Demand Forecasting

Reporting Period: 19st Jun 2017 – 10th Sep 2017

EXECUTIVE SUMMARY

This report provides an overview of national demand, solar and wind forecast errors during the period between the 19th of June 2017 and the 10th of September 2017, and the work currently underway by National Grid to reduce these errors. The magnitude of these errors is discussed at the different lead times of within day, day ahead, 2-14days ahead, and 2-52 weeks ahead.

INTRODUCTION

Under section 4H of the Transmission Licence, National Grid is obliged to publish a quarterly report describing our demand, wind and solar generation forecasts from within-day to 52 weeks ahead. We are also required to describe the actions that we have taken that have affected forecast errors and an analysis of the causes and future actions to reduce these errors.

This quarterly report contains an overview of the differences between national demand, wind and solar forecasts and their outturns with different lead-in times during the reporting period 19th of June to 10th September 2017[1].

Some key demand outturns of the reporting period are given in the table below

Key Numbers		Date	Half hour
Peak demand	35.4 GW	6th Sep 17	2030
Overnight minimum	16.7 GW	02nd Jul 17	0530
Daytime minimum	20.3 GW	02nd Jul 17	1500
Maximum PV Output	8.3 GW	17th Jul 17	1300

The overnight minimum demand was the second lowest ever observed, and the maximum PV output was the second highest ever observed.

At the end of the period, installed generation capacities for wind and solar generation reached 28.6GW. This is 1.1GW higher than reached at the end of the previous quarter.

[1] *19th June 2017-10th September 2017*

Generation Type	Capacity
Metered Wind	10.9 GW
Embedded Wind	5.3 GW
Embedded Solar	12.4 GW
Total Wind & Solar	28.6 GW

This report mainly focuses on the national electricity demand (national demand/INDO equivalent) forecasts and its' major components:

- Embedded PV generation
- Metered- and embedded wind generation
- Weather forecast input data

Furthermore, work to improve forecasts is highlighted.

Special attention is paid to incentivised forecasts, made one, two and seven days ahead.

DEMAND FORECAST ERRORS

We produce forecasts at multiple time horizons, from within day up to five years ahead. Overall we would typically produce over 100 forecasts for the peak demand on a particular day over the preceding five years. In this report special attention is paid to forecasts made one, two and seven days beforehand. These forecasts are subject to OFGEM's demand forecasting incentive scheme.

Forecasts at greater than 14 days ahead are based on seasonal average weather, while those from within day to 13 days ahead use the latest available weather forecasts. It should be noted that most weather forecast models run from 0 to 6 days ahead, and that the accuracy of weather forecasts declines significantly from 7 to 13 days ahead.

The table below shows the mean absolute error by cardinal points and by forecast lead-time. The forecast range stretches from in-day forecasts to 13 days ahead.

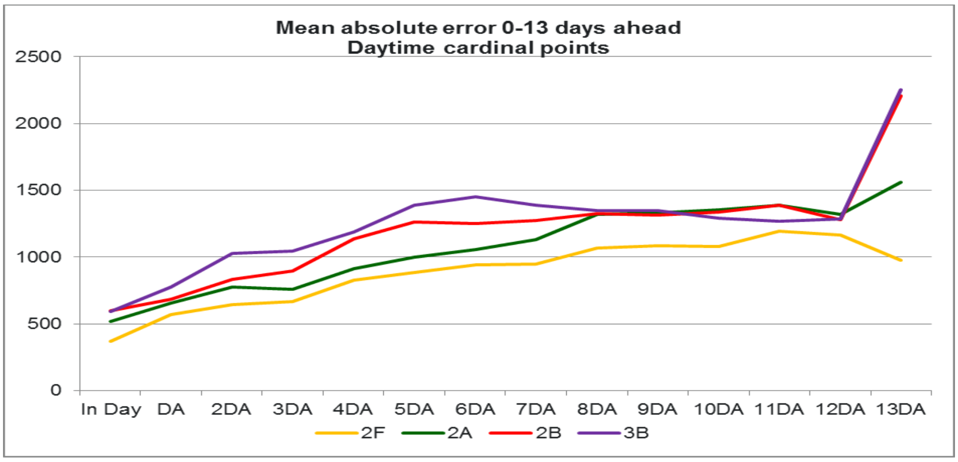
With forecast lead-time increasing (i.e. a forecast projecting further into the future), the errors grow.

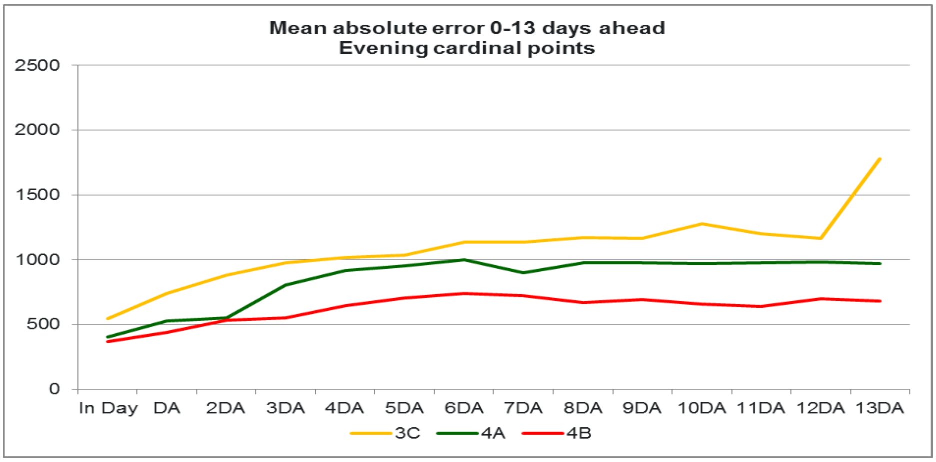
The smallest errors are found the in the night, closest to real time. Daytime errors are larger and increase more with increasing forecast lead time.

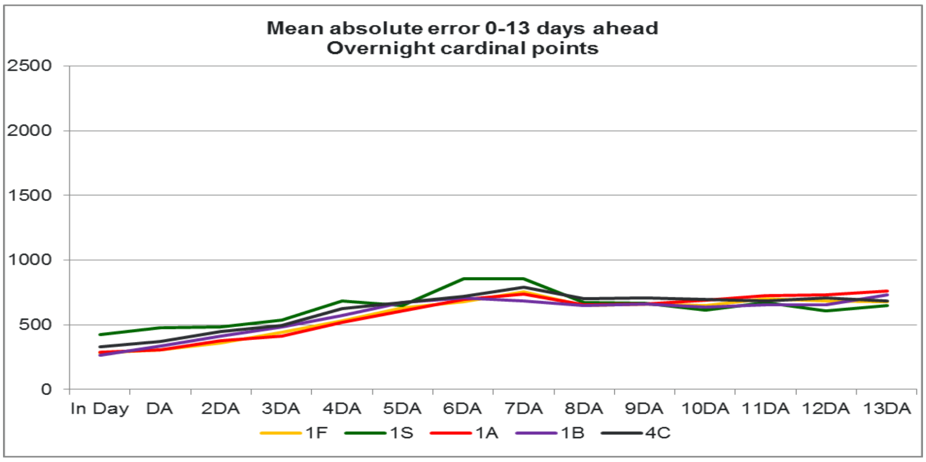
CPID	In Day	DA	2DA	3DA	4DA	5DA	6DA	7DA	8DA	9DA	10DA	11DA	12DA	13DA
1F	281	309	358	441	533	633	679	756	648	658	646	700	684	681
1S	424	477	486	535	686	649	853	857	672	669	614	671	607	650
1A	290	309	378	414	516	608	696	737	657	659	688	726	734	762
1B	263	334	410	486	574	673	705	682	646	658	639	656	652	733
2F	368	568	647	669	826	887	941	949	1066	1084	1081	1194	1165	978
2A	520	657	776	757	916	998	1054	1130	1321	1329	1356	1387	1322	1558
2B	597	685	831	898	1137	1260	1253	1272	1328	1315	1335	1386	1281	2206
3B	591	777	1026	1045	1188	1391	1450	1387	1350	1346	1291	1268	1283	2252
3C	546	741	883	977	1018	1035	1133	1135	1171	1167	1275	1198	1163	1781
4A	402	528	551	806	916	952	997	896	973	977	968	973	984	971
4B	368	439	530	552	644	704	738	720	671	693	654	639	695	681
4C	328	374	446	494	625	672	717	790	699	710	695	684	708	684

The major components of demand forecast and hence demand forecast errors are explained in detail in Appendix 1 – Sources of demand forecast error.

The graphs below show how the mean absolute error in the cardinal point forecasts changes with forecast horizon from 0 to 13 days ahead. The data is broken into forecasts for the daytime, evening and overnight cardinal points. The data shows that the errors increase at greater time horizons, and that daytime errors are significantly higher than those for late evening and overnight when solar generation is not an issue.







INCENTIVISED DEMAND FORECASTS

This section of the report shows a comparison between the previous quarter (Qtr-1[2]) and the current quarter (Qtr-2[3]) for the incentivised demand forecasts, i.e. day ahead, 2 day ahead and 7 day ahead.

Since the beginning of the incentive year, we are improving the accuracy of our forecast and have reduced our mean absolute errors for each forecast horizon. The graph below depicts quarterly MAE for each of the timescales.

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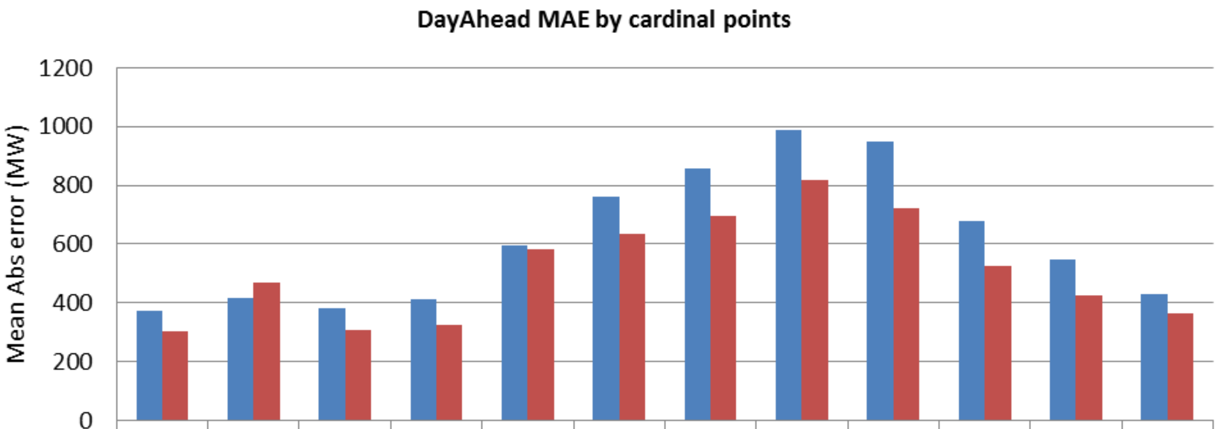
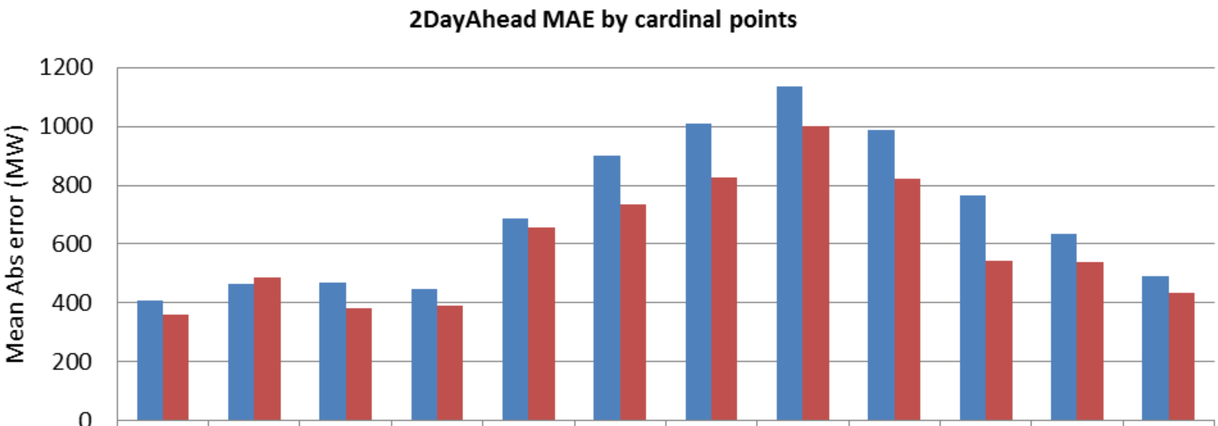
[2] Qtr-1 1st April 2017-30th June 2017

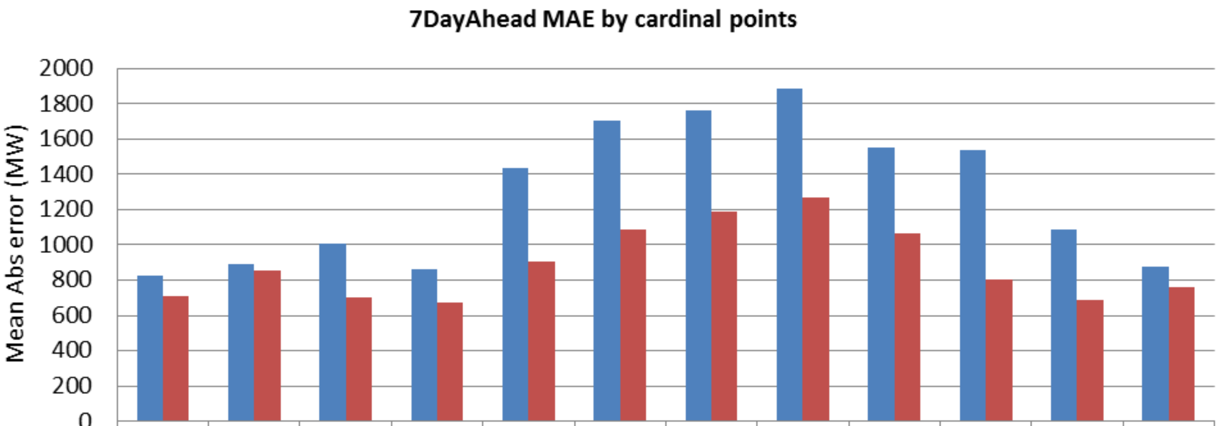
[3] Qtr-2 1st July 2017 –10th Sept 2017



	1F	1S	1A	1B	2F	2A	2B	3B	3C	4A	4B	4C
Qtr-1	372	415	382	411	595	763	855	987	948	679	549	432
Qtr-2	302	468	306	325	580	637	695	818	721	526	427	366

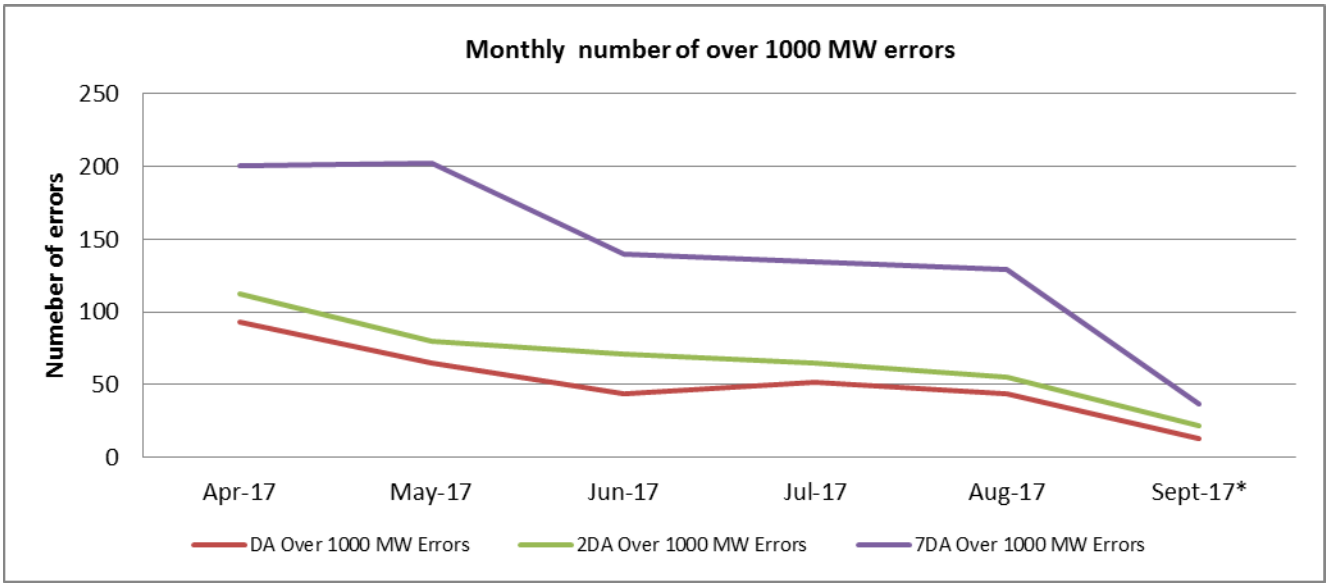


	1F	1S	1A	1B	2F	2A	2B	3B	3C	4A	4B	4C
Qtr-1	407	463	471	446	687	902	1011	1137	988	765	635	490
Qtr-2	358	486	380	391	656	733	828	1001	822	545	539	436



	1F	1S	1A	1B	2F	2A	2B	3B	3C	4A	4B	4C
Qtr-1	826	892	1009	861	1435	1705	1765	1882	1555	1540	1087	876
Qtr-2	712	857	704	675	906	1090	1188	1267	1069	803	691	759

The below graph depicts count of number of errors above 1000MW since 1st April 2017. It should be noted that the data for September[4] only covers 10 days.



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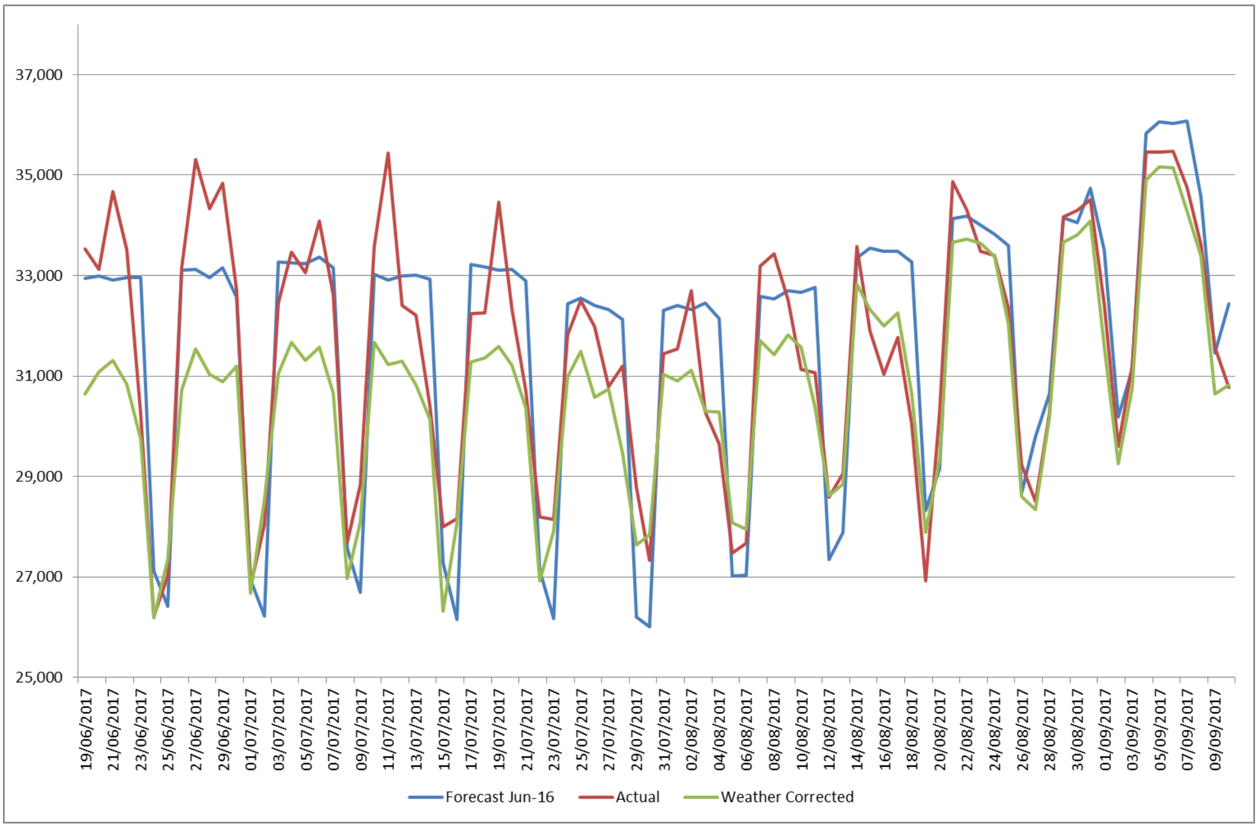
[4] *Sept-17 data is up to end of reporting period 10th Sept 17*

2-52 WEEKS AHEAD DEMAND FORECASTS

The graph below shows our 2-52 weeks ahead peak national demand forecasts published in June 2016 on the BMRS website for the reporting period 19th June – 10th September 17. These forecasts are based on seasonal average weather. The below graph compares our forecasts with both weather corrected demands and actual demands.

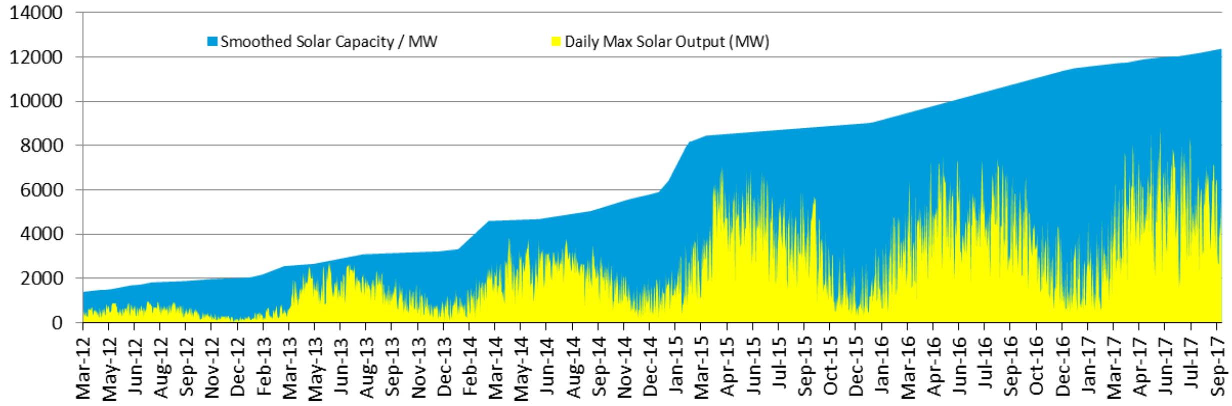


For the reporting period as a whole, the average mean absolute error was 1.1 GW, compared to 1.3 GW during previous quarter.

The maximum error of actual demand was 3.7 GW compared to 5.0 GW during the previous quarter. The maximum error on the weather corrected basis was 3.7 GW compared to 3.3 during previous quarter.

EMBEDDED PV

During the previous quarter, solar generation capacity increased from 12.0GW in June 17 to 12.4GW in Sept 17. The graph below depicts the daily maximum national solar generation output (based on the Sheffield solar PV live data)[5] and the installed solar generation capacity.



DESCRIPTION OF SOLAR GENERATION AND FORECAST ERRORS

Our solar generation forecasts, as published on BMRS and the Data Explorer section of the National Grid website, arise from an internal PV generation forecasting model, based on a number of parameters:-

- Estimated capacities,
- Weather forecasts from our weather provider and
- Empirically derived models connecting radiation and national generation using data from our collaboration with Sheffield Solar.

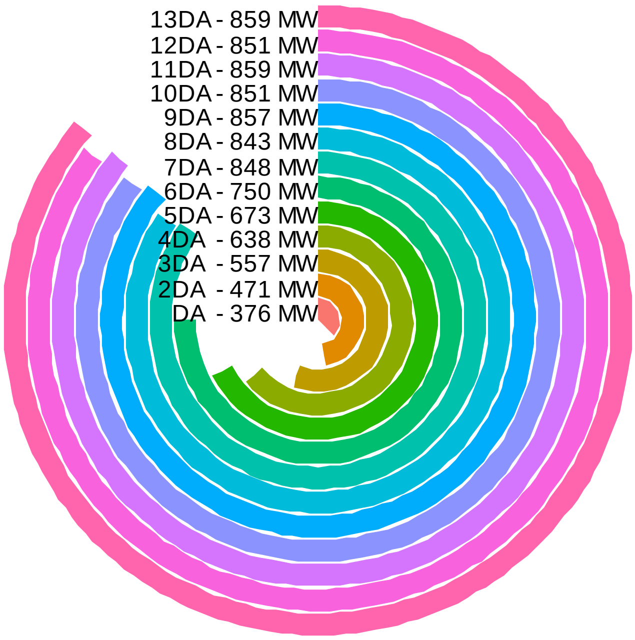
Our weather forecasts extend from the current day out to 14 days ahead, and so our solar generation forecasts have the same time horizon. Beyond this, we use seasonal normal weather.

The figure below gives an illustration of our mean absolute solar generation forecast error for daylight hours, against lead time of the forecast in days ahead (DA). The error is measured against the national generation estimated from our Sheffield Solar NIA project.

Some further details on the trends are given in the analysis section.

[5] *https://www.solar.sheffield.ac.uk/pvlive/*

Mean abs PV Error (MW)



It can be observed that our mean absolute PV error has reduced slightly over almost all forecast time horizons , from Q1 to Q2, although still remains at a sizeable level. Further discussion of this is given below.

ACTIONS AFFECTING SOLAR GENERATION FORECASTS AND ERRORS

During the period 19th June – 10th Sept, a number of actions were been taken to optimise the solar generation forecast:-

- Increased number of weather forecasting stations
  - After some preliminary work earlier in the year, we increased the number of weather forecasting stations that our solar PV forecasting system uses from 28 to 53 on the 28th June.
- Updated PV generation models
  - As part of our regular PV model reviews, we refreshed the PV generation models leading to immediate improvements in mean absolute error.. These improvements generally reduce with time until the next refresh.

Following the improved radiation forecasts that we began receiving on the 5th May, the whole of this Quarter had radiation forecasts based on an improved radiation forecasting methodology. This is one of the prime reasons for our improved PV forecasting during this period..

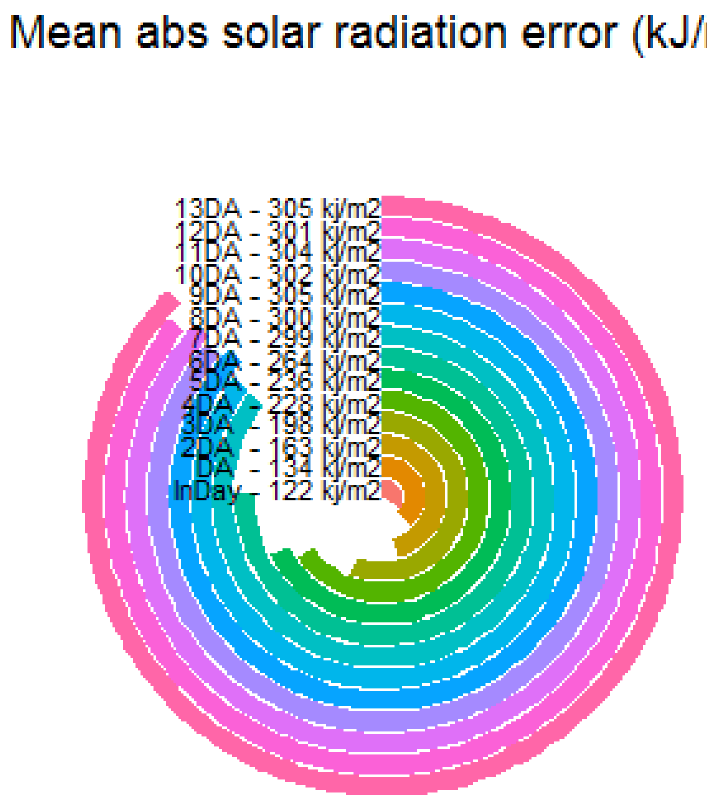
ANALYSIS OF THE CAUSES OF SOLAR GENERATION FORECAST ERRORS & FUTURE ACTIONS

As a number of parameters feed into the forecast of solar generation, errors in each of these contribute to the discrepancy with the actual real generation. However, as error in capacity or outturn can only be estimated theoretically (as there are no standard benchmarks or metering available to National Grid), we take the estimates of capacity and outturn as exact, and break our forecast error down into just two components – *Model Error and Weather Error:-*

Error = *P (weather forecast) – Observed Outturn =*
(P (weather actual) - Observation) + (P (weather forecast) – P (weather actual)) =
Model Error + Weather Error

where P is the function being used to convert weather data into solar generation data.

The radiation forecast is the main weather variable used from our weather forecasts. The figure below illustrates the values of mean absolute radiation forecast error seen during the periods 19th June – 10th Sept. The figure is plotted for daylight hours only (the figure in the June17 report showed the error over all hours of the day) :



We know from sensitivity analysis of our internal models, that an error of 50kJ/m2 in radiation is equivalent to around a 150MW error in our national PV forecast.

Using this scaling to cross compare the values in the above figure to those in the figure of mean absolute PV error, shows that radiation or weather error is again clearly the dominant source of our overall solar PV forecast error. Further discussion on this point can be found in the previous report.

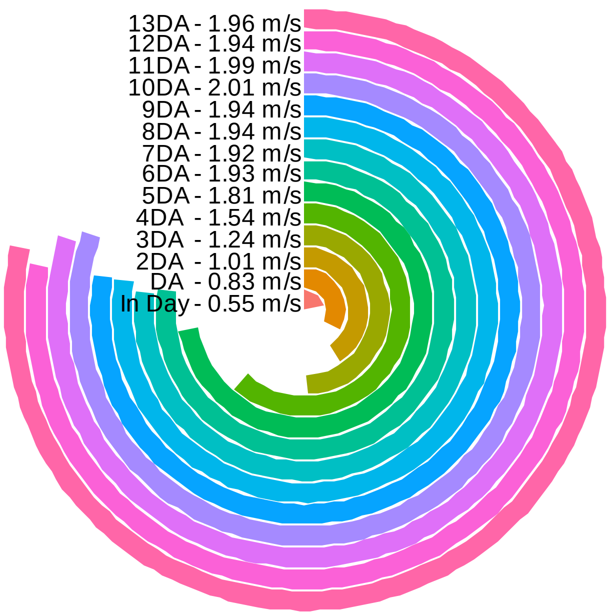
Our NIA project with our weather forecast provider, which aims to improve our radiation forecast accuracy, in this frontline area of meteorology, is ongoing.

During the summer, we embarked on a new NIA project with the Alan Turing Institute. This project looked at potential improvements to our wind and solar PV forecast models. The solar PV work produced an innovative new model relating solar radiation to solar PV power. From our ongoing Reading University NIA project, we also received and coded another model connecting the same quantities. Both of these newly proposed models are being run in parallel testing, and we anticipate implementing improvements to the radiance to power mapping operationally during the next quarter.

WIND FORECASTS

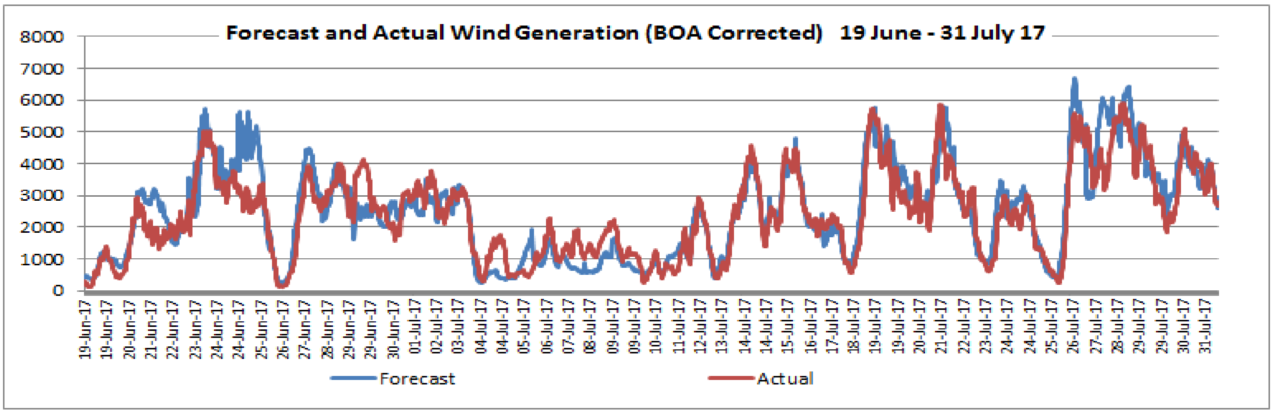
The key input to our forecasts is the wind speed forecast. The graph below shows the mean absolute error in wind speed forecast in m/s at different time horizons. As an indication of the impact of the errors, in the mid part of a wind power curve, between around 5 and 15 m/s, a 1 m/s error in wind speed forecast equates to around a 10% error in wind power forecast for the generator.

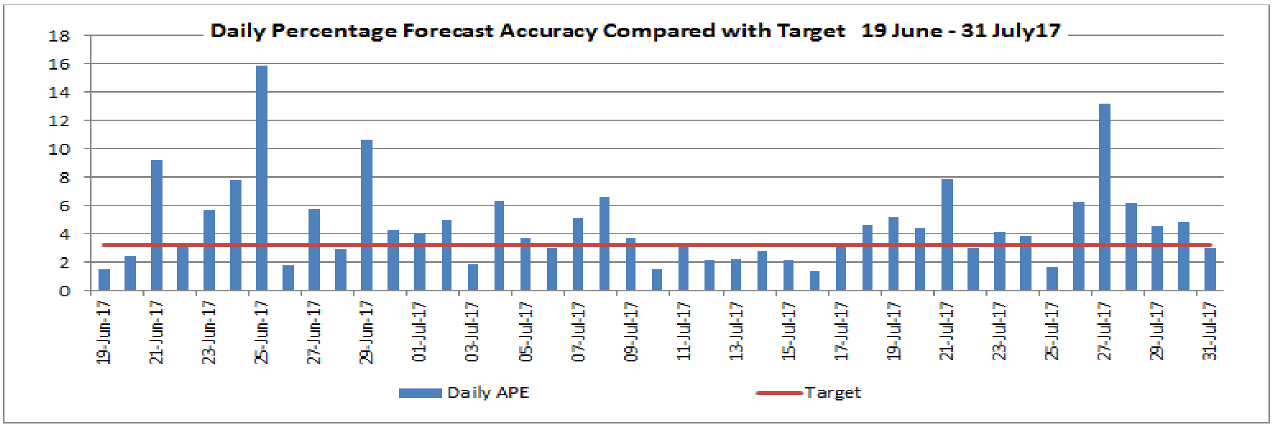
Mean abs wind speed error (m/s)

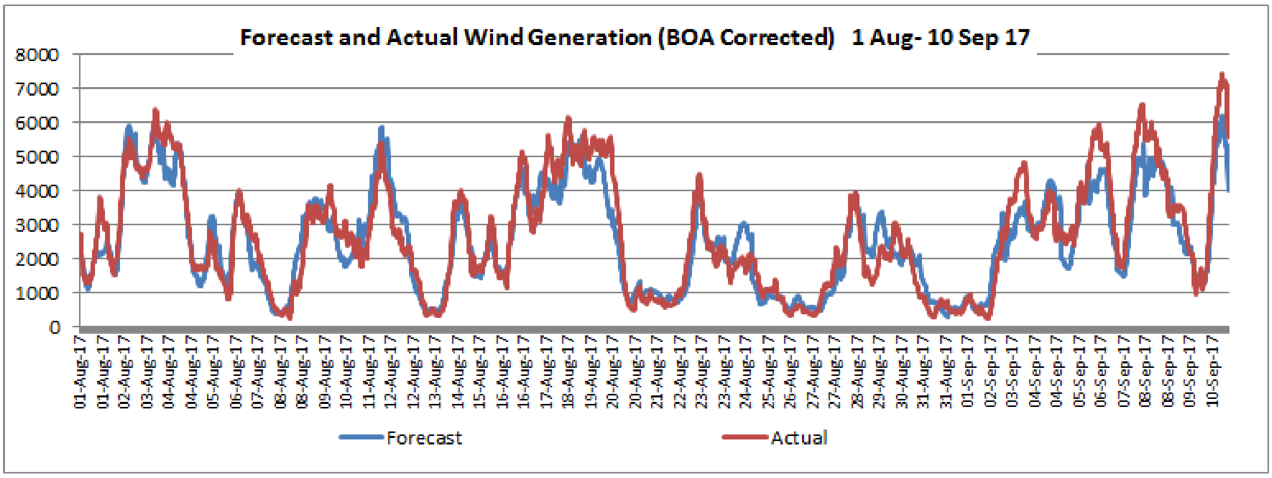


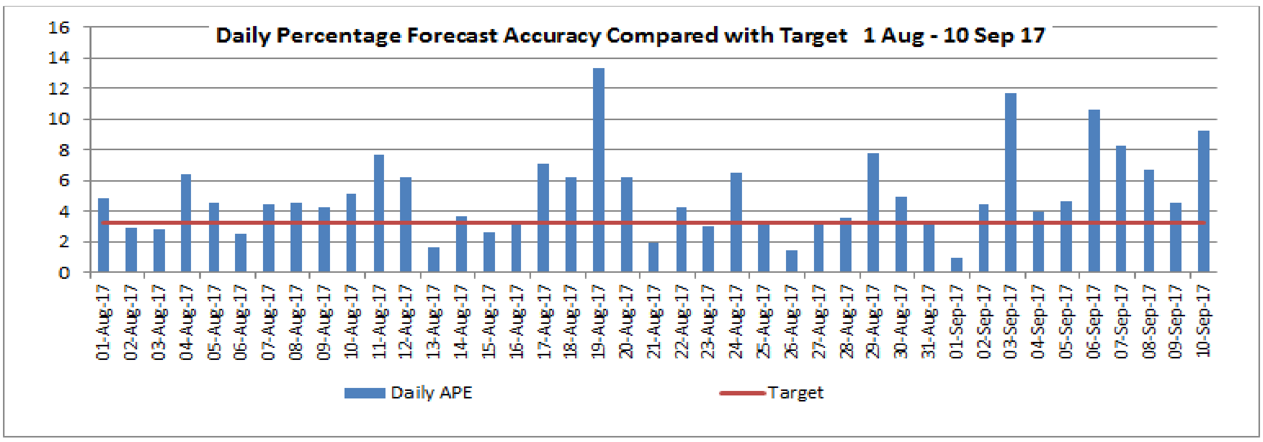
The wind incentive measures our performance in forecasting the wind power that is available, and does not require us to forecast the actual wind output after the control room have taken action (BOA's) on wind farms to manage constraints, or other system issues in real time. We cannot forecast the latter. In order to report our performance, the forecasts for each individual wind farm for each half hour are recorded. For the half hour where a BOA is taken on that farm, the unit is discounted for the calculation of corrected forecast, corrected outturn and corrected installed capacity. The percentage error for the forecast for that half hour is then calculated from the corrected values, and a daily average then calculated which is used in the formulae described in the incentive to calculate the outcome for that day.

In terms of overall performance, the graphs below show the comparison of the corrected forecast and actual wind generation for the period 19th June until 10 September, as well as the daily average percentage error used to calculate the outcome of the incentive.


Forecast and Actual Wind Generation (BOA Corrected) 19 June - 31 July 17
0 1000 2000 3000 4000 5000 6000 7000 8000
Forecast
Actual


Daily Percentage Forecast Accuracy Compared with Target 19 June - 31 July17
0 2 4 6 8 10 12 14 16 18
Daily APE
Target


Forecast and Actual Wind Generation (BOA Corrected) 1 Aug- 10 Sep 17
0 1000 2000 3000 4000 5000 6000 7000 8000
Forecast
Actual


Daily Percentage Forecast Accuracy Compared with Target 1 Aug - 10 Sep 17
0 2 4 6 8 10 12 14 16
Daily APE
Target

The other component of the incentive is the bias incentive. In this component, for the objective is to have as many wind power over-forecasts as under-forecasts, with a break-even target of 60:40 and a floor of 70:30.

There is also a separate term in the incentive that says if any two individual forecast times are 70% biased then we hit the floor. For the wind incentive, this means if any two out of 48 half hourly forecasts are 70% biased then we hit the floor. This equates to 9 out of 31 forecasts in a month being one side of zero and 22 being the other side.

In June the forecasts overall were 57.08% biased and so we hit the flo or as more than one individual forecast time exceeded the 70% biased . In July, the overall bias was 46.98%. In August, the overall bias was 50.67%. In July and August, only one individual forecast time exceeded the 70% bias.

WIND GENERATION MODELLING

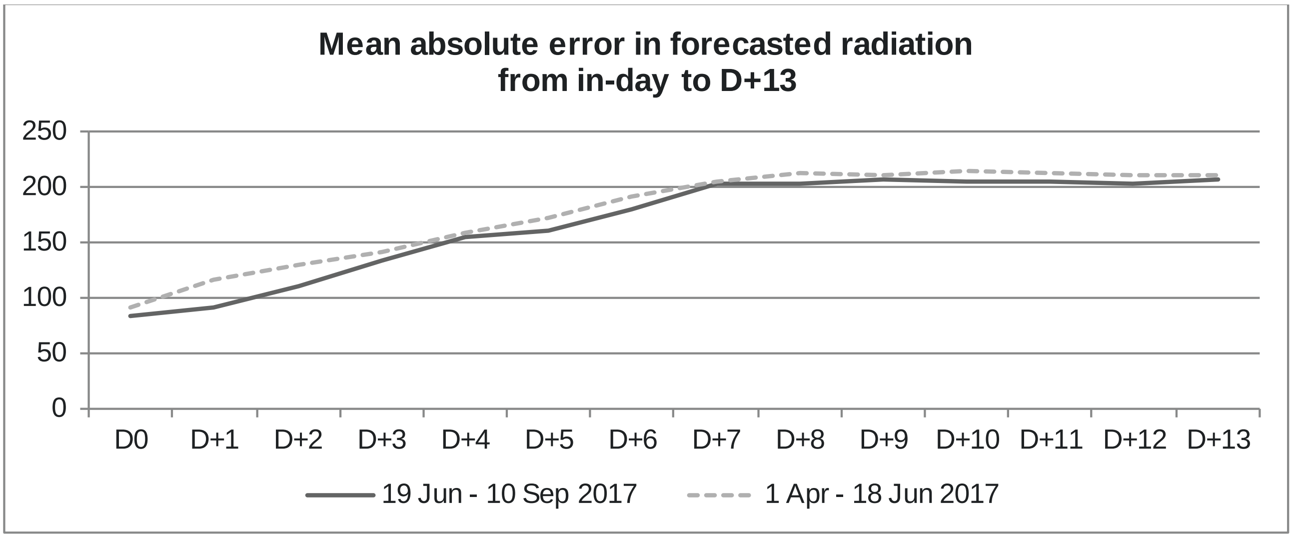
Efforts to review and improve models for larger wind farms are continuing. We have also been working with the Turing Institute to prototype the interpolation of wind speed forecasts to un-forecast locations and prototype more advanced wind power forecast models.

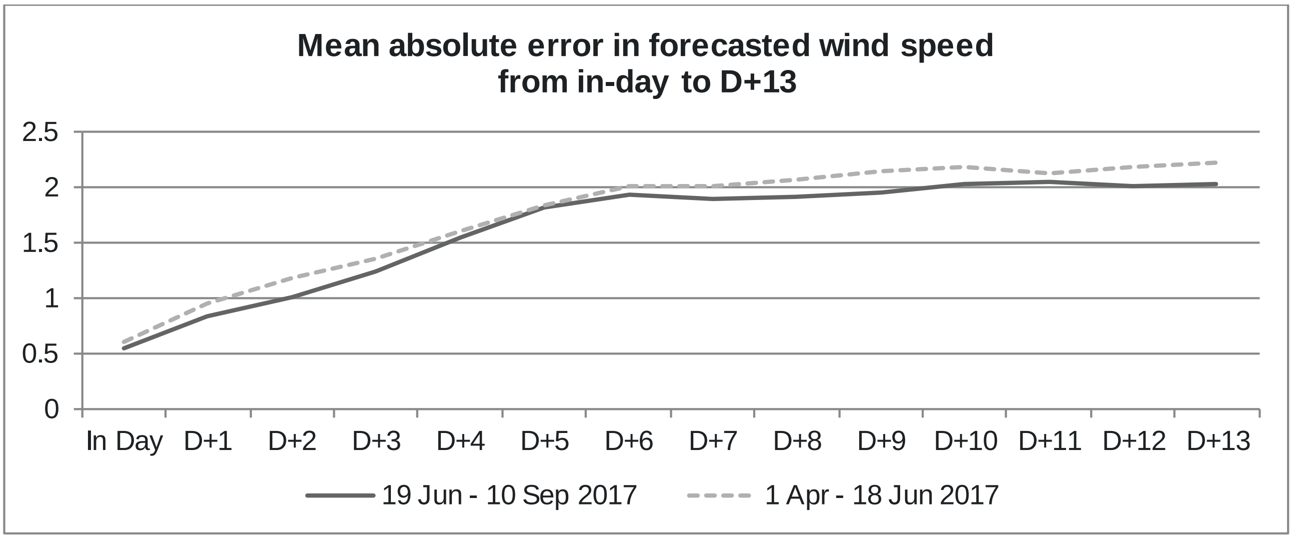
WEATHER ANALYSIS

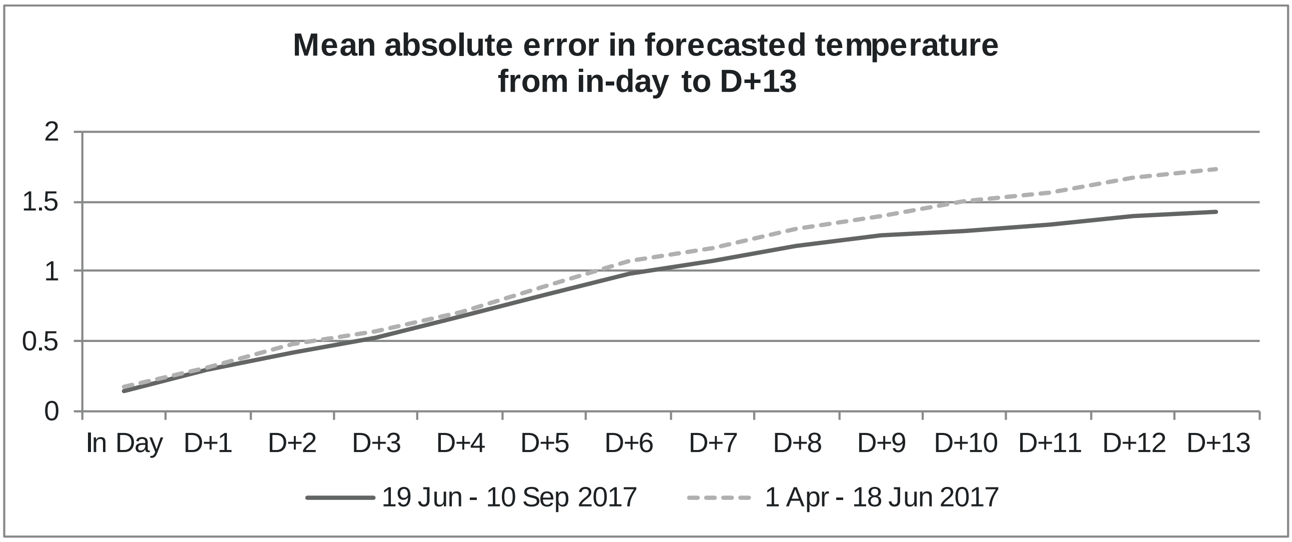
The graphs below show the mean absolute errors in the forecasts that we receive for our key weather parameters over the 0 to 13 day ahead forecast horizons.

- Temperature is measured in °C, with 1°C equating to a demand forecast error of the order of 500 MW.
- Solar radiation is measured in kJ/m^2, with 50 kJ/m^2 approximating to an error of 150 MW in our PV forecasts
- Wind speed is measured in m/s, with 1 m/s in the range 5 – 15 m/s corresponding to an error in generation forecast for the wind farm of around 10% of capacity

Each graph shows the mean absolute weather forecast error for this quarter, as well as a comparison to the same error for the previous quarter.







For further wind and solar radiation error data, please also refer to the PV forecasting and wind forecasting sections of this report.

With increasing forecast lead-time, weather forecast errors become larger. Beyond a forecasting horizon of around 6-7days, it can be seen that the maximum error values are maintained for radiation and windspeed forecasts, and there had been limited forecasting skill. This observation is typical for all weather forecasting providers. The forecast on average no longer benefits from the current knowledge of the state of the atmosphere. Given that these two parameters are the main drivers of our renewable generation forecasts, this presents a limiting factor to the accuracy of our long term renewable generation forecasts, and also places limits on our 7day-ahead demand forecasts. This is then especially challenging as capacity increases.

The effect of weather errors are of course not in general independent, although for renewable generation where one variable is usually the driving factor, this proves correct in practise.

For demand forecast errors, there is in general more coupling (eg one weather error can cancel or magnify the effect of another). Discussion and illustration of this point was described in the report for the previous quarter.

Immediately before this quarter, we arranged with our weather provider to receive two of our weather forecasts earlier in the day. The consequence of this was that we were able to take advantage of a weather forecast with more up to date data for our D+2 demand forecast. This will have fed through into improved accuracy for this particular demand incentive.

WORK TO IMPROVE FORECASTS

An authoritative discussion of the work which we are undertaking to improve our forecasting accuracy was been given in the last quarterly report.

In summary, this listed 5 projects with external projects, funded by the NIA scheme , as well as internal development work. The projects with external partners have been focussed on the key factors which drive our solar power and wind power forecasting errors.

Progress in these areas has been mentioned within earlier sections, but fo r completion, highlights of these include:-

- Increased number of weather forecasting locations for solar power forecasts
- Updated PV generation models

Some anticipated future outputs within the next quarter include:-

- Potential implementation of a new solar power model as provided by the Reading University NIA
- Potential implementation of a new solar power model as provided by the Turing Institute
- Potential implementation of a new wind power model as provided by Turing Institute, and an interpolation algorithm to provide wind forecasts at un-forecast locations.
- Noise reduction and smoothing of our radiation forecasts.
- Potential implementation of new embedded, non weather-dependentgeneration forecast models. These cover for example biomass and landfill gas-driven power generation, as well as 5 other sources, equating to around ¾ of the capacity of metered embedded generation.
- Refreshing our wind generation forecast models. We are also engaged in a number of internal projects, including a strategic review of the Energy Forecasting system as well in talks with potential future research partners.

CONCLUSIONS

A detailed analysis is presented, describing the errors and sources of errors in National Grid's demand, solar and wind generation forecasts for the period 19th June 2017 to 10th September 2017. In addition, the work that is being done to improve these forecasts is described.

Some highlights during this reporting period were that we experienced the second lowest ever overnight demand, as well as the second highest ever PV generation.

For almost all cardinal points, our demand forecast errors reduced compared to the previous quarter, as per historic trends during the late summer period. For our wind generation forecast, we remained within the unbiased bounds in July & August.

Work continues on our internal projects and with our NIA-funded collaborations to improve our forecasting accuracies further.

APPENDIX 1 – SOURCES OF DEMAND FORECAST ERROR

Forecast error is made up of many independent, but interacting components. On some days small errors due to several different components can result in a large overall error, while on other days two very large errors can cancel out leaving a net very accurate forecast.

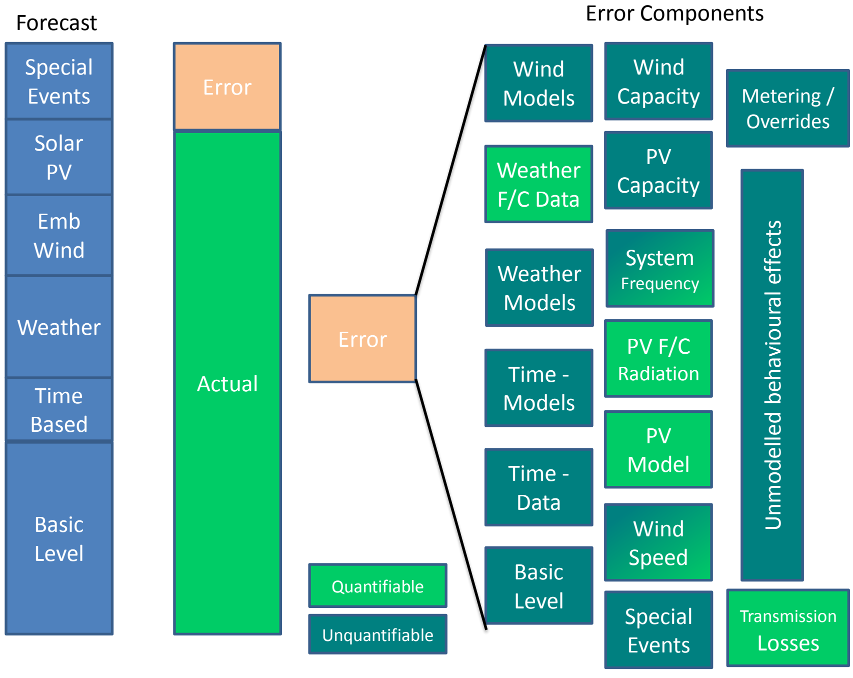
The components of error are:

- Error in basic underlying demand level – cannot be directly quantified on a day to day basis
- Error in time data – some components such as day of week do not have any errors while other components such as the number of schools on holiday each week will have an error that cannot be quantified
- Error in time models – eg our representation of how day of week affects demand, or how the number of schools on holiday affects demand cannot be separately quantified
- Error in weather forecast data – difference between forecast and actual observed weather at weather stations can be measured, and our weather models can be used to estimate the impact of these errors on our demand forecasts
- Error in weather models – the error in how well we model the effects of weather on demand cannot be independently measured and so cannot be quantified
- Error in wind and PV capacity – our embedded wind and solar models assume a capacity of generation, and its geographical location. National Grid has limited data on such installations; some are notified to us while data on others has to be gathered from publically available data sources. This data will not be exhaustive and so is a significant source of error, particularly in areas of rapid growth. For PV installations there can be some months delay between installations going live and data being available to indicate the existence of the installation. As such installations are built without public subsidy, registered capacity data will be increasingly difficult to obtain. The error in capacities is significant and cannot be quantified.
- Error in solar radiation forecasts – the solar radiation forecasts are a key input to our forecasts for PV generation, and can be a significant source of errors. One source of error is in the solar radiation forecast we receive for a specific weather station location. The error can be quantified by comparing forecast and measured solar radiation at the location. The second error is in how representative the weather station is of the surrounding area. It is possible for a cloud to be correctly forecast over the weather station, but for the majority of the surrounding area to be in sunshine. We currently receive solar radiation forecasts for 53 locations round the country, where a 100 cm^2 radiation sensor at each weather site is assumed to be representative of an average area of 8840 km^2. The error this introduces cannot be quantified.
- Error in PV models – we use models to convert forecast solar radiation into forecast PV generation in MW. There will be an error due to the accuracy of these models. This error can be estimated using the output of a Network Innovation Allowance funded project run by National Grid in collaboration with the Sheffield Solar team of Sheffield University. This team take around 1200 real time data feeds from domestic PV installations and use complex algorithms to extrapolate the output to an estimate for the total national output from all 900,000 or so PV installations in the UK. There is an estimated 5-10% error in the value of PV generation. We can compare the estimated national PV generation with the

value that our models would have forecast given the outturn solar radiation and so estimate the error associated with the PV models.

- Error in wind speed forecasts – we currently receive wind speed forecasts for around 100 locations in the country. Some of these are weather station locations where an outturn measurement is available, allowing us to quantify the error at these locations, but other forecasts are for sites near large wind farms where outturn data may not be available. We can however estimate the error from those points that we can measure.
- Error in embedded wind generation models – we use models to convert the nearest available wind speed forecast into a generation forecast for embedded wind farms that we are aware of. As we do not have any metering from these embedded wind farms we cannot measure this error, although we can estimate it is likely to be broadly similar to the errors in our national metered wind generation forecast.
- Error due to system frequency deviation from 50 Hz – our models assume the system is operating at 50 Hz. In reality is it possible for the average frequency over a half hour settlement period to vary from 50 Hz, typically by up to 0.1 Hz once a week. This introduces a change in demand from that forecast for 50 Hz. The change is in the range 70 – 140 MW for a 0.1 Hz deviation, and can be estimated based on frequency measurements.
- Error due to transmission losses – our demand forecasts are for National Demand, which includes transmission losses. We assume typical losses in our forecasts, however it is possible for operational issues on the day to require an abnormal system configuration which could result in higher than normal losses. It is possible for a difference of over 500 MW in transmission losses in consecutive days for the same settlement period. This error can be quantified from Settlement Metering values for generation and demand that are available via Elexon from at Day + 5.

The separate components of the demand forecast, and associated error, are represented visually in the illustration below.



APPENDIX 2 – BREAKDOWN OF LARGE INDIVIDUAL ERRORS

Day Ahead largest forecasting errors

Date	CP	Forecast	Actual	Error	Forecaster Note
27th Aug 17	2B	26100	23004	3096	**August Bank Holiday Weekend**. Temperature forecast error 0.3 ºC Radiation forecast error 347 kJ m^{-2} Wind forecast error -1 m/s
26th Jul 17	3B	32070	28991	3079	Temperature forecast error 0.6 ºC **Radiation forecast error 723 kJ m^{-2}** Wind forecast error 3 m/s
19th Jul 17	3B	29180	32139	-2959	This day was during a hard-to-forecast **thundery breakdown of a spell of warm weather**. In the night and evening there were thunderstorms, but during the day the storms were absent. Temperature forecast error -0.5 ºC Radiation forecast error -383 kJ m^{-2}
8th Jul 17	2B	28290	25485	2805	Temperature forecast error -0.2 ºC **Radiation forecast error 694 kJ m^{-2}** Wind forecast error -1 m/s
8th Jul 17	3B	25140	22620	2520	Temperature forecast error 0.6 ºC **Radiation forecast error 1051 kJ m^{-2}**

2Days Ahead largest forecasting errors

Date	CP	Forecast	Actual	Error	Forecaster Note
2nd Jul 17	2A	24830	21718	3112	Temperature forecast error -0.3 ºC **Radiation forecast error 1031 kJ m^{-2}** Wind forecast error 1 m/s
19th Jul 17	2B	30400	33450	-3050	This day was during a hard-to-forecast **thundery breakdown of a spell of warm weather**. In the night and evening there were thunderstorms, but during the day the storms were absent. Temperature forecast error -0.3 ºC **Radiation forecast error 633 kJ m^{-2}** Wind forecast error 1 m/s
26th Jul 17	3B	31890	28991	2899	Temperature forecast error 0.4 ºC **Radiation forecast error 650 kJ m^{-2}** **Wind forecast error 3 m/s**
29th Jul 17	3B	21010	24177	-3167	During this day, a band of rain and clouds was forecast to pass just south of the English south coast. In the end, this band reached a more northerly extent, affecting the entire south of England. Temperature forecast error -0.4 ºC Radiation forecast error 453 kJ m^{-2} Wind forecast error -1 m/s
27th Aug 17	2B	26330	23004	3326	**August Bank Holiday Weekend.** Temperature forecast error -0.1 ºC Radiation forecast error kJ m^{-2} Wind forecast error -1 m/s

7Days Ahead largest forecasting errors

Date	CP	Forecast	Actual	Error	Forecaster Note
11th Jul 17	3B	29830	33728	-3898	**Temperature forecast error 5.3 °C** Radiation forecast error -108 kJ m^{-2}
19th Jun 17	4A	28550	32339	-3789	**Temperature forecast error 5.9 °C** Radiation forecast error -103 kJ m^{-2} Wind forecast error -2 m/s
21th Jul 17	4A	29520	33169	-3649	Temperature forecast error -0.8 °C **Radiation forecast error 1210 kJ m^{-2}**
2nd Aug 17	2A	25260	21718	3542	Temperature forecast error -1.0 °C **Radiation forecast error 1262 kJ m^{-2}** Wind forecast error -2 m/s
2nd Aug 17	2B	25550	22086	3464	Temperature forecast error -0.4 °C **Radiation forecast error -706 kJ m^{-2}** **Wind forecast error -2 m/s**