GOVERNMENT OF WESTERN AUSTRALIA
Department of Treasury

Energy Transformation Implementation Unit

Transformation Design and Operation Working Group

Meeting 1 – 12 August 2019

ESTABLISHMENT OF THE TDOWG

- Chaired by the Energy Transformation Implementation Unit (ETIU) on behalf of the Energy Transformation Taskforce.
- Provides a forum to engage with stakeholders on Energy Transformation Strategy workstreams.
- Replaces the previous market design and power system operation MAC working groups.
- A terms of reference will be emailed to stakeholders.
- Meetings will be held at Treasury or other venues.

GROUND RULES

- The Chair will aim to keep the meeting to time so that we can get through the large volume of material for discussion.

- Questions and issues raised must be kept relevant to the discussion. Other matters can be raised at the end of the meeting or via email to marketdesign.wg@treasury.wa.gov.au

- Please state your name and organisation when you as a question to assist with meeting minutes.

- This meeting will be recorded for minute-taking.

CAPACITY CREDITS IN A CONSTRAINED NETWORK

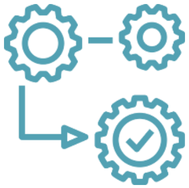
THE NEED FOR REFORM

Purpose of the Reserve Capacity Mechanism (RCM)

The RCM is important considering the South West Interconnected System (SWIS) is a small isolated system with high peak demand.

- ✓ Provide consumers with a reliable electricity supply
- ✓ Incentivise sufficient investment in capacity to meet demand
- ✓ Provide generators certainty about revenue adequacy

Issues arising from the transition to a constrained network access model:



Network constraints will be a more prominent factor in accrediting and allocating Capacity Credits to facilities

Accounting for constraints may create an uncertain outlook for existing and new investment in capacity

Could result in new entrants displacing incumbents’ Capacity Credits, creating an unhedgeable risk

PREVIOUS PROPOSAL

In 2018, the Public Utilities Office consulted on the Capacity Priority Rights concept which aimed to:

Maintain investor certainty

PUO proposed to allocate rights that would protect an incumbent's capacity revenue from being displaced

Provide locational signals

New entrants that displace incumbents' Capacity Credits would be required to reimburse the revenue associated with those credits

Maximise Reserve Capacity

Prioritise the allocation of Capacity Credits to generators that contribute least to network constraints

STAKEHOLDER FEEDBACK

Stakeholders supported:

- Accounting for constraints in allocation of Capacity Credits
- First in first serve rights, protecting capacity investments

Stakeholders raised the following issues:

- Complexity, difficulty for investors to interpret
- Interference with contracts
- Gaming, increasing barriers to entry
- Duration of rights being inadequate
- ‘Use it or lose it’ clause causing unintended consequences

Stakeholders suggested:

- Adopt an approach similar to the Generator Interim Access solution
- Locational pricing

OUR OBJECTIVES

Investment certainty

Maintain the level of investment certainty the RCM currently provides

System reliability

Reward capacity for the reliability it provides to the system

The ETIU assessed alternative methods based on:

1. Minimising complexity
2. Minimising contractual interference
3. Minimising barriers to entry and exit

UPDATED PROPOSAL

Capacity Credit Rights to protect the quantity of Capacity Credits from being displaced for a period of time

Existing generators

Capacity Credits based on previous allocations

New generators

Capacity Credits up to the residual capacity in the network

Capacity Credits will not be allocated beyond the physical limitations of the network

Holders of Capacity Credits will retain the obligation to provide their capacity

Similar to the current Constrained Access Entitlement allocation process (under the GIA)

PROPOSAL ASSESSMENT

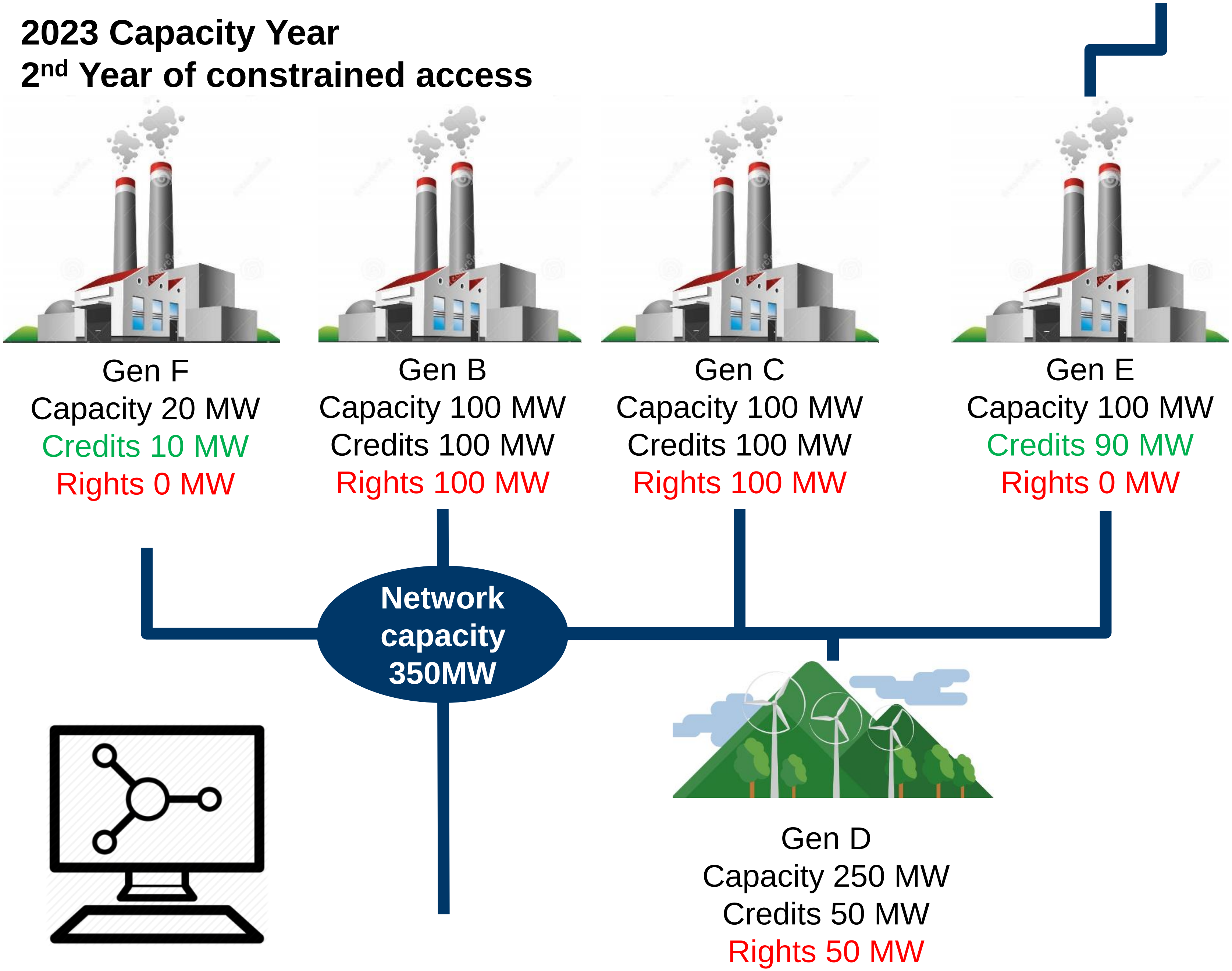
✓ ADVANTAGES

- ✓ Simple to understand and implement
- ✓ No contractual interference
- ✓ Maintains principle that 1 Capacity Credit = 1 MW of physical capacity
- ✓ No change to reserve capacity credit obligations
- ✓ Locational signals

POTENTIAL DISADVANTAGES

- Potential for disconnect between outcomes in the capacity mechanism and energy market
  - BUT the system will still deliver the required capacity during peak
- Potentially less opportunity for new entrants to secure capacity credits
  - BUT new entrants gain access to the network without need to fund network augmentation

2023 Capacity Year
2nd Year of constrained access



MORE WORK REQUIRED

Further work required to develop the design, including:

Develop process for accrediting and allocating residual capacity to new entrants	Interaction with Relevant Level Method (RLM) and facility performance
Timing of reforms	Impacts on existing Reserve Capacity Cycle timeline

NEXT STEPS

Early September 2019
Detailed design proposal for feedback

September – October 2019
Consultation via working groups and 1:1 meetings as required

October 2019
Information Paper

October 2019 – Early 2020
Draft rule amendments

Further information

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ESSENTIAL SYSTEM SERVICES
Part 2

FREQUENCY CONTROL

CONTENTS

1. New frequency control services

FREQUENCY CONTROL SERVICES

Current state:

- Mandatory requirements (droop settings, UFLS)
- Load Following Ancillary Service
- Single Spinning Reserve service
- Load Rejection Reserve

GHD TECHNICAL REVIEW RECOMMENDATIONS

- Safe level of Rate of Change of Frequency
- Control response to contingency events needs to be delivered faster
- A level of mandatory frequency response needed for baseline system security
- Separate regulation and contingency reserve services for enough quantum to respond to contingencies
- Capability of non-synchronous generation to provide frequency control should be tapped into
- DER inverter standards can be tightened without changing end-user felt experience

FREQUENCY CONTROL SERVICES

Future state:

- Mandatory requirements (droop settings, UFLS)
- ‘Regulation service’
- Single ‘Contingency Reserve’ service (but separated into up and down)
- New ‘RoCoF Control’ service

Regulation service

REGULATION SERVICE CHARACTERISTICS

- Regulation service will have a separate raise and lower component
- Facilities providing regulation must have AGC
- In future ‘ramping’ service may be needed but not anticipated for "Day 1"

REGULATION QUANTITIES

AEMO undertaking modelling to determine how quantities will meet FOS taking into account:

- Variability of demand
- Variability of intermittent sources
- Inherent errors in dispatch
- Damping effects such as available droop and system inertia

Detailed method for setting requirement to be in market procedure, reviewed within 1 year of market start

Expect more dynamic requirements (at the minimum separate peak, off-peak quantities as per current)

2. Contingency Response Service

TERMINOLOGY

<table>
<tr><th>Current Ancillary Services
(WEM Rules)</th><th>System requirements (ESSFR)</th><th colspan="2">Future Essential System Services (this paper)</th></tr>
<tr><td>Load Following Ancillary Service</td><td>Frequency Regulation</td><td colspan="2">Frequency Regulation</td></tr>
<tr><td rowspan="2">Spinning Reserve Ancillary Service</td><td>Primary Frequency Response (raise)</td><td rowspan="4">Contingency Response</td><td rowspan="4">Contingency Reserve</td></tr>
<tr><td>Secondary Frequency Response (raise)</td></tr>
<tr><td rowspan="2">Load Rejection Reserve</td><td>Primary Frequency Response (lower)</td></tr>
<tr><td>Secondary Frequency Response (lower)</td></tr>
<tr><td>N/A</td><td>Rate of Change of Frequency (RoCoF) Control</td><td></td><td>RoCoF Control</td></tr>
</table>

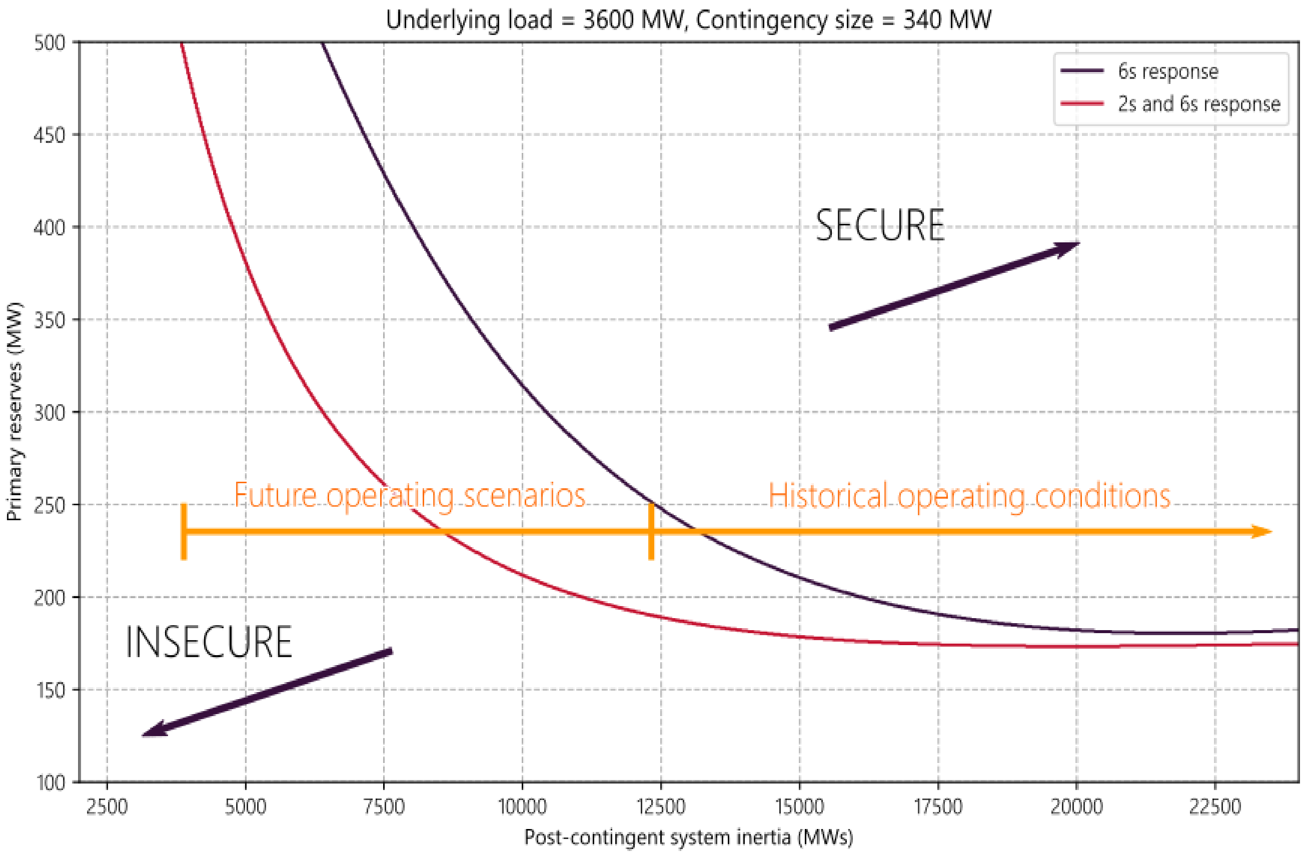
SEPARATE ROCOF CONTROL SERVICE

- Recognises interplay between size of contingency, level of system inertia and PFR

- Fundamentally different response mechanism which doesn't rely on reserve MW

- Market framework should allow for optimising these

RELATIONSHIP BETWEEN INERTIA, PFR, CONTINGENCY SIZE



DIVERSITY IN SUPPLY FLEET

Three classes of future ESS provider:

- Synchronous machines – instantaneous response, subsequent decrease then a slow increase in support over seconds and minutes
- Interruptible load – responds very fast (not instantaneous), potential to provide maximum response within 250ms-1s, and maintain level.
- Inverter-based technologies – responds very fast (not instantaneous), can meet any defined response curve (though a storage battery will be limited by how much energy it holds, and intermittent generation by pre-curtailing).

All three can provide PFR and SFR in a way that can be assessed against the required response curve, but differ materially in their response within the first few hundred milliseconds of a contingency event – a period that is becoming more important.

MULTIPLE RESERVE SEGMENTS ARE NOT ALWAYS VALUABLE

Increased segmentation of reserve:

- increases accreditation and compliance requirements for participants, and ongoing operational complexity for AEMO.
- introduces potential for inefficient offer construction, opportunities for gaming, and increases the complexity of market power monitoring and control.

Where the same facility can provide service across timeframes, further segmenting reserve won't change the total amount of MW to be reserved i.e. sufficient capacity must be held to meet the largest requirement.

Services in each time period are provided from the same cost base (opportunity cost of not providing energy, start/run cost if not in merit for energy)

Therefore: prefer single Contingency Reserve segment (upcoming dispatch modelling will seek to quantify benefits)

ACCREDITATION APPROACH

Still need to reflect different capabilities of different facilities:

- Facilities assigned '*contribution factors'* based on measured performance and contribution to required response curve.
- Facilities offer a $/MW figure
- Clearing engine uses *contribution factor* to ensure required response is met
- In general faster responding facilities will have higher factors
- May be different factors for different system conditions

Settings would be reviewed periodically, including for performance after a contingency event occurs.

Detail to be set out in a market procedure

RESERVE AND ROCOF CONTROL QUANTITIES (1)

The amount of reserve and RoCoF control required depends on:

- Size (MW) of the largest credible contingency (largest single unit injection or multiple facilities lost in a single event)
- Stored energy in the power system (inertia/synthetic inertia)
- Load relief from the underlying system load.

RESERVE AND ROCOF CONTROL QUANTITIES (2)

Dispatch process will optimise dispatch of energy, Regulation, RoCoF Control and Contingency Reserve using:

- Identified credible contingencies (generation & network)
- Level of inertia including RoCoF control present on the system
- Relationship between energy dispatch and ESS capability for individual facilities
- Facility contribution factors
- Facility offers for each of energy, RoCoF control, regulation and contingency response

Accurately capturing RoCoF Control requirement and trade-off between contingency size and RoCoF requirement requires iteration between MCE and aggregate frequency response model.

Work remains to define the operation of the iteration.

3. Procurement

OVERALL APPROACH

Real-time co-optimisation required to ensure short-term optimisation of fleet.

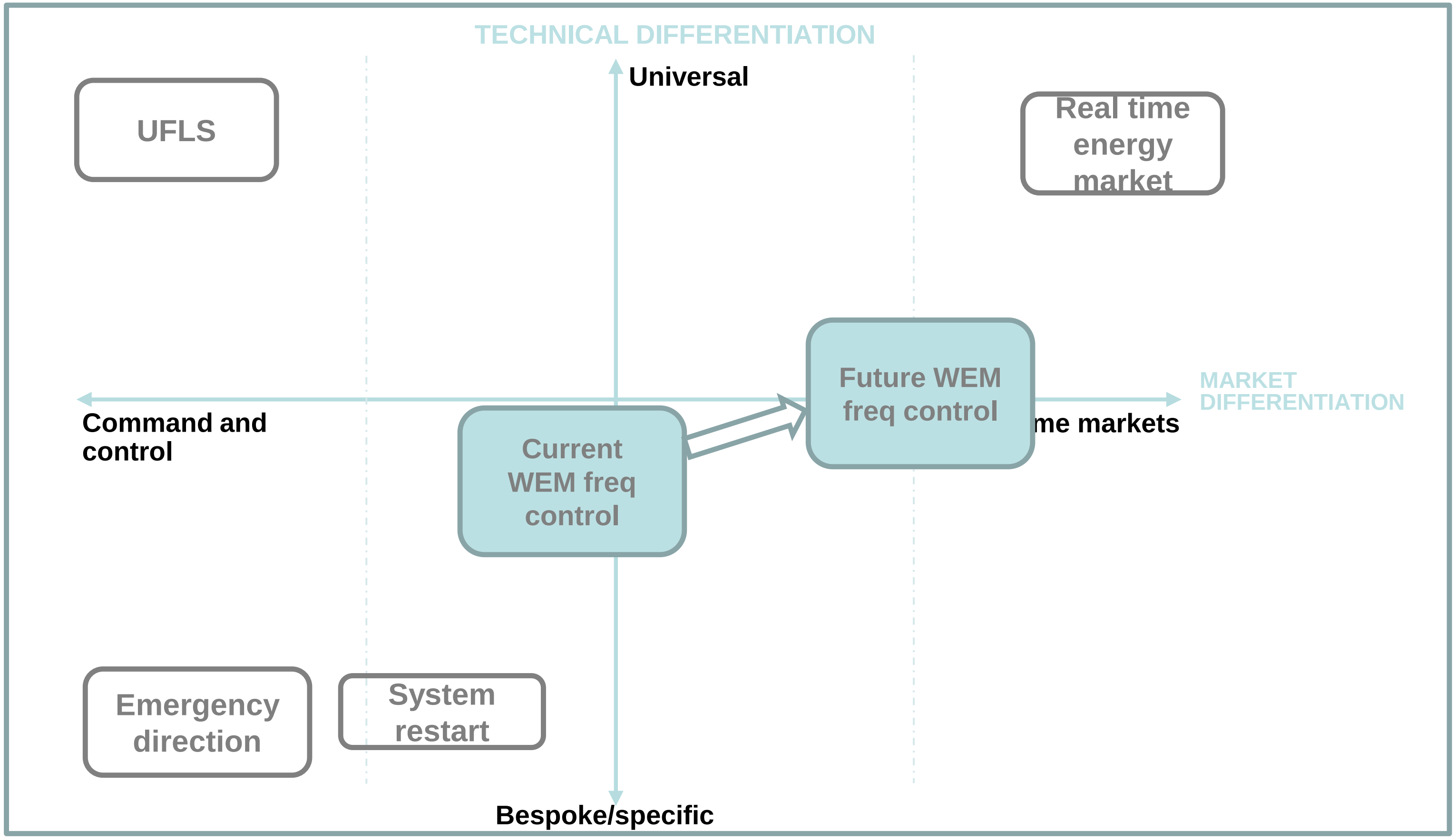
In a small, concentrated market, real-time market alone is risky.

Supplementary mechanism would support:

- System reliability (ensuring capability is available when real time arrives)
- Revenue certainty for new entrants
- Ex-ante opportunity to mitigate and monitor market power

Supplementary mechanism would support these factors.

WHERE DOES THIS FALL ON THE AXES?



KEY CONSIDERATIONS

- Response to scarcity
- Revenue certainty for new entrants
- Mitigate and monitor market power
- Minimise administrative cost
- Least-cost dispatch

SUPPLEMENTARY MECHANISM - OPTIONS

Options under consideration:

- Option A: Additional RCM obligations
- Option B: Availability retainer + real time offer limits
- Option C: Contracts for difference (CFD)
- Option D: Facilitated bilateral contract market

OPTION A: ADDITIONAL RCM OBLIGATIONS

Facilities paid capacity payments are being paid for availability.

RC Target includes an allowance for ESS quantities, so theoretically already includes enough capacity to cover energy + ESS at the system peak.

All facilities holding capacity credits required to:

- be capable of operating on AGC to provide Regulation services
- seek accreditation for all ancillary services
- offer full capability into real-time ESS markets in the same way as required to for energy.

Facilities not assigned capacity credits could choose to be accredited, and participate in real-time ESS markets.

OPTIONS B, C, D – COMMON FEATURES

Options B, C, and D all involve an annual mechanism to support real-time market:

- AEMO required to forecast required quantity, and publish in advance of procurement cycle
- Requirement is defined as a profile over time (granularity TBC – Reserve will be most dynamic)
- Need for supplemental mechanism reviewed as part of regular ERA ESS reviews.

OPTION B: RETAINER + OFFER LIMITS

All facilities can participate in real-time market. Whole fleet is co-optimised, dispatch based on cheapest combination of real-time offers.

Annual mechanism provides fixed payment for availability (retainer) in return for restrictions on offers into real-time market (offer limits).

Offer restrictions in one of two forms:

- Offer price cap
- Delta from energy offer (requires 1 year market history)

AEMO selects offers to meet the forecast requirement, and facilities selected must respect offer restrictions when real-time comes.

Open book submissions – must show cost calculations.

ERA provides specification of explicit definition of differentiation between costs recovered for reserve and costs recovered for energy, and can choose to review figures provided into supplemental mechanism.

Mandatory participation for participants with facilities which have set real-time price in more than a threshold % of intervals in the past year.

OPTION C: CONTRACTS FOR DIFFERENCE

All facilities can participate in real-time market. Whole fleet is co-optimised, dispatch based on cheapest combination of real-time offers.

Mechanism is a financial instrument giving price certainty for market and revenue certainty for participating facilities. No direct availability obligations on a particular facility.

Participants submit a set of reserve price-quantity pairs. AEMO selects lowest priced offers until desired volume met. Highest priced accepted offer establishes the long-term CFD price for all participants.

Facilities receive real-time price x dispatched quantity, plus or minus CFD amount, whether or not participant offers or is dispatched.

CFD price > real-time price = market pays holder.

CFD price < real-time price = holder pays market.

CFD quantity is a cap: if real-time reserve requirement < total CFD quantity across all CFD holders, CFD settlement quantities scaled based on participant share of total CFD quantity.

Mandatory participation for participants with facilities which have set real-time price in more than a threshold % of intervals in the past year.

Open book submissions - must show cost and forecast assumptions.

OPTION D: FACILITATED BILATERAL CONTRACT MARKET

All facilities can participate in real-time market. Whole fleet is co-optimised, dispatch based on cheapest combination of real-time offers.

AEMO assigns *ESS obligations* to market participants

Participants make bilateral contracts to discharge ESS obligations

Participants submit bilateral contract quantities to AEMO, for netting out in settlement.

No explicit market power control mechanism

KEY CONSIDERATIONS (1)

Responding to scarcity:

- B and C provide a mechanism for new entrants to provide services if scarcity is driving up total market costs.
- A and D would need an additional mechanism.

Revenue certainty for new entrants:

- A: relies upon payment through the RCM
- B: guaranteed availability payment to supplement uncertain real-time market revenue
- C: exposure to high/low prices directly linked to the actual level of service required in any given interval
- D: relies upon multiple bilateral contracts

KEY CONSIDERATIONS (2)

Market power:

- A and D would rely solely on ex-post monitoring
- B: transparent pricing on a facility by facility basis
- C: requires consideration of participant portfolio over the procurement duration

Administrative costs:

- B, C, D all need AEMO volume forecasts
- B, C need AEMO procurement process
- D requires bilateral negotiation and contracting

Efficient overall cost:

- All options support real-time co-optimisation
- B and C reduce risk of market failure from market power exercise

4. Cost recovery

CAUSER PAYS

Foundation market principle to allocate market costs to those causing the need for them.

Costs associated with the procurement of a service should be recovered from the participants who most directly increase the quantum of service required.

All frequency control service costs should be recovered from market participants in proportion to the demand they each induce for those services.

COST RECOVERY – REGULATION

Current approach:

- LFAS costs recovered from loads and non-scheduled generators on basis of metered schedules: injection/load is used as a proxy for contribution to variability.
- Rise in behind-the-meter generation means some loads are reducing consumption, but increasing variability

Causer pays principles:

- Scheduled generator/scheduled load pays for variation from dispatch (outside dispatch tolerance)
- Intermittent generation pays for variability vs forecast
- Non-scheduled load pays in proportion to volatility

COST RECOVERY – CONTINGENCY RESPONSE (1)

Current approach:

- Spinning reserve costs recovered from generators based on their contribution to system contingency (runway method). Interval by interval figures for scheduled generators, monthly average injection for intermittent generators.
- Generators associated with intermittent loads are only included for any market portion of their generation. Behind the meter generation does not contribute to the cost of spinning reserve, even where an outage on that generator would trigger the use of spinning reserve.
- Load rejection reserve costs recovered from all market customers according to their share of consumption.
- Network constraints not explicitly considered.

COST RECOVERY – CONTINGENCY RESPONSE (2)

Causer pays:

- Retain runway method for cost allocation of Contingency Reserve for supply contingencies
- Use interval-by-interval values for scheduled and intermittent generation and facilities behind a network constraint
- Include total generation of generators associated with intermittent loads in the runway calculation (except where generator trip would not affect the total withdrawal or injection at the meter)
- Retain consumption-share-based cost recovery for Contingency Reserve for load contingencies

COST RECOVERY – ROCOF CONTROL SERVICE (1)

Current approach:

- No RoCoF Control service in the current WEM

Considerations:

- RoCoF safe limits set to avoid damage to generators, loads and ensure proper operation of network.
- Generator ride-through capability is a key determinant
- Network settings and load characteristics will also drive need, but maximum possible safe limit for network equipment is not known.
- Interval quantum is driven by contingency size (trade-off between Contingency Reserve and RoCoF control)
- Spreading costs across all participants does not provide incentive to improve system performance

COST RECOVERY – ROCOF CONTROL SERVICE (2)

Because need for RoCoF Control Service is created from all these elements, causer pays means placing incentives on each to improve their performance, and reduce the need for the service.

While costs can be allocated to generators according to their output in a given interval, there is no interval-by-interval calculation for network components or load. A simpler approach will be required – e.g. equal split.

Causer pays principles:

- RoCoF Control Service costs for each interval will be shared across:
  - Generators based on RoCoF ride-through capability
  - Loads (including as proxy for network).

Calculation will be determined as part of settlement work

5. Monitoring and review

GOVERNANCE AND REVIEW

Market effectiveness:

- Current 5-yearly interval for ESS RPS review will be too long in future dynamic market
- ERA (with AEMO) to undertake an ESS RPS review within two years of the start of the new ESS arrangements:
  - include explicit assessment of overall economic effects of underlying ESS technical parameters
  - develop a set of market performance metrics including technical, financial and economic outcomes.
  - include proposals to amend ESS acquisition arrangements to improve overall economic outcomes in the WEM.
- Subsequent reviews at least every three years, as part of section 128(1) reviews of market operations
- Out of sequence reviews triggered by market conditions.

MONITORING AND REPORTING

Monitoring and reporting:

- AEMO will publish data on key ESS performance metrics on a weekly (or more frequent) basis
- ERA will report on ESS market data on a regular basis and provide commentary on key trends.

Operational:

- AEMO will continue to monitor performance of ESS providers in response to actual events, and report observed breaches to ERA
- AEMO will regularly review ESS requirements to ensure technical standards are met.
- Processes for setting ESS requirements will be published in a market procedure.
- Changes to ESS requirements made according to published processes will not require ERA approval (i.e. removing approval of annual ESS requirements report)

6. Next steps

NEXT STEPS

Locational ESS

Settlement:

- Supplementary mechanism
- Causer pays calculations

Scheduling and dispatch arrangements:

- Dispatch mechanics
- Participation requirements
- Offer characteristics
- Treatment of intermittent generators and demand side response
- Impacts on STEM
- Compliance and monitoring

MEETING CLOSE

- Questions or feedback can be emailed to marketdesign.wg@treasury.wa.gov.au
- The next meeting will be in September (date TBC). An invite and agenda will be sent closer to the meeting.