Collaboration on Energy and Environmental Markets

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MINIMUM RELIABILITY SUBSCRIPTION, CAPITAL EFFICIENT COMMUNITY MICROGRIDS WITH HIGH SHARE OF RENEWABLES

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The UNSW Collaboration for Energy and Environmental Markets (CEEM) undertakes interdisciplinary research in the design, analysis and performance monitoring of energy and environmental markets and their associated policy frameworks. Our work focuses on the challenges and opportunities of clean energy transition within market oriented electricity industries. More details of this work can be found at the Collaboration website www.ceem.unsw.edu.au. We welcome comments, suggestions, questions and corrections on this submission, and all our work in this area. Please feel free to contact Associate Professor Iain MacGill, Joint Director of the Collaboration at i.macgill@unsw.edu.au.

Abstract

This paper proposes a capacity subscription mechanism combined with a differential pricing technique to create an inherent market to incentivize investments as well as long-term demand response behavior in renewable energy microgrids. This proposed planning framework with the goal of social welfare maximization and revenue adequacy, incorporates customer preferences through individual capacity subscription to ensure the desired minimum level of reliability, so to prevent over-capacity or under-capacity. A dynamic pricing tariff design ensures revenue adequacy, and an easy-to-implement demand response mechanism provides economic incentives for customers to maximize own benefits through generation following. This is particularly advantageous in microgrids incorporating large portions of highly variable renewable energy generations. This framework also greatly simplifies the microgrid investment planning, operation and scheduling. Compared to a standard capacity subscription design, simulation results show the advantages of the proposed method in improving the customers' surplus, and supply-demand matching, achieving cost recovery, and desired level of reliability of the customers.

Key words: **microgrid planning; capacity subscription; dynamic pricing; demand response; minimum reliability subscription**

Symbol	Description
A	Unit cost of firm generation capacity B
B	Unit cost of the intermittent generation X
Γ	System minimum reliability coefficient
γ_1	Minimum reliability coefficient for subperiod 2
ϑ	Consumer index
ξ	Capacity allocation factor
ω	Stochastic state
Φ	Aggregate subscribed capacity
$A(k,z,\vartheta,\omega)$	Subscribed capacity of consumer ϑ
b	Variable cost of firm generation
B	Firm generation capacity
c	Consumer desired consumption
CB	Consumer benefits
CS	Consumer surplus
k	Price of capacity
PS	Producer surplus
q	Ex post demand schedule
Q	Aggregate ex post effective demand
Q_0	Aggregate ex post effective demand during period 1
Q_1	Aggregate ex post effective demand during period 2
SW	Social welfare
T	Total demand cycle
t_1	Off-peak demand subperiod 1
t_2	Peak demand subperiod 2
t_c	Curtailment period
$u(z,q,\vartheta,\omega)$	Marginal willingness-to-pay of consumer ϑ
X	Capacity of intermittent generation
y_{11}	Power supplied by non-zero marginal cost firm generation
Y	Available generation at time t
Z	State-dependent electricity prices

1 Introduction

In developing countries where village-scale microgrids form an effective solution for energy access and rural electrification, a key challenge is often to ensure sufficient cost recovery and resource allocation efficiency so to attract ongoing private and foreign investments (Palit & Chaurey, 2011). To date, a variant of subscription-based mechanisms such as fix service based tariffs (ARE, 2014; Chaurey, Krithika, Palit, Rakesh, & Sovacool, 2012), hybrid revenue model (Williams, Jaramillo, Taneja, & Ustun, 2015), have been used in a number of community microgrid projects, mostly to minimize the hazards of energy payment collection and encourage the subscription to the services, aiming to promote longer-term investments in new capacities. Meanwhile, more complex market-based mechanisms can enhance allocative efficiency and economic efficiency of the microgrid, encouraging demand side response, energy conservation, through consumer participation and efficient price signals.

Existing work on microgrid planning and design that take into consideration of the consumer preferences and their service requirements at the individual level is rare. Microgrid planning, mostly capacity planning and sizing, has been dealt with as a technical optimization problem largely based on least cost principle (Jin, Feng, Marnay, & Spanos, 2017; Parhizi, Lotfi, Khodaei, & Bahramirad, 2015). Microgrid scheduling and energy management operation and pricing strategies, by comparison, generally aim to minimize the operation costs of microgrids, sometimes incorporating demand response (Huang, Mao, & Nelms, 2013; Tushar, Assi, & Maier, 2015).

A more cost-efficient design for a microgrid system is sought to meet consumers' least cost requirements, including demand, reliability level, and payment expectations, with minimum investments, particularly in the presence of high shares of renewables where the demand is expected to follow the generation. Drawing insights and experience from capacity subscription services in competitive electricity markets investigated by a number of researchers (Chao, 2012; Doorman, 2005; Woo, 1991), we propose a differential-pricing Capacity Subscription (dp-CS) mechanism that determines an efficient dynamic rate structure and rationing mechanism to cover system costs and promote long-term demand response behaviour for supply-demand matching. This program design will help to reach optimal resource allocation and maximize the social welfare within the community microgrid, particularly when there are limited financial resources often experienced in developing countries.

2 The proposed Differential Pricing Capacity Subscription Mechanisms

2.1 The relevance of capacity subscription model

Over the last several decades, the standard capacity subscription mechanisms have been explored by various economists, such as (Panzar & Sibley, 1978; Schwarz & Taylor, 1987), to solve supply adequacy and allocative efficiency problems during peak demand. A standard capacity subscription design based on capacity rationing by Woo (1991) entails a two-part tariff to collect fixed costs under demand uncertainty (Woo, 1991), as an alternative to spot pricing. Under this program design, a consumer chooses to subscribe to a capacity level A paying a capacity charge k in advance. When the demand can be met by the available supply, consumers will pay energy prices z for quantity consumed q. During peak periods, when the demand is greater than the available supply, consumers' demand will be curtailed to their subscription level A. Optimal two-part rate design for a linear demand charge and a linear energy charge were solved to equal the marginal costs for energy and capacity to maximize welfare while the optimal installed capacity should be the sum of all subscribed consumer capacities (fuses).

The case for a capacity model with self-rationing is even stronger in a community microgrid environment, particularly in a standalone application. Firstly, sporadic high prices and large price fluctuations in a community microgrid could be a major concern and less acceptable for social reasons. Secondly, a community microgrid often covers only a smaller specific area or region with a limited number of customers bearing the costs, complex market designs and operation can mean high transaction costs that add substantial overheads to customer bills. Thirdly, as customers and service providers of community microgrids typically engage in a 'bilateral monopoly' relationship, the possibility of customer withdrawal once the investments by providers are made, requires some community ownership or upfront financial contribution to reduce investment risks (E.M. Gui, Diesendorf, & MacGill, 2017). On the other hand, commercial providers will need to align their commercial goals with the community objective of social welfare maximization in order to ensure community support and engagement. Finally, the service reliability of individual consumers in community microgrids can become, and is likely best to be treated as a private good, when each consumer's willingness-to-pay (WTP) for it are likely to be different. The optimal electricity reliability literature has also long recognized the association of the WTP for reliability of household, with an specific payment in exchange for improved service reliability as stated preference (Devicienti, Irina, & Stefano, 2005).

In this paper, the standard capacity subscription methods are incorporated in the dp-CS mechanism to develop self-rationed and capital-efficient community microgrid systems, particularly with significant level of intermittent renewable generations such as solar PV and wind, accompanied by battery storage facilities. In these systems, both consumers and providers can benefit from improved investment decisions incorporating the design objectives associated with allocative efficiency and revenue adequacy. Better aligning interests and objectives will, in turn, support greater collaboration among all the parties involved and promote transparency in the design and operation of community microgrids.

2.2 Problem definition

The key problem the proposed program dp-CS solves is: ''How should capacity price and energy prices be set and the microgrid operated to achieve the maximum ex-ante social welfare subject to the constraint that individual consumers' chosen minimum service reliability[1] level is met and the total investment costs are recovered?".

Three design elements are critical:

1) Capacity subscription based on consumer preference to meet their desired minimum reliability
2) Application of differential pricing to incentivise demand response
3) The combination of dynamic pricing and capacity pricing for investment recovery and social welfare optimization

When a large number of variable renewable generations with close to zero marginal cost is present, better asset utilization can be realized when the loads become generation-following (Rolland & Glania, 2011). A cost-efficient design for a microgrid system should meet consumers' least cost requirements, including demand, reliability level, and payment expectations, with minimum investments.

[1] 'Reliability' in the rest of this paper refers to 'service reliability', rather than 'system reliability'.

2.3 Program design

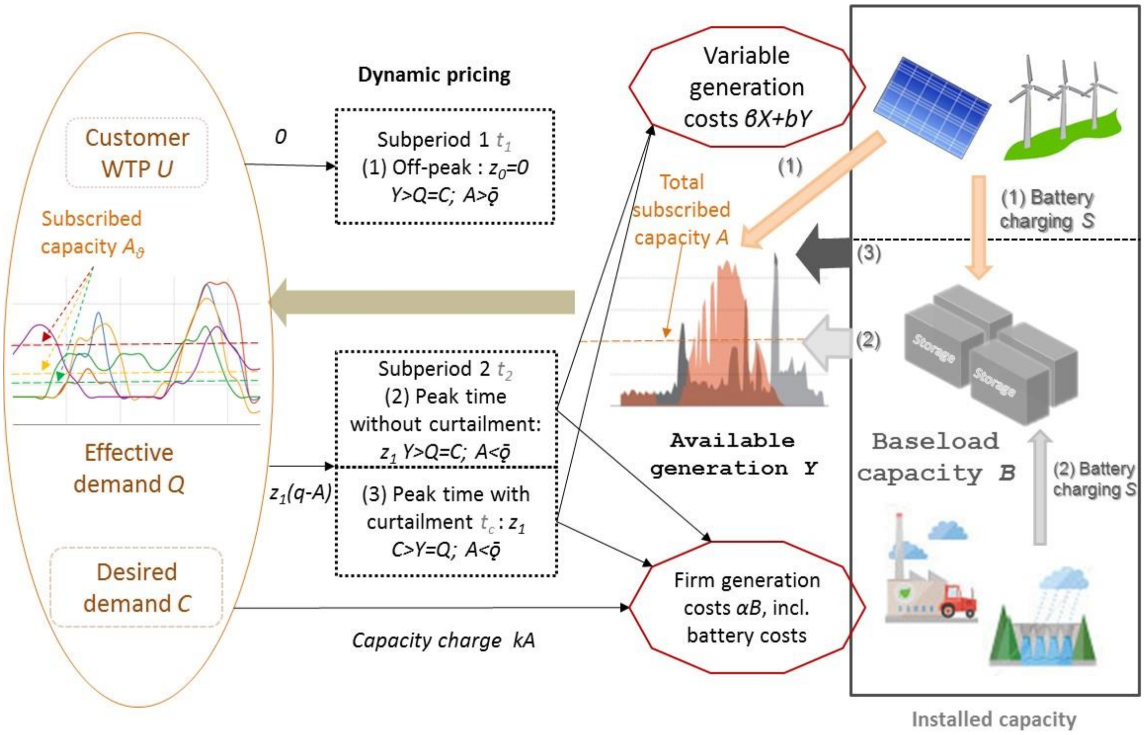

Figure 1. Financial and physical flow of the proposed mechanisms

Let $u(z, c, \theta,\omega)$ be the marginal willingness-to-pay of consumer ϑ with a desired variable demand profile c in a state of world $\omega \in \Omega$, where consumer ϑ can be indexed according to the increasing order of their quantity demand. We assume that u is decreasing in c but is increasing in ϑ. A consumer's decision process involves solving the ex post surplus maximization problem by choosing an effective demand q such that his willingness-to-pay is precisely the energy price, i.e.

$$u(q(z, \vartheta, \omega), \vartheta, \omega)=z \qquad (1)$$

$$Max \int_0^q [u(q, \theta, \omega) - z]\, dq \qquad (2)$$

The likelihood of exercising curtailment is also the loss-of-load probability that can be expressed as follows:

$$LOLP = \int_{\Omega'} dF(\omega) = t_c/T \qquad (3)$$

where $\Omega'=\{ \omega \in \Omega \mid Q>Y \}$ and $F(\omega)$ is the c.d.f. of ω defined on Ω.

The complement of Ω' is $\Omega''=\{ \omega \in \Omega \mid Q_d<Y \}$ which can be used to define the probability of service being available on demand

$$1 - LOLP = \int_{\Omega''} dF(\omega) = (T-t_c)/T \qquad (4)$$

The consumer's ex post effective demand for electricity is thus the function

$$q(z,\theta,\omega) = \begin{cases} c(z,\theta,\omega), & not\ curtailed \\ A, & curtailed \end{cases} \qquad (5)$$

where c is the consumer's desired demand for electricity.

We use $Q = \int_0^{\theta} q dG(\theta)$ to respresent the aggregate ex post effective demand, and the limits to consumption levels Q_0 and Q_1 during the subperiod 1 and 2 are imposed by the economic dispatch of variable generation such as solar PV, firm generation such as diesel generator, and battery storage facilities.

As illustrated in

Figure 1, a differential pricing capacity subscription mechanism in a community microgrid works as follows: each consumer subscribes to a particular level of capacity A_{ϑ} in advance based on their preference for the minimum reliability level when the supply is short. The consumer pays a capacity charge *k* for the amount he subscribes to. The consumer then chooses the ex-post demand schedule *q* after the energy price *z* is revealed, where *z* denotes the state-dependent electricity prices, which reflects the energy costs over a period of some duration, but cannot vary continually (Doorman, 2005). We consider two subperiods in the total demand cycle *T*:

(1) off-peak demand subperiod 1 of t_1 hours when the desired demand can be satisfied by the available renewable generation and battery storage and the residual generation goes to charge the battery or is wasted at the value of zero (the storage bank is only charged with excess renewable power sources); and
(2) peak-demand subperiod 2 of t_2 hours when the desired demand exceeds the available renewable capacity (including battery storage), including a period (3) of t_c hours when the demand of consumers who exceeds their subscription level will be curtailed.

This can be considered as a variant of critical peak pricing that have higher charges for electricity generated from sources of higher variable costs (Gyamfi, Krumdieck, & Urmee, 2013), for example when the diesel generation kicks in as illustrated in the case study in Section 6.

During the subperiod 1 and 2 when the aggregate actual demand *Q* is lower than or equal to the available generation *Y*, the actual demand will be delivered. The difference between the consumer's actual consumption level *q* and the subscribed capacity A_{ϑ} will be settled at the price *z* for a net payment of $z(q-A_{\vartheta})$. This implies that the foregone consumption below the subscribed capacity is also paid at the energy price *z* for providing either demand relief in the system or supply for replenishing the supply (for example recharging the battery storage). When the aggregate desired demand *c* is greater than the available generation *Y* during the subperiod 2, the service will be delivered or curtailed to the subscribed amount of $Min[q(z,\vartheta,\omega),\xi A_{\vartheta}]$ where $\xi>0$ is a capacity allocation factor which does not vary with ϑ or ω and is known to the consumer ex ante.

An optimal capacity planning scheme maximizes social welfare over the system's entire life/ demand cycle that alternates between subperiod 1 and subperiod 2. The task of tariff design is therefore to set optimal energy prices z_0, z_1 (\$/kWh) and capacity prices *k* (\$/kW) to maximize social welfare, recover system costs, as well as to encourage active demand management from consumers.

2.4 Linking investment planning objectives and operation strategies

The proposed program design aims to facilitate the efficient investment decisions and development of community microgrids, that promotes allocative efficiency, social welfare optimization, revenue adequacy and low transaction costs (Emi Minghui Gui, MacGill, & Betz, 2018).

To be able to fulfil these objectives, a coherent program design needs to be efficient at two levels – both the planning level and the operation level. It should be able to sufficiently connect the community microgrid investment planning and operation strategies, not only incentivizing the microgrid development at the planning stage, but also satisfying the needs of participating households and communities at the operational level. To achieve these goals, there needs to a reflection of the expected operations in the community microgrid capacity planning and tariff design, particularly to ensure revenue adequacy for investors, and desired electricity expenditure and preferred minimum service reliability level of individual households.

In this program design, the social welfare optimization model based on capacity subscription mechanism combined with differential pricing techniques becomes a key resource to align both design and operating objectives in the community microgrid investment planning, as illustrated in

Figure 2. Operating decisions can then be made in real time based on local supply and demand conditions while the tariff design and operation strategies defined in the investment planning stage needs to be dynamically deployed.

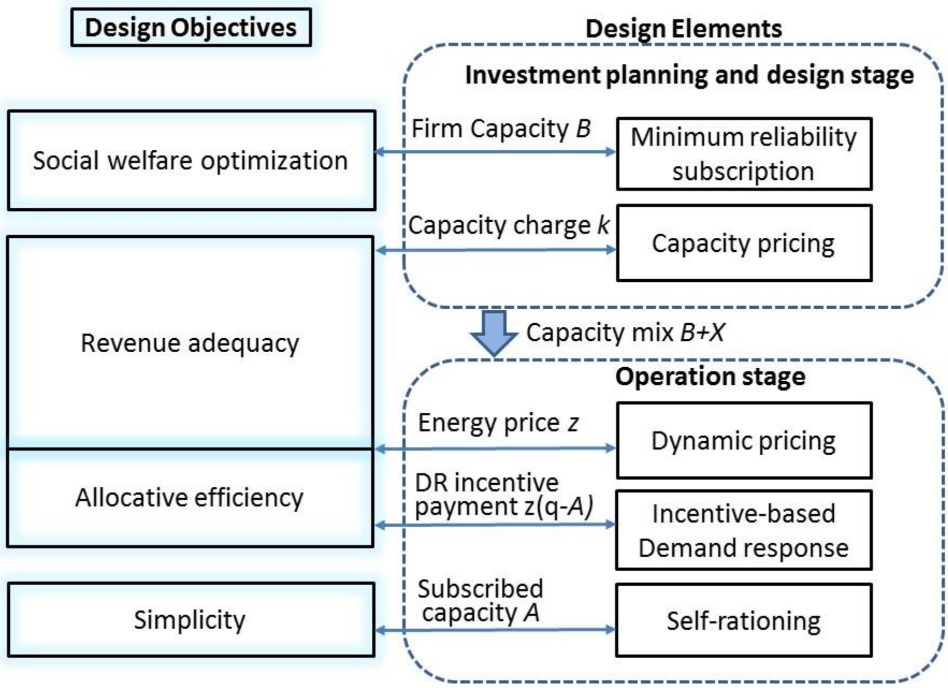

Figure 2. Program design objectives and elements of the dp-CS mechanism

This bi-level program design is coherent in that the upper-level optimization provides guideline for lower-level operation optimization that couples both the community microgrid planning and operation stage. The upper level's objective function given by Eq.(1) maximizing social welfare function, including consumer surplus and producer surplus, subject to the chosen minimum reliability level of each consumer (Eq. (11)). Here, the decision variables are the subscribed capacity (A_ϑ) of each consumer and their post-effective demand. The lower level then optimizes its operation based on the input information passed on from the upper level objectives, generation capacity decisions, and other economic parameters. The operation strategy is to determine the tariff subperiod 1 and subperiod 2 and the corresponding energy prices that are defined by Eq. (10.1) to recover the cost of variable generation. The dispatch problem is subject to the capacity mix of both variable and firm generations, such as solar PV, and firm generation including diesel generator, as well as natural conditions therefore available energy output in real time from both variable and firm generations, and demand response (DR) resources, if DR technology is considered.

3 Social welfare maximization

3.1 Consumer surplus

The consumer consumption and the consumer surplus is determined by two scenarios: after the state of nature is realized the consumer will choose the amount of power he wishes to consume at a price *z,* this amount will be served at $z_0 = 0$ during the subperiod 1, and at z_1 during the subperiod 2. During the subperiod 2, when the demand exceeds the available supply, the demand of some consumers will be restricted proportionally to their subscribed capacity A_ϑ at price z_1, so the aggregate ex post demand for electricity $Q(z) \leq Y$, the available capacity.

Then the consumer, facing energy prices $z_0=0$, z_1 and k, selects a capacity A to subscribe which maximizes his expected surplus.

$$CS = Max \int_{\Omega'}\{\int_0^{min[q,\xi A]}[u(q,\theta,\omega) - z_1]\, dq + z_1 A\}dF(\omega)$$
$$+ \int_{\Omega''}\{\int_0^{q}[u(q,\theta,\omega) - z_1]\, dq + z_1 A\}dF(\omega)$$
$$- kA \qquad (6)$$

where Ω'={ ω ϵΩ |Q(z)>Y } and Ω''={ ω ϵΩ | Q(z)≤Y during subperiod 2}. To simplify, the energy price is set to 0 for the subperiod 1 when the zero marginal cost of PV generation and battery storage prevail.

The first integral averages surplus in those states of the system in which rationing is in effect for the ɵth consumer when his demand is greater than his subscribed capacity under the condition of the ex-ante demand greater than the available capacity; and the second integral averages surplus over states in which the consumer is served his desired demand when the ex-ante demand is no greater than the available capacity; the third item is the capacity costs for the ɵ th consumer. Equation (6) is effectively the same as the work published by Woo (1991) except the item +z1A in the first and second integral. This term compensates load reduction during peak times, and it is called in this thesis the load reduction compensation factor.

It is noted that Equation (6) can be written in the following forms, where qc is the expected average consumption during the curtailment period, and q1 is the expected average consumption during peak time:

$$CS = Max \int_{\Omega'}\{\int_0^{min[q,\xi A]}\left[u(q,\theta,\omega) - z_1(1-\frac{A}{q_c})\right] dq\}dF(\omega)$$
$$+ \int_{\Omega''}\{\int_0^{q}\left[u(q,\theta,\omega) - z_1(1-\frac{A}{q_1})\right] dq\}dF(\omega)$$
$$- kA \qquad (7)$$

It is noted that since $A(k,z,\vartheta,\omega)\geq 0$ the load reduction compensation factor $+z_1A$ reduces the 'real' energy prices proportional to the expected average consumption during the peak time. When the subscription level A is higher or the expected average consumption is lower, the 'real' energy prices in effect for the consumer become smaller. Given the subscription level A is designed to guarantee the minimum reliability level and can be seen as predetermined and fixed prior to consumption, the consumer welfare maximizing strategy would be to reduce average consumption during peak time, which is a desirable outcome.

When A> q_1 we have the 'real' energy prices as negative, it is not a reasonable outcome given A is selected to cover the minimum reliability level. Thus, the subscription level A for each consumer can then be restricted to below his expected average consumption during peak time. Similarly, we have A< q_c , and A< q_1. We can consider A/q_1 and A/q_c as constant, and then set two minimum reliability coefficients $0 \leq \gamma_1 = 1-A/q_1 \leq 1$ and $0 \leq \gamma_c = 1-A/q_c \leq 1$. Equation (7) becomes

$$CS = Max \int_{\Omega'}\{\int_0^{min[q,\xi A]}[u(q,\theta,\omega) - z_1\gamma_c)]\, dq\}dF(\omega)$$
$$+ \int_{\Omega''}\{\int_0^{q}[u(q,\theta,\omega) - z_1\gamma_1]\, dq\}dF(\omega)$$
$$- kA \qquad (8)$$

Equation (8) now has the same form as the consumer surplus function of a standard capacity subscription program design proposed by Woo (1991).

Applying the same reasoning, the optimal subscribed capacity *A(k,z,ϑ,ω)≥0* satisfies the following first-order Kuhn-Tucker condition:

$$\frac{\partial CS}{\partial A} = \int_{\Omega'} D[u(\xi A, \theta, \omega) - z_1\gamma_c]\xi dF(\omega) - k \leq 0 \qquad (6.1)$$

where D=1 if the consumer's electricity consumption is curtailed to A during a capacity shortage; and D=0, otherwise. Equation (6.0) indicates that a consumer subscribes to a capacity level at which the expected marginal benefit at energy price $z_1\gamma_c$ is not less than the demand charge k to arrive at the optimal A.

The consumer benefits (CB) can then be calculated as

$$CB = \int_{\Omega' + \Omega''} \boldsymbol{z_1 A\, dF}(\omega) - VoLL * Load\ curtailed \qquad (9)$$

3.2 Producer surplus and Ramsey prices

Based on this program design, the producer's objective is to collect all costs involved through capacity charges and energy prices, including fixed costs and variable costs for firm and non-firm generation. The intention is to cover firm generation costs through capacity charges, while collecting all variable costs of different generations through energy prices, including non-firm generation costs.

Consider a prospective microgrid with battery storage, an intermittent PV generation, and a diesel generator. Assuming the battery storage is only charged with excess renewable generations, the microgrid serves the demand at near zero marginal cost when PV generation and battery storage output is no less than the demand, and the excess output can either be used to charge the battery storage or be wasted at zero. When the demand exceeds the combined output of PV and battery storage, diesel generator will run to meet the additional demand y_{11} at variable cost of b_1. During the subperiod 2 when the diesel generator is at its maximum and there is still additional demand to be served, curtailment will occur to consumers whose demand exceed their subscribed capacity times the allocation factor. The total costs to supply power for the entire demand cycle is the total cost of the diesel generator $b_1\, y_{11}$ since both PV and the battery storage has zero marginal cost to supply power (assuming that the battery is only charged from renewable power).

We can establish the relationship between the demand charge k and the allocation factor ξ that is defined as $B=\int_\theta \xi A dG(\theta)$. We have $B/\Phi>0$, where Φ is the aggregate subscribed capacity $\Phi = \int_\theta A dG(\theta)$ and B represents the firm generation capacity, including battery storage and diesel generator (may include a percentage of reserve capacity).

During the subperiod 2, given the ex post effective demand Q, an effective pricing policy by producers should aim for breakeven over the entire demand cycle. The energy prices z_1 can be found by:

$$PS(Q_0, Q_1, Æ) = \int_0^{Q1-A} z_1(q)dq - b_1 y_{11} - \beta X \geq 0 \qquad (10)$$

where Y is the total power output, Q is the aggregate ex post effective demand, b_1 is the variable costs of diesel generator.

The breakeven prices z_1 are

$$z_1 = \frac{(b_1 y_{11} + \beta X)/t_1}{(\bar{Q}_1 - \Phi)} = \frac{(b_1 y_{11} + \beta X)/Q_1}{(1-\gamma)} \qquad (10.\ 1)$$

where $\bar{Q}_1$ is the aggregate average load during the peak period, γ is the system minimum reliability coefficient, $(b_1 y_{11}+\beta X)/\bar{Q}_1 t_1$ is the average cost of variable generation during the peak period. The lower the level of firm capacity subscribed, the lower the energy prices.

Under a standard CS design, we have

$$z'_1 = \frac{(b_1 y_{11} + \beta X)}{Q_1} = z_1\left(1 - \frac{\Phi}{\bar{Q}_1}\right) = z_1 \gamma \qquad (10.\ 2)$$

Since $0 < \gamma < 1$, lower energy prices are expected under a standard CS design. Equation (10.1) suggests that the intermittent generation fixed costs should be born by the consumption during the peak subperiod 2 when the diesel generator is supplying power. This is reasonable since given the capacity of diesel generator cannot be modified easily in a short period of time, the additional marginal demand should be supplied by the solar PV generation.

Our optimization problem then becomes to find the optimal demand charge which maximizes the ex-ante social welfare subject to the constraint that the firm generation fixed costs to be collected are equal to αB where $\alpha > 0$ is the per unit cost of capacity, which can be stated as follows:

$$Max\ \ SW = \int_{\theta} CS(\theta) dG(\theta) + k\Phi \qquad (11)$$

subject to firm capacity cost constraint $k\Phi = \alpha B$ (12).

This equation also has the same property as what Woo (1991) proved in his work, i.e. $dSW/dk=0$ suggesting that the ex-ante social welfare SW is independent of the level of the demand charge k. In addition, the fixed cost for the firm generation can be collected exactly with certainty. The optimal demand charge k^* can be solved by Equation (12).

We have *both consumer surplus and breakeven energy prices* $z_0 = 0$ *and* z_1 *are independent of capacity price* k. This simplifies the task of capacity planning since the system costs can be recovered with certainty as long as the operator factor into the expected load profile of consumers, irrespective of the level of subscription consumers select or how they react to the capacity price k. The separation of capacity planning and consumer welfare determination also allows us to use a microgrid system optimization software such as HOMER Pro to demonstrate the results.

From equation (10.2), it is evident that the proposed dp-CS program design has more elevated peak energy prices than the standard CS. Under the dp-CS program consumers are compensated for demand savings below the minimum reliability by z_1 during peak times, which can encourage consumers to subscribe to the capacity prior and reduce consumption during peak period. Under the standard design, consumer benefits are only reflected implicitly in the energy bills they pay. Therefore, consumers under the dp-CS program are more inclined to decrease their own consumptions for immediate economic benefits, based on price signals sent by the operator following the supply curve. This will consequently, create incentives for consumer subscription and participation to the program for their own benefits as well as mutual benefits for the community.

4 Experimental case studies and discussion

The dp-CS program design is tested using HOMER Pro on an example off-grid community microgrid design consisting of solar PV, battery storage, a backup diesel generator and two hypothetical electric loads, as illustrated in Figure 1. Electric load 1 has the peak demand in the early evening, with an average consumption of 111 kWh/d, (hence an average supply requirement of 4.5 kW) and peak demand of 22.9 kW. Electric load 2 has the peak demand in the early morning and low demand during the day, with average consumption of 200 kWh/d, (hence an average supply requirement of 8.3 kW) and peak demand of 45.4 kW. Solar irradiation data for a sample site at New South Wales Australia is downloaded from the NASA Surface Meteorology and Solar Energy Database to determine PV outputs.

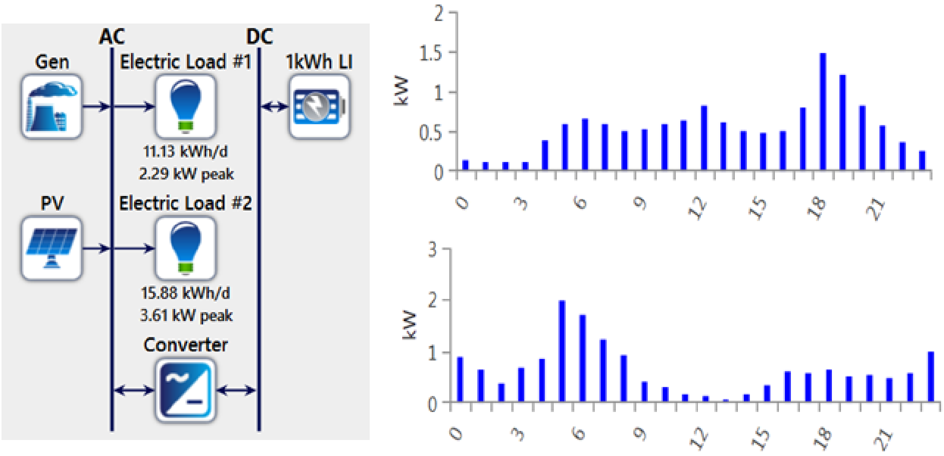

Figure 3. Test microgrid system setup and daily demand profile (unscaled) for hypothetical consumer 1 (above) and 2 (below).

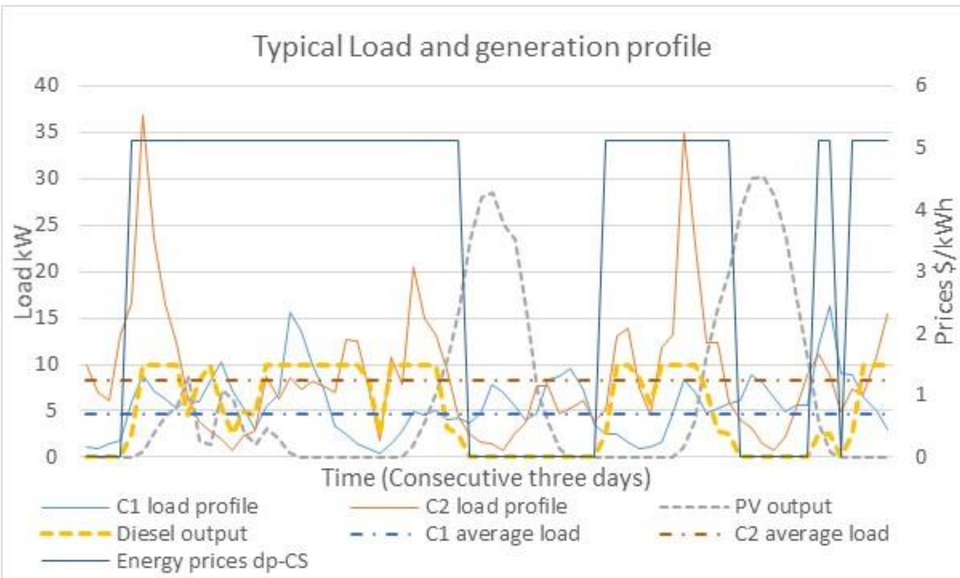

Figure 4. Hypothetical generation curves for solar PV and diesel generator, daily demand profile and average demand for consumer 1 and 2, and energy prices

Figure shows a typical 72 hour supply and demand profile including generation from the solar PV and diesel generator, demand profile and average demand for consumer 1 and 2, and dp-CS energy price. It is apparent that the consumer 1 has a higher day time load that generally coincides with the solar PV generation output, while the consumer 2 mostly consumes before the solar PV starts generating and thus triggers the start of diesel generation. Energy prices are 0 when the solar PV output is high, and charged at price z_1 calculated from equation (10.1) to reflect the variable cost of the system when the diesel generator starts supplying.

The minimum reliability level is assumed to be 10kW, guaranteed by a 10kW diesel gen set. The optimal generation capacity mix and economic dispatch are then solved using HOMER Pro, results listed in Table 3. Homer's *Load Following* battery control strategy is selected to ensure that the battery bank is charged with renewable generation only.

Table 3. System parameters for the tested community microgrid

Diesel Gen (kW)	10	COE ($)	0.425
1kWh LI	100	NPC ($)	572,326
Converter (kW)	29.5	Operating cost ($/yr)	31951
PV (kW)	30	Initial capital ($)	301,566
Diesel fuel price ($/L)	1.35	PV capital cost ($)	163,787
Renewable Frac (%)	47.8	Unmet load	37.4%
Excess electricity (%)	0.298%	Capacity shortage	48.7%

Table 4. Design parameters for the tested community microgrid

Peak average load consumer 1 (kW)	4.4	Peak average load consumer 2 (kW)	17.7
Firm Capacity subscribed (kW)	10	Capacity charge k ($/kW)	13,519
Variable cost collected through energy prices ($)	437,802	Capacity costs collected ($)	134,524
Dp-CS z_1 ($/kWh)	2.54	Standard CS z_1 ($/kWh)	0.45

The dispatch results from HOMER are then fitted to the capacity subscription program design to ration consumers and used to calculate the consumer expenditure[2] including electricity bill payments and capacity charges, and consumer benefits taken into account the consumer value of lost load and the consumer compensation.

Capacity costs and energy costs are calculated based on the HOMER dispatch profile, and energy prices are calculated according to equation (10.1) and (10.2). These results are listed in Table 4.

This microgrid has high level of unmet load and high level of capacity shortage and little excess electricity. It therefore may be reasonable to increase both variable and firm generation capacity. However, given the relatively high energy price of $2.54 /kWh, a better outcome could be that consumers can adjust their demand and more closely follow the PV generation forecasted to reduce capacity shortage and save money over time.

[2] Customer expenditure is the sum of capacity prices paid by the customer, plus energy prices paid by the customer, not adjusted for time value of money.

4.1 Subscription incentives

The original design for capacity subscription in a competitive wholesale market assumes the consumer demand is inelasticity at *ξA*. This suggests that each consumer is only affected by their own decision, indifferent of other consumers' decision, therefore his willingness to pay will be the only concern. This assumption can approximately hold in dealing with individual larger consumers who normally place high value on the loss of load.

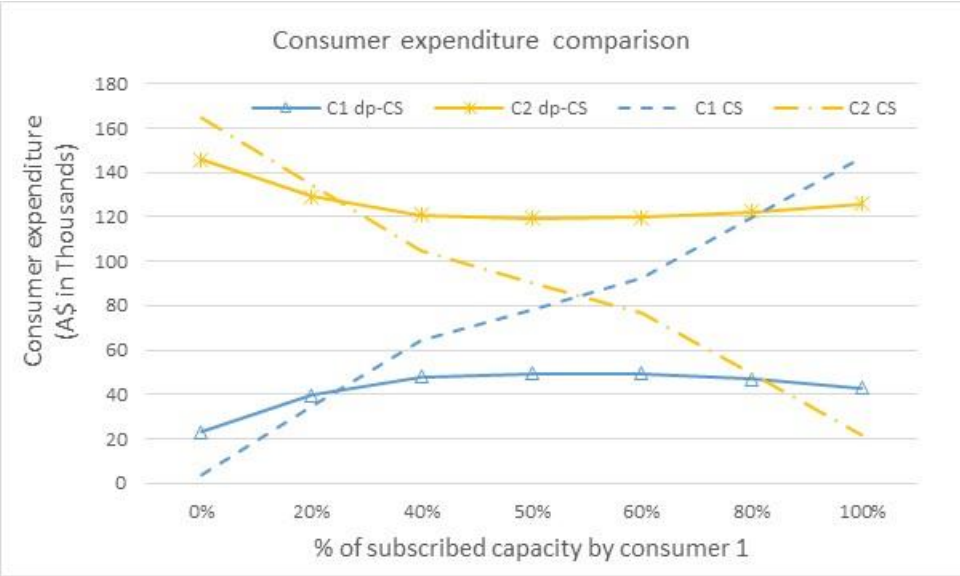

Figure 5. Comparison of consumer expenditure under both the dp-CS program and the standard CS program design.

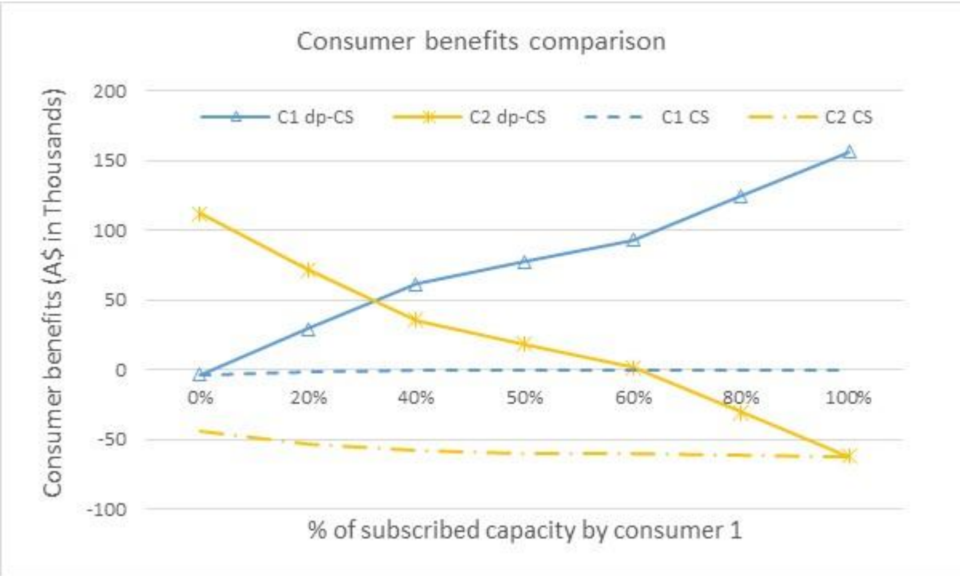

Figure 6. Comparison of consumer benefits under both the dp-CS program and the standard CS program design.

In a community microgrid environment, this assumption is however undesirable since individual consumer investment and consumption decision is most likely to affect others and the whole community. As seen in our case study in

Figure and

Figure , consumers who subscribe to higher levels of capacity pay more for their electricity under the standard CS design. This would discourage consumer subscription since consumers of low VoLL will not subscribe to any capacity but can free-ride from the investments from other consumers who subscribe to firm capacities. Or it may also lead to zero firm capacity subscribed, therefore the system can experience much higher level of capacity shortage for all consumers, leading to significant loss of consumer welfare.

Conversely, the proposed dp-CS design encourages consumers to subscribe to higher levels of capacity as the economic savings below the subscribed capacity can reduce consumers overall payments for electricity. The optimal choice for individual consumers in the dp-CS design would be to subscribe to the maximum allowed capacity. It should be noted that when all consumers choose equal minimum reliability coefficients, i.e. $\gamma_1 = \ldots = \gamma_\theta = \ldots = \gamma$, consumers will pay the same 'real' energy price, thus yielding fairer distribution of benefits. Consumers with low consumption during peak periods have incentives to stay low, while consumers with high consumption will pay to consume or can choose to reduce consumption for economic benefits. Compared to a standard CS design, consumers who subscribe to a higher level of minimum capacity may decide to increase their peak consumption to take advantage of their subscription, which will reduce the overall welfare and the economic efficiency. The dp-CS design naturally favors consumers with a 'benign' consumption pattern that follows zero marginal cost renewable generation, which serves as incentive for other consumers to shift loads to off-peak periods to maximize own economic benefits.

4.2 Demand response benefits

Consumers who value their convenience to consume electricity above their subscribed level will pay to increase their utility as long as there is sufficient available generation. This program design incentivizes consumers to maximize their own social and economic benefits through active demand management.

Consumers can reduce their electricity payment and loss of load through load shifting. As demonstrated in Figure , consumer 2 saves between 3-12 % of electricity expense by shifting the load curve to take advantage of off-peak period when the energy price is zero.

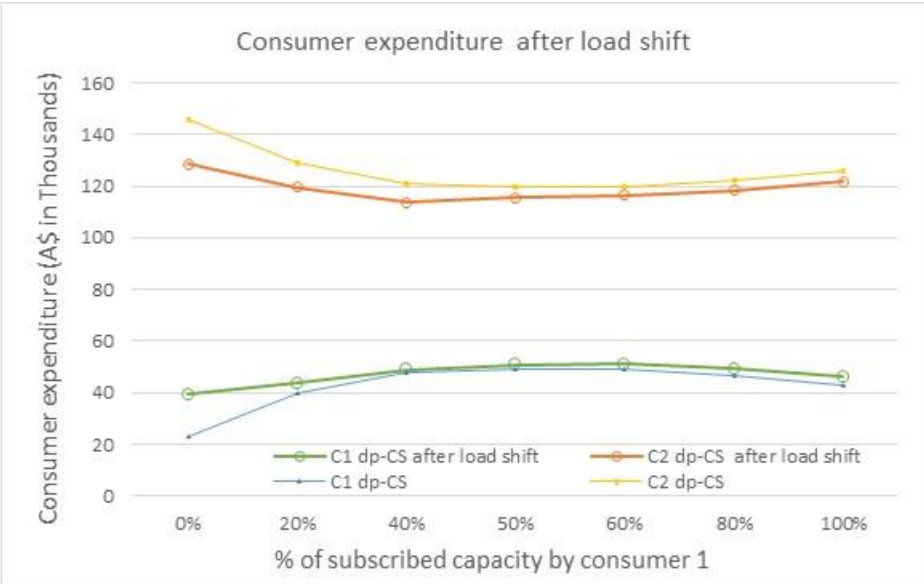

Figure 7. Consumer expenditure before and after load shift by consumer 2 under the dp-CS program.

4.3 Optimal reliability and consumer self-selection

Under both program design, the capacity charge *kA* is designed to recover costs for firm generation capacity so *kA* is likely to be high when the capacity shortage is low. The energy price *z* is to recover the variable generation costs, such as solar PV so the energy price *z* will be high when the variable generation output is high. When the firm capacity in the system is limited, supply shortage occurs more frequently. Consumers who have higher willingness-to-pay or higher VoLL, are more likely to buy capacity *A* in advance. The consumer that chooses not to subscribe to any capacity beforehand will be cut-off during supply shortage. Thus, the capacity subscription mechanism reveals the value of lost load for consumers, and allows them self-selection as those who value the reliability will pay for the capacity, while those who do not will subscribe to zero capacity. This in turn informs the planner and operator on the number of consumers who value the reliability and then to invest the optimal firm capacity and appropriate tariff structure to recover costs.

When there are high levels of excess capacity in the system, the energy price *z* can become negative, which signals capacity over-investment. On the other hand, under-investment will lead to frequent curtailments of customer loads, which can be corrected by adding generation capacity such as Solar PV and battery storage bank, accompanied by an increase of peak period energy prices.

Under the dp-CS program design, consumers are incentivized to alter their consumption for own economic benefit by lowering consumption during peak period or shifting peak period to off-peak period taking advantage of zero energy prices. The incentive to shift or lower peak period consumption during the CS program design is however less prominent since the energy prices are generally much lower.

5 Conclusions

In this paper, an optimal strategy for capacity planning and pricing for capital constraint microgrids, through minimum reliability subscription and self-rationing, dynamic pricing and incentive-based demand response, is investigated. The proposed program design is demonstrated in a hypothetical case study to promote demand response activities, energy efficiency, and social welfare savings for consumers, and to achieve revenue adequacy and allocation efficiency for the microgrid planners.

To our knowledge, this work is the first to propose such an easy-to-implement program design for community microgrids in creating adequate incentives and compensation mechanisms to address the variability of intermittent renewable generations, and creating appropriate balance between the community's social welfare objectives and the providers' financial requirements. The experimental results have also demonstrated the potential effectiveness of the proposed program design, including enhanced consumer economic benefits to encourage consumer participation.

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