Balancing Services Charges

2nd Task Force

11 February 2019

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Welcome and introductions

Colm Murphy

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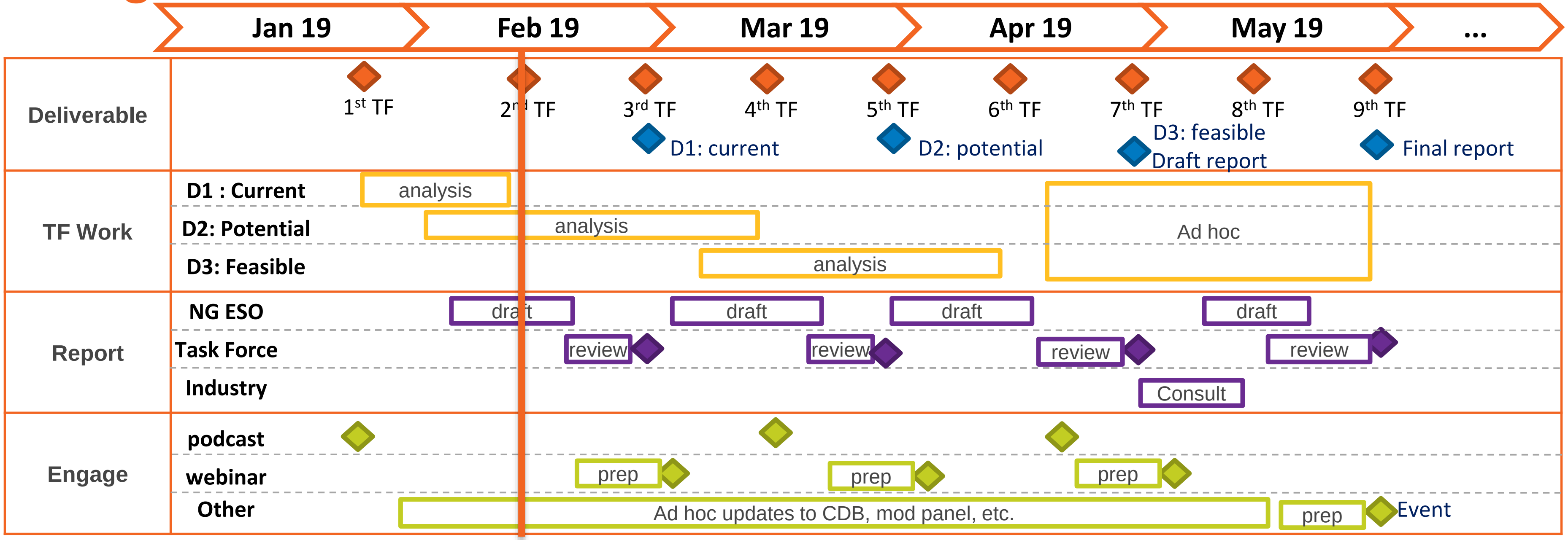
Programme Plan



1- TF 29Jan	2- TF Feb	3- TF Feb	4- TF Mar	5- TF Mar	6- TF Apr	7- TF Apr	8- TF May	9- TF May
• TF plan • **Currently**: analysis actions	• **Currently**: agree conclusion • **Potential**: agree scope + analysis actions	• **Potential**: further analysis actions + draft conclusions	• **Potential**: agree conclusion • **Feasible**: define criteria + analysis actions	• **Feasible**: further analysis actions + predictability + other signals	• **Feasible**: agree conclusion	• **Report**: finalisation before consultation	• **Report**: comments review and actions	• Final **report** + event

Purpose

- The **purpose** of the task force meeting today is:
  - To collectively recap on Deliverable 1 and allow outputs to be documented
  - To start to explore Deliverable 2 with blue sky thinking and some initial data analysis

- The **agenda** of today is therefore as follows:

No	Subject	Lead	Time
1	Welcome and introductions	Colm Murphy	10:00-10:15
2	Minutes, Actions and Engagement Update	Joe Henry and Sophie VC	10:15-10:45
3	Deliverable 1 Update and Discussion	Sophie VC	10:45-11:30
4	Breakout Session on Deliverable 2	Mike Oxenham	11:30-12:00
	Lunch	-	*12:00-12:30*
5	Breakout Session on Deliverable 2 (continued)	Mike Oxenham	12:30-15:00
6	Summary, Actions and Next Steps	Colm Murphy	15:00-15:30

Minutes, Actions and Engagement

Joseph Henry

Sophie van Caloen

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Action Log

No	Action	Owner	Open/Closed
1	Come back to the next meeting with Information on whether a formal consultation process would follow the Task Force	Tim Aldridge (Ofgem)	Open
2	Think about how feedback received from the wider industry is taken into account	Sophie van Caloen (ESO)	Open
3	Check if Terms of Reference refer to conflicting opinions and subsequent decisions	Mike Oxenham (ESO)	Open
4	Ensure additional information is produced in a streamlined and targeted fashion.	Sophie van Caloen (ESO)	Open
5	Give consideration to analysis, questions and data sets required and provide this to the taskforce where possible	All TF Members	Open
6	Live Data Sets/Dashboards to be looked into	Mike Oxenham, Paul Wakeley (ESO)	Open

Engagement - Feedback

Feedback from previous engagements:

- No feedback received from CF newsletter of the 31st Jan
- Additional bilateral input :

Input	Action
Input of CMP308: - little correlation is observed between **power prices and BSUOS** **- day-night shape**: low demand, occurring mainly overnight, drives BSUoS cost up	To be added to the analysis of D1 (see further detail in presentation).
Comments on link between BSUoS and **other market arrangements** (BM, imbalance price, etc.), actions/cost could be reduced by: • More active demand in BM • Introduction of a non-zero Information Imbalance charge • Introduction of a payment for inertia	To be added in the analysis of D3 – looking at feasibility of BSUoS signal in wider market context
Regarding **constraints**, need to understand if the costs are high because of delays in providing the required transmission upgrades (in which case this is a temporary problem until they are commissioned) or because SQSS is not requiring sufficient network capacity to be built (in which case SQSS needs to be reviewed)	To be added in the analysis of D2/D3

Engagement - Future

Next planned engagements:

- TBC – webinar early March, with outcome of Deliverable 1

Additional planned/potential engagements:

- TCMF, 13th Feb
- DCMG
- Energy Intensive Users Group (EIUG)
- Operational Forum, 26th March
- Frontier Economics meeting, early March

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D1 – Update and Discussion

Sophie van Caloen

The objective is to discuss:

- some further analysis
- The proposed approach for the assessment of D1

Analysis

ESO analysis

- **Daily pattern of costs of elements of BSUoS**
- Correlation between costs of elements of BSUoS and other variables
- Additional correlation graphs for each Settlement Period

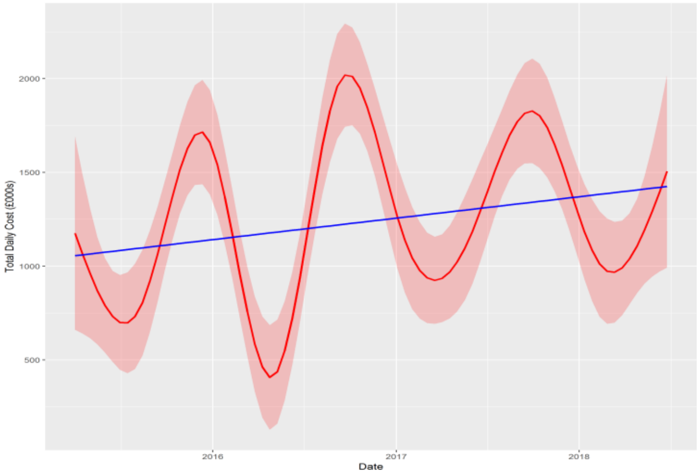
Additional analysis

- Impact of BSUoS variability on power prices (some input from CMP308)
- BSUoS volatility and forecastability (some input from CMP250)

Deliverable 1

Approach

- Data drawn from 3 years' of data between 1 April 2015 and 25 June 2018.
- It currently only reflects costs incurred through the BM. Cost categories analysed include: Constraints, Positive reserve, Energy imbalance, Negative reserve, Ramping, Other.

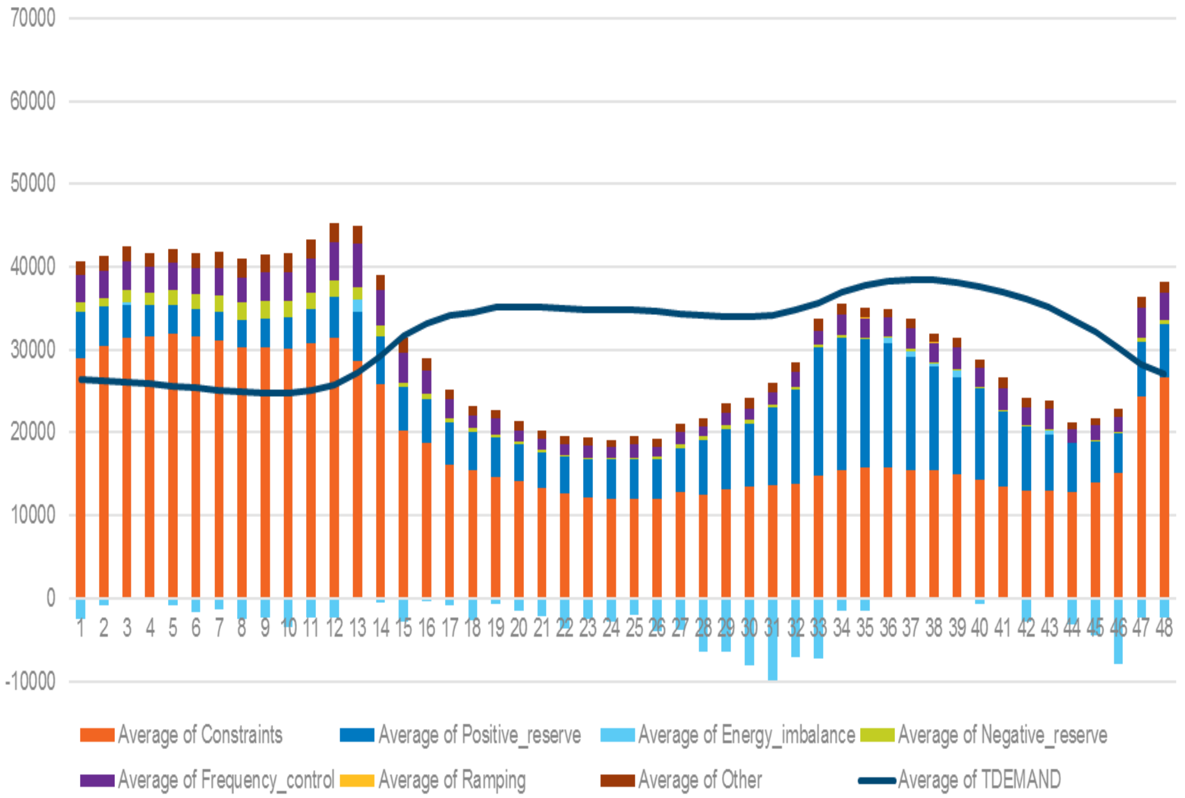


A warning about limitations of correlations

- Graph shows trends represented by daily total cost and the linear trend (in blue) shows costs have been rising over the period. Non-linear trend (in red, with confidence interval shaded) indicating seasonal fluctuations.
  - Immediately makes correlation suspect as a tool
  - If other variables are increasing or decreasing over this time period, correlations can easily occur without any causal link
- Correlations will be induced by other variables that have a seasonal component (e.g. PV generation, Wind generation, Demand) without necessarily any causal link

correlation ≠ causality

Daily pattern of costs of elements of BSUoS (I/II)



- The graph shows the cost of elements of BSUoS as they vary on average over the settlement periods (data 04/2015 – 06/2018).
- Constraints and positive reserves are the two main drivers.
- Constraint costs are higher when demand is low. As the ESO need to take actions to manage lower demand periods (e.g. create foot room, provide dynamic response and inertia, etc).
- Positive reserves are higher when the system margin is low (often when demand is at the highest).

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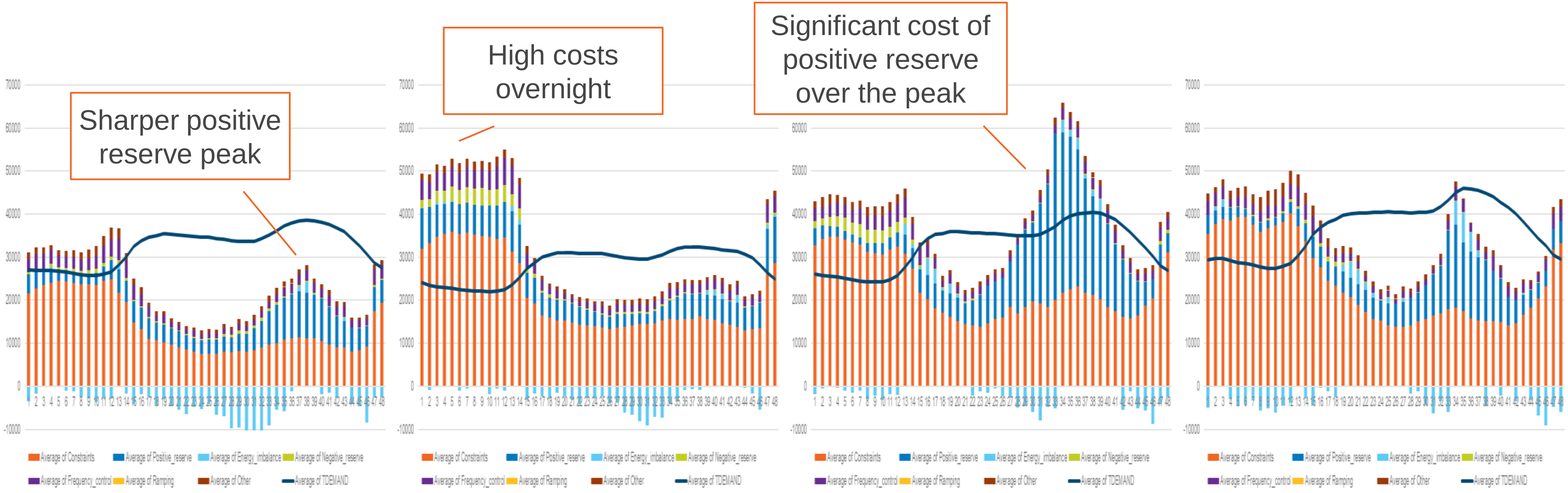
Daily pattern of costs of elements of BSUoS (II/II)



Spring **Summer** **Autumn** **Winter**

What does this tell us?

- Overall, higher constraint costs are observed overnight, when demand is low.
- There are differences between the costs of elements of BSUoS between seasons

Analysis

ESO analysis

- Daily pattern of costs of elements of BSUoS
- **Correlation between costs of elements of BSUoS and other variables**
- Additional correlation graphs for each Settlement Period

Additional analysis

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- BSUoS volatility and forecastability (some input from CMP250)

Deliverable 1

Multi- variables regression

The objective is to explain the costs of elements of BSUoS, the "dependent variable", by a series of explanatory variables (wind, PV, demand, etc.).

This is called a multivariate regression analysis.

$$Costs\ of\ element\ of\ BSUoS = f\ (wind, PV, demand, IC, etc.)$$

How to read the results? →

Explanatory variables

Costs	Coef	Measure (%)
Wind		
Demand		
PV		
IC import		
Availability		
Inflexibility (Nuke)		
SP		
Day of week		
Month		
Year		
R-squared		

Coefficient of the regression. The sign indicates the relationship, i.e. a positive (negative) number indicates that the costs increase (decrease) when the explanatory variable increases

Statistical measure that indicates which explanatory variable contributes most to explain the cost. i.e. how to "split" R-squared between variables

R-squared is the % of the variance of costs explained by all explanatory variables

Multivariate regression – constraints costs

Constraints costs	Coef	Measure
Wind	2.197	20.42
Wind (square)*	0.000393	
Demand	-10.85	17.81
Demand (square)*	0.000122	
PV	-1.826	1.330
IC import	-3.869	1.326
Availability	-0.179	0.000805
Inflexibility (Nuke)	0.790	0.128
Time trend	0.619	1.983
SP	592.9	-4.131
Day of week	6431.2	-0.449
Month	-3039.7	0.499
Year	-13284.8	-1.184
R-squared	**37,7%**	

* Square functions added to the linear functions (i.e. to take into account U-shapes)

What does this table tell us?

- Overall R-squared of 38% (i.e. % of the variance of constraints costs explained by the variables)
- Constraints costs are mainly explained by 2 variables: wind and demand
- The importance of wind and demand is similar when explaining the constraint costs

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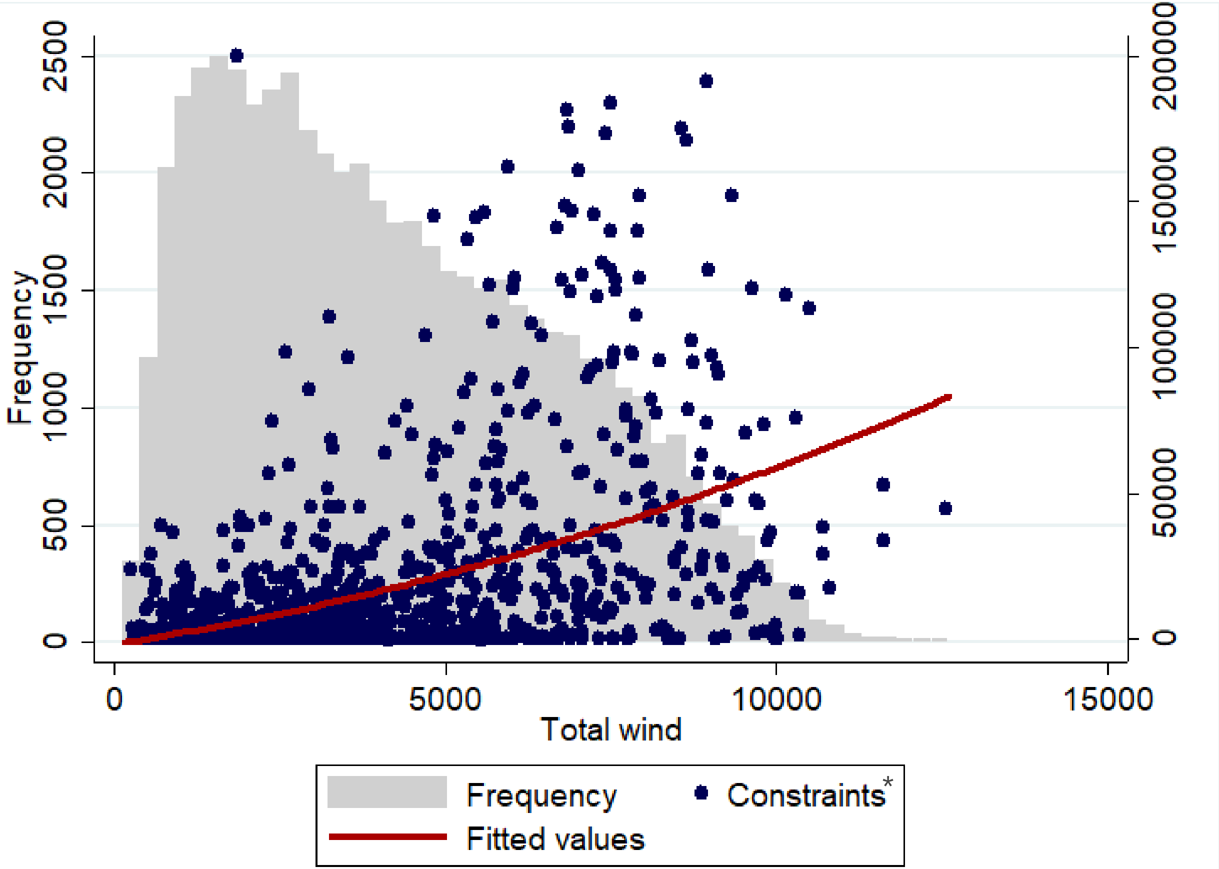
Constraints costs & wind – shape of relationship



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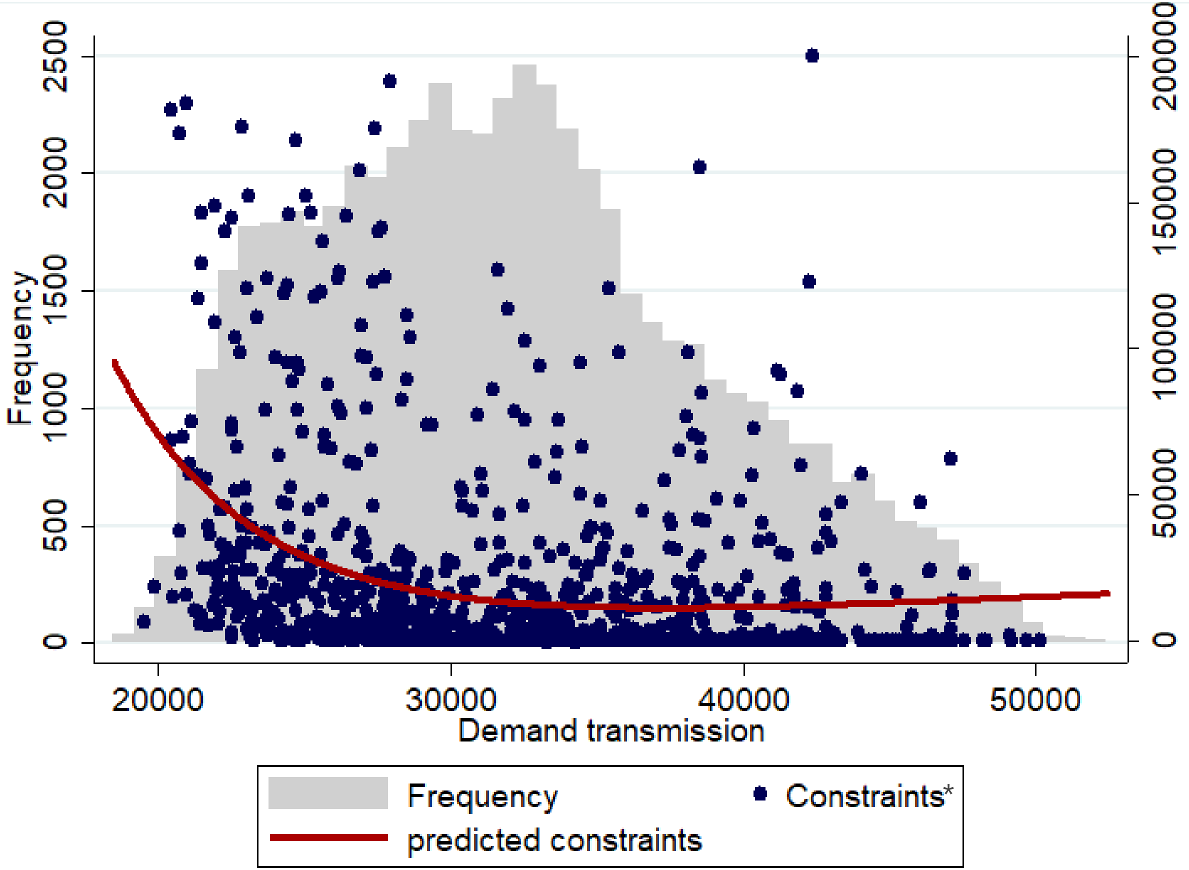
*Data: for constraints points only, 1000 observations randomly selected (for clarity)

Constraints costs & demand – shape of relationship



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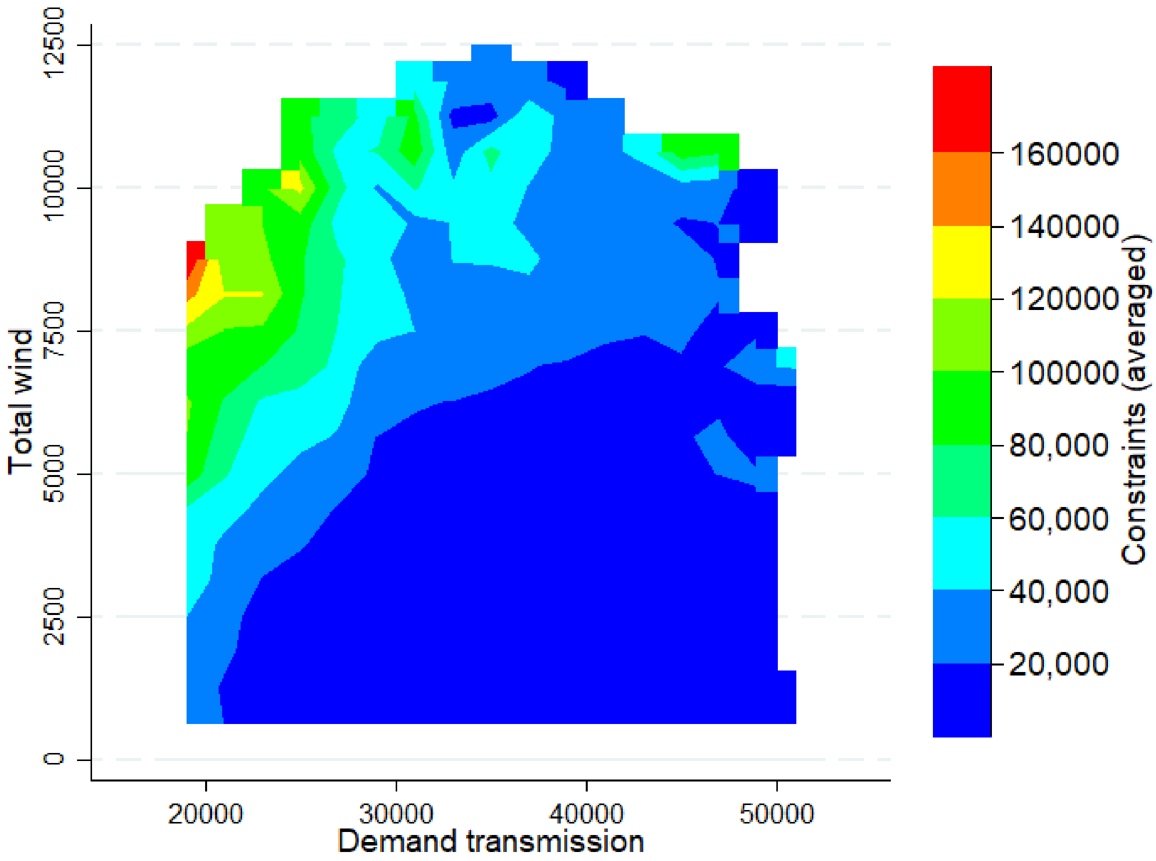
*Data: for constraints points only, 1000 observations randomly selected (for clarity)

Constraints costs values for wind and demand



What does this graph tell us?

- There is an important reinforcing effect when wind is high and demand is low

Multivariate regression – other costs (non-constraints)

Non-constraints costs	Coef	Measure (%)
Wind	0.939	0.173
Demand	1.697	3.031
PV	-5.913	5.255
IC import	-1.042	0.170
Availability	-0.783	-0.105
Inflexibility (Nuke)	3.582	0.402
Time trend	-0.829	0.485
SP	1252.4	0.0323
Day of week	-6039.7	0.153
Month	846.2	1.428
Year	17633.4	-1.082
R2	**9.9%**	

What does this table tell us?

- Overall R-squared of only 10% (i.e. % the variance of non-constraints costs explained by the variables)
- Demand and PV seem to be the main (however week) explanatory variables

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Analysis

ESO analysis

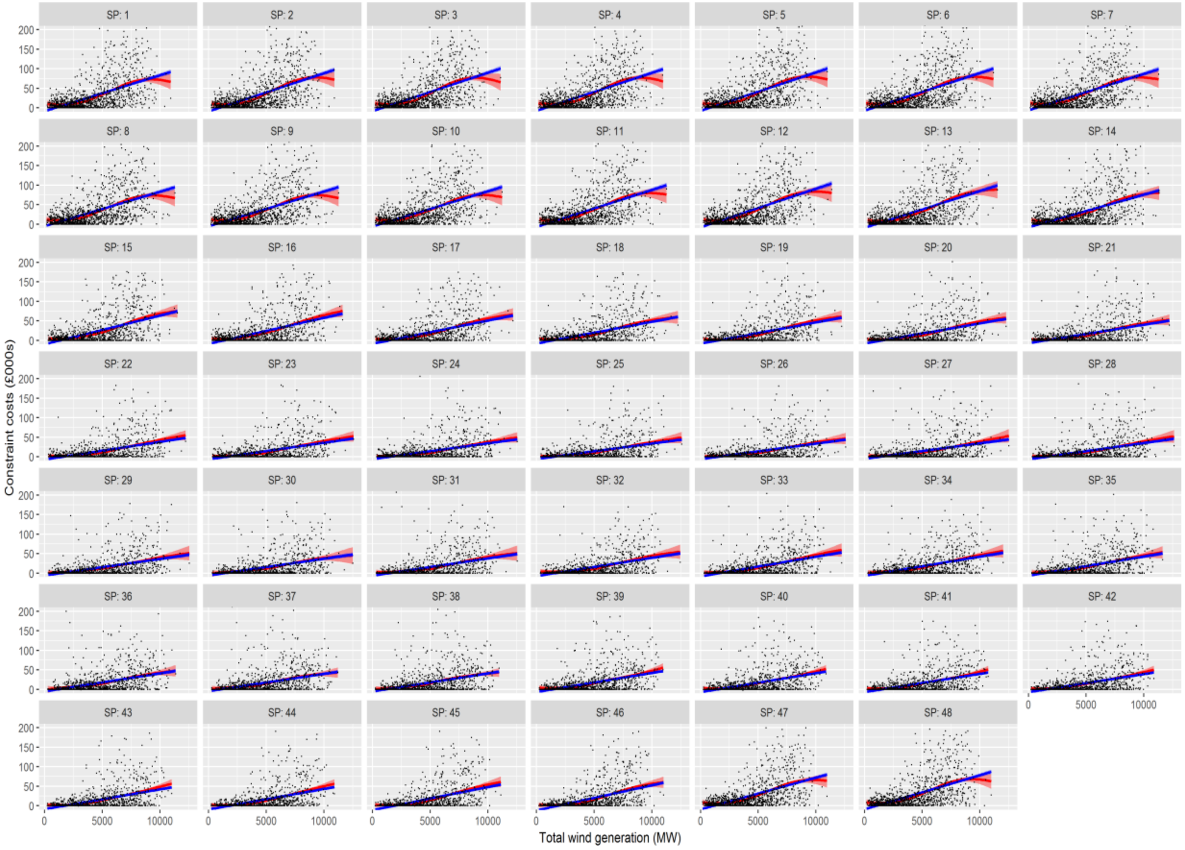
- Daily pattern of costs of elements of BSUoS
- Correlation between costs of elements of BSUoS and other variables
- **Additional correlation graphs for each Settlement Period**

Additional analysis

- Impact of BSUoS variability on power prices (some input from CMP308)
- BSUoS volatility and forecastability (some input from CMP250)

Deliverable 1

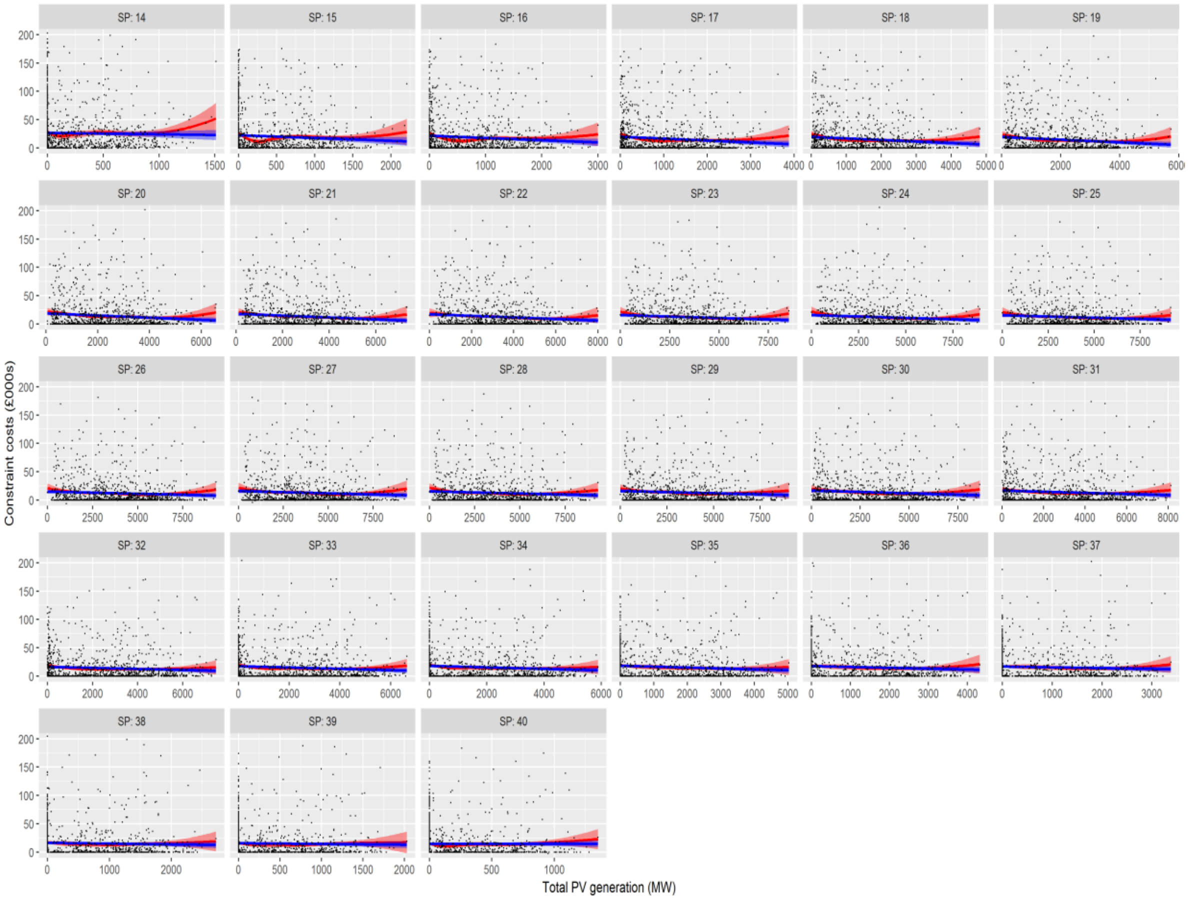
Constraint costs: Is total wind an explanatory factor?



- There's good operational experience which says yes
- Reasonable evidence for linearity – although high wind overnight deviates from linear trend
- Other evidence we have (e.g. from Plexos models) makes it likely that wind is an explanatory factor for constraint costs
- If we use forecast wind rather than outturn wind, link remains, but weaker

Data: split by Settlement Period, curtailed at £200,000 (for clarity) but few data points have very high constraints costs (up to £730,000)

Constraint costs: other factors - PV?



- Minimal if any explanatory power
- What small correlations exist can be caused by confounding of growth of costs with
  - Growing capacity of installed PV
- Also confounding of lower constraint costs in Summer with
  - Higher PV generation in Summer

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Constraint costs: other factors - Interconnectors?

- Some evidence that overnight higher imports are associated with lower costs
- Note that non linear trend suggests this only kicks in at very high import levels
- Will this continue now there is extra IC capacity?
  - It’s possible that IC imports over 4000MW could start to increase costs

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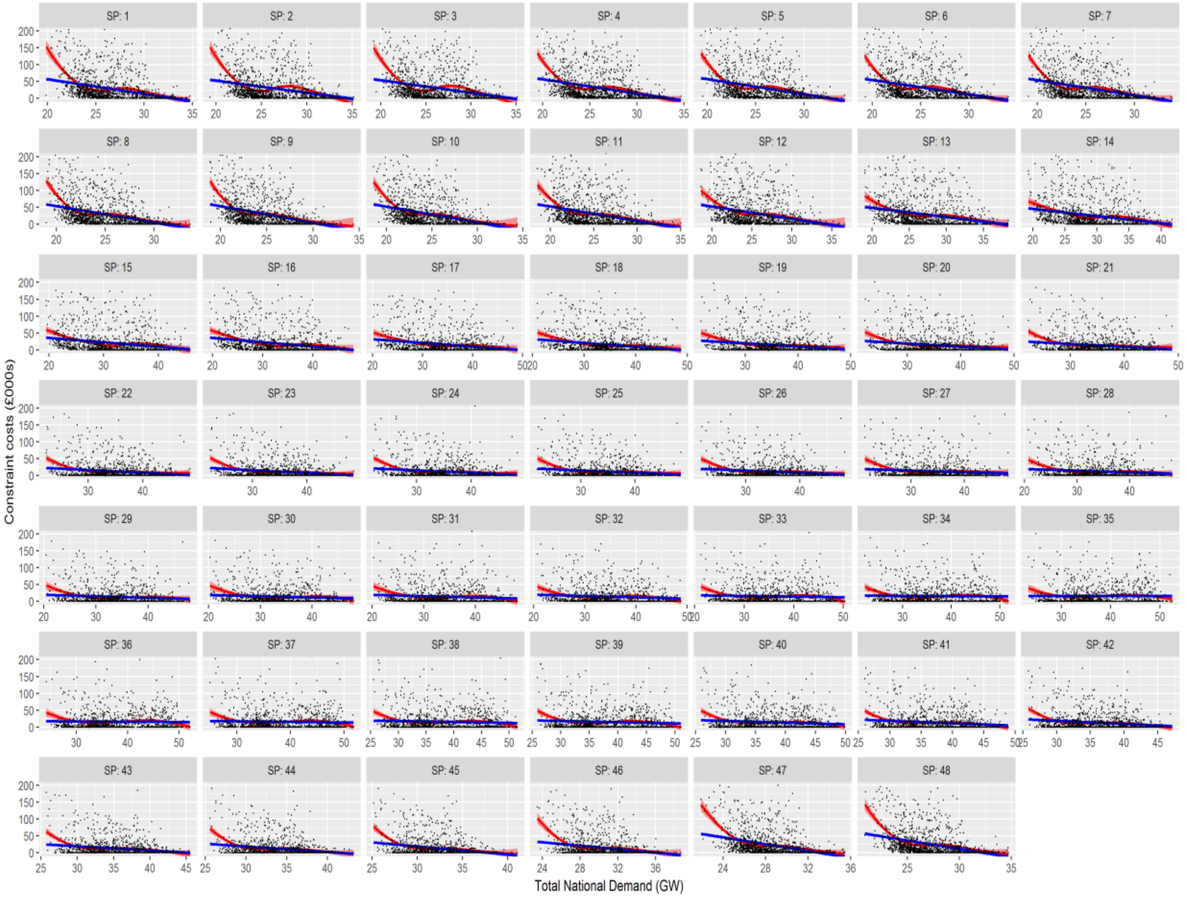
Constraint costs: other factors - Demand?



- Some explanatory power
- Non-linear trends suggest very low demands overnight associated with higher constraint costs

Data: Constraint costs against demand on the transmission system (National Demand)

Non-Constraint costs: Is total wind an explanatory factor?

- Minimal if any explanatory power

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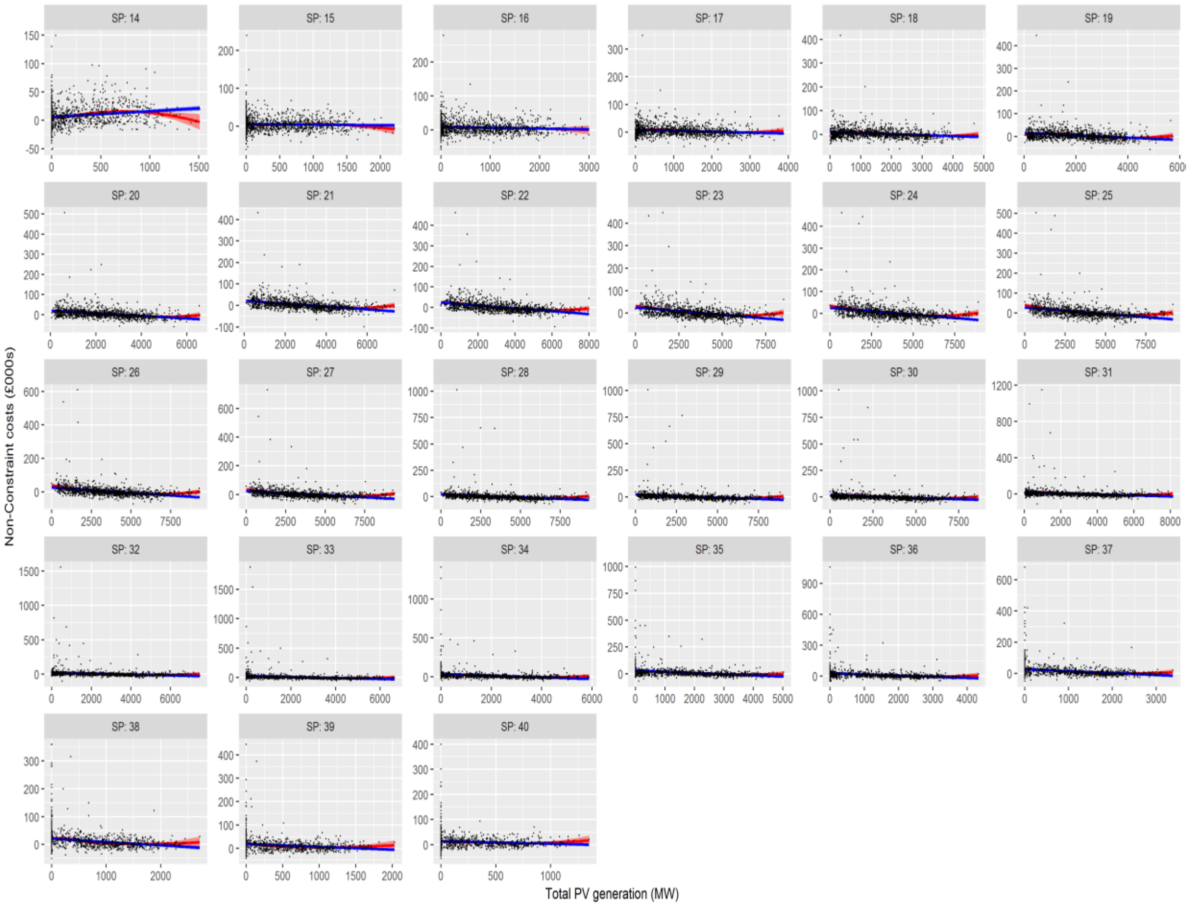
Non-Constraint costs: other factors - PV?



- Minimal if any explanatory power

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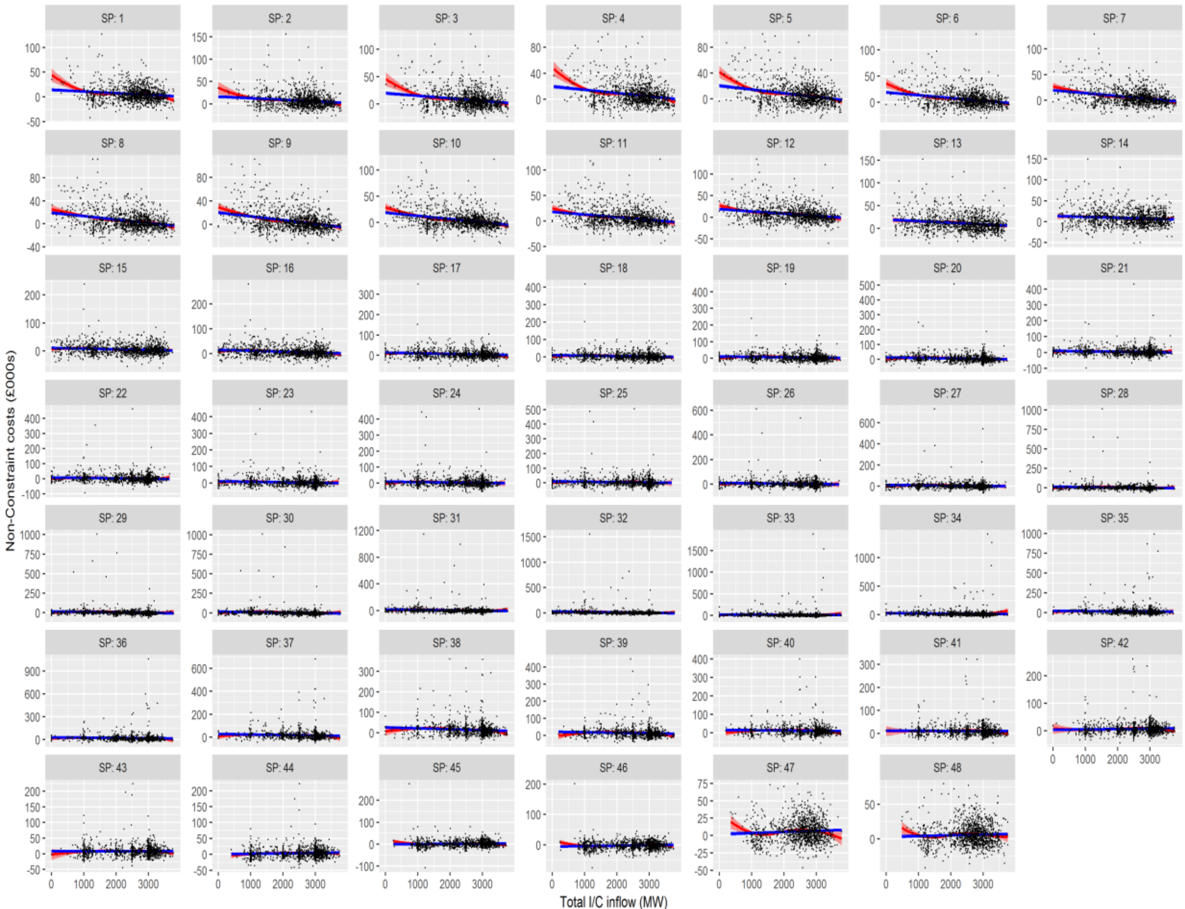
Non-Constraint costs: other factors - Interconnectors?



- Some evidence that overnight higher imports are associated with lower costs (requires further exploration)
- Non-linear trend suggests lower I/C inflows associated with higher costs

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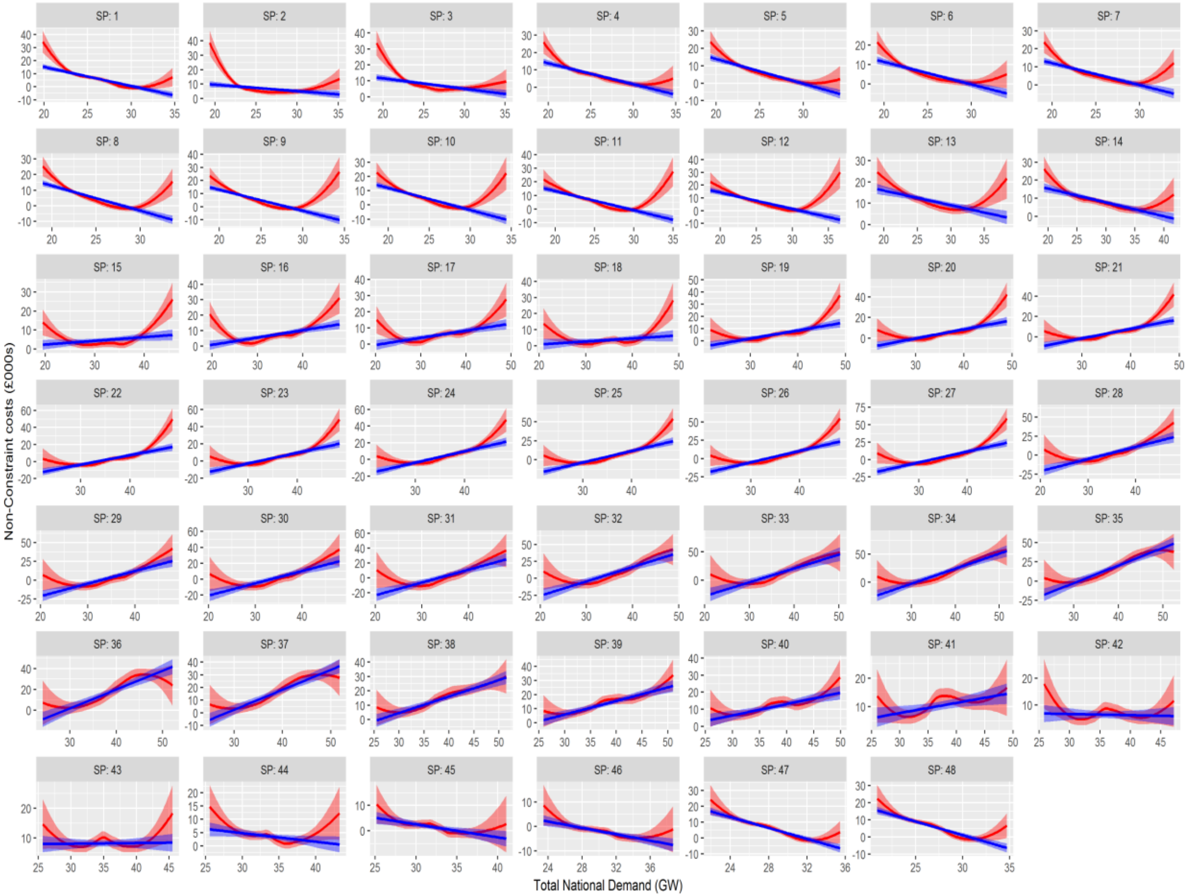
Non-Constraint costs: other factors - Demand?



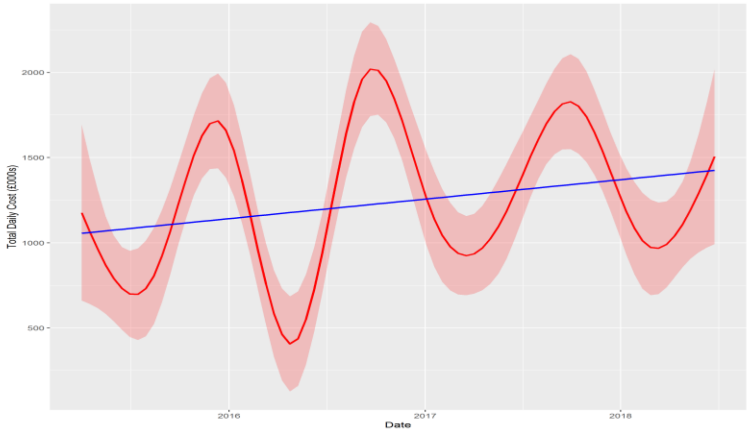
- There does appear to be some relationship here
- We should be cautious because there has been a trend downward in demand met by the transmission system
- The non-linear trends suggest a U-shape (however this is almost certainly non-causal)

Explanatory variables - overview

Costs	Variable	Correlation
Constraints	**Wind**	**Good evidence of linear trend (high wind/high costs)**
	PV	Minimal
	ICs	Some evidence (higher import/low costs)
	Demand	**Good evidence of non-linear (low demand/high costs)**
Non-constraints	Wind	Minimal
	PV	Minimal
	ICs	Some evidence (lower import/high costs & higher import/low costs)
	Demand	Suggest U-shape

Reminder - a warning about limitations of correlations

Graph shows trends but correlation can easily occur without any causal link!



Analysis

ESO analysis

- Daily pattern of costs of elements of BSUoS
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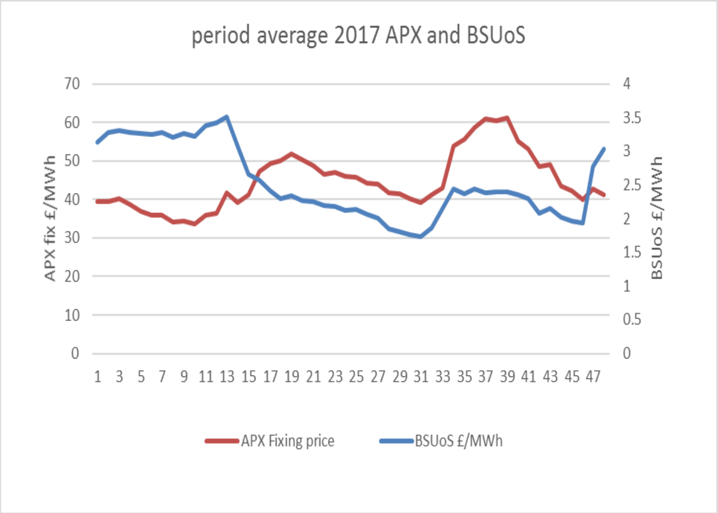
Additional analysis

- **Impact of BSUoS variability on power prices (some input from CMP308)**
- BSUoS volatility and forecastability (some input from CMP250)

Deliverable 1

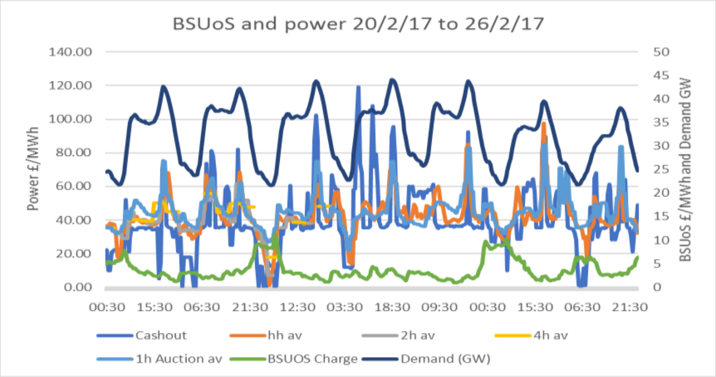
Impact of pattern of BSUoS costs on Power prices (I/II)

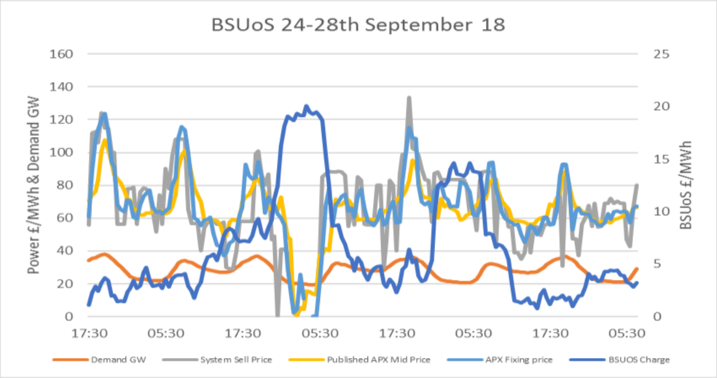


- In theory we expect power prices to adjust as BSUoS vary but the reality is different.
- As can be seen on the chart, there is little evidence that prices of short term markets adjust as BSUoS vary (half-hourly volatility). It would be expected that high BSUoS would lead to higher energy prices but he opposite effect is actually seen in general. This gives support to the theory that BSUoS is not a significant driver to short term power prices.
- Also, there are several products available on the market, in particular half-hourly products, where BSUoS hh volatility could be reflected. However, it has been observed that the volume of APX hh trades are small. Therefore, we might conclude that the majority of traded products effectively “smooth” BSUoS over a longer time period.
- However, in the long term, there might be adjustments of prices. We expect that the long run average BSUoS is reflected in power prices.

(charts and information from CMP308).

Impact of pattern of BSUoS costs on Power prices (II/II)





- The charts picks out some high BSUoS days from 2017 and 2018 these show various market related short term traded prices as well as BSUoS and demand
- It can be seen that BSUoS rises and power prices fall, during low demand periods. This is counter intuitive, but it is believed to be driven by the short-term effects of the ESO actions (resolve constraints, provide foot room, ensure the largest loss can be catered for, etc.).
- Also, on days of low BSUoS there is little or no energy price movement in the short term to reflect the change in BSUoS.

Conclusion

- Little evidence that prices adjust in the short term (however some adjustment expected in the long term)

(charts and information from CMP308).

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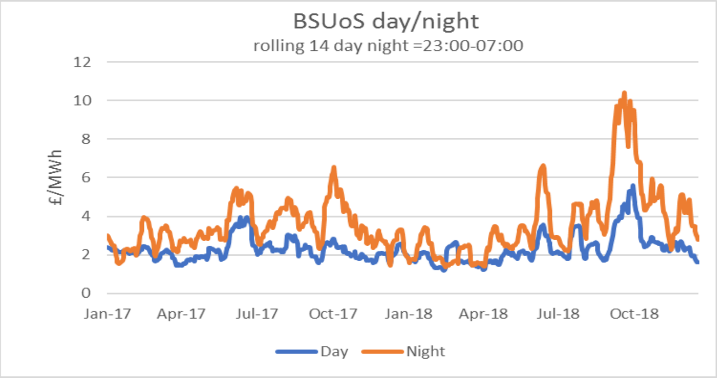
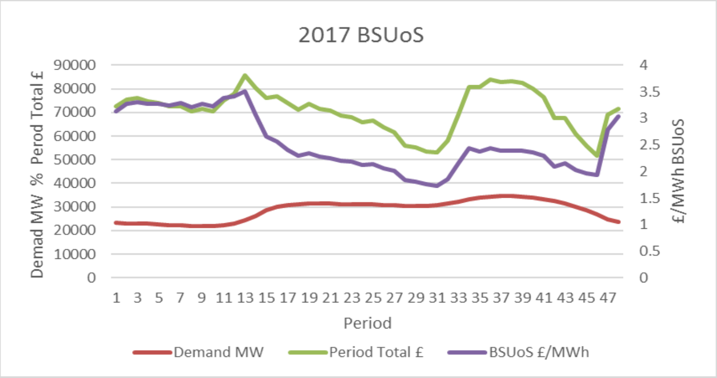
Issue with day-night patterns





- BSUoS is higher overnight than during the daytime. As can be seen on the charts, this corresponds in general to lower demand periods.
- Higher BSUoS prices is driven by two main reasons:
  - The "denominator factor", i.e. lower demand levels over night that are used as a denominator for BSUoS calculation.
  - The fact that the ESO needs to take actions to manage lower demand periods (e.g. create foot room, provide dynamic response and inertia, etc).
- This trend will affect parties that take power over night.

Conclusion

- Higher overnight BSUoS prices might affect parties that take power over night and be not effective.

(charts and information from CMP308).

The first chart shows the average shape of BSUoS for 2017/19 split into day night. The second chart shows this on an aggregated basis.

Analysis

ESO analysis

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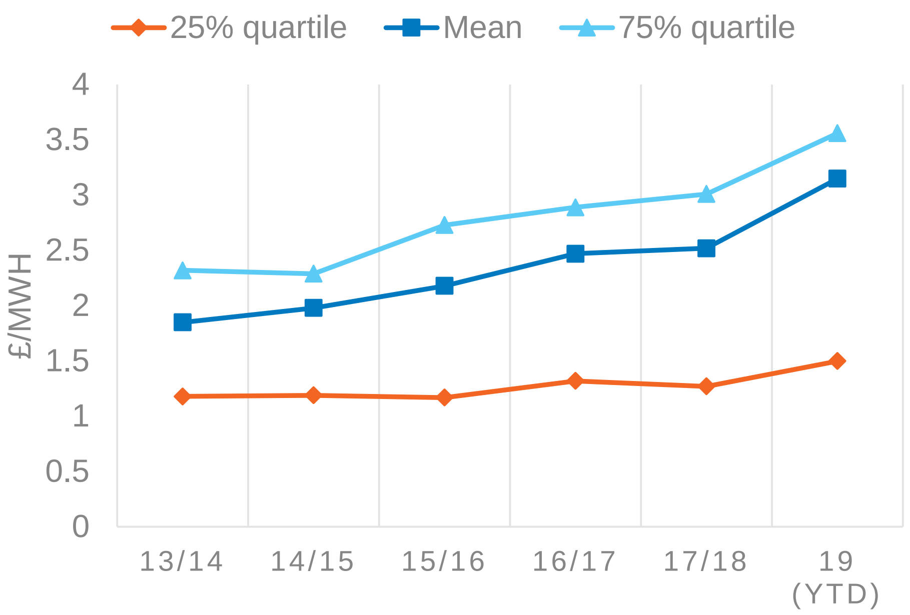
Additional analysis

- Impact of BSUoS variability on power prices (some input from CMP308)
- **BSUoS volatility and forecastability (some input from CMP250)**

Deliverable 1

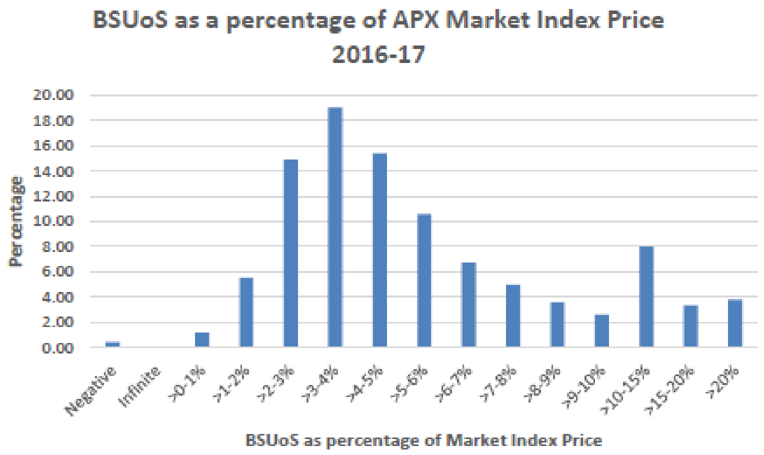
BSUoS volatility



Data: Settlement Period data for over the past 5 years

- We can observe an increased mean and volatility (25% and 75% quartiles are diverging) in BSUoS prices.
- (CMP250) There are three primary drivers for increasing half hourly prices:
  - Falling transmission demand (including an increase in embedded generation) which is a key factor in the determination of the BSUoS price
  - Increased constraint costs resulting from the “Connect and Manage” regime (where generators are permitted to connect to the transmission network ahead of reinforcement)
  - A reduction in ‘traditional’ service providers resulting in a reduction in inertia, Black Start capability etc.

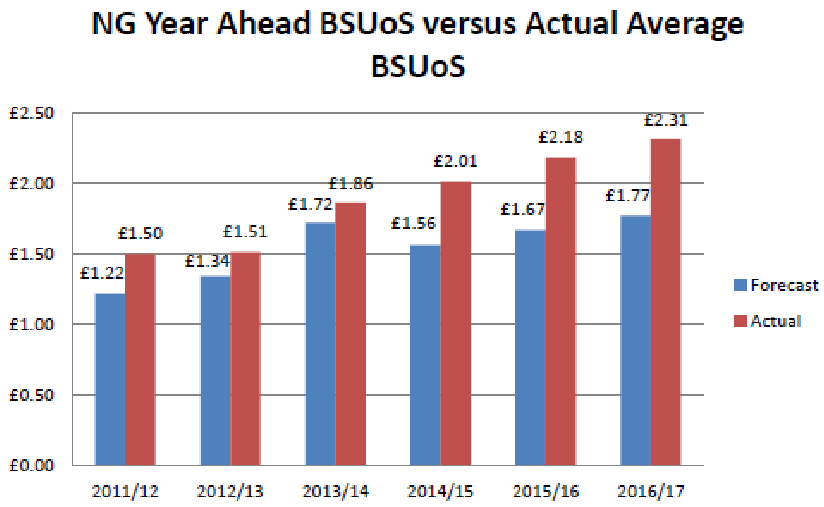
BSUoS volatility



- The average cost of BSUoS can be compared to the average price of different wholesale power products. For example, the average cost of BSUoS in 2015 was £2.24/MWh and the average price of day ahead power in 2015 was £40.43/MWh. As such BSUoS constituted 5.54% of the average day ahead price for 2015.
- BSUoS accounts for varying proportions of the wholesale energy price, in some cases very large proportions.
- The data shows that BSUoS tends to lie in region of between 2%-6% of the power price the majority of the time.
- However, it is not uncommon for BSUoS to represent much higher percentages of the power price for example being greater than 20% of the power price over three and a half percent of the time. This can occur where the power price falls significantly or where BSUoS charges are far greater than the average.
- As renewables increase as a proportion of the generation mix in future such instances can be expected to increase in frequency.

(charts and information from CMP250).
Data: Negative percentages occur where either the power price or BSUoS charge is negative. Infinite percentages occur where the power price equals £0/MWh. Less than 0.5% of settlement periods are affected so the high level conclusions are not impacted.

BSUoS forecastability



(charts and information from CMP250).

- The graph shows that over recent years National Grid has tended to under-forecast the annual average BSUoS price, and if Suppliers are using the National Grid forecast without applying a risk margin, they are potentially exposed.
- It was argued that larger companies are perhaps more able to take their own view of BSUoS prices, whereas smaller participants are more likely to take the National Grid forecast at face value.
- In an attempt to quantify the value of the “appropriate” risk margin that Suppliers should have applied if they had used the National Grid forecast and had perfect hindsight, the value of the Supplier risk premium is approximately £75m per annum.

What can we conclude on BSUoS volatility and forecastability?

- The average BSUoS is increasing. It accounts for varying proportions of the wholesale energy price, in some cases very large proportions.
- We observe an increased volatility in BSUoS prices.
- BSUoS is difficult to forecast and NG has tend to under-forecast in the past. It is expected that BSUoS price will be factored in the price with an additional risk margin.

Analysis

ESO analysis

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Deliverable 1

Deliverable 1: proposed approach

The approach to assess the extent to which elements of balancing services charges currently provide a forward-looking signal that influences the behaviour of system users is as follows:

1. In general, elements of balancing services charges **do not provide forward-looking signal** for the 4 main reasons:
   - Hard to forecast
   - Complexity
   - Increasingly volatile
   - Other market elements take precedence
2. However, some industry parties expressed that elements **might provide some signal**, in the following case:
   - High wind and low demand drives BSUoS cost up
3. In any case, the current BSUoS signal does **not drive market behaviour efficiently**
   - In general, balancing services charges do not drive market behaviour but are included in prices (with risk premium)
   - In the specific case of high wind and low demand, the signal might be counter-productive (affecting parties with high demand).

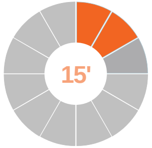
Breakout Session on D2

Mike Oxenham

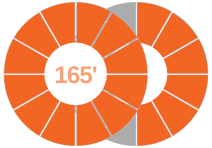
Session Objective

Deliverable 2: assess the **potential** for existing elements of balancing services charges to be charged more cost-reflectively and hence provide better forward-looking signal.

Group discussion on scope of deliverable 2



Break-out session (3 Groups)



- Deliverable 2 Question and Breakout Session Overview

- **Does each existing element of BSUoS have the potential to be charged more cost-reflectively and hence provide better forward-looking signals?**
- **Facilitated Group Debate per MBSS Component with Regular Feedback Loop**

Summary, Actions and Next Steps

Colm Murphy

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Task Force - Future Meeting Dates

Date	Time	Location
Tuesday 26 February	10am – 4pm	The Strand
Tuesday 12 March	10am – 4pm	The Strand
Tuesday 26 March	10am – 4pm	The Strand
Monday 8 April	10am – 4pm	TBD
Wednesday 24 April	10am – 4pm	TBD
Tuesday 7 May	10am – 4pm	TBD
Thursday 23 May	10am – 4pm	TBD

Thank you

If you have further views please contact **ChargingFutures@nationalgrid.com**.