Filing Receipt

Filing Date - 2023-11-14 09:11:13 AM

Control Number - 53911

Item Number - 62

MEMORANDUM

FROM: Jason M. Ryan, ADER Task Force Chair
Arushi Sharma Frank, ADER Task Force Vice-Chair

RE: Project No. 53911, *Aggregate Distributed Energy Resource (ADER) ERCOT Pilot Project*

DATE: November 14, 2023

The ADER Task Force conducted a workshop on November 10 to continue the discussion from the October 26 workshop on the current status of the pilot project, challenges to growing participation in the pilot project, and potential paths forward as we look to the next phase of the pilot. The agenda and material presented and referenced during the workshop are attached. Also attached are notes from the October 26 and November 10 workshops.

A recording of the November 10 workshop is available on the Texas ADER Task Force YouTube channel at: https://youtu.be/kHw2eSom0Yo

AGENDA FOR THE
MEETING OF THE
AGGREGATED DISTRIBUTED ENERGY RESOURCE (ADER) TASK FORCE

FRIDAY, NOVEMBER 10, 2023, 9:00 AM
VIRTUAL ONLY VIA TEAMS

1. Welcome, Antitrust Compliance Reminder and Logistics

   Section 4 of the Charter provides:

   "The Commission strictly prohibits members of the Task Force and their employees and other entities or persons that may participate in Task Force activities from using their participation in Task Force activities as a forum for engaging in practices or communications that violate applicable antitrust laws."

   The Task Force representatives and their member organizations are committed to full compliance with federal and state antitrust laws and to maintaining the highest ethical standards in the way we conduct our activities.

2. Issues for Discussion and Solutions
   a. Caps
      i. 20% per ADER provider
      ii. 80MW and 40MW divided on load ratio share per load zone
      iii. 80MW and 40MW caps generally
   b. Changes to governing document to reflect learnings in Phase 1
   c. Density on the distribution system (continued from October 26)
   d. Interoperability (continued from October 26)
   e. Other ancillary services (continued from October 26)

3. Dates and Topics for Upcoming Meetings
   a. Task Force Quarterly Meeting – December 15

11/10/23 ADER Task Force Workshop – Challenges, continued

Purpose of Meeting: The ADER Task Force will conduct the following workshop to hear from market participants and other stakeholders on the current status of the pilot project, challenges to growing participation in the pilot project, and potential paths forward as we look to the next phase of the pilot.

Current Challenge	Possible Solution	Discussion points	Steps to address	Action item	Gov doc change?
ADER QSE and LSE has to be the same entity	Loads in SCED v2?				
Interoperability	Require IEEE 1547-2018 and IEEE 2030.5	-Interoperability isn't just about ancillary service participation, it can be used for other services for example demand response, peak shaving, etc. -Adopting standards now will prevent stranded assets later. -Only approving a standard for the pilot may be narrow.	-Could be included in the interconnection rulemaking (54233). -Could be required in the pilot project governing document. -Could have a separate interoperability/API meeting.	Task Force members to provide comments on the proposal for publication on 25.212 in 54233.	
	Mandate/Cap API Fees	-Current API fees are too expensive and the revenues don't cover the fees – especially difficult for residential and small commercial systems.	-Could be included in the interconnection rulemaking (54233). -Probably couldn't be required in the pilot project governing document. -Could have a separate interoperability/API meeting.		
Density on distribution system. Even with a fully subscribed pilot, you may still not see density. (Not a gating issue for Phase 2)	Multi-family subsidies through TDU EE programs - possibly add in batteries into the solar programs.	-Could be a pathway but program implementation would be important to ensure it's non-competitive. -Align the value with load reduction in the area – "ADER readiness" opt-in for the customer. -Similar to "Connected Solutions". -Could possibly address LMI goals with this approach. -New homebuilder programs could be a possible pathway.	-Would need a rule change so would take time if this was an approach. -TDUs could use their piloting authority. -Future workshop – invite other utilities from other parts of the country to share wins and losses.	Future workshop – invite other utilities from other parts of the country to share wins and losses; think through how to support multi-family; Texas distribution utilities (TDUs and NOIEs) to think through fleshing out a program.	

Current Challenge	Possible Solution	Discussion points	Steps to address	Action item	Gov doc change?
	TDUs suggest hot spots	-May be considered non-competitive against other wholesale market resources. Depends on how the program was administered. -Would this be connected with HCA?			
Customers may not have a clear signal of the benefit of participation					
Ability to unlock full value of DER	Allow resources to participate in ADER and TDU load management programs	-The resources may have already been deployed as an ADER so won't have anything left to participate in a load management program. -PUC had delayed the conversation about load management programs and ancillary services (39674).			
Other Ancillary Services	Allow ECRS	-Performance requirements are similar to non-spin but has a shorter duration requirement. -ADERs can help LSEs manage their costs. Non-spin only hasn't been enough to push LSEs to build their portfolio, but ECRS could be. -Update NPRR 1171 provisions to allow ECRS as well. -Could help overcome API fee issues but interoperability is still an issue to get enough resources.	Add ECRS to governing document.	Workshop to discuss with the ERCOT operations team on the barriers to ECRS addition – chicken and egg problem: ERCOT wants to see more participation but non-spin isn't enough incentive. ERCOT to provide dates on a workshop.	
No non-spin deployment	Non-spin test				
	Allow blocky participation like NCLR	Allow $75/MWh price floor similar to online resources.			
Caps – 20% QSE (revisit quarterly)	-Could move the cap incrementally.				

Current Challenge	Possible Solution	Discussion points	Steps to address	Action item	Gov doc change?
Caps – 80 MWs/40MWs (revisit quarterly)		-ERCOT would prefer to change 20% QSE and Load Zone cap over the overall caps.			
Caps – Load Zone (revisit quarterly)	-Still keep something for the less active load zones but not pro-rata share.	-Wanted geographic diversity but resources are currently concentrated in a few places in Texas. -Houston is closest to hitting load zone cap, but there's still a lot of room. -If larger commercial systems try to participate, they will hit the load zone cap quickly in areas like AEP's territory. -This doesn't seem to be an urgent issue yet. -Reported ADERs are based on DOTAs received not which ADERs are qualified. -LSEs need to know that there is room for them as they put their ADERs together.	-ERCOT could change the load zone caps. -Task Force could revisit this conversation once ADERs get closer to the cap. -Could take a look at this during each quarterly meeting/report. -Make sure governing document is drafted with flexibility in mind –20% QSE And Load Zone caps are already flexible, but the overall cap is hard coded.	Revisit quarterly.	
Telemetry validation language made it almost impossible to comply				Update the governing document	
State of charge of distributed aggregation of storage	-Clarify in the governing document.			Update the governing document	
ERS participation	-Create some sort of process in the governing document.	-How can the process for validating resources be streamlined to ensure there isn't back and forth on customers participating in ERS or ADER?		Update the governing document	

How to proceed:

- ERCOT would start first draft.
- Task Force members would provide alternate redlines.
-

Texas ADER WG

IEEE 1547 discussion

What is a DER?

- FERC definition of DER: “A distributed energy resource is any resource located on the distribution system, any subsystem thereof or behind a customer meter.” FERC states that these resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment

- The SPIDERWG’s definition of DER is a “Source of Electric Power located on the Electric system”, and in many instances the definition of DER varies depending on the context of the paper. The SPIDERWG definition includes only generation and storage devices on the distribution system and not inclusive of flexible loads, i.e. Demand Response.

FERC is creating enabling policy for DERs to gain access to the market. NERC is solely concerned with reliability. Context is crucial in the conversation and should be established at the outset. Conversations literally need a full-time referee to keep the conversation bounded to DER definition without constant obfuscation by participants to non-relative topics or ‘edge cases’. EX: Well FERC definitions transmission above 100kV but sometimes 69kV, and even 46kV gets included. So? IEEEE-2800 covers transmission connected IBR’s.

Texas ADER

This Pilot Project is intended to provide a means for Premises with any combination of generation, energy storage technologies, or controllable load with the capability of 1 MW or less to participate in the ERCOT wholesale markets. This Pilot Project is not intended to investigate or propose changes to existing participation models, such as those for Distributed Generation Resources (DGRs), Distributed Energy Storage Resources (DESRs), Aggregate Load Resources (ALRs), or Settlement Only Distributed Generators (SODGs) greater than 1 MW. Aggregations of multiple Premises that include only Load may already participate as ALRs and are not eligible to participate in this Pilot Project.

IEEE 1547-2018 Communication Protocols

IEEE 1547-2018 requires all DER, independent of type and size, to have communications capability and requires an open, standardized local DER communications interface to provide interoperability with utility communication systems. There are four types of information that are provided for in IEEE 1547-2018: Nameplate Information which is indicative of the as-built characteristics; Configuration Information which is indicative of the present capacity and ability of the DER to perform functions which may change based on relatively static configurations or may reflect dynamic weather or electrical conditions; Monitoring Information that provided present operating conditions of the DER, typically status data, active and reactive power output, but also what functions are active; Management Information which is used to update functional and mode settings for the DER, thus allowing new settings and the enabling/disabling of functions. In IEEE 1547-2018, the DER must support at least one of the three protocols at the local DER communication interface:

- SunSpec ModBus
- IEEE 1815 (DNP3)
- IEEE 2030.5 (SEP2)

All three of the protocols now support the four types of data specified in IEEE 1547-2018.

Looking Forward

- In Maryland, smart inverter settings will be the subject to a Commission meeting on November 15.
- NERC/EPRI/NAESB and IEEE 1547WG continue to further develop dynamic standards for smart inverters – Auto-reporting is on the horizon.

In general, DERs have been proven to be a significant problem to for the grid (Australia) when uncontrolled and uncoordinated. However, they have also been proven to be invaluable additions to the grid when allowed to be integrated to the grid effectively.

New Example: Pecan Street Project – 1547-2018 compliant inverters can dynamically dial power factor between 0.8 lagging and 1.2 leading to correct Power Factor 24x7x365 ‘without penalty’.

At a minimum, any premise with a smart inverter can be operated at perfect power factor. With utility signaling from the substation feeder at higher penetrations, smart inverters can correct PF for the entire feeder.

Technology Dumping

- Manufacturer’s doing the obvious thing – Dumping existing ‘dumb’ inventory to state’s that have not adopted 1547-2018.
- A state’s decision for future DER programs will require consideration of existing DER inverter fleet
  - Allow them to be included?
  - Only allow them if ‘upgraded’?
  - Only allow them if ‘replaced’?
- Most recent hybrid inverters are four quadrant – Push manufacturers to have upgrade firmware/software for compliance

Myth busting

- We don’t need to worry about this now – we don’t have high enough penetrations to cause problems.
    - Now is the time to get in front of this and start a process to effectively integrate DERs to grid and markets to make them used and useful. Later just makes it harder – Does Texas want another ‘IBR issue’ by waiting too long?
- API fees? This is primary reason why standards exist – adopt them, use them and API fees disappear with standards adoption. Proactive vendors are moving toward CIM compliant interfaces.
- Dual Registration – DERs have proven to be invaluable resources at the distribution level and appropriate rules can be written to accommodate dual participation without dual compensation

UK Flexibility Market

Flexibility Services

Product	DNO Requirement	Payment and Dispatch Structure
Sustain	To manage an ongoing requirement to reduce peak demand	Typically, dispatch is scheduled well in advance for a fixed fee
Secure	To manage peak demand on the network, usually weekday evenings	Predominantly paid based on utilisation, but with some use of availability payments also. Timing of dispatch varies by DNO (e.g. WPD dispatch one week ahead while UKPN dispatch in real time)
Dynamic	To support the network during fault conditions, often during maintenance work	Typically dispatched at short notice with low availability payments and high utilisation payments
Restore	To support the network during faults that occur as a result of equipment failure	Typically dispatched at short notice with low availability payments and high utilisation payments

Source: DNO Flexibility Service Revenue Stacking (2022-07)

UK Flexibility Market

Flexibility Services

Same Time Period	Whole-sale	CM	BM	RR	NIV Chase	FFR	FR	STOR	DNO Sustain	DNO Secure	DNO Dynamic
DNO Restore	No	Yes **	No	No	No	No	No	No	No	Yes ***	Yes ***
DNO Dynamic	No	Yes **	No	No	No	No	No	No	No	Yes ***	
DNO Secure	No *	Yes **	No	No	No	No	No	No	No		
DNO Sustain	Yes	Yes **	No	No	No	No	No	No			
STOR	No	Yes	No	No	No	No	No				
FR	No	Yes	No	No	No	No					
FFR	No	Yes	No	No	No						
NIV Chase	No	Yes	No	No							
RR	Yes	Yes **	Yes								
BM	Yes	Yes									
CM	Yes										

* Varies by DNO. Some dispatch for Secure in advance (e.g. week-ahead for WPD) so the relevant BRP can trade to that position. Others dispatch closer to real time.
** No obligation not to provide but could expose the provider to risk of CM penalty.
*** Cannot dispatch for both Restore and Dynamic or Secure services in the same time period, but DNO has visibility of all services for which an FSP is available so can optimise dispatch.

Source: DNO Flexibility Service Revenue Stacking (2022-07)

Myth busting

- Hot-Spot Management – Congestion pricing is good for transmission but bad for distribution? A feeder reconductor can disrupt a community for months and cost millions – Properly identifying Non-Wires alternatives should be allowed and priced accordingly. In addition, in my opinion, utilities should have the ability to own and operate non-wires alternatives in partnership with customers.
- Software/Firmware and utility/ISO signaling is going to constantly evolve over the foreseeable future, if a vendor cannot support this, they need to re-think their development efforts.

Summary

- DERs are going to become a crucial element in our overall supply mix. They can solve 100-year-old problems like PF and PB and provide low-cost, effective alternatives to problematic upgrades. Utilities and ISOs must have the ability to signal/communicate with DERS moving forward.
- Interoperability and Standards are the foundation for success
- DERs are generators, not just load management and require more effective coordination and integration to grid and market operation.
- You have to start somewhere; 1547 adoption is that starting point.
- Begin with the end in mind – Treat them like the resource they are and move your standards and market products to allow them to serve effectively.
- These are customer owned resources. They invested, it's their money and this fact should be front of mind in developing rules that allow the maximum flexibility to monetize their investments. The only way to protect the customer who owns Mfg A battery, Mfg B EV, Mfg C Solar and Mfg D Home Energy Management System is through effective interoperability standards.

UK FLEXIBILITY MARKETS

Scott Coe

GRID OPTIMIZE

STABLE GRIDS. FLEXIBLE THINKING.

Regulators

Utility Regulator
ELECTRICITY GAS WATER
An Coimisiún
um Rialáil Fóntais
CRU
Commission for
Regulation of Utilities
ofgem

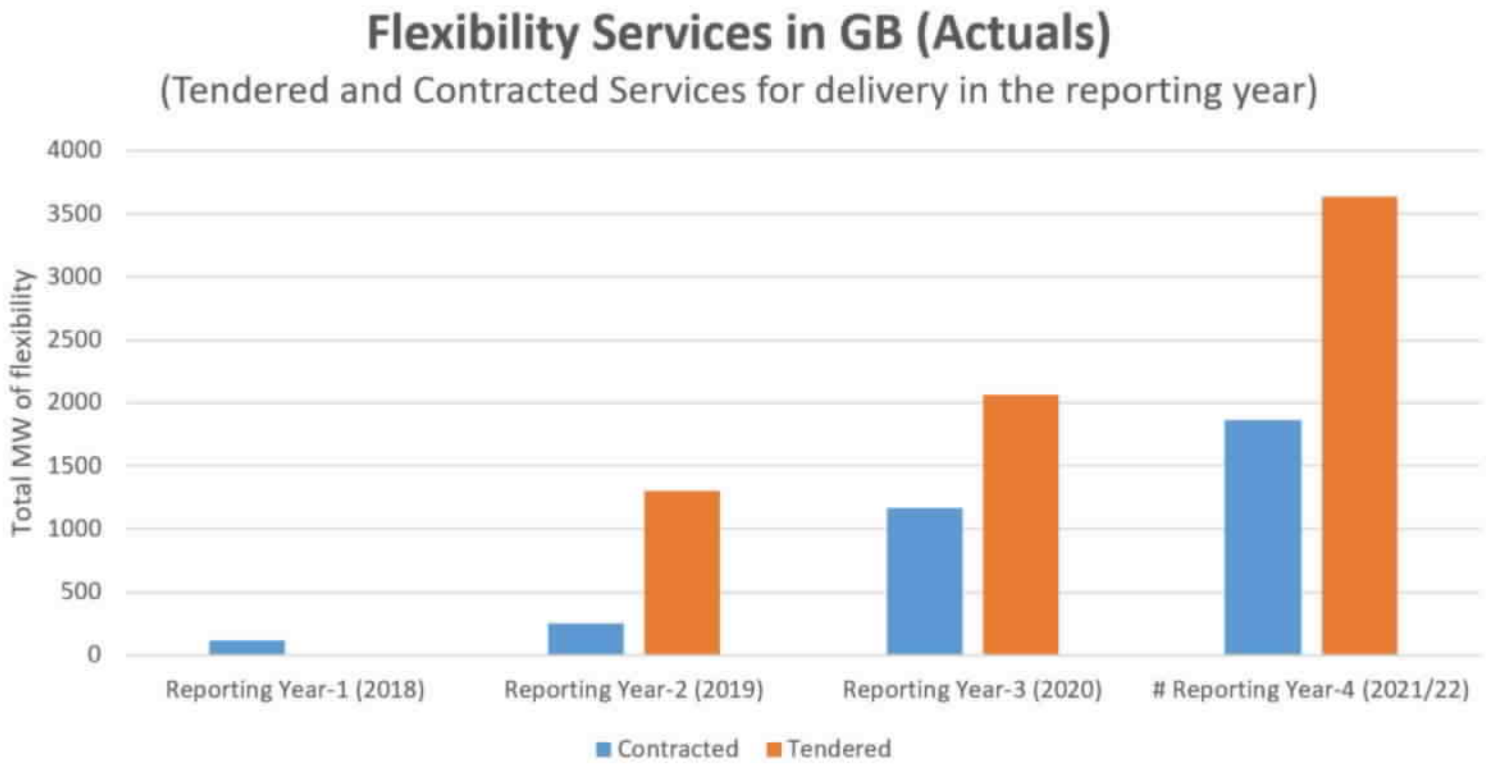
System Operators

Transmission Asset Owners

Distribution System Operators

Flexibility Services Statistics

- DNOs tendered 3.7 GW of network flexibility
- Enable networks to manage network congestion
- With no reinforcements, equivalent of:
  - connection of over 500,000 7kW electric vehicle charge points
  - providing electricity to over 4,000,000 homes.



Source: ENA Flexibility Figures (2022-07)

Flexibility Services

Product	DNO Requirement	Payment and Dispatch Structure
Sustain	To manage an ongoing requirement to reduce peak demand	Typically, dispatch is scheduled well in advance for a fixed fee
Secure	To manage peak demand on the network, usually weekday evenings	Predominantly paid based on utilisation, but with some use of availability payments also. Timing of dispatch varies by DNO (e.g. WPD dispatch one week ahead while UKPN dispatch in real time)
Dynamic	To support the network during fault conditions, often during maintenance work	Typically dispatched at short notice with low availability payments and high utilisation payments
Restore	To support the network during faults that occur as a result of equipment failure	Typically dispatched at short notice with low availability payments and high utilisation payments

Source: DNO Flexibility Service Revenue Stacking (2022-07)

Flexibility Services

Same Time Period	Whole-sale	CM	BM	RR	NIV Chase	FFR	FR	STOR	DNO Sustain	DNO Secure	DNO Dynamic
DNO Restore	No	Yes **	No	No	No	No	No	No	No	Yes ***	Yes ***
DNO Dynamic	No	Yes **	No	No	No	No	No	No	No	Yes ***	
DNO Secure	No *	Yes **	No	No	No	No	No	No	No		
DNO Sustain	Yes	Yes **	No	No	No	No	No	No			
STOR	No	Yes	No	No	No	No	No				
FR	No	Yes	No	No	No	No					
FFR	No	Yes	No	No	No						
NIV Chase	No	Yes	No	No							
RR	Yes	Yes **	Yes								
BM	Yes	Yes									
CM	Yes										

* Varies by DNO. Some dispatch for Secure in advance (e.g. week-ahead for WPD) so the relevant BRP can trade to that position. Others dispatch closer to real time.
** No obligation not to provide but could expose the provider to risk of CM penalty.
*** Cannot dispatch for both Restore and Dynamic or Secure services in the same time period, but DNO has visibility of all services for which an FSP is available so can optimise dispatch.

Source: DNO Flexibility Service Revenue Stacking (2022-07)

Standarized Service Parameters

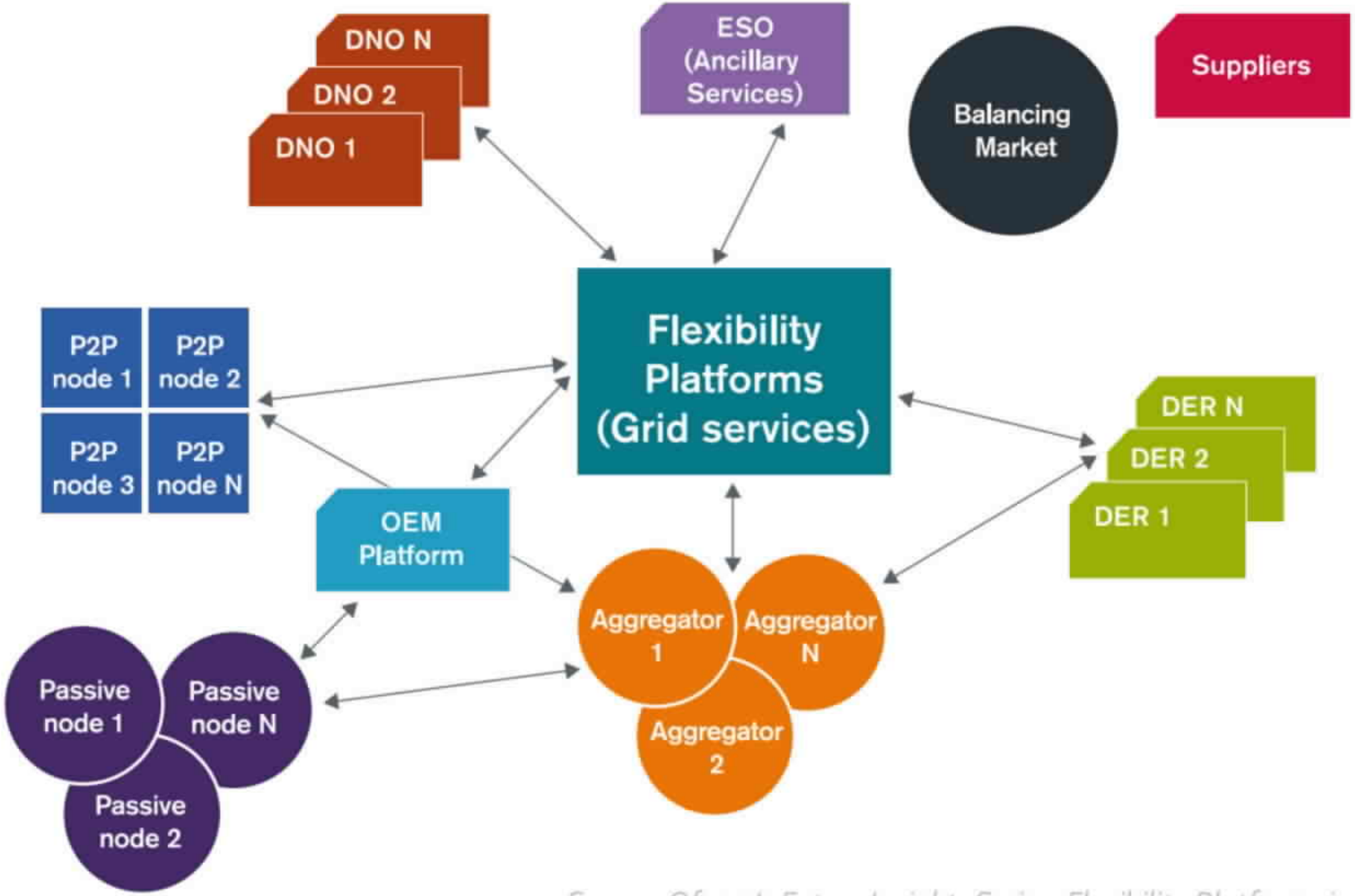
Service Parameter	DNO Flexibility Products				
	Sustain	Secure (Scheduled)	Secure (Dispatched)	Dynamic	Restore
When required?	Scheduled forecast overload	Pre- fault / peak shaving		Network abnormality / planned outage	Network Abnormality
Risk to Network	Low	Medium		High	High
Utilisation Certainty	High	High		Low	Low
Frequency of Use*	High	Medium		Low	Low
Minimum Flexible Capacity	0-50kW				
Minimum Utilisation Duration Capability	30 mins				
Minimum Utilisation	15 - 30 mins				
Maximum Ramping Period	N/A	N/A	<15 mins	<15 mins	<15 mins
Availability Agreement Period	N/A	Contract stage	Week ahead	Contract stage if appliccable	Contract stage if appliccable
Utilisation Instruction Notification Period	Scheduled in advance**	Contract stage	Real Time	Real Time	Real Time

* Frequency is location specific defined at the point of procurement

** Utilisation requirements may differ to schedule and be instructed in real time

Source: ENA Active Power Services Implementation Plan (2020-12)

Next Up: A Flexibility Exchange



Source: Ofgem's Future Insights Series: Flexibility Platforms in Electricity Markets (2019-09)

Flexibility Exchange Activities

Task	Importance*	Link to network and system operators
Coordination	High	Medium
Procurement	High	Medium
Dispatch and Control	High	High
Platform Transaction Settlement	High	Low
Platform Market services	Low	Low
Analytics and Feedback	Low	Low

Source: Ofgem's Future Insights Series: Flexibility Platforms in Electricity Markets (2019-09)

Scope Options

Uncoordinated ◀▶ Coordinated (incl. market coupling) ◀▶ Super-platform ◀▶ Single Market

	Uncoordinated	Coordinated	Super - platform	Single Market
Platforms	Many	Many	Single	Single
Markets	Many	Many	Many	Single
Common Standards	No	Yes	Yes	Yes
Governance	Independent	Negotiated	Centralised	Centralised

Source: Ofgem's Future Insights Series: Flexibility Platforms in Electricity Markets (2019-09)

The Assignment

“Ofgem extended the scope of the Long Term Development Statement (LTDS) reforms work to include this small piece of work on market standards. The LTDS reforms project aims to improve network planning data by implementing updated data standards using the Common Information Model (CIM). This technical work was tendered via Crown Commercial Services and the competitive tender won by Open Grid Systems (OGS).”

“The market standards study was a short, focused 6-week piece of work, combining deskbased research with a limited number of stakeholder interviews to investigate a range of international data standards. The report utilises a ‘traffic-light system’ to assess each candidate data standard based on objective criteria . This approach identifies and evaluates a small set of potentially applicable standards, selects the most suitable option, and outlines possible next steps for progressing that option.”

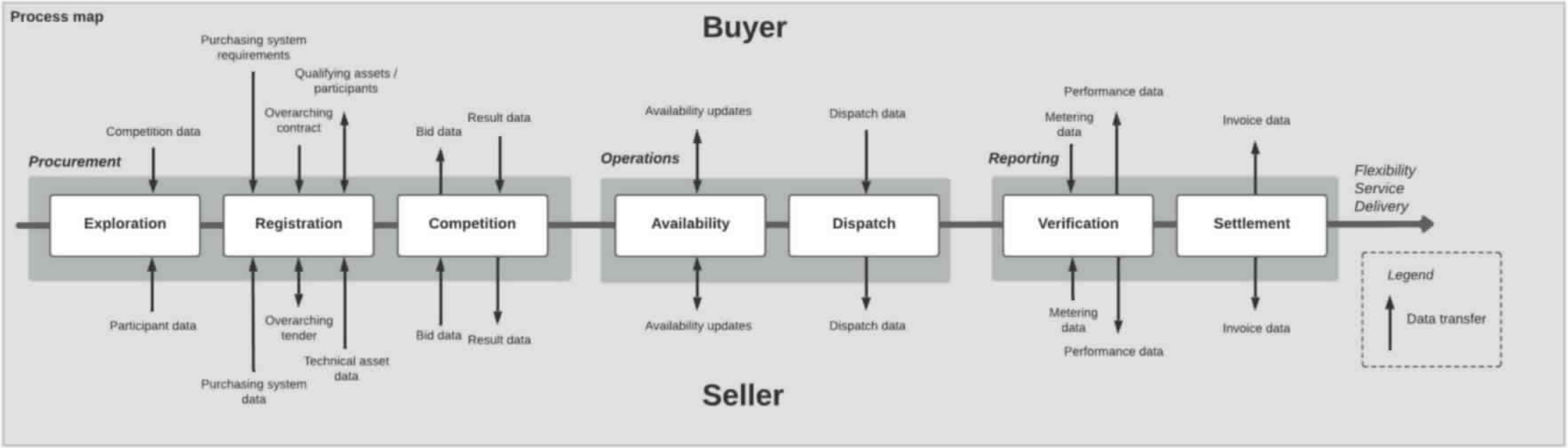
Our Approach

This report evaluates the candidate industry data exchange standards using a "traffic signal" style rating for each of four metrics indicative of the potential of a standard to support the data exchanges of a common digital energy infrastructure. They are:

1. Data Domains
2. Data Model
3. Development Process
4. Message Library

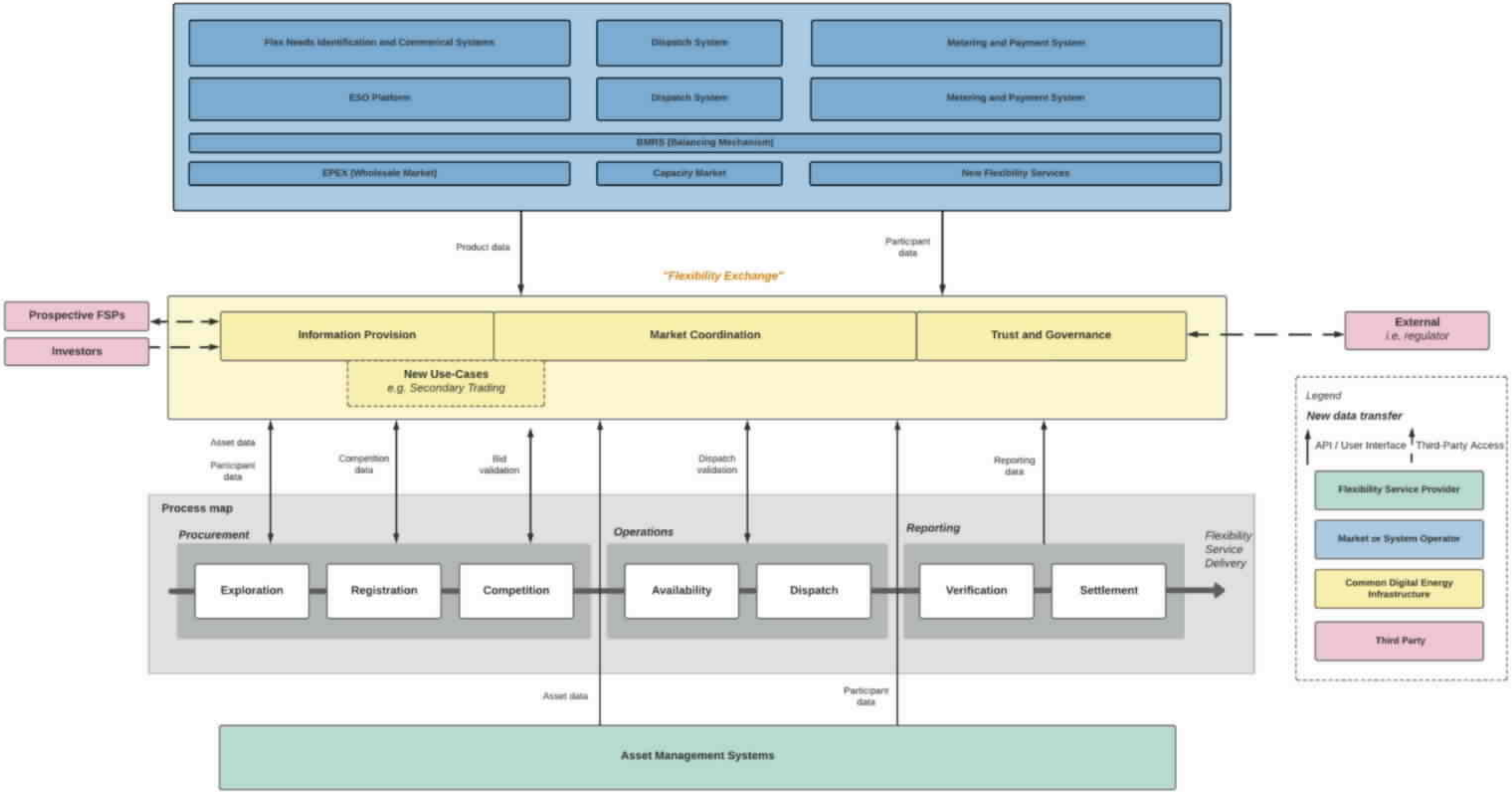
These metrics reflect essential characteristics that the authors believe are indicators of the capability of a standard to be "grown" into complete and robust support of flexibility market interoperability.

Process Map



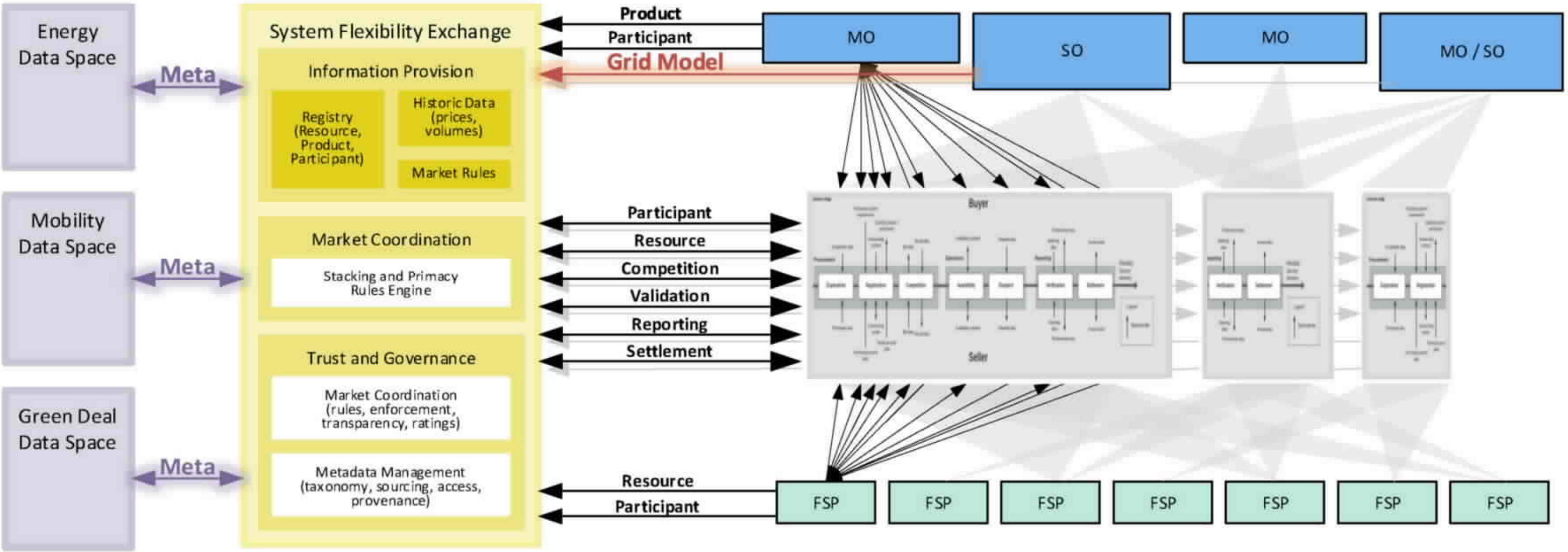
Source: Ofgem's Technical Annex to the Call for Input on The Future of Distributed Flexibility (2023-03)

Flexibility Exchange Architecture



Source: Ofgem's Technical Annex to the Call for Input on The Future of Distributed Flexibility (2023-03)

Establishing Data Domains



Source: Open Grid Systems' Flexibility Markets: Market Standards Study (2023-05)

Evaluation Criteria

#1: Data Domains

Registration
Competition
Availability
Dispatch
Reporting
Performance
Settlement
Grid Model
Meta

- Covers 0 – 3
- Covers 4 – 7
- Covers All 8

Not Relevant:

Device Information
Device Measurements / Controls

#2: Data Model

- None
- Message Model
- Semantic Model

#3: Development Process

- None
- Community
- Curated

#4: Development Process

- Limited
- Developed
- Rich

Industry Data Exchange Standards

- IEC Common Information Model (CIM)
- Energy Business Information eXchange (ebIX)
- OpenADR
- IEC 61850
- IEEE 2030.5

Implementations & Tools

UK Flexibility Platforms

- Flex by Piclo
- deX by GreenSync
- KrakenFlex by Octopus
- ElectronConnect by Electron
- NODES by Agder Energi
- DERMS by Opus One
- Crowd Balancing Platform by Equigy
- Flexible Power
- FlexR by ElectraLink
- Cornwall Local Energy Market (LEM)
- Flexibility Services Platform @ UKPN
- FUSION @ SPEN
- TRANSITION @ SSEN & ENWL

Wholesale/Upstream Implementations

- ENTSO-E Transparency Platform
- North American Wholesale Electricity Markets
- California ISO Market
- EPEX SPOT
- Nord Pool
- National Grid ESO

Flexibility Market Activities in Australia

- Dynamic Operating Envelopes (DOE)
- Post-2025 Market Design

Source: Open Grid Systems' Flexibility Markets: Market Standards Study (2023-05)

Summary of Results

	IEC CIM	ebIX	OpenADR	IEC 61850	IEEE 2030.5
Data Domains	8	4	5	3	3
Data Model	Semantic Model	Message Model	Message Model	Semantic Model	Semantic Model
Development Process	Curated	Curated	Community	Curated	Curated
Message Library	Rich	Developed	Developed	Developed	Developed

Source: *Open Grid Systems' Flexibility Markets: Market Standards Study (2023-05)*

Thank You

Download the report here:

https://www.ofgem.gov.uk/publications/call-input-future-distributed-flexibility

OGS Report - Market Standards Study