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Distributor pricing approaches enabled in Smart Grid to differentiate delivery service quality

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Abstract

Industry practitioners who advocate retail competition and Demand-side Participation now look for approaches to link both initiatives through distributor pricing. As distributors incrementally convert more traditional assets into Smart Grid assets, they also need to consider different pricing approaches to recover the investment costs and meet the regulatory business requirements. Small electricity consumers need incentives to take part in these initiatives but their delivery service quality should also be closely guarded. Hence this paper addresses the above needs as a whole and investigates a set of distributor pricing approaches with Smart Grid technologies. Pricing of network and non-network based solutions should follow the incremental basis, such as the long run average incremental cost ($LRAIC$). The benefit of deferring network investment is calculated and should be passed to consumers as peak pricing rebate. A concept of reliability premium (RP) based on load point reliability index is proposed, through which customers can express their preference of service quality and adjust their network tariff payment accordingly. A service delivery model is also proposed to utilize the savings from wholesale market trading to compensate for the downgraded service when loads are controlled. The IEEE 123-node distribution test feeder and the IEEE distribution system for RBTS Bus No. 2 are simulated, and solved using General Algebraic Modeling System (GAMS) to demonstrate the proposed distributor pricing approaches in Smart Grid.

Keywords: Asset management, load management, power distribution, power system economics, power system reliability.

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1. Introduction

Several industry initiatives have been taking place in the deregulated electricity markets around the world including the New Zealand Electricity Market. A recent development is the 'model use-of-system agreement' for contractual arrangement between retailers and distributors, so that the rights to develop controllable loads are made clear, and the communication protocols are standardized.

Meanwhile trend of retail competition and Demand-side Participation continues, which has seen the demand dispatch (DD) scheme being implemented. In this full locational marginal price (LMP) based market without the capacity market structure, the system operator now publishes the price-responsive schedule (PRS) and the non-responsive schedule (NRS) to inform stakeholders about how price-responsive bids affect the schedules.

Although participation in DD scheme is still limited to only a few large electricity customers right now due to the strict compliance requirements, controllable load development is expected to enable more participation in wholesale market by aggregation of small customers. Instead of solely relying on undercutting retail profit margin, retail competition may be promoted through peak network tariff rebate for a non-network solution provider or through service quality differentiation in a retailer offer package.

Although the long run average incremental cost ($LRAIC$) is officially endorsed as the principle of distributor pricing methodology, to protect consumer interest the 'CPI-X' regime will still be in force to track total revenues earned by distributors over the five-year regulatory period.

This paper firstly reviews the distributor pricing approaches for both network and non-network based solutions, and the pricing approaches involving system reliability indices in distribution networks. It then describes the formulations of distributor pricing approaches enabled by Smart Grid development, with a focus on $LRAIC$, controllable loads and load point reliability indices. Following that case studies are simulated using the IEEE 123-node distribution test feeder and the IEEE distribution system for RBTS Bus No. 2. After solving the problems using General

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Algebraic Modeling System (GAMS), it is found that providing controllable loads is entitled a peak tariff rebate as network investment is deferred. Service quality differentiation is also a viable option to enable small customers to participate in wholesale market through enabling controllable loads.

2. Review of distributor pricing approaches

2.1. The evolving distributor pricing practice

Distributor pricing methodologies gradually evolve from average basis to cost-causation basis. Traditional 'cost-of-service' pricing categorizes electricity delivery costs into energy, demand or customer-related costs [1], which is still the fundamental of distributor pricing methodology.

Throughout years of network investment and reinforcement, distributors own and manage a large asset base to deliver their services, so additional fixed asset costs are usually incremental to the asset base. Long run marginal cost (*LRMC*) pricing is usually considered as forward looking and economically efficient but has the revenue reconciliation problem, so using fuzzy set to model load uncertainties [2] is one solution, and the sensitivity based analytical method[3] is the other. The long run incremental cost (*LRIC*) pricing approach is developed to reflect fixed asset utilization in distribution network [4]. The long run average incremental cost (*LRAIC*) pricing methodology [5] differs from *LRIC* slightly, which does not strictly allocate the incremental fixed asset costs to the particular customers who cause the network congestion, so it is less complex to understand and less costly to implement in practice.

2.2. Deriving long run average incremental cost

The *LRAIC* method categorizes the fixed asset cost (capital cost) into asset groups according to different voltage levels, and grouped fixed asset costs are then assigned to the corresponding load group (such as residential, commercial or industrial) that utilizes the asset group's equipments as well as all upstream equipments. Day-to-day operational cost on the other hand is not related to demand growth, whose allocation can still be averaged across all customer load groups. Figure 1 provides an overview of optimization and evaluation processes [6] of deriving *LRAIC*, which can vary among different distributors but should follow 'a set of principles that aim to promote subsidy-free, efficient, responsive and transparent pricing structures transactionally equivalent to all retailers'.

2.3. Pricing non-network based solutions

It is becoming the norm to consider alternative network planning approaches, such as using distributed

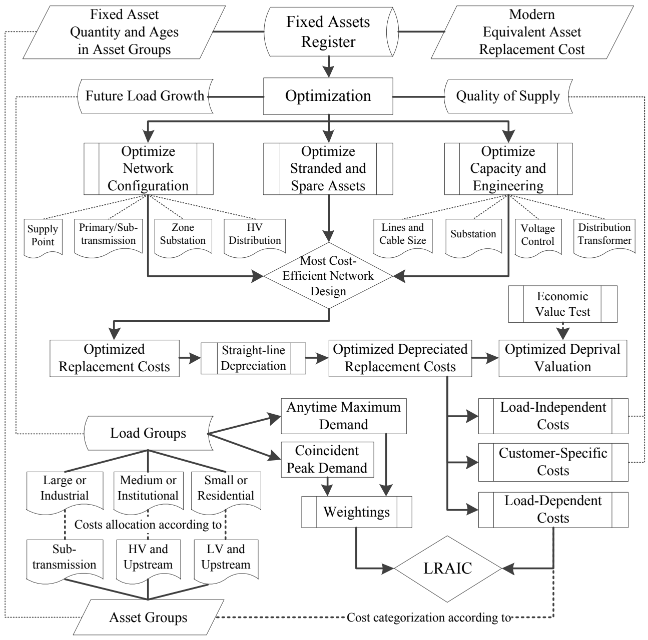

Figure 1. Deriving long run average incremental cost

generations, to determine the deferred capital investment value [8] [9], and then remunerate the particular distributed generator based on its ability to support distribution network capacity. Like distributed generations, direct load control and demand response can also be used to support distribution network capacity management, hence can follow the similar pricing methodologies.

Controllable loads provide another set of tools for electricity distributors to maximize return on capital investment and to improve asset utilization rate. Controllable loads provide more system reserve for transmission network operator. Electricity retailers who own controllable loads can reduce wholesale purchase payments or reduce transmission tariffs when the transmission network is congested. The rights to develop controllable loads can be obtained by either distributor or retailers, if customers entered into the contract that allows some of their appliance loads to be controlled, such as heating or cooling appliances. Using controlling and signalling equipments that operate under the standardized communication protocols, either distributor or retailers can coordinate controllable loads to maximize benefit.

2.4. Distributor pricing with system reliability indices

It has been a standard practice for many network companies to plan network maintenance and expansion based on reliability indices, but reliability indices have not yet been factored in distributor pricing practice. A real-time priority pricing for customers with various reliability requirements is proposed in [10]. Expected reward or penalties for service disruption payments can be estimated by reliability index probability distributions [11]. Distributed generations can be dispatched by considering the hourly reliability worth [12]. A reliability-based distribution network pricing model recovers investment-related costs [13].

Some argue that distributor economics needs to consider the right granted to serve the load in a region, so it also accompanies the obligation to connect the load at certain level of connection quality [14]. To differentiate delivery service quality to customers, it is proposed that a payment to be named as reliability premium (*RP*) can be charged in addition to the normal network tariff. In other words, customers who choose to pay for the *RP* will get compensation from distributor in event of outage.

However, differentiating reliability in distribution networks is challenging because of the 'free-rider' problem that customers on the same feeder generally receive the same level of power availability. Reliability guarantee and network reconfiguration can help optimize network assets to partially address the problem [15].

2.5. Pricing with load point reliability indices

The *RP* based service delivery model is proposed to be different from other models that the formulation starts with load point reliability index, which penalises 'free-rider' in terms of load disconnection while providing benefits to other stakeholders, such as wholesale purchase saving and system peak management. The detailed processes [7] are illustrated in Figure 2.

Throughout the years, regulators have imposed rules to monitor load point reliability indices and require distributors to record the delivery failure statistics. Therefore, there is no additional investment required to monitor reliability statistics to be used in the proposed model.

Paying higher *RP* by a particular customer does not guarantee to receive higher level of delivery service quality, but the direct financial penalty to distributor may influence the company decisions to allocate more resources to address the problems, such as investing in automatic restoration, reinforcing the network sections, installing temporary storage devices, or dispatching repair crews in priority.

It is argued that the cost of investing in reliable networks will finally be borne by the customers, so the problem of providing one level of high reliability to all consumers can be addressed by building less reliability into networks to improve overall welfare [16]. The proposed *RP* does not discourage to invest in more reliable networks, because the extra service quality built into the distribution networks can be 'sold' to wholesale market if not desired by the 'free-rider' customers.

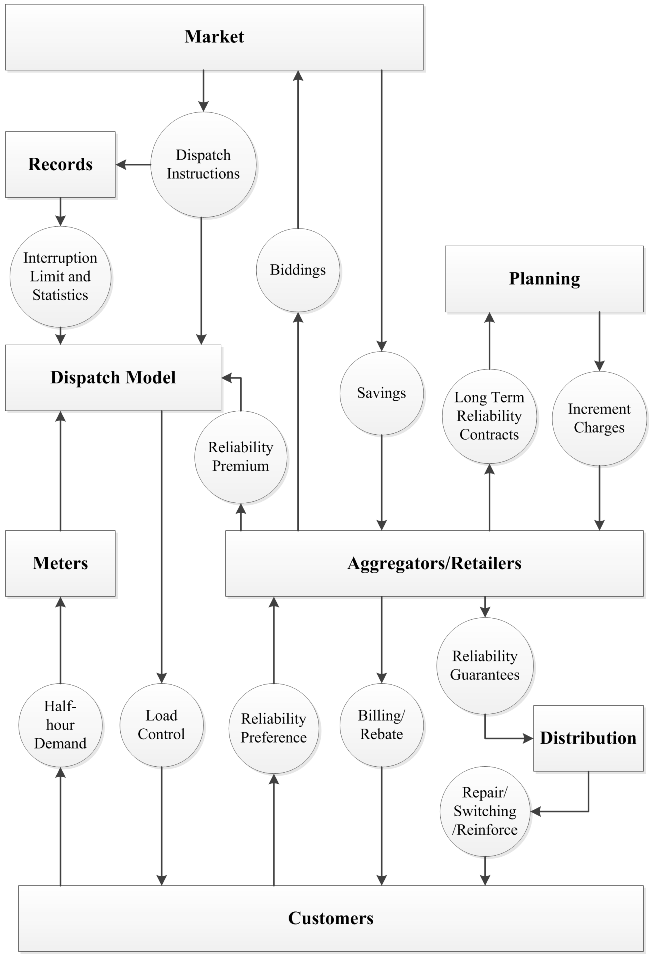

Figure 2. Processes of utilising load point reliability indices

3. Distributor pricing approach formulations

3.1. Fixed asset cost evaluation

To find the most cost-efficient network design in an incremental fashion, network configuration, capacity and engineering are systematically tested against optimization criteria. The formulation here only shows the process of determining feeder types and sizes, based on current profiles during peak loading

$$min \sum_{j\in\Omega_{j,p}} \sum_{p\in\Omega_{j,p}} \sum_{s} C_{p,s} \cdot (1 + D_j) \cdot T_{j,s} \tag{1}$$

where $C_{p,s}$ is the feeder replacement cost for total number of j feeders, with p being the feeder types and s being the sizes. $\Omega_{j,p}$ is a binary matrix parameter specifying the type for each feeder, D_j is a binary variable vector indicating if Feeder j needs reinforcement, and $T_{j,s}$ is a binary variable matrix indicating the chosen size for each feeder conductor. The above objective function is minimized and is subject to the following constraints.

Firstly, designed feeder ampacity must be able to support future feeder current flow, while considering the peak capacity margin, L_I. The margin can be determined in reliability assessment with feeder switching and reconfiguration using Monte Carlo analysis

$$\sum_{p\in\Omega_{j,p}} \sum_{s} M_{p,s} \cdot (1 + D_j) \cdot T_{j,s} > \frac{I_j \cdot (1 + r)^n}{L_I} \cdots \forall j \quad (2)$$

where $M_{p,s}$ is the feeder ampacity, r is annual load growth rate, and n is the number of years to reinforce. I_j is the feeder current at peak load, which can be obtained by unbalance three-phase power flow using GridLAB-D software.

Secondly, the chosen conductor size must have reasonable voltage drop limit per unit length of feeder, L_V

$$\sum_{p\in\Omega_{j,p}} \sum_{s} \sqrt{3} \cdot R_{p,s} \cdot I_j \cdot (1 + r)^n \cdot T_{j,s} < L_V \cdots \forall j \quad (3)$$

where $R_{p,s}$ is the conductor resistance per mile.

Lastly, each feeder conductor is restricted to one size

$$\sum_{s} T_{j,s} = 1 \cdots \forall j \quad (4)$$

and one type only, and $\Omega_{j,p}$ has the similar property.

This formulation can be solved in GAMS using Mixed Integer Non-linear Programming (MINLP). If the problem is difficult to solve, discrete requirements can be relaxed (RMINLP).

Solving the above produces the notionally optimised feeder replacement plan. On one hand, instead of using the actual amount of feeder replacement costs, the notionally optimised replacement costs (ORC) are substituted in asset base valuation and straight-line depreciation method is then applied

$$ODRC = ORC \cdot \frac{RL}{TL} \quad (5)$$

where TL is total life of the asset, RL is remaining life, and $ODRC$ is the optimized depreciated replacement cost.

On the other hand, for reinforcement in the near future, ORC of these feeders are brought forward to the present value, ORC_{pv}

$$ORC_{pv} = ORC \cdot \left(\frac{1 + CPI}{1 + WACC}\right)^n \quad (6)$$

where CPI is the average inflation rate used to track asset replacement costs in the future, and $WACC$ is the weighted average cost of capital or the discount rate.

Finally, the total $ODRC$ in the asset group is the sum of individual $ODRC$ of network fixed assets. Other asset groups, such as subtransmission networks, zone substations, low voltage feeders and distribution transformers, can follow the similar methodology to determine the total $ODRC$ for their asset groups.

3.2. Revenue reconciliation and deferred investment

To establish the link between costing and pricing so that distributor businesses can be regulated by government agency, one of the methods to is to track and control the total distribution revenue earned by each distributor. Target revenues to be collected, TR, reflect the $LRIC$ of feeder replacement and reinforcement. The $LRAIC$ is then calculated by

$$LRAIC = \frac{TR \cdot w_{peak}}{CPD} \quad (7)$$

where w_{peak} is the weighting of TR for conductors that is load-dependent, $w_{independent}$ is the weighting for poles that is load-independent, and CPD is the coincident peak demand that measures the load group demand at the same time of the network peak demand.

Load-independent costs and other customer specific costs, such as day-to-day operational costs, can be recovered by volume-based price, VP

$$VP = \frac{TR \cdot w_{independet}}{ES} \quad (8)$$

where ES is total energy served in the year.

As opposed to constructing new lines or transformers when existing assets have reached the designed peak loading, non-network based solutions, such as controllable loads, provide alternative solutions to meet the growing demand. Distribution network planner can factor in the available controllable loads and develop alternative feeder reinforcement plans, which may require less reinforcement or replacement in the current regulatory period. It implies that notional savings, SV, can be achieved by distributors, compared with the feeder reinforcement plan without considering any controllable load

$$SV = DEP + ORC_d \cdot \left[1 - \left(\frac{1 + CPI}{1 + WACC}\right)^n\right] \cdot WACC \quad (9)$$

where DEP is the yearly depreciation value of the delayed feeder reinforcement costs, and ORC_d is the delayed capital expenditure that would otherwise be included in the present regulatory asset base instead of n years later.

The savings should be attributed to the reduced peak loads, so the daily rebates, RB, are calculated as

$$RB = \frac{SV}{\Delta CPD \cdot 365} \quad (10)$$

where ΔCPD is reduced coincident peak demand due to controllable loads. Controlled energy usage is most likely shifted to another time period, so the effect on volume-based price is assumed to be minimal.

Frequent use of controllable loads may result in some customers experiencing degraded service quality, such as no heating or air conditioning for long time. However, other normal loads are not interrupted, so the system supply is continuous and system reliability indices can be assumed as the same.

3.3. Network tariff and reliability premium

Charging a minimum network tariff, such as the $LRAIC$ above, to each customer comes with a connection service of minimum quality obligation. Individual customer n at load point m can specify the payment of reliability premium (RP) in terms of interruption payment, IP, and duration payment, DP, if the service is lost due to both natural causes and forced outage

$$RP_{m,n} = (IP_{m,n} + DP_{m,n} \times r) \times \lambda \tag{11}$$

where λ is the government regulator agency prescribed value of failure rate per year, r is the prescribed repair time, and both of which are system level reliability indices.

The reliability differentiated charge, RDC, is therefore composed of the minimum network charge and reliability premium

$$RDC_{m,n} = IC + RP_{m,n} \tag{12}$$

Using the Markov chain to study the distribution network reliability and derive the steady-state probabilities [17], the total failure rate, $\overline{\lambda_{ij}}$, and the average repair rate, $\overline{r_{ij}}$, of the particular zone i and branch j can be calculated [18]. These are load point reliability indices at customer level that are more granular than the system reliability indices.

3.4. Service delivery model with reliability premium

Advanced meters capable of interval metering and load controlling can be installed at consumer premise level. When the benefit of controlling a load exceeds the benefit of servicing the load during a particular interval, the load of the 'free-rider' consumer or device can be controlled. Such benefit consists of wholesale market trading savings and deferred network investment. Only the wholesale trading part is formulated here.

The RP based service delivery model is formulated as a mixed integer optimization problem with binary variables, which can be solved using GAMS as well. The objective function is to maximize the net benefit, NB, for the combined entity of energy retailers and distributors. NB is the difference between wholesale savings, WS_1 and WS_2, and total penalty cost, TPC

$$NB = WS_1 + WS_2 - TPC \tag{13}$$

There are two major incentives derived from trading controllable loads in wholesale market. The first part of wholesale saving is to avoid paying very high wholesale market price, P_{prs}, by responding to reduce the demand of an amount equal to $\Sigma L_{m,n} \times K_{m,n}$, but the retailer's revenue of energy and network charges is also lost, so the benefit is offset by the retail price of P_{ret}

$$WS_1 = \Sigma L_{m,n} \times K_{m,n} \times (P_{prs} - P_{ret}) \tag{14}$$

where $L_{m,n}$ is the demand metered for customer n at load point m in the previous interval. $K_{m,n}$ is a binary variable, with value 1 being the customer or device controlled in the current interval, and 0 being uncontrolled.

The second part of wholesale saving is to pay less for the uncontrolled load by responding to the system operator's instructions to reduce demand

$$WS_2 = \Sigma L_{m,n} \times (1 - K_{m,n}) \times (P_{nrs} - P_{prs}) \tag{15}$$

where P_{nrs} is the indicated market price without reducing the demand.

The direct penalty cost, DPC, is the sum of duration payments for actually controlling the loads, ignoring the interruption payments in this formulation

$$DPC = \Sigma DP_{m,n} \times K_{m,n} \tag{16}$$

The industry has been using the Value of Lost Load ($VoLL$) to coarsely approximate the interruption cost for average customers. The RP can refine the interruption cost model, so that $VoLL$ represents the social cost of losing the electricity service and the RP is the private cost. As discussed in the 'free-rider' problem, some consumers may elect not to participate in any of the compensation schemes, so for those customers, only the social cost of controlling their load is considered.

Therefore, the total penalty cost of load control is

$$TPC = \Sigma(DP_{m,n} + L_{m,n} \times VoLL \times K_{m,n} \tag{17}$$

Two constraints are proposed in the differentiated service delivery model. The first constraint considers the strict compliance requirement that is similar as the dispatch instruction of the generators

$$L_{dd} = \Sigma L_{m,n} \times K_{m,n} \tag{18}$$

where L_{dd} is the exact load reduction has to be maintained according to operator instructions.

The second constraint imposes the limit on the allowed hours of load interruption every year for each customer load or device, T, which can have different values depending on the nature of the load or device. For example, controllable loads such as controlled electric vehicle charging or hot water cylinders may have higher limit than other loads at the household level. The limits can be set based on outage records of individual customer and outage probabilities at the load point m

$$T_{m,n} + \frac{K_{m,n}}{2} + \lambda_m \times r_m < T \tag{19}$$

where λ_m and r_m are reliability indices at load point m, obtained using the zone-branch technique. $T_{m,n}$ is the accumulated hour of interruption for customer n at load point m during the past 365 days, which can be modified on a seasonable basis as $T'_{m,n}$ for a particular season to account for temperature, rain fall or storm activity variations

$$T'_{m,n} + \frac{K_{m,n}}{2} + \lambda'_m \times r_m < \frac{T}{4} \tag{20}$$

where λ'_m is the adjusted load point average failure rate in the particular season.

The voltage variations, network loss, reactive support, and distributed resources are not considered in this formulation.

4. Simulation and case studies

4.1. Test networks and assumptions

In the first half of the analysis, the IEEE 123-node distribution test feeder [19] is implemented to simulate distributor revenue reconciliation and controllable load rebate calculation.

The feeder replacement cost data are assumed in Table 1.

Table 1. Feeder standard replacement costs ($000/km)

ACSR size	*556*	*336*	*#4/0*	*#1/0*	*#2*	*#4*
$Cost_{O/H-4}$	155	135	123	113	110	108
$Cost_{O/H-3}$	149	126	113	102	98	96
$Cost_{O/H-2}$	144	118	102	90	86	83
Cable size	*2*	*1/0*	*2/0*	*250*	*500*	*1000*
$Cost_{U/G-cb}$	268	286	296	310	322	344

All conductors and poles are assumed 60 years of standard life, which have been in service for 45 years. All loads specified are assumed to be peak values, whose average values are assumed to be half of the peak values. The original network is very unbalanced, so Phase-A loads at Node 1, 28, 68, 69, 70 and 71 are reallocated to Phase B, and loads at Node 45 and 46 to Phase C. Several feeders can be notionally downsized from three-phase to single-phase, which are feeders between Node 55-56, 54-55, and 78-79.

To respect the reliability limits of the test network, it is assumed that the peak capacity margin on some of three-phase feeders can accommodate the extra flow as a result of switching in additional loads during network emergency. A value of 60% is chosen for L_I in the case study. Given the voltage level of the test network, L_V is 300 volt/mile for three-phase overhead lines, 100 for single-phase, and 200 for two-phase overhead lines and underground cables.

Two load growth scenarios are studied, which assume 2% for normal load growth rate annually across all loads and 5% for high growth rate. CPI is assumed to be 2% and $WACC$ is 8%. w_{peak} and $w_{independent}$ are both assumed to be 50%. The peak demand of the 123-node test network is 3490kW, so average load is assumed to be half of peak load or 1745kW every hour, and total energy served is 15286.2MWh every year.

Each load point in the 123-node test network is assumed to have certain percentage of loads controlled, which spread equally across different portions of the network in the case study. The cases of no controllable load, 10% controllable loads, 25% and 40% are studied respectively for comparison.

In the second half of the analysis, the simulation is carried out using the data on the IEEE distribution system for RBTS Bus No. 2 [20]. The base case load point reliability indices for overhead lines are used, with disconnects, fuses, alternative supply and repairing transformers. The constraint used in the simulation is the yearly formulation. The penalty costs to be paid to individual customer in event of losing electricity service are assumed in the last column of Table 2.

Table 2. Simulation data used as in RBTS Bus 2

Type	Load point	Customer number	Metered demand	Compensation required
Residential	1–3, 10,11	210×5	2.55kW	50% none 30% $25/h 10% $50/h 10% $100/h
	12, 17–19	200×4	2.25kW	
Industrial	8	1	1MW	$3000/h
	9	1	1.15MW	$5000/h
Government Institution	4,5,13	1×3	0.566MW	$1000/h
	14,20,21	1×3	0.566MW	$2000/h
Commercial	6,7,15,	10×5	45.4kW	50% none 30% $100/h 10% $500/h 10% $1000/h

There are 1908 small customers or devices in total numbered by the order of the serving load point, which have an average total demand of 12.291MW. The demand interval is half an hour to match the wholesale trading period. Retail price is assumed to be $350/MWh, including energy and variable network charges. The total allowed service lost hour is set to be 5 hours per year, starting with no accumulated disconnection hour, i.e. $T_{m,n} = 0$.

4.2. Distributor revenue reconciliation

Firstly, several feeders in IEEE 123-node distribution test feeder are identified as having over-built capacity, such as feeders between Node 25-26, 35-36, and 47-48.

Secondly, the optimization also identifies several feeder reinforcement plans for different load growth scenarios.

In the normal growth scenario, if demand management or alternative supply switching is not implemented, immediate reinforcement as shown in Table 3 should be undertaken to construct a parallel flow path along the set of feeders between Node 149-1, 1-7, 7-8 and 8-13, denoted as Group-1 feeders. Group-1 feeders reinforcement costs are included in *ORC*, with newly commissioned service life of 60 years.

Table 3. Planning of Group-1 feeders with 2% peak growth

G-1 replace	ACSR size	G-1 reinforce	ACSR size
In 15 yrs	*336*	Now	*336*

In the high growth scenario as shown in Table 4, the replacement and reinforcement of Group-1 feeders require larger sized conductors, hence *ORC* is up-sized in this case. In addition, Group-2 feeders are expected reinforcement in 10 years, which are feeders between Node 152-52, 52-53, 53-54, 54-57, 57-60 and 160-67.

Table 4. Planning of Group-1 and 2 feeders with 5% peak growth

G-1 replace	ACSR size	G-1 reinforce	ACSR size
In 15 yrs	*556*	Now	*556*
G-2 replace	**ACSR size**	**G-2 reinforce**	**ACSR size**
In 15 yrs	*336*	In 10 yrs	*336*

Finally, referring to the modern equivalent asset replacement costs of feeders in Table 1, total *ODRC* for feeders is calculated as \$398,249.80 in the normal load growth scenario and \$448,633.10 in the high one as shown in Table 5. Hence, peak prices for the coming year and volume-based prices are shown in Table 6.

Table 5. Target yearly distribution revenue (\$000)

Growth scenario	Total ODRC	Return (WACC)	Depre-ciation	Target revenue
2%	398.25	31.86	24.08	55.94
5%	448.63	35.89	24.32	60.22

4.3. Distributor tariff rebate with controllable loads

The different percentages of controlled peak load used in the case study show many scenarios of controllable load penetration levels in the test distribution network, which generate several alternative feeder reinforcement plans as shown in Table 7.

Table 6. Peak price and volume price

Growth scenario	Recovered revenue (\$000)	Peak load (kW)	Peak price (\$/kW/day)	Volume price (\$/kWh)
2%	27.97	3559.8	0.0215	0.00179
5%	30.11	3664.5	0.0225	0.00188

Table 7. Feeder reinforcement plans with controllable loads

Growth	*2%*	*2%*	*5%*	*5%*
$Demand_{peak}$	**Group 1**	**Group 2**	**Group 1**	**Group 2**
Uncontrol	Now	–	Now	In 10 yrs
−10%	In 5 yrs	–	Now	In 15 yrs
−25%	In 10 yrs	–	In 5 yrs	In 20 yrs
−40%	In 20 yrs	–	In 10 yrs	In 20 yrs

With controllable load penetration level at 10% of total coincident peak, Group-1 feeders as identified in Table 3 can have reinforcement delayed to 5 years later under the normal load growth scenario, but the reinforcement is still imminent with 10% penetration level under the high load growth scenario.

Similar to the calculation in Table 5, the notional savings can be derived from the above alternative feeder reinforcement plans. Peak price rebates as shown in Table 8 can be offered to customers who provide controllable loads.

Table 8. Peak price rebates for controllable loads

Growth	*2%*	*2%*	*5%*	*5%*
Peak Demand	**Saving (\$000)**	**Rebates (\$/kW/day)**	**Saving (\$000)**	**Rebates (\$/kW/day)**
−10%	1.817	0.01397	–	–
−25%	2.555	0.00787	1.812	0.00542
−40%	3.534	0.00680	2.543	0.00475

Compared with the original peak price without controllable loads in Table 6, the discount on peak price is 0.65 off with 10% penetration level of controllable loads in the network.

As more controllable loads are enabled, the savings are distributed among more controllable load providers, so the discount decreases to 0.405 and 0.316 off for penetration levels of 25% and 40% respectively. It resembles the market mechanism that increased supply of controllable loads decreases the rebate (price) payable to additional controllable loads.

The case of 10% penetration level of controllable loads is not enough to achieve substantial saving in the high load growth scenario, because Group-1 feeder reinforcement is still commissioned during the current planning year. However, there may be other rebates provided by distributor on savings achievable from deferring upstream assets, or by retailers who desire controllable loads.

If the rebates on peak prices are passed to electricity customers through retailer pricing packages, the retailer who actively develops or acquires controllable loads can appear to be more price competitive than other retailers.

4.4. Differentiated services with reliability premium

While the distributors can pass the benefit of deferring network investment by controllable loads through tariff rebate, retailers can also transfer the wholesale trading benefit from controlling loads into differentiated service quality offers.

In the case study conducted on IEEE distribution system of RBTS Bus No. 2, the service delivery model algorithm tries to reduce the customer load or device load of the appropriate size starting from the lowest penalty cost during each interval. Once the limit is reached for a particular customer, the load or device will not be selected to control any more. The algorithm then tries to select the next best load or device to reduce its load. However, the service delivery model formulation and its constraints ensure that controlling loads by retailers or distributors needs to meet certain criteria.

Firstly, with the social cost imposed as $VoLL$, the wholesale non-responsive price, P_{nrs}, has to reach certain level in order to trigger any load disconnection as summarized in Table 9. As the chosen $VoLL$ increases or the amount of load disconnection increases, it requires higher non-responsive wholesale price to justify the load disconnection.

Table 9. Triggering non-responsive price level

VoLL ($/MWh)	10000		20000	
Total load reduction (MW)	1	1	2	2
Triggering price level ($/MWh)	900	1700	1700	3300

Secondly, in every half-hour trading period, retailers who submit the quantity bids of electricity usage at different wholesale responsive price P_{prs} levels must ensure the settled market price at least make the load controlling break-even in terms of net benefit. Table 10 shows the maximum level of price responsive bids required at different load reduction steps.

Table 10. Break-even price responsive bids

VoLL ($/MWh)	10000			
Non-responsive price ($/MWh)	1800			
Total load reduction (MW)	0.5	1.0	1.5	2.0
Responsive price level ($00/MWh)	14	10	6	1
Social cost & net profit ($00)	25	50	75	100

Lastly, the lowest cost loads are usually chosen first to be disconnected because if the accumulated hour of disconnection has not yet exceeded the limit. As shown in Table 11, when all customers in the system are assumed to have accumulated 1 hour of disconnection, the allowed hours of disconnection are exhausted for some customers who are receiving lower level of reliability. As a result, the maximum responsive price level is lower, reflecting the fact that the spare reliability as a resource in the system becomes scare.

Table 11. Effect of interruption limit

VoLL ($/MWh)	10000	
Non-responsive price ($/MWh)	1800	
Total load reduction (MW)	1	
Accumulated interruption hour for all customers (h)	0	1
Responsive price level ($/MWh)	1000	700
Load point	12,17-19	8
Load type	Residential	Industrial
Compensation required	None	$3000/h

5. Conclusions

After recognizing the replacement and reinforcement nature of distribution network assets, distributor pricing approaches should adopt the incremental basis, such as the long run average incremental cost ($LRAIC$) pricing methodology. Considering non-network solutions in distribution network planning, such as controllable loads, helps identify alternative network reinforcement plans that defer capital investment costs into the future. Notional savings with controllable loads can be calculated in network peak pricing approach according to $LRAIC$. The standardised contractual arrangement among electricity retailers and distributor helps clarify the rights of developing and utilising controllable loads, so that the penetration level of controllable loads can be increased in low-voltage distribution networks.

However, implementing controllable loads may affect service delivery quality in the granular customer level, so the additional payment of reliability premium (RP) to distributor is proposed to pay for better service quality and indicate customer reliability preference with load point reliability indices. The proposed service delivery model encourages to invest in more reliable Smart Grid, but retailers and distributor who seek to maximise net benefit by trading aggregated controllable loads to the wholesale market also need to consider the reliability limit at the consumer level.

Overall, distributor pricing approaches can follow a set of principles, but diversify to enable more options to utilise Smart Grid when engaging customers.

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