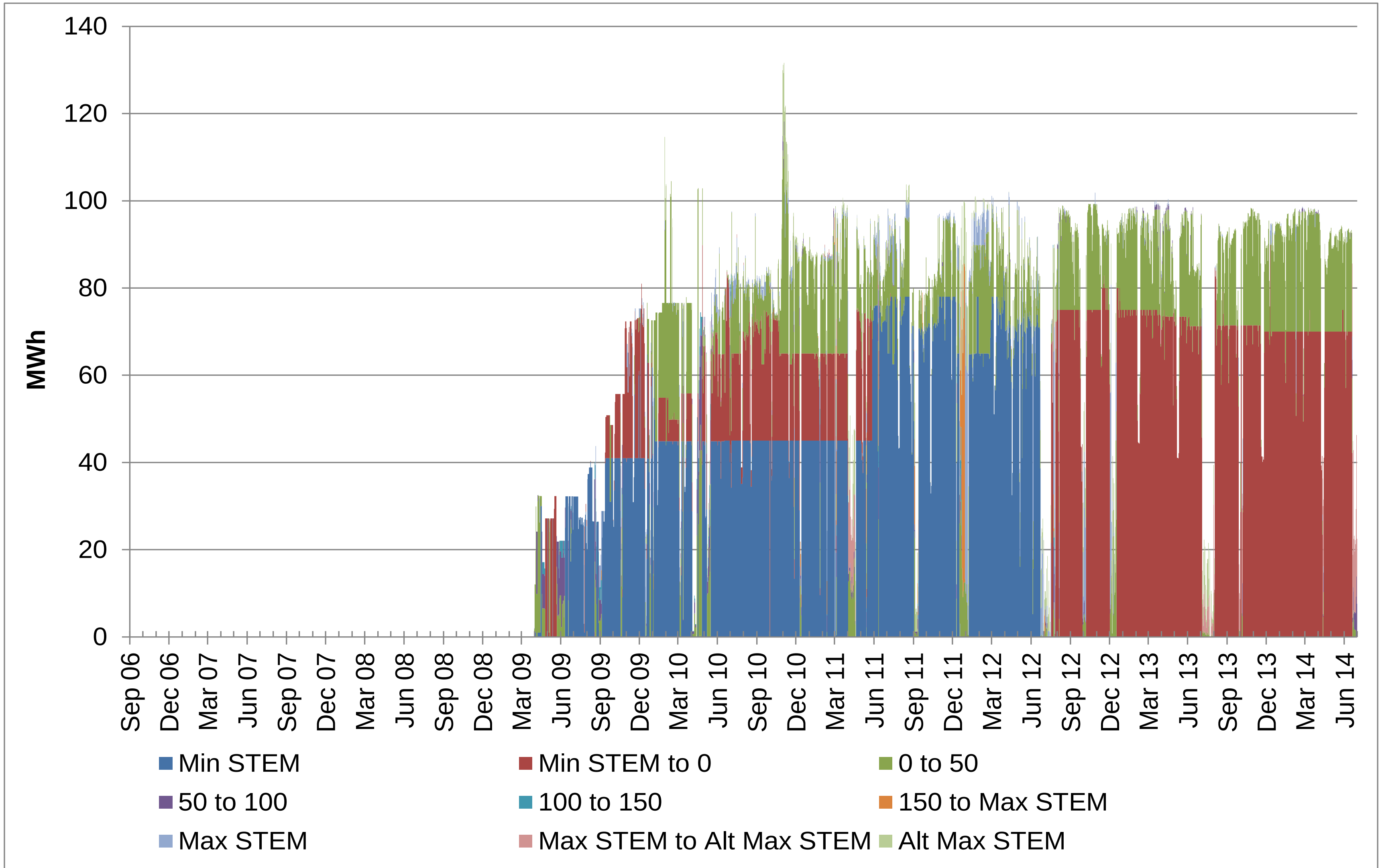


Figure 56 Griffin Power 2's daily average STEM Bids (cumulative MWh per Trading Interval)

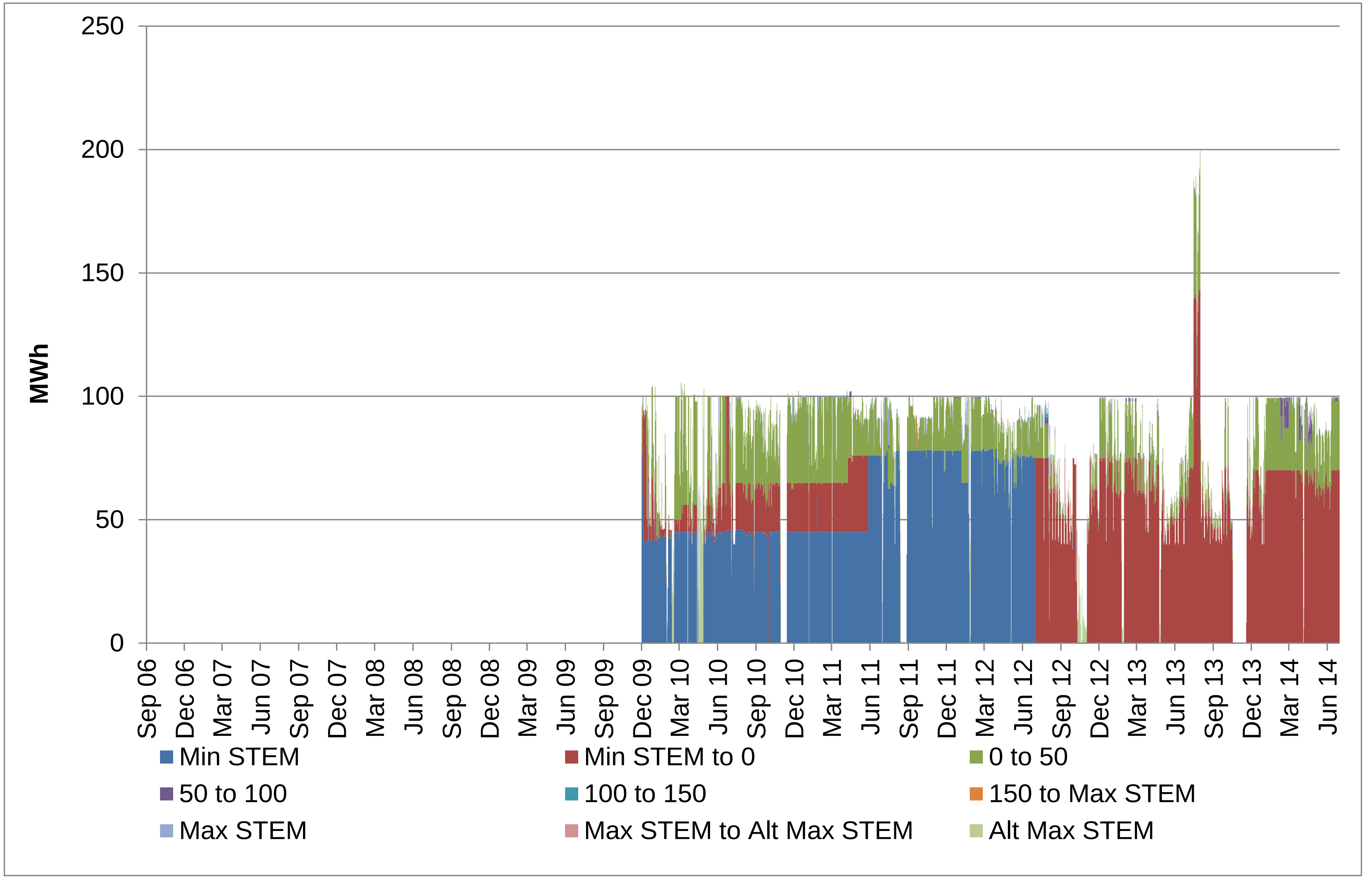


Figure 57 Karara's daily average STEM Bids (cumulative MWh per Trading Interval)

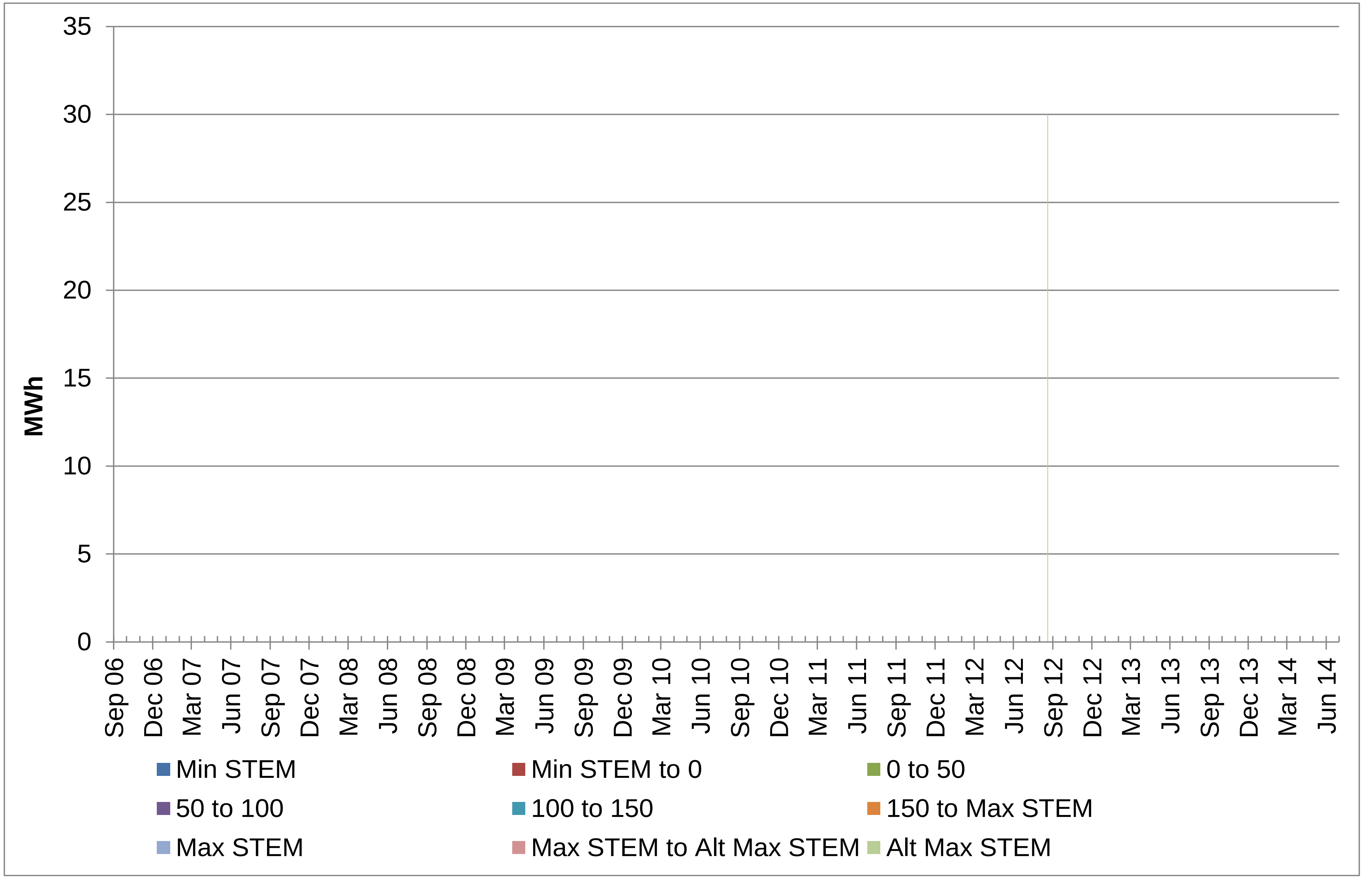


Figure 58 Landfill Gas and Power's daily average STEM Bids (cumulative MWh per Trading Interval)

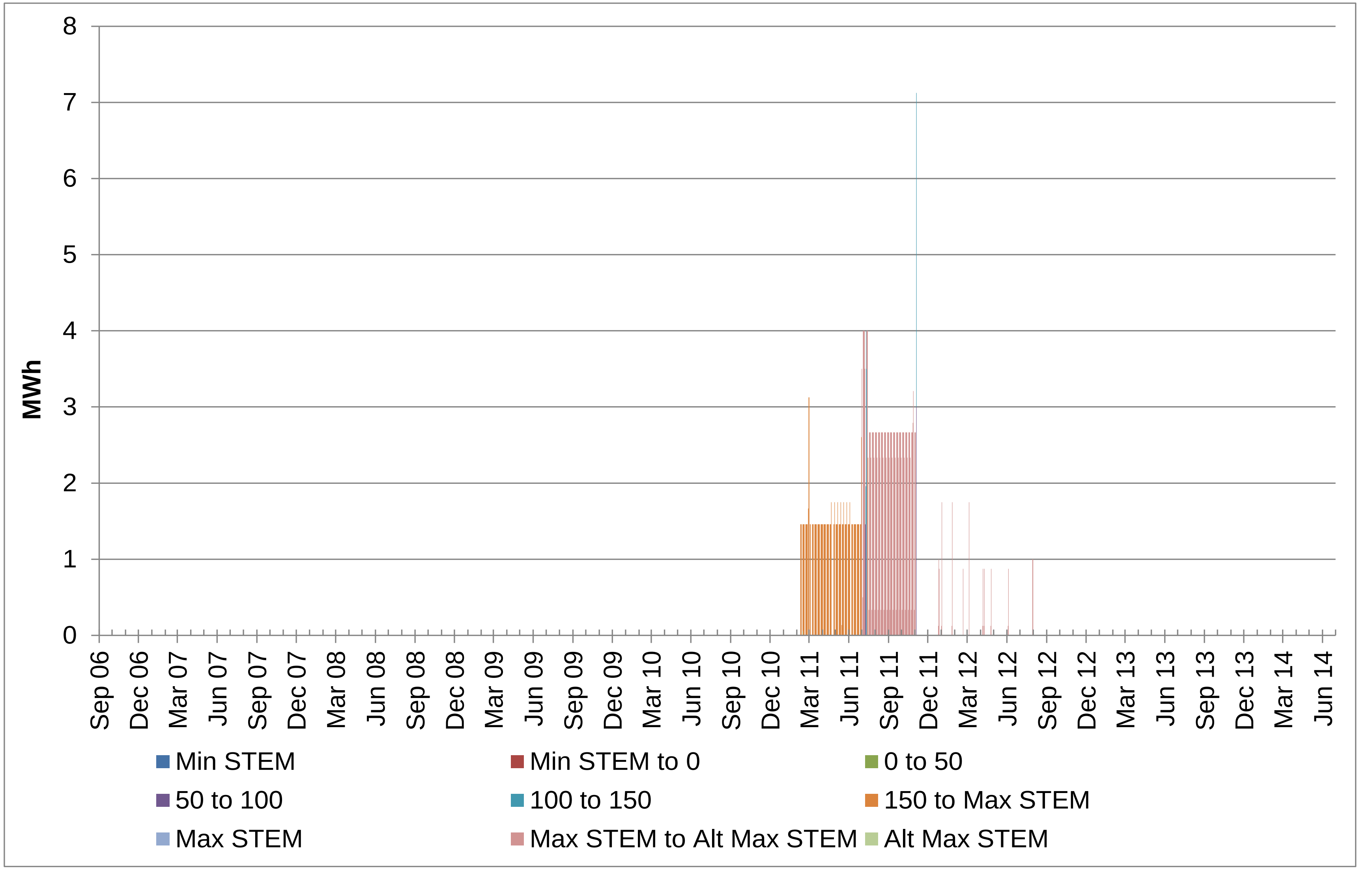


Figure 59 NewGen Power Kwinana's daily average STEM Bids (cumulative MWh per Trading Interval)

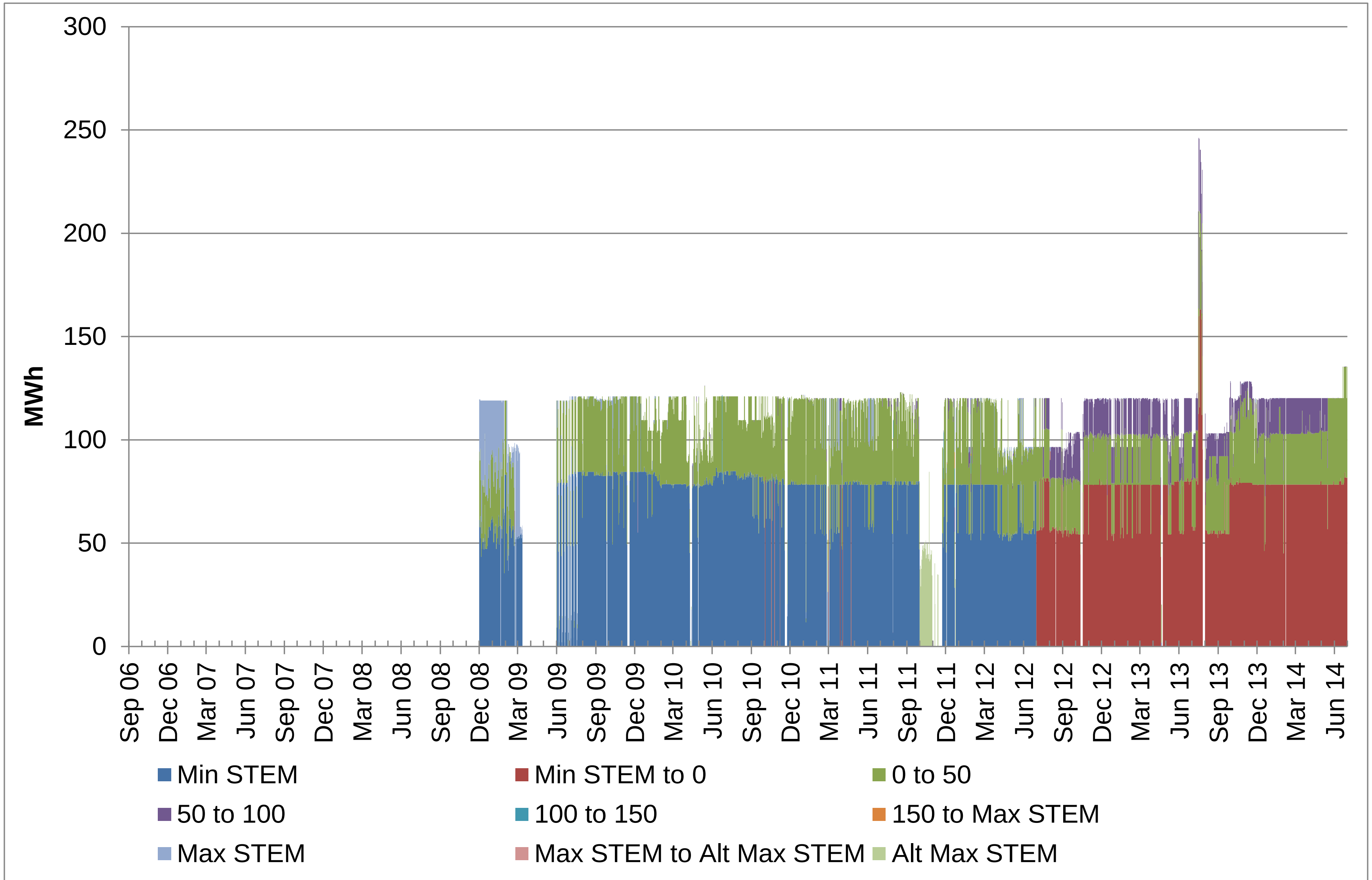


Figure 60 NewGen Neerabup's daily average STEM Bids (cumulative MWh per Trading Interval)

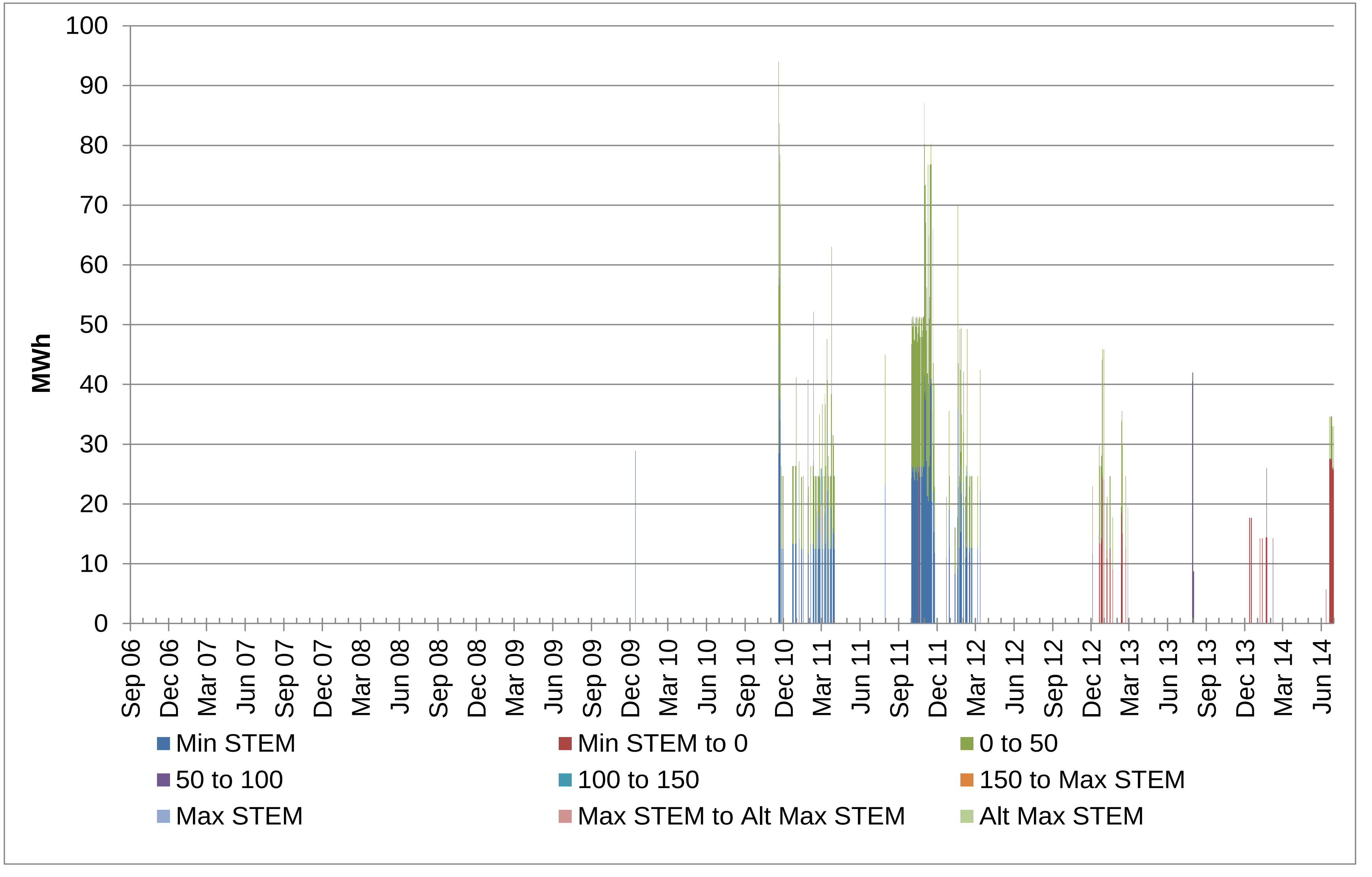


Figure 61 Perth Energy's daily average STEM Bids (cumulative MWh per Trading Interval)

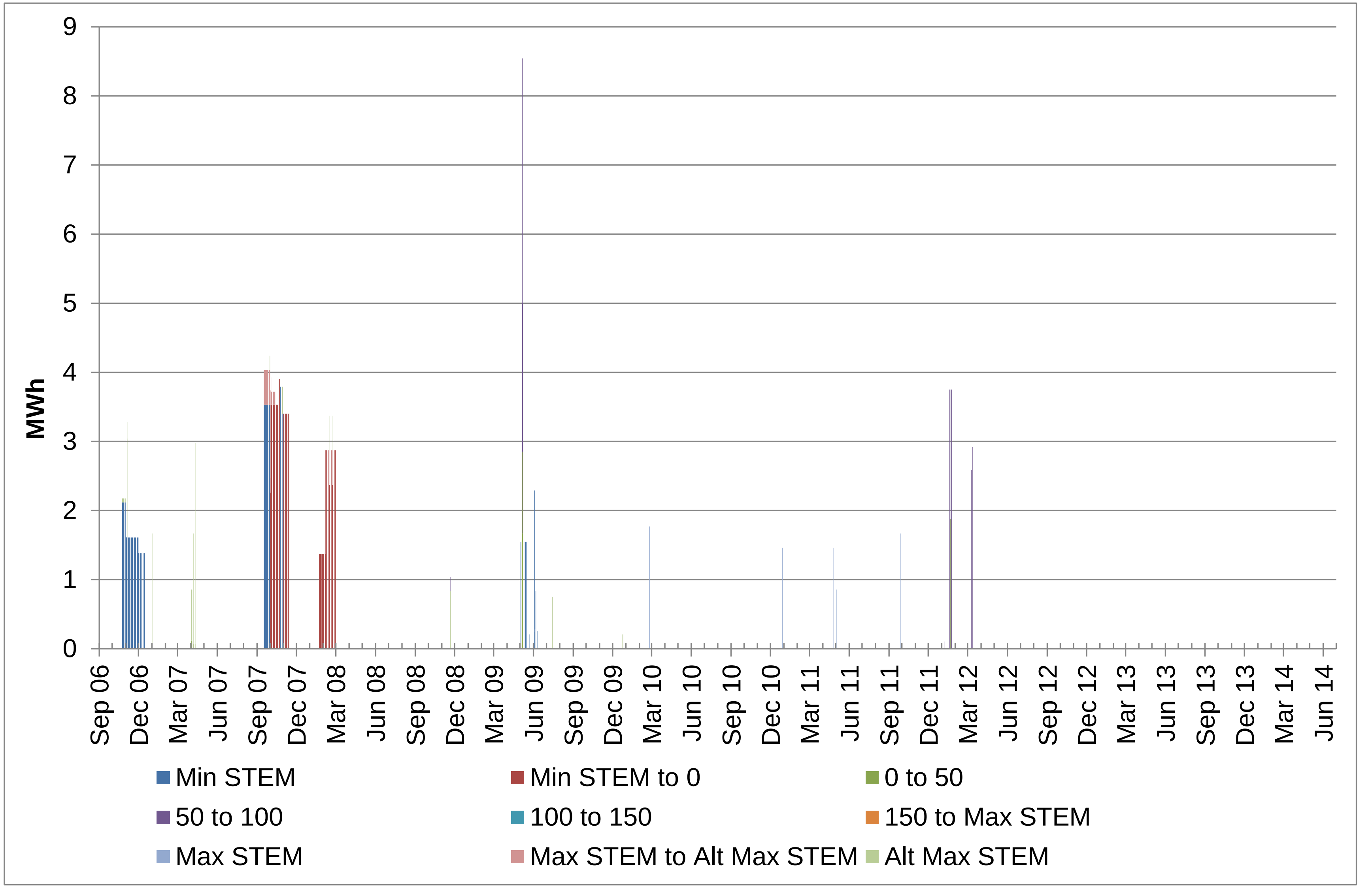


Figure 62 **Southern Cross Energy's daily average STEM Bids (cumulative MWh per Trading Interval)**

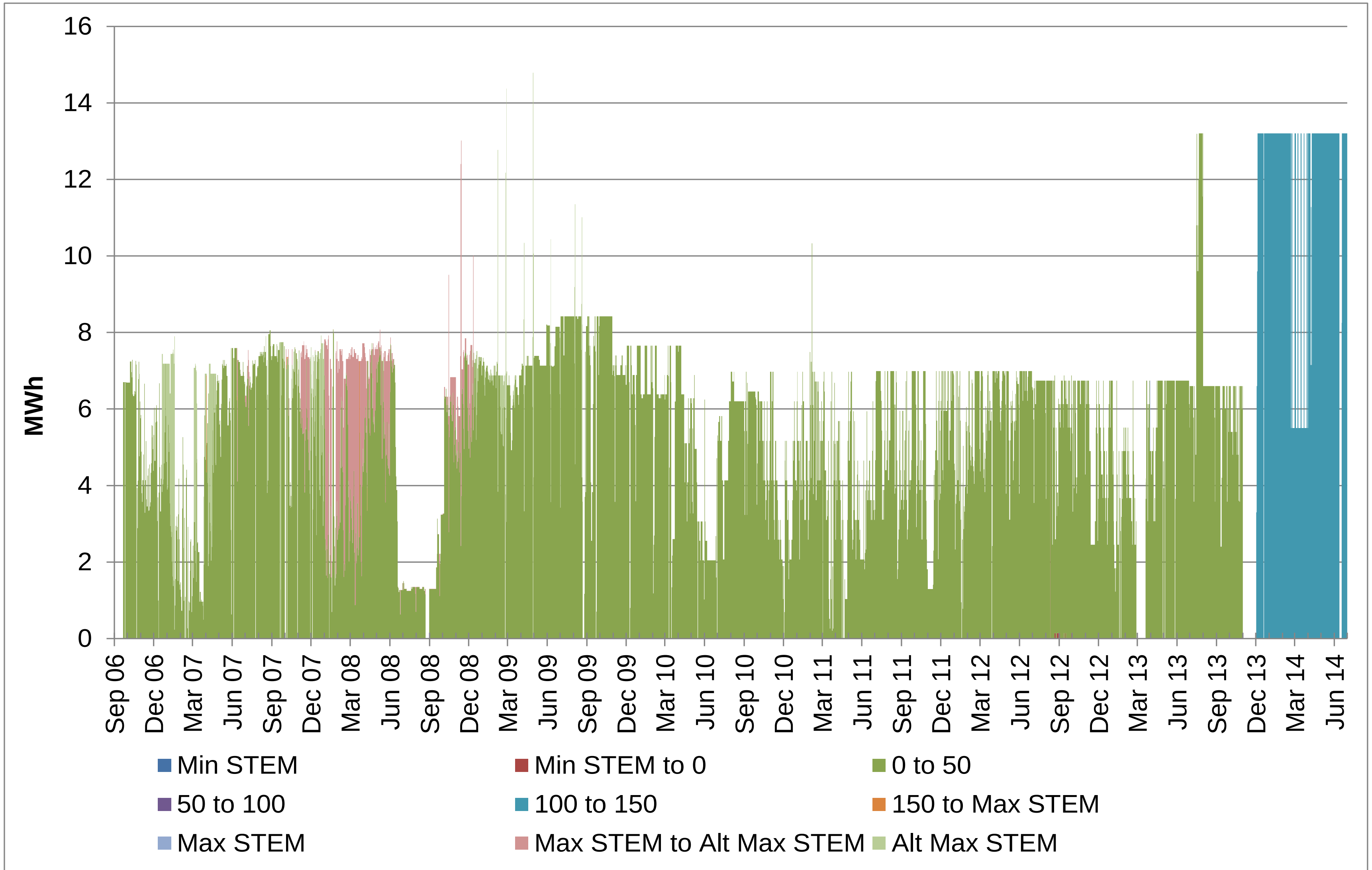


Figure 63 Tiwest's daily average STEM Bids (cumulative MWh per Trading Interval)

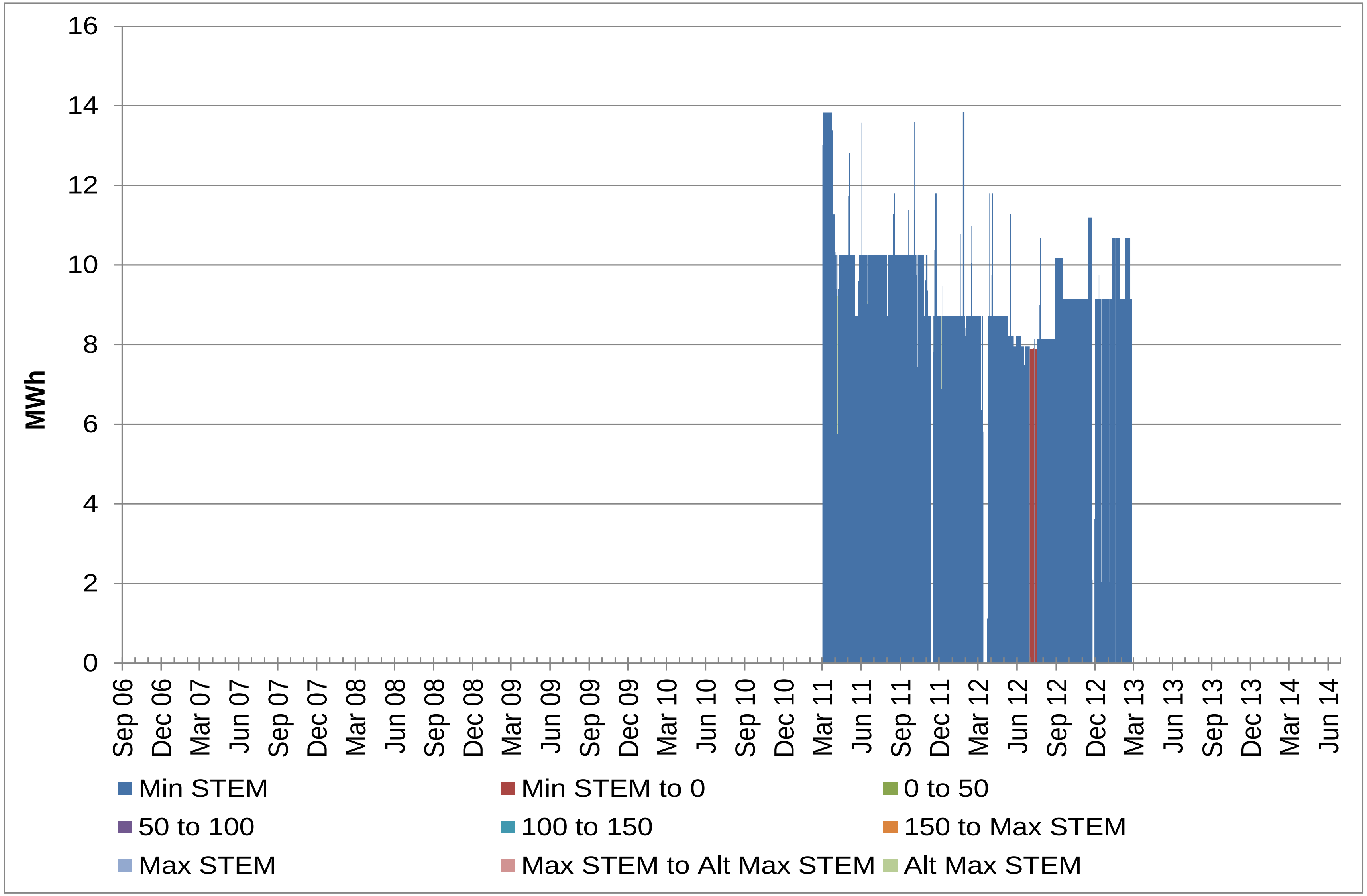


Figure 64 Western Energy's daily average STEM Bids (cumulative MWh per Trading Interval)

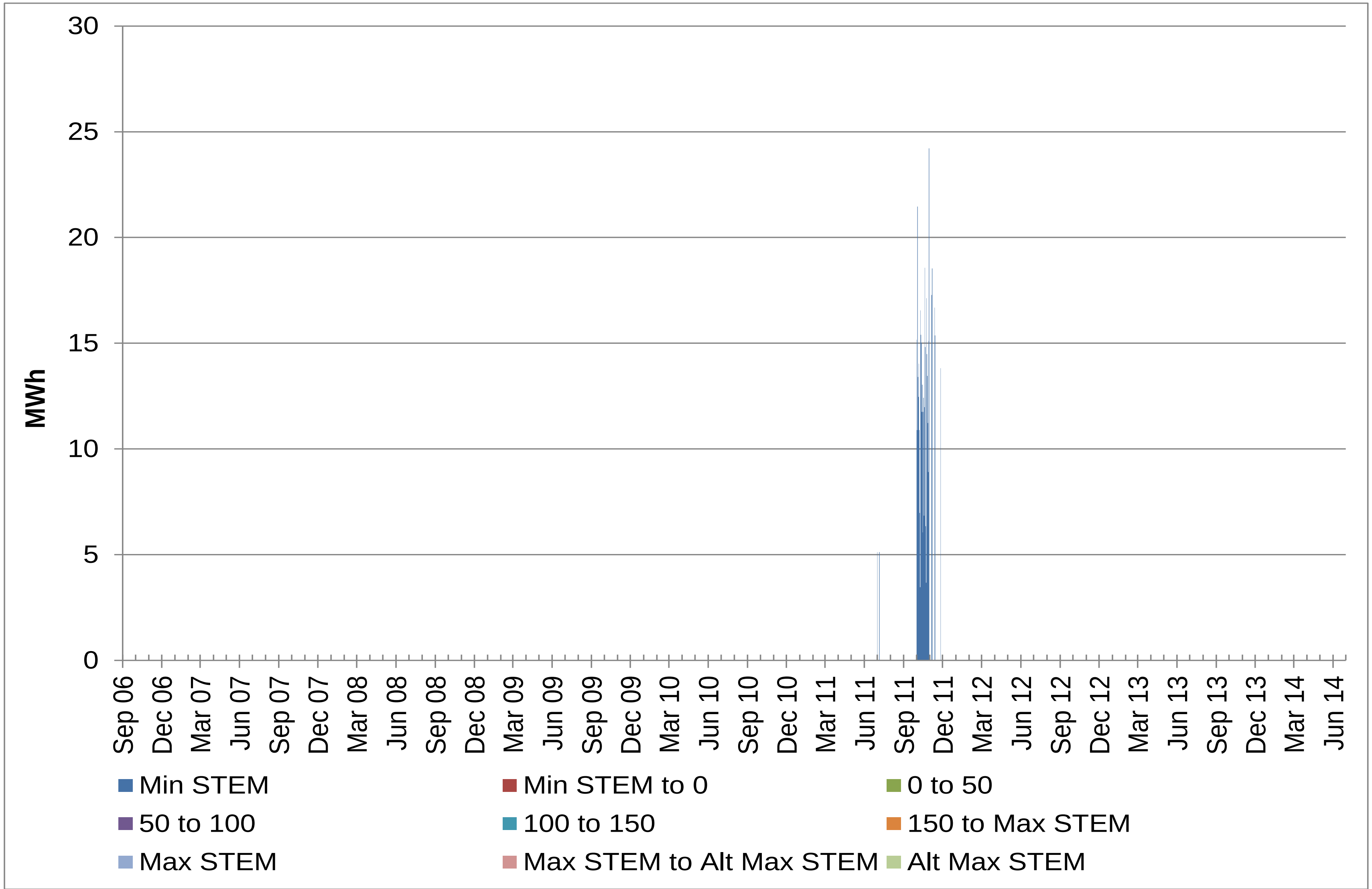


Figure 65 Synergy's daily average STEM Bids (cumulative MWh per Trading Interval)

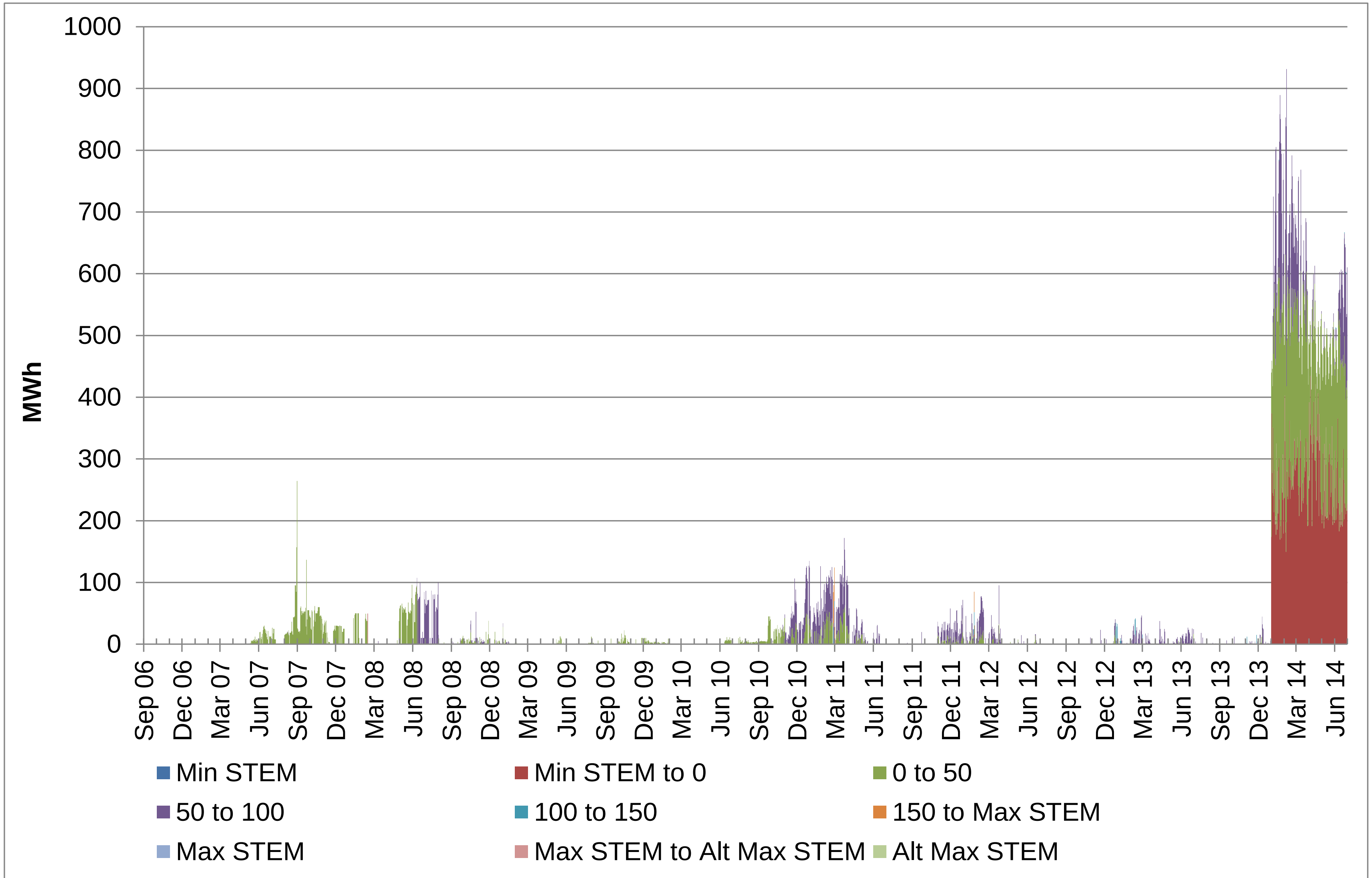


Figure 66 Verve Energy's daily average STEM Bids (cumulative MWh per Trading Interval)

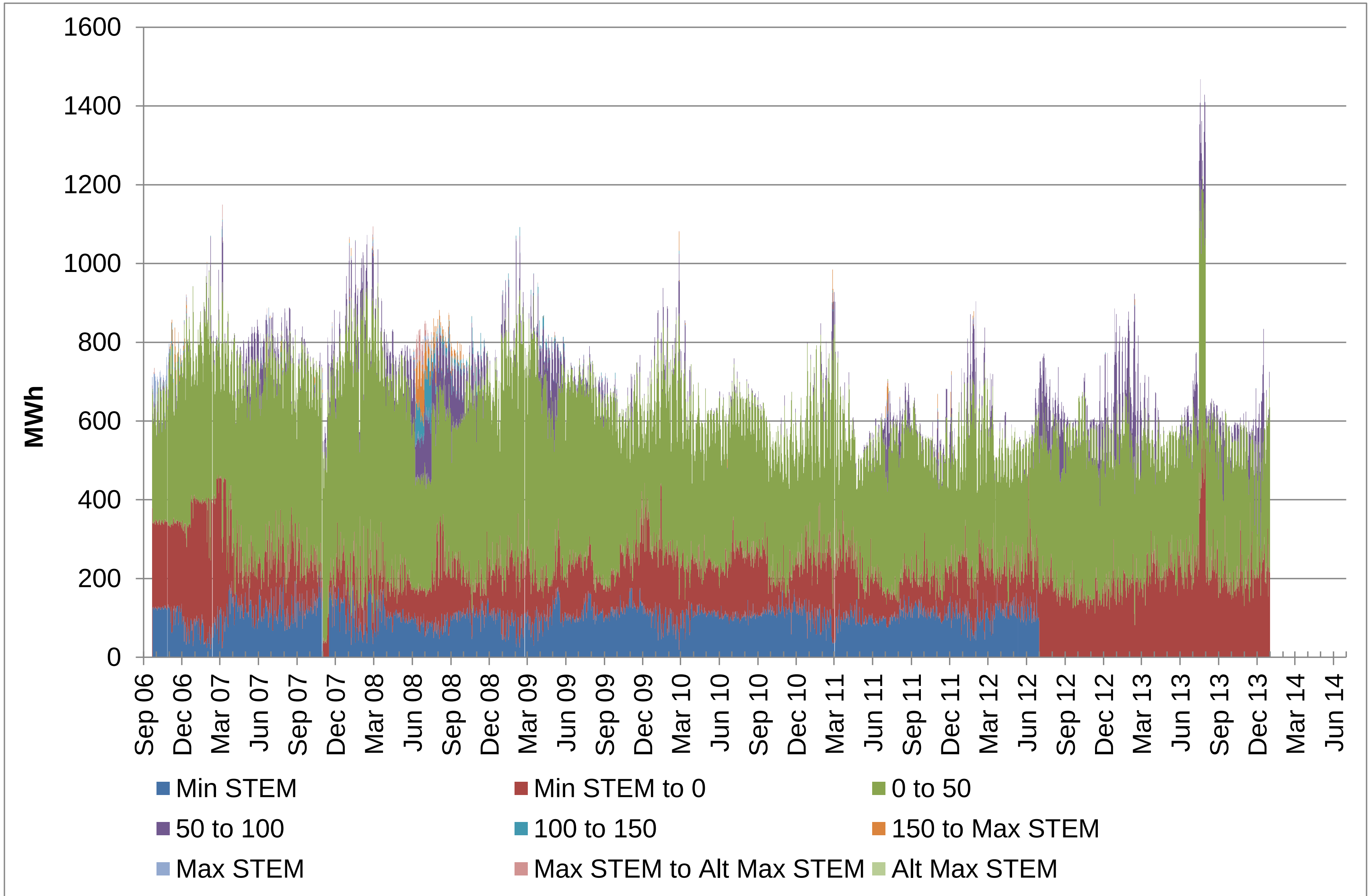


Figure 67 Vinalco's daily average STEM Bids (cumulative MWh per Trading Interval)

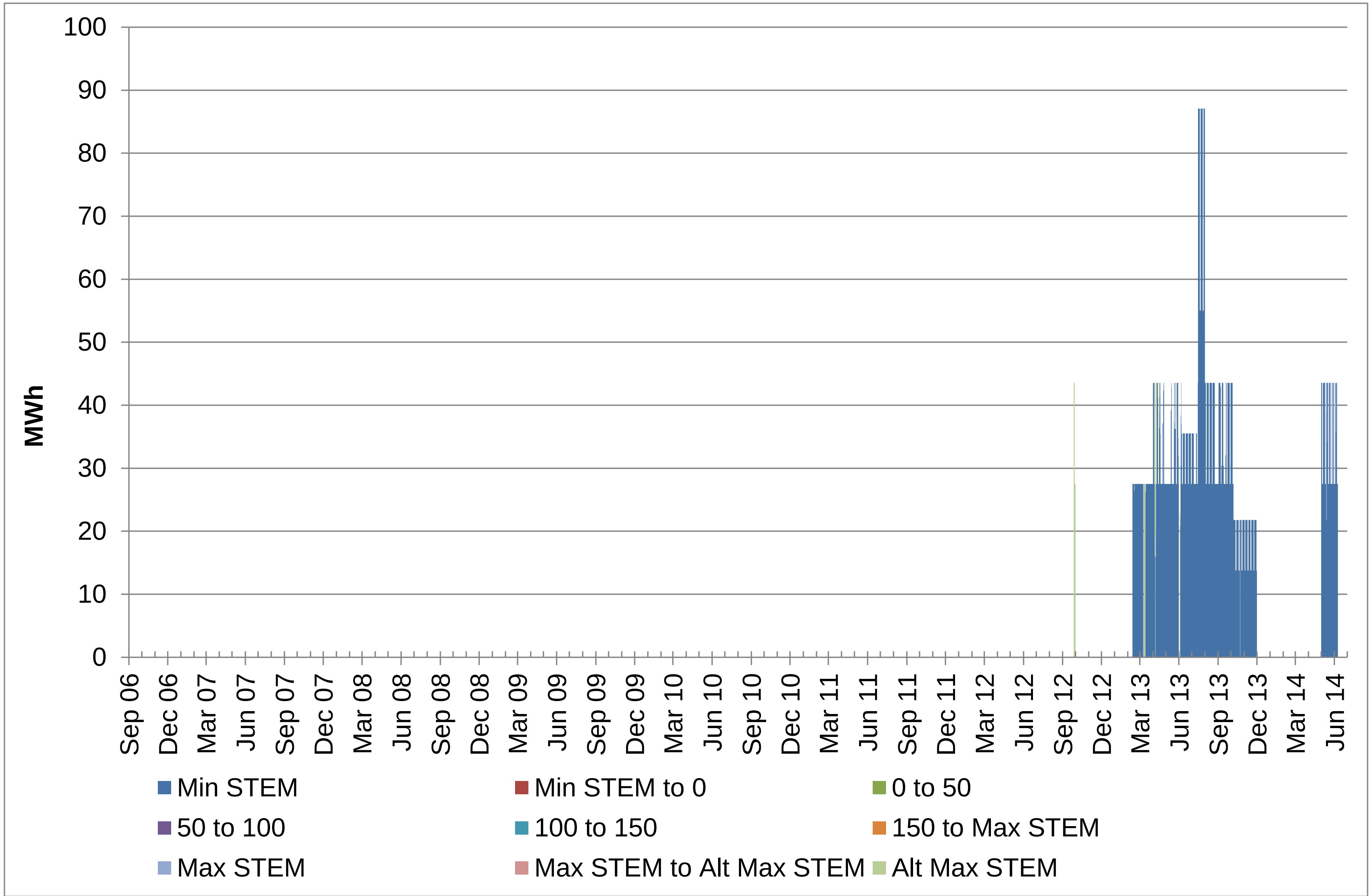


Table 5 Fuel Declarations (last three Capacity Years)

Participant	Resource Name	Liquid declaration 2010/11 Cap Year	Non-liquid declaration 2010/11 Cap Year	Liquid declaration 2011/12 Cap Year	Non-liquid declaration 2011/12 Cap Year	Liquid declaration 2012/13 Cap Year	Non-liquid declaration 2012/13 Cap Year	Liquid declaration 2013/14 Cap Year	Non-liquid declaration 2013/14 Cap Year
Alcoa	ALCOA_KWI								
Alcoa	ALCOA_PNJ								
Alcoa	ALCOA_WGP	36.7%							
Alinta	ALINTA_WGP_AGG	1.6%	20.8%						
Alinta	ALINTA_WGP_GT	8.3%	69.0%	20.3%	79.7%		100.0%		100.0%
Alinta	ALINTA_WGP_U2	6.9%	70.3%	20.0%	80.0%		100.0%		100.0%
Goldfields Power	PRK_AG	97.9%	1.8%	100.0%		98.3%	1.7%	99.7%	
NewGen Neerabup	NEWGEN_NEERABUP_GT1				30.9%		100.0%		100.0%
Perth Energy	PERTHENERGY_KWINANA_GT1	99.7%		100.0%		100.0%		100.0%	
Southern Cross	STHRNCRS_EG								
Synergy	KEMERTON_GT11	1.1%	98.6%		100.0%		100.0%		99.7%
Synergy	KEMERTON_GT12	1.1%	98.6%		100.0%		100.0%		99.7%
Synergy	KWINANA_G3								
Synergy	KWINANA_G4								
Synergy	KWINANA_G5	1.1%	98.6%	0.3%	99.7%		94.1%		90.4%
Synergy	KWINANA_G6		99.5%		71.2%		75.5%		91.8%
Synergy	KWINANA_GT1	99.7%		100.0%		100.0%		99.7%	
Synergy	KWINANA_GT2				30.1%		100.0%		99.7%
Synergy	KWINANA_GT3				38.8%		100.0%		99.7%
Synergy	PINJAR_GT1	0.3%	99.5%	0.3%	99.7%		100.0%		99.7%
Synergy	PINJAR_GT2	99.2%	0.6%	99.7%	0.3%	100.0%		99.7%	
Synergy	PINJAR_GT3	0.6%	99.2%	0.3%	99.7%		100.0%		99.7%
Synergy	PINJAR_GT4	99.2%	0.6%	99.5%	0.5%	100.0%		99.7%	
Synergy	PINJAR_GT5	0.6%	99.2%	0.3%	99.7%		100.0%		99.7%
Synergy	PINJAR_GT7	99.2%	0.6%	99.5%	0.5%	100.0%		99.7%	

*Blanks in the above table denote no values to be reported in respective category.

Figure 68 Daily average Availability Declarations (MWh unavailable per Trading Interval)

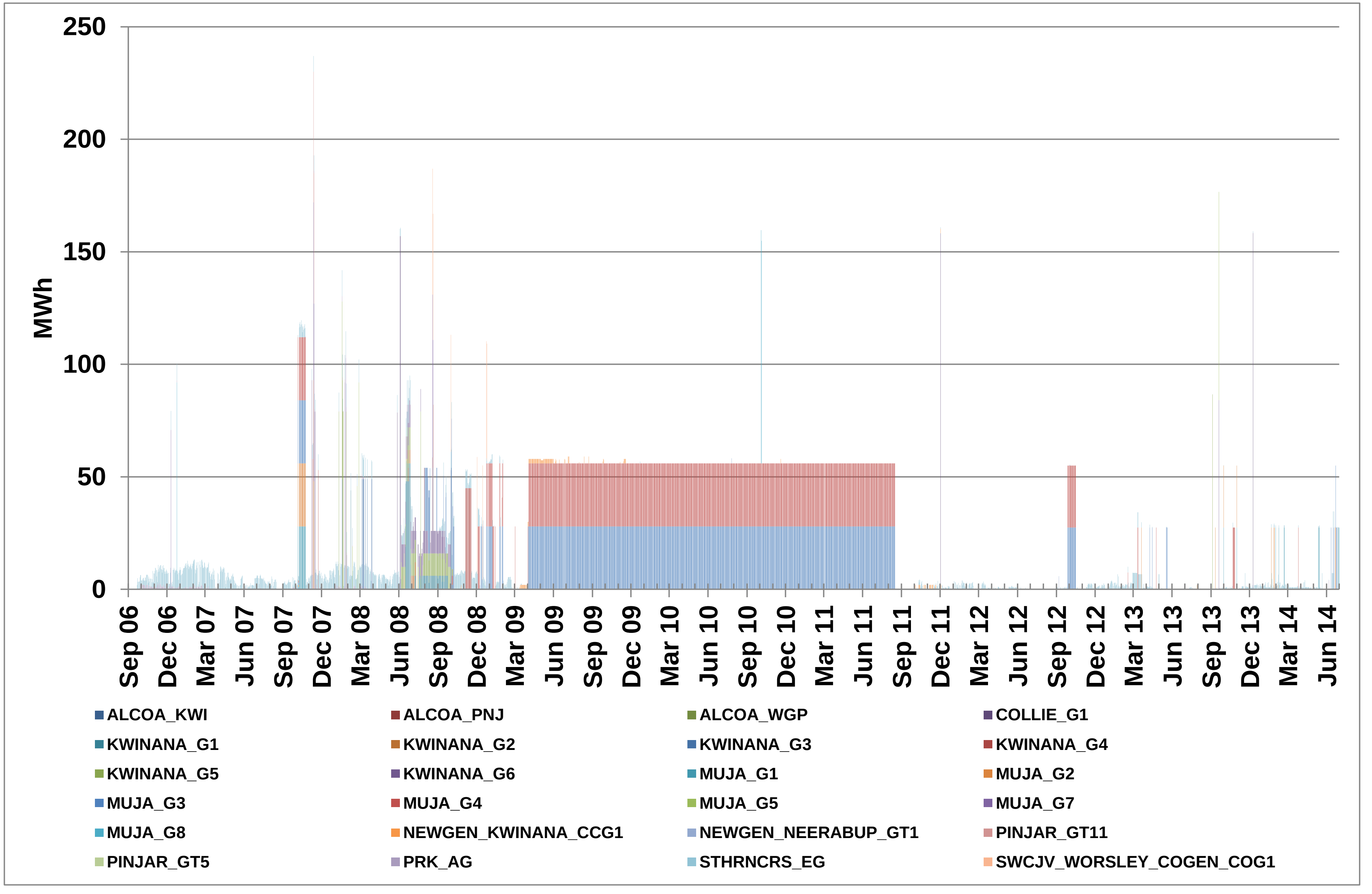


Table 6 Proportion of Trading Intervals for which actual output exceeds Availability Declarations (last three Capacity Years)

Participant	Resource Name	Cold season 2011/12 Cap Year	Hot season 2011/12 Cap Year	Intermediate season 2011/12 Cap Year	Cold season 2012/13 Cap Year	Hot season 2012/13 Cap Year	Intermediate season 2012/13 Cap Year	Cold season 2013/14 Cap Year	Hot season 2013/14 Cap Year	Intermediate season 2013/14 Cap Year
Alcoa	ALCOA_WGP	2.31%		9.29%	5.98%	2.41%	0.33%	1.81%		1.88%
Alinta Sales	ALINTA_PNJ_U1	1.50%			0.03%		0.01%	3.26%		
Alinta Sales	ALINTA_PNJ_U2	1.50%					0.90%	1.53%		4.54%
Alinta Sales	ALINTA_WGP_U2				0.10%			0.01%		
Alinta Sales	ALINTA_WGP_GT							0.38%		
Blair Fox Pty Ltd	BLAIRFOX_WESTHILLS_WF3							0.02%		
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	0.06%		16.97%	0.20%	0.21%	0.01%			
Goldfields Power	PRK_AG	0.02%		0.14%		0.03%	0.02%	0.01%		0.07%
Greenough River	GREENOUGH_RIVER_PV1	0.38%								
Griffin Power 2	BW2_BLUEWATERS_G1	1.53%				0.03%	0.02%	0.02%	0.03%	0.61%
Griffin Power	BW1_BLUEWATERS_G2	0.02%	1.50%			0.10%	0.01%	0.08%	0.22%	0.48%
Landfill Gas and Power	KALAMUNDA_SG	0.02%	0.09%		0.07%			0.02%		0.07%
Landfill Gas and Power	RED_HILL							0.07%		37.43%
Landfill Gas and Power	TAMALA_PARK	7.99%	32.17%							
Merredin	NAMKKN_MERR_SG1	0.06%				0.03%	0.07%	0.03%		0.10%
Mount Barker	SKYFARM_MTBARKER_WF1	0.03%						0.02%		
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1	0.18%		6.22%			0.11%	0.27%	0.05%	0.07%
NewGen Neerabup	NEWGEN_NEERABUP_GT1		0.31%	0.10%			0.02%	0.41%	0.03%	
Perth Energy	ATLAS									
Perth Energy	ROCKINGHAM						15.91%			
Perth Energy	SOUTH_CARDUP	1.58%		0.34%	0.03%					
Southern Cross Energy	STHRNCRS_EG					0.03%				
Tesla	TESLA_GERALDTON_G1	0.01%			3.24%	2.82%	0.38%	0.02%	0.02%	
Tesla	TESLA_KEMERTON_G1							0.12%	0.03%	
Tesla	TESLA_NORTHAM_G1							0.01%	0.05%	
Tesla	TESLA_PICTON_G1	0.01%	0.02%	0.10%			0.01%	0.16%	0.05%	
Tiwest	TIWEST_COG1	0.03%	0.14%	0.00%	0.03%	0.96%	0.06%	0.17%		0.10%

Participant	Resource Name	Cold season 2011/12 Cap Year	Hot season 2011/12 Cap Year	Intermediate season 2011/12 Cap Year	Cold season 2012/13 Cap Year	Hot season 2012/13 Cap Year	Intermediate season 2012/13 Cap Year	Cold season 2013/14 Cap Year	Hot season 2013/14 Cap Year	Intermediate season 2013/14 Cap Year
Synergy	ALBANY_WF1	0.01%	0.26%							
Synergy	COCKBURN_CCG1	10.29%	1.28%	8.23%	2.32%		5.59%	12.67%	2.74%	24.15%
Synergy	COLLIE_G1	0.79%	1.83%	0.79%	0.41%	2.98%	0.74%	1.02%	0.55%	3.72%
Synergy	GERALDTON_GT1	0.06%		0.24%		0.03%				0.03%
Synergy	KEMERTON_GT11	1.50%	0.72%	0.55%	0.20%	0.55%	0.98%	0.35%	0.40%	0.38%
Synergy	KEMERTON_GT12	0.57%	3.31%	0.79%	0.07%	0.33%	0.11%	0.92%	0.24%	0.24%
Synergy	KWINANA_G1									
Synergy	KWINANA_G2									
Synergy	KWINANA_G4									
Synergy	KWINANA_G5	1.71%	0.67%	1.02%	0.07%	0.31%	0.73%	0.03%		
Synergy	KWINANA_G6	0.55%	0.97%	0.14%	0.07%		0.22%	0.02%	0.03%	
Synergy	KWINANA_GT1		0.05%		0.07%		0.07%			
Synergy	KWINANA_GT2	1.63%			0.79%	1.12%	0.86%	0.40%	0.26%	0.24%
Synergy	KWINANA_GT3	1.98%			0.79%	4.67%	2.54%	1.55%	0.09%	0.44%
Synergy	MUJA_G5	13.35%	16.12%	13.59%	4.68%	3.00%	2.34%	0.03%		2.49%
Synergy	MUJA_G6		3.53%	7.41%	0.03%	12.24%	9.64%	0.20%		1.64%
Synergy	MUJA_G7	3.01%	3.33%	6.39%	0.14%	0.29%	1.05%	1.38%	0.98%	0.41%
Synergy	MUJA_G8	0.68%	3.69%	4.34%	2.05%	0.33%	0.58%	1.48%	0.84%	0.03%
Synergy	MUNGARRA_GT1	0.01%			0.61%		0.17%	0.52%	0.03%	
Synergy	MUNGARRA_GT2	0.44%		0.10%	0.44%		0.72%	0.40%	0.14%	
Synergy	MUNGARRA_GT3	0.03%				0.02%	0.09%	0.07%	0.29%	
Synergy	PINJAR_GT1	0.01%					0.22%	0.02%		
Synergy	PINJAR_GT10	0.66%	0.24%	0.65%	0.17%	0.12%	0.09%	0.71%	0.05%	0.03%
Synergy	PINJAR_GT11	0.58%	1.37%			0.02%	0.02%	0.06%	0.09%	0.07%
Synergy	PINJAR_GT2	0.03%						0.01%		
Synergy	PINJAR_GT3	0.03%	0.26%			0.02%	0.01%	0.02%	0.02%	
Synergy	PINJAR_GT4	0.60%	0.03%			0.07%	0.02%	0.02%	0.02%	
Synergy	PINJAR_GT5	0.02%	0.02%			0.19%	0.09%	0.02%		

Participant	Resource Name	Cold season 2011/12 Cap Year	Hot season 2011/12 Cap Year	Intermediate season 2011/12 Cap Year	Cold season 2012/13 Cap Year	Hot season 2012/13 Cap Year	Intermediate season 2012/13 Cap Year	Cold season 2013/14 Cap Year	Hot season 2013/14 Cap Year	Intermediate season 2013/14 Cap Year
Synergy	PINJAR_GT7	0.01%	0.05%			0.03%	0.01%	0.03%		
Synergy	PINJAR_GT9	1.05%	0.22%	0.10%	0.65%		0.18%	0.10%		0.61%
Synergy	PPP_KCP_EG1	7.22%	6.20%	9.12%	9.97%	0.59%	21.99%	30.78%	1.20%	12.40%
Synergy	SWCJV_WORSLEY_COGEN_COG1	91.80%	59.17%	87.19%	88.70%	59.21%	94.57%	80.02%	41.56%	65.47%
Synergy	WEST_KALGOORLIE_GT2		0.02%			0.03%	0.06%	0.03%		
Synergy	WEST_KALGOORLIE_GT3		0.03%		0.24%					
Vinalco	MUJA_G1							0.06%	0.24%	0.1%
Vinalco	MUJA_G2							0.83%	0.15%	
Vinalco	MUJA_G3					7.28%	3.71%	0.01%	1.27%	
Vinalco	MUJA_G4	0.07%				23.64%	7.18%	0.01%	0.03%	0.03%

*Blanks in the above table denote no values to be reported in respective category.

Figure 69 **Daily average Ancillary Services declarations (MWh per Trading Interval)**

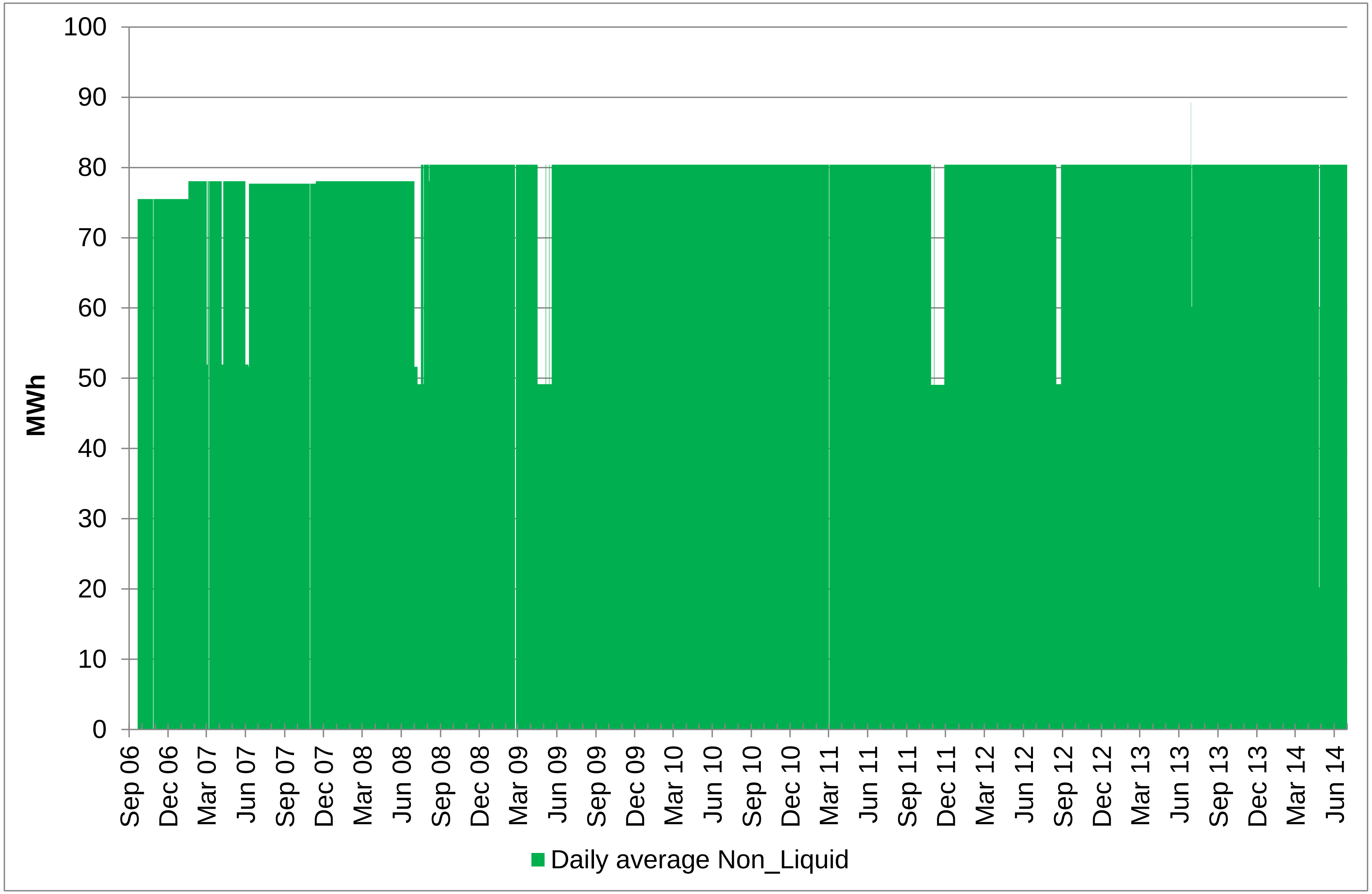


Table 7 Registered Market Generators and Market Customers

	14 October 2010	3 October 2011	10 December 2012	30 September 2013	1 October 2014
Market Generators and Market Customers	Alcoa of Australia Limited	Alcoa of Australia Limited	Alcoa of Australia Limited	Alcoa of Australia Limited	Alcoa of Australia Limited
	Alinta Sales Pty Ltd	Alinta Sales Pty Ltd	Alinta Sales Pty Ltd	Alinta Sales Pty Ltd	Alinta Sales Pty Ltd
	Griffin Power Pty Ltd	Griffin Power 2 Pty Ltd	Blair Fox Pty Ltd	Blair Fox Pty Ltd	Blair Fox Pty Ltd
	Griffin Power 2 Pty Ltd	Griffin Power Pty Ltd	Griffin Power 2 Pty Ltd	Clear Energy Pty Ltd	Clear Energy Pty Ltd
	Landfill Gas and Power Pty Ltd	Landfill Gas and Power Pty Ltd	Griffin Power Pty Ltd	Griffin Power 2 Pty Ltd	Griffin Power 2 Pty Ltd
	Metro Power Company Pty Ltd	Metro Power Company Pty Ltd	Landfill Gas and Power Pty Ltd	Griffin Power Pty Ltd	Griffin Power Pty Ltd
	Perth Energy Pty Ltd	Perth Energy Pty Ltd	Metro Power Company Pty Ltd	Landfill Gas and Power Pty Ltd	Landfill Gas and Power Pty Ltd
	Southern Cross Energy	Southern Cross Energy	Perth Energy Pty Ltd	Metro Power Company Pty Ltd	Metro Power Company Pty Ltd
	Verve Energy	Tiwest	Southern Cross Energy	Perth Energy Pty Ltd	Perth Energy Pty Ltd
		Verve Energy	Tiwest	Southern Cross Energy	Southern Cross Energy
			Verve Energy	Tiwest	Tiwest
				Verve Energy	Synergy
Market Generators (only)	Advanced Energy Resources	Advanced Energy Resources	Advanced Energy Resources	Advanced Energy Resources	Advanced Energy Resources
	Biogen	Biogen	Biogen	Biogass Pty Ltd	Biogass Pty Ltd
	Collgar Wind Farm	Blair Fox Pty Ltd	Collgar Wind Farm	Biogen	Biogen
	Coolimba Power Pty Ltd	Collgar Wind Farm	Coolimba Power Pty Ltd	Collgar Wind Farm	Collgar Wind Farm
	EDWF Manager Pty Ltd	Coolimba Power Pty Ltd	Denmark Community Windfarm Ltd	Coolimba Power Pty Ltd	Coolimba Power Pty Ltd
	Eneabba Gas Limited	EDWF Manager Pty Ltd	EDWF Manager Pty Ltd	Denmark Community Windfarm Ltd	Denmark Community Windfarm Ltd
	Eneabba Energy Pty Ltd	Eneabba Energy Pty Ltd	Eneabba Gas Limited	EDWF Manager Pty Ltd	EDWF Manager Pty Ltd
	Goldfields Power Pty Ltd	Eneabba Gas Limited	Eneabba Energy Pty Ltd	EMRC	EMRC
	McNabb Plantation Alliance Pty Ltd	Goldfields Power Pty Ltd	Genthrust Pty Ltd	Eneabba Gas Limited	Eneabba Gas Limited
	Mount Herron Engineering Pty Ltd	McNabb Plantation Alliance Pty Ltd	Goldfields Power Pty Ltd	Eneabba Energy Pty Ltd	Eneabba Energy Pty Ltd

	14 October 2010	3 October 2011	10 December 2012	30 September 2013	1 October 2014
	Namarkkon Pty Ltd	Merredin Energy	Greenough River	Genthrust Pty Ltd	Genthrust Pty Ltd
	NewGen Power Kwinana Pty Ltd	Mount Herron Engineering Pty Ltd	Merredin Energy	Goldfields Power Pty Ltd	Goldfields Power Pty Ltd
	NewGen Neerabup Pty Ltd	Mt.Barker Power Company Pty Ltd	Moonies Hill Energy	Greenough River	Greenough River
	NewGen Neerabup Partnership	Mumbida Wind Farm Pty Ltd	Mount Herron Engineering Pty Ltd	Merredin Energy	Merredin Energy
	SkyFarming Pty Ltd	Namarkkon Pty Ltd	Mt.Barker Power Company Pty Ltd	Moonies Hill Energy	Moonies Hill Energy
	Tesla Corporation Pty Ltd	NewGen Neerabup Partnership	McNabb Plantation Alliance Pty Ltd	Mount Herron Engineering Pty Ltd	Mount Herron Engineering Pty Ltd
	Vinalco Energy Pty Ltd	NewGen Neerabup Pty Ltd	Mumbida Wind Farm Pty Ltd	Mt.Barker Power Company Pty Ltd	Mt.Barker Power Company Pty Ltd
	Wambo Power Ventures Pty Ltd	NewGen Power Kwinana Pty Ltd	NewGen Power Kwinana Pty Ltd	McNabb Plantation Alliance Pty Ltd	McNabb Plantation Alliance Pty Ltd
	Waste Gas Resources Pty Ltd	SkyFarming Pty Ltd	NewGen Neerabup Partnership	Mumbida Wind Farm Pty Ltd	Mumbida Wind Farm Pty Ltd
	Western Australia Biomass Pty Ltd	Tesla Corporation Management Pty Ltd	NewGen Neerabup Pty Ltd	NewGen Power Kwinana Pty Ltd	NewGen Power Kwinana Pty Ltd
	Western Energy Pty Ltd	Tesla Corporation Pty Ltd	SkyFarming Pty Ltd	NewGen Neerabup Partnership	NewGen Neerabup Partnership
		Tesla Geraldton Pty Ltd	Tesla Corporation Pty Ltd	NewGen Neerabup Pty Ltd	NewGen Neerabup Pty Ltd
		Tesla Holdings	Tesla Geraldton Pty Ltd	Phoenix Energy	Phoenix Energy
		Tesla Kemerton Pty Ltd	Tesla Holdings	SkyFarming Pty Ltd	SkyFarming Pty Ltd
		Tesla Northam Pty Ltd	Tesla Kemerton Pty Ltd	Tesla Corporation Pty Ltd	Tesla Corporation Pty Ltd
		Vinalco Energy Pty Ltd	Tesla Corporation Management Pty Ltd	Tesla Geraldton Pty Ltd	Tesla Geraldton Pty Ltd
		Walkaway Wind Power Pty Ltd	Tesla Northam Pty Ltd	Tesla Holdings	Tesla Holdings
		Wambo Power Ventures Pty Ltd	UON Pty Ltd	Tesla Kemerton Pty Ltd	Tesla Kemerton Pty Ltd
		Waste Gas Resources Pty Ltd	Vinalco Energy Pty Ltd	Tesla Corporation Management Pty Ltd	Tesla Corporation Management Pty Ltd
		Western Australia Biomass Pty Ltd	Western Australia Biomass Pty Ltd	Tesla Northam Pty Ltd	Tesla Northam Pty Ltd
		Western Energy Pty Ltd	Walkaway Wind Power Pty Ltd	UON Pty Ltd	UON Pty Ltd
			Wambo Power Ventures Pty Ltd	Vinalco Energy Pty Ltd	Vinalco Energy Pty Ltd
			Western Energy Pty Ltd	Wambo Power Western Australia Biomass Pty Ltd	Wambo Power Western Australia Biomass Pty Ltd

	14 October 2010	3 October 2011	10 December 2012	30 September 2013	1 October 2014
			Waste Gas Resources Pty Ltd	Walkaway Wind Power Pty Ltd Western Energy Pty Ltd Waste Gas Resources Pty Ltd	Walkaway Wind Power Pty Ltd Western Energy Pty Ltd Waste Gas Resources Pty Ltd
Market Customers (only)	Amanda Australia Pty Ltd Barrick (Kanowna) Limited Clear Energy Pty Ltd DMT Energy Energy Response Pty Ltd EnerNOC Australia Pty Ltd ERM Power Retail Pty Ltd Karara Energy Pty Ltd Newmont Power Pty Ltd Premier Power Sales Pty Ltd Synergy Water Corporation	Amanda Australia Pty Ltd Barrick (Kanowna) Limited Clear Energy Pty Ltd DMT Energy Energy Response Pty Ltd EnerNOC Australia Pty Ltd ERM Power Retail Pty Ltd Karara Energy Pty Ltd Newmont Power Pty Ltd Premier Power Sales Pty Ltd Synergy Water Corporation	Amanda Australia Pty Ltd Clear Energy Pty Ltd DMT energy EnerNOC Australia Pty Ltd Energy Response Pty Ltd ERM Power Retail Pty Ltd Focus Operations HBJ Minerals Pty Ltd Barrick (Kanowna) Limited Karara Energy Pty Ltd La Mancha Resources Newmont Power Pty Ltd Premier Power Sales Pty Ltd Water Corporation Synergy	AER Retail Pty Ltd Amanda Australia Pty Ltd Cockburn Cement Ltd DMT energy EnerNOC Australia Pty Ltd Energy Response Pty Ltd ERM Power Retail Pty Ltd Focus Operations HBJ Minerals Pty Ltd Barrick (Kanowna) Limited Karara Energy Pty Ltd La Mancha Resources Newmont Power Pty Ltd Premier Power Sales Pty Ltd Water Corporation Synergy	A Star Electricity AER Retail Pty Ltd Amanda Australia Pty Ltd Amanda Energy Pty Ltd Blue Star Energy Pty Ltd Community Electricity Cockburn Cement Ltd DMT energy EnerNOC Australia Pty Ltd Energy Response Pty Ltd ERM Power Retail Pty Ltd Focus Operations HBJ Minerals Pty Ltd Barrick (Kanowna) Limited Karara Energy Pty Ltd

	14 October 2010	3 October 2011	10 December 2012	30 September 2013	1 October 2014
					La Mancha Resources Newmont Power Pty Ltd Premier Power Sales Pty Ltd Water Corporation