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Market Framework for Distributed Energy Resources-based Network Services

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Extended Executive Summary

Context

Operational flexibility will be at the core of facilitating a cost-effective evolution to a low-carbon electricity system. Given the reduction in capacity of conventional fossil-fuel power generation, that historically was the principal source of flexibility, evolving distributed energy resources (DER), including distributed generation (DG), distributed storage (DS) and demand side response (DSR), connected to the distribution networks, will provide core flexibility services needed for real-time demand-supply balancing and management of congestion in transmission and distribution networks.

Optimal utilisation of DER will reduce the need for investment in conventional technologies and transmission and distribution infrastructure. However, a new system operation paradigm and suitable market design will be essential for enabling DER resources to support the future system. In order to facilitate cost-effective system integration of DER, the following radical changes are required:

- A shift *from isolated operation of energy supply, transmission and distribution businesses towards a more integrated approach; and*
- *Design of a new market* that would maximise the overall economic value of DER considering both national and local objectives enabling DER to provide multiple services to different sectors of the electricity system. This can be achieved if DER has the opportunities to access various markets at the local level (e.g. congestion management of distribution networks) and national level (various forms of the reserve, capacity, reactive support, network management). In this context, *the role of Distribution System Operator (DSO) needs to evolve in order to facilitate the application to DER services not only for local distribution network management but also for the benefit to the national transmission system.* This development will require significant changes in operational practices and standards, and also regulatory market and commercial frameworks.

Operational challenges arise as the use of DER by different operators may trigger conflicts between serving the local or national objectives. This indicates that coordination will be required to maximise the synergy of using the distributed resources to provide multiple services. In this context, the Power Potential project investigates the possible technical and commercial frameworks which will bridge the operational coordination between national transmission system operator (NETSO) and distribution system operator (DSO) while enabling maximum use of DER and stimulating competition in the provision of transmission services by the local DER and transmission connected generators on a level of playing field.

Objective

The principal objective of the work described in this report is to inform the development of market arrangements and the commercial framework through selecting the most cost-effective portfolio of contracts for the provision of reactive power support based on offers from different service providers (range of DER and conventional sources). The contracted reactive capacity should provide adequate control resources for delivery of voltage control across a set of loading conditions while considering credible contingencies. The market framework also considers dynamic availability and cost characteristics of virtual power plant (VPP)[1] driven by changes in the local distribution system conditions in coordination with the state of the transmission network. The commercial arrangements also consider differences in costs that market participants would offer in the auction process.

To achieve the objective, a sequential two-stage approach (Figure E. 1) has been developed and used to simulate some illustrative cases demonstrating the feasibility and effectiveness of the proposed methodology.

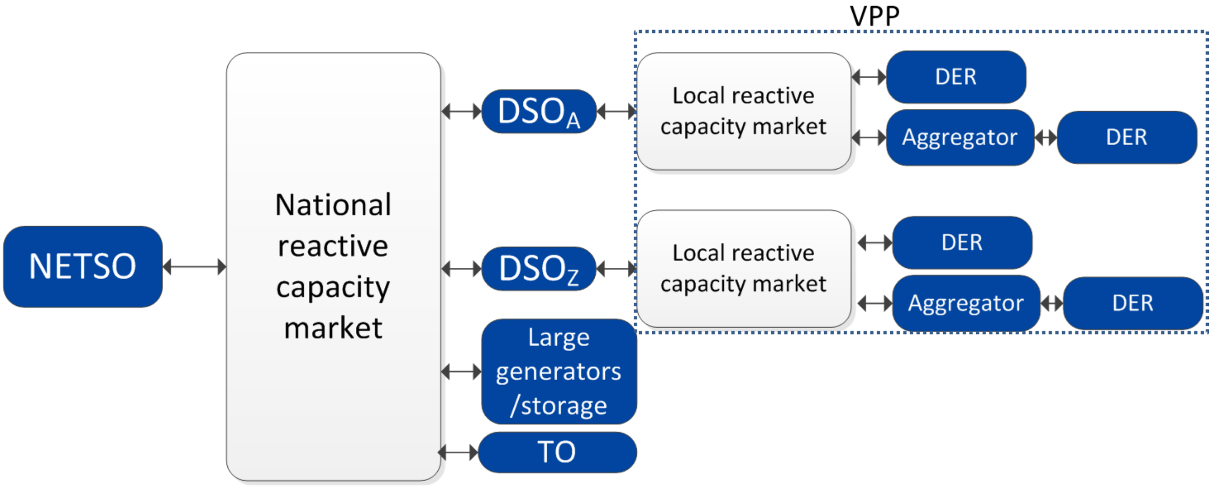


Figure E. 1 Provision of reactive power sources via local and national market

The two-stage reactive market approach is described as follows:

1. The first step is to aggregate the technical and economic characteristics of the DER taking into consideration the distribution network constraints while optimising the network assets and control settings. This enables all distributed energy resources including the network assets to be presented as a large-scale transmission-connected generator which is fundamentally the concept of VPP. Within the VPP area, DER will compete in a local energy market to provide their services to both distribution and transmission system.
2. The second step involves the application of security constrained optimal power flow (SCOPF) algorithm to identify the optimal portfolio of commercial contracts in the

[1] The integration of DER in the concept of VPP connected to the transmission system, requires parameters of the DER to be aggregated while ensuring that (i) the delivery of services to transmission network will not violate local distribution network constraints and (ii) the DER are used in the most efficient manner.

national reactive capacity market, of different durations, considering temporal changes in cost and capability of VPP in order to support secure transmission system operation. At present, traditional tools for selecting contract portfolio for voltage control of the transmission network are not capable of taking these effects into account. The services from VPP will compete with services from transmission-connected generators on a level playing field basis.

By using this two-stage approach, alternative designs of services market for voltage control that may be specific to system conditions and different contract durations have been investigated. The enhanced VPP tool and SCOPF algorithm have also been used to carry out a range of studies to demonstrate the feasibility of the proposed concept. An alternative approach is to solve the local and national reactive market concurrently, which further optimises the allocation of reactive power sources as it ensures the complete synergy of using DER for both distribution and transmission objectives. The pros and cons of both approaches are subject to our investigation in the next phase of this project.

Key findings

The key findings of the analysis carried out are listed as follows:

1. *Value of reactive power support varies in time and with location - depending on the system conditions. As the reactive supports from DER are likely to be more distributed across the system than the conventional large-scale generators connected to transmission network, the participation of DER will not only increase the number of service providers and hence the market competitiveness, but also the effectiveness of the service provision due to a higher spatial distribution of the resources.*

Although a specific voltage problem tends to be a local phenomenon, it could cascade to the broader system if it is not managed appropriately. Voltage problems in the transmission network are generally caused by the inadequacy of local reactive power sources. Due to the high-reactance nature of transmission circuits, reactive power sources should be provided locally. Thus, the voltage sensitivity to reactive power injection /absorption at different buses varies depending on the network characteristics and the electrical proximity of the associated nodes. As DER is more distributed across the system compared to large-scale transmission connected generators, DER may provide reactive sources more efficiently as it can be closer electrically to the part of the system that needs support.

An illustrative case study on a simplified South-East transmission system (Figure E. 2) is described as below.

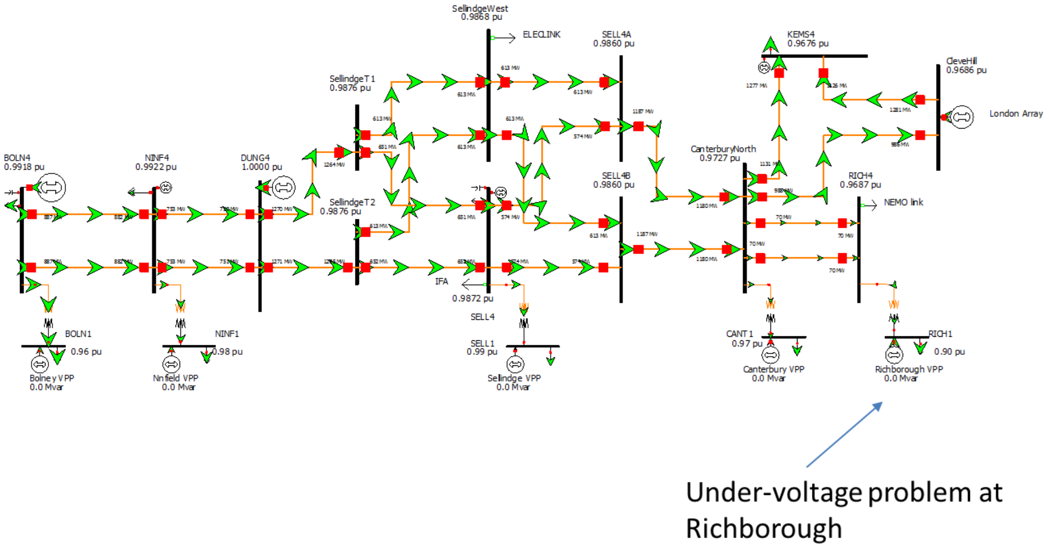


Figure E. 2 Illustration of the under-voltage problem that can be solved using DER services

The study uses the winter peak condition where the system loading is relatively high and coincides with low renewables (RES) output and no import from the interconnectors. This condition results in a low-voltage problem across the test system; notably, the voltage at the node RICH1, i.e.132 kV substation in Richborough[2] at the end of long transmission corridor is at the lower limit[3]. In order to solve this problem, NETSO considers reactive power services from 5 VPPs present in the system, i.e. VPP at Bolney, Ninfield, Sellindge, Canterbury, and Richborough. The amount of reactive power services that would need to be contracted from each of the VPP to solve the voltage problem not only in the intact system but also in the contingent conditions is calculated using the Imperial's SCOPF model. The results are shown in Figure E. 3.

The modelling results indicate that the value of reactive power service from Richborough is higher than the value of reactive power services from other VPPs in different locations. This shows the locational specific value of reactive power support. The results are expected considering that the voltage at Richbourough is the lowest one and therefore, injecting reactive power at that location will be the most effective solution. Given the initial assumption in this study that all VPPs bid the same price (i.e. £3/Mvarh) for their reactive power services, the model proposes VPP Richborough provide all reactive power needed.

Without reactive power support at Richborough and other VPPs, transmission-connected generating units at Dungeness have to be engaged. Due to the distance between Dungeness and Richborough, reactive services from Dungeness will be less effective to support voltages at Richborough than the local services. The study also demonstrates that by enabling access to DER services using the VPP concept, the number of service providers increases and there are more

[2] Note that 400kV Richborough transmission substation is not currently present and it will be developed in near future.

[3] In this study, the voltage drop limit is 10%.

options available. This will stimulate market competition in providing the reactive power services.

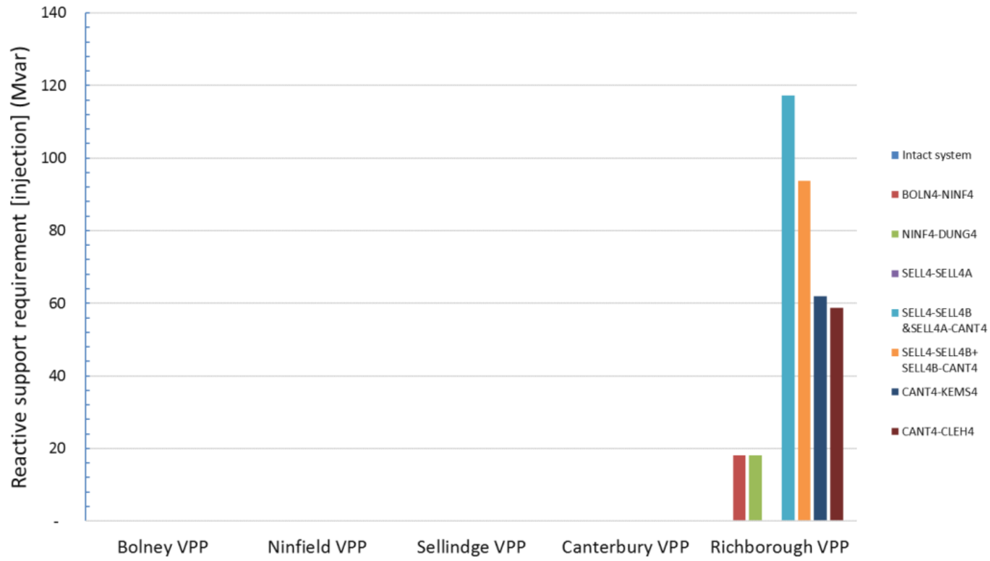
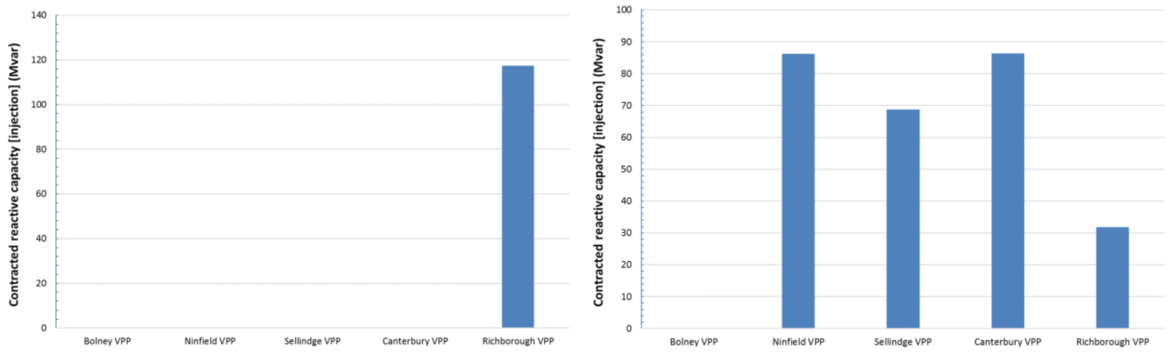


Figure E. 3 Optimal volume of reactive power injection needed from each VPPs

It is also interesting to note that in the context of VAR support, the system requirement for VPP is mostly driven by contingencies as shown in Figure E. 3. Thus, it can be concluded that most of the value of reactive services is associated with the *capacity / availability* rather than with *utilisation* of reactive services.

The results show the different volumes of reactive power will be needed depending on the system condition. In the intact system, although the voltage is at the lower limit, it is still within the permissible limit, and therefore, there is no need for additional reactive power. More severe voltage problems occur during outages of transmission circuits. There is a need to inject 118 MVAr when a fault occurs disconnecting the line between SELL4 and SELL4B. This demonstrates that the reactive power requirement will be system condition dependent. Given that the conditions are dynamically changing over the time, the value of reactive power becomes time specific as well.

To deal with all credible contingencies, the volume of reactive power services needed to be contracted from Richborough VPP is 118 MVAr. To illustrate the locational importance of reactive power support, the analysis is carried out assuming that Richborough VPP decided to bid five times higher prices than other VPPs. In this case, the model relocates the reactive power contracts to other VPPs to minimise the overall cost; the results are shown in Figure E. 4.



(a) Same bid (b) Bid five times higher

Figure E. 4 Optimal volume of reactive power contracts allocated to different VPPs for different bids

This analysis demonstrates the following[4]:

- When Richborough VPP bids five times higher prices when compared with other VPPs, the model reallocates some of the reactive services to other VPPs. As the voltage sensitivity of other VPPs is lower, this will require a larger volume of reactive power to be contracted to solve the problem. Although the volume of reactive power is larger, the cost will be lower compared to the cost of reactive power services supplied only by Richborough VPP.
- As the value of reactive power services varies depending on the volume offered, in this particular case around 32 Mvar services from Richborough VPP would be still needed as this is the least-cost solution. Alternatively, a higher volume of Mvar services, possibly from more distant nodes, would be required leading to further increase in cost.

2. *Different market timescale may require a different portfolio of reactive capacity to be contracted to cope with the range of possible conditions within the associated time scale*

Reactive power requirements vary depending on system conditions, e.g. during low-loading conditions, more reactive absorption may be needed to mitigate over-voltage problems while during high-loading conditions, the reactive injection will be used to prevent voltage reductions (Figure E. 5). Therefore, the duration of the reactive service will have an impact on the portfolio of reactive power contract needed. If the market is (near) real-time, then the range of system conditions that should be covered by the contracted reactive portfolio would only include the intact and contingent conditions considered for that particular operating snapshot. If the duration is longer, for example, a day-ahead market, the contracted reactive services should cover all spectrum of the possible operating snapshot that may materialise on that day. This will generally increase the portfolio of reactive services as the system conditions vary. This is illustrated in Figure E. 5.

[4] These findings apply to the voltage problem studied in this scenario; other system conditions may result in different allocation and volumes of reactive services.

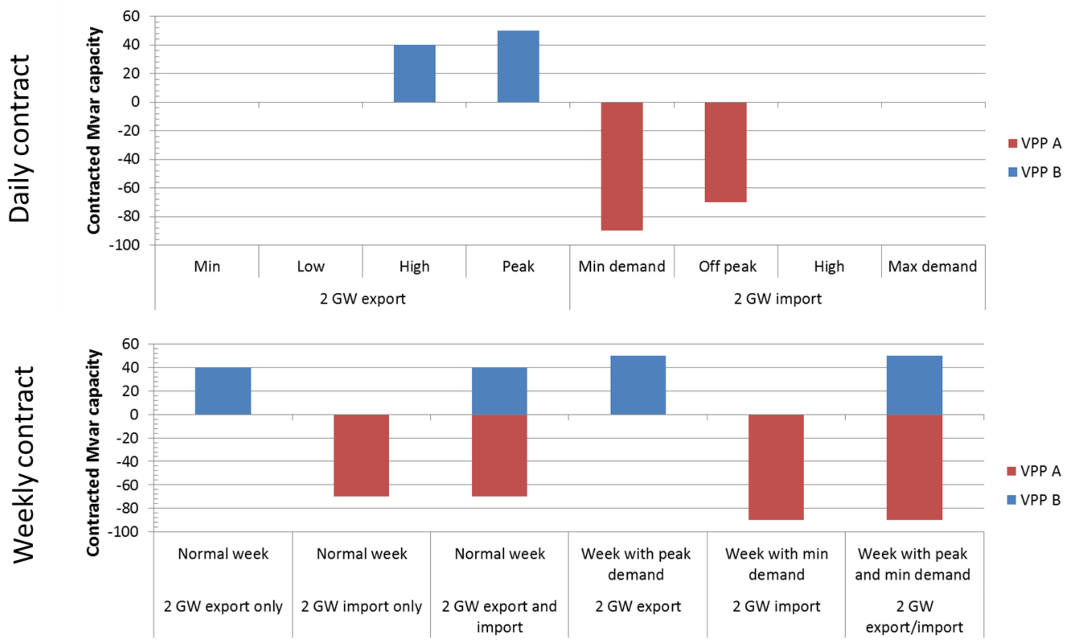


Figure E. 5 Illustrative example of the impact of having a different market timescale on the portfolio of the reactive power contract

In this particular case, a day-ahead market may be considered as appropriate compromise between the (near) real-time market and long-term market (>weeks). While the real-time market could provide efficient economic signal related to the real-time value of the services, the prices would be volatile; it would also increase the complexity of market operation as the time window for operating decisions to be taken would be much shorter than the one with the day-ahead market. This could also increase the transactional cost of the process involved in the trading. In contrast, the long-term market may provide simpler market process, more stability in terms of prices and the availability of resources, but it would tend to lead to a static or less dynamic market, which may undervalue the services and discourage new participation to the market.

There are two possible approaches to allocate the reactive power services to support the transmission and distribution network operations. The approaches are described as follows.

- A sequential approach where DER services are used to solve the local network problems first; the remaining capacity can be offered to TSO. The advantage of this approach is to decompose the problems into local network problems and transmission network problems. However, actions at distribution can affect transmission positively or negatively.
- An integrated approach where transmission and distribution network problems are solved simultaneously using all the resources connected to both systems. This approach would be more complex in terms of system control and the computational time required to identify the optimal portfolio of contracts, as the optimisation problems become much more complicated.

The pragmatic sequential approach will be demonstrated in the Power Potential, which will support coordination between DSO and TSO. Furthermore, it is important to note that DER may provide services to both distribution and transmission network at the same time, as demonstrated in the modelling. In this context, appropriate cost allocation would need to be developed.

3. *The VPP concept enables the aggregated capability of resources and network assets to be quantified and used without violating local distribution network constraints.*

Virtual Power Plant is an overarching representation of a portfolio of DER and network (Figure E. 6). VPP not only aggregates the capacity of many diverse DER, but it also creates a single operating profile from a composite of the parameters characterising each DER and incorporates spatial (i.e. network) constraints into its description of the capabilities of the portfolio. The VPP is characterised by a set of parameters usually associated with a traditional transmission connected generator, such as scheduled output, ramp rates, voltage regulation capability, reserve etc. Since the VPP parameters are derived taking into consideration the network constraints, the active and reactive power capability of VPP inform NETSO on the resources at distribution that can be used for transmission services without having the risk of violating local network constraints.

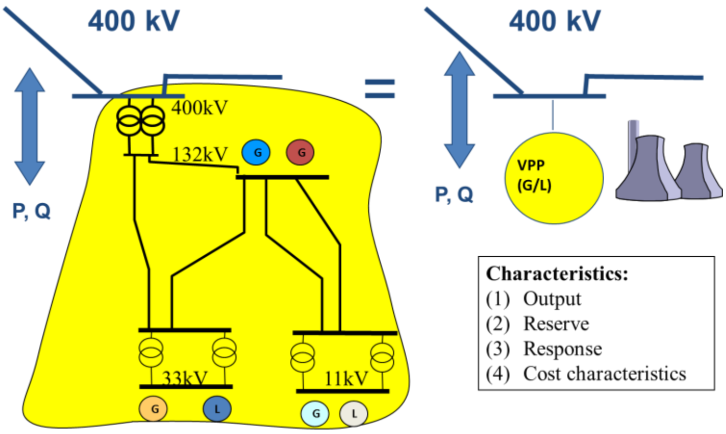


Figure E. 6 VPP as a flexible representation of the aggregated DER and networks

Five VPP models (Bolney, Ninfield, Sellindge, Canterbury, Richborough) have been developed and analysed in this report. As an example, the reactive power capability and reactive power cost function of the Bolney VPP during summer peak condition is illustrated in Figure E. 9. The study considers real distribution network, demand, and generation data in Bolney (right diagram) and uses the modelling approach to characterise the reactive capability and its active and reactive power (PQ) curve in Bolney as shown in Figure E. 7.

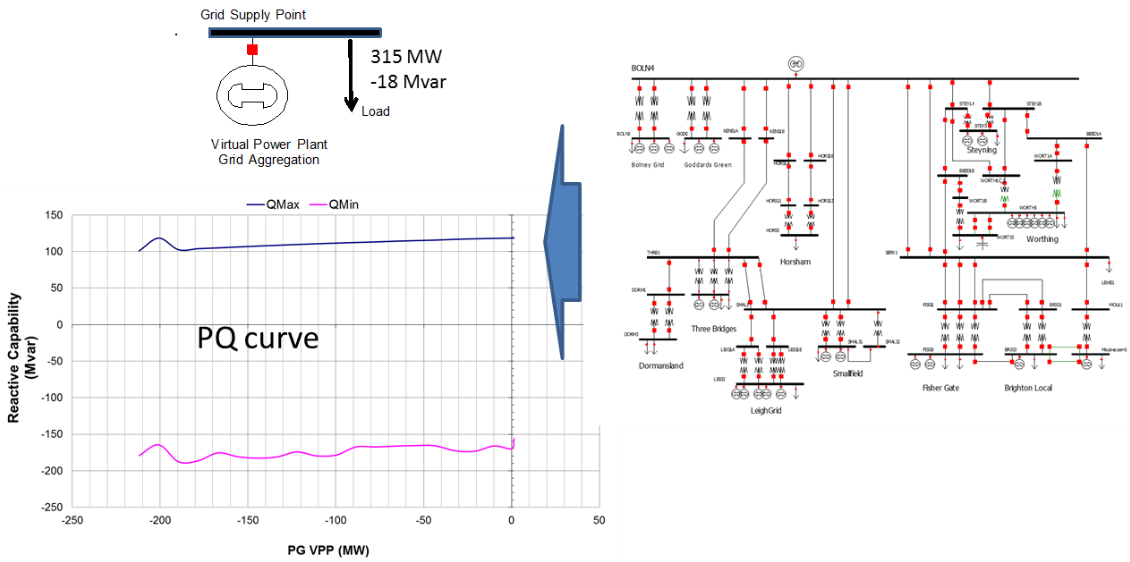


Figure E. 7 Reactive power capability and its cost function of Bolney VPP

The characteristic of the VPP also captures the network controllability, e.g. the use of tap changer optimisation for voltage control and reactive power management. It is important to note that the VPP does not only aggregate the technical characteristics of the DER and network but also captures the cost characteristics of using the resources in the system covered by the VPP.

4. *Smart operation of distribution network assets enhances reactive power services to transmission.*

We have identified that optimising transformer taps could enhance the ability of reactive resources located in the distribution network to provide voltage support to the transmission system. This is demonstrated in the results of one of the studies in characterising the cost of reactive services from Bolney VPP (Figure E. 8). There is a range of reactive power capability where the cost is zero - due to the assumption that no costs are allocated to reactive power support from distribution network assets (including reactive from distribution circuits, and reactive power compensators installed at distribution).

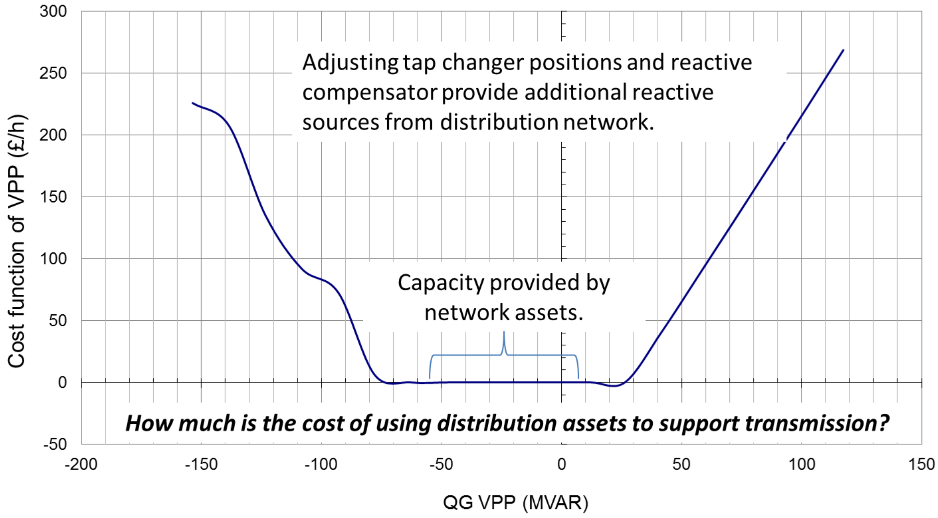


Figure E. 8 Mvar cost function [Bolney VPP] with optimised tap changers and distribution reactive assets

Another example is illustrated in Figure E. 9 where the reactive capability and its cost function is evaluated with and without utilising shunt reactive power compensation. The results demonstrate that distribution network assets can also provide reactive power services to the transmission network, similar to reactive power services from DER. Hence, maximising the use of assets would enhance their value.

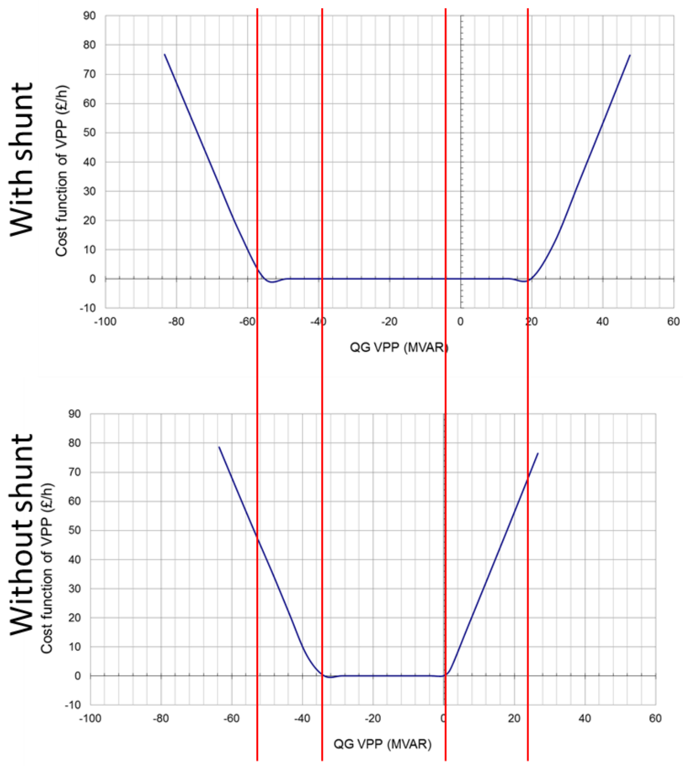


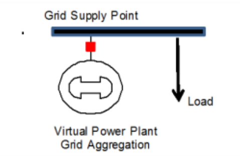
Figure E. 9 Mvar cost function [Sellindge VPP] with and without shunt reactive compensator

These results highlight the importance of having appropriate cost recovery mechanisms or incentives that should be in place to facilitate application of cost-effective measures, such as optimisation of transformer taps, or other active distribution network management measures that DSOs may take to enhance DERs access to providing services to the TSO.

It may also be possible to temporarily overload distribution network assets (e.g. grid supply transformers or overhead lines) to enhance the provision of services from DERs to the transmission network.

5. VPP's capability is dynamic and changes according to local system conditions.

In contrast to a conventional generation, parameters of the VPP will vary depending on the system conditions following the changes in demand, generation availability, network topology and conditions, network control optimisation, etc. This is demonstrated by the results of the study characterising the VPP's parameters for the Canterbury VPP using two different operating conditions: (i) summer peak and (ii) winter peak condition.



Summer peak

MW load	-63.7
MVAr load	11.6
VPP parameters	
Pmax (MW)	42.6
Pmin (MW)	-228.3
Qmax (MVAr)	86.4
Qmin (MVAr)	-115.2

Winter peak

MW load	60.5
Mvar load	29.1
VPP parameters	
Pmax (MW)	1.3
Pmin (MW)	-187.3
Qmax (MVAr)	87.5
Qmin (MVAr)	-97.1

Figure E. 10 Comparing the characteristics of Canterbury VPP in the summer peak and winter peak condition[5]

The modelling results demonstrate that during Summer Peak, the VPP exports 63.7 MW of active power to the grid and consumes 11.6 Mvar; while in the Winter Peak, the VPP imports 60.5 MW and 29.1 Mvar. Focusing on the reactive capability of the VPP, the range of reactive absorption becomes lower during the Winter Peak. This is expected since the voltage in the Winter Peak tends to be low which may limit the ability of the system to absorb reactive power further. In contrast, reactive power injection capability during Summer Peak is slightly lower, which may be constrained by the upper limit voltage. This example demonstrates that VPP's parameters are dynamic and follow changes in the local system conditions.

6. Relatively strong 132 kV and 33 kV distribution networks in South-East England enables efficient delivery of reactive power services from DER.

[5] VPP parameters reflect the capability of the VPP to modulate its output from the scheduled (expected) operating point.

As demonstrated by system studies, distribution networks can facilitate full access to DER capacity. This implies that in the intact system, the networks are relatively strong and do not cause any barrier to DER to access the market of transmission services. Constraints may occur due to outages, but in general, the network capacity is sufficient since the majority of DER modelled is connected directly to 33 kV substations. This has important implications:

- There is no loss of reactive power capability due to strong 132 or 33 kV systems.
- Faults at distribution may affect access to DER; however, the N-1 design at 33 kV or 132 kV seems to lessen the impact especially for active power services while the impact on reactive sources tends to be much higher, as expected. This is illustrated by the results of the study on Canterbury VPP which is presented in Figure E. 11.

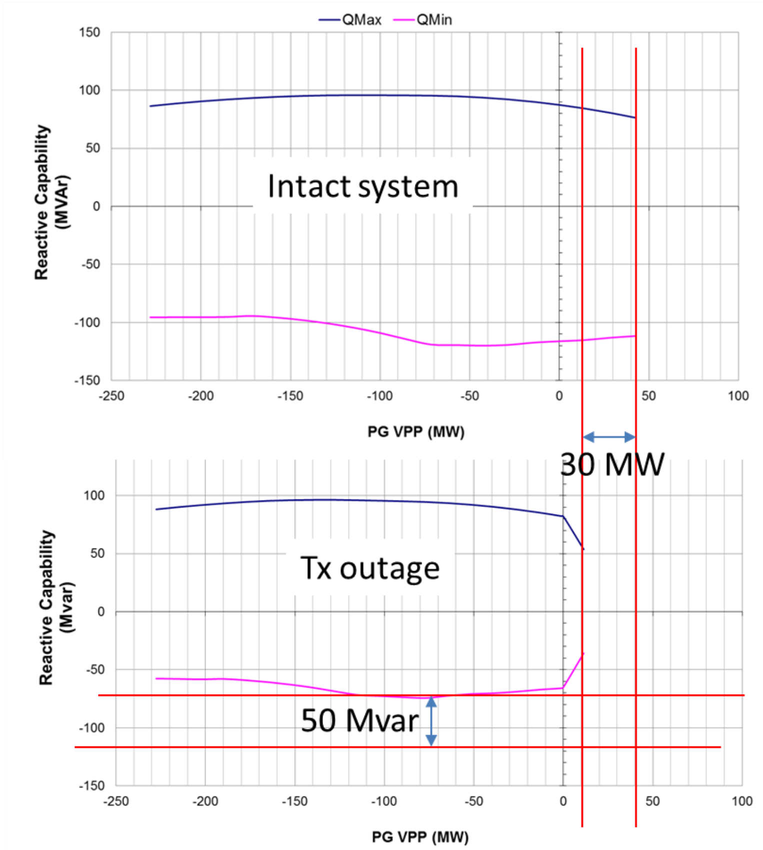


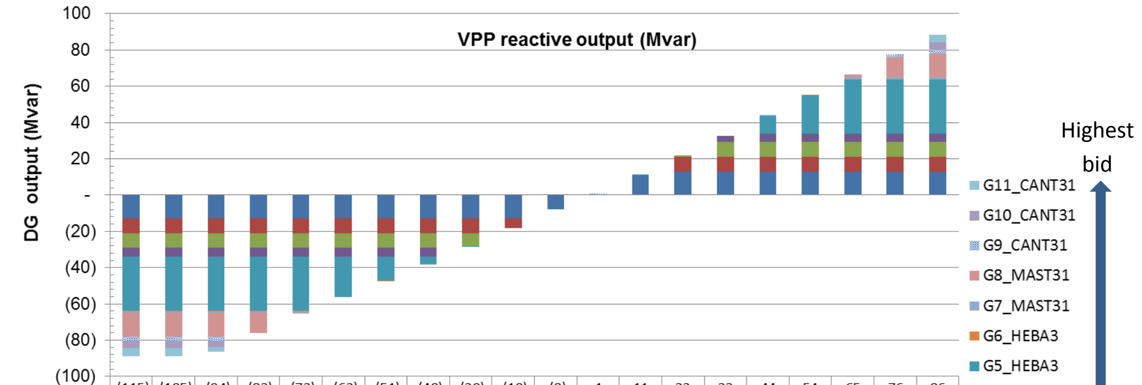
Figure E. 11 Impact of a transformer outage on the PQ curve capability of Canterbury VPP

This study investigates the impact of a transmission outage at the HEBA 132kV substation; the secondary transformer is able to maintain the network access to substantial amount of DER at the HEBA 33 kV substation, but the outage still reduces the maximum power output (PMax) capability of the VPP by 30 MW and reactive absorption capability (Qmin) by around 50 Mvar. The effect of the outage on reactive power injection (Qmax) and minimum power output (Pmin) is relatively marginal.

7. Strong distribution networks facilitate competition, the dispatch of DER is sensitive to price.

Enabling competition in the provision of ancillary services is vital to improve efficiency and minimise the cost of the services. As the distribution networks involved in the Power Potential (mostly at 132 kV and some 33 kV) are relatively strong, the networks do not impose any significant barriers for the DER to access and compete in both transmission's ancillary service markets and the provision of local services. At a certain extent, this may also be contributed by the spatial distribution of the DER which tends to be clustered and connected to the low voltage of 132/33 kV substation.

Figure E. 12 shows the dispatch of reactive power from each of the DER within the Canterbury VPP. The x-axis is the range of VPP's reactive power capability, and the y-axis shows the aggregated reactive power output of individual DER. In this example, it is assumed that G1 has the lowest bid, and G11 has the highest bid. Therefore, the dispatch is done in the merit order from G1 to G11.



	(115)	(105)	(94)	(83)	(72)	(62)	(51)	(40)	(29)	(19)	(8)	1	11	22	33	44	54	65	76	86
G11_CANT31	-4.93	-4.93	-2.14	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.28
G10_CANT31	-3.94	-3.94	-3.94	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.94
G9_CANT31	-1.97	-1.97	-1.97	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.46	1.97
G8_MAST31	-13.1	-13.1	-13.1	-10.8	-0.27	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.51	11.0	13.1
G7_MAST31	-1.05	-1.05	-1.05	-1.05	-1.05	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.05	1.05	1.05
G6_HEBA3	-0.39	-0.39	-0.39	-0.39	-0.39	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.39	0.39	0.39
G5_HEBA3	-29.5	-29.5	-29.5	-29.5	-29.5	-22.3	-13.2	-3.93	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	9.55	21.0	29.5	29.5	29.5
G4_HEBA3	-4.93	-4.93	-4.93	-4.93	-4.93	-4.93	-4.93	-4.93	-0.00	-0.00	-0.00	0.00	0.00	0.00	3.34	4.93	4.93	4.93	4.93	4.93
G3_HEBA3	-8.15	-8.15	-8.15	-8.15	-8.15	-8.15	-8.15	-8.15	-7.34	-0.00	-0.00	0.00	0.00	0.69	8.15	8.15	8.15	8.15	8.15	8.15
G2_HEBA3	-8.15	-8.15	-8.15	-8.15	-8.15	-8.15	-8.15	-8.15	-8.15	-5.50	-0.00	0.00	0.00	8.15	8.15	8.15	8.15	8.15	8.15	8.15
G1_HEBA1B	-12.8	-12.8	-12.8	-12.8	-12.8	-12.8	-12.8	-12.8	-12.8	-12.8	-7.92	0.42	11.1	12.8	12.8	12.8	12.8	12.8	12.8	12.8

Figure E. 12 Reactive power dispatch of each DER in Canterbury VPP

A sensitivity study was also carried out by reversing the merit order of the generator bids; the dispatch is also changed according to the new merit order. This demonstrates that the dispatch is sensitive to the bid price and therefore, this should promote the competition at the local level to provide reactive services.

Conclusions

As a summary, from the modelling and analysis carried out, following key findings are identified:

- The studies demonstrate that DER connected to the local distribution network, in the scope of the Power Potential project, could be used to provide reactive power services and support secure operation of the transmission network.
- The sequential reactive power market framework using the VPP approach to aggregate DER capacity and local distribution network characteristics is technically sound, and the case studies demonstrate successfully the feasibility of the concept. The application of this concept will provide DER the opportunities to access ancillary service markets at the local level and national level.

- The value of the reactive power of VPP varies with time, location, demand and system conditions. As DER is more highly distributed across the system compared to large-scale transmission connected generators, DER can provide reactive sources more effectively as it can be closer electrically to the part of the system that needs support.
- The importance of distribution active network management on dynamic capabilities of the virtual power plant has been demonstrated in the studies. This suggests that:

  (i) it would be beneficial that DSO optimises network operation to maximise the DER access not only to local energy markets but also to transmission ancillary service markets (i.e. reactive power market in the context of Power Potential). This demonstrates that it would be beneficial that the role and responsibility of DSO evolve to facilitate access for DER to transmission ancillary service markets.

  (ii) Distribution network assets can also provide reactive power support to transmission, and this resource could play a role in the reactive power market. The capability of network assets can be aggregated as well, but it requires the development of a commercial framework that can remunerate the services from distribution assets.
- The networks studied in Power Potential are capable of providing access of DER to the intact system.
- VPP reactive power dispatch is sensitive to the price, due to the high distribution network capacity, which will facilitate competition in the local reactive power market.
- The reactive capability of VPP is dynamic and changes according to local conditions in the distribution network. This requires real-time monitoring and active management of the resources.

Abbreviations

DER	Distributed Energy Resources
DG	Distributed Generation
DSR	Demand Side Response
SVC	Static Var Compensator
DSO	Distribution System Operator
SCOPF	Security Constrained Optimal Power Flow
NETSO	National Electricity Transmission System Operator
VPP	Virtual Power Plant
UK	United Kingdom

Contents

Chapter 1. Introduction

1.1 Context

Operational flexibility will be at the core of facilitating a cost-effective evolution to a low-carbon electricity system. Given the reduction in capacity of conventional fossil-fuel power generation, that historically was the key source of flexibility, evolving distributed energy resources (DER), including distributed generation (DG), distributed storage (DS) and demand side response (DSR), connected to the distribution networks, will provide core flexibility services needed for real-time demand-supply balancing and management of congestion in transmission and distribution networks.

Optimal utilisation of DER will reduce the need for investment in conventional technologies and transmission and distribution infrastructure. However, a new system operation paradigm and corresponding novel market design will be essential for enabling DER resources to support the future system. In order to facilitate cost-effective system integration of DER, the following radical changes are required:

- A shift *from isolated operation of energy supply, transmission and distribution businesses towards a more integrated approach; and*
- *Design of a new market* that would maximise the overall economic value of DER considering both national and local objectives enabling DER to provide multiple services to different sectors of the electricity system. This can be achieved if DER has the opportunities to access various markets at the local level (e.g. congestion management of distribution networks) and national level (various forms of the reserve, capacity, reactive support, network management). In this context, *the role of Distribution System Operator (DSO) needs to evolve in order to facilitate the application to DER services not only for local distribution network management but also for the benefit to the national transmission system.* This development will require significant changes in operational practices and standards, and also regulatory market and commercial frameworks.

Operational challenges arise as the use of DER by different operators may trigger conflicts between serving the local or national objectives. This indicates that coordination will be required to maximise the synergy of using the distributed resources to provide multiple services. In this context, the Power Potential project investigates the possible technical and commercial frameworks which will bridge the operational coordination between national transmission system operator (NETSO) and distribution system operator (DSO) while enabling maximum use of DER and stimulating competition in the provision of transmission services by the local DER and transmission connected generators on a level of playing field.

In order to maximise the access of DER for transmission, DSO may need to operate differently within the statutory limits as the current practices may impose a constraint on the usage of DER and hinder full access of DER to provide transmission services. For example, sub-optimal voltage management may constrain the use of the DG capacity, especially during the low-demand period. Pudjianto [1] illustrated the case where the capacity of DG that can be used for providing frequency response or reserve services was constrained by the voltage limit, especially during the low demand periods.

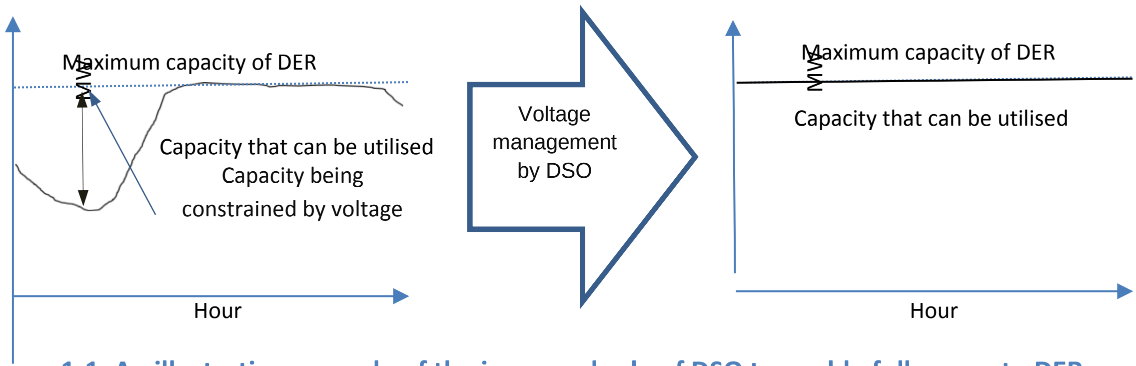


Figure 1-1. An illustrative example of the increased role of DSO to enable full access to DER capacity to provide transmission services

In this example (Figure 1-1), the high output of DG in low-demand periods would cause voltage-rise effect and may trigger the over-voltage problem if the transformer's tap position is not optimal. Improving voltage management by optimising the tap setting of distribution transformers can help relieve the 'latent' capacity of the DG so it can be used entirely to provide ancillary services needed by the system when needed.

At present, the responsibility to balance the supply and demand in the system lies on the NETSO and not on the DSO; however, the inability of the NETSO to access the capacity of DER will increase the system costs as this inability reduces the ability of the DER capacity to displace the capacity of the large-scale generators which are the traditional sources for system flexibility for the NETSO. As a consequence, this also means that the utilisation of the capacity in the system will be less reducing the overall system efficiency. In this context, the DSO will need to start optimizing their distribution system management not only for DSO's objective but also to enable NETSO access to DER optimally bearing in mind the constraints at distribution networks. This DSO's whole-system thinking aims to reduce the overall system costs.

In this context, the Power Potential project investigates the possible technical and commercial frameworks which will bridge the operational coordination challenges between NETSO and DSO while enabling maximum use of DER and stimulating competition in the provision of transmission services from the local DER and transmission connected generators with the same level of playing field.

1.2 Key objectives

The principal objective of the work described in this report is to inform the development of market arrangements and the commercial framework through selecting the most cost-effective portfolio of contracts for the provision of reactive power support based on offers from different service providers (range of Virtual Power Plants (VPP) and conventional sources). The optimal allocation of the contracts is based on the offers from different service providers including DER and conventional sources with the aim to provide adequate reactive sources for delivery of voltage control across a set of loading conditions while considering credible contingencies.

In this analysis, it is critical to explicitly take into consideration the variation in the availability and cost characteristics of DER and the dynamic changes in the local distribution system conditions in coordination with the state of the transmission network. The commercial arrangements should consider differences in costs that market participants would offer in the auction process.

The outcome of this analysis aims to inform SDRC 9.3 which describes the tendering processes, the initial projection of the volumes of DER services for various technologies that can be contracted to support transmission operation, and the development of the methodology to allocate the reactive services contracts based on the tendering process to be conducted in the trials.

1.3 The scope of the work

The scope of the work described in this report can be grouped into the following areas:

1. Development of the market framework to maximise the benefits of DER services in supporting secure operation of transmission and distribution networks. In this task, a set of possible market arrangements considering the use of the different length of contracts has been analysed and illustrated. In addition, an approach that enables the use of DER services for transmission and distribution network management system using the Virtual Power Plant (VPP) concept has been reviewed and evaluated.
2. Development of the VPP methodology for determining the available aggregated capacity, technical and commercial characteristics of the reactive sources at the distribution network. A non-linear SCOPF model has been used to quantify the spectrum of active and reactive power contracts needed to support transmission network operation.
3. Construction of the simplified Power Potential commercial VPP models of the relevant distribution networks in the South East region. Based on the 33 kV network data, and the selected scenarios with respect to the installed capacity and locations of the Distributed Energy Resources, a set of the VPP models has been constructed using the developed methodology. The VPP models will enable the DER connected at 33 kV (and below) to be represented as large-scale power generators in support of the secure operation of the transmission network. In this task, the VPP concept is applied as the commercial interface between NETSO and DSO.
4. Construction of the network and system backgrounds for the transmission studies with the VPPs. In this task, the transmission and distribution grid of interest (in the South East) have been modelled based on the data provided by National Grid and UK Power Networks. A set of optimal security constrained power flow analyses have been carried out taking into consideration a range of critical contingencies to identify how the reactive power and voltage control requirement changes in the system and to determine the

locations and the magnitude of service contracts needed to deliver transmission network security at the minimum cost.

5. Studies on the optimal allocation of reactive power contracts with DER. A set of simulation studies has been carried out to demonstrate the concept and identify the optimal volumes of reactive power contracts from the VPPs and traditional sources (e.g. large-scale generators) needed to support secure operation of the transmission network. Sensitivity analysis has also been performed to determine the drivers (conditions) and cost competitiveness of the reactive power services across different providers including DERs and traditional sources.
6. Synthesis of the key conclusions found based on the modelling results and the analysis.

Following the structure above, the results of the work are described as follows.

Chapter 2. Market Framework for DER-based Network services

The development of the market framework for DER-based network services should be put in the context of maximizing the overall social economic welfare of the system. This particular topic is critical in the system where transmission and distribution systems are planned and operated by different commercial entities resulting in coordination challenges technically and commercially among planners and operators in different commercial entities. In order to maximise the value and benefit of DER, the whole-system approach – such as the Power Potential - should be used instead of optimizing the use of DER based on a single system operator's interest.

2.1 Whole-System versus Silo approach

DER provides alternatives for DSO and NETSO to manage and solve their network problems. However, as the current practice in Europe, NETSO and DSO are operated by different commercial entities with their own objectives. This raises an important question on how DER should be controlled to maximise its value. As the use of DER for transmission is relatively new, there is still no clear framework put in place to address this issue. At present, NETSO deals with aggregators to purchase ancillary services from DER; however, this commercial arrangement does not involve DSO. There are two main issues associated with this approach.

- First, the DSO may not be able to use the DER capacity that has been contracted by NETSO although the capacity is not used by NETSO at the time when DSO needs it. This is due to a contractual obligation between the NETSO and DER which does not allow the DER capacity to be used by other entities. As the DER can be used by DSO to defer network investment, the loss of this ability leads to higher distribution network costs. Bear in mind that NETSO does not have interest in reducing DSO's cost.
- Second, the use of DER by NETSO may trigger the violation of local network constraints, which will be addressed by DSO by limiting the usage of DER.

The second approach, DSO controls DER for its own objectives. This can be for improving supply restoration, voltage quality, or flow management through active demand and maximising the use of microgeneration. However, as DSO does not have commercial interests to reduce the transmission operating costs, DSO's ANM may not be optimal from the overall system perspective and limit the NETSO's access to DER leading to increased generation and transmission costs. For example, the decision by DSO to reduce the peak load of its distribution network by shifting the peak demand to off-peak demand may increase transmission congestion if the local network is in the exporting area. A classic example of this situation is the GB case where the electricity flows from the North to South. Reducing the North's distribution load during high export conditions will increase transfer capacity requirement between the North and

South boundaries. In a specific case, the cost of reinforcing transmission can be higher than the benefit obtained by reducing distribution load.

In order to overcome the weakness of the previous two silo approaches, the third approach optimises the control from the whole-system perspective. In this approach, there is a requirement to have control coordination between DSO and NETSO to maximise the use of DER to provide services for both distribution and transformer. This can be achieved for example in the centralised control environment where the transmission and distribution systems are optimized simultaneously, and therefore the resources can be utilized in the most economical way taking into consideration all system constraints. However, in the current system where transmission and distribution are optimized separately, improving NETSO and DSO coordination is a complex challenge.

Previous studies by Imperial [2] analysed three aforementioned approaches to assess their relative benefits for the GB system:

- Whole system approach, i.e. coordinated operation and design of the transmission and distribution networks, which would enable DER to be used to maximise the whole-system benefits by managing the synergies and conflicts between local and national level objectives (e.g. maximising the value of combined benefits delivered through energy arbitrage, providing support to local and national network infrastructure, delivering various ancillary services to optimize system operation, while reducing the investment in conventional and low-carbon generation capacity).
- Transmission centric model, which focuses on the use of available flexibility resource for deferring transmission/interconnection investment and reducing system operating costs, while ignoring the benefits of DER to the distribution network.
- Distribution centric model, which focuses on managing local distribution network operation and investment through applying DER for peak demand reduction at the local network.

The savings due to integrating new sources of flexibility such as demand response and DG in all three approaches are shown in Figure 2-1.

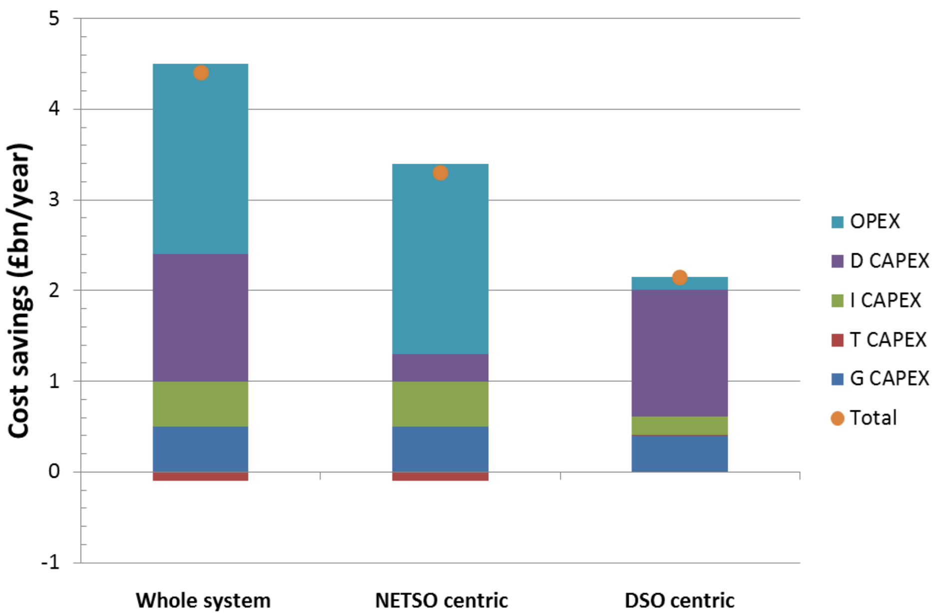


Figure 2-1. system benefits of the Whole system versus silo approach (TSO/DSO centric)

It is important to highlight that the savings include not only distribution CAPEX (D CAPEX) but also CAPEX of power generation (G CAPEX), interconnection (I CAPEX), transmission (T CAPEX) and savings in OPEX. This suggests that the flexibility provided by DER facilitated by th*e use of smart technologies can benefit not only local distribution networks but also the overall national electricity system*. In this example below, e.g. the whole-system case, the cost savings in distribution network cost is only 1/3 of the overall system savings. Therefore, ignoring the savings beyond the distribution is inappropriate and wasting 2/3 of the value.

The savings are primarily due to the lower requirement of the system capacity as the peak load can be shifted to off-peak period and the operational efficiency also improves as the DER also enables the use of resources more efficiently by contributing to the provision of ancillary services. This result also suggests that restricting the use of DER only for managing distribution network will reduce the value of DER substantially which may discourage development and deployment of DER technologies in the system.

The results demonstrate that the use of DSO centric approach, the benefit to distribution will be maximized; however, the other benefits, i.e. savings in generation and transmission/interconnection will be substantially less. On the other hand, the benefits of the NETSO centric are dominated by the savings in OPEX, generation and cross-border interconnection costs while the saving in distribution cost is much smaller compared to the one found in DSO centric approach.

On the other hand, the whole-system approach can maximise the total system benefits although the savings in distribution CAPEX in the whole-system is slightly less than the savings in DSO centric approach and the savings in OPEX in the whole-system is slightly less than the savings in NETSO centric approach. This example demonstrates that the coordinated (i.e. whole-system) approach may result in significant additional savings in system operation and investment costs, i.e. between £1.1bn/yr and £2.3bn/yr, relative to transmission or distribution network-centric models.

Before establishing stronger control coordination between DSO and NETSO, there is a need for clearly defining their future roles and responsibilities and through establishing appropriate regulatory and incentives frameworks. The whole-system concept has attracted some attention and some recent activities, in Europe including the UK, have attempted to clarify the future roles and responsibilities of system operators. For example, Ofgem and BEIS in the UK have recently proposed alternative models for the future roles of system operators (at both transmission and distribution levels)[3]. In this context, Transmission and Distribution Interface Steering Group of Energy Network Association's (ENA), also aims at providing the strategic direction and to identify the upcoming TSO/DSO issues [4].

2.2 The strategic role of DSO

The current model of contracting transmission services from DER does not allow a substantial operational (and planning) coordination between NETSO and DSO as the involvement of the local network operator is considered minimal. NETSO makes a direct contractual arrangement with DER or aggregators without strong coordination with DSO. This practice works well when the volume of DER service is considered small and does not affect significantly the operation of the local network. However, increased capacity and participation of DER to provide transmission ancillary services as well as rolling out of the active distribution network management requires a fundamental review of the current model because of the following reasons:

- In the active network management, the utilisation of DER may be constrained due to the requirement to manage the local network. This implies that *DSO may need to adjust their operating conditions to enable more access for DER to provide transmission services*;
- There is a need to have the synergy of using the local DER for both transmission and distribution network services and to prevent conflicts caused by different objectives applied by different users of DER services.

In this context, the future model (Figure 2-2) envisages a stronger interaction between NETSO-DSO and more active roles for DSO in enabling access for DER to NETSO's ancillary services while at the same time using the services for managing distribution constraints.

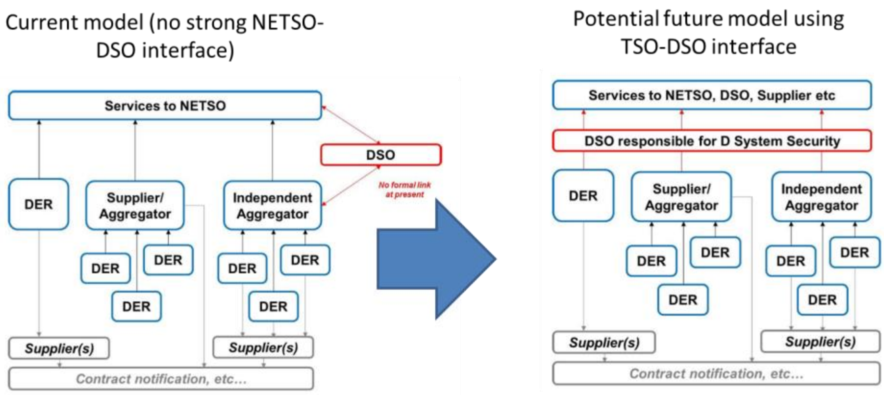


Figure 2-2 A potential future model of TSO-DSO interface[6]

[6] Source: ENA's report on the Commercial Principles for Contracted Flexibility [5] which assumes that DSOs have a range of contracts with DER for distribution network management purposes.

In the future model, DSO may have a central role in providing the interface between NETSO, DER and independent aggregator. This framework allows DSO to maximise the value and system benefits of DER by enabling DER to provide both distribution and transmission services as well as facilitating DER to access energy market. DSO will also have a role in providing aggregated information to NETSO on the volume of DER that can be accessed by NETSO. This information is not static but dynamic following the changes in the DER availability and local system conditions. It is important to highlight that an outage at distribution may have a significant effect in reducing the volume of DER that can be accessed by transmission and DSO would be the best entity to capture this effect and provide such information to NETSO.

2.3 Overall approach in developing reactive power markets

Based on this future model, a sequential two-stage approach has been developed and used to carry out some case studies demonstrating the feasibility and effectiveness of the proposed approach.

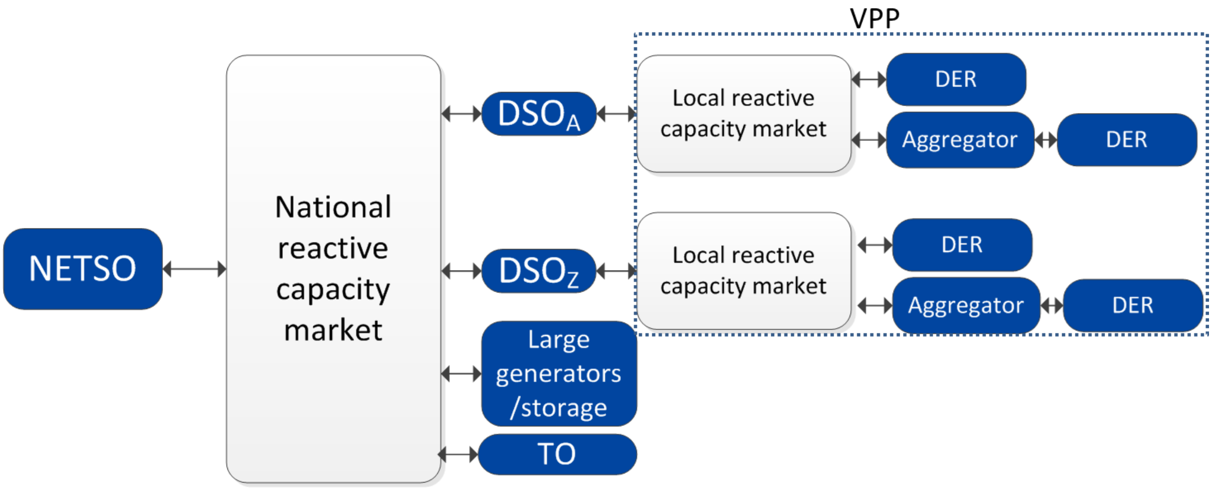


Figure 2-3 Provision of reactive power sources via local and national market

The approach is described as follows:

1. The first step is to aggregate the technical and economic characteristics of the DER taking into consideration the distribution network constraints while optimising the network assets and control settings. This enables all distributed energy resources including the network assets to be presented as a large-scale transmission-connected generator which is fundamentally the concept of virtual power plant (VPP). Within the VPP area, DER will compete in a local energy market to provide their services to both distribution and transmission system.

2. The second step involves the application of security constrained optimal power flow (SCOPF) algorithm to identify the optimal portfolio of commercial contracts in the national reactive capacity market, of different durations, considering temporal changes

in cost and capability of VPP in order to support secure transmission system operation. At present, traditional tools for selecting contract portfolio for voltage control of the transmission network are not capable of taking these effects into account. The services from VPP will compete with services from transmission-connected generators on a level playing field basis.

By using this two-stage approach, alternative designs of services market for voltage control that may be specific to system conditions and different contract durations have been investigated. The enhanced VPP tool and SCOPF algorithm have also been used to carry out a range of studies to demonstrate the feasibility of the proposed concept. An alternative approach is to solve the local and national reactive market concurrently, which further optimises the allocation of reactive power sources as it ensures the complete synergy of using DER for both distribution and transmission objectives. The pros and cons of both approaches are subject to our investigation in the next phase of this project.

2.4 Virtual Power Plant

Virtual Power Plant (VPP) is comparable to transmission connected generating plant (Figure 2-4) as defined in [6]. Transmission connected plant has a profile of characteristics, e.g. schedule of generation, generation limits, operating cost characteristics etc.; using this profile individual plant can interact directly with other market participants to offer services and make contracts. Via direct communication with the transmission system operator or through market-based transactions, a transmission connected generating unit can contribute to system management. Generation output and other associated services can be sold through interaction in the wholesale market or direct contact with energy suppliers and other parties. When operating alone many DSR resources do not have sufficient capacity, flexibility or controllability to make this system management and market-based activities cost effective or technically feasible. However, with the creation of a Virtual Power Plant through aggregating a group of DER, these issues can be counteracted. Instead of controlling a large number (millions) of individual, small-scale DER, NETSO only controls a manageable number of VPPs and large-scale generators.

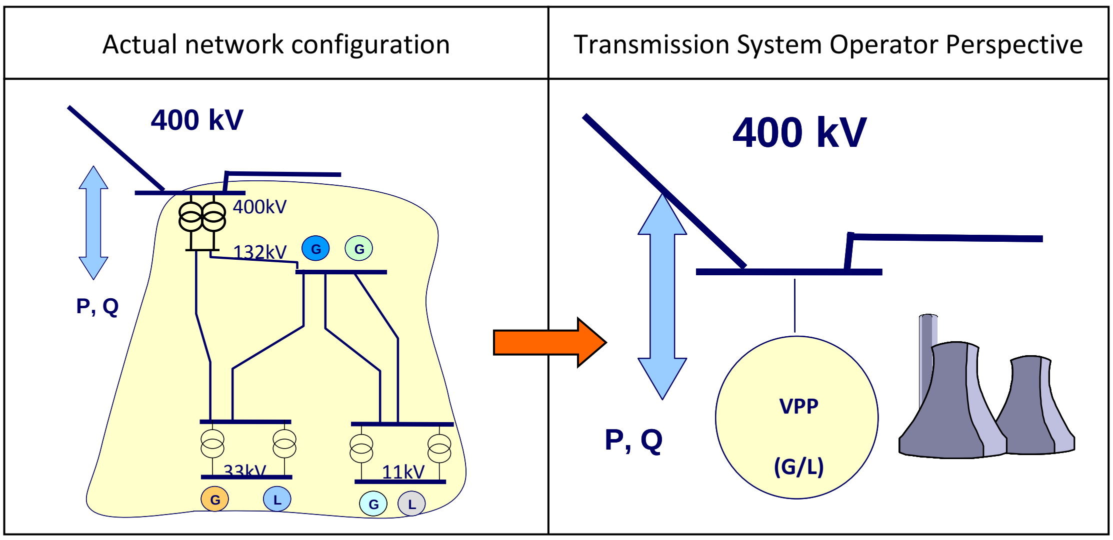


Figure 2-4 Characterisation of DER as a Virtual Power Plant

A Virtual Power Plant is a flexible representation of a portfolio of DER that can be used to make contracts in the wholesale market and to offer services to the system operator – subject to the firmness of access to distribution networks. A VPP not only aggregates the capacity of many diverse DER, but it also creates a single operating profile from a composite of the parameters characterising each DER and incorporates spatial (i.e. network) constraints into its description of the capabilities of the portfolio. The VPP is characterised by a set of parameters usually associated with a traditional transmission connected generator, such as scheduled output, ramp rates, voltage regulation capability, reserve etc. Furthermore, as the VPP also incorporates controllable demands, parameters such as demand price elasticity, load recovery patterns are also used for characterisation of VPP. Table 2-1 outlines some examples of the generator and controllable load parameters that can be aggregated and used to characterise the VPP.

Table 2-1 Examples of generation and controllable load parameters for aggregation to characterise a Virtual Power Plant

Generator parameters	Controllable load parameters
• Schedule or profile of generation • Generation limits • Minimum stable generation output • Firm capacity and maximum capacity • Stand-by capacity • Active and reactive power loading capability • Ramp rate • Frequency response characteristic • Voltage regulating capability • Fuel characteristics • Efficiency • Operating cost characteristics	• Schedule or profile of the load • The elasticity of load to energy prices • Minimum and maximum load that can be rescheduled- Active and reactive power loading capability • Load recovery pattern • Ramp rate • Frequency response capabilities • STOR capability • Voltage regulating capability • Operating cost characteristics

Given that a VPP is composed of a number of DER of various technologies with various operating patterns and availability, the characteristics of the VPP may vary significantly in time. Furthermore, as the DER resources that belong to a VPP will be connected to various points in the local distribution network, the network characteristics (network topology, impedances, losses and constraints) will hence also impact the overall characterisation of the VPP.

The VPP can be used to facilitate trading of DER in the wholesale energy markets (e.g. forward markets and the Power Exchange) and can provide services to support transmission system management (e.g. reserve, frequency and voltage regulation) as well as to contribute to the active management of distribution networks.

2.5 Illustrative cases demonstrating the requirement and allocation of reactive power services

2.5.1 Description of the studies

To demonstrate the use of VPP concept, a set of illustrative examples has been developed. A simplified system is used for this purpose; the network resembles the network characteristic of the South-East transmission but does not reflect the actual network (Figure 2-5). The focus of this illustration is to identify at the high level, the feasibility of using VPP for supporting transmission voltages and the technical or commercial issues that may arise. The study assumes that the circuits between Kemsley and Canterbury North and between Kemsley and Cleve Hill are open due to unplanned outages; this causes some part of the South-East transmission corridor between Lovedean, and Cleve Hill operates radially. This long corridor is prone to voltage stability and congestion problems. Two VPP are modelled and connected to Bolney (VPP A) and Ninfield (VPP B) 400 kV substations to support transmission. ±5% voltage limit is used in the study.

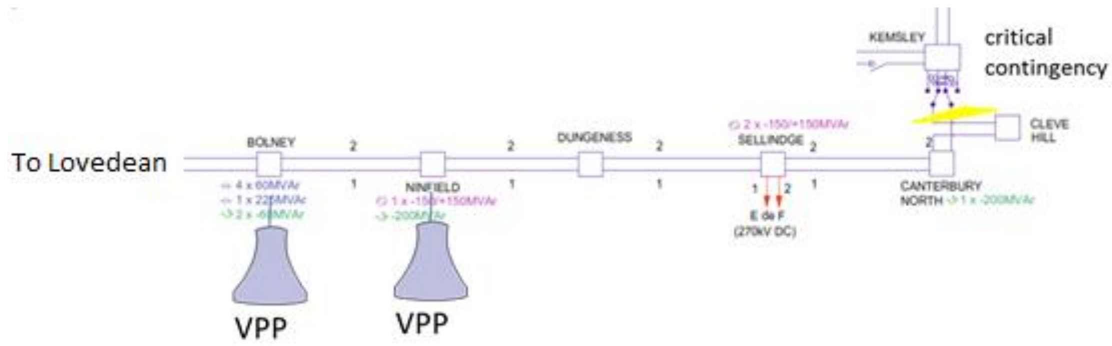


Figure 2-5 South-East transmission system model

A number of operating conditions, i.e. a set of combination using peak and minimum demand together with 2 GW export and import were simulated in the study. First, a peak condition with 2 GW export (Figure 2-5) was simulated resulting in low voltages across the corresponding system. Without any support from VPP Under-voltage problem is observed at the end of the system (node 5). There is no voltage issue when the minimum condition is used even if it coincides with 2 GW export at node 5. All voltages are within limits. This case is shown in Figure 2-7. The results suggest that the service from the VPPs will be valuable in the first case (with under voltage) while there is no need for any support from the VPPs in the second case.

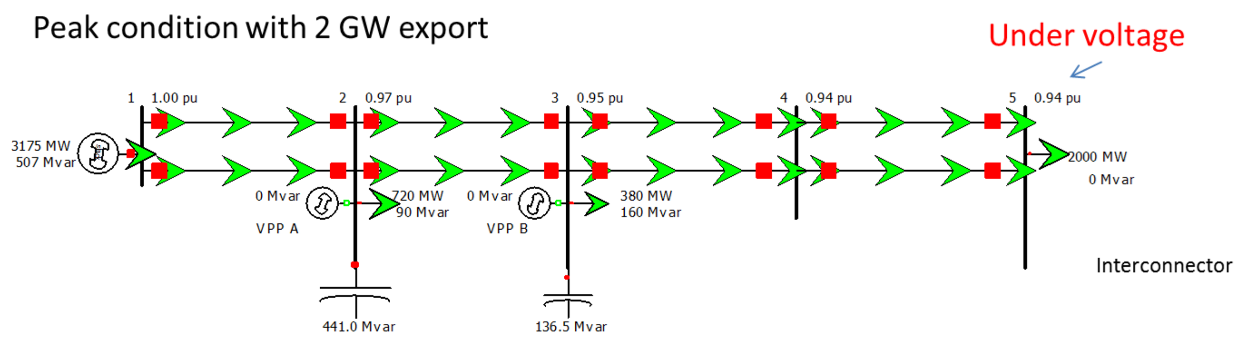


Figure 2-6 An illustrative example showing an under voltage problem during peak load condition with 2 GW export

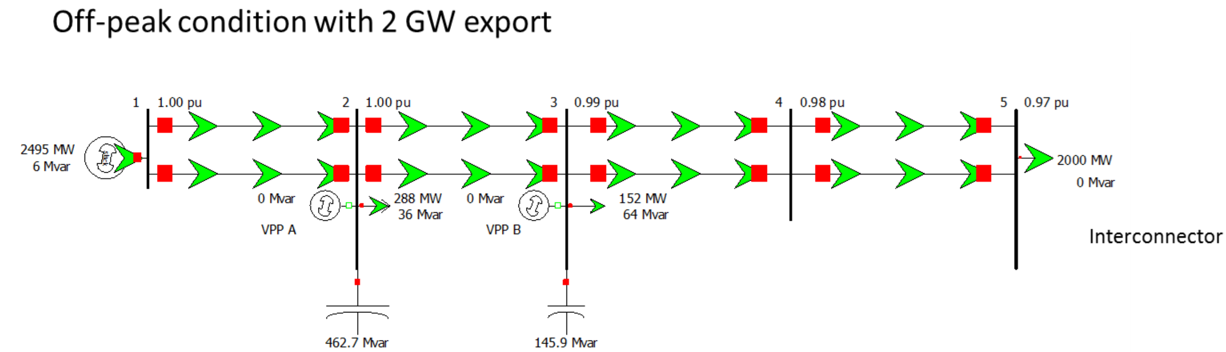


Figure 2-7 An illustrative example showing a normal minimum condition with 2 GW export

The operating condition with peak demand and 2 GW import (Figure 2-8) is secure, i.e. all voltages are within the permissible limits. During the peak demand, the importing power can reduce the flows at transmission resulting in less voltage drop across the system. In this case, there is no demand for the VPP services.

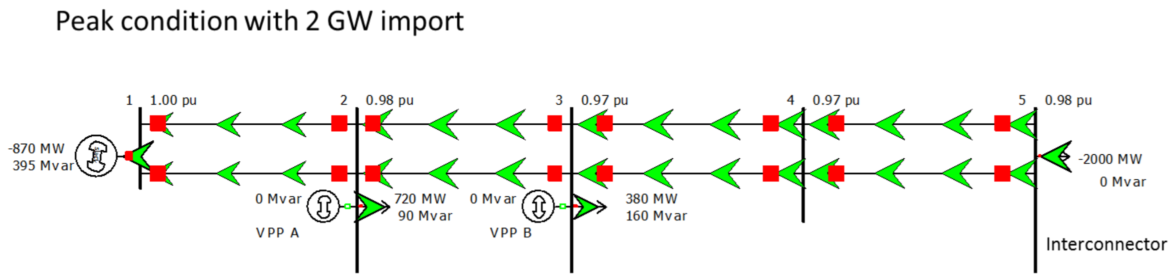


Figure 2-8 An illustrative example showing a normal peak condition with 2 GW import

The fourth case simulates the minimum condition with 2 GW import (Figure 2-9). During minimum demand, voltages are higher across the system as the lines generate more reactive power than what being absorbed. The problem is more severe as the minimum condition coincides with having 2 GW import at node 5, which increases the voltage further. Therefore, an over-voltage problem is found at node 5.

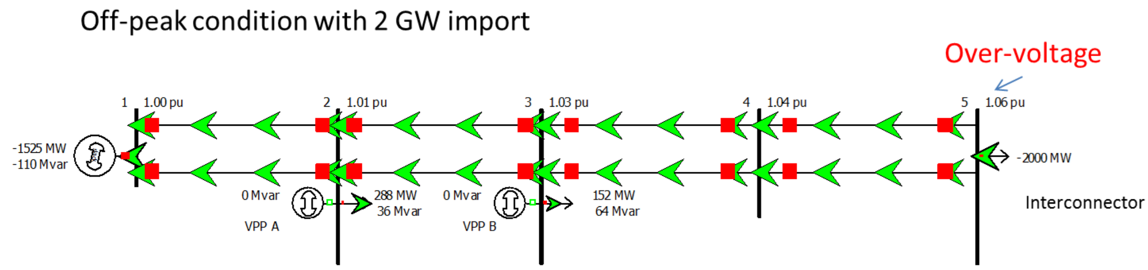


Figure 2-9 An illustrative example showing an over-voltage problem during minimum demand with 2 GW import

In order to identify the solutions for the voltage problems, reactive power services from DER via the corresponding VPP are required. The challenge is to identify and quantify the volume of the services required from each of available sources.

2.5.2 Location-specific value of reactive power services

To solve the under-voltage problem during the peak load condition with 2 GW export, 100 Mvar reactive injection from VPP A (at node 2) is required as shown in Figure 2-8; this increases the voltage at node 5 to 0.95 p.u which is the permissible lower limit (-5%). Voltages at other buses also improve.

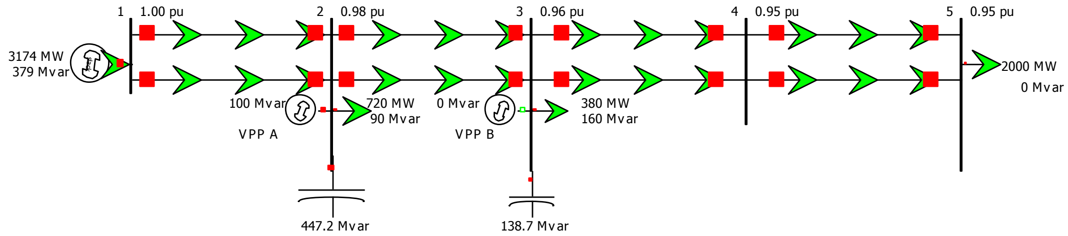


Figure 2-10 Solving the under-voltage problem using 100 Mvar from VPP A

As an alternative to 100 Mvar from VPP A, 50 Mvar reactive injection from VPP B can achieve the same solution. This is not unexpected since the VPP B is closer (electrically) to node 5 so the impact of 50 Mvar at node 3 is equivalent to 100 Mvar injection at node 2.

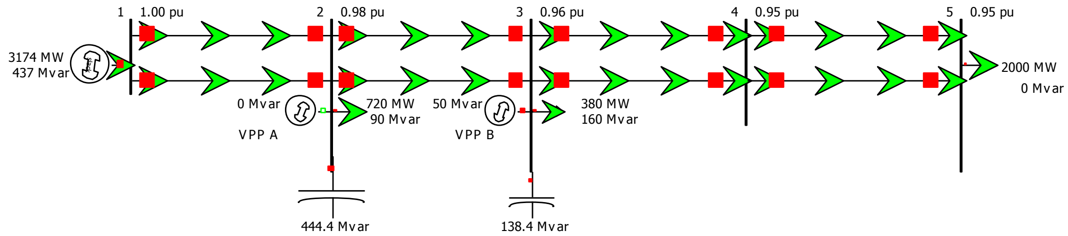


Figure 2-11 Solving the under-voltage problem using 50 Mvar from VPP B

In this case, VPP B has the location advantage compared to VPP A. To gain benefit from this location advantage, VPP B can bid up to two times the bid of VPP A. This demonstrates that the value of the reactive services is location specific. This is not a new finding since this phenomenon is already well known in the literature.

To solve the over-voltage problem, 90 Mvar reactive absorption from VPP A is needed. This will bring down the overvoltage at node 5 to the permissible upper limit as shown in Figure 2-12.

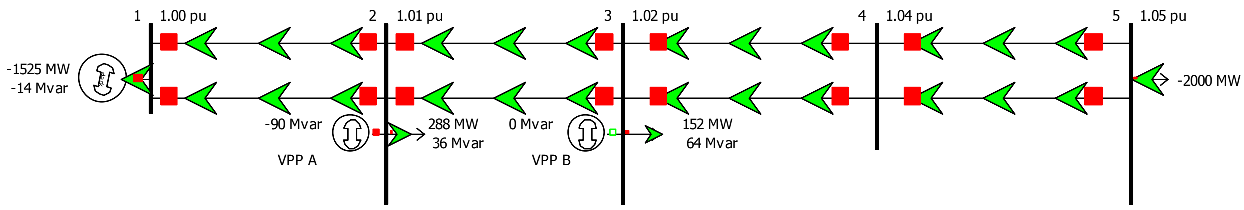


Figure 2-12 Solving the over-voltage problem using 90 Mvar absorption from VPP A

Alternatively, 40 Mvar reactive absorption from VPP B also solves the voltage problem at node 5 and reduces the voltages across the system as shown in Figure 2-13. As VPP B is located closer to node 5, its impact on the node 5's voltage is higher than VPP A similar to the phenomenon in the previous case as well.

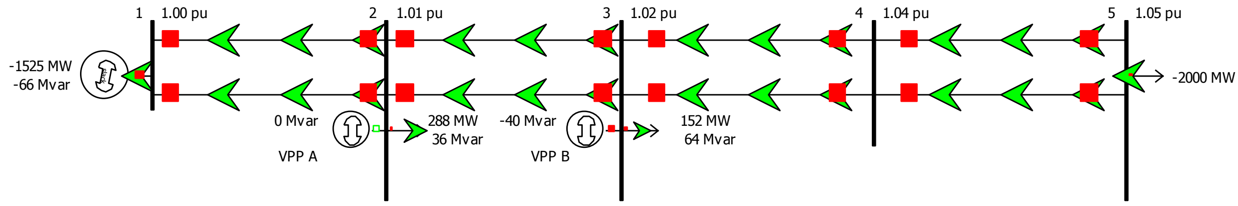


Figure 2-13 Solving the over-voltage problem using 40 Mvar absorption from VPP B

This means that VPP B can offer the bid for reactive service, in this case, 2.25 times higher than VPP A so that both offers have equal cost to the system operator.

2.5.3 Optimal allocation of VPP's reactive services

Assuming that the cost function of reactive power services from VPP A and VPP B during the peak demand condition is as shown in Figure 2-14, the optimal solution is to contract VPP B at 50 Mvar. If VPP A is selected, the cost of contracting 100 Mvar from VPP A will be £170/h. If VPP B is selected, then the cost of contracting 50 Mvar from VPP B is £115/h. Therefore, the solution is to contract VPP B resulting in lower cost. The cost of VPP A should be lower by more than 33% to be able to compete with the bid from VPP B.

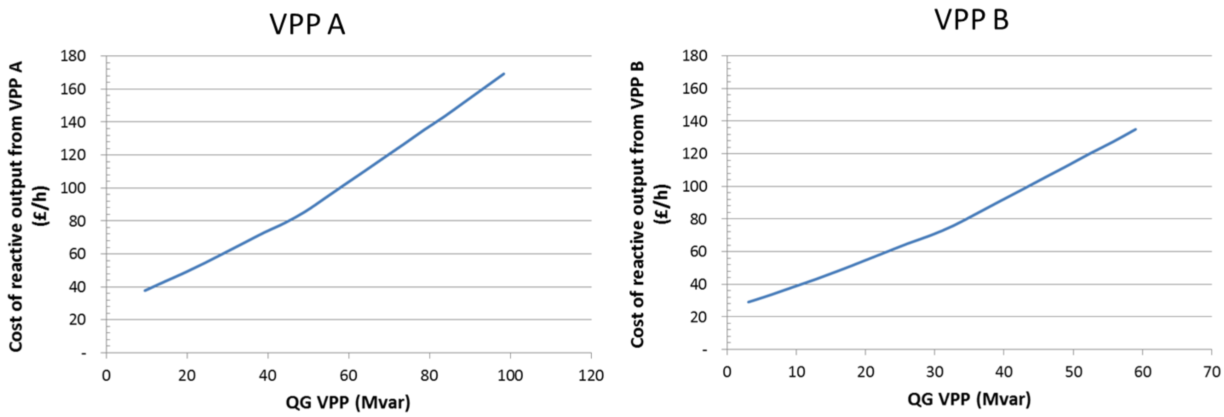


Figure 2-14 Cost function of reactive power services (injection) from VPP A and VPP B during peak demand[7]

Assuming that the cost function of reactive power services from VPP A and VPP B during the minimum demand condition is as shown in Figure 2-15, the optimal solution is to contract 90 Mvar(lag) from VPP A. If VPP A is selected, the cost of contracting 90 Mvar (lag) from VPP A will

[7] The reactive power cost function of VPP A and B in this example were created for the purpose of illustration only.

be £78/h. If VPP B is selected, then the cost of contracting 50 Mvar (lag) from VPP B is £90/h. Therefore, the solution is to contract VPP A resulting in lower cost.

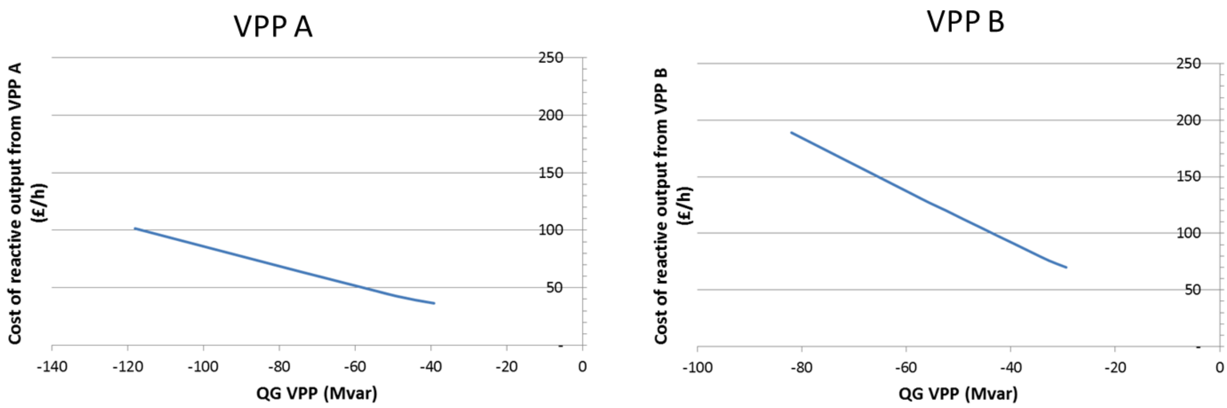


Figure 2-15 Cost function of reactive power services (absorption) from VPP A and VPP B during minimum demand

Using these results of the illustrative cases above, the reactive power contract can be allocated to VPP A and VPP B. Since the system may require a different volume of reactive power services depending on the system conditions as illustrated above, the volume of reactive power that needs to be contracted will depend on the range of plausible system operating conditions covered within the duration of the contract. Two additional demand levels were added in this example, i.e. (i) low – which is 10% higher than the minimum (min) demand, and (ii) high demand – which is 10% lower than the peak demand. The reactive requirement for the high demand condition with 2 GW export is 40 Mvar, which is 10 Mvar less than the requirement during the peak condition. The reactive requirement for low demand condition with 2 GW import is 70 Mvar (lag), which is 20 Mvar less than the requirement during the minimum demand condition.

Figure 2-15 shows an example of how the reactive power services are allocated to VPP A and B on a daily basis assuming that there is only one condition that dictates the reactive requirement. For example, if the day ahead operational planning forecasts that the high demand may occur and coincide with 2 GW export, then VPP B will get a contract to provide 40 Mvar (injection). If the forecast suggests that low demand may occur and coincide with 2 GW import, then VPP A will get a contract to provide 70 Mvar(lag). The contract allocated to VPP A and VPP B for different conditions is illustrated in Figure 2-16.

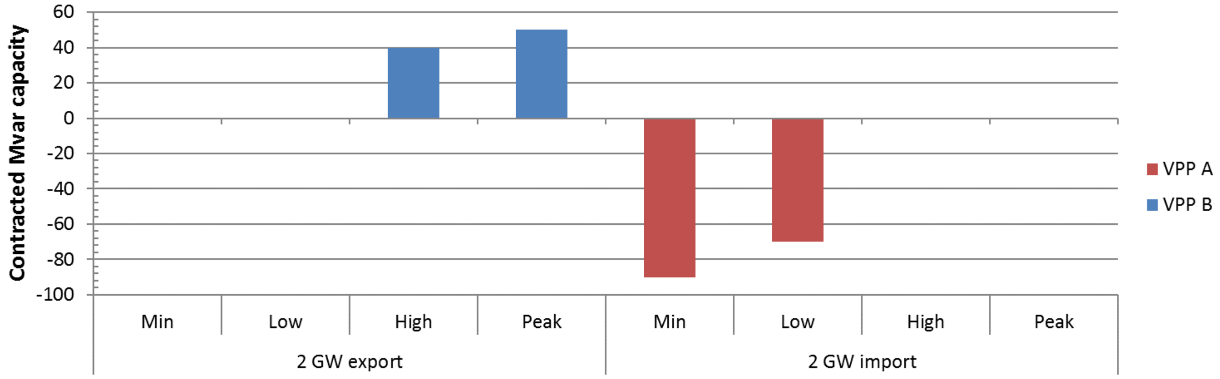


Figure 2-16 Allocation of reactive power contract to VPP A and VPP B depending on the system conditions forecasted a day ahead

The volume of reactive contract is likely to be different if the duration of the contract is longer since more operating conditions need to be considered. For example, Figure 2-17 shows different contracted reactive power services from VPP A and B depending on what conditions may occur within the forecasted week. If it is a typical (normal) week consisting of high and low demand with 2 GW export, then VPP B will get the contract to provide 40 Mvar (lead). If it is a typical week with 2 GW import, then 70 Mvar(lag) from VPP A is needed. If it is a typical week, but the conditions involve 2 GW export and import then the portfolio of the contract should include both 40 Mvar (lead) from VPP B, and 70 Mvar(lag) from VPP A. If the week involves extreme demand conditions (minimum or peak demand) then the quantity of reactive services needed is higher.

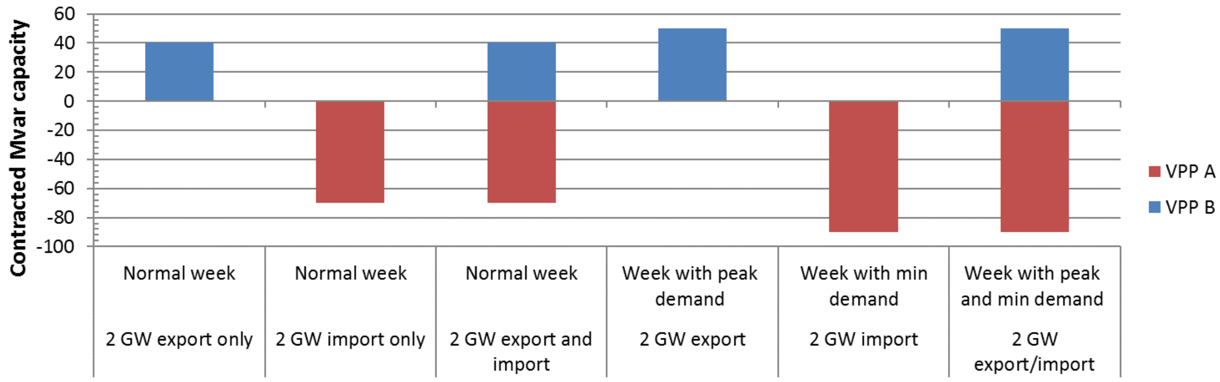


Figure 2-17 Allocation of reactive power contract to VPP A and VPP B depending on the system conditions forecasted a week ahead

If the duration of the contract is long enough such that all combination of the operating conditions discussed previously may happen, for example, the contract duration is one year, then the contract should cover all extreme conditions. In this case, VPP A needs to provide 90 Mvar (lag) and VPP B 50 Mvar(lead).

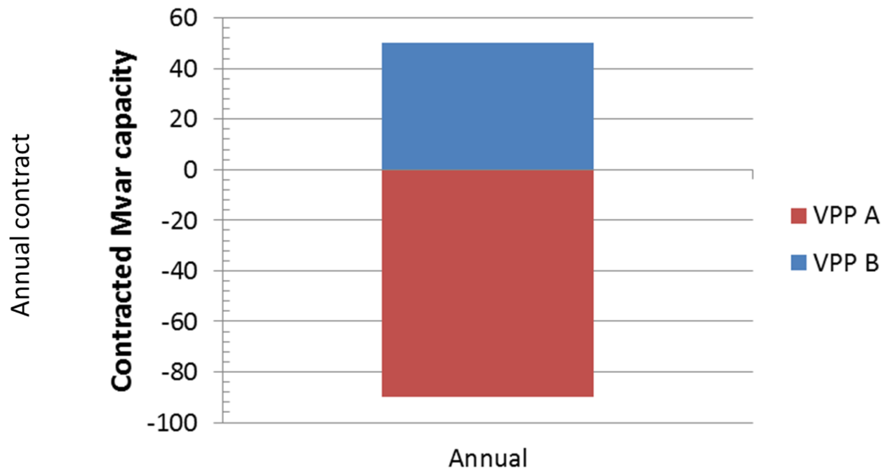


Figure 2-18 Allocation of reactive power contract to VPP A and VPP B depending on the system conditions forecasted a week ahead

It can be concluded that a higher volume of reactive contract is likely to be needed if the duration of the contract is longer as it needs to cover all possible operating conditions that may happen during the length of the corresponding contract. However, having a long-term market may reduce the volatility of the market prices of the services compared to the volatility in the short-term. There is also a possibility to mix different length of contracts to get the right balance between the stability of market prices and the reflectivity of the market prices on the temporal system value of the services.

Chapter 3. Power Potential's VPP

3.1 The Imperial's VPP tool: a modelling approach

The Imperial's VPP tool builds a set of VPP parameters, i.e. similar to large-scale conventional generator data and its cost function of delivering energy and system services. By using this approach, a large number of DSR resources connected to lower voltage networks can be represented as a single large-scale power plant connected at the respective transmission supply points. The tool determines the characteristics of VPP taking into account local network constraints which ensures that the delivery of the energy output or system services from the VPP will not be constrained by the local system. The outline of the tool is presented in Figure 3-1.

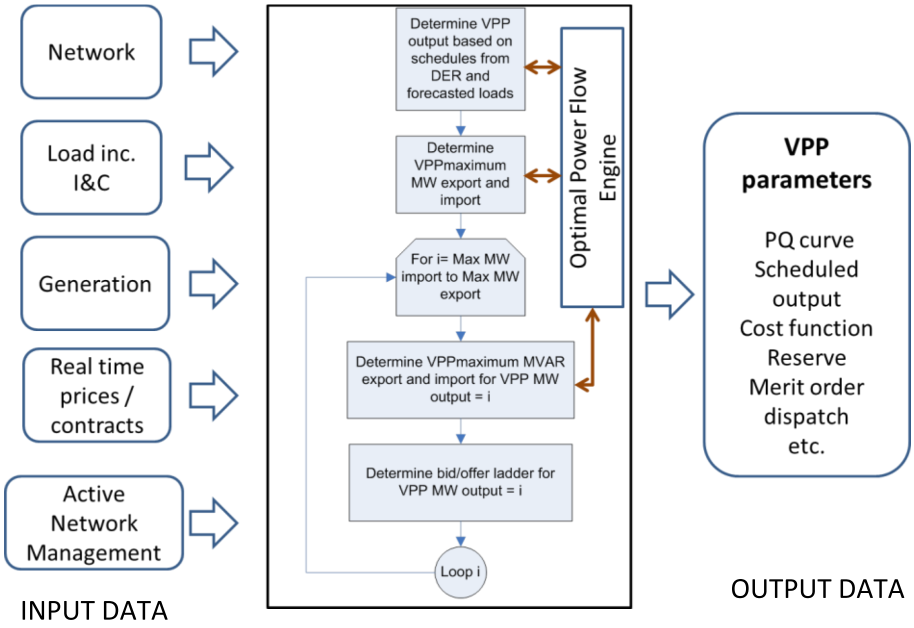


Figure 3-1 Outline of the Imperial's VPP tool

The input data of the tool comprise network data (impedances, topology, ratings), load data including the flexibility of controllable loads, generation data (rating, reactive power capability) and real-time prices or contracts for using the generators or flexible loads in the system balancing or constraint management.

The scheduled generation outputs and the loads in the VPP area are then aggregated by the tool which calculates the scheduled power injection from the VPP using the Optimal Power Flow (OPF) formulation. The tool also calculates the maximum MW export and import which satisfy all the operating constraints of the local network in terms of voltage and flow limits. Once the spectrum of the MW output is identified, the tool calculates the range of reactive power output that can be exported or imported by the VPP area without violating operation constraints of the generators, loads and the network. At the same time, the tool also calculates the changes in generation cost due to the requirement to increase or decrease the output of VPP.

From those calculations, the VPP parameters can be obtained. The parameters include the PQ curve and scheduled generation/load of the VPP, the VPP cost function, the amount of reserve, and the merit order dispatch.

3.2 Simplified commercial VPP models

Based on the real network data provided by National Grid and UK Power Networks, five VPP models have been derived using the VPP tool aggregating the DER and distribution network connected to the grid supply point (GSP) substation at Bolney, Ninfield, Sellindge, Canterbury North, and Richborough. The fundamental assumptions used to derive the VPP models are as follows: (unless otherwise stated, the following are used as default assumptions)

- The cost of reactive power is £3/Mvarh. This is applied uniformly to all DER.
- The operation of the local network is optimised by optimising the setting of tap changing transformers, reactive compensators. There is no cost associated with optimising the operation of network assets.
- All DER are treated on an equal basis providing a level of playing field.

The modelling results are described and analysed as follows.

3.2.1 Bolney VPP model

The reduced model of 132 kV and 33 kV distribution network in Bolney is presented in Figure 3-2. The total demand is 515 MW, 60 Mvar. The total available capacity of DER in Bolney used in this study is 203.5 MW, 91 Mvar (lag and lead). It is important to highlight that DER reactive capacity requires a proper market framework so that this capacity can be used optimally by the system. Without a proper market framework, the value of this capacity will not be recognised fully which discourages further deployment of DER reactive services.

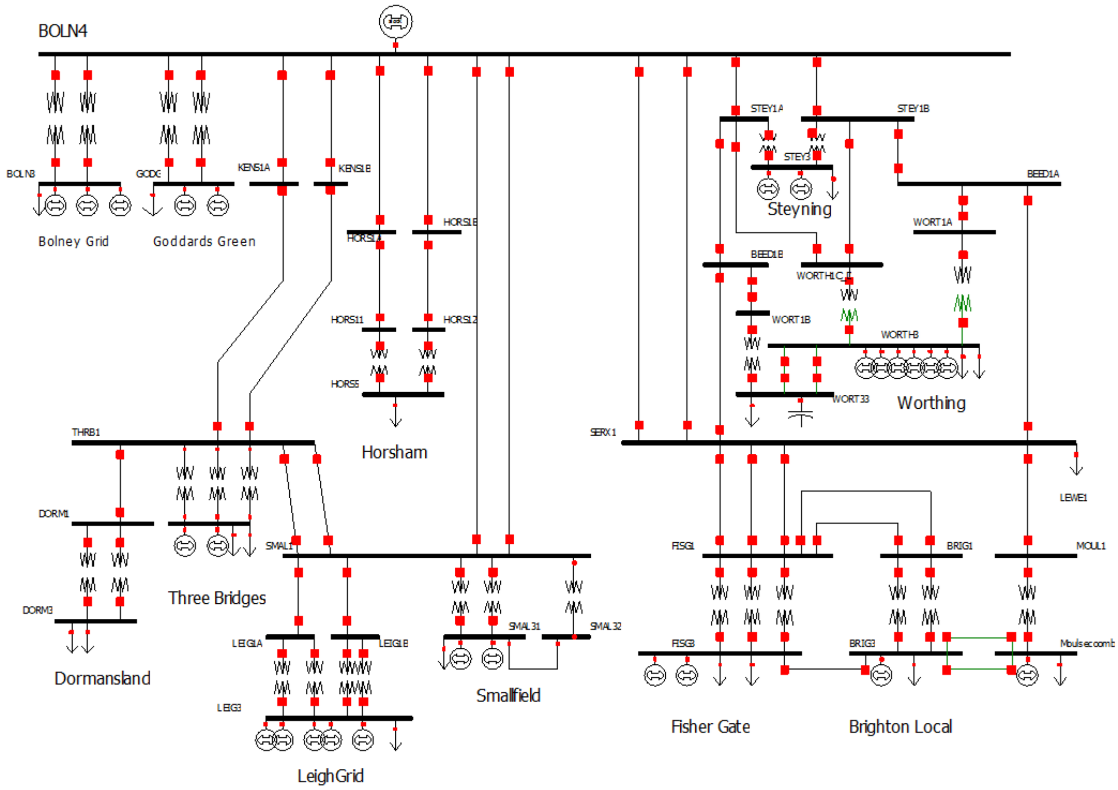


Figure 3-2 Reduced Bolney distribution network model

The aggregation of DER and the distribution network in Bolney produces two sets of parameters: (i) scheduled load and (ii) the flexible generation (VPP) whose output can be modified according to the system requirement. The scheduled load calculated by the VPP tool is 315 MW (import) and -18 Mvar (export). Given that the total load is 514 MW, the scheduled output of DG is 203.5 MW, and the losses are 4.4 MW, in this condition, Bolney GSP imports 315 MW. However, it injects 18.2 Mvar to the system as the reactive load is 60.3 Mvar and there is 78.5 Mvar injection from the grid even with all DG produces zero reactive power output.

The identify the MW and Mvar capability of the VPP, the PQ curve of the Bolney VPP is calculated using the VPP tool, and the result is presented in Figure 3-3. The graph shows that the output of Bolney VPP can be reduced by 212 MW. This can be achieved by reducing the DER MW output in Bolney. In addition, the losses will increase which as well explains why the volume of MW reduction can be larger than the total scheduled DER output (203.5 MW) in Bolney.

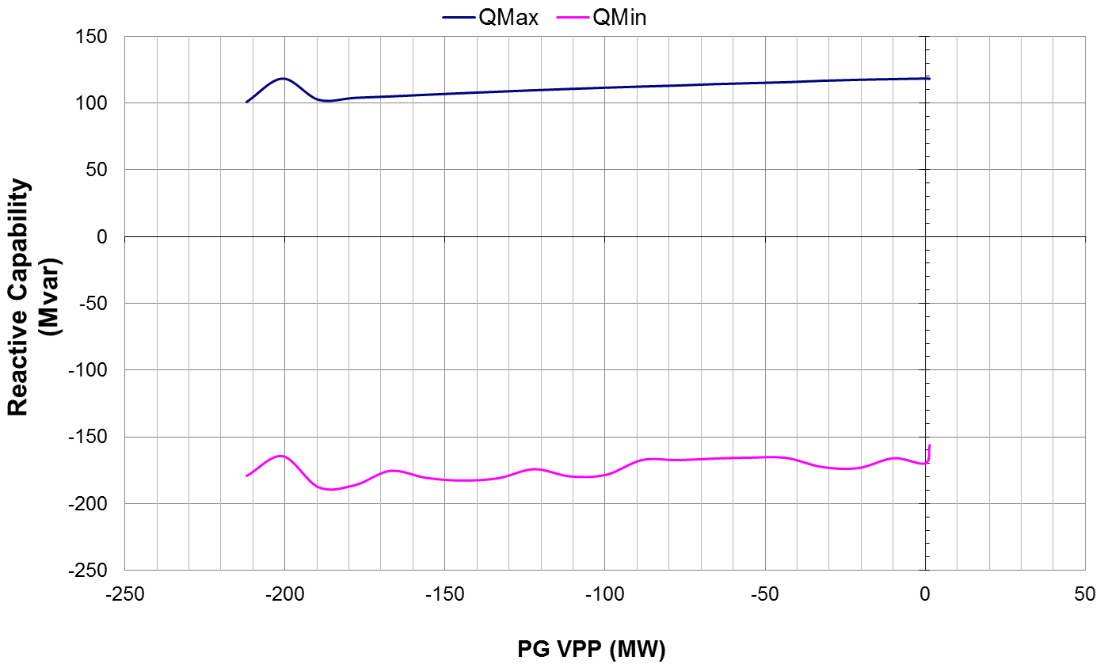


Figure 3-3 PQ curve of the Bolney VPP

The modelling results also demonstrate that the reactive capability of the VPP at 0 MW (117 Mvar (lag) and 169 Mvar(lead)) is larger than the total reactive capability of DG, i.e. 91 Mvar (lag and lead). This indicates that:

- There is the contribution of reactive power from the local distribution network assets;
- There is no market access to DG's reactive power capability in Bolney at the operating condition considered in this study, i.e. normal (intact) condition.

Figure 3-4 shows the cost function of reactive power services provided by Bolney VPP. The results suggest that between 75 Mvar (lag) and 25 Mvar (lead), the cost is zero since it is assumed that there is no cost of using distribution network assets to provide reactive injection/absorption at the GSP. Beyond that range, the VPP starts utilising resources from DER and the cost increases accordingly. The cost function for reactive power absorption is less linear than the one observed for reactive power injection; this may be caused by (i) the optimisation of voltages and reactive power control settings (transformers, and reactive compensators) which also affect (ii) losses and (iii) the numerical precision of the optimisation technique used in the VPP tool.

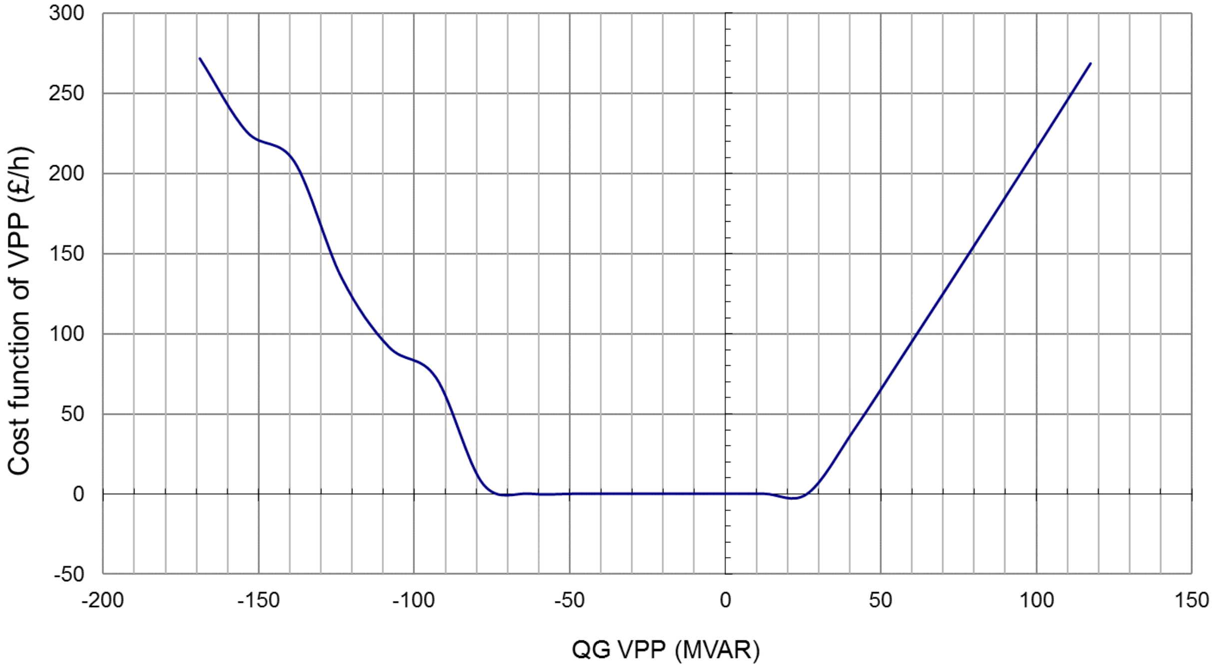


Figure 3-4 Reactive power cost function of Bolney VPP

It is important to note that the cost function reflects the aggregated bids of reactive power services submitted by individual DER. This is important as it provides a price signal on the market value of reactive power services.

3.2.2 Modelling Ninfield VPP model

Figure 3-5 shows the reduced model of the distribution network in Ninfield with DER used in this study. The total load is 203 MW and 39 Mvar. The installed capacity of DG is 225 MW with the reactive capability of ±86 Mvar (lag/lead). The scheduled output of generation is 202.6 MW. Unless otherwise stated, the scheduled reactive power output is 0 Mvar, if the reactive power services are not used to solve a local voltage problem. The VPP parameters of DER and the network in Ninfield are calculated using the VPP tool, and the results are as follows.

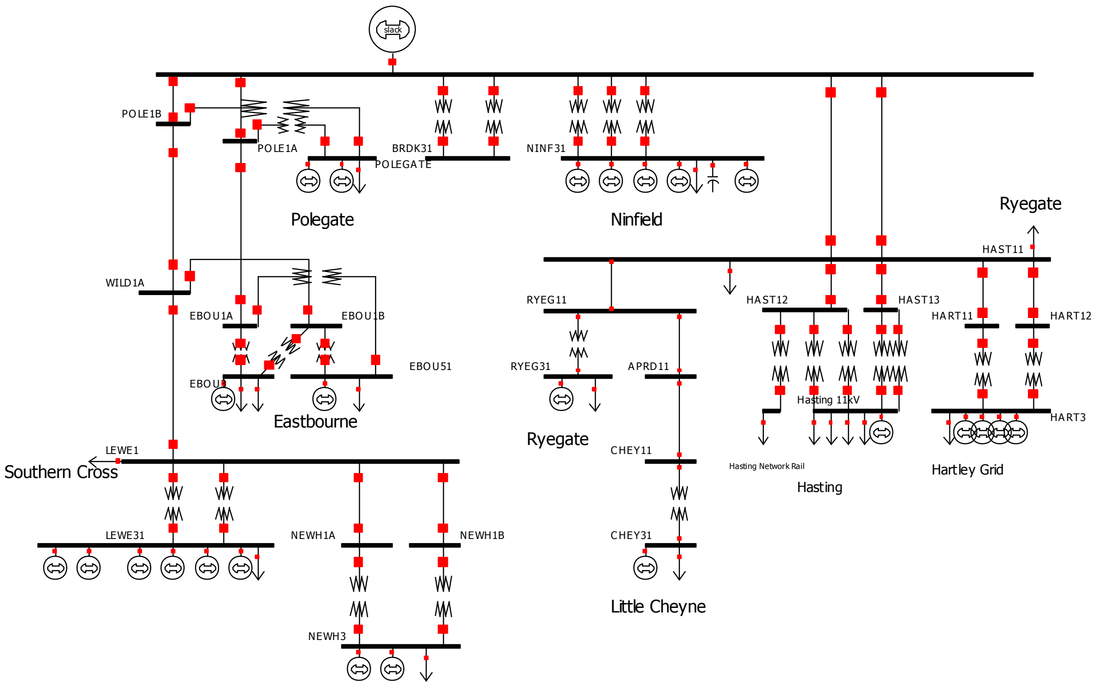


Figure 3-5 Reduced model of the Ninfield distribution network

The scheduled load for the VPP is 1.7 MW and 30.7 Mvar taking into consideration scheduled generation, losses and reactive power injection from the grid. The MW and Mvar capability of the aggregated Ninfield system calculated using the VPP algorithm are presented in Figure 3-6.

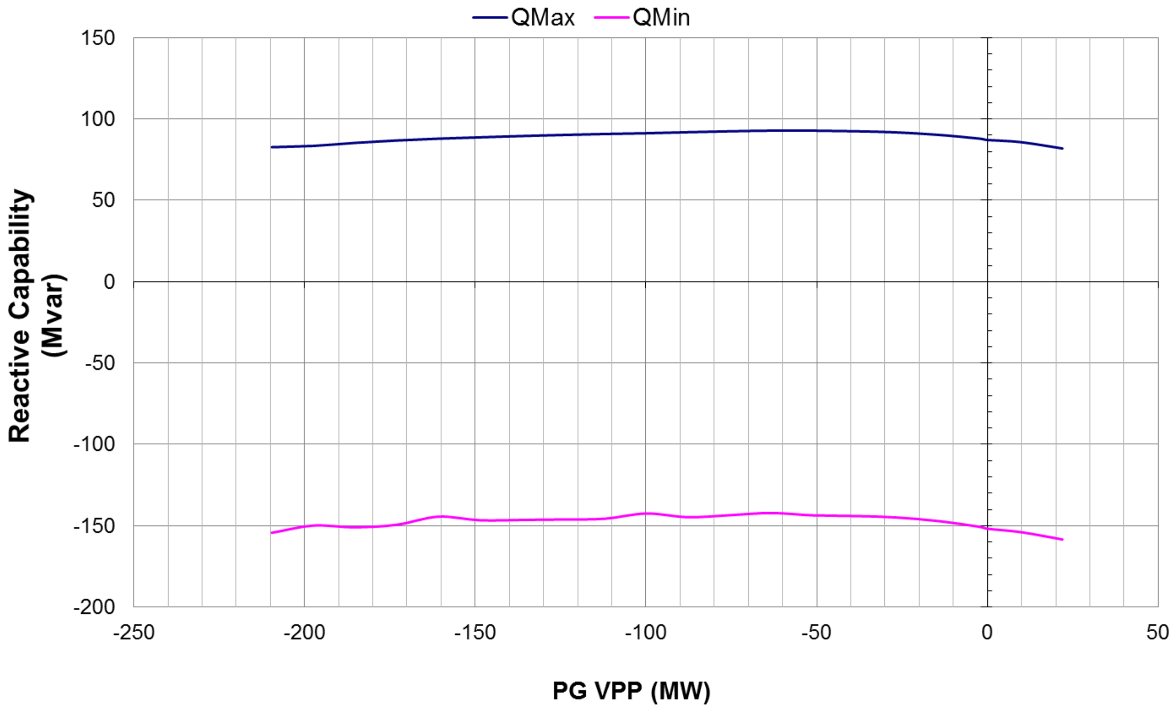


Figure 3-6 PQ curve of the Ninfield VPP

In this case, the VPP can increase its output to 22 MW or act as a load up to around 210 MW by reducing the DER output. The maximum reduction is higher than the scheduled output as the losses at distribution network increase. The maximum reactive power injection is 86 Mvar (lag) and maximum absorption of 151 Mvar (lead). While the maximum reactive power injection is equal to the total reactive power capacity from DER (86 Mvar), the maximum of reactive power that can be absorbed by the system, i.e. 151 Mvar (lead) is almost double than the capacity provided by DER (86 Mvar (lead)).

Similar to the previous case, it is observed that there is a range of reactive power (up to 60 Mvar [lead]) control that can be provided by the local distribution network without cost. This is shown in the cost function of reactive power services from the modelling results as shown in Figure 3-7.

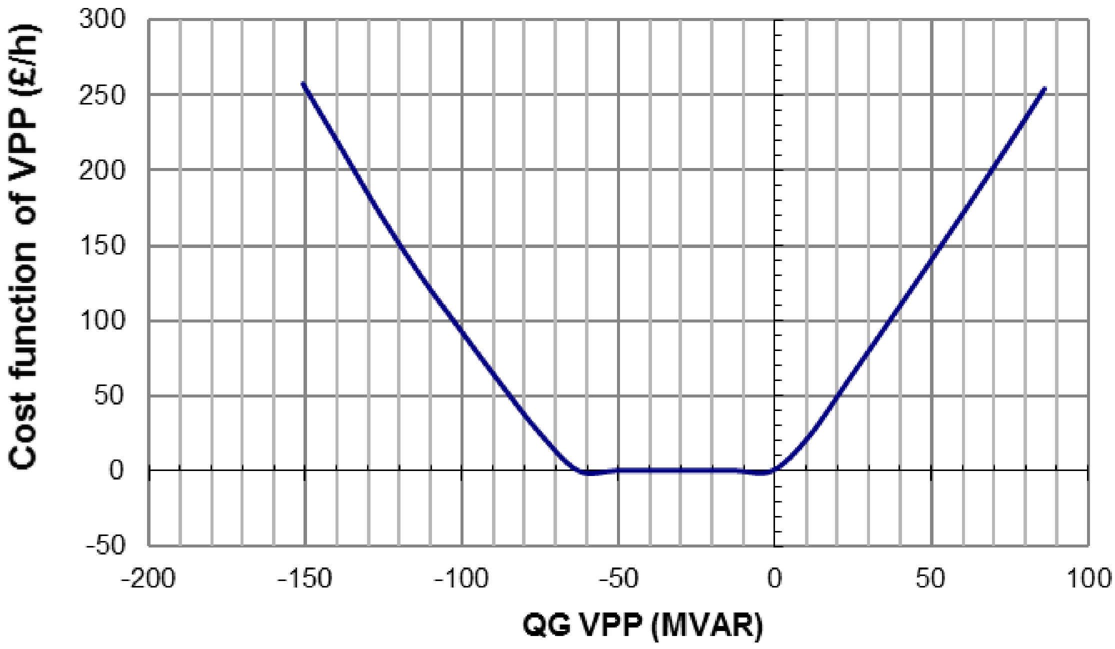


Figure 3-7 Reactive power cost function of Ninfield VPP

3.2.3 Sellindge VPP model

The reduced distribution network model in Sellindge is depicted in Figure 3-8. The total load is 125.7 MW and the network exports 64.1 Mvar contributed by the reactive compensator in that area. The installed capacity of DG is 80 MW with around ±28 Mvar reactive capacity. The scheduled generation output is 71.4 MW.

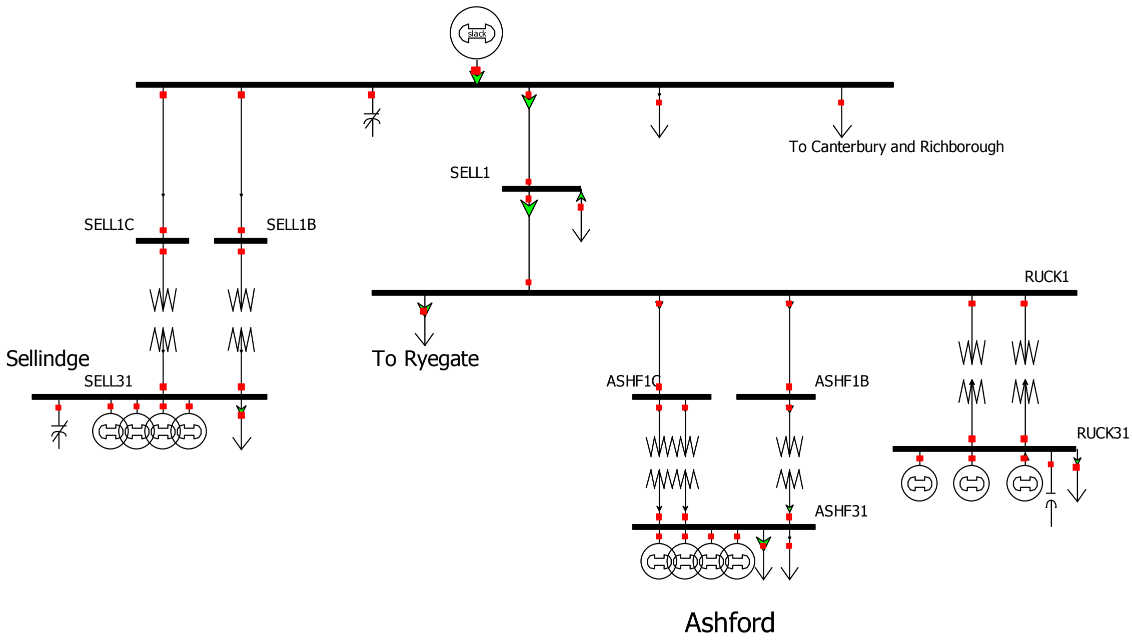


Figure 3-8 Reduced Sellindge distribution network model

The scheduled load is 55 MW and -85 Mvar (export). The MW and Mvar capability of the VPP are depicted in Figure 3-9. The VPP can reduce its active power output up to 75.9 MW and increase the output up to 8.9 MW. Again, the model uses the changes in distribution network losses as a means to control the power flows towards the transmission. The maximum reactive injection is 47.7 Mvar(lag), and absorption is 83.4 Mvar (lead).

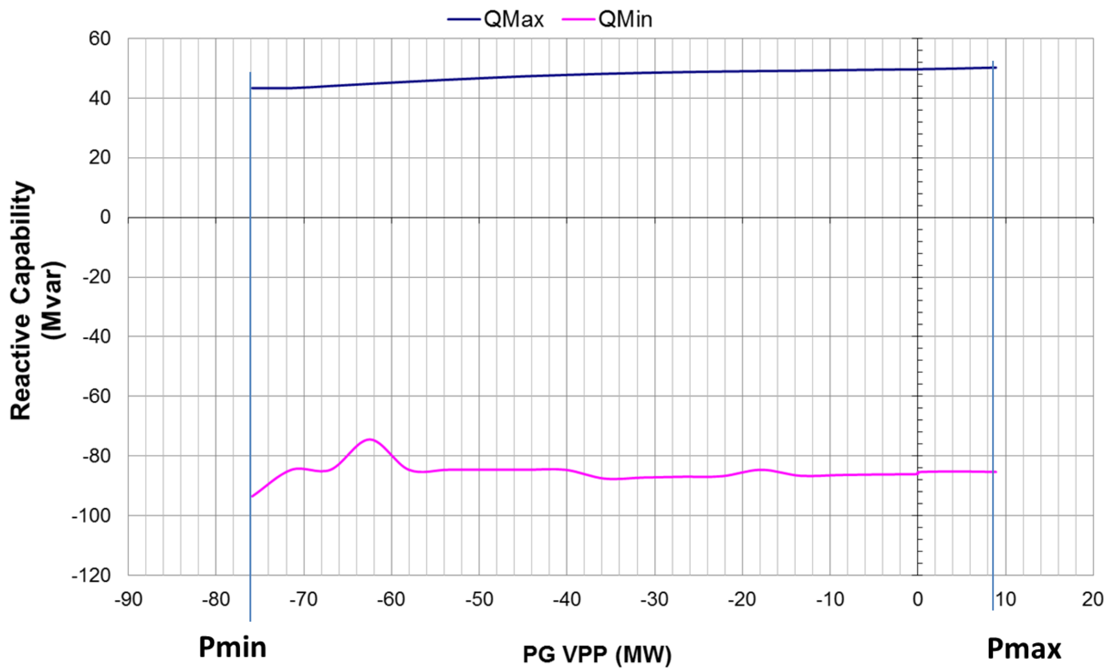


Figure 3-9 PQ curve of the Sellindge VPP

Similar to the previous cases, the reactive capability of the Sellindge VPP is much larger than the reactive capability provided by the DER. The contribution of the network assets including reactive compensators cause this effect which also affects the reactive cost function of the VPP, as shown in Figure 3-10.

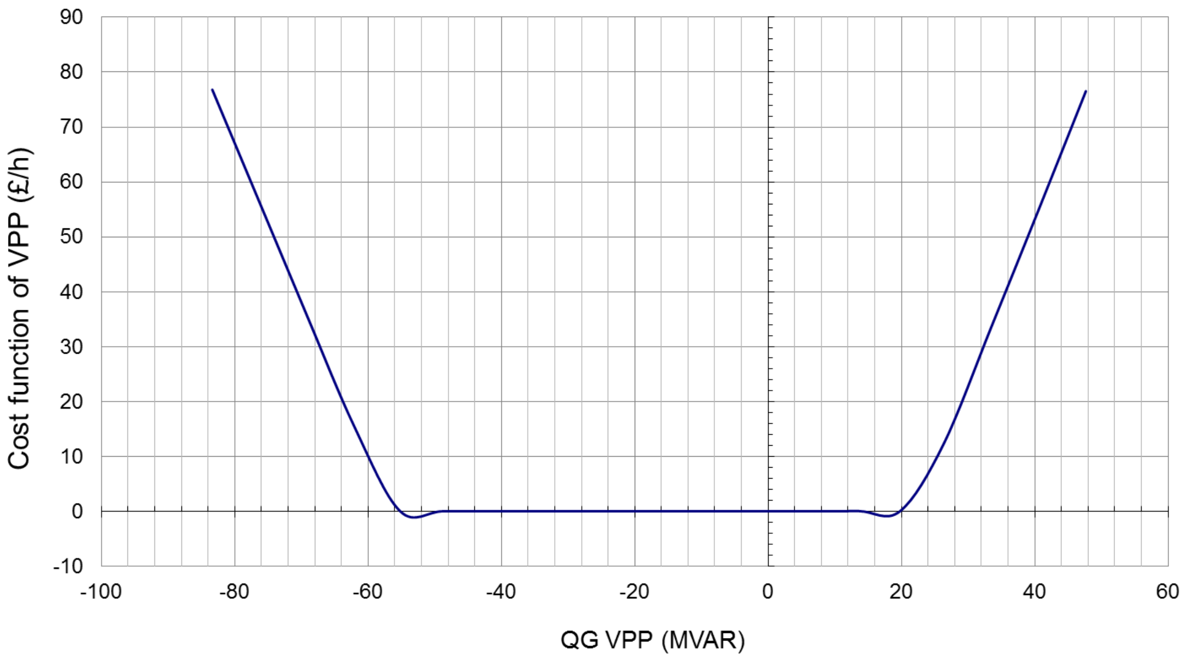


Figure 3-10 Reactive power cost function of Sellindge VPP

3.2.4 Canterbury VPP model

Figure 3-11 depicts the reduced network model of the Canterbury distribution network considered in this study. The total load is 163 MW and 6.9 Mvar. The total generation capacity is 271 MW and ±89 Mvar with scheduled generation output of 227.7 MW.

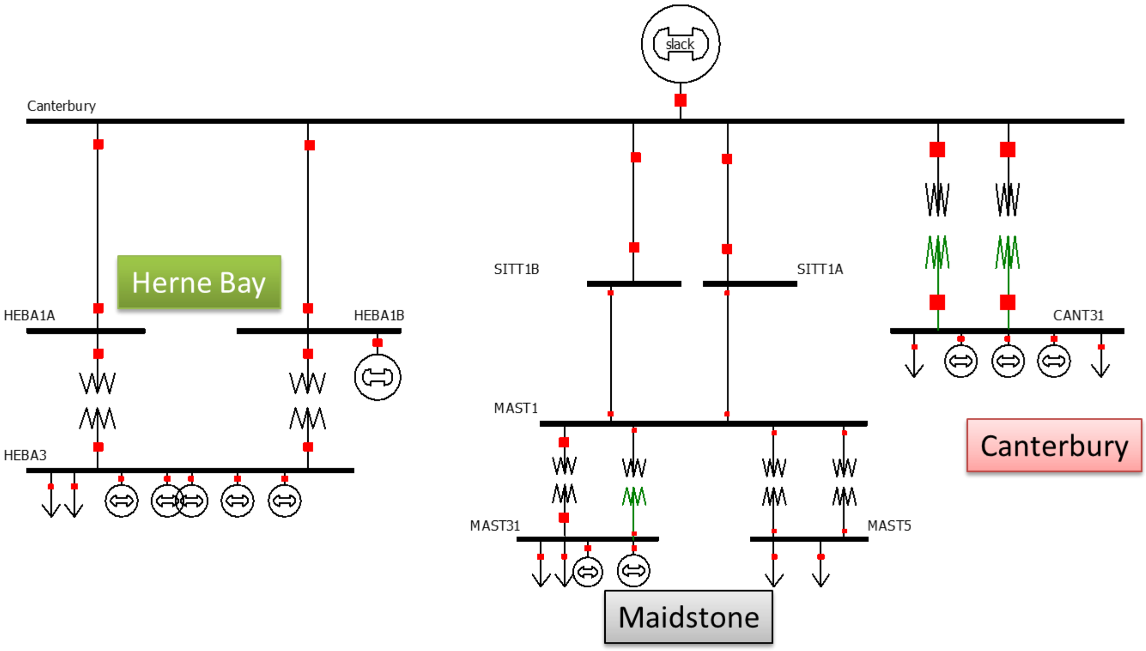


Figure 3-11 Reduced Canterbury distribution network model

The scheduled load of the aggregated demand and DER in Canterbury is -63.7 MW and 11.6 Mvar taking into consideration losses in the system. The flexibility that can be provided by the Canterbury VPP calculated by the VPP tool is shown in Figure 3-12. The results demonstrate that the VPP can reduce its output by around 228 MW (i.e. by reducing its DER output) and increase the output by around 43 MW. The reactive capability that can be controlled by the VPP is 86 Mvar (lag) and 115 Mvar (lead).

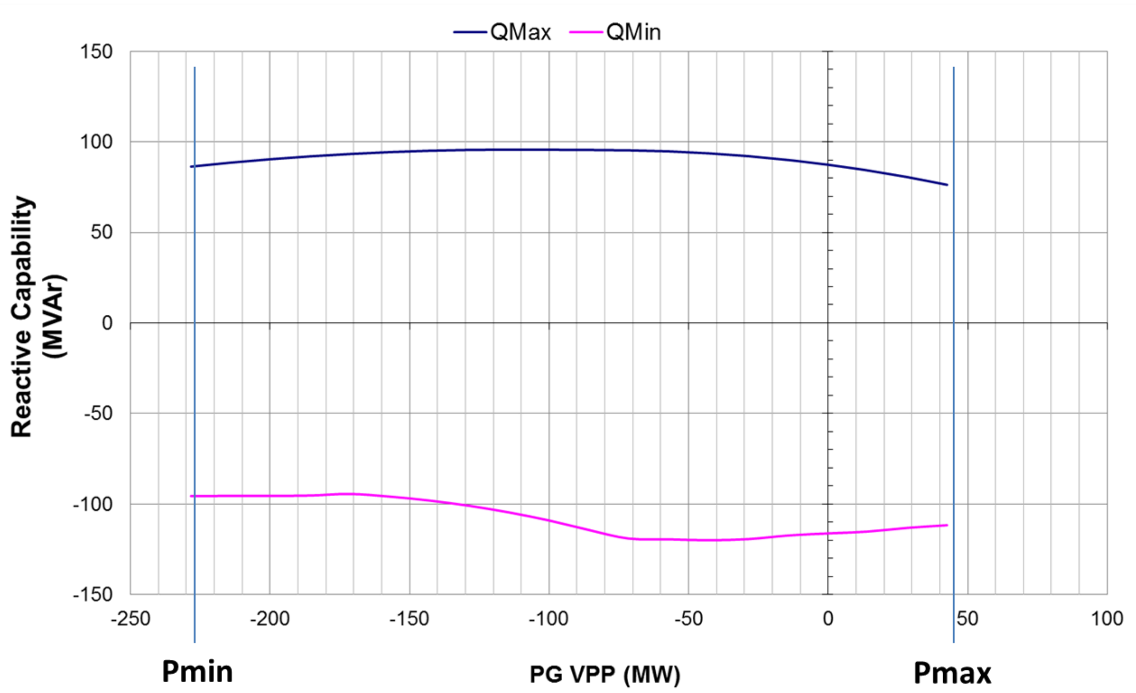


Figure 3-12 PQ curve of the Canterbury VPP

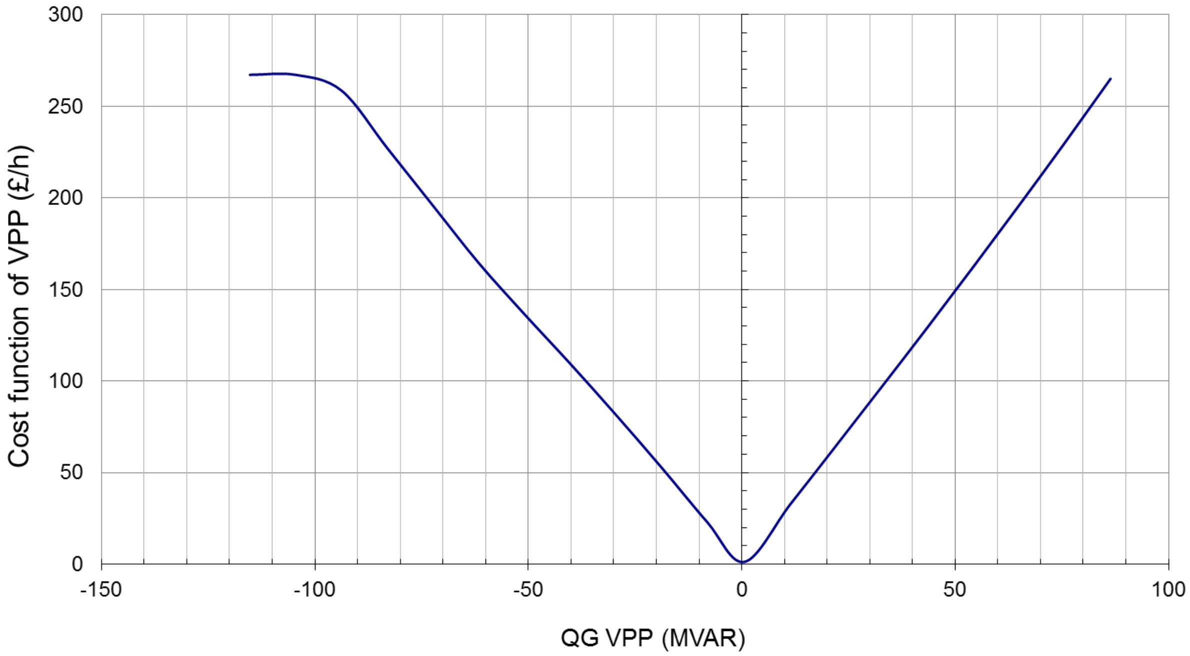


Figure 3-13 PQ curve of the Canterbury VPP

3.2.5 Richborough VPP model

The reduced distribution network model of Richborough is illustrated in Figure 3-14. The total load is 264.7 MW and 97.5 Mvar. The total available generation capacity is 372 MW and ±144.6 Mvar. The scheduled generation output is 296.1 MW.

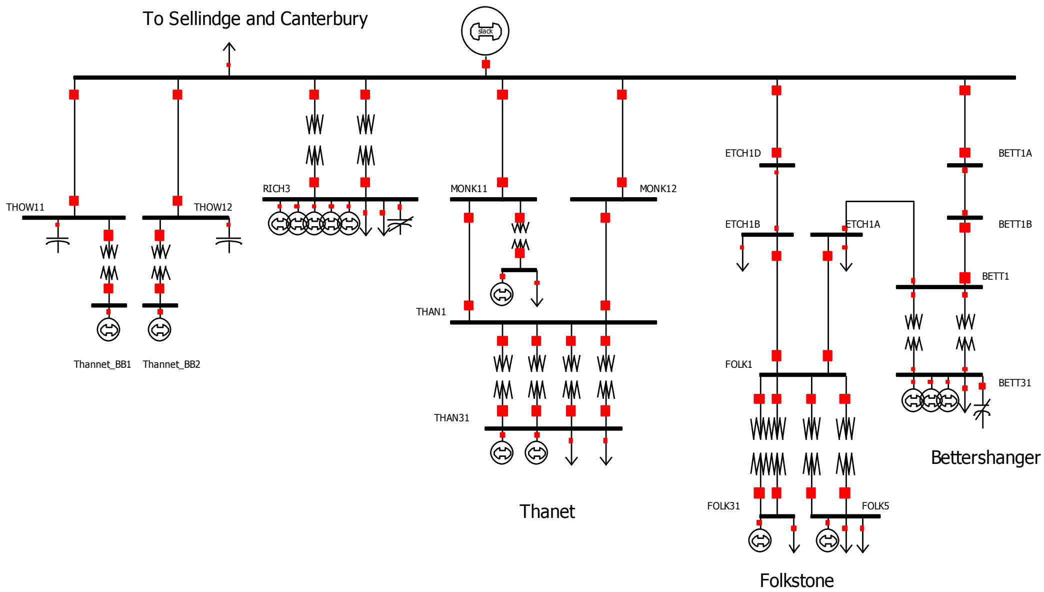


Figure 3-14 132 kV and part of 33 kV distribution network in Richborough

The scheduled load of the VPP is -30.4 MW (exporting) and 124.2 Mvar. The VPP can modify its MW output between -296 MW and 75 MW, and it has the reactive capability of -160 Mvar (lead) to 150 Mvar (lag).

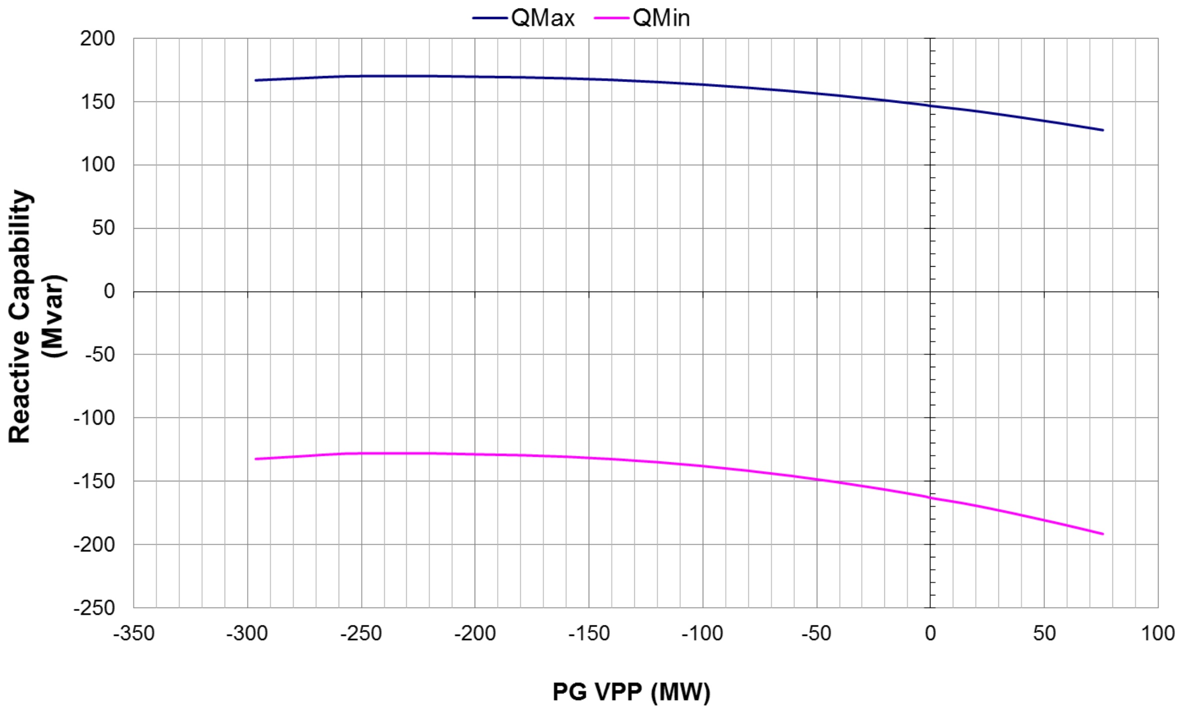


Figure 3-15 PQ curve of the Richborough VPP

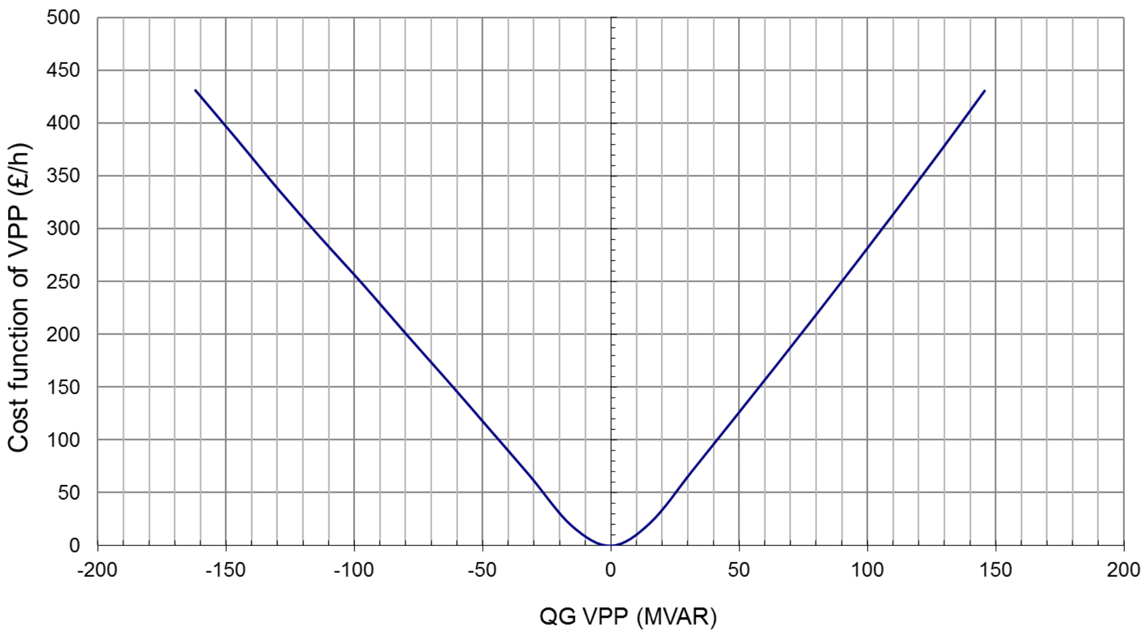


Figure 3-16 PQ curve of the Richborough VPP

3.3 Key findings from analysing the VPP Characteristics

3.3.1 Impact of smart operation of distribution network assets on reactive power capability of VPP

We have identified that optimising transformer taps could enhance the ability of reactive resources located in the distribution network to provide voltage support to the transmission system. This is demonstrated in the results of one of the studies in characterising the cost of reactive services from Bolney VPP (Figure 3-17). There is a range of reactive power capability where the cost is zero - due to the assumption that no costs are allocated to reactive power support from distribution network assets (including reactive from distribution circuits, and reactive power compensators installed at distribution).

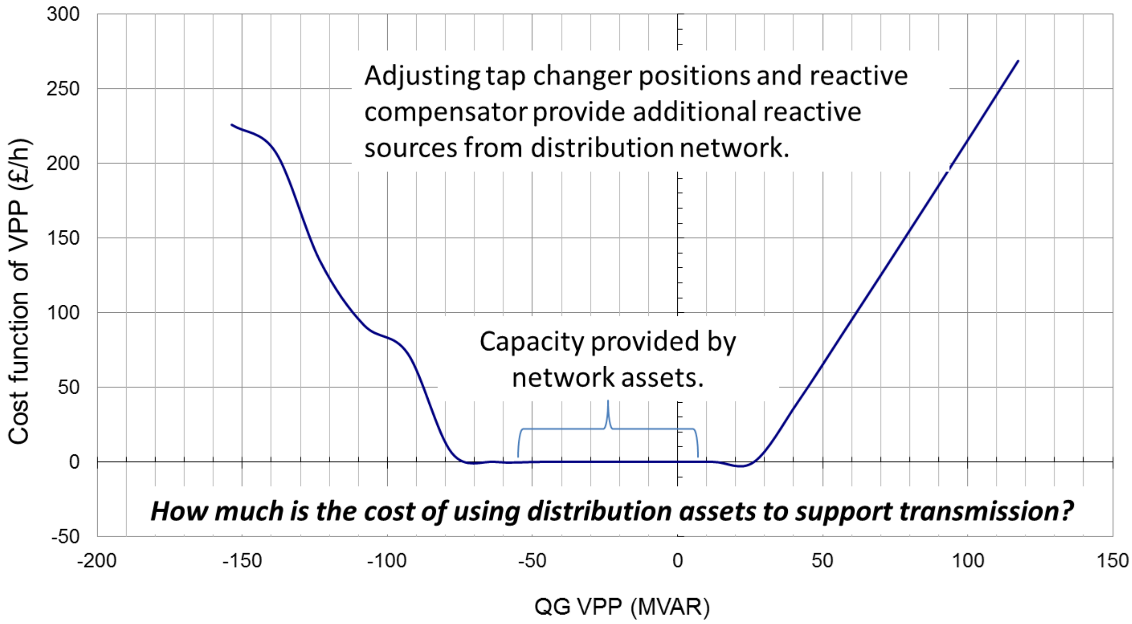


Figure 3-17 Mvar cost function [Bolney VPP] with optimised tap changers and distribution reactive assets

Another example is illustrated in Figure 3-18 where the reactive capability and its cost function is evaluated with and without utilising shunt reactive power compensation. The results demonstrate that distribution network assets can also provide reactive power services to the transmission network, similar to reactive power services from DER. Hence, maximising the use of assets would enhance their value.

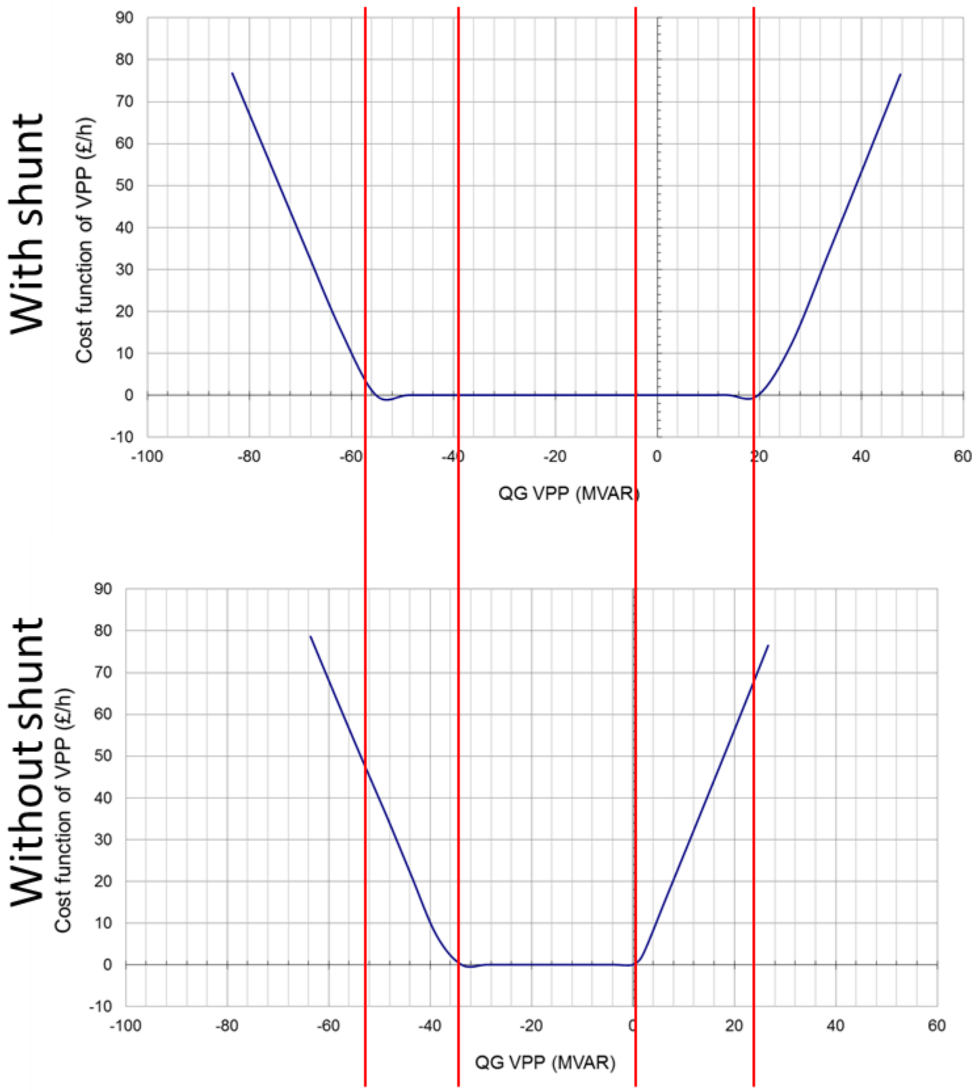
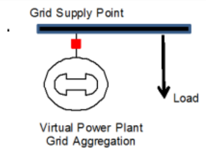


Figure 3-18 Mvar cost function [Sellindge VPP] with and without shunt reactive compensator

These results highlight the importance of having appropriate cost recovery mechanisms or incentives that should be in place to facilitate application of cost-effective measures, such as optimisation of transformer taps, or other active distribution network management measures that DSOs may take to enhance DERs access to providing services to the TSO. It may also be possible to temporarily overload distribution network assets (e.g. grid supply transformers or overhead lines) to enhance the provision of services from DERs to the transmission network.

3.3.2 VPP's capability is dynamic and changes according to local system conditions.

In contrast to a conventional generation, parameters of the VPP will vary depending on the system conditions following the changes in demand, generation availability, network topology and conditions, network control optimisation, etc. This is demonstrated by the results of the study characterising the VPP's parameters for the Canterbury VPP using two different operating conditions: (i) summer peak and (ii) winter peak condition; the results are shown in Figure 3-20.



Summer peak	
MW load	-63.7
MVAr load	11.6
VPP parameters	
Pmax (MW)	42.6
Pmin (MW)	-228.3
Qmax (MVAr)	86.4
Qmin (MVAr)	-115.2

Winter peak	
MW load	60.5
Mvar load	29.1
VPP parameters	
Pmax (MW)	1.3
Pmin (MW)	-187.3
Qmax (MVAr)	87.5
Qmin (MVAr)	-97.1

Figure 3-19 Comparing the characteristics of Canterbury VPP in the summer peak and winter peak condition[8]

The modelling results demonstrate that during Summer Peak, the VPP exports 63.7 MW of active power to the grid and consumes 11.6 Mvar; while in the Winter Peak, the VPP imports 60.5 MW and 29.1 Mvar. Focusing on the reactive capability of the VPP, the range of reactive absorption becomes lower during the Winter Peak. This is expected since the voltage in the Winter Peak tends to be low which may limit the ability of the system to absorb reactive power further. In contrast, reactive power injection capability during Summer Peak is slightly lower, which may be constrained by the upper limit voltage. This example demonstrates that VPP's parameters are dynamic and follow changes in the local system conditions.

3.3.3 Robust 132 kV and 33 kV distribution networks in South-East England enables efficient delivery of reactive power services from DER.

As demonstrated by system studies, distribution networks can facilitate full access to DER capacity. This implies that in the intact system, the networks are relatively strong and do not cause any barrier to DER to access the market of transmission services. Constraints may occur due to outages, but in general, the network capacity is sufficient since the majority of DER modelled is connected directly to 33 kV substations. This has important implications:

- There is no loss of reactive power capability due to the relatively strong 132 or 33 kV systems.
- Faults at distribution may affect access to DER; however, the N-1 design at 33 kV or 132 kV seems to lessen the impact especially for active power services while the impact on reactive sources tends to be much higher, as expected. This is illustrated by the results of the study on Canterbury VPP which is presented in Figure 3-20.

[8] The VPP parameters reflect the capability of VPP to modulate its output from the scheduled(expected) operating point.

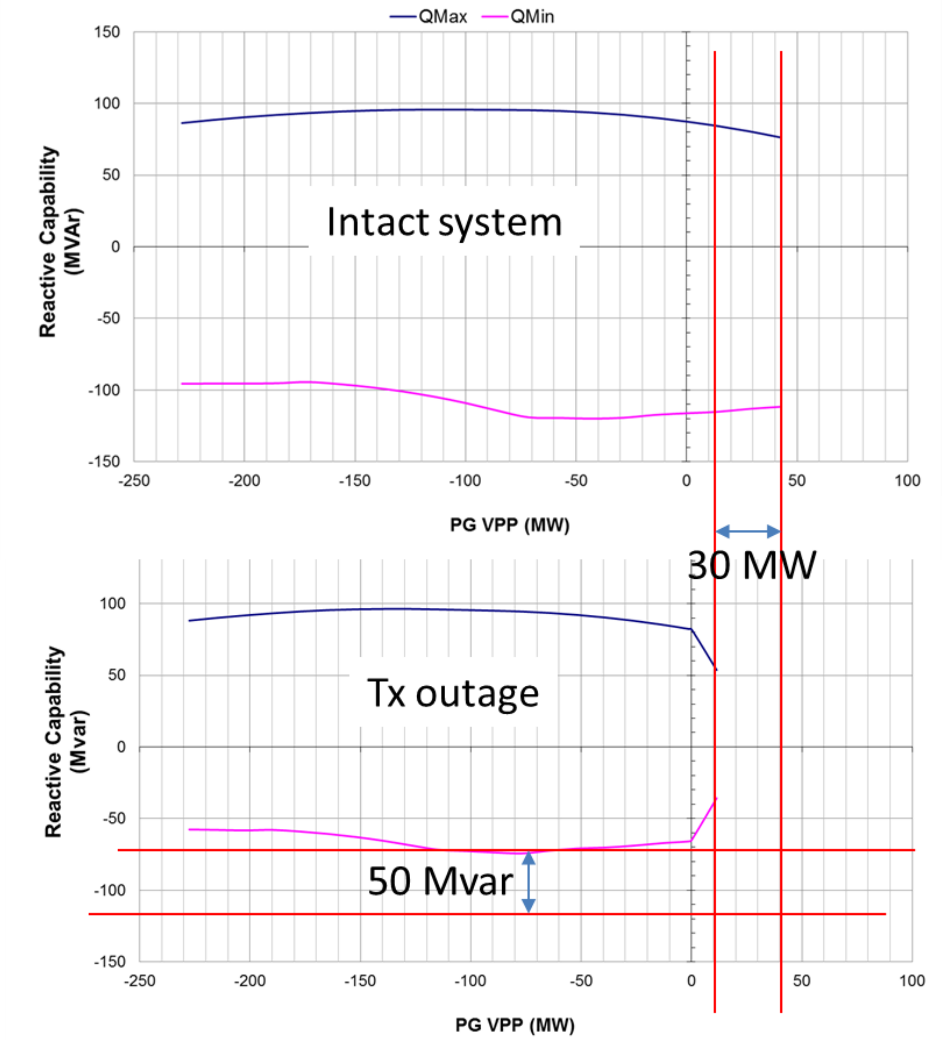


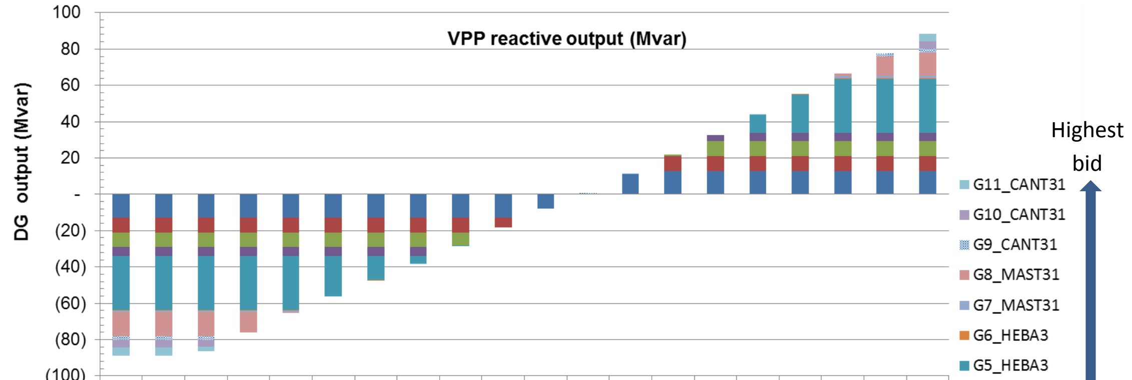
Figure 3-20 Impact of a transformer outage on the PQ curve capability of Canterbury VPP

This study investigates the impact of a transmission outage at the HEBA 132kV substation; the secondary transformer is able to maintain the network access to substantial amount of DER at the HEBA 33 kV substation, but the outage still reduces the maximum power output (PMax) capability of the VPP by 30 MW and reactive absorption capability (Qmin) by around 50 Mvar. The effect of the outage on reactive power injection (Qmax) and minimum power output (Pmin) is relatively marginal.

3.3.4 Competitiveness of local VPP reactive power market

Enabling competition in the provision of ancillary services is vital to improve efficiency and minimise the cost of the services. As the distribution networks involved in the Power Potential (mostly at 132 kV and some 33 kV) are relatively strong, the networks do not impose any significant barriers for the DER to access and compete in both transmission's ancillary service markets and the provision of local services. At a certain extent, this may also be contributed by the spatial distribution of the DER which tends to be clustered and connected to the low voltage of 132/33 kV substation.

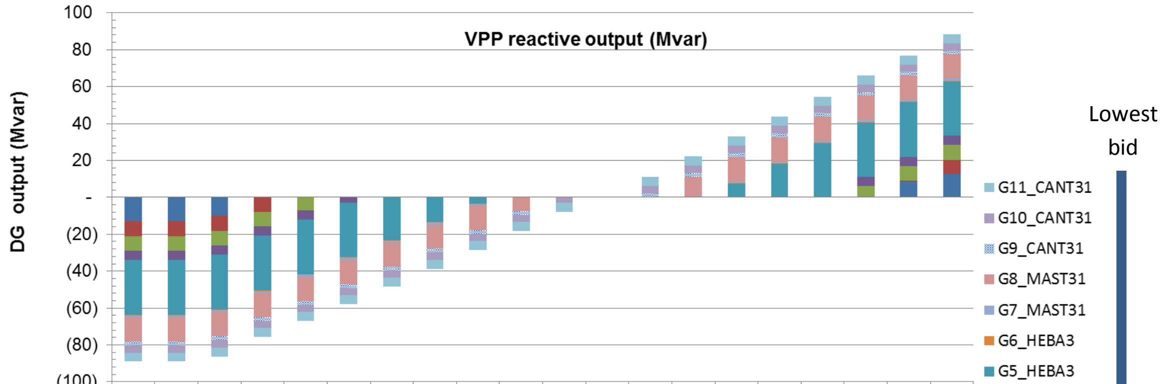
Figure 3-21 shows the dispatch of reactive power from each of the DER within the Canterbury VPP. The x-axis is the range of VPP's reactive power capability, and the y-axis shows the aggregated reactive power output of individual DER. In this example, it is assumed that G1 has the lowest bid, and G11 has the highest bid. Therefore, the dispatch is done in the merit order from G1 to G11.



	(115)	(105)	(94)	(83)	(72)	(62)	(51)	(40)	(29)	(19)	(8)	1	11	22	33	44	54	65	76	86
G11_CANT31	-4.93	-4.93	-2.14	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.28
G10_CANT31	-3.94	-3.94	-3.94	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.94
G9_CANT31	-1.97	-1.97	-1.97	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.46	1.97
G8_MAST31	-13.1	-13.1	-13.1	-10.8	-0.27	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.51	11.0	13.1
G7_MAST31	-1.05	-1.05	-1.05	-1.05	-1.05	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.05	1.05	1.05
G6_HEBA3	-0.39	-0.39	-0.39	-0.39	-0.39	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.39	0.39	0.39
G5_HEBA3	-29.5	-29.5	-29.5	-29.5	-29.5	-22.3	-13.2	-3.93	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	9.55	21.0	29.5	29.5	29.5
G4_HEBA3	-4.93	-4.93	-4.93	-4.93	-4.93	-4.93	-4.93	-4.93	-0.00	-0.00	-0.00	0.00	0.00	0.00	3.34	4.93	4.93	4.93	4.93	4.93
G3_HEBA3	-8.15	-8.15	-8.15	-8.15	-8.15	-8.15	-8.15	-8.15	-7.34	-0.00	-0.00	0.00	0.00	0.69	8.15	8.15	8.15	8.15	8.15	8.15
G2_HEBA3	-8.15	-8.15	-8.15	-8.15	-8.15	-8.15	-8.15	-8.15	-8.15	-5.50	-0.00	0.00	0.00	8.15	8.15	8.15	8.15	8.15	8.15	8.15
G1_HEBA1B	-12.8	-12.8	-12.8	-12.8	-12.8	-12.8	-12.8	-12.8	-12.8	-12.8	-7.92	0.42	11.1	12.8	12.8	12.8	12.8	12.8	12.8	12.8

Figure 3-21 Reactive power dispatch of each DER in Canterbury VPP

A sensitivity study was also carried out by reversing the merit order of the generator bids; G1's bid is the highest and G11's is the lowest. The results of the study are shown in Figure 3-22.



	(115)	(105)	(94)	(83)	(72)	(62)	(51)	(40)	(29)	(19)	(8)	1	11	22	33	44	54	65	76	86
G11_CANT31	-4.93	-4.93	-4.93	-4.93	-4.93	-4.93	-4.93	-4.93	-4.93	-4.93	-4.93	0.41	4.93	4.93	4.93	4.93	4.93	4.93	4.93	4.93
G10_CANT31	-3.94	-3.94	-3.94	-3.94	-3.94	-3.94	-3.94	-3.94	-3.94	-3.94	-2.81	0.00	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94
G9_CANT31	-1.97	-1.97	-1.97	-1.97	-1.97	-1.97	-1.97	-1.97	-1.97	-1.97	-0.00	0.00	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97
G8_MAST31	-13.1	-13.1	-13.1	-13.1	-13.1	-13.1	-13.1	-13.1	-13.1	-7.43	-0.00	0.00	0.23	11.3	13.1	13.1	13.1	13.1	13.1	13.1
G7_MAST31	-1.05	-1.05	-1.05	-1.05	-1.05	-1.05	-1.05	-1.05	-1.05	-0.00	-0.00	0.00	0.00	0.00	1.05	1.05	1.05	1.05	1.05	1.05
G6_HEBA3	-0.39	-0.39	-0.39	-0.39	-0.39	-0.39	-0.39	-0.39	-0.39	-0.00	-0.00	0.00	0.00	0.00	0.39	0.39	0.39	0.39	0.39	0.39
G5_HEBA3	-29.5	-29.5	-29.5	-29.5	-29.5	-29.5	-23.0	-13.2	-3.19	-0.00	-0.00	0.00	0.00	0.00	7.39	18.1	29.2	29.5	29.5	29.5
G4_HEBA3	-4.93	-4.93	-4.93	-4.93	-4.93	-2.88	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.93	4.93	4.93
G3_HEBA3	-8.15	-8.15	-8.15	-8.15	-7.07	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.07	8.15	8.15
G2_HEBA3	-8.15	-8.15	-8.15	-7.73	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.31	7.44
G1_HEBA1B	-12.8	-12.8	-9.96	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.56	12.8

Figure 3-22 Reactive power dispatch of each DER in Canterbury VPP

The modelling results demonstrate that the reactive power dispatch is also changed according to the new merit order. It can be concluded that that the dispatch is sensitive to the bid price which indicates that there is competition at the local market to provide reactive services within the VPP area. Further investigation on the competition and market power in reactive power services will be carried out in the next phase of our work.

Chapter 4. Transmission studies – VPP based transmission services

A spectrum of studies has been performed to demonstrate the use of DER interfaced by VPP in the context of solving transmission problems. Two primary applications of VPP are addressed:

- VPP for network congestion management
- VPP for controlling network voltages

In order to facilitate the study, a test system of the South-East GB transmission is modelled based on the real network data. DER and distribution networks at the five GSPs (Bolney, Ninfield, Sellindge, Canterbury, and Richborough) are modelled as VPPs using the parameters described in the previous chapter. The intact condition of the transmission test system is shown in Figure 4-1. The total load of the system is around 1422 MW, -84 Mvar (exporting). Three interconnectors are in the system, i.e. (i) IFA , (ii) NEMO, and (iii) ElecLink. Voltages and flows are within the permissible limits in the intact system.

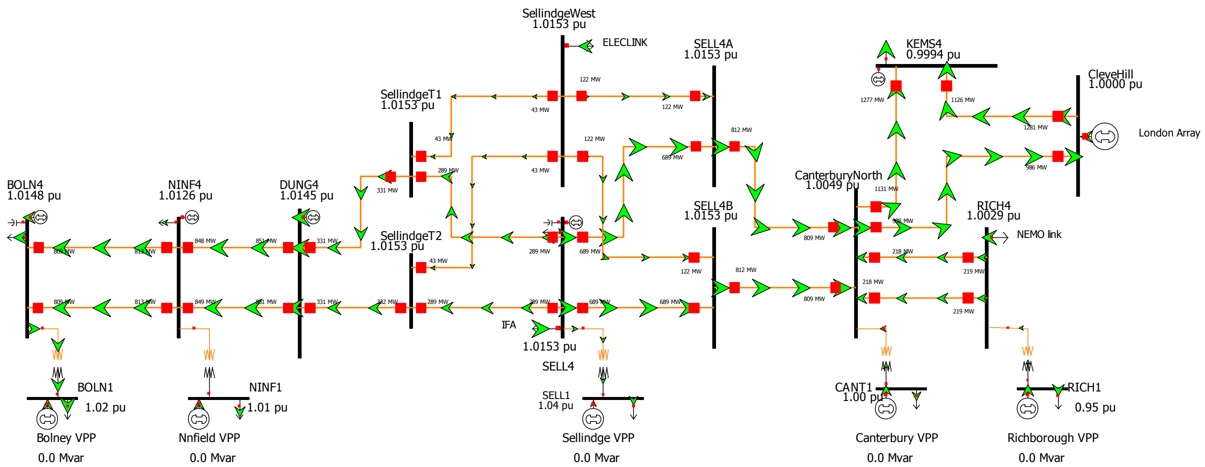


Figure 4-1 South-East GB transmission test system

4.1 VPP as a solution for network congestion problems

This study simulates a double circuit outage: (i) between Canterbury to Kemsley, and (ii) between Kemsley to Cleve Hill which results in circuits overloads between Bolney and Dungeness. This problem is illustrated in Figure 4-2

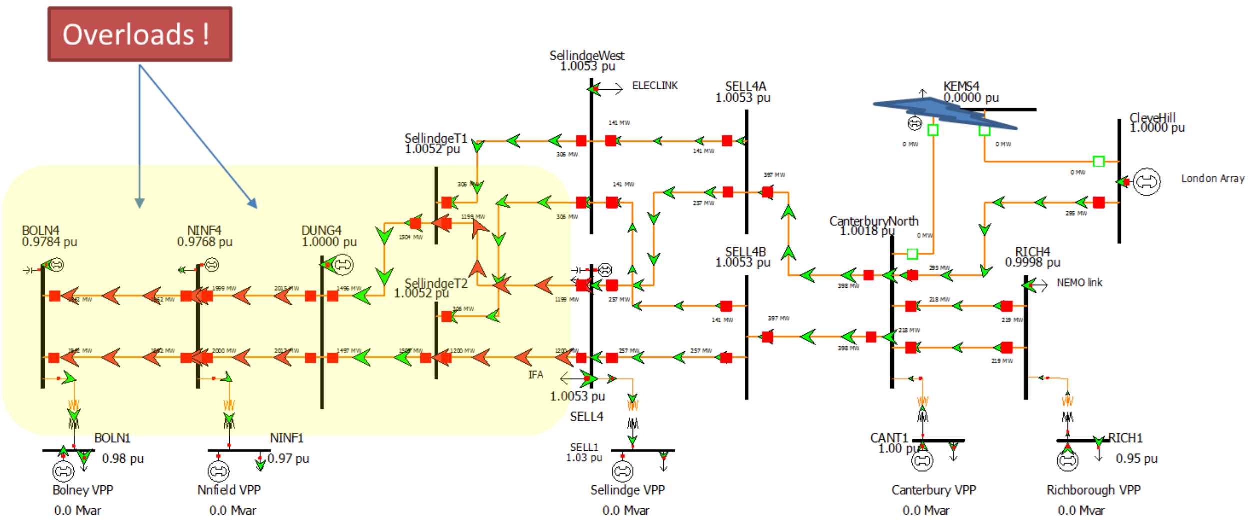


Figure 4-2 Network congestion problem caused by a double circuit outages

In order to reduce the flows between Bolney and Dungeness, the OPF model accepted the bids from the conventional generators and VPP as shown in Table 4-1. G1-G2 are transmission connected generators. G2 especially is the only conventional plant in the model that is traditionally used to support the system in this area. G4-G8 are the VPP models derived in the previous chapters. It is assumed that all generators have the same bid; in this case, the generator bid will be accepted based on the location value of the generators.

Table 4-1 Accepted market bids from different generators (including VPP)

Generators	Accepted DEC (MW)
G1_BOLN4	-
G2_DUNG4	371.7
G2_DUNG4	371.7
G3_CleveHill	0.0
G4_BOLN1	0.0
G5_NINF1	156.0
G6_SELL1	33.5
G7_CANT1	0.0
G8_RICH1	0.0

The modelling results that Ninfield VPP and Sellindge VPP are selected to reduce their electricity generation along with the generators at Dungeness. This suggests that both VPP and transmission connected generators can compete in the same market to provide the optimal solution for the NETSO in managing the network.

By re-dispatching the generators, the overload between Bolney and Dungeness can be mitigated as shown in Figure 4-3. All flows are within limits, and the solution is optimal since the flows at the congested corridors (Bolney-Ninfield, and Ninfield-Dungeness) are at the upper limits as shown in Figure 4-4. This illustrative example demonstrates that the service from VPP can be used to manage network flows and relieve network constraints.

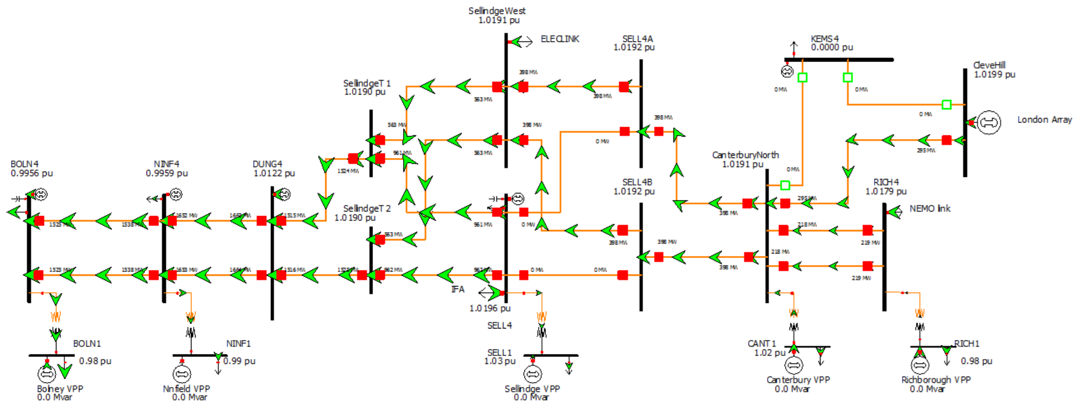


Figure 4-3 Solving network congestion problem using a combination of the transmission connected generators and VPP

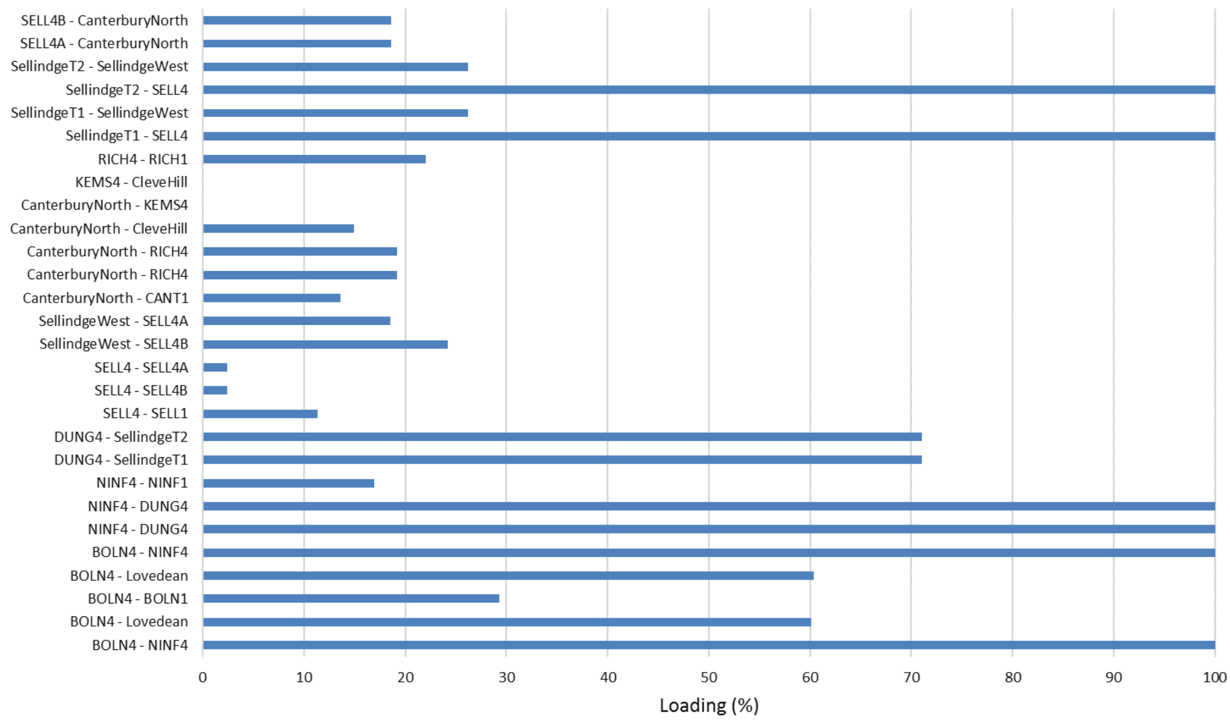


Figure 4-4 Loading of each circuit after redispatching the output of VPP and transmission connected generators

Figure 4-4 shows the loading level of each circuit after the corrective action taken by re-dispatching the output of VPP and generating units at Dungeness. At some circuits, the maximum loading is 100% indicating that the flows are at the upper limit, but there is no overloading observed after the correction action is taken place.

4.2 VPP as a solution for voltage problems

Traditionally, transmission connected generators provide the reactive power services to support the voltage management at the transmission. In this case, the generating units at Dungeness are essential for the South-East transmission. However, these thermal units act as peaking units and therefore, the cost of constraining on these units to provide voltage support will be high. In this context, a set of the study was carried out to investigate the use of VPP as an alternative solution to this problem. The generators at Dungeness are switched off, and the voltages across the system are high considering there is a significant amount of generation in the system and demand is relatively low. In addition, the scenario assumes import from interconnectors; this increases further the voltages in the system. In particular, voltages at Sellindge are above the upper limit (+5%); the results are shown in Figure 4-6.

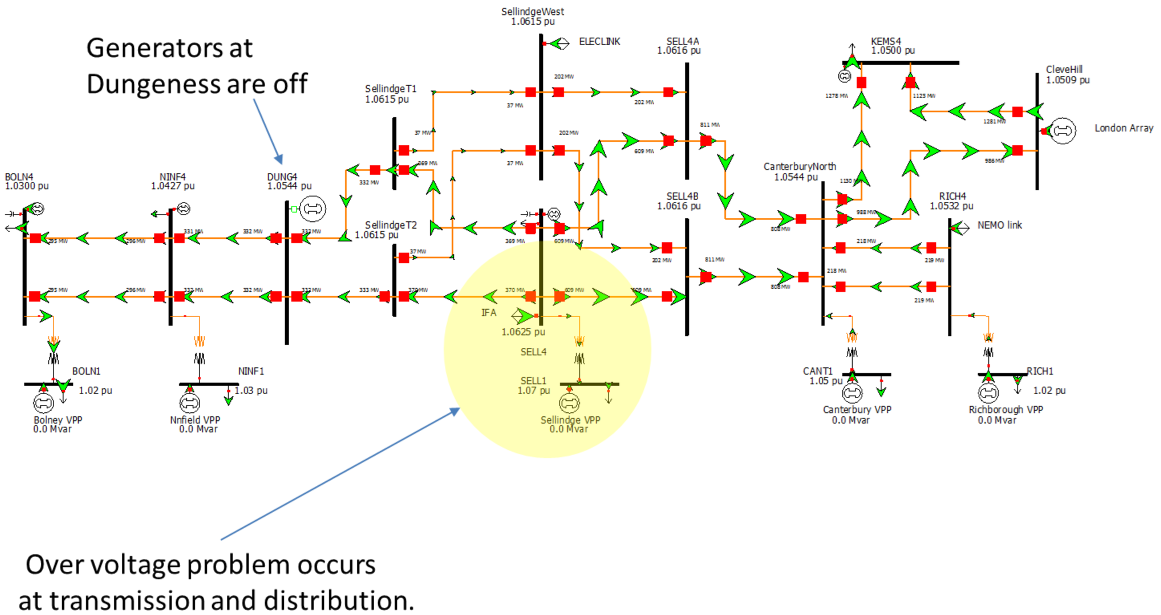


Figure 4-5 Illustrative case study simulating an over-voltage problem on the test system

Instead of using the traditional solution to engage generating units at Dungeness, the Power Potential project is investigating an alternative solution using VPP. The SCOPF model is used to calculate how much reactive power from VPP needs to be contracted to solve this solution. The modelling results suggest using 63 Mvar(lead) at Sellindge and 5.1 Mvar (lead) at Richborough. Reactive power absorption from both of the VPPs reduces the voltages in the system and brings back the voltages Sellindge to be within the upper limit, as shown in Figure 4-6.

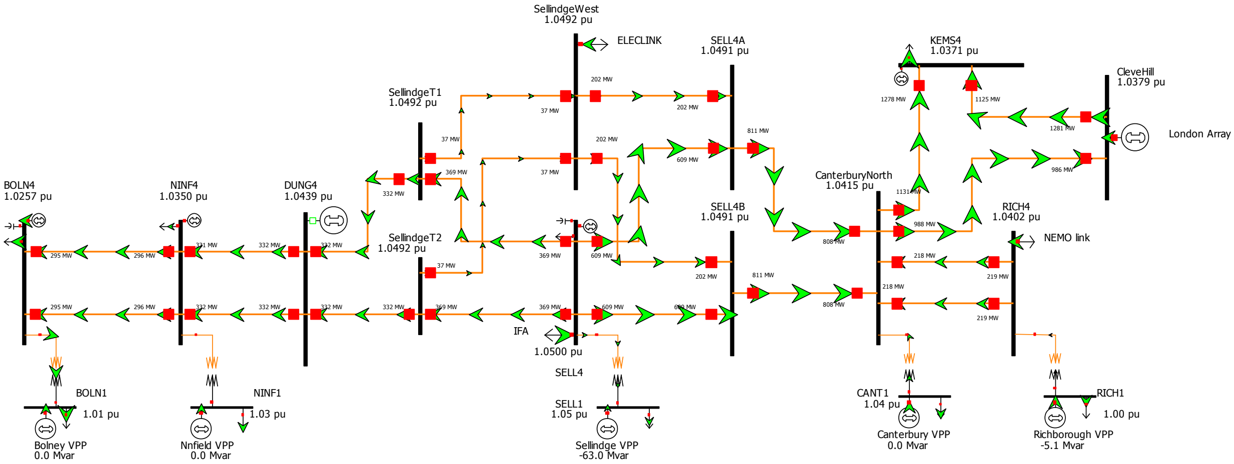


Figure 4-6 Solving network over-voltage problem using VPP

As DER is more distributed across the system compared to large-scale generators and considering the local nature of the reactive requirement, DER may have the locational advantages compared to large-scale generators.

4.3 Location-specific value of reactive power services

A sensitivity study was carried out to identify the location-specific value of reactive power services. In this study, the same amount of reactive contract is given to Ninfield VPP instead of Sellindge VPP. However, the results (Figure 4-7) show that the voltages at Sellindge are still high suggesting that the allocated reactive power supports are not adequate.

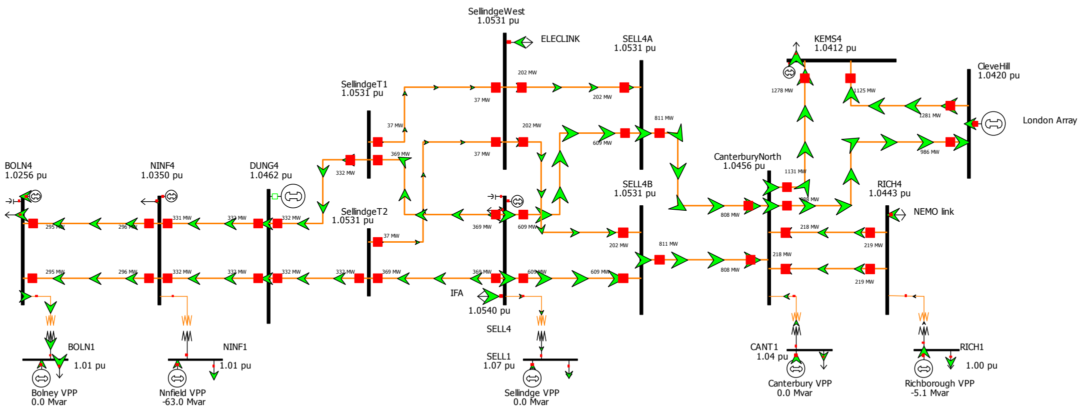


Figure 4-7 An illustrative study demonstrating ineffective reactive power allocation

In order to use reactive power from Ninfield to solve the Sellindge voltage, it requires 180 Mvar(lead) as depicted in Figure 4-8. This requirement is almost three times larger than the reactive requirement if it is provided by Sellindge VPP.

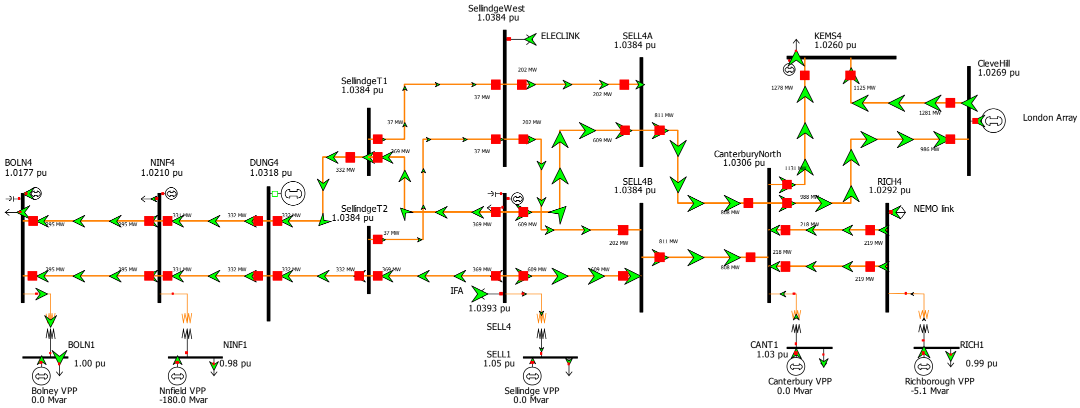


Figure 4-8 Solving network congestion problem using a combination of the transmission connected generators and VPPs

Although it requires a much higher capacity of reactive sources, the study demonstrates that there is an alternative solution to the capacity provided by Sellindge VPP. This creates competition across VPP in providing reactive power services which are then expected to stimulate more cost-effective deployment of the reactive sources in the system.

Chapter 5. Optimal allocation of reactive power contracts

5.1 Description of case studies

Another set of studies has been carried out to investigate how the reactive power requirement may vary in different conditions considering intact and contingent system conditions. The studies use a number of credible contingencies which are used to evaluate the capacity adequacy of the system including the sufficiency of the reactive power services. Table 5-1 shows the list of the contingencies which consists of five single-circuit outages and two double-circuit outages. Figure 5-1 shows the circuit(s) affected by the contingencies.

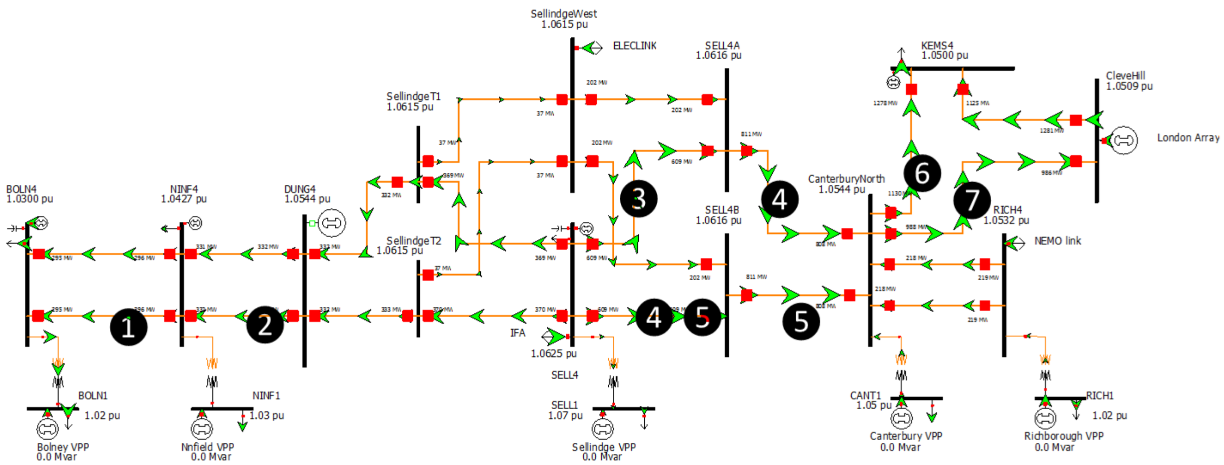


Figure 5-1 South-East GB transmission test system

Table 5-1 List of credible contingencies for transmission operational planning

Contingency	1	2	3	4	5	6	7
Circuits	BOLN4-NINF4	NINF4-DUNG4	SELL4-SELL4A	SELL4-SELL4B &SELL4A-CANT4	SELL4-SELL4B+ SELL4B-CANT4	CANT4-KEMS4	CANT4-CLEH4

A range of case studies has been performed to demonstrate:

- Different reactive requirements in different system conditions, and in most time, the reactive requirement is driven by contingent conditions rather than the intact system;

- The allocation of reactive power services taking into consideration the requirement during intact and contingent conditions;
- The sensitivity of the reactive power allocation to reactive bids; and
- The impact of reactive power market time-frame on the allocation of reactive power services.

5.2 Impact of contingencies on the reactive power requirements

For the intact and contingent conditions considered in the studies, the reactive requirement is calculated using the SCOPF. The results of the study are shown in Figure 5-2.

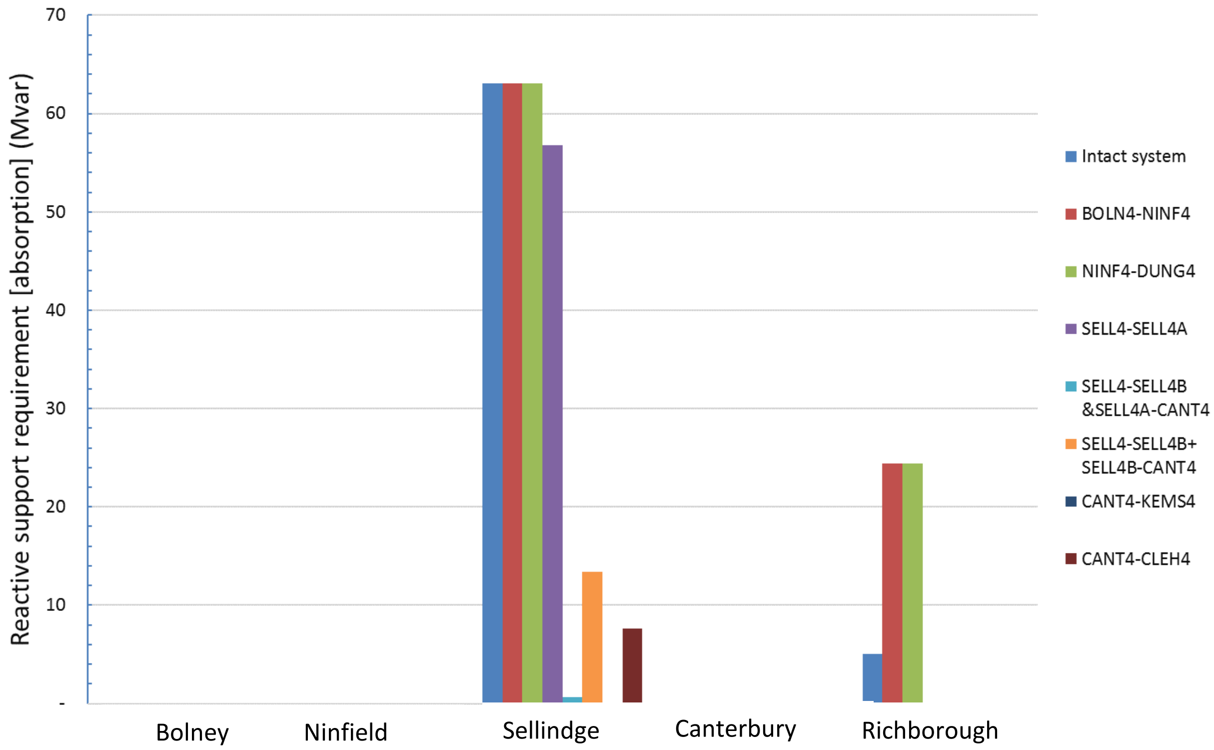


Figure 5-2 Reactive power requirement in different system conditions

The key findings analysed from the modelling results can be summarised as follows:

- Reactive power requirements are location specific; not all VPP are selected by the model.
- Reactive power requirements are system condition specific. The different volume of reactive power services is needed in a different location depending on the system condition. Different contingencies are likely to trigger different reactive requirements.
- In general, contingent conditions require more reactive requirement than in the intact system. This is not surprising given that a circuit outage tends to increase the system impedance and amplify the voltage problems in the system. This may have an implication on how the reactive power services should be remunerated, e.g. to use both availability and utilisation payment in the market rather than having only the utilisation payment.

5.3 Coordinated solution to determine the optimal allocation for reactive power services

In order to cover the system reactive requirement during intact and contingent conditions, the SCOPF model optimises the requirement simultaneously considering both intact and contingencies. It is important to note that taking the maximum reactive requirement from each node obtained from the contingency analysis could be suboptimal and leads to over contracted capacity of reactive power services. The optimal allocation of reactive support services is shown in Figure 5-3.

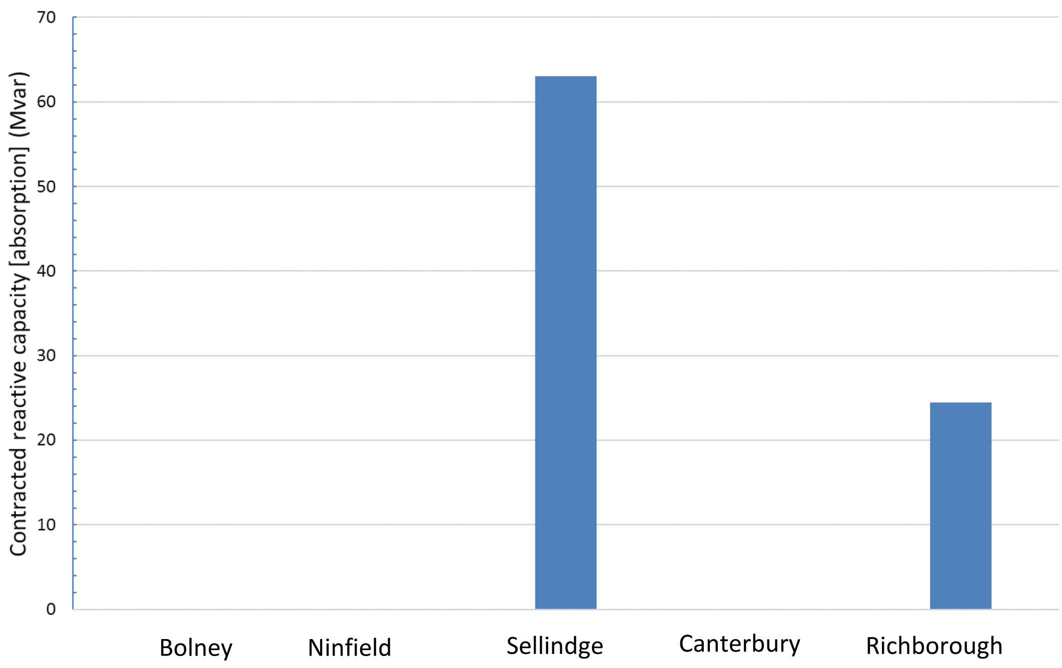


Figure 5-3 Contracted reactive capacity for the summer peak condition

For this particular case, the maximum reactive requirement at Sellindge and Richborough coincide in the contingent condition number 1 and 2; therefore, the optimal contracted reactive capacity is the maximum reactive requirement identified in these contingent conditions as shown in Figure 5-3.

Another study uses the winter peak condition where the system loading is relatively high coincide with low RES output and no import from the interconnectors. This condition results in low voltage problem across the test system; notably, the voltage at Richborough (the end of long transmission corridor)is at the lower limit[9] as shown in Figure 5-4.

[9] In this study, the voltage limit is 10%.

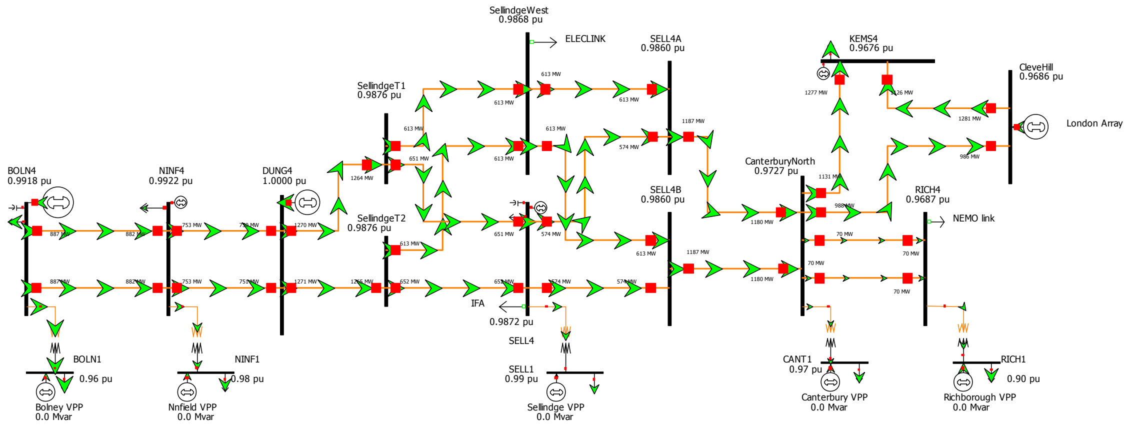


Figure 5-4 Winter peak condition with under-voltage at Richborough

In order to solve this problem, NETSO considers the offered from the 5 VPPs present in the system, i.e. VPP at Bolney, Ninfield, Sellindge, Canterbury, and Richborough. The amount of reactive power services that need to be contracted from each of the VPP to solve the voltage problem not only in the intact system but also in the contingent conditions is calculated using the Imperial's model. The results are shown in Figure 5-5.

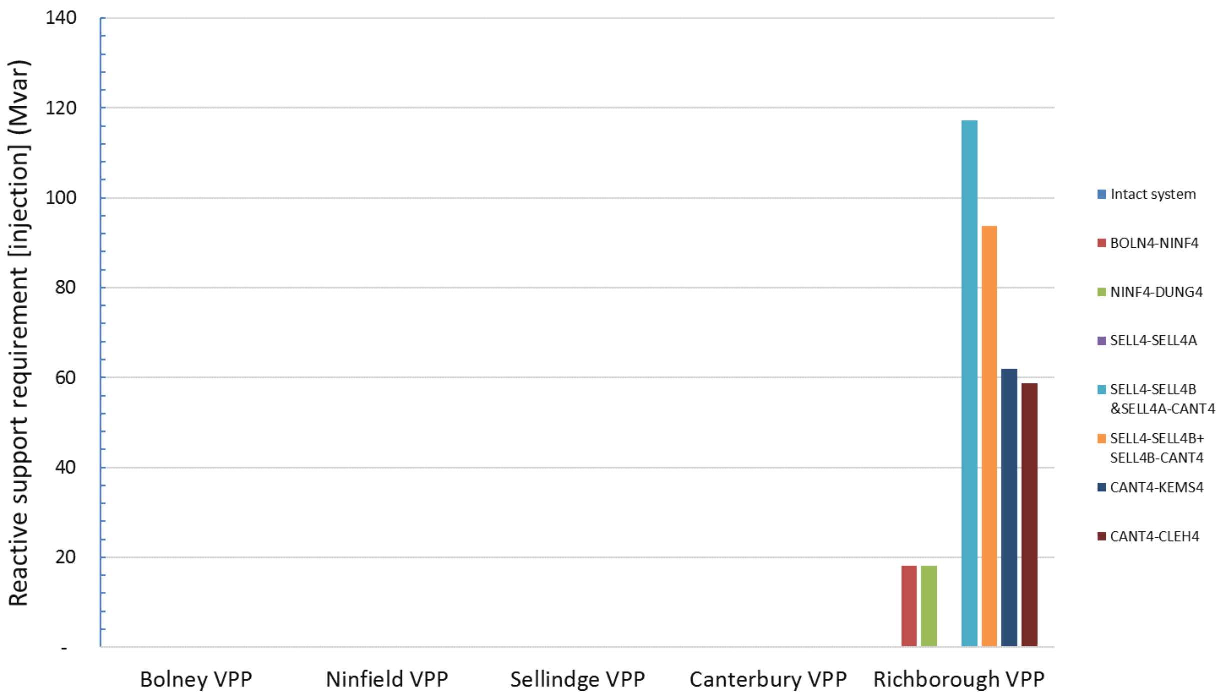


Figure 5-5 Reactive power requirement in different system conditions

As all the reactive requirement can be provided by VPP Richborough, the contracted capacity to deal with the intact and contingent conditions is the maximum reactive requirement (118 Mvar[lag])across those conditions as shown in Figure 5-6.

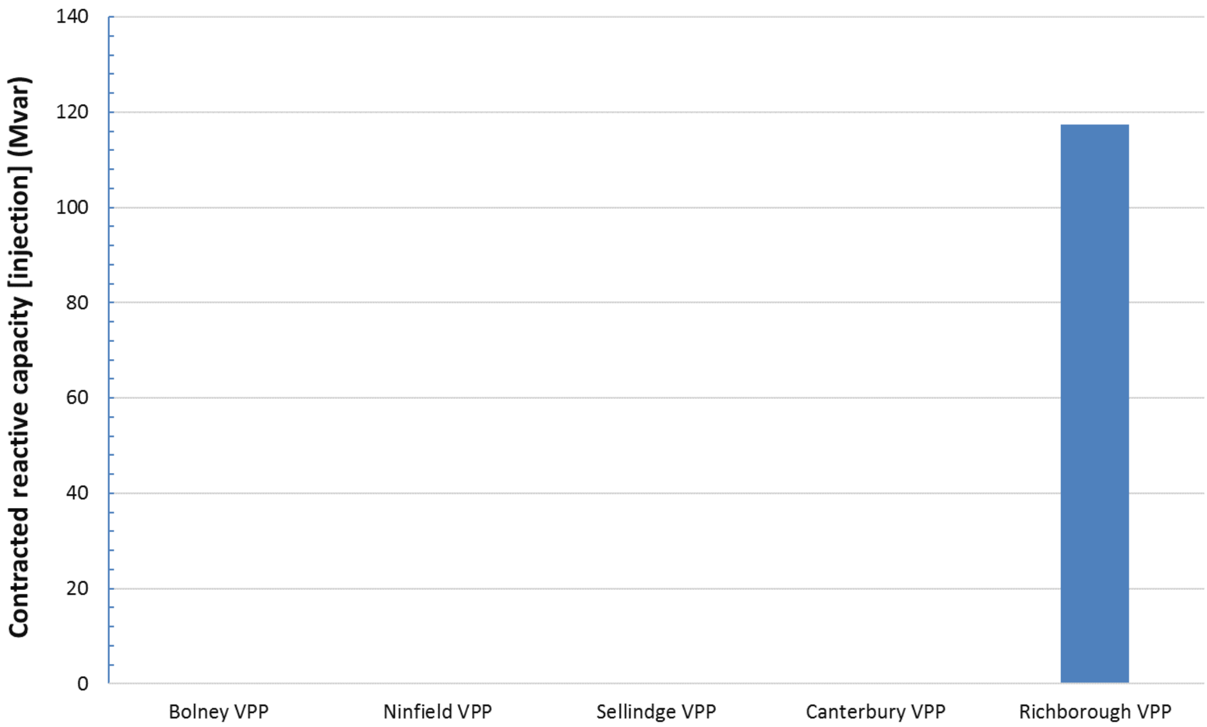


Figure 5-6 Contracted reactive capacity for the winter peak condition

5.4 Sensitivity of the optimal allocation of reactive power services to reactive market bids

In this study, we investigate the sensitivity of the optimal allocation of reactive power to the market bids. Two scenarios are used in the study, i.e. the Richborough VPP bids (i) two times or (ii) five times relative to the bids from other VPP. The modelling results for these two scenarios are shown in Figure 5-7and Figure 5-8 respectively.

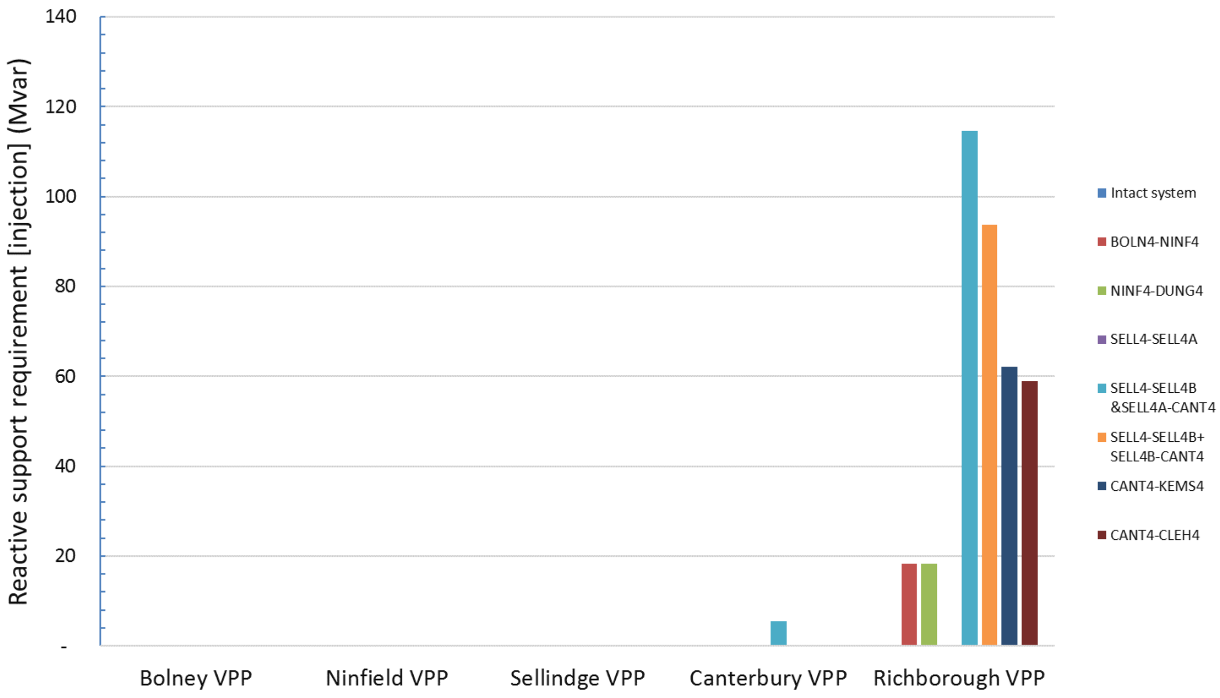


Figure 5-7 Allocation of reactive power services with Richborough VPP bids 2x

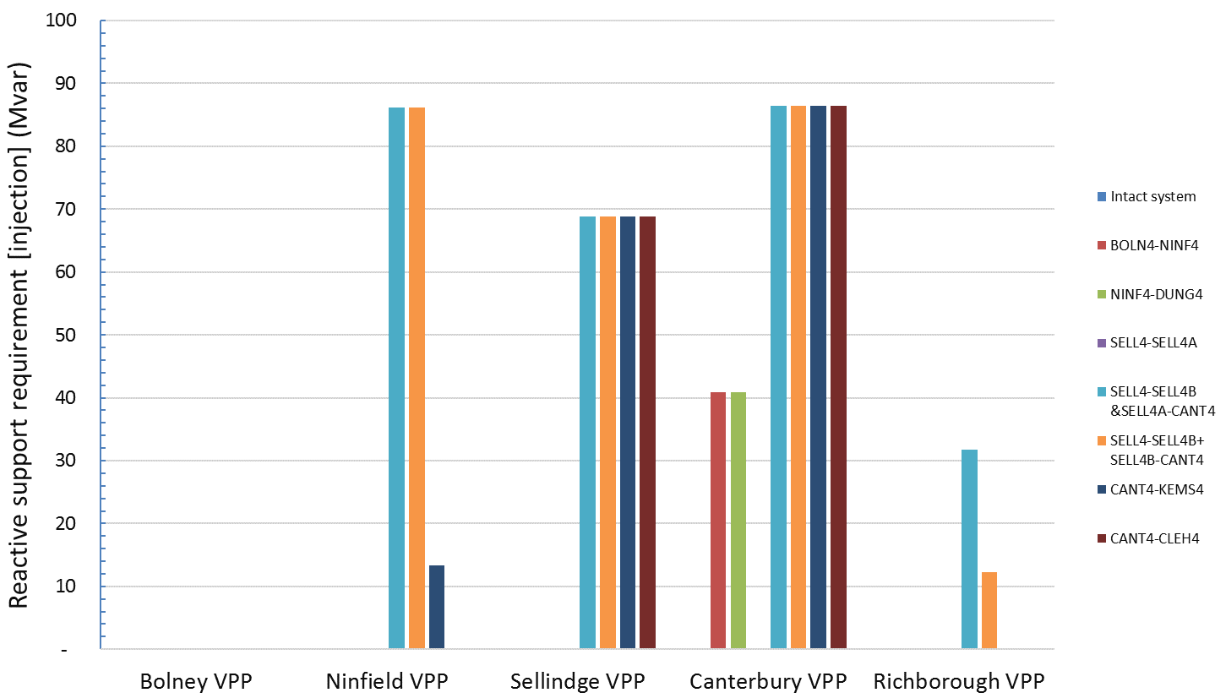


Figure 5-8 Allocation of reactive power services with Richborough VPP bids 5x

The output of the modelling results shows that even if the reactive bids from the Richborough VPP is two times higher, a similar solution is obtained, but when the bid is five times higher, the model reallocates the reactive services to other VPPs. However, the amount of reactive power needed is much larger compared to the reactive power required if it is supplied at Richborough. As the voltage sensitivity of other VPPs is lower, this will require more volume of reactive power needs to be contracted to solve the problem. However, the cost of this solution is still lower than the cost of the solution by accepting the bids from Richborough VPP. It is interesting to note that even with five times higher bid, Richborough VPP still needs to provide 30 Mvar. This demonstrates the location-specific value of reactive power services at Richborough is higher in this particular system condition.

5.5 Impact of the reactive power market time-frame on the optimal portfolio of reactive power contract

In this study, we use the SCOPF tool to allocate reactive power contract with different market time-frame. We use the results of the previous study for the winter peak demand assuming that the Richborough VPP bids 5 times higher than other VPP. The results are shown in Figure 5-8.

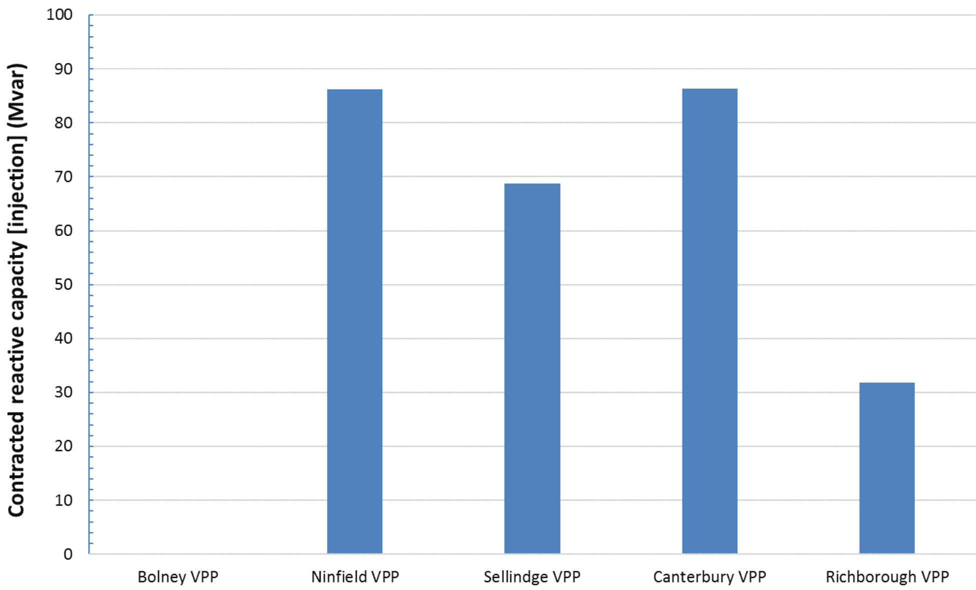


Figure 5-9 Reactive allocation for high demand [injection]

In this case, only reactive power injection capability is needed as the system voltages are low driven by the high demand condition in winter.

The same study has also been carried out for a lower demand level, i.e. medium scenario. In this case, both reactive power absorption and injection are needed due to different contingencies as demonstrated in Figure 5-10 and Figure 5-11 respectively.

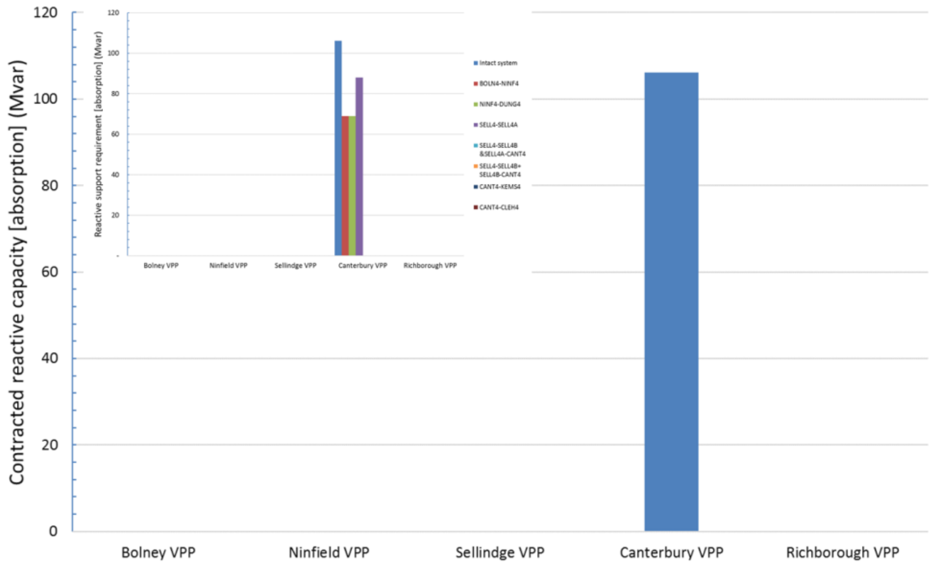


Figure 5-10 Reactive allocation for medium demand [absorption]

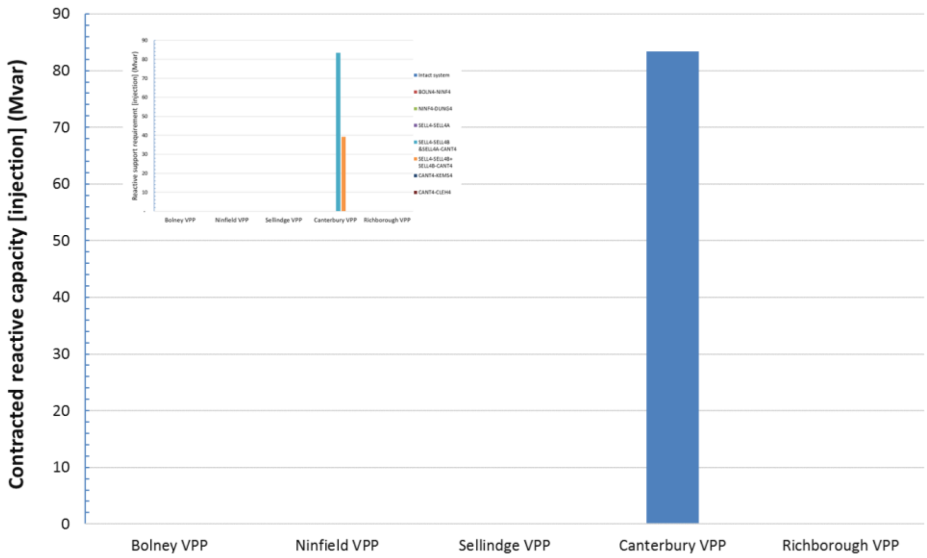


Figure 5-11 Reactive allocation for medium demand [injection]

Another study has been carried out to identify the optimal portfolio for a low demand system. In this case, only reactive power absorption is needed because the system voltages are relatively high driven by low demand. The reactive requirements obtained from the model are shown in Figure 5-12

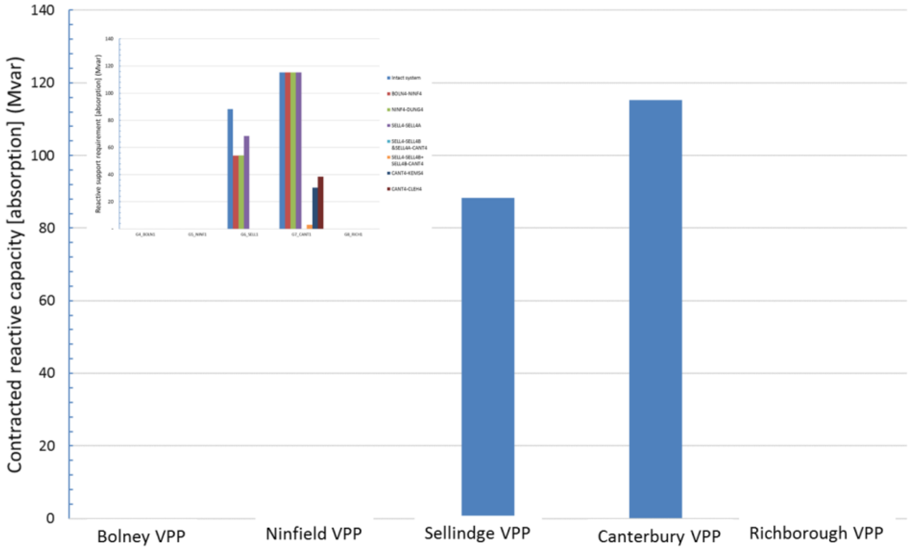


Figure 5-12 Reactive allocation for low demand [absorption]

The results demonstrate that depending on the system conditions covered by the duration of the reactive power contract, the optimal portfolio of the contract could be different. For example, during high demand condition, it requires only reactive power injection while in the low demand condition, it requires reactive power absorption. For the medium demand, it requires both but in different volume as shown in Figure 5-11.

If the contract needs to cover all the three demand conditions, then the model proposes to contract both reactive power absorption and injection as shown in Figure 5-13 and Figure 5-14.

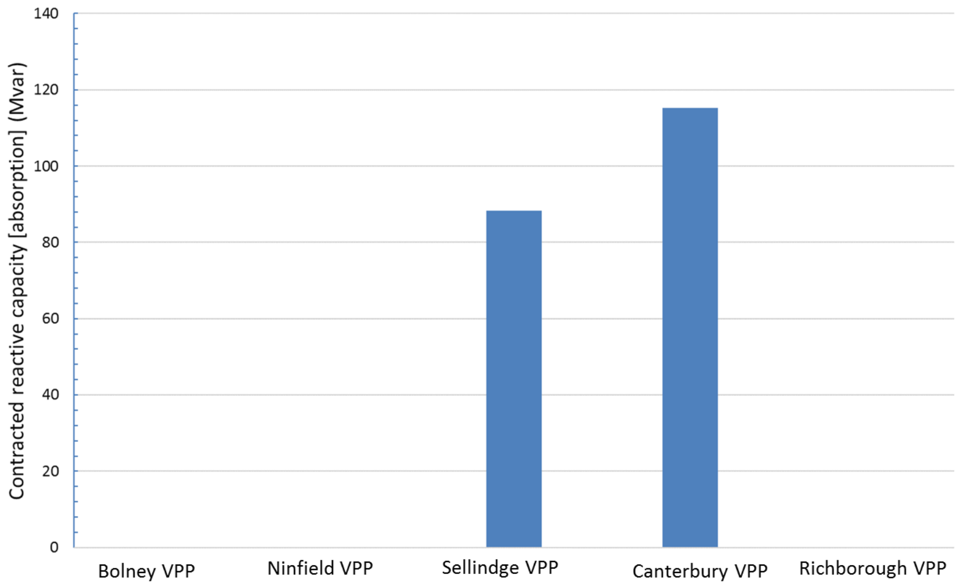


Figure 5-13 Reactive allocation for low demand [absorption]

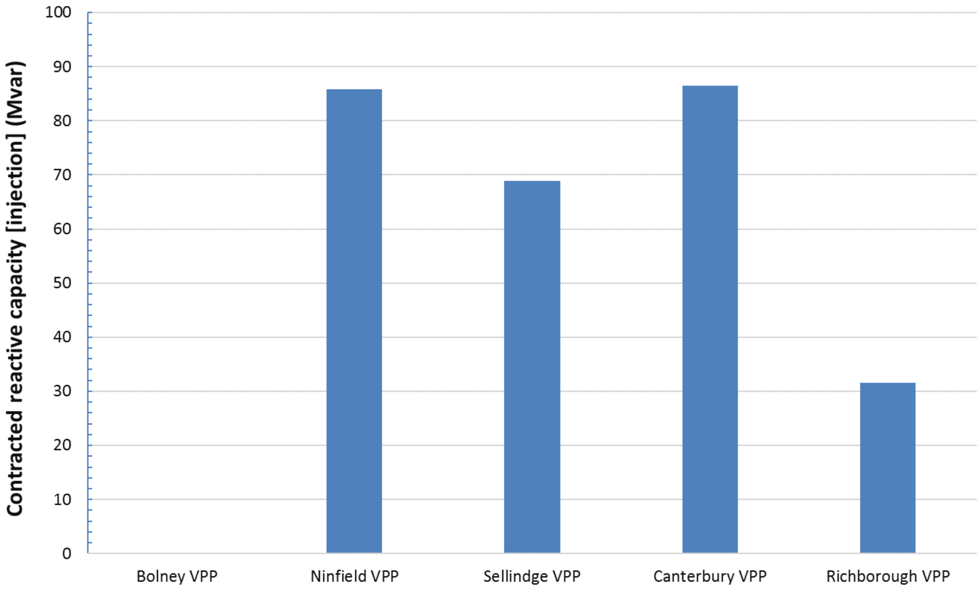


Figure 5-14 Reactive allocation for low demand [injection]

The results demonstrate that the longer the market time-frame, the range of possible operating conditions that have to be considered in the optimisation becomes broader and more reactive capacity is expected to be required.

Chapter 6. Conclusions

Cost-effective system integration of DER requires the following radical changes:

- A shift *from isolated operation of energy supply, transmission and distribution businesses towards a more integrated approach; and*
- *Design of a new market* that would maximise the overall economic value of DER considering both national and local objectives enabling DER to provide multiple services to different sectors of the electricity system. This can be achieved if DER has the opportunities to access various markets at the local level (e.g. congestion management of distribution networks) and national level (various forms of the reserve, capacity, reactive support, network management).

In this context, *the role of Distribution System Operator (DSO) needs to evolve in order to facilitate the application to DER services not only for local distribution network management but also for the benefit to the national transmission system***.** This development will require significant changes in operational practices and standards, and also regulatory market and commercial frameworks.

A range of modelling work and simulation studies has been carried out to test and demonstrate the feasibility of the reactive power market framework. As a summary, the following key findings can be concluded from the analysis of the modelling results:

- The studies demonstrate that DER connected to the local distribution network, in the scope of the Power Potential project, could be used to provide reactive power services and support secure operation of the transmission network.
- The sequential reactive power market framework using the VPP approach to aggregate DER capacity and local distribution network characteristics is technically sound, and the case studies demonstrate successfully the feasibility of the concept. The application of this concept will provide DER the opportunities to access ancillary service markets at the local level and national level.
- The value of the reactive power of VPP varies with time, location, demand and system conditions. As DER is more highly distributed across the system compared to large-scale transmission connected generators, DER can provide reactive sources more effectively as it can be closer electrically to the part of the system that needs support. This principle applies to both transmission and distribution.
- The importance of distribution active network management on dynamic capabilities of the virtual power plant has been demonstrated in the studies. This suggests that:
  (i) it would be beneficial that DSO optimises network operation to maximise the DER access not only to local energy markets but also to transmission ancillary service markets (i.e. reactive power market in the context of Power Potential). This demonstrates that it would be beneficial that the role and responsibility of DSO evolve to facilitate access for DER to transmission ancillary service markets.

(ii) Distribution network assets can also provide reactive power support to transmission, and this resource could play a role in the reactive power market. The capability of network assets can be aggregated as well, but it requires the development of a commercial framework that can remunerate the services from distribution assets.

- The networks studied in Power Potential are robust and capable of providing access of DER to the intact system.
- VPP reactive power dispatch is sensitive to the price, due to the high distribution network capacity, which will facilitate competition in the local reactive power market.
- The reactive capability of VPP is dynamic and changes according to local conditions in the distribution network. This is in contrast to the reactive sources provided by large-scale generators which are relatively defined and not influenced by network conditions. In order to measure the real-time capability of the VPP, it requires real-time monitoring and active management of the resources.

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