TRANSPOWER

Distributed Energy Resource Management Briefing to IPAG #3

Richard Hobbs, Conrad Edwards, Che Lewis, 1 December 2020

Transpower's proposals for DERM discussions with IPAG

<table>
<tr><th>22 July 2020</th><th>21 October</th><th>1 December</th><th>2021</th></tr>
<tr><td colspan="3">Focus on learnings from Transpower's programme</td><td rowspan="2">Focus on how to move forward</td></tr>
<tr><td>• Introduction
• Transpower's RCP2 DR programme
• Transpower's DERMS platform</td><td>• RCP2 outcomes
• Mechanics of our DERMS platform
• Operationalising DERM: overview</td><td>• Value stack and pricing interactions
• Operationalising Grid Owner DERM
• DERM market development issues</td></tr>
</table>

Transpower's intention is to lend our experience and analysis to the IPAG to assist you spark an effective DERM work plan with the Authority, and so facilitate:

- Competition in provision of DER aggregation, DERM and DERMS services
- Incentives for DER investment
- An efficient, least cost transition to electrification and decarbonisation

Agenda

- Introduction (5 minutes)
- Follow-up points (10 minutes)
- Operationalising Grid Owner DERM (30 minutes)
- DERMS value stack (30 minutes)
- Pricing interactions (30 minutes)
- How might DERM be integrated with the market? (30 minutes)
- How might markets evolve to incorporate DERM? (30 minutes)
- Discussion and next steps (15 minutes)

Follow-up points from last meeting

Some terminology

DER	Distributed Energy Resource	The object, e.g. a battery or EV charger
DER<u>M</u>	DER Management	The approach to managing a specific DER market, e.g. aggregating many DER
DERM<u>S</u>	DERM System	The software system central to that market, that performs e.g. registration, calling, verification and settlement

Flexibility market

- A very useful term, but…
- Perhaps best reserved as the generic term for not just a DERM market but also for:
  - demand response to price signals (nodal price, TPM, DPM)
  - demand participation in ancillary services directly rather than through a DERM market (current practice)

Transition from DR pilot to DERM operations

RCP2 period

- DR Programme = ‘DERM 0.1’ pilot
- Regulated RCP funding of the pilot
- Consideration of DERM in all investments (MCP and base capex)
- Potential economic use cases found for the RCP2 period were deferred into RCP3 due to investment prioritisation
- A number of use cases trialled at GXPs

RCP3 period

- Exploring evolutionary development of DERM from pilots to ‘DERM 1.0’
- We did not propose continued specific RCP funding of further DERM pilots. We will support the future development of DERMS for transmission deferral or risk management, through prioritisation of the base capex and opex portfolio
- Where DERM is an economic solution for transmission deferral or risk management, then RCP capex will be converted into RCP opex to fund the DERM solution
- Any development or service offerings for external parties will be commercially funded, external to our regulated funding.

Transition from DR pilot to DERM operations – changing characteristics of the programme

From: RCP2 Demand Response pilot	To: RCP3 Operational DERM
• Programme to trial different characteristics of Demand Response (e.g. consumer participation, technology participation, price points, event calling methods etc.)	• Operational programme that targets specific network investment projects (e.g. economic deferral of a new transmission line, or managing construction risk)
• Programme that spreads trial money across multiple locations in New Zealand to learn from a diverse range of consumers and technology across different network applications	• Programme that will invest significantly in specific, targeted parts of the network where economic DERM options arise
• Programme where procurement method for DR was based on call payments to promote price discovery	• Programme where RFPs would be used for targeted DERM programmes and the best economic options (e.g. capability, and call and/or availability payment) provided by tenderers would be selected
• Programme where a few targeted demand response events were largely triggered manually	• Programme where DERM events are specific to a network need and will be increasingly automated

DER payment mechanism: GSC design feature 34

"A payment structure will be proposed as part of the RFP process, based on some or all of:

- Preparation payments
  - establishment payment to cover up-front costs of participation
- Operation payments
  - availability: payment for being available to call, per month, conditional on not failing to deliver against calls (including test calls)
  - delivery [call]: payment per MW delivered per hour up to the contracted amount

Transpower will consider variants on this mechanism or other payment structures, but will require that the payment structures for GSCs for DSP [DER participation] include financial incentives for performance"

Report: *Transpower, Design features for grid support contracts, July 2016*

Choice of DER payment mechanism will depend on the situation

- Transpower has trialled a variety of DER payment structures, with a focus to date on price discovery for targeted DER types
- Transpower has designed its DERMS system to be flexible enough to manage all these payment options

	Call payment	Availability payment	Pilots 2007 - 2020	Operational 2020+
			Focus on: • Price discovery • Targeted DER types • Refining end-to-end DERM process	Focus on: • Least cost reliability
A	Yes, as agreed through RFP (call price fixed* months beforehand)	May or may not be availability payment too	Yes: we called this our 'non-price responsive' programme	Most economic mix of DER types, payment structures and call conditions would be selected from RFP responses
B	Yes, as accepted through an offer window open prior to call notification (call price fixed* hours beforehand)		Yes: we called this our 'price responsive' programme	
C	None, maximum calls per month included in availability payment	Yes	Not trialled yet, but under consideration for our planned battery trial	
D	Yes, fixed price e.g. $200/kWh (set to elicit required volume, discovered through experience)	May or may not be availability payment too	Not trialled due to focus on price discovery	

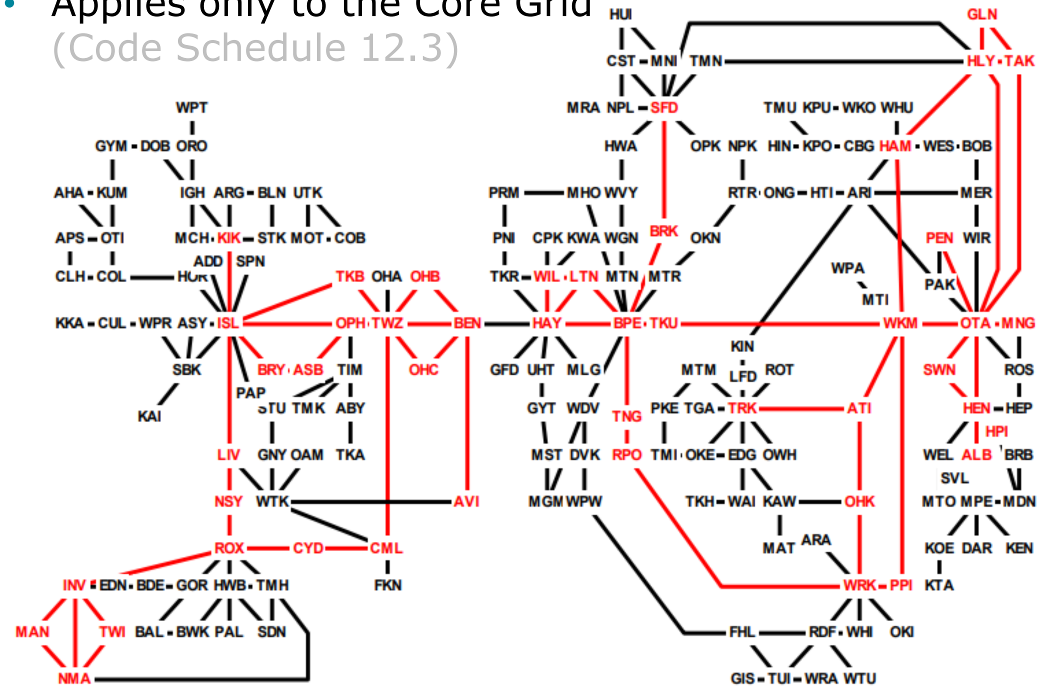
** We used pay as bid for our call prices in our trials to minimise costs and because of low liquidity – operationally we could use marginal price*

Transpower's mandate is to apply N-1 minimum security standards only to the core grid

- Grid Reliability Report (Code 12.76) identifies capacity need, to which Grid Reliability Standard (GRS, Code Schedule 12.2) is applied to determine if action required
- GRS has in effect two limbs, deterministic and economic

'Deterministic' limb

- 'Safety net' minimum reliability standard of N-1
- Applies only to the Core Grid (Code Schedule 12.3)



Economic limb

- Economic (probabilistic) standard for the whole grid
- Assessed at each GXP and GIP
- For major capex, economic test is that the investment must have the highest expected net electricity market benefit (Code references the CapexIM)
- For connection assets, we assess the economics of a range of possible solutions:
  - Supply side 'poles and wires' (Transpower)
  - Demand side SPS (Transpower)
  - Demand side DERM (Connected party)

The evolving new TPM

<table>
<tr><th rowspan="2"></th><th colspan="2" rowspan="2">Interconnection</th><th colspan="2">Connection</th></tr>
<tr><th>Replacement & refurbishment</th><th>Enhancement & development</th></tr>
<tr><td rowspan="2">TPM now</td><td>HVDC</td><td>• Not to load so not relevant</td><td rowspan="6">Fixed as recoverable costs all allocated to beneficiary (connected party) … except that there is a load-based allocation of costs of any shared assets</td><td rowspan="6">Fixed with full cost recovery contracted over an agreed time period</td></tr>
<tr><td>HVAC</td><td>• RCPD – strong peak signal</td></tr>
<tr><td rowspan="4">New TPM</td><td>HVDC and major historical HVAC</td><td>• Fixed</td></tr>
<tr><td>New investments</td><td>• Fixed once investment decision made ~2-3 years ahead of need date</td></tr>
<tr><td>Residual</td><td>• Almost fixed (changes slowly based on energy usage across multiple years)</td></tr>
<tr><td>Transitional congestion charge</td><td>• Possible additional charge
• If used, limited in time and location
• Under design consideration</td></tr>
</table>

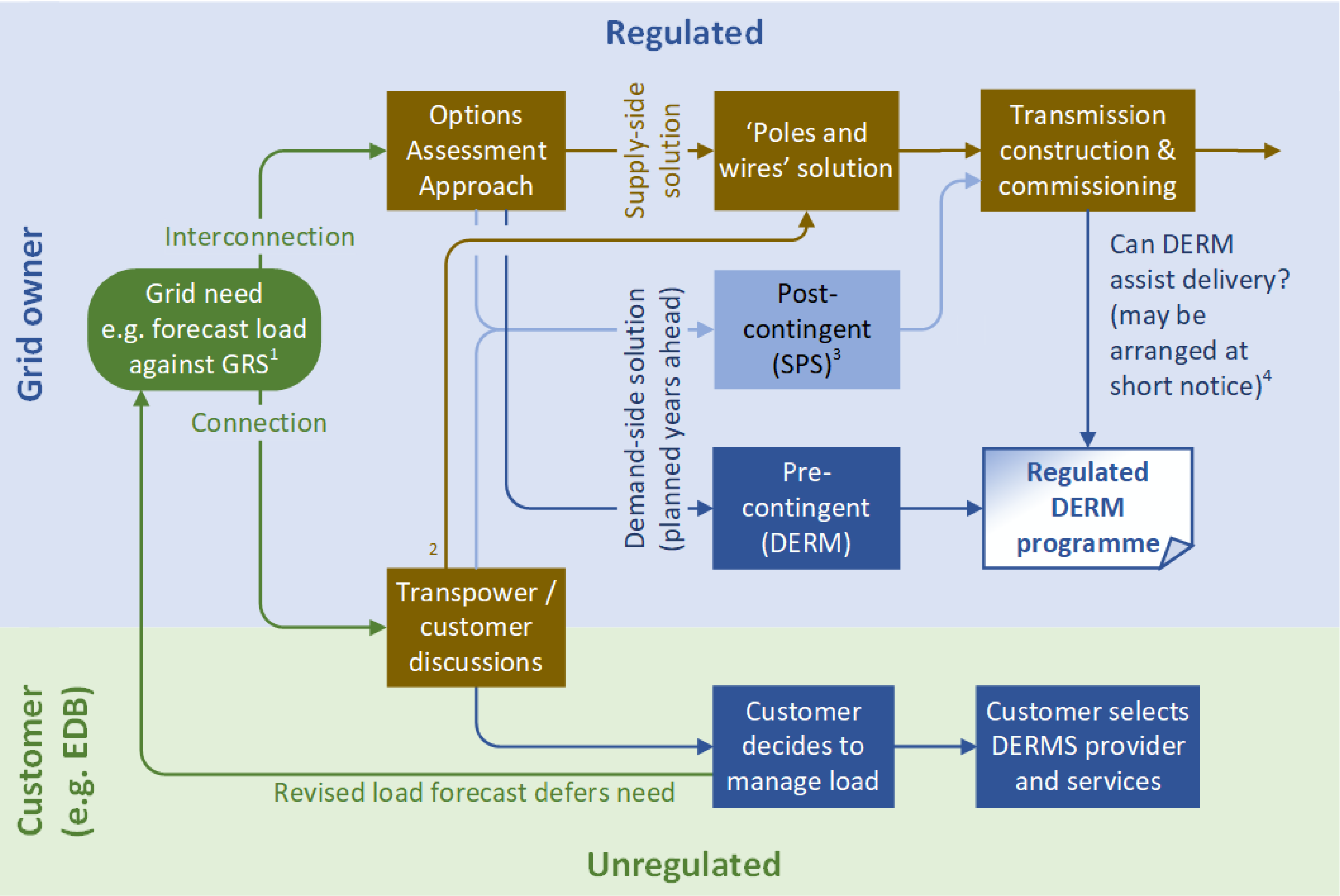
Fixed: charge not affected by load profile in the short-term. Interconnection charges may change over years consequent on sustained and substantial changes in grid use.

Operationalising Grid Owner DERM

Need and economics will drive Grid Owner's operational DERM

This slide and the next few illustrate Transpower's current processes for deciding on and running a DERMS programme

We expect to evolve these processes with further work and experience



1 *Grid Reliability Report (Code 12.76) identifies capacity need, to which GRS is applied to determine if action required*

2 *Customer transmission or SPS investments funded through base capex or, where customer need exceeds grid need, as an investment contract*

3 *Transpower is planning post-contingent DERM trials to investigate whether DERM can be integrated with an SPS*

4 *Could be planned e.g. to cover temporary need, or unforeseen to cover risk of delayed commissioning or higher than forecast demand growth*

DRAFT – this is Transpower's current thinking on a process that will likely evolve

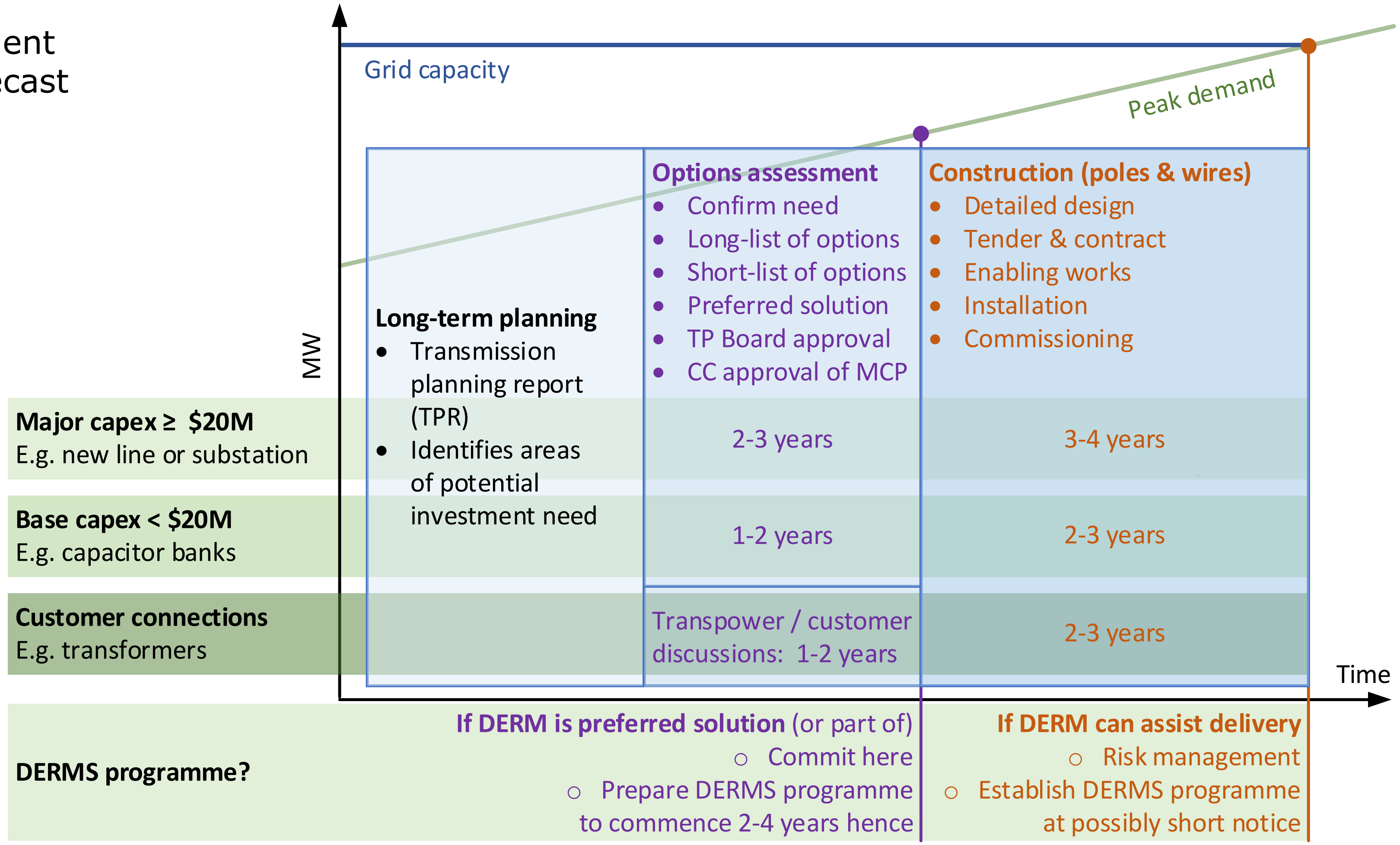
Timings for Grid Owner DERM decisions typically driven by ‘poles and wires’ solution timings

Timings for a typical capacity enhancement investment driven by a load growth forecast

From identification of need to delivery:

- Major capex can take 5-7 years
- Smaller capex can take 3-5 years

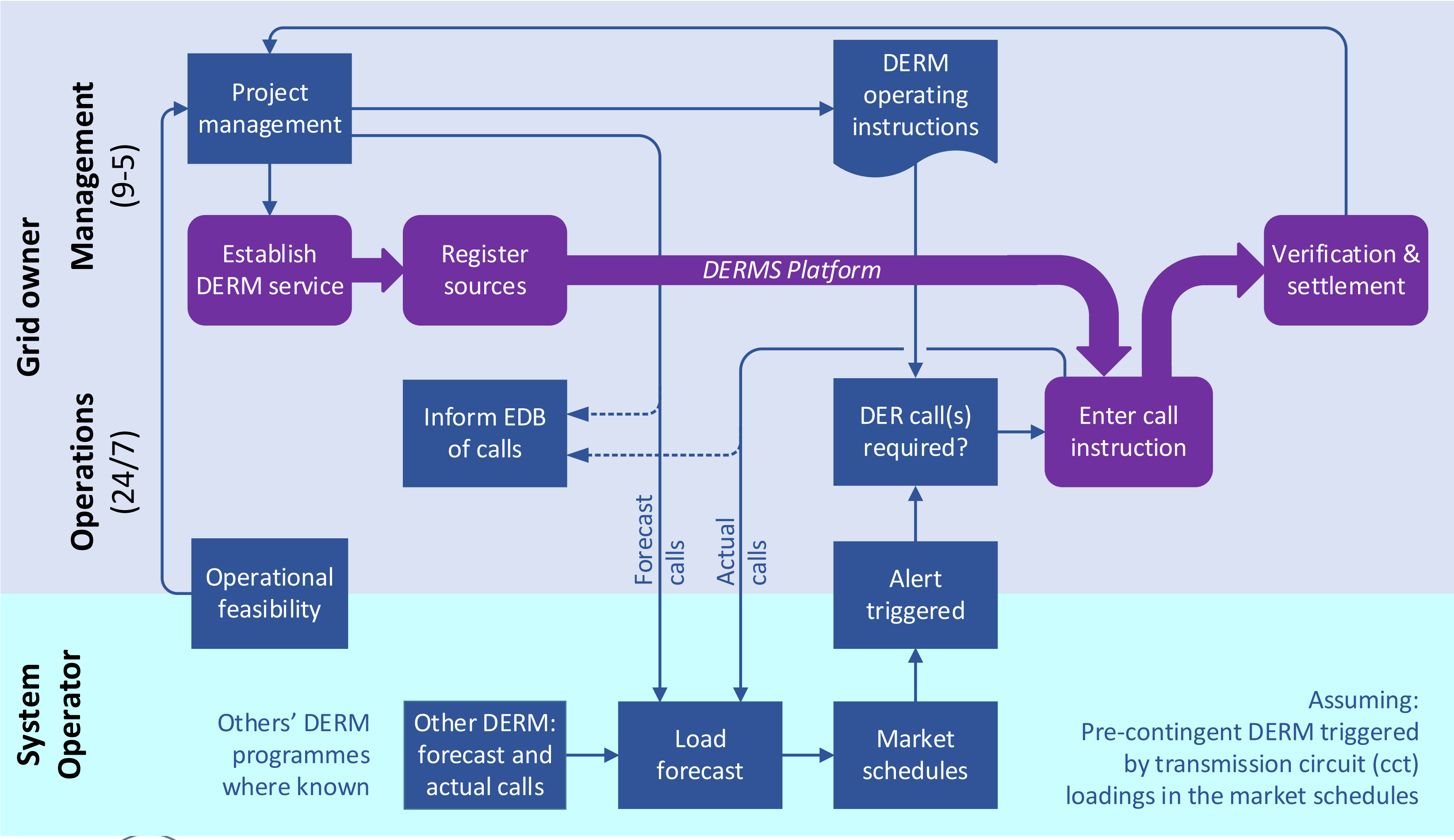
In both cases, decision to proceed is almost half of project duration



Our proposed process to deliver regulated transmission DERM…

- The following three slides outline a simplified, conceptual framework for Transpower operationalising regulated DERM
- Control room processes outlined here have been trialled as part of Transpower's DR Pilot, but only manually and for a few, pre-planned and pre-contingent calls
- The processes illustrated assumes pre-contingent DERM triggered by transmission circuit loadings in the market schedules, say 2-3 hours ahead of real time. Different process are expected to be required for:
  - Pre-contingent DERM operated closer to real-time
  - Post-contingent DERM
- Many enhancements to the basic process illustrated here are likely to be required as we learn further, and as we prepare for specific operational use:
  - Four major enhancements are highlighted in the third slide (Slide 18)
  - We have not budgeted for these in RCP3 but they could be progressed as part of a capital investigation if necessary

Our proposed process to deliver regulated transmission DERM…

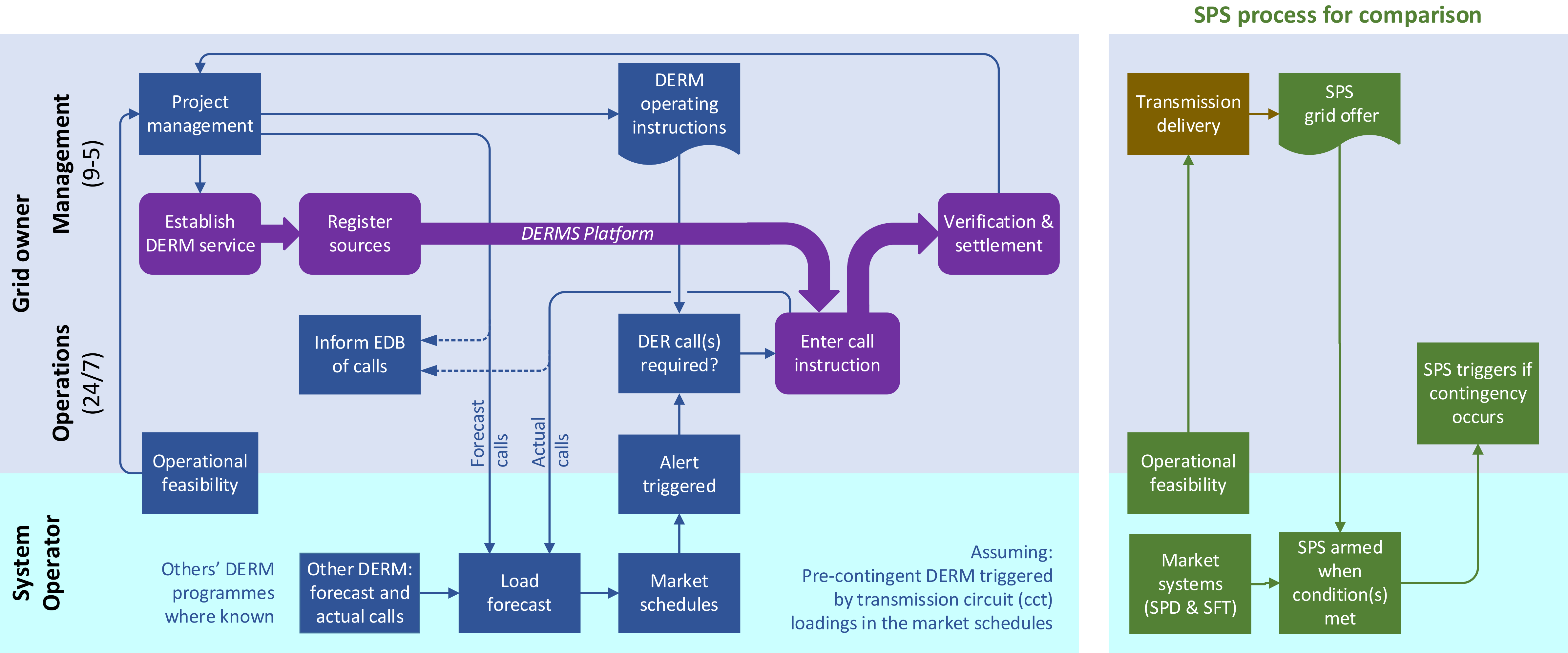


DERM operating instructions

- A key process document
- Instruction to operations on when and how to call DER, and when not
- Entirely objective – no operational discretion required or allowed
- Purely physical – economic considerations paramount in developing the operating instructions, but not in their implementation
- Owned by Grid Owner
- Agreed by SO
- Actions taken by Grid Owner's operational team
- Continually reviewed
- Some similarity to an SPS offer from Grid Owner to SO (next slide)

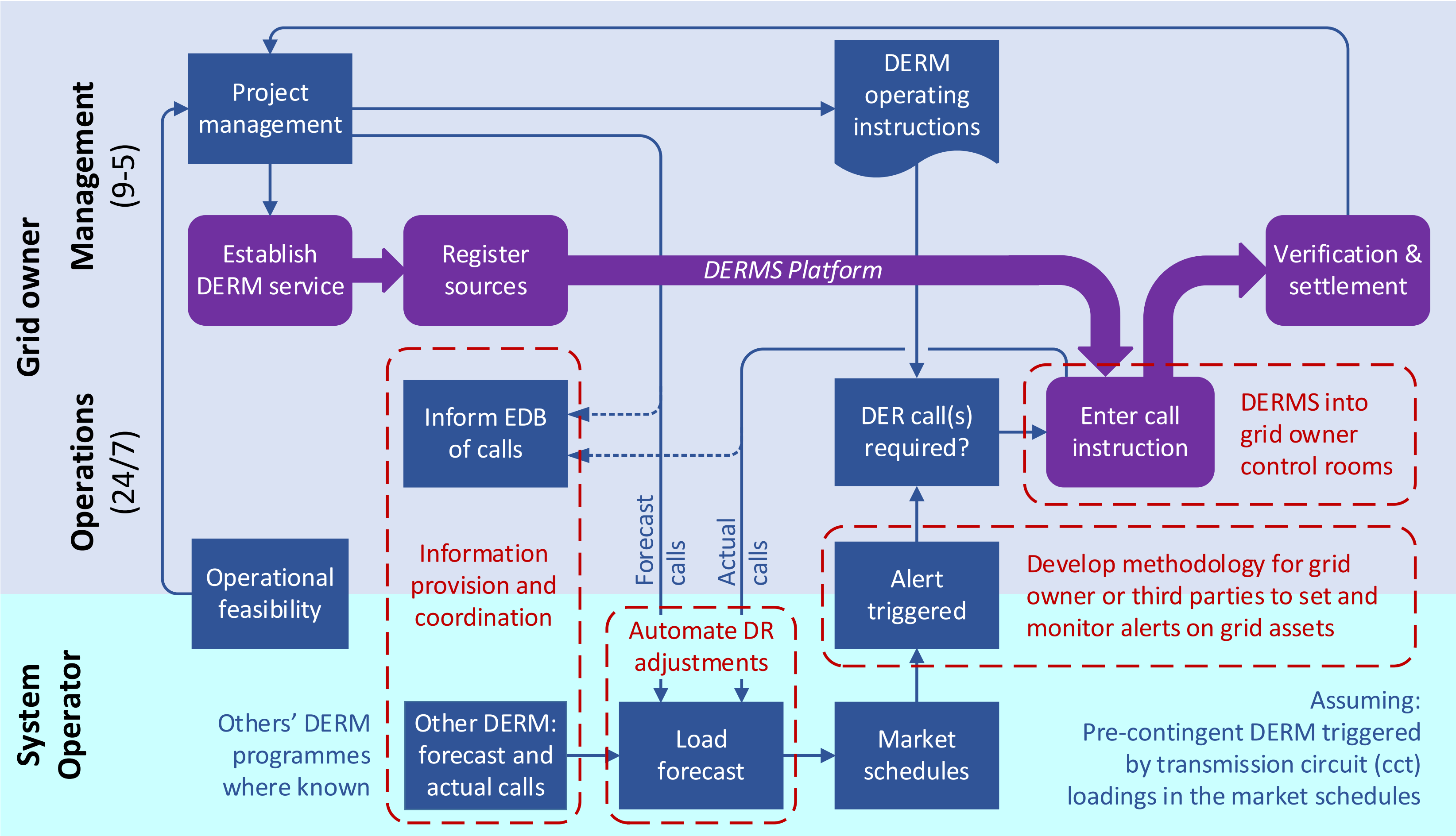
DRAFT – this is a simplification of Transpower's current thinking on a process that will likely evolve

… is a bit more complicated than operating an SPS scheme …



DRAFT – this is a simplification of Transpower's current thinking on a process that will likely evolve

… and some aspects will need enhancement as volumes increase



Enhancements needed

- Automate the currently manual process of adjusting the load forecast for planned and actual DER calls
- Transfer of information and Transpower-EDB co-ordination
  - Third-parties with active DERM to inform the SO of planned and actual DER calls in a timely manner
  - Likewise Transpower to EDBs
- Integrate the DERMS platform into the grid owner's control rooms to support 24/7 operations
- Develop methodology for grid owner or third parties to set and monitor trigger alerts on grid assets from the market schedules

DRAFT – this is a simplification of Transpower's current thinking on a process that will likely evolve

DERMS value stack

The value stack is the key to unlocking the value of DER

- DER will be great for consumers and for the system: not "disruptive", but empowering
- DER can add value in multiple ways
- We need to unlock those ways to maximise:
  - Direct benefits to consumers
  - Indirect benefits to consumers of lowering system costs

Potential distributed battery value streams by stakeholder

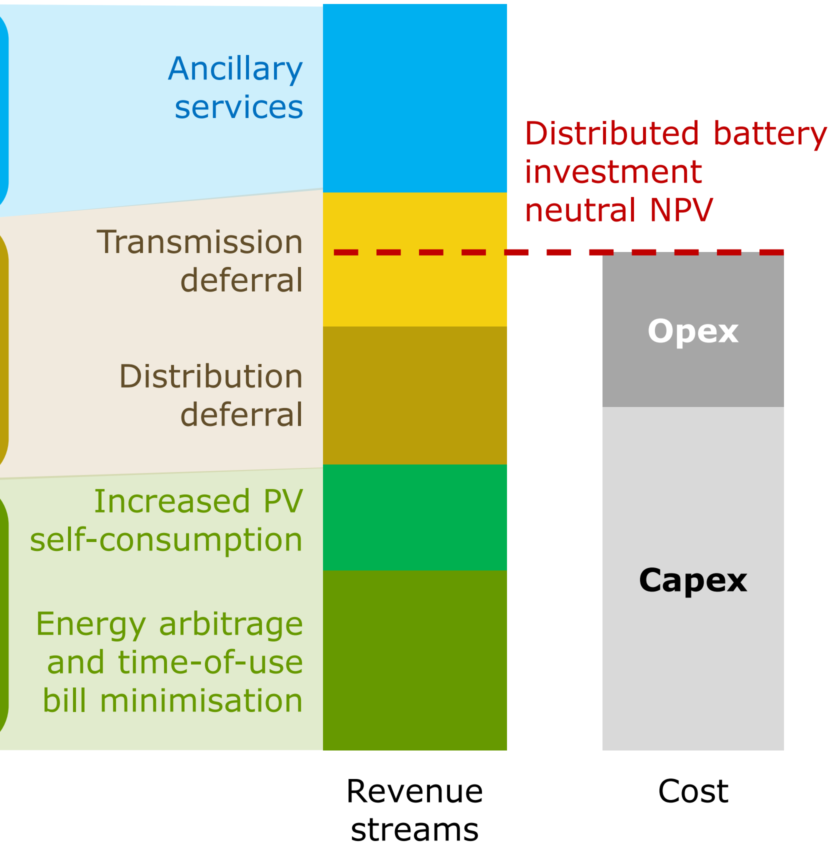
System operator
- Frequency keeping
- Instantaneous reserves
- Voltage support
- Black start

Network companies
- Resource adequacy
- Network congestion relief
- Transmission investment deferral
- Distribution investment deferral

Consumer / DER owner
- Energy arbitrage
- Time-of-use bill minimisation
- Increased PV self-consumption
- Demand peak-charge reduction
- Back-up power

Note that not all DERs will be eligible for all value streams, which can be very location and context-dependent

Illustration of potential distributed battery NPV contribution by value stream



Based on the Rock Mountain Institute's "The economics of Battery Energy Storage". See also Transpower's reports on this subject.

A qualitative view of the DERMS value proposition

Sources of DER value	Distributed Energy Resources	Demand reduction classic DR e.g. industrial plant		Embedded generation controllable plant e.g. diesel		Embedded batteries including EV fast-chargers	
		Value	**Rationale**	**Value**	**Rationale**	**Value**	**Rationale**
Energy market	Wholesale through DERMS	Low	Little benefit over self-dispatch or dispatch through Retail DERMS, once nodal prices go ex-ante	High	Aggregation as virtual power plant can become price maker or moderator in constrained regions	High	Best of both worlds Can, depending on where in charge / discharge cycle, act as either
	Retail through DERMS	Medium	Avoidance of high price – by consumer if exposed, by retailer if they've hedged the consumer	Low	Little benefit over self-dispatch, depending on contractual position	Medium	
Network investment deferral through TPM / DPM or DERM	Distribution	High	• Load reduction, embedded generation and battery services are equivalent at peak-lopping • Distribution investment requirements higher and utility resources more limited than for transmission • There remains a risk that if peak-pricing is removed from the TPM, the use of DERM for transmission peak management may need to increase commensurately				
	Transmission	Medium					
Ancillary services	Frequency keeping (FK)	Medium	Some possibilities for grid-friendly appliances and controls	Low	Most incumbent technology not responsive enough	High	Ideal technology. FK low value now but will increase with intermittency
	Instantaneous reserves (IR)	High	Some technologies fast enough – ripple control, cold stores…				
	New e.g. inertia, balancing	Medium	Some possibilities with inverters				
Firming intermittent generation		Low	Limited possibilities beyond FK	Low		High	Ideal complement

DER owners should be able to 'value stack' across markets

Value stacking is good…

- Obtains maximum economic value of and return from DER investment
- Provides efficient incentives for renewables investment and electrification
- Maximises DER's ability to support the system
- Increases competition
- Minimises unnecessary network and peaking generation investment
- Financial 'double dipping' across different markets can be economically efficient

…but must be done securely

- Need to avoid DER participating simultaneously in two physically different markets (physical 'double-dipping') where that could compromise security
- Transpower's Grid Support Contract (GSC) design is:
  - GSCs will not be offered if they would compromise other security products, including ancillary services and extended reserves, or the markets for these products
  - GSCs will require that there is no physical 'double dipping' between GSC operation and operation of the GSC resources in an ancillary service market
  - GSCs for DER or aggregators within distribution networks will require each DER, the aggregator or Transpower to notify its retailer and local distribution network

The DERM value stack

- From the authors of a recent independent report that the System Operator commissioned
- The report's authors assessed the 'size of the pie' that DER providers may be able to access
- Values derived from current market pricing, including the assumed avoided costs of new grid generation and 'poles-and-wires' to meet the expected growth in demand from decarbonisation

$NZ million per annum	2020	2035	2050	Additive?
Energy arbitrage	$3	$21	$70	Yes
Resource adequacy	$24	$588	$861	Yes
Transmission	*$7*	*$166*	*$230*	
Distribution	*$10*	*$234*	*$324*	
Generation	*$7*	*$187*	*$306*	
Instantaneous reserve	$0	$20	$20	Yes
Frequency keeping	$0	$1	$0	Yes
Voltage	$0	$10	$14	No
Harmonics	$0	-$1	-$7	Yes
Simulated inertia	$0	$21	$85	Yes
Black start	$0	$0	$0	Yes
Total	**$26**	**$650**	**$1029**	

Report: *Sapere, Distributed Energy Resources – Understanding the potential, July 2020 (link)*

Pricing interactions

An example of a DERM use case at a GXP

- Wiri, close to Otahuhu in South Auckland, is a GXP substation providing Vector with supply
- Wiri provides a good example of a potential DERM use case
- It has been identified in Transpower's Transmission Planning Report (TPR) 2020 as:
  - Peak load at Wiri will exceed the winter n-1 capacity of the transformers in 2022
  - Transpower is discussing medium to long term investment options to resolve the supply transformer capacity issue with Vector
  - In the medium-term, the supply capacity issue could be managed by installing an SPS or DERM
  - In the long-term, the possible option is replacing both supply transformer units with higher capacity units

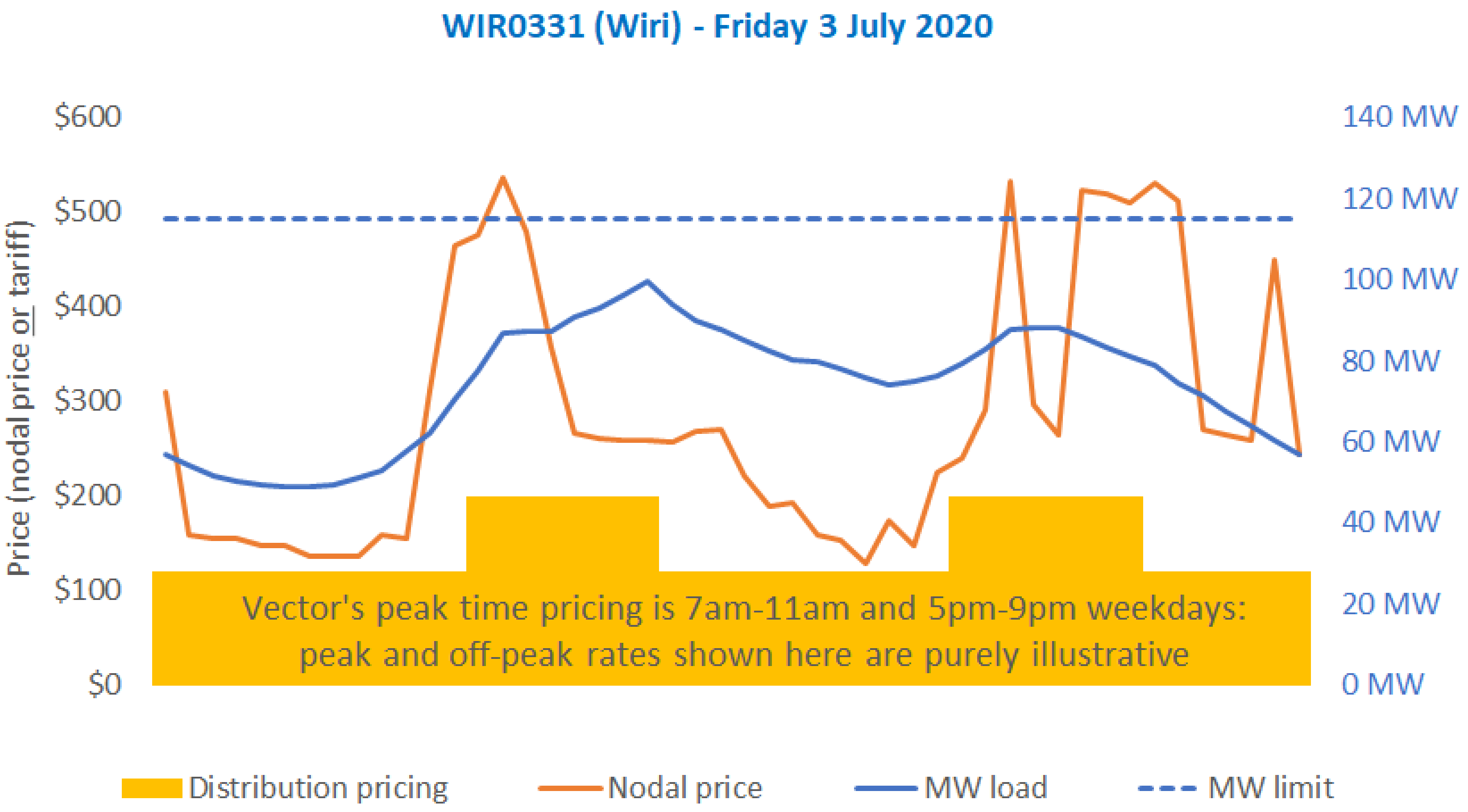
Table 8-10: Wiri supply transformer overload forecast

From TPR 2020

Grid exit point	Transformer overload (MW)										
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035
Wiri	0	0	4	7	10	10	11	11	12	12	13	20

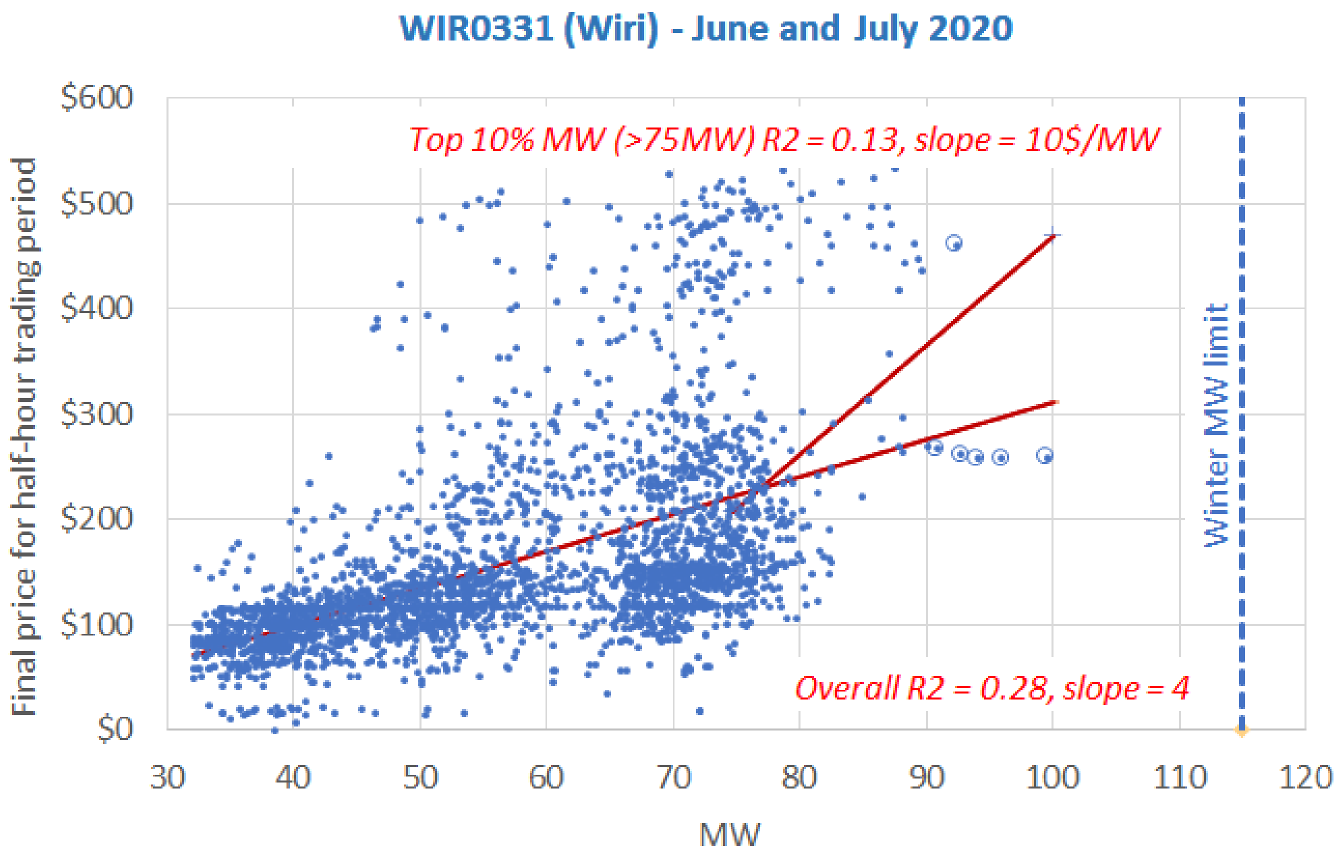
Nodal prices and TOU tariffs do most of the work

- In 2020, Wiri's maximum load during June and July load was on 3 July
- As illustrated here, both nodal prices and Vector's peak time pricing give signals to shift load off-peak
- Any role for DERM as load approaches the limit would be to 'top up' rather than replace those price signals



DERM can 'top up' nodal prices to help defer network investment

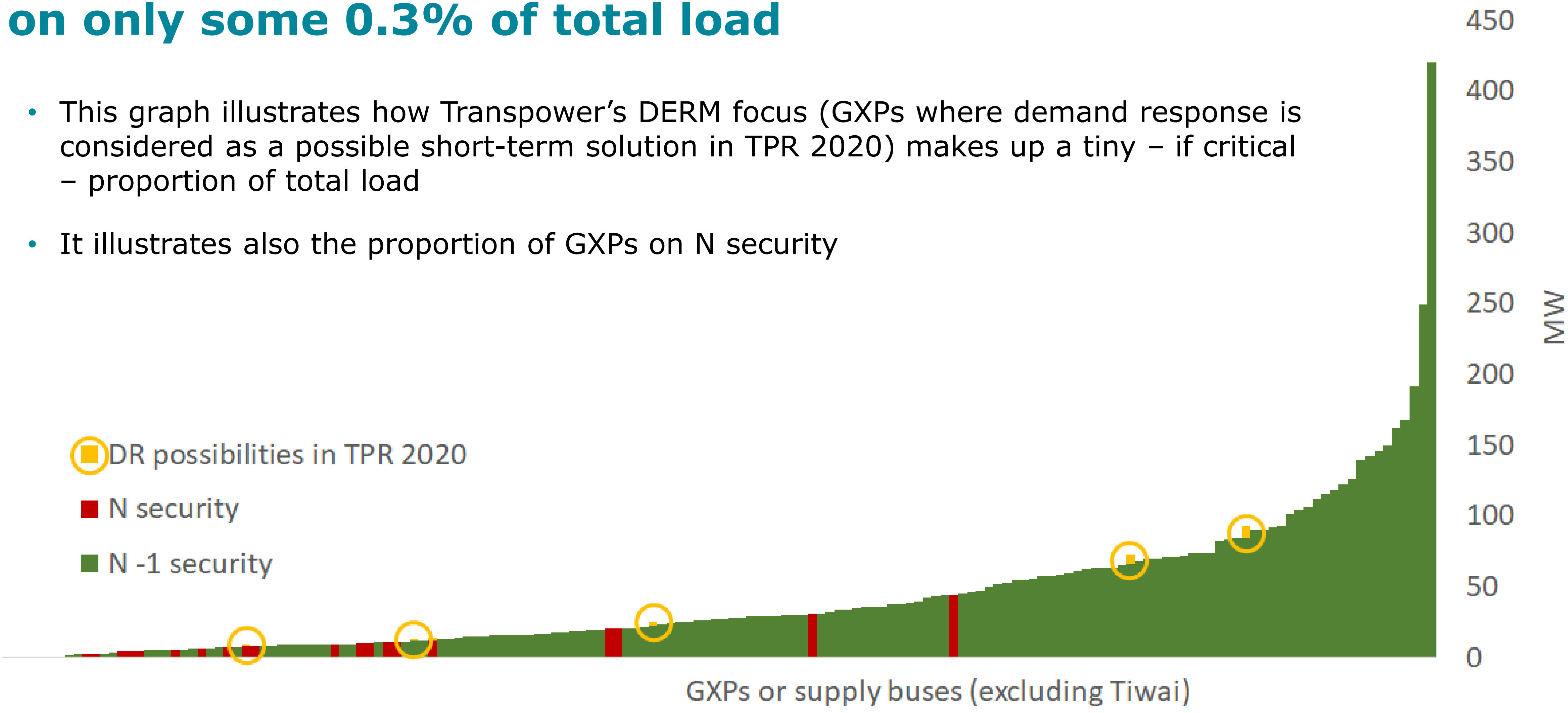
- This graph shows the load to nodal price correlation at Wiri
- DERM can add value by capping demand on occasions where the nodal price is not high enough to (e.g. the five circled lower-right data points)
- As an illustration of the effect of RTP, as load grows and starts exceeding the limit, one can imagine that if load growth was such that the six circled data points exceeded the MW limit, then the Wiri price for them would jump to a scarcity price of $10,000*
- DERM could be used to keep load within limits, avoiding the scarcity price too



* $10,000/MWh is the value for the first 5% tranche from the Authority's RTP consultation paper

DERM for transmission network deferral focuses on only some 0.3% of total load

- This graph illustrates how Transpower's DERM focus (GXPs where demand response is considered as a possible short-term solution in TPR 2020) makes up a tiny – if critical – proportion of total load
- It illustrates also the proportion of GXPs on N security



Who on the demand-side gets or can set price signals or load control?

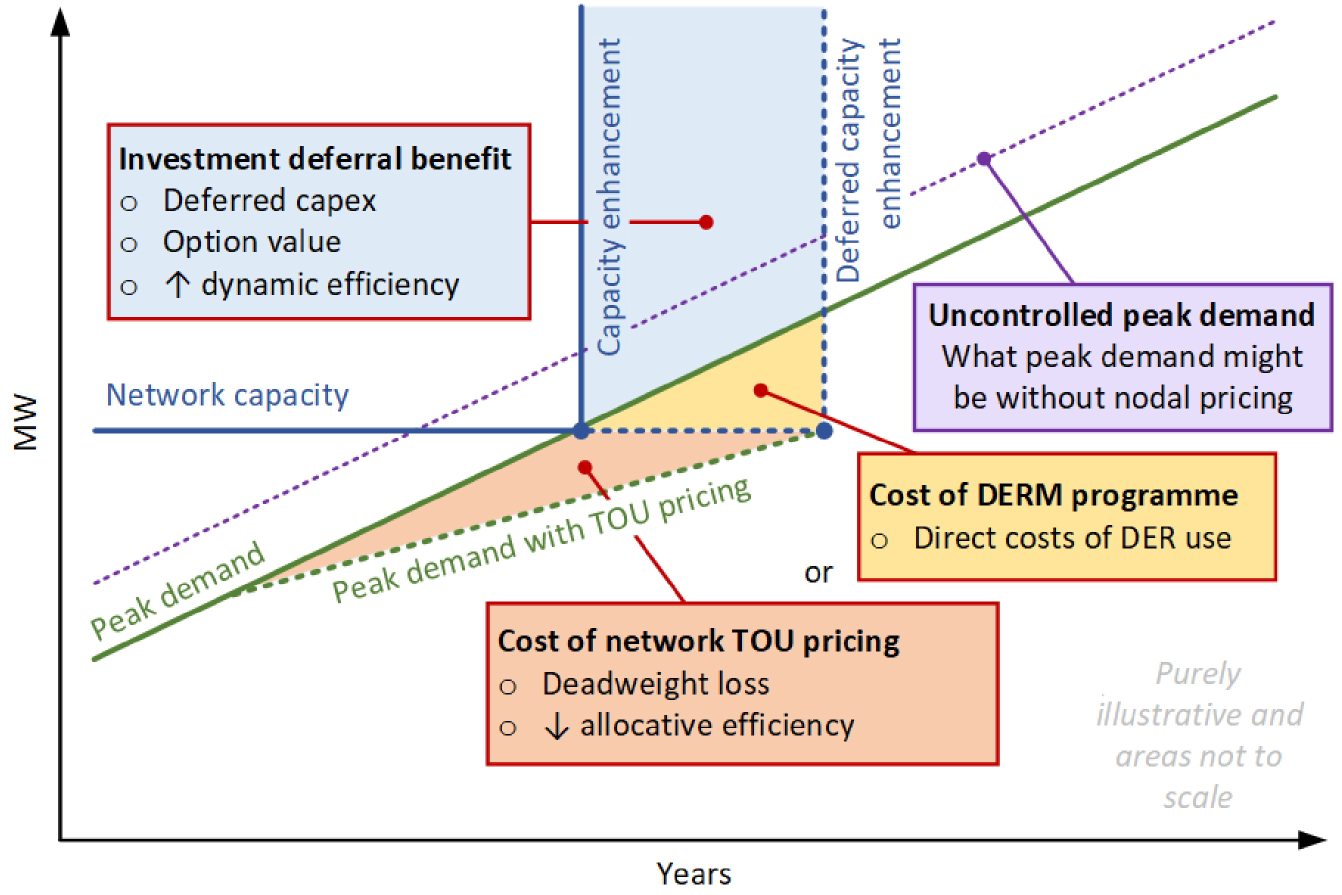
Key
No
Limited
Yes

Flexibility market

<table>
<tr><th></th><th></th><th>Distributor</th><th>Retailer</th><th>Consumer / DER owner</th><th>Grid direct connects</th></tr>
<tr><td rowspan="3">Prices</td><td>Wholesale energy price (to be RTP with scarcity prices)</td><td></td><td>Yes – and combines it with TPM, DPM and its margin into a tariff</td><td rowspan="3">Maybe, dependent on retail tariff designs and tariff chosen</td><td rowspan="3">Yes</td></tr>
<tr><td>Transmission pricing (TPM)</td><td>Passed through</td><td>Maybe, depending how passed through by EDB</td></tr>
<tr><td>Distribution pricing (DPM)</td><td></td><td>Maybe, depending on DPM design</td></tr>
<tr><td rowspan="2">Payments</td><td>TP or EDB DERM</td><td></td><td>Yes if retailer is an aggregator</td><td rowspan="2">Yes if a DER owner and in a DERM market area</td><td rowspan="2">Yes if in a DERM market area</td></tr>
<tr><td>Retail DERM</td><td></td><td>Can run DERM programme as its own as an aggregator</td></tr>
<tr><td rowspan="4">Control</td><td>EDB ripple control</td><td>Manages network</td><td></td><td>Yes but can opt out</td><td></td></tr>
<tr><td>SO emergency load shedding</td><td colspan="3">SO load shedding instructions issued (via GO) to EDBs usually as "keep load below X”. Usually the EDB first turns of ripple, controllable water pumps, street lights etc. In extreme cases may open a feeder</td><td rowspan="2">Controllable</td></tr>
<tr><td>Grid owner SPS operation</td><td colspan="3" rowspan="2">Typically controlled at a feeder level</td></tr>
<tr><td>Extended reserves (AUFLS)</td><td></td></tr>
</table>

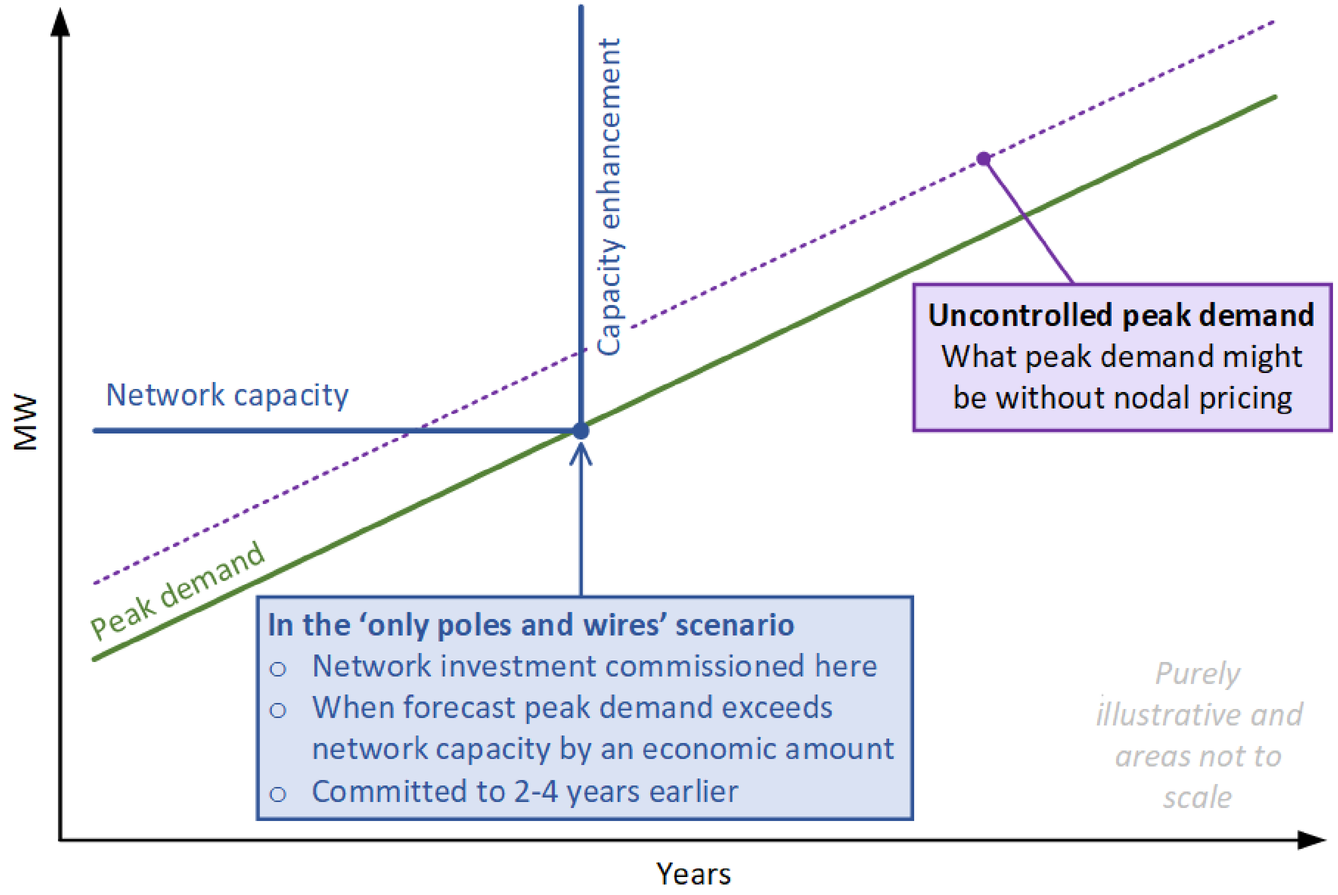
How to optimise network investment deferral

- For overall economic efficiency we need to balance the:
  - Benefits of network deferral
  - Costs and efficacy of any network TOU pricing
  - Cost of any DERM programme
- This is explored in the next few slides



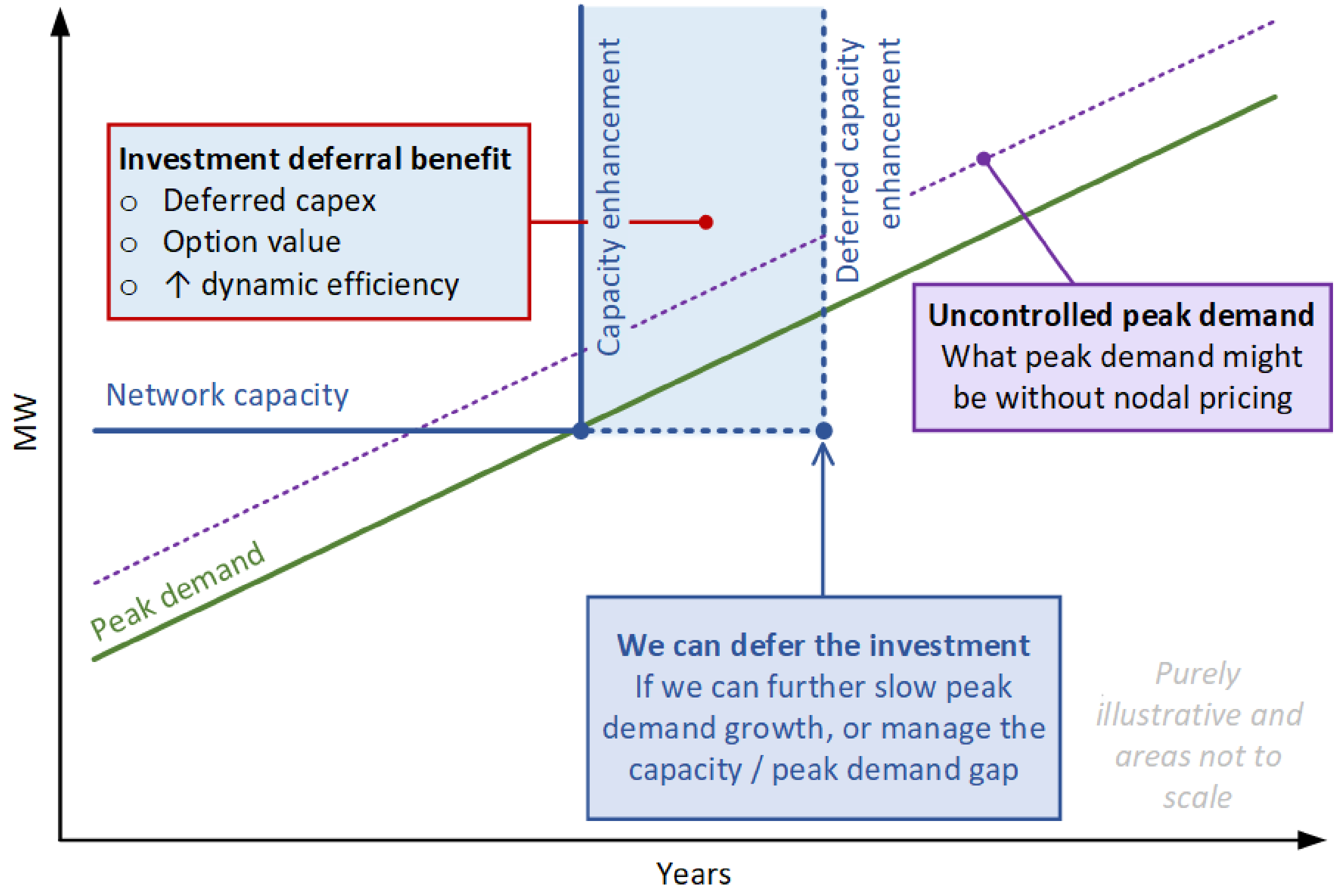
The base case for network capacity enhancement investment is to commission it when forecast demand meets network

- Network companies need to commit to a 'poles and wires' investment years ahead of the planned commissioning date to allow for some or all of:
  - Detailed design
  - Tender & contract
  - Enabling works
  - Installation
  - Commissioning
- Investments are therefore timed against a forecast of peak demand



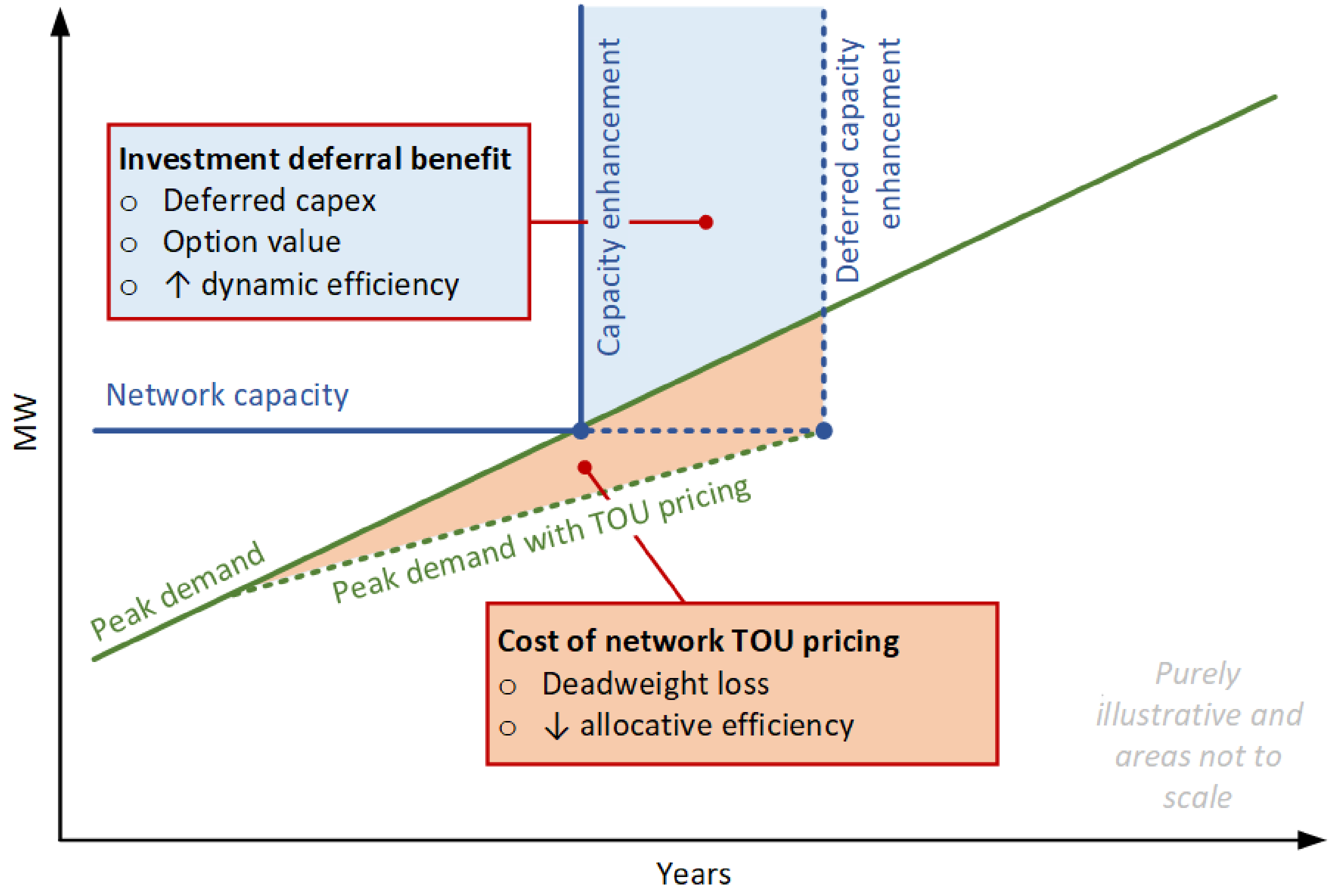
There are potential benefits of network investment deferral

- If a network company could efficiently encourage peak demand reduction, it could capture the benefits of deferring network investment
- This would defer capex and provide optionality given an uncertain future
- It could therefore improve investment efficiency, or in economic-speak dynamic efficiency



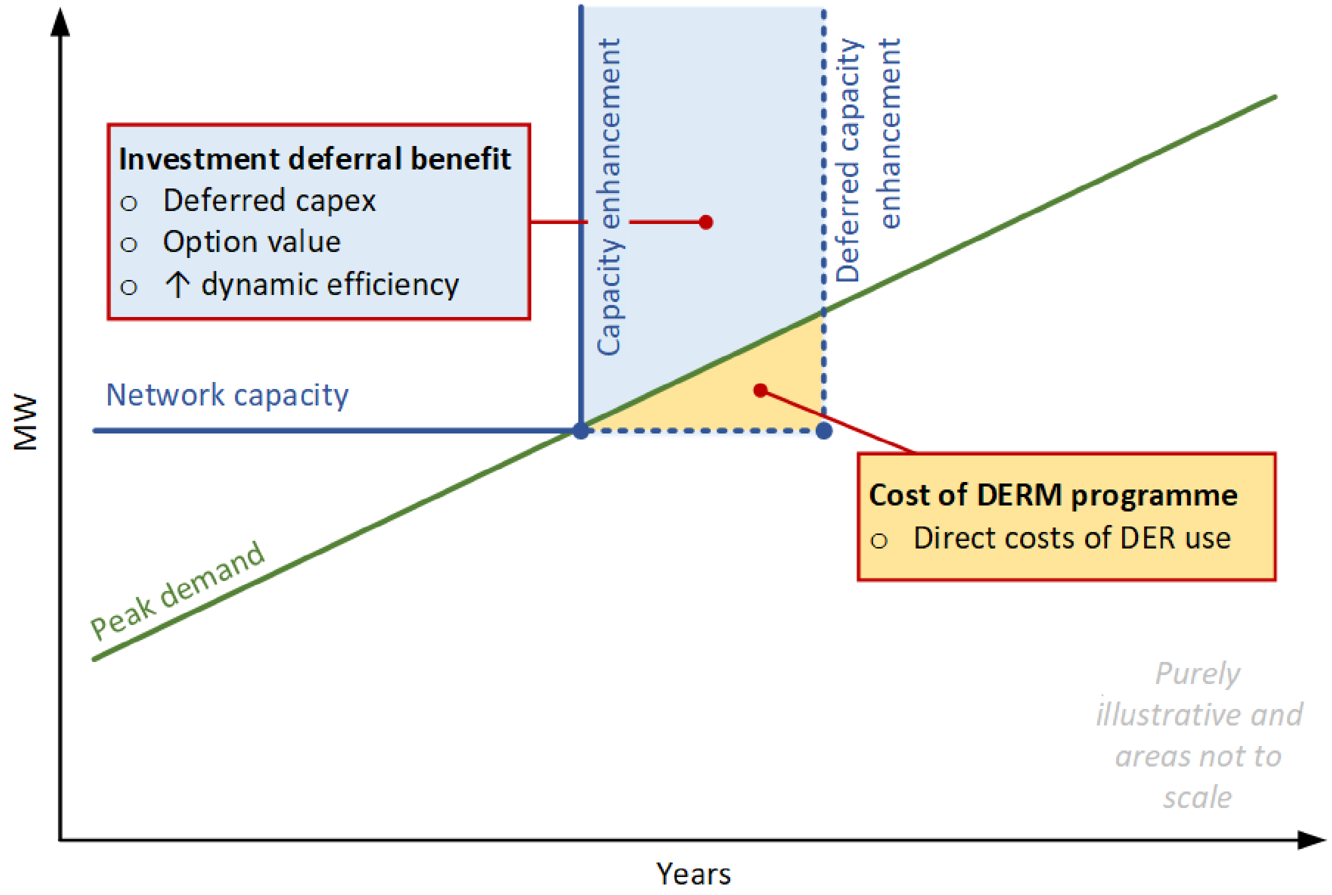
We could defer network investment with network TOU pricing

- We could achieve network investment deferral through time of use (TOU) pricing
- However, prices would then have to rise above marginal direct costs. This could create counter-veiling inefficiencies in use and resource allocation. In economic-terms this would create deadweight loss and allocative inefficiencies
- Current network TOU pricing e.g. distribution pricing can also have practical limitations:
  - TOU tariffs can have low granularity e.g. day/night rather than half-hourly
  - Given the choice, consumers often prefer simple, flat-rate retail tariffs



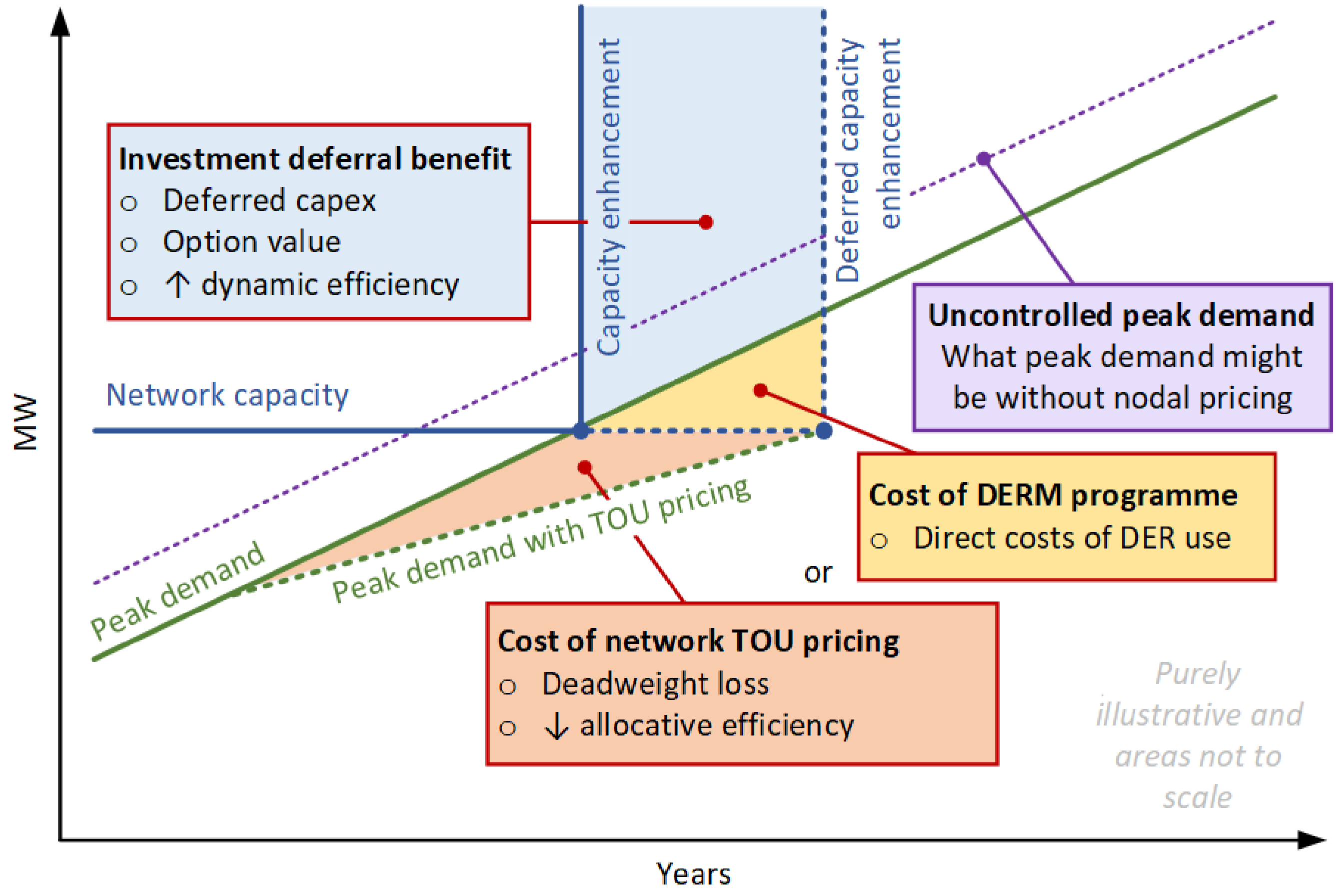
Or, we could defer network investment with DERM

- Alternatively (or as well) we could achieve network investment deferral through a DERM programme
- This would have a direct cost in payment to DER providers but (managed carefully) can preserve the allocative efficiency of the nodal prices
- Such a DERM programme could be used also for network investment risk management, to manage risk of:
  - Delayed commissioning
  - Higher than forecast demand growth



How to optimise network investment deferral

- So, for overall economic efficiency we need to balance the:
  - Benefits of network deferral
  - Costs and efficacy of any network TOU pricing
  - Cost of any DERM programme
- Often, the costs of TOU pricing (beyond nodal prices) and DERMS programmes will be too great, and the network investment should proceed
- Sometimes, one or other (or both) of TOU pricing and DERMS could be an economically optimal solution for a limited period



Network TOU pricing could increase network investment efficiency

- The main price is the nodal price, made up of:
    - The ‘baseload’ energy price, being the offer price of the marginal generator on the unconstrained grid
    - Losses
    - When there’s a grid constraint, a congestion component based on the offer price of the marginal generator in the constrained region
- The nodal price is very accurate at reflecting the marginal cost of energy and leads to high allocative efficiency in real-time

Price signals

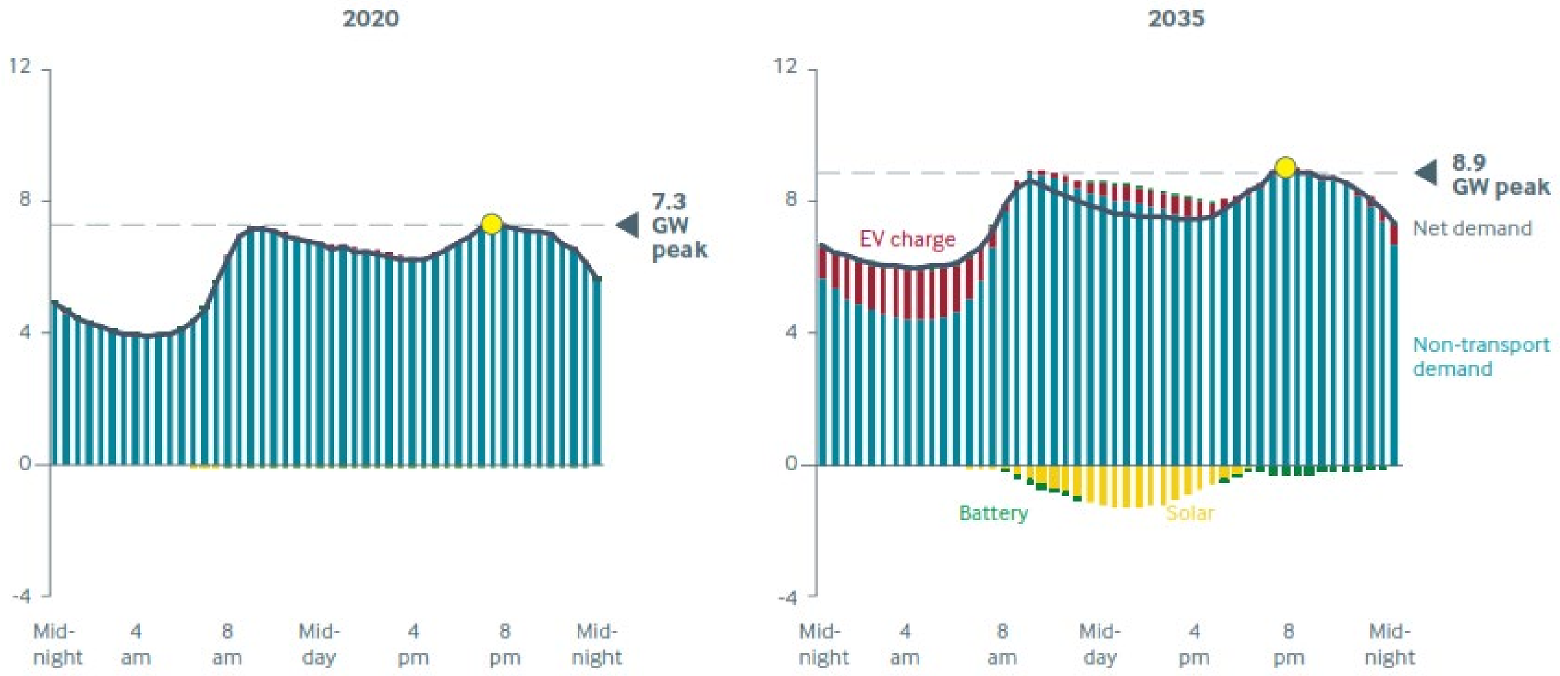
Price signals
Energy
Losses
Congestion
Network investment deferral value

- Network deferral value is not included in the nodal price
    - For transmission, the nodal price is the same whether the next investment is $1M or $1B
    - For distribution, the nodal price only goes to GIP/GXP level, not deeper into the network
- Network TOU pricing - in effect - adds this component into a ‘complete’ price signal
- Usually the deferral value is zero:
    - When there is no imminent need for network investment
    - When it’s not a local/regional peak
- But, at very specific places and times, this value-based price could be material

How might DERM be integrated with the market?

Why we need a flexibility market, reminder…

- WiTMH envisages that peak demand will grow slower than energy demand, based on assumptions of such peak-flattening measures as EV smart charging
- This will save billions in network investment, reduce the requirement for and emissions of peaking generation, and improve power system management
- Nodal pricing, network pricing and DERM all have their part to play in incentivising such ‘smart’ behaviour and realising this future



How can we enable rather than be reactive to new DER?

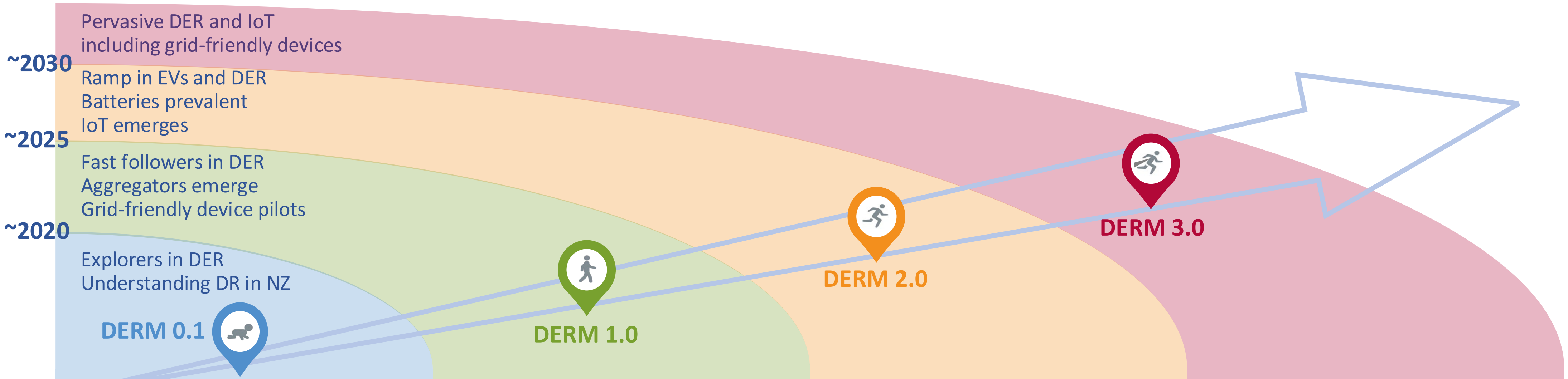
- The ‘Operationalising Grid Owner DERM’ section focus on DERM for transmission, and by extension how EDBs might operationalise DERM
- This section and the next pose questions of how might DER be integrated with other markets, especially the wholesale spot market – both through participation and through arbitrage – and ancillary services markets

Areas of development	Some suggested principles for market development
• Pricing	• Simple and profitable consumer participation
• DER Markets	• Minimise transaction and industry costs
• Technology standards	• Encourage competition, innovation and customer choice
• Platforms and aggregators	• Support multiple markets
• Regulatory framework	• Integration with the wholesale market
	• Support secure system operation
	• Evolutionary approach

Focus here on specific parts of the DERMS value proposition

Distributed Energy Resources Sources of DER value		Demand reduction classic DR e.g. industrial plant		Embedded generation controllable plant e.g. diesel		Embedded batteries including EV fast-chargers	
		Value	**Rationale**	**Value**	**Rationale**	**Value**	**Rationale**
Energy market	Wholesale through DERMS	Low	Little benefit over self-dispatch or dispatch through Retail DERMS, once nodal prices go ex-ante	High	Aggregation as virtual power plant can become price maker or moderator in constrained regions	High	Best of both worlds Can, depending on where in charge / discharge cycle, act as either
	Retail through DERMS	Medium	Avoidance of high price – by consumer if exposed, by retailer if they've hedged the consumer	Low	Little benefit over self-dispatch, depending on contractual position	Medium	
Network investment deferral through TPM / DPM or DERM	Distribution	High	• Load reduction, embedded generation and battery services are equivalent at peak-lopping • Distribution investment requirements higher and utility resources more limited than for transmission • There remains a risk that if peak-pricing is removed from the TPM, the use of DERM for transmission peak management may need to increase commensurately				
	Transmission	Medium					
Ancillary services	Frequency keeping (FK)	Medium	Some possibilities for grid-friendly appliances and controls	Low	Most incumbent technology not responsive enough	High	Ideal technology. FK low value now but will increase with intermittency
	Instantaneous reserves (IR)	High	Some technologies fast enough – ripple control, cold stores…				
	New e.g. inertia, balancing	Medium	Some possibilities with inverters				
Firming intermittent generation		Low	Limited possibilities beyond FK	Low		High	Ideal complement

DR markets could develop as DER and participants are supported through market and regulatory frameworks – possible evolution



DER pilots

- EDBs (Vector, Orion) and participants (Contact) piloting DER with price signals
- Ripple control and other DER tools used by EDBs & retailers to manage exposure
- Battery pilots (Vector, Mercury, Alpine, Counties Power)
- Transpower (TP) DR pilot RCP2 funded
- Improved participation
- Analysis of use cases

Early, manual DER market

- Pre-contingent calls hours-ahead
- EDBs, retailers and aggregators use DER to manage commercial exposure
- TP and EDBs use DER for asset management
- Code expanded to include aggregators
- Market learnings and commitment to develop DER wholesale market portal
- Maintenance of DER standards
- Trials of post-contingent DER

Flexibility, Automated DER market

- DER market portal aggregating multiple other DER platforms in an integrated DER market
- Pre-contingent calls mins to hours-head
- EDBs, aggregators and retailers call DER to control risk & manage congestion
- Code fully agnostic to technology
- Transpower and EDBs use DER to manage wave of electrification
- Full DER value chain is realisable

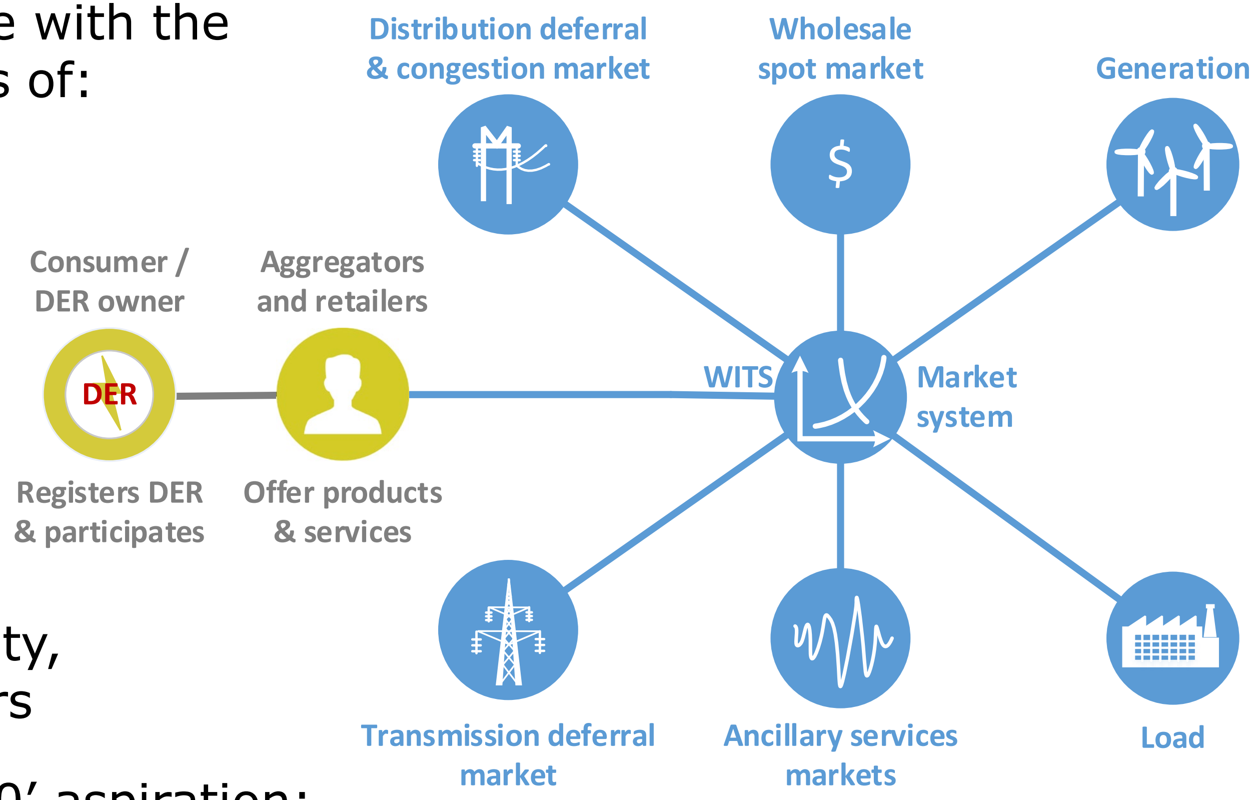
Interactive DER market

- Centralised and interactive DER activation platform
- Pre-contingent and fast, automated post-contingent calls
- Market schedules DER via offers and bids
- 'Plug and play' IOT becomes a reality
- Dynamic realtime interactive market
- Aggregators, EDBs and DER programme managers offer DER into the market as virtual large load, generation & batteries

RCP2 period | **RCP3 period**

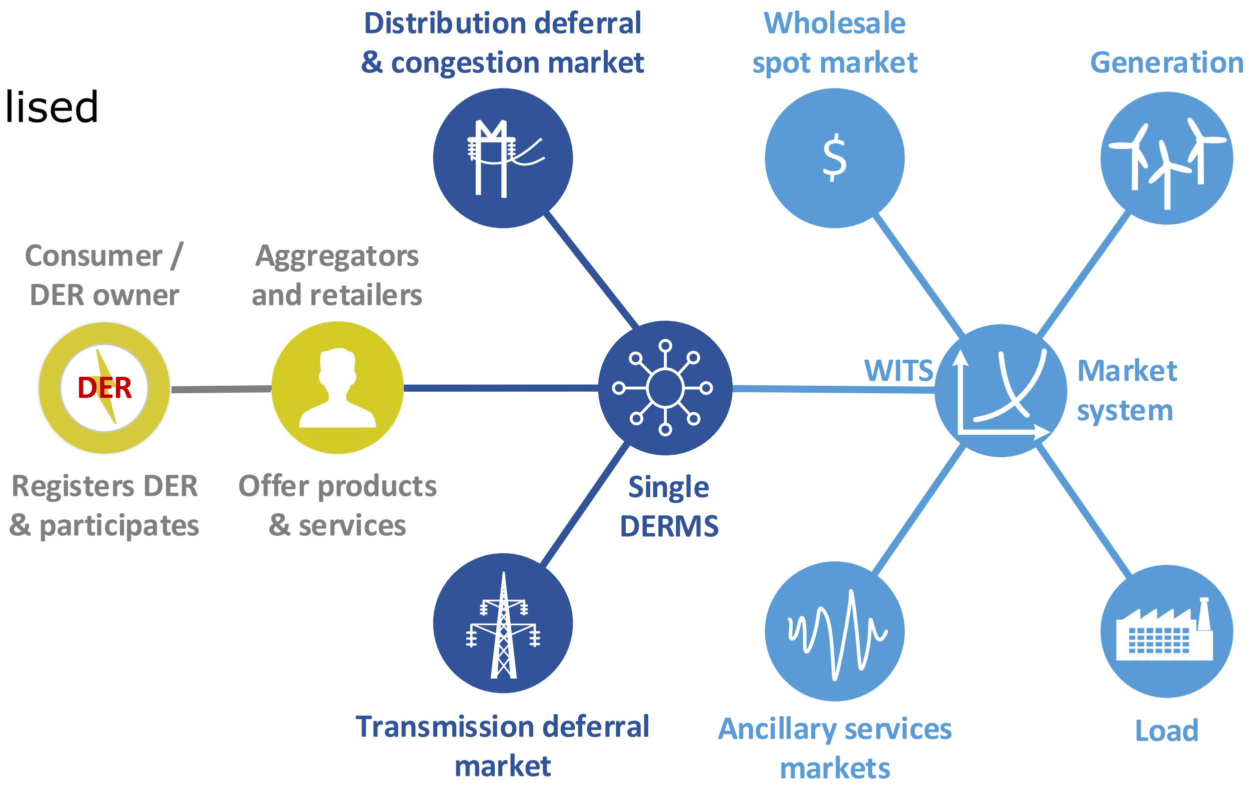
DERM – How to proxy a fully DER-capable market system in the near term

- Conceptual models for DER to interface with the market system could include variations of:
  - Total integration (shown here)
  - Single centralised DERM
  - Multiple DERMs
  - Hybrid
- Each has it own challenges and advantages and would need further consideration by the Electricity Authority, system operator and other stakeholders
- Total integration could be a 'DERMS 3.0' aspiration: the others, practical, evolutionary steps towards it



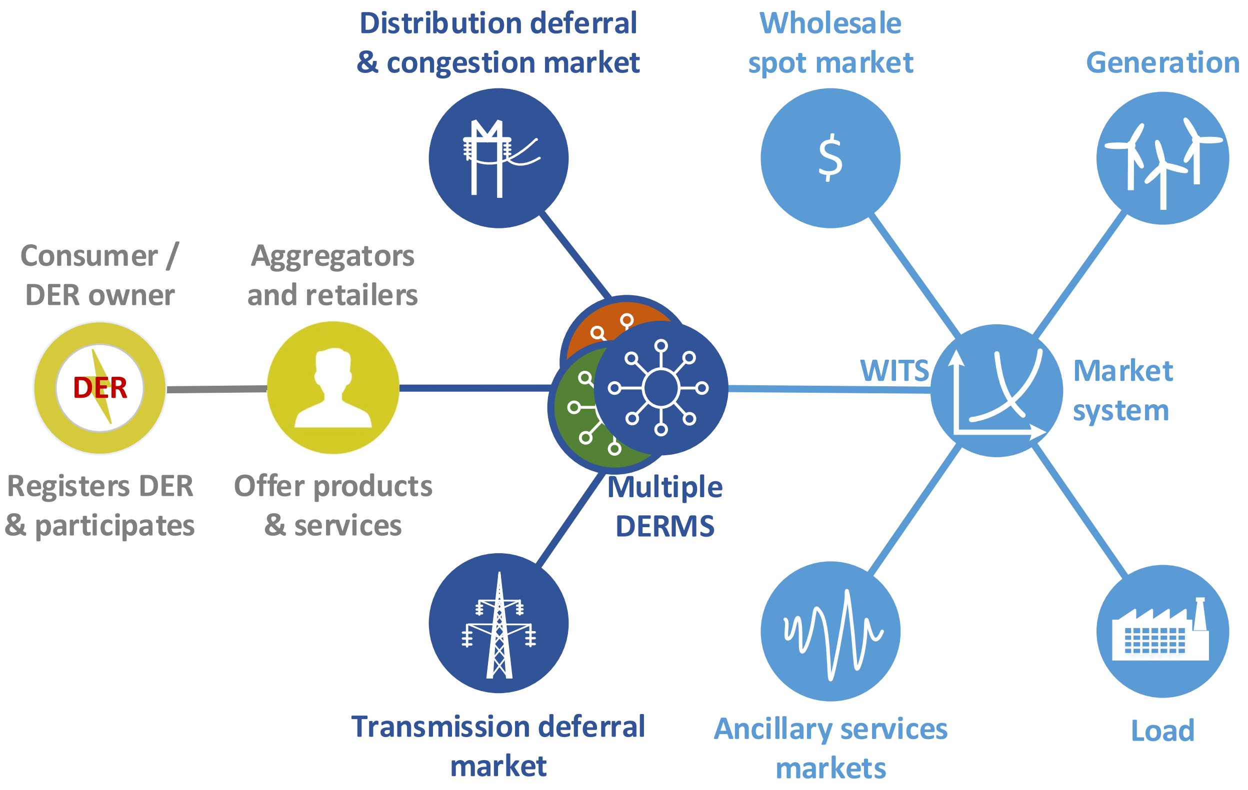
One model would be a single, centralised DERMS

- The market could develop in different ways
- One model would be that of a single, centralised DERM system (DERMS) that would provide:
  - The DER registration, aggregation, verification and settlement services
  - Access to the spot and ancillary service markets through the market system
  - Direct access to network deferral markets
  - Aggregated arbitrage of ex-ante spot prices
- But, as a single system, this model could compromise competition and innovation in DERMS services



Another model would be multiple DERMS

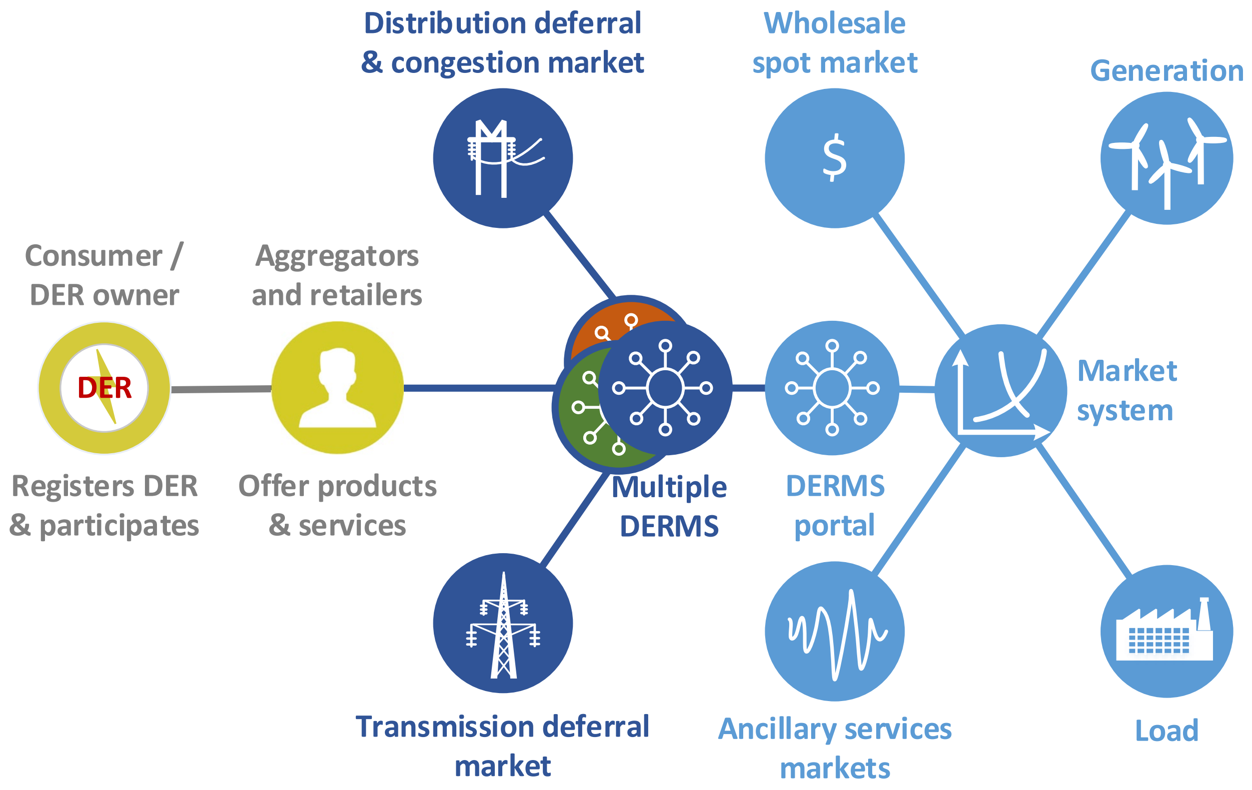
- The market could develop in different ways
- Another model would be that of multiple DERM systems that would each provide that same range of services, including access to the spot and ancillary service markets through the market system
- This would encourage competition and innovation in DERMS services
- Each DERMS that needed to interface with the market systems would need to meet the WITS communications requirements*



* Currently, web services or ICCP: see slide 51)

And another model would be a hybrid

- The market could develop in different ways
- Another model would be that of a single 'wholesale' DERMS portal or gateway to the spot and ancillary service markets through the market system, providing equal access to multiple other 'retail' DERMS
- It would have the functionality of a fully DER-capable market system, but be simpler (and probably significantly cheaper) to build, as a simple extension of existing DERMS technology and market rules



RTP may encourage DER to self-dispatch rather than bid into the wholesale spot market

- Potential arbitrage value is high (Sapere estimate $21M pa by 2035)
- But DER can choose between:
  - 'Self-dispatch' in response to spot price or spot price forecasts
  - Participating in the spot market, e.g. through an aggregator and Dispatch Notified
- Table here assumes RTP and its 5-minute ex-ante prices
- Bidding contributes to overall system accuracy, but that has limited benefit to individual DER

<table>
<tr><th>Speed of DER response</th><th>Fast
<<5-minutes</th><th>Medium
>5 but <30 minutes</th><th>Slow
>30 minutes</th></tr>
<tr><td>Examples of DER types</td><td>Automated batteries and heating / cooling systems</td><td>Those requiring manual control</td><td>Industrial processes</td></tr>
<tr><td rowspan="2">How could DER self-dispatch?</td><td colspan="2">Constantly adjust its 'strike price' to include other factors e.g. amenity, state of charge, customer orders
Monitor RTP price
Only beneficial if on a spot-price pass-through tariff</td><td rowspan="2">Monitor scheduled price</td></tr>
<tr><td>Can avoid a sudden high 5-minute price</td><td>Can partly mute a high 5-minute price</td></tr>
<tr><td rowspan="3">Benefit of participating in the spot market</td><td colspan="2">Can set the price (but statistically unlikely as small)</td><td rowspan="5">Can't actively participate as needs to self-dispatch ahead of trading period</td></tr>
<tr><td colspan="2">Gets a dispatch instruction</td></tr>
<tr><td colspan="2">Access to constrained-on payments (DD only)</td></tr>
<tr><td rowspan="2">Cost of participating in the spot market</td><td colspan="2">Transaction cost</td></tr>
<tr><td colspan="2">Has to bid for each GXP separately (not aggregated)</td></tr>
</table>

How might markets evolve to incorporate DERM?

TRANSPOWER

DERM market development – some observations and questions

- What market evolution may be needed to capture this value, and encourage efficient levels of DER and DERMS investment?
- Currently DERM is not fully accommodated within the:
  - Wholesale market: energy and ancillary services
  - 'Retail' market: network services and energy price arbitrage
- How should the Code and the Market Systems be evolved to include DERM?
- What balance should be struck between minimising transaction and industry costs and accelerating the introduction of a flexibility market?
- What is the role of technology and communications standards in DERM market development?

DERM wholesale market developments – some observations

- RTP's ex-ante and scarcity pricing will encourage DER price-responsiveness
- RTP will introduce dispatch-notified generation/load as a 'half-way house' participation category:
  - Greater flexibility than full dispatch
  - Ineligible for constrained on/off payments
- Substantive challenges remain for DERM post-RTP and are likely to require changes to regulatory settings and the market system
- Future rules for aggregation might need to consider:
  - Compliance with bids, offers and dispatch instructions
  - Interaction with forecasts
  - Provision of information

RTP introduces

- Five minute pricing
- Ex ante prices, published and final at start of five minute period
- Automated, ex-ante scarcity pricing, starting at $10,000/MWh
- 30-minute time-weighted average settlement
- Dispatch notified generation/load

Some items that could become DERMS spot market issues

DRAFT for discussion

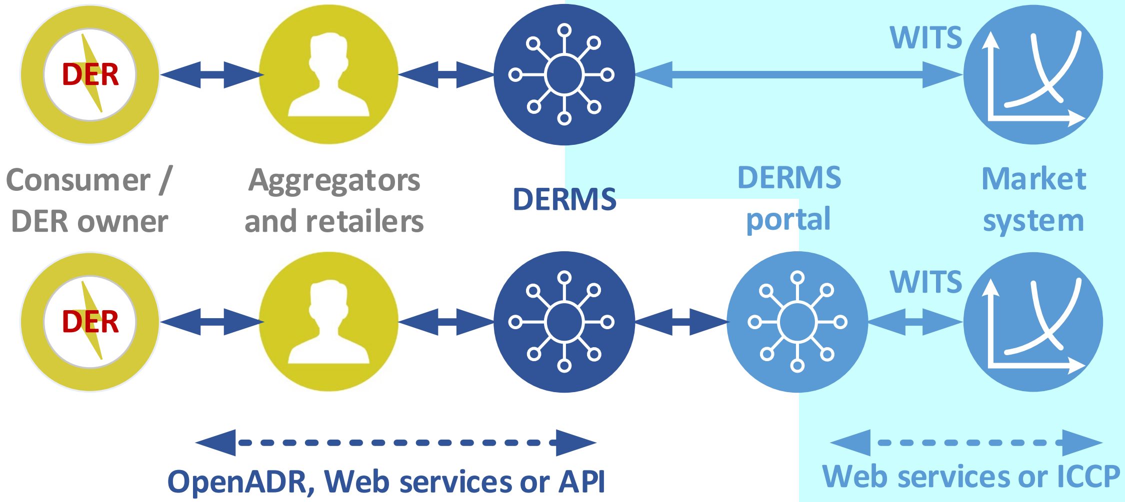
#	Potential Issue		Needed for DER market participation? Retail	Needed for DER market participation? Wholesale
1	Aggregation across retailers	Enabling aggregation across participants and or GXPs may be needed to achieve critical mass for DER	Yes	Yes
2	Replace profiling with TOU data	Retailers need to apply half hour or five minute reconciliation where available	Desirable	Yes
3	DER comms standards	Communications between DR platforms, DER and DER owners are critical for calls and verification	Desirable	Yes
4	DER technical standards	Benefits of common standards for DER connection and operation that do not cause unwarranted system issues	Desirable	Yes
5	DER information provision	Key system players (SO, EDBs, Grid owner) need information on connected and active DER	Yes	Yes
6	DERM information provision	Need to incorporate planned and actual DR calls into SO's and EDBs' load and hence price forecasts	Yes	Yes
7	Pass-through participation	How to incorporate a third party into the market rules who is not the 'owner' of the electricity?	n/a	For market portal

Key
Change
Maybe
No

DER communications standards – important to get right

- Communications between DER, DER owners and DERMS platforms are critical for registration, calls and verification
- International, open-source DR communications standards have emerged and continue to evolve: OpenADR is the emerging international standard
- Modern DERMS platforms allow DER owners direct access using:
  - DERMS existing graphical user interface (GUI)
  - Web services
  - Application programming interfaces (APIs), or
  - OpenADR
- The AS/NZS 4755 standard for this for a DER is DRED (Demand Response Enabled Device)

- DERMS portal needs to bid/offer into and be dispatched by the market system
- This currently requires a WITS interface: web services or ICCP*



* ICCP might be preferred by the DERM operator if real-time SCADA data is required e.g. for source verification

DERM ancillary service market developments: some possibilities

- DER can be physically highly capable of providing instantaneous reserves (IR) and frequency keeping (FK) ancillary services
- DER participation not currently fully enabled in IR
  - Aggregated DR as interruptible load IR is enabled
  - IR allows for a battery to reduce charging, but
  - Battery injection is not currently able to provide IR (on EA's 2020/21 work programme)
- IR is per-island not at a GXP level so wider aggregation possible than for the spot market
- DER participation in FK not enabled currently
- Effecting change likely to require contractual, Code and market system changes as well as study by the system operator to ensure security will be maintained

DERM ancillary service market developments: some impossibilities

- Unlikely that DER will be able to provide our other ancillary services:

Black start

- Needs grid-connected generation plant (or charged batteries) that can self-start without needing grid power, so DER connected at the distribution level would not help
- For DER connected at grid level (e.g. at a direct connect industrial plant), SO could contract for them under existing arrangements
- No Code or Market System changes required for this

Voltage support

- Voltage issues are local
- Inverters can create over-voltage issues but this is best (at least initially) addressed through network asset management and standards, not markets
- Batteries can inject/absorb kVars as well as kW
- Var pricing could be a long-term approach
- Otherwise, contracts with distributor, Transpower as Grid Owner or Transpower as SO would suffice without Code or Market System changes

Over-frequency reserve

- Currently generating units that can be armed when required and automatically disconnected if there is a sudden rise in system frequency
- DER is unlikely to be of sufficient volume to contribute, but if so the SO could contract for them under existing arrangements
- No Code or Market System changes required for this

Potential future services?

- Maybe, but not considered here

DER could operate in multiple markets with minimal issues

… can it be active through the same or a different aggregator in this market?

If a DER is active through an aggregator in this market …

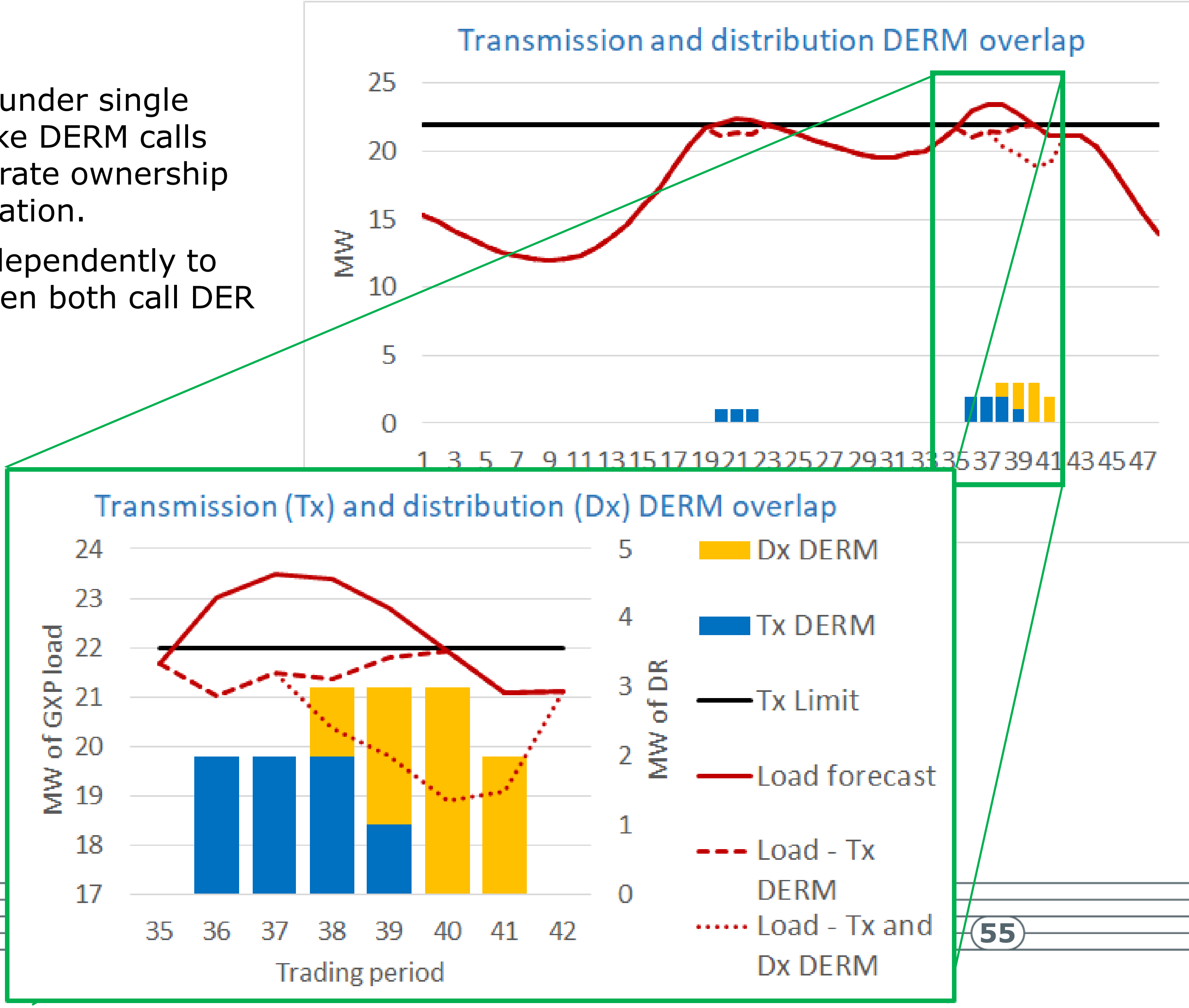
<table>
<tr><th></th><th>Wholesale market participation</th><th>Energy arbitrage</th><th>Transmission deferral</th><th>Distribution deferral</th><th>Instantaneous reserve</th><th>Frequency keeping</th><th>Extended reserves</th></tr>
<tr><td>Wholesale market participation (e.g. Dispatch Lite)</td><td colspan="2" rowspan="2">OK if within dispatch compliance limits</td><td colspan="2">No problem for DR calls > gate closure (1 hr)
Within gate closure, OK if within dispatch compliance limits</td><td colspan="2">Already allowed for in market rules</td><td rowspan="2">Network company (EDB or TP) ensures relay load always meets its obligations (equivalent to IL obligation)</td></tr>
<tr><td>Energy arbitrage (self-dispatch in response to price)</td><td colspan="2">No physical problem - lucky DER could be called when they would have reduced load for price reasons anyway</td><td colspan="2">Where dispatched as IR or FK, needs to meets its commitments. Can use MW not dispatched to arbitrage</td></tr>
<tr><td>Transmission deferral
Distribution deferral</td><td colspan="2">Can participate in wholesale market or arbitrage if it meets terms of its network DER contract. E.g. a DER on a two-hour call contract could particpate if not called by then</td><td colspan="2">We can expect minimal interactions between transmission and distribution DERM. Easily co-ordinated, and worst outcome is occasional over-calling or double-paying</td><td colspan="2">Can participate in ancillary services if meets terms of its network DER contract. E.g. a DER on a two-hour call contract could participate in IR or FK if not called by then</td><td rowspan="2">DER operator must inform lines company, who can then adjust their relay settings to continue to meet obligations</td></tr>
<tr><td>Instantaneous reserve
Frequency keeping</td><td>Already allowed for in market rules</td><td colspan="3">Where dispatched as IR or FK, needs to meets its contractual commitments. Can use MW not dispatched, and unable to be disatched (e.g. hasn't been dispatched at 30 ahead ot real-time) in other markets</td><td colspan="2">Interactions between the IR and FK markets managed through existing market rules and SO contracts. Needs information at source level. FK and IR not technology agnostic yet.</td></tr>
<tr><td>Extended reserves</td><td colspan="6">Extended reserves is not an active market at the DER level</td><td></td></tr>
</table>

Key:			
	No issues, or covered by existing rules	*Can be managed contractually*	*No compliance impacts currently but maybe new rules needed*

See next slide for detail

No practical issues between transmission and distribution markets

- Overseas where transmission and distribution are under single ownership, it would be natural and efficient to make DERM calls that support both. In New Zealand, with our separate ownership structures, this could be achieved through coordination.
- Say transmission and distribution DER is called independently to manage peaks in their networks. Only issue is when both call DER simultaneously (TPs 38 and 39 in diagram):
  - If DER sources are different, this will solve both peak issues, but more DR at higher overall cost will have been called
  - If DER sources overlap, then this too will solve the peak issue, but some DER sources might be paid twice (financial double dipping)
  - Neither would create a security issue
- Coordination benefits both Transpower and the EDB, so unlikely to be a practical (or urgent) problem, or require regulation



Discussion and next steps

Transpower's proposals for DERM discussions with IPAG

<table>
<tr><th>22 July 2020</th><th>21 October</th><th>1 December</th><th>2021</th></tr>
<tr><td colspan="3">Focus on learnings from Transpower's programme</td><td rowspan="2">Focus on how to move forward</td></tr>
<tr><td>• Introduction
• Transpower's RCP2 DR programme
• Transpower's DERMS platform</td><td>• RCP2 outcomes
• Mechanics of our DERMS platform
• Operationalising DERM: overview</td><td>• Value stack and pricing interactions
• Operationalising Grid Owner DERM
• DERM market development issues</td></tr>
</table>

For IPAG feedback please