DEMAND RESPONSE AND NETWORK RECONFIGURATION ON DISTRIBUTION SYSTEM INVESTMENT DEFERMENT

Guillermo GUTIERREZ-ALCARAZ
Instituto Tecnológico de Morelia – México
ggutier@itmorelia.edu.mx

Chan-Nan LU
National Sun Yat-sen University – Taiwan, ROC
cnl@ee.nsysu.edu.tw

ABSTRACT

For a distribution area that is fully developed and loaded to near capacity, and the reinforcement cost to handle the expected load growth is high, it may be worthwhile to consider non-traditional capacity investment options, such as distributed generation (DG) and demand response (DR) in the distribution network planning. In this paper, load reduction (LR) is considered as an alternative for deferring a distribution network upgrade for one or multiple years and an optimization problem is formulated to study multi-year distribution network operation planning. In this study, price elasticity of demand and demand management contract scheme are used to estimate feasible LR for investment deferment.

INTRODUCTION

Traditional distribution system planning which considers expansion of the substations and feeders in a multistage fashion to handle the load growth needs to be reformulated under new technological and organizational changes in the electric power industry. Very expensive and little-used capacity to meet peak electricity demand could be addressed more efficiently through non-traditional alternatives such as retail pricing, DG or DR. Nowadays, DG is considered for network investment deferment and to gain support and time for implementing better solution [1]. Other models, especially those analyzing a market environment, propose different mechanisms for DR as a short-term alternative [2]. Performing a minimum cost system planning requires an assessment of costs for providing reliable service and quantifying its worth.

Over the past years, several utilities have performed DR market potential studies, primarily to develop a demand-side section of utility resource plans. DR is an efficient tool for resolving the inconsistencies between electric power supply and demand. It provides another resource to ensure reliable and economical grid operations.

The U.S. Department of Energy (DOE) defines demand response as: "changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." The potential for electricity peak demand reductions from DR programs across the U.S. is expected to offset 20% of electricity peak load growth between 2008 and 2019 [3]. The methods used for estimating DR market potential include [4]:

1. *Customer surveys.* Participation rates and expected load curtailments obtained from surveying utility customers about their expected actions if offered hypothetical DR options are used to estimate market potential.
2. *Benchmarking.* Participation rates and LR observed among customers in other jurisdictions are applied to the population of interest.
3. *Elasticity approach.* This approach involves estimating price elasticity from the usage data of customers exposed to DR programs and/or dynamic pricing tariffs.

In this paper a two-stage distribution network expansion planning approach is presented. In the proposed method, the distribution network capacity expansion/upgrade plan needed is first determined by using the successive elimination method (SEM) [5]. DR and feeder reconfiguration considering system loss minimization are then executed to refine the expansion plan for optimizing network usage and deferring investment.

Network Expansion Problem Formulation

The objective of the distribution network expansion planning problem is to determine an investment schedule to ensure an economic, efficient and reliable energy supply. In this study, without considering contingency, the goal is to minimize the present value of costs of investment decisions to expand/upgrade substations and feeders throughout the study period. Mathematically the problem can be formulated as follows.

$$\underset{\{x^f_{l,t},x^{tr}_{l,t}\}}{Minimize} \sum_{t=1}^{T}\left\{\sum_{l=1}^{Nf}\frac{C^f_{l,t}x^f_{l,t}}{(1+d)^t}+\sum_{l=1}^{Ntr}\frac{C^{tr}_{l,t}x^{tr}_{l,t}}{(1+d)^t}\right\} \quad (1)$$

$$S.to \sum_{k\in Kout} S^t_{pk} \le S^{Max}_p \quad \forall p\in Nt \quad \forall t=1,...,T \quad (2)$$

$$\left|V^{Min}_k\right| \le \left|V_{k,t}\right| \le \left|V^{Max}_k\right| \quad \forall t=1,...,T \quad (3)$$

$$S^t_j \le S^{Max}_j \quad j\in Nb \quad \forall t=1,...,T \quad (4)$$

and radial structure of the network (5)

where d is the discount rate, N_f is the number of proposed feeders for expansion/upgrade, Ntr is the number of proposed transformers, $C^f_{l,t}$ is the investment cost of feeder l at period t (\$), $C^{tr}_{l,t}$ is the investment cost of transformer l at period t ($), $x_{l,t}^{f}$ is a discrete variable denoting whether feeder l at period t is installed (1) or not (0), $x_{l,t}^{tr}$ is the variable denoting whether transformer l at period t is installed (1) or not (0), Nb is the total number of feeders, Nt is the set of all substation transformers, K_{out} is the set of feeders receiving power from transformer p, S_{pk}^{t} is the power flowing from transformer p to feeder k at period t, S_{p}^{Max} is the rating of transformer p, $\left|V_k^{Min}\right|, \left|V_k^{Max}\right|$ are the allowed minimum and maximum voltage magnitude at node k, S_j^t is the loading of feeder j at period t, S_j^{Max} is the rating of feeder j,

Network Reconfiguration Problem Formulation

Feeder reconfiguration is often performed to find an optimal radial network s^* among all possible radial networks $s \in S$ such that the resultant network has better operation performance to meet the objectives. Network reconfiguration for loss minimization and load balancing involve similar type of operations. Network reconfiguration for loss reduction indirectly mitigates some of the congestion problems. In this study the following problem is formulated to balance the substation load and seek short term mitigation for network congestions.

$$\underset{\{s\}}{Minimize}\ P_{loss}(s) = \sum_{j=1}^{Nb} \frac{P_j^2 + Q_j^2}{V_j} r_j \quad (6)$$

$$S.to\ \ Sg_k - Sd_k = V_k I_k^* \quad (7)$$

$$\left|V_k^{Min}\right| \le V_k \le \left|V_k^{Max}\right| \quad (8)$$

$$S_j \le S_j^{Max} \quad (9)$$

and radial structure of the network (10)

where P_j and Q_j are the active and reactive power flows through the branch j, and r_j is the resistance of the branch j.

Estimation of LR due to DR

To study the use of LR as one of the alternatives in the integrated resource planning (IRP) it is necessary to estimate the amount of LR from the estimated market potential. Price elasticity of demand model measures the sensitivity of demand (Q) changes to the price (P) change.

$$\alpha_d = \left(\frac{\Delta Q}{\Delta P}\right)\left(\frac{P}{Q}\right) \quad (11)$$

For a case with a 100% increase in the electricity price, if there is a 20% load reduction, then $\alpha_d = -0.2$. LR can be estimated from a given electric price change if the price elasticity of demand is known.

Another model to estimate LR by DR is through demand management contracts which use the pay per curtailment method. The contract offered by the utility aims at maximizing utility's benefit and customers are compensated sufficiently in order to induce voluntary participation. A general service interruption cost function proposed in [6] for different types of customers is defined as:

$$c_i = K_1 x_i^2 + K_2 x_i \left(1-\theta_i\right) \quad (12)$$

where x is the curtailed quantity in kW, K_1 and K_2 are the coefficients of the cost function, and θ is a continuous variable describing the customer type, that "sorts" the customers from "least willing" to "most willing" to shed load. The complete set of customer types can be characterized by allowing θ to vary from 0 to 1. K_1, K_2 and customer types (θ) need to be calibrated using data from the utility [6]. To simplify the study and without loss of generality the coefficients K_1 and K_2 can be assumed known with ½ and 1, respectively. Once the customer outage cost function is estimated, the utility can design an incentive interruptible load contract model by maximizing its benefit function subject to individual rationality constraint and the incentive compatibility constraint. One of the results shown in [6] is as follow:

$$x(\theta) = \begin{cases} 0 & if\ 0 \le \theta < 1-0.5\lambda \\ 2\theta + \lambda - 2 & if\ 1-0.5\lambda \le \theta < 1 \end{cases} \quad (13)$$

$$y(\theta) = \begin{cases} 0 & if\ 0 \le \theta < 1-0.5\lambda \\ \theta^2 - 2\theta + 2\theta\lambda & \\ +0.75\lambda^2 - 2\lambda + 1 & if\ 1-0.5\lambda \le \theta < 1 \end{cases} \quad (14)$$

For a given customer type (θ) and the value of power not delivered to a customer (λ) in $/kWh, equations 13 and 14 define the targeted consumers' LR (x) in exchange for an incentive (y) in $.

Investment Deferment Assessment

The distribution network planning procedure that takes feeder reconfiguration and DR into account is as follow:

1. Find the least cost expansion plan for the studied distribution area. The objective is to find the multistage least cost expansion plan as defined in (1)-(5). The inputs to the network expansion problem are: existing network configuration, forecasted system peak demand, new T&D routes and substation sites and their costs, and existing substation expansion capability. The network expansion problem is studied by using SEM and arrives at an optimal set of projects in a plan for substation and feeder capacity expansion /upgrade. All these plans are passed on to network reconfiguration and LR process.
2. Knowing the distribution area least cost expansion plan, identify the time when equipment in the plan will be installed.
3. Apply network reconfiguration to transfer load and determine the maximum investment deferral time if possible.
4. Consider realistic achievable potential scenarios [7] to estimate LR by using elasticity values (11) and/or

demand management contracts (13-14) under dynamic pricing option. If estimated LR offsets the demand growth, determine the investment deferrable time. If this is the last expansion/upgrade stage in the least cost expansion plan, the expansion plan is rescheduled, and go to step 5. Otherwise, select the next expansion/upgrade project in the plan and go to step 3.

5. Aggregate the avoided costs associated with the each rescheduled project. The avoided cost is the difference in the present values of the total investment requirement before and after the investment is deferred:

$$\sum_{j=1}^{N}\left[\sum_{t=1}^{T}\frac{K_{t,j}}{\left(1+r\right)^{t}}-\sum_{t=1}^{N}\frac{K_{t,j}\left(1+i\right)^{\Delta t}}{\left(1+r\right)^{t+\Delta t}}\right] \quad (15)$$

where T is the finite planning horizon in years, N is the number of expansions/upgrades required, i is the inflation rate, r is the discount rate, $K_{t,j}$ is the cost of investment j in year t, and Δt is the deferral length in years.

Considering different constraints and costs, the methodology can be used to screen different non-wire alternatives such as DG and energy storage system. Avoided generation capacity costs, T&D losses, and environmental costs can also be considered as benefits of LR if desired.

CASE STUDY

A distribution system with two substations is used to illustrate how feeder switching operations and LR could play a role in IRP and investment deferment. The complete network data is available in [9] and the network diagram is depicted in Fig. 1. Peak demands in the current year at substations A and B are 19.63 MVA and 13.94 MVA, respectively. An annual load growth of 3% and a 15-year planning horizon are assumed. Without considering feeder load transfer, Table I shows the candidate (one plan with two reinforcement projects) proposed to meet the load growth, with the commissioning schedules and costs. As shown in Table I, the least cost expansion alternative is to install new transformers at substation A. Additional reactive power equipment is required to compensate the voltage drop [9] which is not included in Table I.

TABLE I. Proposed candidate options

Name	Capacity (MVA)	Cost (US $k)	Year
New Transformer at Sub A	1 x 24	400	8
New Transformer at Sub B	1 x 24	400	12

Table II shows the substations' peak load projections for years 9-13 without and with load transfer between substations by switching actions. The amount of load transfer from substation A to substation B is the difference of loadings of base case and switched topology at each year. For instance, in the second row, at year 9 the amount of load transfer from substation A to substation B is 3.44 MVA if switches S11 and S88 change their ON/OFF status. Table II shows that with feeder reconfiguration the investment can be deferred for 2 to 4 years and the deferral values are 27.61k$ and 52.17k$, respectively. The maximum deferral time can be achieved by installing the transformer in substation B at year 12.

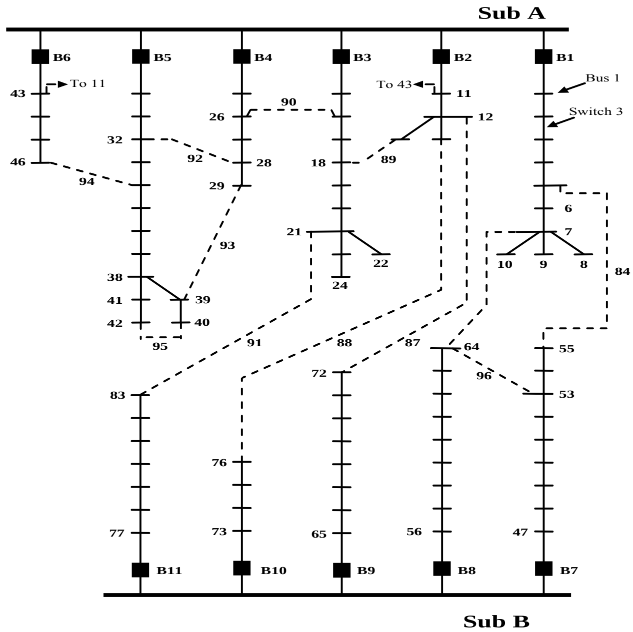

Fig. 1. Test System.

TABLE II. Peak demands during year 9 to 13 (in MVA)

Switching	Year	9	10	11	12	13
Base case, no switching	Sub A	$\boxed{24.47}$	25.20	25.96	26.74	27.54
	Sub B	18.06	18.60	19.16	19.73	20.32
S11/S88	Sub A	21.03	21.66	22.31	22.98	23.67
	Sub B	21.52	22.16	22.83	23.51	$\boxed{24.22}$
S7/S85	Sub A	23.00	23.69	$\boxed{24.40}$	25.13	25.89
	Sub B	19.54	20.12	20.73	21.35	21.99

Next, elasticity demand response approach and demand management contract scheme are used to estimate LR. Assume that critical price pricing (CPP) is the tariff mechanism being implemented starting in year 2. CPP rate compensates customers who voluntarily reduce some or their entire energy load during a few peak periods. The assumed tariffs rates are shown in Table III.

TABLE III. Tariff rates

	Flat tariff rate ($/kWh)	Dynamic Tariff rate ($/kWh)
Critical Peak	0.10	0.90
Peak	0.10	0.14
Off peak	0.10	0.09

If the price elasticity of demand is assumed -0.02, the demand would decrease 13%, given that critical peak price increased around 650% with respect to the peak price. Based on demand management contract, using equations 13-14, Fig. 2 shows a family of LR (continuous line) and incentive functions (dashed lines) as λ varies. As an example, for λ = \$0.9/kWh and a customer type $\theta = 0.8$, the customers are willing to reduce consumption of 1200 kW (demand decreases around 6.7%) with a \$287.5/hour incentive they obtain in return. It can be observed that the lower the incentive the lower amount of LR.When customer participation in DR programs is completely voluntary, it would be difficult to accurately estimate the amount of energy reduced. Therefore, a conservative LR value, 50% or less of the potential value estimated by price elasticity of demand method or demand management contract method, is suggested

Assuming uniform load growth at each feeder section, after performing switching of S11/S88 or S7/S85 during peak load hours, partial load originally supplied from substation A is transferred to substation B, The projected demands at each substation with (red and black lines) and without (blue line) network reconfiguration are shown in Fig. 3. Dashed lines represent the effect of a 4% LR and the dotted lines represent a 6 % LR due to DR. From Fig. 3 we observe that the investment can be deferred up to 6 years (74.04 k\$ deferral value) only by applying LR. When combined with network reconfiguration, the investment can be withdrawn from the 15-year planning study.

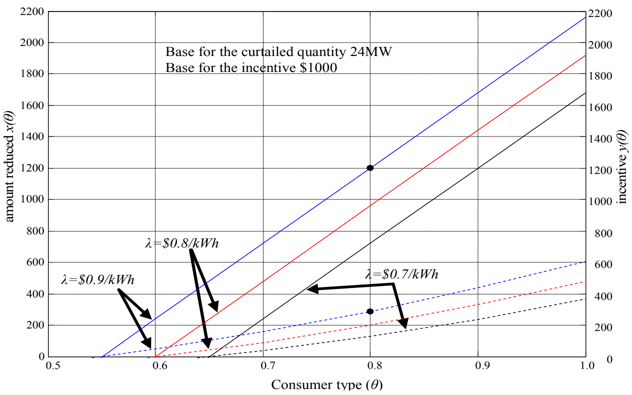

Fig. 2. Incentive and LR as function of consumer type (θ).

CONCLUSION

In this paper a study that takes LR and feeder reconfiguration into account in distribution operation and planning for handling load growth is presented. Two techniques are used to estimation the possible LR due to tariff design. Numerical results show the values of feeder reconfiguration and LR in network investment deferment. In the future, non-traditional options would find there applications in distribution network planning in order to optimize the existing network utilization.

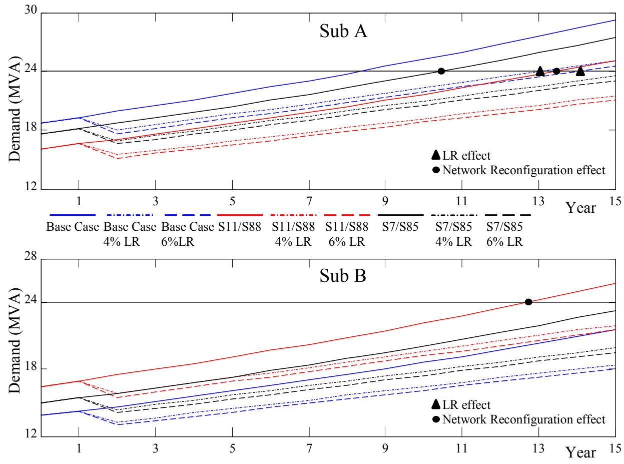

Fig. 3. Investment deferral time with a 4 and 6% LR.

REFERENCES

[1] D. T.-C. Wang, L. F. Ochoa, and G. P. Harrison, "DG impact on investment deferral: Network planning and security of supply," *IEEE Trans. Power Systems*, vol. 25, no. 2, May 2010.

[2] A. K. Kazerooni, J. Mutale, "Transmission network planning under a price based demand response program," *Proceedings 2010 IEEE/PES T&D Conference and Exposition*, pp. 1-7, Apr. 2010.

[3] A national assessment of demand response potential, staff report, federal energy regulatory commission," prepared by The Brattle Group (TBG), Freeman, Sullivan & Co. (FSC) and Global Energy Partners (GEP) Jun. 2009.

[4] C. Goldman, N. Hopper, R. Bharvirkar, B. Neenan, and P. Cappers, "Estimating demand response market potential among large commercial and industrial customers: a scoping study," Ernest Orlando Lawrence Berkeley National Laboratory, LBNL 61498 January 2007.

[5] R. E. Brown, J. Pan, X. Feng, and K. Koutlev, "Siting distributed generation to defer T&D expansion," *Proceedings 2001 IEEE/PES T&D Conference and Exposition*, vol. 2, pp. 622-627, Oct. 2001.

[6] M. Fahrioglu, "The design of optimal electric power demand management contracts," *Ph.D. Thesis*, University of Wisconsin-Madison, 2000.

[7] I. Rohmund, G. Wikler, A. Faruqui, O. Siddiqui, and R. Tempchin, Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010–2030).

[8] X. Li, and G. K. Zielke, "One-year deferral method for estimating avoided transmission and distribution costs," *IEEE Trans. Power Systems*, vol. 20, no. 3, pp. 1408 – 1413, Aug. 2005.

[9] Y.-K. Wu, C.-Y. Lee, L.-C. Liu, and S.-H. Tsai, "Study of reconfiguration for the distribution system with distributed generators," *IEEE Trans. Power Delivery*, Vol. 25, No. 3, July 2010, pp. 1678-1685.