2015 Wholesale Electricity Market Report to the Minister for Energy

Issues Paper (Appendices)

NOVEMBER 2015

Economic Regulation Authority
WESTERN AUSTRALIA

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Appendix 1 Matters required to be included in the Authority's review

Role of the Authority

The Authority is responsible for monitoring the effectiveness of the market in meeting the Wholesale Market Objectives and must investigate any market behaviour if it considers that the behaviour has resulted in the market not functioning effectively.

The Market Objectives are:

- To promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West Interconnected System.
- To encourage competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors.
- To avoid discrimination against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions.
- To minimise the long-term cost of electricity supplied to customers from the SWIS.
- To encourage the taking of measures to manage the amount of electricity used and when it is used.

The Authority, with the assistance of the IMO, must monitor:

- Ancillary Service Contracts that System Management enters into and the criteria and process that System Management uses to procure Ancillary Services from other persons;
- inappropriate and anomalous market behaviour, including behaviour related to market power and the exploitation of shortcomings in the Market Rules or Market Procedures by Rule Participants including, but not limited to,
  - prices offered by a Market Generator in the STEM which do not reflect its reasonable expectation of the short run marginal cost of generating the relevant electricity;
  - prices offered by a Market Generator in the Balancing Market which exceed its reasonable expectation of the short run marginal cost of generating the relevant electricity;
  - prices offered by a Market Generator in the LFAS market which exceed its reasonable expectation of the incremental change in short run marginal cost incurred in providing the relevant LFAS;
  - Availability Declarations that may not reflect the reasonable expectation of a Facility's availability, beyond outages of which System Management has been notified;
  - Ancillary Service Declarations that may not reflect the reasonable expectation of the Ancillary Services to be provided by a Facility; and
  - Fuel Declarations that may not reflect the reasonable expectation of the fuel that a Facility will be run on in real-time;
- market design problems or inefficiencies; and

- problems with the structure of the market.

The Authority must also review:

- The effectiveness of the Market Rule change process and Procedure Change Process;
- The effectiveness of the compliance monitoring and enforcement measures in the Market Rules and Regulations; and
- The effectiveness of the IMO and System Management in carrying out their functions under the Regulations, the Market Rules and Market Procedures.

The IMO is responsible for collection and primary analysis of data in relation to monitoring the effectiveness of the market. It is required to compile data specifically identified in the Market Rules, the Market Surveillance Data Catalogue (MSDC) and to provide that data to the ERA. The Market Rules set out certain analysis the IMO must undertake and provide to the ERA. These requirements are set out in Appendix 1.

The remainder of this appendix sets out relevant information in relation to the above requirements in the following order:

- Reserve Capacity Mechanism
- Energy Markets
- Ancillary Services
- Dispatch Process
- Planning Processes
- Market Rule Change and Procedure Change Process
- Compliance Monitoring and Enforcement Measures
- Independent Market Operator functions
- System Management functions

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.

Sufficient capacity has been secured under the RCM to meet forecast capacity requirements, with the number of Capacity Credits[1] assigned to participants exceeding the Reserve Capacity Requirement (**RCR**) in each of the Capacity Years since its inception.

Reserve Capacity Auctions

The IMO may cancel the Reserve Capacity Auction if no Certified Reserve Capacity is made available for auction and the IMO considers that the Reserve Capacity Requirement (**RCR**) will be met without an auction. As there has been sufficient capacity to meet the RCR in each Reserve Capacity Cycle so far, the IMO has not called the Reserve Capacity Auction.

Performance in meeting Reserve Capacity obligations

The capacity certification process requires the IMO to satisfy itself that any facility assigned Capacity Credits will be able to meet its obligations and provide capacity when required. A market participant applying for capacity certification needs to provide the IMO with information such as: details of its facility's capacity; evidence of network access arrangements; information on environmental approvals; evidence of contracted fuel supplies; information about the expected availability of the facility; and key project dates for new facilities.

Under clause 4.11.1(h) of the Market Rules, the IMO may decide not to certify a Market Generator's capacity if it believes that the facility is not likely to be available. Under clause 4.27 of the Market Rules, the IMO may impose conditions on planned outages.

Under clause 4.11.1(h) of the Market Rules, the IMO may decide not to assign Certified Capacity to a facility if it has operated for at least 36 months, and has had a poor availability record. The criteria are a forced outage rate of greater than 15 per cent or a combined planned and forced outage rate of greater than 30 per cent over the preceding 36 months.

Capacity Credit holders are obliged to make that capacity available to the market for the relevant capacity year. In the event that the capacity is not made available, a penalty is applied (either a refund of the capacity payment or forfeiture of a security deposit).

Number and frequency of outages

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 total assigned Capacity Credits for that Facility.

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[1] 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 1 below sets out, for each Facility, the ratio of capacity subject to outages relative to the weighted total effective capacity by Capacity Credits, for the financial years 2010-11 through 2014-15. Note that Facilities KWINANA_G5 and KWINANA_G6 were retired on 8 July 2014 and 3 April 2015, respectively; high Forced Outage rates for Vinalco units in part reflect delays in commencing active operation.

Table 1 Ratio of quantities subject to outages to total effective financial year capacity (1 July 2010 to 30 June 2015)

Participant	Facility name	2010-11 FY			2011-12 FY			2012-13 FY			2013-14 FY			2014-15 FY		
		Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan
Alcoa of Australia	ALCOA_WGP	13.6	12.8%	21.6%	21.6	4.4%	23.1%	24	3.8%	30.7%	24	26.2%	9.6%	24	1.4%	3.5%
Alinta Sales	ALINTA_PNJ_U1	129	0.1%	11.2%	129	0.3%	9.1%	131.9	0%	5.8%	132.8	0.5%	14.8%	132.8	0.1%	9.7%
Alinta Sales	ALINTA_PNJ_U2	131.2	0.1%	4.4%	132	0.2%	4%	132.3	0.3%	13.6%	132.4	0.3%	13.9%	132.4	0.3%	6.5%
Alinta Sales	ALINTA_WGP_GT	175.5	0.9%	1.9%	175.9	0.5%	1.7%	176	0.3%	2.5%	178.3	0.2%	6.8%	179.1	0.3%	7.1%
Alinta Sales	ALINTA_WGP_U2	175.5	0.4%	2%	175.9	0.4%	3.6%	176	1.2%	2%	178.3	0.5%	7.2%	179.1	0.5%	7.1%
Alinta Sales	ALINTA_WWF	40.5	0%	0%	39.6	0%	0%	38.9	0%	0%	39	0%	0%	30.4	0%	0.1%
Blair Fox	BLAIRFOX_KARAKIN_WF1	0			0			0			0.8	0%	0%	1.3	0%	0%
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	0			67.4	0%	0%	90	0.3%	0.8%	90	0%	0.3%	37.7	0.9%	0.5%
Denmark Community Windfarm	DCWL_DENMARK_WF1	0			0			0			0.5	0%	0%	1.1	0%	0%
EDWF Manager	EDWFMAN_WF1	31.1	0%	0%	30.2	0%	0.1%	29.5	0.9%	0%	28.8	0%	0.3%	23.9	0%	0%
Goldfields Power	PRK_AG	61.4	1.5%	7.1%	61.4	0%	0.5%	61.4	0%	0.3%	61.4	0.1%	0.1%	61.4	0.1%	0.3%
Greenough River	GREENOUGH_RIVER_PV1	0			0			0			2	1.1%	0.8%	5.1	0%	0.2%
Griffin Power	BW1_BLUEWATERS_G2	204	1.1%	9%	212.9	3.5%	11.4%	215.9	4.9%	9%	215.9	2.1%	12.9%	216.7	0.2%	9.2%
Griffin Power 2	BW2_BLUEWATERS_G1	204	2.4%	4.7%	212.9	1.7%	6.3%	215.9	0.5%	11.5%	215.9	0.3%	9.5%	215.9	1.5%	8.1%
Landfill Gas & Power	CANNING_MELVILLE	1.7	0%	0%	1.3	0%	0%	1.1	0%	0%	0.8	0%	0%	0.2	0%	0%
Landfill Gas & Power	KALAMUNDA	0.1	0%	0%	0			0			0			0		
Landfill Gas & Power	KALAMUNDA_SG	1	0%	0%	1.3	0%	0%	1.3	0%	0%	1.3	0%	0%	1.3	0%	0%
Landfill Gas & Power	RED_HILL	2.7	0%	0%	2.4	0%	0%	2.7	0%	0%	3	0%	0%	2.9	0%	0%
Landfill Gas & Power	TAMALA_PARK	3.3	0%	0%	3.4	0%	0%	3.5	0%	0%	3.8	0%	0%	3.9	0%	0%
Merredin Energy	NAMKKN_MERR_SG1	0			0			52.4	0.8%	4.9%	79	1.4%	3.3%	82	0%	9.2%
Mount Herron Engineering	MHPS	0.8	0%	0%	0.3	0%	0%	0.1	0%	0%	0			0		
Mt.Barker Power Company	SKYFRM_MTBARKER_WF1	0.7	0%	0%	0.9	0%	0%	0.9	0%	0%	0.9	0%	0%	1	0%	0%
Mumbida Wind Farm	MWF_MUMBIDA_WF1	0			0			0			11	0%	0%	17.3	0.3%	1.2%
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.6	0%	6.8%	330.6	0%	2.8%	330.6	0%	5.1%	330.6	0%	5.1%	330.6	0%	1.2%

Participant	Facility name	2010-11 FY			2011-12 FY			2012-13 FY			2013-14 FY			2014-15 FY		
		Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1	320	0.4%	2.2%	320	0.7%	15.5%	320	0.4%	3.4%	320	0.6%	2.1%	320	0.1%	2.7%
Perth Energy	ATLAS	1	0%	0%	0.9	0%	0%	0.9	0%	0%	0.8	0%	0%	0.7	0%	0%
Perth Energy	GOSNELLS	0.8	0%	0%	0.7	0%	0%	0.6	0%	0%	0.5	0%	0%	0.1	0%	0%
Perth Energy	ROCKINGHAM	1.3	0%	0%	1.5	0%	0%	1.6	0%	0%	1.7	0%	0%	2.3	0%	0%
Perth Energy	SOUTH_CARDUP	2.9	0%	0%	2.8	0%	0%	2.9	0%	0%	2.7	0%	0%	2.5	0%	0%
Southern Cross Energy	STHRNCRS_EG	2.6	1.8%	1.9%	9	1.5%	2.9%	12	5.9%	5.3%	3	0.6%	2.5%	0		
Synergy	ALBANY_WF1	7.2	0%	0.4%	7.1	0%	0.2%	6.9	0%	0.1%	6.6	0%	0%	9.4	0%	0%
Synergy	BREMER_BAY_WF1	0.2	0%	0%	0.2	0%	0%	0.2	0%	0%	0.1	0%	0%	0	0%	0%
Synergy	COCKBURN_CCG1	231.8	0%	3.7%	231.8	0.9%	20.5%	231.8	0.3%	2.6%	231.8	0.5%	8.1%	231.8	0.4%	6.3%
Synergy	COLLIE_G1	318	0.6%	15%	318	3.3%	10.3%	318	0.6%	3.4%	316.5	2.2%	15.6%	316.9	0.7%	5.5%
Synergy	GERALDTON_GT1	15.9	0.3%	0.1%	15.6	0.6%	5.6%	15.6	0%	15.6%	15.7	1.1%	3.1%	15.5	58.9%	1.2%
Synergy	GRASMERE_WF1	0			0			3.7	0%	0.5%	4.6	0%	0%	5.7	0%	0%
Synergy	KALBARRI_WF1	0.6	0%	0%	0.6	0%	0%	0.6	0%	0%	0.5	0%	0%	0.3	0%	0%
Synergy	KEMERTON_GT11	142.2	0%	6.6%	143	0%	3.5%	143	0.1%	13.8%	144.9	0%	1.3%	145.5	0%	5.5%
Synergy	KEMERTON_GT12	141.3	0%	19%	141.7	0%	0.2%	141.7	0.5%	1.4%	144.5	0%	17%	145.5	0.3%	0.8%
Synergy	KWINANA_G1	108	0%	7.8%	27.1	5.5%	11.5%	0			0			0		
Synergy	KWINANA_G2	108	1.1%	17.2%	27.1	1.7%	14.5%	0			0			0		
Synergy	KWINANA_G5	174	0%	47.1%	174	0.1%	33.1%	176.6	4.7%	7.8%	177.5	5.2%	8.3%	177.5	85.7%	0%
Synergy	KWINANA_G6	174	0%	70.5%	176.2	2.9%	25.6%	182.2	3%	13.5%	184	2.5%	19.1%	111.9	2.8%	12.8%
Synergy	KWINANA_GT1	17.2	0%	43.3%	16.9	0%	2.7%	15.7	0.2%	21.1%	15.1	1.7%	5.4%	15	5.7%	9.2%
Synergy	KWINANA_GT2	0			69	0%	0%	92.2	2.7%	7.2%	92.2	0.9%	25.7%	94.4	0.7%	18.1%
Synergy	KWINANA_GT3	0			69	0%	0%	92.2	3.7%	5.8%	92.2	0.7%	20.6%	94.4	4.7%	14.1%
Synergy	MUJA_G5	185	5.2%	41.8%	185	11.1%	13.2%	188	1.2%	14.5%	193.5	1.6%	22.8%	195	1.8%	5.4%
Synergy	MUJA_G6	185	0.4%	19.7%	185	4.1%	30.5%	185	0.5%	48.3%	186.1	0.9%	5%	189.1	20.9%	2.4%
Synergy	MUJA_G7	211	0.7%	28.1%	211	0.1%	22.1%	211	2.7%	2.9%	211	0.3%	9.1%	211	22.7%	20.9%
Synergy	MUJA_G8	211	2.9%	7.7%	211	0.4%	26.5%	211	2.5%	6.9%	211	2.4%	2.4%	211	6%	30.5%
Synergy	MUNGARRA_GT1	33	0%	9.1%	32.4	2.2%	0.2%	32.8	0%	10%	33	0.8%	9.9%	33	0%	15.8%
Synergy	MUNGARRA_GT2	33	0.7%	0.9%	32.4	0.3%	7.1%	32.7	0.1%	0.5%	32.4	0.3%	10.1%	31.7	0.5%	1.2%
Synergy	MUNGARRA_GT3	34	2%	10.1%	32.5	0%	2.9%	31.7	0.4%	20.5%	31.9	1.8%	0.7%	31.6	1.5%	11.8%

Participant	Facility name	2010-11 FY			2011-12 FY			2012-13 FY			2013-14 FY			2014-15 FY		
		Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan
Synergy	PINJAR_GT1	32.4	0%	0.2%	32.2	0%	8.5%	32.2	0%	1.4%	32.2	0%	5%	31.9	0.7%	0.1%
Synergy	PINJAR_GT2	33	0.3%	0.3%	32	0%	6.2%	31.6	0%	6.6%	31.5	0.5%	6.1%	30.7	0.6%	0.2%
Synergy	PINJAR_GT3	37	0.3%	10.4%	37	0%	0.2%	37	0%	13.2%	37	0%	0.3%	37	0.2%	10.3%
Synergy	PINJAR_GT4	37	0%	20.7%	37	0%	1.6%	37	0%	7%	37	0.4%	0.3%	37	0.2%	22.2%
Synergy	PINJAR_GT5	37	0.3%	0.2%	37	1.2%	8.8%	37	0%	6.2%	37	0.1%	0.2%	36.5	0%	0.2%
Synergy	PINJAR_GT7	37	0.1%	8.4%	37	0.2%	5.6%	37	0.2%	1%	37	0%	10.1%	36.3	0%	0.3%
Synergy	PINJAR_GT9	109	0%	35.2%	107.2	0.1%	4.6%	107	0.2%	20.7%	108.5	0%	1.2%	107.5	2.7%	23.1%
Synergy	PINJAR_GT10	107.2	0.6%	8.5%	106.6	0.5%	38.7%	107	0.3%	9.5%	108.5	0.7%	39.2%	108.8	0.8%	0.4%
Synergy	PINJAR_GT11	115.8	0.1%	53.6%	114.8	0.2%	45.2%	115	0%	6.4%	117.2	0.3%	11.4%	119.5	6.3%	8.5%
Synergy	PPP_KCP_EG1	76.9	0%	3.4%	76.9	0.1%	2.4%	79.5	1%	9.5%	80.4	0.1%	6%	80.4	1.8%	5.7%
Synergy	SWCJV_WORSLEY_COGEN_COG1	106	0.3%	18%	106	1.8%	4.7%	106	0.4%	3.2%	106.7	0.1%	7.3%	107	0.7%	2.2%
Synergy	WEST_KALGOORLIE_GT2	33.6	0.1%	0%	34.2	1.1%	4.9%	34.2	0%	10.4%	34.3	2.2%	10.5%	34.3	1.7%	2.8%
Synergy	WEST_KALGOORLIE_GT3	21	0%	1.3%	19.5	0%	3.7%	19	0.2%	29.5%	18.6	1.6%	3%	18.8	0%	3.5%
Tesla Corporation Management	TESLA_PICTON_G1	0			7.4	0.4%	3.9%	9.9	0%	2.2%	9.9	0%	2%	9.9	0%	0.7%
Tesla Geraldton	TESLA_GERALDTON_G1	0			0			7.4	0%	33.8%	9.9	0%	3.5%	9.9	0%	1.8%
Tesla Kemerton	TESLA_KEMERTON_G1	0			0			7.4	0%	12.1%	9.9	0%	1.3%	9.9	0%	0.7%
Tesla Northam	TESLA_NORTHAM_G1	0			0			7.4	0%	6.3%	9.9	0%	0.8%	9.9	0%	1.1%
Tiwest	TIWEST_COG1	33	1.3%	3.5%	33	0.2%	4%	33	1.1%	2.5%	35.2	6.7%	8.9%	33.5	2.4%	1.6%
Vinalco Energy	MUJA_G1	0			0			41.1	99.3%	0%	55	67.7%	0%	55	5.5%	5.1%
Vinalco Energy	MUJA_G2	0			0			41.1	99.3%	0%	55	58.5%	0.1%	55	2.3%	2.8%
Vinalco Energy	MUJA_G3	0			0			41.1	67%	5.4%	55	4.7%	9.6%	55	1.6%	3.8%
Vinalco Energy	MUJA_G4	0			0			41.1	50.9%	9.7%	55	4.8%	4.7%	55	0.6%	2.4%
Waste Gas Resources	HENDERSON_RENEWABLE_IG1	2.8	0%	0%	2.7	0%	0%	2.4	0.5%	0%	2.3	0.5%	0%	2.3	0.7%	0%
Western Australia Biomass	BRIDGETOWN_BIOMASS_ PLANT	40	0%	0%	40	0%	0%	10.1	0%	0%	0			0		
Western Energy	PERTHENERGY_KWINANA_GT1	63.6	0%	0%	100	0%	0%	107.2	0%	0%	108	0%	0%	108	0%	0%
TOTAL CAPACITY AND WEIGHTED OUTAGE RATES		5088	0.7%	15.1%	5201	1.4%	12.1%	5463.7	3.4%	8.1%	5575.3	2.4%	9.1%	5461	5.6%	7.2%

Participant	Facility name	2010-11 FY			2011-12 FY			2012-13 FY			2013-14 FY			2014-15 FY		
		Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan	Eff. cap (MW)	Force	Plan
Alinta		651.7	0.4%	4.2%	652.4	0.3%	4%	655.1	0.5%	5.1%	660.8	0.3%	9.5%	653.8	0.3%	7.2%
Griffin		408	1.8%	6.9%	425.8	2.6%	8.9%	431.8	2.7%	10.3%	431.8	1.2%	11.2%	432.6	0.8%	8.7%
NewGen Neerabup Partnership		330.6	0%	6.8%	330.6	0%	2.8%	330.6	0%	5.1%	330.6	0%	5.1%	330.6	0%	1.2%
NewGen Power Kwinana		320	0.4%	2.2%	320	0.7%	15.5%	320	0.4%	3.4%	320	0.6%	2.1%	320	0.1%	2.7%
Synergy		3113.3	0.8%	21.7%	3084	1.7%	16.3%	3092.1	1.3%	10.2%	3111	1.2%	11.4%	3051.9	9.6%	9.1%

In the 2014-15 financial year, the highest Forced Outage rates were recorded for Synergy's Facilities. KWINANA_G5 at 85.7 per cent as it approached retirement, and GERALDTON_GT1 (15.5 MW) at 58.9 per cent and Muja G7 and G6 at 22.7 per cent and 20.9 per cent. Vinalco's Muja Facilities G1 and G2 showed marked declines as the highest Forced Outage rates in the previous 2013-14 financial year, falling from 67.7 per cent and 58.6 per cent to 5.5 and 2.3 per cent respectively. Alcoa's Wagerup Facility also reduced Forced Outages from 26.2 per cent to 1.4 per cent in 2014-15.

Synergy Facilities also accounted for the highest Planned Outage rates in 2014-15. Muja G8 and G7 recorded rates of 30.5 per cent and 20.9 per cent, while Pinjar units GT9 and GT4 (37 MW) were at 23.1 and 22.2 per cent. Alcoa Wagerup's Planned Outage rate continued its decline from levels previously persistently above 20 per cent to 9.6 per cent in 2013-14 financial year and 3.5 per cent in 2014-15. Synergy's Kwinana gas units GT2 and GT3 Planned Outage rates reduced slightly from 25.7 and 20.6 per cent in 2013-14 to 18.1 per cent and 14.1 per cent.

Of the IPP Facilities only, all recorded both Forced and Planned Outage rates below 10 per cent in financial year 2014-15. Alinta's Pinjarra U1 and U2 reduced their Planned Outage rates from 14.8 per cent and 13.9 per cent in the 2013-14 financial year to 9.7 and 6.5 per cent in 2014-15. Similarly, Griffin Power's Bluewater units G1 and G2 reduced Planned Outages from 9.5 and 12.9 per cent to 8.1 and 9.2 per cent.

Figure 1 illustrates the distribution of outage rates across the five financial years presented in Table 1 (2010-11 through 2014-15), where all Facilities are aggregated by Participant. For legibility, Figure 1 is limited to Participants with aggregate effective capacity of at least 100 MW; Vinalco is excluded due to the distorting effect of its high Forced Outage rate prior to the units being successfully commissioned. The shaded area spans the third to the first quartile of the outage rates; the horizontal bar is the median value; and the length of the whiskers represents the maximum and minimum values up to 1.5 times the interquartile range. Any outlier values beyond this are shown by individual points. The total outage rate is the sum of Forced and Planned outages per Participant.

Figure 1 **Distribution of outage rates by Participant with at least 100 MW total capacity for FY 2010-11 through 2014-15**

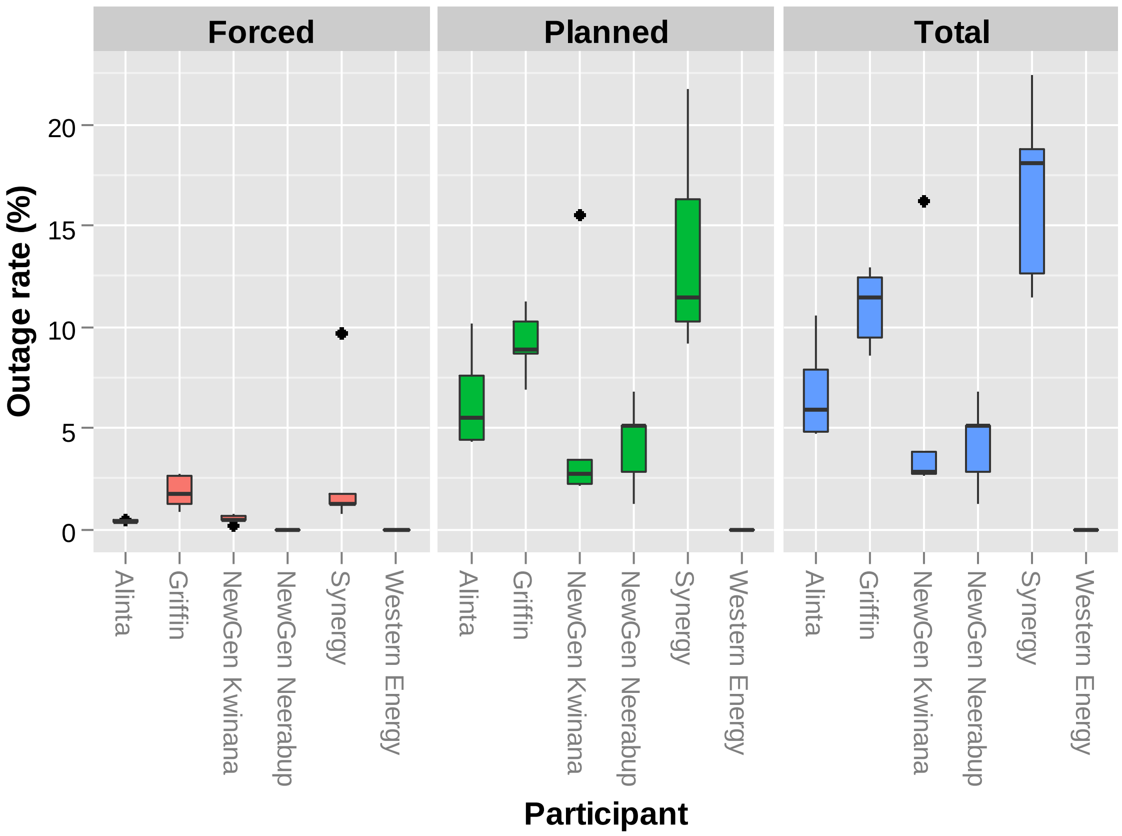
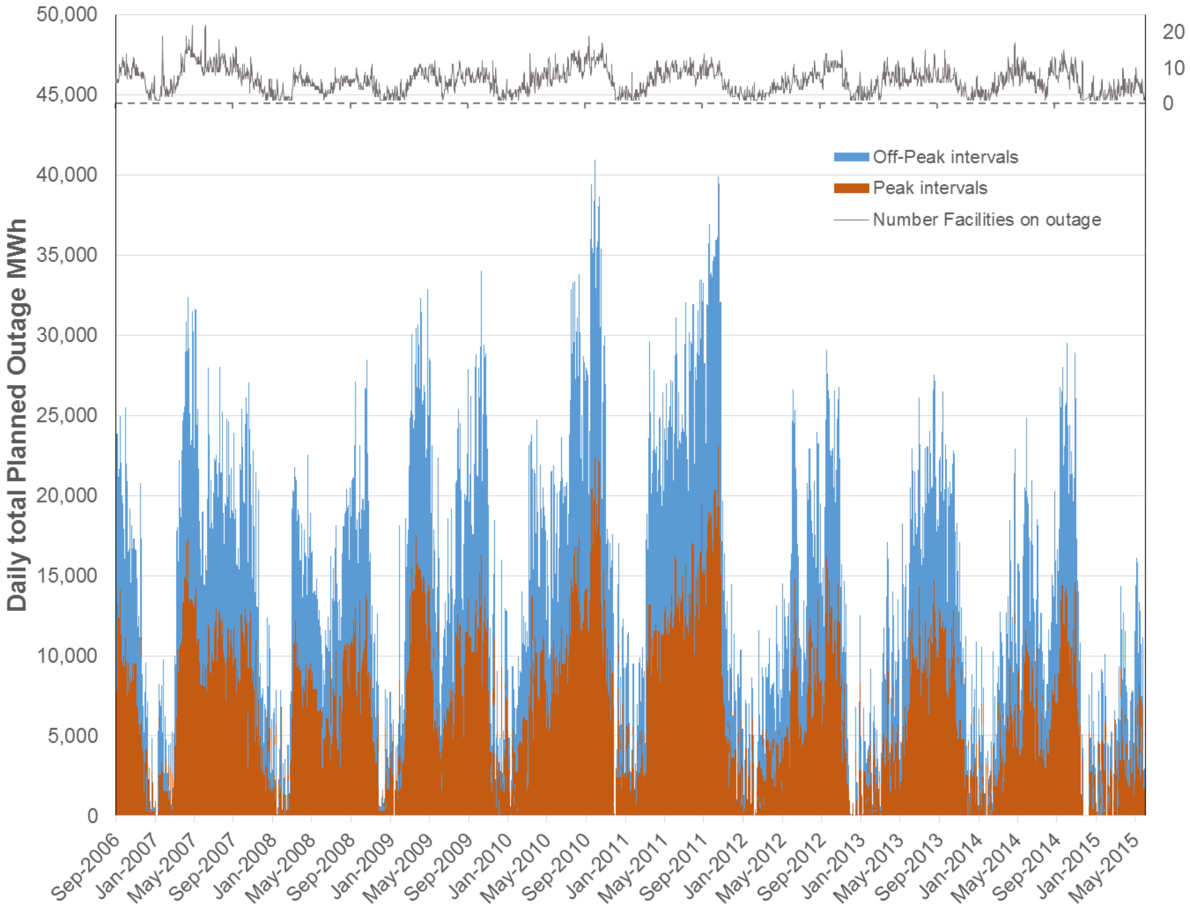


Figure 2 below illustrates Planned Outages for all Facilities as the daily total MWh, distinguishing outages in Peak versus Off-Peak Trading Intervals. The total number of individual Facilities recording outages on that day are shown in the top panel. Planned Outages exhibit a clear seasonal pattern, with distinct increases in activity during the winter months and minima during the peak demand months.

Figure 2 Daily total quantity of energy subject to Planned Outage by Peak versus Off-Peak Trading Intervals



Pursuant to clause 4.27 of the Market Rules, the IMO is required to monitor Planned Outages undertaken by Market Generators only when the resulting system availability is dropped to a certain threshold as defined under clause 4.27 of the Market Rules.[2] Hence, a

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2 Clause 4.27 of the Market Rules outlines the role of the IMO in monitoring Reserve Capacity performance, with the total availability of capacity on a particular day measured in terms of the total Capacity Credits held by Market Participants on that day, less the maximum amount of capacity unavailable due to Planned Outages. The IMO must assess, by the 25th day of each month, the number of days in the preceding 12 calendar months, where the total available capacity in the SWIS has dropped below 80% (in the Hot Season), and 70% (in either the Intermediate or Cold Season), of the total Capacity Credits held by Market Participants, for more than six hours on the day.

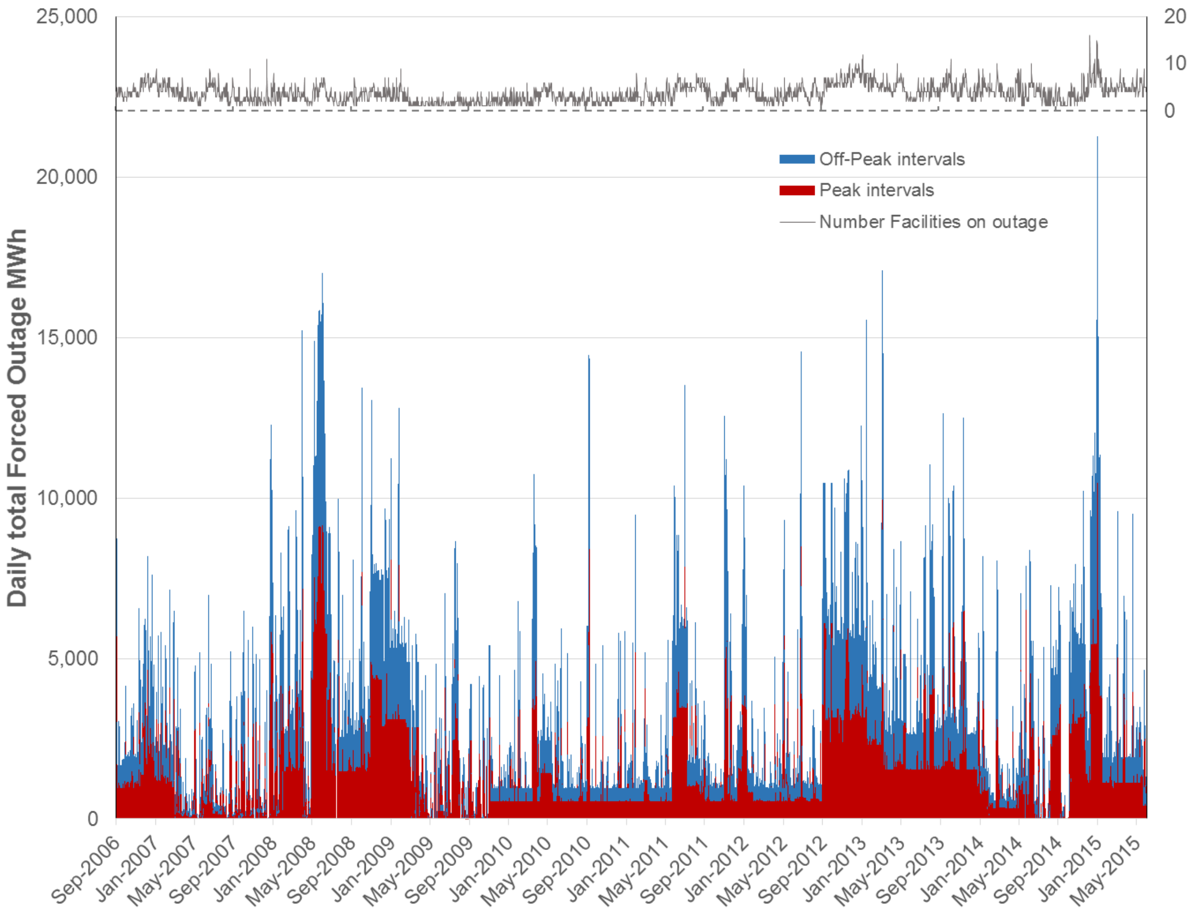
If the maximum amount of capacity unavailable due to Planned Outages has exceeded the above threshold for more than 40 days, the IMO must require reports to be filed by Market Participants for each facility that has been unavailable due to planned outages for more than 1000 hours during the past 12 calendar months.38 The report must include explanations of all Planned Outages in the preceding 12 months, a statement of the expected maximum number of days of Planned Outages to be taken by the facility in each of the next 24 months (with explanations), and proposed measures for increasing the availability of the facility.

The IMO must then consult with System Management on the implications of the report. If the IMO considers that the maximum expected number of days that the facility will be on Planned Outage in the ensuing 24 months is unjustified, it may, at its sole discretion, limit the number of days that the facility can have Planned Outages in each of those 24 months. In such a case, the IMO's determination as to whether extended periods of Planned Outage are justified is to be based on "good industry practice" (Market Rules pp. 244).

facility with a poor availability record, e.g. on Planned Outage for extended periods of time, may not be called to explain its availability problems if the system availability threshold is not reached.

Figure 3 below illustrates Forced Outages in the same manner as **Figure 2** above in relation to Planned Outages. Note that the scale for number of Facilities recording Forced Outages is reduced.

Figure 3 **Daily total quantity of energy subject to Planned Outage by Peak versus Off-Peak Trading Intervals**



Fuel Declarations

A Market Participant submitting a STEM Submission must include a Fuel Declaration.[3] **Table 2** below details Fuel Declarations for the last three Capacity Years.

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[3] See clause 6.6.1 of the Market Rules.

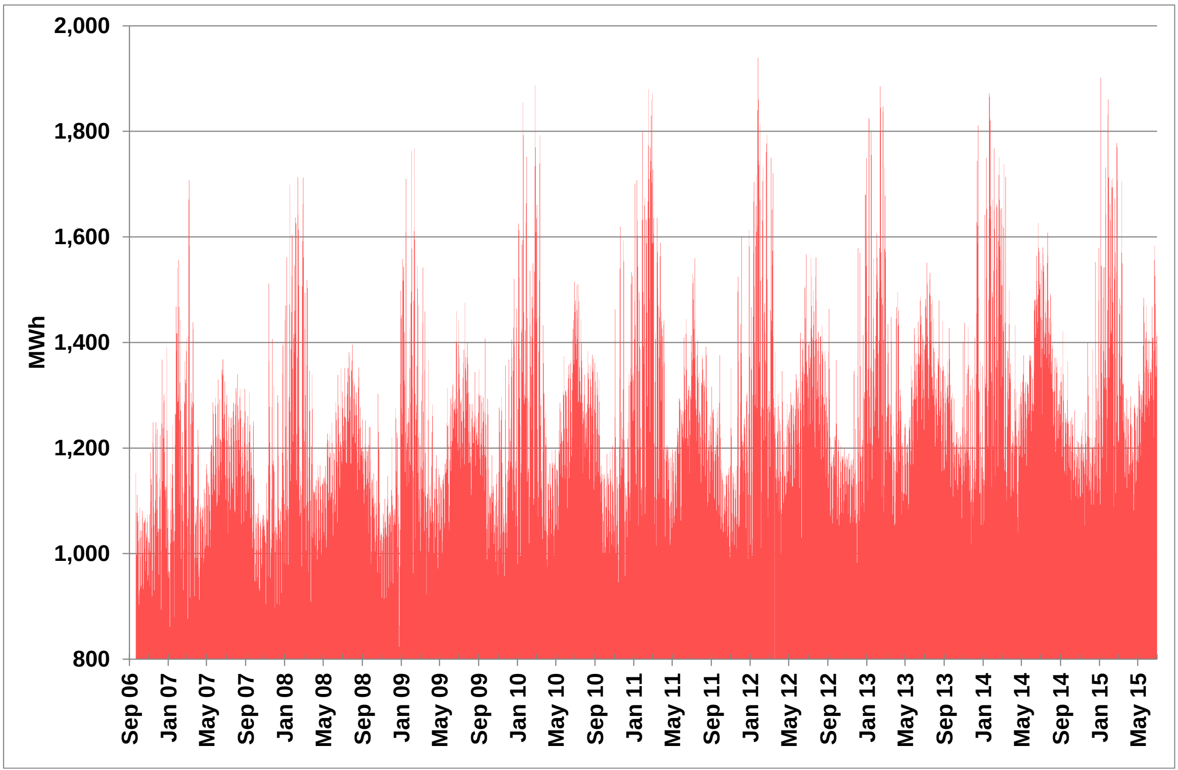
Table 2 Fuel Declarations (last four Financial Years)

Participant	Resource Name	2011/12		2012/13		2013/14		2014/15	
		Liquid	Non liquid	Liquid	Non liquid	Liquid	Non liquid	Liquid	Non liquid
Alcoa	ALCOA_KWI								
Alcoa	ALCOA_PNJ								
Alcoa	ALCOA_WGP								
Alinta	ALINTA_WGP_AGG		16.9%						
Alinta	ALINTA_WGP_GT	8.8%	74.3%	12.9%	87.1%		100.0%		100.0%
Alinta	ALINTA_WGP_U2	7.1%	75.9%	12.9%	87.1%		100.0%		100.0%
Goldfields Power	PRK_AG	100%		100.0%		100.0%		99.4%	
NewGen Neerabup	NEWGEN_NEERABUP_GT1		5.7%		100%		100.0%		100.0%
Perth Energy	PERTHENERGY_KWINANA_GT1	100%		100.0%		100.0%		100.0%	
Southern Cross	STHRNCRS_EG								
Verve Energy	KEMERTON_GT11		100%		100.0%		100.0%		99.7%
Verve Energy	KEMERTON_GT12	0.5%	99.5%		100.0%		100.0%		99.7%
Verve Energy	KWINANA_G3								
Verve Energy	KWINANA_G4								
Verve Energy	KWINANA_G5	2.7%	99.7%		95.7%		98.4%		15.6%
Verve Energy	KWINANA_G6		76.5%		85.8%		78.9%		77.8%
Verve Energy	KWINANA_GT1	100%		100.0%		100.0%		99.7%	
Verve Energy	KWINANA_GT2		4.9%		100%		100.0%		99.7%
Verve Energy	KWINANA_GT3		13.7%		100%		100.0%		99.7%
Verve Energy	PINJAR_GT1		100%	0.3%	99.7%		100.0%		99.7%
Verve Energy	PINJAR_GT2	99.7%	0.3%	99.7%	0.3%	100.0%		99.7%	
Verve Energy	PINJAR_GT3	0.3%	99.7%	0.3%	99.7%		100.0%		99.7%
Verve Energy	PINJAR_GT4	99.7%	0.3%	99.5%	0.5%	100.0%		99.7%	
Verve Energy	PINJAR_GT5	0.3%	99.7%	0.3%	99.7%		100.0%		99.7%
Verve Energy	PINJAR_GT7	99.5%	0.5%	99.7%	0.3%	100.0%		99.7%	

Energy Markets

Figure 4 illustrates the maximum SWIS demand each day (measured in megawatt hour (MWh) per Trading Interval[4]) from market commencement (21 September 2006) to 30 June 2015.

Figure 4 Daily maximum demand (21 September 2006 to 30 June 2015)



Bilateral contracts

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.

Short Term Energy Market

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

[4] A Trading Interval is a period of 30 minutes commencing on the hour or half-hour during a day. Settlement calculations in the WEM are based on Trading Interval data.

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) in **Table 3** below.

Table 3 Mean and standard deviations of STEM Clearing Prices ($/MWh)

	1 Aug 11 - 30 Jun 12		1 Jul 12 - 30 Jun 13		1 Jul 13 - 30 Jun 14		1 Jul 14 - 30 Jun 15	
	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev
Off-Peak	29.04	13.79	41.05	11.90	41.92	10.76	**31.74**	**12.42**
Peak	50.86	28.84	60.78	18.24	61.51	14.58	**49.09**	**15.70**

Figure 5 and **Figure 6** below 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 2015, as well as 30-day, 90-day and annual moving average prices.

Figure 5 Daily Average STEM Clearing Prices (Peak Trading Intervals)

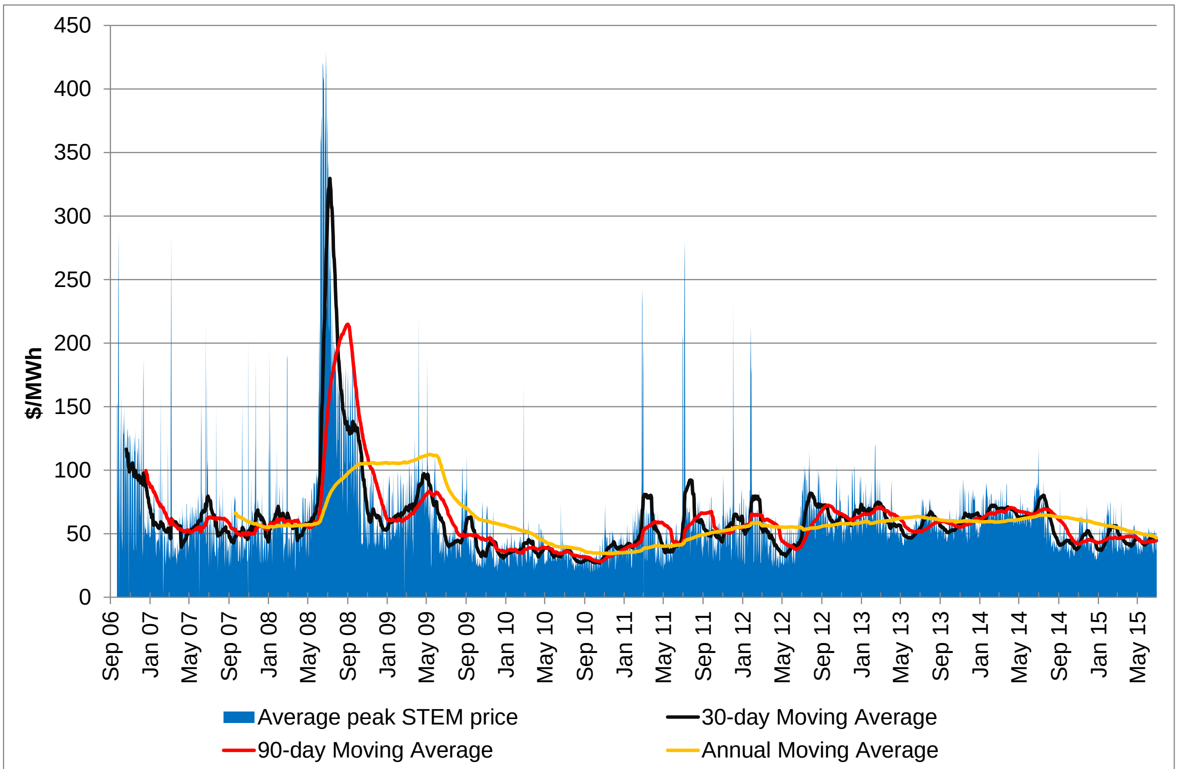
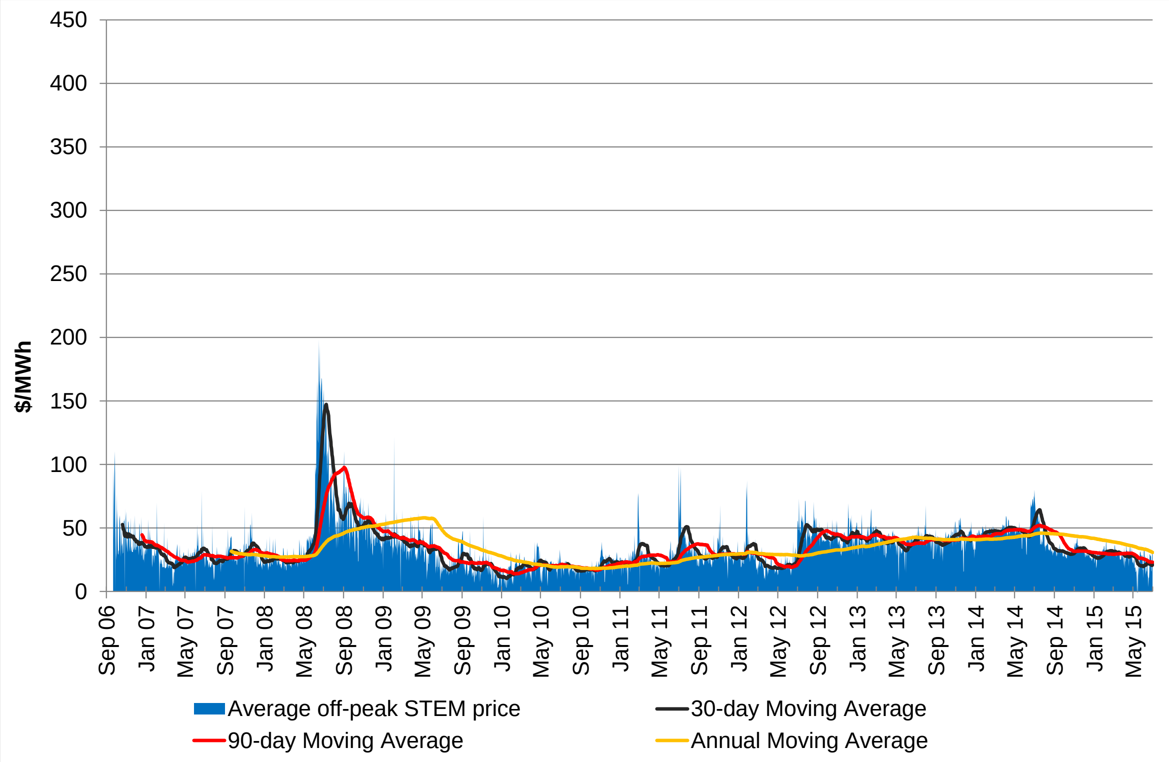


Figure 6 Daily Average STEM Clearing Prices (Off Peak Trading Intervals)



The impact of the carbon tax, which was introduced in July 2012 and removed in July 2014, needs to be considered when comparing prices across periods.

Volatility of Short Term Energy Market Clearing Prices

The Market Rules require the Authority to publish statistical analysis of the volatility of prices in the STEM Auctions. **Figure 7** and **Figure 8** 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 2015.

Figure 7 Summary statistics for STEM Clearing Prices in Peak Trading Intervals (per calendar month)

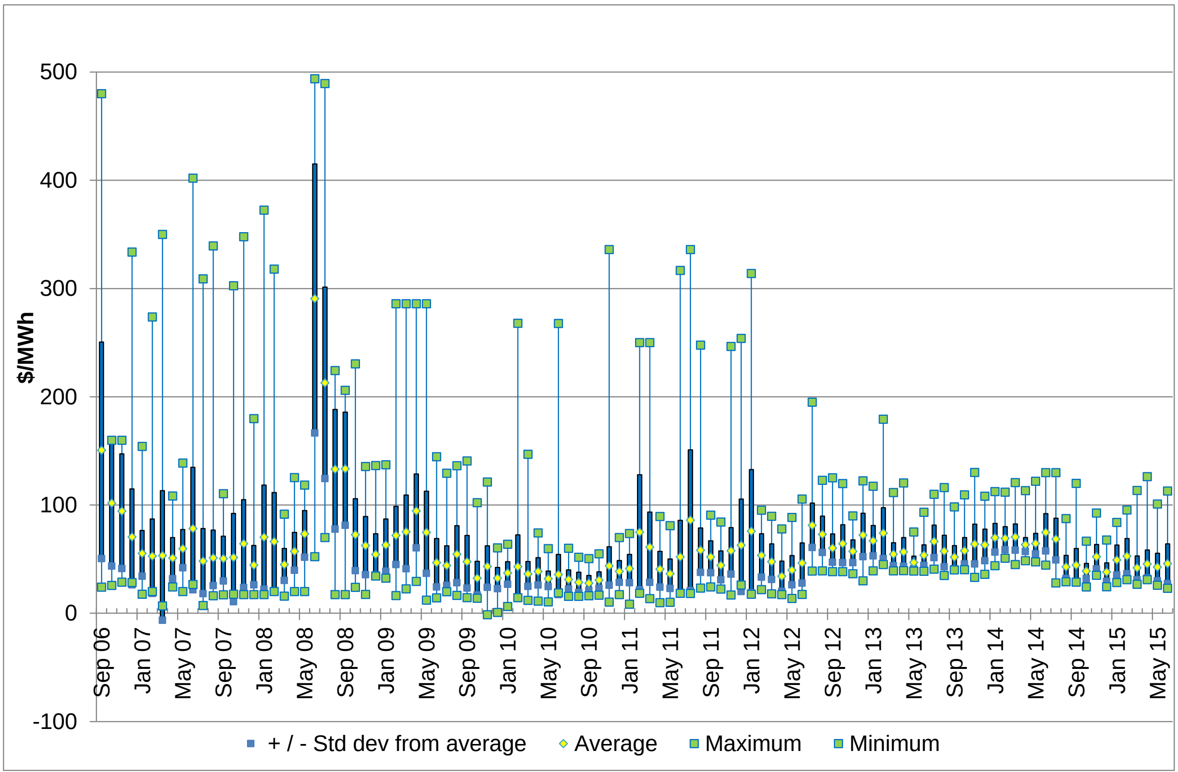
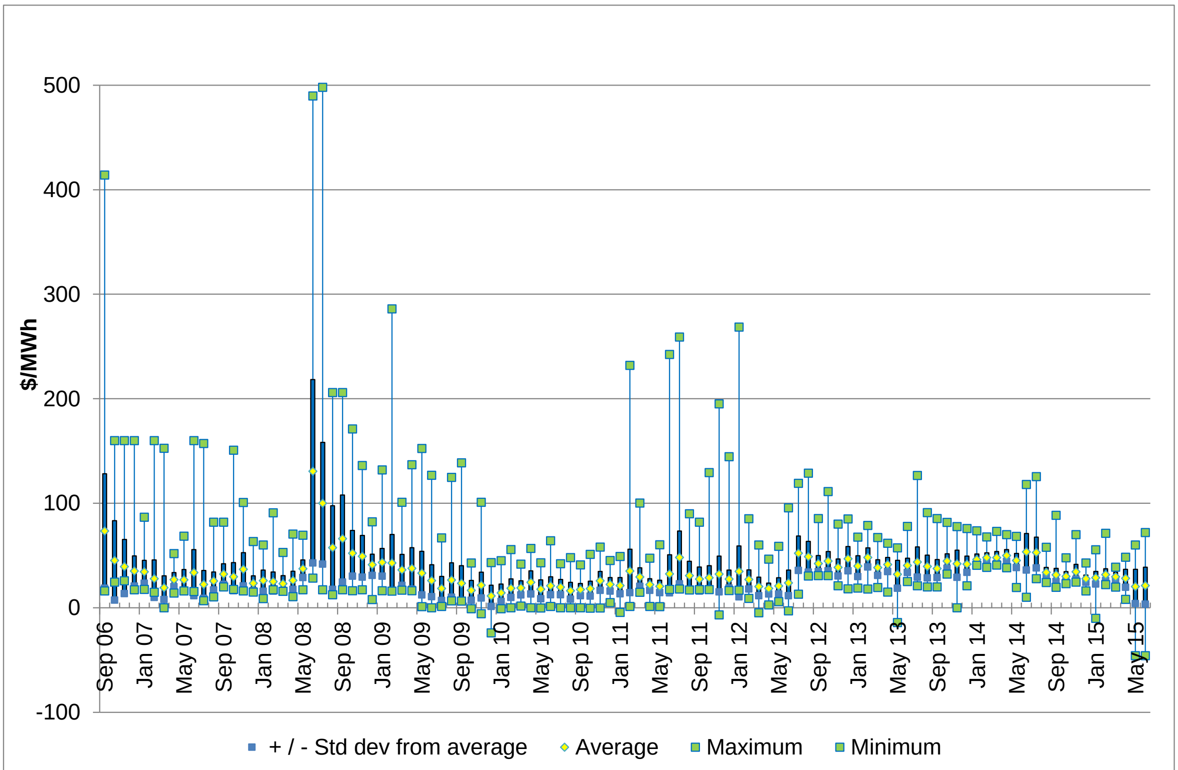


Figure 8 Summary statistics for STEM Clearing Prices in Off-Peak Trading Intervals (per calendar month)



High prices in the Short Term Energy Market

One way of examining the incidence of high prices is to assess the proportion of time that STEM Clearing Prices are at the Energy Price Limits.[5] There are two Energy Price Limits set out in the Market Rules that act as a cap on high prices.

- The Maximum STEM Price sets the price cap for generators using fuel types other than liquid fuel. This price is determined based on the IMO's estimate of the SRMC of the highest cost generating unit in the SWIS fuelled by natural gas. The Market Rules specify that the IMO must review the Maximum STEM Price annually. For the current Reporting Period, the Maximum STEM Price was $330/MWh, compared with $305/MWh in the previous Reporting Period.
- The Alternative Maximum STEM Price sets the price cap for generators running on liquid fuel. This price is determined based on the IMO's estimate of the short run marginal cost of the highest cost generating unit in the SWIS fuel by distillate. The Market Rules specify that the IMO must review the Alternative Maximum STEM Price annually and the price is adjusted monthly to reflect changes in oil prices and the Consumer Price Index (**CPI**). During the current Reporting Period, the Alternative Maximum STEM ranged between $424Wh (May 2015) and $562Wh (for July 2014).[6]

Figure 9 and **Figure 10** 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.

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5 The Energy Price Limits comprise of the Maximum STEM Price, the Alternative Maximum STEM Price and the Minimum STEM Price. Refer to clause 6.20 of the Market Rules for more details.

6 Since market commencement, the Alternative Maximum STEM Price has been as low as $380/MWh (during March 2007 and April 2007) and as high as $779/MWh (during September 2008).

Figure 9 Proportion of Trading Intervals STEM Clearing Prices at Maximum STEM Price (per calendar month)

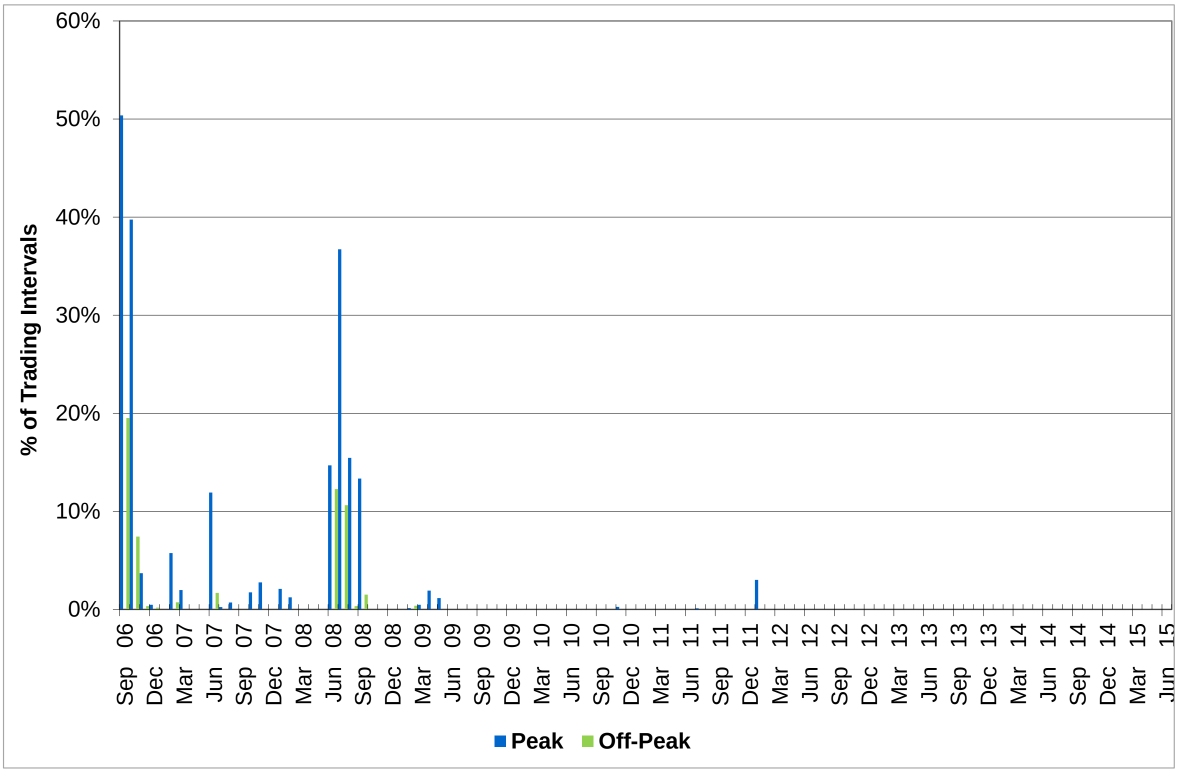
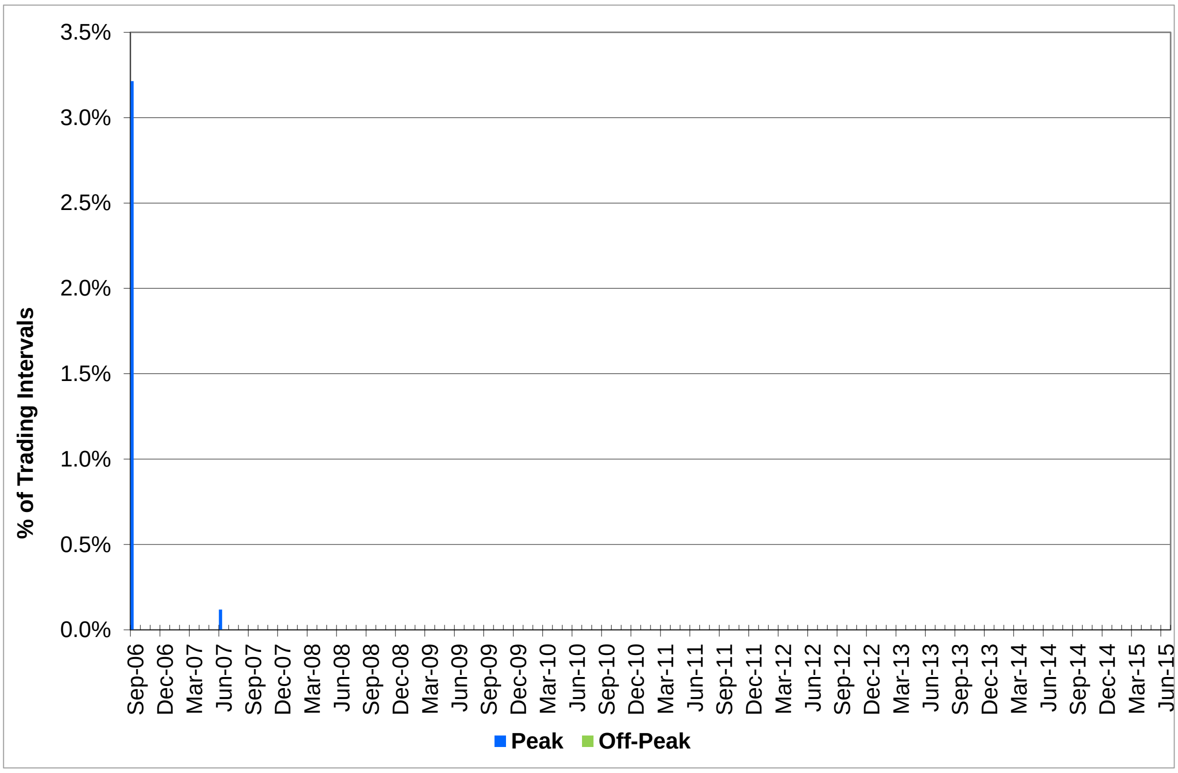


Figure 10 Proportion of Trading Intervals STEM Clearing Prices at Alternative Maximum STEM Price (per calendar month)



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.

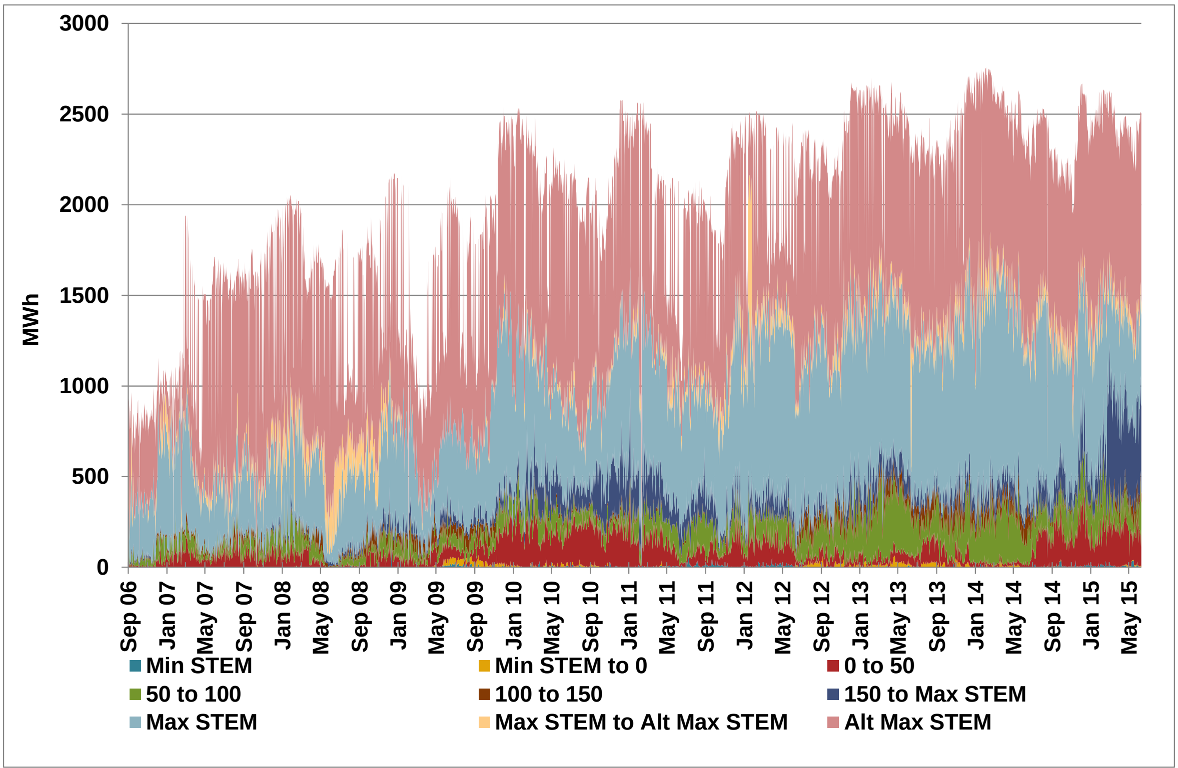
Short Term Energy Market Offers and Bids

The Market Rules require that the IMO determines STEM Offers and STEM Bids for each Market Participant, and for each Trading Interval that a STEM Submission is received. The IMO determines STEM Offers and STEM Bids by converting a Market Participant's Portfolio Supply Curve and Portfolio Demand Curve into a single STEM price curve, and then converting this into STEM Offers and STEM Bids, relative to the Market Participant's Net Bilateral Position.

Short Term Energy Market Offers

STEM Offers reflect an increase in generation or a decrease in consumption. **Figure 11** illustrates the daily average quantity of STEM Offers per Trading Interval for all Market Participants from market commencement until 30 June 2015.

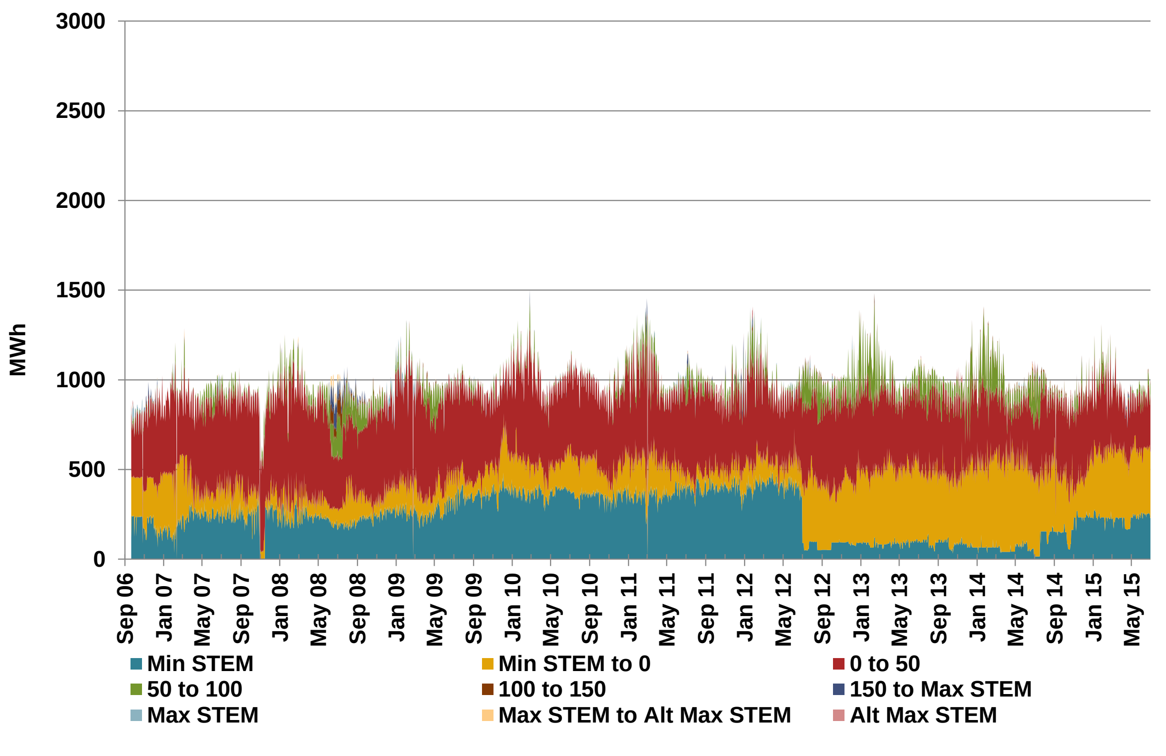
Figure 11 Daily average quantity of STEM Offers (MWh per Trading Interval)



Short Term Energy Market Bids

STEM Bids reflect a decrease in generation or an increase in consumption. **Figure 12** illustrates the daily average quantity of STEM Bids per Trading Interval for all Market Participants, from market commencement until 30 June 2015.

Figure 12 Daily average quantity of STEM Bids (MWh per Trading Interval)



By design, the high level of Market Customer's bilateral commitment (in terms of its demand) will result in the volume of STEM Bids being lower than the volume of STEM Offers. This is evident in a comparison of **Figure 11** and **Figure 12**.

Short Term Energy Market traded quantities

Table 4 shows the annual average of STEM traded quantities among Market Participants (cumulative MWh per Trading Interval) over the last six years.

Table 4 Average STEM traded quantities (MWh per Trading Interval)

	1 Aug 09 - 31 Jul 10	1 Aug 10 - 31 Jul 11	1 Aug 11 - 31 Jul 12	1 Aug 12 - 30 Jun 13	1 Jul 13 - 30 Jun 14	1 Jul 14 - 30 Jun 15
STEM traded quantities	53.60	64.39	50.56	67.82	63.49	43.31

Note: 'Average quantities' are for the overall period, i.e., 21 September 2006 to 30 June 2015.

Figure 13 illustrates daily average quantities traded in the STEM from market commencement until 30 June 2015.

Figure 13 Daily average quantities traded in the STEM (21 September 2006 to 30 June 2015)

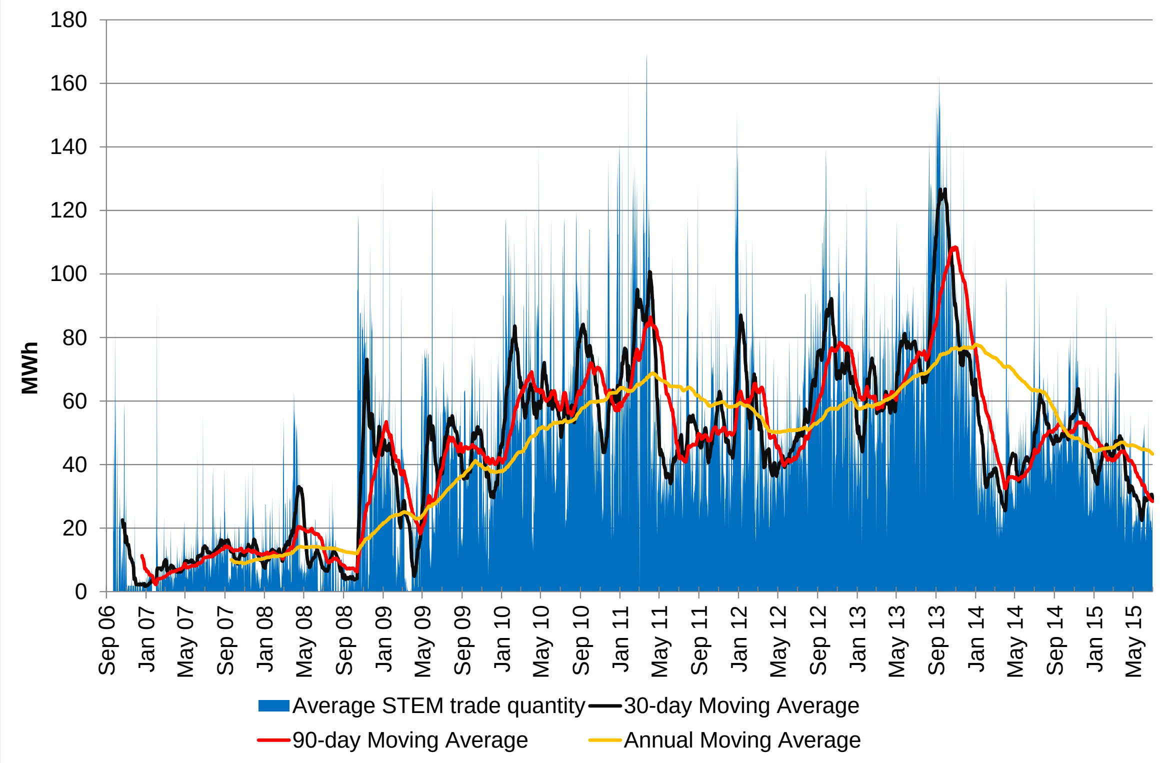


Figure 14 and **Figure 15** show the daily average volume bought and sold in the STEM, respectively, for all Market Participants, from market commencement to 30 June 2015.

Figure 14 Daily average quantities bought in the STEM (MWh)

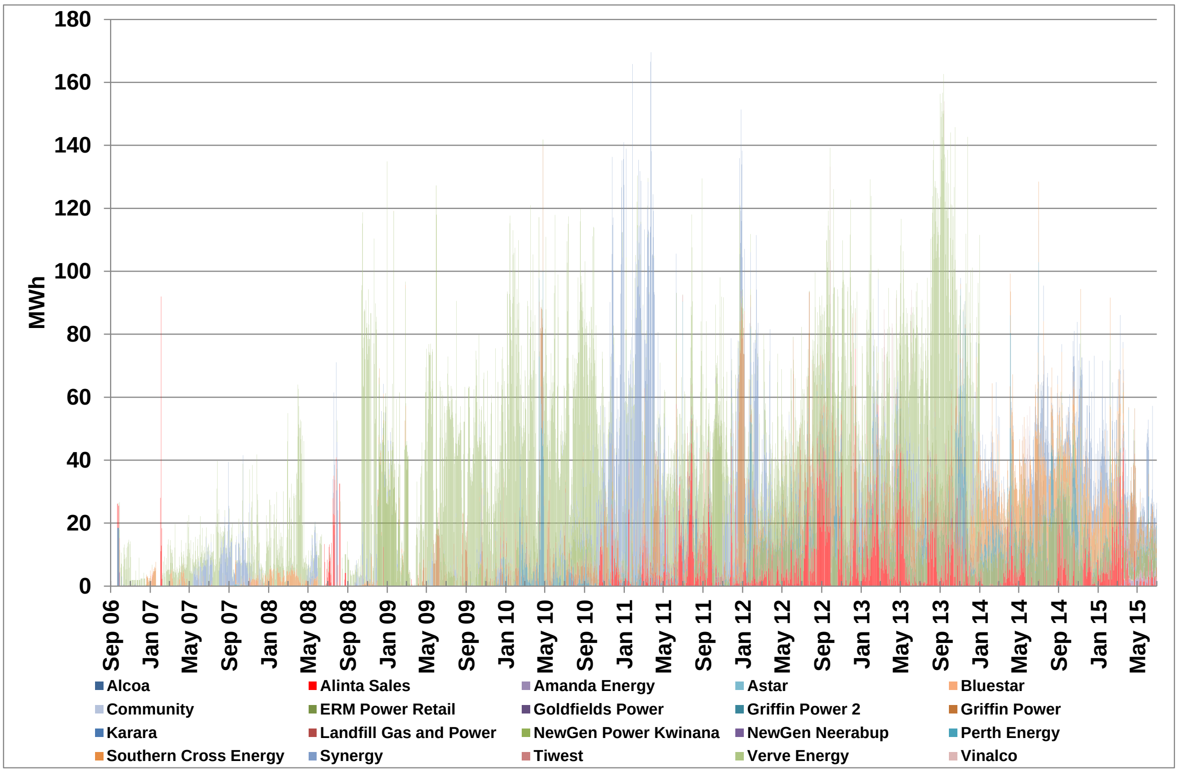
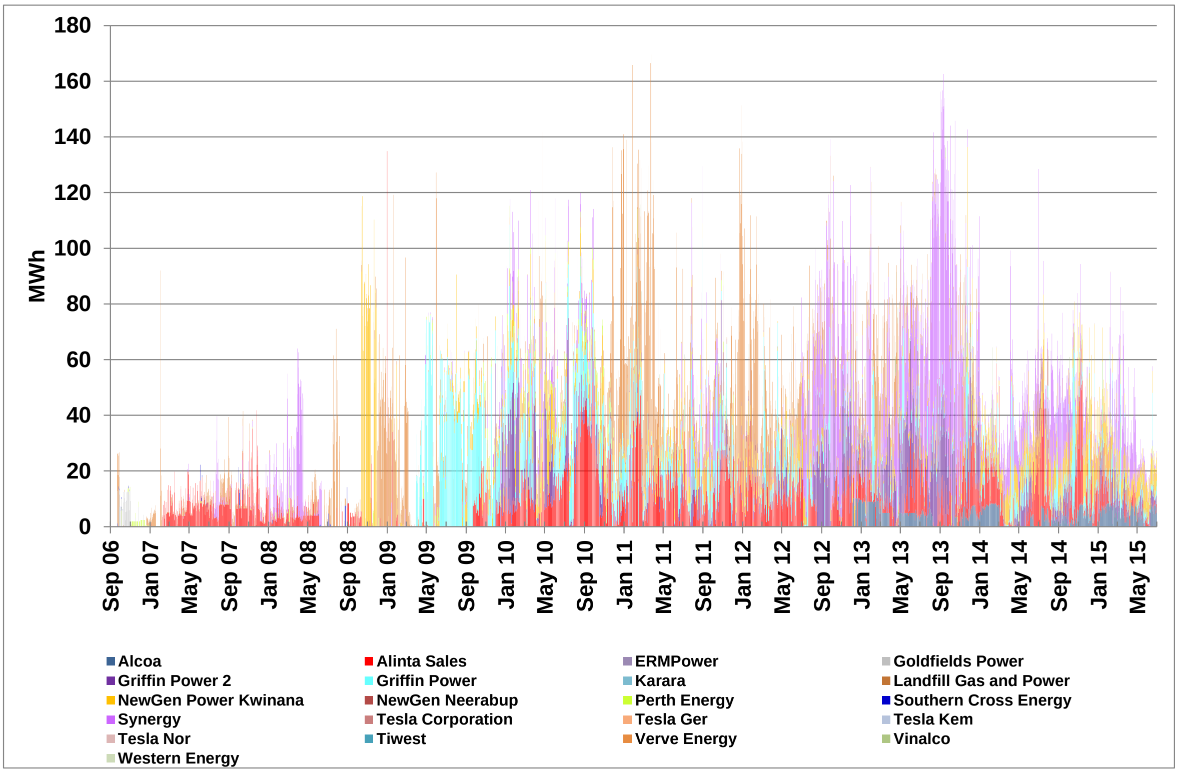


Figure 15 Daily average quantities sold in the STEM (MWh)

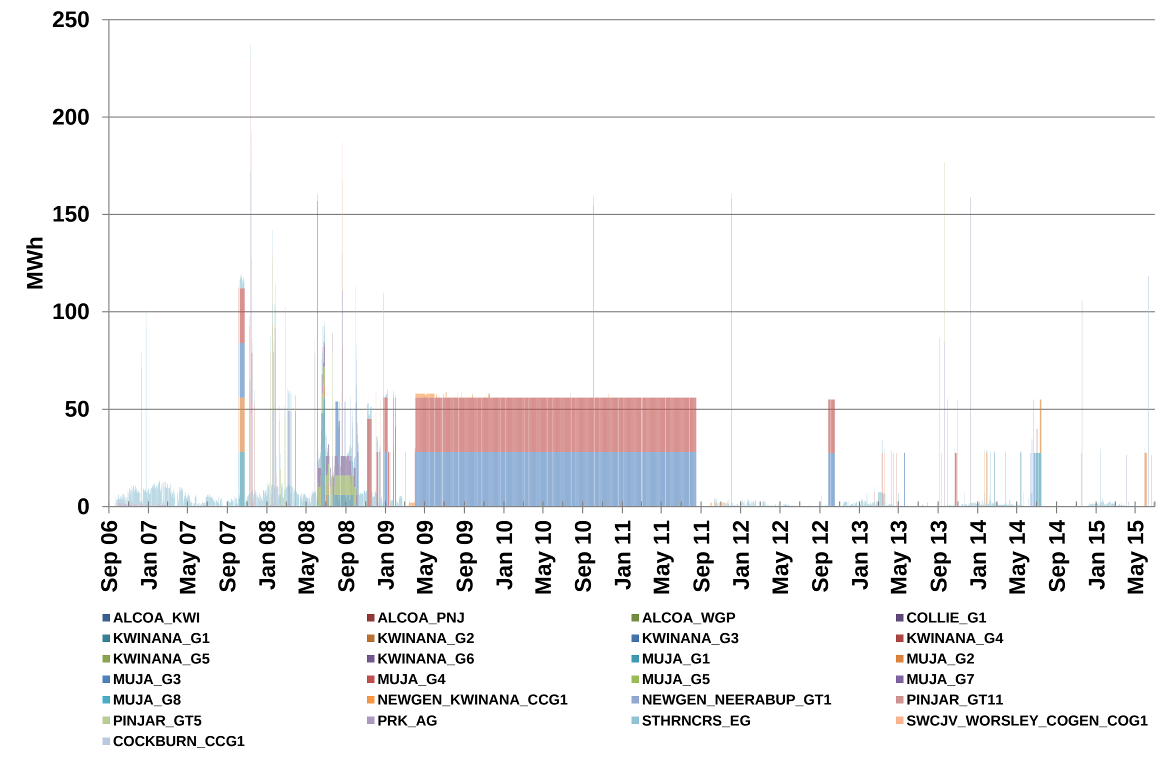


Availability Declarations

A Market Participant submitting a STEM Submission must include an Availability Declaration on net available energy.[7]

Figure 16 below details the daily average Availability Declarations since market inception.

Figure 16 Daily average Availability Declarations (MWh unavailable per Trading Interval)



Significant variations between Availability Declarations and the actual real-time operation of a Market Participant are assessed by comparing:

- the remaining capacity available after taking into account quantities declared in an Availability Declaration, with
- the total (Loss Factor-adjusted) quantity supplied, as measured by System Management's Supervisory Control and Data Acquisition (**SCADA**) system.

If, on the basis of this comparison, the remaining capacity available is less than the quantity supplied, this indicates that a Facility has been available to supply the market to a greater extent than was indicated in the STEM Submission for that Facility. The purpose of this statistic is to detect whether a Market Participant falsely declares that low cost capacity is unavailable. By leaving out low cost capacity the Market Participant will be able to put in a submission with a higher cost schedule. This could result in a higher STEM Clearing Price.

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7 See clause 6.6.1 of the Market Rules. The Availability Declaration is to set out, for each Trading Interval and for each of the Market Participant's facilities, as the difference between the energy available from the facility based on its Standing Data (adjusted to account for any energy committed to providing Ancillary Services and any energy unavailable due to outages reported by the IMO) and the energy assumed to be available from the facility in forming the Portfolio Supply Curve for the Trading Interval. Only quantities greater than zero need to be reported in the Availability Declaration.

The Market Participant could then generate with the low cost capacity, which is truly available, and make an excessive profit.

Table 5 below sets out the proportion of Trading Intervals for which a Facility was actually available to a greater extent than set out in a STEM Submission during the 2011/12 through 2014/15 Capacity Years.

Table 5 Proportion of Trading Intervals for which actual output exceeds Availability Declarations (last three Capacity Years)

Participant	Resource Name	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	Cold season 2014/15 Cap Year	Hot season 2014/15 Cap Year	Intermediate season 2014/15 Cap Year
Alcoa	ALCOA_WGP	5.98%	2.41%	0.33%	1.81%		1.88%	1.81%		
Alinta Sales	ALINTA_PNJ_U1	0.03%		0.01%	3.26%			3.26%	1.26%	
Alinta Sales	ALINTA_PNJ_U2			0.90%	1.53%		4.54%	1.53%	1.65%	6.15%
Alinta Sales	ALINTA_WGP_U2	0.10%			0.01%			0.01%		
Alinta Sales	ALINTA_WGP_GT				0.38%			0.38%		
Blair Fox Pty Ltd	BLAIRFOX_WESTHILLS_WF3				0.02%			0.02%		
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	0.20%	0.21%	0.01%						
Goldfields Power	PRK_AG		0.03%	0.02%	0.01%		0.07%	0.01%		0.03%
Greenough River	GREENOUGH_RIVER_PV1									
Griffin Power 2	BW2_BLUEWATERS_G1		0.03%	0.02%	0.02%	0.03%	0.61%	0.02%	0.02%	2.25%
Griffin Power	BW1_BLUEWATERS_G2		0.10%	0.01%	0.08%	0.22%	0.48%	0.08%		0.51%
Landfill Gas and Power	KALAMUNDA_SG	0.07%			0.02%		0.07%	0.02%	0.03%	
Landfill Gas and Power	RED_HILL				0.07%		37.43%			
Landfill Gas and Power	TAMALA_PARK									
Merredin	NAMKKN_MERR_SG1		0.03%	0.07%	0.03%		0.10%	0.03%	0.05%	
Mount Barker	SKYFARM_MTBARKER_WF1				0.02%					
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1			0.11%	0.27%	0.05%	0.07%	0.27%		0.03%
NewGen Neerabup	NEWGEN_NEERABUP_GT1			0.02%	0.41%	0.03%		0.41%		0.17%
Perth Energy	ATLAS									
Perth Energy	ROCKINGHAM			15.91%						
Perth Energy	SOUTH_CARDUP	0.03%								
Southern Cross Energy	STHRNCRS_EG		0.03%							
Tesla	TESLA_GERALDTON_G1	3.24%	2.82%	0.38%	0.02%	0.02%		0.02%	0.14%	
Tesla	TESLA_KEMERTON_G1				0.12%	0.03%		0.13%	0.02%	
Tesla	TESLA_NORTHAM_G1				0.01%	0.05%		0.01%	0.02%	
Tesla	TESLA_PICTON_G1			0.01%	0.16%	0.05%		0.16%	0.02%	
Tiwest	TIWEST_COG1	0.03%	0.96%	0.06%	0.17%		0.10%	0.17%	0.50%	

Participant	Resource Name	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	Cold season 2014/15 Cap Year	Hot season 2014/15 Cap Year	Intermediate season 2014/15 Cap Year
Verve Energy	ALBANY_WF1									
Verve Energy	COCKBURN_CCG1	2.32%		5.59%	12.67%	2.74%	24.15%	12.67%	1.31%	6.22%
Verve Energy	COLLIE_G1	0.41%	2.98%	0.74%	1.02%	0.55%	3.72%	1.02%	0.40%	1.43%
Verve Energy	GERALDTON_GT1		0.03%				0.03%			
Verve Energy	KEMERTON_GT11	0.20%	0.55%	0.98%	0.35%	0.40%	0.38%	0.35%	1.03%	0.20%
Verve Energy	KEMERTON_GT12	0.07%	0.33%	0.11%	0.92%	0.24%	0.24%	0.92%	1.03%	0.17%
Verve Energy	KWINANA_G1									
Verve Energy	KWINANA_G2									
Verve Energy	KWINANA_G4									
Verve Energy	KWINANA_G5	0.07%	0.31%	0.73%	0.03%			0.02%		
Verve Energy	KWINANA_G6	0.07%		0.22%	0.02%	0.03%		0.02%	1.15%	
Verve Energy	KWINANA_GT1	0.07%		0.07%						
Verve Energy	KWINANA_GT2	0.79%	1.12%	0.86%	0.40%	0.26%	0.24%	0.40%	0.77%	2.02%
Verve Energy	KWINANA_GT3	0.79%	4.67%	2.54%	1.55%	0.09%	0.44%	1.55%	0.46%	4.06%
Verve Energy	MUJA_G5	4.68%	3.00%	2.34%	0.03%		2.49%	0.03%	1.79%	
Verve Energy	MUJA_G6	0.03%	12.24%	9.64%	0.20%		1.64%	0.20%	0.19%	0.07%
Verve Energy	MUJA_G7	0.14%	0.29%	1.05%	1.38%	0.98%	0.41%	1.38%	9.90%	2.94%
Verve Energy	MUJA_G8	2.05%	0.33%	0.58%	1.48%	0.84%	0.03%	1.48%	10.81%	
Verve Energy	MUNGARRA_GT1	0.61%		0.17%	0.52%	0.03%		0.52%		0.07%
Verve Energy	MUNGARRA_GT2	0.44%		0.72%	0.40%	0.14%		0.40%		0.65%
Verve Energy	MUNGARRA_GT3		0.02%	0.09%	0.07%	0.29%		0.07%		
Verve Energy	PINJAR_GT1			0.22%	0.02%			0.02%		
Verve Energy	PINJAR_GT10	0.17%	0.12%	0.09%	0.71%	0.05%	0.03%	0.71%	0.02%	
Verve Energy	PINJAR_GT11		0.02%	0.02%	0.06%	0.09%	0.07%	0.06%	0.15%	
Verve Energy	PINJAR_GT2				0.01%			0.01%		
Verve Energy	PINJAR_GT3		0.02%	0.01%	0.02%	0.02%		0.02%	0.02%	0.10%
Verve Energy	PINJAR_GT4		0.07%	0.02%	0.02%	0.02%		0.02%	0.02%	0.10%
Verve Energy	PINJAR_GT5		0.19%	0.09%	0.02%			0.02%		0.03%

Participant	Resource Name	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	Cold season 2014/15 Cap Year	Hot season 2014/15 Cap Year	Intermediate season 2014/15 Cap Year
Verve Energy	PINJAR_GT7		0.03%	0.01%	0.03%			0.03%		0.03%
Verve Energy	PINJAR_GT9	0.65%		0.18%	0.10%		0.61%	0.10%		0.10%
Verve Energy	PPP_KCP_EG1	9.97%	0.59%	21.99%	30.78%	1.20%	12.40%	30.78%	0.26%	5.46%
Verve Energy	SWCJV_WORSLEY_COGEN_COG1	88.70%	59.21%	94.57%	80.02%	41.56%	65.47%	80.02%	50.93%	49.83%
Verve Energy	WEST_KALGOORLIE_GT2		0.03%	0.06%	0.03%			0.03%	0.03%	
Verve Energy	WEST_KALGOORLIE_GT3	0.24%								
Vinalco	MUJA_G1				0.06%	0.24%	0.1%	0.06%	0.38%	
Vinalco	MUJA_G2				0.83%	0.15%		0.83%	0.12%	
Vinalco	MUJA_G3		7.28%	3.71%	0.01%	1.27%		0.01%	0.03%	0.17%
Vinalco	MUJA_G4		23.64%	7.18%	0.01%	0.03%	0.03%	0.01%	0.22%	0.03%

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

Balancing Market

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 when such behaviour relates to market power. Market Participants other than Synergy are able to revise their offers up to two hours prior to the Trading Interval commencing to reflect changes in market conditions. Synergy has further restrictions and different gate closure times.

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 IPPs can offer ten tranches for each scheduled generating facility. Intermittent generating units can only be offered as a single tranche and offers include price and estimated 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**) which is 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.

System Management is required to dispatch all participants based on the BMO. Any generator that is dispatched out-of-merit by System Management receives compensation. A generator receives Constrained On compensation if more energy is dispatched from that generator than its Balancing Submission indicated when compared to the Balancing Price (for example, a situation like Forced Outage when another generator covers for lost generation). A generator receives Constrained Off compensation if it was within the BMO but was not, or could not be dispatched by System Management for system related reasons (e.g. a transmission line outage).

Balancing prices

Table 6 sets out the mean and standard deviations of the peak and off-peak MCAP or Final Balancing Price over the last three years.

Table 6 Mean and standard deviations of Balancing Prices ($/MWh)

		1Jul12-30Jun13		1Jul13-30Jun14		1Jul14-30-Jun15	
	Trading Interval	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev
MCAP/Final Balancing Price	Off-Peak	34.24	36.07	44.93	20.60	**32.55**	**19.00**
	Peak	59.44	58.21	65.68	22.54	**49.88**	**29.68**

Figure 17 and **Figure 18** below illustrate average daily peak and off-peak period Balancing Prices (respectively) for each Trading Day, from market commencement to 30 June 2014.

Figure 17 Daily Average Balancing prices (Peak Trading Intervals, $/MWh)

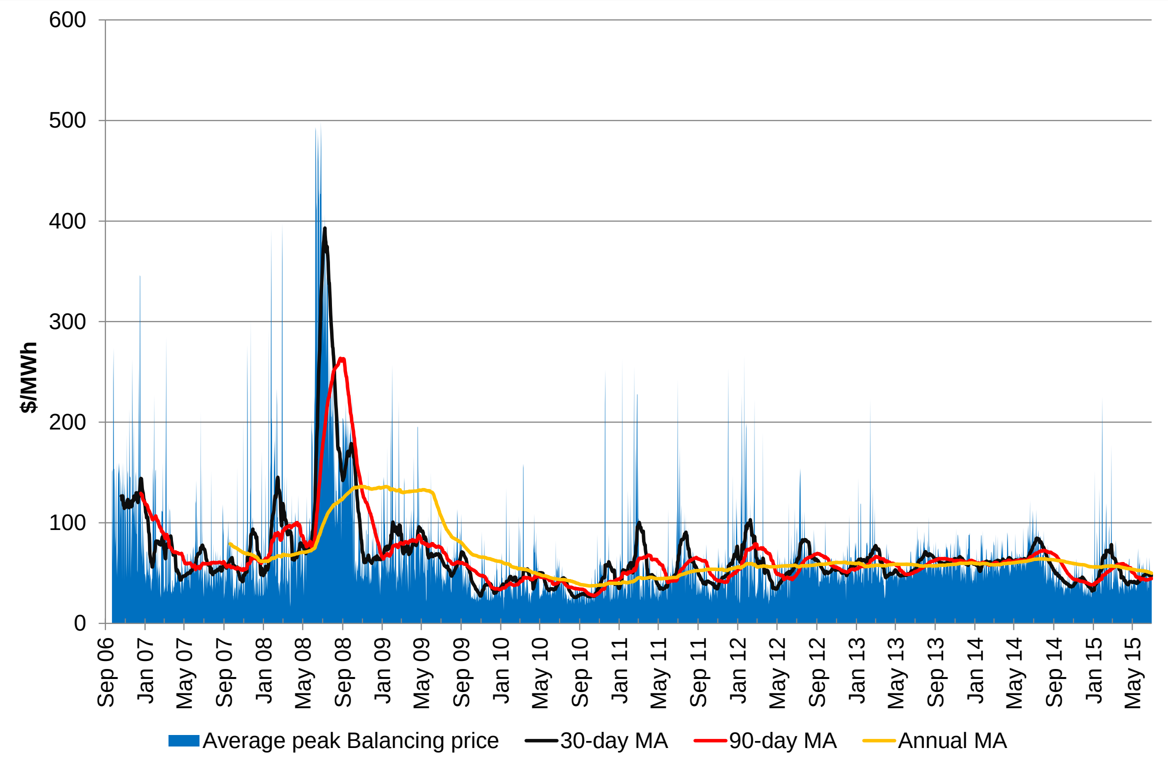
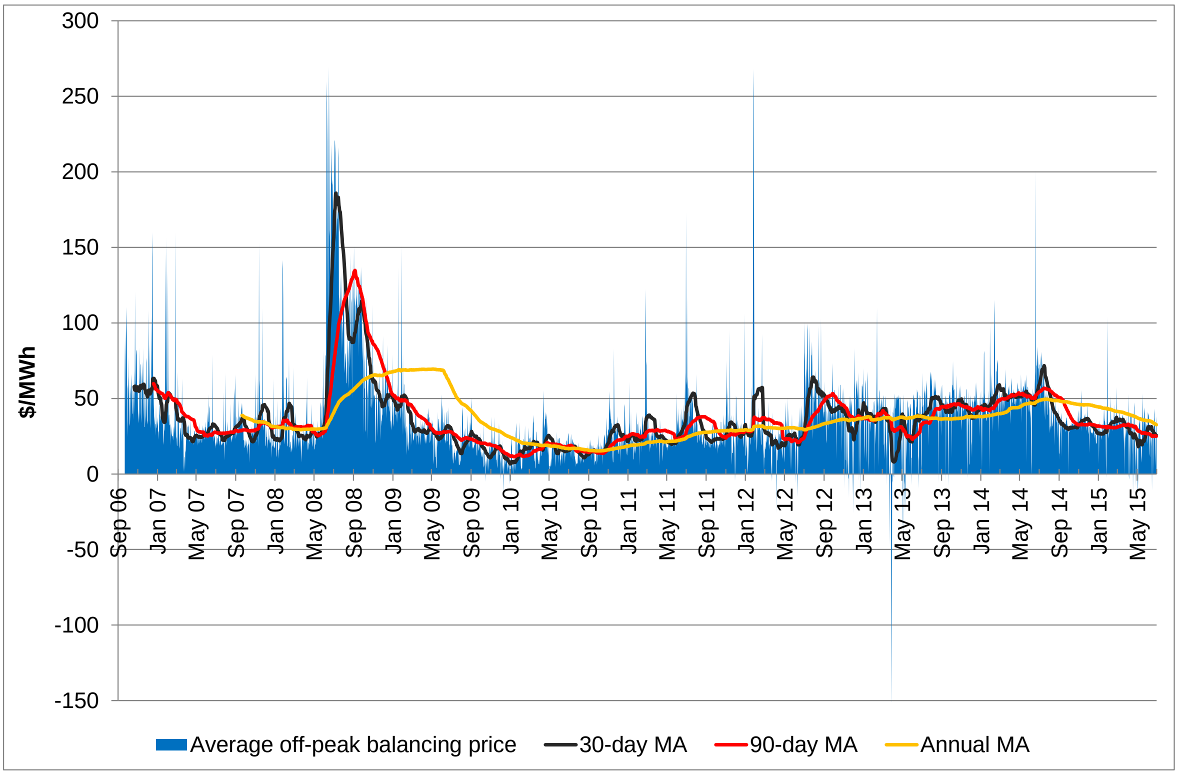


Figure 18 Daily Average Balancing prices (Off-Peak Trading Intervals, $/MWh)



The impact of the carbon tax, which was introduced in July 2012 and removed in July 2014, needs to be considered when comparing prices across the period.

Figure 19 shows Peak Balancing Prices since commencement of the new Balancing Market in 2012. **Figure 20** compares Off-Peak Balancing prices from 1 July 2012 to 30 June 2015.

Figure 19 Peak Trading Intervals Final Balancing Prices (1 July 2012 to 30 June 2015)

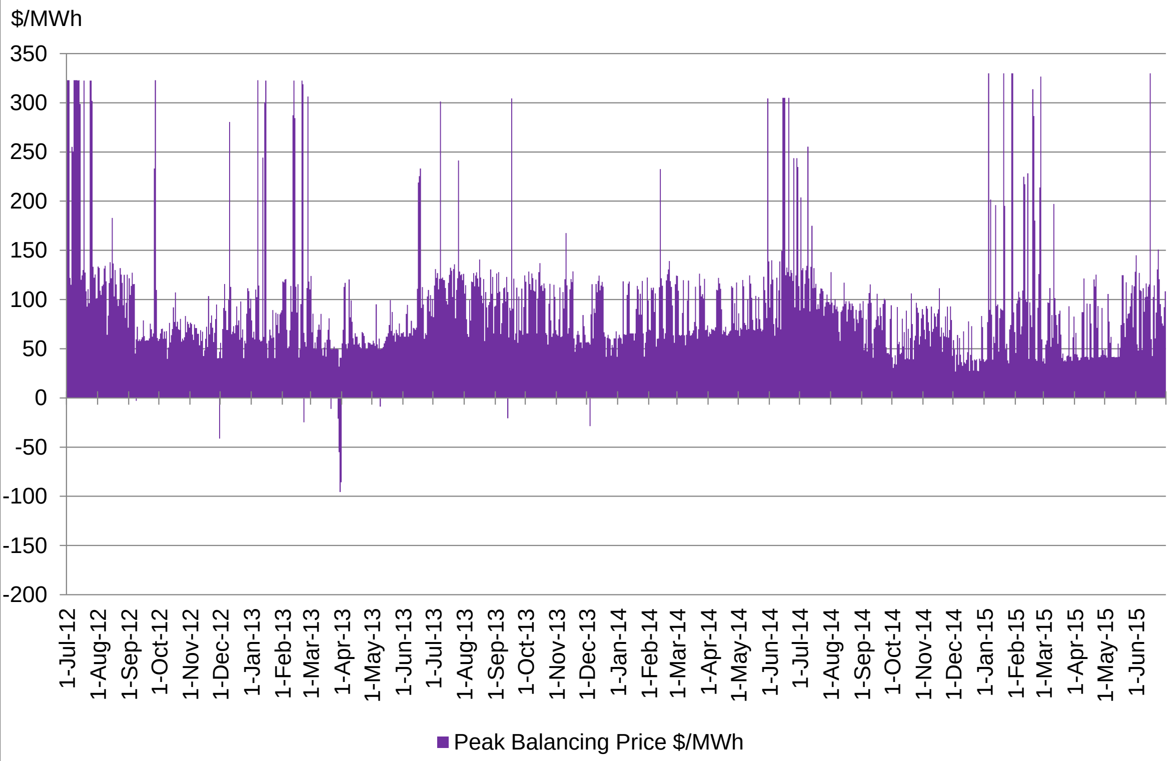
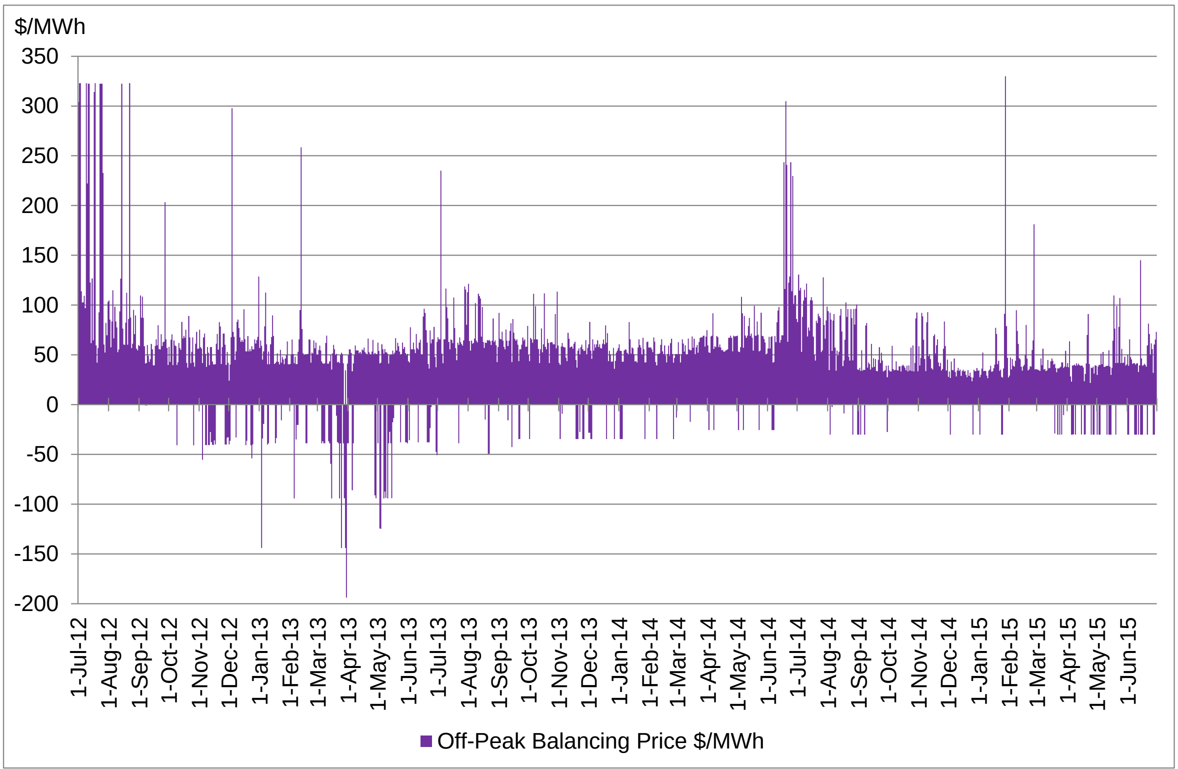


Figure 20 Off-Peak Trading Intervals Final Balancing Prices (1 July 2012 to 30 June 2015)



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 2015 of MCAP/ Final Balancing prices are illustrated in **Figure 21** and **Figure 22**.

Figure 21 Summary statistics for MCAP/ Final Balancing Price during Peak Trading Intervals (per calendar month)

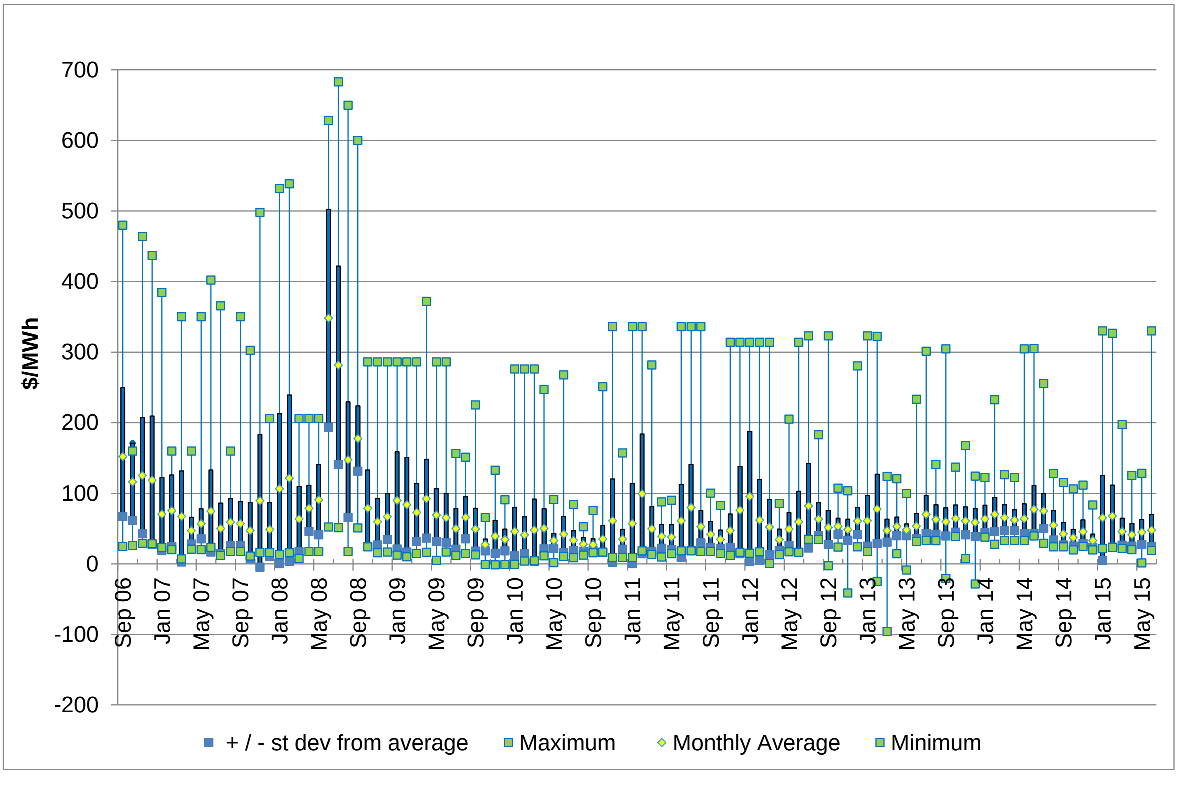
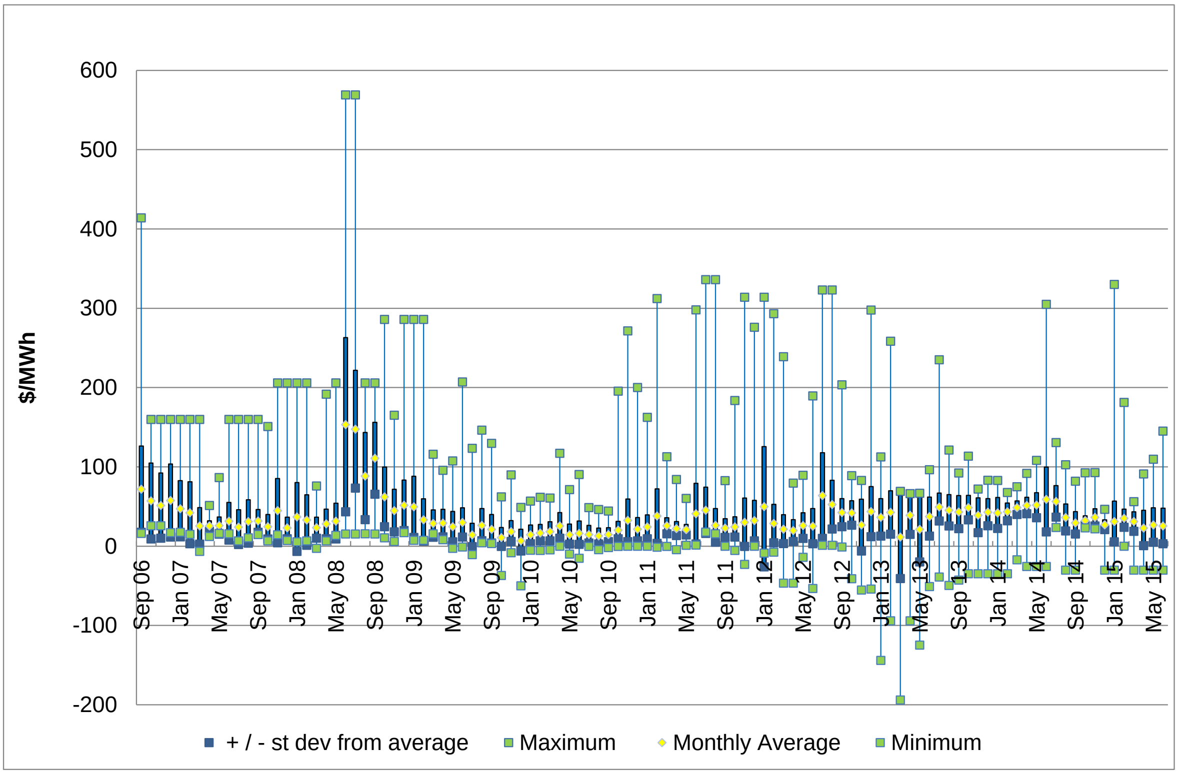


Figure 22 Summary statistics for MCAP/ Final Balancing Price during Off-Peak Trading Intervals (per calendar month)



High Balancing prices

The Market Rules require an examination of both the incidence and causes of high Balancing prices. As with STEM Clearing Prices, the incidence of high Balancing prices is examined by considering the proportion of time that Balancing prices are at the Energy Price Limits and by considering the price duration curve for Balancing prices.

Figure 23 illustrates the proportion of Peak Trading Intervals and Off-Peak Trading Intervals during which MCAP/ Final Balancing prices were at the Maximum STEM Price.

Figure 23 Proportion of Trading Intervals MCAP/Final Balancing prices at Maximum STEM Price (per calendar month)

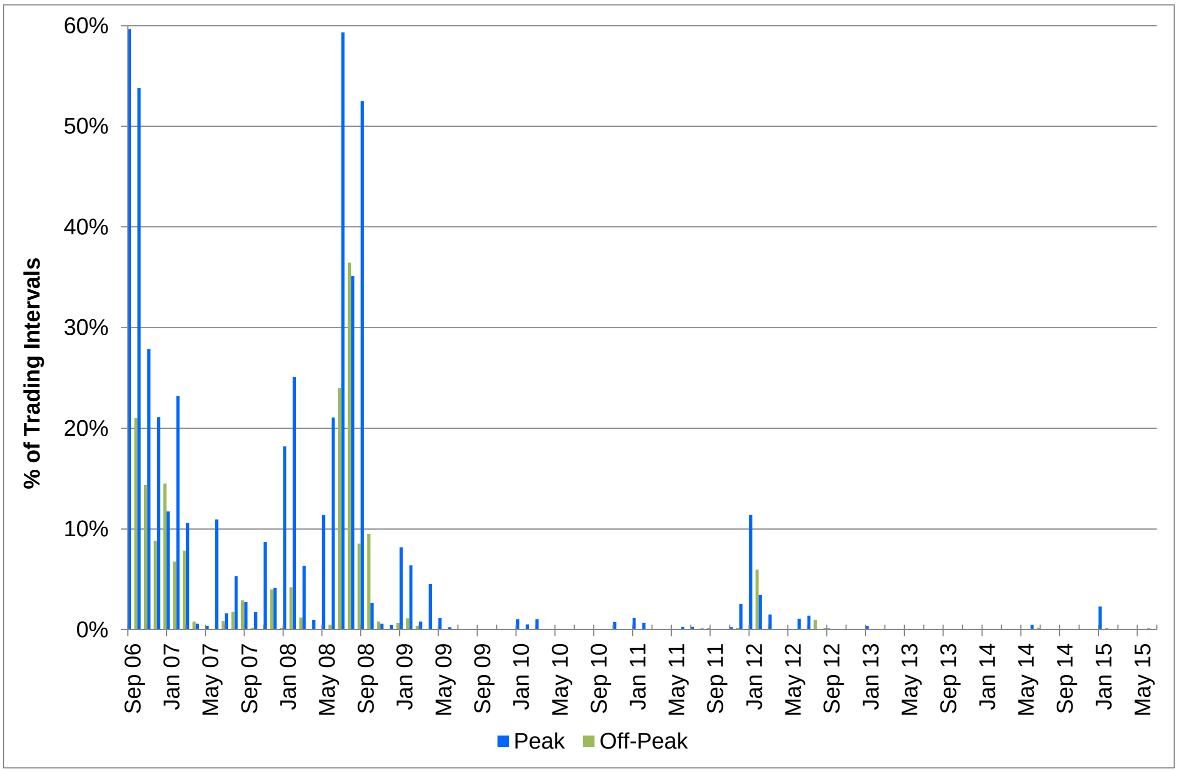
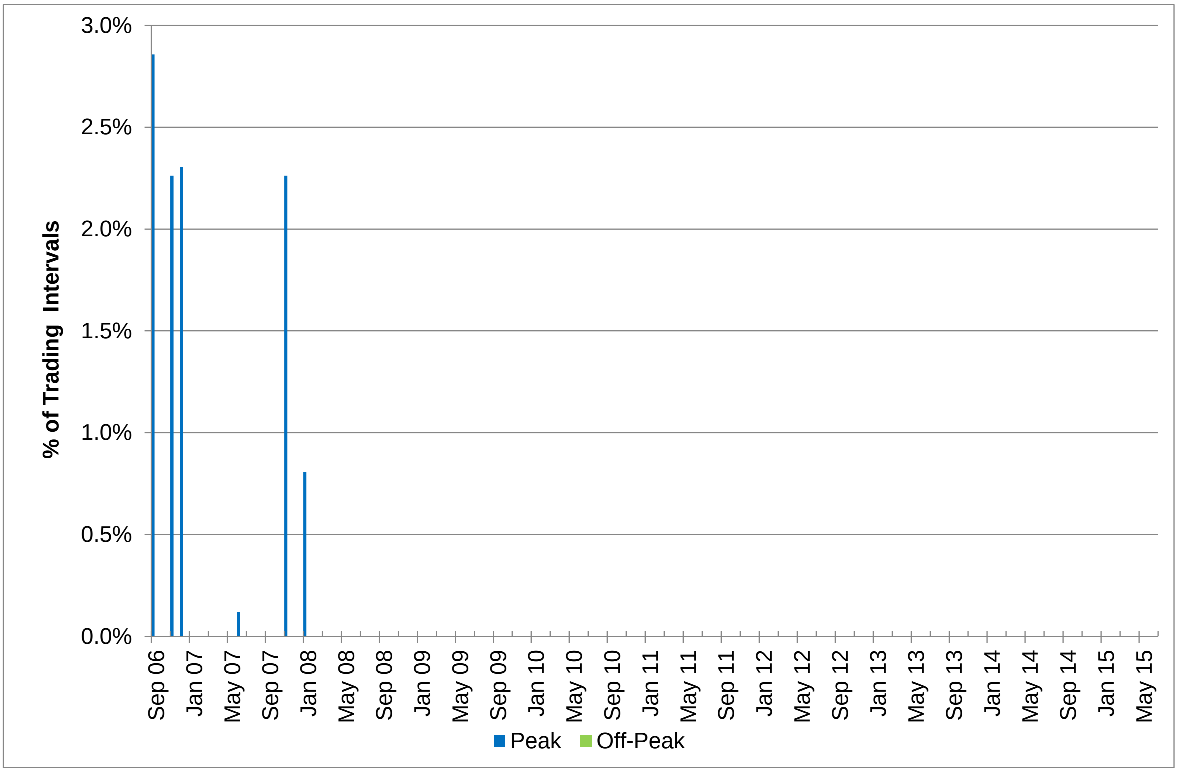


Figure 24 illustrates the proportion of peak and off-peak periods during which MCAP/Final Balancing prices were at the Alternative Maximum STEM Price.

Figure 24 Proportion of Trading Intervals MCAP/Final Balancing prices at Alternative Maximum STEM Price (per calendar month)



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.

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.[8] 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.[9] 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 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

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

9 These Ancillary Services are defined in section 3.9 of the Market Rules.

- the Ancillary Service requirements for the coming year and the Ancillary Services plan to meet those requirements.

System Management is required to source Ancillary Services on a least cost basis, either from Synergy (the default provider) or from IPPs. The IMO recovers the costs of the Ancillary Services from Market Participants through the market settlement process.

Each year System Management must prepare a report pursuant to its obligations under clause 3.11.11 of the Market Rules.[10] The report 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.

Spinning Reserve

Synergy has been the default provider of the Spinning Reserve Ancillary Service[11] 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.[12] The Spinning Reserve Ancillary Service cost is recovered from Market Generators.

Load Following

LFAS are the primary mechanism in real-time to ensure that supply and demand are balanced. Load following accounts for the difference between scheduled energy and actual load. Load following resources must have the ramping capability to pick up the load ramp between scheduling steps as well as maintain the system frequency. Load following can only be provided by units operating under Automatic Generation Control (**AGC**). LFAS Up refers to the service of adjusting output upwards to meet demand and LFAS Down refers to the service of adjusting output downwards, when demand is low.

A competitive LFAS market was introduced on 1 July 2012. Prior to that date, Synergy was the sole provider. The key elements of the new market included market derived prices rather than administratively derived prices, and participation being open to all IPPs. NewGen is the only IPP providing LFAS services in addition to Synergy. 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.

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[10] System Management *Ancillary Services Report 2015* http://www.imowa.com.au/docs/default-source/System-Management-Reports/final-2015-ancillary-services-report-for-imo-website.pdf?sfvrsn=0

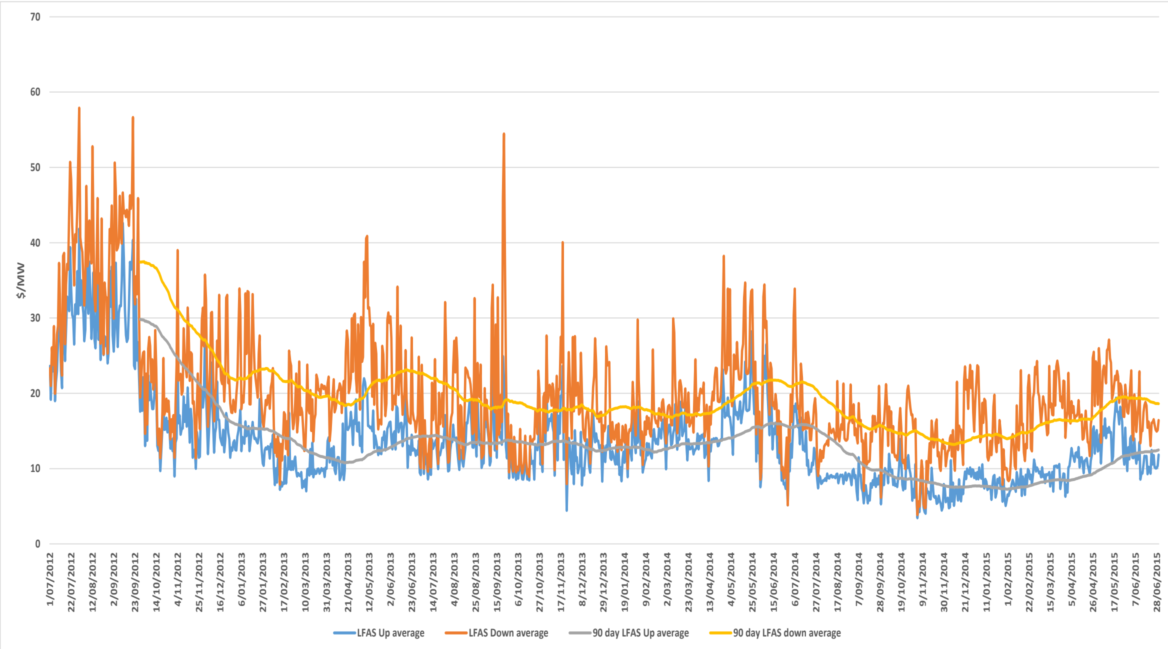
[11] Spinning Reserve is reserve that is synchronised to the system that can respond almost immediately and provide frequency or voltage support for a short duration.

[12] 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.

The LFAS requirement is set by System Management and must meet the standard according to section 3.10.1 of the Market Rules. This states that the level must be the greater of 30 MW or the level sufficient to maintain system frequency between 49.80 Hz and 50.20 Hz for at least 99.9% of each month.

The total cost of providing LFAS is passed on to Market Customers and Non Scheduled Generators, based on each Market Customer's monthly aggregate demand, as a proportion of that month's total system load. **Figure 25** below shows the average daily LFAS prices since the competitive market commenced.

Figure 25 Daily average LFAS Up and LFAS Down prices July 2012 to June 2015



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.

System Restart

System Management requires at least three generating stations to provide System Restart Ancillary Services[13]. 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.

Currently, System Management has three System Restart services until 30 June 2016. These services are being provided by Synergy's gas turbines at Kwinana and Pinjar, as well as Perth Energy's Kwinana GT1 facility. System Management has initiated a procurement

[13] 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.

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 2014/15 period.

Payments for these System Restart contracts are collected via the R value of the Cost_LR parameter,[14] 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 will publish its determination on the Cost_LR parameter for the 2016/17, 2017/18 and 2018/19 financial years in March 2016.

Load Rejection Reserve

The Load Rejection Reserve service[15] 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. The Authority will make a determination on this value for the 2016/17, 2017/18 and 2018/19 financial years in March 2016.[16]

Dispatch Support

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

Ancillary Service Declarations

A Market Participant that is a provider of Ancillary Services must include an Ancillary Services Declaration in its STEM Submission.[17] Clause 2.16.2(gC) of the Market Rules requires that the MSDC identify all Ancillary Service Declarations. There is also a requirement under clause 2.16.4(cA) of the Market Rules to calculate any consistent or significant variations between Ancillary Service Declarations and the actual real-time operation of a Market Participant.

Figure 26 below displays the Daily average Ancillary Services declarations since market commencement.

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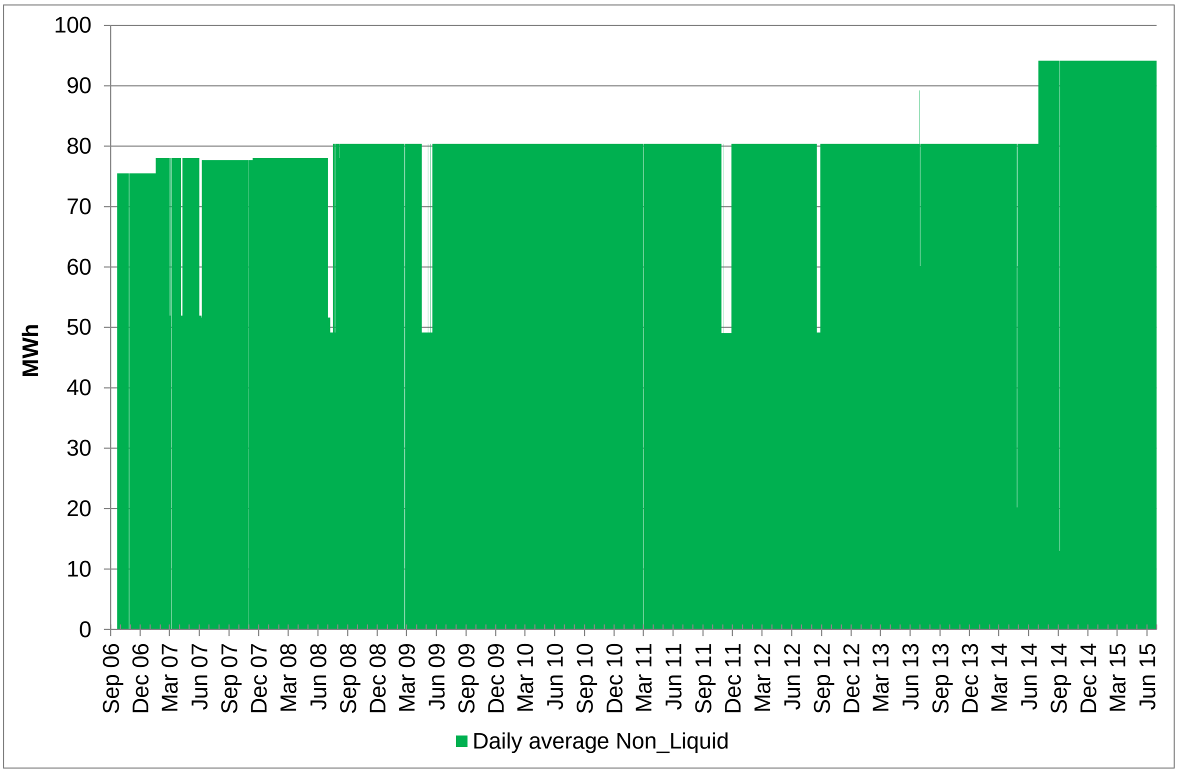
14 The Cost_LR parameter covers the payment to a Market Generator for the costs of providing the Load Rejection Reserve and System Restart Ancillary Services, and specific Dispatch Support Ancillary Services.

15 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.

16 Required by clause 3.13.3B of the Market Rules.

17 Required by clause 6.6.1(c) of the Market Rules.

Figure 26 Daily average Ancillary Services declarations (MWh per Trading Interval)



Dispatch process

In the Balancing Market, 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 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.

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.[18]

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

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**).

Long Term 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.[19]

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). 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

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

- 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.

Market 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.[20] 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.

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;

[20] 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.

- 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 is required to produce biannual reports on enforcement action taken to the ERB pursuant to clause 2.13.26 of the Market Rules. No proceedings were brought before the ERB by the IMO during 2014/15.

The IMO's compliance with the Market Rules is audited once a year by the Market Auditor.[21] 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,[22] 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.[23]

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.

Clause 2.13.9 of the Market Rules requires System Management to monitor Market Participants' compliance with Dispatch Instructions and Operating Instructions.[24] A Market Participant must comply with the most recently issued Dispatch Instruction, Operating

[21] 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.

[22] 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.

[23] 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

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

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.[25]

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.[26] 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.

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 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:

25 Clause 7.11.7 of the Market Rules.

26 See the IMO website, http://www.imowa.com.au/system_management_reports

- 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.

The Authority and the IMO utilise an SRMC modelling tool to assist in the monitoring of prices offered by generators to assess whether these prices reflect the Market Generator's reasonable expectation of the SRMC of generating the relevant electricity. The Authority issues regular information requests to significant generators, for the necessary data and information as inputs into the SRMC model. The IMO manages the operation of the SRMC model. The Authority and the IMO regularly review the results of this modelling.

The Authority recently undertook two investigations into pricing by Vinalco Energy. The Authority published its findings on 30 October 2015 and has requested the IMO, as required under clause 2.16.9G, to apply to the Electricity Review Board for an order for contravention of clause 7A.2.17 in relation to prices in a number of trading intervals.[27]

[27] The Authority published its findings on the ERA website on 30 October https://www.erawa.com.au/cproot/13938/2/Notice%20-%20First%20Vinalco%20Investigation.pdf and https://www.erawa.com.au/cproot/13939/2/Notice%20-%20Second%20Vinalco%20Investigation.pdf

Independent Market Operator 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.

System Management 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;
- 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:

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

Appendix 2 Summary of MSDC Requirements

Clause 2.16.12 (a) requires a summary of the information and data the IMO must provide the Authority under clause 2.16.1. These requirements are set out in **Table 7** below.

Table 7 MSDC data and analysis requirements under the Market Rules

Market Rule clause	Market Rule reporting requirement
2.16.2(a)	The number of Market Generators and Market Customers in the market
2.16.2(b)	The number of participants in each Reserve Capacity Auction
2.16.2(c)	Clearing prices in each Reserve Capacity Auction and STEM Auctions
2.16.2(d)	LFAS Submissions
2.16.2(dA)	All Reserve Capacity Auction offers
2.16.2(e)	All bilateral quantities scheduled with the IMO
2.16.2(f)	All STEM Offers and STEM Bids, including both quantity and price terms
2.16.2(g)	Balancing Submissions, including associated Balancing Price-Quantity Pairs and Ramp Rate Limits
2.16.2(gA)	All Fuel Declarations
2.16.2(gB)	All Availability Declarations
2.16.2(gC)	All Ancillary Service Declarations
2.16.2(h)	Any substantial variations in STEM Offer and STEM Bid prices or quantities relative to recent past behaviour
2.16.2(hA)	Any evidence that a Market Customer has significantly over-stated its consumption as indicated by its Net Contract Position with a regularity that cannot be explained by a reasonable allowance for forecast uncertainty or the impact of Loss Factors
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)
2.16.2(hC)	Any substantial variations in Balancing Prices, Non-Balancing Facility Dispatch Instruction Payments or Balancing Quantities relative to recent past behaviour
2.16.2(i)	The capacity available through Balancing from Balancing Facilities, Dispatchable Loads and Demand Side Programmes
2.16.2(j)	The frequency and nature of Dispatch Instructions and Operating Instructions to Market Participants
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
2.16.2(l)	The performance of Market Participants with Reserve Capacity Obligations in meeting their obligations
2.16.2(m)	Details of Ancillary Service Contracts that System Management enters into
2.16.2(n)	All LFAS Prices
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
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.

Market Rule clause	Market Rule reporting requirement
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
2.16.4(c)	Statistical analysis of the volatility of prices in the STEM Auctions, the Balancing Market and the LFAS Market
2.16.4(cA)	Any consistent or significant variations between the Fuel Declarations, Availability Declarations, and Ancillary Service 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
2.16.4(e)	Correlation between capacity offered into the STEM Auctions and the incidence of high prices
2.16.4(f)	Correlation between capacity offered into and made available in the Balancing Market and the incidence of high prices
2.16.4(fA)	Correlation between capacity offered into and made available in the LFAS Market and the incidence of high prices
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
2.16.4(h)	Such other analysis as the IMO considers appropriate or is requested of the IMO by the Economic Regulation Authority

Appendix 3 Additional Charts and Tables

Figure 27 Alcoa's daily average STEM Offers (cumulative MWh per Trading Interval)

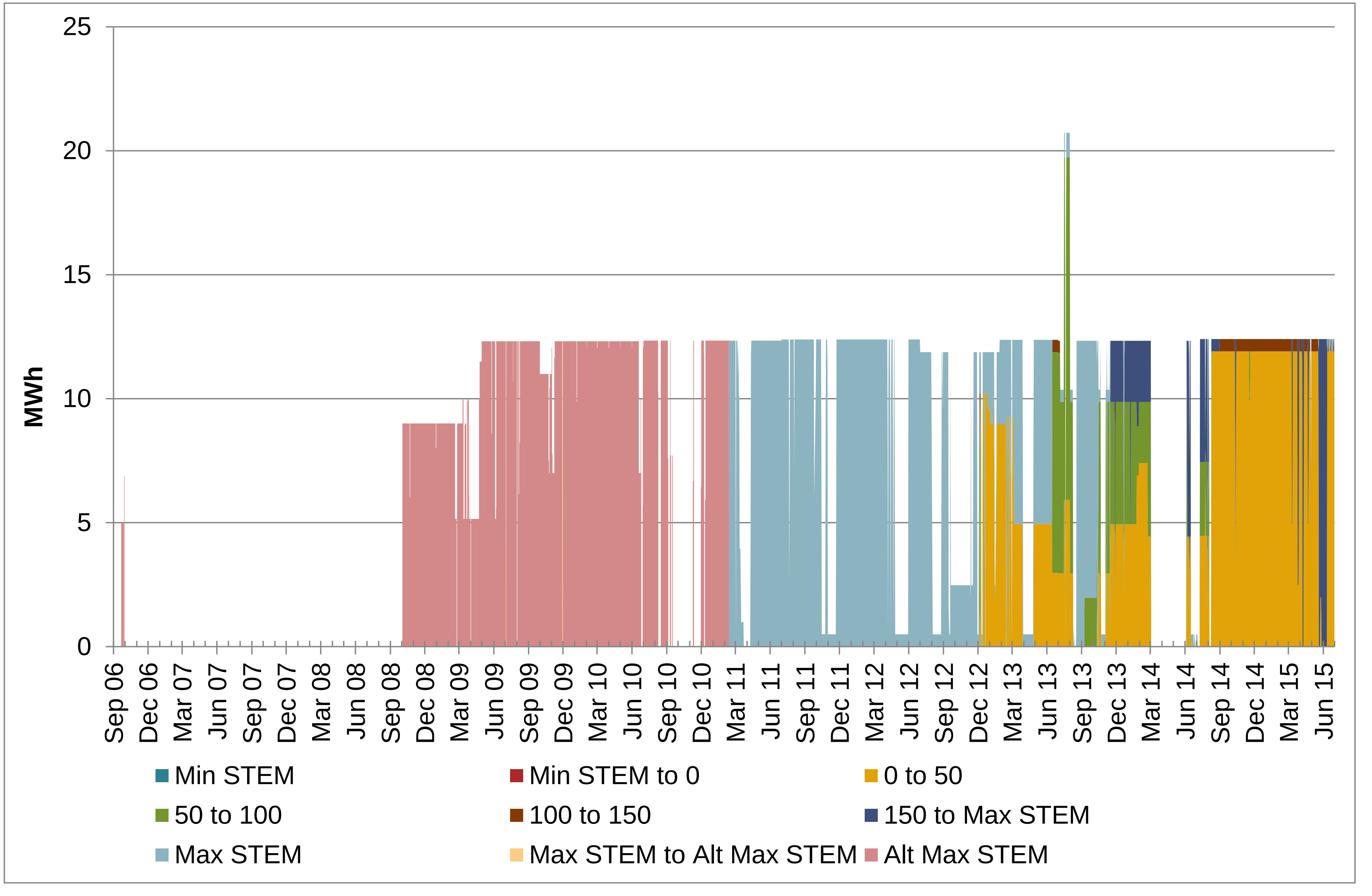


Figure 28 Alinta's daily average STEM Offers (cumulative MWh per Trading Interval)

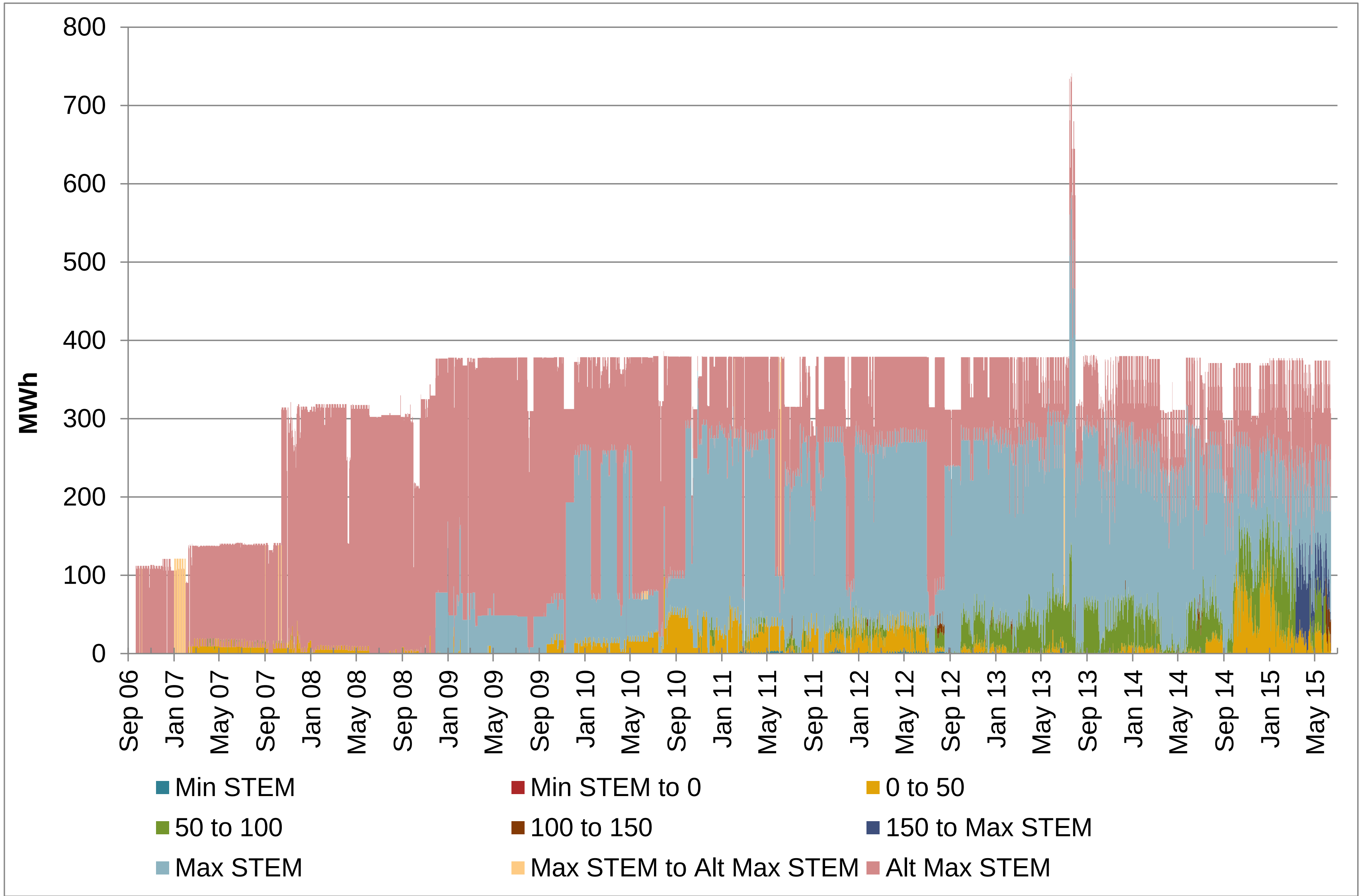


Figure 29 ERM Power's daily average STEM Offers (cumulative MWh per Trading Interval)

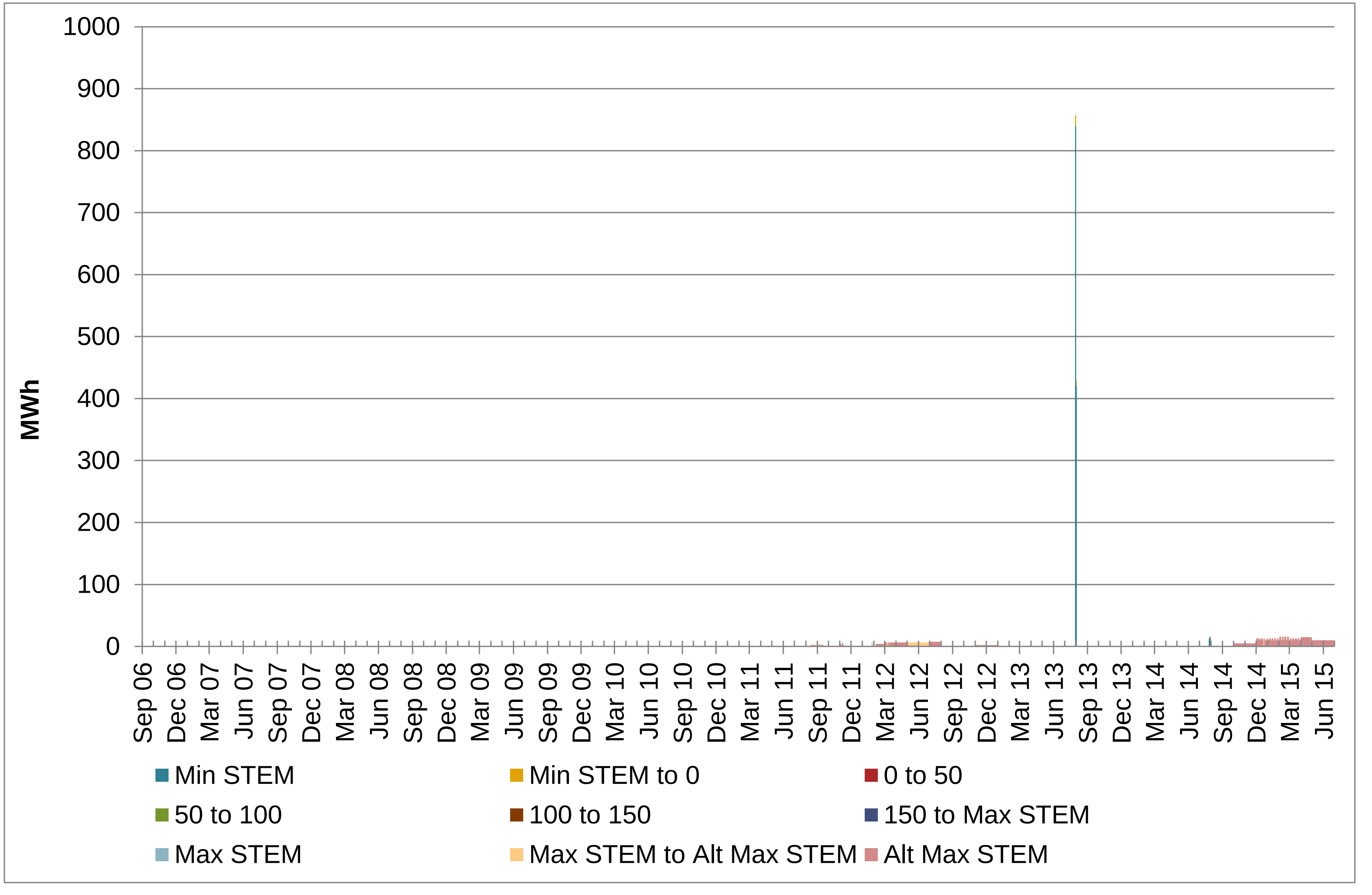


Figure 30 Goldfields Power's daily average STEM Offers (cumulative MWh per Trading Interval)

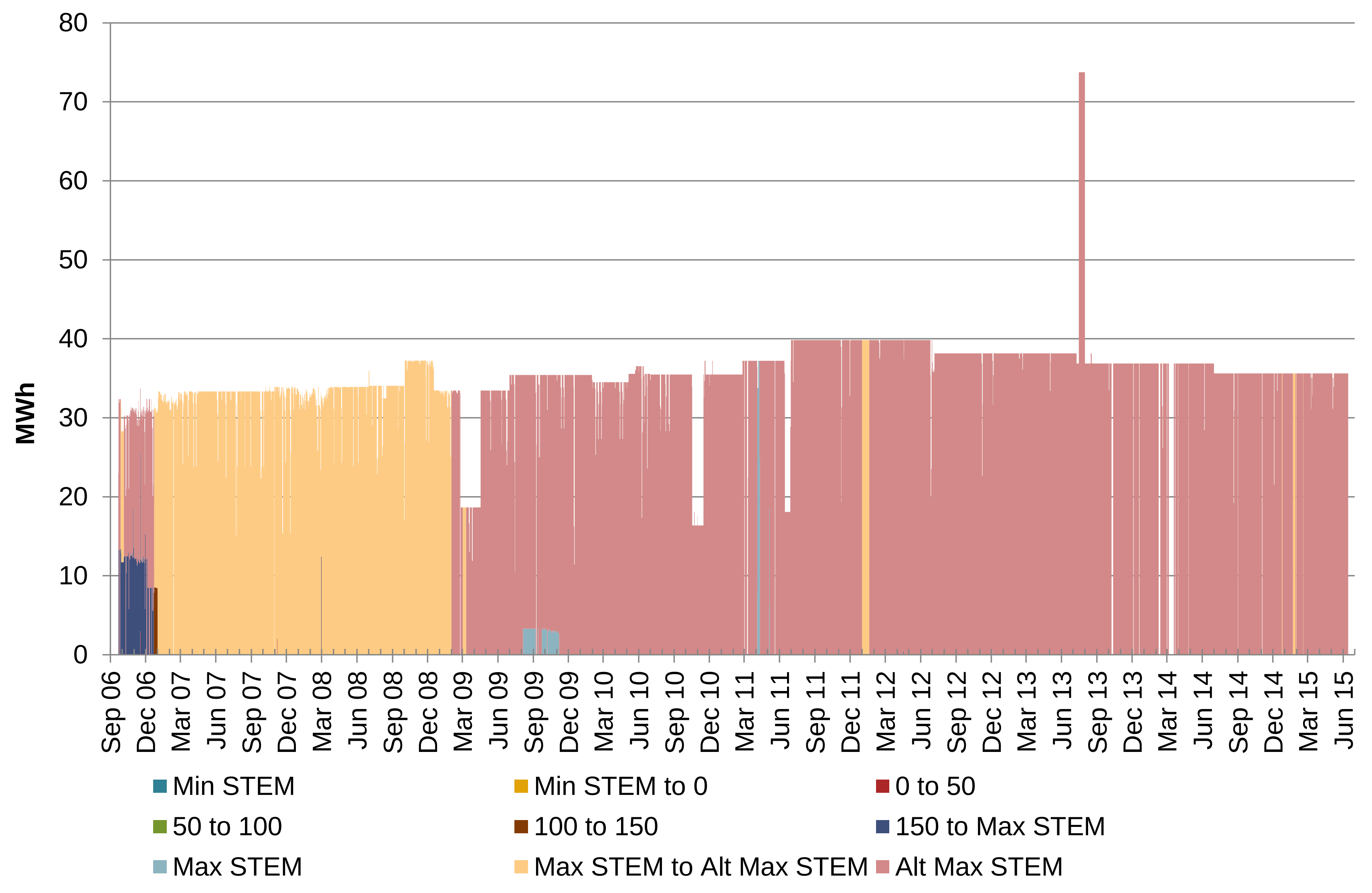


Figure 31 Griffin Power's daily average STEM Offers (cumulative MWh per Trading Interval)

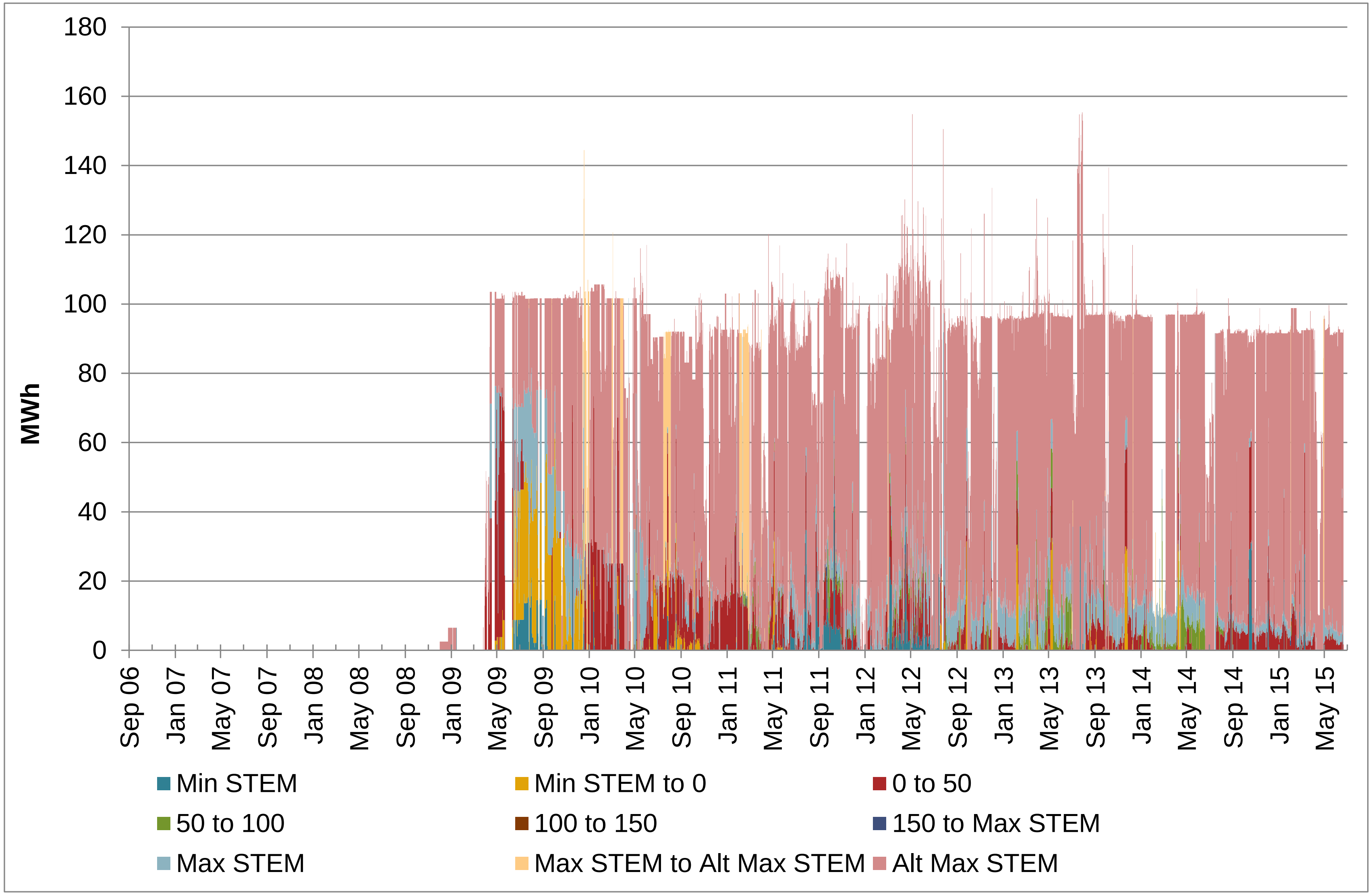


Figure 32 Griffin Power 2's daily average STEM Offers (cumulative MWh per Trading Interval)

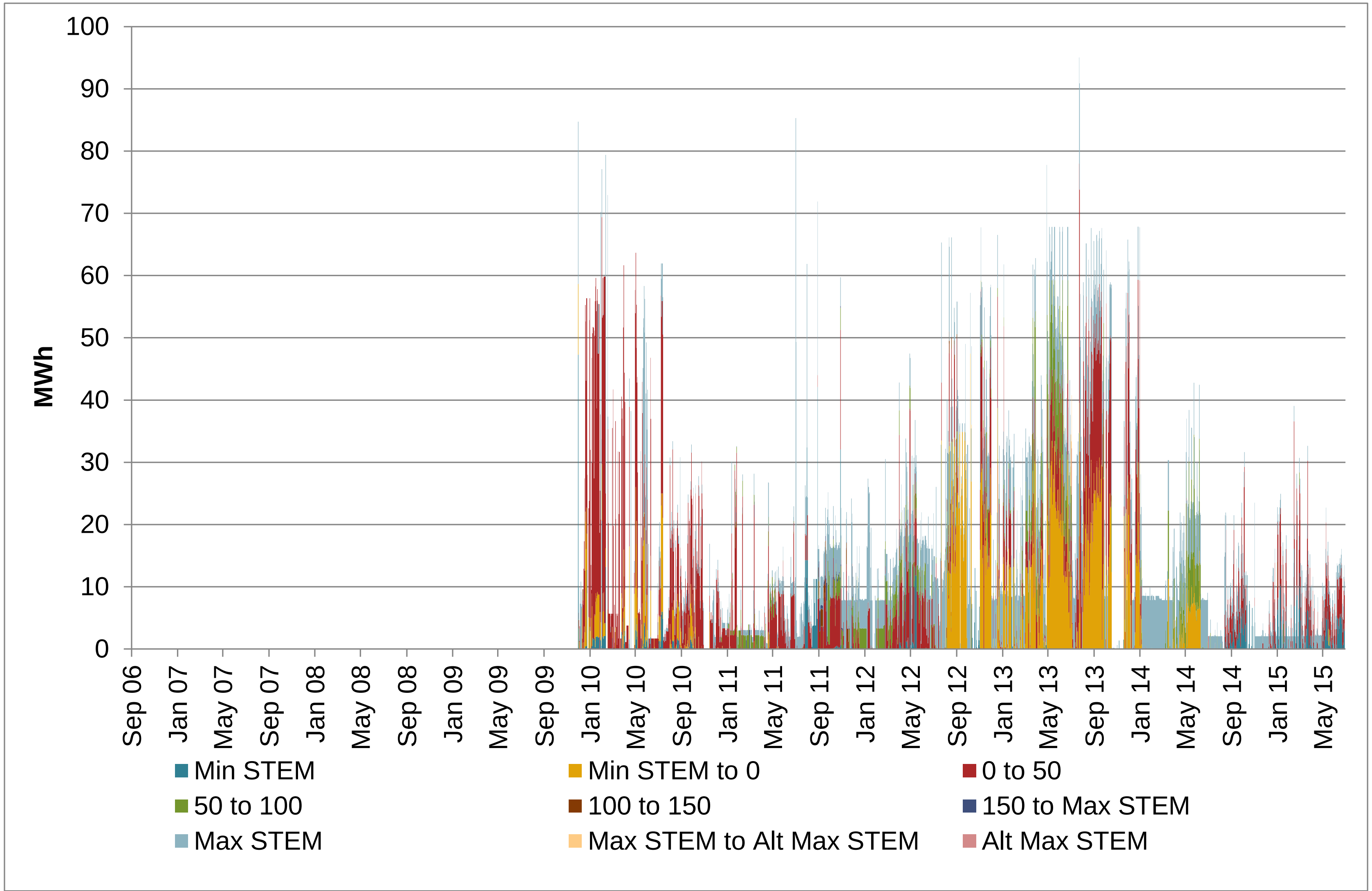


Figure 33 Karara's daily average STEM Offers (cumulative MWh per Trading Interval)

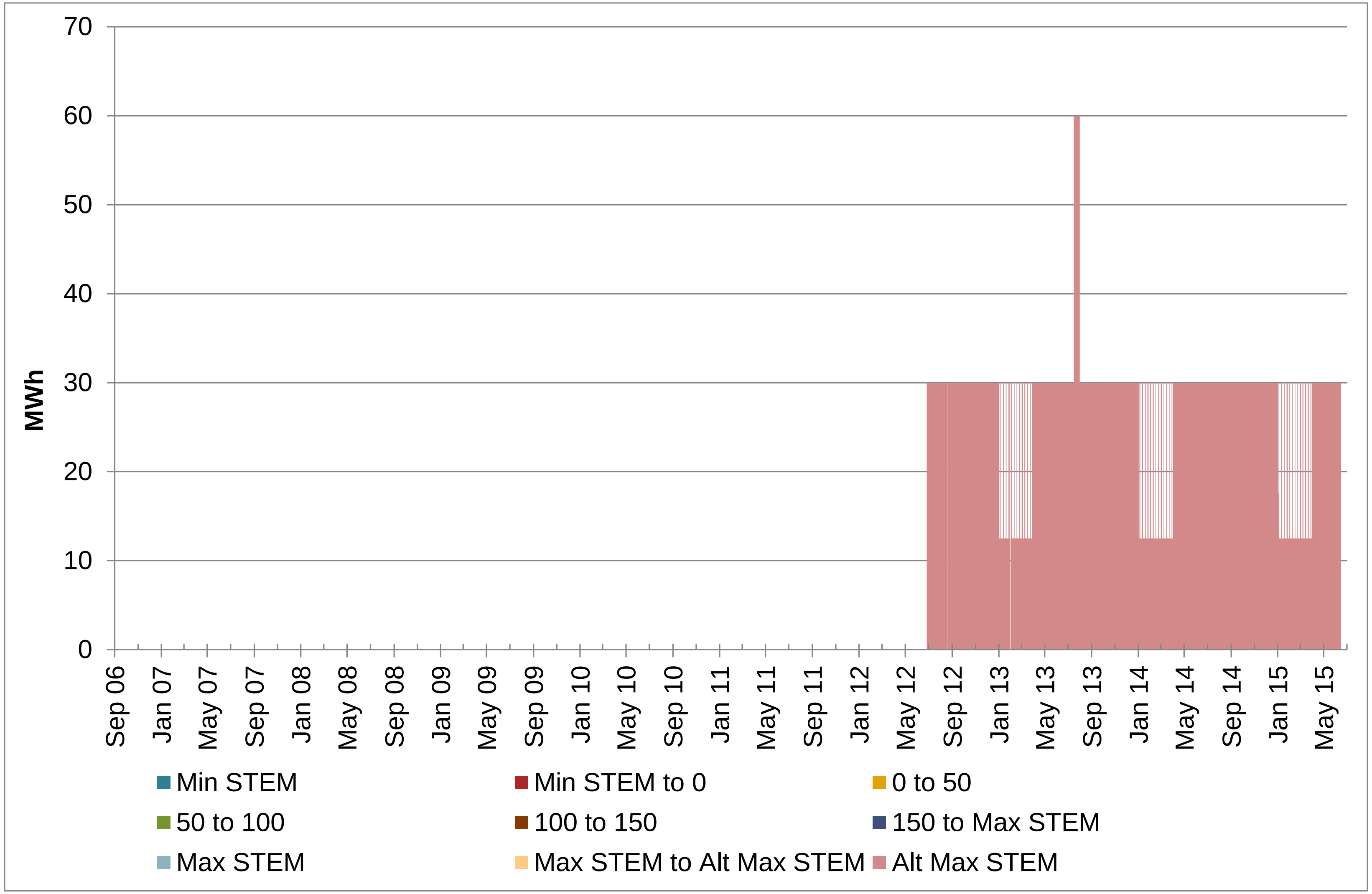


Figure 34 Landfill Gas and Power's daily average STEM Offers (cumulative MWh per Trading Interval)

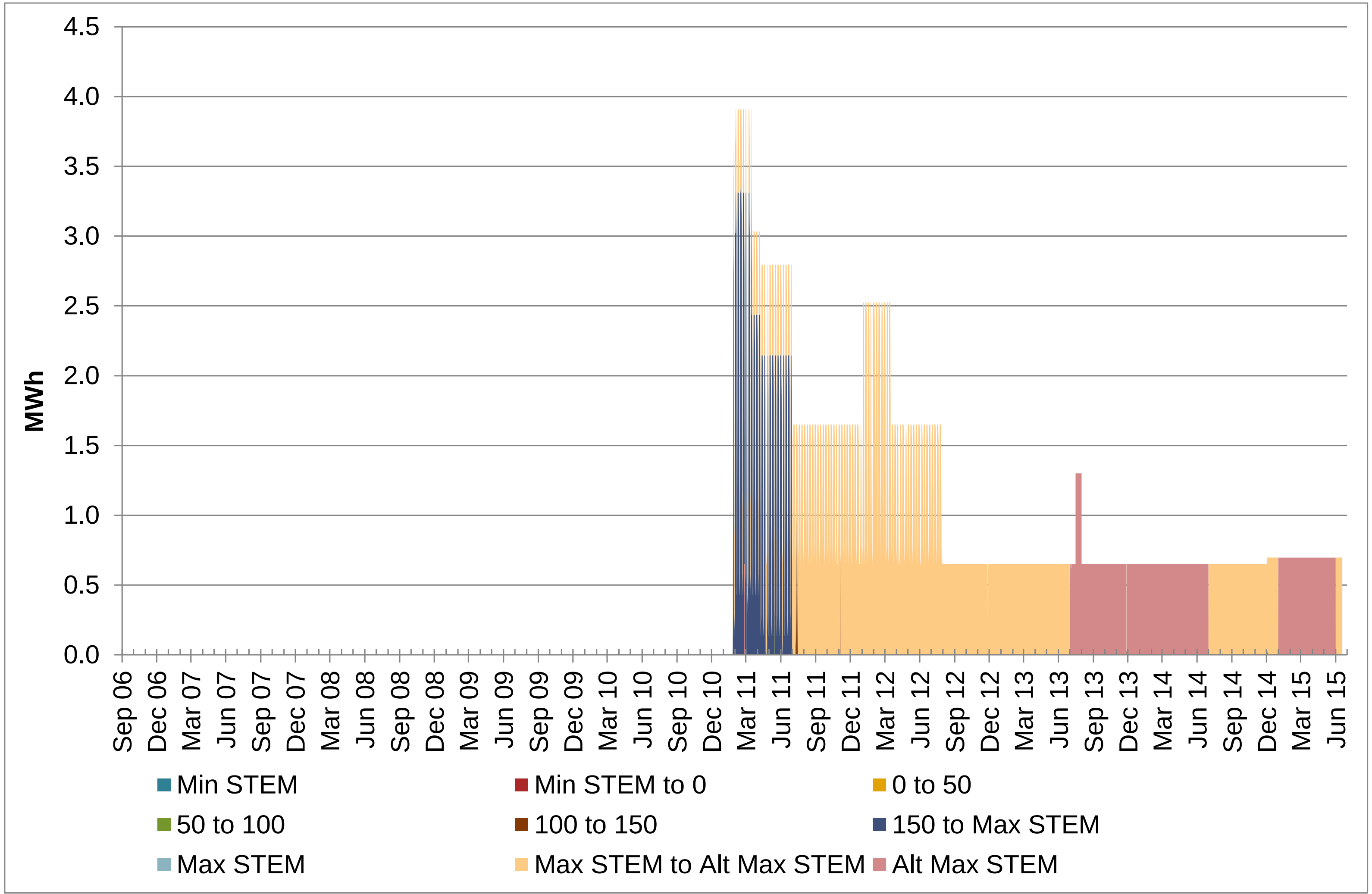


Figure 35 Merredin daily average STEM Offers (cumulative MWh per Trading Interval)

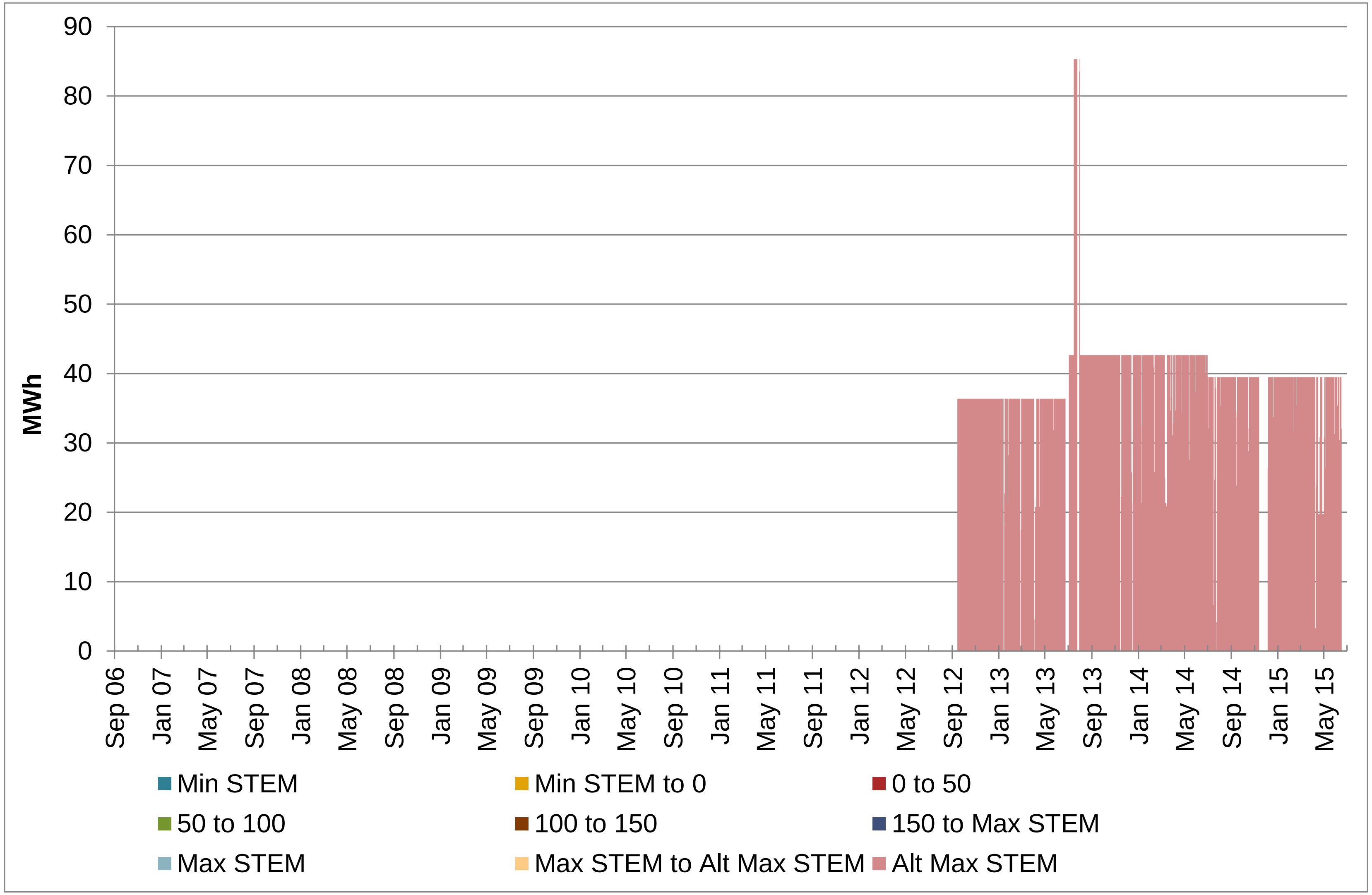


Figure 36 NewGen Power Kwinana's daily average STEM Offers (cumulative MWh per Trading Interval)

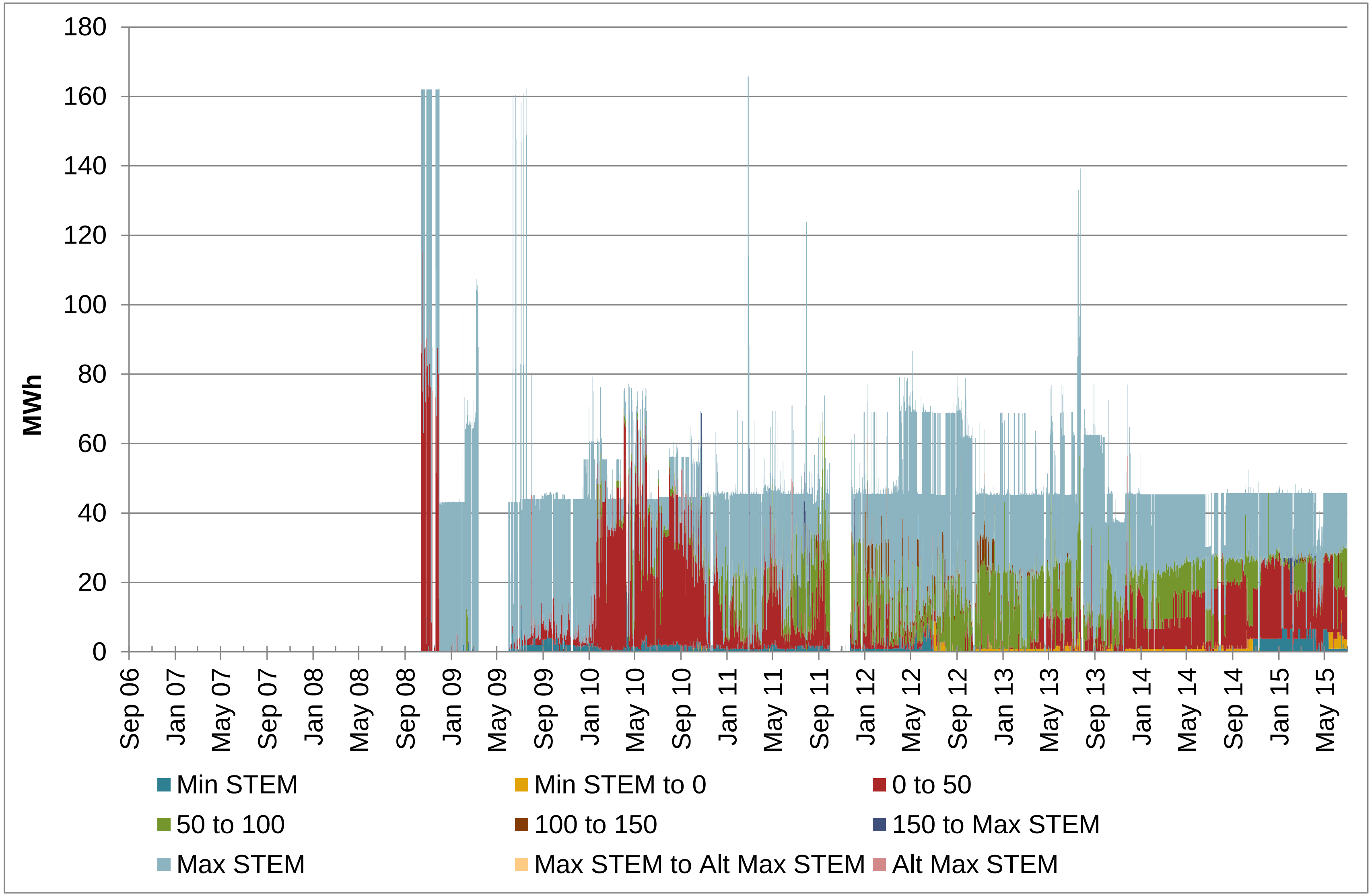


Figure 37 NewGen Neerabup's daily average STEM Offers (cumulative MWh per Trading Interval)

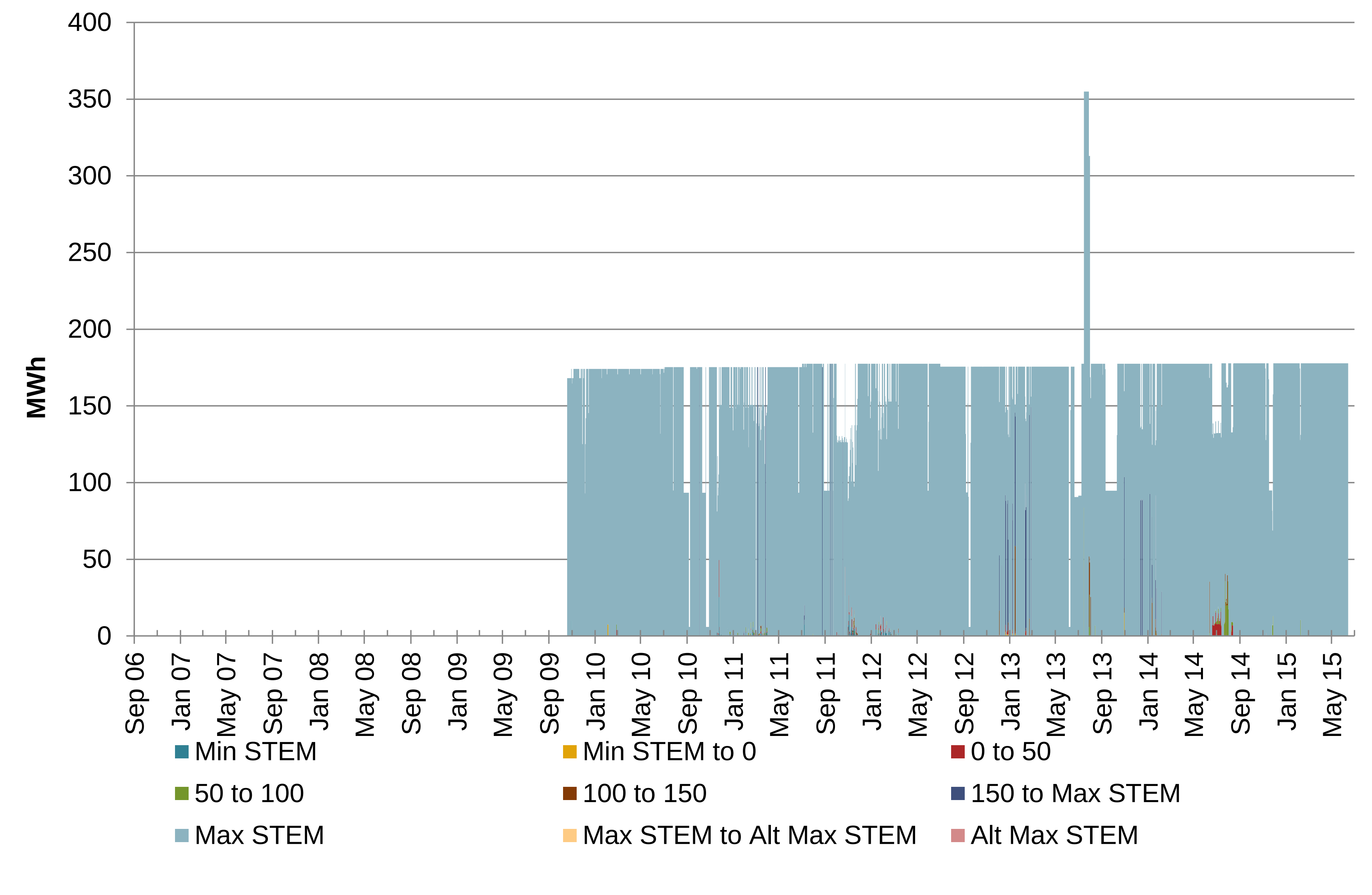


Figure 38 Perth Energy's daily average STEM Offers (cumulative MWh per Trading Interval)

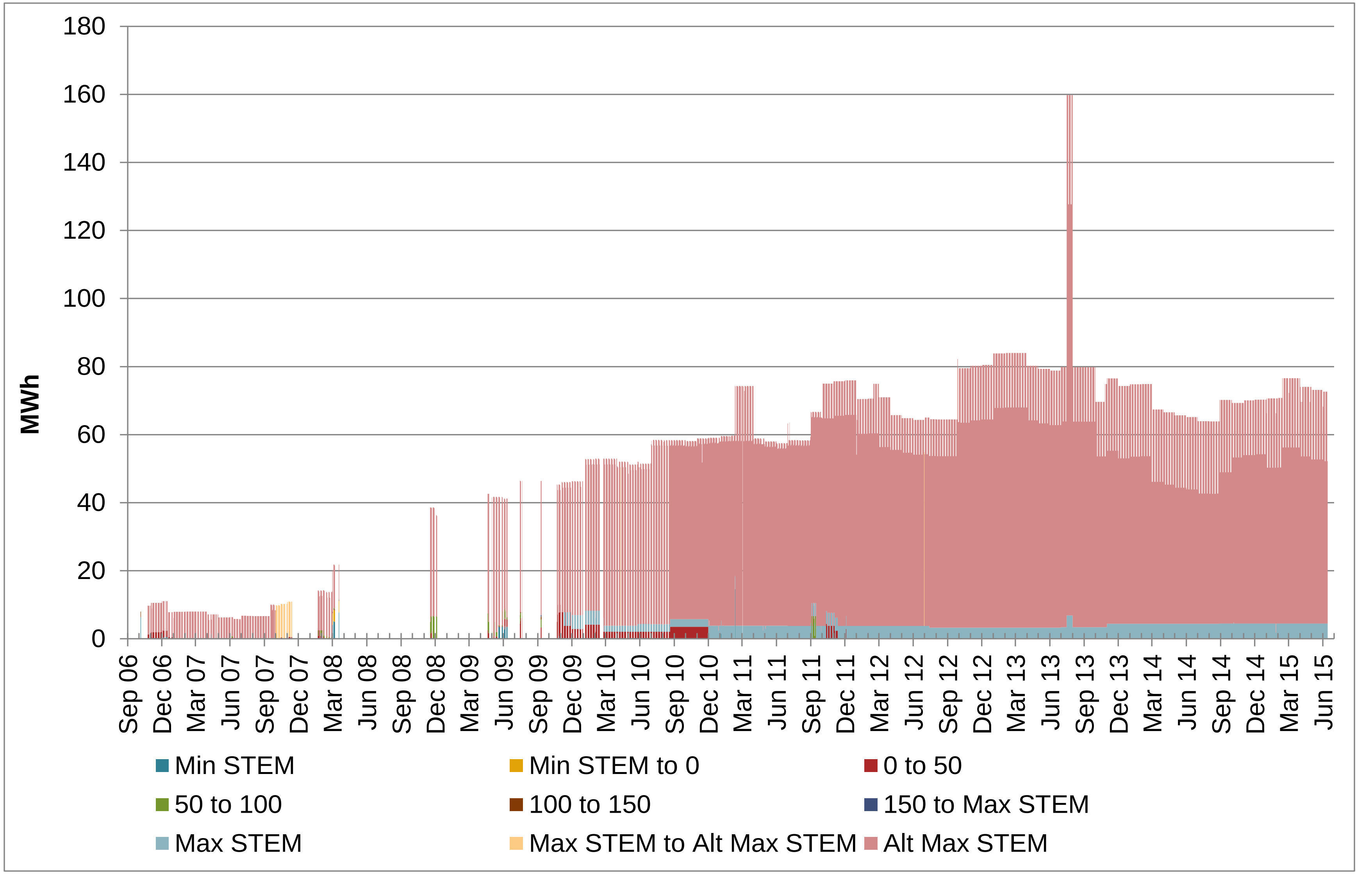


Figure 39 Southern Cross Energy's daily average STEM Offers (cumulative MWh per Trading Interval)

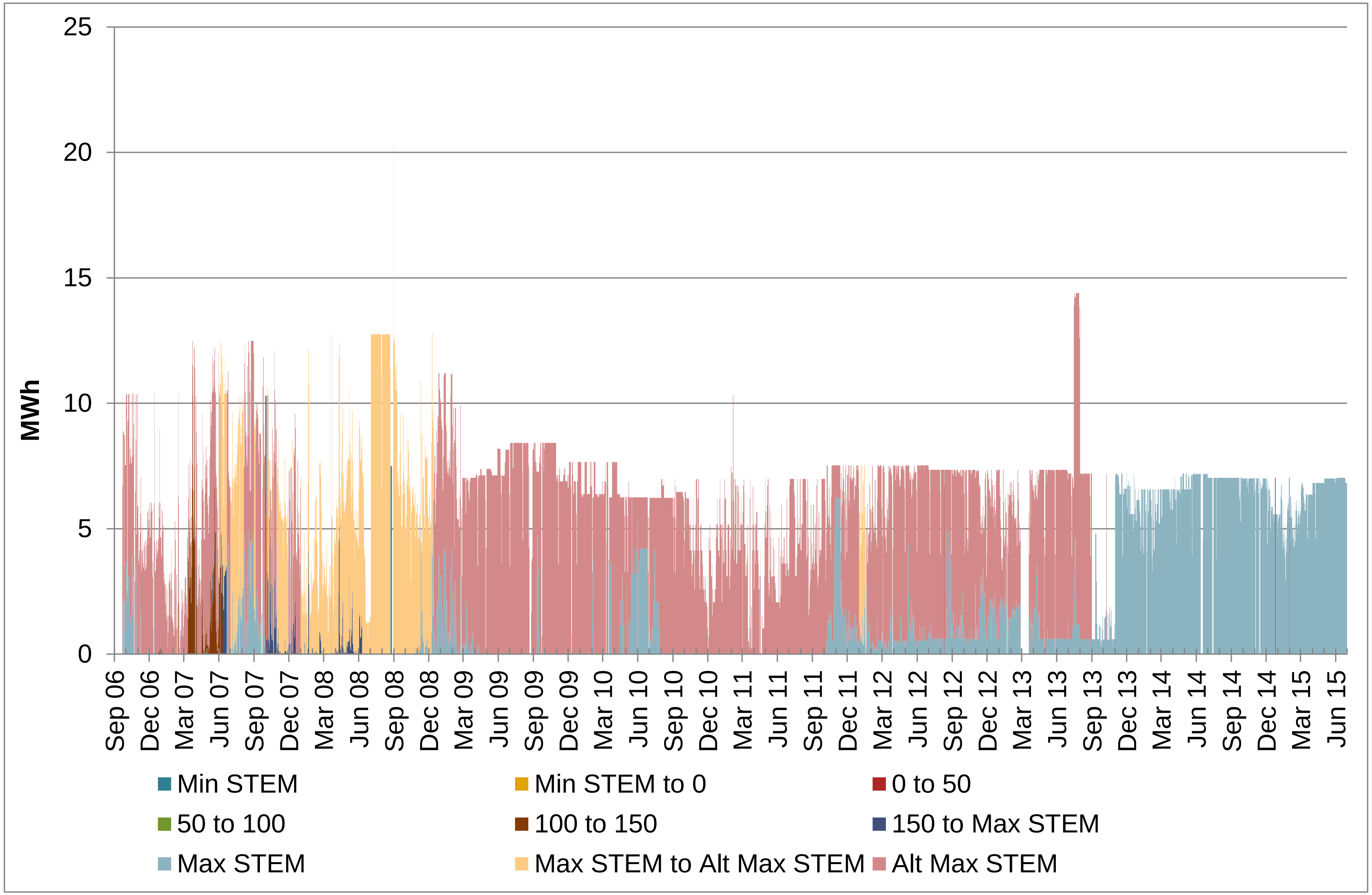


Figure 40 Tiwest's daily average STEM Offers (cumulative MWh per Trading Interval

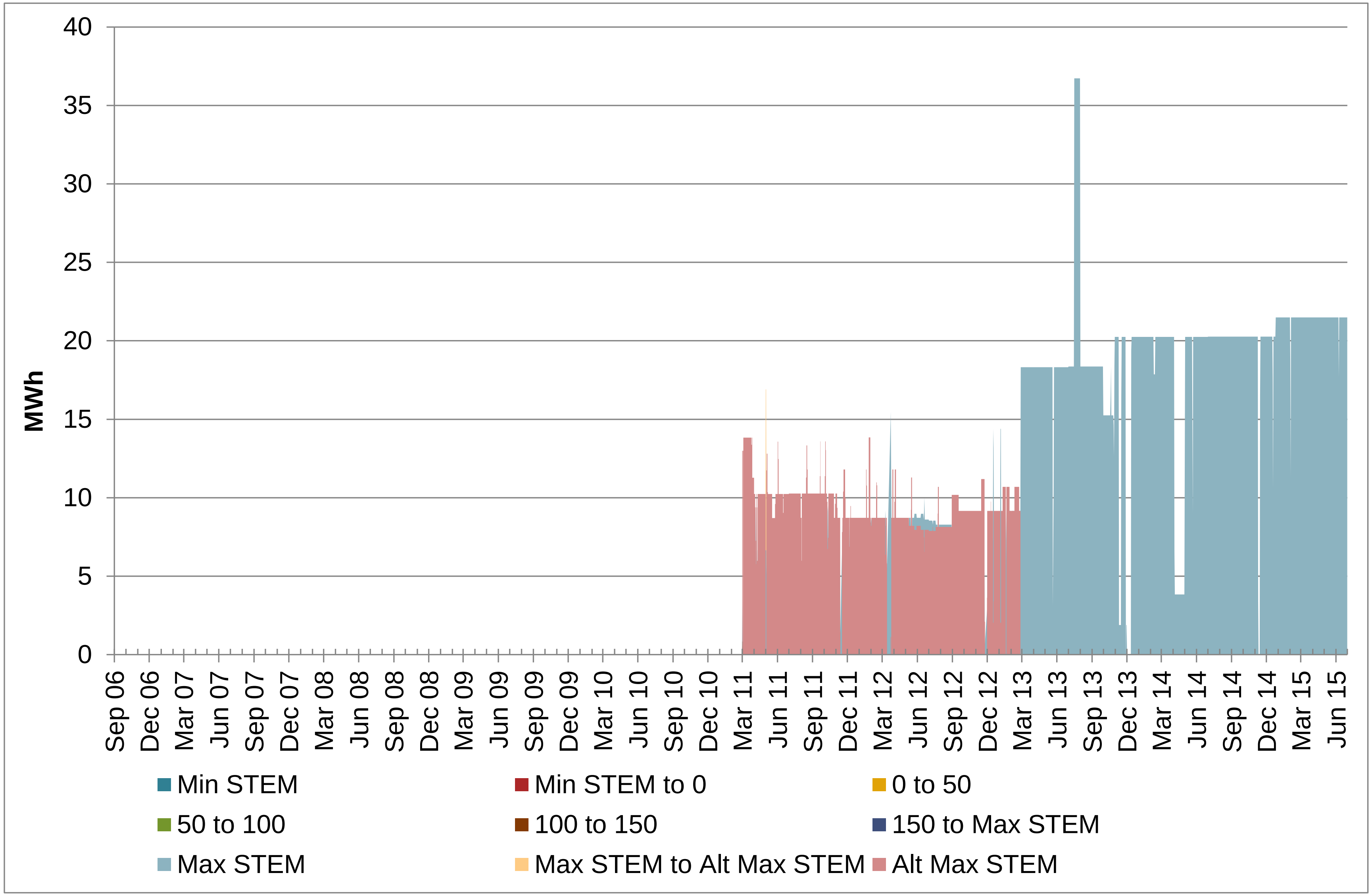


Figure 41 Tesla Management's daily average STEM Offers (cumulative MWh per Trading Interval)

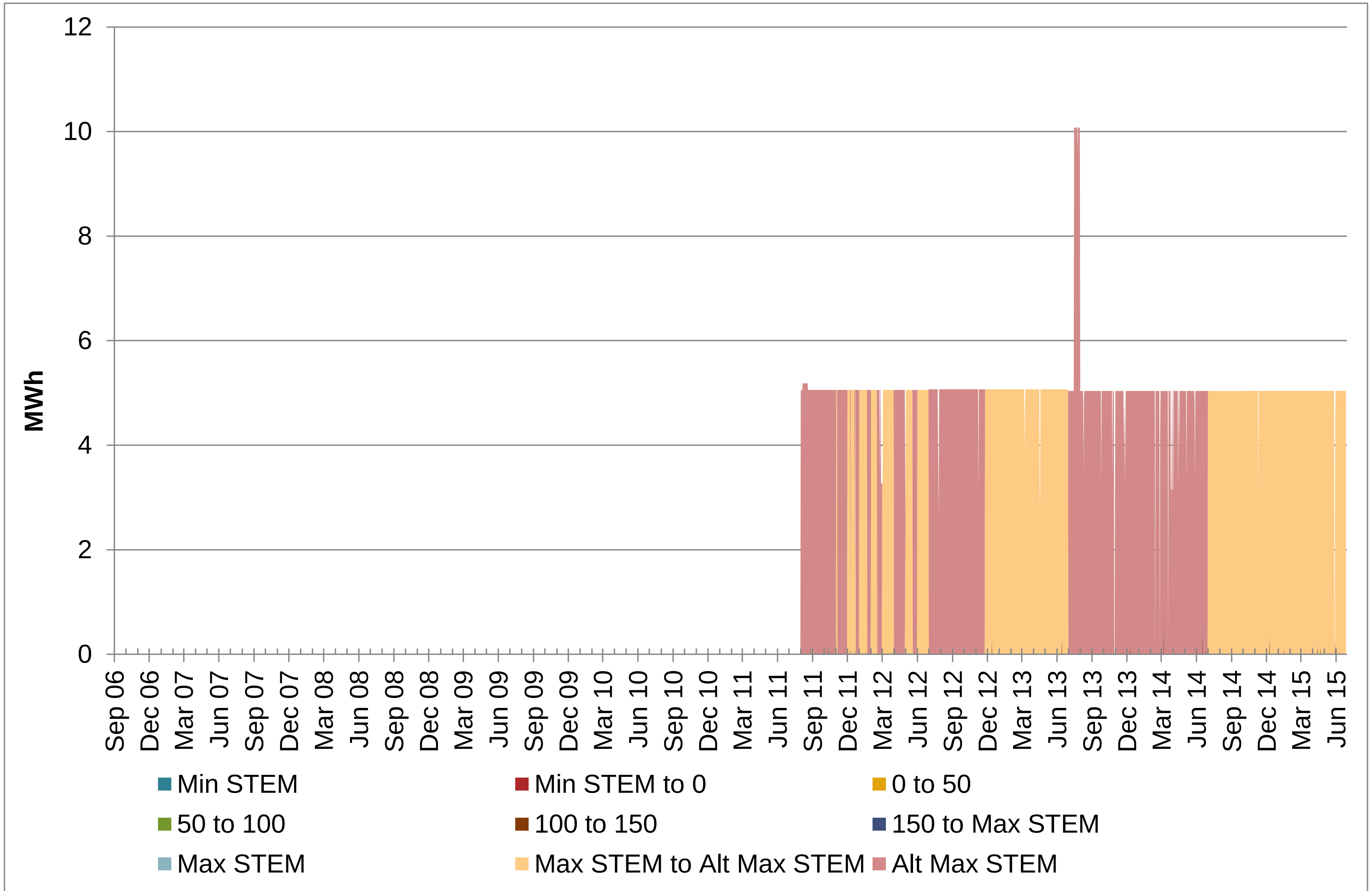


Figure 42 Tesla Geraldton's daily average STEM Offers (cumulative MWh per Trading Interval)

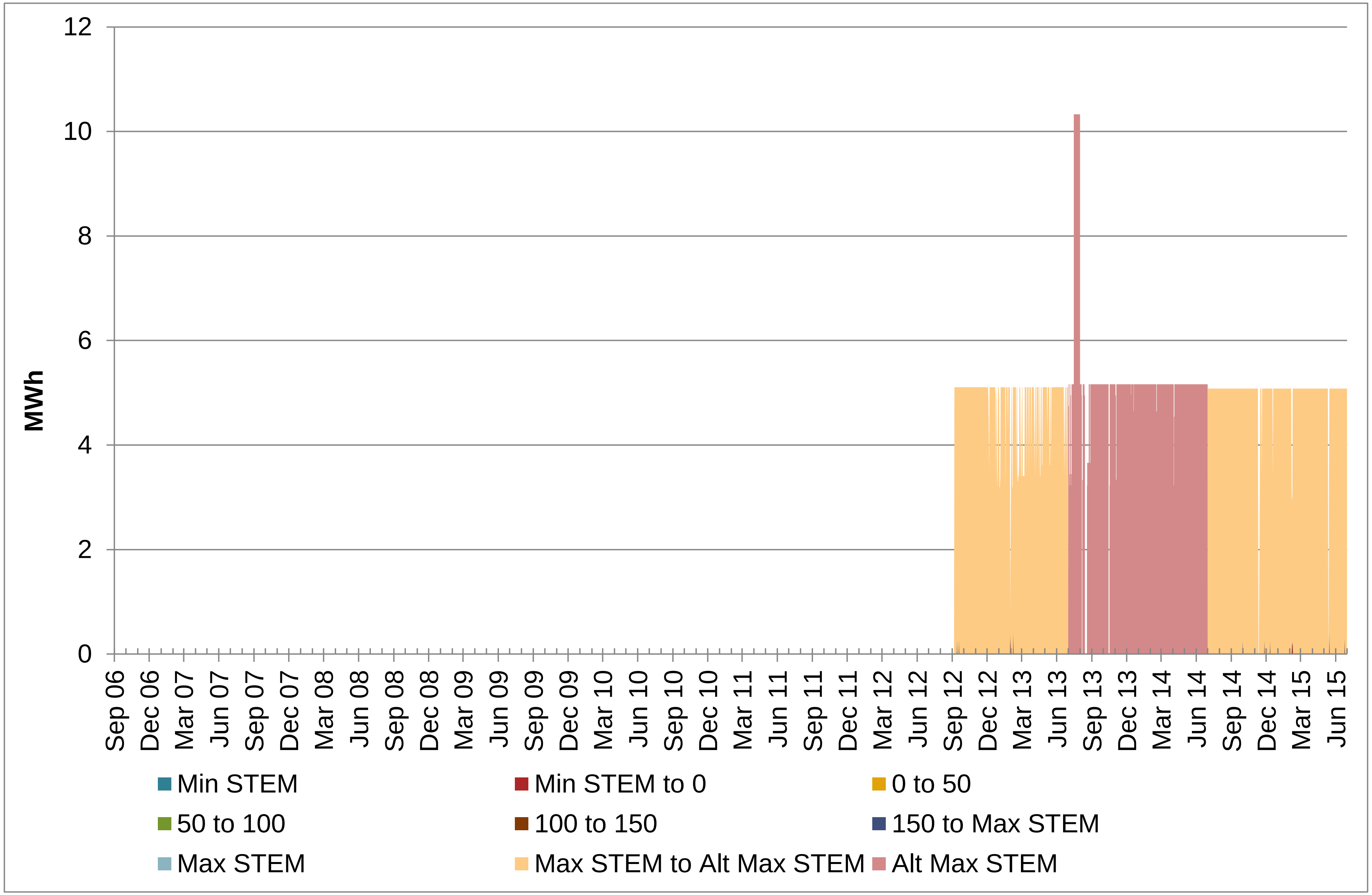


Figure 43 Tesla Kemerton's daily average STEM Offers (cumulative MWh per Trading Interval)

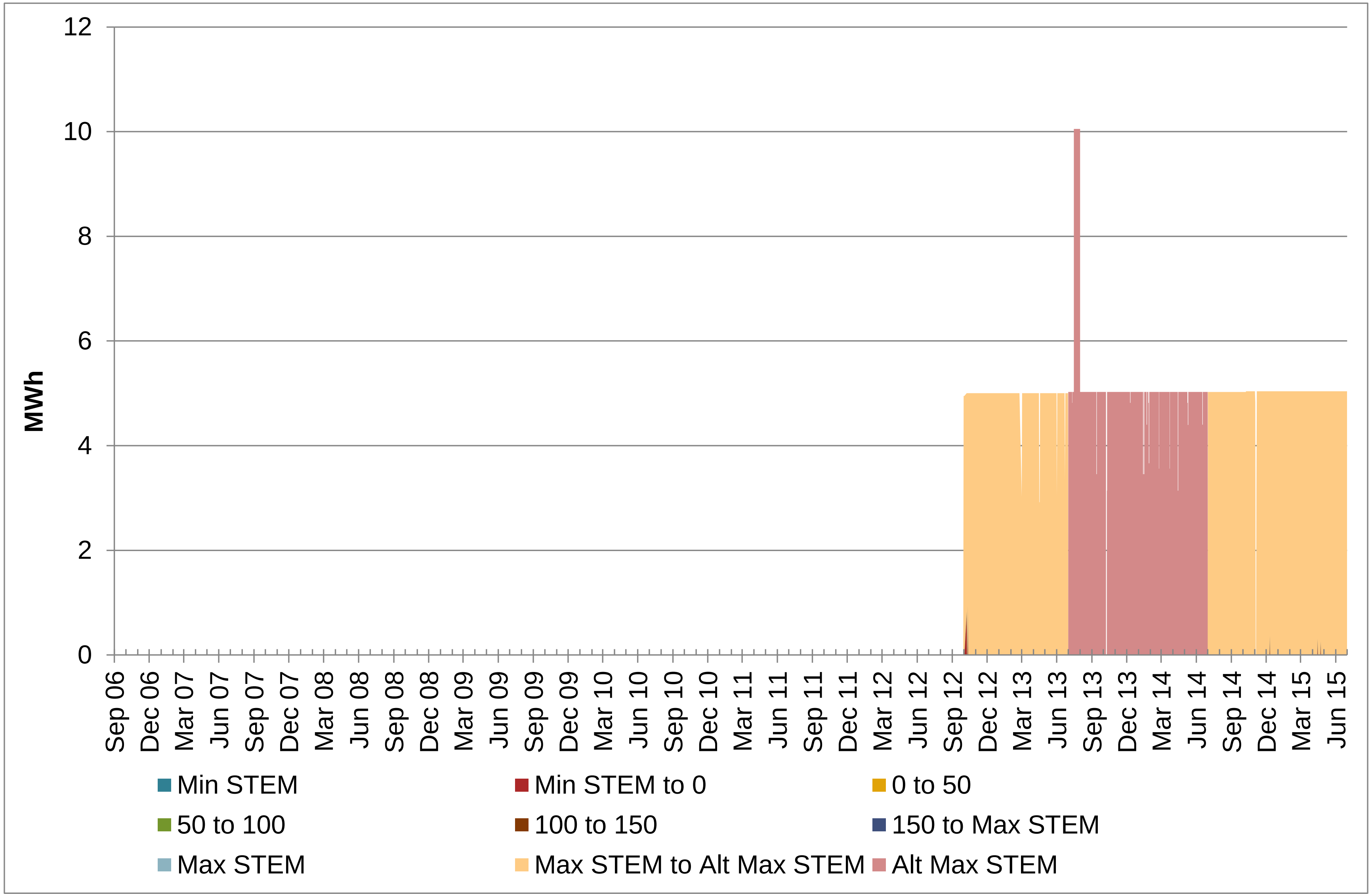


Figure 44 Tesla Northam's daily average STEM Offers (cumulative MWh per Trading Interval)

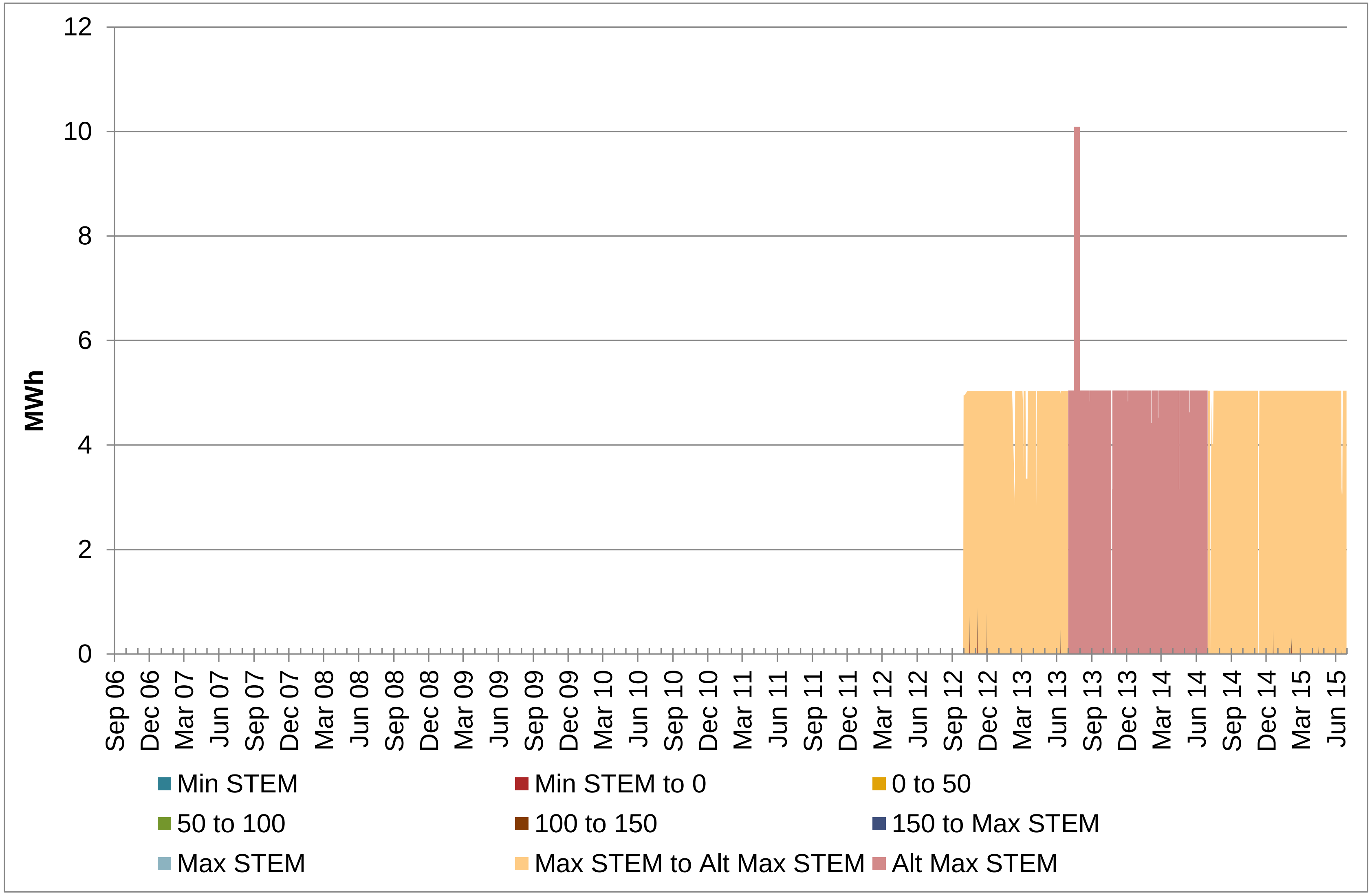


Figure 45 Western Energy's daily average STEM Offers (cumulative MWh per Trading Interval)

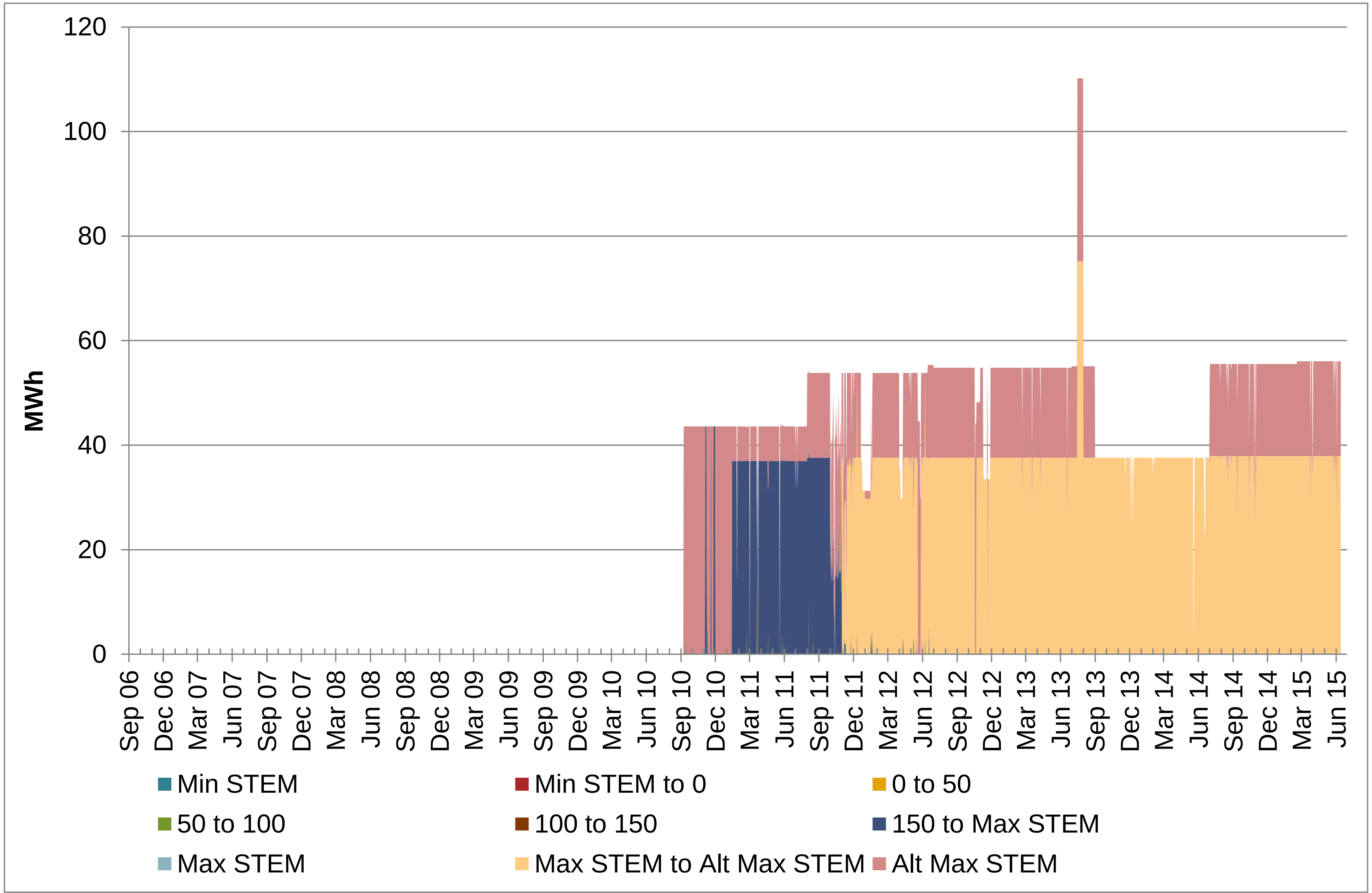


Figure 46 Synergy's daily average STEM Offers (cumulative MWh per Trading Interval)

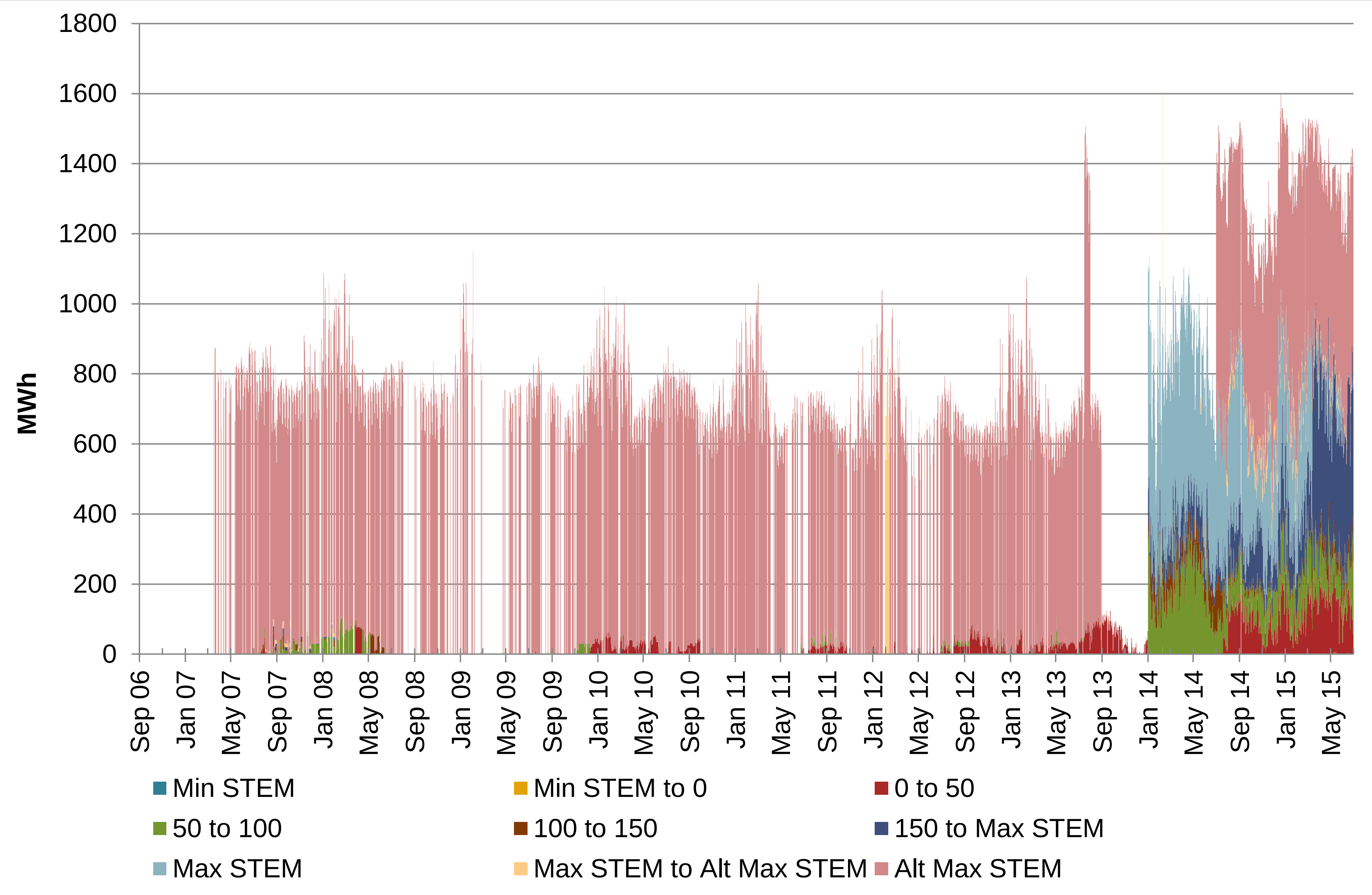


Figure 47 Verve Energy's daily average STEM Offers (cumulative MWh per Trading Interval)

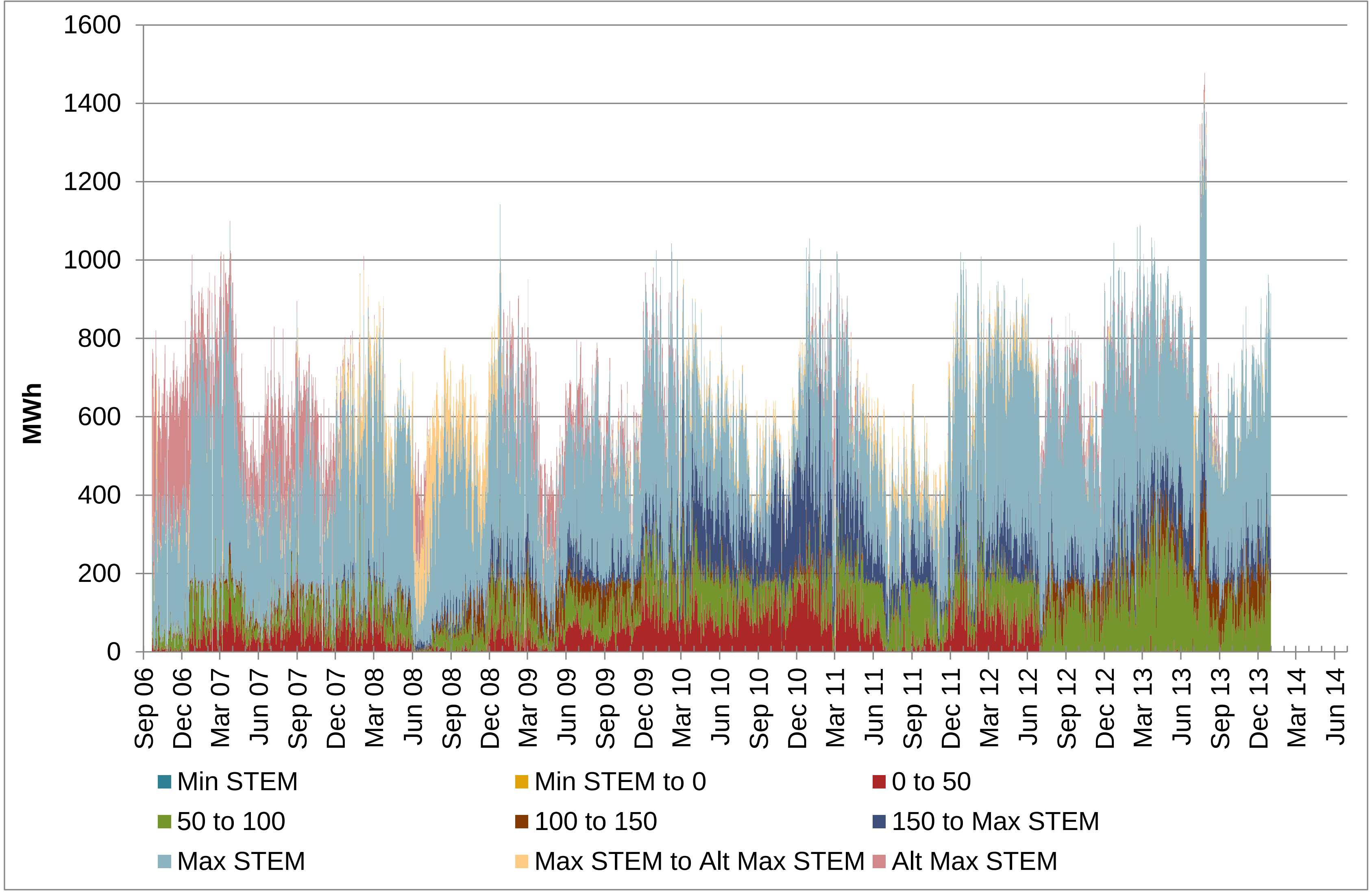


Figure 48 **Vinalco's daily average STEM Offers (cumulative MWh per Trading Interval)**

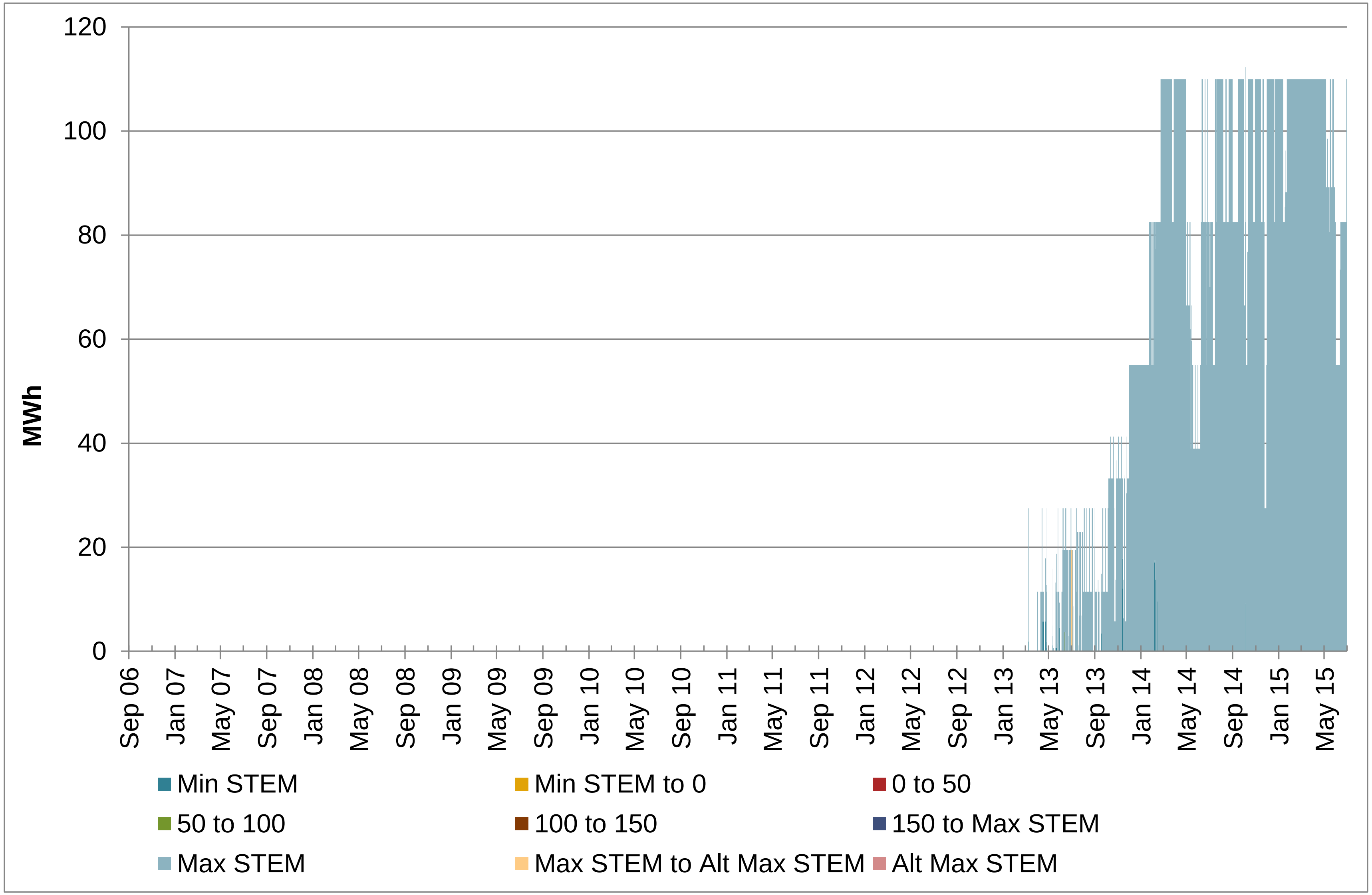


Figure 49 Alcoa's daily average STEM Bids (cumulative MWh per Trading Interval)

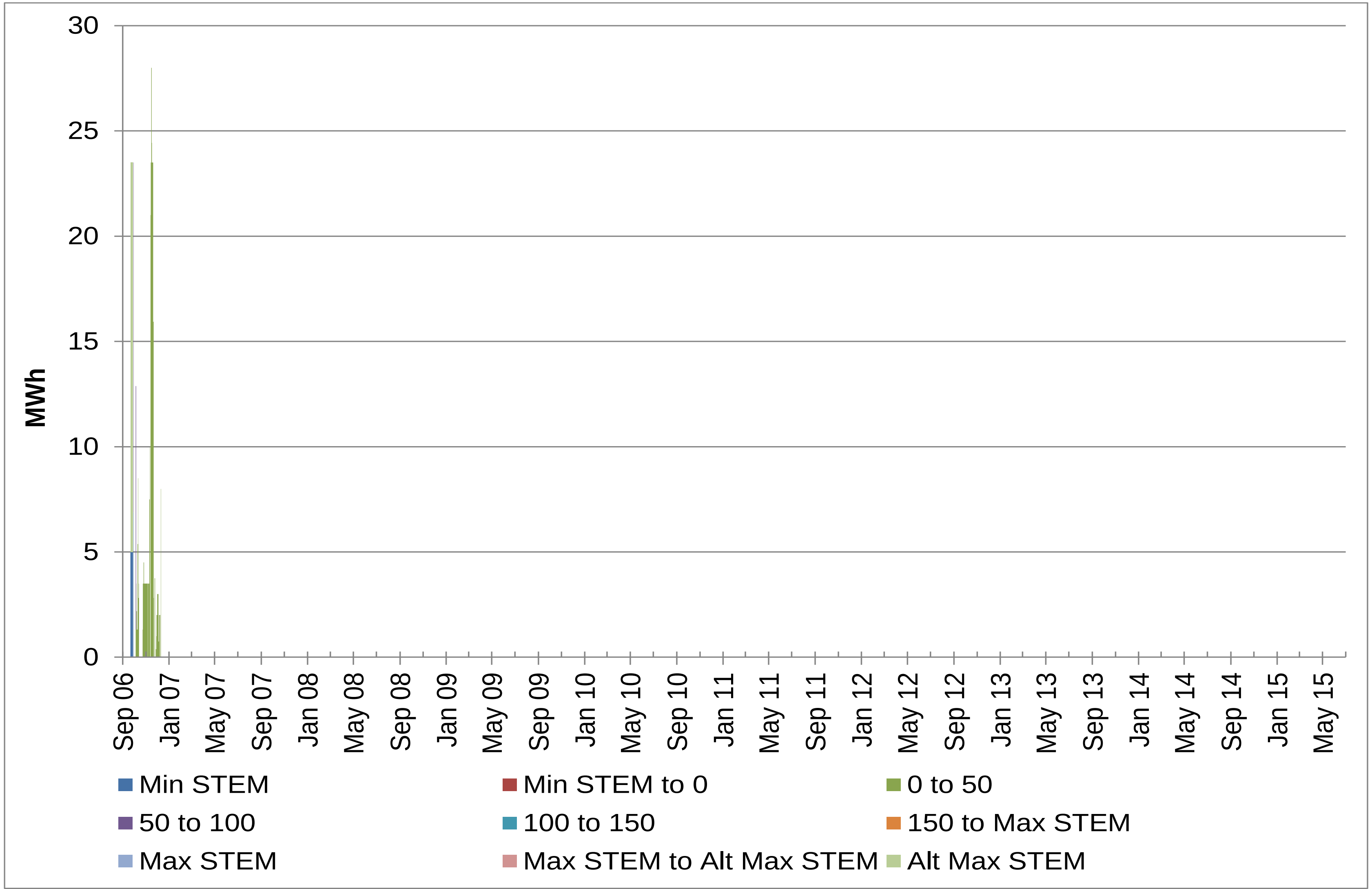


Figure 50 Alinta's daily average STEM Bids (cumulative MWh per Trading Interval)

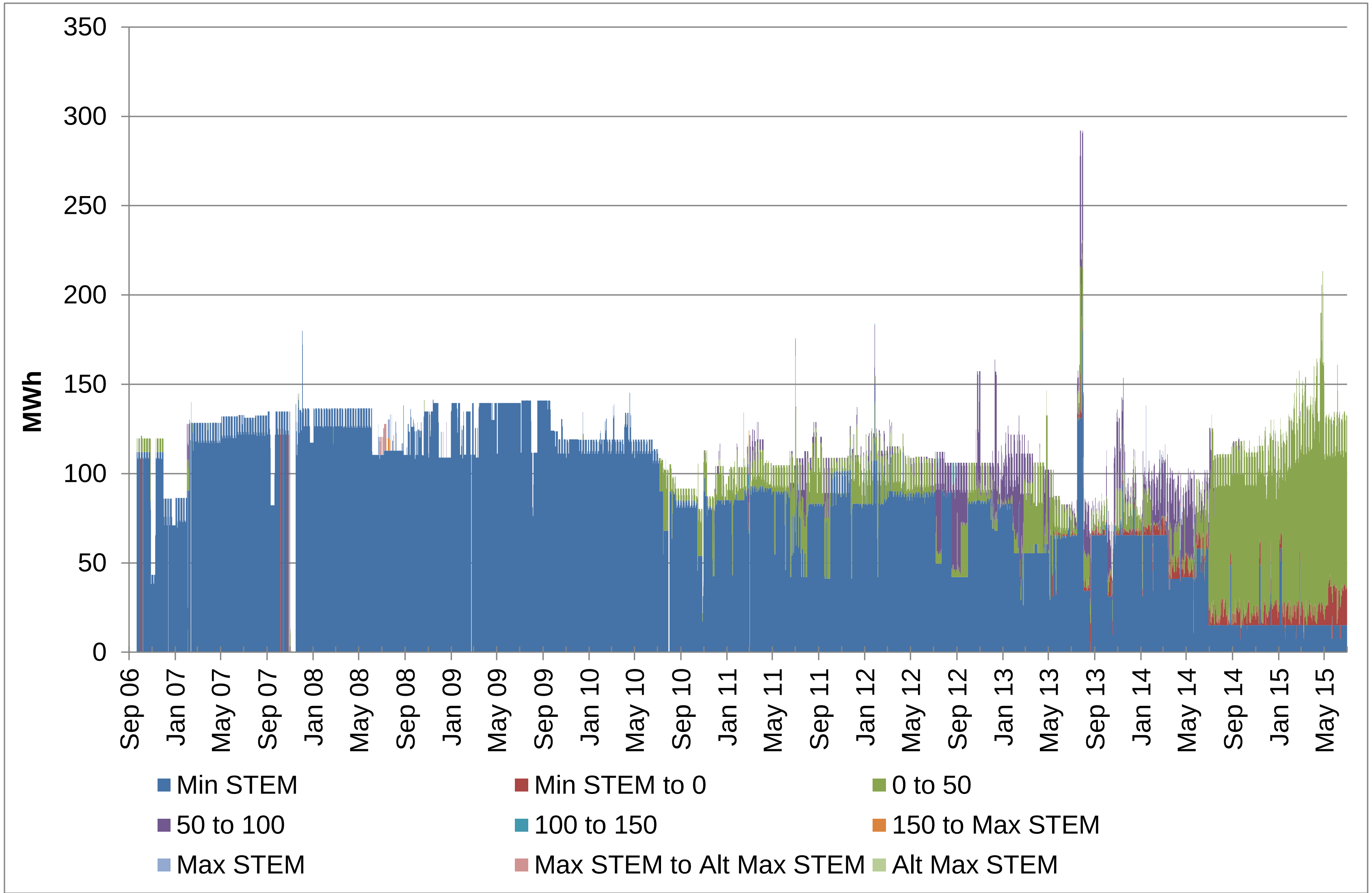


Figure 51 ERM Power's daily average STEM Bids (cumulative MWh per Trading Interval)

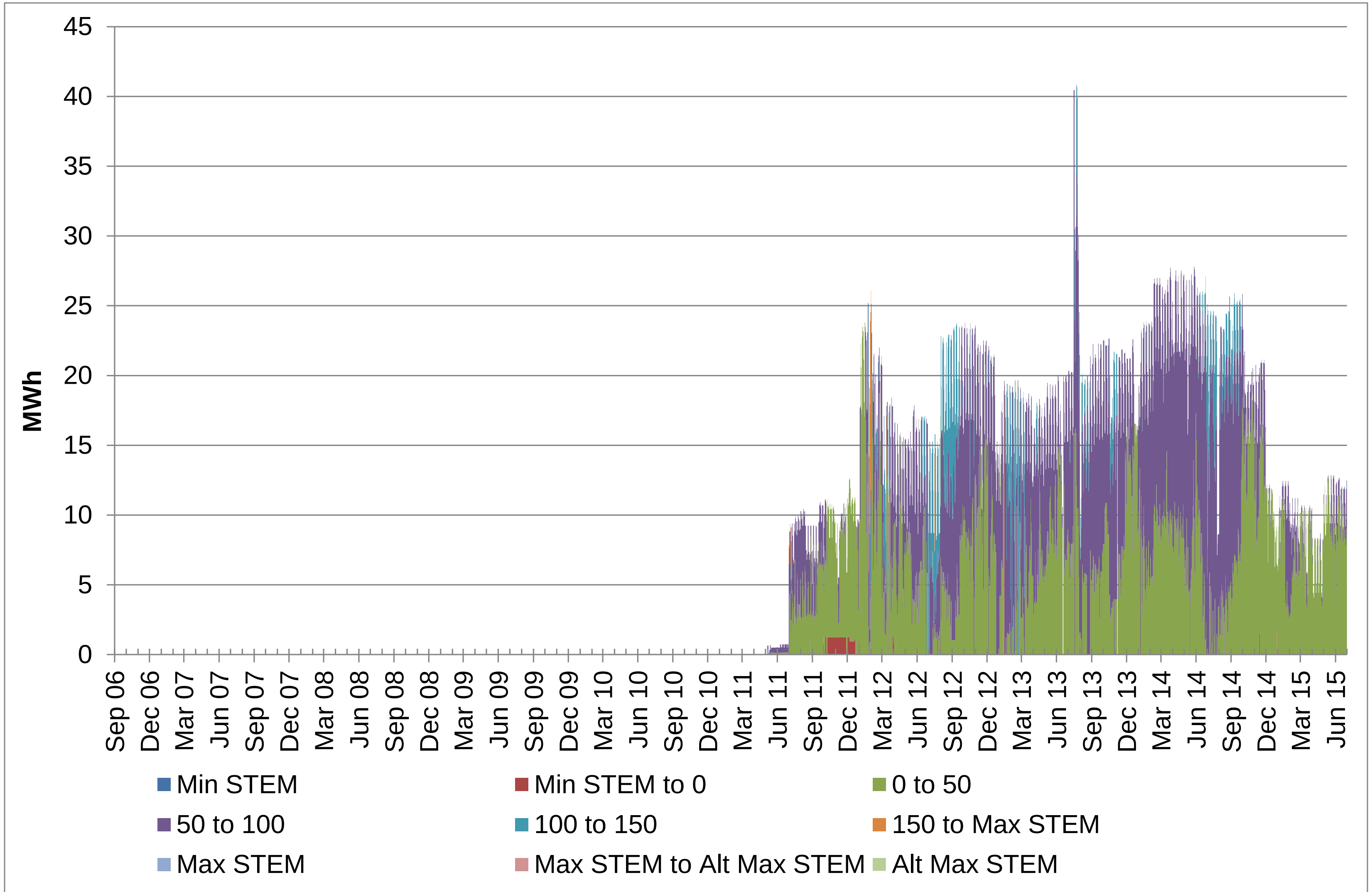


Figure 52 Goldfields Power's daily average STEM Bids (cumulative MWh per Trading Interval)

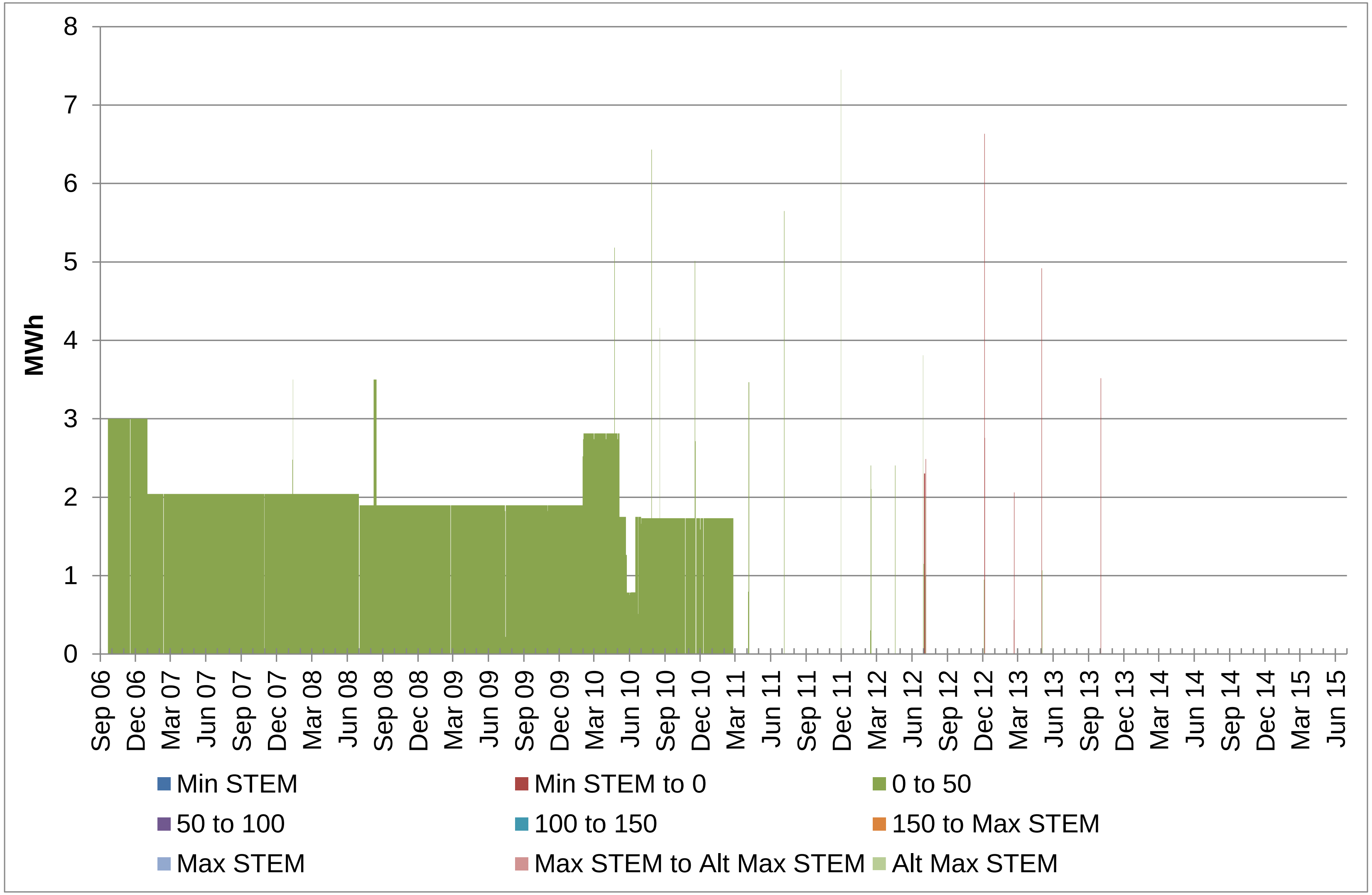


Figure 53 Griffin Power's daily average STEM Bids (cumulative MWh per Trading Interval)

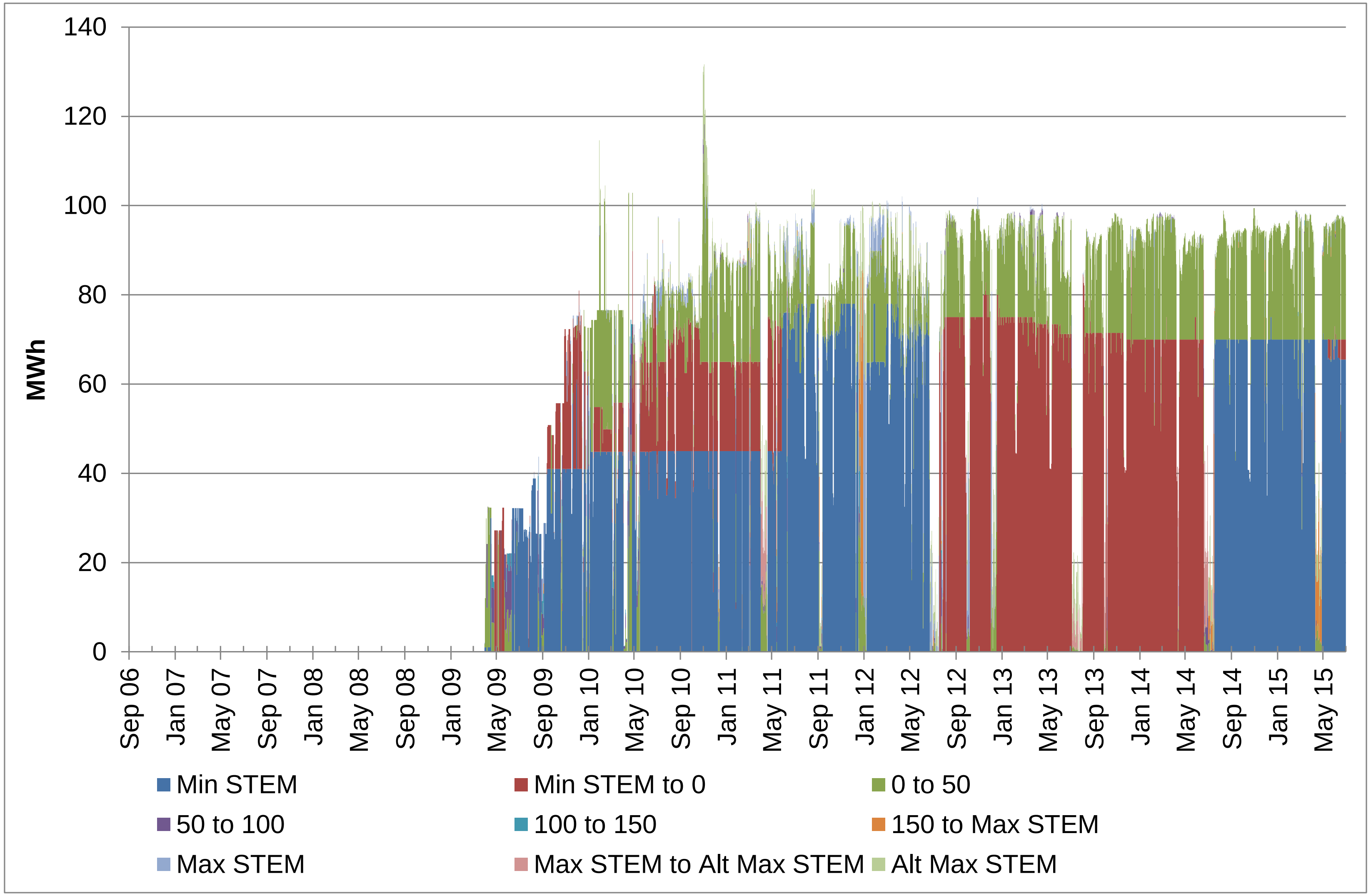


Figure 54 Griffin Power 2's daily average STEM Bids (cumulative MWh per Trading Interval)

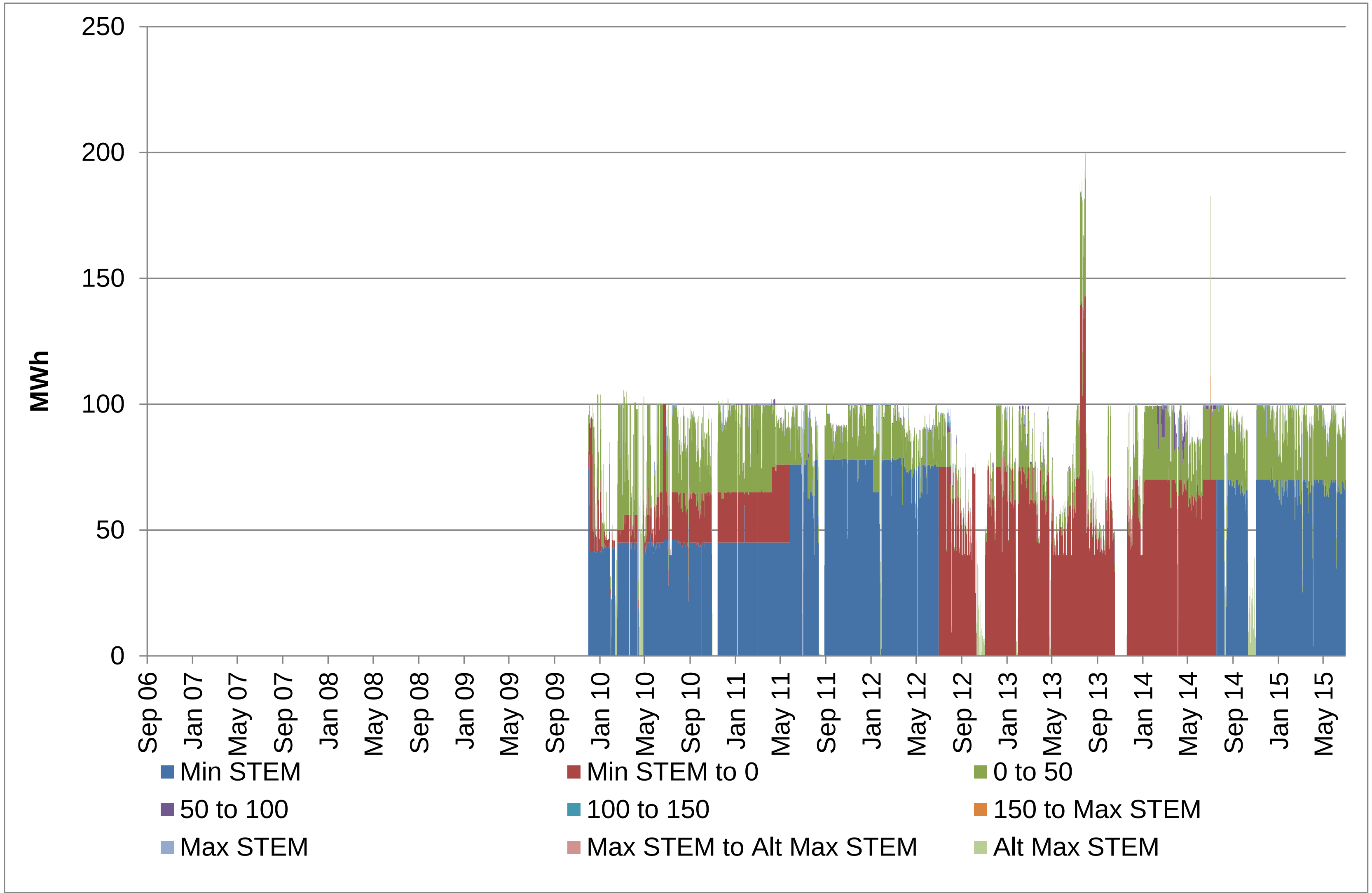


Figure 55 Karara's daily average STEM Bids (cumulative MWh per Trading Interval)

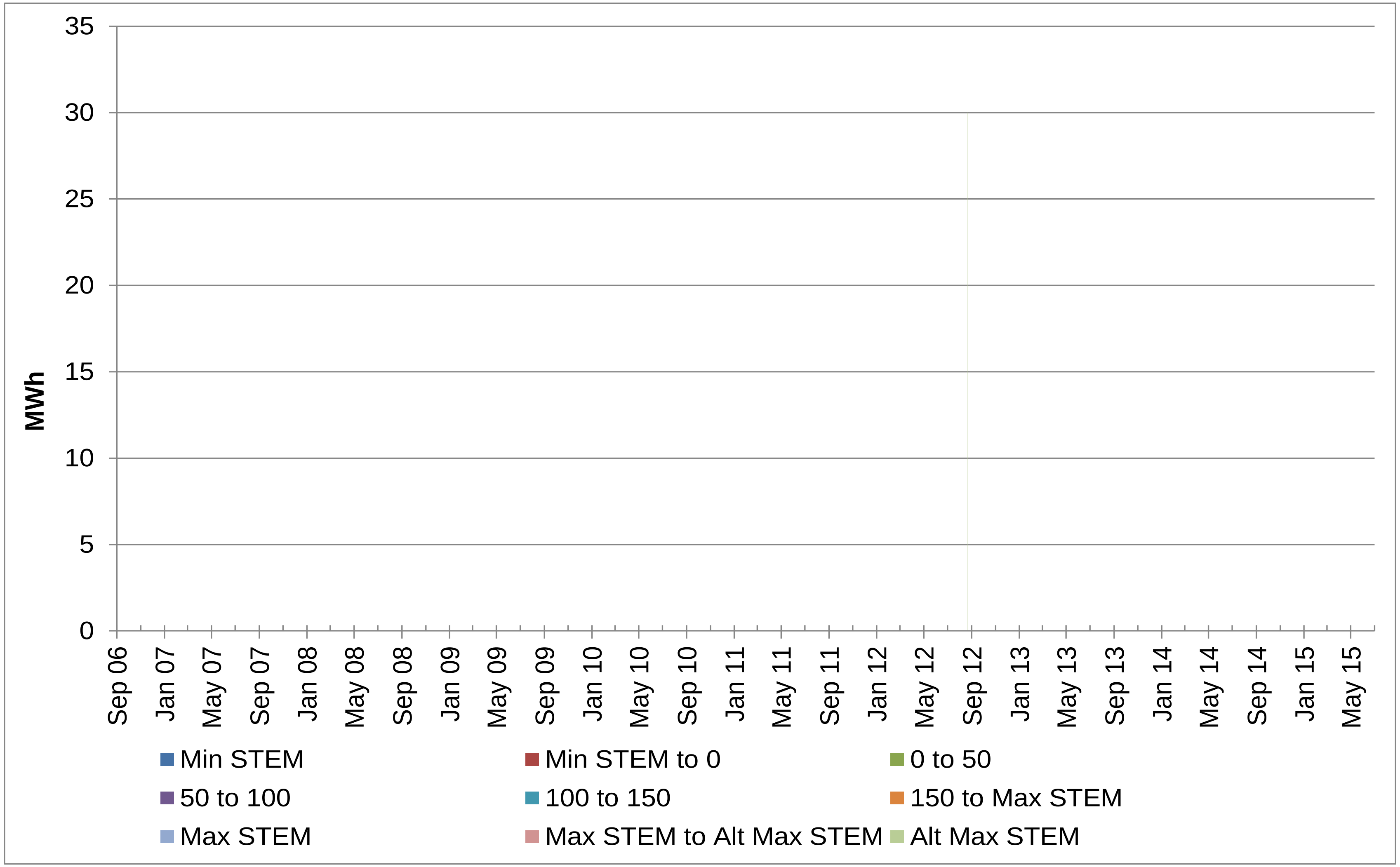


Figure 56 Landfill Gas and Power's daily average STEM Bids (cumulative MWh per Trading Interval)

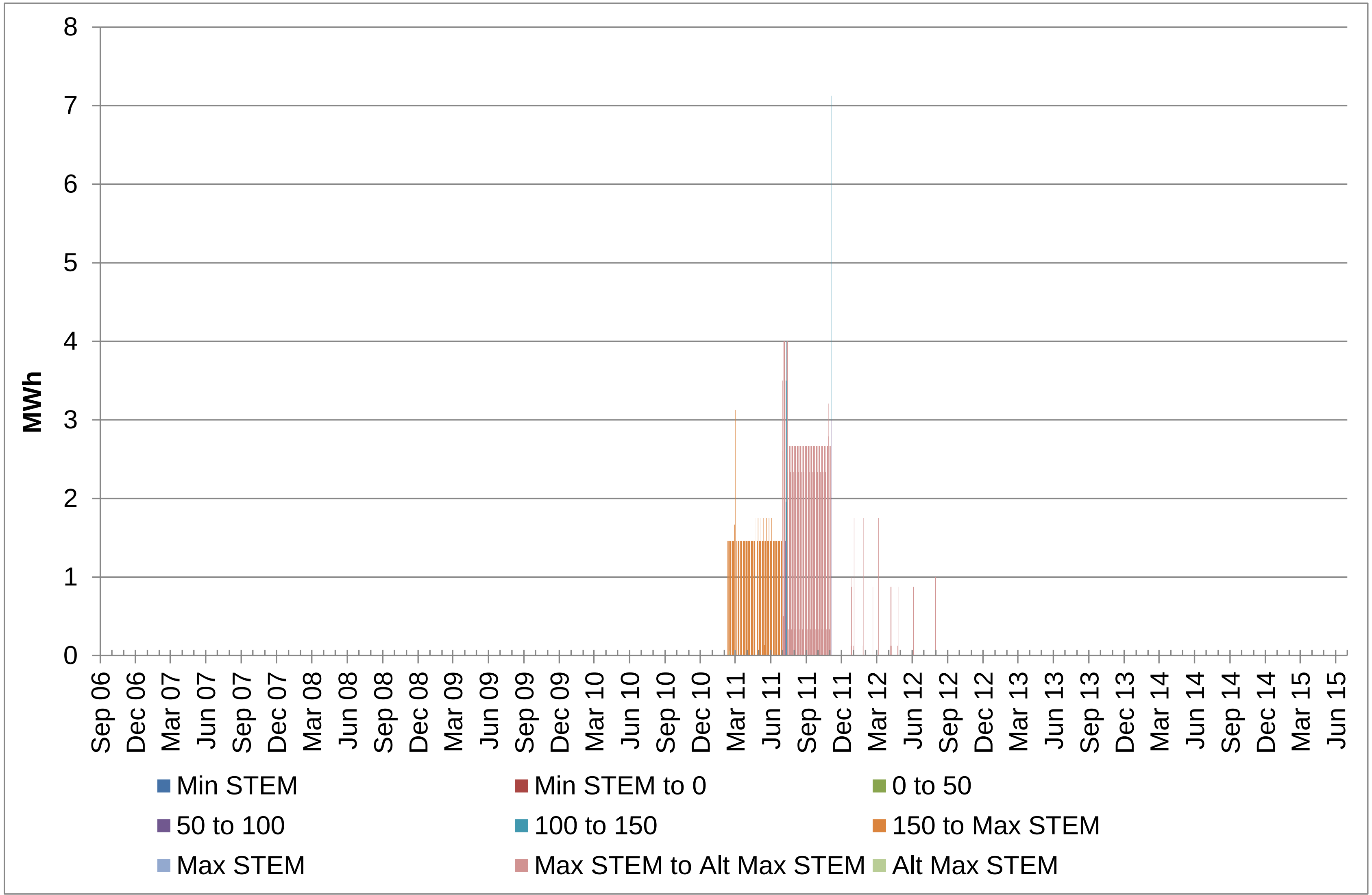


Figure 57 NewGen Power Kwinana's daily average STEM Bids (cumulative MWh per Trading Interval)

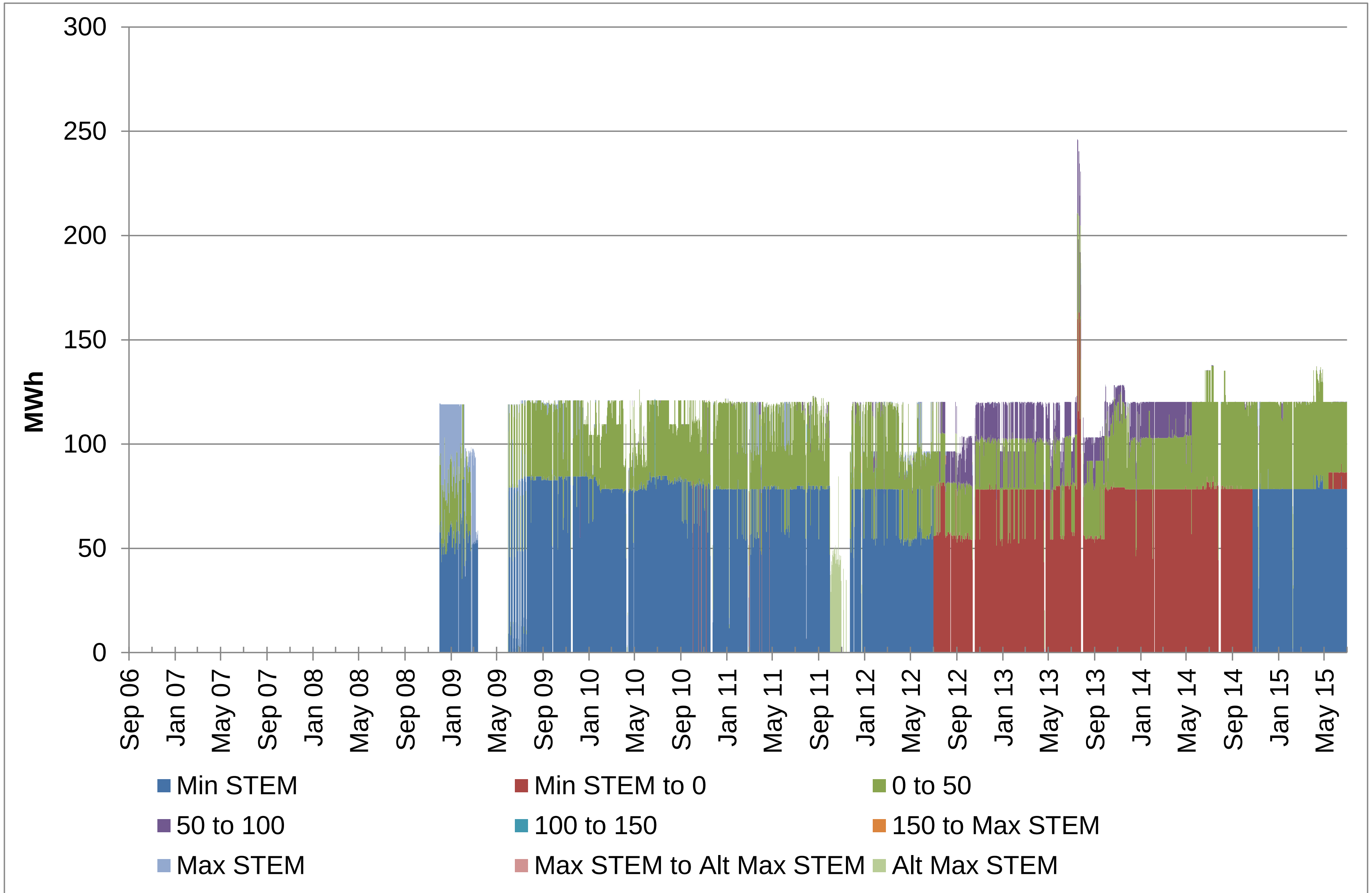


Figure 58 NewGen Neerabup's daily average STEM Bids (cumulative MWh per Trading Interval)

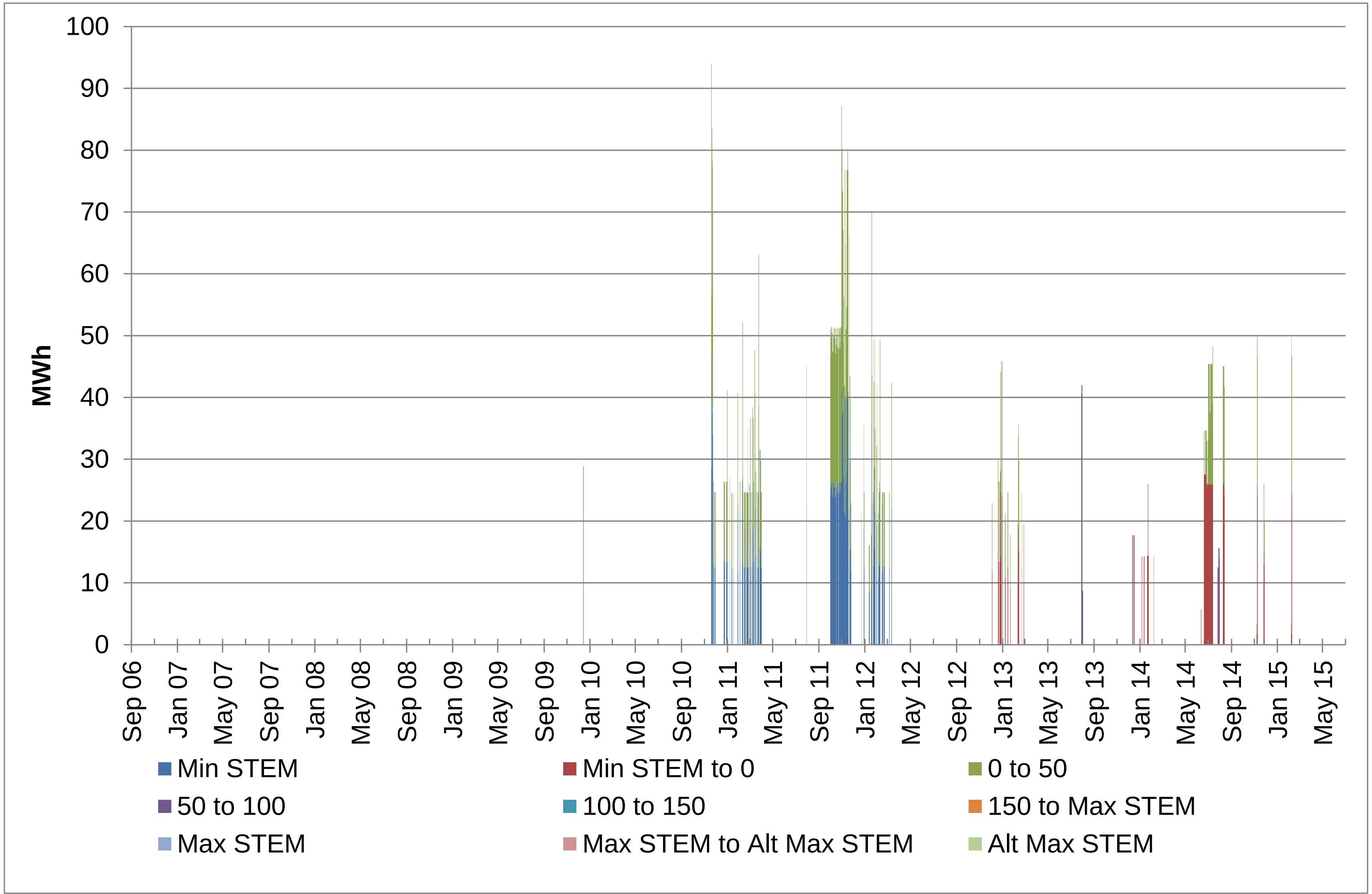


Figure 59 **Perth Energy's daily average STEM Bids (cumulative MWh per Trading Interval)**

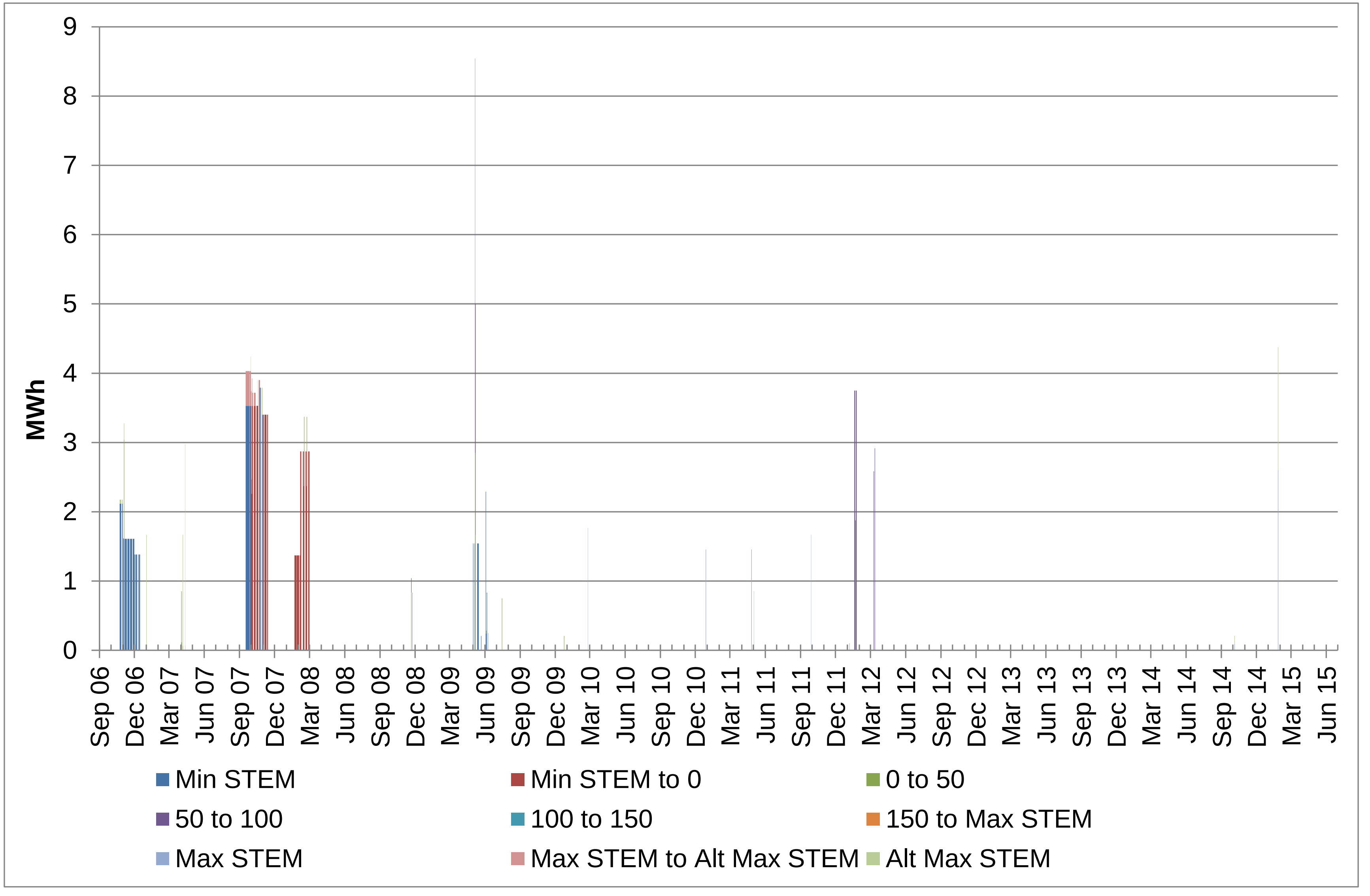


Figure 60 Southern Cross Energy's daily average STEM Bids (cumulative MWh per Trading Interval)

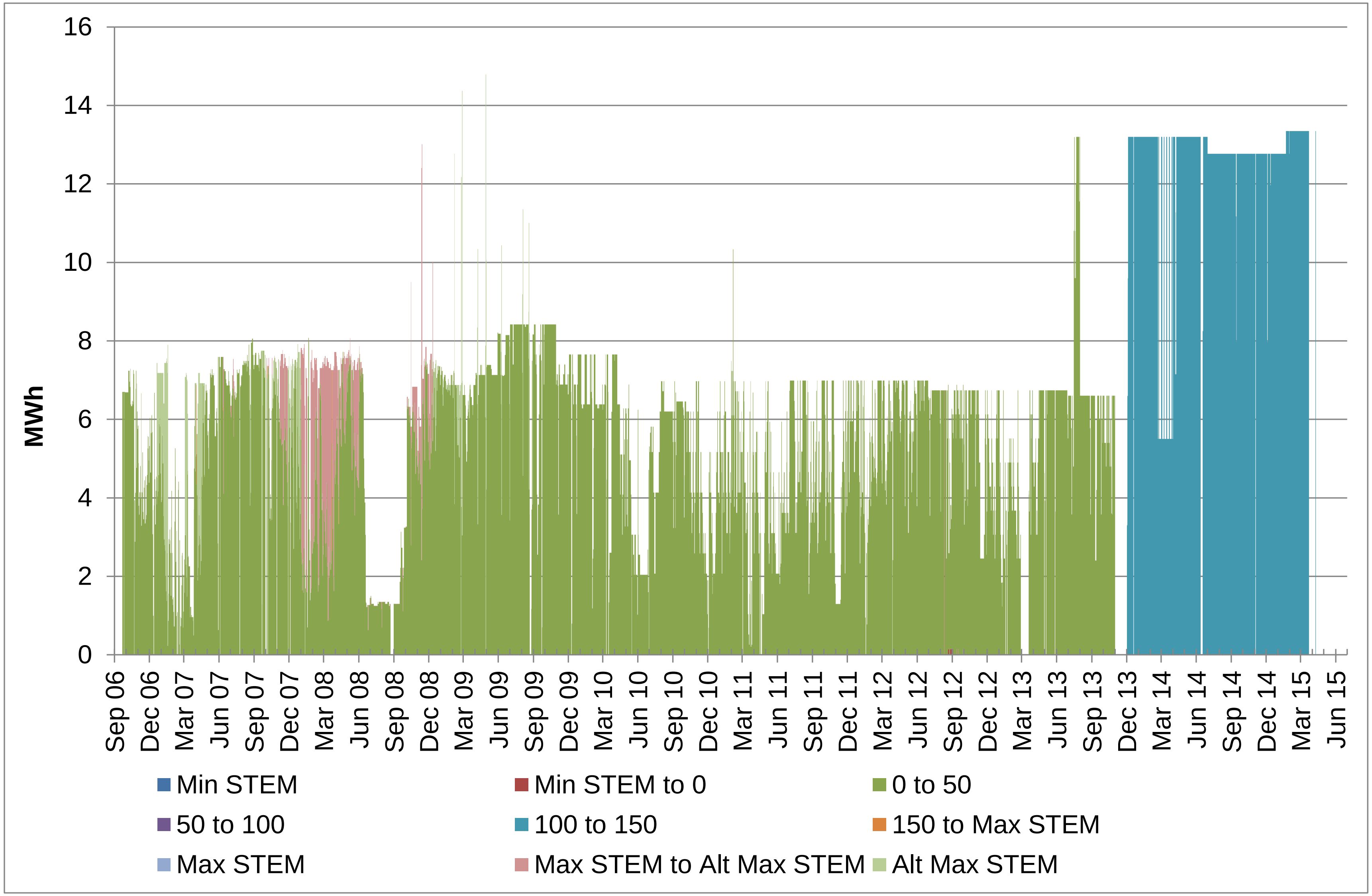


Figure 61 Tiwest's daily average STEM Bids (cumulative MWh per Trading Interval)

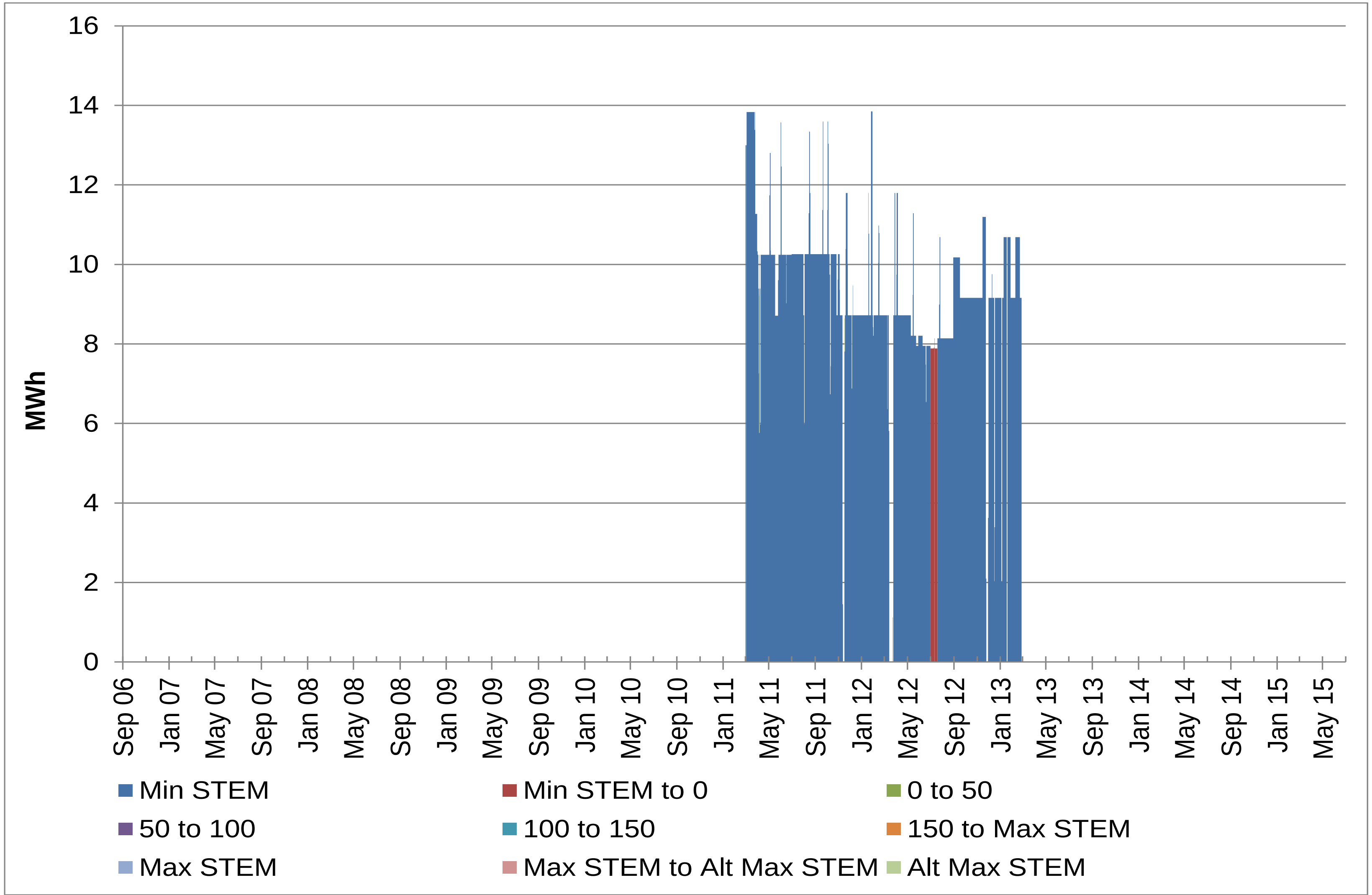


Figure 62 Western Energy's daily average STEM Bids (cumulative MWh per Trading Interval)

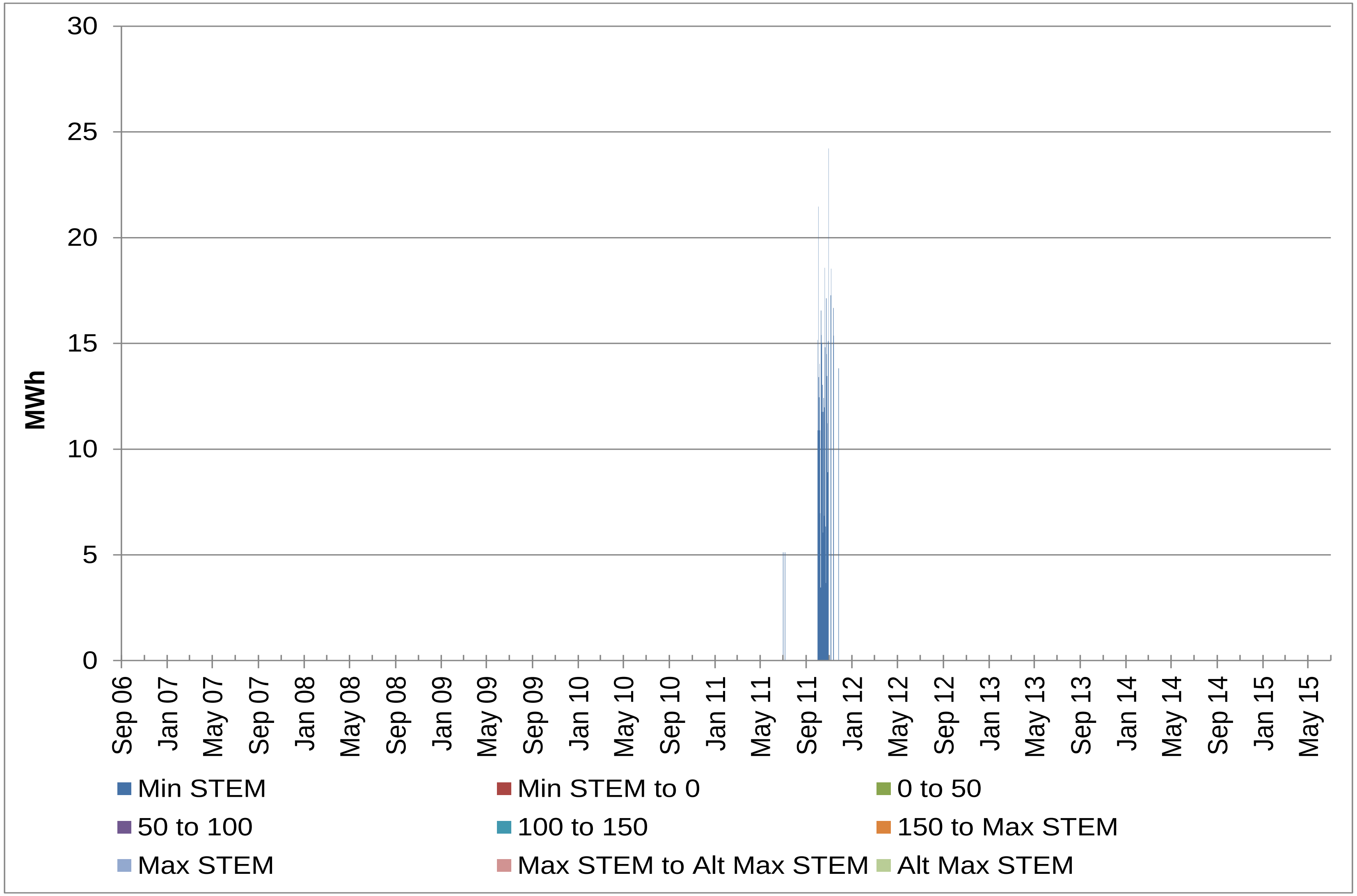


Figure 63 Synergy's daily average STEM Bids (cumulative MWh per Trading Interval)

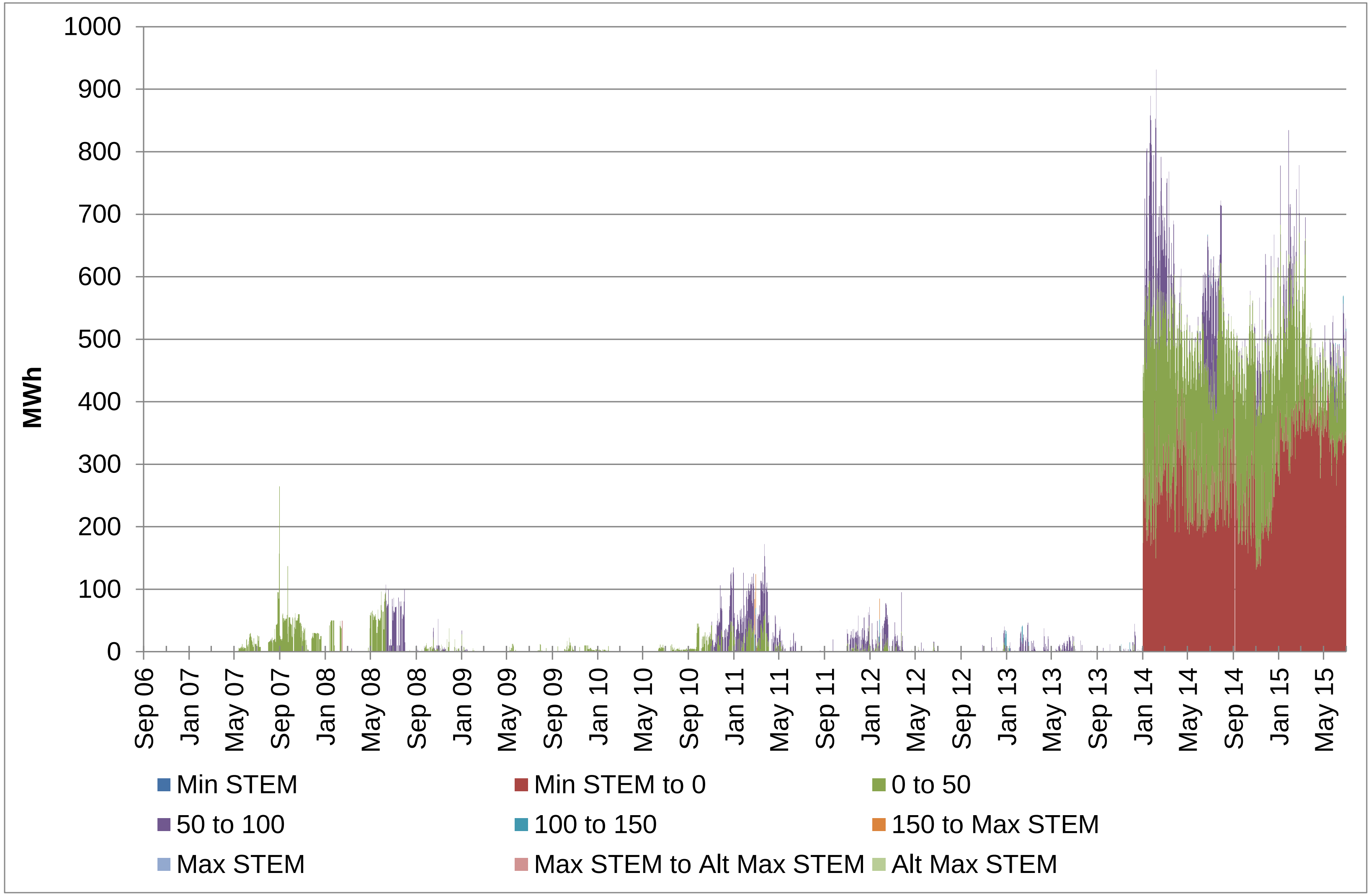


Figure 64 Verve Energy's daily average STEM Bids (cumulative MWh per Trading Interval)

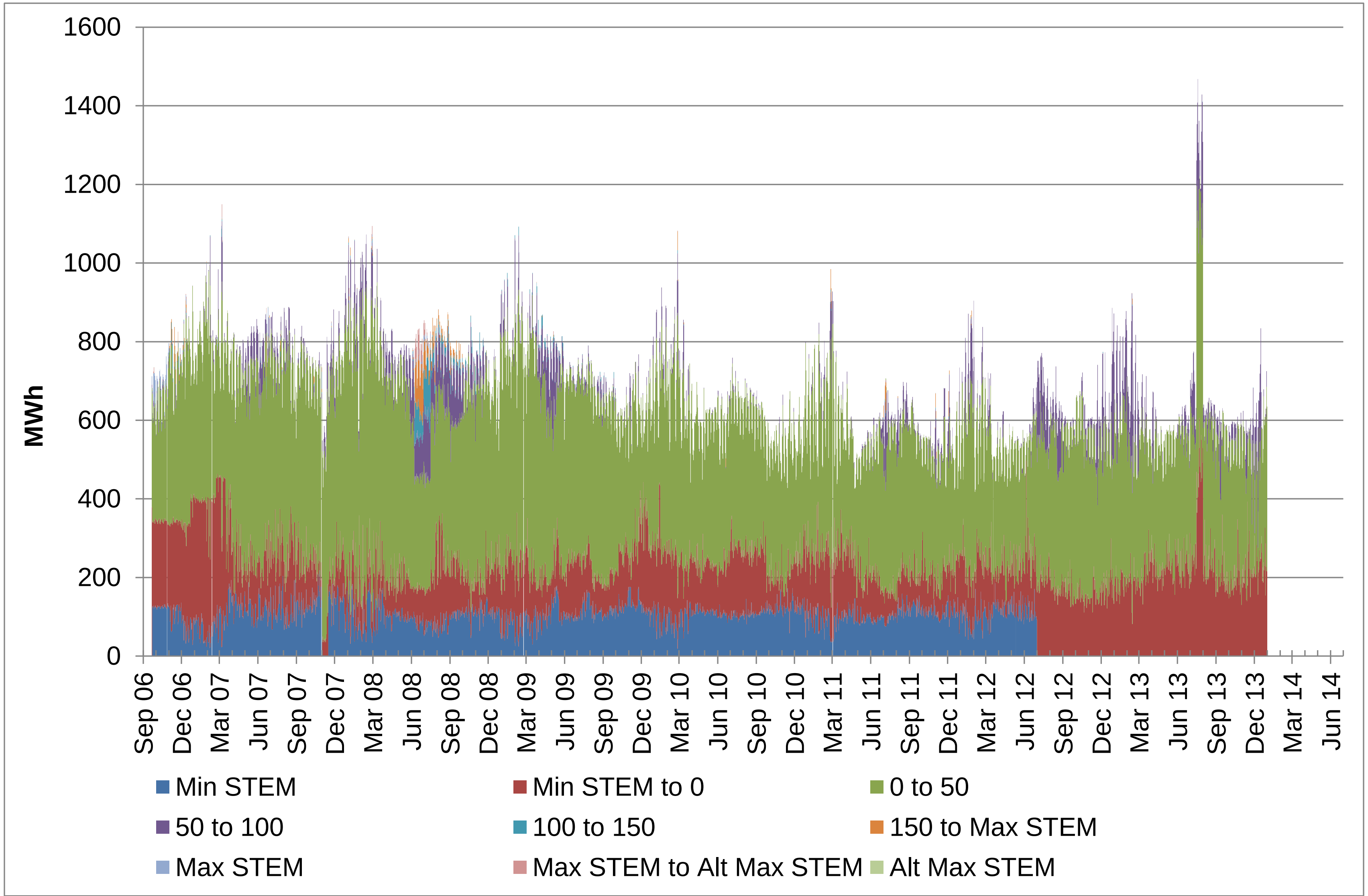


Figure 65 Vinalco's daily average STEM Bids (cumulative MWh per Trading Interval)

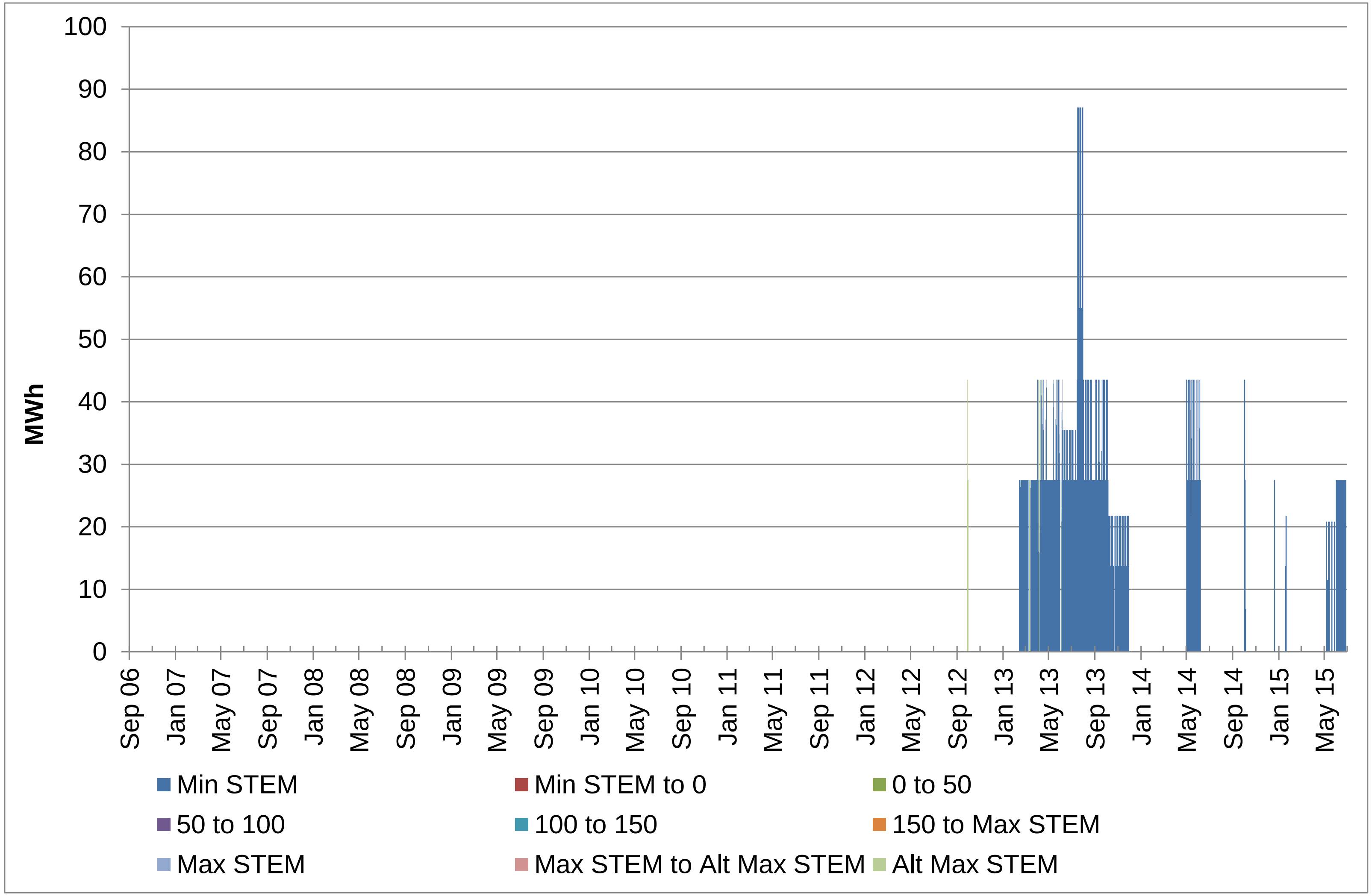
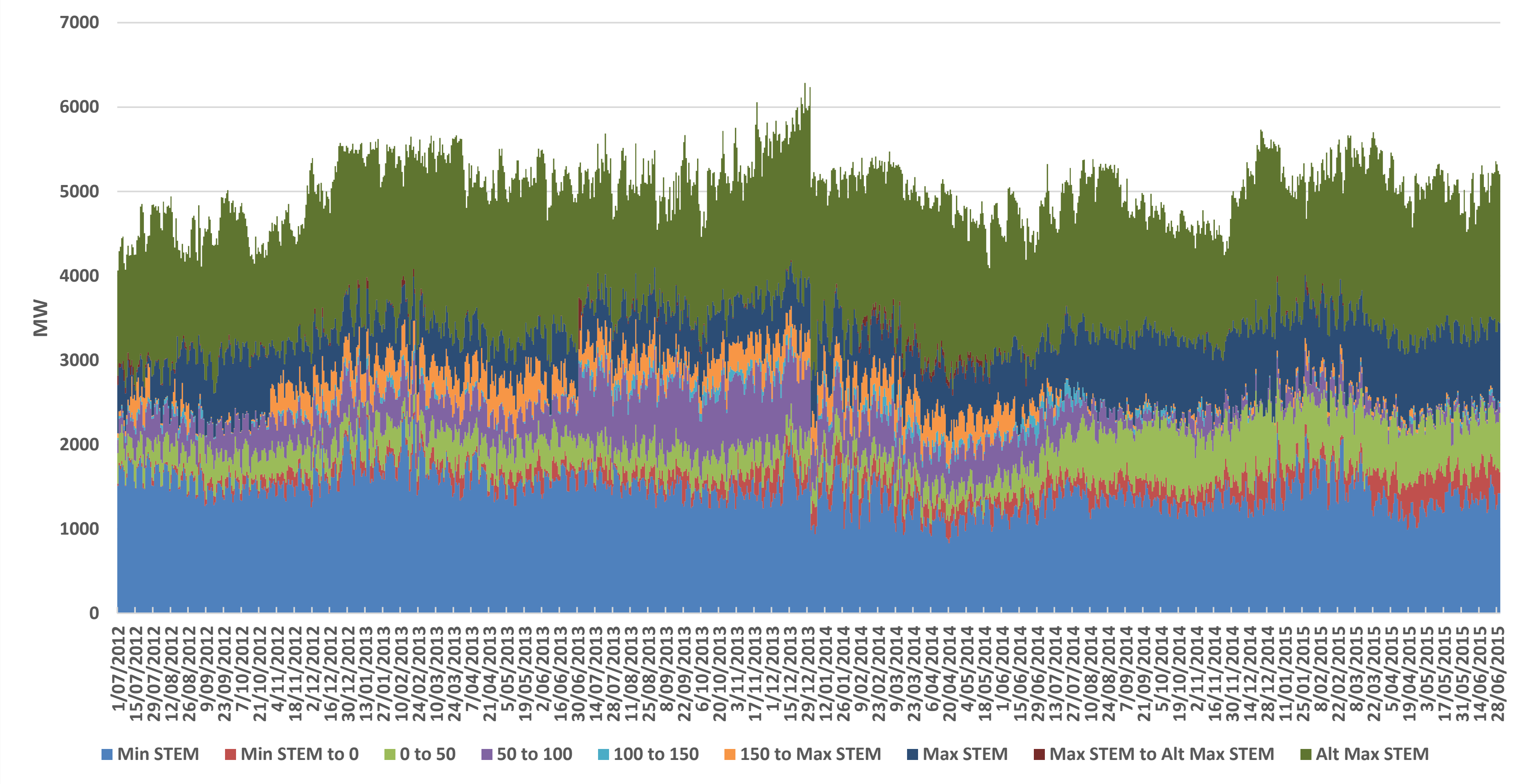


Figure 66 Daily average Balancing Submissions [28] (cumulative MWh per Trading Interval)



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[28] Capacity volumes at Alt Max STEM Price also include ramp-rate constrained volumes

Figure 67 IPP Capacity available through Balancing (cumulative MWh per Trading Interval)

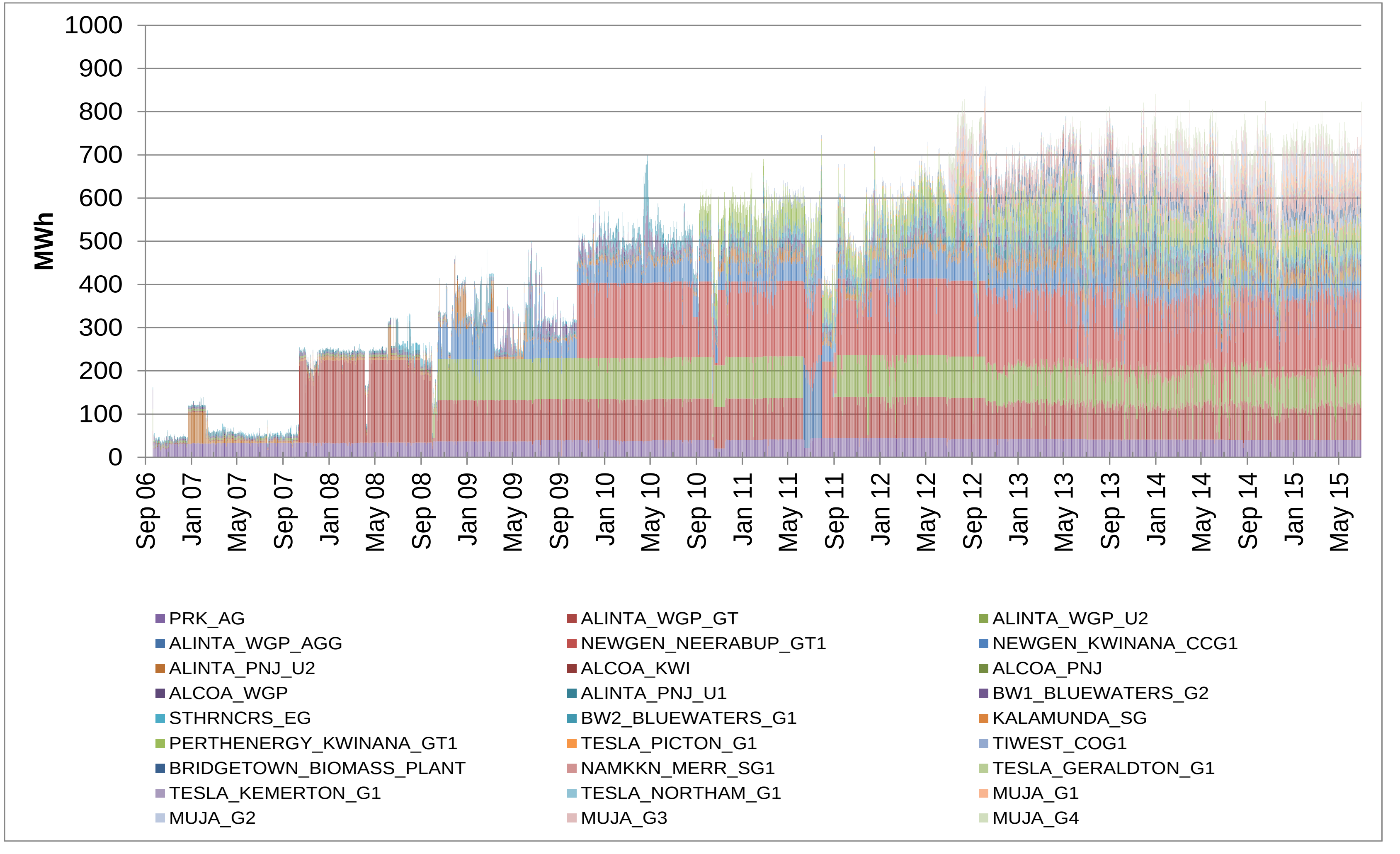

Table 8 Registered Market Generators and Market Customers

	3 October 2011	10 December 2012	30 September 2013	1 October 2014	1 October 2015
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 2 Pty Ltd	Blair Fox Pty Ltd	Blair Fox Pty Ltd	Blair Fox Pty Ltd	Blair Fox Pty Ltd
	Griffin Power Pty Ltd	Griffin Power 2 Pty Ltd	Clear Energy Pty Ltd	Clear Energy Pty Ltd	Clear Energy Pty Ltd
	Landfill Gas and Power Pty Ltd	Griffin Power Pty Ltd	Griffin Power 2 Pty Ltd	Griffin Power 2 Pty Ltd	Griffin Power 2 Pty Ltd
	Metro Power Company Pty Ltd	Landfill Gas and Power Pty Ltd	Griffin Power Pty Ltd	Griffin Power Pty Ltd	Griffin Power Pty Ltd
	Perth Energy Pty Ltd	Metro Power Company Pty Ltd	Landfill Gas and Power Pty Ltd	Landfill Gas and Power Pty Ltd	Landfill Gas and Power Pty Ltd
	Southern Cross Energy	Perth Energy Pty Ltd	Metro Power Company Pty Ltd	Metro Power Company Pty Ltd	Metro Power Company Pty Ltd
	Tiwest	Southern Cross Energy	Perth Energy Pty Ltd	Perth Energy Pty Ltd	Perth Energy Pty Ltd
	Verve Energy	Tiwest	Southern Cross Energy	Southern Cross Energy	Southern Cross Energy
		Verve Energy	Tiwest	Tiwest	Tiwest
			Verve Energy	Synergy	Synergy
Market Generators (only)	Advanced Energy Resources	Advanced Energy Resources	Advanced Energy Resources	Advanced Energy Resources	Advanced Energy Resources
	Biogen	Biogen	Biogass Pty Ltd	Biogass Pty Ltd	Biogass Pty Ltd
	Blair Fox Pty Ltd	Collgar Wind Farm	Biogen	Biogen	Collgar Wind Farm
	Collgar Wind Farm	Coolimba Power Pty Ltd	Collgar Wind Farm	Collgar Wind Farm	CleanTech Energy Pty Ltd
	Coolimba Power Pty Ltd	Denmark Community Windfarm Ltd	Coolimba Power Pty Ltd	Coolimba Power Pty Ltd	Coolimba Power Pty Ltd
	EDWF Manager Pty Ltd	EDWF Manager Pty Ltd	Denmark Community Windfarm Ltd	Denmark Community Windfarm Ltd	Denmark Community Windfarm Ltd
	Eneabba Energy Pty Ltd	Eneabba Gas Limited	EDWF Manager Pty Ltd	EDWF Manager Pty Ltd	EDWF Manager Pty Ltd
	Eneabba Gas Limited	Eneabba Energy Pty Ltd	EMRC	EMRC	EMRC
	Goldfields Power Pty Ltd	Genthrust Pty Ltd	Eneabba Gas Limited	Eneabba Gas Limited	Eneabba Gas Limited
	McNabb Plantation Alliance Pty Ltd	Goldfields Power Pty Ltd	Eneabba Energy Pty Ltd	Eneabba Energy Pty Ltd	Eneabba Energy Pty Ltd

3 October 2011	10 December 2012	30 September 2013	1 October 2014	1 October 2015
Merredin Energy	Greenough River	Genthrust Pty Ltd	Genthrust Pty Ltd	Genthrust Pty Ltd
Mount Herron Engineering Pty Ltd	Merredin Energy	Goldfields Power Pty Ltd	Goldfields Power Pty Ltd	Goldfields Power Pty Ltd
Mt.Barker Power Company Pty Ltd	Moonies Hill Energy	Greenough River	Greenough River	Greenough River
Mumbida Wind Farm Pty Ltd	Mount Herron Engineering Pty Ltd	Merredin Energy	Merredin Energy	Merredin Energy
Namarkkon Pty Ltd	Mt.Barker Power Company Pty Ltd	Moonies Hill Energy	Moonies Hill Energy	Moonies Hill Energy Ltd
NewGen Neerabup Partnership	McNabb Plantation Alliance Pty Ltd	Mount Herron Engineering Pty Ltd	Mount Herron Engineering Pty Ltd	Mt.Barker Power Company Pty
NewGen Neerabup Pty Ltd	Mumbida Wind Farm Pty Ltd	Mt.Barker Power Company Pty Ltd	Mt.Barker Power Company Pty Ltd	Mount Herron Engineering Pty Ltd
NewGen Power Kwinana Pty Ltd	NewGen Power Kwinana Pty Ltd	McNabb Plantation Alliance Pty Ltd	McNabb Plantation Alliance Pty Ltd	Mumbida Wind Farm Pty Ltd
SkyFarming Pty Ltd	NewGen Neerabup Partnership	Mumbida Wind Farm Pty Ltd	Mumbida Wind Farm Pty Ltd	NewGen Power Kwinana Pty Ltd
Tesla Corporation Management Pty Ltd	NewGen Neerabup Pty Ltd	NewGen Power Kwinana Pty Ltd	NewGen Power Kwinana Pty Ltd	NewGen Neerabup Partnership
Tesla Corporation Pty Ltd	SkyFarming Pty Ltd	NewGen Neerabup Partnership	NewGen Neerabup Partnership	NewGen Neerabup Pty Ltd
Tesla Geraldton Pty Ltd	Tesla Corporation Pty Ltd	NewGen Neerabup Pty Ltd	NewGen Neerabup Pty Ltd	Phoenix Energy
Tesla Holdings	Tesla Geraldton Pty Ltd	Phoenix Energy	Phoenix Energy	SkyFarming Pty Ltd
Tesla Kemerton Pty Ltd	Tesla Holdings	SkyFarming Pty Ltd	SkyFarming Pty Ltd	Tesla Corporation Pty Ltd
Tesla Northam Pty Ltd	Tesla Kemerton Pty Ltd	Tesla Corporation Pty Ltd	Tesla Corporation Pty Ltd	Tesla Geraldton Pty Ltd
Vinalco Energy Pty Ltd	Tesla Corporation Management Pty Ltd	Tesla Geraldton Pty Ltd	Tesla Geraldton Pty Ltd	Tesla Holdings
Walkaway Wind Power Pty Ltd	Tesla Northam Pty Ltd	Tesla Holdings	Tesla Holdings	Tesla Kemerton Pty Ltd
Wambo Power Ventures Pty Ltd	UON Pty Ltd	Tesla Kemerton Pty Ltd	Tesla Kemerton Pty Ltd	Tesla Corporation Management Pty Ltd

	3 October 2011	10 December 2012	30 September 2013	1 October 2014	1 October 2015
	Waste Gas Resources Pty Ltd	Vinalco Energy Pty Ltd	Tesla Corporation Management Pty Ltd	Tesla Corporation Management Pty Ltd	Tesla Northam Pty Ltd
	Western Australia Biomass Pty Ltd	Western Australia Biomass Pty Ltd	Tesla Northam Pty Ltd	Tesla Northam Pty Ltd	UON Pty Ltd
	Western Energy Pty Ltd	Walkaway Wind Power Pty Ltd	UON Pty Ltd	UON Pty Ltd	Vinalco Energy Pty Ltd
		Wambo Power Ventures Pty Ltd	Vinalco Energy Pty Ltd	Vinalco Energy Pty Ltd	Walkaway Wind Power Pty Ltd
		Western Energy Pty Ltd	Wambo Power Western Australia Biomass Pty Ltd	Wambo Power Western Australia Biomass Pty Ltd	Western Australia Biomass Pty Ltd
		Waste Gas Resources Pty Ltd	Walkaway Wind Power Pty Ltd	Walkaway Wind Power Pty Ltd	Western Energy Pty Ltd
			Western Energy Pty Ltd	Western Energy Pty Ltd	Waste Gas Resources Pty Ltd
			Waste Gas Resources Pty Ltd	Waste Gas Resources Pty Ltd	
Market Customers (only)	Amanda Australia Pty Ltd	Amanda Australia Pty Ltd	AER Retail Pty Ltd	A Star Electricity	Waste Gas Resources Pty Ltd
	Barrick (Kanowna) Limited	Clear Energy Pty Ltd	Amanda Australia Pty Ltd	AER Retail Pty Ltd	AER Retail Pty Ltd
	Clear Energy Pty Ltd	DMT energy	Cockburn Cement Ltd	Amanda Australia Pty Ltd	Amanda Australia Pty Ltd
	DMT Energy	EnerNOC Australia Pty Ltd	DMT energy	Amanda Energy Pty Ltd	Amanda Energy Pty Ltd
	Energy Response Pty Ltd	Energy Response Pty Ltd	EnerNOC Australia Pty Ltd	Blue Star Energy Pty Ltd	Barrick (Kanowna) Limited
	EnerNOC Australia Pty Ltd	ERM Power Retail Pty Ltd	Energy Response Pty Ltd	Community Electricity	Blue Star Energy Pty Ltd
	ERM Power Retail Pty Ltd	Focus Operations	ERM Power Retail Pty Ltd	Cockburn Cement Ltd	Broadcast Australia Pty Ltd
	Karara Energy Pty Ltd	HBJ Minerals Pty Ltd	Focus Operations	DMT energy	Cockburn Cement Ltd
	Newmont Power Pty Ltd	Barrick (Kanowna) Limited	HBJ Minerals Pty Ltd	EnerNOC Australia Pty Ltd	Community Electricity
	Premier Power Sales Pty Ltd	Karara Energy Pty Ltd	Barrick (Kanowna) Limited	Energy Response Pty Ltd	DMT energy
	Synergy	La Mancha Resources	Karara Energy Pty Ltd	ERM Power Retail Pty Ltd	EnerNOC Australia Pty Ltd
	Water Corporation	Newmont Power Pty Ltd	La Mancha Resources	Focus Operations	ERM Power Retail Pty Ltd
		Premier Power Sales Pty Ltd	Newmont Power Pty Ltd	HBJ Minerals Pty Ltd	Focus Operations

3 October 2011	10 December 2012	30 September 2013	1 October 2014	1 October 2015
	Water Corporation	Premier Power Sales Pty Ltd	Barrick (Kanowna) Limited	HBJ Minerals Pty Ltd
	Synergy	Water Corporation	Karara Energy Pty Ltd	Newmont Power Pty Ltd
		Synergy	La Mancha Resources	Karara Energy Pty Ltd
			Newmont Power Pty Ltd	La Mancha Resources
			Premier Power Sales Pty Ltd	Premier Power Sales Pty Ltd
			Water Corporation	Water Corporation