GOVERNMENT OF WESTERN AUSTRALIA

Energy Transformation Taskforce

Market Design and Operations Working Group

Meeting 3

3 July 2019

AGENDA FOR TODAY

- Introduction and recap
- Energy scheduling & dispatch – follow up matters
- Essential System Services review
- RCM Update

Note: Meeting will be recorded to assist with minute taking.

GROUND RULES

- There is a large amount of material to work through in the workshop today, and the session chair will try to keep us on time in order to have sufficient time for discussion
- Should it not be possible to get through all the material within the available workshop time, a second session may be scheduled depending on the amount of material remaining and availability of attendees, or alternatively feedback may be provided out of session
- Questions/issues raised should be relevant to the material discussed today, although questions/issues affecting other areas of reform will still be captured
- We will attempt to capture all questions/answers discussed during the session today, for circulation after the workshop along with these slides
- All feedback/discussion is relevant, if attendees do not have a chance to ask a question or raise an issue, please feel free to contact marketdesign.wg@@treasury.wa.gov.au

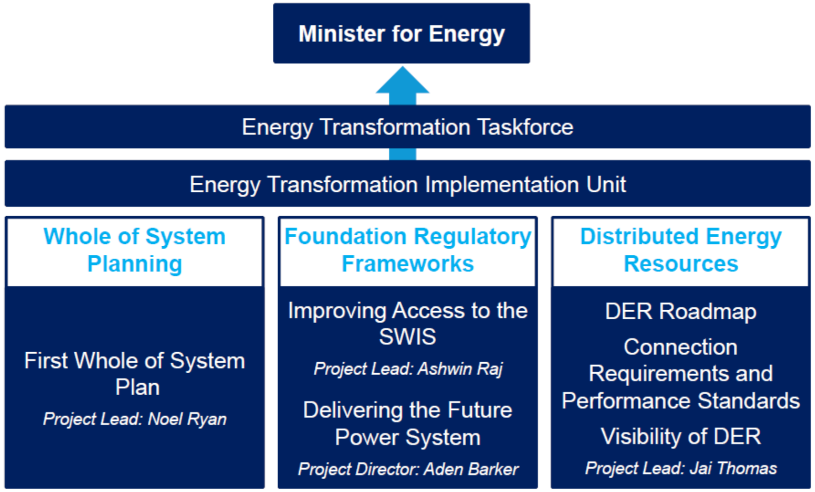
MINUTES AND ACTIONS FROM PREVIOUS SESSION

- AEMO document on Interim Pathway to enable the registration of energy storage systems published on MDOWG website June 2019

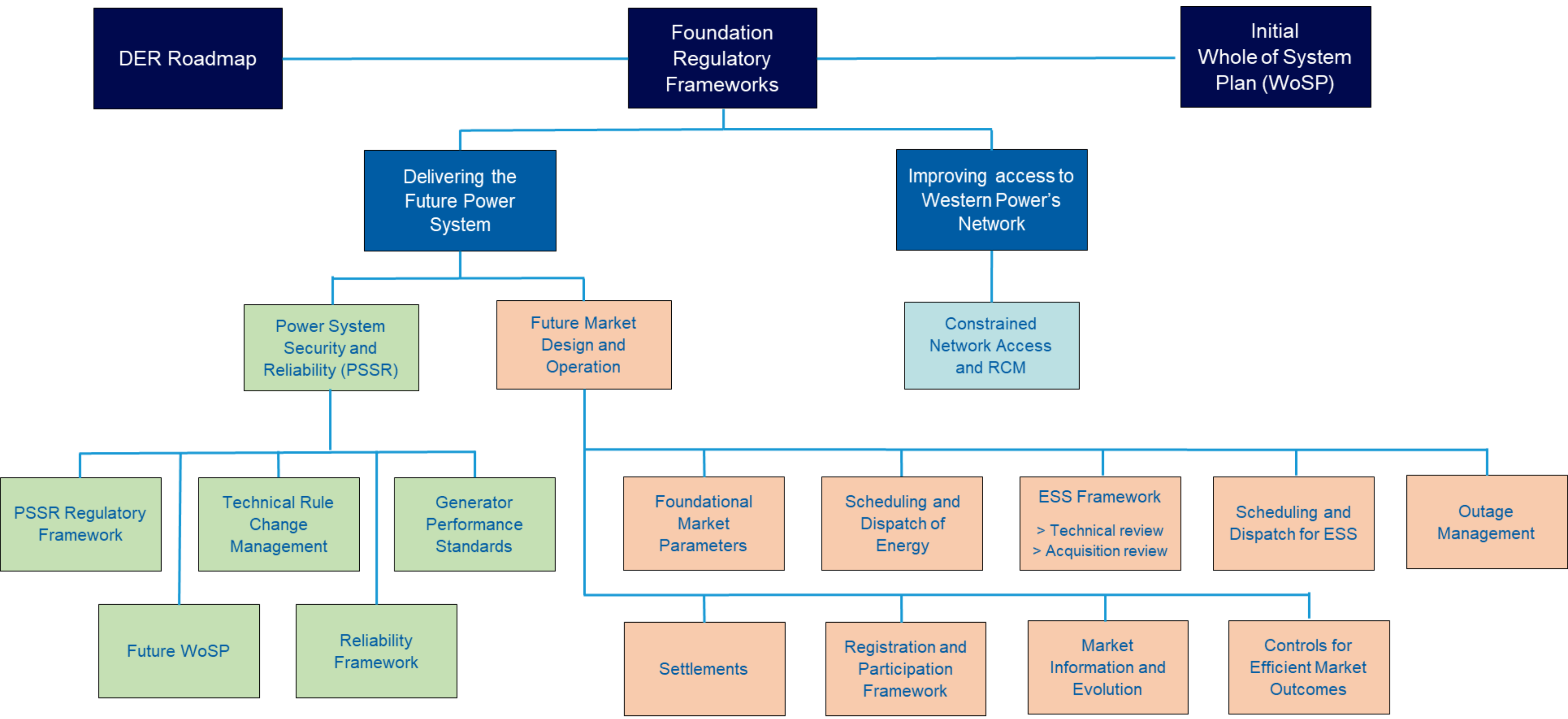
- Energy scheduling and dispatch – Facility Aggregation and FSIPs

REFORM UPDATE

- The Minister has formed the Energy Transformation Taskforce supported by the Energy Transformation Implementation Unit (ETIU) to implement the Government's Energy Transformation Strategy
- The Taskforce is led by an Independent Chair.



FOUNDATION REGULATORY FRAMEWORKS



ESS: Essential System Services
RCM: Reserve Capacity Mechanism

CONSULTATION PROCESS

- MDOWG and PSOWG will remain the primary avenues for consultation with industry on design options and recommendations
- ETIU, AEMO and other industry bodies will continue to collaborate to develop design options
- ETIU will continue to chair the MDOWG and AEMO the PSOWG
- All design recommendations are to be endorsed by the Taskforce
- Information Papers will be published

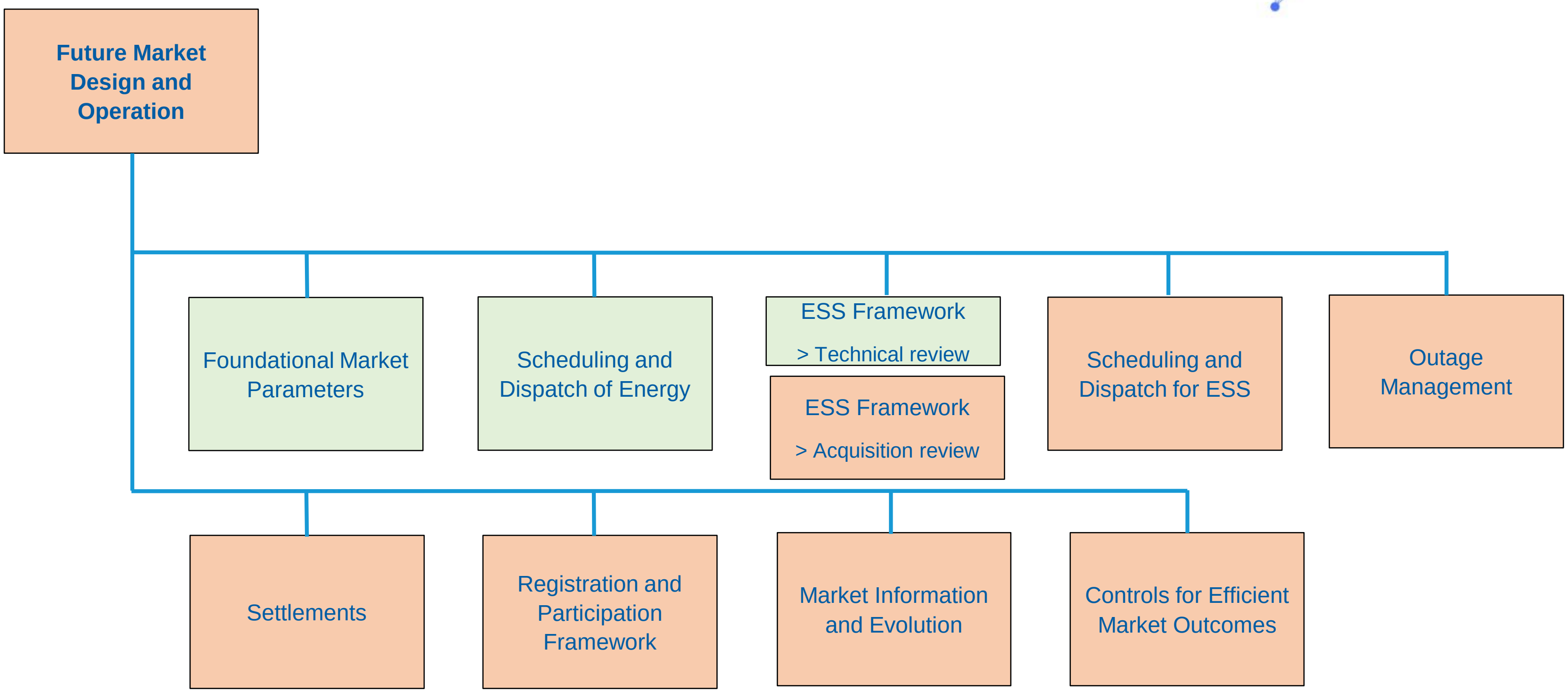
DESIGN DECISIONS REGISTER

- Traffic light reporting
- Hyperlinks to information papers
- Published on ETIU website

Market design feature	Information Paper	Drafting Instructions	Proposed Amending Rules drafted
Fully security-constrained dispatch	Hyperlink to paper	Status of completion	Status of completion Hyperlink to rules
Facility bidding and dispatch			
Co-optimisation of energy and at least some essential system services			

EXAMPLE ONLY

STATUS OF WORK



Papers on the green-shaded items are planned to be published in early August

RECAP OF FOUNDATIONAL MARKET PARAMETERS

- Core design features of the new market:
  - Security constrained economic dispatch (SCED)
  - Individual facility bidding and dispatch
  - Co-optimisation of energy and at least some essential system services
- Supported by:
  - Reduced gate closure – 15 minutes at market start going down to zero in 6 months
  - 5-minute dispatch interval
  - Ex-ante pricing

RECAP

- Other design features:
  - Single zone hub and spoke network model
  - Single reference node at a load centre – Southern Terminal
  - Single market price
  - Both as-generated and sent-out dispatch arrangements possible
  - Settlement design items:
    - 5-min settlement
    - Weekly settlement
    - Whether NWM approach should change
  - Retain constrained-on payments
  - Remove constrained-off payments
  - STEM retained
  - Redefine market power controls in light of other market design changes

AGENDA ITEM 2

ENERGY SCHEDULING AND DISPATCH – FOLLOW UP MATTERS

CONTENTS

- Facility aggregation examples
- Fast start inflexibility profiles

FACILITY AGGREGATION (1)

Offer granularity is the level of detail at which information about each facility is made visible to the market clearing engine

Current state

- Synergy offers as a portfolio into market clearing processes
- Some other facilities represent a single generating unit, some represent a number of aggregated generating units
- Essential system services are cleared separately in advance of energy
- Intermittent generators injecting at a common network connection point must be aggregated. Aggregation of others at AEMO discretion

Future state

- 5-min security constrained dispatch requires facility dispatch for Synergy
- Least-cost dispatch of energy and Essential System Services requires them to be co-optimised together

FACILITY AGGREGATION (2)

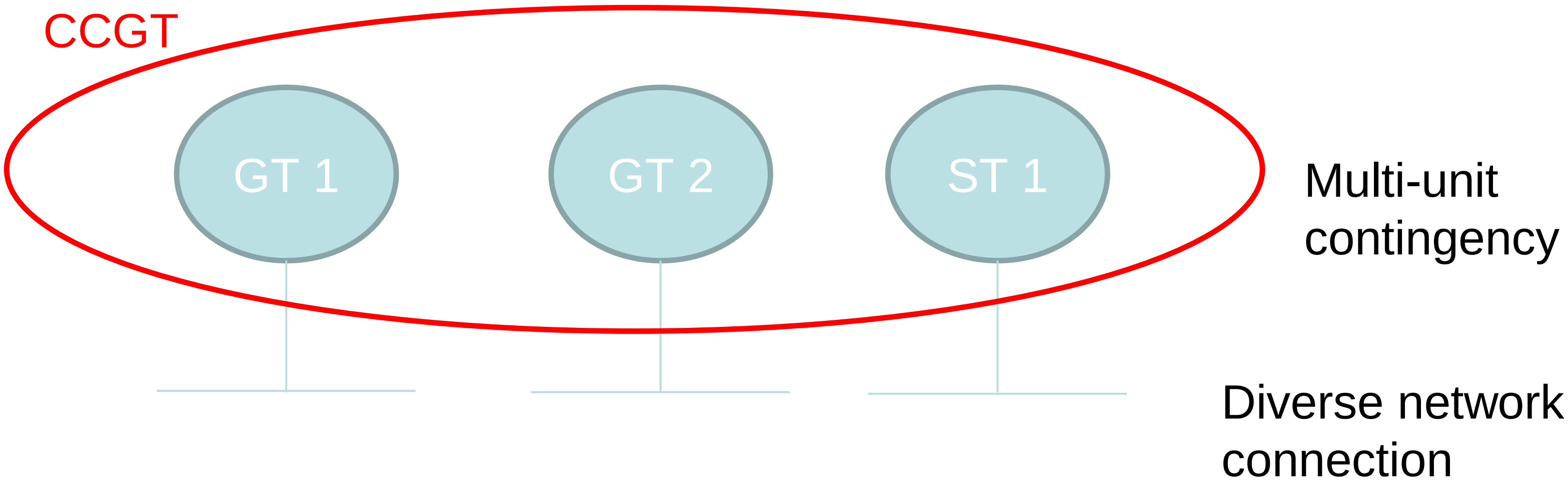
Considerations:

- Offers must be sufficiently granular to make trade-offs visible to MCE
- Aggregation of large generators would change real-time AS results
- Credible contingency may cover multiple generating units (CCGT)

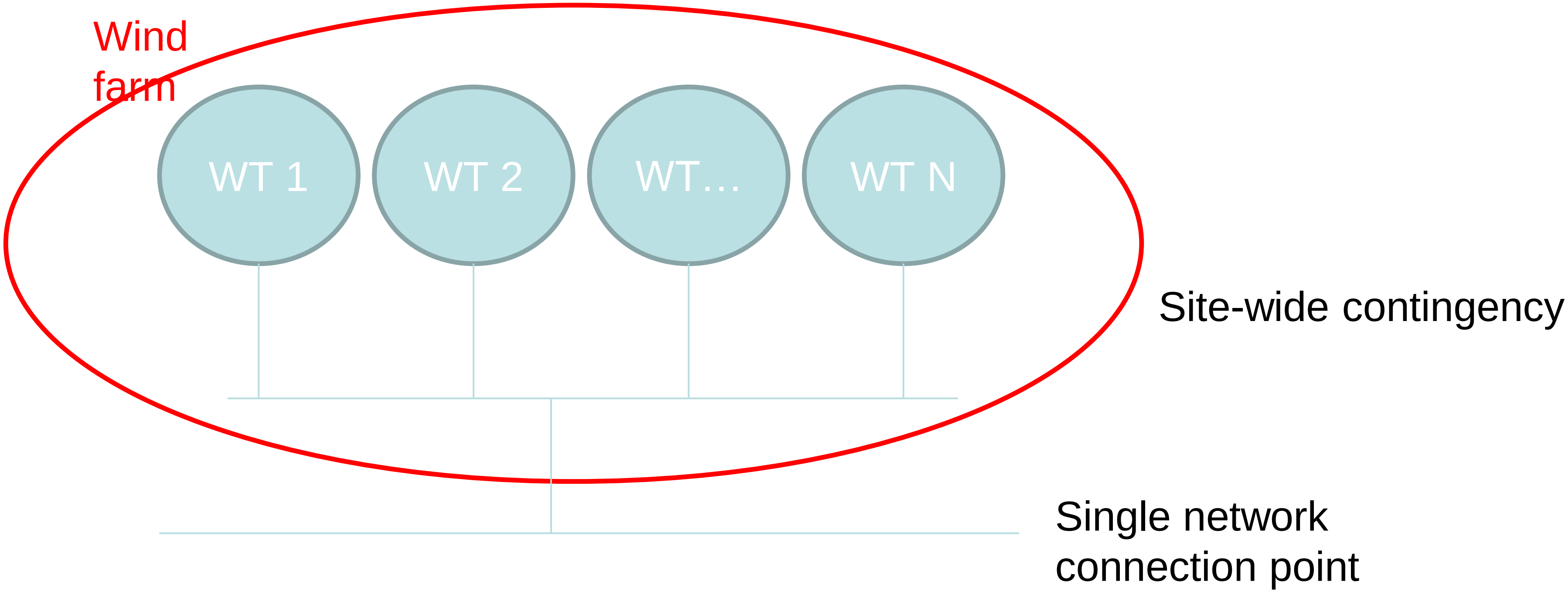
Proposal:

- SCADA visibility and standing data required at generating unit level
- Facility aggregation mandatory where credible contingency is a multiple generating unit outage for reasons other than network connectivity
- Facility aggregation permitted where electrically co-located and ESS results are unlikely to be affected (AEMO discretion)

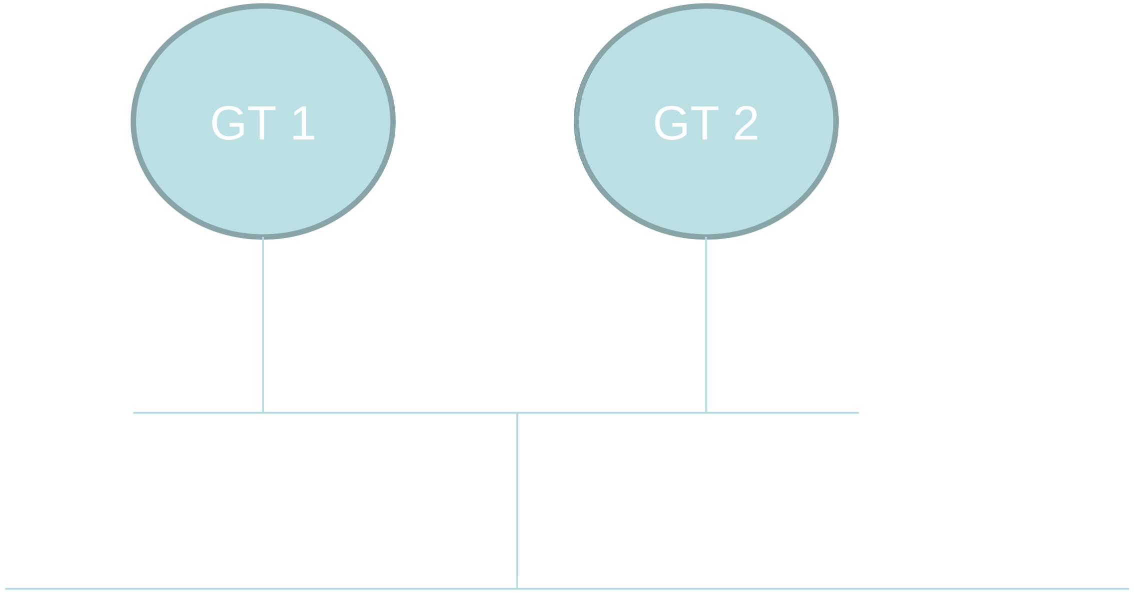
EXAMPLE 1: CCGT – AGGREGATION MANDATORY



EXAMPLE 2: WIND FARM – AGGREGATION MANDATORY



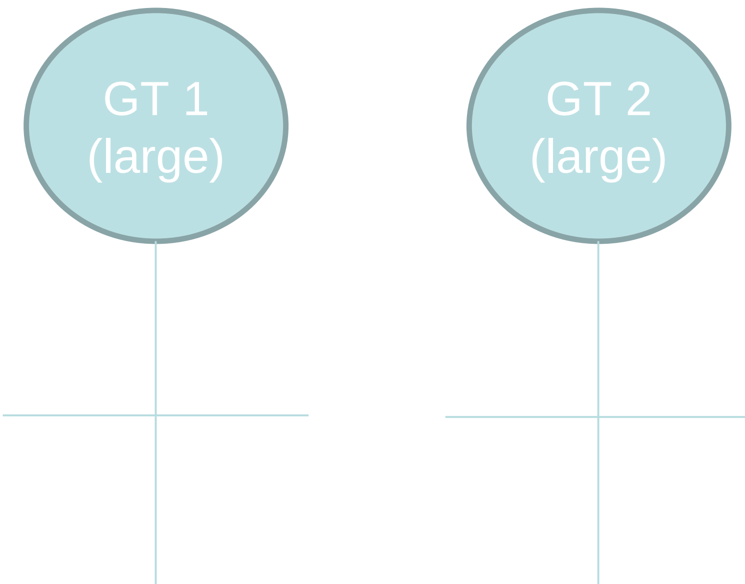
EXAMPLE 3: TWO LARGE UNITS, SINGLE CONNECTION - AGGREGATION MANDATORY



Side-wide contingency

Single network connection point

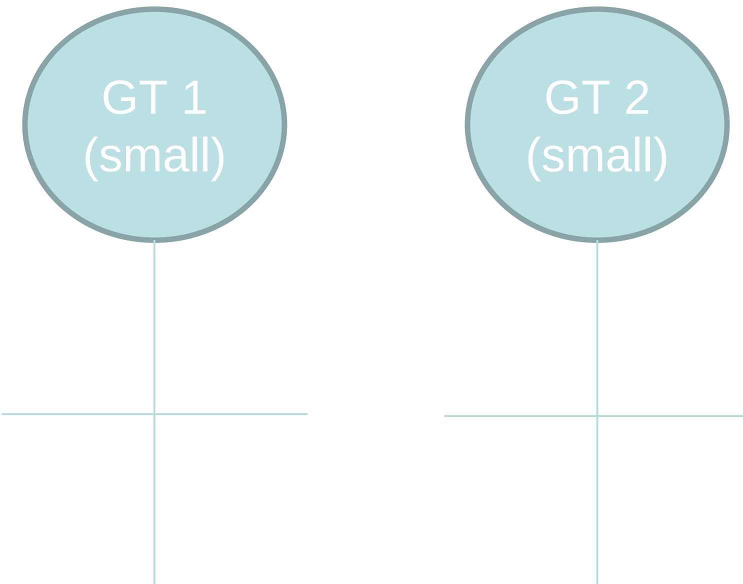
EXAMPLE 4: TWO LARGE UNITS, DIVERSE CONNECTION – AGGREGATION PROHIBITED



No unit dependency

Diverse network connections at same electrical location

EXAMPLE 5: TWO SMALL UNITS, SAME ELECTRICAL LOCATION – AGGREGATION OPTIONAL (AEMO DISCRETION)



No unit dependency

Diverse network connections at same electrical location

TREATMENT OF FAST START UNITS (1)

Current state

- System management commits Synergy facilities
- Other participants reflect commitment decisions in offer structure
- Facilities sometimes receive dispatch instructions they cannot meet (within startup window, or to less than min running), but this is infrequent

Future state

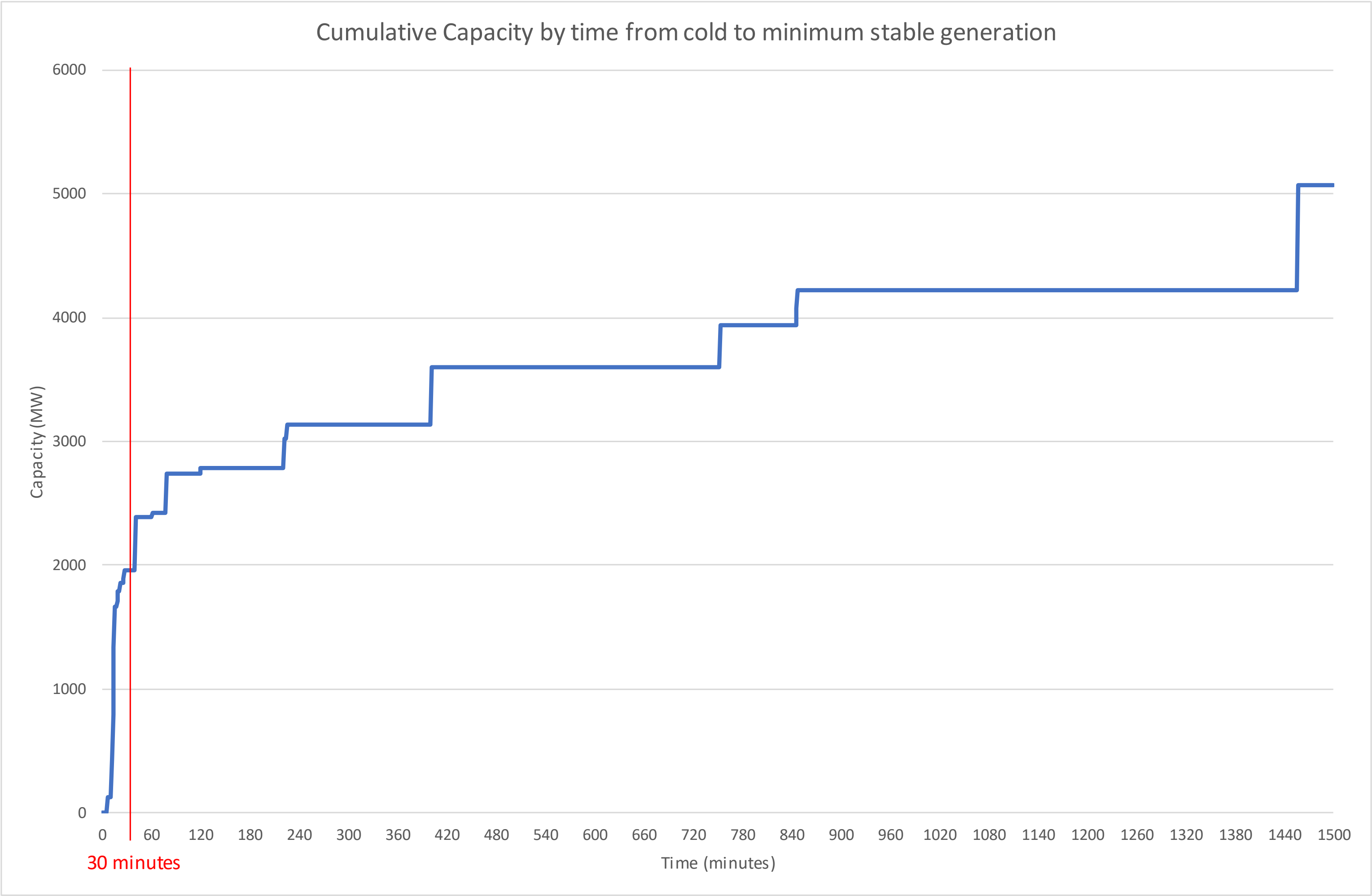
- SM will no longer manually commit Synergy facilities
- Shortened dispatch interval reduces the time for response
- Participants will continue to make their own commitment decisions, but incidence of unachievable dispatch instructions could increase, particularly for fast start units
- Useful to have optional mechanism by which the MCE can reflect the limitations of fast start facilities

TREATMENT OF FAST START UNITS (2)

Considerations

- Mechanism only reflects facility capability, not start costs
- MCE does not optimise across time, but profiles respected across intervals
- Large proportion of WEM fleet can start quickly
  - No facilities can start and reach minimum running within 5 minutes
  - 19 facilities (1600MW) could reach minimum running level within 15 minutes
  - Another 10 facilities (400MW) could reach minimum running within 30 minutes
  - Only two facilities between 30 and 60 minutes
- Respecting startup profiles would reduce likelihood of dispatch instructions that cannot be followed, and help flexible plant to be efficiently used in the real-time market

WEM FLEET START CAPABILITY



TREATMENT OF FAST START UNITS (4)

Design proposal

- Participants can choose to opt-in facilities with start-to-min-running time of 30 minutes or less
- Opt-in facilities submit a start-up inflexibility profile
- Commitment based on the next-but-one 5 minute dispatch interval (e.g. the 5-10 minute interval)
- Clearing engine will dispatch according to startup profile until minimum running reached
- Facilities required to follow startup profile and are not permitted to re-bid to avoid starting up
- Facilities operating within inflexibility profile not eligible to set price
- Facilities not compensated for losses if market price dips while operating within inflexibility profile.

Further work

- Need to consider power system security implications for scenarios where the startup of a facility fails
- Need to consider longer startup facilities (likely through other mechanisms such as Pre-Dispatch and PASA)

QUESTIONS/FEEDBACK

- Please email marketdesign.wg@treasury.wa.gov.au

Government of Western Australia
Department of Treasury

Energy Transformation Implementation Unit

Essential System Services – Part 1

3 July 2019

CONTENTS

1. Introduction: Why do we need to review ESS?
2. New technical framework for Essential System Services^
3. Approach to Contingency Frequency Response
4. Evaluation of technical options
5. Other ESS
6. Next steps

^ Essential System Services captures all services that can be used to maintain system security and reliability. This new term reflects the essential nature and applicability of such services to the entire system.

Introduction – why review ESS?

HOW DO WE ACQUIRE ESS TODAY?

Category	Current Ancillary Services	Purpose	Size	Market compensation ($ '19)	Acquisition method
1. System-wide Frequency Control	Connection obligations for freq resp	Helps to maintain frequency stability	0~20MW	$0m	Mandated in technical rules
	LFAS	Correct supply/demand forecast error	72MW up 72MW down	$79m	Bidding Market and Synergy mandated (Backup LFAS)
	SR	Stabilise frequency after contingency	~238MW	$22.5m	Synergy mandated default, contracts for cheaper providers
	LRR		120MW	$1m	
2. Locational Services	DSS (AEMO)	Special services not available via other means, e.g. voltage support additional to network/NCS.	0MW	$0	Contract (tendered)
	NCS (Western Power)	Network augmentation alternative, (e.g. reliability improvement)	N/A	N/A	N/A
	System restart	Re-energise SWIS after cascade failure	3 facilities (geog. diverse)	$1m	Contract (tendered)
3. Emergency & Scarcity Response	Emergency Response	Secure power system operation/restoration	N/A	$0m	Powers of direction in WEM rules

DRIVERS FOR CHANGE

Energy transformation means power system is changing in both demand and supply

Technical

Aggregate power system physical characteristics and service requirements evolving

Traditional equipment has different needs and capabilities from new fleet

New technologies can provide system services in different ways

Market / economic

Inefficiencies in existing dispatch of AS

Lack of providers/ineffective entry and exit signals

New opportunity for co-optimisation of Energy and ESS

Policy

Introduction of Synergy facility bidding & dispatch

DER roadmap

WoSP

Operational

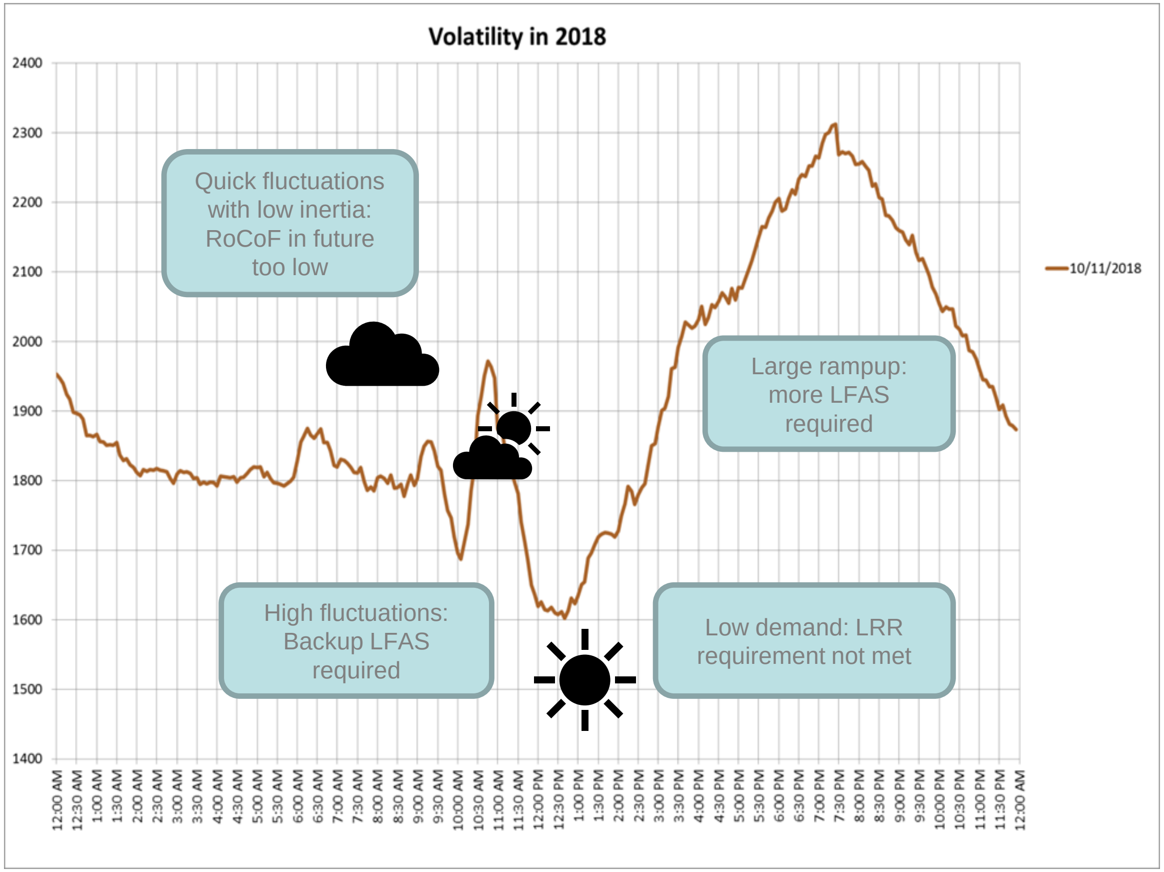
Security Constrained Economic Dispatch

Gate closure much closer to real time

Introduction of 5 minute dispatch

INCREASING LOAD PROFILE VOLATILITY CREATES URGENCY

- **LOW DEMAND CHALLENGES**
- **DECREASING INERTIA LEVELS**



WHAT IS THE PROBLEM?

Overall problem

The current ancillary services framework is inadequate for the current and future environment in respect of speed of response, duration, and service types (frequency, local/voltage, emergency).

This is because the current and future environment will have different (more challenging) power system dynamics, as a consequence of:

- the increase of DER and utility scale renewable generation
- the decline of synchronous generation
- the opportunities for service provision by new technologies.

Problem areas / Sub-problems

Lack of diversity in participation

- Non-scheduled generators unable to participate fully in ESS
- DER opportunities are restricted
- Barriers to entry by utility storage
- Synergy is the default provider. Market concentration and network access limitations discourages new entrants

No co-optimisation with energy

- Absence of Synergy facility bidding means that automated co-optimisation between energy and AS is not possible,
- No price driven competition with administered Synergy prices

Suboptimal acquisition methods

- No price driven competition with Synergy admin prices
- Prices have increased over recent years but cause is unclear
- Current acquisition methods don't stimulate new technologies, DER, to participate in ESS provision
- Difficult to design for a new future without benchmarks

Cost inefficiencies and lack of transparency

- The existing market based procurement mechanism for LFAS lacks transparency and effective pricing review mechanisms
- Uncertainty about effective cost allocation
- Emergency powers do not specify obligations and cost recovery arrangements for participants

Alignment and clarity of regulatory instruments and standards

- NCS vs. DSS → Western Power vs. AEMO accountabilities
- Network investments as a means to provide ESS
- DSO market participation is not possible.

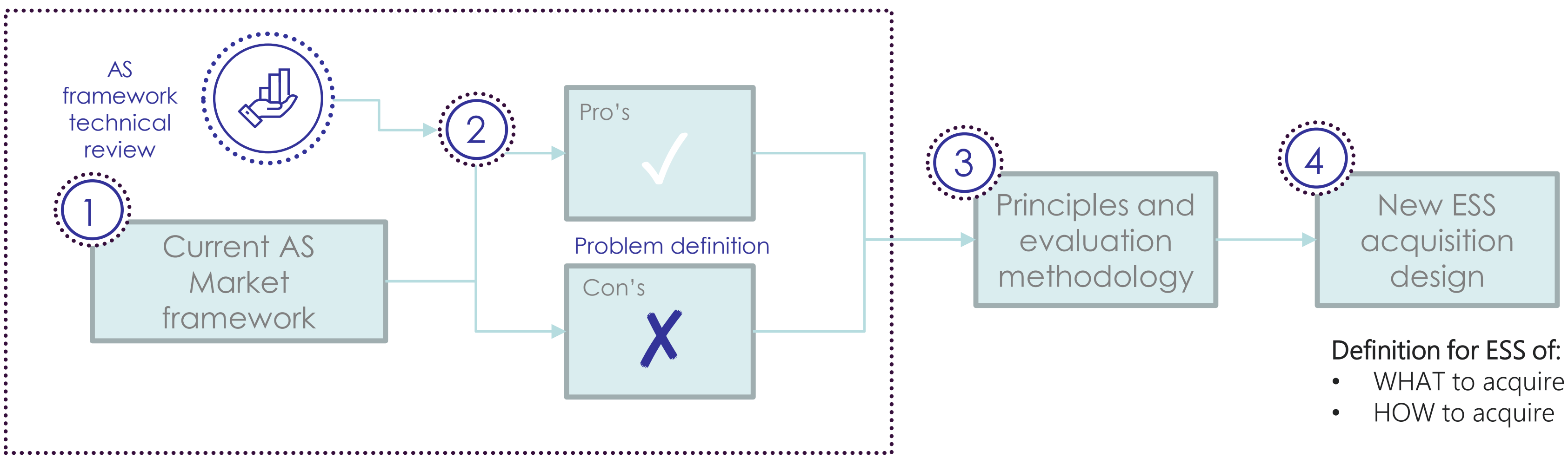
DEFINING THE FUTURE: CORE QUESTIONS

What services will we have?

For each service:

- How much do we need to acquire?
- What is the method for determining real-time requirements?
- How do we acquire the service (mandate/real-time market/contract market)?
- How is the service operationalised for dispatch?
- How will the costs be recovered?
- How will we monitor compliance?

APPROACH TO ANSWERING THE QUESTIONS



Definition for ESS of:

- WHAT to acquire
- HOW to acquire

X **Note:** numbers refer to steps

ESS technical framework

ESS TECHNICAL FRAMEWORK REVIEW

Category	Current Ancillary Services (AS)	Expected Future Essential System Services (ESS)
1. Frequency Control	Technical Rules (connection obligations for frequency response)	Connection Standards (include Generator Performance Standards)
	Load Following Ancillary Service (LFAS)	Frequency Regulation
	Spinning Reserve Service (SR) Load Rejection Reserve (LRR)	**Primary Frequency Response (under 2 and 6 seconds) + RoCoF**
		Secondary Frequency Response
2. Locational and other Services	Dispatch Support Services (AEMO)	Further assessment necessary
	Network Control Services (Western Power)	
	Black start	System restart (linked to the system restart standard)
3. Emergency Response	WEM Rule 7B.3.8. System Management can set aside LFAS and Balancing Merit Order to operate the SWIS in a reliable and safe manner	System Management will retain powers to direct operation in emergency conditions.

Area of current focus

CHANGING DEFINITIONS FOR CONTINGENCY RESPONSE

Current definitions are defined by initial response time and duration of sustain. Eg Spinning Reserve:

- Respond within 6 seconds, sustain for 60 seconds
- Respond within 60 seconds, sustain for 6 minutes
- Respond within 6 minutes, sustain for 15 minutes

Enablement decisions use a flat MW figure.

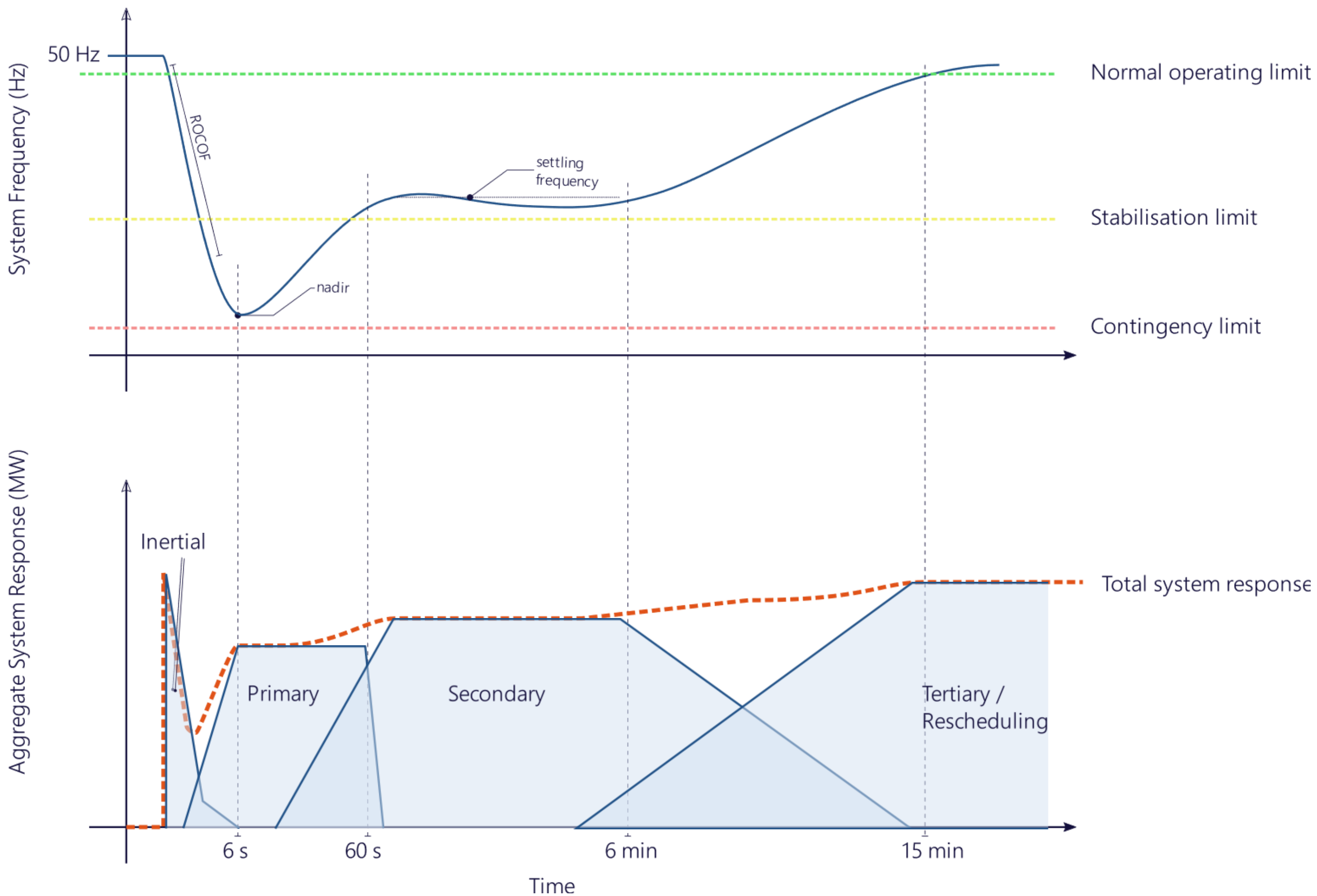
In the future power system, the critical period will be inside 6 seconds, due to:

- the direct relationship between total system inertia, RoCoF and required quantum of reserve (therefore likely cost)
- the changing capabilities of connected services.

Therefore, service definitions will be defined using the response required from the system to meet FOS (a required response curve).

REQUIRED CONTINGENCY RESPONSE CURVE

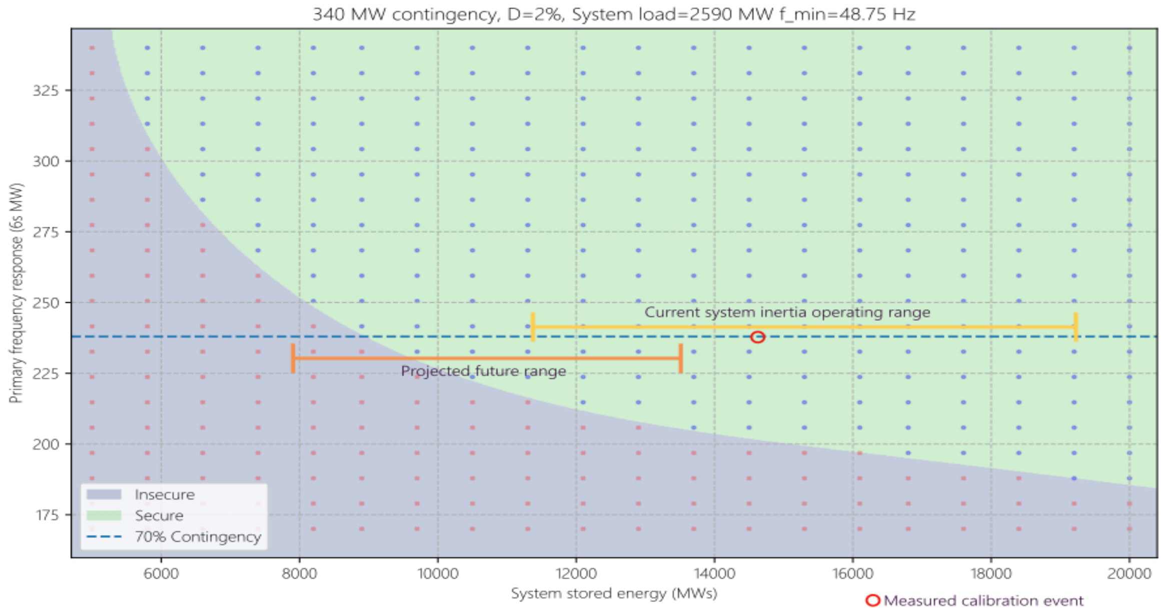
- Primary phase – to arrest divergence and limit nadir
- Secondary phase – to settle frequency
- Tertiary phase – restore to normal limit



RELATIONSHIP BETWEEN INERTIA AND PFR

As presented at PSOWG and captured in the Contingency Frequency Response in the SWIS paper^, there is also a relationship between available inertia and required PFR:

For a given contingency size, the required level of PFR can be reduced as the inertial response is increased (and vice versa)



Paper published - https://www.erawa.com.au/cproot/20175/2/2019.02.11%20--%20Presentation%204%20--%20Contingency%20Response%20in%20the%20WEM%20-%20AEMO.PDF

COMMONALITY BETWEEN PFR AND SFR

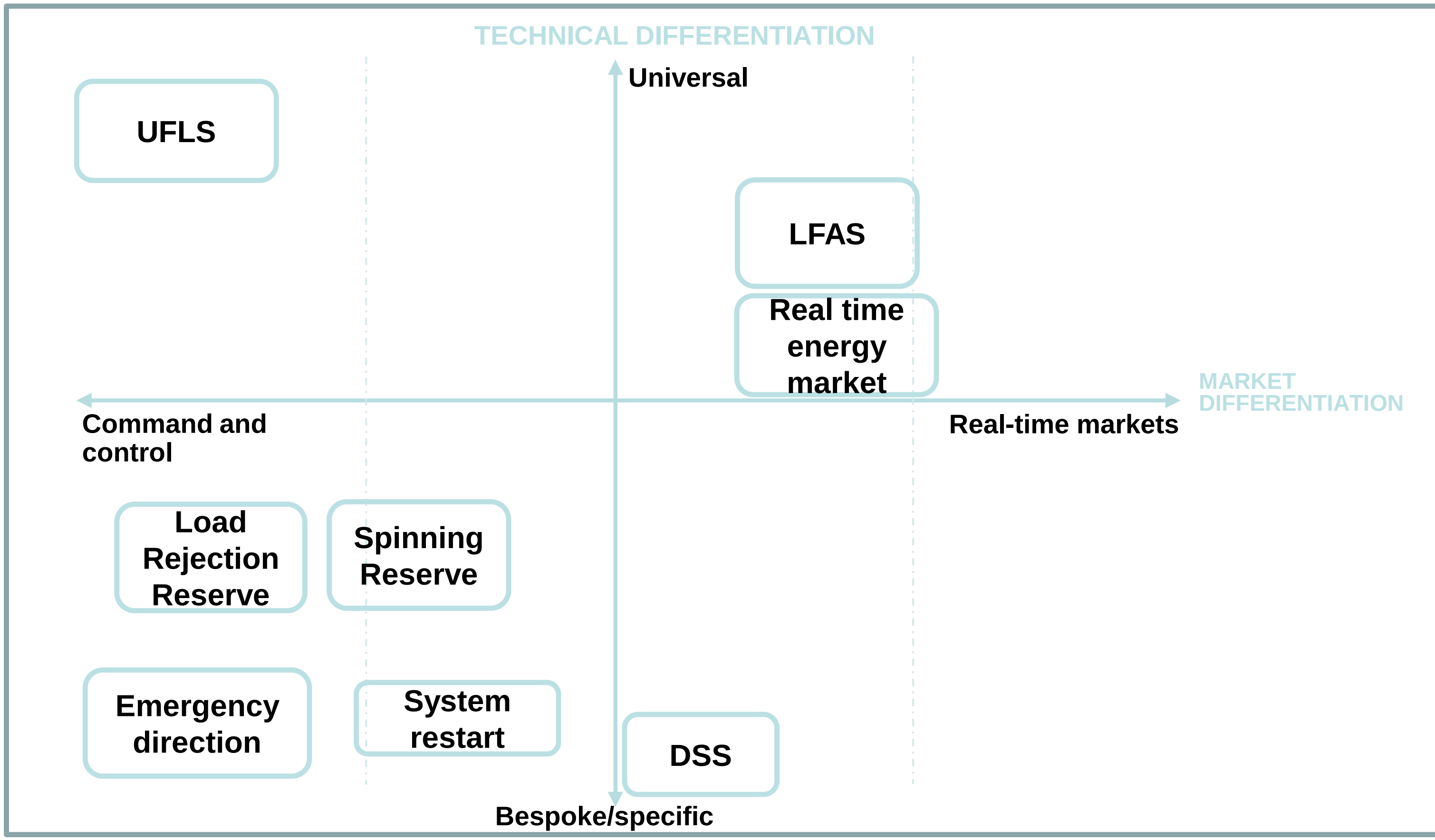
There is also a potential commonality between PFR and SFR

- PFR operates automatically to prevent the frequency from falling too far (keeping the system operating within the Frequency Operating Standards)
- SFR responds to instructions issued by AEMO to “take over” from PFR and move the frequency back towards 50Hz

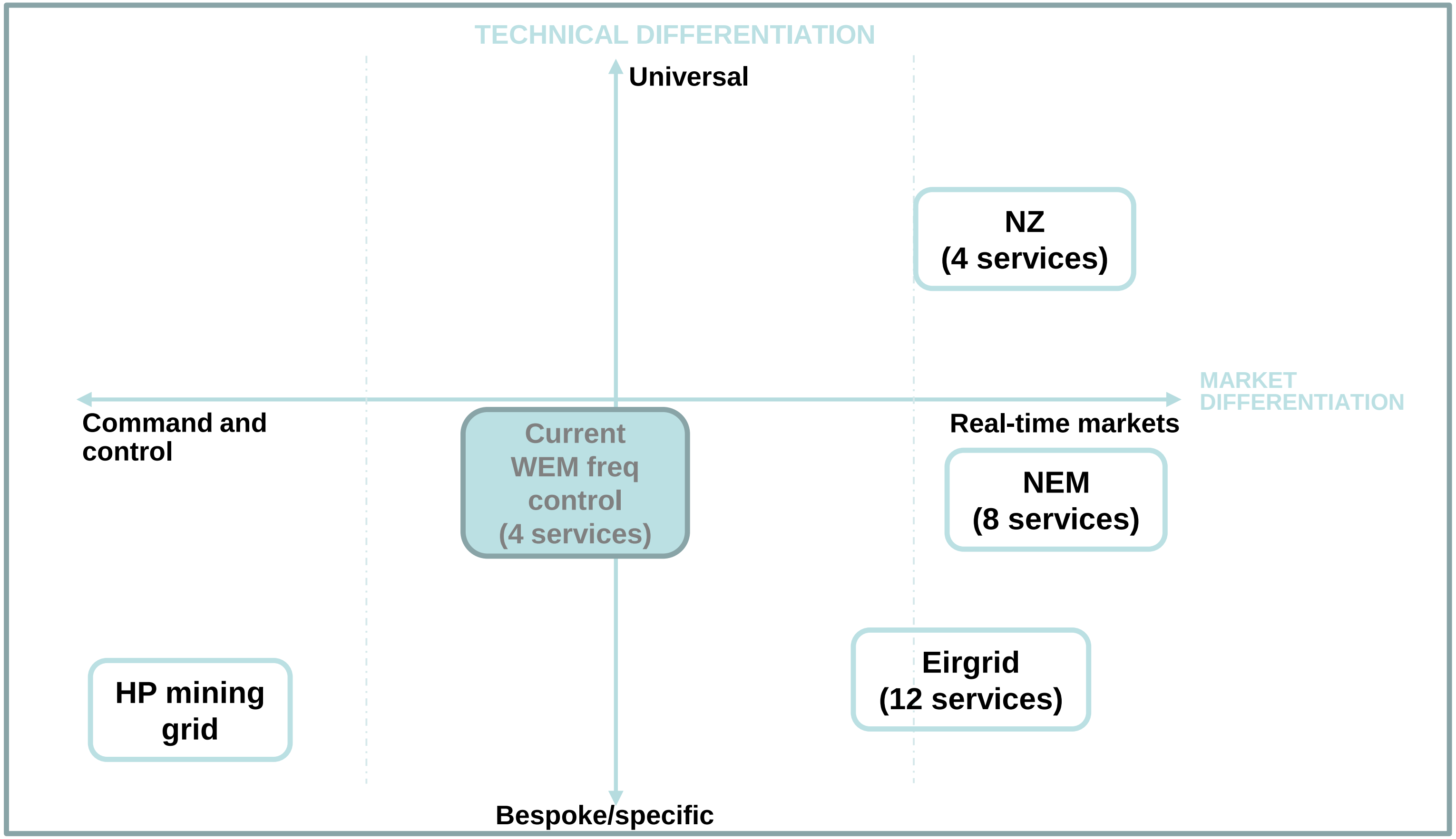
Many facilities can provide **both** PFR and SFR, responding both automatically and in response to AGC instructions and sustaining/ increasing their response over the full timeframe.

Approach to contingency response

2 DIMENSIONS OF SEGMENTATION – CURRENT WEM SERVICES

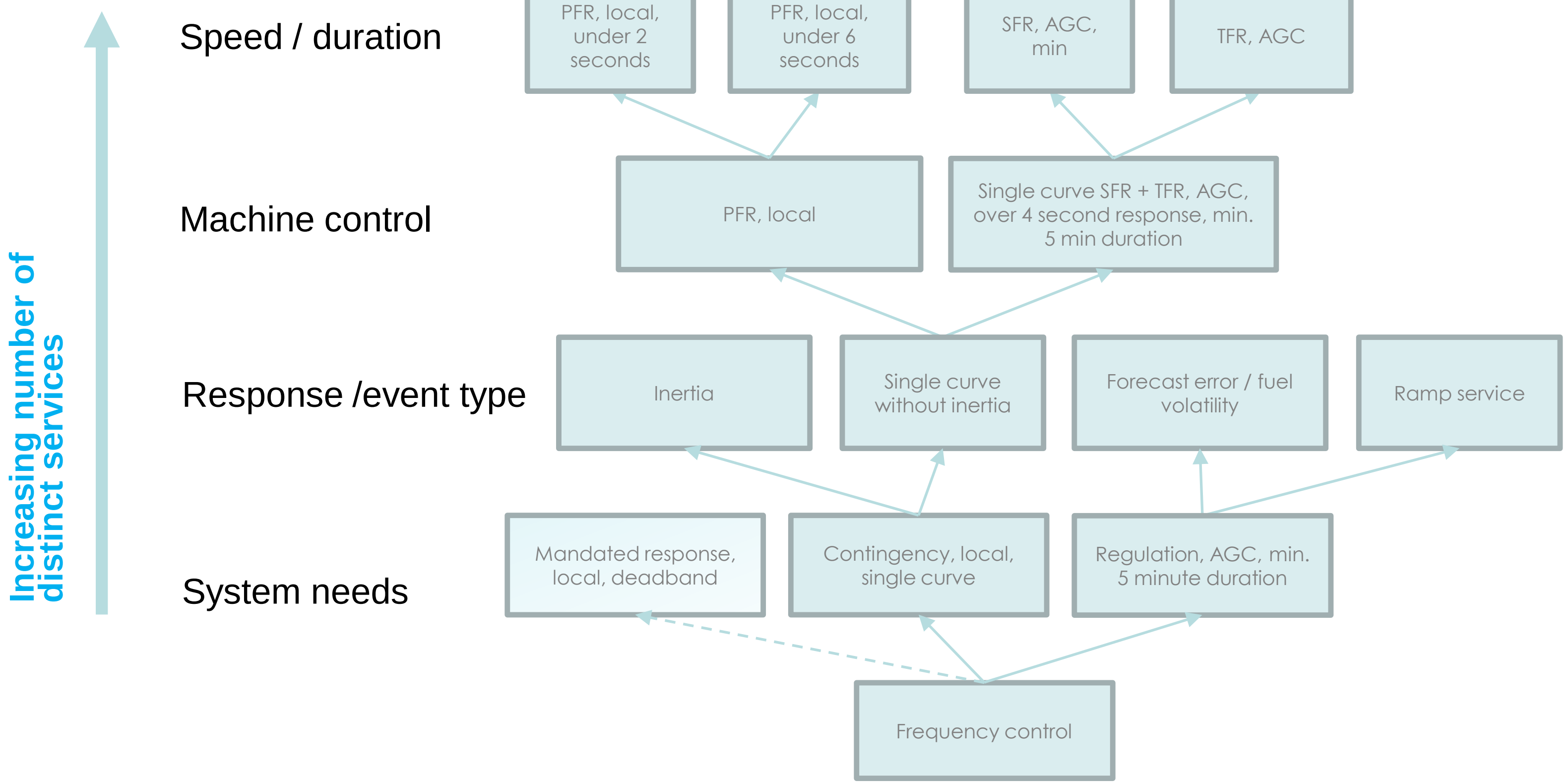


2 DIMENSIONS OF SEGMENTATION – INTERNATIONAL FREQUENCY CONTROL SERVICES

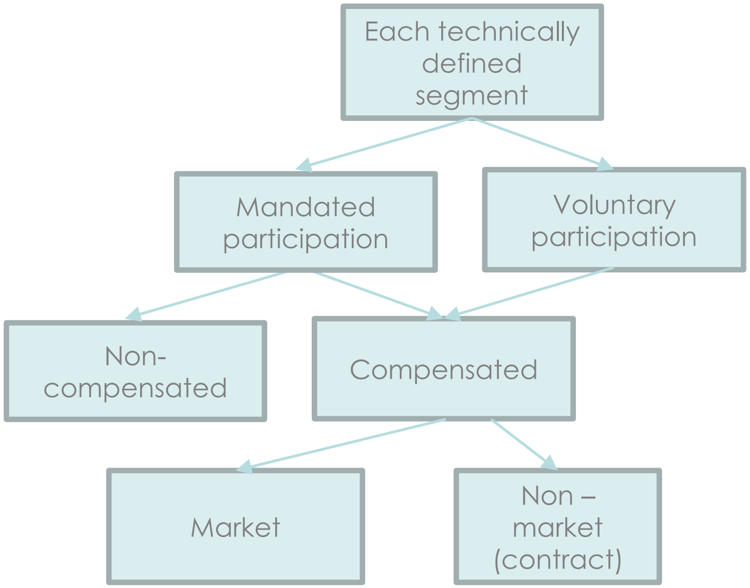


TECHNICAL DIFFERENTIATION FOR FREQUENCY RESPONSE

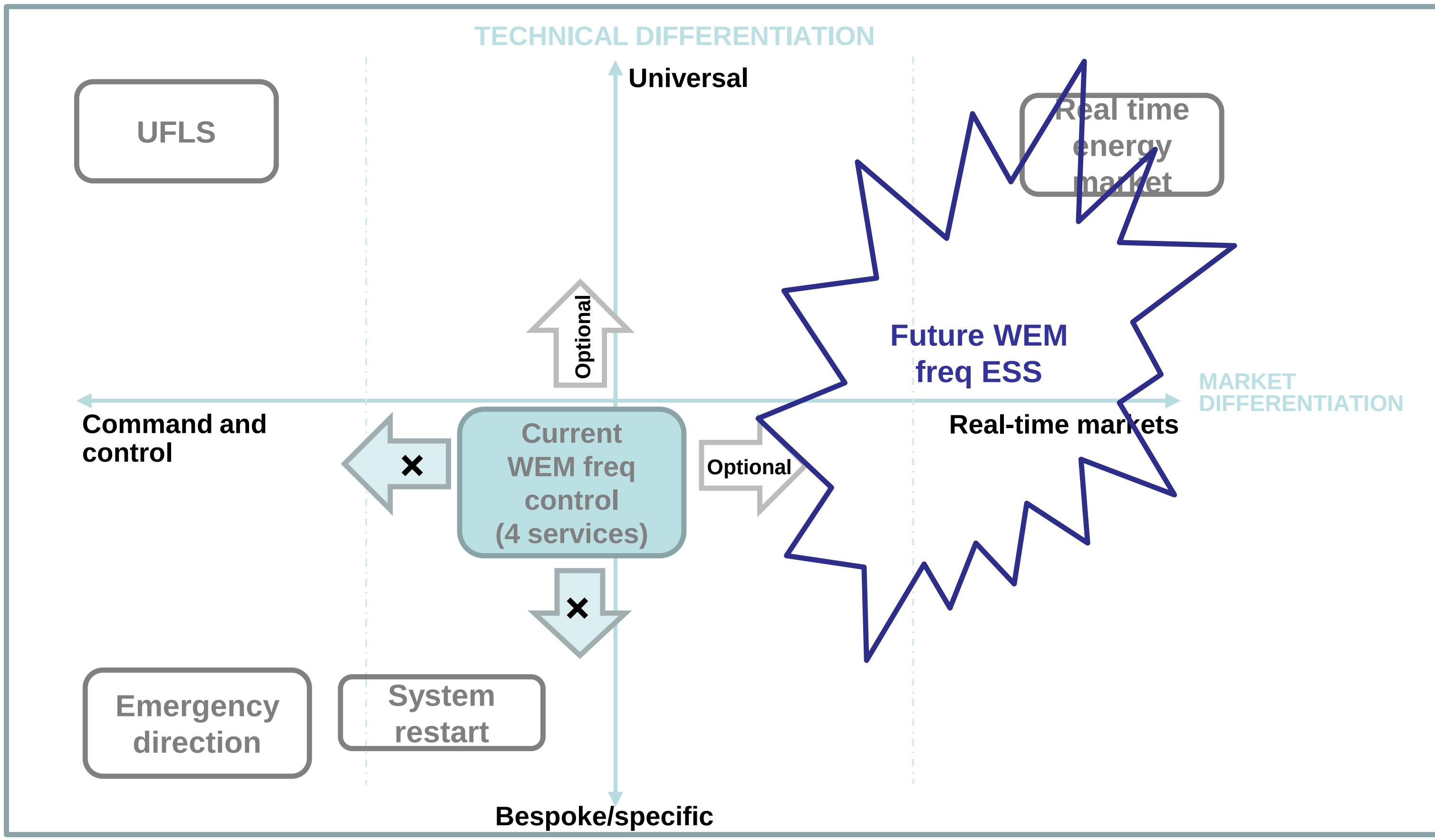
Segmentation options



SECOND SEGMENTATION: ACQUISITION METHOD



2 DIMENSIONS WITH EXPECTED FEASIBLE SOLUTION SPACE



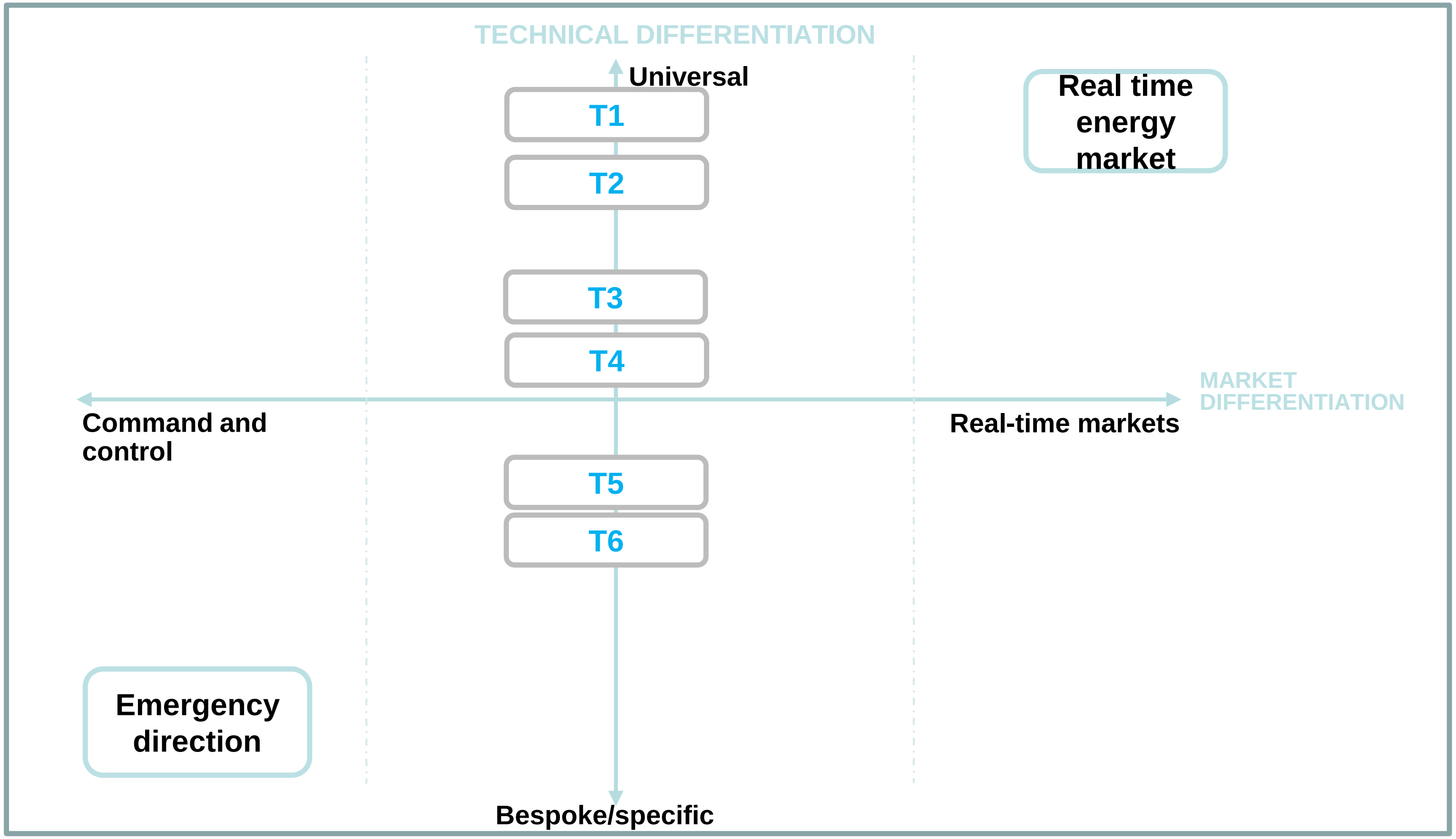
TECHNICAL SEGMENTATION OPTIONS FOR CONTINGENCY RESPONSE

All options deliver frequency operating standard

#	Specification	Time segments
T1	One contingency response service (single response curve or two equivalent response curves)	0.25 s to 15 min
T2	T1+RoCoF	
T3	Two contingency response services, segmented by time	a) 0.25s to 2s b) 2s to 15 min
T4	T3+RoCoF	
T5	Three contingency response services, segmented by time	a) 0.25s to 2s b) 2s to 60s c) 60 s to 15 min
T6	T5+RoCoF	

Question: What are your thoughts on contingency reserve segmentation?

TECHNICAL OPTIONS MAPPED



Evaluation of technical options

Meeting the design principles

GUIDING PRINCIPLES OF REFORM

All design features:

- Measured against WEM objectives
- Fit-for-purpose for WEM, learning from best practice approaches in other jurisdictions
- Align control and responsibility for market outcomes to empower entities able to effect an outcome to do so
- Avoid unnecessary cost impost and administrative/regulatory burden (consider practicality of implementation)
- Avoid complexity if no demonstrable benefit
- Improve transparency of information and outcomes

KEY PRINCIPLES FOR ESS ACQUISITION

- Allow delivery of a secure power system
- Ensure they are compatible with foundation design decision of cooptimisation
- Maximise use of diverse fleet capability (both existing and future)
- Do so at efficient overall system cost
- Support effective ex-ante control and ex-post monitoring of efficient market outcomes
- Minimise regulatory burden
- Be practical to implement and operationalise

ANALYSIS OF SEGMENTATION OPTIONS

Thank you for contribution to data to support the detailed modelling work.

Modelling will kick off once that data is in, and will run over three months (including assumptions document) to quantify the overall case for change, as well as options within areas such as this one.

Currently exploring implications and drivers between options using simpler methods until data available.

INITIAL HIGH LEVEL ASSESSMENT

- Key considerations for segmentation

Option	Can it deliver a secure system?	Can it be cooptimised?	Is all facility capability accessible?	Compliance burden	Efficient overall cost?	Supports efficient market outcomes?
T1	Yes	Yes	Work underway	Lowest	TBC	TBC
T2	Yes	Yes		Low		
T3	Yes	Yes	Yes	Moderate		
T4	Yes	Yes	Yes			
T5	Yes	Yes	Yes	Higher		
T6	Yes	Yes	Yes	Highest		

DRIVERS AND DYNAMICS

In general, the more that individual facilities vary in their ability to deliver responses in each part of the curve from a single cost base, the more value can be generated from increased numbers of segments.

Conversely, if facilities can meet the requirements of the whole curve from the same cost base (e.g. start and run cost for GTs), the benefits of increased segmentation of contingency response are limited.

When assessing impacts of segmentation, we want to avoid:

- opportunity to game
- increased complexity of market power monitoring and control

To assist in narrowing down options, we have developed a simple co-optimisation model to explore facilities offering services based on pricing derived from the current definition of SRMC.

INITIAL RESULTS FROM SIMPLE MODEL

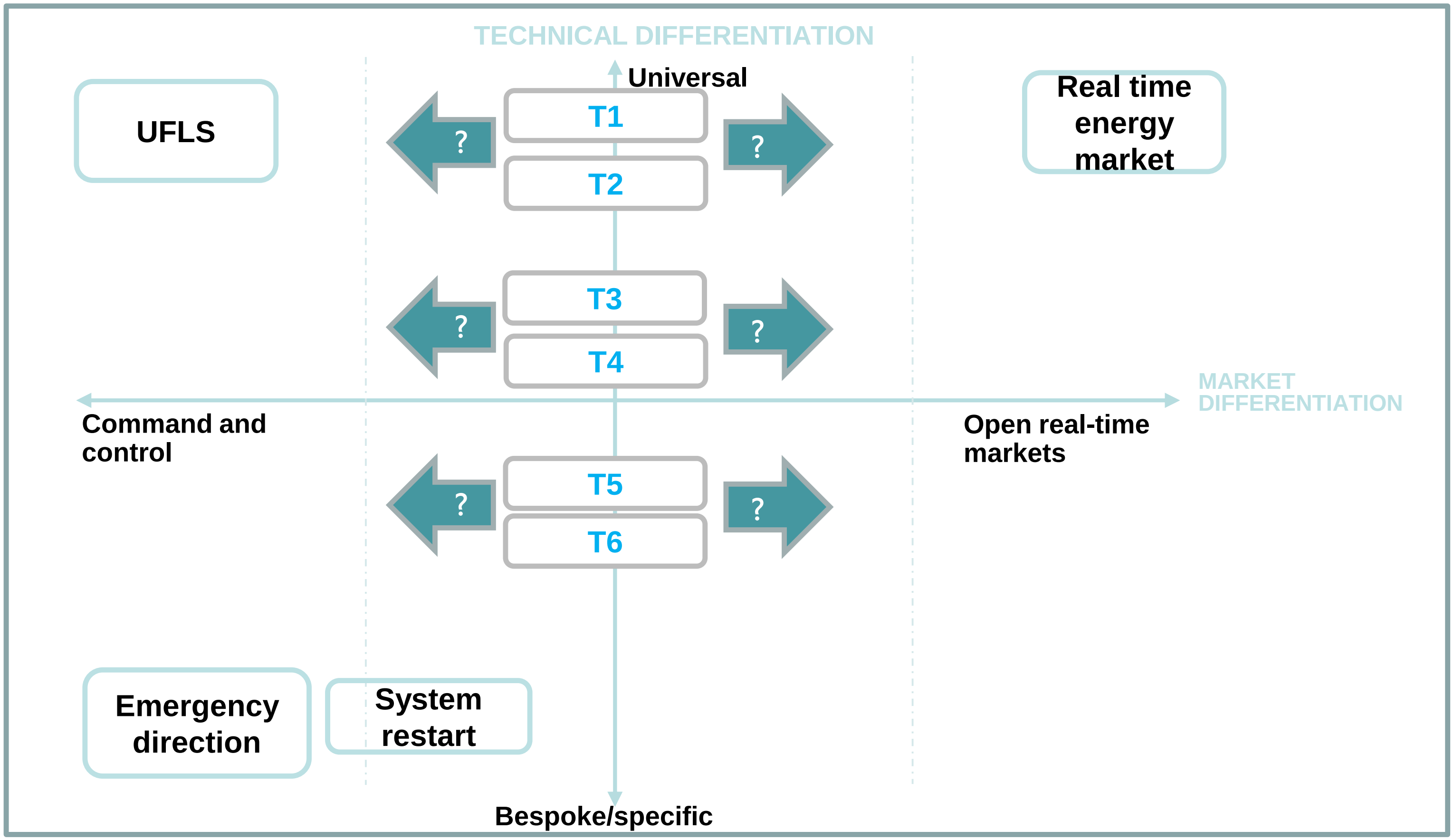
Given the following assumptions:

- Secondary reserve MW requirement > primary reserve MW requirement
- Variability in capabilities, i.e. some units can provide more primary than secondary reserve
- ESS offers constructed based on short run cost (including start cost if applicable)

If we then introduce random fluctuations around offers to reflect imperfect knowledge, and perform a simple cooptimisation of energy and reserve classes, we can gather some potential design insight.

Implications: it may be possible for a greater number of contingency reserve markets to drive undesirable outcomes. To be confirmed using data from participants.

NEXT STEP: ACQUISITION OPTIONS FOR SUITABLE TECHNICAL OPTIONS



Note: WEMSIM modelling to be done using the input from market participants

NEXT STEPS

Contingency response:

- accreditation
- operationalisation
- cost recovery
- compliance and monitoring
- market power implications

Other ESS acquisition (regulation, locational)

Scheduling and dispatch arrangements

GOVERNMENT OF WESTERN AUSTRALIA
Department of Treasury

Energy Transformation Implementation Unit

RCM Update

3 July 2019

PROJECT MILESTONES

Jul 2019
In-principle support from Taskforce for the proposed changes to the Reserve Capacity Mechanism.

Oct 2019
Taskforce endorses the proposed approach to allocate capacity in a constrained grid.

Nov 2019
- Minister endorses the constrained access implementation approach
- ERC/Cabinet endorses the constrained access implementation approach

Q3 2019	Q4 2019	Q1 2020	Q2 2020

Aug – Sep 2019
Industry consultation on proposed approach to allocate capacity in a constrained grid.

Nov – Dec 2019
Industry consultation on regulatory amendments

Early 2020
- Taskforce endorses the regulatory amendments
- Minister endorses the regulatory amendments

Mid-2020
Regulatory amendments enacted