AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Real-Time Market Insights Forum

28 November 2023

Hosted by the WA Real-Time Market Monitoring Team

Please send questions, feedback and ideas to:
wa.rtm@aemo.com.au

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This material provides general information about the operation of the Western Australian Wholesale Electricity Market (WEM).

The information may be subject to specific exceptions or may not apply to particular circumstances.

To fully understand their obligations, participants should refer to the WEM Rules and WEM Procedures.

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Participants in AEMO discussions **must**:

- Ensure that discussions are limited to the matters contemplated by the agenda for the discussion
- Make independent and unilateral decisions about their commercial positions and approach in relation to the matters under discussion with AEMO
- Immediately and clearly raise an objection with AEMO or the Chair of the meeting if a matter is discussed that the participant is concerned may give rise to competition law risks or a breach of this Protocol.

Participants in AEMO meetings **must not** discuss or agree on the following topics:

- Which customers they will supply or market to
- The price or other terms at which Participants will supply
- Bids or tenders, including the nature of a bid that a Participant intends to make or whether the Participant will participate in the bid
- Which suppliers Participants will acquire from (or the price or other terms on which they acquire goods or services)
- Refusing to supply a person or company access to any products, services or inputs they require.

Under no circumstances must Participants share Competitively Sensitive Information. Competitively Sensitive Information means confidential information relating to a Participant which if disclosed to a competitor could affect its current or future commercial strategies, such as pricing information, customer terms and conditions, supply terms and conditions, sales, marketing or procurement strategies, product development, margins, costs, capacity or production planning.

Agenda

#	Time	Item	Speaker
1	13:00 – 13:10	Record Operational Demand Overview	Damian Mugridge
2	13:10 – 13:20	RTM Submissions Reminder	Douglas Birse
3	13:20 – 13:35	Refund Calculation Overview	Nicholas Nielsen
4	13:35 – 13:55	Investigation: SCED vs Merit Order Comparison	Rachel Tandy
5	13:55 – 14:00	Questions, Feedback, Ideas	Attendees

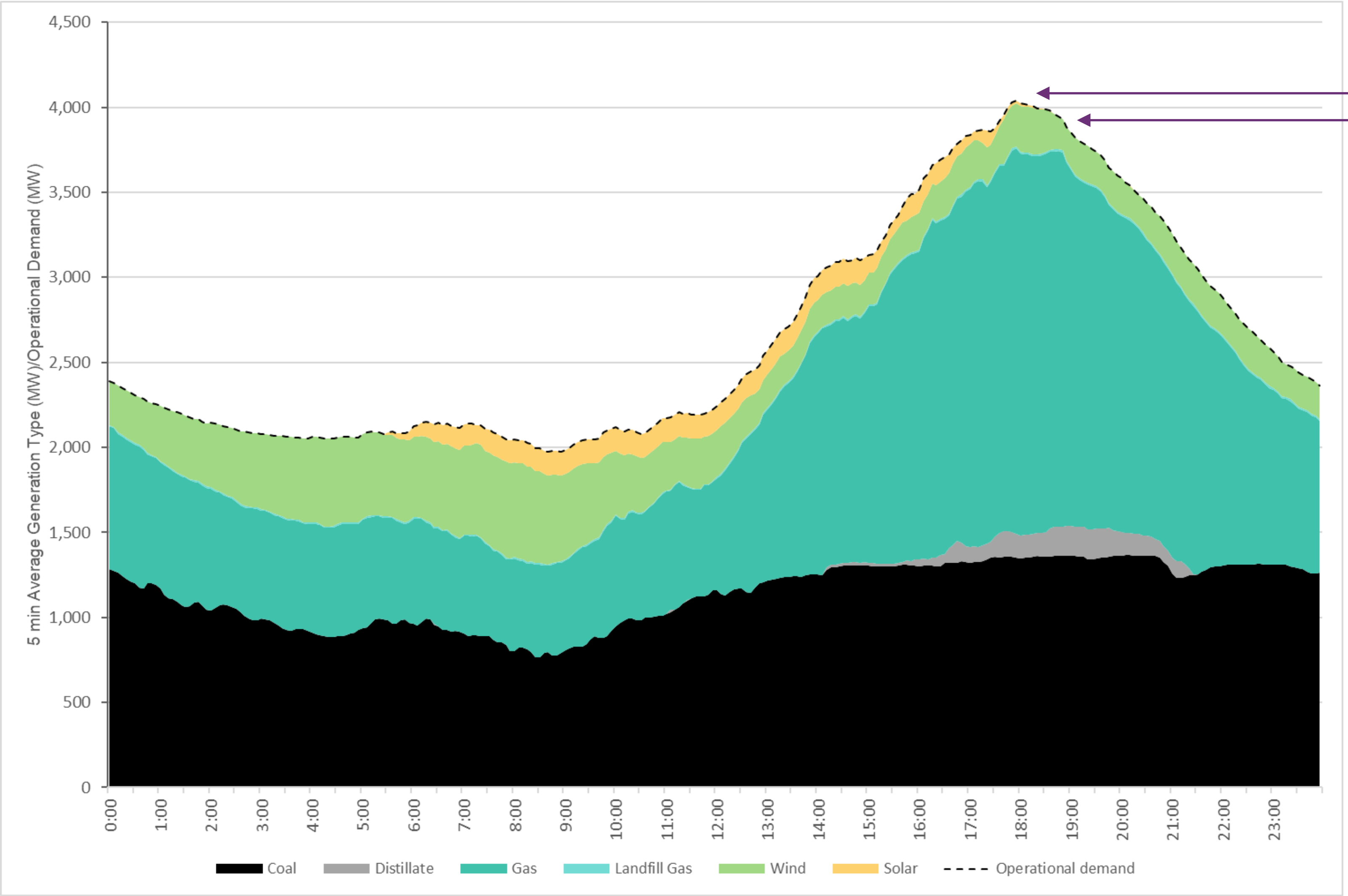
Record Operational Demand Overview

Presenter	Damian Mugridge
Purpose	To provide participants insight to the record demand event.
Driver	Record Operational Demand in the SWIS.
Outcome	-

Evening peak of 23 November

- A new maximum Operational Demand record of 4,041 MW was set over the 17:55 Dispatch Interval.
  - Non-market generators were directed on and GRIFFINP_DSP_01 was dispatched to reduce load by 20 MW over the peak period.
  - Scheduled generation met ~86% of the daily demand with low wind generation meeting only ~9% of demand and
  - On the 17:55 (max demand interval) scheduled generation rose to ~90% of the total.
- 25 consecutive intervals where Energy was at the price cap of $738/MWh which led to three 30-minute Reference Trading Prices (used for settlement) between 18:00 and 19:00 at the price cap.
- NEWGEN_KWINANA_CCG1 tripped at ~18:40 with a loss of 340 MW to 0 MW by 19:00 causing a drop in frequency to 49.49Hz with a 5-minute recovery time.
- 40 consecutive intervals of CR shortfalls from 17:40 with an average shortfall of 88 MW as facilities provided Energy rather than Contingency Raise.
- The control room asked facilities to operate in manual mode for the peak period to enable a higher maximum output.
- Contingency Lower requirement dropped to 0MW in intervals from 17:40 to 18:55.

Summary of 23 November

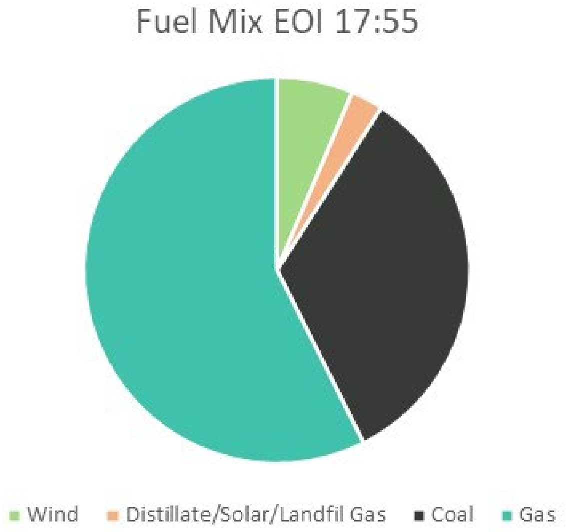


Peak demand within the 17:55 interval

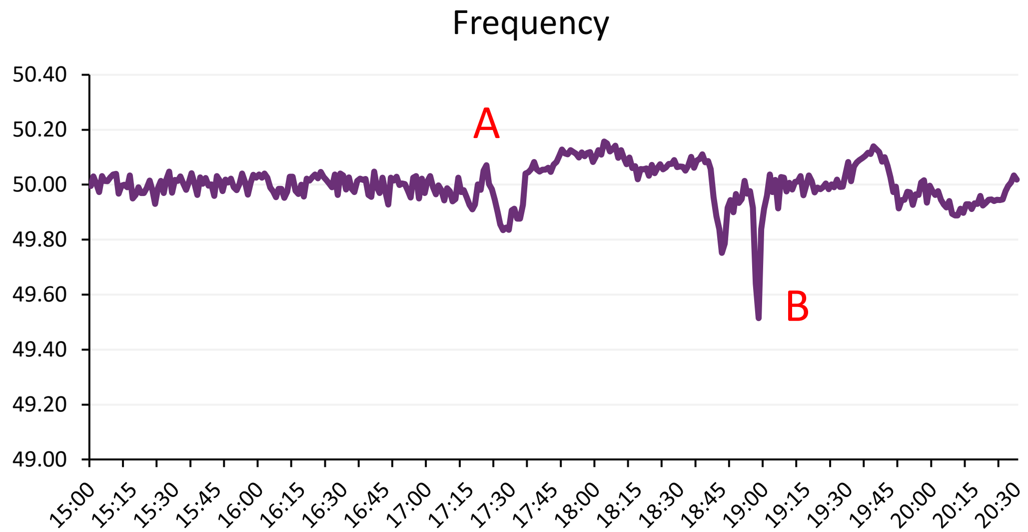
Loss of ~ 340 MW synchronous generation and ~ 100 MW reduction in wind from about 18:43
Frequency dropped to 49.49 Hz, before restoring to the Normal Operating Frequency Band.

- Intense heatwave experienced across the SWIS.
- On the day, temperatures maintained between 37 and 38 degrees from 15:00 – 18:00 resulting in a record demand.
- A number of generator outages were cancelled in advance of the week.
- There was significant engagement and support across the industry.
- Low Reserve Condition notification was sent out.
- All available capacity was dispatched, including that for which an Emergency Operating State was required.

Fuel mix



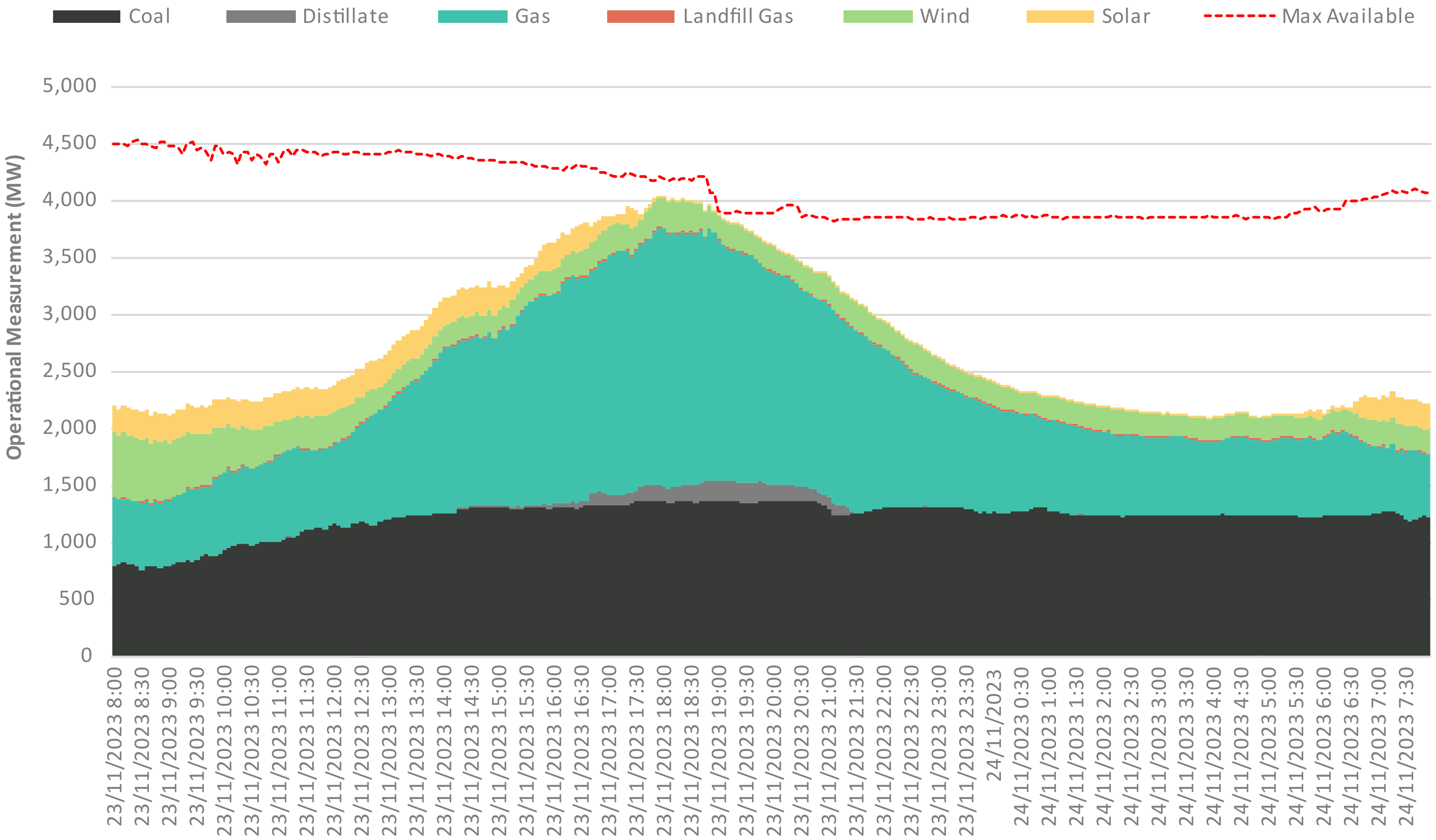
Fuel Type	MW (EOI)	%
Gas	2,317	57.4%
Coal	1,353	33.5%
Wind	257	6.4%
Distillate	82	2.0%
Solar	17	0.4%
Landfill Gas	11	0.3%
Total	**4,037**	



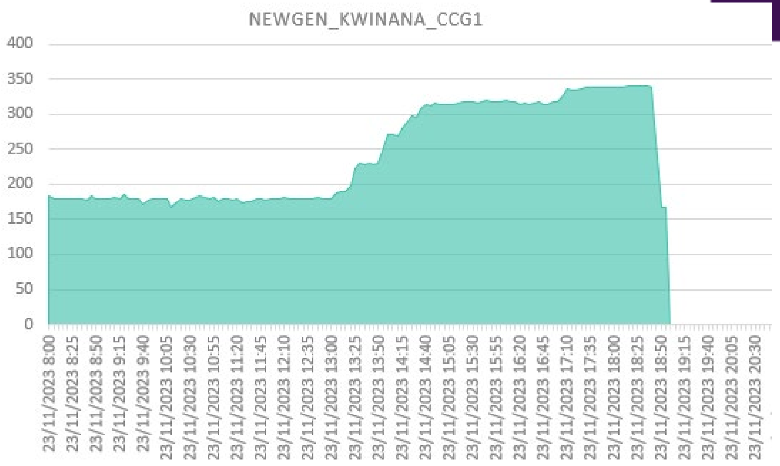
A. AEMO declared Emergency Operating State. After initial variability, the frequency averaged 50.08 Hz between 17:35 and 18:40 as facilities took manual control.

B. NEWGEN_KWINANA_CCG1 tripped at ~18:40 with a loss of 340 MW to 0 MW by 19:00 causing a drop in frequency to 49.49Hz with a 5-minute recovery time

Headroom



Coal
Distillate
Gas
Landfill Gas
Wind
Solar
Max Available
Operational Measurement (MW)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
23/11/2023 8:00
24/11/2023
24/11/2023 7:30



NEWGEN_KWINANA_CCG1
400
350
300
250
200
150
100
50
0
23/11/2023 8:00
23/11/2023 20:30

RTM Submissions Reminder

Presenter	Douglas Birse
Purpose	To clarify and remind Market Participants of the obligations related to RTMS in different time horizons.
Driver	Market Participants not making commitment intentions clear in correct time horizons.
Outcome	Market Participants consistently meet their obligations related to RTMS.

Requirements to Submit Capacity Week Ahead

7.4.2. Subject to clause 7.4.37, a Market Participant must make reasonable endeavours to ensure that its Real-Time Market Submission for each of its Scheduled Facilities, Semi-Scheduled Facilities and Interruptible Loads for each Dispatch Interval accurately reflects:

(a) for Dispatch Intervals in the Week-Ahead Schedule Horizon:

i. the Market Participant's **reasonable expectation of the capability of its Registered Facility** to be dispatched in the Real-Time Market;

ii. any applicable tests required under these WEM Rules, including tests for Reserve Capacity under section 4.25; Chapter 7 544

iii. any Outage Plans applicable to the Dispatch Interval that have not been rejected, withdrawn or subjected to an Outage Recall Direction that affects the Dispatch Interval; and

iv. any applicable Forced Outages applying to the Dispatch Interval;

Should not account for known Network Outages that impact the Registered Facility

Requirements to Submit Capacity Pre-Dispatch

7.4.2. …

(b) for Dispatch Intervals in the Pre-Dispatch Schedule Horizon, all information reasonably available to the Market Participant, including:

i. the Market Participant's **intentions for commitment,** control and decommitment;

ii. the Market Participant's intentions for providing Frequency Co-optimised Essential System Services; and

iii. in the case of a Semi-Scheduled Facility, any changes to the Market Participant's Unconstrained Injection Forecast or Unconstrained Withdrawal Forecast that exceed the Tolerance Range or Facility Tolerance Range applicable to the Semi-Scheduled Facility; …

Made via AVAILABE/IN-SERVICE capacity declaration

RTMS Obligations Summary

Week-Ahead

Capacity & Outages

Pre-Dispatch

(48 hours)

Commitment Intentions

Comparison of New & Old Market Outcomes

Presenter	Nicholas Nielsen
Purpose	Compare costs of Energy & FCESS in new and old market
Driver	Participant queries
Outcome	Insights shared at forum; participant feedback on future analysis

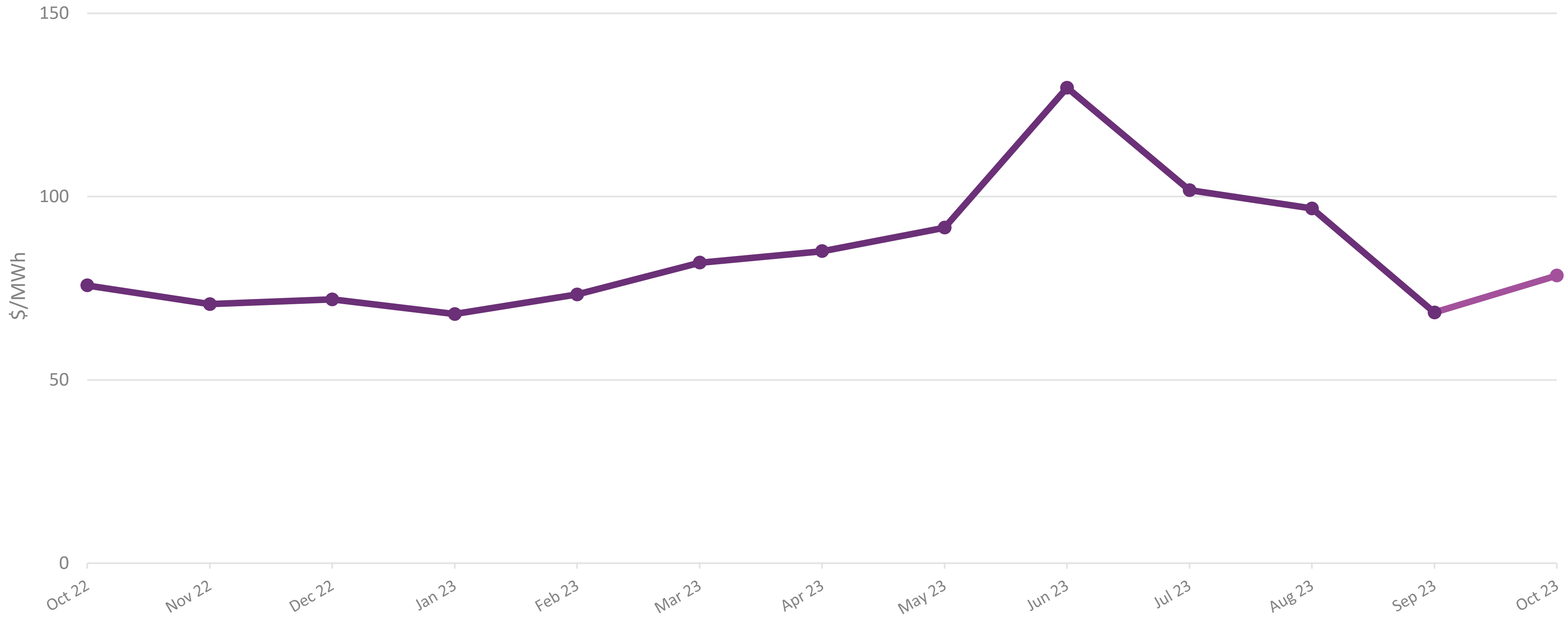
Introduction

- The following slides compare costs in the old and new markets
  - As presented at the WA ECF, plus additional detail.

- Data for October 2023 is based on three settled Trading Weeks plus Prudential estimates for remaining days, as at 17 Nov 2023.

Balancing and Real Time Energy Prices

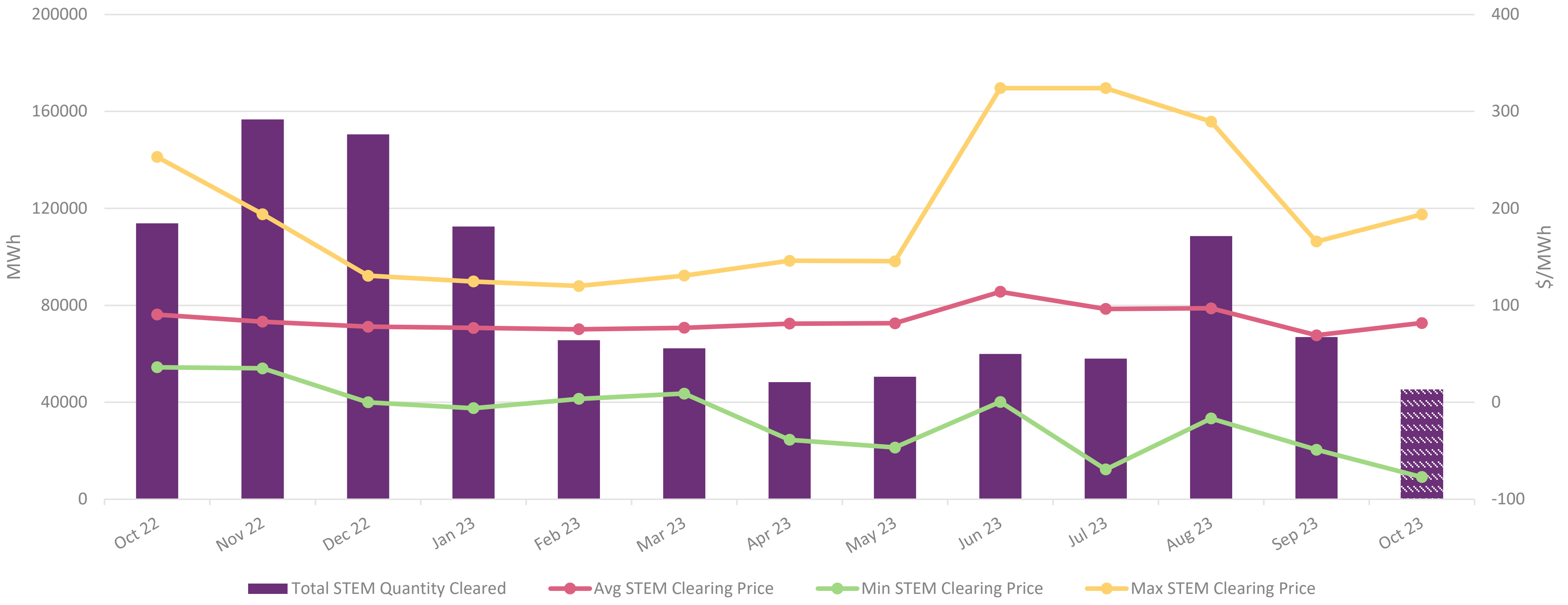
Monthly Balancing Price



- Average Balancing Price peaked around June 2023, with a maximum price of $805/MWh, driven by tight conditions in the system as a result of high outages and higher than normal winter demand.
- The average Final Reference Trading Price was 78.45/MWh in October 2023, an increase of $10.07/MWh compared to Balancing Prices in September 2023 but comparable to October 2022 Balancing Prices.

STEM Prices

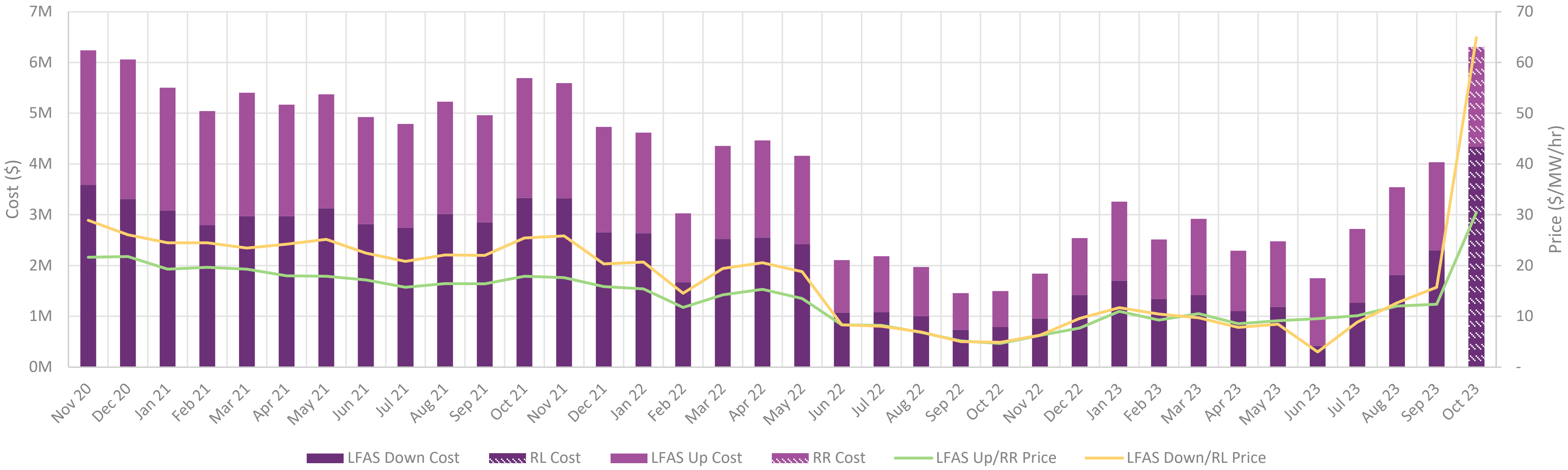
Monthly STEM Quantity and Price



- The Short Term Energy Market remains largely unchanged in the new market, although it is now settled along with all non-STEM segments as part of a single invoice.
- STEM prices appear unaffected by the cutover to the new market, and while traded quantities dropped, it is unclear whether this is related to the cutover or just a continuation of the significant variation seen throughout the year. The average STEM Price was similar throughout the year despite changes in quantities.
- Maximum cleared STEM prices peaked noticeably in Jun-Aug 2023, probably driven by high Balancing Prices, although traded quantities did not appear to be affected.

Regulation (LFAS)

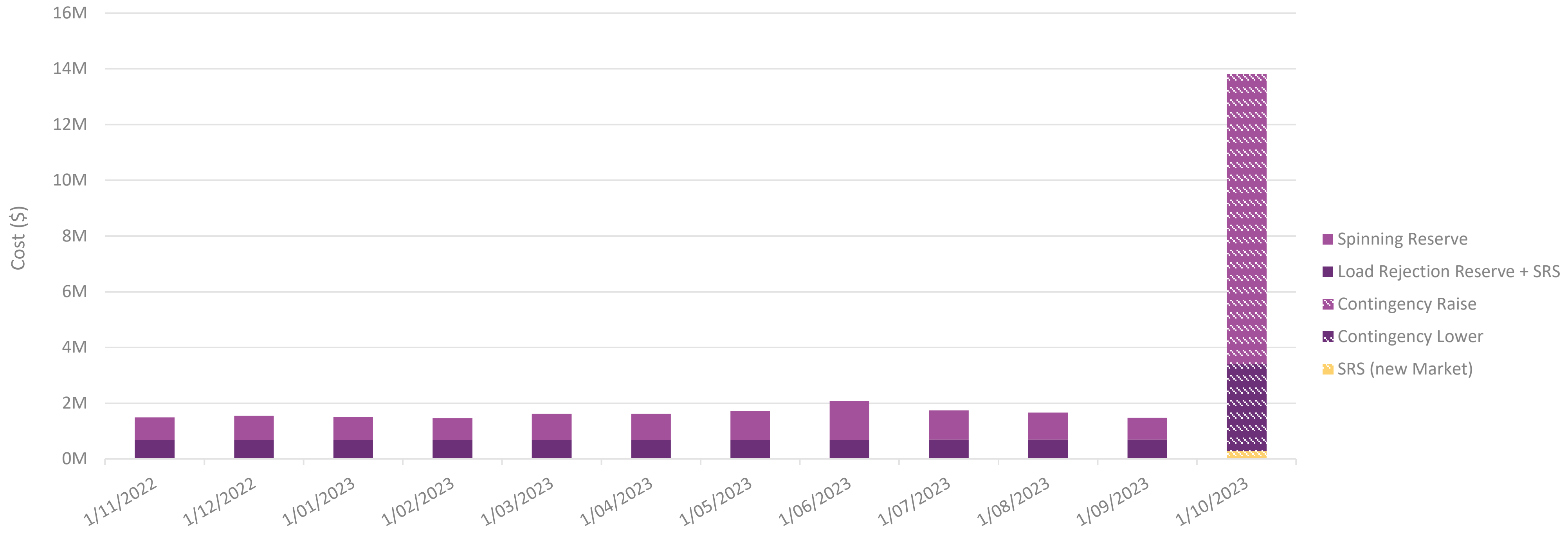
Monthly Costs & Prices



- Total cost of Regulation rose compared to LFAS in recent months, however this is consistent with trends in the LFAS market since June 2023.
- While the monthly cost of Regulation is high compared to recent months, it is similar 2020/2021, despite prices being notably higher. This appears to be mainly driven by different price-quantity dynamics in the new market. Lower average procured quantities in the new market and the addition of backup LFAS payments (which are not reflected transparently in price outcomes) in the total cost in the old market also contributed, though less so.

Contingency (SRAS, LRR) and SRS

Monthly Costs



- In the old market, Spinning Reserve (SRAS), LRR, and SRS costs/prices were set by the ERA through their Margin Values and Cost_LR parameters. Since October 2023, Contingency Raise and Lower are co-optimised markets (SRS remains a contracted service). Load Rejection Reserve (LRR) & System Restart Service (SRS) costs are grouped together under the Cost_LR parameter prior to October 2023.
- Very high Balancing Prices in around May-July drove high SRAS costs, peaking in June at 57% higher than the previous 6-month average.
- The total cost of Contingency Raise and Lower has risen considerably in the new market.

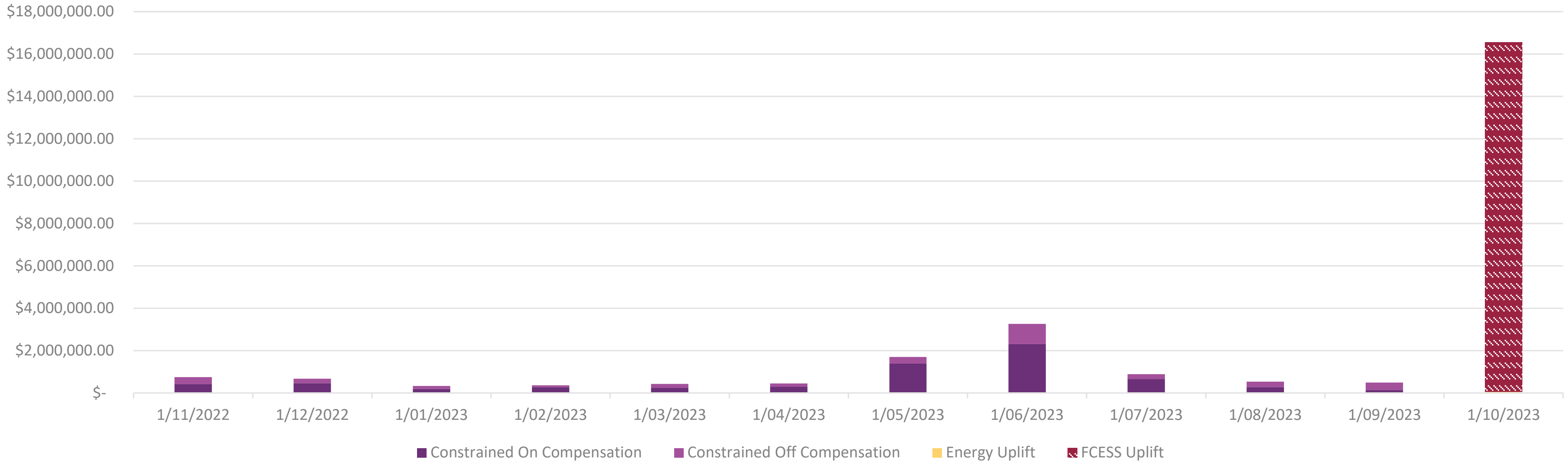
RoCoF Control Service

Daily Costs

- RoCoF Control Service (RoCoF or RCS) is a new service introduced in the new market for the provision of inertia.
- RoCoF costs in October are dominated by a single Dispatch Interval on 4 October, which cleared at $300/MWs and cost $160k in total. Excluding that Dispatch Interval, the total cost of RoCoF in October was approximately $80 – too little to be visible on the graph.

Uplift & Constrained Compensation

Monthly Costs



- Though not the same, FCESS Uplift & Energy Uplift in are somewhat comparable to Constrained On Compensation in the old market. Constrained Off Compensation has no analogue in the new market.
- Constrained Compensation peaked considerably in June (173% above the 12-month average), driven by tight conditions on the market.
- October Energy Uplift costs were low at $54k, suggesting there was limited congestion in the system However FCESS uplift costs have been significant, as a result of Facilities being dispatched at higher Energy levels in order to be able to provide FCESS.

Old vs New Market Comparison

On a $/MWh of Energy basis

New Market (Oct 2023)

RT Energy	Reg. Raise	Reg. Lower	Con. Raise	Con. Lower	RoCoF	SRS	Uplift	=	Total
$78.45	$1.44	$3.18	$7.62	$2.30	$0.12	$0.20	$12.14	=	$105.45

ESS total = $14.86

Old Market (12-month Ave to Sep 2023)

Balancing	LFAS Up	LFAS Down	SRAS	LRR + SRS	Constr. Comp.	=	Total
$84.97	$0.88	$0.88	$0.63	$0.46	$0.63	=	$88.45

AS total = $2.85

- This compares the cost of the Real-Time Market (Energy and ESS) vs the old Balancing market and Ancillary Services, normalised by energy consumed. Capacity costs are excluded.
- To calculate a dollar per MWh of energy consumed, AEMO divided the total segment cost by total gross consumption in the WEM, calculated as:
  - For the new market: the sum of CCQ_P_I
  - For the old market: the sum of (MSNDL_P_I - ABSLOAD_P_I)/2 + min(MS_F_I of Registered Facilities, 0)

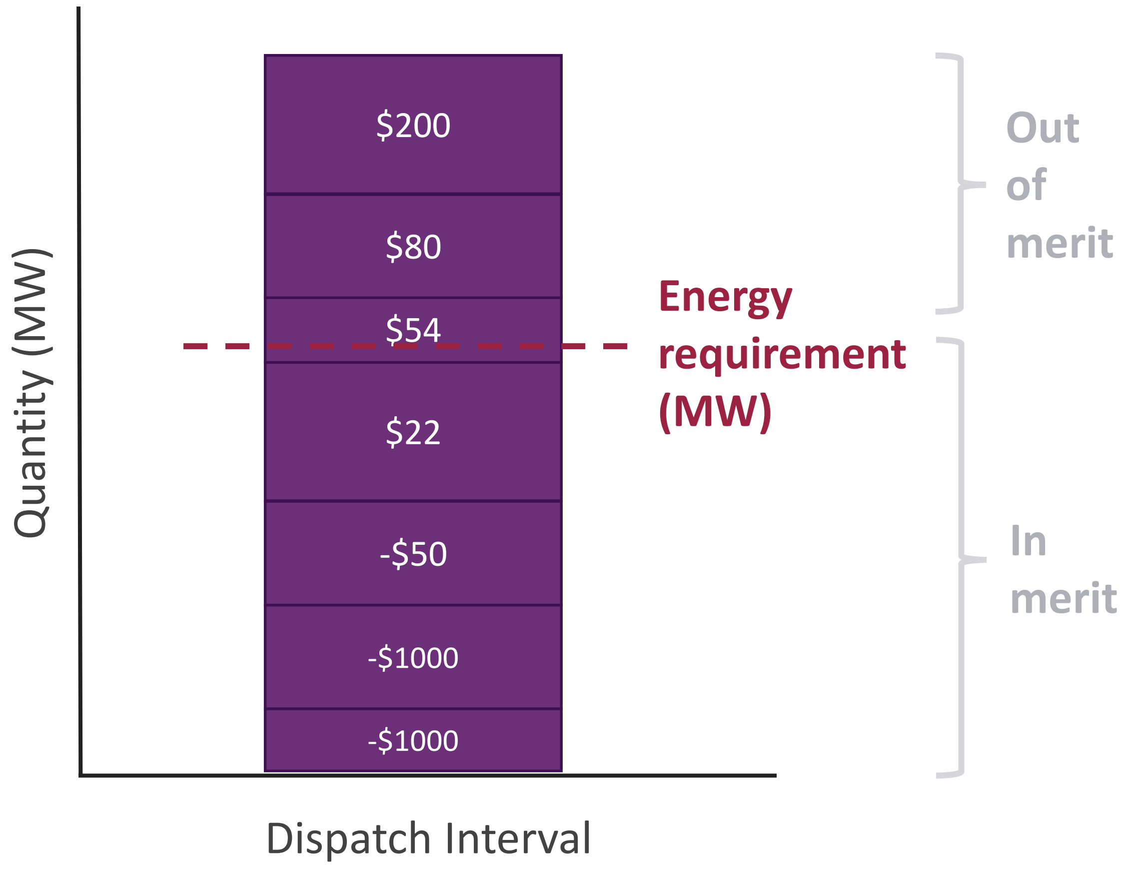
Investigation:
SCED vs Merit Order Outcome Comparison

Presenter	Rachel Tandy
Purpose	Demonstrate how market outcomes under co-optimisation diverge from energy-only merit order outcomes.
Driver	Participant queries on the relationship between merit order and dispatch outcomes.
Outcome	Insights shared at industry forum and identified potential for future analysis in this area.

Overview

Period of analysis	13 October 2023 – 13 November 2023
Scenarios	**SCED**: Actual market outcomes as determined by WEMDE
	Merit order: Market outcomes based on energy only merit order.

Background concepts – merit order dispatch



- Energy offers are ordered from least to most cost
- Price is determined by where the energy requirement intersects with the merit order
- In this example, price is equal to $54

Background concepts – trapping

- When a facility passes ESS pre-processing, it becomes "trapped" in its trapezium for that ESS: its energy dispatch must be >= the Enablement Minimum and <= the Enablement Maximum.

ESS Enablement Minimum and Enablement Maximum Constraints

$IF\ ESSFlag_{f,m} = False$

$$SKIP\ CONSTRAINT$$

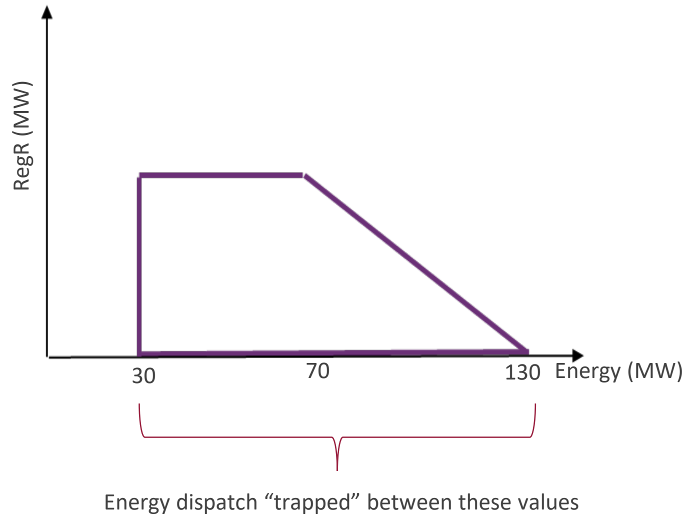
$ELSE$

$$TrancheSum_{f,energy} + EnablementMinDeficit_{f,m} \geq EnablementMin_{f,m}$$

$$for\ f\ in\ \boldsymbol{F},\ for\ m\ in\ \boldsymbol{M}\ where\ m \neq energy$$

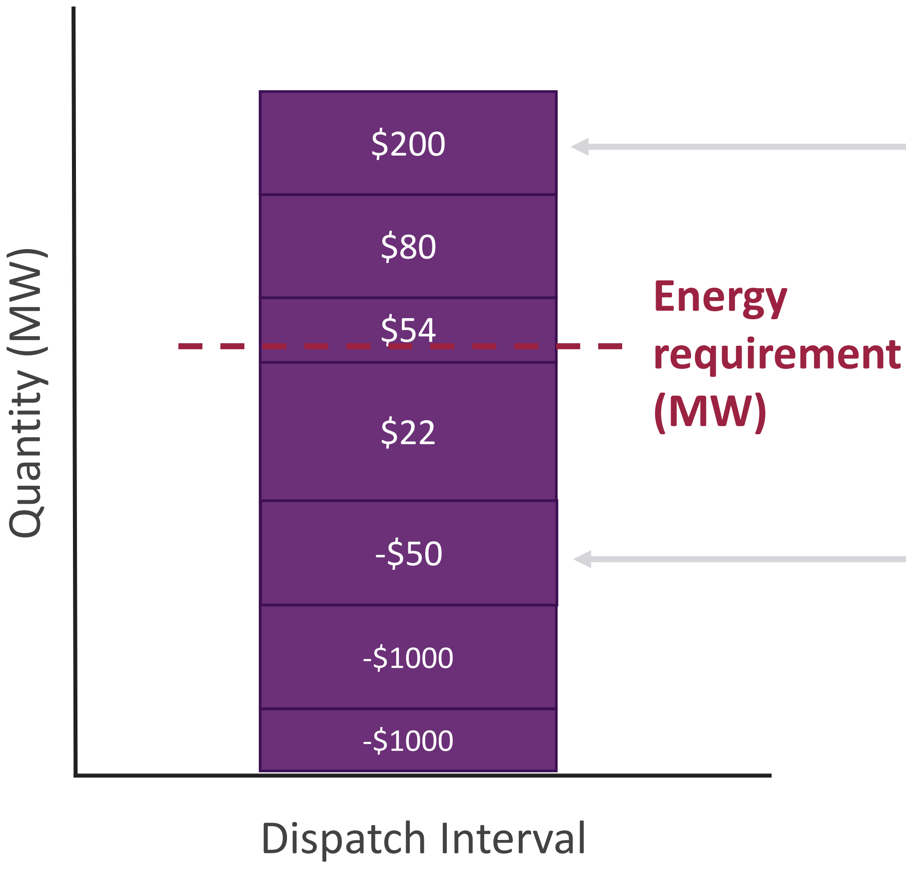
$$TrancheSum_{f,energy} - EnablementMaxSurplus_{f,m} \leq EnablementMax_{f,m}$$

$$for\ f\ in\ \boldsymbol{F},\ for\ m\ in\ \boldsymbol{M}\ where\ m \neq energy$$

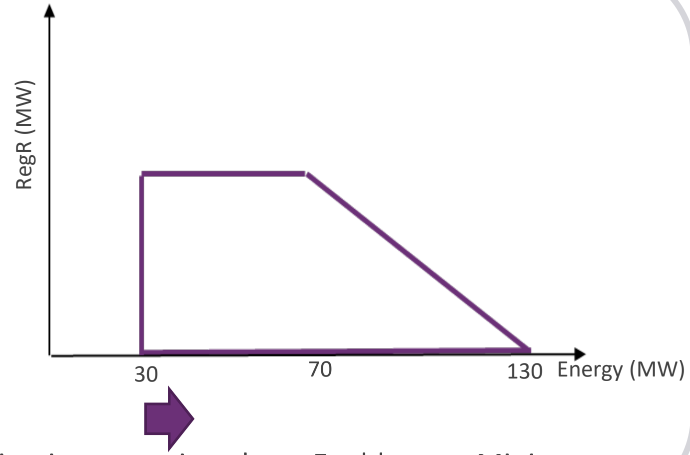


- Trapping at Enablement Minimum means that a facility has an Energy offer price above the clearing price but it is dispatched at its Enablement Minimum quantity anyway (may be eligible for FCESS Uplift payments)
- Trapping at Enablement Maximum means that a facility has an Energy offer(s) below the clearing price but its total dispatch is limited to its Enablement Maximum.

Background concepts – trapping

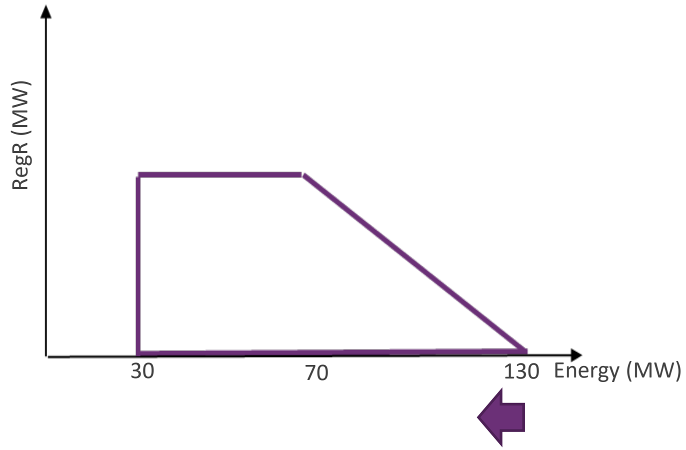


Facilities trapped at Enablement Minimum may be dispatched above the clearing price.



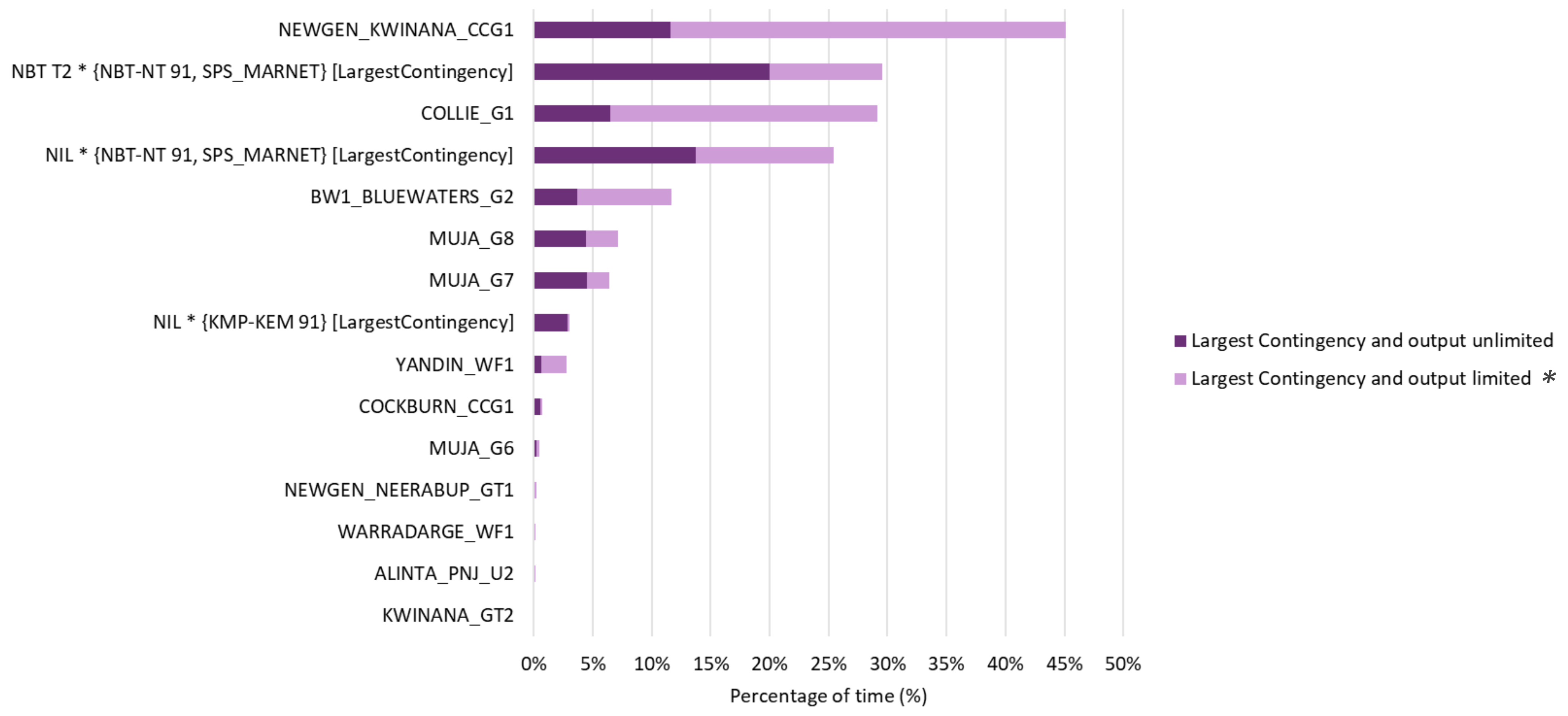
The maintain generation above Enablement Minimum

Facilities trapped at Enablement Maximum may have their dispatch limited to their Enablement maximum despite having quantities below the clearing price.



Contingency management

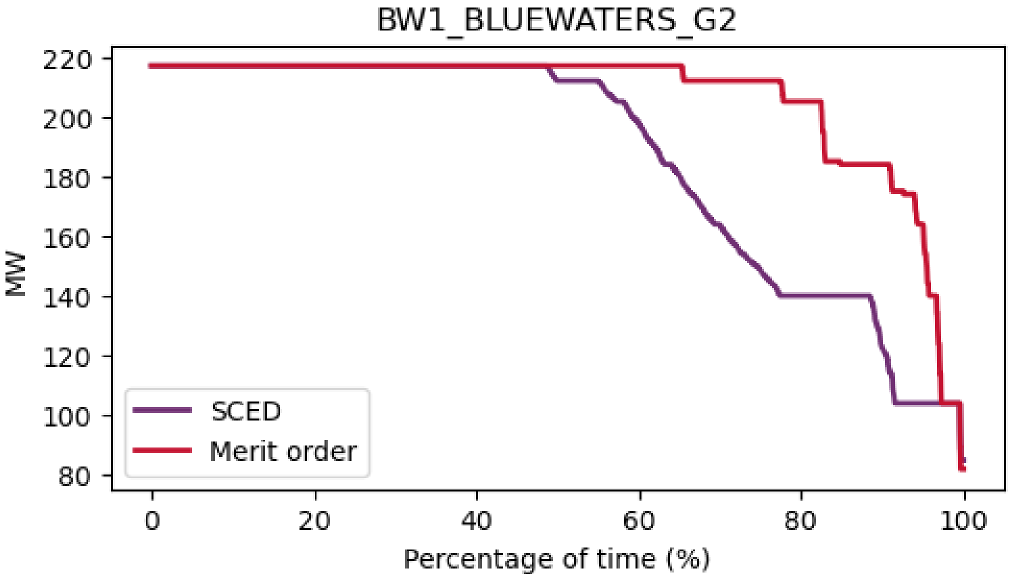
Largest Contingency units

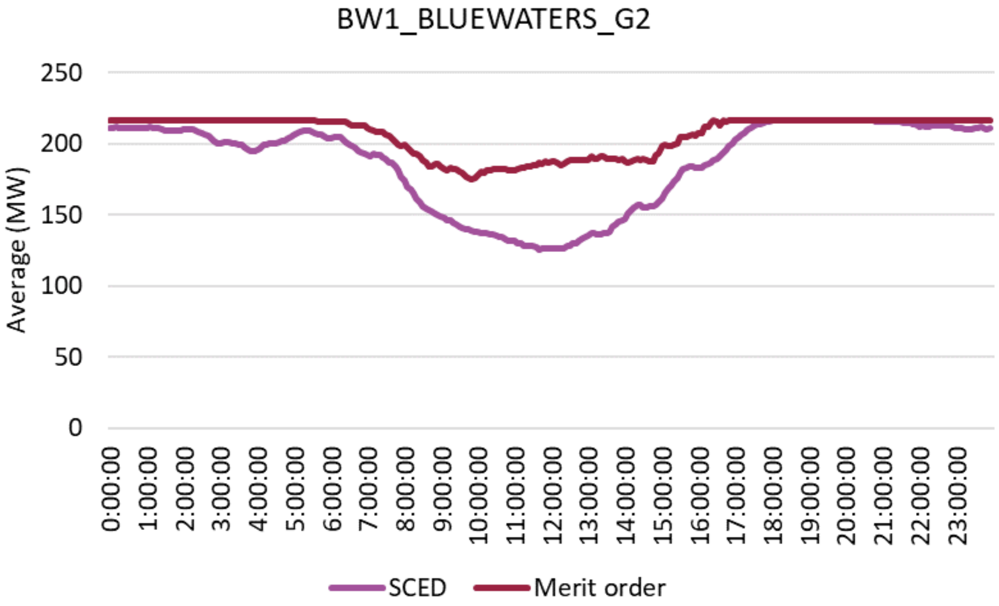


**Output limited here means SCED output was less than pure merit order output*

Bluewaters G2

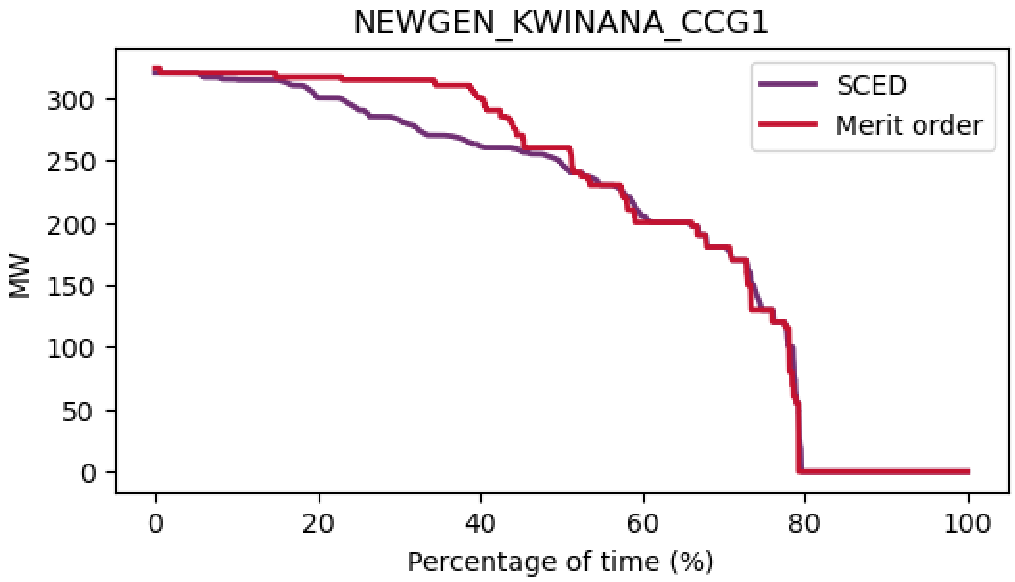
- Bluewaters does not participate in Regulation or Contingency markets.
- When Bluewaters G2 output is less than its in-merit quantity:
  - in 19% of instances it's also setting the largest contingency.
  - during other periods, their generation is displaced by Contingency and Regulation service providers
- When output is above in-merit quantities Bluewaters G2 is providing RoCoF.

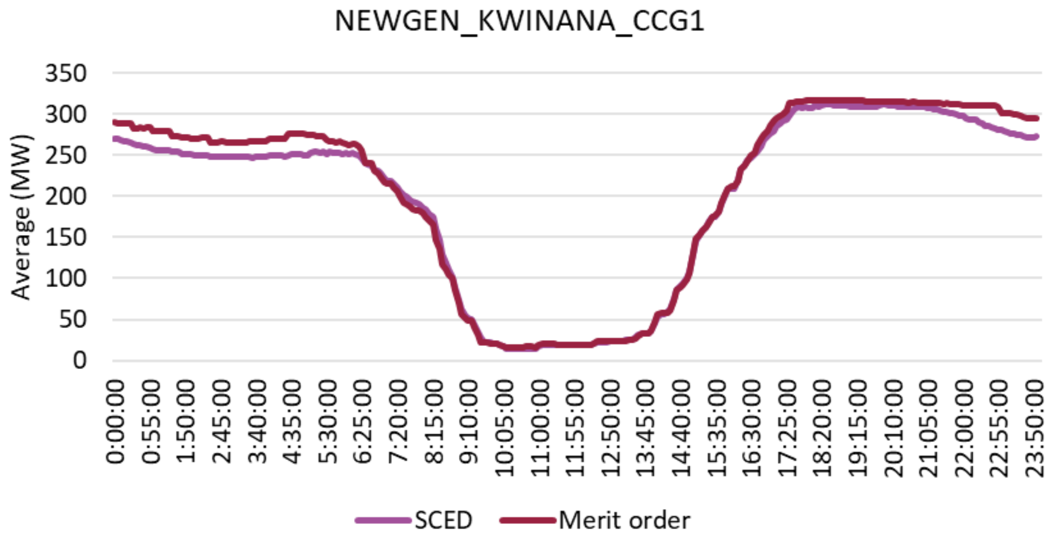




Newgen Kwinana CCG1

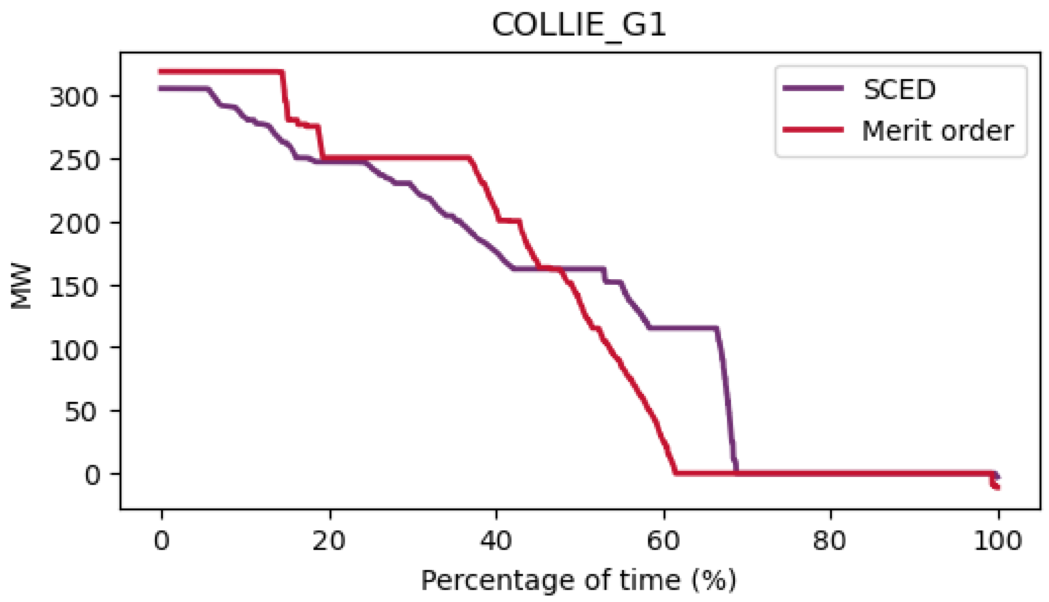
- When NGK output is less than its in-service quantity:
  - in 74% of instances it is also setting the largest contingency.
  - Output reduced more often while operating at higher end of generation range (250MW<)
- NGK output under SCED is also largely influenced by their provision of Regulation Lower and RoCoF
- In periods when they're operating above in-merit quantities, they're providing:
  - RoCoF (~91%)
  - Regulation Lower (~89%)
  - Regulation Raise (~9%)

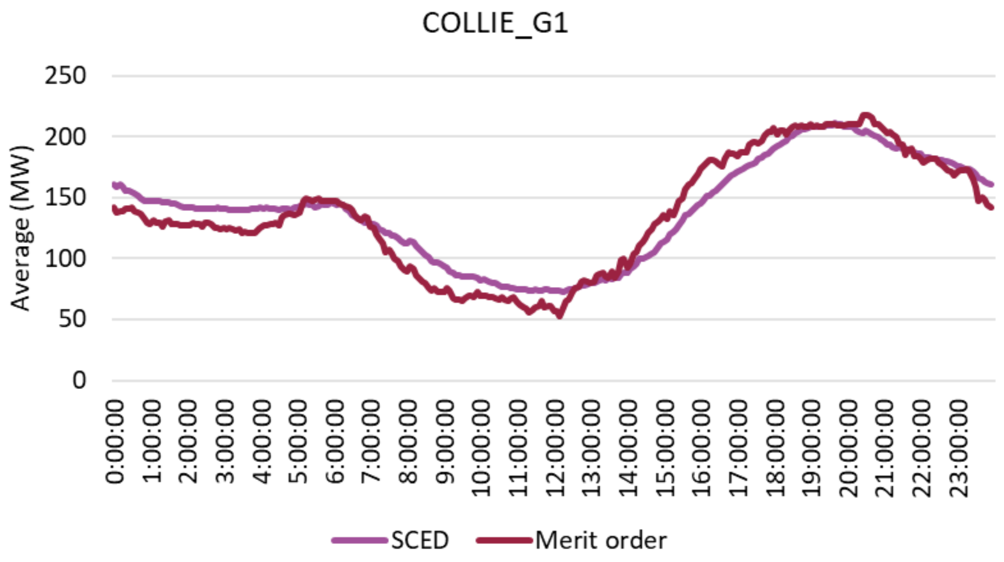




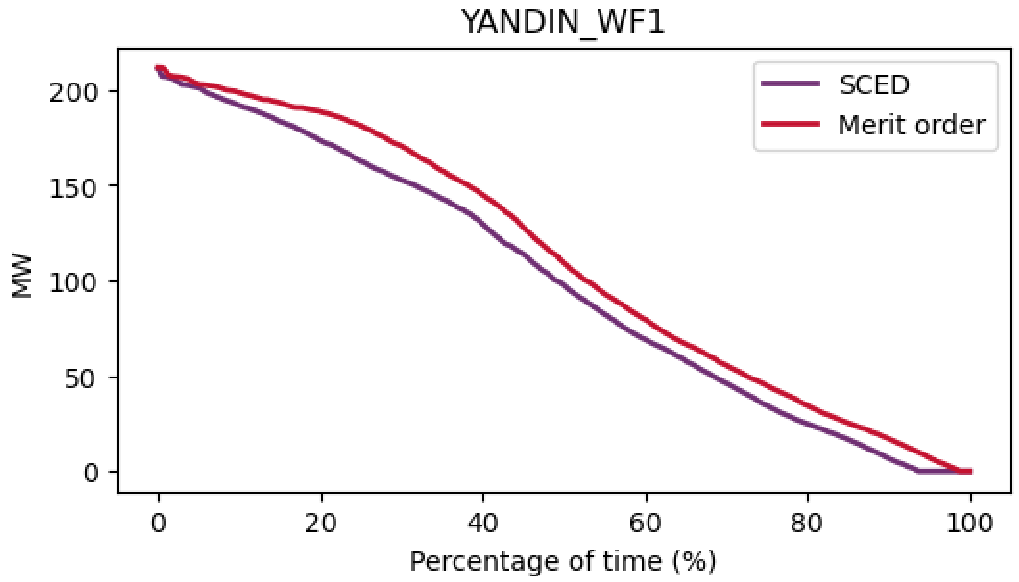
Collie G1

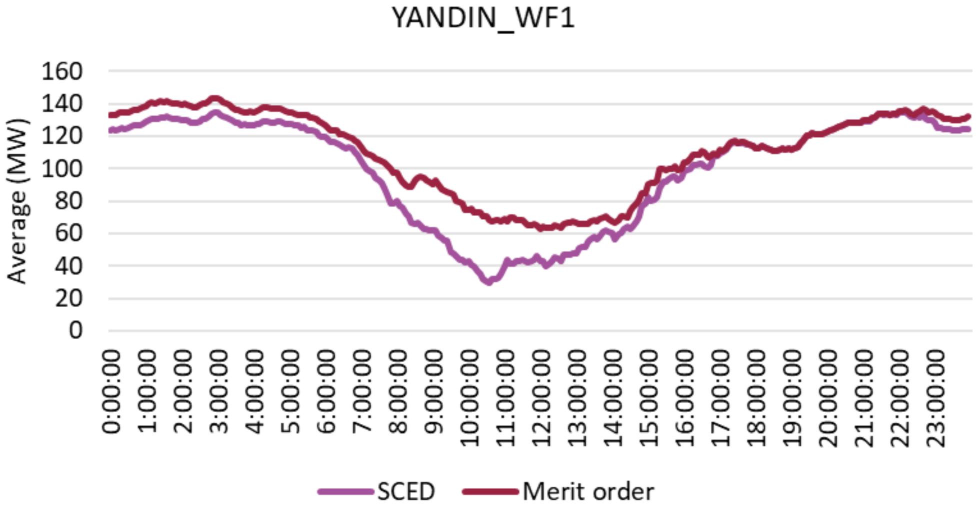
- When Collie output is less than their in-merit quantity:
  - in 50% of instances it's also setting the largest contingency
  - during other periods, their output is influenced by provision of Contingency and RoCoF services
- When Collie is dispatched above its in-merit quantity, it's providing:
  - RoCoF (~91%)
  - Contingency Raise (~78%)
  - Contingency Lower (~23%)
- Output capped at 305MW under SCED (i.e. does not reach max of 31W) due to an enablement maximum.





Yandin WF

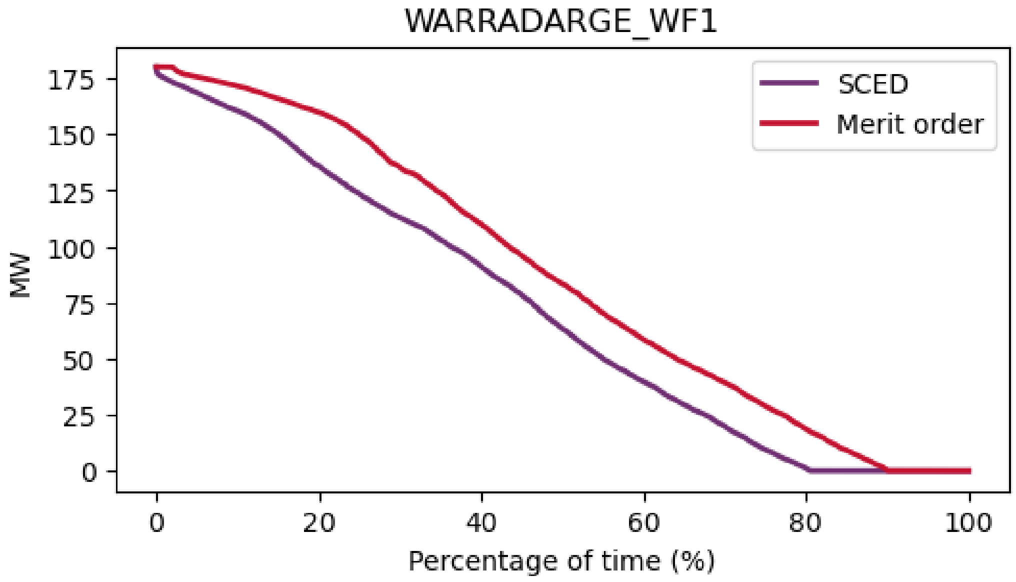


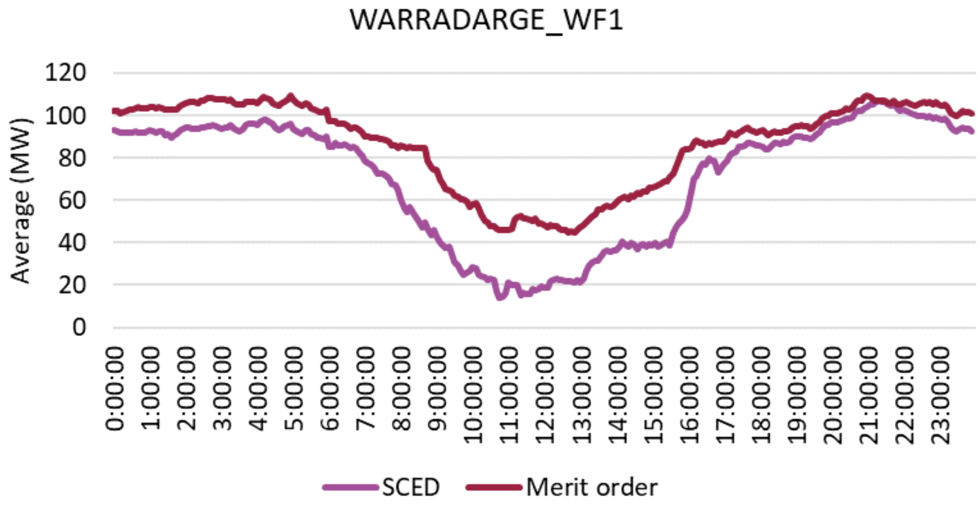


- When output is less than in-merit quantity:
  - in 53% of instances Yandin are also contributing to the largest contingency (as part of MARNET or otherwise)
  - Generation is also displaced by Contingency and Regulation service providers

Warradarge WF

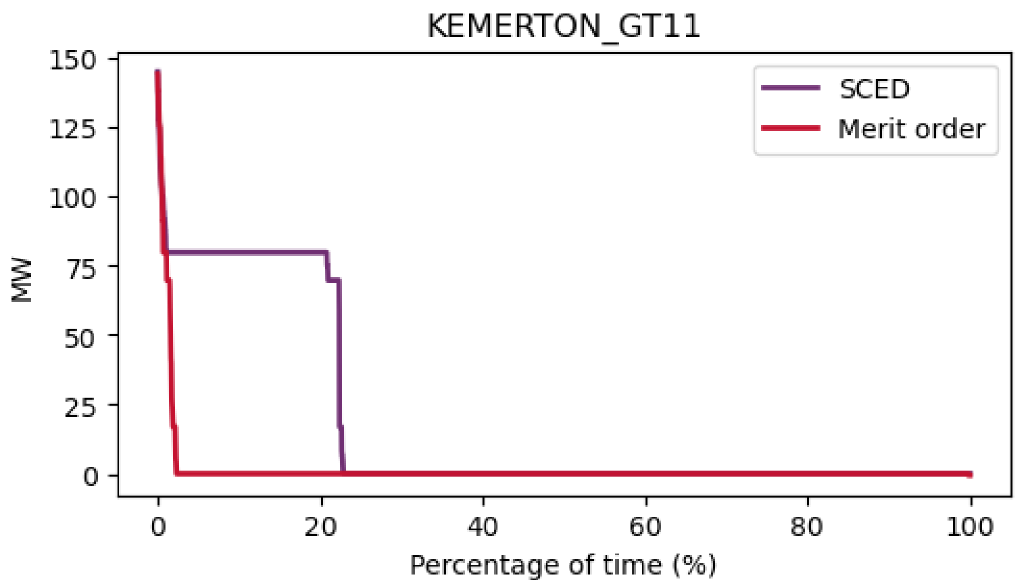
- When output is less than in-merit quantity:
  - in 45% of instances the MARNET is setting the largest contingency
  - Generation is also displaced by Contingency and Regulation service providers

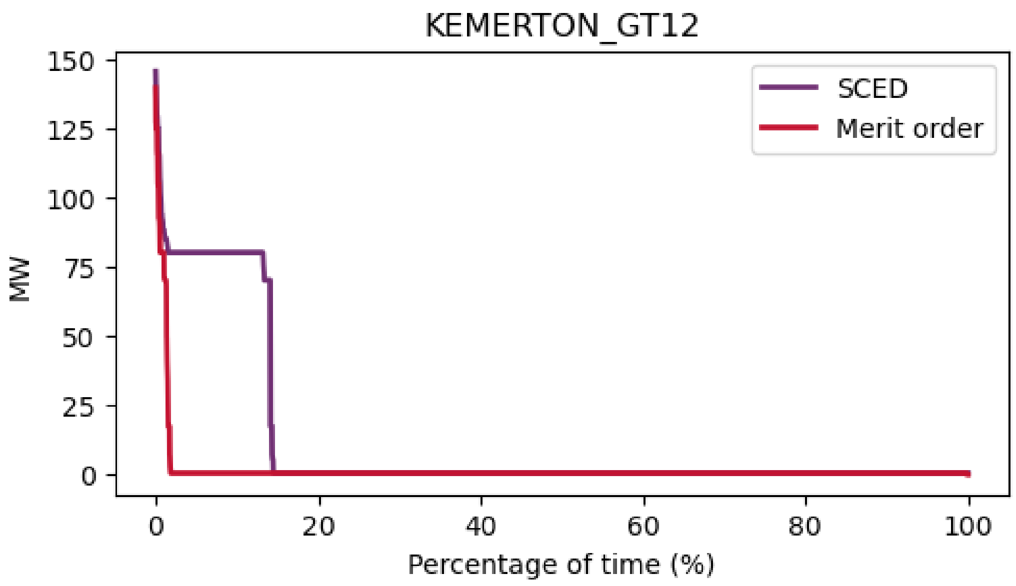


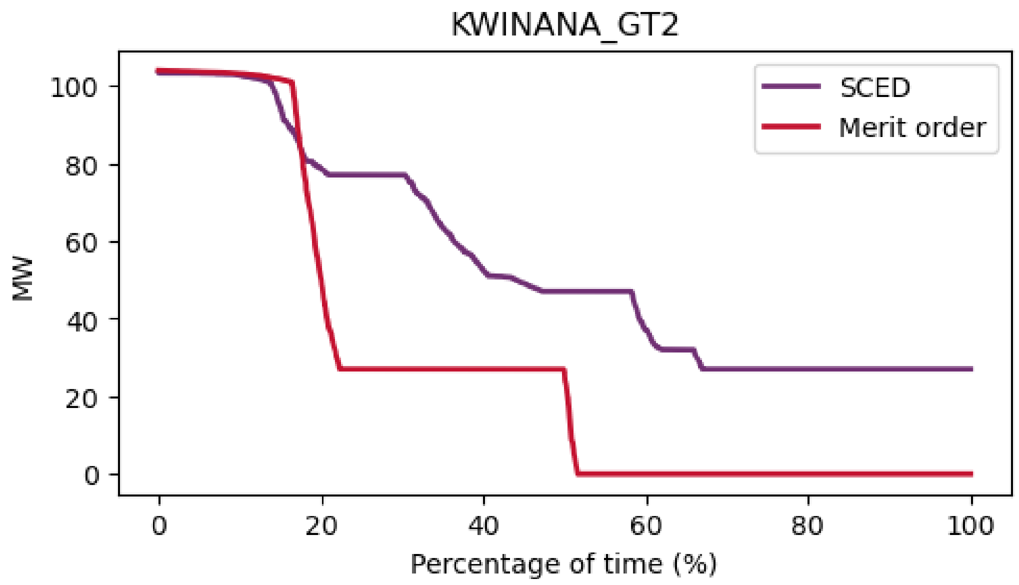


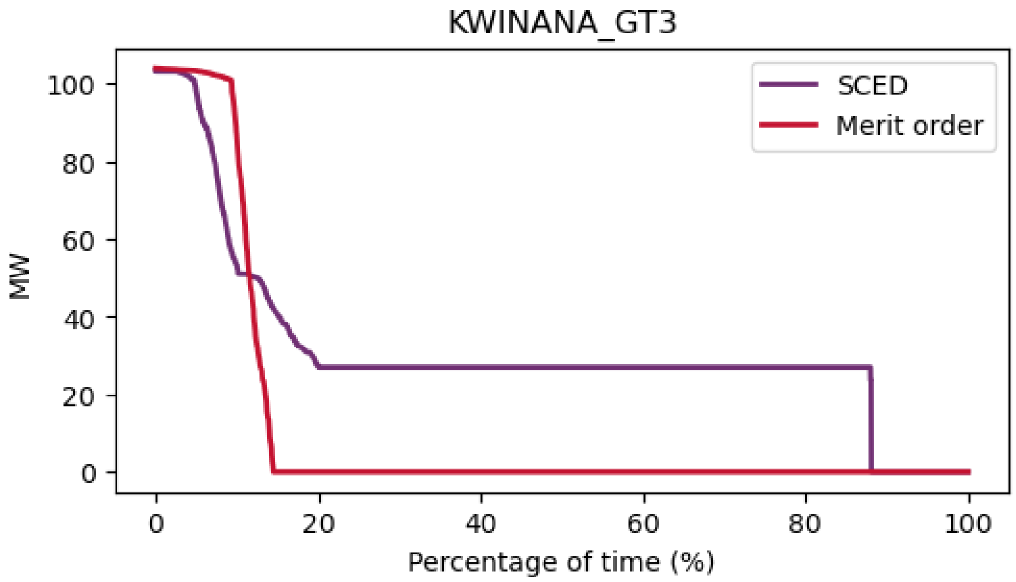
Co-optimisation and trapping

Kwinana and Kemerton GTs

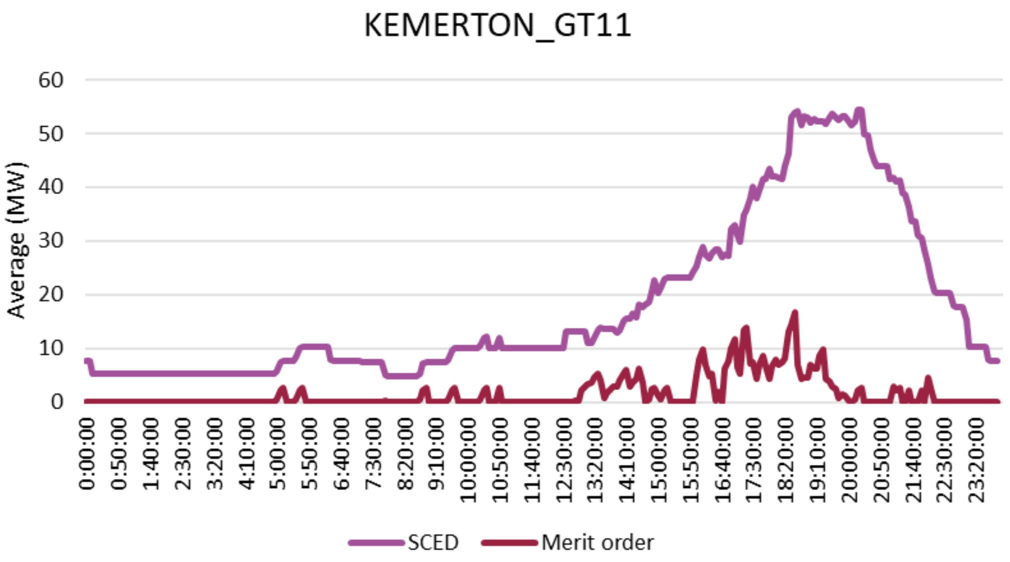


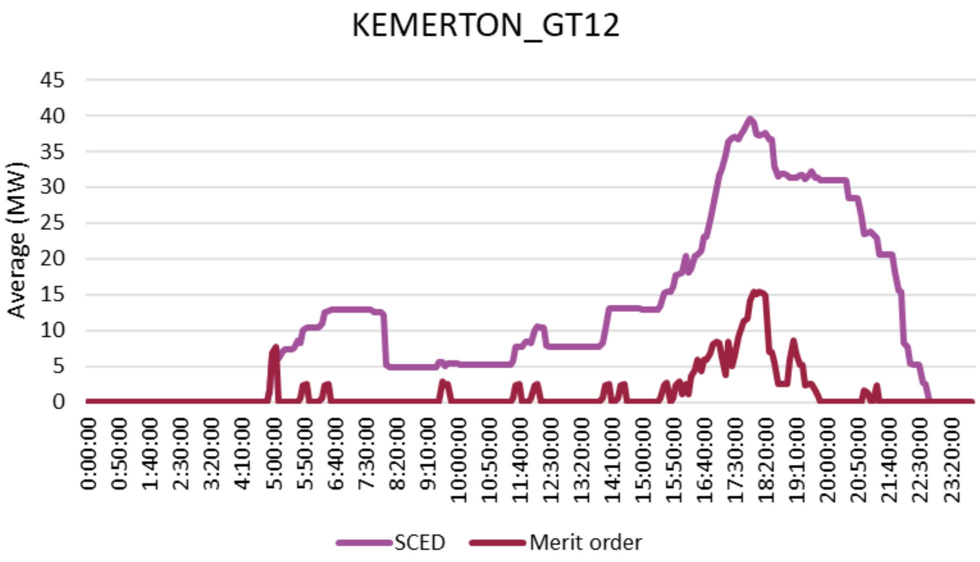


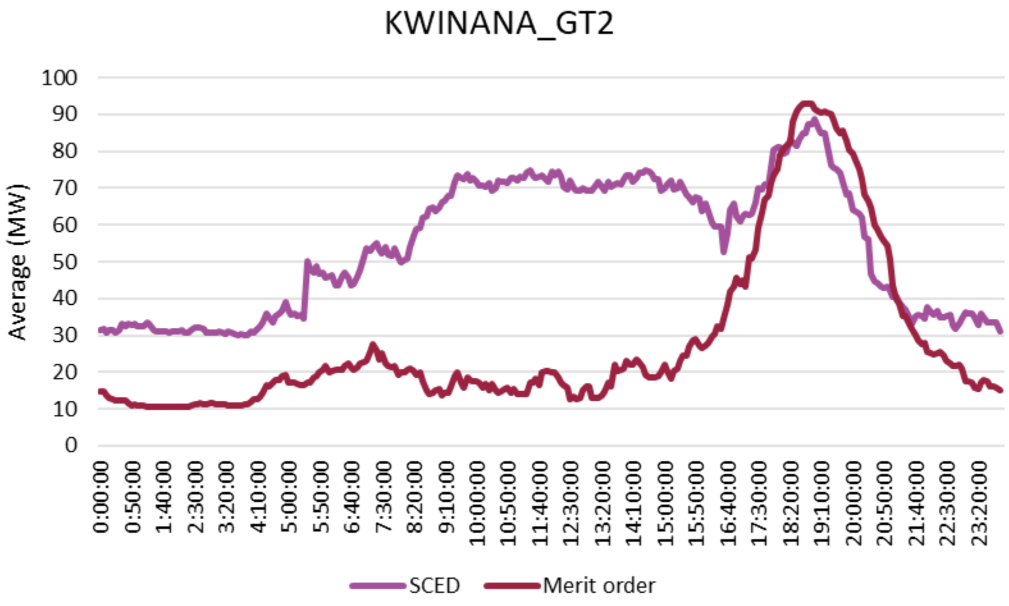


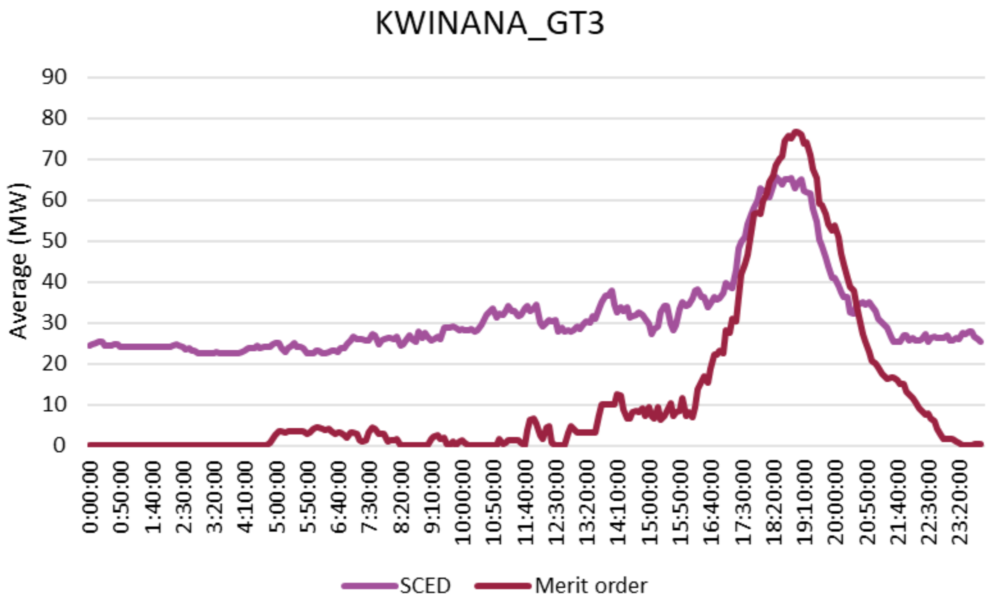


Kwinana and Kemerton GTs



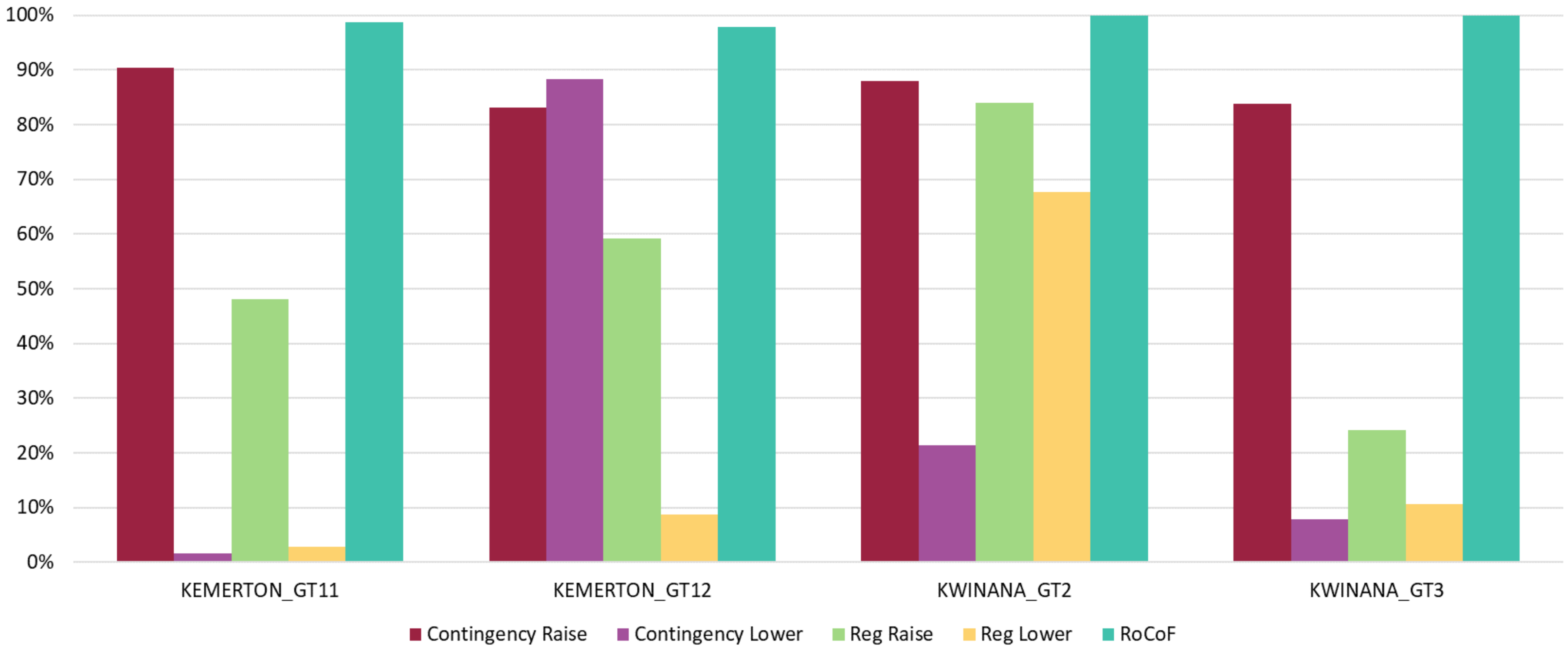




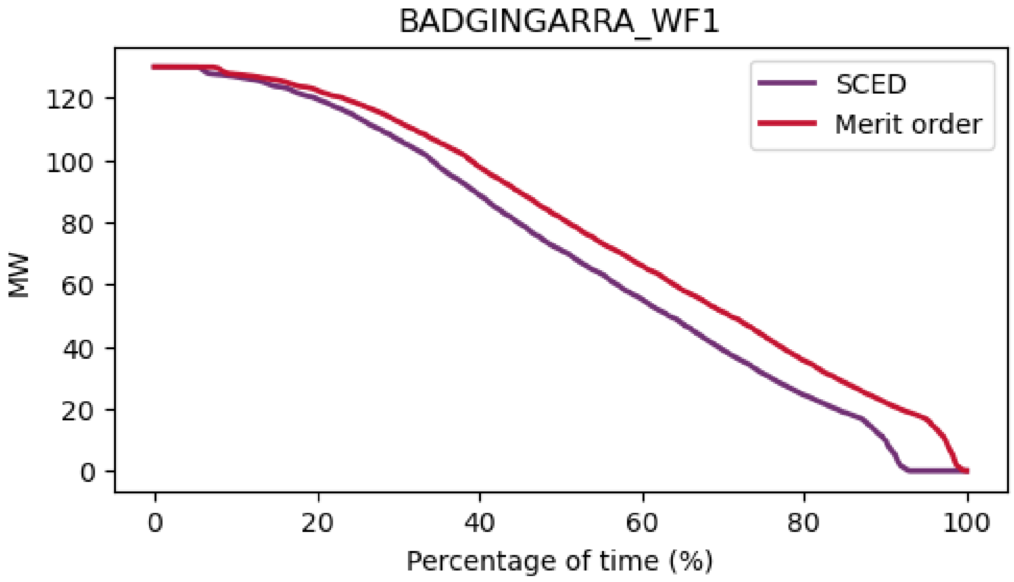


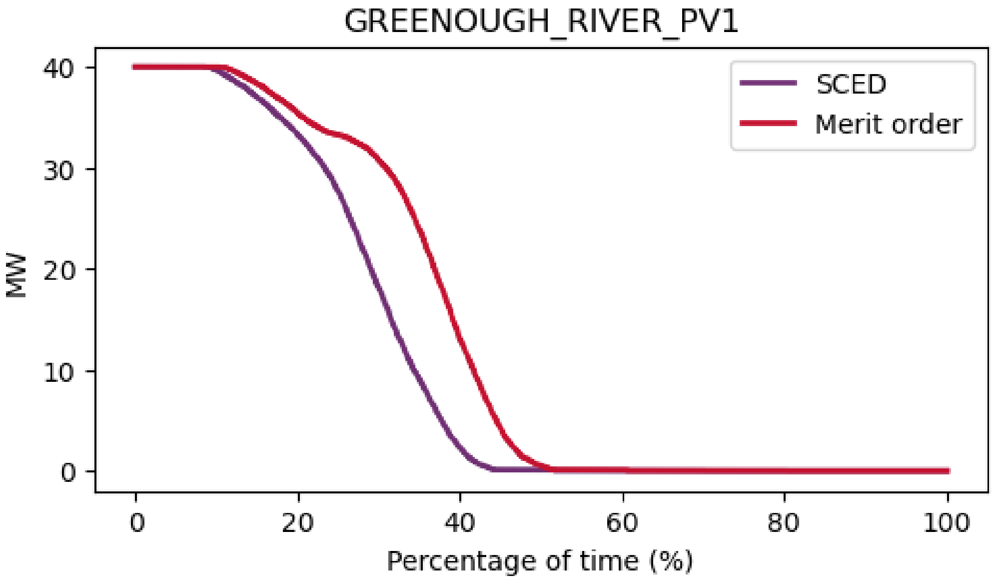
Kwinana and Kemerton GTs

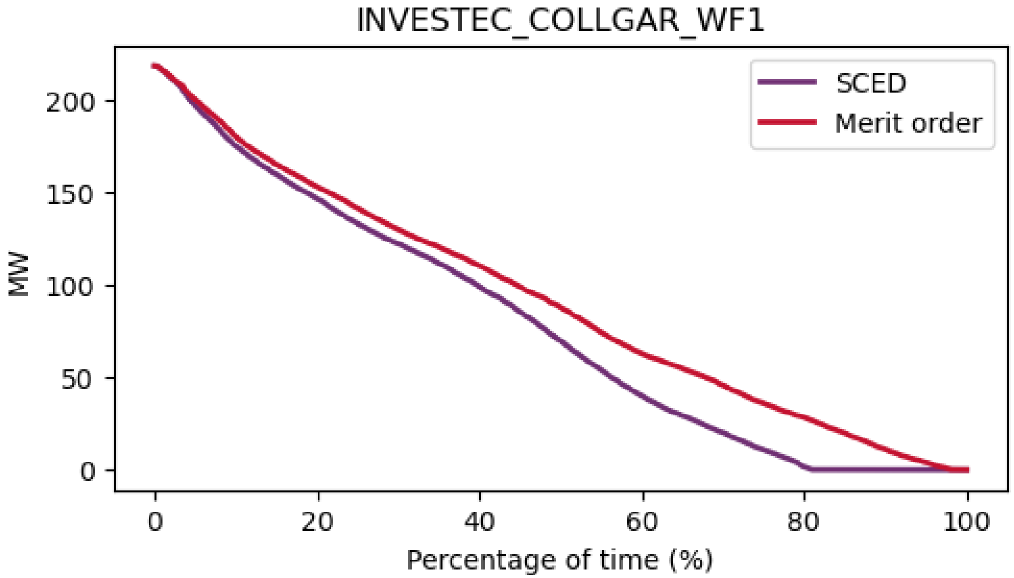
Provision of FCESS during periods where dispatch exceeds in-merit quantities

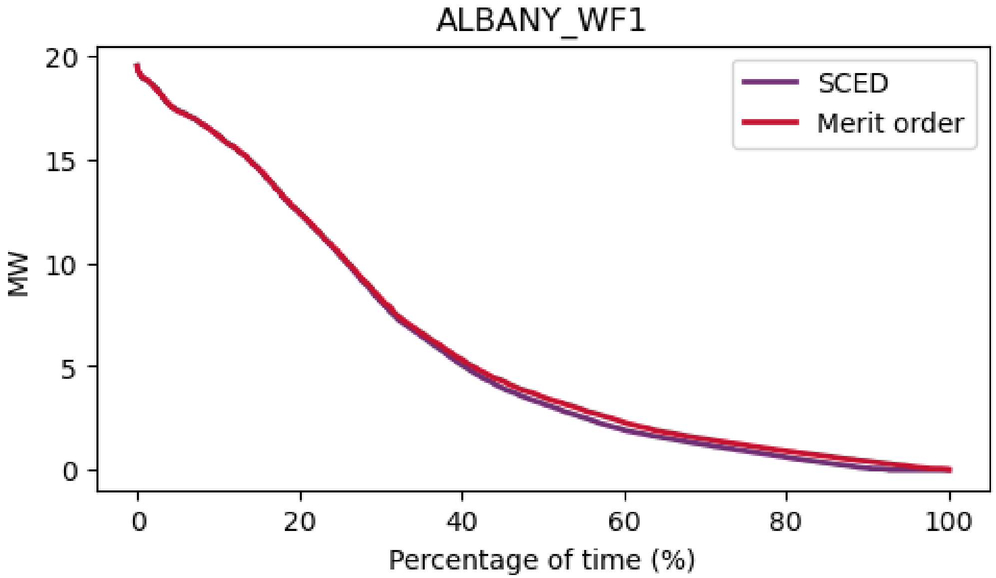


Semi-scheduled









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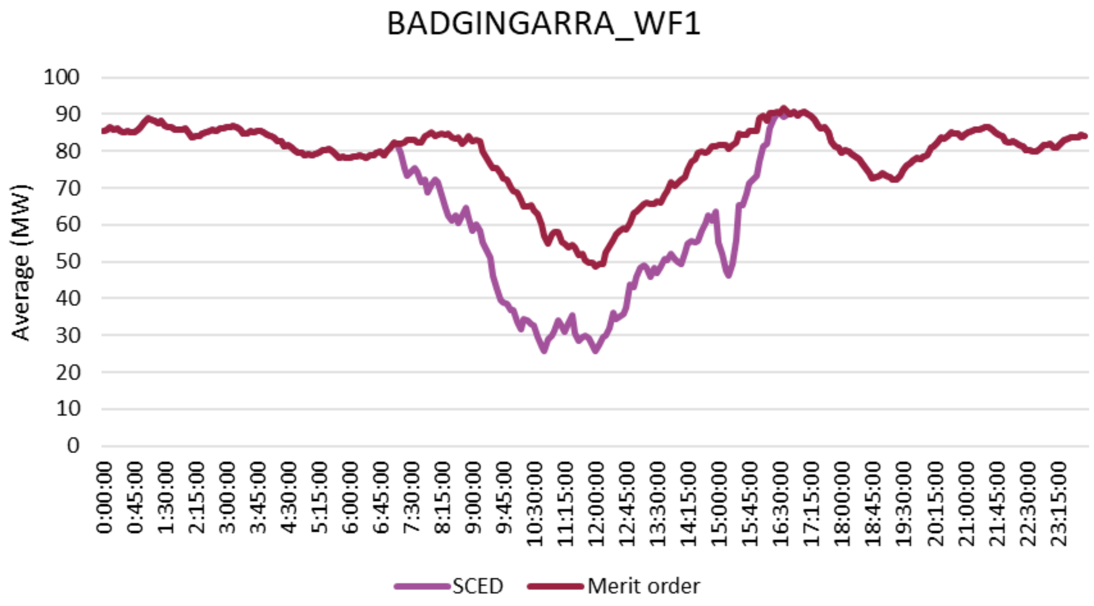
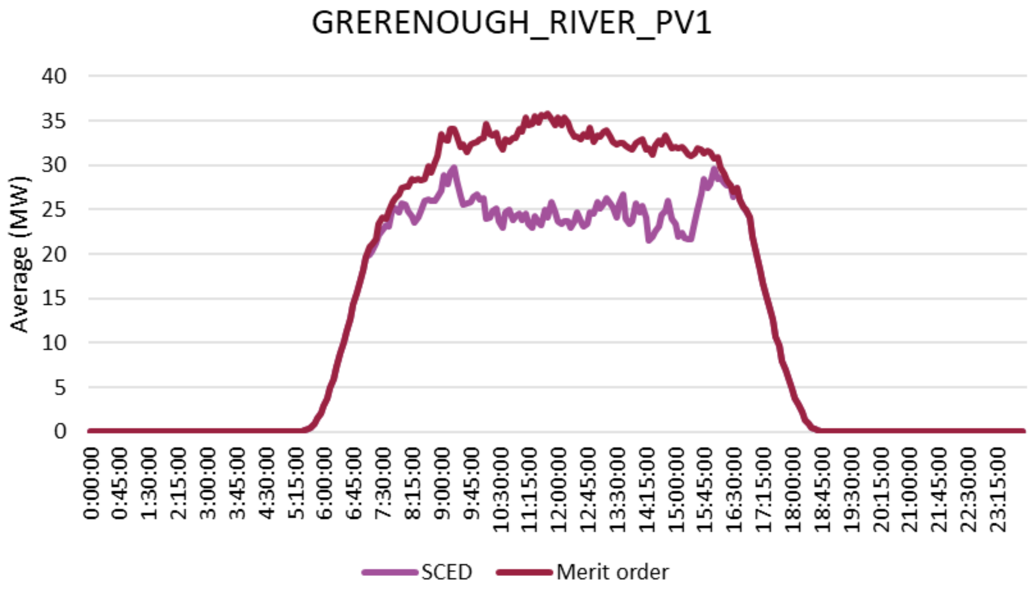
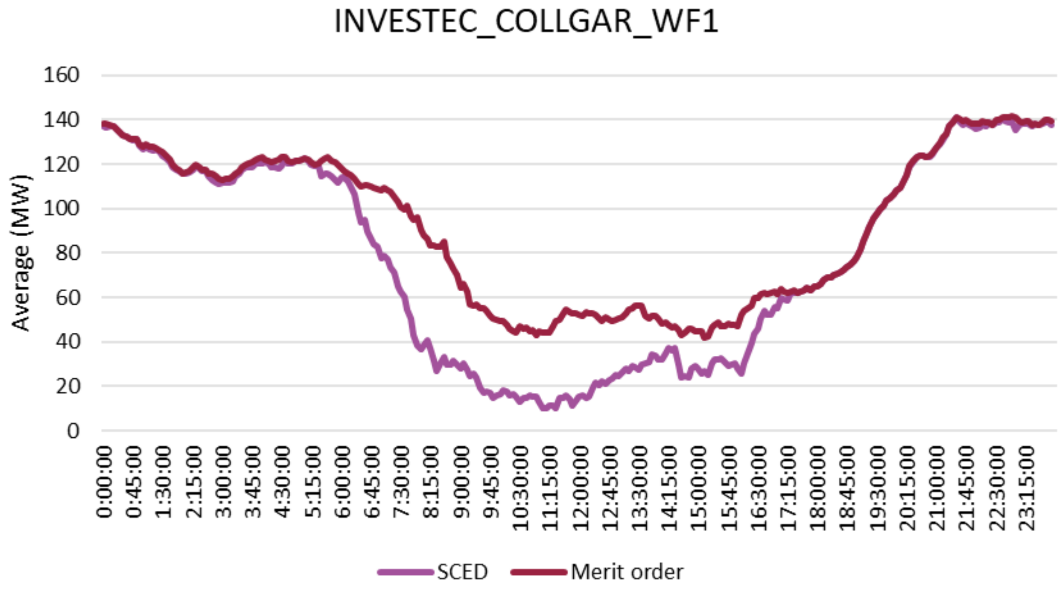
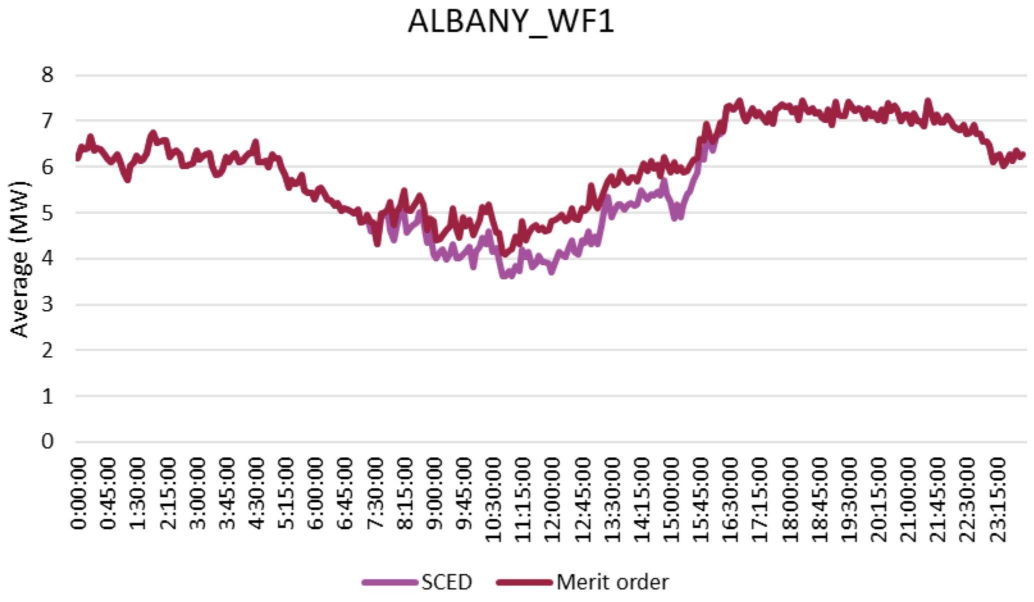


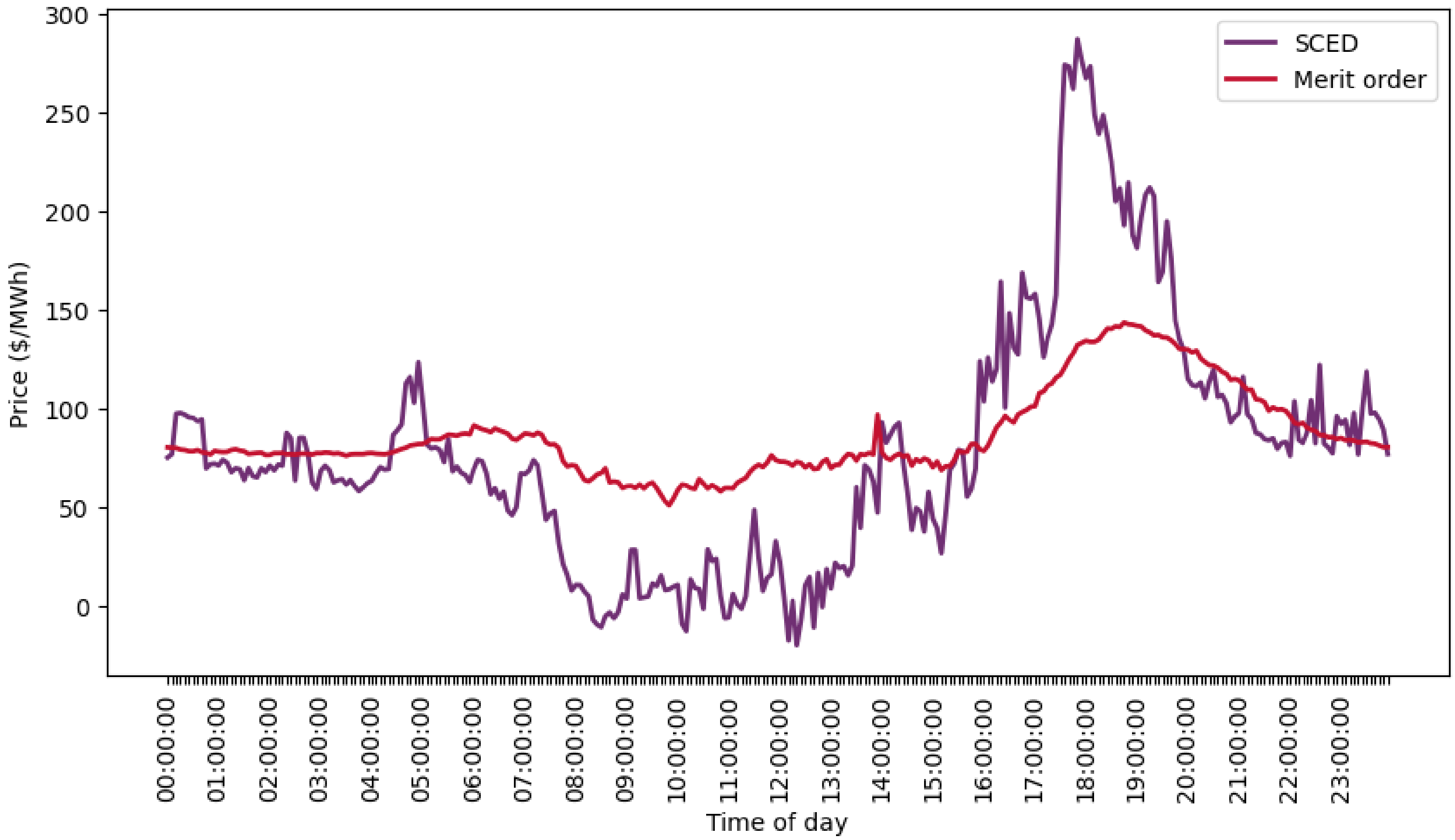






Price outcomes

Average daily price outcomes



Questions, Feedback, Ideas

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