Meeting 116

2 September 2021

Transmission Charging Methodologies Forum and CUSC Issues Steering Group

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Agenda

1	Introduction, meeting objectives	**Jon Wisdom - NGESO**	10:30 - 10:35
2	Code administrator update	**Paul Mullen - Code Administrator NGESO**	10:35 - 10:45
3	TNUoS gen cap error margin calculation - 2021 result	**Jo Zhou - NGESO**	10:45 - 10:55
4	BSUoS incentive recovery	**Nick Everitt - NGESO**	10:55 - 11:15
5	Early Competition Plan update	**Katharina Meehan - NGESO**	11:15 - 11:45
6	Net Zero Market Reform	**Market Strategy team - NGESO**	11:45 – 12:05
7	AOB and Meeting Close	**Jon Wisdom - NGESO**	12:05 – 12:20

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Code Administrator Update

Paul Mullen, Code Administrator NGESO

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Authority Decisions Summary (as at 2 September 2021)

Authority decisions since last TCMF		
Modification	**What this does?**	**Decision Date**
CMP280	Seeks to remove Transmission Demand Residual charges from generation and electricity storage	**Rejected 30 June 2021** given the high implementation costs, the short-term nature of the potential solution (implementation of CMP280 for the charging year 2022/23 could be superseded by any decision to implement CMP343) and the absence of evidence that the benefit would outweigh the costs
CMP300	Seeks to improve the cost reflectivity of the Response Energy Payment ("REP") for Balancing Mechanism Units ("BMUs") with low or negative marginal costs, as a consequence of having a Contract for Difference ("CfD")	**Sent back 9 July 2021** asking to 1) Provide more evidence that demonstrates objective (b) would be better facilitated for CfD BMUs as a class of users, 2) Seek further feedback from industry and affected parties to improve the robustness of the assessment of the proposals and 3) Make best endeavours to secure further supporting evidence to demonstrate the economic impact of the Proposal against the class of users that would be affected
CMP365	Creates a more efficient process for CUSC modifications and to align the CUSC with other code governance rules	**Decision received 16 July 2021 approving the CMP365 Original** – implemented 30 July 2021
CMP326	Introduces a cap on the MW element in the holding payment calculation for Frequency Response provided by sites with Power Park Modules (PPMs)	**Decision received 10 August 2021 approving the CMP326 Original** – to be implemented 1 December 2022

Authority Decisions Summary (as at 2 September 2021)

On 4 May 2021 (last updated 9 July 2021), Ofgem published a table that provides the expected decision date, or date they intend to publish an impact assessment or consultation, for code modifications/proposals that are with them for decision here

Modification	What this seeks to achieve?	Decision Date / Anticipated Decision Date
CMP335/336 and CMP343/340	Proposes the methodology for Transmission Demand Residual charges to be applied only to 'Final Demand' on a 'Site' basis, as well as how to treat negative locational charges and the application of any charging bands.; CMP335/336 looks at the Transmission Demand Residual billing and consequential changes	Expected decision dates for all these Modifications was 27 August 2021; however Ofgem confirmed at CUSC Panel on 27 August 2021 that this date will not be met and will advise on the new expected decision date as soon as possible.
CMP292	Introduces a cut-off date for changes to the Charging Methodologies	30 September 2021 (previously 30 June 2021) as Ofgem consider this to be low priority
CMP371	Seeks to update CUSC Section 8 such that it is possible, under one CUSC Modification Proposal, to change CUSC provisions relating to Connection Charges, and Use of System Charging Methodologies alongside non-charging provision	Final Modification Report received 7 July 2021 – expected decision date 29 September 2021
CMP370	Seeks to align the CUSC with the new Interactivity policy that has been developed collaboratively with industry through the Energy Networks Association (ENA) Open Network Projects	Final Modification Report received 13 August 2021 – expected decision date 20 September 2021

Implementations Summary (as at 2 September 2021)

Implementations

Modification	What this does?	Implementation Date
CMP365	Creates a more efficient process for CUSC modifications and to align the CUSC with other code governance rules	30 July 2021
CMP372	Ensure that retained EU law functions effectively in the context of the CUSC following the UK-EU Trade and Cooperation Agreement and the end of the transition period	3 August 2021

Withdrawals

- None since last TCMF

Last Panel

27 August 2021

- 1 New Modification
  - **CMP378** seeks to inserts a new Clause into the CUSC to place an obligation on the ESO and Code Admin to comply with the obligations insofar as these apply to them under Section C12 (Market-wide Half-Hourly Settlement Implementation) of the Balancing and Settlement Code (BSC). Panel noted that **CMP378** will follow the AUTHORITY LED SCR MODIFICATION process as set out in CUSC 8.17B, They also agreed that **CMP378** should follow standard governance route and proceed straight to Code Administrator Consultation. The Code Administrator Consultation was issued on 31 August 2021 and will close 5pm on 14 September 2021.
- No Workgroup Reports
- No Draft Final Modification Reports
- Presented forward look out on CUSC, Grid Code and STC Modifications for next 12 months – really helps see where the gaps and constraints are and enables the right conversations about prioritisation

Next Panels

14 September 2021

- Panel votes on whether or not to recommend implementation of **CMP368/CMP369** and **CMP308**

Next Panels

24 September 2021

- Possible New Modifications:
  - Determining TNUoS demand zones for use in setting TNUoS tariffs for transmission-connected demand at sites with multiple DNOs
- Panel to determine if **CMP328** Workgroup has met its Terms of Reference and this can proceed to Code Administrator Consultation
- Panel votes on whether or not to recommend implementation of **CMP377 and CMP378**
- Forward look out on Modifications for next 12 months
- Update on CMP326 Implementation
- Future Panel meeting arrangements

In Flight Modification Updates

In flight Modifications (as at 2 September 2021)

2 open Workgroup Consultations

CMP298 closes 10 September 2021
CMP361/362 closes 24 September 2021

2 open Code Administrator Consultations

- **CMP377** closes 5pm on 2 September 2021
- **CMP378** closes 5pm on 14 September 2021

6 CUSC Workgroups held in August 2021

- 11 held across CUSC, Grid Code, STC and SQSS
- 12 to be held across CUSC (8 CUSC), Grid Code, SQSS and STC in September 2021

For updates on all "live" Modifications please visit "Modification Tracker" at:
https://www.nationalgrideso.com/industry-information/codes

2021 Dates

CUSC 2021 - Panel dates

CUSC	(TCMF) CUSC Development Forum	Modification Submission Date	Papers Day	Panel Dates
January	7	14	21	29
February	4	11	18	26
March	4	11	18	26
April	8	15	22	30
May	6	13	20	28
June	3	10	17	25
July	8	15	22	30
August	5	12	19	27
September	2	9	16	24
October	7	14	21	29
November	4	11	18	26
December	25/11	2	9	17

TNUoS gen cap error margin for 22/23 tariffs

Jo Zhou, National Grid ESO

September 2021

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Background

The EU gen cap and the error margin

- The limit of [€0 ~ €2.50]/MWh on generators' average transmission network charges
- For TNUoS tariff setting: forecasting TWh volume ➔ applying the €[0, 2.50] range ➔ applying the €/£ exchange rate ➔ derive the maximum total charge on generators
- Risk of forecasting errors: "error margin" to reduce the maximum total gen charge by a % error margin

The current error margin

- The error margin for 2021/22 tariffs is 20.8%.
- Please refer to the July 2020 TCMF and was the August 2020 TNUoS five-year view report for further details

The error margin update

- We have re-calculated the error margin for year 2022/23 tariffs

Calculation of the error margin

- The updated error margin (for year 2022/23 tariffs) and the underlying calculation, has been published as part of our August TNUoS tariff forecast

The approach

- Using historical data in the past five whole years (for year 2022/23, data from 2016/17 – 2020/21)
- Data include generation £m revenue and generation output TWh, and the % errors are calculated by using (actual – forecast)/ forecast
- Generation revenue errors are further adjusted by the "systematic error", which is the average of past five years' generation revenue errors%
- The tariff error is then derived:

- $$\frac{1 + \max(\text{absolute}((\text{generation revenue error\%}))}{1 - \max(\text{absolute}(\text{ generation output TWh error\%}))} - 1$$

Error margin comparison

Data from year:	Gen Revenue inputs				Gen output variance
	Gen Revenue variance*	Systematic error (2015/16 ~ 2019/20)	Systematic error (2016/17 ~ 2020/21)	Adjusted variance	
2015/16	-8.7%			-0.1%	-12.2%
2016/17	-5.1%	-8.6%	-9.5%	3.5%	-7.9%
2017/18	-5.2%			3.4%	-1.5%
2018/19	-9.2%			-0.6%	-7.5%
2019/20	-14.6%			-6.1%	-4.1%
2020/21	-13.2%			-3.7%	7.5%

Adjusted variance = the revenue variance - systematic error

Systematic error = the average of all the values in the series

Adjusted error = the maximum of the (absolute) values in the series

* Gen Revenue: the "eligible revenue" under the CUSC methodology as the time of tariff setting

Calculation for 2021/22 tariffs (based on 2015/16 – 2019/20 data)				
	Systematic error:	-8.6%		
	Adjusted revenue error:	6.1%	Output error:	12.2%
	Error margin = **20.8%**			

Calculation for 2022/23 tariffs (based on 2016/17 – 2020/21 data)				
	Systematic error:	-9.5%		
	Adjusted revenue error:	5.2%	Output error:	7.9%
	Error margin =**14.2%**			

The reduction from 20.8% to 14.2% was mainly driven by the reduced gen output (TWh) variance, as year 2015/16 data are now excluded from the latest calculation

BSUoS incentive recovery

Rebecca Yang, National Grid ESO

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BSUoS – ESO Incentive 2020/21

Key Points

- The ESO incentive is determined by Ofgem at year end based on the recommendation of an independent panel.
- Under normal circumstances the ESO incentive is recovered in that same years BSUoS SF run against a forecast and reconciled via RF run based on Ofgem's decision.
- The recovery of the 2020/21 ESO incentive was put on hold as part of the ESO response to support the industry through the COVID-19 pandemic.
- Ofgem awarded the ESO an incentive of £5m for the 2020/21 charging year (30th July Ofgem letter)
- Having engaged with some of the industry parties and considered feedback from previous recovery discussions with the industry, the ESO are minded to recover the 2020/21 ESO incentive through the remainder of the SF run for the 2021/22 charging year.
- Ofgem approval for this recovery approach would be sought with recovery via the SF run starting in October 2021.
- Assuming recovery from 1st October 2021 to 31st March 2021 settlement day, there would be a daily recovery amount of £27,472.53

2020/21 BSUoS Scheme Year												2021/22 BSUoS Scheme Year											
Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22
																		2020/21 incentive Recovery Period £5m					
Daily Recovery of £0																		Daily Recovery of £27,472.53					

BSUoS – ESO Incentive 2021/22 & 2022/23

Key Points

- For the 2021/22 and 2022/23 charging years the ESO Incentive arrangements have been revised by Ofgem to complement the regulatory arrangements for the ESO under the RIIO-2 price control. (ESORI guidance Ofgem)
- The ESO incentive scheme will run as a two-year scheme with a final determination of the incentive by Ofgem in August 2023. It was agreed with Ofgem that the incentive forecast for the first year of RIIO2 was set to zero consistent with other licensees.
- We currently forecast £10m for the two-year scheme and are proposing that we recover the forecast 2021/22 and 2022/23 incentives together in the 2022/23 BSUoS charging year.
- Assuming recovery from 1st April 2022 to 31st March 2023 settlement day, there would be a daily recovery amount of £27,397.26
- The intention of phasing the recoveries in this way is to smooth out the impact that the incentive recovery has on overall BSUoS charges.

<table>
<tr><td colspan="12">2020/21 BSUoS Scheme Year</td><td colspan="12">2021/22 BSUoS Scheme Year</td><td colspan="12">2022/23 BSUoS Scheme Year</td></tr>
<tr><td>Apr-20</td><td>May-20</td><td>Jun-20</td><td>Jul-20</td><td>Aug-20</td><td>Sep-20</td><td>Oct-20</td><td>Nov-20</td><td>Dec-20</td><td>Jan-21</td><td>Feb-21</td><td>Mar-21</td><td>Apr-21</td><td>May-21</td><td>Jun-21</td><td>Jul-21</td><td>Aug-21</td><td>Sep-21</td><td>Oct-21</td><td>Nov-21</td><td>Dec-21</td><td>Jan-22</td><td>Feb-22</td><td>Mar-22</td><td>Apr-22</td><td>May-22</td><td>Jun-22</td><td>Jul-22</td><td>Aug-22</td><td>Sep-22</td><td>Oct-22</td><td>Nov-22</td><td>Dec-22</td><td>Jan-23</td><td>Feb-23</td><td>Mar-23</td></tr>
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£5m</td><td colspan="12">2021/22 and 2022/23 incentive Recovery Period
£10m</td></tr>
<tr><td colspan="18">Daily Recovery of £0</td><td colspan="6">Daily Recovery of £27,472.53</td><td colspan="12">Daily Recovery of £27,397.26</td></tr>
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BSUoS – Controls Enhancement

Following on from the incident that led to the failure to timely recover BSUoS for FY21, PwC were appointed to support the ESO in looking to further enhance our end – to – end Control environment

What was the programme of work	The ESO team, supported by PwC have performed an in-depth review of the key processes, controls and spreadsheets within the BSUoS process. Focus has been on enhancing existing controls prior to further automation which will be delivered in April 23 through delivery of new Charging and Billing system
Outputs	1. Establishment of a revised monthly end-to-end BSUoS Revenue Governance group 2. Creation of our granular RACI to better refine responsibilities and accountabilities across teams 3. Enhanced oversight of data, through greater use of four eye checks and reconciliations – supported with evidence of control execution 4. Unified data objects and definitions utilised across the whole BSUoS process 5. Enhanced controls and checks added to core process steps

Early Competition Plan
TCMF

Sept 2021

Katharina Meehan
Network Competition

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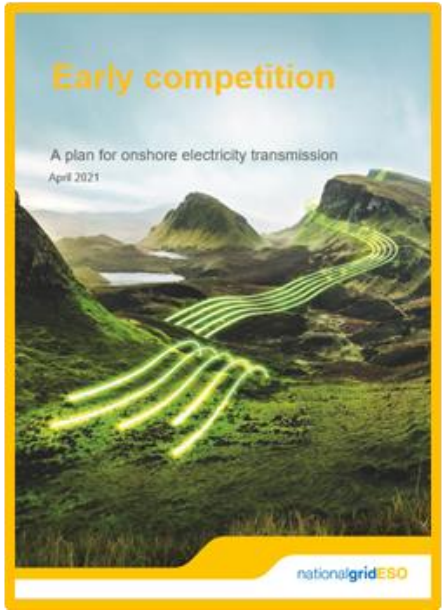
Early Competition

Ofgem asked the ESO to work alongside stakeholders in and outside the electricity industry to Deliver an Early Competition Plan (ECP)

Our final Early Competition was submitted to Ofgem in April 2021



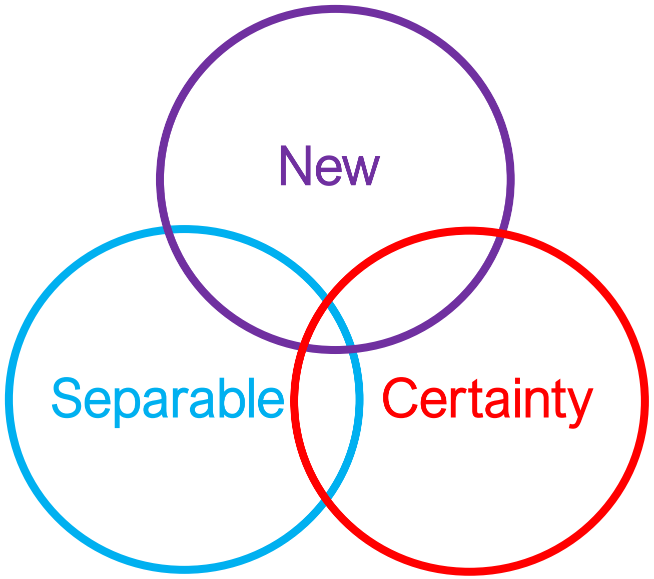
The plan explores

- The scope and form of each model, and associated processes
- Roles and responsibilities of different parties
- Pathways and timeframes for introduction, including legislative and framework changes

Setting out our proposals on

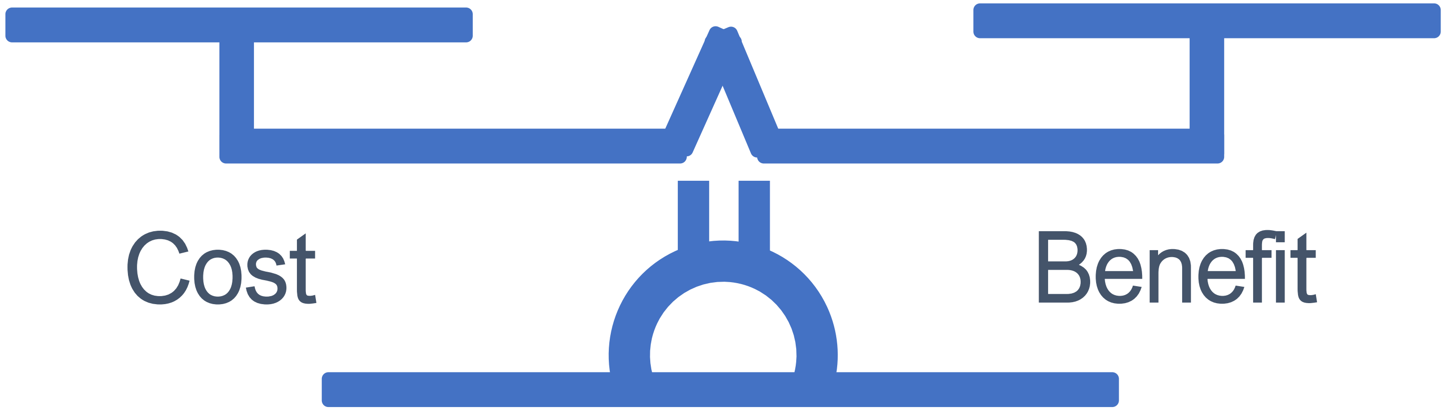
- Early and very early competition models
- Competition for non-network solutions
- The role ESO could play in distribution level competition

Early competition criteria assessment

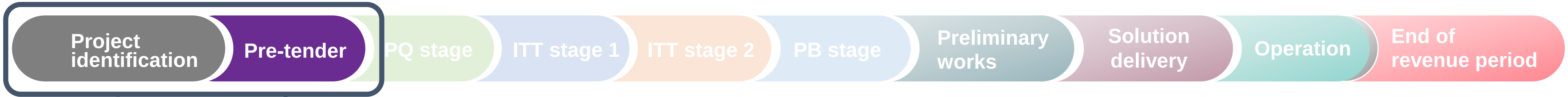


- Procurement costs
- Constraint costs
- Winning bidder costs
- Contract management and governance costs

- Cost efficiencies
- Lower cost of financing
- Environmental or social benefits
- Innovation benefits

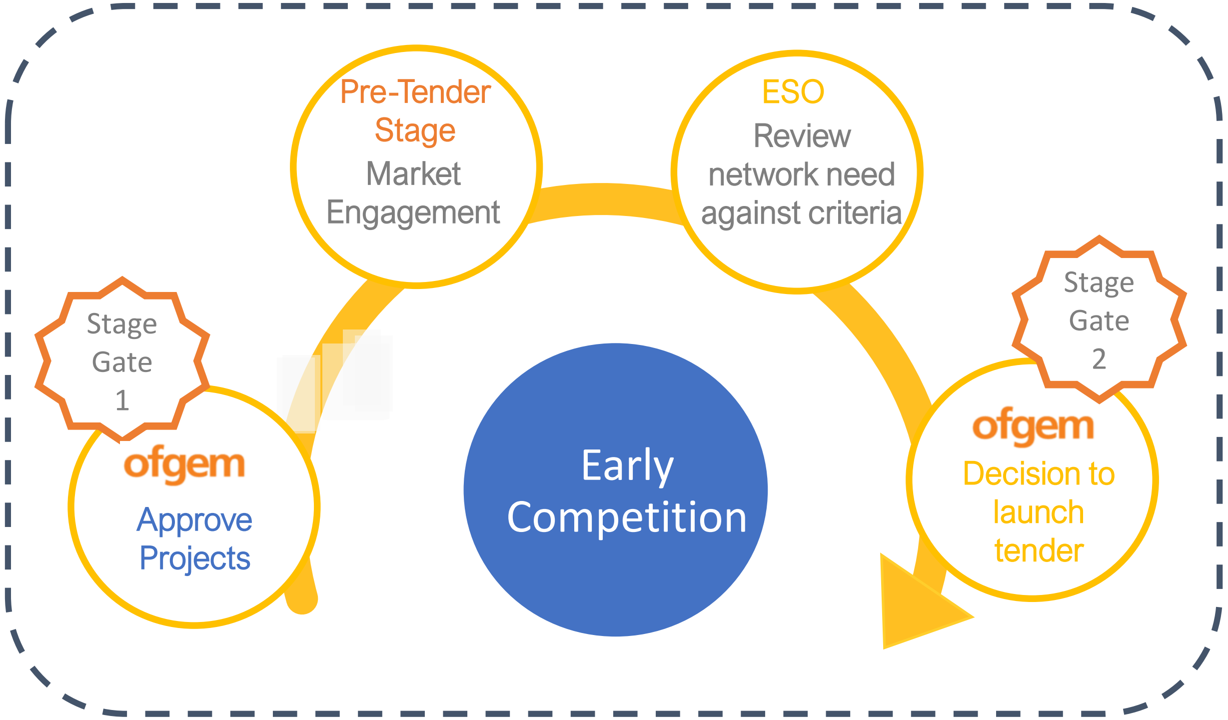


Project Identification & Pre-tender



Project Identification

- Tender launched 'early', after NOA
- Greater stakeholder involvement in solution development for NOA
- Enhanced role of the ESO in network planning



Tender Process

Pre-tender
- Market consulted
- Reassessment against project criteria
- Ofgem approves projects to be competed

ITT Stage 1
- Stage 1 assessment based on pass/fail against technical and policy requirements. Costings not assessed
- Technology readiness of 8/9 required
- Procurement body arranges impact studies

Preferred bidder stage
- Final negotiations
- Licence or contract awarded
- Connection agreement
- Tender disputes process

Project identification | **Pre-tender** | **PQ stage** | **ITT stage 1** | **ITT stage 2** | **PB stage** | Preliminary works | Solution delivery | Operation | End of revenue period

Pre-qualification Stage
- Suitability of bidders determined
- Passporting utilised where appropriate

ITT Stage 2
- Scored assessment for technical and project delivery.
- TRS adjusted based on scores.
- Final bidder ranking based on the adjusted TRS

Commercial Model

Revenue

- A Consumer Price Index partially indexed Tender Revenue Stream up to 45 years
- Fixed milestone-based payments for preliminary works
- Several end of revenue period options

Cost Risk

- Mix of fixed and adjustable costs – adjustable post-award via a Cost Assessment process with upward cap
- Debt competition post preliminary works - linked incentive and debt refinancing gain share mechanism
- The need for a form of security until the successful commissioning date

Other Considerations

- The need for a Transmission Licence or a commercial contract and associated potential heads of terms
- Potential impacts on the industry codes
- The need for 'Provider of Last Resort' arrangements

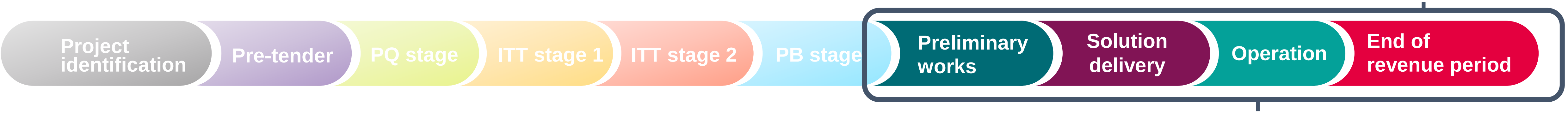
Post-Tender Award

Preliminary works / solution delivery

- A reputational stakeholder engagement incentive
- TRS commencement upon commissioning with potential adjustments for late delivery

End of Revenue Period

- Decommissioning costs built into the TRS and limited decommissioning securities



Operation

- A secured financial availability incentive and an environmental incentive
- A new investment obligation and a timely new connections incentive

Roles and responsibilities

Roles and responsibilities	Key considerations

Network Planning Body (existing role)
• Assessing suitability for competition
• Supporting technical assessment of bids
	• Potential conflicts of interest between TO's network planning roles and their participation in the competition
	• Mitigation of conflicts through changes to network planning roles should be considered further in parallel to the BEIS review of intuitional arrangements
	• We recommend
	  • TO's – ringfence bidding teams
	  • ESO – an enhanced role in initial solution development

Roles and responsibilities

Roles and responsibilities	Key considerations

Procurement Body
• Design of procurement structure and process
• Support development of tender and contractual documents and manage procurement process
 	
Contract Counterparty
• Managing and monitoring any obligations placed on successful bidder who holds a non-network contract
 	
Payment Counterparty
• Managing financial transactions between the successful bidder and the other counterparties
	• ESO is best positioned:
	  • Relevant experience and knowledge
	  • Existing relationships with key stakeholders
	  • Less cost and time required to upskill compared to a new entity
	  • Economies of scope across roles
	  • Align with RIIO-2 ambitions

Roles and responsibilities

Roles and responsibilities	Key considerations
Approver • Responsible for making formal decision to progress to stages of the early competition end-to-end process* Licence Counterparty • Managing and monitoring any obligations placed on successful bidder who is issues or holds a transmission license	• Ofgem is best positioned: • Alignment with their statutory duty to protect consumers • Legal authority to manage and issue licences • Experience in comparable roles (e.g. milestone approvals for interconnector business cases

* *Early Competition end-to-end process*

Project identification → Pre-tender → PQ stage → ITT stage 1 → ITT stage 2 → PB stage → Preliminary works → Solution delivery → Operation → End of revenue period

Next steps

May to early 2022

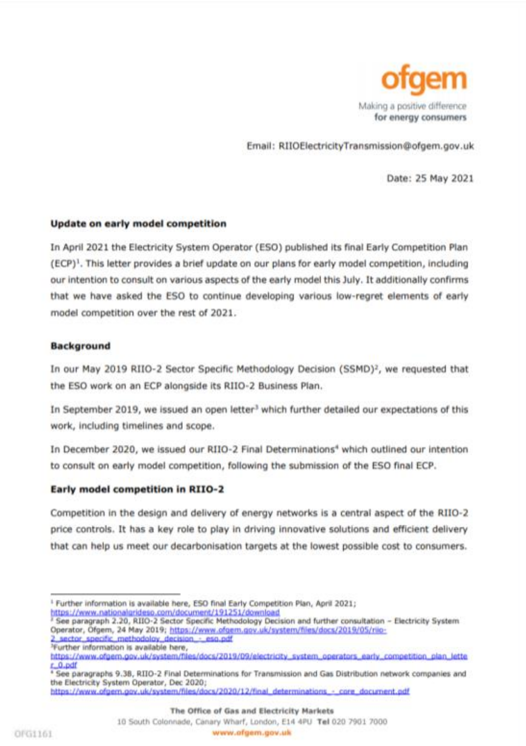
ESO Low Regret activities

Ofgem Consultation launches August 2021

Ofgem decision early 2022

Early Competition Low Regret activities

1. Finalise process for identifying possible projects for early competition
2. Explore the potential for expanding pathfinders as a pre-legislative form of early competition
3. Scope out potential Code changes
4. Develop a detailed programme plan with Ofgem
5. ESO organisational design development
6. Further work to explore interactions with Electricity Distribution



ofgem
Making a positive difference
for energy consumers

Email: RIIOElectricityTransmission@ofgem.gov.uk

Date: 25 May 2021

Update on early model competition

In April 2021 the Electricity System Operator (ESO) published its final Early Competition Plan (ECP)[1]. This letter provides a brief update on our plans for early model competition, including our intention to consult on various aspects of the early model this July. It additionally confirms that we have asked the ESO to continue developing various low-regret elements of early model competition over the rest of 2021.

Background

In our May 2019 RIIO-2 Sector Specific Methodology Decision (SSMD)[2], we requested that the ESO work on an ECP alongside its RIIO-2 Business Plan.

In September 2019, we issued an open letter[3] which further detailed our expectations of this work, including timelines and scope.

In December 2020, we issued our RIIO-2 Final Determinations[4] which outlined our intention to consult on early model competition, following the submission of the ESO final ECP.

Early model competition in RIIO-2

Competition in the design and delivery of energy networks is a central aspect of the RIIO-2 price controls. It has a key role to play in driving innovative solutions and efficient delivery that can help us meet our decarbonisation targets at the lowest possible cost to consumers.

[1] Further information is available here, ESO final Early Competition Plan, April 2021; https://www.nationalgrideso.com/document/191251/download
[2] See paragraph 2.20, RIIO-2 Sector Specific Methodology Decision and further consultation – Electricity System Operator, Ofgem, 24 May 2019; https://www.ofgem.gov.uk/system/files/docs/2019/05/riio-2_sector_specific_methodoloy_decision_-_eso.pdf
[3] Further information is available here, https://www.ofgem.gov.uk/system/files/docs/2019/09/electricity_system_operators_early_competition_plan_letter_0.pdf
[4] See paragraphs 9.38, RIIO-2 Final Determinations for Transmission and Gas Distribution network companies and the Electricity System Operator, Dec 2020; https://www.ofgem.gov.uk/system/files/docs/2020/12/final_determinations_-_core_document.pdf

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OFG1161

Net Zero Market Reform

Transmission Charging Methodology Forum

2nd September 2021

nationalgridESO

Agenda

- The Market Strategy team
- Introduction to project
- Analysis framework
- External engagement
- Locational case for change analysis
- Locational case for change workshop feedback
- Q&A and future engagement

Phase 2 and 3 Overview

Apr-21 **PHASE 2 (WP1-WP3)** *Sep-21*

What are the current and future challenges in the electricity market and what is the 'Case for Change'?

- Phase 2 has been divided into workstreams:

Investment Will we see the investment we need?	**Location** Will investment happen in the right place?
Flexibility How will supply and demand be matched?	**Operability** Will operability issues be manageable?

- Market objectives and success criteria for achieving Net Zero
- Emerging problems with current market design
- Evolution of the characteristics of the energy system
- Range of market design options to address the challenges

Oct-21 **PHASE 3 (WP3-WP5)** *Mar-22*

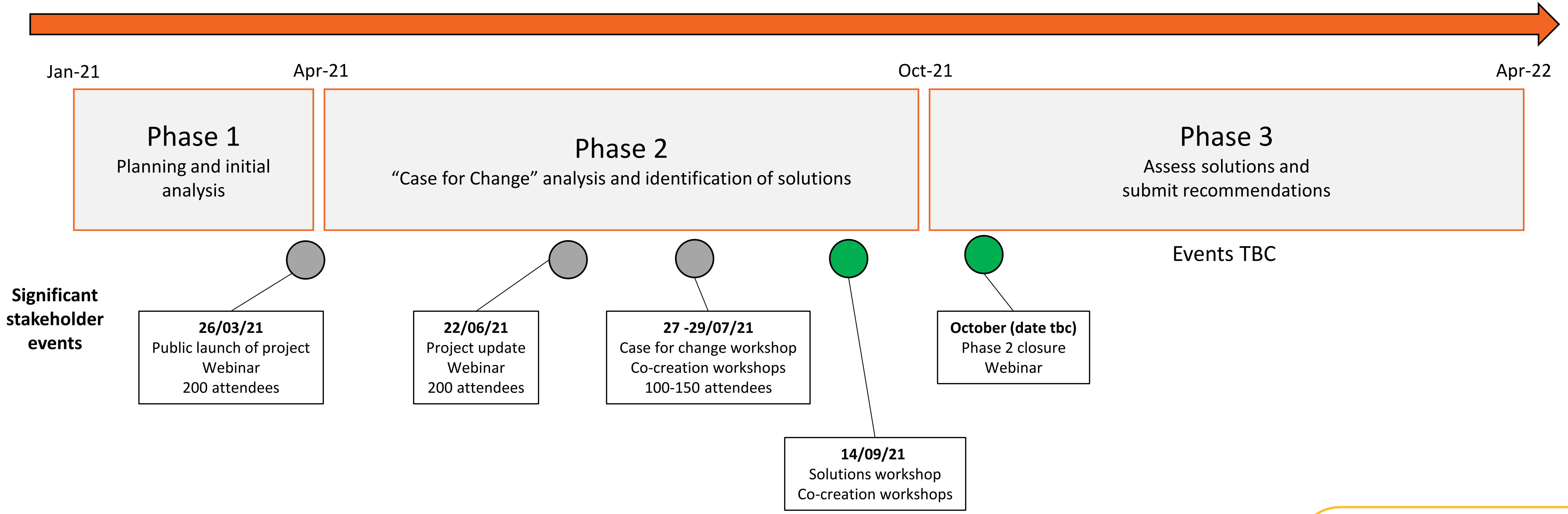
Options assessment and recommendations

- Assess the range of market design options to address the challenges in Phase 2
- Inherent trade-offs, natural combinations and incompatible options
- Evaluate each credible set of solutions identified against agreed market objectives and success criteria
- Recommend preferred high-level package of solutions

Stakeholder engagement throughout

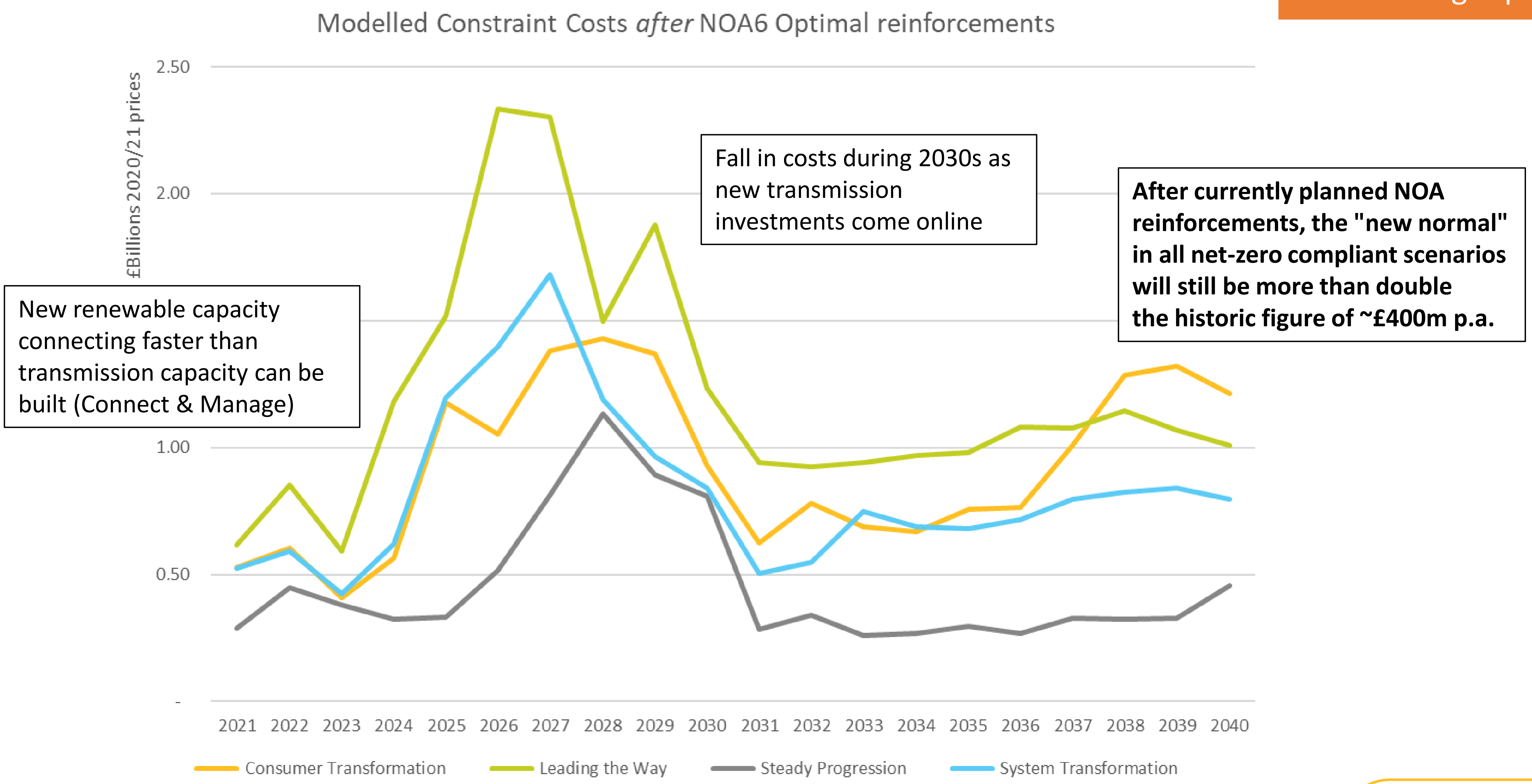
The Net Zero Market Reform project

The Market Strategy team is leading on a project looking at long term market reform (2030 onwards) with recommendations to be published by the end of March 2022. The Market Strategy team will be working closely with BEIS and Ofgem, and will be engaging with stakeholders across the industry throughout ensuring all possible solutions are considered before being assessed and refined into a package of recommendations.



Location: How will constraint costs evolve?

Location
Will investment happen in the right place?



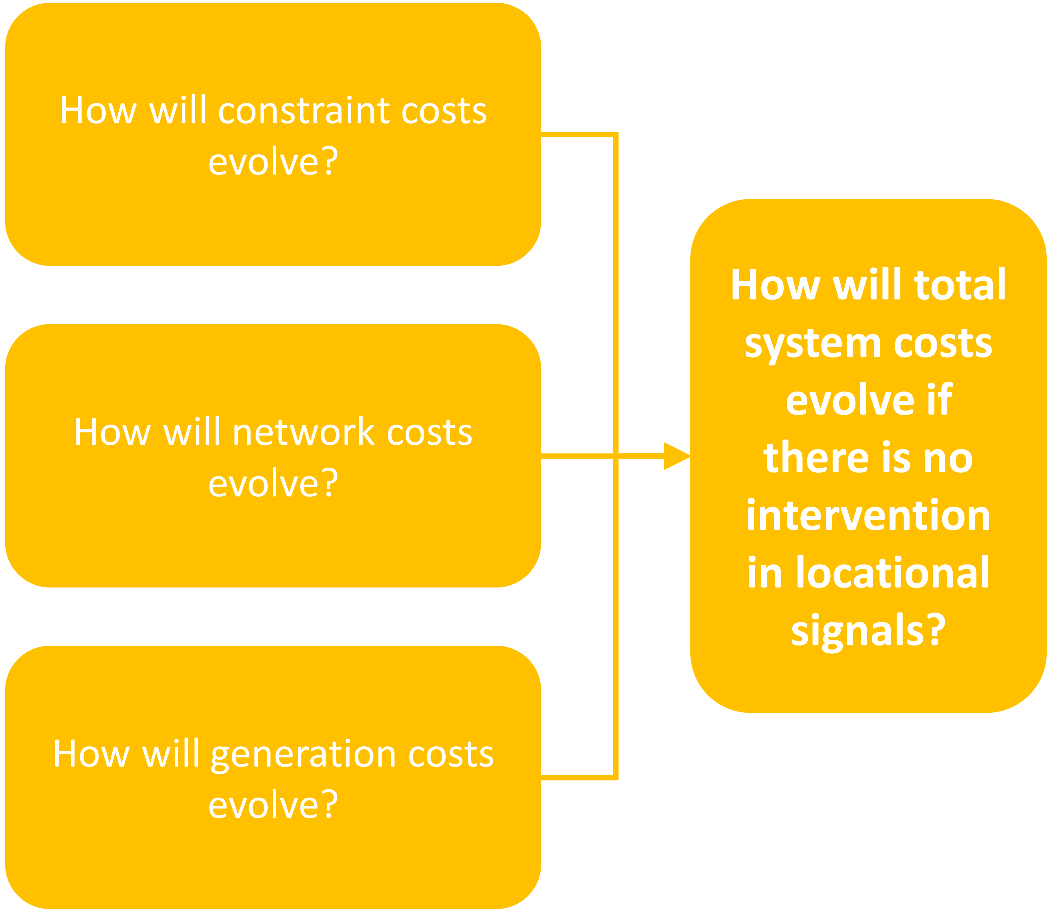
** Thermal constraint costs only (excl. actions required for Voltage and stability limits & ROCOF)*

Location: Current GB Signals – Transmission

Location
Will investment happen in the right place?

How will total system costs evolve if there is no intervention in locational signals?

Current market signal	Locational?
Wholesale Market	No
Balancing Mechanism	Yes
Capacity Mechanism	No
CfD	No
BSUoS	No
TNUoS	Yes
DUoS	Yes
Transmission and Distribution Losses	Yes



Location workshop: What problems, if any, are there with current locational signals?

Volatility, unpredictability & inability to hedge

- Large year to year variations in TNUoS tariffs
- No accurate long-term TNUoS forecasts
- TNUoS unpredictability has increasing influence on projects' business case as generation technology costs fall over time.
- Complexity of TNUoS methodology favours larger, vertically integrated developers (more resource) over smaller, local developers
- Short-term nature of TNUoS signals (only one year in advance) frustrates investors' desire for long-term bankable revenues
- BM revenues provide signals for cost of constraints but challenging as long-term investment signal
- Lack of coherence and transparency across different locational signals, e.g. operability through pathfinders
- Unpredictability & inability to hedge TNUoS → higher risk premia
- Impact on cost of capital for OWF projects

Demand-side effectiveness

- Asymmetric demand and supply side locational signals
- Perception of less effective existing demand-side locational signals
- Need more locational wholesale prices to stimulate demand elasticity e.g. siting of energy-intensive industries and electrolysis plant

Conflict between locational signals & other key drivers

- Most attractive wind farm locations are in areas with highest TNUoS
- Perceived conflict between net zero target and locational signals
- Lack of clarification of relative importance of decarbonisation and cost-reflectivity objectives
- Perceived conflict between government planning policy & locational signals

Lack of effective locational dispatch signal

- Efficient use of MW and MWh not incentivised
- Risk that lack of integration between wholesale market and BM will lead to two increasingly independent markets
- Increasing carbon cost associated with resolving constraints

Coordination across networks

- Incoherent charging between embedded and transmission-connected generation
- Need more granular DSO level signals to facilitate electrification of transport and heat and coherence with DSO flex market signals
- Current signals favour development of radial OWF connections and do not incentivise more efficient co-ordinated offshore network
- Lack of incentive to co-locate variable renewables & storage

Location workshop: What principles, objectives and trade-offs should be considered when setting locational signals?

Volatility, predictability & investor confidence

- Longer lived (3-4 years+) signals needed to drive investment.
- Potential trade off between signal duration and cost reflectivity
- Potential trade off between transparency and data confidentiality?
- Inability to build where signalled due to lack of connection capacity
- Trade-off between locational granularity and liquidity of wholesale market

Primacy of decarbonisation objective

- Highest level guiding principle should be consistency with delivery of economically efficient net-zero
- Anticipatory investment in network reinforcement could save money over the long term. Potential risk of over-build.

ESO/DSO coordination

- Local flexibility market signals created by DSOs in constrained areas of the distribution system must be coherent with broader market design
- Procurement approaches should be consistent across all locations/ DSOs
- Possible trade-off in terms of solving specific issues and speed of adaptation.

Competition / Level playing field/ Equity & fairness

- Locational signals should be symmetrical across supply & demand
- Parties must be able to respond to signals
- Signals must not be a barrier to smaller/ more innovative solutions
- Zonal/Nodal pricing – impact on consumers and wider market participants (place risk on those best to manage rather than consumer)

Efficient investment & efficient dispatch

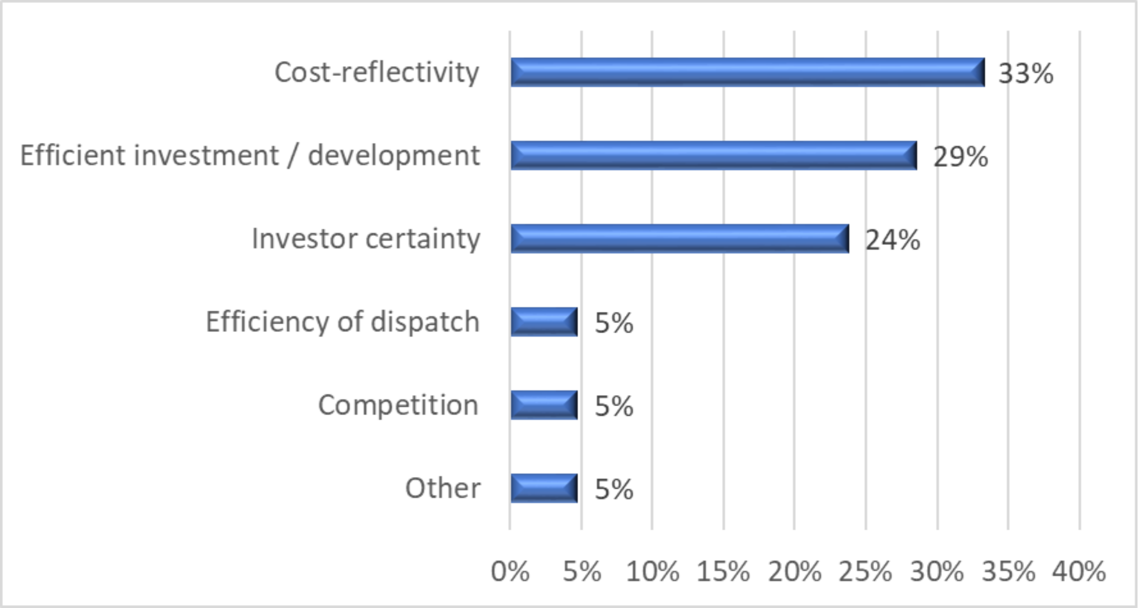
- The future requires both MW and MWh locational signals – efficient dispatch is critical
- Ultimately we are trying send signals that lower overall costs for consumers via efficient siting and operation.
- Balance to be struck between sharp and sufficiently effective signals.

Transition period & ease of implementation

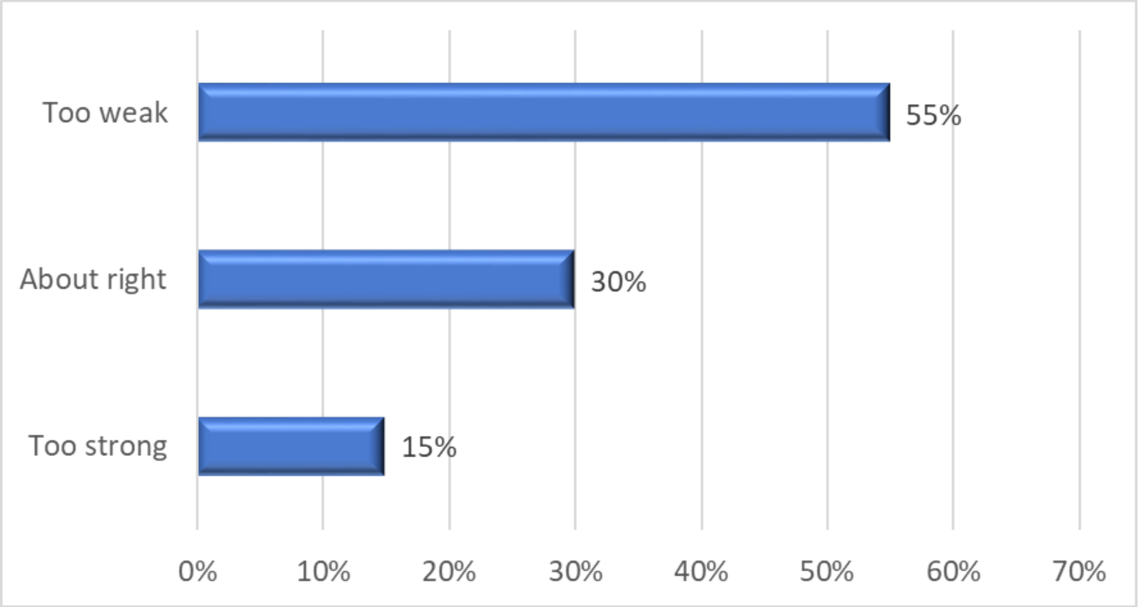
- Need to avoid major upheaval in signals to avoid a hiatus in investment?
- Systems required to implement locational wholesale market would be costly to design and implement.
- Knock-on impact on network charging (to avoid "double counting") and Financial Transmission Access Rights of locational wholesale market
- How much can/should we consider the transitional period in pursuit of a good enduring solution?

Location Workshop: Polls

Which principle/objective is the most important when setting locational market signals? (21 responses)



How would you rate the strength of current locational signals? (19 responses)



For any questions, comments or for more information on future engagement events please contact us:

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AOB & Close