Charging Futures
Reforming electricity charging together

Access Task Force

Electricity Network Access Project

2nd Access TF meeting

18 December 2017

Introduction

Agenda

Task	Timing
Welcome and introductions	10:00 - 10:05
Ensuring successful task force outcomes	10:05 – 10:15
Discussion on network topology, network planning and network costs	10:15 – 11:00
TAR and current access arrangements	11:00 – 11:50
Option development – introduction	11:50 – 12:00
Lunch	12:00 – 12:40
Nature of access rights – options for change	12:40 – 13:40
Initial allocation of access rights – options for change	13:40 – 14:40
Coffee Break	14:40 – 14:55
Reallocation of rights – options for change	14:55 – 15:55
Meeting wrap up	15:55 – 16:00

Minutes and actions from the last meeting

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Ensuring successful task force outcomes

Task force objectives

- We are committed to consulting on our initial proposals for reform in Summer 2018.
- The TF is one of the inputs that we wanted to use to inform our thinking.
- To meet these timescales the TFs needs to make progress immediately. We want to review the draft sections of the document at the Jan TF.

Date	Task
Dec 2017/Jan 2018	Produce a document identifying the initial options agreed for further assessment.
Feb/March 2018	Produce a document assessing each of the detailed options, based on the agreed assessment criteria.
End of April 2018	Produce a report outlining the TF's conclusions on what changes should be taken forward.

- To make this work will need members to contribute outside of TF meetings

The TF Terms of Reference states…

"TF Members will… (e) ***actively contribute*** *towards the work of the TF outside of TF meetings; (f) be expected to* ***contribute*** *towards the TF milestones."*

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Facilitating TF member contributions

- We are working with the ENA and NG to provide briefing information on the existing arrangements and previous reviews of charging/access.
- For future meetings we intend to provide TF documents five working days prior to each meeting, so that you have time to review.
- We want to provide more direction on required TF work:
  - Flagging more clearly our expectations on future work in agendas/meeting documents
  - Engaging with those taking actions to help the work meet our needs
- Unless agreed otherwise, our expectation is that all TF Members should be contributing to work outside of the TF meetings. Given that other parties are keen on becoming TF Members, if existing TF Members fail to contribute then the Chair may review TF Membership.

Question: Can we do anything else to help you actively contribute towards the work of the TF?

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DNO presentation network information and network costs

Network topology

Network topology (i.e. the way in which constituent parts are interrelated or arranged) is defined by the following characteristics:

- Industry and company planning and design standards (both existing and historic),
- Company’s materials and equipment specifications (both existing and historic),
- Number of customers,
- Type of customers,
- Customer, load and generation densities,
- Connections to Transmission assets (e.g. National Grid, Scottish Power and Scottish Hydro),
- Proximity to other utilities’ assets,
- Environmental factors, for example height above sea level, ground conditions, proximity to water courses, rivers and estuaries, within or near to National Parks or Areas of Outstanding Beauty etc.

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Current network user information (from CDCM and EDCM)

		Electricity North West	Northern Powergrid (Northeast)	Northern Powergrid (Yorkshire)	SHEPD	WPD East Midlands	WPD South Wales	WPD South West	WPD West Midlands	Eastern Power Networks	London Power Networks	South Eastern Power Networks	SEPD	SP Distribution	SP Manweb	Total
Low Voltage - Domestic	MWh	7,688,130	4,949,441	7,315,323	3,169,616	9,328,353	3,533,003	5,537,543	8,821,143	13,193,544	7,074,737	8,206,092	11,340,798	6,958,454	4,938,601	**102,054,775**
Low Voltage - Domestic	MPANs	2,244,286	1,519,386	2,150,125	782,733	2,523,944	1,040,369	1,475,827	2,319,033	3,413,937	2,109,395	2,138,711	2,882,035	2,016,609	1,400,767	**28,017,158**
Low Voltage - Domestic	Capacity kVA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Low Voltage – Small Non-Domestic	MWh	2,390,140	1,214,715	2,182,037	1,038,665	3,186,170	1,113,952	1,726,967	2,364,056	3,896,758	3,465,419	2,288,563	3,449,043	2,128,450	1,631,311	**32,076,246**
Low Voltage – Small Non-Domestic	MPANs	161,021	94,674	138,766	66,964	180,524	78,107	141,790	180,207	254,132	267,382	173,045	229,679	128,098	98,635	**2,193,024**
Low Voltage – Small Non-Domestic	Capacity kVA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Low to High Voltage – Other Non-Domestic	MWh	9,224,761	6,156,650	9,233,210	2,857,032	11,659,243	3,689,383	4,959,165	11,259,126	12,127,259	13,215,324	6,698,785	11,507,808	7,446,505	4,390,325	**114,424,575**
Low to High Voltage – Other Non-Domestic	MPANs	21,512	21,314	19,096	8,204	20,558	8,748	16,004	28,907	31,093	22,326	18,479	29,423	17,409	12,667	**275,740**
Low to High Voltage – Other Non-Domestic	Capacity kVA	4,226,858	2,739,467	3,979,267	1,240,845	4,908,673	1,468,095	2,031,542	4,614,543	5,224,744	6,034,752	2,744,922	5,230,127	2,993,468	1,898,411	**49,335,713**
Unmetered Supplies	MWh	307,893	208,842	292,718	129,276	324,722	150,714	138,467	325,190	353,347	225,705	209,816	261,449	377,447	209,939	**3,515,526**
Unmetered Supplies	MPANs	666	1,283	766	4,067	3,171	1,391	1,566	1,831	3,948	755	1,269	3,461	4,938	633	**29,743**
Unmetered Supplies	Capacity kVA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Low to High Voltage – Generation	MWh	923,067	789,083	675,685	2,156,908	890,891	298,521	735,270	800,628	1,036,568	111,632	380,813	1,032,963	941,155	307,925	**11,081,110**
Low to High Voltage – Generation	MPANs	582	319	920	1,497	522	378	1,052	553	1,449	118	376	1,929	602	355	**10,653**
Low to High Voltage – Generation	Capacity kVA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Total	MWh	20,533,991	13,318,730	19,698,973	9,351,498	25,389,379	8,785,573	13,097,413	23,570,144	30,607,475	24,092,816	17,784,068	27,592,061	17,852,011	11,478,101	**263,152,233**
Total	MPANs	2,428,067	1,636,976	2,309,672	863,465	2,728,719	1,128,993	1,636,239	2,530,531	3,704,558	2,399,977	2,331,881	3,146,527	2,167,656	1,513,057	**30,526,319**
Total	Capacity kVA	4,226,858	2,739,467	3,979,267	1,240,845	4,908,673	1,468,095	2,031,542	4,614,543	5,224,744	6,034,752	2,744,922	5,230,127	2,993,468	1,898,411	**49,335,713**
EDCM Total	Customer count	95	56	135	305	250	187	292	78	208	39	86	318	111	221	**2,381**

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Open Network Project Definition of Customer Categories

Category		Characteristics	Customer Type Examples	Contract Examples

A	**System Service Providers**	Their core function (or a key element of their overall business portfolio) is to manage load, generation or storage **to sell ancillary services to TSOs and DSOs**.	• TSO **contracted** service provider, e.g.
			  • Balancing Mechanism Units (BMUs)
			  • Enhanced Frequency Response services
			  • Ancillary Services
			• DSO service **contracted** flexibility service provider
				• Bilateral agreements between the customer and the DSO / TSO
				• Could be DSO / DSO agreements for DNO-DNO interconnection

B	**Active Participant**	Have invested in generation, storage, demand side management and / or low carbon products. They will **actively participate in the energy market** to make money from generation, reduce operating costs and/or for low carbon social responsibility reasons. They **do not have contracts for services** to TSOs or DSOs. Could have automated controls to maximise savings / returns.	• Distribution connected generation, e.g. solar farm exporting • Behind the meter generation/storage, e.g. for peak lopping, triad avoidance • Demand side response e.g. for peak lopping, triad avoidance • Residential customers actively engaged e.g. timing of EV charging, use of heat pumps/solar/storage	• Power Purchase Agreements • Suppliers via Time of Use tariffs or products • Contracts with Aggregators – residential and industrial and commercial
C	**Passive Participant**	Energy conscious low carbon investor generally off-setting demand for benefits (**passive/fit and forget**). Have invested in ‘off the shelf’ low carbon **products** such as solar panels, heat pumps, EV or smart appliances **to reduce energy bills**. May be exporting and importing and would be interested in reducing costs via Time of Use tariffs.	• Businesses or residential with installed products, e.g. solar panels, heat pumps, EV or smart appliances • Residential customers with customised Time of Use tariffs	• Suppliers via Time of Use tariffs or products
D	**Passive Consumer**	Normally demand customers. Little or no knowledge or interest in Time of Use tariffs. Normally on standard single rate tariff but could include customers on standard 2 rate tariffs and storage heaters.	• Business or Residential customers	• Basic Supplier tariff contract

Network constraints

Drivers of network constraints (driven by both demand and generation) are:

- Thermal capacity,
- Voltage headroom,
- Fault level restrictions
- Reverse power capability
- Network resilience (e.g. N-1 etc.)

Network development options

Network options to manage constraints

- Network reinforcement – general DUoS funded
- Connection reinforcement – under cost sharing rules
- Active customer management
  - demand side response
  - curtailing users at particular times etc.
- Active network management
  - dynamic ratings etc.
  - DNO takes risk on diversity (current practice with LV demand)

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Information needed to inform network planning

Network planners look at the following key aspects:

- ENA Engineering Recommendation (ER) P2/6 compliance, which includes assessment of diversity, profiles of demand/generation and assessment of ‘un-used capacity,
- Fault level analysis,
- Current and future Load Index of assets, and
- Load/generation growth forecasts from various sources.

Network information we have and publish

- Asset and mapping information e.g. GIS for all voltage levels
- Long Term Development Statement (primarily EHV networks)
  - Geographic and schematic diagrams
  - Current and forecast network loadings
  - Connected generation and accepted generation quotes
  - Fault level analysis
- Capacity information
  - Network capacity maps ie heat maps for D and G for HV

Network constraints remedies

Processes to manage network constraints

- Understand driver for network constraint i.e.
  - New connection (normal connection network planning), or
  - General growth (normal annual demand and generation network planning).
- Evaluate the size of the issue e.g. forecast load growth pushes future demand over existing network capacity by 5 MVA
- Evaluate opportunities and costs for each solution to mitigate network constraint
- Choose minimum cost scheme/lowest whole life cost option

Drivers of Network Costs

The 'old days'

- Electro-mechanical monitoring
- Demand driven network
- Peak demand driven reinforcement
- Tariff support in connection charging

Current

- Electronic monitoring & network protection
- Distributed generation established.
- Battery storage emerging
- Peak DG /demand reduction
- DG Network constraints
- Flexible connections
- ANM capital and licencing
- Shallowish connection charging with any reinforcement partly socialised
- Choice of asset installers and owners

Future

- Increase in network monitoring
- Smart network support from DER
- DSO manages peak
- Constrained DG vs Reinforcement
- More ANM
- Whole network management TSO/DSO
- Stronger locational signals in connection charges?

Cost Drivers (initial thinking)

Current	Future
Peak demand reinforcement (locational variation)	Peak demand reinforcement or DSO solution for EVs, electric heating and localised growth. Assistance from storage.
Asset Replacement – condition/ age related.	Asset replacement sized for demand or DG growth (timing assisted by DSO).
System automation for better fault management.	More granular automation for fault management.
Roll out of more granular system monitoring.	System monitoring informs DSO actions and required services.
Customer connections triggering cost shared reinforcement.	Revised connection charging rules? and managed access.
Other network innovation.	Further network innovation.
Minimum scheme investment where future is fairly stable	Options/minimum regret based investment to manage an uncertain future

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Common Connection Charging Methodology

Design in accordance with Minimum Scheme principles

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Determine appropriate cost allocation

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Costs to be paid in full by customer	Extension Assets
	Requirements over min. scheme
	Reinforcements costs > £200/kW
Costs to be apportioned between customer & DNO	Reinforcement (add Network capacity)
	• Security CAF
	• Fault Level CAF
Costs to be paid in full by DNO	Reinforcement > 1 voltage level above
	Rft. at existing LV premises, equipment install at 100amps or less per phase

Recover costs of previous works (ECCR)	Assets installed to provide connection to another customer
	Other customer has paid in part or full

Security CAF – costs driven by thermal capacity / voltage

$$= \frac{\text{Required Capacity}}{\text{New Network Capacity}} \times 100$$

Fault Level CAF – costs driven by fault level restrictions

$$= \frac{\text{3x Fault level contribution from NC}}{\text{New Fault Level Capacity}} \times 100$$

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Application of Principles – the Security CAF

Example 1: 21 MW STOR Connection

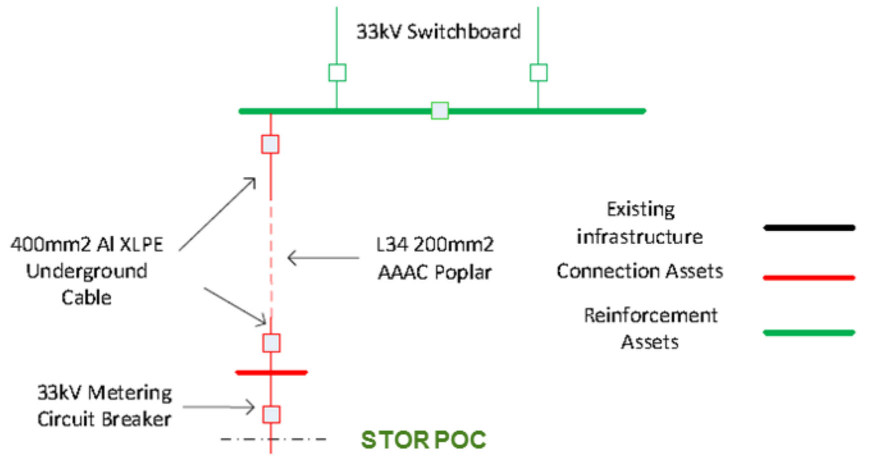
Total Cost of Connection: £3.8m

Reinforcement
- Switchgear replacement at GSP
- Cost: £1.8m

SPD Contribution: £1.45m
Customer Contribution: £0.35m

Extension Assets
- Two-panel 33kV Switchboard
- 7km 33kV circuit

SPD Contribution: £0
Customer Contribution: £2m



$$Security\ CAF = \frac{Required\ Capacity}{New\ Thermal\ Capacity} * 100\%$$

$$Security\ CAF = \frac{21.18}{108.59} * 100\%$$

$$Security\ CAF = 19.51\%$$

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Cost categories and influences

Load related	Connections within the price control	Closely driven by customer behaviour
	Reinforcement (Primary Network)	Closely driven by customer behaviour
	Reinforcement (Secondary Network)	Closely driven by customer behaviour
	Fault Level Reinforcement	Closely driven by customer behaviour
	New Transmission Capacity Charges	Closely driven by customer behaviour
Non-load capex (excluding non-op capex)	Diversions (Excluding Rail Electrification)	Closely driven by customer behaviour
	Diversions (Rail Electrification)	Closely driven by customer behaviour
	Asset Replacement	Influenced by customer behaviour
	Refurbishment no SDI	Influenced by customer behaviour
	Refurbishment SDI	Influenced by customer behaviour
	Civil Works Condition Driven	Influenced by customer behaviour
	Operational IT and telecoms	Influenced by customer behaviour
	Blackstart	Influenced by customer behaviour
	BT21CN	Influenced by customer behaviour
	Legal & Safety	Intrinsic Cost
	QoS & North of Scotland Resilience	Influenced by customer behaviour
	Flood Mitigation	Influenced by customer behaviour
	Physical Security	Influenced by customer behaviour
	Rising and Lateral Mains	Influenced by customer behaviour
	Overhead Line Clearances	Influenced by customer behaviour
	Worst Served Customers	Influenced by customer behaviour
	Visual Amenity	Intrinsic Cost
	Losses	Closely driven by customer behaviour
	Environmental Reporting	Intrinsic Cost
Non-op Capex	IT and Telecoms (Non-Op)	Intrinsic Cost
	Property (Non-Op)	Intrinsic Cost
	Vehicles and Transport (Non-Op)	Intrinsic Cost
	Small Tools and Equipment	Intrinsic Cost
HVP	High Value Projects DPCR5	Closely driven by customer behaviour
	High Value Projects RIIO-ED1	Closely driven by customer behaviour
Moorside	Moorside	Closely driven by customer behaviour

Network Operating Costs	Faults	Influenced by customer behaviour
	Severe Weather 1 in 20	Influenced by customer behaviour
	ONIs	Influenced by customer behaviour
	Tree Cutting	Closely driven by customer behaviour
	Inspections	Influenced by customer behaviour
	Repair and Maintenance	Influenced by customer behaviour
	Dismantlement	Influenced by customer behaviour
	Remote Generation Opex	Closely driven by customer behaviour
	Substation Electricity	Influenced by customer behaviour
	Smart Metering Roll Out	Influenced by customer behaviour
Closely associated Indirects	Core CAI	Intrinsic Cost
	Wayleaves	Intrinsic Cost
	Operational Training (CAI)	Intrinsic Cost
	Vehicles and Transport (CAI)	Intrinsic Cost
Business Support Costs	Core BS	Intrinsic Cost
	IT& Telecoms (Business Support)	Intrinsic Cost
	Property Mgt	Intrinsic Cost
Other costs within Price Control	Atypicals Non Sev Weather	Intrinsic Cost
	Atypicals Non Sev Weather (excluded from Totex)	Intrinsic Cost
	Network Innovation Allowance (NIA)	Intrinsic Cost
	Network Innovation Competition (NIC)	Intrinsic Cost
	IFI & Low Carbon Network Fund	Intrinsic Cost
Costs outside Price Control	Directly remunerated services (excluding connections, other consented activities, legacy meters and de minimis)	Intrinsic Cost
	Smart Meters	Intrinsic Cost
	Legacy meters	Intrinsic Cost
	De Minimis	Intrinsic Cost
	Other consented Activities	Intrinsic Cost
	Connection costs outside of the price control	Intrinsic Cost
	Out of Area Networks	Intrinsic Cost
	Atypicals Non Sev Weather (Non Price Control)	Intrinsic Cost
NABC	Pass through	Intrinsic Cost
	Other Non Activity Based Costs	Intrinsic Cost

> Closely driven by customer behaviour — Influenced by customer behaviour — Intrinsic Cost

Points to discuss

> What further information would be useful to support our options development and assessment?

> What are views on the description of the cost drivers and the extent to which they are impacted by user behaviour?

Actions

> Identify volunteers where further work required

Appendices

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Customer Category Descriptions

In light of feedback from the Advisory Group, the project believes it would be helpful to provide more details on the customer category descriptions:

System Service Providers

Customers who opt to sell system support services to the TSO or DSO. These customers have generally invested in Distributed Energy Resources to participate in the energy market and provide support services or they are demand customers who are more aware of the energy market and can flex their demand as part of their business, i.e. demand side management. This group includes larger individual customers and also aggregators providing services through the management of a portfolio of smaller customers. The TSO or DSO would agree term contracts on a bilateral basis for the services it needs.

Active Participant

These customers have invested in Distributed Energy Resources, demand side management or low carbon products. This category will include customers actively participating in the energy market to derive income from generation and/or storage , demand customers reducing operating costs and larger customers who have invested in low carbon equipment for social responsibility reasons. They are very likely to be responding to time of use signals, including managing demand or export at times of peak demand. While these customers will have bilateral contracts with suppliers for energy services they do not have contracts for services with TSOs or DSOs.

Typical customers in this category customers are storage, Distributed Generation and flexibility service operators, larger demand customers and community energy schemes, however this category also includes aggregators managing exports and demand side management on behalf of multiple smaller customers.

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Customer Category Descriptions

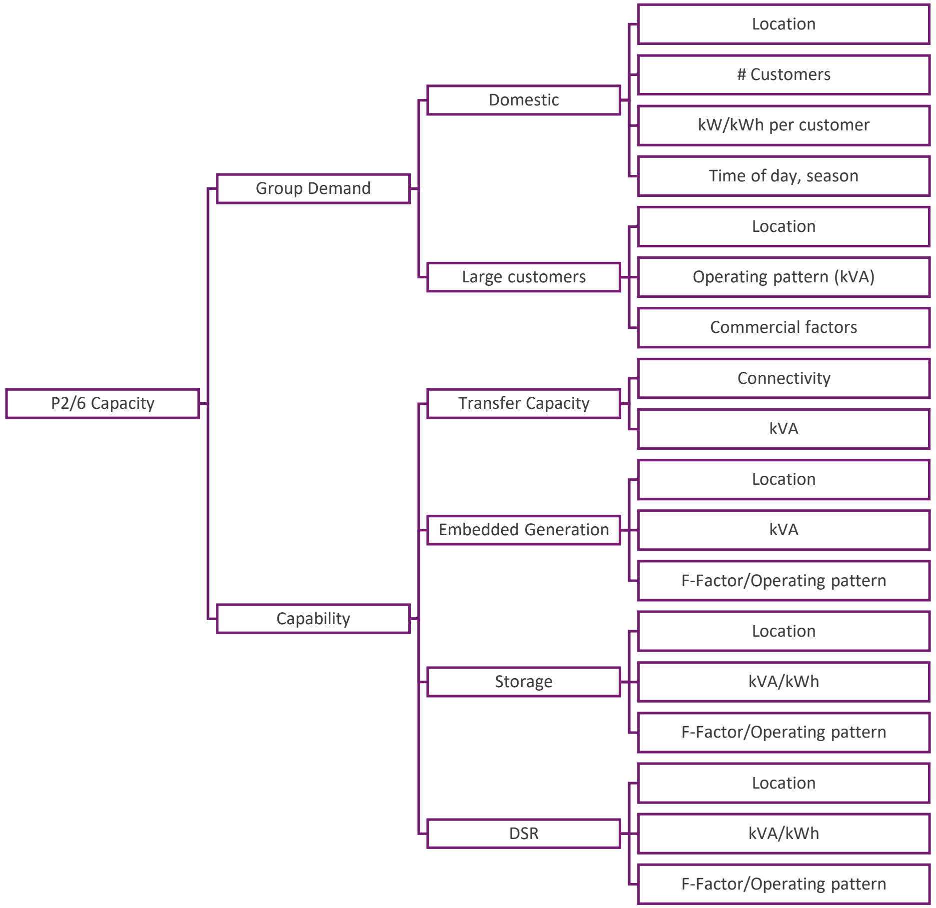
Passive Participant

This category includes smaller energy conscious customers (domestic or non domestic) who have invested in off-the shelf low carbon equipment to derive income from renewable energy schemes, to reduce their overall costs or for social responsibility reasons. Generation or demand is unlikely to be actively managed and is installed on a passive fit and forget basis. ‘Off the shelf’ low carbon equipment in this case includes solar panels, heat pumps or electric vehicles. These customers are likely to be exporting and importing and would seek to benefit from supplier’s time of use tariffs.

Passive Consumer

Normally domestic or smaller non-domestic demand customers with little or no interest in the flexible energy market or low carbon products. These customers may have smart appliances and in due course could agree smart energy contracts with suppliers and aggregators (at which point the key relationship is between the DNO and the aggregator/supplier, therefore the customer will fall out of these categories). This category includes customers in social housing with or without access to a community energy supply contract via their landlord. These customers are likely to be on standard supplier tariff.

Factors affecting load related reinforcement



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Shallowish charging

- The current connection charging rules provide a balance between locational signals through connection charging and avoiding disproportionate/prohibitive contributions to ‘deep’ assets.
- The apportionment rules for reinforcement share costs between the connections customer and DUoS customers based on capacity required or the fault level contribution from export.
- It was decided that apportioning some costs to DUoS customer was justified as the generality of customers gain some benefit from the new incidental spare capacity created by the reinforcement.
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What Information Currently Informs Network Planning?

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Distribution Network Planning

- Distribution system - designed to be safe, reliable, economic and efficient whilst taking into account environmental considerations and sustainable development.
- Distribution system design seeks to strike a balance between quality and security of supply to customers, environmental protection, social equity and economic development, subject to minimum standards of security set out in the Distribution Code.

Relevant Standards:

- ER P2/6 “Security of Supply” - describes the appropriate level of security required for distribution networks classified in ranges of group demand.
- ER G5/4-1 “Planning Levels for Harmonic Voltage Distortion and the Connection of Non-Linear Equipment” - limit the effects of distortion of the system voltage waveform, the harmonic content of any load shall comply with the limits.
- ER P28 “Planning Limits for Voltage Fluctuations caused by Industrial, Commercial and Domestic Equipment in the United Kingdom”
- P29 “Planning Limits for Voltage Unbalance in the United Kingdom”

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Load Related Reinforcement

Internal data:

- Fault Level Studies
- Load flow studies
- Voltage
- Customer Generation & Demand Data
- PI data
- Network data from corporate systems (UMV, SAP, CBRM)
- Local monitoring schemes
- Cost benefit analysis

External data:

- Data from other network operators (IDNOs, National Grid, DNOs, private network operators) – WK24, Wk42, SOW etc...
- Consultancy reports
- 3rd party data (Environment agency, Met Office, SEPA)
- Manufacturer data of equipment

Annual System Review

Identify Constraints

Challenge Existing Plans

Develop Reinforcement Proposals

External factors:

- Customer Service
- Stakeholder groups
- Customer complaints
- Reports from site investigations
- Customer connections requests (including diversions and disconnections)

Policies:

- Licence
- Electricity Act
- Network owner/operator policies and procedures
- Other 3rd party policies and procedures (ENA, BEIS, Government, Local authority, HSE etc...)
- Grid code, Distribution Code, ESQCR, EU codes........

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Non-Load Related Investment

Internal data:
- Fault Level Studies
- Load flow studies
- Voltage
- Customer Generation & Demand Data
- PI data
- Network data from corporate systems (UMV, SAP, CBRM)

Asset Modernisation

Condition Based Risk Management (CBRM)

External factors:
Customer Service
Stakeholder groups
Customer complaints
Reports from site investigations
disconnections)

Ofgem Guidance

Reliability, Customer Service, etc.

Health & Criticality Index

Age, Faults, etc.

Flood risk

External data:
Data from other network operators (IDNOs, National Grid, DNOs, private network operators) – WK24, Wk42, SOW etc...
Consultancy reports
3rd party data (Environment agency, Met Office, SEPA)
Manufacturer data of equipment

Identify Constraints

Policies:
Licence
Electricity Act
Network owner/operator policies and procedures
Other 3rd party policies and procedures (ENA, BEIS, Government, Local authority, HSE etc...)
ribution Code,
odes........

Asset Replacement

Asset Refurbishment

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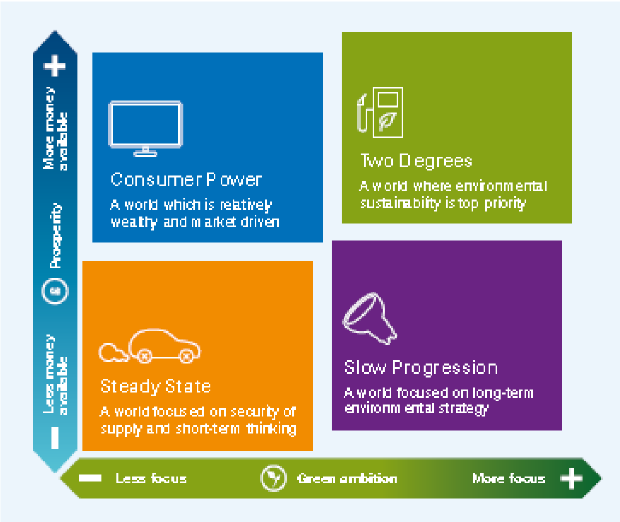
Transmission Network Planning



Future Energy Scenarios (FES) - based on the energy trilemma of security of supply, affordability and sustainability.

The Electricity Ten Year Statement (ETYS)

- produced annually by National Grid in its role as the electricity system operator as part of the annual electricity transmission planning cycle
- shows the likely future transmission requirements of bulk power transfer capability of the National Electricity Transmission System (NETS).

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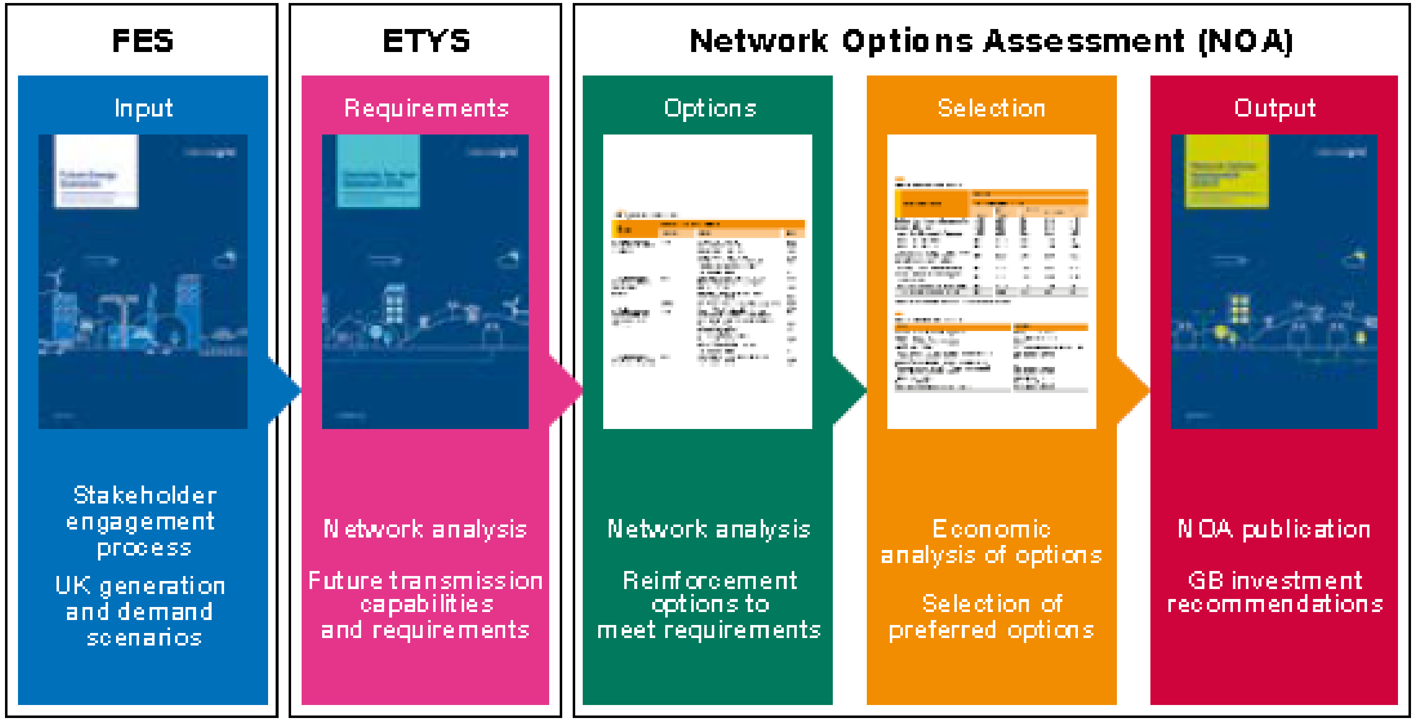
Transmission Network Planning



The *NOA* is the driver for developing an efficient, coordinated and economic system of electricity transmission, consistent with the national electricity transmission system security and quality of supply standard. Its purpose is to make recommendations to the Transmission Owners (TOs) across Great Britain as to which projects to proceed with to meet the future network requirements as defined in the *Electricity Ten Year Statement (ETYS)*.

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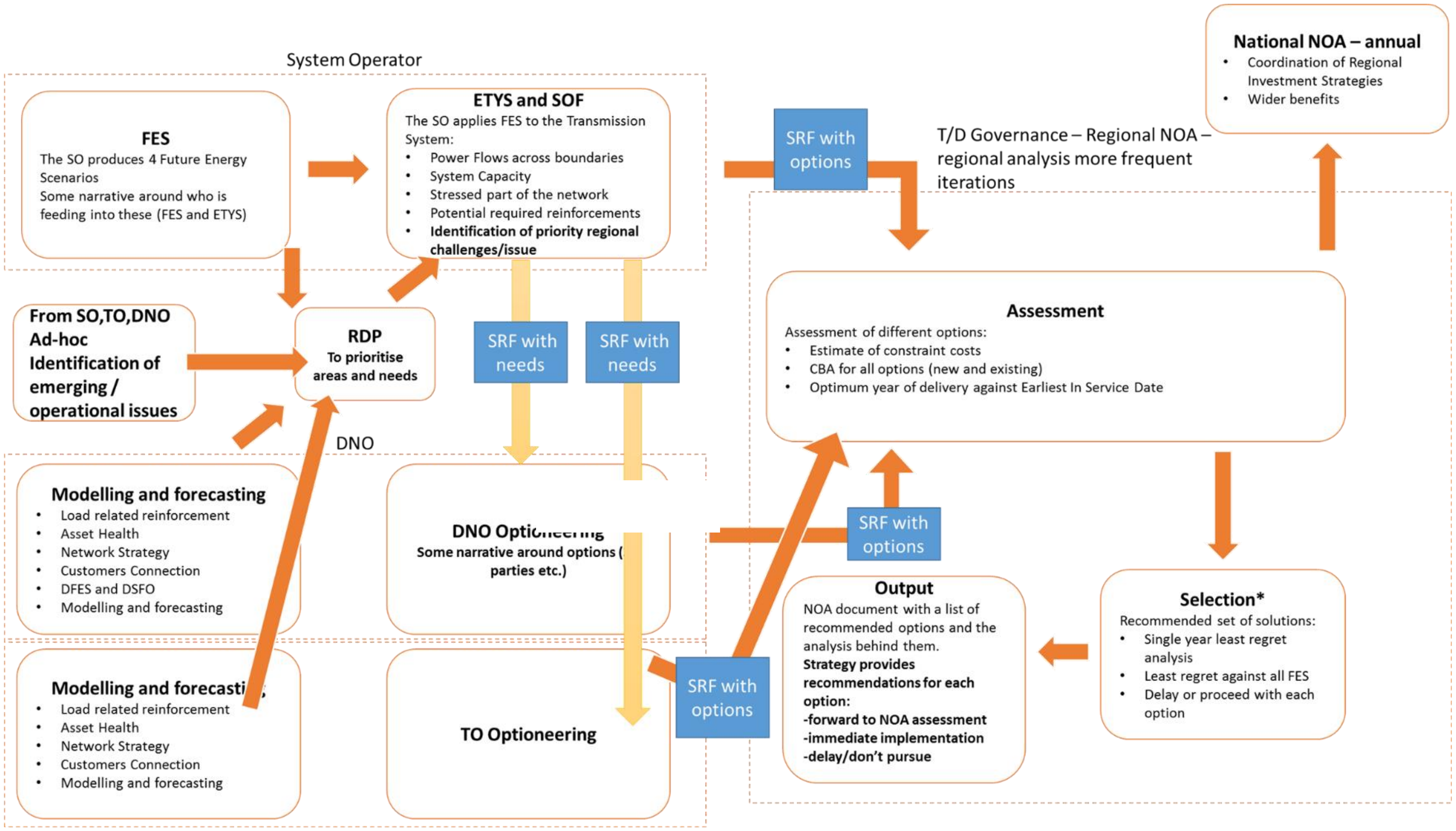
Planned Extended NOA Process



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SO presentation on the Transmission Access Review – A brief history

Overview of TAR

Why was TAR initiated?

Situation

- To meet Climate change targets for 2020 and beyond, large amounts of renewable and other low carbon generation was required to connect to the system
- Replacement of ageing existing nuclear and fossil fuel plant

Complication

- Access granted on a ‘First come first served basis’ meaning that potential viable investments were stuck behind others in the queue
- Delays in waiting for a connection, were threatening climate change targets. ~50GW in the queue with connection dates up to 14 years
- Changing generation profile to one of greater intermittent generation

Solution

- Access rules and commercial incentives changes required to make the best use of the existing transmission capacity and to invest as quickly as possible to deliver more capacity for when required
- Joint Government and Ofgem review launched in May 2007 – Transmission Access Reform

Timeline for TAR

- **May 07** – Ofgem / Gov launch review of Transmission Access
- **Apr 08** – NGET raise 6 CUSC mods (CAP161-166)
- **Jun 08** – TAR final report published with a number of straw men models for access
- **Feb 09** – Ofgem requested NGET review existing arrangements CAP170 and GB_ECM-18
- **Jan / Mar 09** – Final mod reports submitted to Ofgem
- **May 09** – Ofgem implement Interim Connect and Manage
- **Jun 09** – Gov use Energy Act 2008 powers to bring about enduring access reform
- **Mar 10** – GB_ECM-18 rejected by Ofgem
- **Aug 10** – Gov exercised powers to implement Connect & Manage (Socialise constraint costs)
- **Oct 10** – CAP148 and CAP161 to 168 rejected

TAR Principles for Enduring Access Arrangements

Enduring access arrangements should be based on a clear set of high level principles

1. **New generation** projects should be offered **firm connection dates**, reasonably **consistent** with the **development time** of their project
2. Generators wanting long term, **financially firm access** to the system need to make **long term financial commitments**
3. Transmission companies need to have **appropriate incentives** to respond to the long term demand for access signalled by generators. They need the freedom and incentives to invest ahead of full user commitment. They also require appropriate incentives to deliver new connections on time and to **innovate** so that they can **deliver as much capacity as possible from existing assets**.
4. **Access rights** need to be **more clearly defined** and all generators need to be offered **choice** about how they access the system. This choice will need to include **long term fixed price access rights** that guarantee long term access in return for a commitment to pay for capacity, and **shorter term, variable priced** access rights
5. In order to make more efficient use of existing and new capacity there needs to be **better arrangements for sharing of transmission capacity**. One way to achieve this is by making access rights **tradable** between generators

Formed basis for Government intervention

Source: Ofgem / BERR Transmission Access Review – Final Report 26th June 2008

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CUSC proposals designed on a modular basis

CUSC Amendment Proposal

CAP161 – Transmission Access – SO release of short term entry

CAP162 – Transmission Access – Entry Overrun

CAP163 – Entry Capacity Sharing

CAP164 – Connect and Manage

Working Group 1 – Short term proposals

CAP165 – Transmission Access – Finite Long-term Entry Rights

CAP166 – Long-term Entry Capacity Auctions

Working Group 2 – Longer term proposals

Working Group 3 – Sub-group supporting the others

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Main Changes under discussion

Working Group 1

- Zonal access auction for Short term rights on a pay as bid bases
- Nodal access products for 5 weeks ahead, 2 day ahead and blocks of 1 week of access 'Commercial limited duration TEC'
- Zonal and nodal rights with associated charge to exceed TEC
- Sharing of rights on a 1:1 basis within a zone
- Nodal sharing of rights

Working Group 2

- Original CAP165 proposal defined zonal long-term entry rights on the basis of a fixed number of years (nominated by the generators).
- Seven alternatives were developed including nodal access rights and arrangements with different pre-commissioning user commitment, rolling access rights and different timescales for system exit
- CAP166 introduced a pay as bid auction for 1 year capacity rights on a zonal basis. Alternatives were developed for nodal access, a boundary constraint model with a reserve price and a capacity duration auction.

Working Group 3

- Focussed on moving away from the existing TNUoS generation zones and development of a set of zones which better facilitated the release of transmission access as described through – CAP161, 162, 163, 165 and 166
- Consideration of concept of local capacity nominations (LCNs) to facilitate access products and the associated pre commissioning user commitments.

Why was TAR not taken forward

1. Access at the transmission system level is specific to a small geographical areas so cannot be traded effectively as a commodity across GB

2. The transmission system design takes account of diversity of plant effectively mirroring the system to the need

3. In general as old power station close existing connections are taken up by other users - major examples of this are offshore wind connections

4. CMP 192 / 213 were raised a couple of years later to incorporate load factor and diversity into the charging regime

DNO presentation on current access arrangements

Entitlements and rights

Distribution		
Charge	**Customer entitlements**	**Payment to customers**
Use of System – access to use network to the parameters paid for in connection agreement. No compensation if constrained except under the opposite arrangements	Network unavailability rebate for "standard" DG[1] at HV and above (1MW). Mentioned in UoS methodology (DCUSA).	Low value (£2/MWh) – See page 580 of DCUSA (schedule 16). This payment does not apply when Transmission system causes unavailability.
	Electricity standards of performance regulations 2015 (GSoP)	Mostly £150 for business customers. Available to all customers not covered by above.
Normal connection – right to have connection maintained within technical parameters agreed with connection agreement	National terms of connection set out right to be connected to distribution network. Replicates the rights under the Electricity Act.	
Ongoing liabilities	Customer can be de-energised at any time DG customer has the opportunity to offer back capacity at any point without liabilities and can lead to reduction in DUoS. Can only reduce capacity once a year.	No compensation to customer but some costs associated with disconnection. DUoS charges then stop. No incentive on CDCM DG customers to hand back capacity as no capacity charge on DG, so no DUoS reduction. EDCM does have capacity charges on DG.
Bilateral Embedded Generator Agreement (BEGA) [2]	Provides a DG customer with Transmission rights (see transmission section below). Customers can receive embedded benefits if they have a BEGA provided they are licence exempt (under 100MW). Sub 100MW generators don't pay TNUoS charges.	Allows DG customer to received constraint payments from SO (see transmission section below)
Flexible/ANM connection	Customer can connect without requirement for reinforcement (and costs) but agrees to be	Customer would forgo any rights to compensation under network availability or GSoP.

[1] Defined as standard DG in DCUSA. There is ambiguity over what this relates to as standard is not defined in DCUSA.
[2] Large DG (30MW or greater in SPD and 10MW of greater in SHEPD) in Scotland can opt to have a Billateral Embedded large licence exempt agreement (BELLA) with National Grid instead of BEGA. This gives no additional rights or entitlements at Transmission, in terms of constraint payments or require the customer to be BSC/Grid Code compliant.

	interrupted when required for network operational purposes	
Transmission		
Use of system – provides right of access	**Interruption payments** – linked to asset failure i.e. rare local network issue rather than congestion management e.g. outside interference on network. Customer will have entitlement to payments unless the network is non SQSS compliant. TO will flag which parts of the network are non-SQSS compliant and the SO then considers whether payments are valid in these circumstances.	For interruptions with less than 24hours notice the generator is paid the market energy price for outage time. With more than 24hours notice, the pro-rated cost of TNUoS is paid (either its own TNUoS charge or average of GB charge for outage time; whichever is higher) i.e. rebate on TNUoS . Payments are funded by TO but are added to allowed revenue (pass through) as causes are largely out of TOs control.
Constraint payment	Customer have rights to enter bids and offers to SO for system balancing. SO funds out of price control.	Designed to leave generator revenue neutral to interruption based on lost market value. Value is the market rate accepted by SO to interrupt customer in order to manage constraints.
Inter-trips	Customer can chose an inter-trip at time of connection offer to get connected more quickly prior to reinforcement. It is used by SO to support connect and manage policy and also to aid the range of options available to consumers.	No compensation provided when customer is curtailed by the inter-trip as it is designed as a temporary measure until wider reinforcement undertaken.
Ongoing liabilities	Customer must sign up to user commitment. This can be up to 40 years (pay-back period) for connection asset charges and 1 year for TEC (i.e. to stay energised). Transmission generators are required to provide securities for transmission charges (see right hand column).	A charge applies if a customer reduces TEC with less than 12months and 5 days' notice. Liabilities 1) TNUoS 2) BSUoS – 60 days' worth of charges 3) Connection charge – liable for unpaid asset related charge if de-energised within agreed pay-back period.

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Option development

Options development

> By the next meeting we need two deliverables for each option area (nature of access rights; initial allocation; reallocation and trading):

1. A draft of the section of the initial options document for that option area, to be discussed at the next TF meeting and published end January. Each section should set out:
   - A description of how the different options within that area could work
   - A discussion of how the different options would apply to different types of network user
   - A description of what links to other option areas have been identified

2. Slides to set up a discussion at the next TF meeting on the merits of the different options. These should cover:
   - An initial assessment of advantages and disadvantages of each option.
   - The key challenges/opportunities/enablers associated each option.
     >

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TF member allocations

- Propose that we have three groups to deliver both 1. and 2. for each option area. We would like one or two leads for each, with others supporting by providing input and challenge to draft materials.

Option area	1. Lead on options report	2. Lead on initial assessment slides	3. Supporting group
Access rights			
Initial allocation			
Reallocation and trading			

- Leads should send their outputs to the Secretariat/Ofgem by 16 January for circulation to the TF on the 18 January. Ofgem are also happy to engage in discussions as materials are developed.

Options discussion today

- In the next three sessions we will be discussing the initial thinking on the different options.

- We think the key questions to discuss are:
  - Are there further options that have not been identified?
  - How do the options relate to different network users needs?
  - What are the key questions/uncertainties about how they would work that we need to develop a better view on?

- At the end of each session we will look to allocate members to the next round of work as per the table in the previous page.

Lunch

Nature of access rights – option development

Defining options around nature of access rights – Initial brainstorming for comment

SPR/ADE

Access rights – Building blocks

IMPORT	Least			Most
Access to -	Voltage level only	Up to GSP [i.e. without upstream reinforcement]	Up to Tx network [i.e. under C&M]	Up to Tx network
Access at -	Off-peak only (e.g. green only)		All but peak (e.g. no red or super-red bands)	All day
Access at -	Summer minimum periods		All but winter peaks	All year round
Financial firmness -	Uncompensated ANM		ANM but compensated after a certain %/yr of constraint/ curtailment	Compensated for all constraint/ curtailment
Access over -	Short-term (e.g. 1-2 years)	Medium-term (e.g. 15 years)	Long-term (e.g. 30-40 years)	Evergreen
Access for -	The contracted party only (no trading)		Trading parties within a limited geographical area (e.g. GSP)	All eligible trading parties (e.g. across all GSPs)
Access conditions -	Use it or lose it without compensation	Use it or sell it to other parties	Use it or lose it with compensation from operator	Evergreen access to all capacity bought

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Access rights – Building blocks

EXPORT	Least			Most
Access to -	Voltage level only	Up to GSP [i.e. without upstream reinforcement]	Up to Tx network [i.e. under C&M]	Up to Tx network
Access at -	Peak only (e.g. red or super-red bands only)		Not off-peak (e.g. red and amber periods)	All day
Access at -	Winter peaks only		All but summer minimum periods	All year round
Financial firmness -	Uncompensated ANM		ANM but compensated after a certain %/yr of constraint/ curtailment	Compensated for all constraint/ curtailment
Access over -	Short-term (e.g. 1-2 years)	Medium-term (e.g. 15 years)	Long-term (e.g. 30-40 years)	Evergreen
Access for -	The contracted party only (no trading)		Trading parties within a limited geographical area (e.g. GSP)	Eligible trading parties (e.g. across all GSPs)
Access conditions -	Use it or lose it without compensation	Use it or sell it to other parties	Use it or lose it with compensation from operator	Evergreen access to all capacity bought

>

New arrangements– Future objectives(?)

Are these right and what do they mean in practice?

Across voltages

- Households have guaranteed basic (to be defined) access rights
- Reveal the value of reducing need for network reinforcement
- Allow network operators to better maximise use of the network
- Reveal the value of different access rights in a transparent, market-based way
- Competitive fairness across Tx and Dx as far as possible – including depth of boundary
- Allow users greater choice in their access – in a way that works for new technologies, increasing numbers of users with generation, storage and demand, increasing local balancing (on-site/Dx)
- Allow users to easily understand the value of those different choices – in a way that can be included in investment planning
- Parties bear the risks that they are best able to manage
- Mitigate the lumpiness of network reinforcement investments that customers face at distribution level
- Parties have incentives to recycle unused capacity back into the market

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Charging Futures

Initial questions and priorities for evidence-gathering

Network signals

- What access rights are contained within connection agreements now (especially at the lower voltage levels) and what is the range of current bespoke agreements?
- What is the right balance between stable and cost-reflective charges?
- As the network changes, should existing access rights reflect those changes? Should existing access rights change even if the right holders are not those who have impacted the system (e.g. cost of import access changes when generation % in the network area falls)?
- Are distortions created by the difference in boundary depth between distribution and transmission? What would be the wider impacts of moving to a shallower connection boundary at distribution level?
- What type of information would users get from more choice in access rights? How could the cost of access be known before applying for connection?
- What type of information would network/system operators get from more choice in access rights? How would this inform network planning and more real-time system operations modelling?
- Could greater information and granularity on access rights change regulatory planning and design codes?

Initial questions and priorities for evidence-gathering

Interaction with different types of rights

> If in place, how would the short-term rights market interact with the long-term rights market?

> If in place, would users be able to move from long-term to short-term rights as they change their service provision to different networks, exit local energy systems etc. and if so, how?

Access v. forward-looking charges

> Would there be differences in information revealed to the market and to network operators?

> Would there be differences in the range of choice possible to users?

Practical feasibility

> Are there practical limits to the degree of mixing/matching and range of choices in different access right building blocks from a systems operation perspective?

> How practical is significant choice on both import/export down to household level?

> How could users easily compare the value/cost of different access rights in a timeframe that works with investments?

> How much would a large range of choice create significant volatility in a short-term access rights market? Would this be enough hinder investment?

> Would there be liquid competition for more limited access rights?

> How would users understand the queue under these arrangements if there is one? How would this work with others steps in development?

> What transitional arrangements would be required if the maximum choice is adopted?

Annex:
Access Rights Now

(for comparison to future)

Access rights – Now(?)

***All subject to significant variation (bilaterals, NHH v HH etc)**

DEMAND	CDCM	EDCM	CUSC
Mechanism	Connection agreement	Connection agreement	Connection agreement
Value	Deep connection with potential transmission trigger at higher voltages		Shallow connection with local cct & s/s
Access to voltage levels	Little ANM	Some control through ANM	Under C&M
Access over day	All day	All day	All day
Access over year	All year	All year	All year
Financial firmness	Largely non-firm – Dependent on voltage level, time of constraint	Largely non-firm - Dependent on voltage level, time of constraint	Firm
Access for how long	Evergreen	Evergreen	Evergreen
Access for whom?	The contracted party only (no trading)	The contracted party only (no trading)	The contracted party only. Largely unused mechanism for trading TEC
Access conditions	Can volunteer to offer back capacity	Can volunteer to offer back capacity	Charges if reduce TEC at short notice

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Access rights – Now(?)

***All subject to significant variation (bilaterals, NHH v HH etc)**

GEN/STORAGE	CDCM	EDCM	CUSC
Mechanism	Connection agreement	Connection agreement	TEC
Value	Deep connection with potential transmission trigger at higher voltages		Shallow connection with local cct & s/s
Access to voltage levels	If standard, all. If under ANM, up to reinforcement need	If standard, all. If under ANM, up to reinforcement need	If standard, all. If under C&M, up to reinforcement need
Access over day	All day	All day	All day
Access over year	All year	All year	All year
Financial firmness	Non-firm – unless party has BEGA/BELLA	Non-firm – unless party has BEGA/BELLA	Firm
Access for how long?	Evergreen	Evergreen	Evergreen
Access for whom?	The contracted party only (no trading)	The contracted party only (no trading)	The contracted party only. Largely unused mechanism for trading TEC
Access conditions	Can volunteer to offer back capacity	Can volunteer to offer back capacity	Charges if reduce TEC at short notice.

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Volunteers

Option area	1. Lead on options report	2. Lead on initial assessment slides	3. Supporting group
Access rights			
Initial allocation			
Reallocation and trading			

Initial allocation of access rights – option development

3 (+1) options in Ofgem's final TAR 'Enduring' report

Different models		Key features
First come first served	"Evolutionary Change"	1. Strengthen user commitment, 2. SO required to run short term access auctions 3. Overrun charges for generation in excess of long term rights 4. Sharing of access rights between generators (within a zone or nodally)
	"Connect and Manage"	Users to get financially firm connection date prior to completion of necessary network reinforcement

"Entry Capacity Auctions"		1. Two models:
		    1. 'Price based' = generators bid for capacity submitting the price they are willing to pay to secure this capacity. If a generator were to get its pricing strategy wrong it might not pick up long term access rights and would be required to use short term access products in order to generate.
		    2. "Volume based" = generators nominating how much capacity they wanted and for how long, with NGET offering them a two-tier price to use the system – MWh-based short run price in the initial years of rights allocation if there is shortage of capacity, settling to MW-based long run price afterwards.

"Fourth Model" NGET tried to develop model twice through CUSC amendments		1. Connecting generators choose between applying for long term access in annual call run by NGET, or procuring short term products 2. If long term, they declare how much and duration of transmission capacity (MW) they want. 3. Also bid annual load factor and variable / relative buyback price for long term products. This could be dynamic (eg. spark spread). Also could bid supplemented as needed with short term capacity. (Low load factor bids = discounted UoS charge). 4. NGET would set fixed prices for generators per zone to recover year's asset and forecast constraint costs. 5. Long term capacity applied for guaranteed to be granted, (similar to C&M), iterate based on above prices.

Volunteers

Option area	1. Lead on options report	2. Lead on initial assessment slides	3. Supporting group
Access rights			
Initial allocation			
Reallocation and trading			

Dynamic reallocation of access rights – option development

Options for reallocation

Area	Key options
Geographic area	1:1 trading within zones; nodal trading with exchange rate between nodes
What's being traded/reallocated	Firm access right; curtailment liability (eg non-firm connectees being able to pay to move backwards in LIFO curtailment order)
What's the timeframe	Long-term; short-term (eg within year); close to real-time (eg day ahead or BM timeframes)
How is the trade facilitated?	Bilateral; independent platform with DNO/SO network data provision; SO/DNO-run platform

- Are there other key options?
- Which of these are worth further consideration?

Expanding on one option – replicating transmission dynamic allocation to access via BM in distribution

Intro (1)

> Access is all about making use of the system to deliver energy from providers to consumers when its needed.

> Understanding the diversity of fuel source and characteristics of demand allows rights to be used multiple times “Dynamic allocation”

> No point in having rights if the wind isn't blowing.

> The need for Energy and Reserve should drive use.

> Need to define information flows, capacity and a curtailment price to get this organised.

>

Intro (2)

Access rights define the ability deliver energy onto the system they are only needed at a time when providers is able to produce and sell their product with key driver being:

> Fuel availability solar, wind and biomass
> Energy price in the traded markets
> Use by the system operator for reserve
> Use by the distribution company to support flows and voltage.
> The demand profile on the local distribution system at higher demand periods more rights can available.

Access and energy are intertwined

>

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Road map 1

- Define product at the distribution level DTEC for each export connection over [500kw]
- Local infrastructure must be in place comparison with transmission CEC.
- Each DTEC holder will define the characteristics of its generation (Solar, wind, gas, battery etc) to feed into the longer term charging methodology for these right at a GSP/GSP group level.
- Assessment at a GSP/GSP group level of the characteristics of generation and demand may allow more rights be to release in the knowledge that these right may need to be constrained for some periods
- Each DTEC holder notifies scheduled of future generation or reserve holding for next [24] hour period based on fuel and contract position.

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Road map 2

- Cost of longer term rights is based on the characteristics of demand and generation within the GSP group or GSP.
- The DTEC holder will also set a price for curtailment of these rights based on a cost reflective principle [may need to be “managed” if rights have been significantly oversold].
- Rights can be reduce (constrain off) in areas with the following effect:-
  - Fault outage limited compensation (same as transmission) .
  - If rights are curtailed in group the funding for curtailment will be self-funded within the GSP Group on a delivered energy + constrained of volume basis shared [50/50 generation/demand] in the GSP group.
- Users who have stronger connections are less likely to be constrained off but will pay a share of constraints within a GSP group as the characteristics and bid price of the generation is as important as the physical connection

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Volunteers

Option area	1. Lead on options report	2. Lead on initial assessment slides	3. Supporting group
Access rights			
Initial allocation			
Reallocation and trading			

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Meeting wrap up