United Energy Demand Response Project Performance Report - Milestone 4

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1. Summary

This document is the United Energy (UE) Demand Response Project Performance Report for the ARENA Advancing Renewables Programme – Demand Response programme (RB006). It fulfils an obligation under the Knowledge Sharing Plan to provide an update on the status of the delivery of the Dynamic Voltage Management System (DVMS) rollout project including sharing of results and lessons learnt.

This report documents the major achievements of the project since the release of the last milestone report. These achievements include completion of:-

1) testing of United Energy's demand response reserve capability for the upcoming summer period;
2) voltage regulation relay replacement works at each zone substation; and
3) knowledge sharing activities relating to the findings of the project during the period.

To minimise duplication of content, this report should be read as a continuation of the milestone 1, 2 and 3 reports.

Any parties interested in discussing the contents of this report directly with United Energy are encouraged to contact United Energy at planning@ue.com.au.

The milestone reports are available on United Energy's website.

2. Testing of UE's demand response reserve capability

United Energy undertook a summer period demand response test with AEMO.

The objectives of the test undertaken on 17th May 2018 were to :-

1. confirm UE's demand response reserve capability achieves the required 30MW (compared to the previous requirement of 12MW); and
2. ensure the ITT (Invitation to Tender) and activation communication channels were operating correctly and acted on within the required period of time of 30 minutes and 10 minutes respectively.

In summary, high-speed SCADA measurements (presented below) provide evidence that United Energy has delivered at least the required 30MW of demand response capability for all half-hour periods except the first period, and that the communication process to receive and accept the ITT, and the subsequent activation of the demand response reserve capability have been successfully demonstrated. Follow up actions to address the issues of the first half hour period have been addressed and retested with the results presented in this report.

2.1. Fourth Test – 27th November 2018

AEMO called the fourth test with UE on 27th November 2018 for a 2-hour period starting 12:00 market time for a capability of 30MW.

The following chart shows the high frequency sampling rate measurements of the total demand included in United Energy's demand response portfolio, before, during and after the test.

Activation of the demand response by way of voltage reduction is clearly evident in the time before the event start date at 1200 market time with demand falling from 920MW at 11:40 to around 890MW at 12:00. With underlying demand at the time just prior to activation decreasing at 0.066MW/minute, the coincident time demand reduction achieved in the first interval is 920MW – 890MW - 0.066MW/minute x 35 minutes = 27MW. Subsequent intervals achieved demand reductions of at least 30MW.

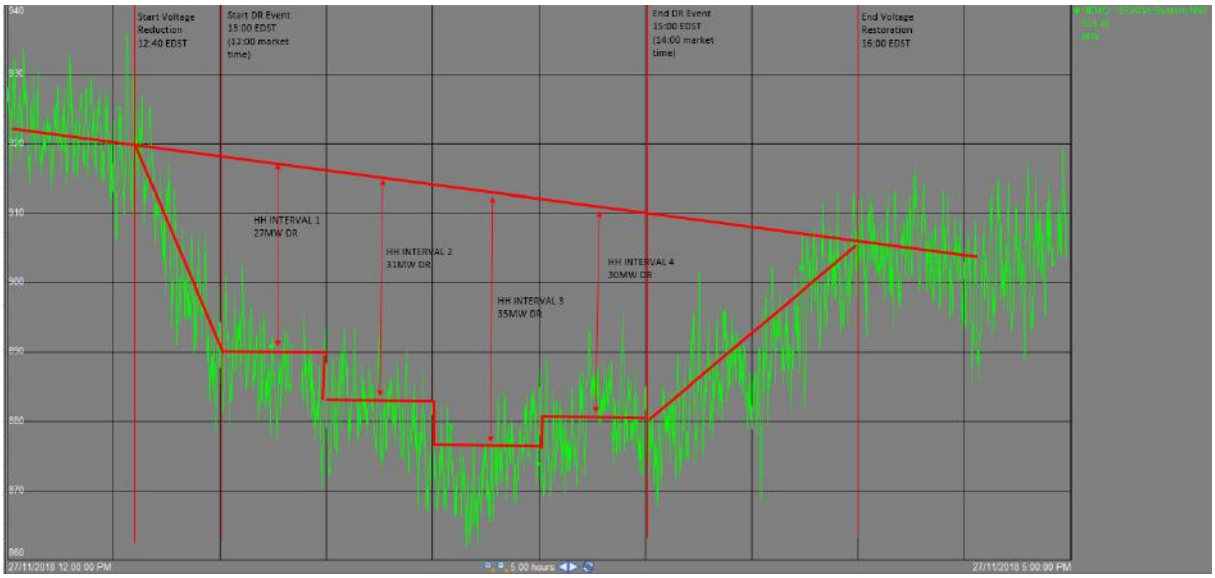


Figure 1 Test showing demand response due to voltage reduction

Removing the demand response was undertaken by restoring network voltages which occurred from 1400 market time with demand rising from 880MW at 14:00 to around 905MW at 15:00. With underlying demand at the time decreasing at 0.066MW/minute, the coincident time demand reduction in the final period is 905MW – 880MW + 0.066MW/min x 75 min = 30MW.

With the Dynamic Voltage Management System acting to limit the size of the voltage reductions to allow customer voltages to remain within the regulatory limits, the demand response magnitude delivered varies throughout the test window with the deepest response delivered in the third half-hour period.

An example of how DVMS is regulating customer voltages with Demand Response (DR) mode on and off on the day of the test is shown below at the 11kV East Malvern (EM) zone substation

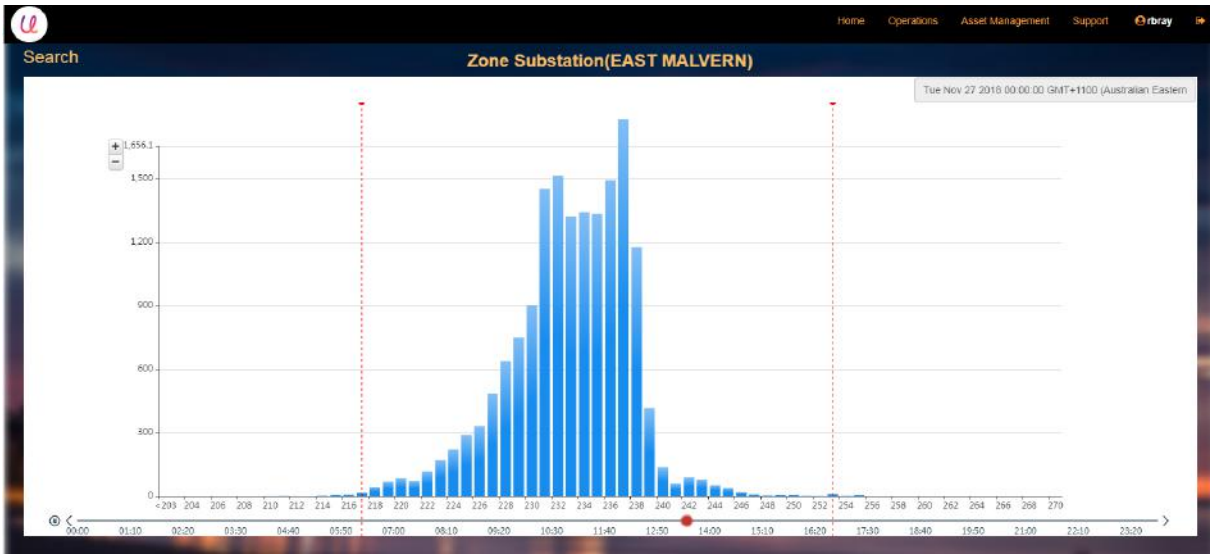


Figure 2 During DR test, showing customer voltages regulated at lower end of regulatory voltage band

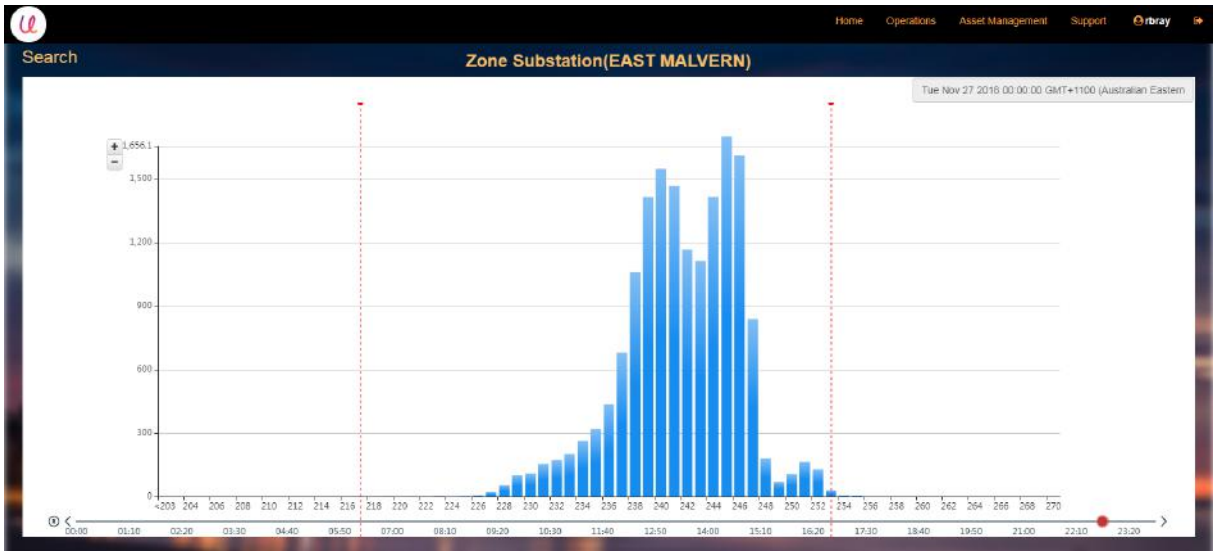


Figure 3 After the DR test showing customer voltages regulated at upper end of regulatory voltage band

2.2. Full Activation Timing Delay

UE were unable to achieve the full 30MW in the first half hour interval during the AEMO test due to a data bandwidth bottleneck problem encountered between the analytics engine/data warehouse (NAP/OSI PI) and the realtime SCADA system (MOSAIC). This resulted in a slower than normal tapping down of transformers as NAP did not have up to date information to drive transformer taps faster during the activiation, with the transformers still tapping down even during the first half hour of the event period. This delay effect from the data bottleneck diluted the demand response delivered in the first half hour period.

An example of this delay in tapping is shown below, again for the EM zone substation.

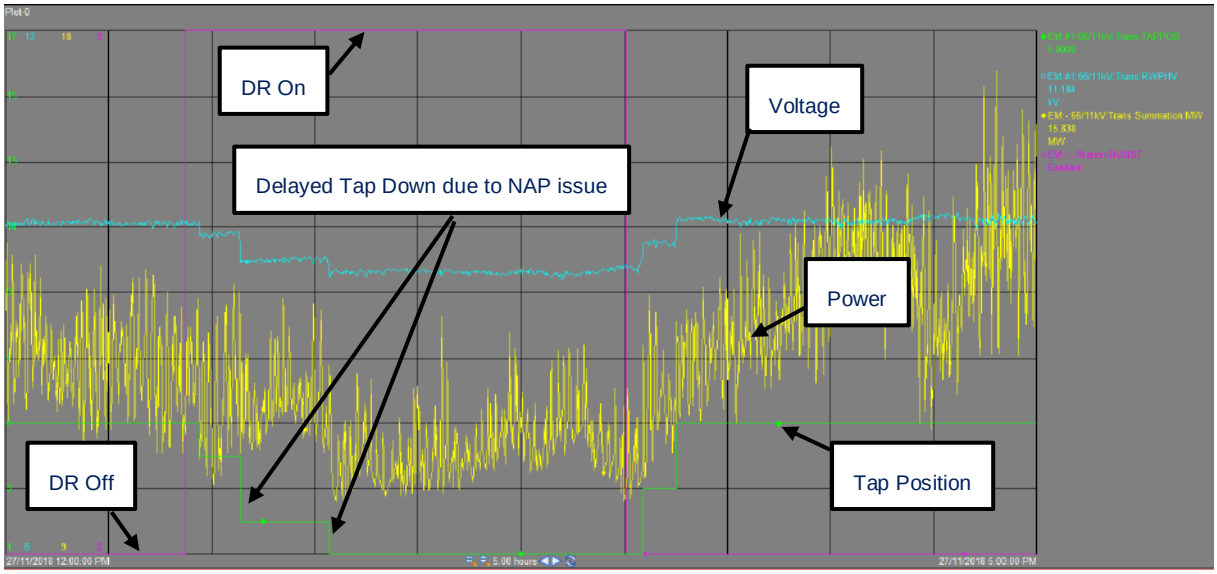


Figure 4 Test showing delayed tapping issue

The delayed tapping down is clearly evident with three tap change steps over a period of 40 minutes.

This issue was promptly identified and rectified subsequent to the AEMO test by increasing the data capacity between the systems and fine-tuning the activation algorithm in the analytics engine. The changes were retested on 10th December 2018, resolving the delay issue. The same EM site is used to present the results of the rectification (on the same time scale), showing a substantial improvement in tapping performance.

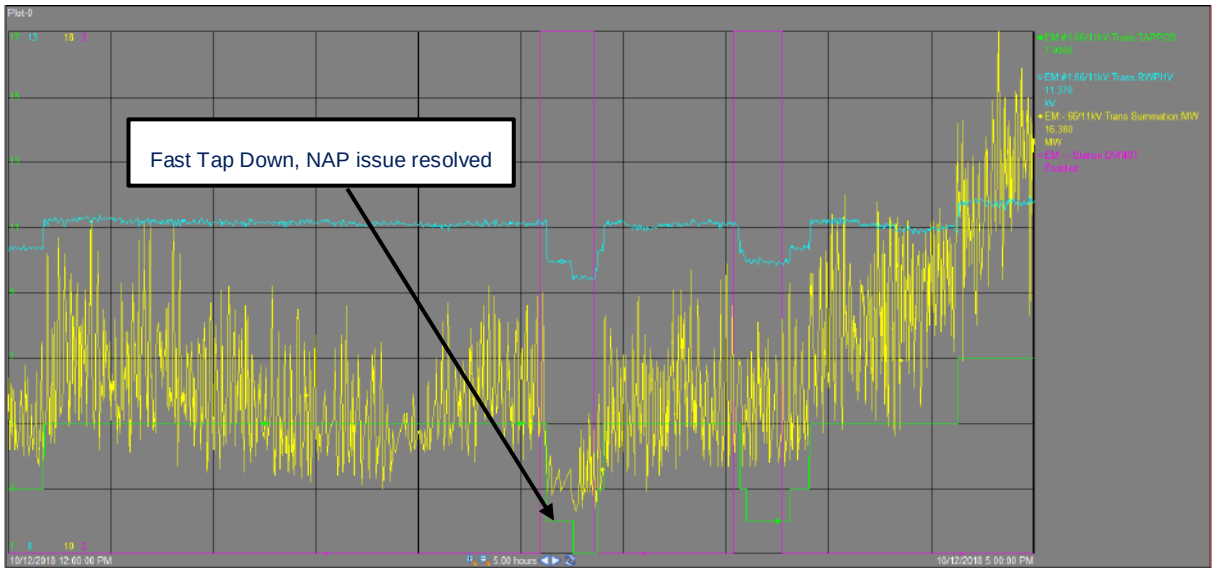


Figure 5 Test showing delayed tapping issue resolved

The tapping down is now clearly much faster, reducing to two tap change steps over a period of 10 minutes.

2.3. End of Tapping Range

The AEMO test which was conducted during a period of light load revealed a possible limiting factor in the performance of the system. The magnitude of the demand response available during light load periods is limited not only by the magnitude of the low demand itself, but also from available tapping range of many zone substation transformers. Under light load, transformers typically operate closer to the bottom end of their tapping range, which could limit the size of the voltage reduction available. This is clearly illustrated in the EM example above, where the tap change from normal operation to demand response operation went from tap 5 down to tap 1 (the bottom tap).

This end of tapping range limitation is however not expected to be applicable at periods of high demand, with transformers likely to be operating much higher in their tapping range to cater for voltage drops through the network. This is illustrated below over a period of 4 days when a high demand day was experienced on 7th December 2018. For the EM example below, the taps are likely to be operating around tap 8 compared to a low demand day of tap 5. This provides an additional voltage margin for demand response of 3 taps x 1.025% step = 3.1%.

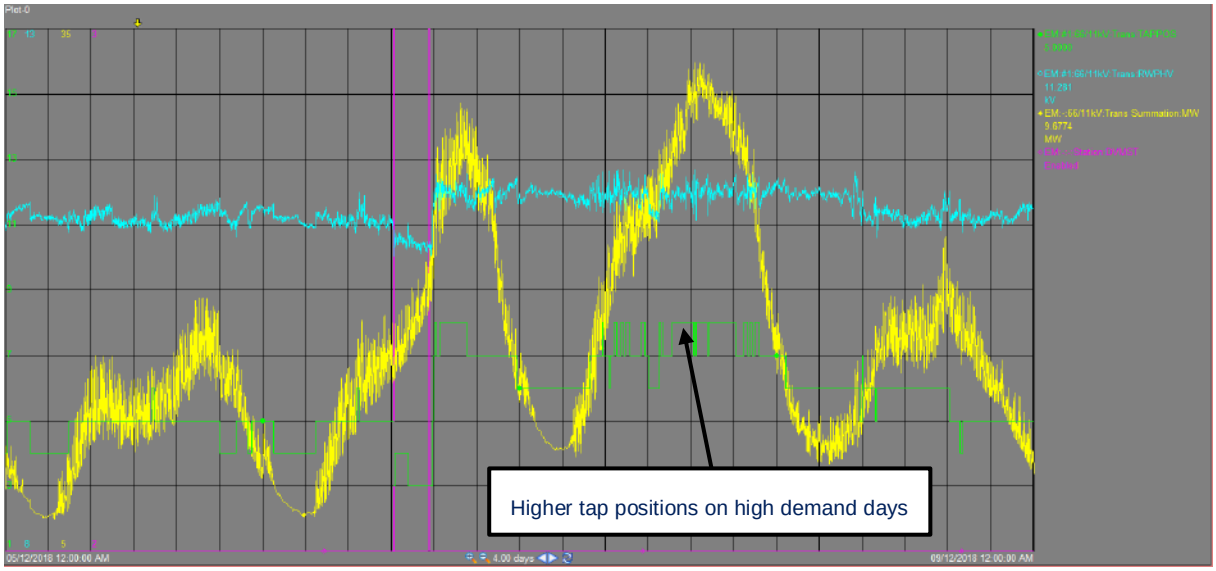


Figure 6 Greater tapping range available for DR on high demand days

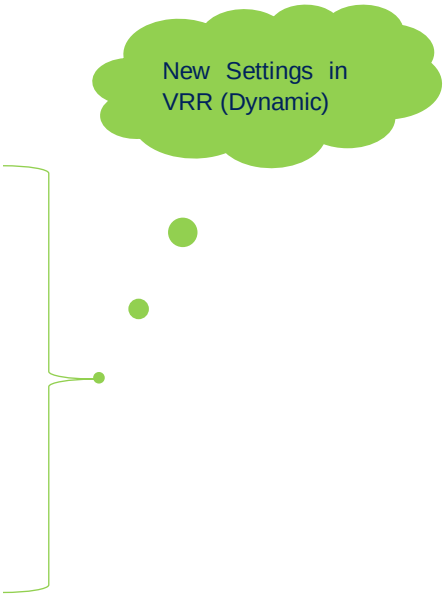
On such days, those the voltage reduction would be limited not by the tapping range, but by the available margin from the spread of customer voltages, which can be controlled through the low voltage network remediation works presented in the Milestone 3 report.

3. Upgrade voltage regulating relays at zone substations

Prior to commencing the construction work for DVMS, the existing voltage regulating relays (VRRs) in UE's zone substations were not capable of operating with multiple voltage set-points and they needed to be upgraded or replaced with new transformer management relays to possess the required capabilities. Therefore, a works program was developed to program the VRRs at all zone substations[1] with new 7 pre-set bus voltage float set points; namely DV0 to DV6. These settings are programmed with pre-defined setting values in the field VRRs as listed in Table 1.

Table 1: Proposed Voltage Set-Points for Voltage Regulating Relays Deployed in DVMS

No	OLTC Operation Setting
1	Default (Static)
2	Emergency1
3	Emergency2
4	DV0
5	DV1
6	DV2
7	DV3
8	DV4
9	DV5
10	DV6



In order to upgrade the zone substations with the highest capacity for demand response, an analysis was carried out on the performance of all zone substations and the below criteria were taken into account for prioritisation of zone substations for delivery of the construction works:

- Zone substation peak demand;
- Contribution of residential customers to the supply zone substation peak demand; and
- The first percentile of the voltage profile for all customers during peak demand.

Then, the associated works were planned to be delivered in two phases:

- Phase 1 which included 24 zone substations; and
- Phase 2 which included 22 zone substations.

[1] The VRRs at Clarinda zone substation (CDA) were upgraded under the DVMS Trial in 2017.
Oakleigh East (OE) and Caulfield (CFD) zone substation VRRs will be replaced in 2019 to align with other work programmes.

3.1. Phase 1 of zone substation works

The scope for Phase 1 was driven by the existing VRRs at each site. For the zone substations in Phase 1 there were DRMCC-T3 and A-Eberle REG-D VRRs previously installed at the zone substation.

This phase consisted of two different high-level scopes applied across the 24 zone substations:

1. Upgrade existing Dynamic Ratings DRMCC-T3 VRRs to DR-E3 VRRs.
2. Upgrade the configuration of A-Eberle REG-D VRRs.

Both scopes required remote terminal unit (RTU) reconfiguration as well to accommodate new SCADA input/output (I/O) associated with the DVMS.

Under the defined scope, UE coordinated with the manufacturers and supplier to develop the base functionality required in both the DR-E3 and A-Eberle REG-D relays to implement DVMS.

Works at DRMCC-T3 sites consisted of upgrading the unit to a DR-E3 by replacing the central processing unit (CPU) module of the transformer regulation relay. The configuration for the DR-E3 then needed to cater for the new required voltage set-points and protocol configuration. UE procured all of the DR-E3 hardware required for the upgrade from DRMCC-T3. The manufacturer (engaged by UE) was responsible for producing the configuration files for the VRRs at each specific location. The Service Provider then worked with the manufacturer to finalise the design in particular the SCADA I/O Schedule (SIOS).

Works at the REG-D sites consisted of a setting and configuration update to incorporate the new set-points and protocol configuration. The Service Provider was responsible for producing the configuration files for the VRRs. The Service Provider liaised with the manufacturer to verify those files.

The site-specific parameters were either provided by UE or retained from the existing on-site settings.

It was unacceptable for any in-service primary plant not to have complete protection coverage available at any time. However, it was acceptable to have a temporary redundant protection scheme outage where necessary. Where these outages extended beyond a day (24 hours), UE had to be advised and consulted on risk management strategies prior to the outage.

The locations of zone substations which were upgraded with the requirements to implement DVMS are given in Table 2.

Table 2: Site Locations for Phase 1 of the DVMS Rollout Project

No	Site Name and Address
1	Beaumaris (BR) Zone Substation
2	Burwood (BW) Zone Substation
3	Carrum (CRM) Zone Substation
4	Dromana (DMA) Zone Substation
5	Dandenong (DN) Zone Substation
6	Dandenong South (DSH) Zone Substation
7	East Burwood (EB) Zone Substation

No	Site Name and Address
8	Elwood (EW) Zone Substation
9	Keysborough (KBH) Zone Substation
10	Lyndale (LD) Zone Substation
11	Langwarrin (LWN) Zone Substation
12	Mentone (M) Zone Substation
13	Mulgrave (MGE) Zone Substation
14	Moorabbin (MR) Zone Substation
15	Mornington (MTN) Zone Substation
16	North Brighton (NB) Zone Substation
17	Notting Hill (NO) Zone Substation
18	Oakleigh East (OE) Zone Substation
19	Rosebud (RBD) Zone Substation
20	Surrey Hills (SH) Zone Substation
21	Springvale South (SS) Zone Substation
22	Sorrento (STO) Zone Substation
23	Springvale (SV) Zone Substation
24	Springvale West (SVW) Zone Substation

3.1.1. Upgrade REG-D (functionality only)

There were no hardware or firmware changes required to upgrade the REG-D to cater for DVMS. The new DVMS set-points and controls were implemented through additional relay logic (H-code).

H-code template for DVMS was provided by UE, however this needed to be adapted as required for sites such as Dandenong South (DSH) and Notting Hill (NO) zone substations where a portion of the H-code was dedicated to cooling control. All drawings relating to H-code and relay logic were updated to reflect the new implementation on-site.

The existing configuration only allowed for four set-points to be configured. The first three set-points cater for the normal/default and emergency set-points, all of which needed to be modified to new values which were provided by UE as part of this project. The fourth setpoint was used by the custom logic to implement the additional seven set-points as summarised in Table 3 that are used by the DVMS.

Table 3: Native Set-Point Configuration (including DVMS) for the REG-D

REG-D Set-Point	UE (DVMS) Naming	Set-Point	Protocol to Enable
SP1	Static	To be modified to new values provided by UE	REGSWindex = 1
SP2	Emergency 1		REGSWindex = 2
SP3	Emergency 2		REGSWindex = 3
SP4	Dynamic Voltage Set-Point	Populated by H-Code	REGSWindex = 4

The REG-D customisation wrote each of the set-points (A21-A27) into “SP4” when controls were sent from SCADA to the corresponding digital bit (B21-B27) as shown in Table 4. The custom code also cater for the watchdog timer reset for the end-to-end DVMS.

Table 4: H-Code DVMS Set-Point Configuration for the REG-D

UE (DVMS) Naming	H-Code Analogue Naming	H-Code Digital Naming
DV0	A21	B21
DV1	A22	B22
DV2	A23	B23
DV3	A24	B24
DV4	A25	B25
DV5	A26	B26
DV6	A27	B27

3.1.2. Upgrade voltage-regulating relays to DR-E3 (hardware only)

Except one station, Oakleigh zone substation(OAK), at which the existing DRMCC-T3 relays were upgraded to DR-E3 relays by swapping the CPU and power supply cards in the existing chassis, all other cards in the chassis were compatible with the upgraded CPU and power supply and did not need to be amended, including wiring and external connections.

The existing DRMCC-T3 human-machine interface (HMI) was incompatible with the DR-E3 and needed to be replaced. The new HMI (named interface unit (IU) by Dynamic Ratings) connects to the DR-E3 using RJ45 copper

connectors which supply power and communications to the unit. As the HMI was replaced in situ, IU extender units (supplied by Dynamic Ratings) were also required at each end to interface the new HMI with the DR-E3 as shown in Figure 7.

Figure 7 A. Interface Unit Extender and HMI Installed for DR-E3 Unit on the United Energy Distribution Network

The changes required to interface the new HMIs are detailed below:

- The fibre optic connector (FOC) used to interface with the existing HMI was connected to the new IU Extenders.
- At the location of the current HMI:
  - An RJ45 patch cable was connected between the new HMI and the IU Extender; and
  - The existing HMI 24Vdc power supply was connected to the new IU Extender (this unit supplies power to the new HMI).
- In the transformer equipment cubicle:
  - An RJ45 patch cable was connected between the DR-E3 IU port and the new IU Extender; and
  - A 24Vdc power supply was provisioned to the new IU Extender using the field supply available on the DR-E3 power supply card.

The configuration for the DR-E3 is not identical to the DRMCC-T3, and as a result needed to be aligned at each site with the existing configuration as part of the upgrade. The dynamic set-points also needed to be incorporated into the new configuration file. Therefore, UE engaged the manufacturer (Dynamic Ratings) to produce the new configuration files which combined the new DVMS settings (as provided by UE) and many of the existing site-specific DRMCC-T3 settings.

The default (static) set-point was equivalent to the previous set-point (float voltage set-point) at the zone substation. While the emergency set-points were configured as voltage set-point reductions in the default set-point group. The

default set-point and emergency set-points needed to be modified to new values which were provided by UE as part of this project. Each other set-point, configured for DVMS, was then configured as the set-point on sequential set-point groups as shown in Table 5.

Table 5: Set-Point Configuration (including DVMS) for the DR-E3

Dynamic Ratings Set-Point Group No	UE (DVMS) Naming	Set-point (kV)	Reduction 1 (%)	Reduction 2 (%)
0	Static	Modified to new values provided by UE		
1	DV0	As prescribed by UE on a site-by-site basis	0%	0%
2	DV1		0%	0%
3	DV2		0%	0%
4	DV3		0%	0%
5	DV4		0%	0%
6	DV5		0%	0%
7	DV6		0%	0%

The set-point groups can be enabled from SCADA via protocol one at a time. To enable emergency set-points the VRR needs to first be placed into the default set-point (Set-Point Group 0) and then have a "Voltage Set-Point Reduction" applied. SCADA have been configured such that:

- Voltage reductions cannot be enabled when the VRR is not in the default set-point group; and
- Dynamic set-points cannot be enabled when voltage reduction is enabled.

It was required that all relevant drawings relating to the DRMCC-T3 to be updated to reflect the installation of the DR-E3. Where applicable, manufacturer's drawings for new DR-E3 were sourced for the site-specific installation and inserted on UE templates.

At OAK zone substation, the ability to quickly disconnect the mobile transformer from the station has been maintained as part of the upgrade. Also, where possible, the existing physical interface was retained or replicated similarly whilst accommodating the new requirements.

3.2. Phase 2 of zone substation works

Phase 2 of the DVMS rollout targeted all of the remaining zone substations on the UE distribution network which had not been upgraded in Phase 1 or the Trial to accommodate the new required functionality. Each site was categorised into a series of type scopes which indicated:

1. What VRR the zone substation was to be upgraded to (DR-E3 or REG-D).
2. The required SCADA communications architecture to achieve the DVMS functionality.

All sites were considered non-standard transformer management implementations, although the existing standards for transformer management, SCADA and communications formed the basis of this scope wherever practicable to do so. The physical locations of new cubicles or equipment were specified on a site by site basis.

The locations for the zone substations targeted for Phase 2 of the DVMS rollout are given in Table 6.

Table 6: Site Locations for Phase 2 of the DVMS Rollout Project

No	Site Name and Address
1	Box Hill (BH) Zone Substation
2	Bentleigh (BT) Zone Substation
3	Bulleen (BU) Zone Substation
4	Cheltenham (CM) Zone Substation
5	Doncaster (DC) Zone Substation
6	Dandenong Valley (DVY) Zone Substation
7	Elsternwick (EL) Zone Substation
8	East Malvern (EM) Zone Substation
9	Frankston South (FSH) Zone Substation
10	Frankston (FTN) Zone Substation
11	Glen Waverley (GW) Zone Substation
12	Hastings (HGS) Zone Substation
13	Heatherton (HT) Zone Substation
14	Gardiner (K) Zone Substation
15	Mordialloc (MC) Zone Substation
16	Noble Park (NP) Zone Substation
17	Nunawading (NW) Zone Substation
18	Oakleigh (OAK) Zone Substation
19	Ormond (OR) Zone Substation
20	Sandringham (SR) Zone Substation

No	Site Name and Address
21	West Doncaster (WD) Zone Substation

The secondary equipment requirements of the scope for Phase 2 were:

- Replace or upgrade the existing VRR to enable new functionality for the DVMS;
- Integrate or augment the communications architecture of the zone substation to accommodate the new or upgraded VRRs; and
- Produce new or amended relay configurations (including settings, functionality, logic and communications mappings) which incorporate the new set-points and functionality required for DVMS.

Similar to Phase 1, sites which had previously utilised DRMCC-T3 required upgrading the unit to a DR-E3 by replacing the CPU module of the transformer regulation relay. The configuration for the DR-E3 then needed to cater for the new required voltage set-points and protocol configuration, whilst retaining existing cooling control configurations. UE procured all DR-E3 hardware required for the upgrade from DRMCC-T3. The manufacturer (engaged by UE) was responsible for producing the configuration files for the DR-E3 at each specific location. The Service Provider also worked with the manufacturer to finalise the design (in particular the SCADA points mapping tables - SIOS).

Sites which had previously utilised any other VRR, or which did not have DRMCC-T3 relays installed for cooling control on all transformers, were replaced with REG-D. These schemes align closely with the current UE standard for transformer monitoring and control, although the physical layout of the equipment are non-standard for the zone substation included in Phase 2. No changes have been made to the existing cooling control arrangement at these sites and the new REG-D only performs voltage regulation. The service provider was responsible for producing the configuration files for the REG-D relays.

The functionality delivered from the new VRRs as part of this project aligns with the trial and Phase 1 of the DVMS rollout. UE confirmed all required templates, functionality and firmware as part of these projects.

The requirements for communications architecture and configuration were stipulated for each site due to the dependency on the existing arrangement and as a result:

- A new or updated SIOS was created which accommodate all required points from new or upgraded VRRs;
- A new or amended configuration was produced for the station RTU or master station interface equipment; and
- Any intermediate communications equipment (media converters, Ethernet switches, protocol converters, or similar) were approved, captured in information systems and appropriately designed.

The site-specific VRR parameters were either provided by UE or retained from the existing on-site settings.

As aforementioned in Section 3.1, it was unacceptable for any in-service primary plant not to have complete protection coverage available at any time. However, it was acceptable to have a temporary redundant protection scheme outage where necessary. Where these outages extend beyond a day (24 hours), UE had to be advised and consulted on risk management strategies prior to the outage.

3.2.1. Upgrade voltage-regulating relays to DR-E3 (hardware and functionality)

At Nunawading zone substation (NW) the existing DRMCC-T3 relays were used exclusively for cooling control. The CPU card and HMI were then replaced. In addition, the scope outlined below were completed:

- The DR-E3 units were interfaced together using FOC and RS-485 to enable Master-Follower VRR scheme as implemented at other UE zone substations (the interconnection between the relays were marshalled at similar locations to other UE zone substations);
- The raise and lower tap controls were wired to the DR-E3; and

- Bus voltage reference (bus voltage transformer (VT)), tap position indicators (TPI) and other relevant I/Os were wired to each DR-E3 to ensure that VRR functionality can be enabled.

The legacy OLTC control was decommissioned and removed from the sit and all of the controls for the OLTC were modified to be via the DR-E3 unit.

3.2.2. Replace VRR with A-Eberle REG-D in a new cubicle

The existing VRRs were replaced with the REG-Ds in a new free-standing station voltage regulation cubicle. All VRRs for the station were situated in the new cubicle, along with the new low-tension bus voltage supervision relays.

After proposing the location for the new cubicle at each site by UE, the Service Providers conducted site visits and confirmed the final location of the new station VRR cubicle.

UE's Zone Substation Secondary Design Standard – Transformer Control and Monitoring, UE ST 2002.3.09, was taken into account for the new relays with the following deviations:

(i) Panel layout was similar to the design examples shown in Section 6.

(ii) Relay logic incorporated the H-code template for DVMS (provided by UE), similar to the Trial and Phase 1 rollout.

(iii) Remote schedule incorporated additional DVMS remote I/O points.

Similar to Phase 1, the existing REG-D standard configuration only allows for four set-points to be configured. The first three currently cater for the default/static and emergency set-points, all of which needed to be modified to new values provided by UE as part of this project. The fourth set-point is used by the custom logic (H-code) to implement the additional seven dynamic set-points required for the DVMS functionality. Figure 8 shows the new REG-D relays in a new cubicle.

Figure 8 A. Eberle REG-D Relays installed on the United Energy Distribution Network

3.2.3. Replace VRR with A-Eberle REG-D on existing panel

This applied to the sites where there was no suitable space in the control room for a new free standing cubicle. In this case 19'' steel frame (SF) inserts, mounted onto existing steel frames in the control room, was used to house the new REG-D VRRs.

The preferred design for the 19' SF inserts is included in Section 7. The front panel layout is similar to the design examples shown in Section 6, except that new low- tension bus voltage supervision relays were not required.

Aside from the physical layout outlined above, this scope aligned with Section 3.2.2.

3.3. Low-Tension Bus Voltage Supervision

The previous setting range for low-tension bus voltage supervision (as prescribed in UE's Protection, Control & Monitoring Settings Standard, UE ST 2004 Clause 9.2) was not compatible with DVMS and hence, were modified as part of the DVMS rollout project. This is because the DVMS has the potential to utilise the entire +/-6% voltage range allowed at the high-voltage level, and therefore the lockout of transformer tapping by the supervision relay must be set marginally beyond this range to prevent unintended lockouts.

Under Phase 1 and 2, the low-tension bus voltage supervision relays were configured such that the limits of the voltage supervision would not impede the ability of the DVMS to augment the bus voltages via the set-point. They were also set such that they would not generate spurious alarms. Table 7 summarises the changes made on the low-tensions bus voltage supervision relays.

Table 7: Proposed Set-Points for Low-Tension Bus Voltage Supervision Relays

Supervision Setting	Existing Standard	DVMS Scope
Over-Voltage	106% of the float voltage	107% of the nominal voltage
Under-Voltage	94% of the float voltage	93% of the nominal voltage

For Phase 2, new low-tension bus voltage supervision relays were installed at the sites where the VRRs were replace with REG-D in a new cubicle. All other sites retained their existing low-tension bus voltage supervision scheme.

Where new low-tension bus voltage supervision relays were required, they were installed as per UE's Zone Substation Secondary Design Standard – Bus Voltage Supervision, UE ST 2002.3.07, with the physical location of these relays similar to the panel layout demonstrated in Section 6. All wiring and included equipment remained as close to the standard as possible whilst accommodating the layout described in the relevant scope mentioned in the previous sections of this report.

The new relays have the hardwired alarms wired to either the existing station RTU or the newly installed SEL-3505-3. Figure 9 shows the low-tension bus voltage supervision relays installed on the UE distribution network.

Figure 9 Low-Tension Voltage Supervision Relays Installed on the United Energy Distribution Network

3.4. Remote terminal unit

For Phase 1 at each of the locations the station RTU which was interfaced to the station VRRs was augmented to accommodate the required controls, statuses and analogues for DVMS. These were included in the latest SIOS template provided by UE with the standard configuration files for the VRRs.

The Service Providers were responsible for updating and creating RTU configuration files, station SIOS and SEMS sheets associated with the project

Table 8 shows the voltage set-point related SCADA I/O for DVMS for DR-E3 relays.

Table 8: Voltage Set-Point related SCADA Input/Output for DVMS

Function	Quantity Names		
	Digital Input	Digital Output	Analog Input
Active Set-Point	N/A	N/A	Dynamic Voltage Active Set-Point
Static Set-Point	DVM Mode	DVM Mode Disable	VRR Set-Point

Function	Quantity Names		
	Digital Input	Digital Output	Analog Input
Emergency Off[2]	VRR Standard Operation	VRR Standard Operation Enable	N/A
Emergency 1	VRR Emergency Stage 1	VRR Emergency Stage 1 Enable	VRR Emergency Stage 1 Set-Point
Emergency 2	VRR Emergency Stage 2	VRR Emergency Stage 2 Enable	VRR Emergency Stage 2 Set-Point
DVMS Set-Point 1	Dynamic Voltage Level 1	Dynamic Voltage Level 1 Enable	Dynamic Voltage Level 1 Set-Point
DVMS Set-Point 2	Dynamic Voltage Level 2	Dynamic Voltage Level 2 Enable	Dynamic Voltage Level 2 Set-Point
DVMS Set-Point 3	Dynamic Voltage Level 3	Dynamic Voltage Level 3 Enable	Dynamic Voltage Level 3 Set-Point
DVMS Set-Point 4	Dynamic Voltage Level 4	Dynamic Voltage Level 4 Enable	Dynamic Voltage Level 4 Set-Point
DVMS Set-Point 5	Dynamic Voltage Level 5	Dynamic Voltage Level 5 Enable	Dynamic Voltage Level 5 Set-Point
DVMS Set-Point 6	Dynamic Voltage Level 6	Dynamic Voltage Level 6 Enable	Dynamic Voltage Level 6 Set-Point
DVMS Set-Point 7	Dynamic Voltage Level 7	Dynamic Voltage Level 7 Enable	Dynamic Voltage Level 7 Set-Point
DVMS Fail[3]	Dynamic Voltage Health	N/A	N/A

For sites which already had the capability to manually override the Group/Independent mode of the VRR, this will no longer be available on the new VRRs. These controls were removed from the SIOS and RTU configuration for the site.

For Phase 2, the configuration for the RTU aligned with the configurations implemented as part of the Trial and Phase 1 of the DVMS rollout. A SIOS was either produced or amended for each site incorporating the points required to implement the DVMS functionality.

Two different scopes, depending on the previous configuration of RTUs, were implemented for Phase 2 which are outlined below.

3.4.1. Augment Existing Remote Terminal Unit

Similar to Phase 1, the existing RTU was reconfigured to cater for the new I/O required for the DVMS scheme. All points and functionality then aligned with the DVMS Trial and Phase 1 sites.

New equipment was only connected using DNP3 over IP. At some sites the existing RTU which had not had an existing master DNP over IP session configured, this was added to the RTU with all relevant mapping tables and configuration completed for the new session.

The existing station SIOS was then updated to include all new digital inputs, outputs and analogue inputs associated with the new configuration. Where existing relays were upgraded, their existing point maps were updated to

[2] This only applied to the DR-E3 configuration, these indications were not required for the REG-D relays.
[3] This was subject to the capability of each of the relays to signal that the relay had timed out to return to the static set-point and would be taken into consideration for future improvements.

incorporate the new points. While where new relays were installed, the new equipment were added to the existing RTU as a new DNP slave. The Service Provider provided the updated station SIOS and logic requirements to UE, who was responsible for producing revised configuration files for existing RTUs.

3.4.2. Install a SEL-3505-3 as the host interface for the VRRs

Where the existing RTU was unable to accommodate the new VRR, a SEL-3505-3 acts as the host interface for the VRRs. In most locations this acts as like-for-like replacement of the MD3311 OLTC RTU which was directly interfaced to the SCADA host. However, sites which previously interfaced via a SEL-2032 using MODBUS also have a new SEL-3505 added for the VRRs.

The SEL-3505-3 has a new SIOS created for the SEL-3505-3 with all points associated with the VRRs connected as per the standard, plus additional DVMS points. This has all I/O over protocol, except for hardwired relay fail alarms which were grouped with existing Station X/A Device Health alarm.

Figure 10 shows one of the SEL-3505-3 installed as the Host Interface for the VRRs on the UE distribution network.

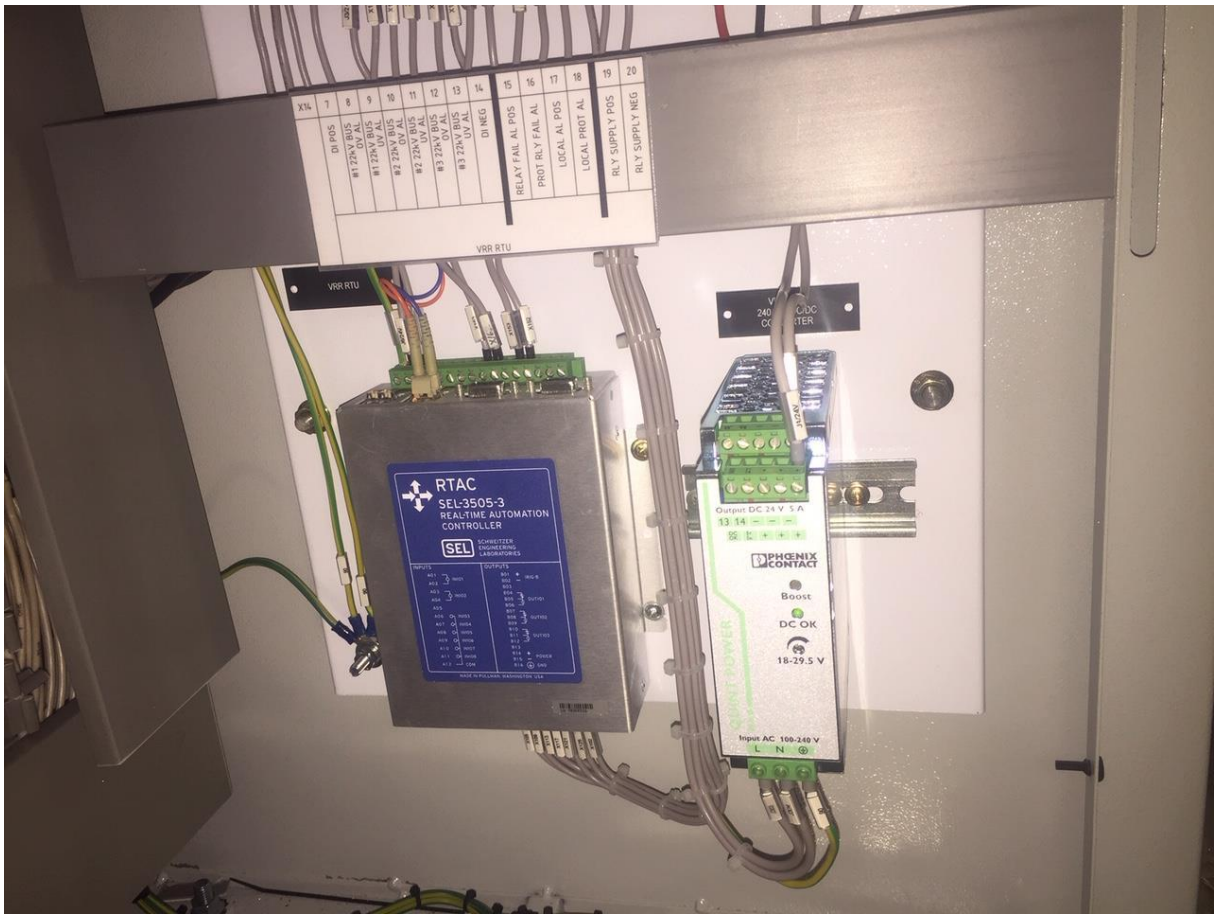


Figure 10 SEL-3505-3 installed as the Host Interface for the Voltage Regulating Relays

Where a new cubicle was installed, the new SEL-3505-3 was physically located in the new VRR cubicle similar to the design examples shown in in Section 6.

For sites which required a new SEL-3505-3 but had not had a new VRR cubicle the location for the SEL-3505-3 was specified separately. It was assumed that the side plane of the communications cubicle at each site could be used to mount the equipment.

3.5. Station communications architecture

The changes made on the station architectures under the DVMS rollout project were dependent upon the existing communications hardware onsite, and the spare capacity available to accept new equipment. The station architectures for the connection of the new or upgraded VRRs are listed below.

3.5.1. Standard architecture

Architecture which was implemented was as per UE's Zone Substation Secondary Design Standard – SCADA & Communications, UE ST 2002.4.

For the station with standard architecture, all VRRs were directly interfaced to the station local area network (LAN) switch which shares its bus designation. The VRRs are polled by the station RTU which is polled by the host.

At sites with an architecture similar to the standard but not fully compliant, the existing architecture was minimally amended to accommodate the new equipment.

3.5.2. Legacy architecture (serial fibre)

The existing serial fibre was not extended for the network sites which had a legacy architecture utilising serial fibre via star-couplers to provide SCADA connectivity to intelligent electronic devices (IEDs) as demonstrated in Figure 11.

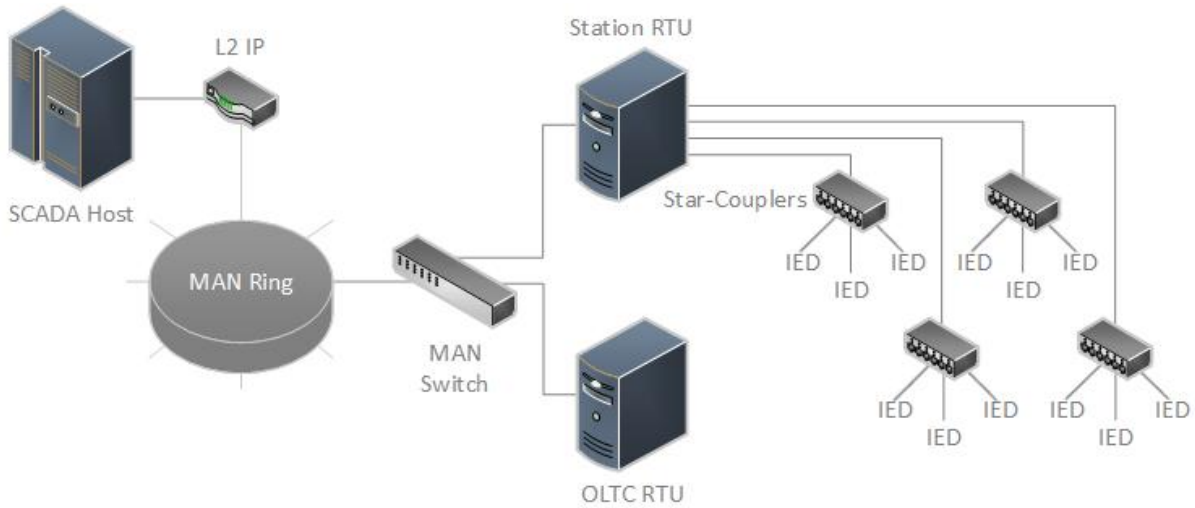


Figure 11 Existing Serial Fibre Communications Architecture

To interface the new IEDs to the station RTU a new station LAN station was established by extending the MAN switch at these sites as shown in Figure 12. The following changes were required to implement the new architecture:

- Installation of a new module (MM3-4FXM2) on the existing station metropolitan-area network (MAN) switch; and
- Connecting the new VRRs to the new module on the MAN switch.

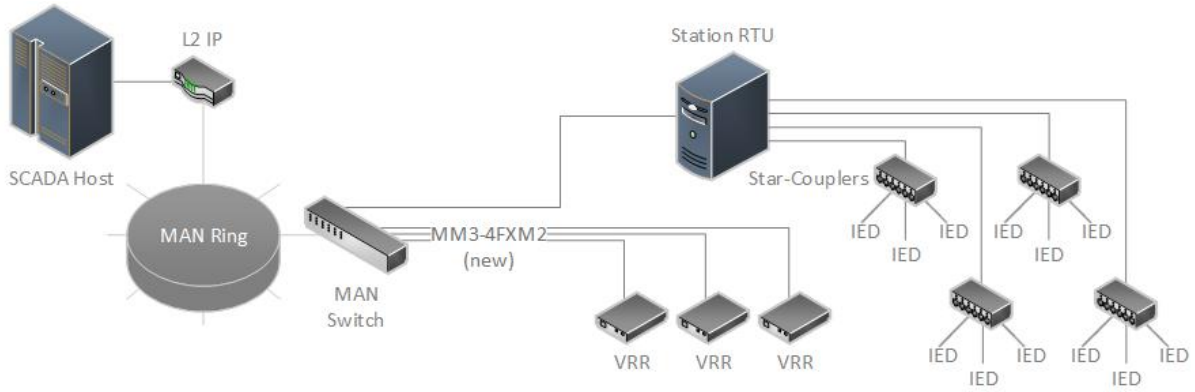


Figure 12 New Communications Architecture with Voltage-Regulating Relays Added

3.5.3. SEL-3505-3 as OLTC RTU Replacement

The VRRs were connected to the SCADA host as a like for like replacement of the previous OLTC RTU at sites which had an incompatible station RTU (MD1000 and SEL-2032). The existing architecture for these sites is demonstrated in Figure 13.

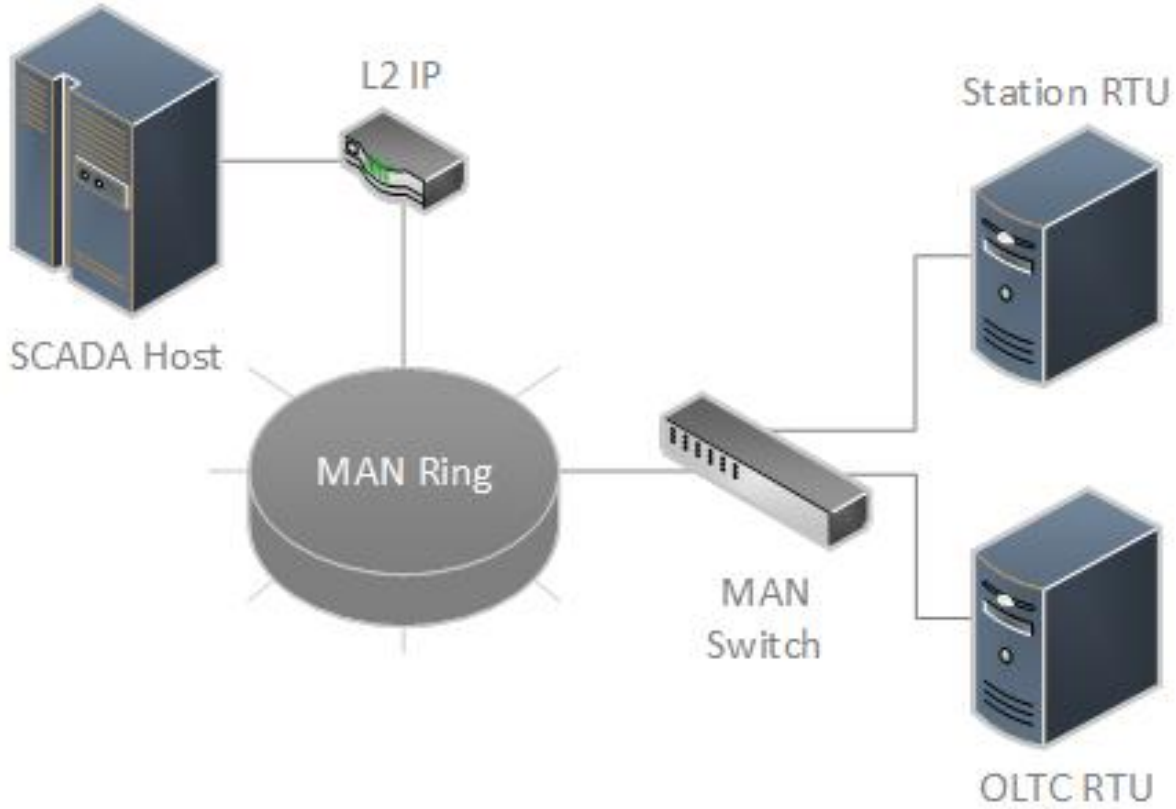


Figure 13 Legacy Communications Architecture with Hardwired, Copper Serial or Proprietary Protocol Downstream of the Station Remote Terminal Unit

Where the interface for the existing VRR was to a SEL-2032 via MODBUS the new VRR was connected via a new SEL-3505-3. If the previous VRR also performed cooling control, the MODBUS connection to the existing relay remained in service to provision SCADA connectivity for the cooling functions.

The new architecture required:

- Installation of a new SEL-3505-3 which acts as the RTU interface for the VRRs;
- Installation of a new module (MM3-4FXM2) on the existing station MAN switch; and
- Connecting the new VRRs to the new module on the MAN switch.

The new communications architecture for these sites is given in Figure 14.

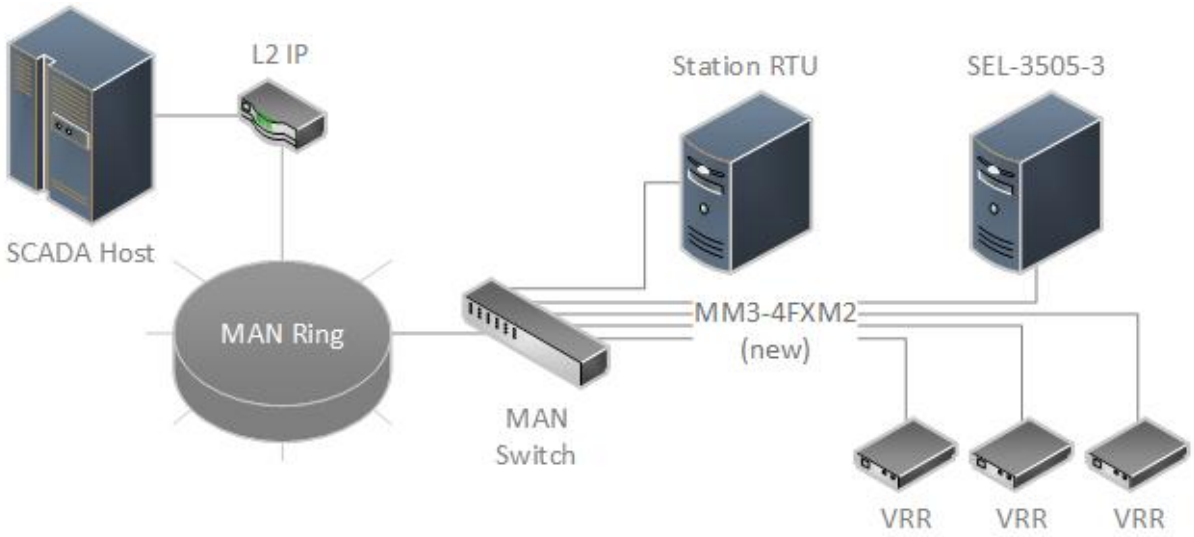


Figure 14 New Architecture with the Voltage-Regulating Relays Communicating via a SEL-3505-3 to the Host

3.5.4. Remote input and output

Remote I/O was implemented in strict accordance with UE's Zone Substation SCADA I/O Schedule (SIOS) template, UE ST 2140.

Additional, non-standard, remote I/O points needed to be added to the SIOS in order to cater for the DVMS functionality. The SIOS template, UE ST 2140, was then updated by UE with new standard remote I/O points for DVMS (REG-D and DR-3 options). These new DVMS remote I/O points are very similar to what was installed at CDA zone substation as part of the DVMS Trial, and in general they consist of the following:

- A status (enabled/disabled) point for each new voltage set-point;
- A control enable point for each new voltage set-point;
- An analogue value returning the set -point voltage for each new set-point; and
- An analogue value returning the current active set-point voltage for the VRR.

Naming conventions and functionality for these points depend on whether the new VRR is a DR-E3 or REG-D as summarised in Table 8.

3.5.5. Time Synchronisation

Time synchronisation for the new VRRs and communications equipment is described below (in order of priority).

1. Local station GPS clock directly using SNTP[4] via the station LAN.
2. Local station GPS clock via the station RTU using SNTP (when station time synchronisation is via IRIG-B).
3. Upstream network time servers using SNTP (liaise with UE SCADA team to confirm target).
4. SCADA Host time synchronisation using DNP.

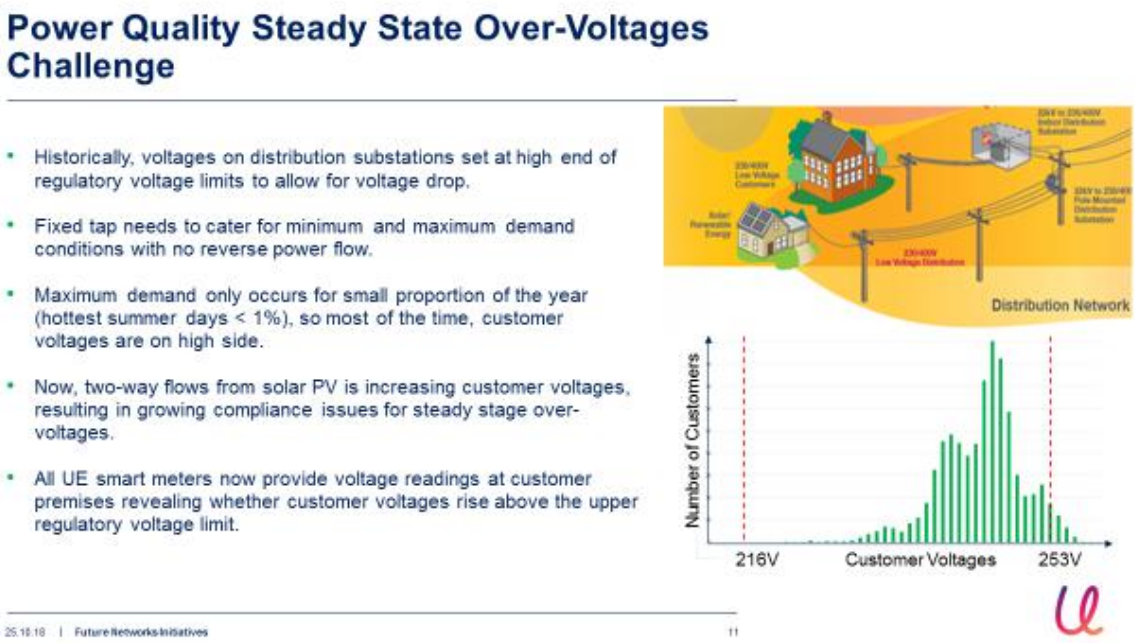
[4] SNTP = Simple Network Time Protocol.

4. Knowledge Sharing Activities

Since the last milestone report, United Energy has participated in the below events and shared the learnings of this project with the broader industry:

- Workshop with University of Melbourne to relating to learnings from the UK CLASS initiative compared to learnings from DVMS on 3rd December 2018.
- ARENA Knowledge Sharing Insights Workshop held by ARENA on 30th November 2018 in Sydney.
- Presented at SA Power Networks Future Networks Distribution Forum in Adelaide in 25th October.
- Workshop on investigations into revised baselining methodologies on 3rd and 24th September 2018.
- Updated the knowledge sharing webpage on the United Energy website for the purposes of sharing our project performance reports and provided input into the ARENA knowledge sharing insights website content.

4.1. SA Power Networks Future Networks Distribution Forum

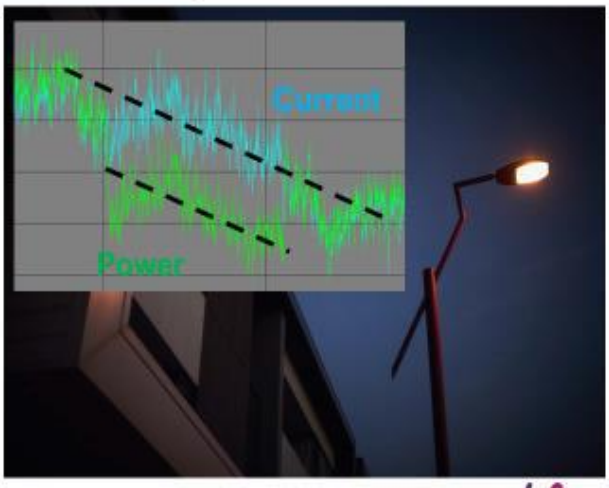


Demand Response Voltages Reduction Challenge

- Reducing voltage reduces active power demand.
- Weighted average test results on United Energy Network give

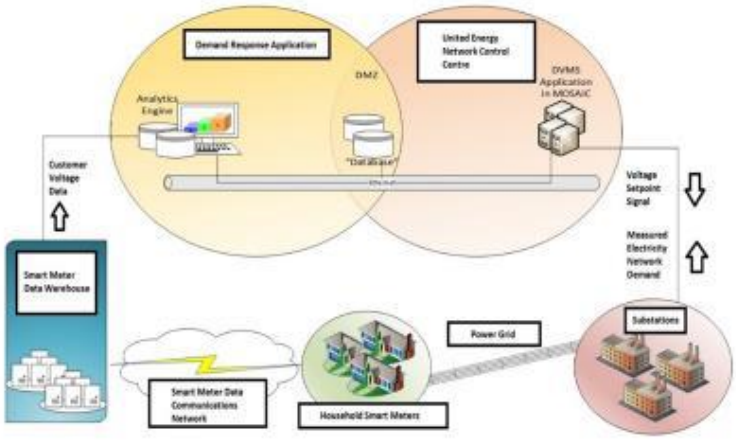
  P% / ΔV% = 0.7 ΔI% / ΔV% = 0.0

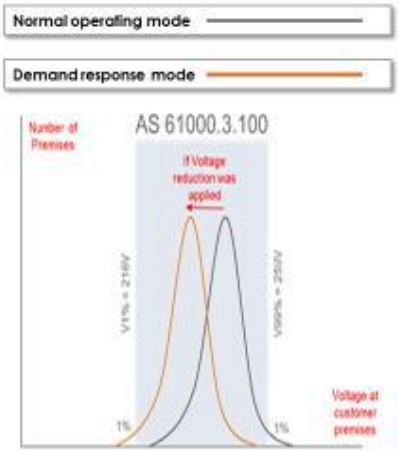
- Constant current behaviour is useful for upstream network constraints and generation shortfalls.
- Historically, limited in use because of its unknown impact on customer voltages relative to regulatory voltage limits.
- All UE smart meters now provide voltage readings at customer premises revealing whether customer voltages fall below the lower regulatory voltage limit.



25.10.18 | Future Networks Initiatives 12

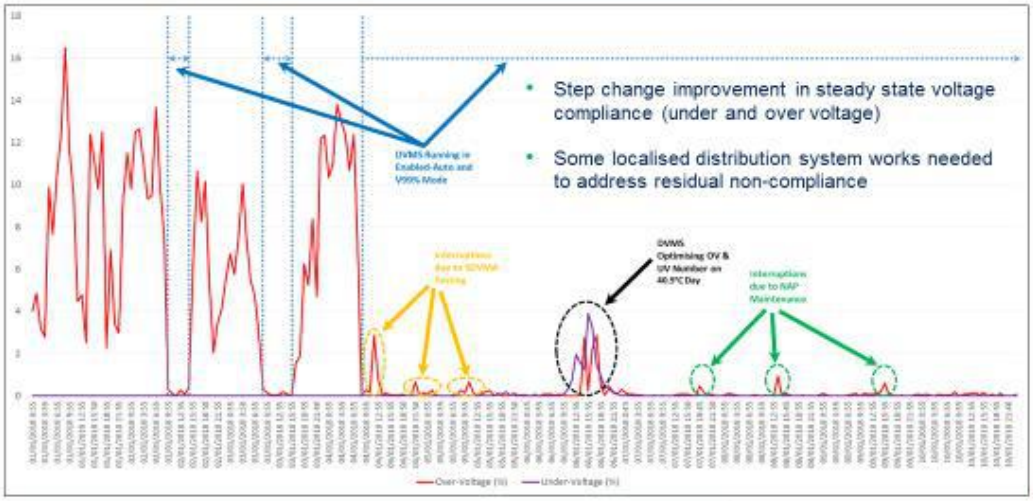
Using Smart Meters to deliver simultaneous Steady State Voltage Compliance and Demand Response capability





25.10.18 | Future Networks Initiatives 13

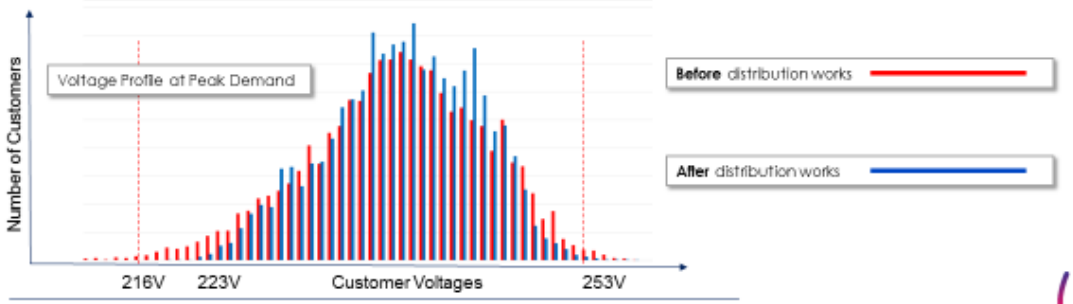
Power Quality Compliance During Commissioning



25.10.18 | Future Networks Initiatives 14

Localised Distribution System Works for Peak Demand Day

- Voltage spread increase on peak demand days can lead to power quality non-compliance (both over and under-voltage) and/or dilutes demand response effectiveness
- Some localised distribution system works needed to tighten the voltage distribution
- Scope includes local tap changes, phase balancing, open point changes and connection checks.
- Achieves compliance plus a 3% margin for voltage reduction.



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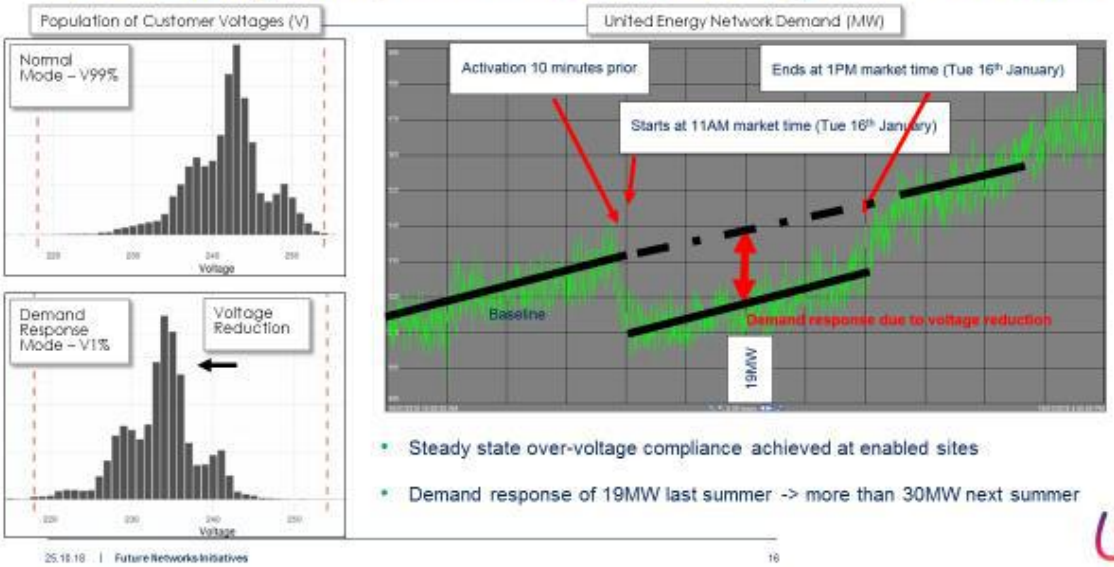
Power Quality Compliance and Demand Response Test Results



- Steady state over-voltage compliance achieved at enabled sites
- Demand response of 19MW last summer -> more than 30MW next summer

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Conclusions

- Smart meters have provided an opportunity for UE to apply conservation voltage reduction to deliver large-scale demand response capability without the risk of violating regulatory voltage limits.
- UE has successfully tested this capability and is now deploying to all zone substations during 2018 funded through ARENA's Demand Response Program.
- Demand response service delivery for AEMO's SN RERT with 10-minute activation time.
- Quality of supply compliance achievable (steady state over-voltage and under-voltage) including during periods of light load or high solar PV generation and high demand.
- Allows for higher penetration of solar PV by automatically adapting to new solar PV connections and variable solar PV output.

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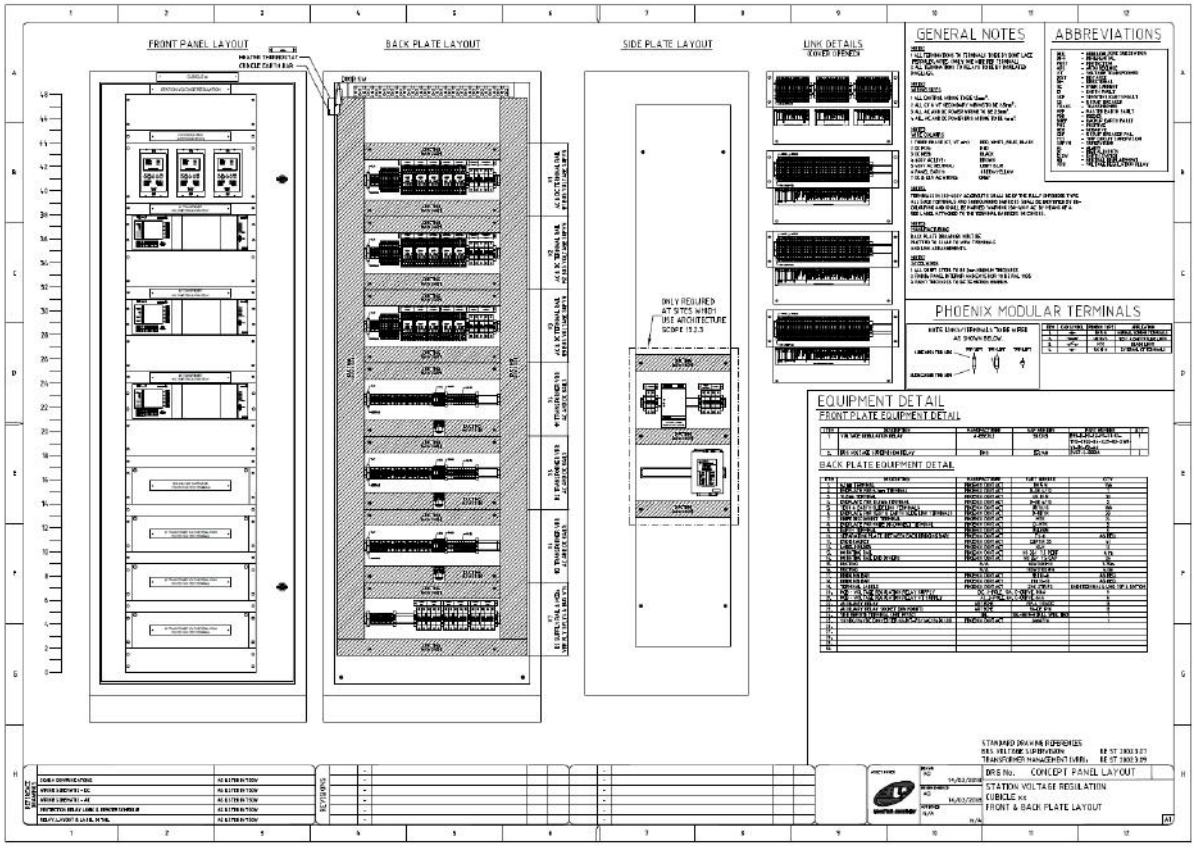
5. Glossary of Terms

The following terms are referenced within this document:

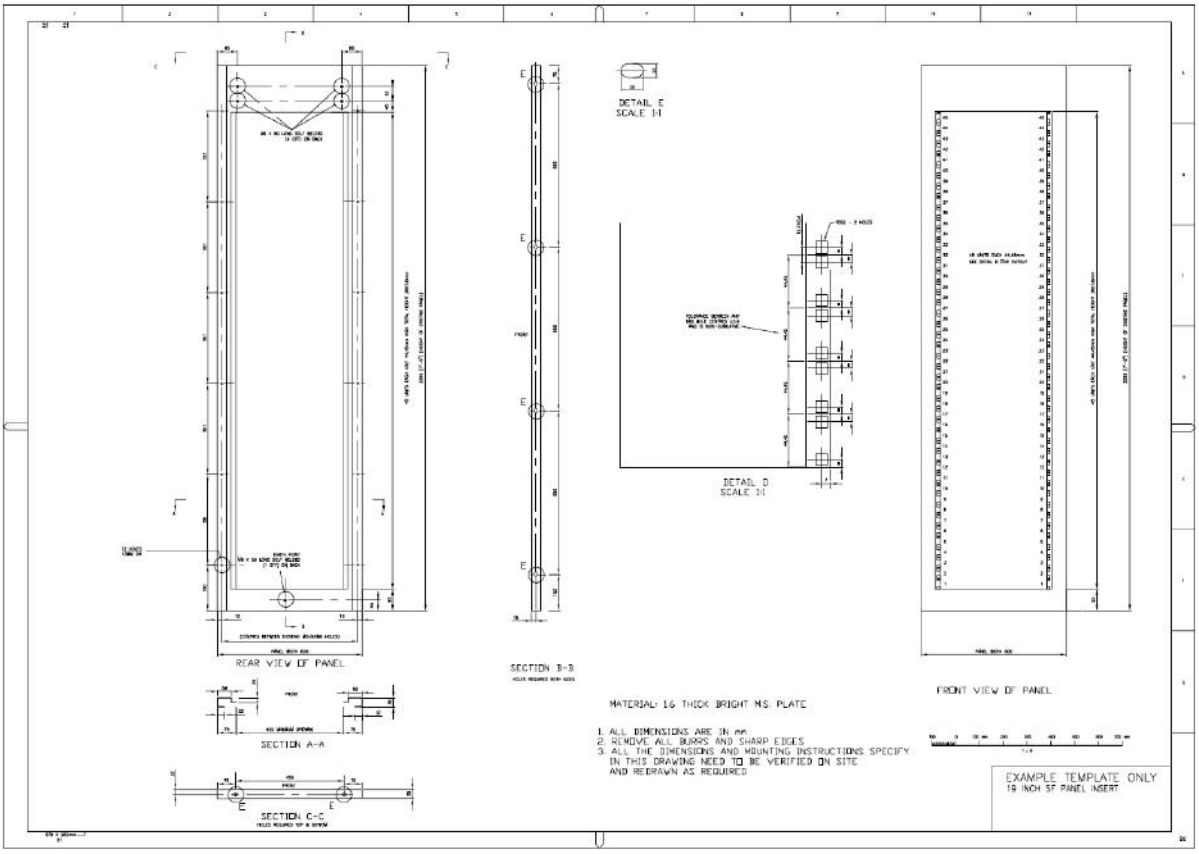
Term	Description
AEMO	Australian Energy Market Operator
AMI	Advanced Metering Infrastructure (Smart Meters)
ARENA	Australian Renewable Energy Agency
CDA	Clarinda Zone Substation
CPU	Central Processing Unit
DVMS	Dynamic Voltage Management System
EM	East Malvern Zone Substation
FOC	Fibre Optic Connector
GIS	Geographical Information System
HMI	Human-Machin Interface
HV	High Voltage
IED	Intelligent Electronic Device
I/O	Input and Output
IU	Interface Unit
LAN	Local Area Network
LV	Low Voltage
NAP	Network Analytics Platform
NCC	Network Control Centre
OLTC	On-Load Tap Changer
OT	Operating Technology
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition

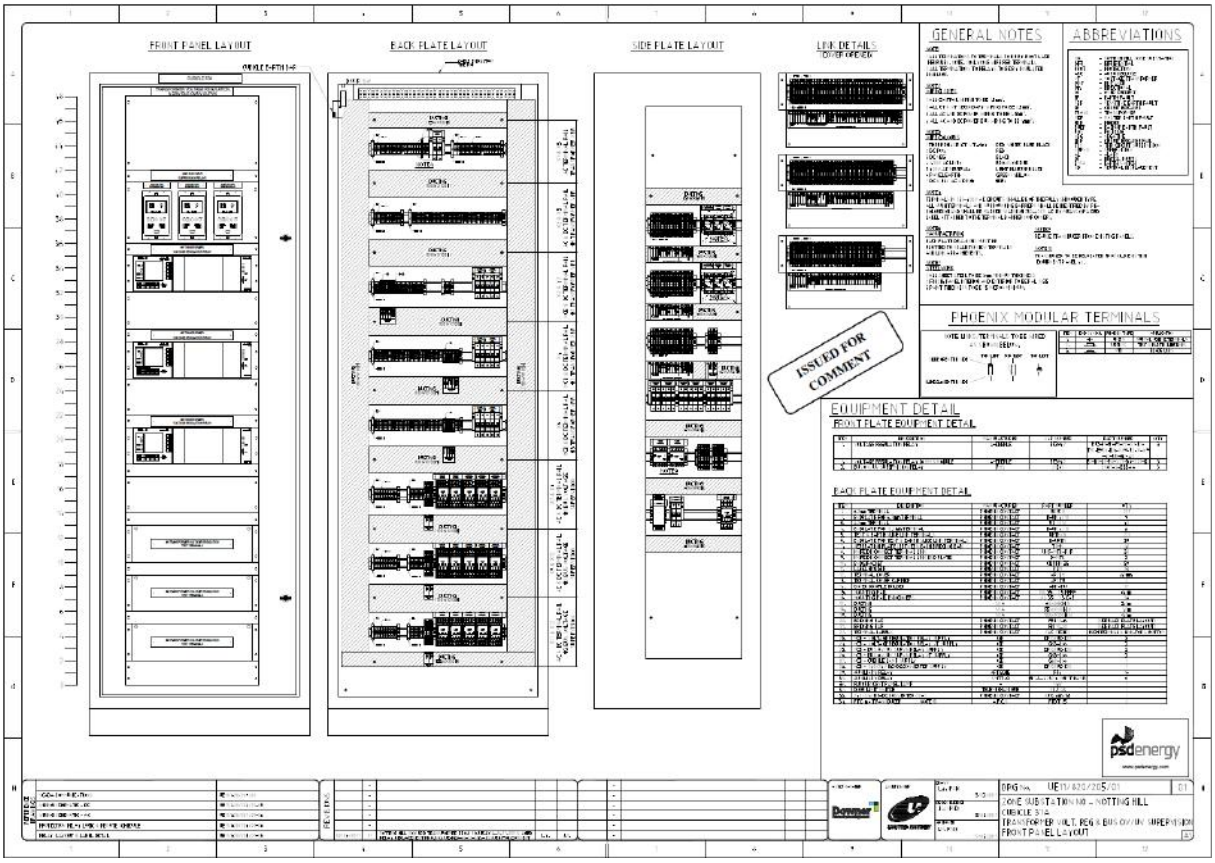
Term	Description
SDVMA	SCADA Dynamic Voltage Management Application
SF	Steel Frame
SIOS	SCADA Input / Output Schedule
SNTP	Simple Network Time Protocol
TPI	Tap Position Indicator
UE	United Energy
VRR	Voltage Regulating Relay
VT	Voltage Transformer

6. Appendix A – Voltage Regulating Relay Panel Layout



7. Appendix B – Standard 19” Steel Frame Insert




FRONT PANEL LAYOUT
BACK PLATE LAYOUT
SIDE PLATE LAYOUT
LINK DETAILS
GENERAL NOTES
ABBREVIATIONS
PHOENIX MODULAR TERMINALS
ISSUED FOR COMMENT
EQUIPMENT DETAIL
FRONT PLATE EQUIPMENT DETAIL
BACK PLATE EQUIPMENT DETAIL
psdenergy