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The technical and economic benefits of utility sponsored renewable energy integration

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Abstract

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The Technical and Economic Benefits of Utility Sponsored Renewable Energy Integration

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This paper presents a coordinated reactive power control scheme to reduce voltage rise along LV distribution feeders with high penetrations of solar PV. The value of privately investing in solar PV and ES for the years 2015 and 2020 from the perspective of an average residential customer is determined. Finally, a business model is proposed outlining how utility sponsored residential solar PV and ES could be implemented by a DNSP. The business model is then evaluated from a technical and economic standpoint.

I. Introduction

Throughout Australia, increasing concerns about climate change has led to the push for more renewable forms of electricity generation. This, along with government incentives and the Australian energy consumer's desire to save money on electricity bills, has brought on a rapid increase in DG, particularly solar PV generation throughout LV distribution networks [1].

As the amount of small scale DG in LV distribution networks increases, the presence of these devices can have several adverse effects on distribution networks including: increased harmonics; increased potential of islanding; and an increase in the level of voltage fluctuations, voltage unbalance, and voltage rise. Voltage rise becomes a significant issue in weaker distribution networks or where there are high levels of DG penetration [1, 2]. For this reason, several Australian utilities have limited the installed capacity of solar PV on a distribution feeder to be around 30% of the peak power demand on that feeder [2].

Along with solar PV, the ES industry has also been rapidly evolving in recent years. When used in conjunction with solar PV, the excess energy that is usually exported back to the network can instead be used to charge the ES. This energy can then be utilised at a more convenient time by the consumer. With the costs of manufacturing ES rapidly decreasing, these two technologies could dramatically shift the way electricity is generated and distributed in Australia [3].

Utilities rely on the income generated from providing customers with electricity, via both energy (kWh) sales and connection charges, to maintain and build network infrastructure, while still turning over a profit [4]. The rise of solar PV and ES means customers are becoming more energy independent, which poses a major risk to current utility business models.

If utilities wish to remain relevant, it is vital they take advantage of the rising solar PV and ES products and services market. By providing customers with services relating to these products, a utility has the potential to improve customer relationships and open up entirely new revenue streams to generate income. This also opens up the potential to holistically control and manage solar PV and ES resources. By implementing the coordinated control of solar PV and ES, a utility can mitigate the adverse effects associated with solar PV, while improving customer relationships and allowing the increase of distributed renewable resources in Australia to grow.

II. DG Power Quality Issues in LV Networks

The rise of solar PV throughout LV distribution networks in Australia has led to power quality issues, majority of which are related to voltage rise [5]. Voltage rise occurs when the amount of power generated from solar PV is greater than the local load demand. The power that is not being utilised by the local load is supplied back to the grid. This subsequently causes the flow of current to reverse along the feeder and, in turn, can lead to a voltage rise along the feeder [2, 6, 7].

The issue of voltage rise due to DG has led to a great deal of research into the potential for inverters to supply and absorb reactive power to assist voltage regulation. Currently in Australia, most solar PV inverters are set at unity power factor to comply with AS 4777.2 [8]. By using inverters as a source of both active and reactive power, DNSPs could potentially increase the hosting capacity along a feeder as well as improve power quality [2, 6, 7].

To mitigate voltage rise [6, 7] propose a decentralised control scheme whereby the active and reactive power supplied from each inverter depend on the voltage magnitude and impedance at the installation location. In [2, 9] a more centralised approach is suggested where the DNSP would send all inverters a command to adjust their VAr output according to an overarching control scheme. This approach has several advantages over the decentralised approach. For example, the decentralised approach has the potential to lead to adverse interactions between the inverters and other voltage regulating devices such as OLTCs, capacitor banks and voltage regulators. By implementing a more centralised control scheme, the DNSP has the potential to ensure all these devices work in conjunction with one another to achieve optimal network operating conditions.

Like solar PV, the decreasing cost of ES is expected to cause a major paradigm shift and potential risk to current utility business models [4]. In recent years, schemes such as the demand management and embedded generation connection incentive scheme (DMEGCIS) and the demand management incentive scheme (DMIS) have been developed to incentivise utilities to find non-network solutions to limit load growth [3]. This can possibly be achieved by using residential ES to assist the grid during periods of peak load. If utilities are able to provide services beyond simply connecting customer PV and providing a feed-in tariff, such as energy storage and voltage regulation, there are possible benefits for both the utility and the customer. This will provide utilities a gateway into a new distributed generation products and services market allowing utilities to benefit both technically and economically [10].

III. DG Induced Voltage Rise Mitigation via Coordinated Reactive Power Control

One of the key benefits of utility sponsored solar PV is the potential to mitigate the inherent adverse effects that are associated with solar, such as voltage rise. An inverter reactive power control scheme is proposed in this section to reduce voltage rise in LV distribution feeders with a high penetration of DG.

A. LV Feeder Classification

LV feeders are the portion of a distribution network that connects to end users. LV feeders vary in their configuration significantly depending on where they are located in the network i.e. if they are in a urban or rural setting. For this reason, it was necessary to develop and model several LV feeder types to represent the different LV circuits that can be found in a typical distribution network. The main factors that were taken into account when developing these LV feeder types were the length of the feeder, the number of customers connected to that feeder, the cables and/or conductor types that make up that feeder and finally, the rating of the upstream distribution transformer (TX).

1) LV Feeder Length: To determine the typical length of LV circuits, a large amount of geographic information system (GIS) data was obtained from an Australian DNSP. The data consisted of information relating to all LV line segments within their network. Each of these line segments had an associated measured length and cable/conductor type. Summing all line segments downstream of a fuse, switch or circuit breaker located at a distribution substation gave the length of a particular LV circuit. Once the length of all 12,059 LV feeders were calculated, the results were analysed to determine the typical length of LV feeders. The LV feeder length summary is shown in Table I.

2) Number of Customers per LV Feeder: Using the GIS data obtained from the DNSP, it was possible to sum all service points that were downstream from a distribution substation. The correlation between the number of customers and the length of the feeder was shown to be linear. From this linear function, the average number of customers for the LV feeder types established in Section III-A1 were determined. Based on the average number of customers and the length of the feeder, the kVA rating of the upstream TX was also determined for each LV feeder type. The average number of customers for each feeder type and the subsequent TX ratings are shown in Table I.

TABLE I: LV Feeder Classification Summary

LV Feeder Type	Range (m)	% of Feeders	No. of Customers	TX Rating (kVA)
Short	0 - 440	50	16	100
Medium	440 - 1,000	25	30	250
Long	1,000 - 1,700	15	45	315
Very Long	> 1,700	10	60	500

B. Network Models

To study the effect high DG penetration has on voltage rise, four network models were created using DIgSILENT PowerFactory. These models were based on the LV feeder types developed in Section III-A. The MV/LV distribution transformer was modelled as an ideal voltage source with an rms voltage of 241.5 V (1.05 per-unit). Each radial feeder was modelled with equally spaced line sections. The number of line sections is determined by dividing the number of customers by three (one customer per phase in each line section). The mercury overhead conductor type (AAC 7/4.5mm with R=0.315 Ω/km and X=0.259 Ω/km) was used to populate the technical data for the line sections. Mercury was chosen as it was the most common LV conductor in the in the DNSP's network.

Customers are grouped together in threes and modelled as one three phase load, connected to a three phase bus. The total power drawn by each customer is 0.7 kW to emulate light feeder loading which occurs during the middle of the day. PV systems are connected to each customer bus within the network model.

C. Coordinated Reactive Power Control Scheme

Many reactive power optimisation algorithms require a great deal of computational power to determine the reactive power requirements of each inverter. As this would lead to significant capital expenditure (CAPEX) for a DNSP to implement such a system, a much simpler controller to regulate voltage throughout each distribution feeder was developed. The authors of [11] suggest a power sharing method to reduce voltage rise, where each distribution feeder is split into three zones as shown in Fig. 1.

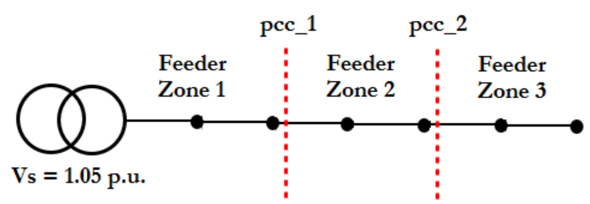

Fig. 1: Single Line Diagram 'Short' LV Feeder

All inverters in each zone then work in conjunction with one another to regulate the voltage at a point of common coupling (PCC). The inverters in feeder *Zone 3* would regulate the voltage at *pcc_2*, while the inverters in feeder *Zone 2* would regulate the voltage at *pcc_1*. The inverters in feeder *Zone 1* would not need to participate in the voltage regulation.

A similar technique was developed for this project to regulate the voltage on each LV feeder type. A closed loop controller was installed at each PCC. Based on the voltage at each PCC, the inverters downstream of that PCC would dynamically shift their power factor based on a *V-Q* droop characteristic. This *V-Q* droop characteristic will vary based on which zone each inverter is in, as well as the LV feeder type.

1) Droop Characteristic: The droop characteristic developed to determine the required reactive power consumption of each inverter is based on an inverse sigmoid function. The y-axis Q_i corresponds with the per-unit reactive power requirement of each inverter in a particular zone, while the x-axis (V_{pcc}) corresponds with the per-unit voltage at the PCC. The curve is centred around V_{set}, which is the voltage set-point. The reactive power set-point (Q_{set}) varies based on the LV feeder type and which feeder zone the inverters are located. The longer the feeder, the larger Q_{set}. Finally, the slope of the droop curve (m_i) is derived from the reactive power set-point. Again, the longer the feeder, the larger m_i. The mathematical expression for the droop characteristic is shown using (1):

$$Q_i = \begin{cases} Q_{\text{set},i} & \text{for } V_{\text{pcc},i} < (V_{\text{set}} - 0.05) \\ m_i(V_{\text{pcc},i} - V_{\text{set}}) & \text{for } V_{\text{pcc},i} \geq (V_{\text{set}} - 0.05) \\ m_i(V_{\text{pcc},i} - V_{\text{set}}) & \text{for } V_{\text{pcc},i} \leq (V_{\text{set}} + 0.05) \\ -Q_{\text{set},i} & \text{for } V_{\text{pcc},i} > (V_{\text{set}} + 0.05) \end{cases} \tag{1}$$

2) Formulating the Control Problem: The goal of the combined solar PV reactive power controllers is to minimise power losses, whilst ensuring all PCC voltages are under the voltage set-point. If the line losses at the j^{th} inverter are $R_{L_{j\text{-}1}} {I^2}_{L_{j\text{-}1}}$, then the total losses can be expressed as:

$$J_{\text{losses}} = \sum_{j=1}^{N} R_{L\,j-1} I^2_{L\,j-1} \tag{2}$$

Considering the droop function developed in (1), the control problem can be formulated as follows:

$$\begin{aligned} \min \quad & J_{\text{losses}} \\ \text{with respect to} \quad & Q_{\text{set},i} \\ \text{subject to} \quad & V_{\text{pcc},i} \leq V_{\text{set}} \end{aligned} \tag{3}$$

D. Simulation and Results

The reactive power droop controller designed in Section III-C was implemented at the PCCs for the 'medium', 'long' and 'very long' LV feeder types. All simulations were executed with a total solar penetration of 40% (based on the transformer rating). A penetration of 40% was chosen as all feeders had a maximum hosting capacity less than this value. The control problem was solved using an iterative solution in MATLAB where all inverter reactive power requirements were determined based on the constraints outlined in 3. DIgSILENT PowerFactory was used as the load flow engine to analyse the feeder voltage profiles before and after the implementation of the coordinated reactive power controller.

The controller was shown to improve the voltage profiles for all LV feeder types, ensuring all PCC voltages were within the voltage setpoint (1.1 per-unit for this analysis). All LV feeders were shown to reach the required voltage set-point in three iterations or less. The 'Short' and 'Long' feeder voltage profile before and after the control was implemented is shown in Fig. 2 and Fig. 3 respectively. The results for the maximum voltage (voltage at the end of the feeder) before and after the control is summarised in Table II.

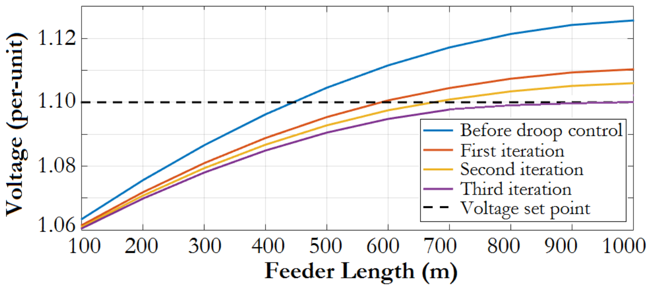

Fig. 2: Short LV Feeder Voltage Profile, Before and After Control

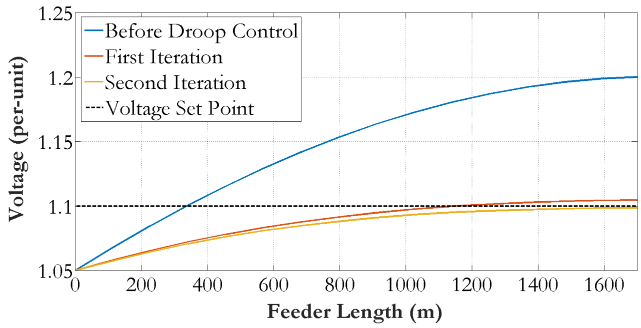

Fig. 3: Long LV Feeder Voltage Profile, Before and After Control

TABLE II: Feeder Maximum Voltages Before and After Control

LV Feeder Type	Max p.u. Voltage Before Control	Iterations	Max p.u. Voltage After Control
Medium	1.126	3	1.1
Long	1.199	2	1.1
Very Long	1.289	3	1.1

The controller developed was also shown to reduce line losses compared to a uncoordinated decentralised *V-Q* droop controller and was shown to increase each feeders hosting capacity. These results are summarised in Table III.

TABLE III: Hosting Capacity Before and After Control

LV Feeder Type	Uncoordinated Control Losses (kW)	Coordinated Control Losses (kW)	Hosting Capacity Before	Hosting Capacity After
Medium	1.911	1.519	28%	75%
Long	3.709	2.945	22%	48%
Very Long	13.355	8.681	16%	36%

IV. The Economic Benefits of Privately Owned Solar PV and ES

This section explores the current costs and benefits associated with solar PV and ES for the average energy consumer in the ACT. The two time periods used for the analysis were 2015 and 2020.

A. Customer Load Profile and Solar PV Output

To calculate the annual income and operating costs for the average residential customer with solar PV and ES, a customer load profile was required to determine the average amount of energy a customer uses annually. This was obtained from an Australian DNSP. The average power consumption for a residential customer in the DNSP's network was 1.35 kW.

To determine the amount of energy produced by solar PV for this analysis, 1 minute solar irradiance interval data was obtained from the the Bureau of Meteorology [12]. To determine the output of a solar PV system over the course of a day, the solar irradiance curve was multiplied by the kilowatt rating of the solar PV system in question, to give the PV output curve. The customer load profile for an average power consumption of 1.35 kW, along with the average solar PV output for a 3 kW rated system is illustrated in Fig. 4.

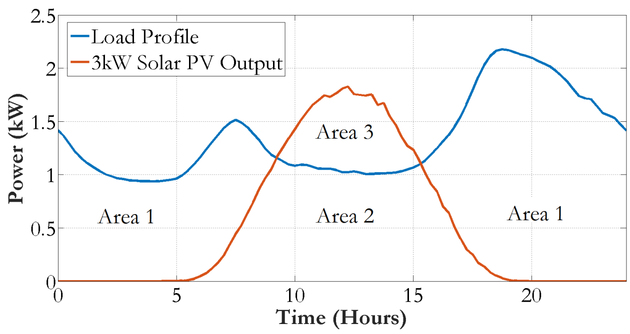

Fig. 4: Average Customer Load Profile with 3 kW of Solar

In Fig. 4, *Area 1* indicates energy that is purchased from the grid. *Area 2* indicates energy that is produced by the solar PV and used locally. Finally, *Area 3* is the energy exported back into the network or potentially stored for later use.

B. System Cost

The average cost for a fully installed solar PV system in the Australian Capital Territory (ACT) per Watt-peak (W_P) was obtained from Solar Choice, a company who undertake a monthly analysis on solar PV system pricing around Australia [13]. This price includes the cost of the solar array, the inverter, the balance of systems as well as the engineering, procurement and construction. The prices for the year 2020 were calculated by trending the Solar Choice data between August 2012 and April 2016 and applying that linear function to the year 2020.

Prices for lithium-ion (Li-ion) batteries have been decreasing rapidly in the last few years and are expected to continue to decrease. As of 2014, Li-ion batteries were averaging \$750/kWh. This value is expected to drop to \$270/kWh by 2020 [3]. From these values, the CAPEX associated with purchasing and installing an Energy Storage Unit (ESU) could be calculated.

C. Economic Analysis

To determine how economically viable privately owned solar PV and ES systems are, the current costs associated with purchasing and installing, the cash flow generated, the payback period of the systems, and finally, the net present value (NPV) were determined. A NPV that is positive indicates that an investment is worthwhile. The results are summarised in Table IV.

TABLE IV: Scenario Results

PV Size (kW_p)	2kW	3kW	4kW	5kW	10kW
2015					
ESU Size (kWh)	1	4	9	13	25
$CAPEX_{Total}$(\$)	5340	9300	15100	19800	37000
Payback (years)	9.92	11.53	14.04	14.72	14.23
NPV	-112.92	-1042.5	-3189.4	-5459.9	-8618
2020					
ESU Size (kWh)	1	4	9	13	25
$CAPEX_{Total}$(\$)	3564	5466	8036	10112	18700
Payback (years)	6.62	6.77	7.47	7.52	7.19
NPV	1881.2	3069.6	3586.4	4628	10391

D. Scenario Results

The results from Table IV show that while a combined residential solar PV/ES system was not economically viable for the year 2015, by the year 2020 all sizes, ranging from 2 kW to 10 kW, are seen as a worthwhile investment. This is evident from the positive NPV and the payback period being significantly shorter than 15 years (the expected life of the system). While this result is favourable for the average Australian energy consumer, it could prove to be a disadvantage for DNSPs. With combined solar PV/ES systems becoming a far more viable form of energy production and subsequent consumption for consumers, utilities will be forced to rethink their current business models and begin to move away from centralised generation.

V. The Economic Benefits of Utility Sponsored Solar PV and ES

A potential business model is proposed in this section for utility sponsored PV and ES. Economic benefits from both the utility and the customer's perspective are explored and recommendations are made on whether such utility involvement in solar PV and ES, from a business stand point, is viable.

A. Utility Sponsored PV Business Model

The following business model relates to how a utility could implement system-wide, fully controlled solar PV and ES. The model aims to:

- Improve customer relationships and increase customer income
- Reduce the need for network augmentation as a result of increasing customer numbers and load growth
- Reduce the amount of energy purchased by the utility from the National Electricity Market (NEM), thus decreasing the utilities carbon footprint
- Ensure utilites/retailers can still turn over substantial profits

1) Stage 1 - Customer Proposal and Installation: The first step in the business model is to approach customers and offer them a quote on an Energy Management System (EMS). An EMS consists of solar PV, a smart controllable inverter, and some form of ES. All of which are installed, controlled and maintained by the utility. To incentivise customers to invest in an EMS, the utility will offer a discounted rate for the solar PV/ES system, compared to that currently offered to private investors. Along with the discounted system cost, the utility will also offer a significantly higher feed-in tariff than that currently available to customers with privately owned solar PV (20 c/kWh).

2) Stage 2 - System Operation: Once a substantial number of EMSs have been installed, the utility can collectively use each system to regulate voltage and reduce peak demand along feeders. Voltage regulation can be achieved by implementing a control system, such as that developed in Section III. Using this control system in conjunction with a system that discharges the ESUs during peak loading periods, could allow for the number of customers per distribution feeder to increase, thus decreasing the need for network augmentation as the customer base along that feeder increases. The utility will also be responsible for any maintenance that is required for each EMS, over the life of the system.

B. Network for Analysis

There is no one solution to determine whether or not the business model proposed in Section V-A is viable for a utility. There are far too many variables that vary between different portions of a distribution network such as: the number of customers; length of feeders; and pre-existing solar PV. For this reason, it was decided to analyse the feasibility of the business model proposed in Section V-A for one zone in an Australian utility's network. The network chosen for the analysis consisted of a zone substation (ZS) with nine MV feeders, which supply power to 11,798 customers. This particular ZS was chosen as it is one of the smaller and relatively newer ZSs in the network, and already has a large penetration of solar PV. The zone consists of 1,400 installs of solar PV with a total rated capacity of 4,096 kW.

C. Economic Model

The following economic model was used to calculate the benefits of the business model proposed in Section V-A. The model only relates to the cash flows generated from the purchasing and dispatching of energy. Therefore, the model will not take into account any regular maintenance on network assets such as poles, wires and transformers.

1) Cash Flow In: The main factors considered when determining the DNSP's annual cash flow in C_{in} for the zone include: the daily, and subsequent, annual cost each customer pays for energy; the daily supply charge each customer pays; and finally, the profit the DNSP will make from selling EMSs.

2) Cash Flow Out: The main factors considered when determining the DNSP's annual cash flow out (C_{out}) for the zone include: the daily, and subsequent, annual cost of purchasing energy from the NEM; the operating expense (OPEX) associated with maintaining each EMS; and finally, the costs associated with supplying those customers a solar feed-in tariff. This will include the old feed-in tariff for customers with privately owned solar, and the new feed-in tariff for those customers who purchase an EMS.

3) Net Present Value: NPV reduces all costs and incomes to a value in the present. This allows the feasability of an investment to be calculated based on current costs and prices. NPV is defined using (4). For this analysis, the NPV equation is updated to account for the deferral of CAPEX (C_{def}), which is seen as an income from the perspective of the utility. The i term is the interest rate, n is the year of cash flow calculation, N is the life of the investment, and C_{T} is the capital investment made by the utility for the EMSs.

$$\text{NPV} = -C_{\text{T}} + \sum_{n=0}^{N} \frac{C_{\text{in}} - C_{\text{out}}}{(1+i)^n} + C_{\text{def}} \tag{4}$$

D. Calculating Technical Parameters

The first step in determining the viability of utility sponsored PV/ES was to establish the technical parameters for the analysis. The first parameter to determine was the percentage of peak demand the utility wishes to reduce. For this analysis, that value was assumed to be 10%. It is then possible to calculate the required number of EMSs to be installed within the zone to achieve this peak reduction.

To determine how much ES is required along each feeder to reduce peak load, a shaved load profile for each MV feeder was created in MATLAB using MV feeder load profiles provided by the DNSP. The shaved load profile for one of the nine feeders is shown in Fig. 5 in red. By calculating the area of the shaded section in Fig. 5, the required amount of storage in kWh was determined.

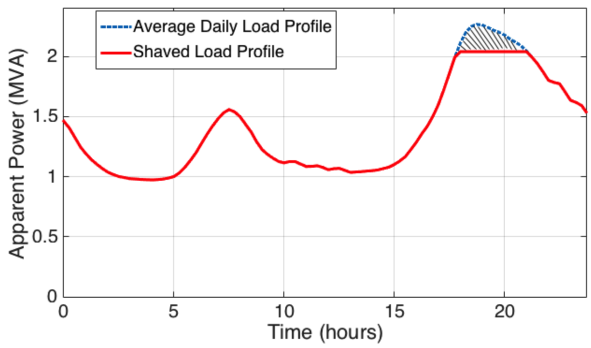

Fig. 5: MV Feeder Shaved Load Profile

For a 10% reduction in peak load across the entire zone, the DNSP would on average require 3,274 kWh of storage. This is equivalent to 642 3 kW EMS installs. With 1,400 solar installs that average 2.93 kW in size, the DNSP already has over double the amount of required solar to meet the storage requirements for this zone.

E. Economical Analysis

Once the technical parameters were established, it was possible to quantify the costs associated with utility sponsored solar PV and ES. The following calculations assume the investment period is 15 years and the investment begins in 2016. The annual cash flows in and out were calculated every year for the investment period. From the annual cash flows in and out over the 15 year period for all nine feeders, it was possible to determine the NPV using (4). The NPV was calculated for both the proposed business model from Section V-A and the current business model the utility uses. The NPV for the proposed business model was calculated using both 2015 and 2020 ACT prices of solar PV and ES. The results are shown in Table V.

These NPV calculations, however, do not take into account the deferral of CAPEX, C_{def}, from (4). The cost of network augmentation can vary greatly depending on how much new infrastructure is required to be installed. Therefore, instead of calculating the value of C_{def}, the minimum value for C_{def} was determined which would lead to the NPV of the proposed business model being greater than the current business model. The minimum value for the CAPEX deferral is shown in Table V.

TABLE V: 15 Year Business Model NPV

Business Model	**NPV ($Mill)**	**Min C_{def} ($Mill)**
Current Model	182.02	-
Proposed Model 2015 Prices	177.88	4.14
Proposed Model 2020 Prices	179.10	2.92

F. Business Model Results

The proposed business model was shown to achieve all the aims outlined at the beginning of this section. With 642 EMSs in place, it was calculated that, on average, the zone could support 1,733 extra customers. Under the current utility business model, increasing the number of customers within a zone by this value would require the installation of an entire extra MV feeder. The NPV for the proposed business model was calculated and compared to the NPV of the current business model. As expected, the proposed business model had a smaller NPV due to the CAPEX and OPEX associated with purchasing and maintaining the EMSs, along with the increased feedin tariff paid to customers. However, if the utility saves over $4.14 million (refer 2015 prices in Table V) by defering network augmentation (which more than likely would be the case if a new MV feeder was required), the proposed business model is seen as a worthwhile investment.

VI. Conclusion and Future Work

A technique to classify LV feeders based on the total feeder length and number of customers was developed. From these LV feeder classifications, a method was developed to reduce voltage rise across all LV feeder types through optimal reactive power settings and active power curtailment. In all instances, the method was shown to reduce PCC voltages below the specified voltage set-point, while minimising line losses.

The value of investing in solar PV and energy storage for a typical residential customer in the ACT was evaluated. It was shown that while it is not currently worthwhile to invest privately in solar PV and ES, by the year 2020, all combined solar PV and ES systems, ranging from 2 kW to 10 kW will be a worthwhile investment.

A business model was proposed describing how an Australian utility could provide its customers with solar PV and ES products and service. Using the annual cash flows and economic model, the value of investing in solar PV and ES from the perspective of the utility was determined.

From the results obtained, it was evident that implementing the business model would allow the utility to increase the number of customers connected to each feeder in the zone, reduce the need for network augmentation, increase both customer and utility income and, finally, improve customer relationships.

Future work includes further research and development of demand response strategies for residential solar PV/ES to reduce peak demand. This includes development of the control strategy and hardware for a single residential demand responsive energy management system.

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