Network Monitoring and Visibility

Summary

This article reviews the shortfalls in legacy monitoring and what will be needed to manage the changing nature of the distribution network. This includes a particular focus on ensuring a successful transition to a DSO.

DSOF June 2018

Note: a glossary and diagram key can be found in the DSOF introduction document on our website

Background

The ability to effectively run a smart and flexible network requires a higher level of real-time network visibility and control, with sufficient monitoring and communication to determine:

- Real and reactive power flows at strategic locations on the network;
- The direction of power flows for both real and reactive power;
- Voltage magnitude and phase angle;
- Switchgear status, operations and failures;
- Transformer tap positions;
- Protection operations; and
- Power quality.

In the past the operational network conditions were determined from limited remote monitoring and onsite interrogation. The existing level of network monitoring and control has progressed significantly. The monitoring equipment installed at a given substation depends on a number of factors such as geographic location and network topology, but is most dependent on the nominal voltage, with the lower voltages having significantly less monitoring.

At a Grid Supply Point (GSP), Bulk Supply Point (BSP) or Primary substation most of the required telemetry and control is already installed, but going down to a distribution substation this is considerably reduced. Historically, low levels of monitoring have been installed at distribution substations, as the benefits were limited when compared with the associated costs to customers.

The transition to a Distribution System Operator (DSO) will require an increased visibility of energy flows at all voltage levels; to achieve this, recording frequency will need to be increased through the addition of extra monitoring points. New and existing metering at strategic locations will need to provide directional MW and MVAr measurements where it does not already. There may also be the need to have network trends stored at a higher sample rate than half hourly averaged, due to intermittent generation and demand technologies connecting to the network causing fluctuations within a half hour.

This transition is fundamentally based on intelligent monitoring and integration of devices within a Distribution Network Management System (DNMS). The main drivers for increased monitoring and control are:

- The increase of Low Carbon Technologies (LCTs) connecting to the distribution network causing uncertainty in network flows. In particular, bi-directional power flows and power factor variations;
- Rolling out smart grid network solutions and smart grid alternative connection solutions;
- A better understanding of pre-fault and post-fault network conditions; and
- Improved accuracy on network losses.

Network Impact

The ability of network monitoring and communication to meet the future requirements as a DSO is crucial for the continued development of the network.

An increasingly complex distribution network will need higher levels of monitoring beyond the current substation boundaries. Data will need to be collected at key network locations and at a higher frequency and granularity, both in relations to real-time system operations and longer term network planning. The ability to control the network, take actions and react to wider system events through the use of enhanced monitoring solutions will aid our ability to detect issues directly impacting network performance and ensure we maintain a safe and reliable network.

Real-time analysis will need sufficient visibility of the network to determine network conditions, so these systems can take actions in the required timeframes. This will need communication links with time delays that are within the limits of the systems.

Without additional monitoring and control, implementation of smart grid solutions will be limited. Without actual measurements to show how the network is functioning, it must be designed in a passive way and operated using conservative assumptions. This leads to a network that operates inefficiently, leading to potentially unnecessary costs from reinforcements or constraints.

Detailed Assessment

Existing Monitoring

With increasing levels of LCTs connecting to WPD's network, it is vital that the magnitude and direction of power-flow is measured accurately and displayed in a consistent manner. There are three different types of Power that are applicable to A.C. systems, Apparent Power, Active Power and Reactive Power.

> *Apparent Power = Voltage x Current and has units of Volt-Amperes (e.g. VA, kVA or MVA).*
>
> *Active Power = Voltage x Current x COS Ɵ, where Ɵ is the angle between the Voltage and Current waveforms. Active Power is expressed in Watts (e.g. W, kW or MW).*
>
> *Reactive Power = Voltage x Current x SIN Ɵ, where Ɵ is the angle between the Voltage and Current waveforms. Reactive Power is expressed in VARs (e.g. VAr, kVAr or MVAr)*

Voltage, Current and Apparent Power by themselves are non-directional quantities and are not assigned a direction. The direction of active and reactive power-flow depends on the relationship between the voltage and current waveform. There are three ways power is determined on the network, with each method giving varying detail on power-flow.

Table 1: Summary of methods to determine power

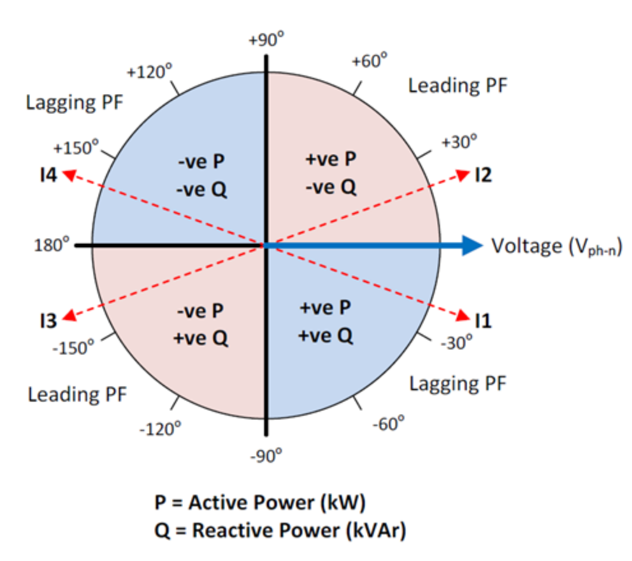
Method	Inputs	Precise MVA value	Direction available	Real (MW) Component	Reactive (MVAr) Component
Amps and Dummy Volts	Amp reading, Voltage assumed from nominal voltage	No – due to assumed nominal voltage	No	No	No
Volts and Amps	Amp reading, Volts reading	Yes	No	No	No
Derived MW and MVAr	Amps and Volts connected to a transducer capable of determining direction	Yes	Yes	Yes	Yes

Amps with dummy Volts – This is where no voltage measurement is available, so an assumption of nominal voltage (1 p.u.) is used. This will give an approximate MVA magnitude, but no directional real or reactive component.

Volts and Amps – This is using measured Volts and Amps to determine power-flow. This will give a true MVA magnitude, but no directional real or reactive component.

MW and MVAr – To get MW and MVAr data requires a volt and amp input into a transducer that can determine the phase angle between the volt and current waveforms, as this determines the direction and magnitude of the real and reactive components.

Figure 1 is a four quadrant diagram showing how the direction and magnitude of real and reactive power can be determined from the phase difference between the Voltage and Current waveforms. To determine this requires a Volts and Amps input into a transducer/device capable of determining the phase angle between the waveforms.



I1 lags the voltage by approximately 20° and, in this case, the Active Power and Reactive Power are both positive.

I2 leads the voltage by approximately 20° and in this case the Active Power is positive and the Reactive Power is negative.

I3 lags the voltage by approximately 160° and so in this case the Active Power is negative and the Reactive Power is positive.

I4 leads the voltage by approximately 160° and so in this case both the Active Power and the Reactive Power are negative.

Figure 1: Four quadrant diagram - direction of power-flow

All of these methods of determining power are utilised to some extent on the network. Amps and dummy Volts are only used where no voltage is available, as it introduces an error where the voltage is not operating at nominal voltage (1 p.u.). Operating above nominal voltage is common at most substation busbars, to account for voltage drop at the extremities of the network.

GSP transformers and feeders normally have directional MW and MVAr data available. Monitoring at a BSP transformer is increasingly directional MW and MVAr metering. All new BSP substations are having it installed as standard and WPD have an active project retrofitting existing BSPs where possible.

Before the unprecedented connection of distributed generation, monitoring of BSP feeders and primary substations was generally via Amps and Volts metering. The direction could be assumed as unidirectional (normally demand) with a constant lagging power factor. This meant there was limited benefit investing in equipment that could determine real and reactive power-flow directions.

Case Study – Directional Monitoring

The connection of LCTs is changing the level of monitoring that is required on the network. An increase in reverse power-flow and varying power factors are being seen more and more across the network.

This example highlights why monitoring just Volts and Amps is not always sufficient to design and operate an increasingly complex and unpredictable network. The network chosen for this study is a 132/33kV transformer at a BSP.

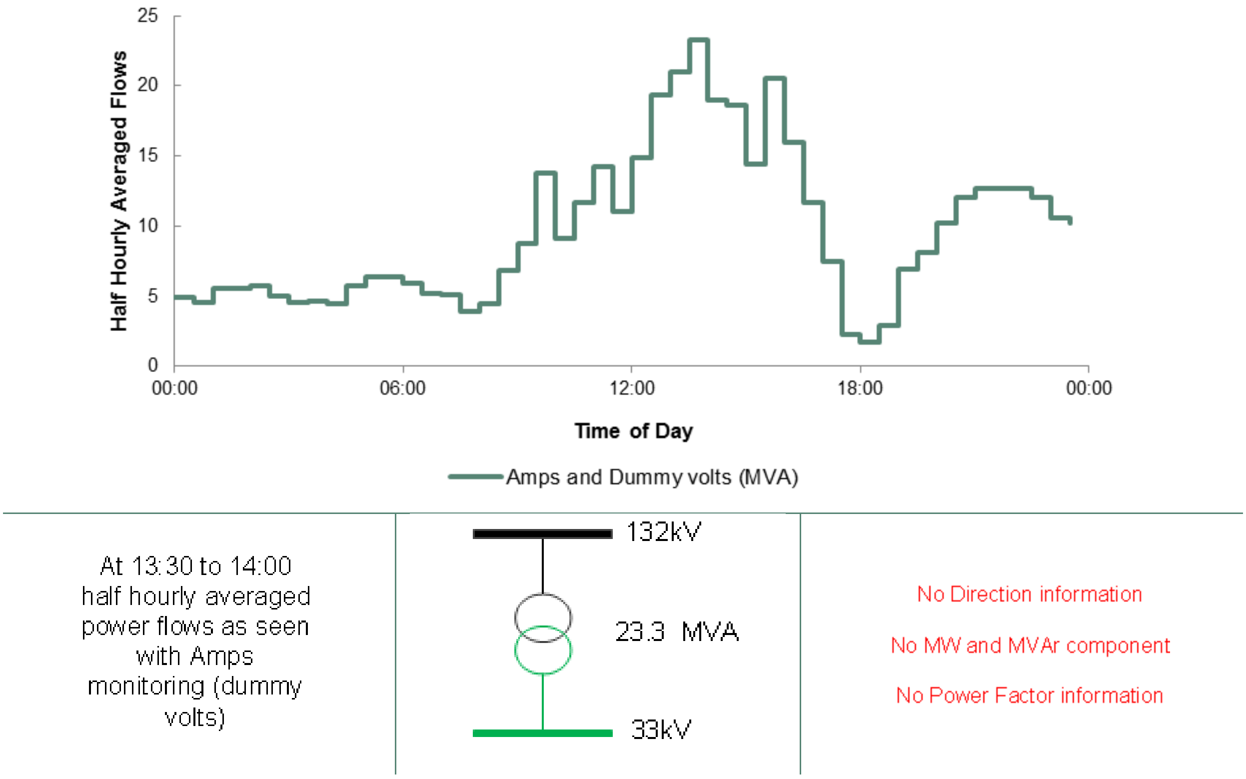
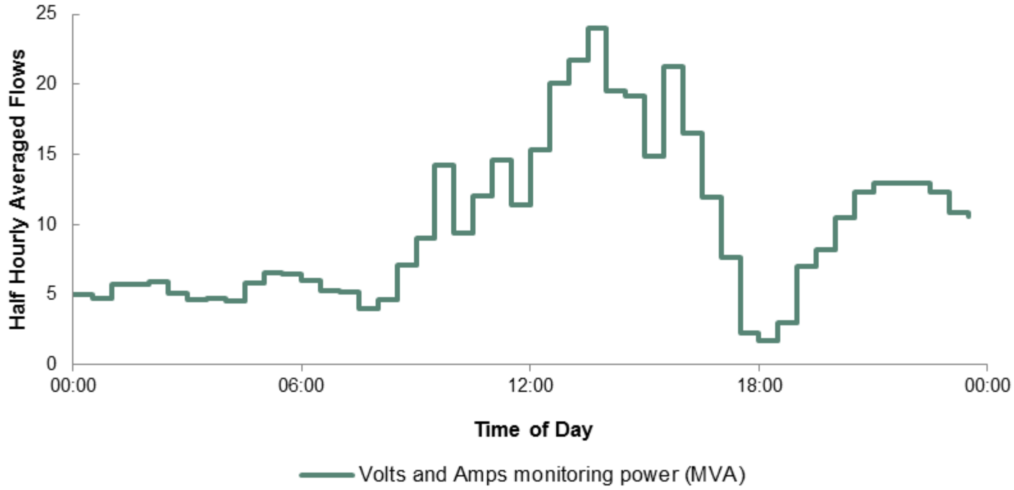


Figure 2: Power-flow at BSP represented with Amps and dummy Volts metering



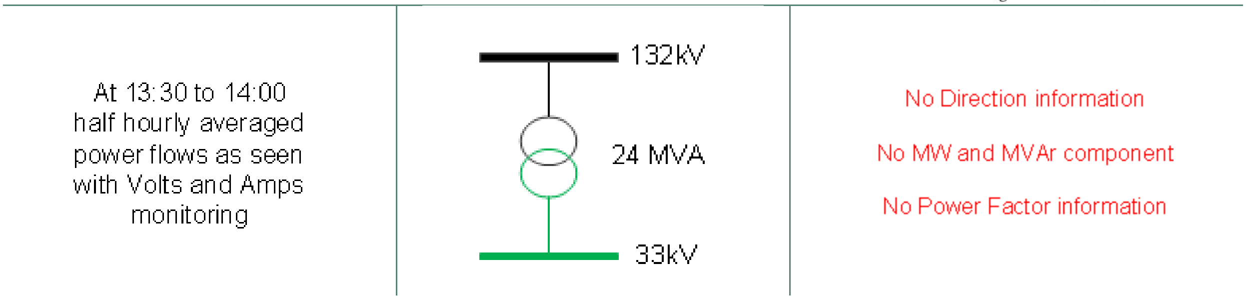
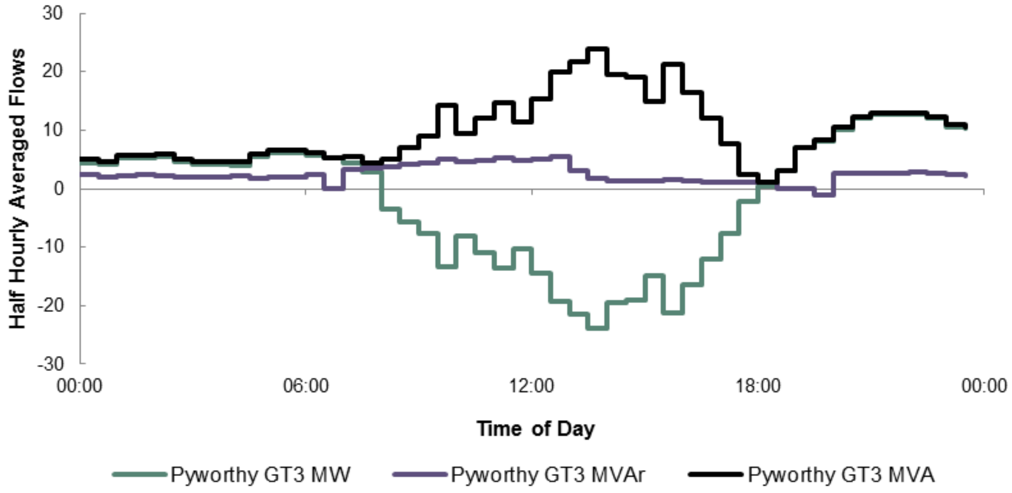


Figure 3: Power-flow at BSP represented with Amps and Volts metering

Both Figure 2 and Figure 3 are showing MVA values; looking at this data suggests it is a daytime peaking load, as there is no way of determining the real and reactive magnitudes and direction. The difference in the peak MVA value of 23.3MVA (Amps only monitoring) compared with 24MVA (Volts and Amps) can be attributed to the voltage at the 33kV operating above nominal voltage.



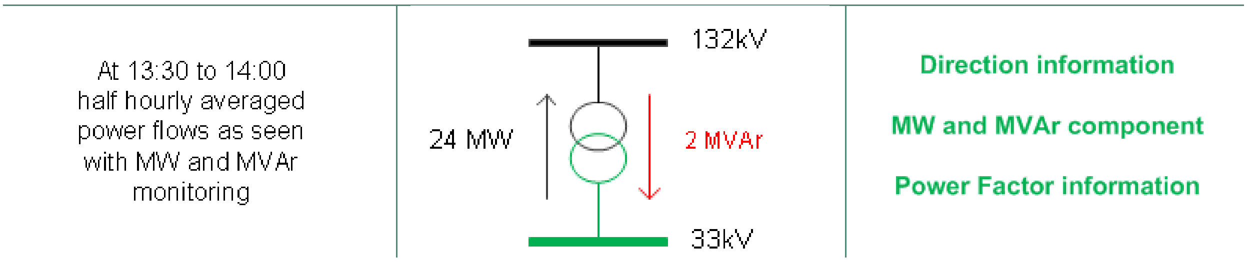


Figure 4: Power-flow at BSP represented with full 4-quandrant MW and MVAr metering

Figure 4 shows the same transformer on the same day, but with full directional MW and MVAr metering. This shows a very different picture of the actual flows on the transformer. What is actually happening is reverse real power-flow, predominately caused by PV generation. The power factor is lagging, with 2MVAr flowing into the 33kV network. This information is completely masked with non-directional MVA values.

Required Monitoring

The site chosen for this study has directional MW and MVAr metering installed, as it was necessary to generate these graphs. What it does highlight is the need for this detail of monitoring at more locations on the network. Full MW and MVAr data will be essential to enable the real and reactive components, with direction to be determined. With the increase in intermittent generation and the connection of disruptive technologies like batteries the need to understand the real and reactive flows on the network is becoming increasingly important.

Impact on Operability

Correct MW and MVAr data with the correct direction are required in real-time to effectively operate the network. This information is also used to accurately represent the network within a power system model. Without this information, assumptions have to be made regarding power-flow direction and power factor. This information is necessary for:

- Making informed decisions about switching and network operation;
- Ratings of transformers, as they are dependent on power-flow direction;
- Running real-time analysis like Active Network Management (ANM) will necessitate this level of detail to ensure the control systems can represent the network accurately; and
- Enabling the network to be correctly represented in power system software as this is used to determine reinforcement requirements and network constraints.

It is likely that real-time analysis, like that currently used for ANM, will be used to a greater degree in the future as flexibility services are used to manage short duration, seasonal constraints where this provides better value-for-money than traditional reinforcement. Accurate modelling of the network will be required to procure and initiate the correct volume of flexibility services at the right time and right location on the network.

Granularity of Averaged Data

WPD's DNMS software receives instantaneous readings for analogues where there is a change in the monitored value beyond a pre-determined hysteresis range. This data is displayed on the control diagram and is used to operate the network. It will also be used by a number of the ANM systems. This data is not currently recorded for future use because it has not previously been required.

What has historically been recorded is a half hourly average value, which is calculated by the DNMS from the instantaneous values. This is used for regulatory reporting and as an input into models to determine network compliance and reinforcement requirements. The granularity of the time averaged data is a trade-off between data processing and accuracy. When networks were demand driven this granularity of data was the standard, as it gave an accurate representation of network conditions. With the increase of intermittent distributed generation and energy storage connecting to the network, there is a concern that a half hourly averaged value is becoming unrepresentative.

This has been previously identified in part of WPD's FALCON project, which was looking at Demand Side Response (DSR) and how without adequate data, it would be theoretically possible that a site being measured with standard half hourly settlement metering could appear to be achieving a consistent reduced maximum demand. The LV templates project also installed a large amount of monitoring equipment at LV across South Wales at 10 minute intervals, as 30 minutes was not been deemed adequate.

Case Study – Recording Interval

The power-flow variation at a given feeder over a half hour period is predominately dependent on the technology mix of demand and generation. A domestic and commercial demand dominated feeder will typically have less variation across a half hour than an industrial demand or an intermittent generation dominated feeder.

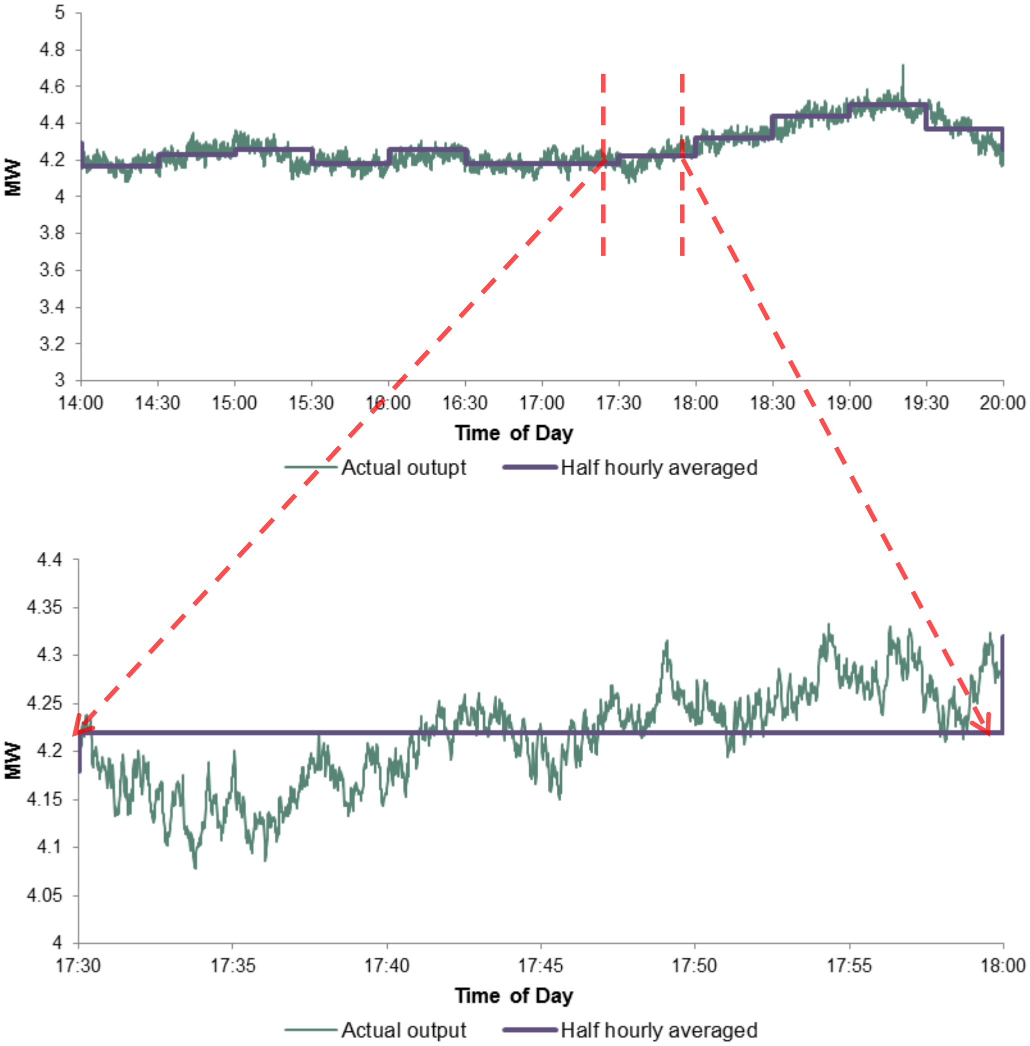


Figure 5: Comparison of half hourly averaged flows against actual flows on a demand dominated transformer

Figure 5 shows the flows on a transformer feeding a demand dominated network. The purple lines are showing the half hourly averaged value, with the green lines showing the second by second variations recorded using a power quality monitor.

This shows the variation from the half hourly average is relatively small. For the half hour between 17:30 and 18:00 the half hourly average is 4.22MWs. There was a maximum of 4.33MW and a minimum of 4.07MW; this represents approximately a 3.5% variation from the half hourly averaged value.

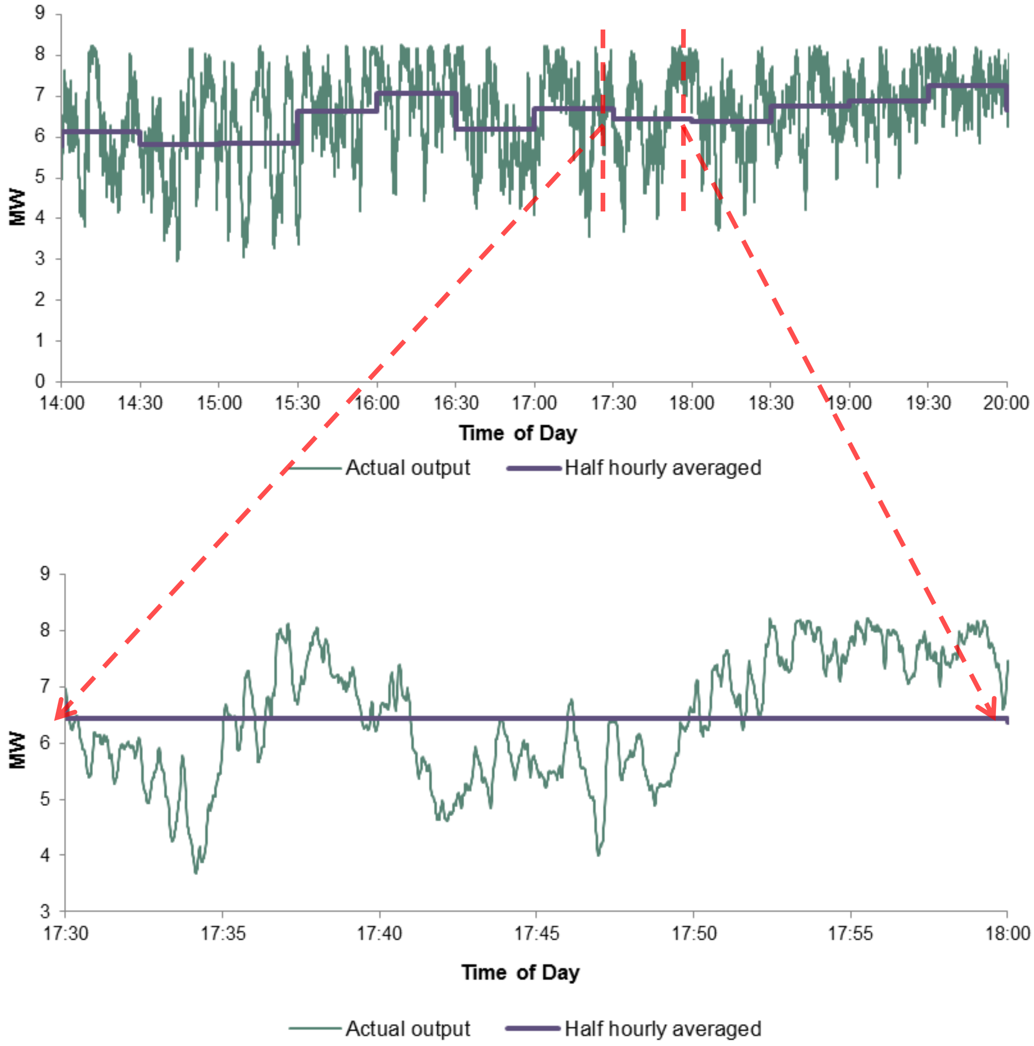


Figure 6: Comparison of half hourly averaged flows against actual flows on a windfarm feeder

Figure 6 shows the variation of real power on a dedicated feeder to a windfarm. This highlights the significant variations seen across a half hour, when compared with the demand dominated feeder in Figure 5. The largest excursion from the average is almost 50%.

This highlights how the increase in intermittent generation is changing the variability of the network, causing half hourly averages to inaccurately represent actual network conditions. As intermittent generation like PV and storage continue to connect to the network, this variation and inaccuracy will only increase.

The second graph in Figure 6 shows the period between 17:30 and 18:00. It is of particular interest, because it shows how the actual flow is considerably over the half hourly average for almost 10 minutes.

Impact on Operability

This half hourly average data is used extensively to design the network. This raises the question as to what recording frequency of monitoring will be needed in the future to determine actual peaks and the length that these peaks persist. This needs to be considered along with the coincident peaks of other generation and demands to determine what granularity of averaging is desirable.

Where the most likely network issue is thermal overloads of cables or transformers, then the thermal inertia of these assets means that the minute by minute effect of load variations is considerably dampened. The degree of variation in the loads is a factor in the methodology for setting ratings for overhead lines, and it may be necessary to reassess ratings if the volatility in loadings resulted in higher levels of average heading. Increased variability in loads within a half hour will also make voltage excursions more likely.

This data is increasingly used to calculate generation and demand load factors (coincident factors). This could lead to underestimated load factors; this relates back to the transient limits of the network and what granularity is required to design the network.

It is also used to determine the underlying demand on the network. This is calculated by looking at the flows at a given substation and using the half hourly averaged generation data to unmask the underlying demand. If the generation is actually significantly lower at times than the half hourly average, the underlying demand could be underestimated.

Communication System Capacity

The existing communication system is a combination of internal radio, microwave and fibre. Where it is not feasible to get any WPD service to a site, third party connections are utilised.

Presently, the telecommunications approach to supporting smart grid network solutions are adaptions of current systems and bespoke systems. Like the power network, the communication network can be upgraded given enough time and investment. The operational challenge will be ensuring there isn’t a sudden need for communication that saturates the system before it can be upgraded.

A recent investigation by WPD looked at the options available for the rollout of new communication technology and their suitability to different applications, so that a set of standard telecoms templates can be derived. One of the main conclusions was that in low volume, non-critical scenario, buying in capacity may be more economical than building a network. However, if the traffic is considered highly critical to network services i.e. reliability and security, then building a network may be necessary to guarantee the core service responsibilities of the Distribution Network Operator (DNO). This may include utilisation of the existing 4G network, or in the future a 5G network. The report states: “to realise the smart grid across the DNO domain will represent the largest single operational and capital investment within the transition to a sustainable smart energy industry”. It is recognised that there are potential cyber security risks in such an approach.

System Security

Recent studies have found a number of potential cyber security threats/risks within the power sector. The importance of having a secure communication pathway within the DNMS is paramount, and will only become more crucial as WPD take on additional roles as a DSO.

WPD has for several years now, been working closely with Government Agencies in several countries and established international companies as well to ensure that the cyber security risks to the overall DNMS are understood and have implemented many of the recommendations that have followed.

Short Term Mitigation and Solutions

The level of monitoring and visibility has been steadily increasing for many years; one of the main drivers for this has been to reduce Customer Minutes Lost (CMLs) and Customer Interruptions (CIs). Monitoring allows detection of customers off supply and switchgear control enables re-energisation of customers without the delay of getting an engineer to site. This increase has primarily been focused on the higher voltages, because the CML and CIs are higher. Investment at the lower voltages for this purpose is less beneficial and in most cases has not been a good use of customer's money.

The main driver for further monitoring and visibility is the changing network and the rollout of flexibility services. WPD are continuing to proactively invest in network monitoring that will meet the needs of the network going forward. This will be a combination of retrofitting existing monitoring and installing new monitoring so it is capable of directional MW and MVAr. The standard for a new BSP and Primary has also been improved to include an increased level of metering. A recent investigation has identified sites across all four WPD licence areas that are in need of full MW and MVAr monitoring, due to likely reverse power-flow or faulty equipment.

The case study on recording intervals shows that analogues' values can change significantly over the course of a conventional half-hour averaging period. This is particularly apparent on analogues of distributed generation (DG) output. Detailed assessment is needed to determine what frequency of recording is needed to represent a distribution network with an increased level of intermittent generation and demand. To undertake these studies will need additional data points to compare against the half hourly average value that is currently recorded.

The Alverdiscott/Indian Queens ANM will record the delta changes from approximately 6500 analogues and switch statues. This can be used to help further the industries understanding on short-term network variations, caused by intermittent generation and demand. This could also assess the benefits of recording a minimum and maximum value for a half hour.

Long Term Solutions

WPD will continue to increase network visibility and control using a coordinated approach when installing monitoring and control equipment at strategic locations. The general trend has always been to have more monitoring and control at the higher voltages, as more customers are affected following a network event. WPD expect this trend to continue, with the rollout of monitoring and control equipment proliferating down the voltage levels, with the LV being the last to get detailed monitoring and control. The need of additional monitoring and control will depend on the speed at which smart solutions are implemented as business-as-usual.

WPD will continue to look at ways to highlight where existing monitoring accuracy is low through effective aggregation of smart meter data.

The instantaneous data is not currently recorded in any system, as it is data intensive and was not required when the variability in a half hour was considered negligible. Shortly, WPD's DNMS will support any time frame required using new functionality. It will also have the functionality via a Time Series Data Store (TSDS) to store the instantaneous values.

To ensure the communication system does not impede network development, a collaborative approach will be taken when engaging Office of Communications (Ofcom), on the need for additional licenced and unlicensed radio spectrum.