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Network Pricing in Distribution Networks

Sapna Ladwal
Dept. of Electrical Engg.
MNIT Jaipur
Jaipur, India
2018psm5335@mnit.ac.in

***Abstract*— Network charging methods plays a valuable role in maximizing the benefits for the network services for serving two key purposes, firstly to encourage the network users for efficient utilizations of existing distribution facilities and secondly, for guiding location-specific signal for future reinforcement of generation or demand. My work focused on improving the operating capably of network and network investments by reducing network investments and lowering operation cost to delay network upgrade deferral. Novel methodology for small systems using LRIC methodology with network congestion management is used by integrating short-run operating cost and long-run investment cost.**

***Keywords*—Congestion management, LRIC, network pricing, smart grid**

I. Introduction

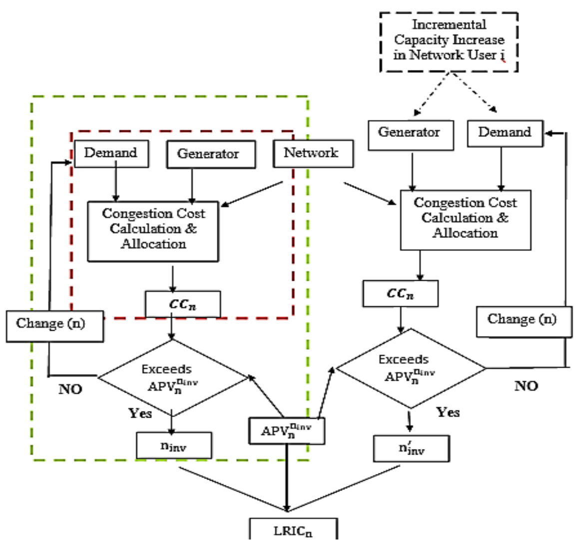
Since privatization was introduced in the electricity network of the power industry to encourage competition and incremental network operating and planning efficiency. The demand for electricity is increasing gradually all over the world. the Majority of network charging methods are drawing for networks dominantly by convention generation. Designing a network charging methodology to recover the costs of capital/ investment cost, operation, and maintenance cost of non-practical network so that the network methodologies can get the desirable return of the investment. The main focal point is to provide incentives that will encourage efficient and effective use of the existing network. So, we had to find an alternate solution to meet the excess demand which reflects the contribution of network users in deferring network reinforcement. the research work aims to develop a network charging method which reflecting network investments for different generation technologies at different locations, and crucially at different times. Its first place identifies network investments under economic criteria and the conditions for developing the LRIC method [5]. LRIC pricing methodologies having some major issues that are preventing its practical positioning. LRIC is an advanced network pricing model for efficient utilization of network and capability to save investment costs. The difference in present values of future investment, resultant of the nodal power disturbance for LRIC pricing method is a most advanced pricing method until now that is efficient of reflecting both distance efficiency and extent of utilization of network assets.

Evolving The paper investigates the trade-off between investment cost and operation cost at the time reinforcement horizons. In novel charging methodology, technologies differentiating by identifying impacts on a reinforcement time horizon of network investments and then translating these impacts to network charging [6-8]. to achieving benefits from technologies are to convey short term behavior of network users with the effect of which efficient utilization of network and mitigating network congestion [11].

II. Network Pricing Model

The proposed mechanism has been illustrated in Fig. 1 reflects the locations with distribution congestions for LRIC charges. This providers clarity on proposed mechanism, by illustrating the first stage is to calculate Congestion Cost calculation (pointed by red box), second stage is to determine the investment time horizon for individual branch (pointed by green box), and third and last stage is to derive long-run incremental cost (LRIC) approach (pointed out by black box) integration of different category user's contributions to network peak demand for network charging.

Fig.1 Flowchart of the Proposed Method



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III. MODEL OF OPERATION COST

The pricing for power network examining its impact on network investment and operation cost. As operating cost at full capacity thus its load factors are high. Demand increases during peak times; additional electricity is required to meet the demand. Sometimes, less efficient generators with high operation cost, perhaps with higher CO2 emissions, are needed. This high cost will be passed onto the customers. By shifting demand at peak times to outside peak hours, where more efficient generators are available, it will reduce or may avoid the needs to run inefficient generators [19]. Therefore, it would reduce/deferral the costs and the emissions of CO2 per kWh electricity.

Power flow management to relive network congestion, for example congestion management. The target of congestion management is to minimize system operation costs [20]. This assumption fails to recognize the effect of congestion management in deferring network investments [21]. Give and take between short-run operational costs and long-run investment costs in distribution network under the remunerative criteria. Distribution network losses; need to strike an optimal balance between operational costs and network investment cost. are two subsections here: to identify nodal power injection to branch flows and to quantify the congestion cost.

Calculation of operational costs is divided into two parts wherein the first step recognizes the nodal power transfer distribution factor injected to branch flow and to quantify the congestion cost.

IV. IMPACT OF DEMAND/GENERATION CHANGE ON BRANCH FLOWS

Impact of Nodal Demand/Generation Change on Branch Flows is applied to calculate the maximum limit of flow in a pair of transactions between end points which can be appraise by the Power Transfer Distribution Factor (PTDF) matrix. Consider a transaction 'P_{mn}' between a seller bus 'm' and buyer bus 'n'. Further consider a line 'l' carrying a part of the transaction power. Let the line be connected between a bus 'i' and a bus 'j'

$$AC\_PTDF_{ij,mn} = \frac{\Delta P_{ij}}{\Delta P_{mn}}$$

For a change in real power transaction between the above seller and buyer say by $\Delta P_{mn,}$ if the change in transmission line. AC Power Transfer Distribution Factors (AC_PTDF) [22-23] is introduced to select the branch *I* that has the largest impact on energy quantity 'P_{ij}' is ΔP_{ij}, the Power Transfer Distribution Factors can be defined as given by eq.1

V. CONGESTION COST

Distribution network upgrades can eliminate distribution congestions, consequently congestion costs caused by distribution congestions. Distribution congestion costs provide the approach to quantify the benefits of network upgrades [49]. Moreover, the key drivers for the increase of congestion costs are the factors that trigger the distribution investments under the economic criteria. And the key conditions for congestion costs can provide an overview of when and where distribution investments are required.

When the producer and consumers of the electric energy wish to produce and consume in amounts that would cause the transmission system to operate at or beyond one more transfer limit, the system is said to be congested. Line outages or higher load demands are the causes of congestion in the transmission network [41]. Causes of network congestion In the transmission system, relevant constraints are introduced due to Kirchoff's laws and system requirements. Usually, congestion will occur in the network when a transmission line reaches its transmitting capacity.

VI. CONGESTION COST ASSESSMENT

Assuming that the number of distributed generators in the system is nG, where n is number of generators. The congestion cost at the settlement period T.

$$p_{it} = a_i * P_{Git}^2 + b_i * P_{Git} + c_i$$

where p_{it} is the energy cost for generator G_i at time t; a_i, b_i and c_i, are the coefficients of generation cost at bus I, where quadratic equation is obtained by approximating the power in MW versus the cost in Rupees curve If the variation of generation cost around the whole year is neglected and the Bids/Offers in Balancing Mechanism are set to be unchanged, p_{it} become constant.

The Congestion cost at settlement period "S" is:-

$$CC_S = P_1 * \left(G_{1,S} - G'_{1,S}\right) + P_2 * \left(G_{2,S} - G'_{2,S}\right) + P_3 *$$

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$(G_{3,s} - G'_{3,s}) + \ldots + P_i * (G_{i,s} - G'_{i,s})$

After we will calculate congestion cost for a whole year:

$$TCC = \sum T * P_1 * (G_{1,S} - G'_{1,S})$$

By multiply and divide with $C_1 * 8760$ (capacity in whole year) assume the variation of generation cost around the whole year is negligible/neglected and the Bids/Offers in are set to be unchanged, pi become constant.

connection locations to distribution networks The congestion cost is allocated to branch *l*, based on ACPTDF, represented as:

$$CC_{il} = AC_{PTDF_l} * TC_i$$

The total congestion cost for branch l is:

$$TC_{il} = \sum_i^{nG} AC_{PTDF_l} * TC_i$$

Here we are assuming zero elasticity of demand is:

$$LF_{it} - LF'_{it} = 0$$

VII. MODEL OF EXISTING INVESTMENT COST RELATED PRICING METHOD

In the proposed method, different generation technologies

$$TCC = P_1 * \sum T * (G_{1,S} - G'_{1,S}) * \frac{C_1 * 8760}{C_1 * 8760}$$

Total Congestion Cost (TC) in one year for specific generator

$$TC_i = \sum_{t=1}^{8760} [C_{it} * P_{it} * (LF_{it} - LF'_{it})]$$

Total congestion cost in one whole year:

$$TC_i = C_{it} * P_{it} * (LF_{it} - LF'_{it}) * 8760$$

where C_{it} is the installed capacity of G_i at time *t*, LF_{it} is the load factor without any constraints, and LF'_{it} is the actual load factor which means the transmission constraints are considered.

Load factors specified for time *t* reflects generator's contribution to different levels of system congestions during different times. The load factor of generator *i*, LF_{it}, is calculated as:

$$LF_{it} = \frac{\sum_{t=1}^{T} GP_{it}}{C_{Gi} * SP}$$

where GP_{it} is the sum of outputs of generator *k* for the time in period T, where T varies from 1,…..,T; C_{Gi} stands for the capacity of generator *i; SP* is the number of time periods (0.5 h) contained, The *CC* for one settlement period (0.5 hour) is calculated based on two economic dispatches.

The annual congestion cost is the sum of congestion costs for $17.5 * 10^3$ settlement periods over the course of a year (1 settlement period per 0.5h, then $2 \times 24 \times 365 = 17.5 * 10^3$ in a year). Congestion significantly depend on the generation technologies and generators' locations. Generators'

In the same location can be differentiated. This is because the production costs and availabilities for various generation technologies are set to be different in the calculation of congestion cost. An incremental capacity increase from different generation technologies will impose different impacts on the investment time horizons of congested distribution branches. The proposed method employs simple principles to differentiate generationtechnologies. For network sector, the investment costs for congested branches are required. For demand sector, the year-round demand profile is needed. However, the proposed method has its advantages as it does not need to assume future generation and network expansion, only using information pertaining to existing generation mix, distribution network and demand

For distribution network investment cost under the economic criteria are reinforced when the annual congestion cost exceeds the annualized investment cost. Previously It is assumed that all congested branches will be upgraded at a future time by new parallel lines along the existing one, and thus doubling the transmission capacity with the same investment cost. In my research, the proposed method of distributed network annualizes investment cost's time periods along the year. And the comparison becomes between the allocated congestion costs for congested periods and the allocated investment costs. This reflect the fact that the severity of system congestions also varies during different time periods, thus requiring to investing transmission branches in different future times.

The proposed method recognizes the impacts of

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distribution system's operation on distribution investments. It chooses the investment time horizon to reflect the comparison between operational congestion costs and investment costs. It employs a long-run incremental cost (LRIC) approach to identify the impacts from different generation technologies on distribution investments, which are thereafter translated to generation technology specific TUoS charges. The major contribution is to apply the LRIC method to distribution networks by exactly reflect the trade-offs between operational and investment costs. .LRIC with network congestion management is Integration of the short-run congestion cost with long-run investment cost. If congestion at n_l occurs, it might be cheaper to payg congestion cost rather than investing the networks

$$n_{inv} = n_l + n_c$$

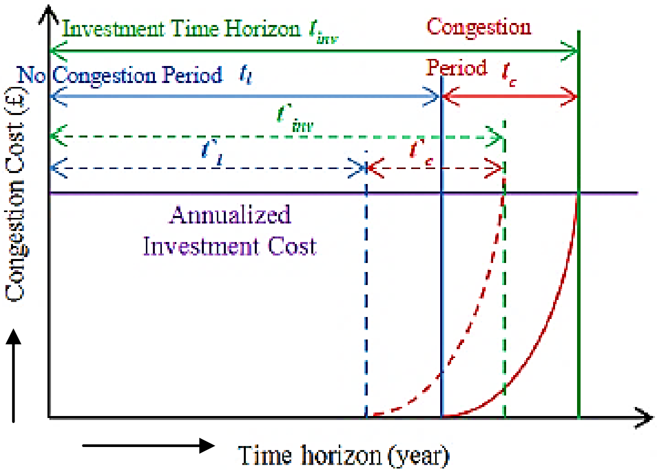
By assuming the demand increases (every year), then power flow would be increase along a distribution network branch. As the power flow starts increasing, Till the time branch doesn't reaches to its capacity distribution congestion does not occur (no congestion lasts for a period of n_l (the blue line in). When

When power flow reaches the capacity limit, congestion occurs. But this branch is not upgraded until the annual congestion cost (*ACC*, the red line) allocated to it in a future time exceeds its annualized investment cost (*APV*, the purple line). The situation of congestion management lasts for a period of n_c (the red line). The time horizon for investing in this branch n_{inv} (the green line) is:

$$n'_{inv} = n'_l + n'_c$$

The time horizon of investing distribution branches under the economic criteria and time horizon of congested branches. The horizontal axis presents the time horizon and vertical axis resents the congestion cost. Clearly shows that incremental change can defer the investment time horizons of congested branches.

Fig.2. Time Horizon of Investing Distribution Branches and Time Horizon of Congested Branches



Where Present Value is defined as a future amount of money that has been discounted to reflect its current value, reflecting the time value of money. The future investment which is yet to be made can be discounted to a present value. Investments made in a project for future so it must be discounted to present value, let the discount rate be 'd' this is the benefit that the investors want to accept delayed payment

If there is an injection from node N, causing power flow change along a circuit to rise by ΔPV_l, then this will advance or delay the future reinforcement, leading to new time horizon- n_l. This future investment can be discounted back to its present value, which will be a function of the time horizon to the investment. Knowing the discount rate, d, the present value of the investment can be evaluated

$$\text{Discount factor} = \frac{1}{(1+d)^{n_l}}$$

We have this PV_l equation

$$PV_l = \frac{Asset_l}{(1+d)^{n_l}}$$

By same upgradation, Given the fixed discount rate *d*, the present value for the annualized investment cost for line *l* in year n_{inv}, $APV_l^{n_{inv}}$ are

l

$$APV_l^{n_{inv}} = \frac{AIC_l}{(1+d)_i^{n_{inv}}}; \text{Where}$$

$$AIC_l = Asset_l * Annuityfactor$$

$APV_n^{n_{inv}}$ is annuilised present value of inestment cost and

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$ACC_n^{n_{inv}}$ where Cost with growth rate r also set as 6.4%
Where

$$APV_n^{n_{inv}} = PV_n * \text{annuity factor}$$

Now with incremental changes from network users can advance the investment time horizons.

$$APV_l^{n_{inv\,new}} = \frac{AIC_l}{(1+d)_i^{n_{inv\,new}}}$$

Here positive sign indicates withdrawal of more power and negative sign indicates injection of more power at node N. so above equation can be written in the form

$$APV_n^{n_{inv\,new}} = PV_{n,new} * \text{annuity factor}$$

So the change in annyalized present value is given by

$$APV_n = APV_n^{n_{inv\,new}} - APV_n^{n_{inv}}$$

Evaluating Long Run Incremental Cost

$$LRIC_n = \frac{AIC_l}{(1+d)_i^{n_{inv\,new}}} - \frac{AIC_l}{(1+d)_i^{n_{inv}}} = \frac{APV_n}{\Delta P_{kN}}$$

As mentioned in paper [11], the LRIC pricing methodology recognizes not only the 'distance' power must travel to meet demand but also the degree of circuits' utilization. LRIC prices are fairly sensitive to the rate of growth of demand. Its publication is also relatively difficult considering the model's complexity and the amount of data needed. Although the LRIC pricing model has its merits in providing economical signals to the network customers, there are some key issues preventing the pricing model froits practical deployment. These issues have to be addressed and tackled. Three of the major issues dealt with in this work are the security factor (effective maximum capacity of assets), the circuit loading growth rate (effective speed reaching the capacity of assets) and the revenue reconciliation method (to produce the final LRIC tariff).

VIII. RESULTS AND DISCUSSION

Employs a simple power system to explain the occurrence of network congestion and the calculation of congestion cost. So that, We will clearly understand the work presented later in this thesis. After explaining the calculation of congestion cost, this study investigates the influences of various factors on the total congestion cost, aiming to identify those that are key drivers for network investments under the economic criteria thus should be considered in the developing charging methods.

1) Three-Bus System

The generators, loads and network data of three-bus system are specified in Table I and Table I. After the simulation of one-year operation, the LF and LF' of each generator is stated in Table III. According to CCi in Table I, G1 and G3 benefit from congestion whereas G2 lose benefit at the same time.

Fig.3. Three Bus Test System

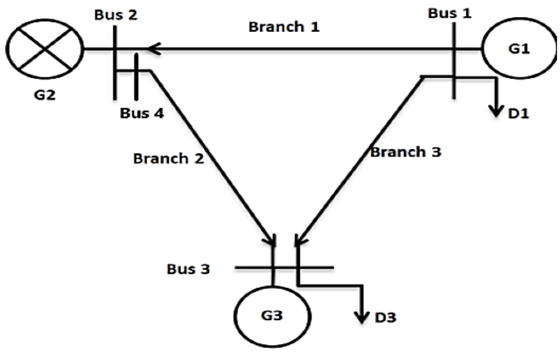

Table 1 Three bus test system data

	G1 Capacity (MW)	G2 Capacity (MW)	G3 Capacity (MW)	Charges for Generation connected			Charges for Demand connected		
C(MW)	200	300	200	G1	G2	G3	D1	D2	D3
Pi ($/MWH)	20	10	50	10	10	10	10	10	10
Li (MW)	250	-	100	60	80	60	60	80	60
TC (MW)	100	100	150	110	150	110	110	150	110
TL (KM)	1000	1000	1000	160	220	160	160	220	160
LF	0.6670	0.3113	0.0873	180	260	180	180	260	180
LF'	0.7926	0.2239	0.0929	190	280	190	190	280	190
CCi	-4.402	0.299	-0.489	200	300	200	200	300	200

The demand peaks at Bus 1 and Bus 2 are assumed to be 200 MW and 300 MW respectively. Network capacity for

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branch 2 is assumed to be 100 MW. The demand peaks at Bus 1 and Bus 2 are assumed to be 200 MW and 300 MW respectively.

Assets cost £3.2*10^6 at its modern equivalent asset value. Percentage utilization is the ratio between the loads connected to the bus bar to the total capacity of bus bar. With Taken a discount rate of 5.6%, and Load growth rate(r) is 1.6% per annum which is the commonly accepted Minimum Acceptable Rate of Return.

Table 2 Three bus test system generation parameters

Generator	*Connection Bus*	*Generation Capacity (MW)*	*Production Cost (£/MWh)*
G1	Bus 1	200	44
G2	Bus 2	300	20
G3	Bus 3	200	0.01

Calculate congestion cost for the whole system to branch level. This facilitates the comparison of congestion cost and investment cost on branch level, which exactly reflects the trade-offs in transmission investments under the economic criteria. With reinforcement of these branches, the congestion cost could be reduced.

Positive congestion charges for network users who contribute to congestion thus advance network investments, and negative congestion charges for network users who help to eliminate congestion thus defer network investments. Furthermore, the magnitudes of total congestion charges reflect the extent of advancing or differing network investments.

Fig.4. Impacts of Network Capacity on Annual Congestion Cost

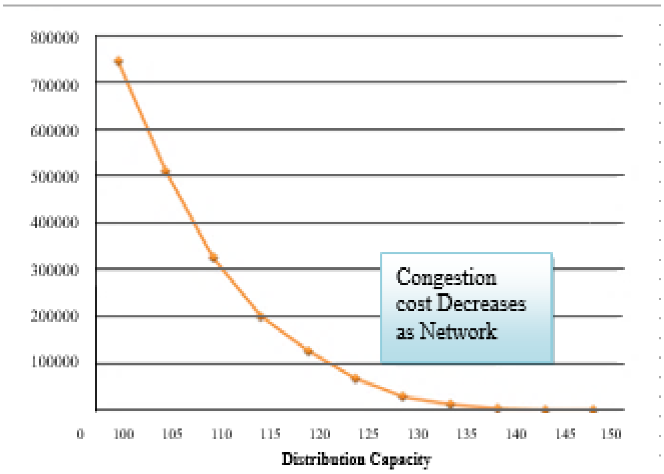
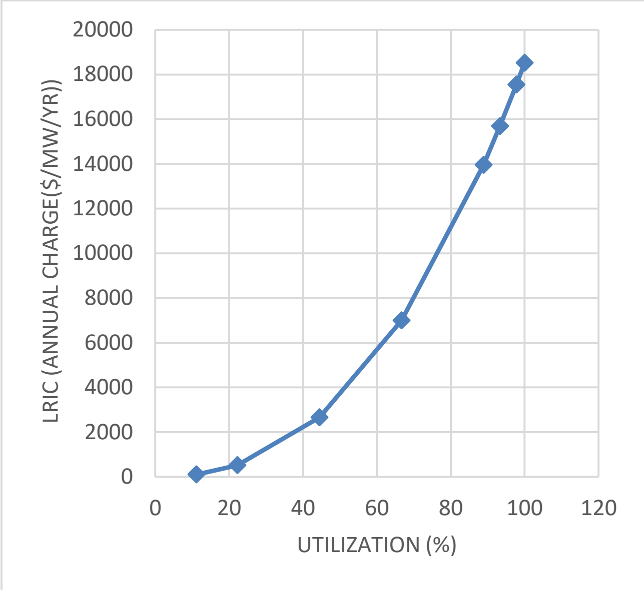


Figure 4 shows after Extremely severe network congestions, expressed by high congestion costs, only occur for a very small duration in a year. After those severe network congestions, congestion cost declines exponentially to zero.

Fig.5. Annual Charge($/MW/yr)



At the point when the circuit use is more than 20%. When the interest is close to the estimation of DG the charges are a little while as the interest expands the charges additionally increments. DGs) to boost effective usage of existing systems along these lines limit the speculation cost for its future turn of events.

With higher components' utilization levels, high charges come out because all components' loading levels increase, which in turn greatly bring forward their future reinforcement horizons. With higher components' utilization levels causes increase nodal reliability levels by decreasing nodal allowed loss of load down to the half of the original values, thus causing nodal tolerable EENS and in turn the tolerable loss of load to be halved as well produces the highest charges lower allowed loss of load means that less demand can be interrupted in contingencies and hence more of assets' spare capacity should be reserved to accommodate potential. Decreasing assets' failure rates to the half of the original ones, causing the tolerable loss of load doubled.

XI. CONCLUSION

This thesis mainly deals with cost analysis of network network with DG. There are many methods for the cost analysis as described in chapter 2 but LRIC method is used for the analysis because of its advantages as described in [19],[25]. In chapter 3 cost analysis of network network is carried out in the

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absence of DG. The capacity of the line is

fixed and no DG is connected to the circuit then charges per MW increases with percentage utilization it is seen from table 1. Now if DG is introduced then charging cost gets affected according to the utilization (%) of the circuit. Although this charge depends on line capacity. As shown in fig 2 it can be said that variation of DG affects the charging cost for any utilization and it decreases with the rating of DG.

The proposed method calculates the annual congestion cost. The allocation of congestion cost is achieved by extending the branch capacity limits via the adopted congestion cost allocation method. The positive CC value of branch 2 means that the Network capacity limit of branch 2 aggravates the congestion. A compare of TCC after reinforcement of branch 2 also supports this conclusion. After branch 2 is reinforced from 150MW to 200 MW, the TCC decreases from 2.592m£ to 0.348m£.

It is desirable that network charging models should be able to recover the investment and provide forward-looking and economic guidance to the existing and prospective users to influence their activities in sitting and sizing so as to encourage efficient utilization of the existing networks.

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