Distribution Network Pricing: Contribution Factor based Long Run Incremental Cost Models

Ph.D. Thesis

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Dedicated to My Mother

DECLARATION

I, **Amita Kumari Sharma,** declare that this thesis titled, **"Distribution Network Pricing: Contribution Factor based Long Run Incremental Cost Models"** and the work presented in it, are my own. I confirm that:

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CERTIFICATE

This is to certify that the thesis entitled "**Distribution Network Pricing: Contribution Factor based Long Run Incremental Cost Models"** being submitted by **Amita Kumari Sharma (ID-2011REE7130)** is a bonafide research work carried out under our supervision and guidance in fulfillment of the requirement for the award of the degree of **Doctor of Philosophy** in the Department of Electrical Engineering, Malaviya National Institute of Technology Jaipur, India. The matter embodied in this thesis is original and has not been submitted to any other University or Institute for the award of any other degree.

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"Guru Bin Gyan Na Upjai, Guru bin Milai Na Moksh,
Guru Bin Lakhai Na Satya Ko, Guru bin Mite Na Dosh"

-Kabir

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ABSTRACT

Power system planning and operation is enduring a prompt change after deregulation of the electric-power industry. The main thrust behind these changes is to improve power plants' operating efficiency and to reduce the electricity cost. Further, the shift of current carbon-intensive and centralized electricity supply system towards a low-carbon, flexible, and responsive system would result in the evolving power networks. Network investment is costly, and its size depends upon the nature and location of future generation and load.

Generation and load investment levy different costs on the network operator, reflecting their location in the electricity network. Locational price offers received by the network users should replicate this cost. These locational price signals are provided to users through locationally differentiated transmission and distribution access charges. Network operators provide their network to users for energy transfer. The charges paid by the users for network usage are termed as use-of-system charges, reflecting both at transmission and distribution levels. Present research is focused on the Distribution Use-of-System (DUoS) charges at distribution levels.

This thesis uses traditional DUoS pricing model as the base model and contributes through various enhancements in the base model, to improve pricing signal offered to the users. In this regard, a smart network pricing mechanism has been proposed to mitigate network congestion and to provide effective network pricing signal to the users. Considering that future smart meters would measure a user's coincident peak demand, Contribution Factor (CF) based smart pricing signal for the users in Long Run Incremental Cost (LRIC) pricing framework is proposed. With this pricing approach, different category customers connected at the same node would face different network charges, based on their coincident demand.

Another contribution of this thesis is the development of a novel customer-specific DUoS charging model based on a hierarchical contribution factor model. This model distinguishes between different customer classes' contributions to the distribution network and all the way to the upstream assets. A novel concept of CF is proposed to evaluate contributions at two levels: i) contribution of the total load connected between any node to each upstream shared asset, and ii) contribution of customer class to the total load connected to any node. Thus, the ultimate goal of the proposed pricing scheme is to offer a customer class specific pricing signal for the distribution network users while incorporating CF to highlight users' contribution to network peak conditions besides the location-based signal.

Increased penetration of intermittent Renewable Generation (RG) would result in generation uncertainty and is likely to create congestion of varying quantum and temporal distribution in the distribution networks. Existing distribution network charging methodologies such as LRIC offer location-specific signal to users and charge them on the basis of their use-of-system. These methodologies can be modified using CF to reflect users' demand and their coincidence with peak network demand. RG is usually encouraged by relieving them from such contribution-based pricing signals. Congestion caused by intermittent RG could be mitigated by utilizing the flexibility of demand customers. In this regard, this work incorporates short-term Demand-Side Response (DSR) signal for customers in the modified LRIC pricing model to mitigate uncertainties caused by RG. These short-term DSR signals in the form of peak / off-peak charge offer, in conjunction with demand elasticity, help to assess customer response. This, in turn, results into modified load profile for various class customers connected at the nodes, which are used for evaluating network charges.

In the evolving power systems, Distributed Generation (DG) would change the grid planning and operating paradigm, creating power flow from lower to higher voltage levels as well. From the cost-causation point of view, DGs contribution to distribution asset utilization should be quantified. Considering this imminent challenge towards distribution networks, the thesis highlights the impact of generation contribution consideration to network utilization, along with load contribution consideration. This contribution is modeled as a load-to-asset contribution factor and generation-to-asset contribution factor for load and generation users, respectively. This assesses the impact of users' contribution during peak load on network investment.

In this thesis, the proposed models are applied to a 22-bus practical Indian reference network. All the proposed approaches are equally applicable to other test and practical networks in offering pricing signals.

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LIST OF SYMBOLS

The symbols used in the text have been defined at appropriate places, however for easy reference, the list of principle symbols is given below.

Symbol	**Explanation**
i	Index of customer sub-classes
j	Index of upstream asset
k	Index of nodes
m	Index of customer classes
d	Discount rate
r	Load growth rate
γ	Signal strength
ε	Price elasticity
r_{im}	Load growth rate for customer sub-class i of customer class m
AC_j	Modern equivalent cost of asset j
AF	Annuity factor
C_{kj}	Capacity of network asset j connected at node k
CD_{kj}	Coincident demand to network asset j connected at node k
CD_{kj}^{g}	Coincident generation to network asset j connected at node k
CF	Contribution factor for various categories
$CLCF_{im,k}$	Class-to-load contribution factor for customer sub-class i of customer class m connected at node k
D	Modified demand profile of customer class
D_o	Reference demand profile of customer class
D_p	Peak demand of customer class
ΔD_k	Power injection at the node k
$GACF_{kj}$	Generation-to-asset contribution factor for network asset j connected at node k
IC_{kj}	Annualized unit incremental cost of network asset j connected at node k
$IC_{im,kj}$	Annualized unit incremental cost of network asset j connected

	at node k due to customer sub-class i of customer class m
$L_{im,k1}, L_{im,k2}$	Two possible load profile of customer sub-class i of customer class m connected at node k
$LACF_{kj}$	Load-to-upstream asset contribution factor for network asset j connected at node k
$LRIC_k$	Long run incremental cost at the node k
n_{kj}	Time horizon required for reinforcement of network asset j connected at node k
$n_{im,kj}$	Time horizon required for reinforcement of network asset j connected at node k due to growth in customer sub-class i of customer class m
$n_{kj\ new}$	New time horizon required for reinforcement of network asset j connected at node k
$n_{im,kj}^{new}$	New time horizon required for reinforcement of network asset j connected at node k due to growth in customer sub-class i of customer class m
P	Time varying price offered to customers
P_o	Reference price
ΔP_{kj}	Power flow change through the network asset j connected at node k
P_{kj}	Current power flow through network asset j connected at node k
$P_{\max}$	Simultaneous maximum demand imposed on network
PV_{kj}	Present value of future investment for network asset j connected at node k
PV_{kj}^{old}	Present value of future investment for network asset j connected at node k with basic LRIC model
$PV_{im,kj}$	Present value of future investment for network asset j connected at node k due to customer sub-class i of customer class m
$PV_{kj\ new}$	New present value of future investment for network asset j connected at node k
$PV_{im,kj}^{new}$	New present value of future investment for network asset j connected at node k due to customer sub-class i of customer class m
ΔPV	Difference in annuitized present value of future reinforcement cost
ΔPV_{kj}	Change in present value of future investment for network asset

	j connected at node k
$\Delta PV_{im,kj}$	Change in present value of future investment for network asset j connected at node k due to customer sub-class i of customer class m
S_{k1}, S_{k2}	Two possible load profile at node k
t_p	Time of peak loading of upstream asset
t_q	Time of total load peak
t_s	Time of peak load occurrence of sub-class
TLC_k	Total LRIC charges for various categories users connected at node k
$TLC_{im,k}$	Total LRIC charges for customer sub-class i of customer class m connected at node k

LIST OF ABBREVIATIONS

The abbreviations used in the text have been defined at appropriate places, however, for easy reference, the list of abbreviations is given below.

Abbreviation	**Explanation**
CF	Contribution factor
CLCF	Class-to-load contribution factor
DG	Distributed generation
DNO	Distribution network operator
DRM	Distribution reinforcement model
DSR	Demand side response
DUoS	Distribution use-of-system
EHV	Extra high voltage
FCP	Forward cost pricing
GACF	Generation-to-asset contribution factor
GSP	Grid supply points
HCM	Hierarchical contribution factor model
HV	High voltage
ICRP	Investment cost related pricing
LACF	Load-to-asset contribution factor
LRAIC	Long run average incremental cost
LRIC	Long run incremental cost
LV	Low voltage
OFGEM	Office of Gas and Electricity Markets
PV	Photovoltaic
SG	Smart grid
SNP	Smart network pricing
UMIST	University of Manchester Institute of Science and Technology
UK	United Kingdom

Chapter 1

Introduction

THIS chapter briefly describes the background, problem statement and rationale of study, motivation, objectives, and contribution for this work. It also provides the structure of the thesis.

Chapter – 1

INTRODUCTION

1.1 Background

Liberalization of the electric power industry intends to bring competition in the field of electricity generation and supply. However, electricity distribution and transmission are natural monopolies. Due to the characteristics of electricity, its production and consumption must take place concurrently, as storage possibilities are still insufficient or expensive. Competitive activities in the sector (generation and sales), therefore are dependent on natural monopolies (distribution and transmission networks) [1-2]. Hence, network portions of the system require regulation to restrict them from exercising their market power. Regulatory mechanisms boost power distribution efficiency to provide better services to end-consumers. Successful regulation of distribution utilities would keep tariffs reasonable, which in turn encourages competition in the energy supply portion of the sectors [3].

Network operator provides various services to its customers, *viz.* connection to the main system, transport of power, security, and ancillary services for stable power system operation. This causes a significant cost to the network operator. The cost includes operation and maintenance cost of the asset for providing the connection to the network and use of system, along with the cost of losses. The cost of offering these services is levied by the network operator in the form of prices to customers. Network pricing has become a critical issue in the evolving power industry, due to the monopolistic nature of the transmission and distribution business [4]. Network pricing represents the mechanism to allocate network and associated circuitry cost involved in transferring power from source to the load. The cost is allocated to all the network users for their network usage.

The main objective of network pricing is to ensure economic efficiency, *i.e.*, it should give an efficient economic signal to network users. Apart from this, network prices must recover the revenue approved by the authorities and provide clear signals for efficient location. Further, prices should not be excessively volatile, and there should be some limits on ‘price shock’ for individual end users [5-6]. Moreover, the determination of these prices must be transparent, auditable, and the pricing regime must be practical to implement. Prices should promote competition in contestable upstream and downstream markets while fostering access for third parties [7].

Electricity network pricing is a complex issue, and use of a single pricing methodology for all circumstances is not possible. Each methodology has its particular benefits and pitfalls. Different pricing methodologies are suitable for different circumstances and different prerequisite under which network facilities are being provided. Transmission networks are complicated in both configuration and operation. Moreover, generation sources are usually situated at a far location from load centers, and therefore the bulk power flows across the transmission networks [5]. So, transmission charging methodologies aim to encourage efficient investment in generation and transmission, along with ensuring efficient network operation.

In contrast to transmission networks, distribution networks are characterized by numerous nodes and less complicated network. Hence simple and approximate charging methodologies could be used for distribution networks. However, in the case of distribution networks implementation issues are more important, and the prerequisites for sophisticated charging methodologies to achieve economic efficiency are less important [8-9]. Considering such inherent differences, various pricing models have been developed in the literature for transmission and distribution network pricing. Further, energy transportation cost through distribution network would escalate in the future, as distributed energy resources grow appreciably in response to the government thrust on low carbon economy. This cost can be minimized by developing an appropriate pricing scheme to alter the location and consumption pattern of existing and new network users. Thus, the present thesis focuses on the development of pricing models for distribution networks.

1.2 Problem Statement and Rationale of Study

Distribution network charging comprises of two major tasks: global remuneration for the distribution utility, and tariff setting by the allocation of the total cost among all network service users [8]. Distribution Use of System (DUoS) charges are the charges against network users for their network usage. Such charges are set to recover the capital, operation, and maintenance cost of the network. DUoS charges comprise of fixed charges, demand charges, capacity charges, and volume charges. Fixed charges reflect the cost of connected assets dedicated to the use of the single customer. Demand charges reflect the incremental cost of a shared network, including the cost of providing additional capacity units. Capacity charges recover DUoS charges that are not recovered through the incremental cost- based demand charges. Volume charges reflect the cost per unit energy delivered in a given period. Space and time differentiation should be applied to cost drivers while establishing a pricing methodology. So, a single charge for energy and power consumed cannot be defined as these charges depend upon the type of customer and the time of consumption.

As the distribution of electricity is a service that is differentiated in space and time, therefore cost causality requires that price signals should be differentiated accordingly. Network charges must have some level of time differentiation so that the economic impact of network usage diversity at different times is recognized [10]. However, the end user's behavior is determined by retail prices and indirectly by the network prices. Retailers often incorporate time-varying network charges in their retail tariffs, but their effects are diluted because other costs significantly impact final retail charges. This tends to smoothen wholesale power price variations. Consequently, time-varying network charges that vary significantly over the peak and off-peak periods would reflect much smaller price differentiation at the retail level [11]. Such differentiation should be considered while developing a pricing mechanism for distribution networks to improve pricing signal offered to network users.

Increasing penetration of distributed energy resources (namely distributed generation, energy storage, and electric vehicles) in the distribution system leads to bidirectional power flows. Traditional network pricing methods don't reflect actual network usage cost for such conditions. Further, a move towards low carbon economy necessitates active demand-side participation to balance intermittent generation and reduce network constraints. Therefore, it is necessary to develop new pricing methods suitable for the evolving power system paradigm. The key concern is whether there is appropriate geographical variation in the charging mechanisms to produce effective signals for the location of demand and renewable generation. Accordingly network operators should improve network-charging methods to meet these challenges. A good charging structure offered to distribution network users could incentivize them to shift their demand to reduce network loading and thus delay necessary network upgrades.

1.3 Motivation for Present Work

Network pricing mechanisms aim to recover revenue for a distribution network utility based on an economic pricing model. A good pricing structure reflects industry regulation and is an instrument to offer users an efficient economic signal. Network price offers impact customer behaviour regarding their location and future consumption pattern [12-13]. Distribution network charges can be calculated ex-ante through various pricing models, *viz.* Distribution Reinforcement Model (DRM), University of Manchester Institute of Science and Technology (UMIST), Investment Cost Related Pricing (ICRP), Long Run Incremental Cost Pricing (LRIC), and Forward Cost Pricing (FCP). Among these models, LRIC is the most advanced pricing model with a verified potential to save hundreds of millions of pounds in terms of investment [14-15]. Further, network security, nodal unreliability tolerance, network component reliability, and uncertain load growth rate has been integrated with LRIC pricing [16-18]. These DUoS charging methodologies further need to be modified considering the evolving electricity market scenario.

Smart Grid (SG) environment can offer innovative mechanisms for efficient network management to relieve the network presently reeling under congestion. Network charges form one of the components of electricity charges which vary with customer segmentation. Customers of similar category usually vary in a similar fashion and impact network congestion in consonance. Two different category users pay the same charges connected at the same node as their contribution to network peak is ignored. There should be a price differentiation for network users (various consumer categories) depending on their contribution to network usage during network peak demand. In the SG era, coincident demand measuring network management systems are available. Hence, customer category contributions to network peak could be determined.

Load on the network can be classified into customer classes to reflect their profile diversity. These customer classes can be further classified into sub-classes based on the nature of customers, tariff types, and loading levels. Due to differing load profiles, it is complicated to identify the impact of various customer classes on distribution network peak. The effect of customer classes on distribution network may vary considerably. Charges for distribution network services depend on some measures of customer contribution to load during peak system demand [19-20]. Traditional DUoS charging methods consider that all customers similarly use the network and do not take into account the timing of their peak demand; this has a significant impact on network reinforcement. Each customer class contribution to peak system demand affects network investment, and hence could be reflected in DUoS charges.

Countries worldwide are under an obligation to reduce their carbon footprints. As a consequence, low-carbon technologies such as renewable generation are incentivized to integrate with existing power systems. Intermittent nature of renewables increases system planning uncertainty and negatively impacts the operation of network infrastructure, both at the transmission and distribution levels [21]. To accommodate these uncertainties, the enhancement of existing pricing methodologies is essential.

Distributed generators are offered negative charges (reward/credit) for their network usage. This reflects the benefit to the network by reducing line flows because of reverse flow injection by Distributed Generation (DG) [22]. The contribution of injected generation to the upstream asset in the network peak usage could be determined to reflect a justified pricing signal. So, contribution based pricing signal could be given to generators located at various nodes.

1.4 Objectives of the Study

The main objective of the present research work is to explore existing network pricing practices and enhance these methodologies to offer pricing signals to users, considering their actual network usage.

Specifically, this research work aims to achieve the following objectives.

i. Develop a smart network pricing model using the Contribution Factor (CF) based pricing signal for various customer categories.

Traditional network infrastructure cannot track coincident network usage. In SG environment, network cost component could be reflected as a component of smart network prices when actual network usage is known. Smart meters at various network levels can capture user’s contributions to network peak demand and can be used to compute network usage charges. Considering the prospective application of SG for Smart Network Pricing (SNP), a part of this thesis proposes a CF-based SNP model of LRIC pricing, where the CF is reflective of customer categories’ contribution to network peak.

ii. Develop a novel hierarchical contribution model based on CF to offer a customer class-specific locational signal to network users.

Existing DUoS charging approaches in the literature offer location-specific signal to customers and charges them based on their use-of-system. However, these models do not differentiate between various customer classes' contributions to the distribution network peak flow. A contribution of this thesis is to propose a hierarchical CF based model to offer a customer class-specific locational signal. This considers various customer class contributions to network peak demand using Load-to-Upstream Asset Contribution Factor (LACF) and Class-to-Load Contribution Factor (CLCF). CF's considered at two levels determine customer classes' effective contribution to asset reinforcements for evaluation of distribution network prices. The proposed model provides a forward-looking economic signal which encourages customer classes to improve their load profile and reduce their contribution to distribution network peaks.

iii. Enhance LRIC pricing methodology incorporating short-term demand-side response signal for demand customers to manage variability caused by renewable generation.

With the large-scale integration of renewable generation, a quantum increase in responsive load is expected to benefit from significant renewable generation supply. Such load responds to energy prices at Grid Supply Point (GSP) leading to congestion in distribution networks during high renewable generation. To mitigate such challenges, existing LRIC pricing approach is enhanced in this work by offering pricing signals based on time differentiated network utilization. This work also considers the contribution of customer-class usage to peak network usage, to reflect class contributions to network peak usage at various network levels. Considering demand flexibility, a time-of-use tariff is offered to users at various locations, and network tariff is evaluated with a modified profile scenario along with CF consideration to reflect actual usage. The offered pricing approach triggers the behavioural change in network users, in response to time-varying charges. This approach would eventually alleviate network congestion and delay investment.

iv. Enhance LRIC pricing methodology to provide pricing signal to network users based on the contribution of generation and load located at various nodes, to network peak of each upstream asset.

Traditional distribution network pricing approaches like LRIC offer location-specific signals to network users, *i.e.*, for both the generator and load. These methodologies consider maximum generation and load at the connection node that may not be coincident with distribution network upstream asset peak demand. As a result, it fails to reflect the user's actual contribution to drive distribution network reinforcement. The final contribution of this thesis is to enhance existing LRIC pricing model by considering the contribution of generation users to network peak of each upstream asset.

1.5 Contribution of Present Work

The present research work includes a study of the fundamentals of power system restructuring and proposes enhanced distribution network pricing methodologies for systems with high renewable penetration in an SG environment.

The main contributions of the present research are to propose:

i. A CF based smart network pricing model of LRIC pricing, where CF is reflective of customer categories' contribution to network peak usage.

ii. A novel hierarchical contribution model based on CF to reflect actual propagation of the key reinforcement driver within a distribution network. This model considers the contribution of customer class load on network peak rather than merely considering peak flow of a customer class. Thus it reflects the actual impact of customer class load on network reinforcement requirement.

iii. An enhanced LRIC pricing methodology to facilitate short-term Demand-Side Response (DSR) for managing variability caused by renewable generation.

iv. An enhanced LRIC pricing considering generation and load contributions to distribution network peak flow in upstream assets.

1.6 Scope and Limitation

This thesis is dedicated towards developing and enhancing DUoS pricing models to offer improved pricing signal to users. The pricing model proposed in this thesis cannot take up real-world distribution pricing challenges. Network pricing volatility could not be mitigated in the present scenario. The models can be further extended to incorporate uncertainty associated with EV, energy storage, and local power exchanges. Impact of different generation technologies on network peak usage could be assessed while evaluating network charges for both generator and load located at various nodes.

1.7 Organization of the Thesis

This thesis starts with the background of network pricing followed by outlining research gaps and the motivation for carrying out research in the area of distribution network pricing. The entire structure of the thesis is illustrated in Fig. 1.1. This thesis has six chapters including "Introduction" as the first chapter. Rest of the thesis chapters are organized as follows:

Chapter 2 offers an overview of the electric power industry, distribution network business and various country practices adopted for network pricing, along with underlining the necessary process adopted for obtaining network charges. Further, different approaches used for the pricing of distribution networks to recover investment cost are illustrated. The challenges appearing in distribution pricing and the necessity for various enhancements in LRIC pricing model are also discussed.

Chapter 3 proposes a smart network pricing mechanism to provide effective network pricing signal to various customer categories for reflecting network congestion. Considering that future smart meters could measure a user's coincident peak demand, the user is offered with CF based smart pricing signal in LRIC pricing framework. The price signal would encourage various category users to modify their demand profile, to minimize their contribution to network congestion.

Chapter 4 proposes a novel Hierarchical Contribution Factor based Model (HCM) which distinguishes between different customer classes' contributions to the network peak of all the upstream distribution network assets. This model considers customer class's contribution to network peak flow in evaluating network charges, rather than considering the customer class's peak as considered in basic LRIC model. Considerations of customer classes' contribution to network peak conditions impose charges based on their actual network usage. A novel concept of CF is proposed to evaluate contributions at two levels: i) contribution of the total load connected at any node to each upstream shared asset, and ii) contribution of customer class to the total load connected to any node. Based on HCM model, the customer-specific DUoS charging model is implemented using basic LRIC approach. The proposed approach encourages various customer classes to modify their distribution network usage pattern. This helps to minimize network peaks, eventually delaying network investment. The ultimate goal of the proposed pricing scheme is to offer a customer class specific pricing signal to the distribution network users, which incorporates CF to highlight users' contribution to network peak conditions besides the location-based signal.

Chapter 5 proposes a modified LRIC pricing model that incorporates short-term DSR signal for demand customers, to mitigate uncertainties caused by renewables. Time-of-use pricing is used for short term DSR mechanism. The short-term DSR signals in the form of peak/off-peak charge offered in conjunction with demand elasticity, helps to modify customer response. This results in a modified load profile for various class customers at the nodes, which is used to evaluate network charges. The proposed approach is applied to a 22-bus practical Indian reference network. Results from the modified LRIC pricing model encourage users to change their short-term consumption pattern and help network owners to alleviate congestion and minimize network investment.

Chapter 6 improves traditional LRIC pricing approach to offer network peak contribution-based signal, along with providing a location-specific signal. This work considers generation and load contribution to network peak demand for determining distribution network prices. These contributions are determined using the Load-to-Upstream Asset Contribution Factor (LACF) and Generation-to-Upstream Asset Contribution Factor (GACF). Consideration of these factors determines generation and load's effective contribution to asset reinforcements for supplying power.

Chapter 7 concludes the major findings of this thesis. A summary of the results shown in Chapter 3-6 of the thesis is also presented. Finally, the future scope of the work in the area of distribution network pricing has been discussed.

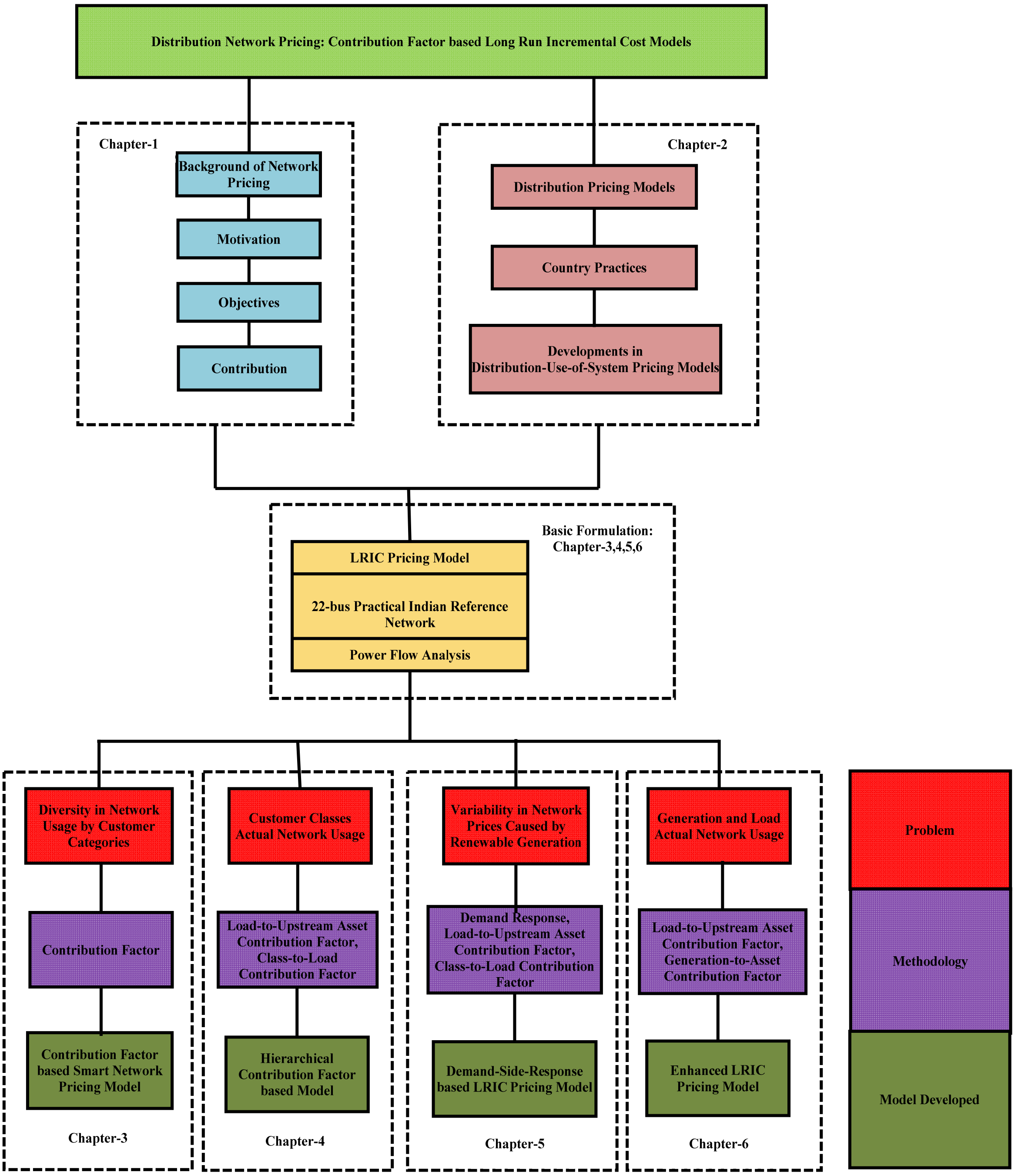


Fig. 1.1 Thesis Structure

Chapter 2

Literature Review

T**HIS** chapter starts with background of distribution network pricing. This includes structure of electric power industry, distribution business, and distribution pricing process. Further various distribution pricing methodologies are described. Then distribution network pricing practices in different countries are reviewed. Finally developments made in distribution use-of-system pricing are discussed.

Chapter – 2

LITERATURE REVIEW

2.1 Introduction

Network pricing has become a critical issue with the deregulation of the electric power industry. This aims to offer locational signal to network users to connect at appropriate locations on the distribution network. The pricing signal incentivizes the network users, *i.e.*, both generators and loads to connect at network points for which future network reinforcement costs would be minimal. This would result in a minimal network investment requirement for meeting a specified load. Various distribution network pricing mechanisms have been modelled in the literature considering a distinct load growth for customers. These pricing methodologies assume that all customers consume energy in a similar way within a distribution network and follow an aggregated load profile. However, the end users consume energy in a different manner and have diverse contributions to network reinforcement. It is critical to develop new pricing models to send a customer-specific signal to users. Over the years, a variety of changes have happened in the distribution networks. Renewable penetration on the distribution networks is increasing with time considering the thrust of government policies worldwide [2, 13]. This creates a need to modify traditional network pricing methodologies to reflect the cost of such penetration. Therefore, the main focus of this thesis is to accommodate such challenges and offer justified pricing signals to users by improving existing network pricing approaches.

Before discussing the contribution of research work covered in this thesis, it is desirable to understand the basics of network pricing problem. This chapter provides a background on electric power industry structure, distribution network business, objectives of network pricing, and overall network pricing process in Section 2.2. Difference between transmission and distribution pricing methodologies is also presented in this section. Further, detailed literature of distribution network pricing methodologies widely used for network cost allocation is discussed in Section 2.3. Section 2.4 gives a brief description of distribution network pricing practices adopted in different countries. This chapter also highlights the developments made in the

DUoS charging models in Section 2.5 for a better understanding of the work contribution.

2.2 Background of Distribution Network Pricing

As the electric power industry disaggregates from its vertically integrated structure, power generation, transmission, and distribution are being handled by three separate entities. The structure of power industry before and after the restructuring is shown in Fig 2.1. The primary purpose of unbundling was to induce competition in the electric power industry. Further, the segments of the electric power industry were regulated, where competition was not considered feasible. This was further expected to reduce electricity prices and improve the performance of the electricity supply industry while maintaining the security and quality of supply. In the deregulated industry, generation and supply became a pivot with the potential to develop into competitive businesses [23]. Ownership and operation of the transmission and distribution networks were viewed as natural monopolies, and their actions and business revenue inevitably require independent centrally administered regulation [10].

Planning and operation of electricity networks are experiencing quick change after deregulation. A primary aim of these changes is to improve the operational efficiency of power supply systems and to decrease the electricity costs. Additional changes are also occurring due to social and government pressure for reducing carbon emissions. These changes further create substantial technical, commercial, and regulatory challenges. Power supply networks transmit electricity from the production to consumption points. Users of the network, *viz.* generating companies, large customers, and suppliers in reality produce and consume the electricity carried by these networks [3].

Traditionally, the business functions of distribution and retailing were performed by a single utility. They are becoming separate licensed activities over a period of time. Retailing is also termed as supply and involves purchasing large quantum of electricity at the wholesale level for selling it to the end users. This activity becomes critical in competitive markets created due to deregulation of the power industry. This is a deregulated activity and is driven by market forces [24]. Distribution is traditionally linked to the transport of electricity from High Voltage (HV) substation to the end users located at lower voltages. This distribution network business or

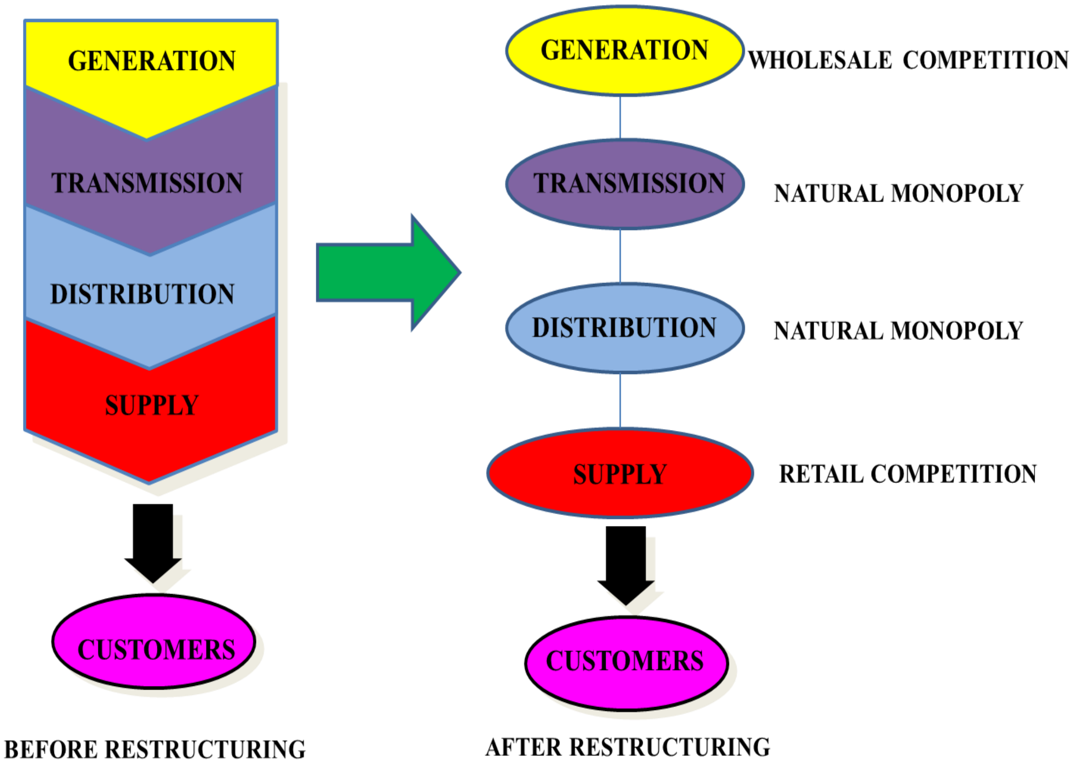


Fig. 2.1. Structure of electric power industry

merely distribution is a natural monopoly and needs to be regulated [25].

The erstwhile paradigm of regulation or rate-of-return regulation defines utility rate base and then sets the price. This regulation ensures a fair return on capital for the utilities and recovery of its operation cost. Further, performance-based regulation has evolved to incentivize distribution companies to be more efficient [21]. This includes a variety of mechanisms, *viz.* price cap, revenue cap, and yardstick regulation. In price cap regulation, regulator set caps on prices that the utility is allowed to charge. These prices are updated periodically to consider inflation and investment in technological advancement by the utility. Under revenue cap regulation, utility revenue is fixed by a formula that is further adjusted to consider inflation and efficiency improvements. In yardstick regulation, the tariff structure is determined from a comparison with peer suppliers. Utility rewards or penalties are based on the selected dimensions of service performance. This brings an element of competition into regulation, although imperfectly [20].

Commercial relationships and flow of payments between the entities involved in distribution business *viz.* customer, retailer, and distributor are shown in Fig. 2.2. The

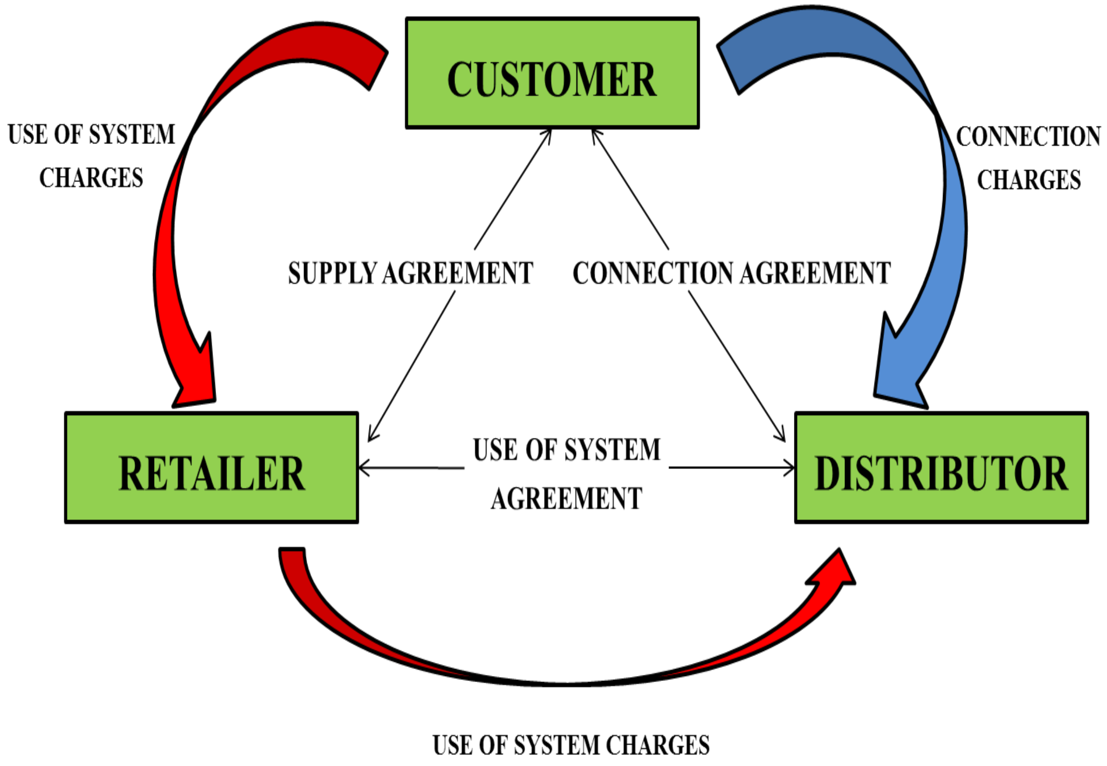


Fig. 2.2. Distribution business cashflows [26]

business relationships between these entities are shown by a set of three bilateral contracts: supply agreement, connection agreement, and use of system agreement. Supply agreement exists between the customer and the retailer in which energy purchased by the retailer is sold to customer. Use of system agreement exists between the retailer and the distributor, and this agreement sets the condition and provision for the use of distribution system. Connection agreement lies between the customer and the distributor, and this agreement formalizes the terms and condition of connection to the distribution network. Payment flows between these participants in the form of connection and use of system charges [26]. It can be seen that the retailer is not usually directly involved with payment and arrangements to provide the connection. Rather, the business of making the physical connection to the network is the responsibility of the distributor and charges for this are levied by the distributor directly to the connectee. Among their responsibilities, distributors are permitted to maintain and cultivate economic, proficient, and coordinated networks. Moreover, they have to ensure the reliable supply of electricity, promptly restore power in the event of outages, and connect new users, *i.e.*, both the load and generators, to their network rapidly and efficiently [23].

In a deregulated environment, there is an absolute need to determine separate prices for energy supply, transmission, and distribution network use. Due to the monopolistic nature of transmission and distribution business, network pricing has become a critical issue in this evolving power industry structure [4]. Network pricing represents the mechanism of allocation of network and associated circuitry cost involved in transferring power from the source to load. The cost is allocated among all the users of the network for their network usage [15]. The network pricing mechanism aims to recover revenue requirement for the network utility based on some pricing model and hence gives an efficient economic signal to the user. This influences customer behavior for their location and consumption pattern [27].

The fundamental principle of a network pricing approach is to allocate all or a part of the existing and new costs of a network to the network users. While allocating network cost among its users, the following objectives should be adopted [7, 28].

i. Economic Efficiency

Network charges should reflect the actual economic cost of providing network services. Economic efficiency refers to the efficiency with which the existing resources are allocated between competing users. This depends largely on input and output prices to reflect their economic cost. This can be achieved by cost-reflective charges allowing network service providers and customers to improve decisions about production and consumption of resources. Economically efficient pricing signal make customers and the distribution companies to behave such that they maximize social welfare both in the short term and the long term.

ii. Revenue Recovery

Network tariff should produce appropriate revenue for the utility. Revenue should be commercially sustainable, and the prices are set accordingly. Revenue recovered for the network services should recover all the expense incurred in the investment, operation, and maintenance and also offer a regulated level of profit.

iii. Simplicity

The pricing approach should be simple to be easily understood by network users. Although the implementation of the respective pricing methodologies might not be easy, the pricing scheme should be simple to understand.

iv. Non-discrimination

Network prices should be same for the users with same location and usage characteristics. Charge differentiation between users on the basis of cost will not be effective in incentivizing users to diminish activities causing such cost.

v. Transparency

Network charges should be transparent so that a user can access the information to understand the whole process of determining charges. In addition to the above-discussed objectives, the network prices should be stable to avoid any risk for operator and users. Also, the network charges should ideally be easy to implement and follow an economic prediction, as this is important for all network participants to be able to forecast the future cost of network usage. Although the broad objectives of distribution network pricing are the same as those for transmission network pricing, yet the pricing models developed for distribution networks are fundamentally different from those developed for transmission networks. This happens due to differences in nature of the network and the eventual aim of these pricing mechanisms as shown in

Table 2.1

Difference between transmission and distribution network pricing methodologies

S. No.	Transmission Network Pricing	Distribution Network Pricing
1.	Although transmission networks are relatively simple compared to the distribution network, but complex methodologies are used to determining prices.	These networks have a large number of nodes, but require simpler methodologies to determine prices.
2.	Prices are determined on an actual network.	Prices are determined on a benchmark reference network.
3.	Due to the large user's strong ability to respond to the price signal, economic efficiency issue is important.	Due to complex network structures, implementation issues are important.
4.	Transmission pricing models give exact charges for the nodes.	Distribution pricing models give approximate charges for the nodes.
5.	In the transmission pricing model, marginal/incremental costs are expressed relative to a "slack node".	In distribution pricing, each grid supply point is effectively a "slack node" and would have a zero cost associated with the connection of generation or demand at this point.

Table 2.1. Distribution networks have a significant number of nodes that create complexity in computing the charges for individual nodes. Hence, distribution pricing models are typically visualized on a benchmark reference network rather than the actual network. This way the distribution pricing models calculate approximate charges for the nodes, whereas the transmission pricing models give exact charges for the nodes. Due to the complex network structure of distribution networks, implementation issues are more important than the need for the sophisticated charging methodologies to achieve economic efficiency. Hence, distribution network pricing models are relatively simpler as compared to transmission network pricing models [8].

Network pricing process consists of three stages, namely cost evaluation, cost allocation, and revenue reconciliation, as shown in Fig. 2.3. The first is a technical issue, the second is an economic issue, and the third is a regulatory issue [29]. Costing or cost evaluation reflects the costs that are to be allocated, like embedded, marginal, and incremental. Embedded cost refers to the cost of all facilities required to pay for using network infrastructure. Marginal cost refers to the cost of all new facilities needed in the network to serve users. The customer needs to pay an allocated share of the cost for any new facilities that the system requires. Incremental cost reflects the cost of any new facility specifically attributable to serve a particular customer. The customer pays the full cost for any new facilities that the transaction requires [30]. Cost allocation reflects the methods by which the cost can be allocated among users. Once the network cost is evaluated, it can be allocated through a number of methods such as DRM [31-33], ICRP [33-35], MW+MVAr-Mile [36-37], Long Run Marginal Cost (LRMC) [38-41], and LRIC [38-39, 42] method.

Incremental and marginal cost-based approaches may not be able to recover the revenue permissible for the network operator. Hence, revenue reconciliation is usually required to adjust the prices so that the revenue recovered from network charges can achieve the set target [29]. The commonly used revenue reconciliation approaches to adjust the nodal prices are fixed adder, fixed multiplier, reliability sensitive adder, and elasticity sensitive adder (Ramsey method). The fixed adder method adds/subtracts a constant amount to/from the nodal charges to make up for the revenue shortfall/surplus. The multiplier method scales the nodal charges by a constant factor, corresponding to the ratio of the target revenue to the recovered revenue. Reliability sensitive adder allocates the revenue shortfall into each hour of the year, in proportion

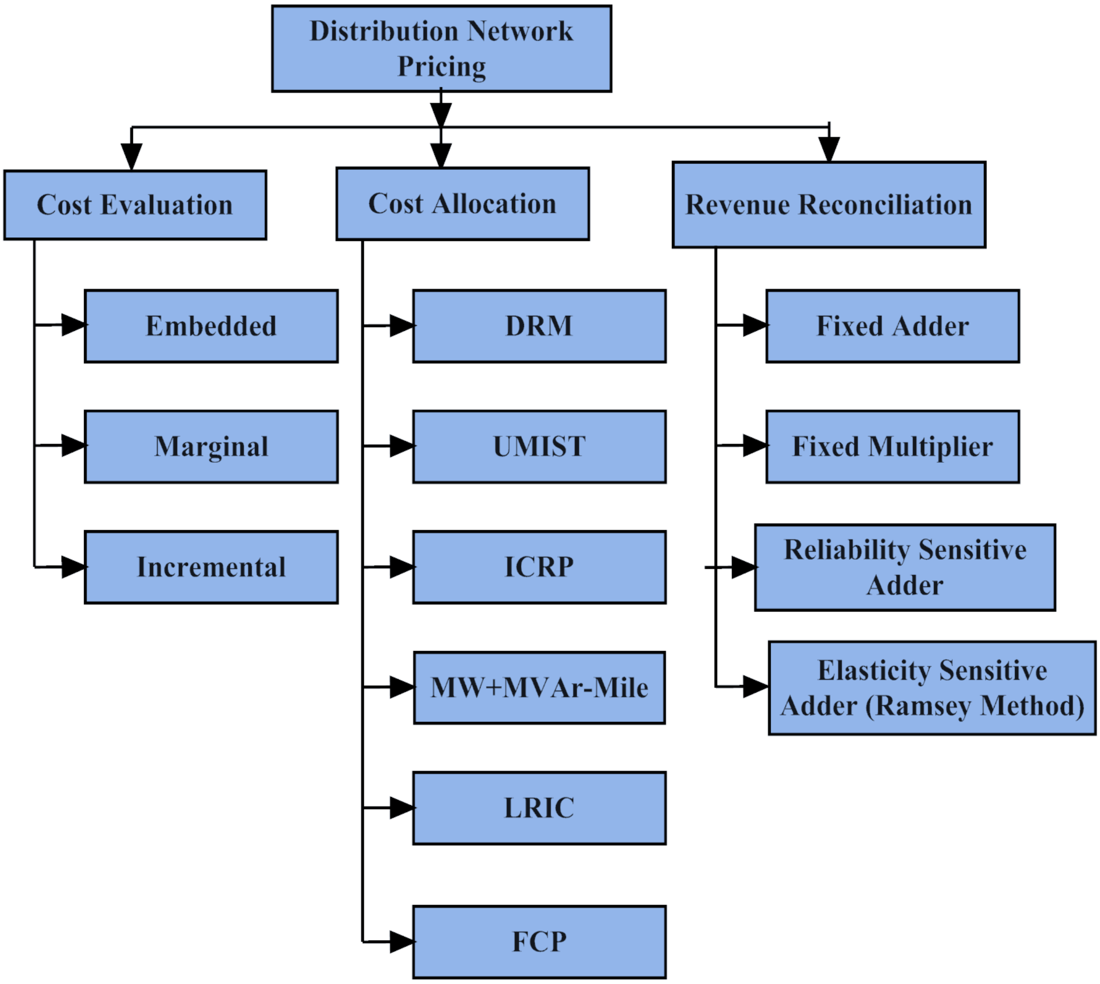


Fig. 2.3. Distribution network pricing process

to some measure of the system reliability in that hour. Loss of load probability is used as a measure of reliability. This method of revenue reconciliation is called the loss of load probability method of allocation. Ramsey method is economically efficient in maximizing social welfare under certain conditions. In the Ramsey method which is also known as the inverse elasticity rule, the marginal price is adjusted to each user in inverse proportion to the price elasticity of demand at the time of their use, but it is a smaller value as the inverse elasticity of demand is multiplied by a constant lower than unity [43-45].

2.3 Distribution Network Pricing Methodologies

The pricing methodologies for distribution system include DRM, UMIST, ICRP, LRIC, MW+MVAr-Mile, and FCP. These pricing methodologies are discussed hence in detail and are summarized in Table 2.2.

2.3.1 Distribution Reinforcement Model

DRM is a hypothetical, independent network and designed as an extension to the existing network. In modeling terms, this model does not fully simulate the actual network rather aims to simulate a scaled down version. This models the cost of providing distribution network service and doesn't model the physical electrical capability of the technical performance of the network. The model allocates the cost of accommodating an increment of 500 MW in the network maximum demand at each voltage level. Therefore, DRM represents most closely an average cost for customers at given voltage levels during peak demand within the marginal 500 MW increment [31-32]. Under this methodology, the load incurs charges that reflect the system elements at the voltage of connection and higher voltages. It is a characteristic of the reference network that charges seen by the load connected to each Extra High Voltage (EHV) bus-bar will be broadly similar.

This model contains asset at modern equivalent prices (current costs) which are based on a scaled representation of the Distribution Network Operators (DNO's) complete network or their network planning or a simulated system. Yardsticks (£/kW) are calculated from the DRM for each voltage level. The model can't be considered efficient due to its failure to accommodate use-of-system charges for the generation. The DRM model is voltage based and does not consider locational factors. It was set up only to take into account the cost needed to meet incremental demand (500MW simultaneous maximum demand) assuming that power flows from grid supply points at HV to customers at lower voltage levels [33]. DRM calculates capital cost annuities over a fixed, notional, lifespan-typically 40 years. This means that the yardstick prices emerging from DRM include a provision for ongoing asset replacement. Distribution use of system charges doesn't reduce the asset age and charges are based on the average age of the network asset base.

DRM is simple to implement but does not produce charges for generation, and it does not deal with the temporal variation or the effect of multidirectional flows on the system. Rather, this model assumes that the assets at all voltage levels above the point of connection are utilized by the connected party [46-47].

Table 2.2

Distribution network pricing methodologies

Pricing Method	Key Characteristics	Advantages	Disadvantages
DRM	• Assumes that assets for all voltage level above the point of connection are utilized • Only voltage level of connection is considered but not topology of network	• Due to simplicity, used as a benchmark against other models to be compared	• Use of system charges for DG can't be derived • Can't deal reverse flows
UMIST	• Calculates charges for both demand and DG • Produces nodal charges rather than average prices	• Recognises interaction between generation and demand • Network topology is considered	• Can't produce reactive power charges • Doesn't consider limitations created by voltage considerations or fault level
ICRP	• Determines incremental cost on the network due to nodal increment/decrement • Considers distance of power flows	• Produces symmetrical charges for both load and generation	• Doesn't recognize the degree of asset loading
MW + MVAr-Mile	• Allocates cost based on the extent of use of network facilities • Provides incentives to users for contributing to better power factor and network utilization • Penalizes for worsening power factor and network utilization	• Separate pricing of real and reactive power help users to evaluate the economics of investing in reactive power compensation devices	• Doesn't discriminate between users who incur additional operating costs or network reinforcement and expansion cost
LRIC	• Considers both distances of power flow and circuit utilisation • Capable of reflecting the impact of positive, negative, and zero load growth rates • Considers reliability, security, and uncertain growth rates	• Produces forward-looking pricing signal • Replicates the extent of network usage	• Doesn't consider the impact of load profile • Model complexity and data magnitude may present practical difficulties with its publication
FCP	• Average pricing model that evaluates cost over the next ten years & allocates to all existing and forecasted future demand and generation. • Considers annuity based on cost recovery period instead of asset lifetime • Treats demand and generation differently.	• Capability to use publicly available data and third-party assumptions in deriving charges • Can be applied for low voltage level 33/11 kV	• Provides relatively weaker locational signal than LRIC • Not appropriate for low utilized network

2.3.2 University of Manchester Institute of Science and Technology Model

This approach is based on the system that reflects real network data for the 132kV and 33kV voltage levels but uses a simplified reference network at 11kV and low voltage (LV). Power flows are run on this network for two scenarios. The first scenario considers the time of maximum demand and minimum generation, while the second one considers the period of minimum demand and maximum generation. A DC load flow algorithm is employed for obtaining charges and is used to find the critical loading of each asset in the network [48]. If the largest power flow occurs at the time of maximum demand, then the asset is known as "demand dominated". On the other hand, if the highest power flow occurs at the time of maximum generation, then the asset is considered as "generation dominated".

The charges for the generator connected at any location on the network are determined by recognizing the costs of upstream assets that are generation dominated but crediting the cost of the upstream assets and circuits that are demand dominated. This charge is applied to the maximum rated output of the generator. Conversely, the charges for load are calculated in terms of the costs of upstream assets that are demand dominated and crediting the costs that are generation dominated. The net charge is then applied to the metered maximum demand [49].

DRM's weakness was rectified in UMIST model, as it recognizes the interaction of generation and demand. It produces nodal charges for generation and demand considering the critical power flow scenarios for network design. This model does not consider the individuality of asset and treats generation and demand in the same manner, which has a different impact on the network [32].

2.3.3 Investment Cost Related Pricing Model

ICRP approach reflects the cost of meeting an increment of demand or generation at each node on the reference network. ICRP charges are derived from the incremental cost of accommodating a 1 MW increment at each study node. The essence of the model is to identify those circuits that support the injection or withdrawal of power from a study node and the power flows in those circuits will be affected by a unit power change at the node [33]. The long-run marginal price at any node is determined as the product of power change through each supporting circuit, and the unit cost over the supported circuits [34].

Two assumptions are generally taken into consideration while evaluating ICRP charges. First, it is assumed that the existing network is fully used. Any nodal increment will thus necessitate immediate network reinforcement [50]. Hence, it doesn't respect the amount of network utilization. Second, it assumes that the circuit is infinitely divisible and therefore an additional 1 MW power flow can be met by the addition of an asset with 1 MW rating.

ICRP derived marginal costs are expressed relative to a reference node, generally denoted as the "slack node", where the marginal cost of connecting load or generation is zero. In its applicability to a distribution system, the ICRP model recognizes all GSP as "slack nodes" because at these locations no cost is incurred for connecting load or generation. Thus, ICRP derived charges will always be relative to the GSP [51].

2.3.4 MW+MVAr-Miles Model

The extent of network use is reflected in MW+MVAr-Miles based distribution charging methodology accounting for both real and reactive power flows [36-37]. This rewards network users for contributing to better power factor and better network utilization while penalizing customers for worsening power factor and network utilization. As a consequence, this model can provide forward-looking economic signals to encourage network users for improving network condition. The separate pricing of real and reactive power gives network users strong signals for the cost of reactive power drawn from the network. This consecutively could help them to estimate the economics in spending for reactive power compensation devices [27].

The usage-based approaches are not economically effective since they do not differentiate between the customers for incurring extra operating costs or network reinforcement and expansion cost. Incremental/marginal charging methodologies have the potential to overcome this drawback [35].

2.3.5 Long Run Incremental Cost Pricing Model

LRIC model reflects the cost of advancing or deferring future investment, consequent upon the addition of generation or load at each node on the network. In this approach, the network charges are determined as the difference in the present value of future reinforcement subsequent upon the nodal power perturbation for generation or demand [33, 35]. The basic concept behind evaluating LRIC pricing is shown in Fig.

2.4. The model provides a forward-looking economic pricing signal to influence the development of future generation/demand. This could help the network planners or operators to form a more realistic projection of the future generation/demand patterns in forward planning their networks.

The LRIC model can reflect the impact of positive, negative, zero load growth rates, and fault growth rate with the connection of DG on network charges [52-54]. Further, the network security, nodal unreliability tolerance, network component reliability, and uncertain load growth rate can be integrated with LRIC pricing [16-18]. The low-carbon technologies such as wind power, solar generation, electric vehicles (EV's), heat pumps, and energy storage devices bring uncertainties to network planning due to their intermittency/unbounded increase. The situation is further complicated by the fact that the individual behavior change of some users can affect network utilization and consequently the network planning and tariffs for other users. To reduce the risk in the use of system charges for network users, the long-term contracts have been designed to mitigate the risk [55].

The mathematical formulation for calculating network charges using the basic LRIC model is given as follows [35].

i. Deriving the time horizon for future reinforcement

For the network asset j supplying node k having a capacity of C_{kj} and supporting a

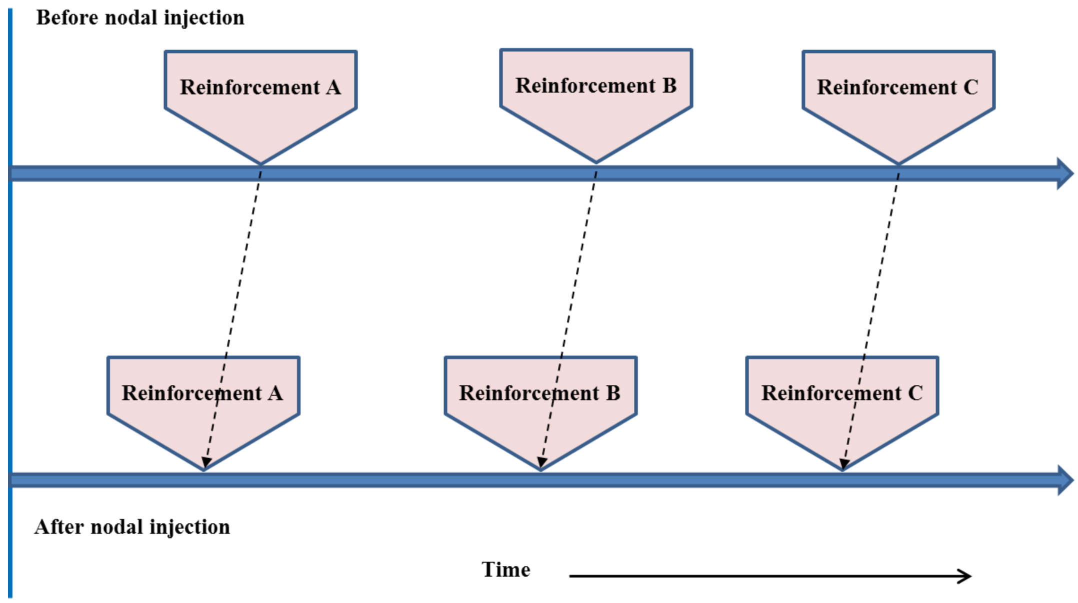


Fig. 2.4. Basic concept of LRIC pricing

power flow of P_{kj}, the time horizons required for future reinforcement for a specified growth rate r can be obtained as

$$n_{kj} = \frac{\log C_{kj} - \log P_{kj}}{\log(1+r)} \tag{2.1}$$

ii. Estimating the present value of future reinforcement

For the discount rate of d, the present value of future reinforcement will be computed as

$$PV_{kj} = \frac{AC_j}{(1+d)^{n_{kj}}} \tag{2.2}$$

where AC_j is modern equivalent cost of network asset.

iii. Calculating the annualized incremental cost associated to nodal increment/decrement

An injection of ΔD_k at node k causes change in the power flow along asset j by ΔP_{kj}. This injection will change the future asset reinforcement from year n_{kj} to year n_{kjnew}.

The new investment horizon is given as

$$n_{kjnew} = \frac{\log C_{kj} - \log(P_{kj} + \Delta P_{kj})}{\log(1+r)} \tag{2.3}$$

This further changes the present value of future reinforcement

$$PV_{kjnew} = \frac{AC_j}{(1+d)^{n_{kjnew}}} \tag{2.4}$$

Now, change in the present value as a result of nodal injection is given by

$$\Delta PV_{kj} = PV_{kjnew} - PV_{kj} = AC_j \times \left(\frac{1}{(1+d)^{n_{kjnew}}} - \frac{1}{(1+d)^{n_{kj}}} \right) \tag{2.5}$$

The annualized incremental cost of the network asset j is given as

$$IC_{kj} = \Delta PV_{kj} * \mathrm{AF} \tag{2.6}$$

where $\mathrm{AF} = \dfrac{d}{1 - \dfrac{1}{(1+d)^n}}$

Annuity factor (AF) reflects the rate of return on investment and allowances for operation, repair, and maintenance. Here, n represents life of asset and is normally set to 40 years.

iv. Calculating the long-run incremental cost

Finally, the LRIC charges at node k will be summation of the incremental cost over all supporting circuits and it is given by

$$LRIC_k = \frac{\sum_j IC_{kj}}{\Delta D_k} \tag{2.7}$$

2.3.6 Forward Cost Pricing Model

In the series of economically efficient charging models, the FCP model was developed by Scottish and Southern, Central Networks, and Scottish Power (collectively known as G3 group) as an average pricing model. It evaluates the total network investment cost over the next ten years and allocates the cost to all the existing and forthcoming demand and generation groups. This model determines demand and generation charges separately. To determine demand charges, the distribution network is first split into a number of 'network groups'. Contingency analysis is then performed on the DNOs network to identify all likely reinforcements within ten years to comply with network security requirements [56-58]. The reinforcements identified within the ten-year horizon are used to determine FCP charges. Demand charges are evaluated based on the revenue recovery period rather than the asset lifetime, as in the LRIC model.

To derive generation charges, the reinforcement costs projected within the next ten years are determined using the same network groups as used for demand. Contingency analyses are performed with a test-size generator connected at different network locations. Reinforcement costs are then evaluated for all overloaded branches, and they contribute to EHV generation charge for the considered network group. Then, these costs are allocated across the total expected EHV generation over the ten years [59-60]. This approach provides limited economic signals than LRIC because of its departure from incremental pricing. The LRIC pricing methodology is less complex than the FCP, and its price signals are not restricted to group signals like those in the FCP. Thus, the LRIC approach offers better prospects to satisfy pricing principles [15, 61].

2.4 Distribution Network Pricing Practices in Different Countries

Network pricing is a complicated issue, and it is impossible to have a pricing methodology that can be used in all circumstances. Each methodology has its advantages and disadvantages. Different pricing methodologies are suitable for different circumstances and requirements under which network services are provided. Hence, the pricing methodologies vary enormously from one country to another and from one distribution network to another within the same country. These are further summarized in Table 2.3.

2.4.1 Chile

Distribution networks are designed to supply electricity under peak demand condition, so the average cost of necessary efficient infrastructure to supply that demand is used for pricing computations. The costs are allocated as average, considering the distance and magnitude of power flows. The pricing models are built for each typical area and therefore provide different tariffs for different distribution companies. Energy valuations are only desired to calculate distribution losses to be paid by demand [62].

2.4.2 Brazil

In Brazil, voltage level is the only parameter to determine distribution tariff, without considering the topological structure of the system. So the marginal cost of each voltage level is computed and applied to allocate distribution charges. It is like a “postage stamp” for each voltage level. Since the distribution companies are in-charge of the entire network composed of voltage from 127 V to 138 kV, the consumers see one tariff for each voltage level no matter where they are located. Postage stamp cost allocation method is used at each voltage level while the LRIC method is used to allocate the cost among different voltage levels [21].

Average long-run incremental costs are determined at each voltage level using the ratio of future investment costs and load growth rate, *i.e.*, percentage increase in energy demand at any node is set in terms of the present value of the future investment. This method is then used to allocate target revenue among all the voltage levels. The approach is applied to all users except for the generators connected to 138 kV and 88 kV. There is a locational signal for generators connected at these voltage levels based on the ICRP. Further, for lower voltages generation, the tariff is based on regional average charges applied to all consumers.

For voltage levels from 138 to 13.8 kV, there are a set of time-of-use tariffs whereas, for low voltages, there are only flat tariffs. Tariffs are set by the regulatory agency for each distribution company according to their time band for peak and off-peak [47, 62].

2.4.3 Germany

In Germany, there are no location-specific signals for generators or load, rather uniform energy and network prices are levied for the services. Network congestion is dealt via re-dispatch, and the associated costs are socialized through the network charges. The network tariff is postage-stamp per voltage level and hence does not send the locational signals for the load. DG receives a premium for avoided network charges of higher voltage levels. Since the avoided network charges are calculated per regional network, a site-specific locational signal is lacking.

The contribution-to-network cost charged from a newly connected generation or load is intended to favor needs based network expansion and avoid over-dimensioned network capacity. This does not convey the locational signals, as the calculations are based on the average cost of similar cases and do not necessarily relate to actual and prompt network investment [63].

2.4.4 Spain

In Spain, there is no geographical differentiation in tariffs for demand and generators. Also, no difference exists in tariffs for various distribution companies. So, tariffs remain the same for all customers connected to the same voltage level all over Spain [62].

In Spain, the distribution charges are paid with a single tariff package which includes the transmission charges. Distribution tariffs and transmission tariffs are not separated,

Table 2.3

Summary of pricing practices in different countries

Country	Parameter considered	Parameters not considered	Approach
Chile	Voltage, Density, Asset type	Geographical differentiation	Postage stamp
Brazil	Voltage level, Geographical differentiation	Density, Asset type	HV/LV network- Postage stamp, EHV- ICRP
Germany	Regional differentiation	Voltage level, Geographical differentiation, Density, Asset type	Postage stamp
Spain	Voltage level	Geographical differentiation, Density, Asset type	Postage stamp
France	Voltage level,Customer classification	Geographical differentiation, Density, Asset type	Time-differentiated pricing
New Zealand	Voltage level, Customer classification, Geographical differentiation	Density, Asset type	LRAIC pricing
Italy	Voltage level	Geographical differentiation, Customer classification	Three-part pricing : fixed charge, demand charge, energy charge
Australia	Voltage level, Geographical differentiation	Density, Asset type	LRMC pricing
United Kingdom	Voltage level, Geographical differentiation, Density, Asset type	Customer classification	HV/LV network- DRM EHV network- LRIC/FCP
Norway	Voltage level, Customer classification	Geographical differentiation, Density, Asset type	Time-differentiated pricing
India	Customer classification	Voltage level, Geographical differentiation, Density, Asset type	Cost-of-supply

and only the final tariff is published. Access tariffs for transmission and distribution networks are set by the government taking into account recommendations from the Spanish regulatory body, National Commission on Markets and Competence. This tariff methodology is based on assigning costs to consumers according to the cost-causality principle [64]. Thus, the network costs are first allocated to energy and capacity taking into account the results of a reference network model. The grid owner is penalized when the grid is less available than a determined reference level. This penalty provides long term signals for new investments in Spain.

Until the year 2011, generators did not pay use-of-system charges. Currently, all the generators connected to transmission and distribution networks pay a €0.5/MWh flat use-of-system charge. They also pay a charge for connection to the network. Connection charge consists of three components: a fixed charge, in €/month; a capacity charge according to their contracted power in €/kW.month; and an energy charge in €/kWh [62].

2.4.5 France

Access tariffs apply only to eligible consumers wanting access to the network. Prices are set on a national level based on consumption and voltage rather than the distance. The capacity charge is based on the subscribed demand and peak capacity at four points in the year (summer/winter-on/off-peak). France is one of the countries where demand charges are applied to households, and the network tariff has been adjusted to reflect equity concerns.

Distribution costs (especially capital costs and costs of losses) are allocated to tariffs through hourly unit costs for using the grids and the consumption characteristics of different user categories (voltage domain, the profile of consumption and duration of usage) [65].

2.4.6 New Zealand

DUoS charges in New Zealand vary from area-to-area. Electricity retailers in New Zealand show separate energy and network line charges in their bills with fixed and variable components. Transmission cost is passed through the distribution network line charges. Distribution tariff is based on aggregate data measured at transmission grid exit points. Distribution loss factors are calculated to adjust the distribution tariff charged to retailers. The LRIC method is particularly relevant to New Zealand distribution companies, as its modified version long-run average incremental cost (LRAIC) is the recommended approach for core distribution network pricing. For policy reasons, the fixed network charges for New Zealand residential customers are kept low. Cross-subsidy is more apparent from urban to rural customers who may distort the economic signals for DG siting in rural regions [66].

2.4.7 Italy

In Italy, the customers are required to pay for the part of the cost of new connections. The amount charged is fixed for residential customers and depends on parameters such as power required, voltage, and distance from the network for non-residential customers. No special provisions apply for renewables or combined heat and power plants. Generators can either ask the distributor to build the connection or build the connection on their own [65].

The structure of the distribution network tariffs in Italy has two interesting features. First, the distribution network tariff has a demand charge for household customers with the demand charge imposed on the "size" of the network connection. Second, there is a defined "ideal" tariff structure towards which tariffs are supposed to evolve with time, but the actual tariffs are different from the ideal to protect low-income customers.

The Italian distribution network tariff has three parts: a fixed charge, a demand charge, and an energy charge. The demand charge is levied on the "size" of the network connection. The customer can select the size of network connection which then acts as a limit on the power (kW) that can be required at any point in time. This approach has been used for a long time in Italy and predates the advent of smart meters. All households in Italy are now equipped with smart meters, and one of the features of a smart meter is that it can put a limit on the maximum power delivered to a house [67].

2.4.8 Australia

In Australia, network tariff is determined by LRMC for each tariff class by annualizing its cost of augmenting capacity and scale growth in operating and maintenance costs associated with network expansion. The application of LRMC to efficient network tariff setting is a two-step process [65]:

i. Select the charging parameter to give the LRMC signal to the customer.
ii. Convert the LRMC estimate from a $/kVA basis to a cents/kWh basis, if required.

Traditionally, various approaches have been used to determine LRMC for providing network facilities. Some of the common approaches are:

i. Average Incremental Cost methodology: This approach estimates LRMC by recognizing various expenses *viz.* capital, operations, and maintenance required to fulfill the projected demand growth over ten years and then to apportion this by projected demand growth. It further calculates the present value of expenses and divides this by the present value of incremental demand growth to evaluate LRMC.

ii. Perturbation or 'Turvey' methodology: This approach includes some steps. First, a small increment or decrement is applied to an identified forecasted demand. Then a change in the present value of cost over the investment planning period is calculated due to this increment or decrement. Finally, the result is divided by the nodal change in demand to reach LRMC estimate.

Among these two approaches, none of them can be said as superior one in the perspective of the network pricing because different methods have their advantages and disadvantages depending on exact conditions of network operators [67].

2.4.9 Norway

In Norway, the long liberalization period has led to large tariff reductions. The central grid tariffs comprise four elements: two dependent on the short-run utilization of the network and the remaining ones fixed on an annual basis. The tariff element covering losses is based on spot market prices of electricity and an approximation to the marginal loss caused by injection and consumption in a region of three typical load situations. This element covers approximately 25% of the total costs.

Distribution network users are charged through two components: the fixed charges and the energy charges. The fixed charges cover the customer-specific cost and a share of the other fixed costs on the network. The energy charges cover the cost of marginal network losses and a share of other costs not covered by the fixed component [64].

2.4.10 United Kingdom

In 1980, the generic pricing model-usually referred to as 500 MW model or DRM was introduced. It has been used for distribution tariffs for all distribution networks in the United Kingdom (UK). It is necessarily an allocation model that attributes the costs of the existing network to the users depending upon the use they make of each voltage level of the distribution system, as inferred from their maximum demand and customer class characteristics. A significant drawback of the DRM model is that the evaluated costs for 500MW capacity are merely scaled from the current existing asset costs without recognizing the system assets utilization. Hence, the model lacks cost reflectivity. There was a need to develop new charging methodology to provide cost reflective charges for HV and LV networks [32].

The UMIST model added a dimension to the DRM by incorporating a DG which was not considered previously. It analyses power flow during maximum load minimum generation and minimum load maximum rated generation [48]. Pre 2005, the most advanced incremental cost pricing model for EHV networks was ICRP devised by National Grid as it directly linked the cost of network reinforcement with nodal generation/demand injections without the least network planning. Charges from the ICRP model are calculated from the incremental network cost of accommodating an additional 1MW increment at each study node. ICRP charge at the study node is determined as the product of the power change in each supporting circuit and the unit cost of the circuit over all the affected circuits [33].

Further, Western Power Distribution uses LRIC as of April 2007, for their EHV networks and for LV networks they still employ the use of DRM. The UK is the first country to introduce locational network charges at the distribution level. The LRIC model utilized at its EHV networks aims to replicate the impact on future network investment as a result of a generation injection or a load withdrawal at each study node.

The other charging model that can be used at EHV distribution networks is FCP. The FCP pricing is an average pricing model and evaluates the total network investment cost over the next ten years while allocating the cost to all existing forecasted future demand and generation customers. The aim is to recover revenue over the ten-years equal to predicted reinforcement cost over the same period. The two approaches

(LRIC and FCP) are considered by the industry and Ofgem (Office of Gas and Electricity Markets) as the best available approaches to achieve high-level charging principles, namely cost-reflectivity, simplicity, and predictability [15].

2.4.11 India

In India, the network charge allocation is based on the cost-of-supply principle. The network costs are initially classified based on the type of costs involved, *i.e.*, demand, energy, or customer related. As per the cost causation principle, the cost-of-supply model allocates the utility's incurred costs to the various categories of consumers. This assumes that different categories of consumers, like domestic, commercial, and industrial, contribute differently to the individual costs.

In India, the tariff structure varies across states. Within any state, the network pricing structure is identical for a given type of customer. There is no geographical variation in tariff. Connection charges reflect the impact of location from the connection point, but there is currently no locational signal to network users.

In India, the total network costs are replicated, and the target revenue is recovered by the usual network pricing approaches. Hence, revenue reconciliation is not required [62].

2.5 Developments in DUoS Pricing Model

The LRIC and FCP approaches are considered by the industry and Ofgem as the best available methods to achieve high-level charging principles including cost-reflectivity, simplicity, and predictability. From April 2012 onwards, Ofgem has allowed the seven DNOs in the UK to choose one of the two charging methodologies to implement.

The LRIC pricing methodology is less compllicated than FCP, and its price signals are not restricted to group signals like those in the FCP. Thus, the LRIC approach offers better prospects for satisfying the pricing principles [15]. Although LRIC is a well-established pricing model, yet various enhancements have been done to improve the pricing signal offered to users.

2.5.1. Smart Network Pricing based on LRIC pricing Model

SG's are electrical grids embedded with information and communication technologies to gather information about the behavior of energy suppliers and consumers. This improves efficiency, reliability, and sustainability of production and distribution of electricity in an automated fashion. These grids are characterized by a two-way flow of electricity and information, providing benefit to both the utility and users. SG's can respond to events that occur anywhere in the system such as generation, transmission, distribution, and consumption [68].

Evolving SGs has the potential for efficient management, planning, and operation of power systems. An essential component of modern-day system operation is dependent on an efficient and responsive electricity pricing mechanism. Such mechanisms employ cost-reflective electricity pricing as an integral tool for effective demand-side management. Smart Meter enables the utilities to offer dynamic prices to customers for the electricity supply. Customers respond to these prices by optimizing their consumption to minimize their electricity charges.

Electricity prices offered to customers are reflective of generation and network costs involved [69]. Network cost includes transmission and distribution network cost. This cost forms a significant component of electricity prices. Users respond to these network charges by modifying their usage pattern. Efficient network charges invariably reflect the impact of network congestion. Thus, the customers effectively respond to network congestion caused by supplying power to a set of customers. The transmission pricing models based on the nodal pricing mechanism provide price signals to customers reflecting the impact of network congestion. However, the distribution pricing models differ from the transmission pricing models because of their inherent technical differences and are unable to provide an accurate reflection of network congestion [21].

Distribution network prices can be calculated ex-ante through various pricing models *viz.* DRM, ICRP, LRIC, and FCP Pricing. The LRIC charging mechanism is the most advanced to date with a verified potential to save hundreds of millions of pounds in terms of network investment [70]. This approach is recognized as an economically efficient approach to allocating network cost. It determines network charges in terms of the difference in the present value of the future investment consequent upon nodal power perturbation for generation or demand [35].

The enhanced versions of LRIC methodology consider network security, component reliability and nodal unreliability tolerance [16-17]. This model also respects the user's security preferences while assessing their impact on network development cost [71]. For calculating the nodal LRIC charges, the diversity factor is used to calculate the maximum demand at individual locations on the network. This factor considers the maximum demand of individual users that may not be coincident to network peak demand. Hence, this factor is not able to reflect the user's network usage during peak demand [72]. Thus, the approach does not charge users by their contribution to network peak conditions.

Networks are designed to supply peak load on the system. Tariff for network services depends on load situation when there is peak demand on the system. Each customer category contribution to system peak demand affects network investment and hence should be reflected in network charges [21, 73]. The network charges are the component of electricity charges. Electricity charges for customers vary with their category classification. Customers of a category usually vary in a similar fashion and impact network congestion in consonance. Customer category contribution to network peak demand can adequately be determined using CF which is defined as the fraction of specific customer category demand at system peak to category peak demand. CF reflects that there exists diversity in the pattern and nature of consumption by various customer categories differs [74]. In SG environment, such coincident network usage can be captured at multiple network levels with smart meters. The network prices evaluated by considering the contribution of users to network peak usage are feasible with such SG scenario. Hence, the smart pricing signal reflecting customer categories contribution to system peak demand could be delivered with SG environment.

2.5.2. Hierarchical Contribution Factor based Model for Customer Class Specific Charges

The UK government has set an ambitious target to transit towards a low carbon energy future by reducing carbon emission and increasing renewable energy [75-77]. The year 2015 has witnessed £3.5bn annual subsidies in the UK just for photovoltaic (PV) installations. With the increasing number of low carbon energy technologies (such as PV, EV's, battery storage and heat pumps) being connected to the edge of the grid, the power distribution networks will have unprecedented complexity and uncertainty [78-83]. Load estimation at various network nodes is becoming a challenging task for the utilities in such a situation [84]. Currently, the default solution to this issue is passive network reinforcement which will finally be paid from customers' rising energy bills.

To accommodate the large influx of low carbon energy technologies without passing the extra economic burden to customers, it is important to design innovative technical and commercial solutions to guide the planning and operation of end-customers [85-90].

Network planning methodologies aim to model the actual network while considering some assumptions to make for data deficit and unknown future variations. For this methodology, the considered modelling may not be a true reflection of the network and the overall formulation of network cost. Further, optimization algorithms may not guarantee global optima as it would depend on the accuracy of the assumed parameters. Such methodologies may lead to incorrect solutions despite adopting the best of optimization algorithms and well thought out assumptions. In contrast to the use of optimization algorithms, use of network pricing involves consideration of a few basic assumptions. A robust and thoughtful pricing model would offer an appropriate customer-class specific pricing signal to the user. Class users would respond to the economic signal by way of optimal location and utilization such that its network utilization is minimized. This would eventually lead to the low requirement of network reinforcement, and thus minimizing network investment required meeting the specified load.

DUoS charges computation is an effective commercial tool for DNOs to guide new network users in a deregulated power market. The aims of DUoS charges are twofold: i) to recover reinforcement cost for the DNOs based on an economic pricing model; ii) to reflect industry_regulation as a whole and to offer an efficient economic signal to the users. According to the energy market regulator in the UK, an ideal DUoS charging model should exactly replicate forward-looking costs. This incentivizes effective usage, development of the network, and incorporates the generation DUoS [91].

A significant quantum of research on DUoS model has been reported from industry and academia. The DRM is a Postage Stamp method and traditionally used by the UK industry, which allocates all the network cost to customers only according to the voltage level of connection. DRM provides no locational signals or ex-ante cost information to customers [21]. It offers no guidance for the planning of DG’s [92]. DRM’s weakness was rectified in several new models proposed by academia. The location is considered as the key factor in most of these models by charging against the critical power flow scenarios, network congestion, and power losses [93]. ICRP was proposed to not only recover the historical investment but more importantly to evaluate the impact of future incremental cost placed on the system as a result of new load or generation being added at any point on the distribution network [94-95]. The LRIC model considers the utilization rate of an asset in addition to the distance [14, 35]. This approach is recognized as an economically efficient approach for allocating distribution network cost. It determines network charges as the difference in the present value of the future investment consequent upon nodal power perturbation for generation or demand.

Further, the impact of network security, contingencies, and reliability has been integrated into the LRIC pricing approach [15-17, 53]. Integration of DG is considered using DUoS price as a signal to encourage DG connection at the appropriate location [96]. The interaction of generation and demand in the distribution network is investigated by nodal pricing, contract pricing, and value-based pricing [97-99]. The uncertainty introduced by DG is also considered in the network reinforcement and charging methodology [100-101]. Demand response plays a significant role in demand reduction and demand shifting, and dynamic pricing models can effectively consider the same [102-105]. To send a customer-specific signal and to effectively guide individual energy behaviour a new DUoS charging model need to be developed. A novel hierarchical contribution factor based model is proposed to recognize the contributions of different customer classes to the network reinforcement of upstream asset. Such contribution will be further propagated to network assets at higher voltage level forming a hierarchical CF model and reflecting the true individual class contribution to the whole-system reinforcement.

2.5.3. Demand Response based Long Run Incremental Cost Pricing Model

Existing DUoS methodologies have covered many attributes of an ideal model considering factors like forward-looking cost, distance, location, utilization rate, reliability, and generation technology. Traditional methods assume that all customers consume energy in a similar way within a distribution network and follow the aggregated load profile. However, end-users consume energy in a dissimilar manner and thus have a different contribution to the networks' reinforcement. Likewise, the downstream asset contributes differently to the upstream assets based on the coincidence level of the load profiles. The industry has attempted to address the issue by introducing a diversity factor, which is the ratio of maximum demand at the substation to the sum of the maximum demand at all points of the immediate lower distribution network served by that substation. However, this factor aims to calculate the after-diversity peak load to evaluate the reinforcement cost, instead of accurately allocating such cost to individual customers [106]. To send customer-tailored signals to guide an individual's energy behavior effectively, it is critical to developing a new DUoS model considering the additional dimension of energy consumption pattern variation among the customers.

Environmental concerns create an obligation for countries to reduce their carbon footprints which in turn is incentivizing transition towards a low carbon electricity supply industry. As a consequence, low carbon generation technologies like RG are incentivized towards higher grid penetration. Intermittent nature of these generation technologies increases uncertainty for system planning and hinders the smooth operation of network infrastructure, both at the transmission and distribution levels.

Unpredictable network usage by RG could potentially increase congestion in distribution systems [19]. Facilitating responsive demand in the system could ease out this congestion. For efficient and effective load management, network operators often incentivize customers by offering a variety of price signals [107-108]. Customers respond to the price signals by optimizing their consumption to minimize their electricity charges, and this mechanism is known as DSR [109-112].

DSR programs include a variety of initiatives including time-of-use pricing with set periods of higher and lower prices, critical peak pricing with higher prices applicable on pre-notified critical conditions, and real-time pricing that follow actual prices updated on an hourly or more frequent basis [69]. DSR program offers financial and operational benefits for electricity customers, network utilities, and load services entities. Financial benefits for participants can be in the form of bill savings and incentive payment earned by customers for modifying demand in response to time-varying electricity prices and incentive-based programs. Market-wide financial benefits include lower wholesale market prices and their reduced volatility. This happens as DSR reduces the total power consumption which provides benefit to both the power utility and customers. This further reduces power generation, minimizing the need to run expensive power plants to meet peak demand. The decrease in production cost results in reduced prices for wholesale electricity purchasers [109]. Operational benefits can be in terms of adequacy saving, improving grid reliability, and flexibility via fast energy balancing, that is particularly important in unpredictable scenarios of high renewable generation penetration [113].

In emerging smart grids with smart pricing mechanisms and smart devices, customers can alter their consumption pattern either by shifting consumption to off-peak times or by altering overall consumption. EV's constitute a major portion of such responsive demand [107, 114]. Customers may find it difficult to find substitutes in response to a price change in the short-term. Over a longer period, customers have an opportunity to modify appliance holdings and other energy-related capital stock. Further, they may learn to utilize innovative techniques and energy efficient appliances to shift consumption to off-peak times [115].

Automation enhances customer response to electricity prices reflective of market conditions. RG and EV's response to these prices may cause network peak as wholesale market prices are often not correlated with network prices. Peak demand requires additional network and generation infrastructure which is utilized only for a small number of hours every year. This imposes significant costs on the power system. These additional costs are ultimately borne by end users of electricity [114].

DSR approaches help to reduce peak demand and thus facilitate the utility's inefficient system operation. This includes the efficient utilization of generation facilities and retards the need for additional capacity [116]. In such schemes, the end-user behavior is governed by dynamic tariff offered by the retailer. This tariff is a combination of generation and network costs and primarily reflects the time-varying nodal prices at grid supply point and time-invariant network charges. This could provide a signal for transmission network congestion in the location marginal pricing scheme, but not for dynamic distribution network congestion [11, 117].

Distribution network cost is allocated among users based on some pricing mechanism to offer them an economic signal. This influences customer behavior regarding their location and consumption pattern [4, 18]. Distribution network charges can be calculated ex-ante through various approaches. LRIC is a well-established approach to evaluate long-term distribution network charges for UK distribution networks assuming that network reinforcement would be required when the loading level of circuit reaches its capacity [33, 35, 62].

Various enhancements have been made in the basic LRIC approach to improve the price signal offered to network users. A modified version of LRIC pricing model is proposed to offer a customer class specific LRIC pricing signal to distribution network users. This modified model incorporates CF to highlight users' contribution to peak network conditions in addition to location-based signal from traditional LRIC model. RGs are promoted to supply as much available generation by offering alternative network usage charges rather than CF based pricing signal of this model [118]. Network congestion so created could only be mitigated by utilizing demand flexibility.

Cost causality requires that network charges must have some level of time differentiation so that diversity in the economic impact of network usage at different times is recognized [116]. The present customer charges which consist of both energy and network cost do not reflect this differentiation, thus diluting the effect of time-variant network congestion. This underscores the need to offer a dynamic tariff mechanism for network usage, as network cost forms a significant component of electricity price [119-120].

In the evolving matrix of things, the primary challenge is that the intermittent nature of RGs increases uncertainty and congestion in distribution systems. Renewable generators are promoted by offering uniform prices rather than time variant network charges for their peak network usage [55, 121]. This way, renewable generation potential is realized and would result in network congestion.

2.5.4. Long Run Incremental Cost Pricing considering Generation and Load Contributions

Network pricing is a mechanism to allocate network cost among all its users, thus giving a forward-looking economically efficient signal for location and extent of network usage. The pricing models developed for distribution networks are fundamentally different from those developed for transmission networks due to differences in the nature of the network and the eventual aims of these pricing mechanism. Network cost can be minimized if the distribution network operators have a suitable distribution network pricing mechanism to guide the existing and new network users regarding the location and timing of the network usage [13, 62].

LRIC is a well-established approach to evaluate long-term distribution network charges for UK distribution networks assuming that network reinforcement will be required when the utilization level of circuit reaches its capacity. This approach determines network charges as the difference in the present value of the future investment consequent upon nodal power perturbation for generation or demand. The charges produced by this methodology reflect both distance and utilization of distribution network components [35]. LRIC pricing methodology has evolved over the years to improve long-term pricing signal given to users.

From the perspective of societal benefit, DG connection to distribution network has been evaluated based on LRIC. In this context, the effect of expanding DG capacity is considered to quantify the network capacity deferral value of DG [122]. DGs contribute to demand growth and system security, thus providing benefits by deferring future demand related network investment [123]. Further, DG's are paid for a reduction in network utilization. Credits given to DG should be based on real benefit produced by them. The extent of the use of distribution network can be measured in terms of the contribution of each customer to the current flow in allocating the fixed cost [96]. Efficacy of various enhancements done in LRIC pricing could be shown by comparing charges obtained from the basic LRIC model.

For efficient distribution network operation, network operators or suppliers offer individual charges to users considering their specific characteristics. Lower distribution network charges can be offered for the customer not contributing to system peak with their peak demand differing significantly from system peak demand characteristics. These charges attract customers with characteristics favorable for distribution network development at the specific locations. Such charges would make the system efficient, and the utilities may delay network reinforcements and investments in new generation units and network infrastructure [7, 63].

Charges for distribution network services depend on some measure of customer contribution to load during peak system demand. Each customer class contribution to peak system demand affects network investment and hence should be reflected in network charges [21]. While calculating the nodal LRIC charges, the diversity factor is used to evaluate maximum demand imposed at individual locations on the distribution network. This diversity factor is defined as the ratio of maximum demand at the substation to the sum of the maximum demand at all points of the immediate lower distribution network served by that substation. This factor does not reflect coincident peak usage of distribution network user, rather considers maximum demand imposed by users that may not be coincident to distribution network peak demand. Hence, this factor is not able to truly reflect the user's distribution network usage during peak network demand [72-73]. Thus, the approach fails to charge generators and loads by their contribution to distribution network peak conditions.

2.6 Conclusion

The presented literature review addresses the challenges to network business in the deregulated environment, and then the significance of pricing approaches for distribution network cost allocation. Further, it reviews various DUoS pricing methodologies *viz.* DRM, UMIST, ICRP, MW+MVAr- Mile, FCP, and LRIC. Then, different country practices for distribution cost allocation are discussed. LRIC is a well-established DUoS pricing methodology to give a forward-looking economic pricing signal to users. Further, to improve the pricing signal offered to network users, various enhancements have been done in the LRIC pricing model.

Chapter 3

Smart Network Pricing based on LRIC Pricing Model

T**HIS** chapter proposes a smart network pricing mechanism to provide effective network pricing signal to various customer categories. Considering that future smart meters could measure a user's coincident peak demand, the user is offered a CF based smart pricing signal in LRIC pricing framework..

Chapter – 3

SMART NETWORK PRICING BASED ON LRIC MODEL

3.1 Introduction

In the previous chapter, distribution network business, network pricing process, methodologies for distribution cost allocation and developments in distribution pricing methodology have been thoroughly discussed. This chapter aims to develop SNP mechanism, providing effective network pricing signal to the network users for congestion.

This chapter considers that the future smart meters could measure users coincident peak demand and the user is offered a CF-based smart pricing signal. The proposed approach is compared with the commonly adopted basic LRIC pricing model for distribution network pricing. This chapter is structured as follows. An introduction to smart network pricing is given in Section 3.1. In Section 3.2, a brief overview of the SG and SNP is included to maintain the continuity of work. A detailed overview of the steps required to evaluate charges using the proposed approach is also presented in Section 3.2. Description of 22-bus practical Indian reference network used for pricing analysis, parameters used for analysis, and the simulation results are shown in Section 3.3. Finally, Section 3.4 concludes the chapter.

3.2 Smart Network Pricing Model

3.2.1 Background

SG's can be pragmatic as an electric system that uses two-way information, cyber-secure communication technologies, and computational intelligence in a unified fashion across electricity generation, transmission, distribution, and consumption to achieve a clean, safe, secure, reliable, resilient, proficient, and viable system. SG's are paving the way for innovative technologies and services. They include automatic responses to the events on the grid; responses such as demand-side management, the operation of storage devices, and control of reactive power sources.

Smart meters support two-way communication between the meter and the central system. This is usually an electrical meter that records consumption during intervals of an hour or less and transfers that information back to the utility for monitoring and billing purposes at least once in a day. From a user's viewpoint, smart metering offers several potential benefits. End users can evaluate bills and adjust their energy consumption to reduce electricity bills. The utility can use smart meters to reflect real-time pricing. Thus, they incentivize users to reduce their demand in peak load periods or to optimize power flows according to the information available from the demand side.

In this Chapter, SNP refers to offering contribution factor based smart pricing signal to users. Traditional network infrastructure cannot track coincident network usage. In an SG environment network, the cost component can be reflected as a component of smart network prices when the actual network usage is known. Smart meters at different network levels can capture the user's contributions to network peak demand and can be used to compute network usage charges [124-125]. Network prices evaluated considering the contribution of users to network peak usage are feasible with such an SG scenario. Hence, the proposed approach is called a SNP. Considering the expected application of SG for SNP, this chapter proposes a CF-based SNP model of LRIC pricing, where the CF is reflective of users' contribution to network peak. In this SNP model network, the users would be responsible for network reinforcement when their peak coincides with the system peak. This would help to generate smart and efficient network pricing signal for the distribution network users.

3.2.2 Pricing Model Framework

The proposed SNP mechanism is illustrated in Fig. 3.1 to show the calculation for smart LRIC charges. Each load point of network used for pricing evaluation here comprises of various category users, *viz.* General, Industrial, Agricultural, and Water-Works. General category users represent the group of Domestic, Non-Domestic, Public Street Lightening, and Mixed Load Customers. Similarly, Metered Agricultural, Flat Rate Agricultural, and Agricultural Nursery comprise the Agricultural category, while Small Industrial, Medium Industrial, and High Tension Industrial are grouped into the Industrial category. Water-Works consists of all types of Water-Works connections for supplying water supplies [126]. Further, this section provides outline of the proposed CF based SNP mechanism illustrating the integration of different category user's contributions to network peak demand in determining the network prices. Category contributions are determined using CF.

The mathematical formulation for calculating smart network prices is also discussed here. As it can be seen from Fig. 3.1 that unit LRIC charges are calculated from the basic LRIC Model as given in Eq. (3.1) to Eq. (3.7) [35].

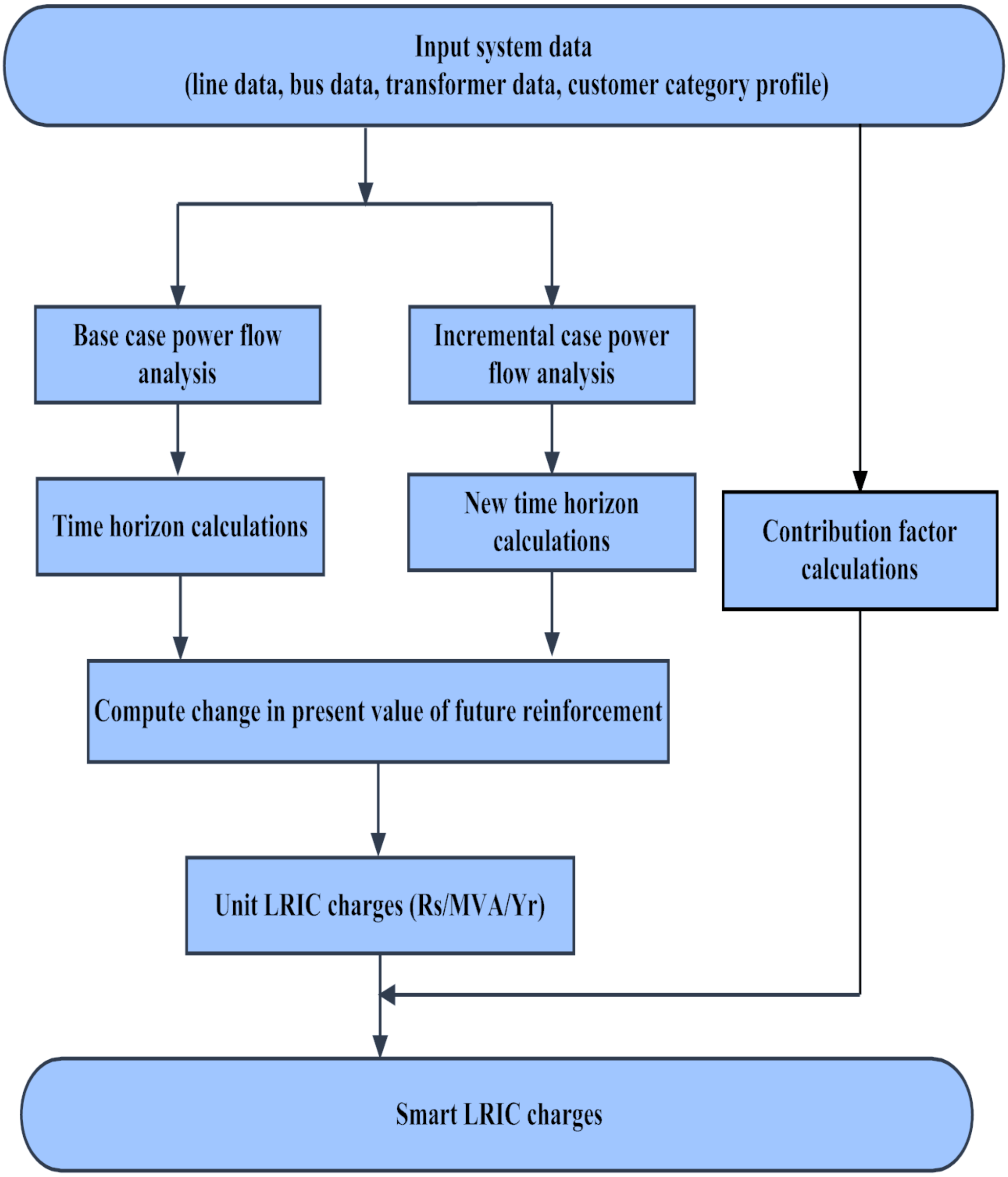


Fig. 3.1 Flow chart for smart network pricing model

3.2.3 Present Value of Future Investment

Network component j supplying node k is supporting a current power flow P_{kj} with capacity C_{kj} and load growth r. Time horizon required for component j reinforcement is given by

$$n_{kj} = \frac{\log C_{kj} - \log P_{kj}}{\log(1+r)} \tag{3.1}$$

For the discount rate d, the present value of the future investment is determined as

$$PV_{kj} = \frac{AC_j}{(1+d)^{n_{kj}}} \tag{3.2}$$

where AC_j is the modern equivalent asset cost of network component j.

3.2.4 Cost Associated with Load Increment

Nodal injection alters power flow along the associated network components by ΔP_{kj}, hence new time horizon for reinforcement is

$$n_{kj\,new} = \frac{\log C_{kj} - \log(P_{kj} + \Delta P_{kj})}{\log(1+r)} \tag{3.3}$$

This further change the present value of future reinforcement in asset j for the load connected at node k

$$PV_{kj\,new} = \frac{AC_j}{(1+d)^{n_{kj\,new}}} \tag{3.4}$$

Now, change in present value as a result of nodal injection is given by

$$\begin{aligned} \Delta PV_{kj} &= PV_{kj\,new} - PV_{kj} \\ &= AC_j \times \left(\frac{1}{(1+d)^{n_{kj\,new}}} - \frac{1}{(1+d)^{n_{kj}}} \right) \end{aligned} \tag{3.5}$$

Annualized unit incremental cost for network component j is given as

$$IC_{kj} = \frac{\Delta PV_{kj} * AF}{C_{kj}} \tag{3.6}$$

where AF is the annuity factor.

LRIC prices at node k is determined by the summation of annuitized incremental cost of all assets j over that node

$$LRIC_k = \frac{\sum_j IC_{kj}}{\Delta D_k} \tag{3.7}$$

where ΔD_k is the power injection at node k.

From Eq. (3.7) unit incremental charges in (Rs./MVA/Yr) at each node are obtained.

3.2.5 Contribution Factor based Smart Network Charges

Total charges for various category users reflecting actual network usage are calculated considering CF. CF for various category users can be evaluated as the ratio of category demand during the node's peak demand at which it is connected to the category peak demand [127].

$$CF = \frac{Category\ Demand\ at\ Nodal\ Peak}{Category\ Peak\ Demand} \tag{3.8}$$

Now, the charges paid by different category users reflecting their contributions to peak network demand are given as

$$TLC_k = LRIC_k * CF * P_{\max} \tag{3.9}$$

where TLC_k is the total LRIC charge for various category users at the nodes, CF is the contribution factor, and $P_{\max}$ is the simultaneous maximum demand imposed on network by specific category users. These charges reflect various category users' contribution towards network peak. Hence, Smart LRIC charges are calculated for various categories from Eq. (3.9).

3.3 Results and Analysis

In this section, the system used for smart network prices evaluation is described. Further, the proposed approach is demonstrated for smart LRIC charges implementation and the results obtained from the proposed approach are compared with the basic LRIC approach.

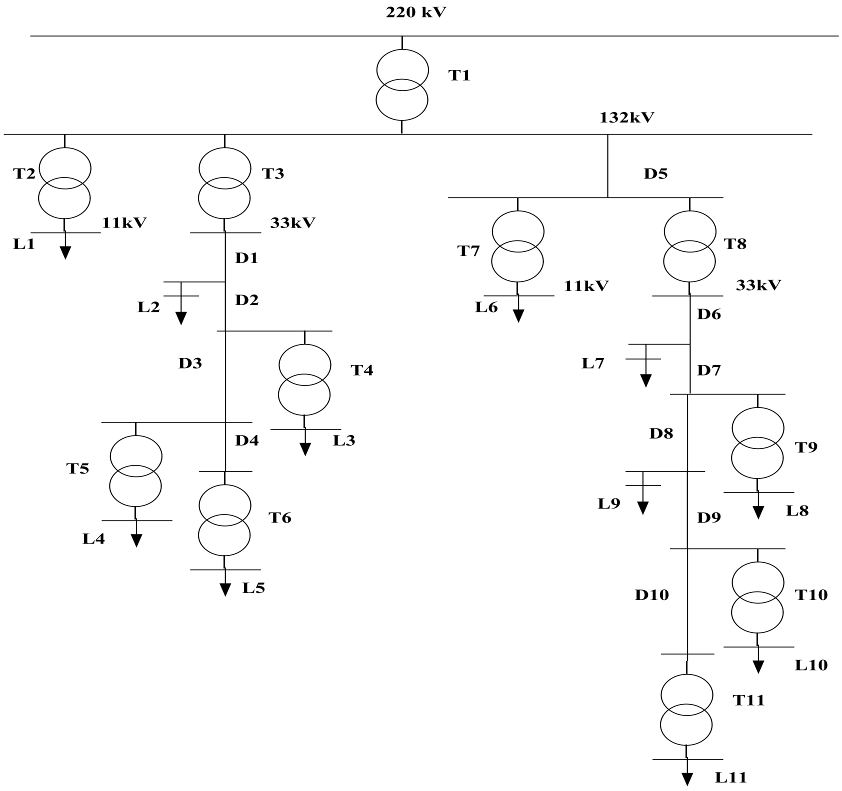


Fig. 3.2. 22-bus practical Indian reference network [128]

3.3.1 *System Description*

The proposed approach is applied to a part of practical Indian reference network [128]. Reference network was formed with practical data available for Jodhpur district, located in the Rajasthan State of Northern India for the months of October and November in 2007. The network has four voltage levels, 220 kV, 132kV, 33kV, and 11kV, consisting of 22 buses, 11 transformers, 10 distribution lines, and 11 load points, as shown in Fig. 3.2. The percentage of various category users conneted at all the nodes is shown in Table 3.1. Profile of total load connected at various nodes is shown in Fig. 3.3. This profile is sufficiently different from profile of various customer categories connected at these nodes.

3.3.2 *Smart LRIC Charges Implementation*

AC load flow is performed to compute flows as required for LRIC charges calculations. Power flows are performed using MATLAB ® software and network charges calculations are done using Microsoft Excel. Line, bus, and transformer data for power flow analysis are given in the appendix. The discount rate, load growth rate,

Table 3.1

Percentage of various category users to total load at the nodes

General	Industrial	Agricultural	Water-Works
37.5	62.5	0	0
100	0	0	0
47.06	23.53	0	29.41
60	0	20	20
0	100	0	0
66.67	33.33	0	0
100	0	0	0
77.5	10	3.33	9.17
100	0	0	0
82	4	0	14
81.82	0	0	18.18

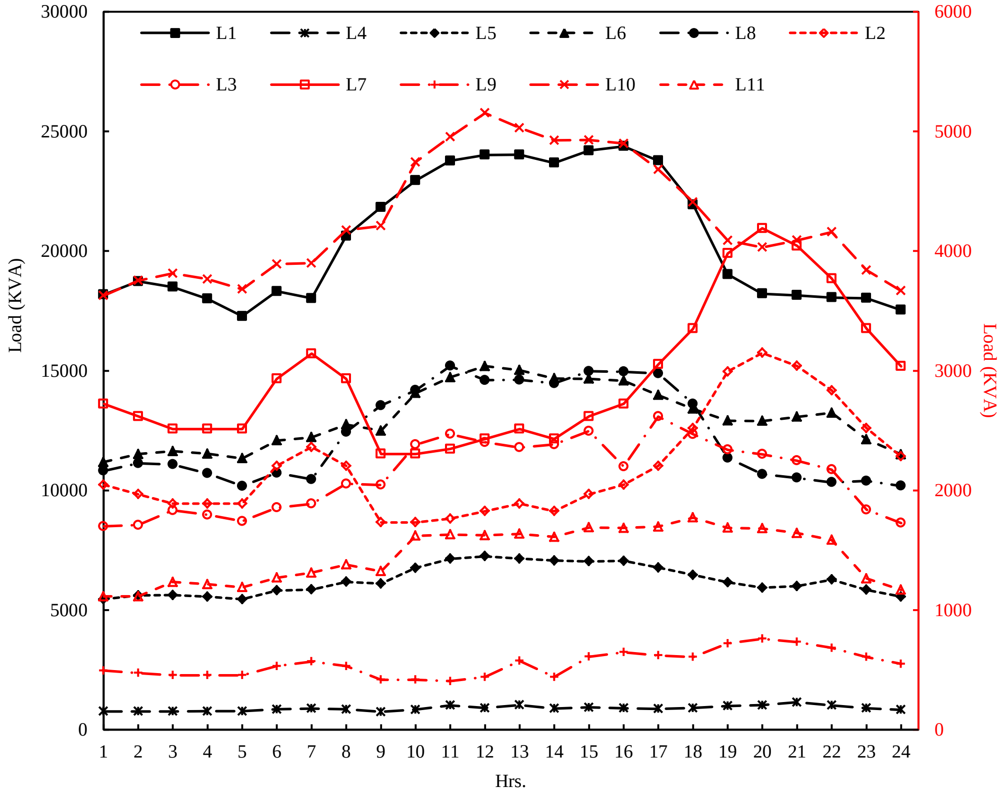


Fig. 3.3. Total load profile at various nodes

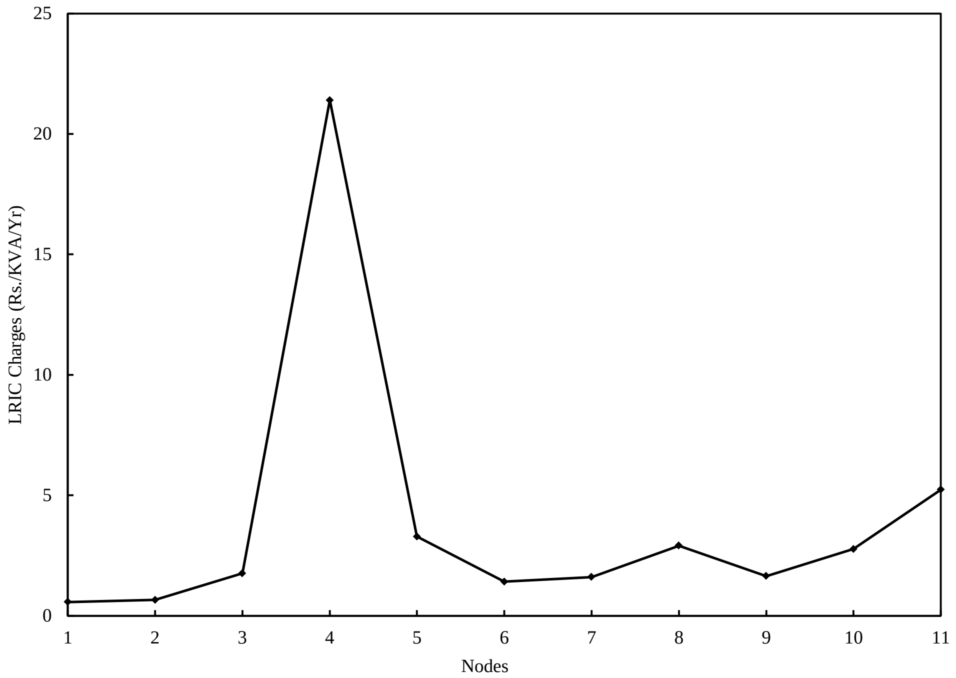


Fig. 3.4. Unit LRIC charges for loads at all nodes

Table 3.2

Contribution factor of various customer categories to total load at the nodes

Nodes	General	Industrial	Agricultural	Water Works
L1	0.63	1.00	-	-
L2	1.00	-	-	-
L3	0.70	0.99	-	0.93
L4	0.97	-	0.36	0.95
L5	-	1.00	-	-
L6	0.58	0.97	-	-
L7	1.00	-	-	-
L8	0.63	1.00	0.77	0.99
L9	1.00	-	-	-
L10	0.58	0.97	-	0.96
L11	0.80	-	-	0.96

and the annuity factor are assumed as 6.9%, 1.6%, and 7.4%, respectively [35]. Unit charges computed using Eq. (3.7) is shown in Fig. 3.4. These charges reflect both distance and utilization of network components. Extremely high LRIC charges at node 4 reflect that major component serving load at this node has very small capacity to accommodate 0.1 MVA load increment. After the computation of unit LRIC charges from the load profile data available at various nodes, CF of various category users to the total load connected at the nodes are determined from Eq. (3.8). These CF for various categories are shown in Table 3.2.

It can be seen in Table 3.2 that users of General category have the lowest contribution to peak of load L6 and L10, while having the highest contribution to the peak of load L2, L7, and L9. Industrial category users have the lowest contribution to the peak of load L6 and L10, while having the highest contribution to the peak of load L1, L5, and L8. The agricultural category has the lowest contribution to peak of load L4 and the highest contribution to the peak of load L8. Water-Works category users have the lowest contribution to peak of load L3 and highest contribution to peak of load L8. These CF shows the dominance of various category customers at the connection nodes.

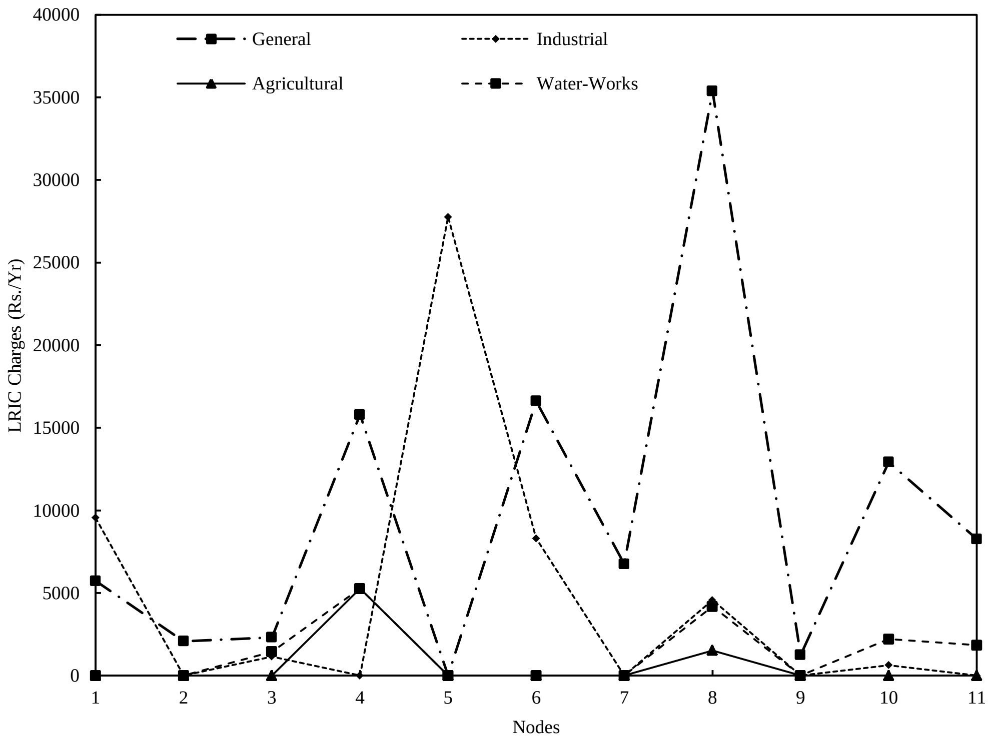


Fig. 3.5. LRIC charges for various category users without CF

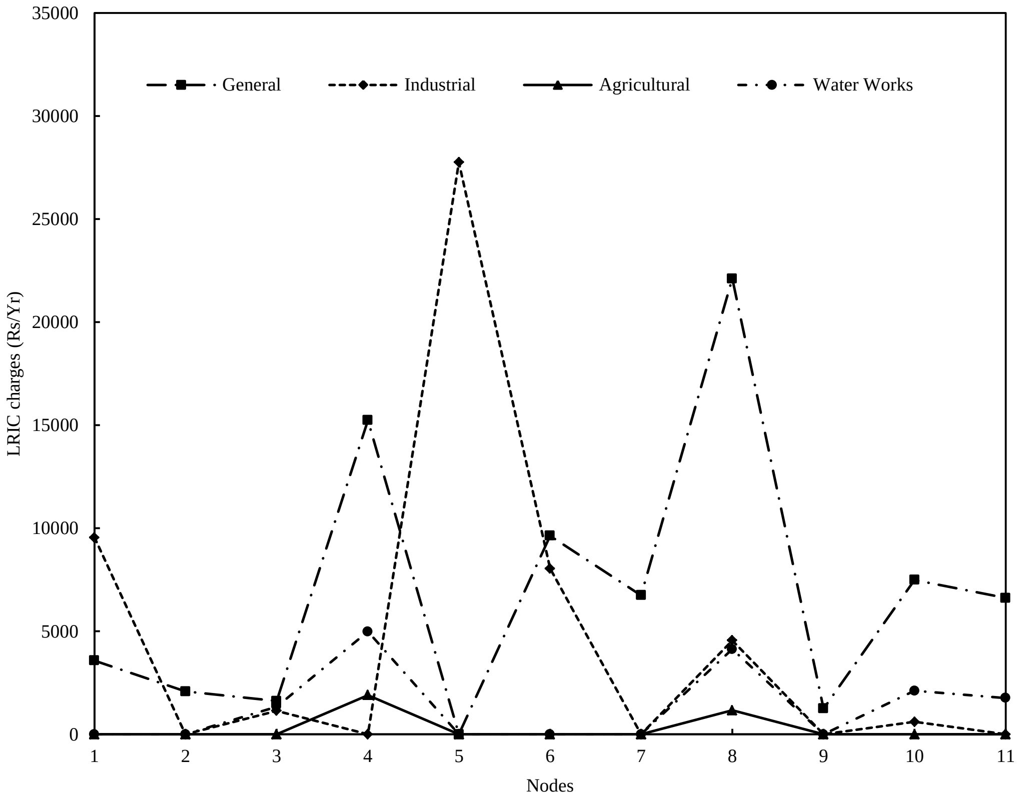


Fig. 3.6. LRIC charges for various category users with CF

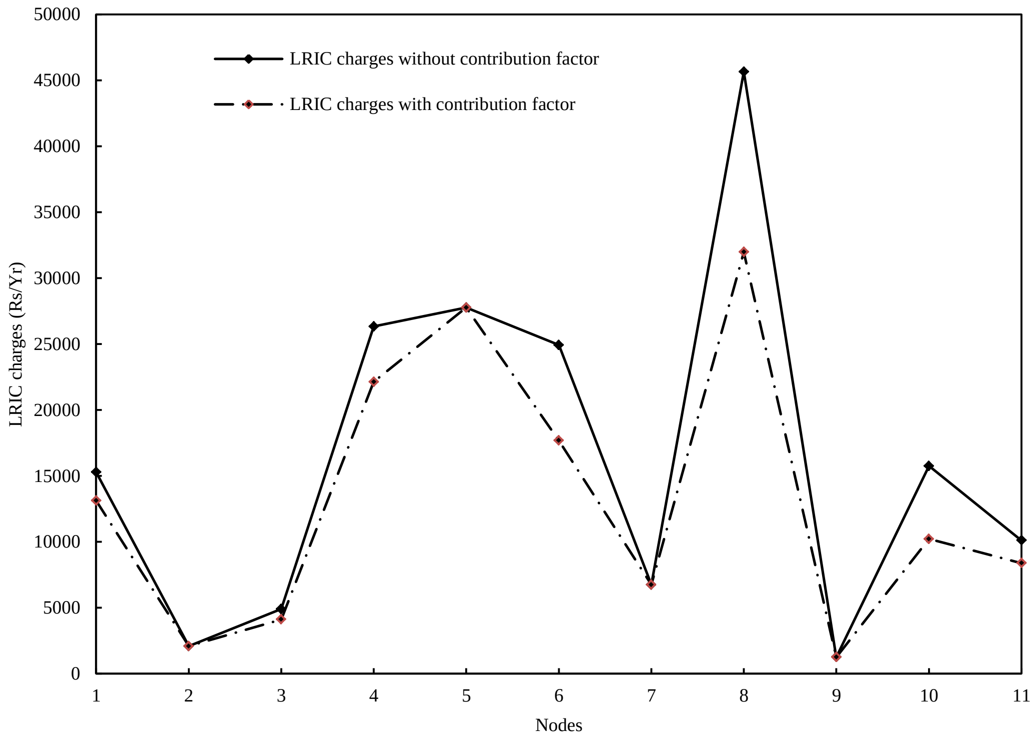


Fig. 3.7. Impact of CF on LRIC charges

From these CF’s, LRIC charges for various category users at all nodes are calculated using Eq. (3.9). LRIC charges for various categories without CF consideration are illustrated in Fig. 3.5. These charges are evaluated by multiplying various category loads at the nodes with unit charges calculated from Eq. (3.7) at that node. Here, various category users pay network charges for their connected load, and not for the load that is responsible for network reinforcement. This does not encourage the users to modify their usage as per network peak conditions.

Next, LRIC charges are computed for various category users considering their contribution to network peak demand. These charges are computed using Eq. (3.9) that reflects different categories’ peak demand contribution. Fig. 3.6 shows that various category users with different usage profile face different charges for connecting at the same node. It can be seen that charges for General category users are highest at all nodes except for node 5 as CF is highest for this category. At node 5, Industrial category users pay high charges due to absence of other category users at this node. Agricultural category users pay lowest charges because of their lowest coincidence to network peak. Water-Works users pay charges higher than Agricultural but lower than the Industrial category as their CF are lower than the Industrial category users.

For all consumer categories, charges are lower for various category users with CF consideration compared to those without CF considerations. This happens because category user’s actual usage contributions are less than their maximum demand imposed on the network. Finally, the overall charges paid by users at the nodes with and without consideration of CF are shown in Fig. 3.7.

As can be seen from Fig. 3.7, overall charges paid by users considering coincident demand are lower than those without coincidence consideration. Users are responsible for network reinforcement when their imposed demand on network results in its full utilization. CF consideration reflects the users’ contribution towards attaining full network capacities. Users contributing less towards peaks face lower incremental charges. As the coincident demand is lower than maximum demand imposed on network, the incremental charges paid by users are less in this case. Consideration of CF incentivizes users by offering reduced network charges for their low usage during network peaks. Hence, users are encouraged to improve their demand profile.

3.4 Conclusion

Considering the potential of SG technologies for providing smart network pricing, this chapter proposes a CF based LRIC model to be integrated in a smart grid environment. The CF is reflective of customer's contribution to network peak flow. The price signal would encourage users to improve their demand profile, to minimize their contribution to network congestion. This smart pricing signal is beneficial to both utility and users as they would bear reduced network charges, and as a result, the utility would face lower network congestion. Such modified behavior has the potential to provide effective demand-side management for reduced network investment.

This chapter gives a brief idea of incorporating customer category CF to existing LRIC pricing methodology, to offer category-specific signal. The contribution of users connected downstream is further propagated to network asset at the higher voltage levels reflecting their contribution to whole system reinforcement. In the next chapter, a new hierarchical CF based DUoS charging methodology is proposed to consider the true contribution of customer classes' load on network peak flows.

Chapter 4

Hierarchical Contribution Factor based Model for DUoS Charges

T**HIS** chapter proposes a novel Hierarchical Contribution Factor based Model, recognizing the contribution of different customer classes to the network reinforcement of upstream assets. Such contribution will be further propagated to network asset at higher voltage levels, forming a hierarchical CF model and reflecting the true individual class contribution to whole-system reinforcement.

Chapter – 4

HIERARCHICAL CONTRIBUTION FACTOR BASED MODEL FOR DUoS CHARGES

4.1 Introduction

In the previous chapter, a CF-based SNP model of network pricing is proposed where the CF is reflective of customer categories contribution to network peak. This chapter aims to develop a hierarchical CF based model to offer customer class-specific signal, along with a location-specific signal. For this purpose, to determine customer class contributions to upstream asset peak usage, two CF's are evaluated. Such contribution is further propagated to network assets at the higher voltage level forming a hierarchical CF model and reflecting the actual contribution of individual class to the whole-system reinforcement. The benefit of the proposed model on investment deferral is assessed by determining the annuitized present value of future investments, and impact is evaluated on a 22-bus practical Indian reference network.

This chapter is organized as follows. An introduction to the hierarchical CF based DUoS charging model is provided in Section 4.1. In the subsections of Section 4.2, a brief overview of the background, pricing framework, CF concept, and the mathematical formulation in determining DUoS charges are illustrated. Subsequent subsections of Section 4.3 describe the network used for proposed pricing analysis, parameters used, and the results obtained through simulations. A comparison of the results of the proposed model with the existing basic LRIC pricing methodology is also discussed in the successive sub-sections. The benefit of the proposed approach in terms of investment reduction is also discussed in Section 4.3. Finally, Section 4.4 concludes the outcomes of this chapter.

4.2 Hierarchical Contribution Factor based DUoS Charging Model

4.2.1 Background

Distribution network investment is mainly driven by peak demand. The power industry widely uses peak demand to classify customers as in UK [129], Finland [130] and India. UoS charges influence several operations for power system management such as network planning, customer tariff, and settlement. These activities are currently operated based on the load profiles. Therefore, to implement a pricing methodology for practical industry and also to ensure its compatibility with other activities, load profiles based on peak demand and customer class are required.

Traditional distribution network pricing approaches like LRIC pricing could give a location-specific signal to users, but they do not consider their contributions to network peaks. LRIC pricing methodology determines network charges as the difference in the present value of the future investment, consequent upon nodal power perturbation for generation or demand. Charges produced by this methodology reflect both distance and utilization of the distribution network components. However, these charges do not reflect actual network usage, and hence they do not give users a pricing signal based on their contribution in deriving network reinforcement.

This chapter develops a novel customer-specific DUoS charging model based on an HCM which distinguishes between different customer classes' contributions to the distribution network and to the upstream assets. As a first, this considers customer class's contribution to network peak flow instead of considering customer class's peak flow which may occur at a different time. A novel concept of CF is proposed here to evaluate contributions at two levels: i) contribution of the total load connected at any node to each upstream shared asset, and ii) contribution of customer class to the total load connected at any node. Based on this HCM model, the customer-specific DUoS charging model is implemented using the basic LRIC approach. The proposed approach encourages various customer classes to modify their distribution network usage pattern to minimize network peaks that result in delaying network investment. The ultimate goal of the proposed pricing scheme is to offer a customer class specific pricing signal to the distribution network users which incorporates CF to highlight users' contribution to network peak conditions, besides the location-based signal. Main contributions of the proposed work are summarized as follows:

i. A novel hierarchical contribution model based on CF to reflect actual propagation of the key reinforcement driver within a distribution network.

ii. The proposed model considers the contribution of customer class load to network peak rather than merely considering peak flow of a customer class. This reflects the actual impact of customer class load on network reinforcement requirement.

iii. For the first time, it proposes a usage-based pricing signal to customer classes in addition to the locational signal. This directly encourages them to modify their usage pattern in response to changed distribution network prices.

The research could make a significant impact on the efficient planning and operation of DNOs in a low carbon environment, offering individual charges to customer class considering their specific class characteristics. Lower distribution network charges can be provided for customer classes not expected to contribute to system peak, with their peak demand differing significantly from system peak demand characteristics. These charges attract customers with characteristics favorable for distribution network development at specific locations. Such charges would make the system efficient, and utilities may delay network reinforcements and investments in new generation units and network infrastructure [7, 131]. LRIC pricing is a well-established approach to evaluate long-term distribution network charges for UK distribution networks assuming that network reinforcement would be required when the loading level of circuit reaches its capacity. Hence, the proposed HCM based approach to offer customer class-specific signal is implemented using LRIC as the base approach. However, the HCM approach is equally applicable to other DUoS charging methodologies.

4.2.2 Pricing Framework

The proposed HCM based charging mechanism illustrated in Fig. 4.1 shows the algorithm to calculate customer class specific DUoS charges. This integrates the reflection of different customer class contributions to distribution network peak demand for network charging. The contributions are determined using CF, based on which coincident demand is calculated. CF is incorporated at two levels to reflect user’s actual network usage. First, contribution of the total load connected at any node to each upstream shared asset is considered using LACF. Based on this LACF, unit charges are computed at all nodes. Second, the contribution of customer class to the total load connected at that node is determined using CLCF. DUoS charges from the proposed model are evaluated for various customer classes connected to the network.

Outline of the proposed model is as follows:

i. Use input system data to evaluate LACF and CLCF.

ii. Obtain coincident demand from LACF.

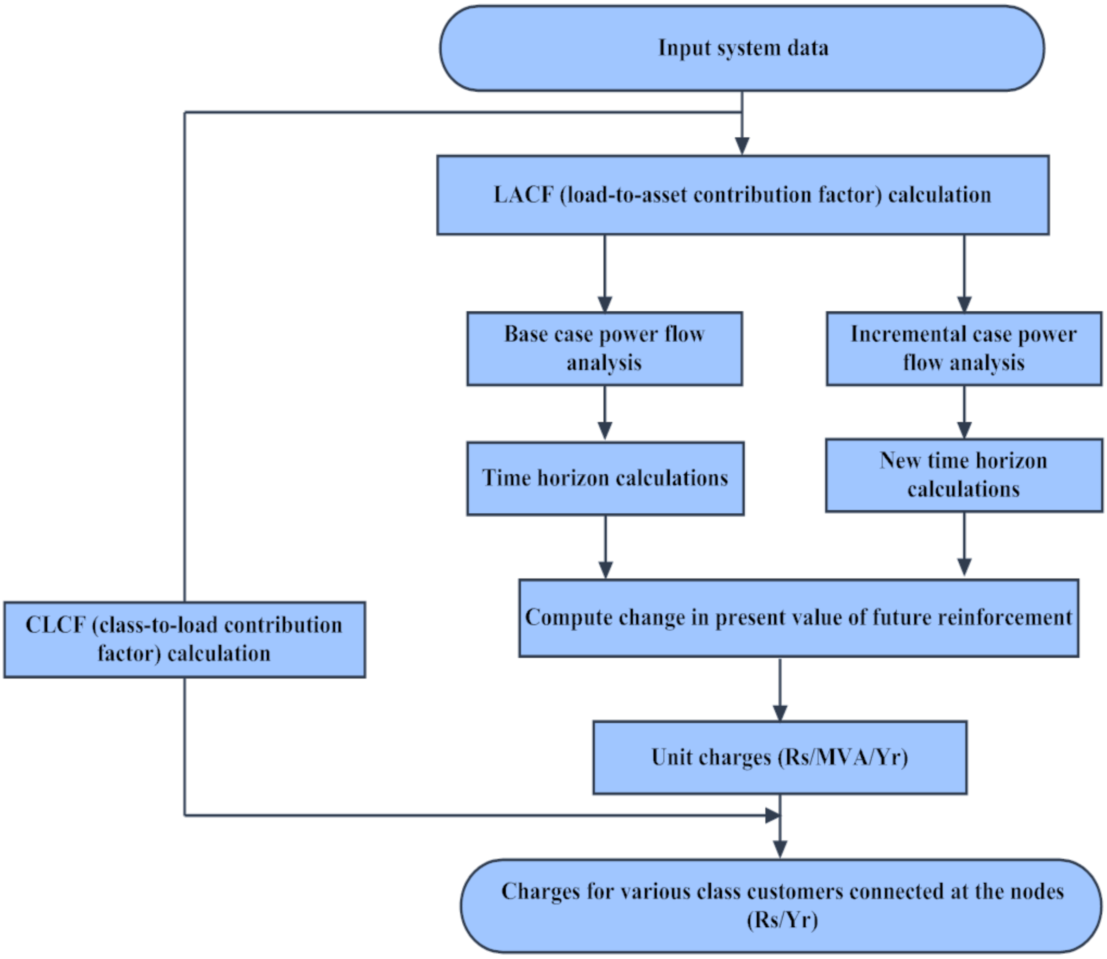


Fig. 4.1. Flow chart for Hierarchical Contribution Model

iii. Use these demand to perform power flow analysis. Evaluate time horizon and the present value of future reinforcement with and without nodal injections.

iv. With this change in the present value of future reinforcement, obtain the unit charges.

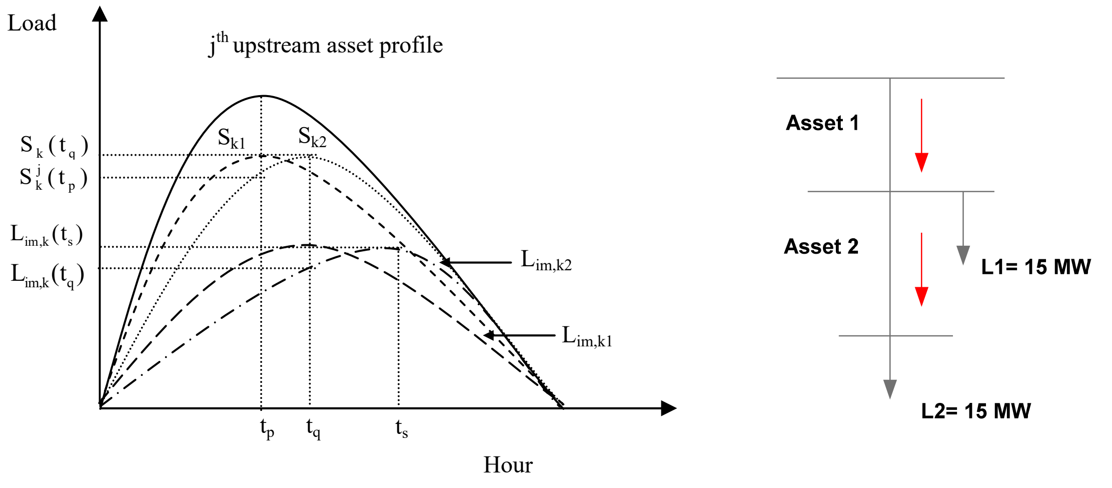
v. Use unit charges and CLCF to compute total DUoS charges for various classes of customers.

vi. Calculate the benefits of the new model through the annuitized present value of future reinforcement cost.

Flowchart of Fig. 4.1 describes the proposed model for evaluating customer class specific charges. Input system data, *i.e.*, sub-class profile, upstream asset profile, and total load profile at the node is used to assess LACF and CLCF. Coincident demand is computed from LACF and further used to calculate power flow through network asset. When the capacity of any network component is fully utilized, it needs to be reinforced in the upcoming future depending upon the load growth rate. Load growth rate refers to the percentage increase in demand at the node. This enhancement is known as future reinforcement in the network over a given planning horizon. Base case and incremental case load flows are run to compute the time horizon required for future network asset reinforcement. Base case power flow analysis determines network utilization under normal demand/generation condition, whereas incremental case power flow analysis assesses the effect of demand/generation change at the study node. After that, the present value of future reinforcement is calculated with and without nodal injections for all customer classes. Further, the annualized incremental cost of components is evaluated for all customer classes at the connection node. Aggregating the annualized incremental cost of components for all customer classes, unit charges are obtained. CLCF and unit charges are used to compute customer class specific charges. CF considered at two levels helps to determine the effective contribution of customer class on distribution network asset peak usage and reinforcement costs.

4.2.3 Contribution Factor Concept

The concept and impact of HCM approach can be highlighted using Fig. 4.2 (a). This figure represents multiple load profiles at different distribution network levels. S_{k1} and S_{k2} are two possible profiles of total load at node k, where k is the index of nodes. The traditional LRIC model evaluates charges for usage of j^{th} asset based on peak profile at k^{th} node. Here, j is the index of upstream assets. Since the peaks of both profiles are same, the traditional model does not differentiate between the impacts of two profiles on network charges. The proposed HCM approach uses LACF to evaluate the contribution of load at node k during the time of peak occurrence at the upstream asset j. Node k's contribution to upstream asset's peak is equal to $S_k^j(t_p)$ for profile S_{k2}, where t_p is the time of peak load occurrence of upstream asset j. This would result in higher charges for S_{k1} as compared to a relatively lower charge for S_{k2} despite their peaks being similar. This appropriately reflects the contribution of each profile to asset reinforcement and signals the user of profile S_{k1} to shift towards profile S_{k2}. Similarly, $L_{im,k1}$ and $L_{im,k2}$ are two possible load profiles of customer sub-class i in customer class m supplying node k. Here, m and i are the



(a) Load profile at different network levels (b) Simple 3-bus bar network

Fig. 4.2. Illustration of contribution factor concept

indices of customer classes and sub-classes respectively. CLCF is the contribution factor from customer sub-class i in customer class m to total load at node k during the occurrence of peak at node k. The contribution of subclass's load to total load's peak is equal to $L_{\mathrm{im,k}}(t_q)$ for profile $L_{im,k2}$, where t_q is the time of total load's peak occurrence at node k. This results in higher charges for $L_{im,k1}$ and lower charges for $L_{im,k2}$, despite their peaks being equal. This encourages user with $L_{im,k1}$ profile to shift towards profile $L_{im,k2}$ to reduce its contribution to peak of S_{k2}. This CLCF consideration reduces peak of total load at node k that result in reducing the upstream asset peak. CLCF calculation is independent from the load flow analysis and is calculated from the existing load profile scenario of customer sub-classes and total load connected at any node.

The proposed approach is highlighted using a 3-node network illustrated in Fig. 4.2 (b). Concerning to Fig. 4.2 (a) S_{k1} and S_{k2} are two possible profiles of load L2. $L_{im,k1}$ and $L_{im,k2}$ are two possible load profiles of customer sub-class i in the customer class m of load connected at load L2. Load L1 is supplied by asset 1 while load L2 is supplied by two networks identified as asset 1 and asset 2. Value of L1 and L2 loads is 15 MW each. The two assets are assumed to be identical having a capacity of 45 MW each with an overall cost of Rs.1000. Power flows are shown with red arrows. For this scenario, asset 2 supplies power only to load L2, hence it has a power flow of 15 MW. Asset 1 supplies power to both loads L1 and L2, hence it has a power flow of 30 MW.

For illustration, charges are calculated for load L2 only. To evaluate unit charges with the proposed approach, it is assumed that LACF for load L2 to upstream shared asset, *i.e.* asset 1 is 0.80. Asset 1 is the shared asset while asset 2 is the individual asset for this load. Thus, LACF for asset 2 would always be 1. With this LACF, coincident demand of load 2 to asset 1 comes out to be 12 MW. With the consideration of coincident demand, power flows through asset 1 and asset 2 will be 27 MW and 15 MW, respectively. From the power flows, time horizons for future reinforcement of asset are evaluated with and without 0.1 MW increment in load L2. The value of these time horizons for asset 1 and asset 2 are 31.94 and 32.18 (in Years), respectively. Then, the change in present value is evaluated from these time horizons which further gives unit charges. Unit charges for L2 node is 0.0346 Rs/MW/Yr.

Further, it is assumed that load L2 consists of A, B, C, and D classes having 30%, 40%, 20%, and 10% share in peak load at the connection node, respectively. CLCF for A, B, C, and D classes are presumed to be 0.5, 0.8, 0.6, and 0.7, respectively. With these unit charges and CLCF, total distribution-use-of system charges would be 0.078, 0.166, 0.062, and 0.036 (all in Rs/Yr) for the four customer classes, respectively.

A mathematical formulation reflecting the flowchart has been developed here. The unit LRIC charges are evaluated from the basic LRIC model, as detailed in Eq. (4.3) - (4.9) [35].

4.2.4 Mathematical Formulation

4.2.4.1 Coincident Demand Calculations for Each Upstream Asset

From the load profile data available at various nodes, the coincident demand of total load connected to any node k to the peak of an upstream asset j is calculated using load-to-asset CF. This factor is calculated as

$$\mathrm{LACF_{kj}} = \frac{S_k^j(t_p)}{S_k(t_q)} \tag{4.1}$$

where $S_k = [S_k(t_1), S_k(t_2), \cdots, S_k(t_n)]$ is the total load at node k for different times t, $t = [t_1, t_2, \cdots, t_n]$ is the time moment of daily load profile, $S_k^j(t_p)$ is the total load at node k at p^{th} time instant t_p which is the time of peak loading of an upstream asset j connected above node k, $S_k(t_q)$ is the total load connected at node k at time instant t_q which is the time of total load's peak at node k, $\mathrm{LACF_{kj}}$ is the contribution of total load connected at any load point k to any of its upstream asset j, k is index of network nodes, and j is the index of upstream assets feeding node k from the load point to the grid supply point. Here, j may or may not be an immediate upstream asset of node k.

From these LACF's, coincident demand of load at node k to each upstream shared asset j, *i.e.* CD_{kj} is evaluated as

$$\mathrm{CD}_{kj} = \mathrm{LACF}_{kj} * S_k(\mathrm{t}_q) \tag{4.2}$$

4.2.4.2 Unit LRIC Charges Calculation

Coincident demand calculated from Eq. (4.2) is used as input power flow data to assess actual asset usage. Distribution network asset needs reinforcement when its loading level approaches its capacity. So time horizon required for future reinforcement can be evaluated from current loading and capacity of network asset. Distribution network asset j supplying node k has power carrying capacity C_{kj} and supports power flow P_{kj}. Load growth rate for sub-class i of customer class m is assumed as r_{im}. Time horizon, in years, required to reinforce network asset j due to load growth in sub-class i of customer class m connected at node k is given by

$$n_{im,kj} = \frac{\log C_{kj} - \log P_{kj}}{\log(1+r_{im})} \tag{4.3}$$

LRIC charges are evaluated by reviewing the present value of future reinforcement cost with and without the load increment. The future investment can be discounted back to its present value. For a discount rate d, present value of future reinforcement in network asset j is determined for sub-class i of customer class m connected at node k as

$$PV_{im,kj} = \frac{AC_j}{(1+d)^{n_{im,kj}}} \tag{4.4}$$

where AC_j is the modern equivalent asset cost of network asset j. The present value of future investment is determined by discounting the modern equivalent asset cost to its present value.

The present value with nodal increment is evaluated considering new time horizon for future reinforcement. Power flow along the associated network assets j is altered by ΔP_{kj} due to nodal injection by customer sub-class i of customer class m supplying node k. The new time horizon for reinforcement of asset j is

$$n_{im,kj}^{new} = \frac{\log C_{kj} - \log(P_{kj} + \Delta P_{kj})}{\log(1+r_{im})} \tag{4.5}$$

This further changes the present value of future reinforcement in asset j for sub-class i of customer class m connected at node k

$$PV_{im,kj}^{new} = \frac{AC_j}{(1+d)^{n_{im,kj}^{new}}} \tag{4.6}$$

As a result of nodal injection, change in the present value for an asset j for sub-class i of customer class m connected at node k is

$$\begin{aligned} \Delta PV_{im,kj} &= PV_{im,kj}^{new} - PV_{im,kj} \\ &= AC_j \times \left(\frac{1}{(1+d)^{n_{im,kj}^{new}}} - \frac{1}{(1+d)^{n_{im,kj}}} \right) \end{aligned} \tag{4.7}$$

Annuitized unit incremental cost for network asset j due to sub-class i of customer class m connected at node k is

$$IC_{im,kj} = \frac{\Delta PV_{im,kj} * AF}{C_{kj}} \tag{4.8}$$

where AF is the annuity factor.

LRIC prices at node k is determined by the summation of annuitized incremental cost of all assets j by all customer classes over that node

$$LRIC_k = \frac{\sum_{j,im} IC_{im,kj}}{\Delta D_k} \tag{4.9}$$

where ΔD_k is the overall power injection at node k. From Eq. (4.9), unit LRIC charges in (Rs/MVA/Yr) at node k are obtained.

4.2.4.3 LRIC Charges for Various Customer Classes at the Nodes

After calculating unit LRIC charges, total charges are calculated for sub-class i of customer class m, considering that CF reflects class customer's contribution to peak of total load connected at node k. This class-to-load CF is

$$\mathrm{CLCF}_{\mathrm{im,k}} = \frac{L_{\mathrm{im,k}}(t_q)}{L_{\mathrm{im,k}}(t_s)} \tag{4.10}$$

where $L_{im,k} = [L_{im,k}(t_1), L_{im,k}(t_2), \cdots, L_{im,k}(t_n)]$ is the load of sub-class i of a customer class m connected at node k during time t; $t = [t_1, t_2, \cdots, t_n]$ is the time interval of daily load profile; $L_{\mathrm{im,k}}(t_q)$ is the load of sub-class i of a customer class m at q^{th} time instant t_q which is the time of total load's peak at node k; $L_{im,k}(t_s)$ is the load of sub-class i of customer class m connected at node k at time instant t_s which is the time of peak load occurrence of sub-class i, $\mathrm{CLCF}_{\mathrm{im,k}}$ is the contribution from customer sub-class i of class m to peak of total load at node k.

Charges for customer sub-class i of class m, reflecting its contribution to peak of total load connected at node k is

$$TLC_{im,k} = LRIC_k * \mathrm{CLCF}_{im,k} * L_{im,k}(\mathrm{t}_s) \tag{4.11}$$

where $TLC_{im,k}$ is the total LRIC charge for customer sub-class i of customer class m at node k. These charges reflect contributions of various customer classes to network peak. Hence, total LRIC charges are calculated for various customer classes from Eq. (4.11).

4.2.4.4 Investment Deferral Evaluation

The present value of future investment for asset j supplying node k is obtained from the proposed model. This is evaluated using $PV_{im,kj}$ obtained from Eq. (4.4).

$$PV_{kj} = \sum_{i,m} PV_{im,kj} \tag{4.12}$$

Benefit of the proposed model can be assessed in terms of the difference in the annuitized present value of future reinforcement cost of network assets, defined here as ΔPV . Mathematically this can be evaluated for the whole system as

$$\Delta PV = \sum_{k,j} (PV_{kj}^{old} - PV_{kj}) * \mathrm{AF} \tag{4.13}$$

where PV_{kj}^{old} is the present value of future investment for asset j supplying node k, evaluated from basic LRIC model [35].

4.3 Results and Analysis

This section first describes the system used for DUoS charges evaluation. Then the proposed HCM approach is illustrated for CF based DUoS charges determination, and the results obtained from the proposed approach are compared with the basic LRIC approach.

4.3.1 System Description

Efficiency evaluation of any network pricing methodology requires modelling of the network. Considering the large network size and the quantum of data to be handled,

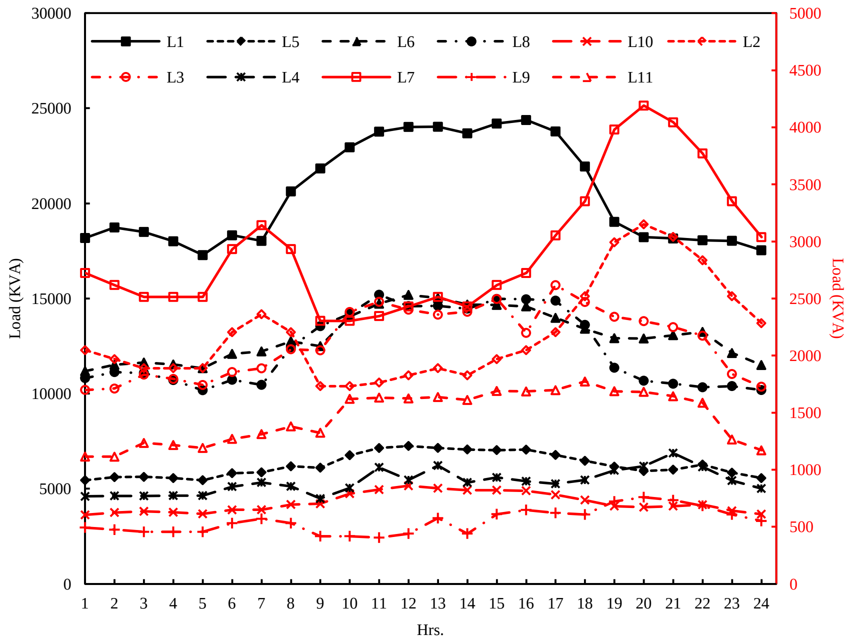


Fig. 4.3. Total load profile at various nodes

network pricing analysis could become a complex and challenging task. This necessitates reducing large practical networks into smaller representative networks called reference networks. The reference network used for analysis is the same as discussed in Chapter 3. Profile of the total load connected at various nodes is shown in Fig. 4.3. This profile is sufficiently different from various customer class and sub-class profiles of customers connected at these nodes. This diversity in load profile is represented by considering each customer class to be classified into customer sub-classes representing the capacity up-to which connection can be offered to various customers of that class. The General class comprises of three sub-classes with capacities 1 kW, 2 kW, and 5 kW. Industrial, Agricultural and Water-Works classes comprise of two sub-classes with capacities 17 kW & 50 kW, 7 kW & 25 kW and 5 kW & 15 kW, respectively.

With consideration of total load profile at various nodes, a representative average load profile for every sub-class over the preceding year is assumed to represent its network usage characteristics. Peak demand for these profiles is used to evaluate the contribution of different sub-classes to peak load at the connection node. Customer sub-classes of a particular class are presumed to have similar load profiles, and their response to price signals is presumed to be convergent. The cost of all transforming assets (T1, T2, …, T11) and line assets (D1, D2, …, D10) is to be allocated between customers of all sub-classes connected at load points (L1, L2, …, L11).

4.3.2 HCM based DUoS Charges Implementation

This section discusses the customer class specific charges based on HCM for the Indian reference network obtained from the proposed model. Coincident demand to each upstream asset is calculated for the demand at each node using its load profile. First, LACF's are calculated at the nodes from Eq. (4.1). CF's for loads at various nodes to each upstream shared asset is shown in Table 4.1.

As seen in Table 4.1, loads L1 and L8 dominate the usage of asset T1, while L2 and L7 have the lowest contribution to T1 usage. Also, L7 has the lowest contribution to the usage of asset D5, and L8 dominates usage of asset D5. Similarly, the contribution of other loads can be visualized for their usage contribution of asset supplying them power.

Table 4.1

Contribution factor of load to each upstream shared asset

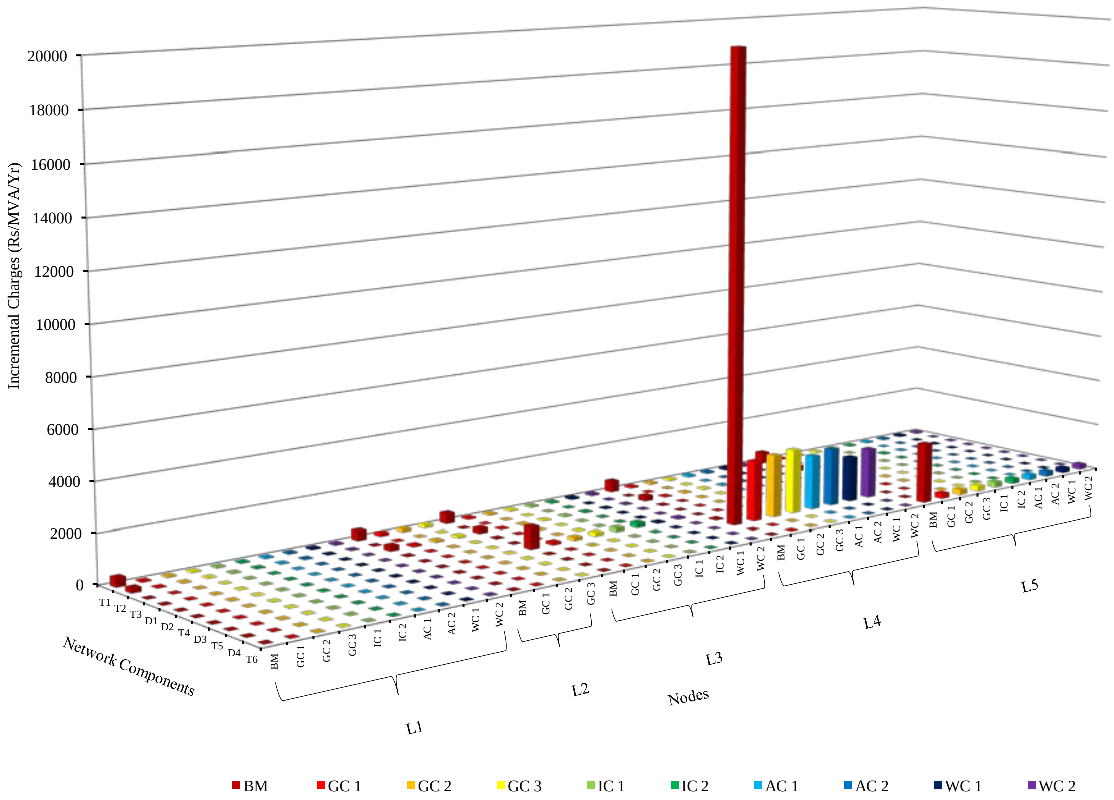
Nodes	**T1**	**T3**	**D1**	**D2**	**D3**	**D5**	**T8**	**D6**	**D7**	**D8**	**D9**
L1	0.99	-	-	-	-	-	-	-	-	-	-
L2	0.62	0.95	0.95	-	-	-	-	-	-	-	-
L3	0.95	0.89	0.89	0.94	-	-	-	-	-	-	-
L4	0.81	0.86	0.86	0.89	0.90	-	-	-	-	-	-
L5	0.97	0.84	0.84	0.98	0.98	-	-	-	-	-	-
L6	0.96	-	-	-	-	0.96	-	-	-	-	-
L7	0.62	-	-	-	-	0.65	0.72	0.72	-	-	-
L8	0.98	-	-	-	-	0.98	0.97	0.97	0.98	-	-
L9	0.80	-	-	-	-	0.85	0.81	0.81	0.80	0.75	-
L10	0.95	-	-	-	-	0.94	0.90	0.90	0.95	0.97	0.99
L11	0.94	-	-	-	-	0.93	0.95	0.95	0.94	0.92	0.91

Table 4.2

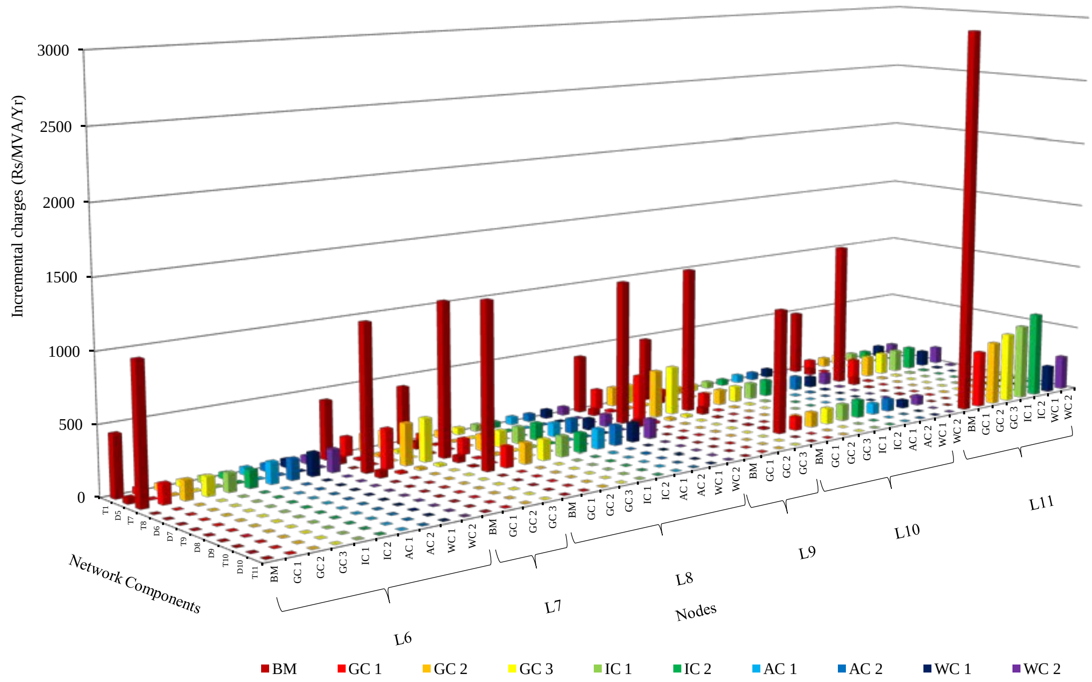
Percentage load growth rate for customer classes

Class	**Water Works**		**Agricultural**		**General**			**Industrial**	
Sub-class	Class 1	Class 2	Class 1	Class 2	Class 1	Class 2	Class 3	Class 1	Class 2
% LGR	1	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.9

Further, coincident demands of load to the upstream asset are evaluated from Eq. (4.2). Using these coincident demands as input network data, AC power flow is performed to compute flows required for calculating unit charges. Line, bus, and transformer data for power flow analysis are given in the appendix. The discount rate



(a) At Nodes L1-L5



(b) At Nodes L6-L11

Fig. 4.4. Component incremental charges for customer sub-classes

and the annuity factor are assumed as 6.9% and 7.4%, respectively [35]. Load growth rate varies in the range of 0 - 3% [53]. Growth rates assumed for various customer sub-classes are given in Table 4.2. All simulations are performed using MATLAB ® software. For unit charges at all nodes annualized incremental cost of all distribution network components is evaluated using Eq. (4.1) to Eq. (4.8) for customer sub-classes.

Incremental charges by customer sub-classes are shown in Fig. 4.4. Here, the component charges are shown with the basic LRIC model as well as for various sub-classes at all nodes with the proposed model. Individual network component charges for the customer of different classes connected at nodes L1 to L5 are represented in Fig. 4.4 (a), while that at nodes L6 to L11 are represented in Fig. 4.4 (b). The basic LRIC model offers the same incremental charges to each customer sub-class connected at a node while the proposed model offers different charges to each sub-class. The vertical axis of the plot represents incremental charges while the depth axis represents network components. Charges for each component by various sub-classes are shown in different colour. The horizontal axis shows customer sub-classes at the respective nodes. The first label of each nodal component, BM, represents incremental charges from the basic LRIC model. Depending on the customer sub-classes existing at each node, remaining labels of each nodal component are indicated by GC1, GC2, & GC3, IC1 & IC2, AC1 & AC2, and WC1 & WC2, representing various sub-classes of General, Industrial, Agricultural, and Water-Works classes, respectively.

As it can be seen from Fig. 4.4 (a), with the consideration of proposed model, a significant difference between the charges is created at node L4 comparing to the basic model. This happens because network component T5 serving load at this node is highly utilized, and hence the high charges are applicable to accommodate any nodal increment. Also, the charges for various sub-classes at all nodes consider LACF, hence they are relatively lower than that of BM. A similar difference can be visualized for nodes L6 to L11 in Fig. 4.4 (b).

For the explanation, the branch incremental charges calculated for every sub-class of customers connected at node L8 are shown in Table 4.3. The charges for asset T8 and T9 are high, but minuscule for D7 used by all customer classes. This is because T8 and T9 are highly loaded while D7 is lightly loaded. Another factor affecting charges for customer classes at any location is load growth rate. It can be seen in Table 4.3

Table 4.3

Branch incremental charges for node L8 (Rs/MVA/Yr)

		T1	D5	T8	D6	D7	T9
Water-Works	**Class 1**	62.32	3.07	83.01	5.02	0.37	141.39
	Class 2	59.76	3.66	92.27	5.16	0.43	145.61
Agricultural	**Class 1**	57.28	4.20	100.02	5.25	0.48	148.12
	Class 2	54.92	4.70	106.40	5.29	0.52	149.32
General	**Class 1**	52.68	5.14	111.59	5.30	0.56	149.54
	Class 2	50.58	5.53	115.75	5.28	0.59	149.03
	Class 3	48.60	5.87	119.02	5.24	0.61	147.98
Industrial	**Class 1**	46.76	6.16	121.54	5.19	0.64	146.53
	Class 2	43.42	6.63	124.79	5.06	0.67	142.82

that, for components like T1 (with 91% loading), the incremental charges decrease continuously as growth rate increases for various classes. For components like D5, T8, and D7 (with loading as 64.05%, 71.82%, and 68.11%, respectively), the charges rise

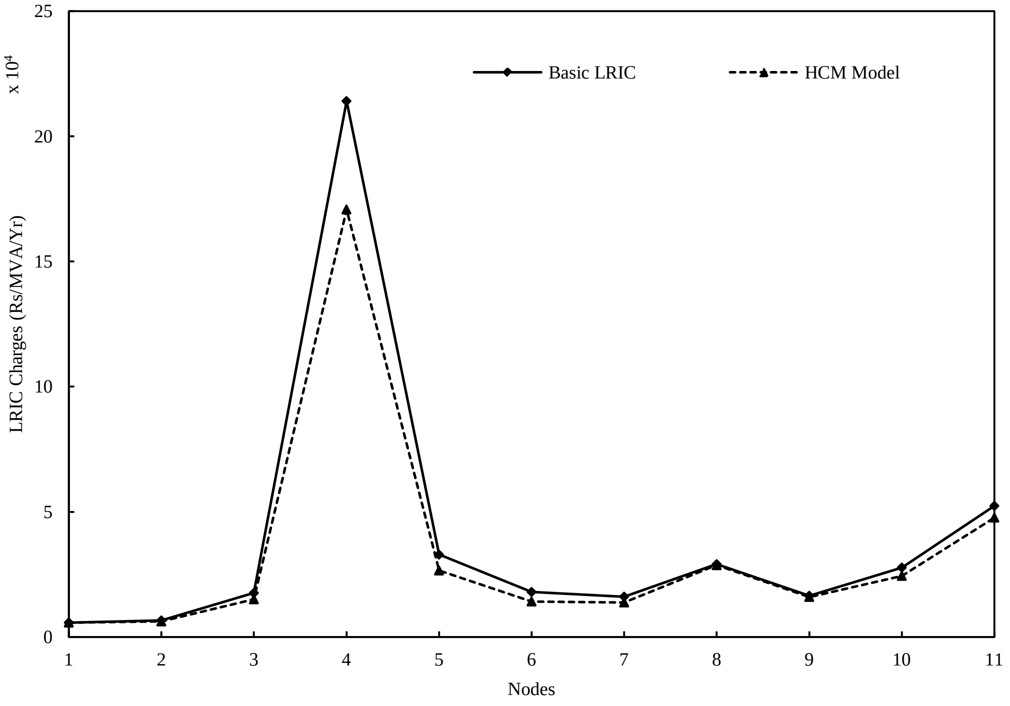


Fig. 4.5. Unit LRIC charges at all nodes

continuously with increase in growth rate. For components like D6 and T9 (with loading 81.52% and 81.44% respectively), the charges increase with growth rate till it reaches 1.4%, after which they decline. As these charges are evaluated considering coincident demand in upstream asset usage, they reflect actual incremental cost due to specific customer class. After computing annualized incremental cost for network components, unit LRIC charges are calculated at all nodes.

Unit charges computed from Eq. (4.9) are shown in Fig. 4.5. The impact of considering LACF in the proposed approach vis-à-vis the traditional approach can be visualized as the difference between charges. Basic LRIC model reflects only distance and utilization, whereas charges from the proposed model consider users' coincident demand on network usage reflecting distance utilization of network component and coincident peak usage of the asset by users. A high value of charge at node 4 reflects that major network asset serving load at this node has low capacity to accommodate overall 0.1 MVA load increment.

Table 4.4

Contribution factor of various customer classes

	General			**Industrial**		**Agricultural**		**Water Works**	
Nodes	**Class 1**	**Class 2**	**Class 3**	**Class 1**	**Class 2**	**Class 1**	**Class 2**	**Class 1**	**Class 2**
L1	0.57	0.51	0.44	0.91	0.81	0.60	0.62	0.76	0.74
L2	0.86	0.80	0.73	-	-	-	-	-	-
L3	0.77	0.67	0.69	0.87	0.71	-	-	0.88	0.93
L4	0.71	0.85	0.73	-	-	0.59	0.77	0.79	0.82
L5	0.56	0.50	0.52	0.86	0.75	0.87	0.81	0.88	0.78
L6	0.55	0.53	0.57	0.87	0.84	0.83	0.86	0.75	0.82
L7	0.88	0.85	0.83	-	-	-	-	-	-
L8	0.77	0.79	0.67	0.68	0.81	0.69	0.74	0.70	0.57
L9	0.74	0.78	0.77	-	-	-	-	-	-
L10	0.47	0.53	0.48	0.81	0.89	0.87	0.90	0.69	0.78
L11	0.58	0.62	0.68	0.77	0.78	-	-	0.84	0.88

Table 4.5

Total charges (Rs/Yr) for various class customers

	General			Industrial		Agricultural		Water-Works	
Nodes	**Class 1**	**Class 2**	**Class 3**	**Class 1**	**Class 2**	**Class 1**	**Class 2**	**Class 1**	**Class 2**
L1	8194	4721	1389	44250	37905	5208	4161	5241	6205
L2	7997	4969	2965	-	-	-	-	-	-
L3	4658	2031	1609	9403	5337	-	-	6626	4495
L4	16697	58278	24822	-	-	14613	13117	19796	13935
L5	10874	13218	10951	34890	19821	22753	14964	20844	16514
L6	13070	19030	20358	39116	30330	25263	30877	27565	29574
L7	14484	23474	11492	-	-	-	-	-	-
L8	12541	13510	7720	140390	115885	4369	6364	16048	10521
L9	3083	3741	2462	-	-	-	-	-	-
L10	4008	6432	4658	16305	23907	11325	13129	11104	13357
L11	5892	4459	8083	10326	11194	-	-	13455	16877

After computing unit charges, the contribution of specific class customers to the total load is evaluated from Eq. (4.10) and shown in Table 4.4. This CLCF reflects the contribution of various customer sub-classes to the total load connected at any node. As seen from Table 4.4, the sub-classes of General class have the lowest contribution while the Industrial sub-classes have the highest contribution to the peak load of L1. Further, the sub-classes of Water-Works class have the highest and the sub-classes of General classes have the lowest contribution to the peak load of L11. Similarly, the contribution of various customer sub-classes in the total load connected at the nodes can be observed. This reflects customer class contribution to the nodal peak loads responsible for network reinforcement. Customer classes are charged only for part of load coinciding with peak nodal demand and not for their maximum load. Due to this, charges with the proposed model would be more cost-reflective than that with the traditional model.

Total DUoS charges for various class customers located at different nodes are given in Table 4.5. Characteristics of individual customer class are considered to calculate total network charges with CLCF from Eq. (4.11). Customers are charged for network usage based on their contribution to the nodal peak conditions. These charges with CF consideration reflect individual customer class contribution to the network loadings.

The total charges paid by users at different nodes with and without CF consideration are shown in Fig. 4.6. As it can be seen that the total charges paid by users connected at the nodes considering CF are lower than that without CF consideration. Charges are lower because consideration of coincident demand reduces future distribution network investment. DUoS charges without consideration of coincident demand reflect both the distance and utilization of distribution network components. These charges do not reflect actual network usage, and hence they do not give users a pricing signal based on their load profile. Distribution network users are responsible for reinforcement of components when their imposed demand on network results in its full utilization.

Information about the timing of network peak usage is reflected in the electricity bill. Consideration of CF incentivizes users by offering reduced charges for their low usage

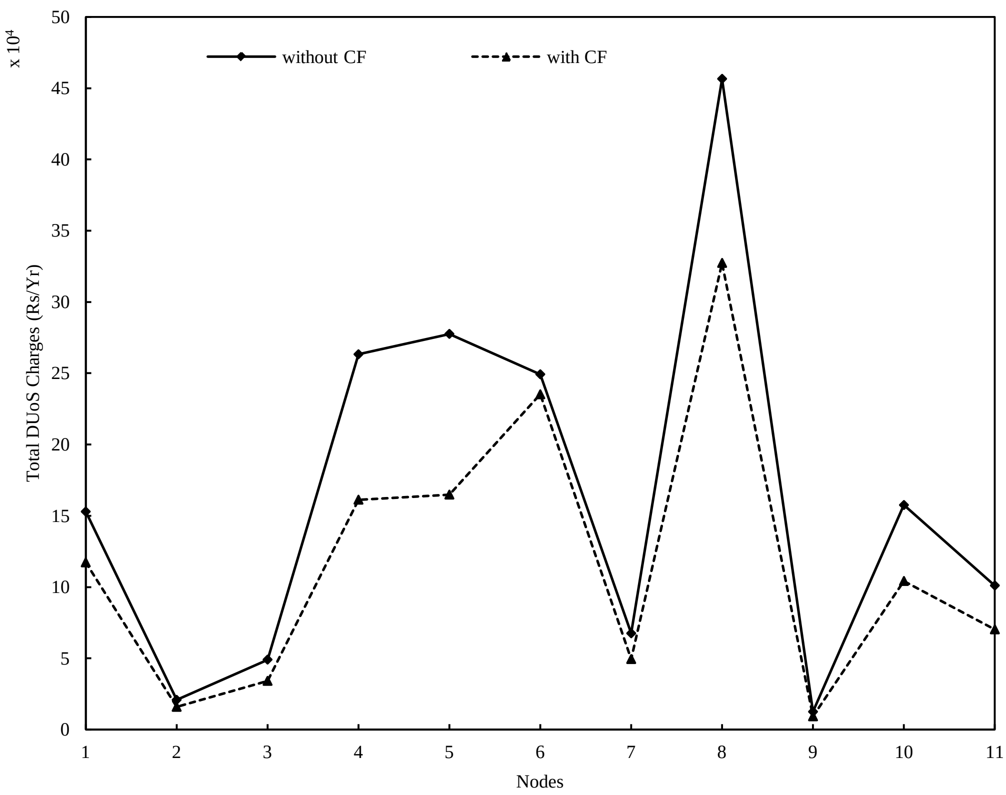


Fig. 4.6. Impact of CF on total DUoS charges

during network peaks. Hence, users are encouraged to improve their load profile and reduce their contribution to the network peak. This results in lowering the total charges for users with CF consideration, as compared to the basic model which does not consider customer contributions. Modified load profile reduces network peaks resulting in network reinforcement delay and investment deferral. Here, the load profiles over the preceding year are used and updated every year. As the signal offered is based on a yearly profile, the customer response can be visualized as a composite load profile change over the following year.

4.3.3 Deferral in Network Investment

The annuitized present value of future reinforcement cost over all assets evaluated from Eq. (4.13) is shown in Fig. 4.7. Here, network component T1 and T8 have high annuitized present value. Investment for these components comes down significantly with the proposed pricing model. The proposed HCM approach offers lower annuitized present value for other components as well. The overall present value of future investment for all components with the proposed and basic LRIC pricing models defers investment. The proposed pricing approach offers an investment reduction of Rs. 90.338k per year for the considered 22-bus system.

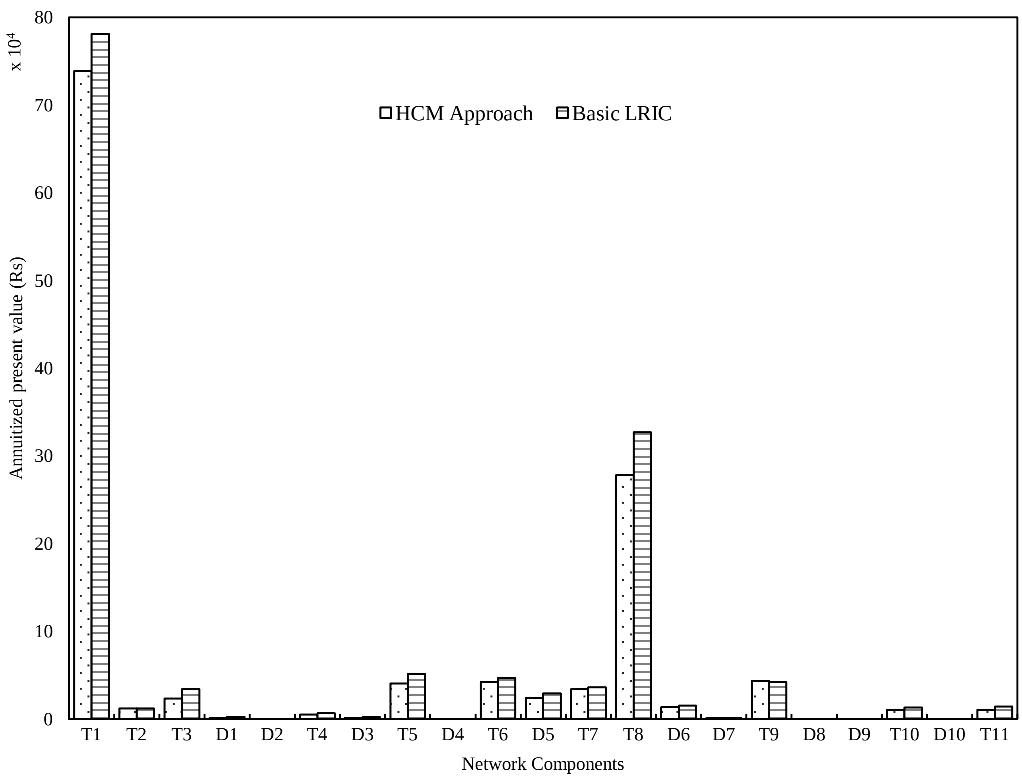


Fig. 4.7. Comparison of annuitized present value

4.4 Conclusion

The existing DUoS charging approaches offer location-specific signal to customers and charge them based on their use-of-system. These approaches consider the load profile in conjunction with the system's peak load, to calculate the component of network charges to be levied on a specific class. The calculations are based on measurements performed at the system level and not based on network flows in any upstream network. Thus, it does not offer a justifiable reflection of network usage, but just an assumed reflective usage. Also, such models do not differentiate between various customer classes' contributions to the distribution network peak flow. This chapter proposes an HCM based model to offer customer class-specific signal along with a locational signal. This considers different customer class contributions to network peak demand using LACF and CLCF. CFs considered at two levels determines customer classes' effective contribution to asset reinforcements for evaluating distribution network prices.

The proposed model provides a forward-looking economic signal, and thus encourages customer classes to improve their load profile and reduce their contribution to distribution network peaks. The price signals provided by this model are beneficial to both utility and users. Consequently, the users would be charged lower network charges and utility would defer network investment. With increasing penetration of smart meters, this pricing model is likely to have a wider influence on the future network charging mechanisms. Major investment is being made in the world over the smart meters and smart distribution management systems, with the UK targeting a complete smart meter roll out at the household level. As a general framework, the smart meters could be used at multiple network levels to measure real-time power flow in networks at each level. With smart distribution management systems and embedded algorithms in place, information from each network level could be correlated and processed to assess any customer's contributions to upstream network asset's peak power flow at each level. These true network usage reflections could be translated into the price signals representing network usage charges. This would offer an opportunity to assess a measured reflection of network usage, rather than the presumed network usage based on customer's peak load.

Due to the limited visibility at LV networks, the existing DUoS charging methodologies assume that all the network users use the network in proportion to their peak flows. This naive supposition fails to reflect the contribution of network users to network peak flows which is the driver for network reinforcement. This chapter proposes a new DUoS charging model recognizing the contributions of different customer classes to the network reinforcement of upstream asset. Further, increasing penetration of RG results in a variable generation. In the modified LRIC pricing model next chapter incorporates short-term DSR signal for demand customers to manage variability caused by RG.

Chapter 5

Demand Response based Enhanced LRIC Pricing Framework

THIS chapter enhances LRIC pricing model that incorporates short-term DSR signal for demand customers, to mitigate uncertainties caused by renewables. The short-term DSR signals in the form of peak/off-peak charge offered in conjunction with demand elasticity, helps to modify customer response.

Chapter – 5

DEMAND RESPONSE BASED ENHANCED LRIC PRICING FRAMEWORK

5.1 Introduction

In the previous chapter, the HCM based DUoS charging mechanism is developed for calculating customer class-specific DUoS charges. This integrates the reflection of different customer class contributions to distribution network peak demand for network charging. The research work on the HCM based modified LRIC pricing framework is further extended to incorporate short-term demand response signal for demand customers to manage variability caused by renewable generation. These short-term DSR signals in the form of peak/off-peak charge offer, in conjunction with demand elasticity, helps to assess customer response. This result in a modified load profile for various class customers connected at the nodes, which are further used to evaluate network charges.

A detailed introduction to DSR has been discussed in Chapter 2. Therefore, only a brief introduction to the need for utilizing demand flexibility with increasing renewable penetration is given in Section 5.2 to maintain the continuity of work. The implementation steps of demand response based LRIC model are also described in Section 5.2. The performance results of the enhanced LRIC pricing framework are presented in subsequent Section 5.3. Finally, Section 5.4 concludes the main findings of the chapter.

5.2 Demand Response based Enhanced LRIC Pricing Model

5.2.1. Background

Development of a low-carbon electricity supply system requires DNO's to be able to influence generators' behavior and to offer ancillary services. Moreover, DNOs have to ensure targeted standards of network operations and expansion. DNOs are expected to undertake significant investment, to accomplish these changes. In particular, they will have to expand their network and improve its reliability to accommodate increased generation from renewable energy sources.

Demand Response based Enhanced LRIC Pricing Framework

As the developed countries are moving towards a low-carbon economy, demand-side management has become a valuable tool to mitigate carbon footprints. Low-carbon demand-side technologies such as renewables, electric vehicles, and electric heat pumps contribute to both daily peak demand and a proportion of elastic demand. At the same time, the need for demand-side flexibility is likely to increase as the electricity generation from low-carbon technologies enhances, which is often highly variable, less flexible and less predictable [104-105].

A pricing signal dependent on future network cost offers prospects for network users to respond if they desire to alter their consumption in such a way that can decrease the cost of network usage. This eventually reduces future network cost and prices for all network users. For the pricing signals to be cost effective users should relate their demand profile to the structure of network prices. This work incorporates short-term DSR with modified LRIC pricing methodology to mitigate uncertainty caused by renewable generation. The proposed framework offers pricing signals based on time differentiated network utilization to change various customer class profiles based on their elasticity. These modified profiles are further used to compute network charges in modified LRIC pricing framework. The approach triggers a behavior change in the network users in response to time-varying charges, eventually alleviating network congestion and delaying investment.

Main contributions of this chapter are:

i. Proposes an enhanced LRIC mechanism to facilitate short-term DSR for mitigating uncertainty caused by renewable generation.

ii. Conveys pricing signal to customer classes to encourage them to alter their behavior in response to time-varying distribution network charges. This alleviates network congestion and delays investment.

5.2.2. Pricing Framework

The proposed LRIC pricing mechanism is illustrated in Fig. 5.1. The approach discussed in this chapter allocates network cost considering demand flexibility and user's actual contributions in deriving future network investment. User's real contributions can be evaluated using CF. The impact of DSR on LRIC charges is assessed based on a representative profile of users which serves as a tool to alleviate

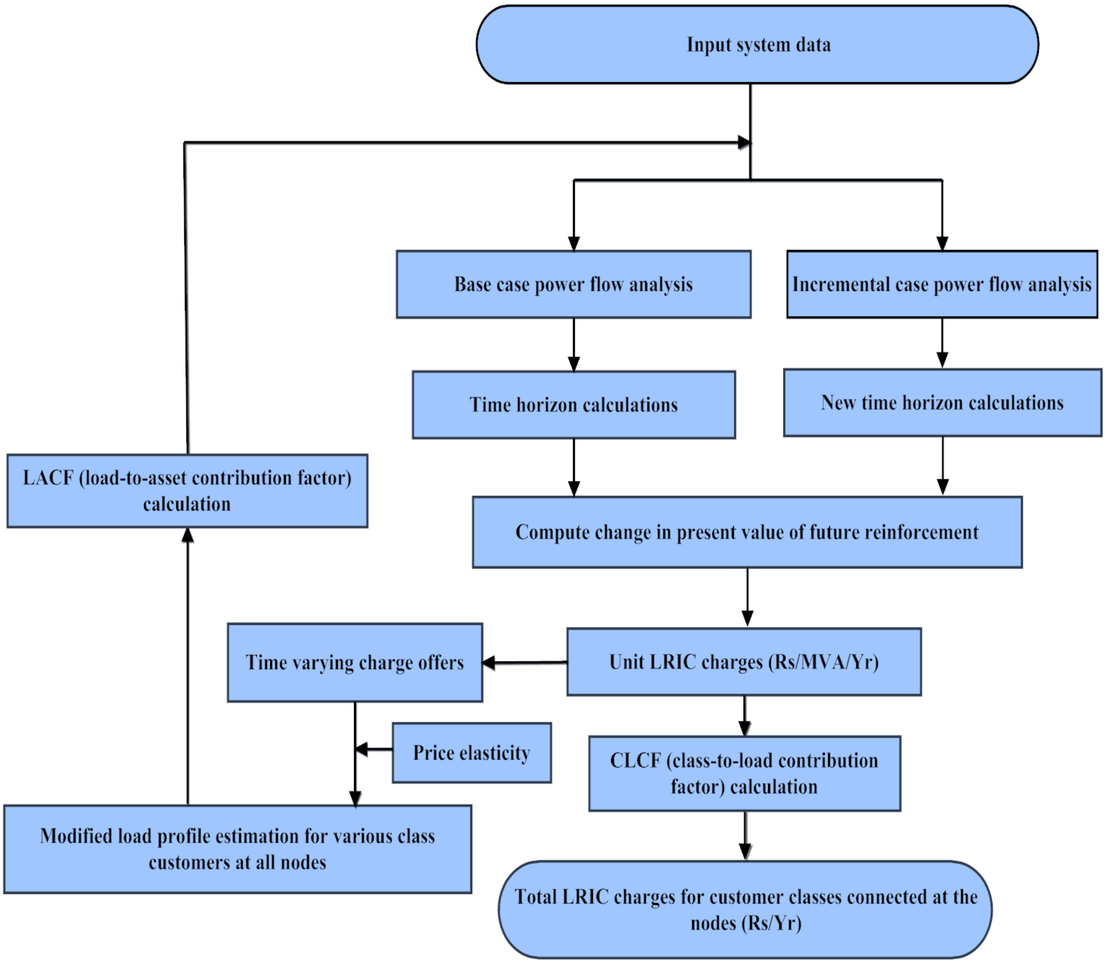


Fig. 5.1. Flow chart for proposed LRIC pricing model

network burden and defer distribution network investment. DSR considered here in the long run significantly reduces peak demand on the network and hence delays the time required to reinforce the network. Fig. 5.1 describes the proposed methodology with the help of a flow chart. From the input system data, base case and incremental case power flow analysis is done to compute the time horizons required to reinforce the distribution network asset. Then, from these time horizons, the present value of future network reinforcement is evaluated with and without nodal injections. Further, changes in the present value of future reinforcement are computed, and multiplying these changes in present value with the annuity factor gives the annualized incremental cost of assets at the connection node. From these annualized incremental costs, unit LRIC charges are obtained by aggregating the annualized incremental cost of all assets. After computing unit charges from the basic LRIC approach, time-varying network charges are offered to users based on their representative load profile. Network users respond to these charges as per their price elasticities. Hence, the load scenario is modified due to DSR. So, unit LRIC charges are re-evaluated for the changed scenario of load profile with due consideration of load-to-upstream asset CF, *i.e.*, LACF.

Further, the approach evaluates different class customers' contribution to the peak network conditions through class-to-load CF, *i.e.*, CLCF for computing total network charges for various customer classes. From these CLCF and unit charges, the total LRIC charges are calculated reflecting customer class contributions to the peak of the total load connected to the node. CF considered at two levels helps to determine the effective contribution of customer class on distribution asset reinforcement costs.

As can be seen from Fig. 5.1, the unit LRIC charges are calculated from the basic LRIC model as in [35]. A reflection of the above flowchart, in the form of the mathematical formulation, is described below.

5.2.3. Mathematical Formulation

5.2.3.1 Demand Response by Various Customer Classes

Unit charges are first obtained from the basic LRIC model [35]. After computing unit charges, the modified demand is obtained through presumed price elasticity for various class customers and time-varying charge offers.

Time-varying charge offers are determined as

$$\begin{aligned} &P_{off-peak} = (1-\gamma)\, P_o && \forall \quad D_o \le 0.2 D_p \\ &P_{flat} = P_o && \forall \quad 0.2 D_p < D_o < 0.8 D_p \\ &P_{peak} = (1+\gamma)\, P_o && \forall \quad D_0 > 0.8 D_p \end{aligned} \tag{5.1}$$

where D_p is peak demand of customer class connected at any node, D_o is reference demand profile of customer class, γ is the signal strength offered to customer class and its value can vary from 0 to 100%, and P_0 is reference price, *i.e.* unit charges from basic LRIC model.

Modified demand in response to price changes can be given as [132]

$$D = D_0 + \frac{\varepsilon\, D_0}{P_0}\left(P - P_0\right) \tag{5.2}$$

where

ε = price elasticity

D = modified demand profile of customer class in response to price changes

P = new price (time varying price) offered to customers

From Eq. (5.2), the modified profile of class customers is obtained.

5.2.3.2 Coincident Demand Calculations for Each Upstream Asset

Traditional LRIC pricing approach evaluates charges for usage of the distribution network asset, based on peak profile at the nodes. Since two load profiles may have same peaks but the timing of their peak occurrence may differ. In such a situation, the existing approach does not differentiate between the impacts of two profiles on distribution network charges. Modified LRIC approach uses LACF for evaluating contribution of load at the node to the peak usage of upstream asset. This could produce different charges for these two profiles having a different contribution to the upstream asset peak usage and thus appropriately reflecting their contribution to asset reinforcement. This, in turn, would signal users to shift their profile towards the profile producing lower LACF.

Mathematically, from the modified load profile data available at various nodes, the total load contribution to upstream asset peak usage can be evaluated using load-to-asset CF. This factor is calculated as

$$\mathrm{LACF}_{\mathrm{kj}} = \frac{S_k^j(t_p)}{S_k(t_q)} \tag{5.3}$$

where $\mathrm{LACF}_{\mathrm{kj}}$ is the contribution of total load connected at any load point k to any of its upstream asset j, k is the index of nodes in the network, and j is index of upstream assets feeding at node k from the load point to the grid supply point, $S_k = [S_k(t_1), S_k(t_2), \cdots, S_k(t_n)]$ is the profile of total load at node k, $t = [t_1, t_2, \cdots, t_n]$ is the time interval of daily load profile, $S_k^j(t_p)$ is the total load at node k at p^{th} time instant t_p which is the time of peak loading of an upstream asset j connected above node k, and $S_k(t_q)$ is the total load connected to node k at time instant t_q which is the time of total load's peak at node k. Here, j may or may not be the immediate upstream asset of node k.

From these LACF, the coincident demand of load at the node k to each upstream shared asset j, *i.e.* CD_{kj} is evaluated as

$$\mathrm{CD}_{kj} = \mathrm{LACF}_{\mathrm{kj}} * S_k^{Rated} \tag{5.4}$$

where S_k^{Rated} is the rated load connected at node k.

5.2.3.3 Unit LRIC Charges

Coincident demand calculated from Eq. (5.4) is used as the input power flow data to assess actual asset usage. Distribution network asset j supplying load to the connection node k has power carrying capacity C_{kj} and supports a power flow P_{kj}. Load growth rate for sub-class i of customer class m is assumed as r_{im}. Time horizon, in years, required to reinforce network asset j due to the load growth in each sub-class i of customer class m connected at node k is given by

$$n_{im,kj} = \frac{\log C_{kj} - \log P_{kj}}{\log(1 + r_{im})} \tag{5.5}$$

The future network investment can be discounted back to the present value according to how far into the future investment will occur. For a discount rate d, the present value of future investment in network asset j is determined for sub-class i of customer class m connected at node k as

$$PV_{im,kj} = \frac{AC_j}{(1+d)^{n_{im,kj}}} \tag{5.6}$$

where AC_j is the modern equivalent asset cost of network asset j.

Further, power flow along with the associated network assets j is altered by ΔP_{kj} due to nodal injection caused by customer sub-class i connected at node k. Hence, the new time horizon for reinforcement of asset j is

$$n_{im,kj}^{new} = \frac{\log C_{kj} - \log(P_{kj} + \Delta P_{kj})}{\log(1 + r_{im})} \tag{5.7}$$

This further changes the present value of future reinforcement in asset j for sub-class i of customer class m connected at node k

$$PV_{im,kj}^{new} = \frac{AC_j}{(1+d)^{n_{im,kj}^{new}}} \tag{5.8}$$

As a result of nodal injection, change in the present value for an asset j for sub-class i of customer class m connected at node k is given by

$$\begin{aligned}\Delta PV_{im,kj} &= PV_{im,kj}^{new} - PV_{im,kj} \\ &= AC_j \times \left(\frac{1}{(1+d)^{n_{im,kj}^{new}}} - \frac{1}{(1+d)^{n_{im,kj}}} \right)\end{aligned} \tag{5.9}$$

Annualized unit incremental cost for network asset j is given as

$$IC_{im,kj} = \frac{\Delta PV_{im,kj} * AF}{C_{kj}} \tag{5.10}$$

where AF is the annuity factor.

LRIC prices at node k is determined by the summation of annuitized incremental cost of all assets j by all customer classes over that node

$$LRIC_k = \frac{\sum_{j,im} IC_{im,kj}}{\Delta D_k} \tag{5.11}$$

where ΔD_k is overall power injection at node k. From Eq. (5.11), unit LRIC charges in (Rs/MVA/Yr) at the node k are obtained.

5.2.3.4 LRIC Charges for Various Customer Classes at the Nodes

After calculating unit LRIC charges, the total charges are calculated for sub-class i of customer class m considering that CF reflects class customer's contribution to the peak of a total load connected to node k. This class-to-load CF is calculated as

$$\mathrm{CLCF}_{\mathrm{im,k}} = \frac{L_{\mathrm{im,k}}(t_q)}{L_{\mathrm{im,k}}(t_s)} \tag{5.12}$$

where $L_{im,k} = [L_{im,k}(t_1), L_{im,k}(t_2), \cdots, L_{im,k}(t_n)]$ is the load of sub-class i of a customer class m connected at node k during time t; $t = [t_1, t_2, \cdots, t_n]$ is the time interval of daily load profile; $L_{\mathrm{im,k}}(t_q)$ is the load of sub-class i of a customer class m at q^{th} time instant t_q which is the time of total load's peak at node k; $L_{im,k}(t_s)$ is the load of sub-class i of customer class m connected at node k at time instant t_s which is the time of peak load of sub-class i, $\mathrm{CLCF}_{\mathrm{im,k}}$ is the contribution from customer sub-class i of class m to peak of total load at node k.

Now, the charges paid by a customer sub-class i of class m reflecting its contribution to peak of total load at node k, is given as

$$TLC_{im,k} = LRIC_k * \mathrm{CLCF}_{im,k} * L_{im,k}^{Rated} \tag{5.13}$$

where $TLC_{im,k}$ is the total LRIC charge for customer sub-class i of customer class m at node k and $L_{im,k}^{Rated}$ is the rated load of customer sub-class i of customer class m at node k. These charges reflect contributions of various customer classes to network peak. Hence, the total LRIC charges are calculated for various customer classes from Eq. (5.13).

5.2.3.5 Investment Deferral

The present value of future investment for a component j connected at node k is obtained from the proposed approach. This is evaluated using $PV_{im,kj}$ as obtained from Eq. (5.6).

$$PV_{kj} = \sum_{i,m} PV_{im,kj} \tag{5.14}$$

Benefit of the proposed approach can be assessed in terms of the difference in annuitized present value of future reinforcement cost of the network components defined here as ΔPV. Mathematically, this can be evaluated for the whole system as

$$\Delta PV = \sum_{k,j} (PV_{kj}^{old} - PV_{kj}) * \mathrm{AF} \tag{5.15}$$

where PV_{kj}^{old} is the present value of future investment for a component j connected to the node k evaluated from the basic LRIC model [35].

5.3 Results and Analysis

This section presents the description of the network used for DR based LRIC charges evaluation. Then, it further illustrates charge determination from the proposed approach and compares its results with that of the traditional LRIC approach.

5.3.1. System Description

The detailed description of this 22-bus practical Indian reference network is the same as given in Chapter 3. Also, customer segmentation considered in this chapter is the same as in Chapter 4. In this case, a 2 MVA wind DG operating at 0.95 power factor is connected at load L4 to highlight the impact of the proposed model on network charges with connected DG and is shown in Fig. 5.2. The profile of total load connected at various nodes is shown in Fig. 5.3.

For simplicity, a representative profile of every customer sub-class is considered in this work to represent their network usage characteristics for the whole year. This can be re-evaluated after some time interval to update the customer behavior. Long run price elasticity considered for each customer sub-class of a specific class is shown in Table 5.1. These values are comparable to elasticity data given for various categories in the Australian electricity market [133].

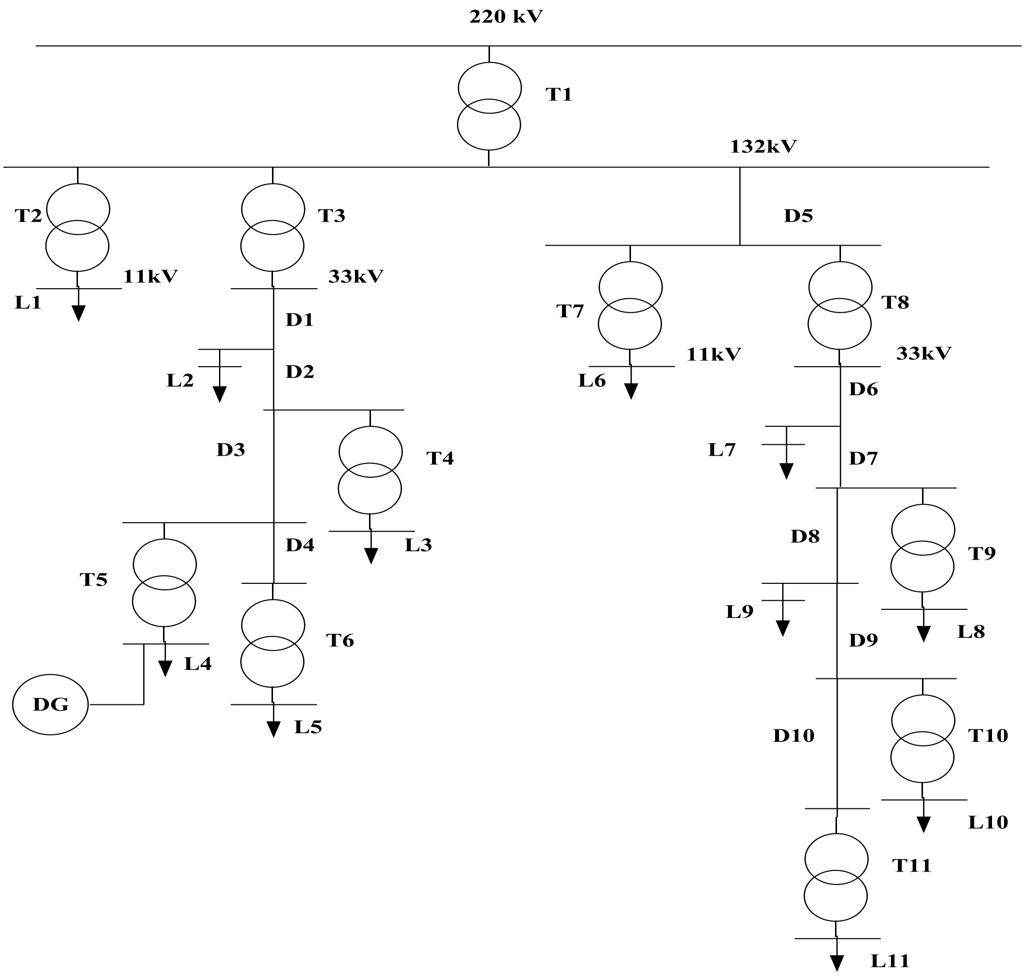


Fig. 5.2. 22-bus practical Indian reference network [128]

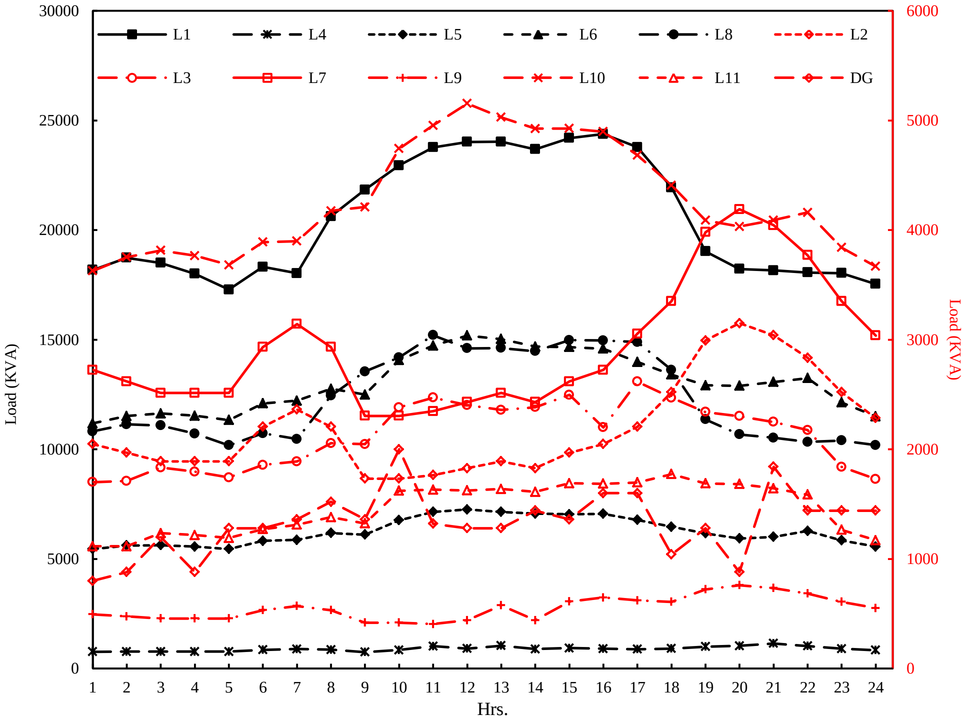


Fig. 5.3. Total load and DG profile at various nodes

5.3.2. Proposed LRIC Charges Implementation

This section illustrates the derivation of LRIC charges considering the impact of DSR and customer class contributions on peak network usage. AC load flow is performed to compute network flows required for calculating unit LRIC charges from the basic LRIC model. Line, bus, and transformer data for power flow analysis are given in the appendix. The discount rate and the annuity factor are considered as 6.9% and 7.4%, respectively [35]. Load growth rates assumed for various customer sub-classes are given in Table 5.2. All simulations are performed using MATLAB ® software. Unit LRIC charges are calculated as per the basic LRIC model from peak load connected at all network nodes [35].

Table 5.1

Long run price elasticity for various class customers

General			Industrial		Agricultural		Water-Works	
Class 1	Class 2	Class 3	Class 1	Class 2	Class 1	Class 2	Class 1	Class 2
-0.15	-0.2	-0.25	-0.3	-0.38	-0.4	-0.45	-0.15	-0.25

Table 5.2

Percentage load growth rate for customer classes

Class	**Water Works**		**Agricultural**		**General**			**Industrial**	
Sub-class	Class 1	Class 2	Class 1	Class 2	Class 1	Class 2	Class 3	Class 1	Class 2
% LGR	1	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.9

Table 5.3

Time-varying charge offers at various network locations (Rs/KVA/Yr)

Nodes	**L1**	**L2**	**L3**	**L4**	**L5**	**L6**	**L7**	**L8**	**L9**	**L10**	**L11**
Unit/ Reference Prices	5.45	5.23	16.16	-31.53	31.00	13.85	15.55	28.41	15.91	27.03	51.77
Peak prices	6.54	6.27	19.39	-37.84	37.19	16.62	18.66	34.09	19.09	32.43	62.13
Off-Peak prices	4.36	4.18	12.93	-25.22	24.80	11.08	12.44	22.73	12.73	21.62	41.42

After the calculation of unit charges from the basic LRIC model, peak and off-peak charge offer at every location are determined using Eq. (5.1). Signal strength is assumed to be 20% for all customer classes for this set of simulations. From the charge offers given in Table 5.3 and long-term price elasticity, the modified demand profile is determined for every class customer from Eq. (5.2). Thus, the altered profiles for each customer class and a total load connected at all nodes are obtained.

From these modified total load profile at various nodes, coincident demand to each upstream asset is calculated for the demand connected at all nodes. First, LACF is calculated from Eq. (5.3). Then, from these LACF's coincident demand of load to upstream assets is computed using Eq. (5.4). Coincident demand is reflective of a user's contribution to upstream asset peak usage and contributes to deriving asset reinforcement. CF's for loads at various locations to each upstream shared asset is shown in Table 5.4. The connection of DG at node L4 modifies the associated asset usage profile leading to a modified LACF at various nodes.

Table 5.4

Contribution factor of load to each upstream shared asset (LACF)

Nodes	**T1**	**T3**	**D1**	**D2**	**D3**	**D5**	**T8**	**D6**	**D7**	**D8**	**D9**
L1	0.98	-	-	-	-	-	-	-	-	-	-
L2	0.85	0.98	0.98	-	-	-	-	-	-	-	-
L3	0.98	0.89	0.89	0.88	-	-	-	-	-	-	-
L4	0.82	0.92	0.92	0.94	0.94	-	-	-	-	-	-
L5	0.93	0.90	0.90	0.99	0.99	-	-	-	-	-	-
L6	0.99	-	-	-	-	0.99	-	-	-	-	-
L7	0.70	-	-	-	-	0.66	0.68	0.68	-	-	-
L8	0.96	-	-	-	-	0.95	0.98	0.98	0.98	-	-
L9	0.70	-	-	-	-	0.66	0.68	0.68	0.68	0.64	-
L10	0.93	-	-	-	-	0.96	0.98	0.98	0.98	0.97	0.97
L11	0.94	-	-	-	-	0.98	0.94	0.94	0.94	0.98	0.98

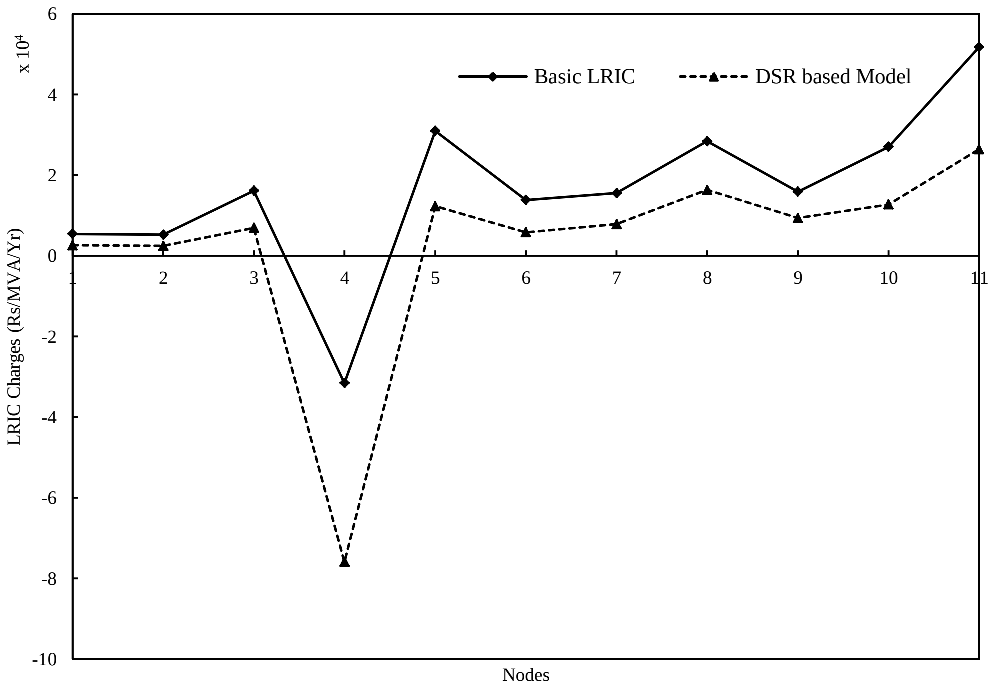


Fig. 5.4. Unit LRIC charges at all nodes

It can be seen in Table 5.4 that load L6 dominates the usage of asset T1 and have the highest contribution to the peak of upstream asset usage T1. Similarly, L7 and L9 have the lowest contribution to peak usage of asset T1. Also, L7 and L9 have the lowest contribution to peak usage of asset D5, and L6 is dominating load in the usage of asset D5. Similarly, the contribution of other loads can be visualized for their usage of asset supplying them power. For individual assets, the value of these LACF would always be 1, and hence they are not shown in Table 5.4. Using coincident demands as input system data, AC load flow is performed to compute flows as required for calculating unit LRIC charges.

Unit LRIC charges computed with a modified load profile due to DSR and CF consideration are shown in Fig. 5.4. These charges consider users' coincident demand on network asset usage and hence can reflect distance, utilization of network component, and coincident peak usage of the asset by users at various nodes. Node 4 is generation dominated as the load connected at this node is lower than the

Table 5.5

Contribution factor of various customer classes (CLCF)

	General			**Industrial**		**Agricultural**		**Water Works**	
Nodes	Class 1	Class 2	Class 3	Class 1	Class 2	Class 1	Class 2	Class 1	Class 2
L1	0.54	0.49	0.41	0.90	0.92	0.57	0.59	0.74	0.72
L2	0.86	0.80	0.73	-	-	-	-	-	-
L3	0.62	0.56	0.54	0.63	0.98	-	-	0.88	0.82
L4	0.68	0.99	0.65	-	-	0.29	0.27	0.75	0.74
L5	0.56	0.49	0.51	0.91	0.75	0.99	0.69	0.87	0.79
L6	0.52	0.50	0.53	0.87	0.84	0.97	0.78	0.89	0.86
L7	0.88	0.93	0.83	-	-	-	-	-	-
L8	0.47	0.49	0.42	0.82	0.91	0.72	0.69	0.58	0.54
L9	0.74	0.78	0.77	-	-	-	-	-	-
L10	0.46	0.51	0.45	0.81	0.89	0.87	0.90	0.99	0.72
L11	0.44	0.49	0.54	0.89	0.95	-	-	0.96	0.90

Table 5.6

Total charges for various customer classes at all nodes (Rs/Yr)

	General			Industrial		Agricultural		Water Works	
Nodes	Class 1	Class 2	Class 3	Class 1	Class 2	Class 1	Class 2	Class 1	Class 2
L1	3500	2032	592	19992	19464	2232	1783	2316	2742
L2	3154	1959	1169	-	-	-	-	-	-
L3	1728	777	585	3112	3411	-	-	3053	1812
L4	-7151	-30088	-9897	-	-	-3252	-2021	-8334	-5650
L5	5054	6080	4984	17151	9180	12059	5917	9536	7805
L6	4048	5834	6176	12666	9821	9532	9069	10537	10073
L7	8250	14614	6546	-	-	-	-	-	-
L8	4350	4752	2753	96507	74081	2609	3383	7618	5602
L9	1801	2185	1438	-	-	-	-	-	-
L10	2030	3224	2310	8513	12482	5913	6855	8361	6450
L11	2482	1930	3594	6604	7538	-	-	8506	8489

generation. In such a situation, congestion would occur in asset T5 when the load at node L4 is minimum and generation is maximum. The proposed methodology gives a pricing signal to demand to modify profile and minimize flow in congested asset T5. Negative LRIC charges at node 4 reflect the benefit to the network by reducing line flows because of reverse flow injection by DG. With the proposed approach, charges are lower at the rest of the nodes as the network peak usage is reduced due to DSR considerations. These charges with DSR reflect distance and utilization of network component with the modified load profile scenario.

After computing unit charges with DSR consideration, CLCF's are calculated from Eq. (5.12) for various class customers at the nodes, as shown in Table 5.5. CLCF determines various class customers' contribution to the total load connected to any node. DG consideration in the network doesn't affect customer classes' contribution to the total load connected at the nodes. Hence, CLCF evaluated in the modified LRIC approach remains the same whether the DG is connected to the network or not.

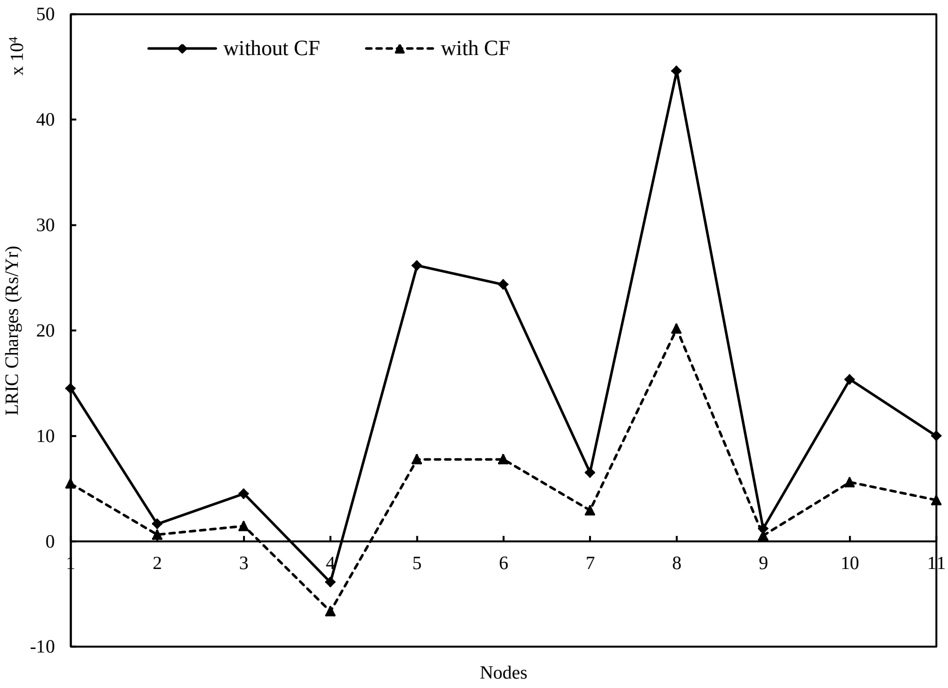


Fig. 5.5. Impact of CF on total LRIC charges

As it can be seen in Table 5.5, sub-classes of General class have the lowest contribution while Industrial sub-classes have the highest contribution to the peak load of L1. Further, sub-classes of Water-Works class have the highest and of General classes have the lowest contribution to the peak load of L11. Similarly, the contribution of various customer sub- classes in the total load connected at the nodes can be observed. This reflects specific customer class contribution in deriving nodal peak loads which is responsible for network reinforcement. Customer classes are charged only for part of the load coinciding with peak nodal demand, and not for their maximum demand.

Total charges for various class customers located at all nodes are given in Table 5.6. Characteristics of individual customer classes are reflected in calculating total network charges with CLCF as Eq. (5.13). Various class customers are charged for network usage based on their contribution to nodal peak conditions. These charges with CLCF consideration reflect individual customer class contribution in attaining network capacities or network congestion. Peak and off-peak network charge offer incentivize customers to modify their profile and help in mitigating congestion. Total charges paid by the users at all nodes with and without CF are shown in Fig. 5.5. DG integration to distribution network impacts total charges in the same way as it impacts unit charges. Because, it affects only LACF computations, and CLCF remains the same in the modified approach with DG.

As can be seen from Fig. 5.5, that total LRIC charges paid by users connected at the nodes considering coincident demand and DSR are lower than without their consideration. LRIC charges with the basic model reflect both distance and utilization of network components. These charges do not reflect actual network usage and hence do not give users a pricing signal based on their load profile. Network users are responsible for reinforcement of components when their demand imposed on network results in its full utilization. Consideration of CF and DSR incentivizes users by reducing network charges for decreasing their usage during network peaks. Hence, users are encouraged to improve their demand profile through the proposed pricing approach. Modified profile aims to reduce network peaks, delaying reinforcement of network asset and hence defer investment.

5.3.3. Deferral in Network Investment

The benefit of the proposed pricing on network investment deferral is shown in Fig. 5.6 which presents the annuitized present value of future reinforcement cost over all network components. As can be seen from Fig. 5.6, network component T1 and T8

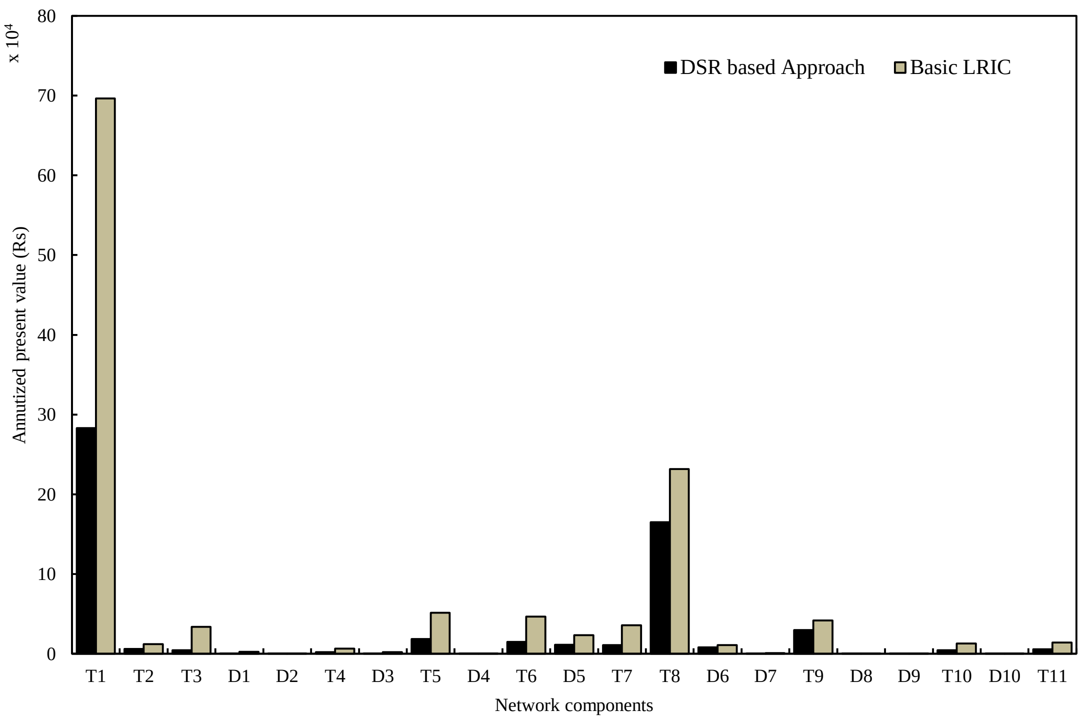


Fig. 5.6. Comparison of annuitized present value

have a high annuitized present value of future reinforcement cost. With the adoption of proposed pricing, investment for these branches comes down significantly. For other branches also, this annuitized present value gets reduced with the proposed approach as the users are offered reduced charges for contributing less to network peaks. Furthermore, consideration of DSR encourages users to modify their usage profile to minimize network peaks. So, the peak network usage of the component gets reduced. This further delays the reinforcement of asset and results in investment deferral.

The addition of the present value of future investment for all components with the basic and proposed pricing approaches gives investment deferral caused by reduced network peaks. With the proposed pricing implementation, a reduction in investment of Rs. 610.349k per year is obtained.

5.4 Conclusion

The present LRIC pricing mechanism produces forward-looking charges that reflect both the extent of the network needed to serve the generation or load and the degree to which the network is utilized by the customers. Such pricing mechanisms are based on diversity factor to calculate the maximum demand at individual locations on the network which may not be coincident with network peak and does not reflect user's network usage during network peak. With the large-scale integration of renewable generation, there is a possibility of a quantum increase in responsive load. Such load responds to energy prices at the grid supply point, leading to congestion in distribution networks during high renewable generation.

This chapter improves the existing LRIC pricing approach to mitigate the above challenges by offering pricing signals based on time differentiated network utilization. This considers the contribution of customer-class usage with peak network usage, to reflect their contributions to the network peak at different network levels. Considering demand flexibility, a time-of-use tariff is offered to users at various locations, and network tariff is further evaluated with a modified profile scenario and CF consideration to reflect actual usage.

The offered pricing approach triggers a behavior change in network users in response to time-varying charges. This eventually alleviates network congestion and delays in investment. This pricing signal is beneficial to both utility and users because the users would bear reduced network charges, and the utility would face lower network congestion and deferral in network investment. Load contribution to upstream asset peak is considered in this as well as the previous chapter. Next chapter also considers generation contribution to upstream asset peak usage in addition to the load contributions.

Chapter 6

Enhanced LRIC Pricing based on Generation and Load Contributions

THIS chapter enhances the LRIC pricing model by incorporating LACF and GACF to consider generation and load contribution to network peak demand for determining distribution network prices.

Chapter – 6

ENHANCED LRIC PRICING BASED ON GENERATION AND LOAD CONTRIBUTIONS

6.1 Introduction

In the previous chapter, short-term DSR is incorporated with the modified LRIC pricing methodology to manage variability caused by RG's. The proposed framework in this chapter offers pricing signals based on time differentiated network utilization, to change various customer class profiles using their elasticities. These altered profiles are further used to compute network charges in the modified LRIC pricing framework. This chapter is dedicated to enhancing the existing LRIC pricing approach, to consider generator and load contributions to upstream asset peak usage. The contribution is modeled as LACF and GACF for the load and generation users respectively, to assess the impact of users' contribution during peak load and consequently on asset reinforcement.

This chapter is structured as follows. In Section 6.2, a brief overview of generation contribution consideration to asset reinforcement with the growth of renewable penetration is included. A detailed overview of the steps required to evaluate charges with the proposed approach is presented in Section 6.2. Description of 22-bus practical Indian reference network used for pricing analysis, parameters used and the simulation results are presented in Section 6.3. Finally, Section 6.4 concludes the chapter.

6.2 Enhanced LRIC Pricing Model

6.2.1 Background

Distribution network costs are influenced by changes in network usage, changes in customer numbers, the timing of generation by renewable sources, and changes in peak demand by location within the network. These considerations need to be reflected in network prices offered to various customers as well as DG's connected to the system. Ideally, customers should be grouped into tariff classes where the costs caused by each customer within the group are broadly similar. Hence the customers of a class respond identically to the price signal offered [131].

The peak loads of several customers rarely occur at the same time, and therefore coincident peak demand is considered. The coincident peak demand represents the maximum demand for a group of customers during the time of system peak demand. This is rational as the equipment in a network has to withstand different loadings contributing differently to the voltage drop [127].

Presently, LRIC pricing methodology considers the unutilized capacity to offer a forward-looking and economical pricing signal for the growth of future generation and demand. The method replicates the cost of advancing or deferring future reinforcement, after the injection/withdrawal of load/generation at each connected node on the network. However, this method fails to consider the coincident peak usage of the network by demand and generation users.

This work proposes an enhanced LRIC pricing methodology considering load and generation contributions to distribution network peak flow in upstream assets. These contributions are determined using LACF and GACF for loads and generators, respectively. The proposed approach encourages network users to modify their distribution network usage pattern to minimize network peaks, thus deferring network investment. The proposed pricing scheme aims to improve the pricing signal offered to users by incorporating CF to the existing LRIC pricing methodology. Therefore, the proposed approach considers users' contribution to network peak conditions, in addition to the location-based signal given by the traditional pricing approaches.

6.2.2 Pricing Framework

The proposed LRIC pricing mechanism illustrated in Fig. 6.1 shows the algorithm for calculating CF based LRIC charges. This integrates the reflection of generation and load contributions to distribution network peak demand for distribution network charging. Fig. 6.1 describes the proposed methodology for evaluating CF based LRIC charges with the help of the flowchart. From the input system data, LACF and GACF are estimated. From these CF's, coincident demand and coincident generation are computed, that to be further used as the load flow input data. Base case and incremental case power flows are run to calculate the time horizon required for reinforcement of network asset. Then, the present values of future reinforcement are

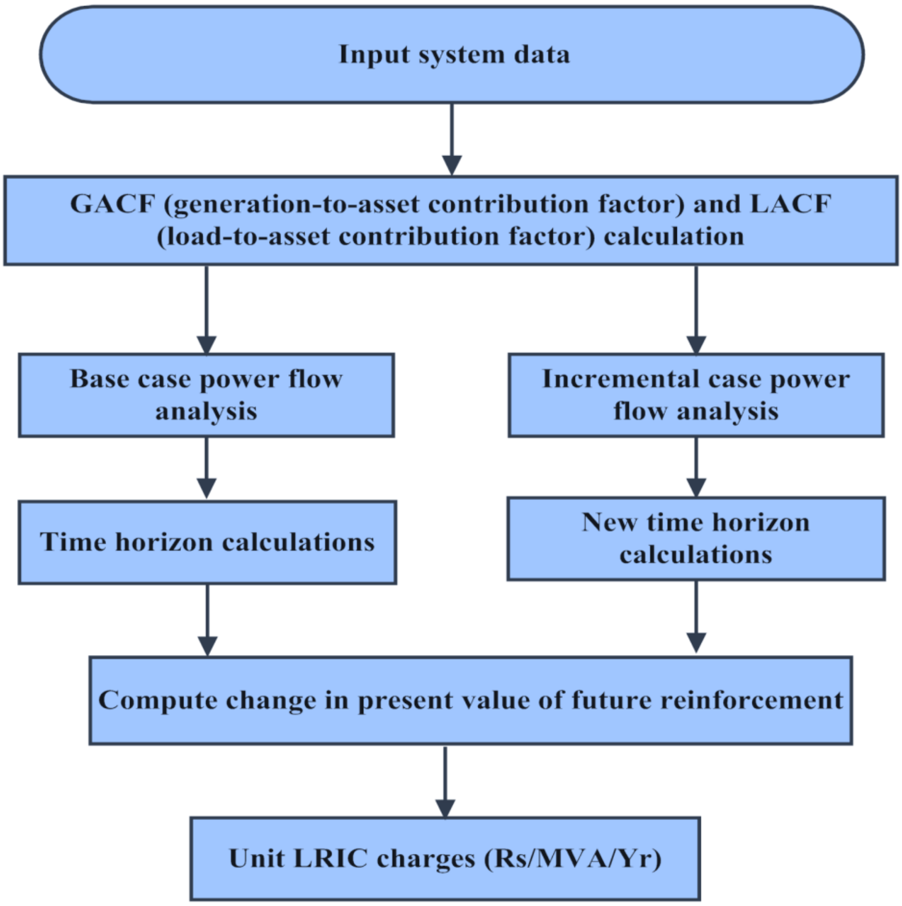


Fig. 6.1 Flow chart for enhanced LRIC pricing model

computed with and without nodal injections. Further, the annualized the incremental cost of components is evaluated. From these annualized incremental costs, unit LRIC charges are obtained by aggregating the annualized incremental cost of components. The mathematical formulation for calculating CF based LRIC charges are discussed hence.

6.2.3 Coincident Demand and Generation Calculations for Each Upstream Asset

From the details of load profile data available at various nodes, the coincident demand of total load connected at any node to the peak of total load at each upstream asset is calculated using load-to-asset CF. This factor is calculated as

$$\mathrm{LACF}_{\mathrm{kj}} = \frac{S_k^j(t_p)}{S_k(t_q)} \tag{6.1}$$

where $S_k = [S_k(t_1), S_k(t_2), \cdots, S_k(t_n)]$ is the total load at node k at time t, $t = [t_1, t_2, \cdots, t_n]$ is the time interval of daily load profile, $S_k^j(t_p)$ is the total load at node k at p^{th} time instant t_p which is the time of peak loading of an upstream asset j connected above node k, $S_k(t_q)$ is the total load connected at node k at time instant t_q which is the time of total load's peak at node k, $\mathrm{LACF_{kj}}$ is the contribution of total load connected at any load point k to any of its upstream asset j, k is the index of nodes in the network, and j is index of upstream assets feeding node k from load point to grid supply point. Here, j may or may not be the immediate upstream asset of node k.

Similarly, generation-to-asset CF can be evaluated as

$$\mathrm{GACF_{kj}} = \frac{G_k^j(t_p)}{G_k(t_s)} \tag{6.2}$$

where $G_k = [G_k(t_1), G_k(t_2), \cdots, G_k(t_n)]$ is the total generation at node k at time t, $t = [t_1, t_2, \cdots, t_n]$ is the time interval of daily generation profile, $G_k^j(t_p)$ is the total generation at node k at p^{th} time instant t_p which is the time of peak loading of an asset j connected above node k, $G_k(t_s)$ is the total generation connected at node k at time instant t_s which is the time of total generation's peak at node k, $\mathrm{GACF_{kj}}$ is the contribution of total generation connected at any node k to any of its associated asset j.

From the LACF, coincident demand of load at node k to each upstream shared asset j, *i.e.* CD_{kj} can be evaluated as

$$\mathrm{CD}_{kj} = \mathrm{LACF_{kj}} * S_k(\mathrm{t}_q) \tag{6.3}$$

Similarly, coincident generation at node k to each associated asset j, *i.e.* CD_{kj}^g can be evaluated as

$$\mathrm{CD}_{kj}^g = G\mathrm{ACF_{kj}} * G_k(t_s) \tag{6.4}$$

6.2.4 Unit LRIC Charges

Coincident demand/generation calculated from Eq. (6.2) and Eq. (6.4) is used as the input power flow data to assess actual asset usage. Distribution network asset j supplying load to connection node k has power carrying capacity C_{kj} and supports a power flow P_{kj}. Time horizon required to reinforce network asset j due to growth of load connected at node k is given by

$$n_{kj} = \frac{\log C_{kj} - \log P_{kj}}{\log(1+r)} \tag{6.5}$$

For discount rate d, the present value of future reinforcement in network asset j is determined for load connected at node k as

$$PV_{kj} = \frac{AC_j}{(1+d)^{n_{kj}}} \tag{6.6}$$

where AC_j is the modern equivalent asset cost of asset j.

Further, the power flow along with the associated network assets j is altered by ΔP_{kj} due to nodal injection caused by load at node k; hence new time horizon for reinforcement of asset j is

$$n_{kj}^{new} = \frac{\log C_{kj} - \log(P_{kj} + \Delta P_{kj})}{\log(1+r)} \tag{6.7}$$

This further change the present value of future reinforcement in asset j for load connected at node k

$$PV_{kj}^{new} = \frac{AC_j}{(1+d)^{n_{kj}^{new}}} \tag{6.8}$$

Now, change in present value for asset j as a result of nodal injection is given by

$$\begin{aligned} \Delta PV_{kj} &= PV_{kj}^{new} - PV_{kj} \\ &= AC_j \times \left(\frac{1}{(1+d)^{n_{kj}^{new}}} - \frac{1}{(1+d)^{n_{kj}}} \right) \end{aligned} \tag{6.9}$$

Annualized unit incremental cost for network asset j is given as

$$IC_{kj} = \frac{\Delta PV_{kj} * AF}{C_{kj}} \tag{6.10}$$

where AF is the annuity factor.

LRIC prices at node k is determined by the summation of annuitized incremental cost of all assets j over that node

$$LRIC_k = \frac{\sum_j IC_{kj}}{\Delta D_k} \tag{6.11}$$

where ΔD_k is the power injection at node k. From Eq. (6.11), unit LRIC charges in (Rs/MVA/Yr) at node k are obtained.

6.3 Results and Analysis

This section describes the system used for enhanced LRIC charges evaluation. Further, implementation of CF based charges for both the generators and load is described by the proposed approach and results are compared with the existing LRIC approach.

6.3.1. System Description

The proposed approach is applied to a part of practical Indian reference network as given in Fig. 6.2 [128]. The details of the reference network are given in Chapter 3. A 2 MVA DG (wind) and a 1 MVA DG (solar) operating at 0.95 power factor are connected at load L5 and L11, respectively, to highlight the impact of proposed

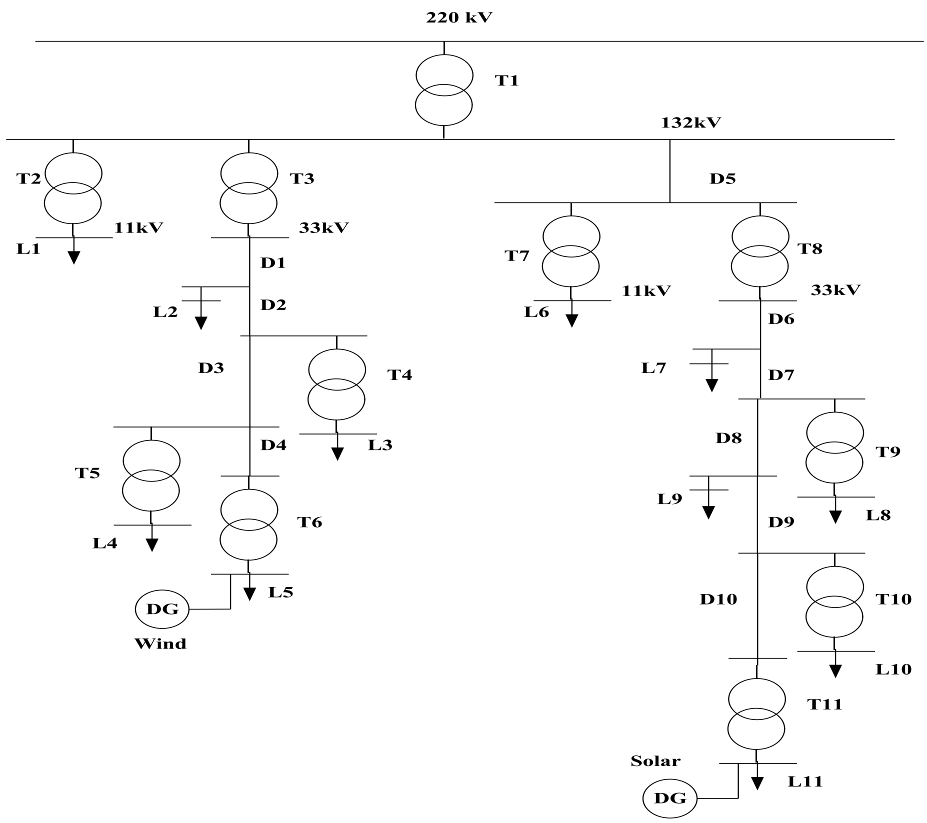


Fig. 6.2. 22-bus practical Indian reference network [128]

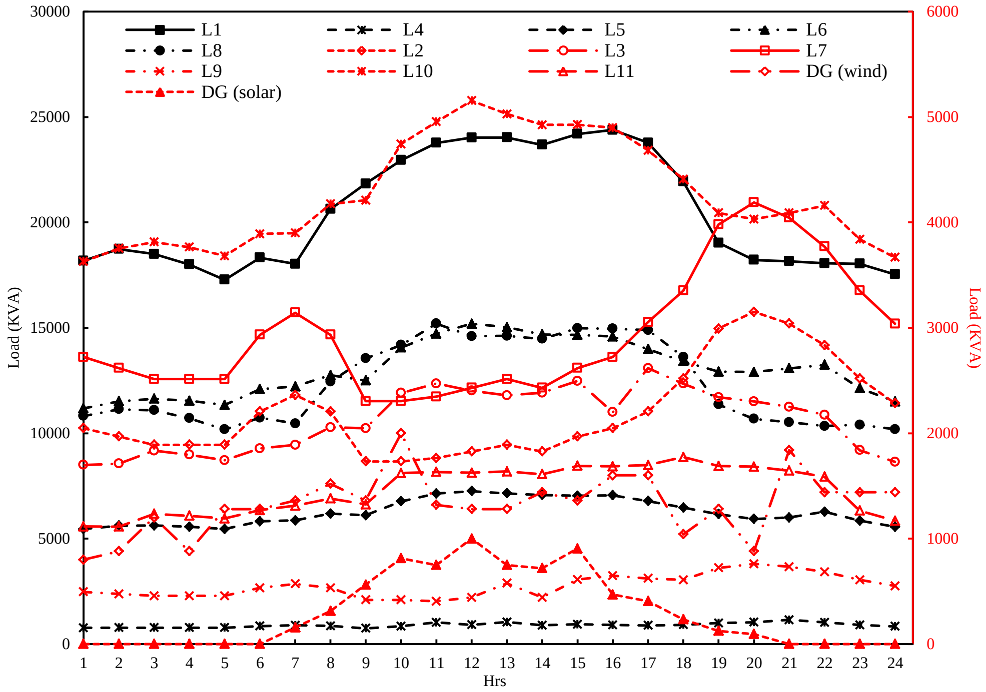


Fig. 6.3. Total load and DG profile at various nodes

methodology on network charges with DG connected network. Profile of the total load and DG connected at various nodes is shown in Fig. 6.3. This profile is sufficiently different from various customer class profiles as well as different sub-class profiles of each class connected at these nodes. Further, the details of customer sub-classification are given in Chapter 4.

6.3.2. Enhanced LRIC Charges Implementation

This section represents the computation of enhanced LRIC prices for a 22-bus practical Indian reference network. The proposed approach considers the impact of load and generation contributions on upstream asset peak usage. From the details of load profile data available at various nodes, coincident demand to each upstream asset is calculated for the demand connected at all nodes. First, LACF's are calculated at the nodes from Eq. (6.1). Then, from these LACF, coincident demand of load to the upstream asset is calculated from Eq. (6.3). Coincident demand is reflective of the user's contribution to asset peak usage and contributes to driving asset reinforcement. CF's for the loads connected at various network locations to each upstream shared asset is shown in Table 6.1.

As it is seen in Table 6.1, load L1 and L6 dominate the usage of asset T1, while L2 and L7 have the smallest contribution to the usage of T1. Also, L7 has the lowest

Table 6.1

Contribution factor of load to each upstream shared asset

Nodes	T1	T3	D1	D2	D3	D5	T8	D6	D7	D8	D9
L1	0.98	-	-	-	-	-	-	-	-	-	-
L2	0.63	0.90	0.90	-	-	-	-	-	-	-	-
L3	0.95	0.94	0.94	0.93	-	-	-	-	-	-	-
L4	0.81	0.79	0.79	0.89	0.90	-	-	-	-	-	-
L5	0.97	0.89	0.89	0.98	0.99	-	-	-	-	-	-
L6	0.98	-	-	-	-	0.96	-	-	-	-	-
L7	0.63	-	-	-	-	0.65	0.73	0.73	-	-	-
L8	0.97	-	-	-	-	0.97	0.96	0.96	0.98	-	-
L9	0.94	-	-	-	-	0.80	0.68	0.68	0.58	0.80	-
L10	0.96	-	-	-	-	0.95	0.91	0.91	0.96	0.95	0.95
L11	0.95	-	-	-	-	0.95	0.96	0.96	0.91	0.95	0.95

Table 6.2

Contribution factor of generation to upstream asset

	T1	**T3**	**D1**	**D2**	**D3**	**D4**	**T6**	**-**	**-**
DG (Wind)	0.68	0.52	0.52	0.66	0.64	0.64	0.64	-	-
	T1	**D5**	**T8**	**D6**	**D7**	**D8**	**D9**	**D10**	**T11**
DG (Solar)	0.91	0.47	0.41	0.41	0.72	0.47	0.47	0.05	0.05

contribution to the usage of asset D5 and L8 dominates the usage of asset D5. Similarly, the contribution of other loads can be visualized for their usage of asset supplying them power. For individual assets, the value of these LACF would always be 1 and hence are not shown in Table 6.1.

Further, GACF’s are evaluated for generators located at various nodes from Eq. (6.2). From these GACF’s, coincident generation of DG’s located at different nodes to the upstream asset is calculated from Eq. (6.4). This reflects injected generation contribution to upstream asset peak usage that delays asset reinforcement. As it can be seen in Table 6.2, DG (solar) has the highest contribution to power injected at the time

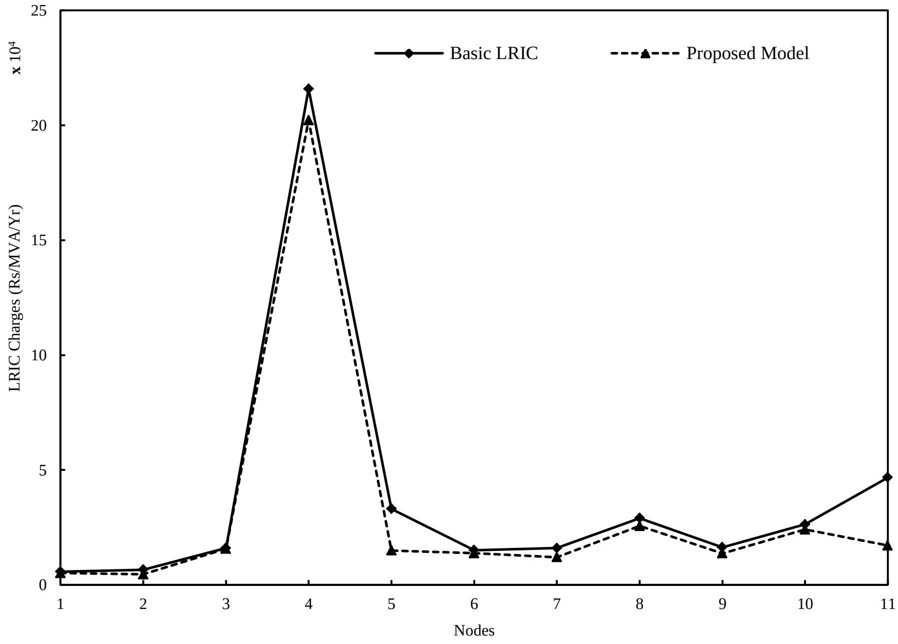


Fig. 6.4. Unit LRIC charges for loads at all nodes

of the peak of asset T1 among two DG's in the network. It can be observed that DG (wind) has lowest injection contribution in peak usage of asset T3 and D1, while DG (solar) has the lowest injection in peak usage of asset D10 and T11. Using the coincident demand and generation as input network data, AC power flow is performed to compute flows required for calculating unit LRIC charges. The discount rate, load growth rate, and the annuity factor are assumed as 6.9%, 1.6%, and 7.4%, respectively [35]. All simulations are performed using MATLAB ® software.

From the obtained flows, branch incremental charges are evaluated for both generators and loads using Eq. (6.4) - Eq. (6.10). Then unit LRIC charges at all the nodes are obtained from Eq. (6.11) for each generator and load connected to the distribution network. Unit LRIC charges computed for loads are shown in Fig. 6.4. Charges from the proposed approach consider users' coincident demand on distribution network asset usage, and hence they can reflect distance, utilization of network component, and coincident peak usage of the asset by users at various nodes. On the other hand, the basic LRIC approach could reflect only distance and utilization of network component. High LRIC charge at node 4 is because major distribution network asset serving load at this node has a minimal capacity to accommodate an overall 0.1 MVA load increment. Difference between charges obtained from both the traditional as well as the proposed approach can be observed in Fig. 6.4, and this difference exists

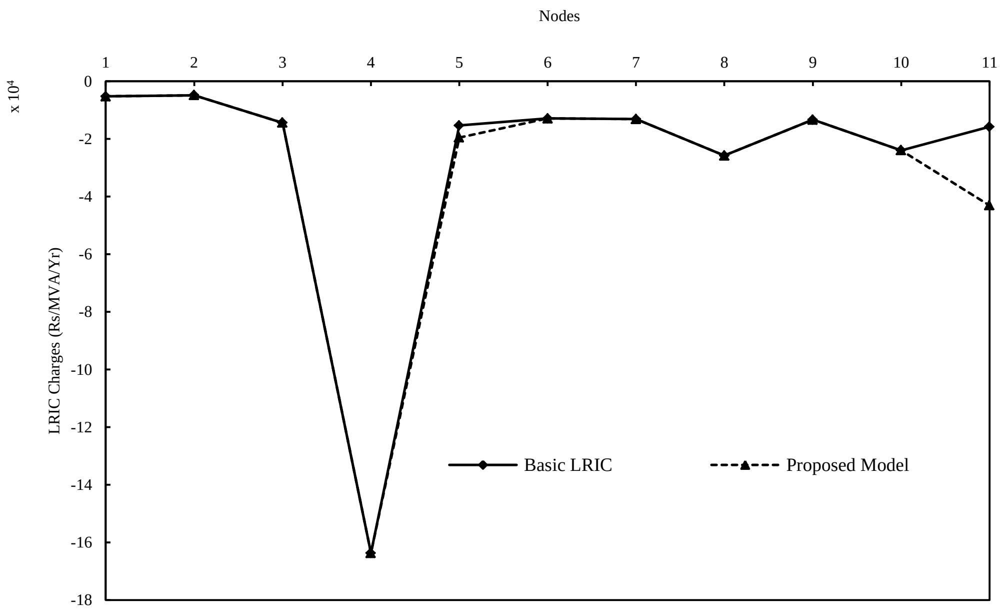


Fig. 6.5. Unit LRIC charges for generation at all nodes

because of LACF consideration in LRIC approach. Consideration of LACF reflects load contribution to upstream asset peak usage, which is responsible for asset reinforcement. Loads connected to distribution network are charged only for part of load coinciding with upstream asset peak and not for their maximum rated load. Similarly, generation charges are evaluated for all the nodes considering GACF.

The impact of considering GACF in the proposed approach can be seen in Fig. 6.5. Here, the charges are determined for the generation injection at node 5 and 11. Negative charges (reward) reflect the benefit to the network through decreasing flows in associated asset due to reverse flow injection by DG. GACF is considered for the generator connected at nodes 5 and 11. The difference between generation charges with the proposed and traditional approaches can be visualized for the nodes with DG. Consideration of GACF gives generation charges/reward based on the peak scenarios of the network, *i.e.*, a quantum of generation injected at the time of the peak of an associated asset to the node at which it is connected. Reward increases at both the nodes with the proposed approach as consideration of GACF increase the benefits to the network given by DG. Generation is attracted at node 4 having the highest negative charge, *i.e.*, reward to the generator is the highest at this node.

Distribution network users are responsible for reinforcement of network asset when their demand imposed on network results in its full utilization. Consideration of LACF incentivizes demand by offering reduced distribution network charges for their low usage during network peaks. Similarly, generation credits get increased with GACF consideration, *i.e.*, generators are encouraged to inject more at the time of network peaks by offering high credits. Hence, loads are encouraged to improve their load profile and reduce their contribution to peak demand, and generators are encouraged to match their injection with network peak. The modified profile aims to reduce network peaks delays reinforcement of network asset and hence defers investment.

6.4 Conclusion

Presently, the charging methodologies for distribution network offer location-specific signal to users and charge them based on their use-of-system. However, these methodologies do not provide a signal based on the contribution to distribution network peaks. This paper improves the traditional LRIC pricing approach to offer network peak contribution based signal, along with providing a location-specific signal. This considers generation and load contributions to network peak demand for determining distribution network prices. These contributions are defined using LACF and GACF. Consideration of these factors determines generation and load effective contribution to asset reinforcements for supplying power.

The proposed methodology encourages network users to improve their load profile to minimize contribution to distribution network peaks. The price signals provided by this approach are beneficial to both utility and users as the users, would be charged lower distribution network charges and the utility would secure network investment deferral.

Chapter 7

Conclusion and Recommendations for Future Work

THIS chapter concludes the significant findings of this thesis. The future scope of the work in the area of distribution network pricing has also been discussed.

Chapter – 7

CONCLUSION AND RECOMMENDATIONS FOR FUTURE WORK

7.1 General

Erstwhile electric power industry was structured around vertically integrated regulated monopolies. Liberalization of the electricity sector was initiated much later than the opening to competition for other network industries *viz.* telecommunication, gas, and airlines. Moving from vertically integrated natural monopolies to competitive structure of the electric power industry; it was believed that open access to transmission and distribution networks is vital to promote effective competition in the electricity supply sector. After liberalization, an intense wave of restructuring hit the distribution sector. Under this new deregulated paradigm, network charging plays an essential role in recovering investment costs for distribution networks from their users.

Network pricing is all about recovering network operators fixed costs in operation, maintenance, and investment, and to provide forward-looking, economically efficient signals for both the existing and future generation and demand. This aims to promote efficient use of the existing networks and a cost-reflective development of future networks. A pricing signal dependent on future network cost offer prospects for network users to respond, if they desire to alter their consumption in such a way that can decrease the cost of network usage. This eventually contributes to reducing future network cost and prices for all network users. This research attempts to focus on developing and enhancing DUoS charging to offer distribution network users (generators and loads) a justified pricing signal. The proposed approaches are illustrated, and network prices are computed for a 22-bus practical Indian reference network. Conclusions about the proposed research work are discussed in the next section.

7.2 Summary of Significant Findings

The research work carried out in this thesis starts with developing an understanding of various distribution network pricing approaches evolved after restructuring.

Upcoming smart grid environment can offer innovative mechanisms for efficient network management to relieve the network presently reeling under congestion. Considering the potential of SG technologies for providing SNP, this thesis proposes a CF-based LRIC model to be integrated into SG environment. The CF is reflective of the customer's contribution to network peak flow. Results discussed in Chapter 3 show that different category customers connected at the same node face different network charges based on their coincident demand. The price signal would encourage various categories to improve their demand profile, to minimize their contribution to network congestion. This smart pricing signal is beneficial to both the utility and users since the users would bear reduced network charges, and the utility would face lower network congestion. Such modified behavior has the potential to provide effective demand-side management for reduced network investment.

The UK power industry is the world leader in the electricity market design, operation, and implementation of modern network pricing mechanisms. It has the world's first and only locational DUoS pricing approach in practice that generates different charges for customers at different locations. Existing DUoS pricing methodologies have covered many aspects of an ideal pricing model considering factors like forward-looking cost, distance, location, utilization rate, reliability, and generation technology. Traditional charging methodologies assume that all customers at same location use distribution network in a similar way. However, end-users access network in a diverse manner and thus have a different contribution to the networks' reinforcement. To send customer-specific signals to effectively guide individual user's behavior, a new DUoS charging model is developed. The novel hierarchical contribution factor model proposed in Chapter 4 distinguishes between different customer classes contributions to the distribution network and all the way to the upstream assets. The simulation results are compared with the basic LRIC pricing model and concluded that the basic LRIC model reflects only distance and utilization, whereas charges from the proposed model consider users' coincident demand on network usage, reflecting distance, utilization of network component, and coincident peak usage of the asset by users. Total charges are computed for various customer classes, using unit charges and CLCF. Results presented in Chapter 4 show that customer classes are charged only for the part of load coinciding with peak nodal demand and not for their maximum load. Due to these charges, the proposed model would be more cost-reflective than the traditional model. This work provides a forward-looking economic signal and thus encourages customer classes to improve their load profile and reduce their contribution to distribution network peaks.

With the large-scale integration of RG, there is likely the possibility of a quantum increase in unresponsive load. Such load responds to energy prices at the grid supply point, leading to congestion in distribution networks during high renewable generation. The existing distribution network charging methodologies offer location-specific signal to users and charge customers reflecting their use-of-system. These methodologies can be modified using CF to reflect users' demand coincident with peak network demand. RG are encouraged by relieving them from such contribution based pricing signals. Congestion caused by intermittent RG could be mitigated by utilizing the flexibility of demand customers. LRIC pricing is a well-established approach to evaluate long-term distribution network charges for UK distribution networks. This makes use of the spare capacity of an asset to assess the time horizon for future reinforcement with and without any nodal injection to the network. These time horizons are further translated into an incremental cost to the network. The approach is guided by the ability of the present network to accommodate future generation and demand. Thus, this approach provides a forward-looking long-term economically efficient signal to impact the growth of future generation/demand.

In work proposed in Chapter 5, short-term DSR signal has been incorporated for demand customers to mitigate uncertainties caused by RG in the LRIC pricing framework. After calculating unit charges from basic LRIC model, peak and off-peak charge offer at every location are determined. As a result, the modified profiles for each customer class and consequently for the total load connected at all nodes are obtained. For these modified profiles, unit charges are further evaluated and compared with the basic LRIC approach. Results obtained in Chapter 5 indicate that charges are lower at all nodes in this case because the peak network usage is reduced due to DSR considerations.

Another point to note is that consideration of DSR encourages users to modify their usage profile to minimize network peaks. So, the peak network usage of the component gets reduced. This further delays the reinforcement of asset and thus results in investment deferral. The offered pricing approach triggers a behavior change in network users in response to time-varying charges, eventually alleviating network congestion and delaying investment. This pricing signal is beneficial to both utility and users, as users would bear reduced network charges, and the utility would face lower network congestion and deferral in network investment.

The final contribution of this thesis is to enhance the LRIC pricing model to give generators and loads a pricing signal based on their contributions to network peak usage. At present, the charging methodologies for distribution network could give location-specific signal to users and charge them based on their use-of-system. However, these methodologies do not provide a signal based on the contribution to distribution network peaks. Hence, the work done in Chapter 6 considers generation and load contributions to network peak demand for determining distribution network prices. These contributions are defined using LACF and GACF. Consideration of these factors determines generation and load effective contribution to asset reinforcement for supplying power. Consideration of LACF reflects load contribution to upstream asset peak usage which is responsible for asset reinforcement.

On the other hand, consideration of GACF gives generation charges/reward based on peak scenarios of the network, *i.e.*, amount of generation injected at the time of the peak of an associated asset to the node at which it is connected. The proposed approach discussed in Chapter 6, rewards increase at the nodes with DG connected. This is because the consideration of GACF increases the benefits to network given by DG. In the proposed approach, loads are encouraged to improve their load profile and reduce their contribution to peak demand, and the generators are encouraged to match their injection with network peak. The modified profile aims to reduce network peaks delaying reinforcement of network asset and hence defers investment.

7.3 Recommendations for Future Work

The research work presented in this thesis started with developing a CF-based LRIC pricing model to give a pricing signal to various customer categories. The novel concept of CF and the impact of reducing network peak started at an elementary level to illustrate the thought, and this thought is further extended to form a hierarchical CF to evaluate DUoS charges. Further, the impact of DSR is also observed on this CF based LRIC pricing framework. At last, generation contributions are incorporated in the existing LRIC pricing approach in addition to load contributions to offer generators a justified pricing signal. In this section, some fundamental extension to work carried out in this thesis shall be recommended to ensure that the developed work could be extended to develop real word distribution network charging methodologies. Those shall be briefly expressed, each in turn, below.

i. There has been a justifiable and predictable transition towards high DG penetration around the globe. DG can be renewable based or non-renewable based including solar, wind, photovoltaic, fuel cells, biomass, gas, geothermal, and combined heat and power technology. Power generation from renewable DG is intermittent and uncertain. The intermittency of their output needs to be modeled to offer justified network prices to all network users, along with providing economic solutions towards integrating renewable DG's. Also, generation dominated areas should be distinguished from demand dominated areas to understand network condition. This can incentivize the renewable DG's to join the system in large numbers and at economically viable locations. This would help in the growth of renewable generation to reduce carbon emissions and mitigate global warming.

ii. Suppliers and large customers can mitigate volatility in the wholesale energy market through the use of hedging instruments. Wholesale energy prices are also determined in a competitive setting where there is quantum information provision over expected changes. Volatility in network charges means changes in charges evaluated per year. Price shocks or significant year-to-year price volatility will make it difficult for consumers to respond to price signals. This volatility may be due to variations of inputs to charging models *viz.* network utilization level, discount factor, and load growth rate. Network users want consistency in tariff as they are vulnerable to tariff fluctuations. They prefer a relatively safe financial environment to reduce this as they are willing to pay risk premium. Volatility or risk need to be managed in network pricing.

iii. A part of this thesis proposes enhanced LRIC pricing to consider generation contributions to upstream asset peak usage, in addition to load. Further, the impact of different generation technologies on network peak usage could be assessed while evaluating network charges for both generator and load located at various nodes.

iv. The current network charges only consider the investment based on annual peak, but cannot reflect the real-time loading condition of the network. The work proposed in this thesis considers that the network charges are typically calculated annually by network operators, reflecting their best knowledge of customer load profiles. The load profile considered is the average over the preceding year to be updated every year. A DUoS charging methodology could be developed to give real-time temporal signals, in addition to the location-based signal to users.

v. Development of retail markets and increased automation enhances customer response to market dependent electricity prices. EV's response to market prices may enhance network congestion as wholesale market prices are often not correlated with network prices. Also, the thrust for emerging low-carbon technologies (e.g., solar PV, EV's, and energy storages) to impose or avoid network costs and the desirability that consumer investment in such technologies is efficient. Hence, DUoS charging models could be developed to consider the behaviour of such technologies.

vi. Additional considerations of micro-grids and new technological devices have changed the scenario further. With the increasing level of interaction between customer and grid, the market mechanism impacts network operation in return. This necessitates developing network charging mechanisms that can be used to handle network management challenges in such an environment.

vii. The non-linear nature of electric loss in relation to electric power brings forth the issue of loss allocation in electricity networks. This is shared among customers or internalized by network operators in the traditional business model. Loss allocation could be considered in the distribution network pricing mechanisms.

viii. The move towards a low-carbon economy within a SG environment necessitates active demand-side participation; users should play an important role in balancing intermittent generation and decreasing network constraints. This structure places the operational cost at the core of pricing and tariff structure that can incentivize active generation/demand interactions at all voltage levels, while reducing network fixed costs. The key challenge is to evaluate and allocate future network costs to maintain the right balance between network investment, performance, and risks.

ix. Exchange of energy over local distribution networks creates substantial power exchanges between prosumers connected to the DG. This would change the traditional power flows occurring in the distribution networks. This could also be modelled as the development of local energy markets. Depending upon the network and generation status, such local power transfers may result in severe network congestion or poor network utilization. Traditional distribution network pricing mechanisms do not address these evolving challenges and need to be modified.

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Publications from the Work

PUBLICATIONS FROM THE WORK

Based on the research carried out, following papers have been published/accepted/submitted for publication in various journals and conferences:

International Journals - Published/ Accepted for Publication

1. A. Sharma, R. Bhakar, H. P. Tiwari, R. Li, and F. Li, "A novel hierarchical contribution factor based model for distribution use-of-system charges," *Applied Energy*, vol. 208, pp. 996-1006, 2017.
2. A. Sharma, R. Bhakar, and H. P. Tiwari, "Demand response based enhanced LRIC pricing framework," *IET Renewable Power Generation*, vol. 11, no. 13, pp. 1723-1730, 2017.

International Conferences – Published/ Accepted for Publication

3. A. Sharma, R. Bhakar, and H. P. Tiwari, "Coincident demand based smart long run incremental cost pricing model", in *Proc. IEEE International Conference on Recent Advances and Innovations in Engineering*, Jaipur, India, May 2014.
4. A. Sharma, R. Bhakar, and H. P. Tiwari, "Smart network pricing based on long run incremental cost pricing model", in *Proc. National Power Systems Conference*, Guwahati, India, Dec. 2014.
5. A. Sharma, R. Bhakar, H. P. Tiwari, and F. Li, "Enhanced LRIC pricing differentiating generation technologies and load classes," in *Proc. IEEE Power Engineering Society General Meeting*, Boston, USA, July 2016.

Appendix

APPENDIX A

A.1 22- bus practical Indian reference network data

Table A1: Line data of 22-bus system

Line Name	Voltage (kV)	R (Ω)	X (Ω)	B (S)
D1	33	0.1026	0.1157	0.0000
D2	33	0.0181	0.0204	0.0000
D3	33	0.1346	0.1519	0.0000
D4	33	0.0385	0.0434	0.0000
D5	132	0.0241	0.0574	0.0066
D6	33	0.0468	0.0528	0.0000
D7	33	0.0103	0.0116	0.0000
D8	33	0.0385	0.0434	0.0000
D9	33	0.1167	0.1316	0.0000
D10	33	0.1408	0.1588	0.0000

Table A2: Bus data of 22-bus system

Bus Name	Voltage (kV)	Power Factor	Load (MVA)
L1	11	0.95	26.6
L2	33	0.96	3.15
L3	11	0.888	2.79
L4	11	0.928	1.23
L5	11	0.953	8.44
L6	11	0.921	17.58
L7	33	0.971	4.19
L8	11	0.91	15.7
L9	33	0.98	0.76
L10	11	0.903	5.68
L11	11	0.917	1.93

Table A3: Transformer data of 22-bus system

Transformer Name	Voltage (kV)	Effective Z (Ω)
T1	220/132	0.0985
T2	132/11	0.284
T3	132/33	0.4096
T4	33/11	1.5
T5	33/11	3.625
T6	33/11	0.75
T7	132/11	0.6135
T8	132/33	0.2702
T9	33/11	0.3901
T10	33/11	0.8742
T11	33/11	2.0952