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The Role of Transmission Pricing in Electricity Industry Restructuring: the Case of Saudi Arabia

By

Ahmed Naser Al-Rajhi

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A Thesis Submitted to the Faculty of Social Science in Candidacy for the Degree of Doctor of Philosophy in Economics

Department of Economics and Finance
University of Durham

2001

2 6 MAR 2002

ABSTRACT

Saudi Arabia has embarked on the restructuring and the full privatisation of its electricity industry with the aim of transforming the industry from a single-buyer structure into a pool-based structure. The objective is to break up the industry into its main segments: generation, transmission, and distribution. In such a decentralised structure, the role of the transmission network extends well beyond mere transportation of electricity to facilitating the emergence of competitive markets by providing a level playing-field for the users.

This interdisciplinary thesis is an application to the optimisation problem facing a multi-plant firm with transportation costs. In the case of electricity, the optimal price at each point (node) on a transmission network equals the marginal cost of producing and transporting electricity to that point. However, the efficiency advantage of marginal pricing is weakened by its volatile charges and implementation difficulties in a deregulated market. *Postage stamp* rates, which are a flat amount per MW of generation capacity (or maximum demand), are usually used to recover transmission costs. Nevertheless, the simplicity of these rates comes at the expense of spatial signalling. The literature on the subject has included the development of the new method of *electricity tracing*, which assumes that power flows are traceable. This property makes it possible to allocate transmission variable (i.e. losses) and fixed costs to the users based on their 'extent of use'.

This research study contributes to this debate by comparing, for the first time, these three methods by using real data. The calculation of tracing charges required the construction of incidence and adjacency matrices for the transmission network of the electricity company, SCECO-central. Thus, it was proper to use MATLAB, which is a mathematical software suitable for such numerical computations. The necessary data were gather from the Load Flow Program of the company. The marginal loss factors were obtained from the output of the Optimal Power Flow for the network. The tracing allocation of losses produced nodal and zonal charges for either generators or demand centres based on their usage of the grid. These charges are simple and transparent, but there is no guarantee that they are efficient. However, while postage stamp rates completely ignores locational differences, the tracing charges have a strong similarity to the marginal charges, especially for distant users.

Computing nodal prices is useful in evaluating the impact of tracing and marginal charges on net social welfare. The tracing charges tend to reduce generators' surplus without any increase in consumers' surplus which result in lower total surplus. On the other hand, the volatility of marginal charges transfers part of the surplus from one group of users to another but keeps total surplus unchanged. The negative impact of tracing charges on economic efficiency is shown to be very small. This research has demonstrated that the tracing charges did not alter the economic dispatching outcomes. In fact even when these outcomes are altered, total production costs increased by only 0.47%. Arguably the practicability of the tracing could induce more trade in the market which could produce sufficient gains to offset efficiency losses. In sum, this thesis is able to: 1) examine marginal cost pricing of transmission with an emphasis on the volatility of marginal prices; 2) confirm the inability of the postage stamp rates to produce efficient prices; 3) show that the tracing charges have high correlation with marginal charges, especially for zonal prices; and 4) conclude that if marginal pricing is not adopted in the Saudi Arabian case, the tracing zonal pricing would be suitable alternative, especially as the country's geographical characteristics define zone boundaries in a simple way.

In the Name of God, the Most Gracious, the Most Merciful

اللَّهُ نُورُ السَّمَاوَاتِ وَالْأَرْضِ مَثَلُ نُورِهِ كَمِشْكَاةٍ فِيهَا مِصْبَاحٌ الْمِصْبَاحُ فِي زُجَاجَةٍ الزُّجَاجَةُ كَأَنَّهَا
كَوْكَبٌ دُرِّيٌّ يُوقَدُ مِنْ شَجَرَةٍ مُبَارَكَةٍ زَيْتُونِةٍ لَا شَرْقِيَّةٍ وَلَا غَرْبِيَّةٍ يَكَادُ زَيْتُهَا يُضِيءُ وَلَوْ لَمْ تَمْسَسْهُ
نَارٌ نُورٌ عَلَى نُورٍ يَهْدِي اللَّهُ لِنُورِهِ مَنْ يَشَاءُ وَيَضْرِبُ اللَّهُ الْأَمْثَالَ لِلنَّاسِ وَاللَّهُ بِكُلِّ شَيْءٍ عَلِيمٌ

God is the Light of the heavens and the earth; the likeness of His Light is as a niche wherein is a lamp (the lamp in glass, the glass as it were a glittering star) kindled from a Blessed Tree, an olive that is neither of the East nor of the West whose oil wellnigh would shine, even if no fire touched it; Light upon Light; (God guides to His Light whom He will.) (And God strikes similitudes for men, and God has knowledge of everything.)

The Holy Qur'an (24: 35),
Arthur J. Arberry's (1964) translation.

DECLARATION

The work presented in this thesis is entirely my own and was carried out at the Department of Economics and Finance at the University of Durham. This material has not been previously submitted to any other university for a degree or diploma.

ACKNOWLEDGEMENTS

This thesis has been written in honour of my mother and in memory of my father.

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ABBREVIATIONS AND ACRONYMS

AFESD	Arab Fund for Economic and Social Development
AGICC	Arab Gulf Interconnection Center
ARAMCO	Arab American Corporation
AMF	Arab Monetary Fund
AUPTDE	Arab Union of Producers, Transmitters and Distributors of Electricity
BOO	Build-Own-Operate
BOOT	Build-Own-Operate-Transfer
BOT	Build-Operate-Transfer
CFDs	Contract for Differences
DSM	Demand-Side Management
EC	The Electricity Corporation
EFA	Electricity Forward Agreements
EMFSU	Energy Modeling Forum of Stanford University
ESRA	Electric Services Regulatory Authority
FDI	Foreign Direct Investments
GATT	General Agreement on Trade and Tariffs
GCC	Gulf Co-operation Council
CCGT	Combined Cycle Gas Turbines
GDP	Gross Domestic Product
GDR	Global Depository Receipts
GIB	Gulf International Bank
GSIA	Gulf States Interconnection Authority
IAEE	International Association for Energy Economics
IEEE	Institute of Electronic and Electrical Engineering
IPPs	Independent Power Producers
IMF	International Monetary Fund
ISO	Independent System Operator
LFP	Load Flow Programme
LNG	Liquefied Natural Gas

MEED	Middle East Economic Digest
MEES	Middle East Economic Survey
MFNE	Ministry of Finance and National Economy
MIE	Ministry of Industry and Electricity
MLF	Marginal Loss Factors
OBUs	Offshore Banking Units
OAPEC	Organisation of Arab Petroleum Exporting Countries
OECD	Organisation for Economic Co-operation and Development
OPEC	Organisation of Petroleum Exporting Countries
OPF	Optimal Power Flow
PIF	Public Investment Fund
PSR	Proportional Sharing Rule
REDF	Real Estate Development Fund
RoR	Rate of Return regulation
SAAB	Saudi Arabian Agricultural Bank
SABIC	Saudi Arabian Basic Industries Corporation
SAIB	Saudi Investment Bank
SAMA	Saudi Arabian Monetary Agency
SAMBA	Saudi American Bank
SCECOs	Saudi Consolidated Electricity Companies
SEC	The Saudi Electricity Company
SIDF	Saudi Industry Development Fund
SMP	System Marginal Price
SWCC	Saline Water Conversion Corporation
TSOs	Transmission System Operators
UCo	The Utility Corporation
UNCTAD	United Nations Conference on Trade and Development
USAID	United States Agency for International Development
UNDP	United Nations Development Programme
WB	World Bank
WTO	World Trade Organisation

NOMENCLATURE

$\mathbf{A_d}$	the $(n \times n)$ downstream distribution matrix
$\mathbf{A}_d^{-1}$	inverse of the $(n \times n)$ downstream distribution matrix
$\mathbf{A_u}$	the $(n \times n)$ upstream distribution matrix
$\mathbf{A}_\mathbf{u}^{-1}$	inverse of the $(n \times n)$ upstream distribution matrix
B	benefits from consuming electricity
C	costs from producing electricity
c	a cost function which specifies the minimal cost assigned for each possible coalition
c_{ji}	the ratio of power on line i-j to the nodal power at (the upstream) node j
c_{li}	the ratio of power on line i-l to the nodal power at (the downstream) node l
D_B	demand at node B
$D_i^{(gross)}$	gross demand at node i
$G_i^{(net)}$	net generation at node i
g_j	generation at node j,
$g_j^{\max}$	generation capacity at node j
g_{crit}	total amount of generation available (critical capacity).
I	current over the transmission line
L	Line (e.g. L1 means line number 1)
$m_i^\pi(c)$	marginal cost vector relating to permutation π
MS	Merchandise Surplus
N	set of participants in the game (i.e. generators or MWs)
(N,c)	co-operative game characteristic function
$\mathbf{P}$	vector of nodal through-power flows
P^*	energy price at the marginal generator (i.e. swing bus)
$\mathbf{P_D}$	vector of nodal demands
P_{Di}	demand at node i
ΔP_{Di}	losses allocated to the load at node i which is the difference between the gross and actual demand

P_{Gi}	generation at node i
ΔP_{Gi}	losses allocated to the generator at node i which is the difference between the actual and net generation
P_i	total nodal flow which is the sum of power inflows (or outflows) through node i
$P_{i\text{-}j}$	line flow into node i in line j-i
P_k	price at node k
$\mathbf{P_G}$	vector of nodal power generations
$\mathbf{P_{gross}}$	unknown vector of gross nodal flows
$P_i^{(gross)}$	unknown gross nodal power at node i
$P_{i-j}^{(gross)}$	unknown gross flow in the line entering the node i
$P_i^{(net)}$	unknown net nodal power at node i
$P_{i-j}^{(net)}$	unknown net flow in the line entering the node i
R	resistance coefficient for transmission line
W	social net welfare
z_i	power flow along line i,
$z_i^{\max}$	maximum power flow allowed on line i

Greek Symbols

α_i^d	set of downstream nodes which are directly supplied from node i
$\alpha_i^{(u)}$	set of upstream nodes which directly supply node i
γ	shadow price on the total generation capacity constraint.
λ	System Marginal Cost
μ_e	shadow price on the energy constraint,
μ_i^{QS}	shadow price on the line flow constraint (Quality of Supply),
$\mu_j^{\max}$	shadow price on the individual generation capacity constraint, and
Π_R	set of all possible permutations of $\{1,...,R\}$
π	a permutation of the set $\{1,...,R\}$
$\phi(c)$	Shapley value of the game

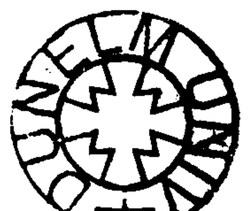
INTRODUCTION

AIMS OF THE RESEARCH STUDY

The electricity industry in Saudi Arabia started as a profitable private enterprise. Practical considerations rather than ideological dogmas led to government direct intervention in this industry, especially since 1975. This intervention was based on the justification that there was an urgent need for sufficient generation, transmission and distribution capacity in the industry to meet the needs of a country subject to sudden economic and social transformation. Also, there was a social aim of providing Saudi citizens, especially in rural and less developed regions, with electricity services at low and affordable prices.

It seems that pursuing this well intended policy may have made the industry, producers as well as consumers, more dependent on this intervention, especially as it has taken the form of subsidisation. The lack of interest by private investors in the electricity industry has been directly linked to its poor financial performance. This was disregarded in the past when plentiful funding was available from the government. The growing constraints on its budgetary allocations, due mainly to declining oil revenues, and the massive future investment requirements of the industry, have led to calls for more participation by the private sector.

From the point view of the private sector, these investment requirements should be looked at as promising opportunities rather than challenges. Studying the issues facing the electricity industry shows that there is no lack of interest or shortage in future funding for the industry. Also, an improvement in its financial performance is expected to arise from combining the new structural reforms and the revised tariffs, on the one hand, with cost reduction, especially in generation, on the other. These developments are in line with the Sixth Development Plan (1995-1999) which considers full privatisation of the electricity industry as a strategic objective for the medium and long term. This objective has to be complemented by promoting competition and choice in as many segments of the industry as possible.



The past restructuring programmes aimed at modernising the industry with the objective of creating adequate supplies for industrial and residential consumers without either group having to meet the full cost. The current restructuring programme has the objective of making it a profitable and market-based industry. Thus, the immediate objective is to remove this industry from direct government interference in its day-to-day operations.

The new reforms also aim at unbundling the industry into its different functions of generation, transmission and distribution. The competitive segment of the industry, that of generation, is already opened for direct investment by private independent power producers. This would be followed by the natural monopoly segments of transmission and distribution. Under the restructuring plan, the newly created holding company will be the owner, but not necessarily the operator, of the national transmission grid. The regional distribution networks will be subject to franchise bidding with the opportunity for retailing activities by private suppliers and other electricity traders. The industry's independent regulator has the function of overseeing the conduct of these different aspects of the industry, which include pricing and trading arrangements. In addition, the restructuring plan gives the regulator responsibility of preparing the industry for the creation of power pool where electricity is to be traded in wholesale spot market.

Opening generation and distribution activities for private companies will require clarification of major issues regarding the use of the transmission network, such as transmission pricing. Transmission pricing becomes an important issue as the industry moves toward competition. In particular, competition in generation makes it necessary to include the cost of transmission in the evaluation of bids. Also, the contracts for purchasing power should specify where the electricity is bought (at which node) on the network. For an electricity network with no transmission losses (costs), the prices at all its nodes are the same. In reality, however, the price of the electricity at any node differs from the price at any other node by the transmission cost between the two nodes. In an ideal competitive market, this difference should be equal to the marginal cost of transmission, which is the marginal transmission loss.

The importance of transmission pricing becomes even more obvious as the electricity industry is structured to include wholesale (and retail) competition. Also, the chosen market mechanisms of pooling or bilateral contracting, require clear consideration of these prices in the electricity trading process. Thus, the evolution of the industry into a decentralised structure has highlighted the pivotal role of transmission prices in the co-ordination between generation and transmission segments. The efficient use and development of the electricity system are directly linked to how good these prices in reflecting the appropriate costs of both segments.

In first-best situation, deriving transmission costs should be based on the method of marginal pricing of transmission losses. The advantage of this method in guaranteeing economic efficiency is diminished by the volatility of its charges and the practical difficulties surrounding its implementation. Therefore, alternative traditional methods such as the 'Postage Stamp' method, which is based on flat rate per unit of power, are used in real practice. The practicality of this method comes at the expense of providing the necessary spatial signalling. A new method has been presented lately which is based on the notional assumption of tracing electricity on the transmission network. The electricity 'Tracing' method considers the proportionality in sharing the electricity flow (and losses) among the system users, which comprise generatores as well as load (demand) centres in the network.

The objective of this thesis is to examine these three methods for pricing transmission costs. It contributes to the above debate by presenting, for the first time, an empirical comparison of the methods based on actual data. The main results of the thesis are that the tracing method is a compromise solution between the other two methods. Secondly, its departure from the marginal method would result in a minimal loss in economic efficiency. Thirdly, it has the advantage over the postage stamp method in its ability to give spatial signalling similar to that of the marginal method. Fourthly, the tracing method is very transparent, fair and easy to implement. Thus, in addition to its academic contribution, the thesis is useful for future policy making for the Saudi Arabian electricity industry or that of any other country embarking on privatising the industry. It is also applicable to cross-

border trade in electricity between countries such as those in the Arabian Gulf region and beyond.

THE STRUCTURE OF THE THESIS

This thesis consists of nine chapters. The first chapter provides a general overview of the Saudi Arabian economy, its potentials and challenges. Chapter Two focuses on the problems facing the electricity industry and the current restructuring effort. The third chapter provides a literature review of the issues related to privatisation and restructuring in general and the electricity industry in particular. This chapter highlights the contentious issue of transmission pricing which is at the heart of this process. Chapter Four reviews the different transmission pricing methods that are usually considered by theorists and practitioners. The focus here is on the ideal method of marginal cost pricing and also on the novel method of electricity tracing.

The fifth chapter is the first in a series of four empirical chapters. Using real data, this chapter presents and explains the main features of the tracing method. Chapter Six presents the main features of the marginal method and evaluates both the tracing and the postage stamp methods with respect to it. Chapter Seven examines the impact of demand variations on transmission charges under these three methods. The eighth chapter is an illustration of two potential applications of the tracing method to today's electricity industry. The first application is concerned with cross-border trade in electricity while the second deals with the design of access charges that recover the network fixed costs. Chapter Nine provides the conclusions and the main findings of this research. Also, it presents several policy recommendations, and suggests some relevant topics for further research.

CHAPTER ONE
The Saudi Arabian Economy

1.1 INTRODUCTION

Saudi Arabia officially follows the Hanbali school of Islamic jurisprudence, which is often described as liberal on economic and business issues. This factor may have made it easier for the government to consider the philosophy of the free market system as the cornerstone of its development strategy. Hence, the lack of sufficient and adequate physical and human capital in the country was interpreted as evidence of market failure and the government took the initiative in adopting economic planning. In contrast to central planning based on socialist ideology followed by some Arab countries in the 1960s, economic planning in Saudi Arabia was intended to redistribute oil revenues, which are the dominant source of national wealth.

The launching of the five-year development plans began in 1970 with emphasis on industrialisation as a strategic move toward achieving economic development objectives. These objectives included reduction in the reliance on oil revenues, economic diversification, increasing private sector involvement in the economy and higher investment in the country's human capital. The role of oil in the economy is expected to remain predominant in the foreseeable future. This means that economic development policies should be concerned not only with the welfare of today's citizens, but also with that of future generations.

The diversification of the economic base is a long-term objective; hence, the current task for the country is to allocate its available resources efficiently between its different priorities. The clarification of the boundaries of both the private and the public sectors would enhance the efficiency in the economy through more specialisation. There are opportunity costs for government activities when the private sector can perform them more effectively. Arguably the objective of economic diversification could be attained more successfully with a greater contribution from the private sector. These issues will be

explored in this chapter with the aims of providing an overview of the Saudi Arabian economy and assesses its potential and future challenges.

1.2 CHARACTERISTICS OF THE ECONOMY

1.2.1 DEPENDENCY ON OIL

Saudi Arabia has nearly 262 billion barrels of crude oil, which is 25 per cent of the total proven world reserves. It is the largest single oil exporter, accounting for over 30 per cent of total production of the Organisation of Petroleum Exporting Countries (OPEC). Despite thirty years of economic development, the oil sector continues to play a dominant role in the economy. In 1999, the production of oil and gas amounted to about 36 per cent of the country's Gross Domestic Product (GDP). The share of crude oil exports in total exports was 88 per cent and the oil revenues represented 78 per cent of total government revenues. These figures are lower than they were during the 1970s and 1980s, especially in comparison with the period of the oil boom. Nevertheless, the Saudi economy is still characterised, rightly, as an oil-dependent economy.

The dependency of Saudi Arabia on a single source, oil, for its national wealth puts the country in an uncertain position. Robert Solow highlighted the main challenge that Saudi Arabia has to face. He states that:

> The Saudi Arabian economy starts with one asset: a vast pool of oil. Its job is to manage the use and using-up of that asset in such a way as to provide the best available flow of consumption benefits over time. That stream of benefits may well have to go on after the pool of oil is more or less exhausted, or is at least much diminished in value. *('Forward' in Askari (1990), p. xxxiii)*

The continuous discoveries of new quantities of crude oil, at the present time, make the physical depletion of oil a less important issue. What is of concern, however, is the present fluctuation in oil revenues and the potential for substitutes in the long run. In addition, the world energy market has witnessed structural changes where the oil share in the total demand for energy sources has substantially declined. The demand for oil from OPEC has fell to only 35 per cent due to the competition from other oil producing countries such as Norway and Mexico. This means the problem that the Saudi Arabian economy has to deal

with is the sustainability of demand for its oil exports and the maintenance of a sufficient level of revenues to meet its long term development needs.

It is worth noting that this issue has an intertemporal dimension as there is a trade-off between current and future consumption and, thus, has implications for the national saving rates. The objectives of economic development should include the achievement of a sustainable high standard of living, not only for the current generation, but also for future generations. Therefore, it is paramount for the economy to be less dependent on oil revenues by developing its internal sources of economic growth. This requires more attention to economic and financial measures which could substantially increase saving and investment rates in the economy.

1.2.2 ECONOMIC STRUCTURE

The growth of the Saudi economy remains closely linked to the growth in the oil sector. This link means that the fluctuations in world oil prices have an indirect impact on the growth of GDP through government expenditures. This was not the case in 1998 when the oil sector had a negative growth rate of 0.5 per cent, due to the large drop in oil prices, but the non-oil sector grew by 2.7 per cent. Within the non-oil sector, the private sector and government sector grew by 2.9 per cent and 2.1 per cent respectively. This may indicate the increasing ability of the different economic sectors to gradually adapt to the uncertainties associated with fluctuations in oil revenues, especially those that began in the 1980s. Also it reflects the potential for the different economic activities to break away from the influence of the oil sector if the necessary economic policies are followed. The following table, Table 1.1, shows the structural changes for the economy during the last three decades.

Table 1.1: The Breakdown of GDP Components and their Growth (at 1989 Constant Prices)

Economic Sectors	1974	1985	1998	Annual Growth Rate (1969-1998)
Oil and Gas	65.3	22.5	27.3	0.5
Agriculture	2.3	5.2	7	7.9
Manufacturing	1.6	5.5	9.7	8.7
Construction	4.6	13.8	9.8	8.8
Trade	2.8	10.2	7.7	8
Transport and Comm.	4.4	8.7	6.9	5
Other services *	19	34.1	31.6	5.1
GDP	100	100	100	3.4

Sources: Ministry of Planning, *'Facts and Figures (1970-1998)'*;
SAMA, Annual Report (1999)
* Includes government services

Table 1.1 shows that the oil and gas sector's relative contribution to the GDP was clearly influenced by the fluctuations in world oil prices. The high share of the non-oil sectors in 1985 and 1998 could have been a result of the decrease in the oil sector's share to 22.5 and 27.3 per cent in these two years respectively. Three important points can be observed from the above table.

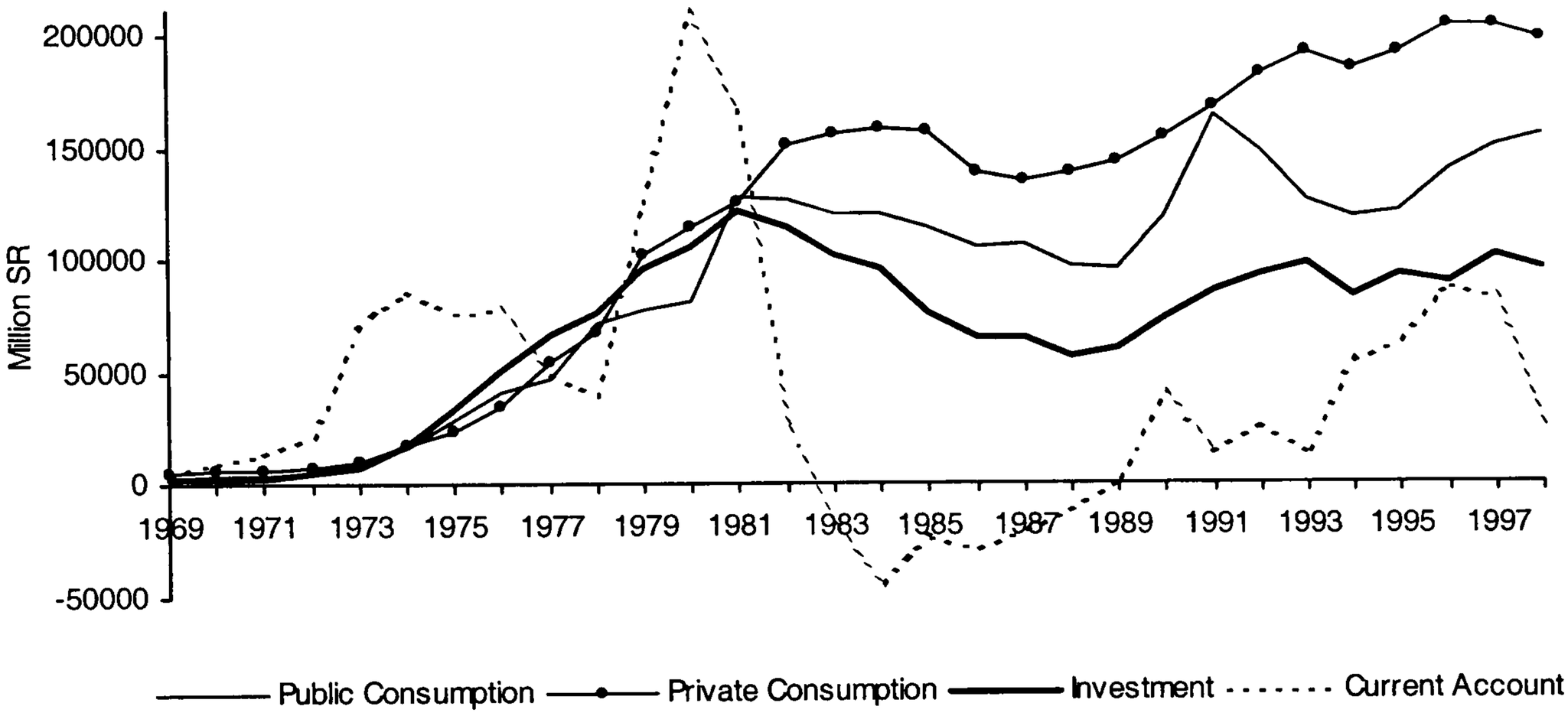
Firstly, the low growth of the oil sector, which was due to the decline in oil revenues during the 1980s and 1990s, coincided with much higher growth for the non-oil sectors. This may indicate that these sectors have been more able to minimise their direct link to the oil sector which caused the GDP to grow at a higher rate than the oil sector. Secondly, the manufacturing sector was able to surpass the agricultural sector, which could be explained by the fact that large part of petrochemical industry has become operational in 1985. In addition to the natural limitation on the growth of the agricultural sector, the reduction in its subsidisation during the 1990s may have caused its growth to slow down. Thirdly, the table shows that the construction sector may have already peaked and its share in GDP may fall below that of the manufacturing sector, as the industrialisation effort is intensified.

1.2.3 INVESTMENT AND SAVINGS

When savings are invested in more capital, it becomes possible to increase the rate of economic growth and produce a higher income level; otherwise there would be what is

called the paradox of thrift where more saving can lead to less investment, not more. Hence, the industrialisation of the economy ought to be combined with a similar effort to enhance the contributions of the financial services such as banking and insurance in the economy. These services could play a major role in increasing the saving rate and channelling savings toward more efficient investments. Figure 1.1, below, reveals how the Gross Domestic Product for Saudi Arabia, or its national output, has been used during the last three decades. As an open economy, the GDP consists of private consumption, government consumption (purchases), gross fixed capital formation (investment) and the current account (net exports of goods and services).

Figure 1.1: Expenditures on GDP in Current Prices (1969-1998)



Source: SAMA, Annual Report (1999)

This figure shows that the public spending remains the driving force in the Saudi Arabian economy. The fluctuation in the current account share in the GDP is almost entirely a reflection of changes in oil exports during the last three decades. The movement of government consumption, private consumption and investment followed similar trends especially during the 1970s. The substantial increase in oil revenues made government spending the main factor influencing the other components of the GDP. As the main employer in the economy, the government was able to influence private consumption through hiring a significant segment of the labour force and providing a substantial increase in salaries. In addition to this effect, private consumption was influenced by

government subsidies to housing, food and public utilities services such as electricity and water.

The government spending on infrastructure projects, especially in the transportation sector, was the main contributor to investment in the capital stock. This was the case until the mid-1980s when most of these projects were completed. The private sector contribution to investment grew in absolute terms during the same period, causing its share in capital formation to increase from 42 per cent in 1984 to over 61 per cent in 1998. This change draws attention to the impact of government spending on private investment.

The study of many developing economies by Blejer and Khan (1984) shows that only the non-infrastructural composites of government spending have a crowding-out effect on private sector investment. However, Looney (1992, 1997) studied key macroeconomic variables in the Saudi Arabian economy and found that the non-infrastructural as well as infrastructural composites of government spending have a crowding-out effect on private sector investment. He attributes his findings to the possibility that the short run sensitivity of private investment to government spending is much greater than the long run advantages of the availability of infrastructure services.

Such findings show that future policies should emphasise the withdrawal of government from direct investment even in infrastructure. The private sector is now more able than before to enter into such large-scale projects when the right framework is put in place. The government can use schemes such as Build-Operate-Transfer (BOT) or Build-Own-Operate-Transfer (BOOT), by involving the private sector in the expansion of the country's physical infrastructure. The advantage of this approach is the opportunity of the government to build such projects at a lower cost than if it has to raise the funds itself. In addition, the government does not to have to relinquish its ownership of the assets of some of the projects which are considered to be 'strategic'.

Figure 1.1, above, raises various issues relating to economic policies on investments and savings. In relation to the other components of GDP, the investment' share has been declining since the early 1980s and it fell to 20 per cent by the end of 1998. This level can

be considered too low as it includes spending on capital depreciation. The long-term objective of increasing capital formation may require a higher level of investment in the capital stock. This level of investment is related to the existing national saving rate. According to Mankiw (1997), there are no agreements on what is the optimal saving rate as that would depend on the level of economic growth of each country. For a developed economy such as that of the United States, a saving rate of 15 per cent is considered acceptable.

The data for the Saudi Arabian economy indicate that the saving rate ranges between 27 to 35 per cent of the GDP. Askari (1990) believes that Saudi Arabia, at this stage of economic development should aim to have a saving rate of 60 per cent. This high rate would be necessary for maintaining the current standard of living in the future. Hence, economic policies would have to pursue an array of measures to reduce the total consumption, especially that of the government through a greater role for the private sector and privatisation of many public enterprises. Also further development of banking services and financial deepening would enhance the incentives for more saving and investment.

1.3 INDUSTRIALISATION

Industrialisation has been a government aim since the early 1960s as reflected by the establishment of the Industrial Studies and Development Center in 1965. Since then, this governmental organisation (renamed Saudi Consulting House) has played a major role in the provision of technical and industrial consultation services to private and public enterprises. This organisational reform was followed by the launching of the five-year development plans in 1970 with emphasis on industrialisation as the cornerstone of the government's economic diversification policy.

The industrialisation policy offers two strategic measures for accomplishing its objectives. The first measure is to support industries that could produce substitutes for imports by utilising domestic raw materials. The aim is to provide the domestic market with needed products such as cement and other construction materials. The second measure is to develop industries that are able to use the country's available natural resources such as oil

and natural gas. These industries include basic industries such as petrochemical, steel and aluminium.

The availability of oil revenues has made it feasible for the government to pursue these objectives through various means including direct and indirect subsidies, provision of soft loans and creation of infrastructure facilities such as industrial estates. These measures have been justified on the ground that these are infant industries. The reduction, if not the removal, of subsidies to such industries, as part of the effort to join the World Trade Organisation (WTO), may provide a challenge for policies of self-reliance and economic diversification.

1.3.1 IMPORT SUBSTITUTE INDUSTRIES

The last three decades witnessed a clear growth in manufacturing industries (excluding petrochemical and related industries). These industries are geared to supply the domestic market and provide substitutes of imports. The annual reports of SAMA reveal that the number of operating factories increased from 199 in 1970 with 14,000 workers to 3,148 factories with 292,102 workers in 1998. This growth was associated with a considerable increase in the capital-intensity of these industries. On average, the amount of capital per worker rose from SR200,000 in 1970 to SR795,000 in 1998. Thus, the high capital intensity of these industries may limit their potential for generating employment opportunities for Saudis, at least in the short term. The lack of strong reliance on economic feasibility studies in the past by the private sector may have led to the establishment of too many factories for the same products. It seems that generous industrial subsidisation may have resulted in an over-capacity in some of these industries. Therefore, the distinction between constructive competition and mere duplication should be an essential part of future industrialisation policies. This could be helped by reforming the existing licensing regimes, as these need to consider the size of the domestic market as well as the export potential for such industries.

1.3.2 HYDROCARBON AND PETROCHEMICAL INDUSTRIES

The creation of the Saudi Arabian Basic Industries Corporation (SABIC) in 1976 was mainly to oversee the establishment of petrochemical and heavy industries for the purpose

of utilising cheap feedstock from oil and natural gas. The available official[1] figures show that by the end of 1996, SABIC had 16 operating plants, from which 60 per cent of the output was accounted for by petrochemicals, 18 per cent fertilisers, 10 per cent plastics and 12 per cent metals. The value of petrochemical exports was over SR15bn, which accounted for about 66 per cent of the country's exports of industrial goods. These numbers are likely to become higher in the next a few years as the world demand for petrochemicals is expected to improve and more new plants become operational.

The exports of Saudi Arabian petrochemicals account for about 5 per cent of the world petrochemical market. The main markets were those of the East Asian countries but the financial crises of the region have had a negative effect on SABIC profits for the last two years. However, the financial performance of the company since the second half of 1999 improved as some of the Asian economies began to recover. For the expected new capacity to be absorbed, SABIC needs to have more aggressive marketing strategies. These strategies should include offering a wider range of products to the existing markets, especially in Europe, and expanding into new markets such those in Latin America.

The rationale for hydrocarbon and petrochemical industries was founded on the comparative advantage argument. These industries are based on utilisation of associated natural gas, which used to be flared in large quantities until the beginning of the 1980s. They benefit from low-cost feed stocks but their high construction costs raised, at that time, many doubts about their long-term profitability. This depends mainly on the demand conditions in the world market and the share of Saudi Arabian exports in it.

The environmental benefits from utilising otherwise flared gas need to be weighed against environmental costs created by petrochemical and other heavy industries. The support for such industries based on the low opportunity cost of natural gas is no longer strong. The move toward more production of non-associated gas and the expected increase in domestic demand for gas, especially for electricity generation and desalinisation plants, will reduce the relative share of such industries in gas consumption. So the viability of the

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[1] Ministry of Planning, *'Facts and Figures (1970-1996)'*

petrochemical industries will be judged mainly on how far these industries are integrated into the Saudi Arabian economy through its linkage with other economic activities.

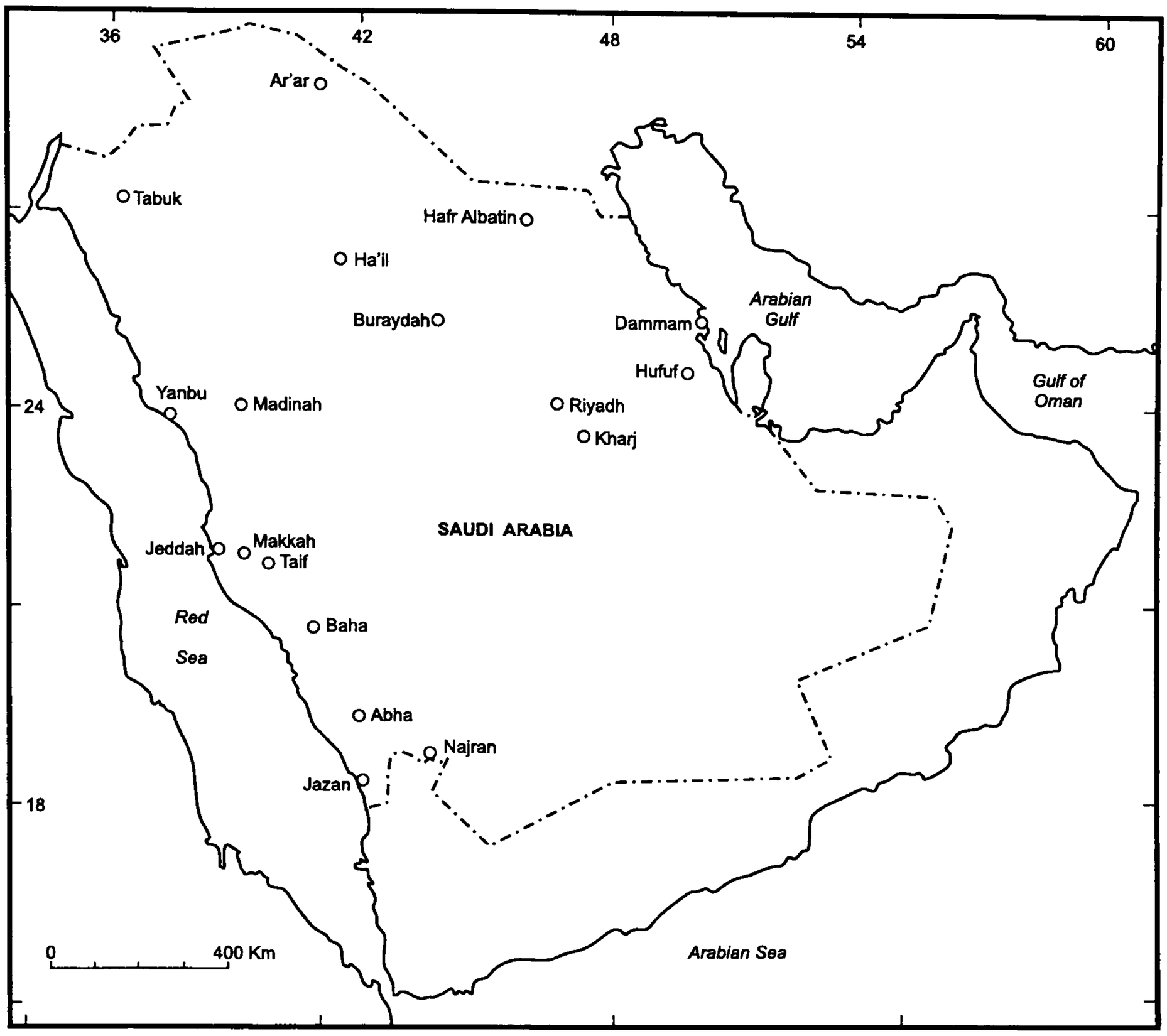
The government is very involved in the petrochemical and other heavy industries. This is usually explained by two factors. Firstly, the financial requirements of these industries are too risky for the Saudi Arabian private sector. Secondly, the close linkages between these industries and both oil and gas policies categorise them as strategic industries. However, the government has encouraged joint ventures with foreign companies in the development of these industries. According to Johany et al, writing in 1986, the joint venture approach would ensure ongoing viability of the projects, as the foreign companies have an established international marketing network. In addition, these companies would provide the needed know-how and managerial skills to these new industries.

Askari (1990) sheds some doubt on the widely accepted assumption that the foreign partner shares the same objective of the long-term viability of these ventures. According to him, the real capital commitment of the foreign company is usually under 10 per cent, with the difference accounted for by intangibles, such as the fees for technology transfer, and the sale of the right to use patents to the joint venture. Also, he sees a low linkage of these industries to the domestic private sector. However, he accepts the benefit of these industries in reducing the gap between the total dependency on the exports of crude oil and the exporting of value-added manufactured goods.

1.4 URBANISATION AND REGIONAL DEVELOPMENT

Although Saudi Arabia is a large country (covering an area of 2,250 million square km) with a relatively small population (20 million people in 1999), it is considered a very urbanised country. The World Bank (1999) data reveal that in 1960 only 30 per cent of the population was considered urban, but this number reached 66 per cent in 1980, and increased to more than 86 per cent in 1998. The following map illustrates the concentration of the urban population in Saudi Arabian into well-defined and distinct centres.

Figure 1.2: Map of Urban Population Centres in Saudi Arabia

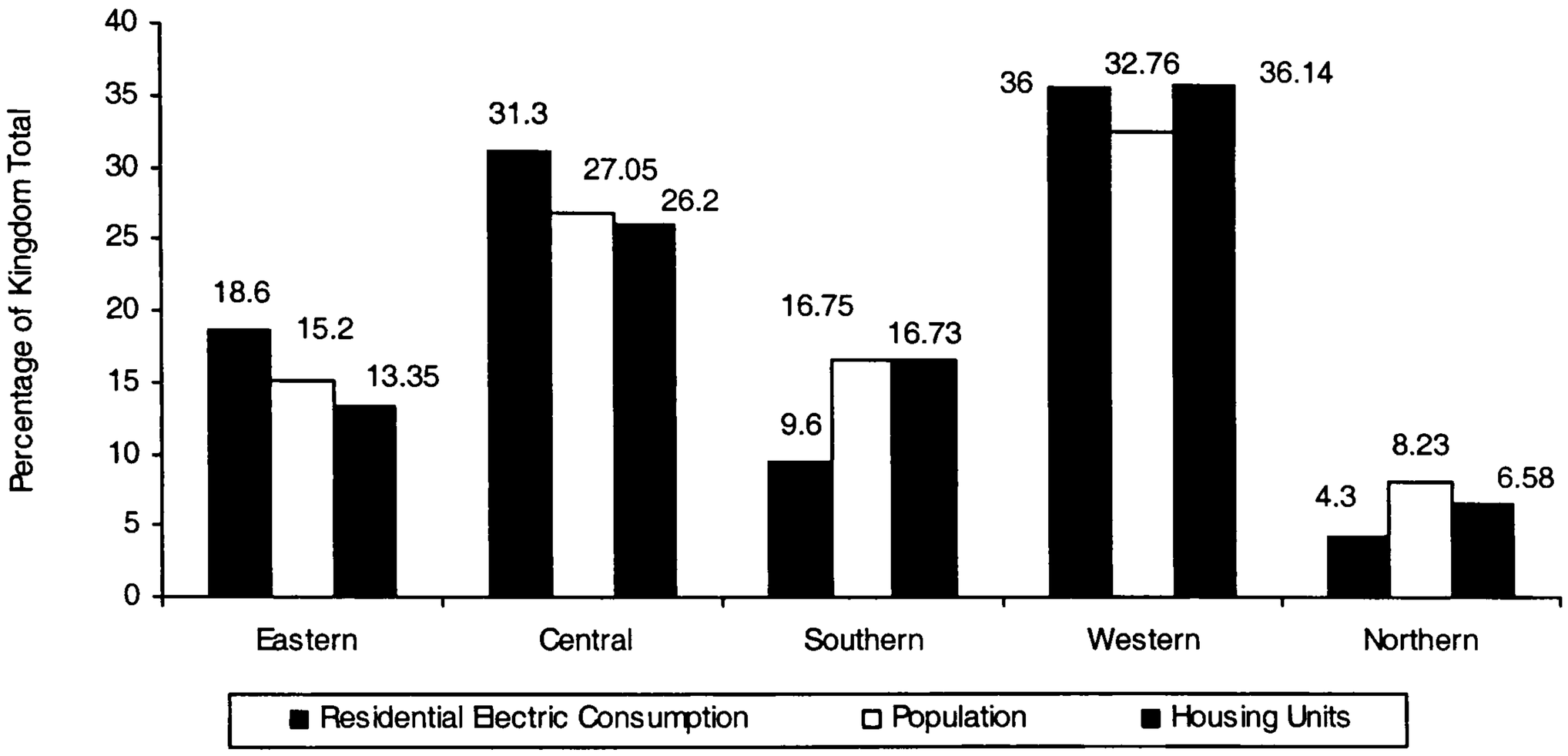


In addition to direct economic factors, the relatively fast urbanisation of Saudi Arabia has been caused by two demographic factors. The first is the relatively high natural population growth, especially in the last two decades due mainly to the improvement in the country's health services. The second factor contributing to this urbanisation is that each region contains a number of modern and developed regional centres which became attractive for migrants from rural areas.

These two demographic aspects of urbanisation development have long-term implications. In addition to increasing demand for employment opportunities, the next a few years are expected to witness very high pressure on the existing social and economic services, including those of education, health and infrastructure. The pattern of urbanisation in the country, which took the form of regional centres, has some positive advantages. This pattern makes the task of future provision to a large percentage of Saudi citizens of the

necessary services relatively easier than in the past. For example, it is easier for the electricity industry to supply its services to large segments of the population as they are concentrated in a limited number of cities and towns across the country. However, Figure 1.3, below, indicates that there is more work to be done toward reducing the differences between the country's five main regions.

Figure 1.3: The Relative Share of Each Region in the Kingdom's Total Population, Residential Electricity Consumption and Housing Units (in1997)



Sources: MP, 'Statistical Yearbook' (1998); MIE, Annual Report (1998)

John Presely, writing in 1984, observed that the eastern, central and western regions of Saudi Arabia had benefited more from economic development than their population would warrant. This observation is still valid at the present time despite the fact that the government's effort to correct such an imbalance began with the Third Development Plan (1980-1985). Figure 1.3, above, compares the five regions of Saudi Arabia in terms of their respective shares in the country's total population, residential electricity consumption and housing units. Although these are only some of the factors which needed to be considered in drawing a cross-regional comparison, the above figure shows that in the present time there still remain a considerable degree of regional imbalance.

In comparison with the eastern, central and western regions, both the southern and northern regions have lower residential electricity consumption in relation to their respective shares in the country's population. The per capita of residential electricity consumption levels for the southern and northern regions are 1,372 kWh and 1,219 kWh respectively which are

substantially lower than the country's average per capita (residential) consumption of 2,487 kWh.

With the exception of the western region, the share of each of the other regions in housing units is lower than their share in the population, which indicates the potential for growth in demand for electricity in these regions. These examples confirm the need for further effort toward achieving a balanced economic and social development. This objective has been considered a strategic principle in the Seventh Development Plan (2000-2005) which attempts to use a bottom-up approach by giving the provincial councils more role in this process.

1.5 FINANCIAL SYSTEM

Xu (2000) reviewed the literature concerning the importance of financial systems to economic growth, and he categorised it according to three distinct points of view. The first sees financial systems as an important factor for economic growth and development. The second views financial development as a result of rather than a contributing factor to economic growth. The third considers financial systems to have a negative impact on economic growth as it has the potential to create a 'credit crunch' by reducing the available credit to domestic firms. In his empirical investigation of these hypotheses, Xu found that there is strong evidence to suggest that the development of financial systems is essential to economic development, which supports the first hypothesis. He explains that the impact of financial system on economic development is channelled through its short- and long-term impact on domestic investments. These findings are clearly very relevant to the case of the Saudi Arabian economy.

In the light of the country's financial wealth, the development of its financial system has been below its potential. Abdeen and Shook (1984) contend that such a development requires three conditions: a high level of lending by the banks, an active stock market, and government borrowing and lending activities by the central bank. At the time they were writing, these conditions had not been met by the financial system. Since then, the economy has gone through changes and moved closer to meeting these conditions. For example, the persistent deficits in its budget have forced the government to stop relying on its foreign reserves and begin borrowing from the domestic banking system. These issues

will be discussed further in the following section which reviews the main components of the financial system in Saudi Arabia. These components consist of the central bank, commercial banks and the stock market.

1.5.1 CENTRAL BANK

Central banking functions are the responsibility of the Saudi Arabian Monetary Agency (SAMA), which reports to the Ministry of Finance National Economy . As a result, SAMA does not have complete autonomy in determining monetary policy. Although MFNE has no explicit targets for inflation or money supply growth, it has the aim of exchange rate stability through maintaining a fixed parity of the Saudi riyal with the US dollar.

The role of SAMA as a central bank is further restricted by the fact that it does not have at its disposal two of the main monetary policy instruments which are normally used by traditional central banks. These instruments are open-market operations and the discount rate. Hence, SAMA has to rely on the required reserve ratio to influence money supply through the commercial bank's ability to create money. Wilson (1999) points out other rules which have been used by SAMA to regulate commercial banking activities. The first of these rules is the use of the so-called Basle ratio of 8 per cent, which is the ratio of capital to risk-weighted assets. The second is that a bank's deposit may not exceed 15 times its capital, reserves and retained earnings. The third is that 7 per cent of demand deposits and 2 per cent of all other account liabilities are to be maintained with SAMA. The fourth is that loans should not exceed 65 per cent of customers' deposits

1.5.2 COMMERCIAL BANKS

1.5.2.1 LOCAL COMMERCIAL BANKS

There was a steady decline in the share of currency in the money supply (M3) from 49.3 per cent in 1970 to 16 per cent in 1998, which clearly indicates the increasing demand for banking services. By the end of 1999, there were 10 banks with total assets of SR415bn. The country had 1,196 branches which means that there were approximately 16,700 people per branch. Although this ratio can be considered acceptable, especially by the standard of developing economies, it signals further opportunities for expanding retail banking.

The banking sector is greatly influenced by the oil revenues, but the continuous government budgetary deficits have increased the role of the commercial banks in the economy. Not only has the private sector had to rely less on public funding but also the government itself has needed to finance its deficits through the commercial banks. In 1999, the commercial banks' claims on the private sector and the public sector reached SR162bn and SR117bn respectively. However, most of the credit provided for the private sector has a short-term maturity and most of these credits were for trade activities. Al-Dukheil (1995) believes that these banks have the potential to play a major role in future economic development. He suggests that they should formulate effective strategies to tap the country's considerable private savings. He also argues that they need to expand their lending to the industrial sectors, especially lending to small business. Such lending is a positive contribution to the economy but it has to be combined with a reform of the bankruptcy laws in the country. However, there is an effort under way to revise the existing system for the Settlement of Commercial Disputes which includes such laws.

The approval by SAMA of recent banking consolidations may indicate its disregard for the likely emergence of market concentration in this sector. This policy may have been based on the premise that such mergers would strengthen the ability of the local banking system to operate efficiently in a competitive global environment. There is some easing in the reluctance of the monetary authority to allow foreign banks to open fully-owned subsidiaries in the country. The Gulf International Bank (GIB), which is based in Bahrain, is being allowed in 2000 to open branches in Saudi Arabia. The commercial nature of this bank is supplemented by its investment banking capabilities and its significant loan syndication activities. In addition, this bank has been offering an advisory services to the Gulf Co-operation Council (GCC) for its electricity interconnection project. Although the banking services in Saudi Arabia are, in general, considered to be very good, the entry of foreign banks may bring with it real competition and better quality for many customers. Thus, the banking sector has to be well prepared to deal with such competition especially if the country is admitted into the World Trade Organisation (WTO).

1.5.2.2 SAUDI INTERNATIONAL BANKS AND OFFSHORE UNITS

O'hali (2000) believes that there are some limitations on the banking services and products which can be offered by the local banks, due to two factors. Firstly, the domestic demand

for such services remains small, though growing. Secondly, the relatively small size of most of these banks prevents them from offering such services efficiently. However, there have been growing off-balance-sheet activities in the last few years. The major income sources, so far, have been 114 mutual funds with assets totalling about SR24.4bn. Other increasing activities in recent years are the management of private client investment funds and positions in derivative financial instruments.

The tie between some of the local banks and the Offshore Banking Units (OBUs) may have helped to provide exposure of these banks to the international banking system. OBUs perform an important function, especially those located in Bahrain, as they provide financial services for international companies operating in Saudi Arabia. Azzam (1997) points out that the Saudi Arabian international banking operations provide a useful tool with which SAMA can influence the offshore riyal market. The recent merger of the Gulf International Bank with the London-based Saudi International Bank (SIB) may indicate a growing interest in enhancing their ability to operate in international capital markets. However, the advantages of OBUs have to be weighed against their disadvantages of transferring domestic savings to be invested in international rather domestic markets. It is worth noting that it is possible that there will be less need for OBUs when the Saudi Arabian market has opened up to foreign banks.

1.5.3 SPECIALISED CREDIT INSTITUTIONS

The Saudi Arabian Agricultural Bank (SAAB) was the first government-sponsored credit institution to be established, in 1963. The early and mid 1970s witnessed the establishment of other institutions. These included the Public Investment Fund (PIF), the Saudi Industry Development Fund (SIDF) and the Real Estate Development Fund (REDF). The objective of these institutions was to extend medium- to long-term credit to the private sector and some public enterprises operating in the relevant activities. In the middle of 1999, their total assets were over SR229bn, which was very large considering that the commercial banks' assets were over SR404bn at that time. In 1997, the loans of these agencies to the private sector were higher than loans from the commercial banks by more than SR45bn. So the current activities of these agencies reflect the fact that there is a considerable demand for longer-term credit which needs to be met by the banking sector.

The specialised agencies' accumulated total disbursement reached over SR 281bn in 1999. However, the ratio of their credit to the gross domestic fixed capital formation declined from 15.4 per cent in 1990 to 9.8 per cent in 1996. Most of the time during the 1990s, the net lending of these agencies was negative, as their repayments exceeded their disbursement. The importance of these agencies has been diminishing as the country's infrastructure is almost completed; also, the government's ability to fund these institutions has become more limited than before. The privatisation of some of these institutions, such as REDF and SIDF, may revitalise their role in the economy. At present these agencies provide funding at below commercial rates, but when privatised they will no longer be able to do so. However, this restructuring would increase competition in the banking sector. This is more likely, as currently the only private source of medium- and long-term financing is the Saudi Investment Bank (SAIB).

1.5.4 FINANCIAL MARKET

1.5.4.1 GOVERNMENT SECURITIES

The financial market in Saudi Arabia is considered to be an underdeveloped market. Wilson (1999) explains this situation by the fact that the economy as a whole was financed by the available cash flow rather than by borrowing. Even at the time of declining oil revenues, especially prior to the mid 1980s, the government as well as the commercial banks were able to draw on their foreign reserves. This situation began to change as the continuous budget deficit compelled the government to rely on bonds for financincing.

In 1988, the Saudi government started to issue, through SAMA, Government Development Bonds (GDB) to cover its budget deficits. In addition, it started to issue Treasury Bills in 1991 and Floating Rate Notes in 1997 for the same purpose. This policy is similar to those followed by other Arab countries. According to Azzam (1997), these governments found it useful to finance their deficit from local funds instead of international loans as this reduced foreign exchange risk. These developments are useful for commercial banks as they can add these financial instruments to the range of assets they can hold. Also, the replacement of direct government borrowing with these instruments is preferable for the banks, since loans are replaced with short-term tradable assets. In addition, the benefits from financing this deficit locally would reduce foreign exchange risk, but the lack of an effective secondary market in Saudi Arabia may lessen such benefits.

1.5.4.2 STOCK MARKET

Soufi and Mayer (1991) emphasise the role that the financial system of Saudi Arabia could play in the expansion of its industrial investment which can materialise through a more effective stock market. The Saudi stock market has been steadily developing: in 1986 the number of joint stock companies listed in the market was only 48 which increased to 72 companies by the end of 1999. This stock market is the largest in the Arab world in terms of market capitalisation. The Joint Arab Economic Report (1998) shows that for the Saudi Arabian stock market the ratio of market capitalisation to GDP was 40 per cent in 1997 which was below the average for the stock market of the other Arab countries. This could be explained partially by the relatively large size of the GDP of Saudi Arabia in comparison with those of the other Arab countries.

The Saudi Arabian stock market used to be closed for direct investment by non-Saudi investors with the exception of nationals from the Gulf Co-operation Council (GCC) countries. This restriction was eased in 1997 by giving permission to the Saudi American Bank (SAMBA) to manage closed-end mutual funds where foreign nationals can buy shares through the fund. These restrictions have been further relaxed in 2000 to allow non-Saudis to invest directly in open-ended local equity funds. The process which is under way to finalise a new stock market law, is a realisation of the stock market's importance in the economy. In addition to its impact on domestic savings, the easing of foreign ownership restrictions means that the savings of a large number of expatriates working in the country can potentially be mobilised. These actions may have been long overdue considering that the annual remittances by these expatriates reach over SR50bn and have had an adverse effect on the country's balance of payment.

The stock market remains low in liquidity because of the relatively small number of issuers and the limited base of investors. The performance of the market, especially in 1998, has been influenced by the changing conditions in the oil markets as well as the weak performance of some emerging markets. However, this performance improved in 1999 as traders found comfort in rising oil prices and anticipated positive measures for improving investment climate in the country. Table 1.2, below, shows the activity of the market during 1999 by economic sector.

Table 1.2: Share Trading by Sectors during 1999

Economic Sectors	Number of Traded Shares	(%)	Value of Shares (in SR)	(%)	Number of Transactions	(%)
Banks	156,121,541	29.6	34,870,321,567	61.6	166,422	38
Industry	82,509,623	15.6	10,236,345,009	18.1	105,729	24.1
Cement	33,862,362	6.4	3,789,893,269	6.7	44,495	10.2
Services	226,967,729	43	6,085,512,505	10.8	96,247	22
Electricity	19,643,425	3.7	11,372,636,049	2.4	17,099	3.9
Agriculture	8,401,026	1.6	224,014,628	0.4	8,234	1.9
Total	527,505,706	100	66,578,723,027	100	438,226	100

Source: SAMA, Research and Statistics Department

This table reveals that the banking and industrial sectors are the most active sectors especially in terms of the value of traded shares and the number of executed transactions. At the bottom of the ranking are the electricity and agriculture sectors. The decline in the growth of the agricultural sector and the cut in government subsidies may explain the weak demand for agricultural companies' shares. The considerable assets and capital invested in the electricity industry, especially by the government, did not translate into good performance in the stock market by the listed companies.

The financial losses of the electricity companies , due to low prices, had made the industry rather unattractive to investors. However, the implementation, at the beginning of 2000,of the new tariff structure has led to an increase of over 50 per cent in the prices of electricity shares. As a result, the new tariffs would not only make the electricity companies improve their internal financing through cash flows, but would also enable them to raise more debt finance as their market values rise.

1.6 PRIVATISATION

The official policy for privatisation is stated in the Sixth Development Plan (1995-1999) which introduced privatisation in the context of enhancing private sector participation in the economic development of the country. The plan states that one of its main priorities is to " rationalise government expenditure and make the national economy more dependent on private sector activities through (among other things) considering the feasibility of privatising some government business-oriented activities" (P.6). The plan indicates that the gradual divestiture of public sector industries could be done through different means, including the flotation of shares on the stock market.

This policy emphasises that privatisation could be implemented by private sector participation in ownership, management, financing, operations and maintenance. The plan favours selling the entire government share in state-owned companies to privately owned venture capital companies listed on the stock market. The plan names the electricity industry as the main candidate for full privatisation in the middle and the long term. This shows that the current restructuring of the industry is intended to improve the profitability of the industry prior to its complete transfer to the private sector.

There were three aspects to Saudi Arabia's past experience of privatisation. The first was the partial privatisation of public services through private provision of these services, which is in parallel with the government. This took the form of private schools and private hospitals, which continue to be regulated and supervised by the government. The second was the privatisation of existing public services through operation and management contracts to provide the service on behalf of the public sector. The third aspect was direct privatisation through the sale of part or the whole project to the private sector.

Full privatisation of a company has not occurred as yet, but the initial partial sale of 35 per cent of SABIC in 1976 was supposed to be followed by another 45 per cent. The inability of the domestic stock market to absorb an additional stock flotation was the official reason for this delay. It is possible, however, that the government found it very difficult to privatise a profitable and strategic company such as SABIC. The telecommunications company, Saudi Telecommunication Company (STC), which is a profitable company is at the top of the list for next privatisation. Thus, it is expected to have some writers such as Wilson (1995) who believe that the government's reluctance to privatise SABIC has been influenced by 'strategic' considerations rather than by its ability to generate revenues.

The reduction of the financial burden of the government should not be underestimated and could be considered as the main motive for privatisation of public enterprises. The decline in oil revenues since the 1980s has made the public sector unable to provide sufficient funding for future financial obligations such as the financing of infrastructure projects. One of the main shortcomings of privatisation policies so far has been the lack of an explicit timetable for privatisation programmes, even for those sectors which are already considered and approved as candidates for privatisation. This would raise the concern that

the commitment to the reform may become subject to the availability of oil revenues. The establishment of such a timetable makes the implementation of the process less dependent on the conditions of the government finances.

CONCLUSION

The adoption of economic planing by the Saudi Arabian government is not in contradiction with its claim of being an adherent to the philosophy of free market. The rise in its oil revenues made it necessary to draw up coherent plans for using these revenues for the purpose of pursuing economic development and diversification. In addition, these plans were useful in making the government able to set priorities for its spending commitments. The objective of economic diversification has been centred on industrialisation through the two strategies of import substitution and export promotion. The pursuit of achieving these strategies has been backed in the past by direct and indirect involvement by the government.

Although the Saudi Arabian economy is described as 'state-heavy', the declining oil revenues and changing world trade environment would make such policies less likely to persist in the coming decades. Notwithstanding the consequences of these changes to the economy, it is time for the private sector to begin serious reduction in its reliance on government support. On the other hand, the government has to do its part by introducing more consistency and continuity in its current reform programmes as this would reduce apprehension and uncertainty by domestic as well as foreign investors. The entry of the economy into this transitional stage is expected to be aided by the achievements of the past. These have not been limited to the physical capital represented mainly by the country's modern infrastructure. They also include the improvement in human capital in the form of the expansion in education and health services during the last three decades. However, for these accomplishments to remain available in the future it is necessary to have suitable measures for improving the saving and investment climate in the country. Economic liberalisation and the deepening of financial markets could helpful. In addition, privatisation of some state-owned enterprises would increase the efficiency of the economy and reduce the size of the public sector. This would reduce the burden on the government budget and redefine the scopes and boundaries of both the public and the private sector.

CHAPTER TWO
The Electricity Industry of Saudi Arabia

2.1 INTRODUCTION

Saudi Arabia is still considered a developing country. Hence, achieving economic growth and, more broadly, economic and social development remain national strategic objectives. The investments in the country's infrastructure projects, including those of electricity, have depended on the availability of government revenues generated from exporting crude oil. The declining oil revenues since the early 1980s and budgetary constraints have limited the ability of the government and the public sector to continue financing such projects.

In addition to being justified on the basis of achieving social and economic objectives, the government involvement in the electricity industry was beneficial during the oil boom period. It has become clear since then that with increasingly limited budgetary allocation, the growth of this industry ought not to come at the expense of other sectors in the economy and vice versa. Consequently, the existing difficulties facing the industry have raised important questions regarding its ability to deal with future challenges. The private sector has become once again the candidate for carrying some of these responsibilities through the encouragement of its direct investments in this industry.

The sixth development plan (1995-1999) considers full privatisation of the electricity industry as a strategic objective for the medium and the long term. So there is an expectation for the industry to return to its historical position when it was owned and operated completely by the private sector. In the mean time, the objective is to raise the needed funds to enhance the industry's ability to meet the growing demand. However, shifting the financial responsibility from the government to the private sector, including national and international sources, should result in lower costs for the industry. This has to be complemented by introducing competition and choice in as many aspects of the industry as possible.

2.2 GENERAL BACKGROUND

2.2.1 REGULATORY AND ORGANISATIONAL DEVELOPMENT

The electricity industry in Saudi Arabia went through distinct stages of development in the last century. The following is a review of these stages based primarily on the regulatory and organisational transformation of the industry over the years.

2.2.1.1 THE FIRST STAGE

The electricity industry in Saudi Arabia started as a private enterprise. The 1920s and 1930s witnessed the introduction of electricity by some businessmen who needed this service for their factories and businesses. They were also able to sell excess capacity to other customers (neighbouring houses and streets) for lighting during early evening hours. Until 1948, the only organised form of power generation was that owned by the Arab American Corporation (ARAMCO), which was utilised mainly for its oil extraction facilities in the eastern region. In 1949 some Saudi citizens and businessmen from the city of Dammam co-operated in establishing the first private electricity company. Other cities and towns followed suit till the early 1970s when the country had over a hundred small commercial companies and co-operative projects (MIE, 1999). During the period between 1961 and 1974 the Ministry of Commerce supervised the electricity industry, which may reflect how electricity was viewed as a commercial commodity rather than just a social service.

2.2.1.2 THE SECOND STAGE

The creation of the new Ministry of Industry and Electricity (MIE) in 1975 meant that the supervision of electricity was transferred to the same ministry responsible for the pursuing the strategic goal of industrialisation. This development may have influenced government policy toward the electricity industry and the expected role of the private sector in this vital industry. The goal of industrialisation does not by itself justify government involvement in the electricity industry especially in a country which claims to be an adherent to the philosophy of free market economy. It seems, however, that practical considerations rather than ideological dogmas may led to government intervention in this industry.

The discussion of this issue may be illuminated by the views of Ghazi Al-Qusibi, who was the first official to head the Ministry of Industry and Electricity. He was known for his commitment to the private sector and was an early advocate of the privatisation of the Saudi Arabian Basic Industries Corporation (SABIC) and the public enterprise, the Electricity Corporation. Al-Qusibi (1998) describes his personal experience in the ministry and states how much he was disappointed with many of the officials in the electricity companies. He discovered in a few weeks how these officials lacked any comprehension of the challenges that the electricity industry was facing. He found that some of these officials were not able to comprehend the situation in their franchised areas even as far ahead as two years, let alone five or fifteen years.

It is possible that this attitude by the companies was based on rational justifications. The introduction of price regulation during the period between 1971 to 1975 may have adversely effected the profitability of these companies. This period witnessed the reduction of electricity prices by as much as 50 per cent from their level in previous years. Further reduction was introduced in 1974, as a nation-wide tariff structure became operative. The reduction in prices to a level below production costs may have contributed greatly to under-investment in the industry by the private sector.

Even if the private companies were able to raise the needed investments for their generation capacity expansion, the existing transmission and distribution capacity was not sufficient to accommodate such expansion. Also the private sector may have been able to raise sufficient funds from the domestic or international markets, but it may have lacked the incentive to enter into such unprofitable infrastructure projects. In addition, the capital costs of such an infrastructure were immense, which made the private sector unable to invest in them, at least in a expeditious manner.

It seems that the rush towards industrialisation and economic development made government technocrats, such as Al-Qusibi, impatient with these private companies who needed to consider what all the sudden changes would mean to them. The patience of these technocrats may have been very limited, especially as they had at their disposal at that time very substantial public funding. It is possible that such a pragmatic approach was based on

three factors. Firstly, there was an urgent need to have the infrastructure in place regardless of its cost. Secondly, the government had the objective of the nation-wide electrification and providing electricity at low prices, especially for consumers in rural areas. Thirdly, the policy-makers were sensitive to public opinion and the social reactions to the frequent and lengthy blackouts especially in large cities such as Riyadh. These factors may have enhanced the perception that the electricity industry was unwilling, or at least unable, to meet these new high expectations by relying on the private sector alone.

2.2.1.3 THE THIRD STAGE

Between 1976 and 1982, the government gradually subsumed individual operating companies under four vertically integrated companies in each region respectively. This led to the formation of the Saudi Consolidated Electric Companies (SCECOs) in the eastern, central, southern and western regions. The initial official intention was to consolidate the northern companies into one integrated company similar to the SCECOs, but the small size and the isolated nature of load (consumption) centres in this region made this objective economically unjustifiable. Also the Electricity Corporation (EC) was created as a public enterprise with two objectives. The first objective was to have the responsibility of financing and supervising the operation and expansion projects of the scattered companies in the northern region. The second objective was to represent the government's share in the industry as a whole including SCECOs.

This stage, which lasted from 1976 to 1999, is the period which witnessed the largest expansion of generation capacity in the industry's history. This may have been helped with government funding especially during the period of the oil boom. However, this achievement came with some drawbacks, which resulted from an excessive government intervention. This industry still faces significant financial losses due to inefficient pricing. Obviously, such intervention did not make the operation of the industry transparent.

2.2.1.4 THE FOURTH STAGE

A new stage began when the holding company the Saudi Electricity Company (SEC) was created in 2000. This is to be followed by a regulatory office called Electric Services Regulatory Authority (ESRA) that has the responsibility to oversee the transformation of

the industry into an unbundled structure. This restructuring of the industry is being done, not on a region-by-region basis but rather, on an activity-by-activity basis. The objective at this stage is to end government intervention in the day-to-day matters of the industry.

The current restructuring plan intends to make the industry a self-financing private enterprise with the introduction of a market mechanism into the different segments of the industry. According to this plan, the industry's new structure will include:

- the opening up of the generation segment to competing private companies
- a privately-owned transmission company
- regional private distribution and supply companies
- the transformation of the industry from a single-buyer structure to a pool structure where electricity is traded in the spot market , and
- the establishment of an 'independent' regulatory body.

The gradual implementation of this restructuring plan could provide the necessary time for the institutional and legal reforms to take place. Healthy competition in generation requires the provision of well-thought out rules and a regulatory system which is fair and transparent. So the reform has to be credible in practice, by tackling directly some of the economic and legal issues that would arise under the new structure and, more importantly, this reform needs to be consistent.

2.2.2 OWNERSHIP MIX

The creation of the Electricity Corporation in 1976 to represent the government's ownership share in the electricity companies, including the SCECOs signified direct government involvement in the industry. Table 2.1 shows the government share in the total equity capital of the companies operating in this industry as of the end of 1998.

Table 2.1: Government's Shares in Electricity Companies (in Million SR)

	Central	Western	Eastern	Southern	Northern	Total
Paid-Up Capital	8000	7350	4151	3564.4	36.98	23102.38
Government Share	5742.03	6281.84	3764.5	3513.24	21.17	19322.78
%	71.87	85.47	* 91	98.6	57.25	83.6

Source: Council of Saudi Chamber of Commerce (1999)
* Includes ARAMCO share of 41%

The electricity industry is, for all practical purposes, a government dominated industry and this is reflected in its high share in these joint-stock companies. Table 2.1 shows that the government is the major shareholder in the industry with about 84 per cent of total paid-up capital. The government's involvement in the industry was based on three justifications: firstly the intention to have the needed generation capacity to meet the growing demand of energy-intensive industrialisation; secondly, the aim of developing the necessary transmission and distribution infrastructure for the country's electrification; thirdly, the social aim of providing Saudi citizens especially in less developed regions with electricity at low and affordable prices.

2.2.3 GROWTH OF DEMAND

In addition to industrialisation, the urbanisation of the country was a major factor in the growth in electricity consumption during the last thirty years. Table 2.2 illustrates that the growth of the industry could be divided into two very distinct periods: the period from 1970 to 1984 and the period from 1985 to 1999. The high growth rates during the first period reflect the time when the country went through the oil boom and economic transformation. The second period shows the time when the country infrastructure was mostly completed and the economy began to slow down.

Table 2.2: Electricity Industry Growth Rates (1970-1999)

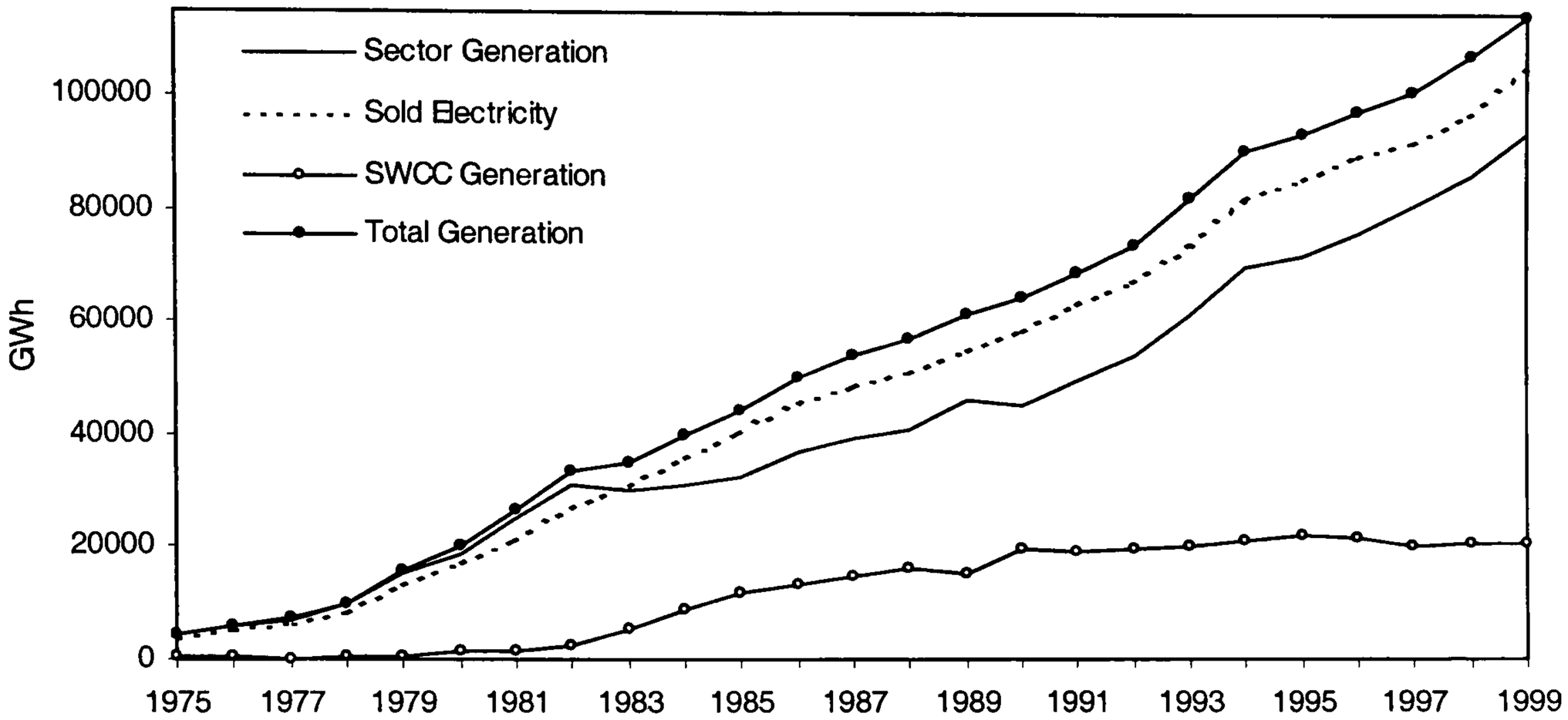
Periods	Generation Cap.	Peak Load	* Generated	Sold
	%	%	%	%
1970-1974	28.5	24.6	19.1	19.1
1975-1979	34.5	32.6	33.7	31.7
1980-1984	23.5	23.5	20.5	21.8
1985-1989	6.8	6.4	9.1	8.9
1990-1994	1.3	8.5	8.1	8.3
1995-1999	3.3	3.1	4.7	5.1
1970-1999	16.32	16.45	15.87	15.82

* Includes Imported Energy from SWCC since 1975
Source: Ministry of Industry and Electricity (1999)

Table 2.2 shows that the 1990s were a difficult time for the industry as it tried to keep up with the growth in electricity consumption. The growth rate of electricity demand, either measured in peak demand or in energy consumption, was at most of the time during this decade higher than the growth rate of generation. In addition to the high natural population

growth of 3.5 per cent, the processes of modernisation and economic diversification were the main driving forces behind the high growth in electricity demand. Figure 2.1, below, illustrates the growth in electricity consumption over the past thirty years and the generation supply.

Figure 2.1: Development of Electricity Generation and Consumption



Source: MIE Annual Report (1999)

The annual growth in generated electricity, in MWh, since 1975 has been 13.8 per cent which was insufficient to keep up with the 14.8 per cent growth in consumption. In 1999 about 106 million MWh were sold, while the industry itself was incapable of generating more than 94 million MWh. The electricity produced by the desalination plants, which are owned by the Slain Water Conversion Corporation (SWCC), covered the deficit of 18 per cent. This indicates the importance of SWCC plants for the electricity industry as the output of these plants have been crucial in closing this deficit since 1984.

Also Figure 2.1 shows the total technical energy losses (i.e. the difference between total generation and total electricity sales) which include station losses as well as transmission and distribution losses. These losses in a percentage term declined from 13.4 per cent in 1980 to only 7.9 per cent in 1999. This percentage is very low even in comparison with the electricity systems of many developed countries, which have an average loss of 9 per cent. The explanation for this increase in efficiency in transporting electricity is due to the establishment of modern and robust transmission and distribution networks. This became

possible with the availability of the allocated government funding for such infrastructure projects during the 1970s and early 1980s.

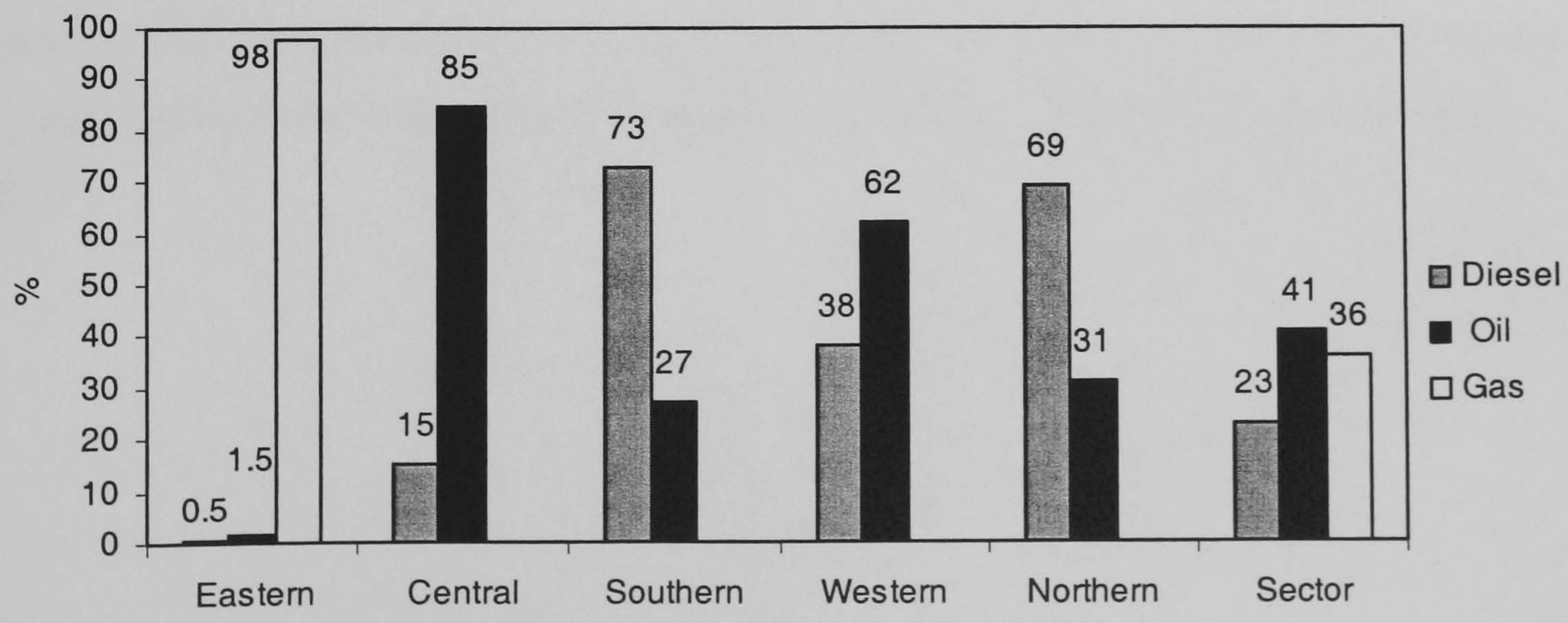
2.3 OPERATIONAL ISSUES

The operational and financial issues facing this industry are closely inter-linked. The following sections review the operational issues first. This is necessary to give the proper background for understanding the financial issues that are facing this industry.

2.3.1 FUEL LOCATION

The location of any industry is determined by a combination of many factors but the most important among them is the proximity to consumption location (markets) and the availability of production inputs such as raw material including fuel. This is also true in the case of the Saudi Arabian electricity industry where the fuel factor has a major influence on the generation location. About 35 per cent of the industry capacity is located in the eastern region, despite the fact that this region has only 15 per cent of the country population. The concentration of oil and gas fields in this region also attracted the petrochemical industries, which are the main consumers of electricity in the region as well.

Figure 2.2: Relative Usage of Fuel Types by each Region



Source: Ministry of Industry and Electricity (1999)

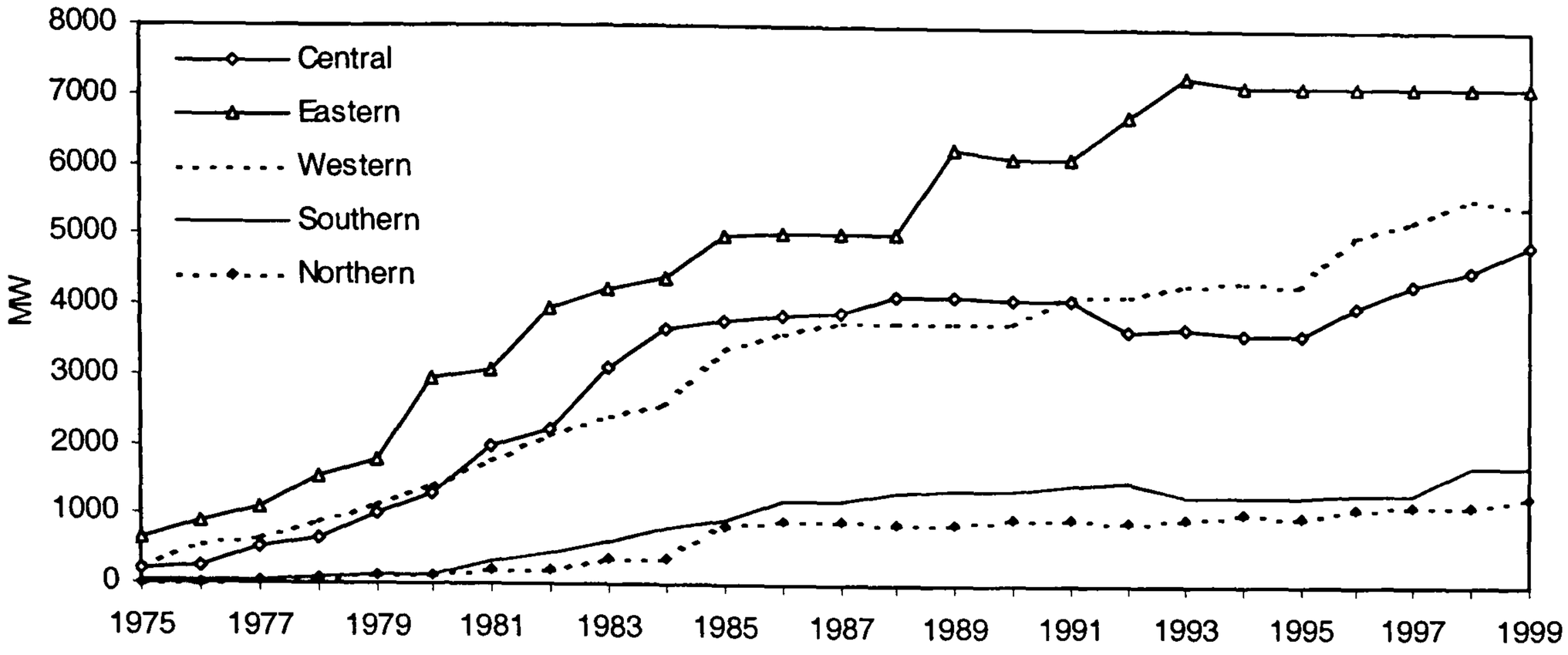
Fuel availability at a reasonable price is one of the major elements in the consideration of the location of generators. Figure 2.2 shows the power generation usage of the different types of fuels by electricity companies in different regions of the country. The availability of gas fields in the eastern region enables SCECO-Eastern to have 98 per cent of the fuel used in its plants coming from natural gas. Also the availability of these fuel sources have influenced the location of its major customers, the petrochemical manufacturers.

Despite the high usage of gas by this company, the industry as whole is still dominated by the usage of crude oil and diesel. Most of the fuel usage by the companies in central and western regions is of crude oil, while most of the fuel usage by the southern and northern companies is of diesel. This variation between regions in fuel usage could be explained in part by the transportation costs of these different types of fuel and the lack of a nation-wide natural gas network. The exception is the single NGL line which runs from the eastern region to Yanbu (in the western region) to supply the petrochemical plants with the required feedstock. The opening up of the industry for independent power producers may increase the demand for gas for electricity generation purposes. The cost advantage of transmitting electricity relative to transporting gas may encourage future generation projects to locate in the eastern region. Consequently the transmission grid will play an essential role by linking consumption centres with generation sources.

2.3.2 REGIONAL GENERATION LOCATION

Figure 2.3 indicates the ranking of electricity companies in terms of their actual generation capacity. Also it shows the pattern of generation location in the different regions since 1975.

Figure 2.3: Regional Generation Location



Source: Ministry of Industry and Electricity (1999)

The growth in generation in these regions during this period has been mainly driven by the growth in demand in each region separately. This has not exactly been the case with the central and eastern regions as they are interconnected regions. The decisions regarding investments in generation capacity have been influenced by the combined demand of both regions. As of 1999, the central region has 29 per cent of its peak load met by imported electricity from the eastern region. On the other hand about 20 per cent of SCECO-Eastern peak load is exported to SCECO-Central. This means that the interconnection between the eastern and central regions plays major role in shaping the growth in their respective generation capacity. It is obvious that SCECO-Central would have to build the generation capacity needed to meet its peak load if there was no interconnection with the eastern region. Al-Shehri et al (1994) calculated the potential benefits from this interconnection and found it to be substantial for both companies due to the differential in their marginal generation costs.

In addition, SCECO-Eastern benefits further from importing electricity from the SWCC plants. This company has been able to save considerably in costs by buying cheaper power from the desalination plants of SWCC. The data obtained from MIE show that the desalination plants produce a kWh of electricity at 3.3 Halalahs, while it is (on average) more than 6 Halalahs for the electricity industry. The low cost of electricity produced from the desalination plants is due to the economies of scope of producing water and as a by-product, electricity. Also SCECO-Eastern was able to capture the difference between the

price it pays to SWCC, which is 1.5 Halalahs per kWh, and the payment it receives from SCECO-Central, which is 5 Halalahs per kWh.

This shows the importance of interconnection in cost saving arising from sharing reserves through energy trade. The effort is under way, especially in line with the announcement of the industry restructuring, to interconnect all regions for the purposes of sharing reserves and trading in electricity. This is also part of the preparation for the beginning of the Gulf Co-operation Council (GCC) interconnection project in 2002. The eastern region is expected to play a central role due to its location between the member states, as it has about 90 per cent of the GCC network and is the host of the headquarters of the project's commission.

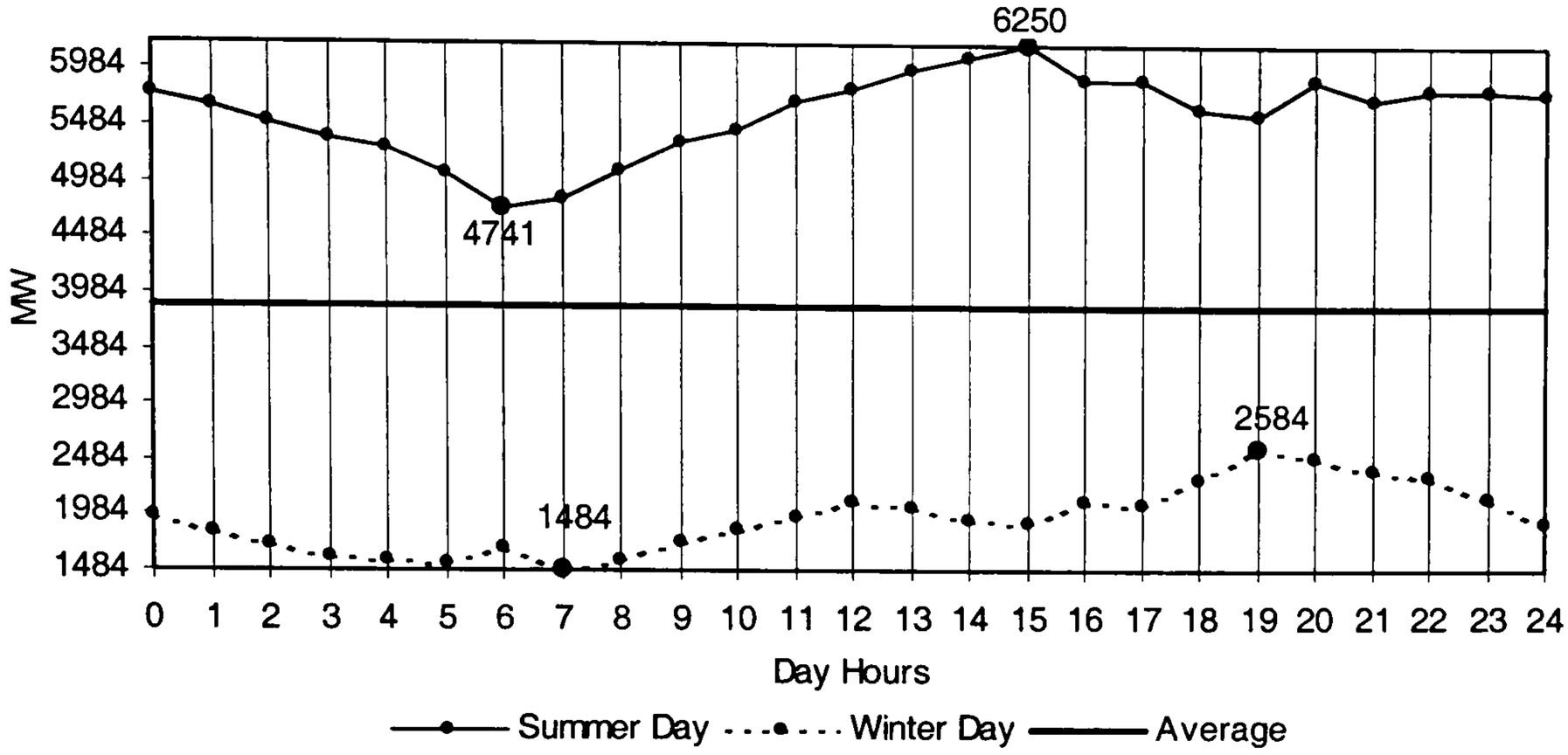
2.3.3 LOAD CHARACTERISTICS

Storing electricity on a large scale is not economically feasible and this makes electricity a demand-driven industry. This would impose additional costs, as the generation and transmission capacities must be designed to meet the estimated system demand at its peak hour. In the case of Saudi Arabia, the peak time for the country occurs during the summer months as the consumption, especially by residential customers, is closely influenced by temperature level due to the use of air-conditioning.

In addition to its impact on demand, high weather temperatures have a constraining effect on the operation of the genertion units by preventing them from reaching their designed capacity. As a result, the load factor ratio, which measures the utilisation level of generation capacity, is less than 48 per cent, which is low by international standards. According to Abu Ras and Azzam (1999) the large differences between the peak (maximum) and minimum loads indicate low thermal efficiency as some generation units operate at low load during the time of minimum peak. Also this would indicate continuous need for installing additional generation units with high operation costs to meet the peak load. So the shrinking of the gap between these levels would result in reducing the capital and operation costs significantly. This could be done through implementation of efficient pricing which reflects the actual cost of production and utilising suitable Demand-Side Management programmes (DSM).

Figure 2.4 compares the daily demand curves for summer and winter days, which represent the maximum and the minimum respectively for 1999 as obtained from the electricity company SCECO-Central.

Figure 2.4: Daily Load Curves for a Summer and a Winter Days in 1999



Source: SCECO-central, System Operation Department (Interconnected Network Control Division).

Figure 2.4 shows the maximum load for the year is 6,250 MW, which occurred on the afternoon of a working day in June. The figure also shows the minimum load for the same day, which is not the minimum for the whole year. In addition, it illustrates the minimum for the year (1,484) which occurred on a weekend day in February. The following calculations, although based on simplified assumptions, demonstrate the impact of the load fluctuations on the utility capital costs.

Let us assume that the demand facing this company is at a constant level through out the year. Let us also assume this level is the average between the maximum and the minimum for the year, which is 3,867 MW. If the actual generation capacity is equal to this load, then the energy generated throughout the year (or 8,760 hours) is 33,884,920 MWh. Since the energy generated at the maximum capacity (at 6,250) is 54,750,000 MWh, then having a constant demand at 3,867 MW will save 20,875,080 MWh or 2,383 MW in idle capacity. This idle capacity is almost equal to the capacity of the largest power station in the country, with a 2,400 MW capacity and costs SR 1.1 billions. This example indicates how the fluctuation of the electricity demand during the year and even during the same day has a large and direct effect on the capital costs for the system. These capital costs are not

limited to generation costs, but also include the investment in the transmission capacity which is needed to prevent line congestion at the peak hour.

The effects of demand fluctuation are more considerable in the case of electricity than in other industries, which explains the need for continued investment in the electricity industry. For these reasons, it is more economical to share generation reserves among the different interconnected regions or countries. Table 2.3 reveals this advantage by showing the ratio of monthly peaks to the year peak for each one of the five regions.

Table 2.3: The Ratios of Monthly Peaks to the Year Peak for 1998

Months	Regions					Country
	Northern	Western	Southern	Central	Eastern	
Jan	0.869063	0.556031	0.81283	0.590061	0.667445	0.65764
Feb	0.745828	0.564418	0.855094	0.522339	0.625788	0.621269
Mar	0.673941	0.690043	0.931321	0.523907	0.615403	0.664459
Apr	0.617458	0.880086	0.976604	0.730992	0.764527	0.840878
May	0.786906	0.905425	0.953962	0.859069	0.859977	0.895286
Jun	0.93068	0.921663	1	1	0.964994	0.968966
Jul	0.91656	0.913812	0.94566	0.871923	0.925321	0.93393
Aug	1	0.963597	0.969057	0.932748	1	0.992242
Sep	0.994865	1	0.957736	0.947954	0.984947	1
Oct	0.810013	0.967166	0.966038	0.863301	0.909452	0.946778
Nov	0.532734	0.768558	0.871698	0.519831	0.700467	0.701077
Dec	0.646983	0.669522	0.767547	0.506349	0.634539	0.642914
Date	Aug-15	Sep-05	Jun-14	Jun-09	Aug-22	Sep-05
Hour	n.a	4:00 PM	8:00 PM	3:00 PM	2:00 PM	4:00 PM

Source: Calculated from the MIE Report (1998)

Although the peak load usually occurs during the summer in Saudi Arabia, there is a regional variation in terms of the peak times. This would indicate the potential for cost savings as generation capacity in one region can function as a reserve for other regions. Table 2.3 provides us with three observations. Firstly, the peaks for all regions do not occur in the same month. Secondly, for regions with the same peak month, the day of the month and even the time of day are different. Thirdly, the central region has only two months with peaks above 90 per cent of the year peak.These observations lead us to the important conclusion that the country should utilise further these regional differences.

The obvious enthusiasm in the last few years for having a completely interconnected national grid is a realisation of this advantage. The large size of the country means that it can benefit from different time zones; at least two will suffice. However, the political sensitivity of such a measure may make this suggestion unacceptable. Instead a shift of working hours by one hour could be a more acceptable solution. This may be a useful solution given the nature of electricity Demand-Side Management programme (DSM) where one hour or even less would make a difference. So more interconnections within the country and with the other GCC countries would produce significant financial benefits including a reduction in generation costs through sharing reserves and higher system reliability by meeting any unexpected increase in demand.

2.3.4 EMPLOYMENT AND 'SAUDISATION' IN THE INDUSTRY

The electricity industry is characterised as a capital-intensive industry with an emphasis on highly skilled labour. The issue of employment is relevant for two reasons. Firstly, it is simply part of the overall expenses. This is an important issue in the context of privatising a loss-making industry. Secondly, the restructuring process has a direct impact on employment, which has social and political dimensions.

The employment level in the electricity industry reached its maximum in 1984 with total employment of 30,551 employees. This coincided with the work on major generation, transmission and distribution projects for the industry, which resulted in a large influx of foreign workers. Replacement or 'Saudisation', which is the replacement of expatriate employees with Saudis, in the electricity industry has been part of the general government policy since the early 1980s. Even though Saudis have started to outnumber non-Saudis since 1987, only 69.1 per cent of the 28,785 employees in 1999 were Saudis. So this objective would need more years to be realised considering that the official Saudisation target is set at 81 per cent.

Table 2.4: The Percentage Share of Saudis in Electricity Personnel (1982-1999)

Category	The Share of Saudis in Total Employment (%)					Annual Growth (%)	
	1982	1985	1990	1995	1999	Saudis	Non-Saudis
Administrative	57.8	60.1	75.6	76.9	81	4.95	-2.67
Engineers	10.6	11.2	22.9	25.9	35.3	30.24	1.72
Technicians	30.3	29.9	47.5	55.7	64.5	10.57	-2.22
Laborers	45.9	65.1	65	77.8	84.4	-0.7	-5.4
Total	40	46.3	56	61.7	69.1	5.6	-2.7

Source: Ministry of Industry and Electricity, annual reports (different issues)

Assuming the target for each employment category is also 81 per cent, an examination of table 2.4 shows that the industry has a long way to go in pursuing this goal. The table reveals that as of 1999, Saudisation has been achieved in non-technical jobs where 81 per cent of administrators and 84.4 per cent of labourers are Saudi nationals. However, about 65 per cent of the posts of engineers and 35.5 per cent of those of technicians remain occupied by non-Saudi employees.

Since the annual growth in the hiring of Saudi technicians is 10.57 per cent, it is possible that Saudisation of this category would be realised within relatively short time. However, the case of Saudisation of engineering jobs is more complicated. It is an issue related to the ability of the education system to provide a sufficient number of qualified Saudi engineers in the coming years. The negative growth rate for labourers and the positive growth rate for engineers reflects a move toward the maturity of the industry. So the combination of industry maturity and privatisation may increase the demand for engineers including non-Saudis.

Hence, restructuring schemes need to address this issue constructively by providing the necessary training programmes as well as the incentives for existing employees to improve their skills. The measures would include giving the existing employees the chance to buy shares in the privatised company. Also, some countries provide a guarantee that the employees will not be fired within a certain number of years. Despite the disadvantages of this approach, it has the advantage of giving the workers sufficient time to improve their working skills, which the company also needs. So if these issue are not considered seriously, it is a possibility that a conflict may arise between the two official objectives of privatisation and Saudisation.

2.4 ELECTRICITY PRICING ISSUES

2.4.1 CONSUMPTION TYPES

The electricity industry currently provides its services to over 3.4 million subscribers, over 95 per cent of whom are in the areas supplied by the four SCECO companies. The type of consumers the company is serving affects its financial position through the impact on its revenues as well as its costs.

Table 2.5: Electricity Sold by Type of Consumption

Type	Eastern	Central	Southern	Western	Northern	Total
Residential	24.17	56.82	74.34	63.8	66.54	48.26
Commercial	5.74	9.12	7.67	12.36	10.62	8.7
Industrial	56.66	6.59	1.3	6.12	1.15	24.2
Agricultural	0.67	4.97	0.61	0.18	5.75	1.8
Government	11.94	19.05	13.03	14.48	13.23	14.6
Hospitals	0.54	2.2	2.12	1.15	1.64	1.25
Charities	0.28	1.25	0.92	1.91	1.6	1.6
Total	100	100	100	100	100	100

Source: Ministry of Industry and Electricity (1999).

Table 2.5 shows that for the industry as a whole, more than 48 per cent of the consumption is by residential consumers and 24 per cent is by industrial consumers, which is followed by the government at about 15 per cent. The situation varies between regions where SCECO-Eastern has the advantage of having a considerable number of large industrial consumers. The table reveals that about 57 per cent of its electricity is sold to these consumers, which include ARAMCO, as well as SABIC with its large petrochemical companies. On the other hand, SCECO-Southern sells over 74 per cent of its electricity to residential consumers, but the disadvantage for this company is that it is in the region with the lowest per capita income in the country.

Even though the government subsidises this industry, it is ironic that the government offices and institutions are the customers who are not paying their bills in full. For example, the data from SCECO-Central show that over the period between 1994 and 1998 these offices paid on average only 38.8 per cent of their dues while the percentage is 99.24 per cent for the residential customers. This means that direct government involvement in the industry has its drawbacks as well as benefits. This situation was not very helpful in creating the transparency needed for making this industry commercially viable.

2.4.2 TARIFF STRUCTURE

The prices for electricity consumption are based on a tariff structure, which is officially set. The tariffs are uniform across the country but they distinguish between consumers based on their type and the level of their monthly consumption. Table 2.6 shows the revised tariff structure for residential customers (commercial and government offices are also charged under identical structure).

Table 2.6: Tariff Structure for Residential Monthly Consumption

Consumption Blocks (kWh)	1999 (Halalah)	2000 (Halalah)	Increase (%)	Share in Consumption
1-500	5	5	0	3.51
501-1000	5	5	0	8.58
1001-2000	5	5	0	20.8
2001-3000	*10	10	0	17.85
3001-4000	*10	10	0	15.68
4001-5000	*13	13	0	8.28
5001-6000	*13	18	38.5	4.5
6001-7000	*20	23	15	3.06
7001-8000	*20	28	40	2.18
8001-9000	*20	32	60	1.36
9001-10000	*20	36	80	1.05
10001+	*20	38	90	13.15
Total				100

* Includes the additional 5 Halalahs that go to the 'Halalah Fund'
Source: Ministry of Industry and Electricity (1999)

The tariffs as presented in table 2.6 could be described as inverted block tariffs. Under such tariffs, the consumer is charged one price for consumption up to a certain number of kilowatt-hours per month and then charged a higher price for any additional consumption. There are some useful observations which can be drawn from this table. Firstly, the lowest three blocks pay the lowest price, which is 5 Halalahs, for any consumption below 2,000kwh. According to Shaikh (1999), this base range can be considered too low in comparison with Organisation for Economic Co-operation and Development (OECD) countries where the range is between 100 and 200 kWh. The political and social considerations of the welfare state, especially in a developing country such as Saudi Arabia, may provide an explanation for such a structure.

Secondly, the new tariff clearly exempts, from the increase in tariffs, groups of customers with any consumption below 5,000 kWh. These groups account for 74.8 percent of total residential consumption or 93 per cent of consumers. This again reflects the attempt to avoid lower and middle class population (assuming that the level of electricity consumption may reflect the income level to large degree). However, it remains to be seen if revenues generated from the increase in prices for the highest 25.2 per cent of consumption will be sufficient. This depends on the price-sensitivity of the demand by high consumption groups as well as the efficiency in bill collection. So there is a possibility that even the lower blocks will face higher prices in the future. The period of the next two years is critical as the new regulator is expected to review the operations of the industry, including electricity prices.

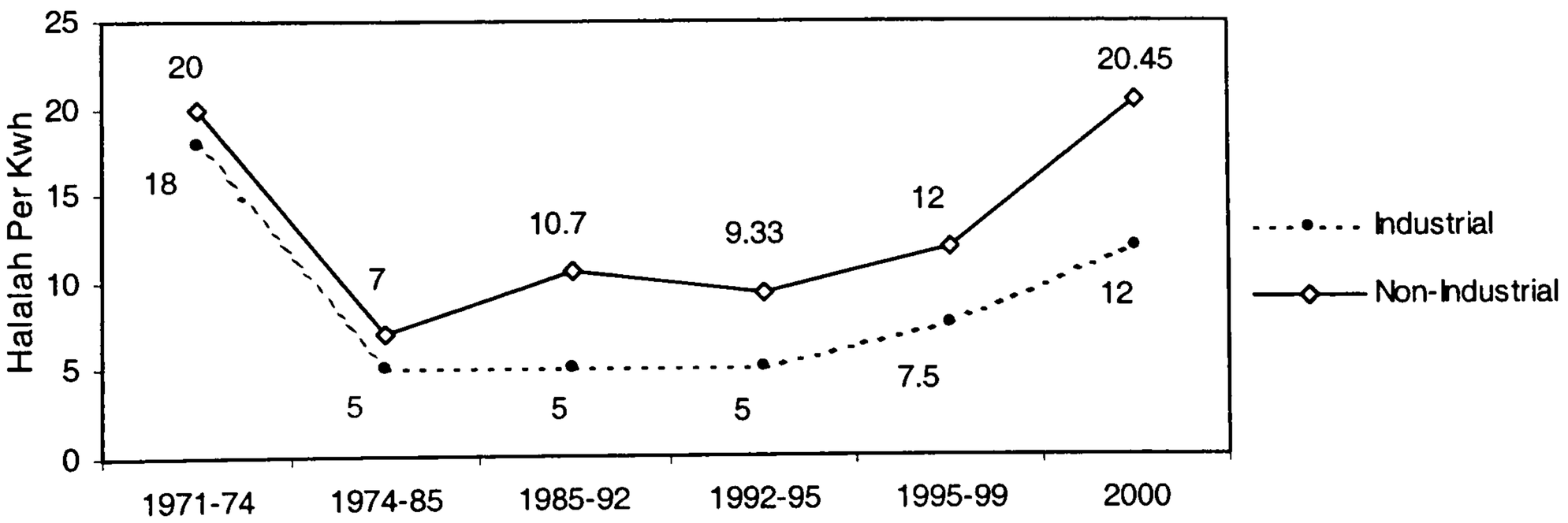
Thirdly, the table shows that the revised tariffs have nine sets of prices in contrast to the previous structure with only four sets. Train (1994) illustrated that increasing the number of blocks leads to welfare gain as prices reflect costs more and diminish the chance of creating what is called 'collection points'. The collection points exist when the different consumers with different consumption levels are paying the same price. So the existence of such points depends mainly on the size of each block. This means that the revised structure reduces these collection points for consumption levels above 5,000 kWh. Since the transaction costs associated with having a greater number of blocks are expected to be very small, it is economically justified to have a greater number of blocks even for consumption below 5,001 kWh. However, such a decision is usually influenced by political and social factors rather than cost considerations and, hence, economic efficiency.

As for industrial consumers, the old structure consisted of two blocks. Any consumption below 2,001 kWh is charged at 5 Halalahs while the charge for any other amount is 10 Halalahs. Under the new structure industrial customers pay a flat rate of 12 Halalahs or $.032 per kWh regardless of their monthly consumption level. Other consumers such as agricultural and charitable societies pay 10 Halalahs if their consumption is below 4,000 kWh, but pay 12 Halalahs for any amount above it.

It is necessary to consider the reasons behind the simplification of tariffs for industrial and other large consumers. Setting different tariff structures for residential and industrial consumers could be explained by two factors. Firstly, residential rates usually, for social and political reasons, take into consideration the income level of the different consumers. So the ability of residential consumers to pay has more weight in the designing of the tariff structure than the cost of supplying them. Secondly, the costs for the system to supply one kW to large consumers are lower than supplying the same amount to residential consumers, due to the difference in their voltages.

The investigation of electricity prices over three decades, as shown in Figure 2.5, indicates that the current tariff structure sets prices at a very low level. This is especially true in comparison with the price level prior to 1971, when the industry was not subsidised and was operated by profit-making private companies. The prices were very high in comparison with current prices and varied across regions and even cities within the same region. The differences in these prices may have resulted from the inability of the companies, at that time, to reduce their average costs by exploiting their economies of scale. In addition to limited markets (the small size of the population), these companies had no access to transmission lines, which resulted in losing the opportunity to export their excess output.

Figure 2.5: Development of Electricity Prices (1971-2000)



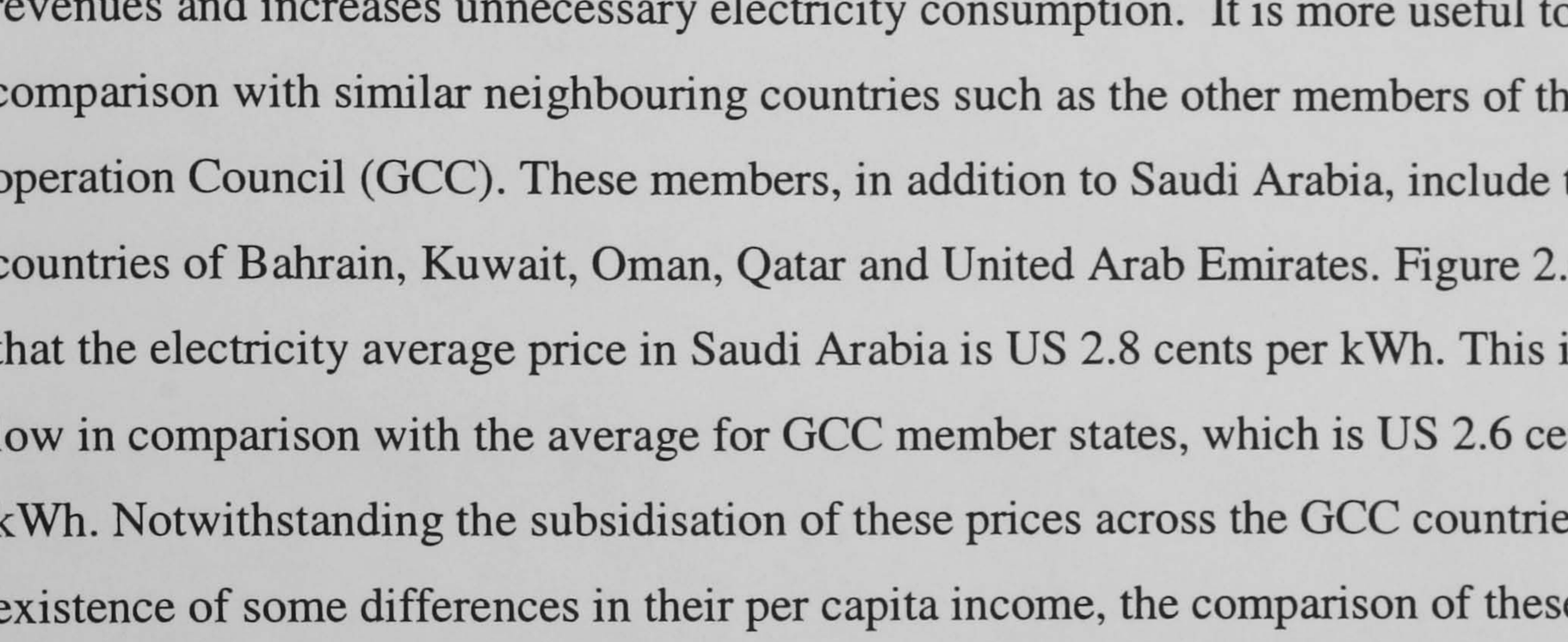
Source: EC (1996) and MIE (2000)

The reduction in prices since 1974 has been part of a tariff structure based on government subsidies to cover the difference between costs and revenues of the companies. The common explanation is that these subsidies were also intended to help these companies against increase in fuel costs. The decline in oil and fuel prices during the 1980s was not

reflected in a similar reduction in subsidies. This may indicate a continuation of the public policy of supporting this industry during this period of economic transformation. Looking back at this development, it is reasonable to assume that this well intended policy made the industry, electricity producers as well as consumers, more dependent on such subsidies.

The electricity prices in Saudi Arabia could be considered among the lowest in comparison with those in developed as well as developing countries. It might be expected that these tariffs would be low in Saudi Arabia due to lower fuel costs, but setting prices below costs of production and delivery reduces the chance for generating an internal stream of revenues and increases unnecessary electricity consumption. It is more useful to draw the comparison with similar neighbouring countries such as the other members of the Gulf Co-operation Council (GCC). These members, in addition to Saudi Arabia, include the five countries of Bahrain, Kuwait, Oman, Qatar and United Arab Emirates. Figure 2.6 shows that the electricity average price in Saudi Arabia is US 2.8 cents per kWh. This is not very low in comparison with the average for GCC member states, which is US 2.6 cents per kWh. Notwithstanding the subsidisation of these prices across the GCC countries and the existence of some differences in their per capita income, the comparison of these prices remains meaningful.

Figure 2.6: Electricity Prices in GCC Countries (in 1998)



Source: Gulf Co-operation Council General Secretariat, Economic Bulletin (1999)

Figure 2.6 also reveals that Oman and Bahrain have the highest prices and this could be explained by the fact that these countries are neither oil nor natural gas producers. Hence it is reasonable to expect electricity prices to be lower in countries such as Kuwait, Qatar,

UAE, and Saudi Arabia. The large size of Saudi Arabia and the relatively high cost of electricity production in some of its regions such as Southern, may explain why it is above the GCC average. However, the increase in the current tariff structure will not be expected to alter the above comparison. In addition to Saudi Arabia, the other GCC countries have also announced their plans to revise upward their electricity tariff structure.

2.4.3 FINANCIAL LOSSES

The lack of interest of the private investors in the electricity industry has been and still directly linked to its weak financial performance. This performance has negative impacts on the ability of the electricity companies to invest in expanding their operations. Also it reduces their ability to borrow, as lenders are expected to have less confidence in companies with such a performance. In addition, the private sector can be more reluctant to lend to these companies unless the loans are based on government guarantees.

Table 2.7: The Financial Losses of SCECOs (in Billion SR)

Exhibit	1995	1996	1997	1998	1999	Total
Total Revenues	6.5	6.7	7.2	7.3	7.9	35.6
Total Expenses	9.5	9.7	10.1	10.6	11.6	51.5
Net Results	-2.96	-3.02	-2.89	-3.24	-3.69	-15.8
%	-31.3	-31	-28.7	-30.7	-31.8	-30.7

Source: SCECOs annual reports (1995-1999)

Table 2.7 shows that these four SCECOs companies collectively had about SR 3.7 billion in net losses at the end of 1999, which makes their accumulated debt since 1995 reach SR15.8 billion. Some financial and organisational factors may have contributed to this negative outcome, but the most cited factor is the tariff structure. For example, the additional 5 Halalahs imposed as a surcharge in 1995 on any monthly consumption above 2000 kWh generated over SR 11 billion for the so-called 'Halalah Fund'. This fund was under the supervision of a ministerial committee rather than collected by the companies themselves. This amount of SR 11 billion accounts for about 31 per cent of the above revenues or about 70 per cent of the accumulated losses. This example shows that a limited adjustment to the tariff structure ought to help significantly with the reduction, if not elimination, of the losses. Table 2.8 reveals the potential for improvement in the financial position of the four SCECO companies.

Table 2.8: Revenue, Cost and Loss per kWh sold by SCECOs in 1998 (in Halalahs)

SCECO Companies	Revenue	Cost	Loss
Central	7.88	11.5	-3.62
Eastern	7.2	8.8	-1.6
Southern	6.3	20.8	-14.5
Western	7.17	11.9	-4.73
Average	7.1	13.3	-6.2
Average (Excluding Southern)	7.42	10.73	-3.32

* 1p = 6.1 Halalahs
Source: Annual Companies Reports (1998)

Table 2.8 also reveals that the average revenue per kWh for the SCECO companies is in line with the industry average of 7.1 Halalahs. This can be explained by the fact that all these companies sell their energy under the same tariff structure. The situation is considerably different on the cost side, which reflects the variation in cost structures of these companies. The lowest average cost is for SCECO-Eastern which benefits from its location in a fuel-abundant region as well as having the advantage that most of its output is0 sold to bulk industrial consumers. On the other hand, SCECO-Southern has very large residential consumers and is located in a region with very difficult geographical conditions. This put limits on its ability to generate enough revenues under these circumstances.

With the exception of SCECO-Southern, the other companies would have been able to eliminate their losses if they had received the additional surcharge for themselves. Also the improvement in the productive efficiency of these companies would have helped close this gap. If the average revenue for the three companies increased by the 31 per cent (based on the Halalah Fund ratio in total revenues as mentioned above), then their revenue per kWh would increase to 9.72 Halalahs, which is very close to their average cost of 10.73 Halalahs per kWh. This simplified calculation clearly shows that financial losses are not impossible to eliminate with slight increase in tariffs.

So an improvement in the industry's financial performance would result if the restructuring and tariff reforms were combined with cost reduction. The reduction of costs should mainly target the generation expenses, which account for about 55 to 60 per cent of the companies' expenses. According to the Economist Intelligence Unit (2000) the revised tariff structure would increase the industry's revenues by about 78 percent. This indicates

the potential for the industry to be profitable in a relatively very short time as the current losses-to-revenues ratio is only 44 percent. However, the unexpected reduction in tariffs at the end of 2000 is not expected to damage this profitability prospect, but, more seriously, it has created concerns for private investors about the consistency of the restructuring process itself.

2.4.4 ELECTRICITY SUBSIDISES

The government has a direct involvement in the various aspects of electricity industry, including subsidisation. The government subsidies in the past took two forms. The first form is when the government pays the difference between the actual cost and the price. The second happens when the shareholders receive from the government a guaranteed annual dividend of 7 per cent for each share despite the fact that the companies incur losses. This latter form has the objective of keeping private investors interested in the industry and may also have provided a justification for indirect subsidies for the industry itself. The payment of these dividends has, however, been delayed, especially during the 1990s. As will be shown by Table 2.9, the level of these subsidies may have been influenced by the conditions of the government budget.

Table 2.9: Annual Growth Rate of Government Subsidies (%)

Years	Total Subsidies	Electricity Subsidies
1970-74	163.6	Not Subsidised
1974-79	36.7	241.3
1979-84	25.3	34.4
1985-89	-7	-30.4
1990-94	6.1	11.33
1995	-34	0
1996	-6.5	0

Source: Ministry of Planning, Figures and Facts (1998)

The oil boom of the 1970s made the government able to subsidise a large segment of the population and different sectors of the economy. The total government subsidies to electricity and other sectors such as agriculture increased sharply between 1974 and 1984. The decline in oil revenues in the 1980s caused these subsidies to slow down and for the electricity sector it had been reduced ever since. The general trend is to reduce subsidies for many sectors of the economy including electricity industry.

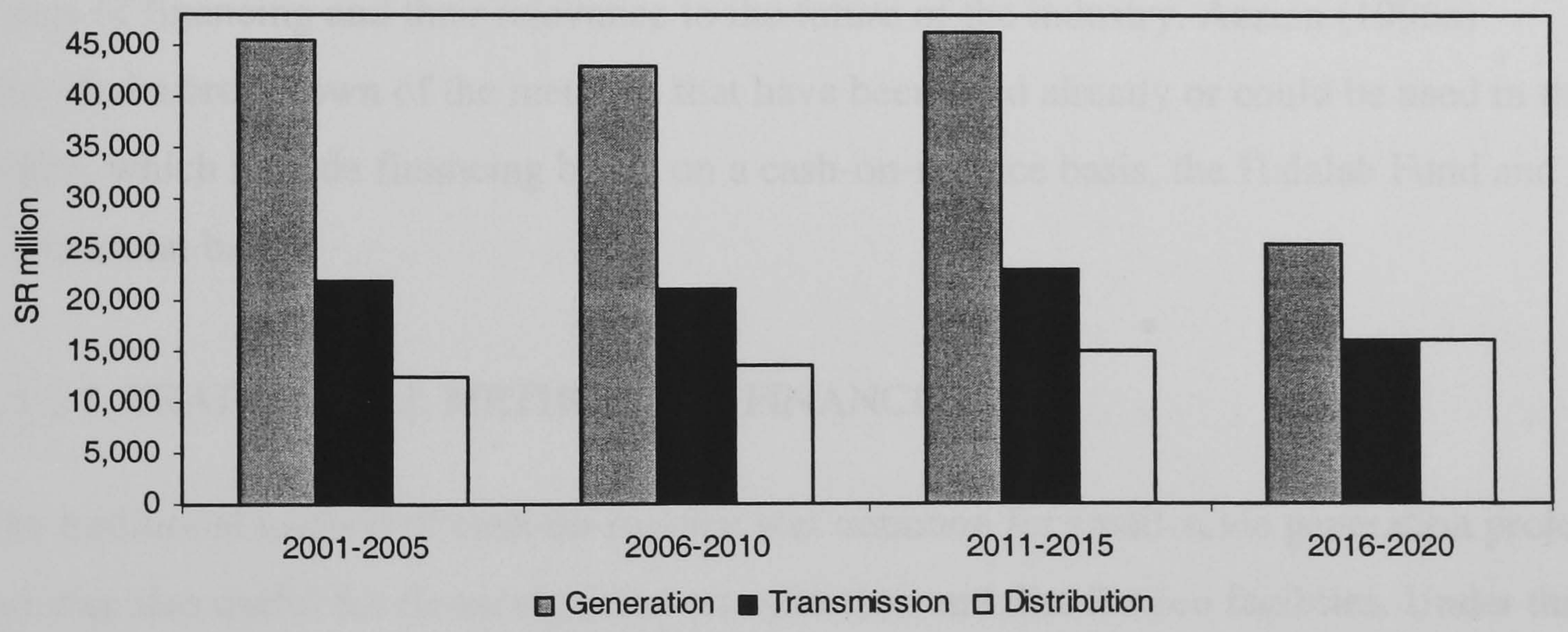
2.5 FINANCIAL ISSUES

The previous sections described the operational and pricing conditions under which the industry is run. This is would be very helpful in understanding the industry financial position and its ability to coup with future challenges.

2.5.1 INVESTMENT REQUIREMENTS

The factors behind the growth in electricity demand during the past thirty years may have become less forceful, but they remain substantial. The demand for the next twenty years is expected to grow at an annual rate of about 5 per cent. So it is expected that the country will need to have a generation capacity of 60,000 MW in the year 2020, which is about three times the current capacity. In addition to the expansion of generation capacity, transmission and distribution capacities have to be proportionally available. Figure 2.7 illustrates investment requirements until the year 2020 as estimated by the Long Term Plan.

Figure 2.7: Investment Requirements until 2020



Source: Long Term Electrification Plan, Electricity Corporation (1996)

According to the Plan, the total investments needed for this industry are expected to exceed SR440 billion until the year 2020, or SR 23 billion annually. The generation investments are expected to account for 60 per cent of total investments, while transmission and distribution investments will account for 22 per cent and 18 per cent respectively. These investment figures also reflect not only challenges but also opportunities for private investors.

2.5.2 CURRENT FINANCING SOURCES

Government support to the electricity industry came through the Electricity Corporation (EC) in the form of financial assistance and financing the establishment of power projects on behalf of the electricity companies. The total amount spent on these projects by the EC between 1977 and 1996 was about SR 26 billion or $6.9 billion (EC, 1996). Other governmental agencies such as the Saudi Industry Development Fund (SIDF) was responsible for providing funds to electricity companies until 1984, when this responsibility shifted to the Electricity Corporation. The SIDF data (1985) shows that this fund was able to provide these companies with loans valued at over SR 38 billion or $10 billion between 1975 and 1984.

The government involvement may have been useful during the oil boom but, as Looney (1992) suggests, this may have the effect of crowding out short- run private investments. In the case of electricity, the excessive government involvement may also have mixed results as it has introduced less accountability in the industry and may have made the electricity companies lack the incentives to be profitable. The following section will review the other forms of financing and their relevance to the future of the industry. Azzam (1996a) provided a breakdown of the methods that have been used already or could be used in the future, which include financing based on a cash-on-invoice basis, the Halalah Fund and commercial banks.

2.5.2.1 TRADITIONAL METHODS OF FINANCING

The traditional method of cash-on-invoice was common for small-scale generation projects but was also useful for financing some transmission and distribution facilities. Under this method the government pays contractors directly as soon as each stage of the project is completed as agreed. However, this method is not expected to contribute greatly to future expansions especially for meeting the capital requirement for most generation projects. In addition to this method, the use of export credits to finance some generation facilities was considered in the past, but the government was reluctant to provide a sovereign guarantee for such credits.

2.5.2.2 THE 'HALALAH' FUND

The second method used was introduced in 1995 and known as the 'Halalah Fund' which is based on the additional surcharge of five Halalahs levied on any monthly consumption exceeding two thousand kilowatt-hours. The revenues from this fund were deposited in a special account at the central bank, SAMA. This fund was limited to financing generation expansion projects which made it very useful for attracting contractors to finance fund-backed projects. The significance of this fund manifested in its ability to finance over 44 per cent of project costs during that period and the total amount deposited under the fund accounted for over 70 per cent of the industry losses. This fund was also useful in providing a security payment for important lump-sum turnkey projects.

However, this fund has not been without some drawbacks as it may have created a disincentive to a company such as SCECO-East to operate efficiently as it perceives that some of its revenues are financing projects for other companies. This indicates that the usefulness of this method is diminished by such cross-subsidy. However, the cancellation of this fund and the explicit incorporation of the surcharge into the new tariff structure (see Table 2.6) may provide us with the conclusion that the elimination of the industry's financial losses is an achievable objective.

2.5.2.3 THE COMMERCIAL BANKS

The third source of financing for the industry is commercial banks. The foreign assets of the national banks are about a third of their total assets with net foreign assets of 19 per cent. This indicates the potential for these banks to play a major role in project financing, in the right supporting investment environment. The role of national banks in project financing has been on the increase during the last decade. The banking credit channelled to electricity utilities increased from SR 1.4 billion, which is 1.5 per cent of total credits in 1993 to SR 8.5 billion (7.2 per cent) in 1996. As of 1997, these commercial banks are involved with the financing of about 24 per cent of the cost of four major generation projects around the country, while the Halalah Fund was able to guarantee the financing of the rest.

This example reflects the importance of providing security support to attract these banks to such projects. Another arrangement, which has been tried as late as 1999, was where one of the national commercial banks was invited to finance a transmission project using the Islamic banking scheme of Istisnaa. Under this scheme the electricity company SCECO-Central signed an agreement with the bank which was responsible for dealing directly with the contractor. When the project is completed the company will become the owner and then the bank will start to receive annual instalments for a number of years as determined in the signed agreement.

The involvement of international banks in financing infrastructure and in particular electricity projects has been very limited. The example of the power station in Ghazlan in the eastern region is an interesting case to study. The project consisted of adding capacity to the station of 2,400 MW at $1.1 billion. The international syndicate loan method was used for financing the project. Cash from the existing operation provided 42 per cent of the total financing requirement. The security package, which accounted for 12 per cent, was based on the advance from large customers such as ARAMCO and SABIC. International banks that found the quality of the receivable package very attractive provided the rest. This example illustrates the possibility of attracting willing international funding if innovative schemes are presented and the right legal framework is in place.

2.5.3 POTENTIAL FINANCING SOURCES

2.5.3.1 BOO, BOT AND BOOT SCHEMES

The involvement of the private sector in infrastructure projects under schemes such as Build-Own-Operate (BOO), Build-Operate-Transfer (BOT) and Build-Own-Operate-Transfer (BOOT) are new concepts for the country. Under these schemes investment banks participate by arranging both equity and debt finance for the project. The viability of this method greatly depends on the transparency of the process and good security support to attract private operators and their financial backers. The first indication of interest in this method was in 1997 when SCECO-Western invited bids for building a Shoaiba power plant with 1,750 MW on a lump-sum turnkey or on BOOT basis. Under the BOOT scheme SCECO-Western would purchase electricity from the independent power producer (IPP) against monthly payments over twenty years. According to Khoshaim (1997), the financial structure of the project was supposed to have 30 per cent of total capital in equity. The

developer would have a 50 per cent stake in the equity while the rest would be shared between the company and domestic investors, either directly or through a holding company. A syndicate of domestic and international banks would generate the debt capital. Two international groups were commissioned to study the feasibility of these schemes. By 1998, it became apparent that the BOOT scheme would not materialise given the existing tariff structure as prices were below the actual production costs and there was a lack of a suitable foreign investment framework to reduce project risk.

This case should not be used to make a sweeping judgement on the potential of these types of finance for three reasons. Firstly, the BOOT scheme had never been top priority for SCECO-Western as it was a distant alternative to the other traditional methods. In addition, there were high expectations that the merger of SCECOs under one electricity company was very imminent and as such this kind of long-term contract would be taken up by the newly formed company. Secondly, the experimentation with such a large project was in itself a risky proposition. Therefore, it would be better in the future for these schemes to be tried on smaller scale projects. Thirdly, the investment laws, which were supposed to govern these agreements, are going to be changed in the very near future. The government had approved in 2000 three measures to improve the investment environment in the country. These measures include: a more transparent foreign investment code, reorganisation of investment commission and the permission for the Saudi Industry Development Fund (SIDF) to finance projects fully owned by foreign investors.

2.5.3.2 OTHER SOURCES

The lack of significant demand for these different methods of financing was due to the availability of funds mainly from public sources. The changing conditions mean that these methods and other forms of equity and debt financing will remain very relevant for the future. Internal cash flows may benefit from a changing tariff structure, but they may remain insufficient. Sufficient cash flows do not exclude the need for funding diversification, which is necessary for the minimisation of the financing costs. There is an opportunity to benefit from privately sponsored investments including national and foreign direct investment. According to Azzam (1996b), like other infrastructure projects, electricity projects could tap international equity markets by issuing Global Depository Receipts (GDR). The role of Saudi Arabia in multilateral organisations such as the Arab

Fund for Economic and Social Development (AFESD) may also help in providing the needed backing for private power projects.

This is on the equity side; on the debt side there is the potential for export credits to help in financing power projects if the new Saudi Electricity Company (SEC) proves its creditworthiness and is able to provide the required repayment guarantees. The experience of the Ghazlan power station shows that using international syndicated loans is a realistic option when banks find the presented security package attractive. Also the industry would find it useful to benefit from lower interest rates if international bond financing is an acceptable choice.

Islamic financing methods can contribute greatly, especially when combined with the conventional forms of financing. These forms of financing may prove to be useful for power projects, especially as they require long maturity debt financing. Also they would provide Islamic investors with long-term investments on more acceptable terms. These methods are various but usually include Istisna, Mudarabah (trust financing) and Ijarah (leas) arrangements. The method of Istisna is defined as a contract to purchase a product now which is going to be manufactured in the future against a price agreed upon. Payments are made to the contractor at each stage of completion of the project. This purchasing mechanism is likely to be the most relevant among these methods for electricity projects. Under Mudarabah, a project partnership is established between the provider(s) of capital and the client (i.e. entrepreneur), in consideration of which the partners get an agreed proportion of the net profit. The method of Ijarah (leasing) involves the bank buying and then leasing for rental fee equipment required by the client.

2.6 RESTRUCTURING AND PRIVATISATION

Government involvement during the initial stage of the restructuring process, especially in developing countries, is inevitable and can even be necessary for long-term success. Yajima (1997) believes that the government presence would introduce flexibility in the choice of the reform model for the electricity industry. He contrasts the reform experience of the US with those of countries such as Chile where full reform models have been realised with government engagement. Sioshansi (2000) explains how private ownership in

the US electricity industry made the modification of the existing structure more complicated. He argues that issues such as stranded costs have to be dealt with before an efficient competition can be established. These views indicate that the existence of private interests in the industry prior to restructuring would complicate the process itself. The complication may result when some of these parties believe that the process would negatively effect their own interests. These expectations may even give these participants the incentives to undermine the process itself.

2.6.1 THE OBJECTIVE OF RESTRUCTURING

The electricity industry has gone through different stages of restructuring during the last twenty-five years with the long-term objective of creating a modern and self-financing industry. This industry was singled out by the Sixth Development plan (1995-2000) as the main candidate for full privatisation in the medium and long term. It emphasises profit making in the industry as the ultimate objective of the restructuring process. The government commitment to privatising the electricity industry has been presented within the context of providing the private investors in the industry with the opportunity to make profits on their investments. This notion is reiterated by the Seventh Development Plan (2000-2004), which puts great emphasis on market-based pricing for the services, even those provided by public enterprises. This official attitude is expected to contribute positively toward creating the conditions needed for the industry to raise finances based on its creditworthiness, especially as the declared official objective is to make this industry completely unsubsidised (MEED, 19 March 1999).

The need for broader a approach to deal with this objective has been under consideration since 1995 with the coming of new technocrats to the Ministry of Industry and Electricity. This development had created a debate about the revitalisation of the industry. There were two different views regarding how this goal can be achieved. The proponents of the first view (price reform) argued that the existing structure could be maintained while the reform should focus on improving the tariff structure, which need to be coupled with an efficient system of bill collection.

The proponents of the second view (restructuring) argued that the above suggestions were necessary, but they had been tried since 1982 without any notable success. So they

believed in restructuring the whole industry to make it commercially viable and attractive for permanent private investments. The proponents of the first view made some reasonable suggestions, but it could be described as a status quo argument. Also the recent changes in the industry may indicate that the second argument has won the policy maker's approval. It is not unexpected that both arguments acknowledge the government's role in the reform process in a developing country such as Saudi Arabia. It is worth noting that within the second view there were two different approaches to the speed and the scope that the restructuring should take. The difference between the two approaches is based on their respective perceptions of what was attainable in practice.

The current restructuring plan is a transitional step toward full privatisation of the industry. The regional SCECOs and the northern companies were merged at the beginning of January 2000 into one holding company (i.e. SEC). The immediate objective of the plan is to make the existing industry structure commercially viable and more attractive to private investors. The implementation of the new tariffs is likely to make this joint stock company profitable and ready for privatisation starting with share flotation. The ownership mix of the government and private sectors in the company remains equal to their original shares as in the previous companies prior to the merger. This means that the government owns about 84 per cent of the new company equity's capital, while the private sector owns the rest. The company's board of directors comprises twelve members including six members from the private sector (MEED, February 18, 2000). Also the top two positions in the administration were given to former SCECO-eastern officials which has been very welcomed development by the private sector.

2.6.2 REGULATORY ISSUES

The privatisation of the industry should not result in replacing the public monopoly with a private monopoly. This will be especially true during the next two years when SEC will be the sole supplier of electricity. This situation requires thorough supervision from the newly appointed independent regulator to prevent any exploitation of its monopolistic powers. The next period would result in other tasks for the regulator, as he will be responsible for dealing with different issues as the industry is separated into generation, transmission and distribution segments.

The generation segment of the industry is to be opened for direct private investments and competition between private producers. The prevailing expectation among many high ranking officials in the industry is that the SEC will become the owner of the national grid while the regional distribution networks will be offered to private sector through franchise bidding. Since the new reform gives the large customers the freedom to choose their source of supply, it is expected that even residential consumers would be able to have the same choice in the future. These issues and other regulatory issues will be under revision by the independent regulator who is expected to submit his first regulatory review of the industry by the end of 2002.

One of the issues, which is expected to arise in the future, is the issue of transmission pricing. This issue would have to be in place prior to the full privatisation of the industry. The unbundling of the industry will make the transmission grid play a major role in linking consumption centres with generation sources. As electricity trading increases, the demand for transmission services will grow as well. The benefits from competition in generation will not materialise if this natural monopoly segment of the industry is not well regulated. So the transmission function is the main segment which the regulatory system has to consider at an early stage of the restructuring process. This becomes necessary in order to reduce potential disputes among the different participants such as generators and distribution companies (or large customers).

2.6.3 EXTERNAL PLAYERS

2.6.3.1 SELF-GENERATION PROJECTS

The fact that the iron and steel company, Hadeed, began building its own power generation plant is a significant development for the electricity industry. This is particularly true as the new reform gives such large customers the opportunity to sell any excess capacity that it may have. This situation may become more common when the tariff structure gives the incentive, through time-of-use pricing, to such large consumers to shift their demand from the peak hour and benefit from selling their excess capacity at market price at that hour.

2.6.3.2 SALINE WATER CONVERSION CORPORTATION (SWCC)

In addition to these projects, the involvement of the Salin Water Conversion Corporation (SWCC) in power generation would provide additional sources of competition. The

corporation has already announced its intention to expand these projects by involving private investments in the new dual-purpose desalination plants, under BOO or BOOT schemes. The electricity generated by these plants is known to be produced at a very low cost which may help create an environment for more competition and cost reduction in the industry as a whole.

2.6.3.3 THE ROYAL COMMISSION OF JUBAIL AND YANBU

The other change in the industry is the establishment of the joint stock company, Utility Corporation (UCO), in 1999 with SR 2 billion in capital. The purpose of this company is to carry out the operation, management, and expansion of infrastructure facilities for the industrial cities of Jubail and Yanbu. One of the main tasks for this new company is the provision of over 3000 MW capacity of electricity for the two cities. The main partners in this company are the Royal Commission of Jubail and Yanbu, the Public Investment Fund, SABIC and ARAMCO.

The immediate objective is to involve Uco in leasing the Royal Commission utility assets until valuation is completed and they are transferred to Uco ownership. The shares of this new company will be floated three years after its formation, on the condition that two of these years must be profitable. Currently the management services' contracts for the utilities in these two cities have been given to the American companies, Parsons and Bechtel (MEED, 23 July 1999).

2.6.3.4 THE GCC INTERCONNECTION PROJECT

The expected interconnection of national grids of the GCC countries into one integrated system, with its headquarters in Saudi Arabia, would introduce more competition into the Saudi electricity industry. The large industrial consumers, especially those located in the eastern region, will be able to buy electricity from independent power producers in other countries such as Qatar or UAE. The expectation is that within a few years from the time when the interconnection is operational a pool mechanism will be established to facilitate trading on a half-hourly basis. So it is likely that these developments would have very positive future effects on the direction, speed and the dynamic operation of the Saudi Arabian electricity industry.

CONCLUSION

The history of the electricity industry shows that this industry was originally in the domain of the private sector. The government's involvement in the industry could be viewed as a transitional process with specific objectives for each stage. The objective of electricity industry's modernisation, through creating a modern and robust infrastructure, followed by the objective of privatisation through the improvement of its finances.

The review of the issues facing the industry shows that, despite its large financial requirements, there is no lack of interest or shortage in funding availability for the electricity industry. What is needed are innovative methods backed by creditworthiness and a transparent legal framework. The recent reforms in the industry as well as changes in the country's investment laws could greatly help in improving the environment for private investment, national and international alike. This is particularly true in the case of Foreign Direct Investment (FDI) which is needed not only for funding purposes but also for providing the know-how and the managerial expertise. As a result, the industry is entering a stage where competition between different private companies, initially in the generation activities, is the ultimate objective.

Nevertheless, the benefits from introducing competition will not materialise if it is not complemented by a regulatory regime that is fair and transparent. So for the reform to be credible in practice, it has to tackle directly some of the economic and legal issues that would arise under the new structure. For example, opening up the generation and distribution activities to private companies will require clarification of major issues regarding the use of the transmission network, such as transmission pricing. Therefore, prior to their entry into the industry, these private participants need to have clear sets of rules relating to the issues of pricing and cost allocation. The objective of this thesis is to examine three different methods for pricing transmission. It contributes to the above debate by presenting, for the first time, an empirical comparison of these methods based on actual data. In addition to its academic contribution, the thesis will be useful for future policy making, not only in the case of the Saudi Arabian electricity industry, but also in other countries in the Gulf region and beyond.

CHAPTER THREE
Literature Review

3.1 INTRODUCTION

The previous two chapters provided a review of the issues facing the economy of Saudi Arabia in general and its electricity industry in particular. These issues include policies which are related to privatisation and restructuring, some of which are under way and some of which are planned for the future. Hence, prior to proceeding further to the main focus of the thesis, it would be appropriate to provide at this stage a review of the literature which is related to these issues. This chapter aims at clarifying the meaning of privatisation and more broadly the policies of restructuring and reform.

In order to attain this objective, the link and overlap between privatisation and other concepts such as restructuring, liberalisation, competition and regulation are discussed. The chapter focuses on the electricity industry and explores the issues that could arise from privatising and restructuring such an industry. Attention is drawn to the contentious issue of transmission pricing which arises as a result of privatising and unbundling the industry into the separate segments of generation, transmission and distribution. Thus, the chapter is organised into three main sections. The first section analyses the issue of privatisation and related matters; the second focuses on the electricity industry and transmission pricing; and the third presents a summary of the chapter and conclusions.

3.2 PRIVATISATION

Since the start of the British experience of privatisation in the early 1980s, many countries have tried different forms and methods of privatisation. Kikeri et al (1992) indicate that since then privatisation has become widespread and more than eighty countries now have considerable privatisation programmes. Although the term 'privatisation' is a recent term, Johnson (1990) believes that the practice itself could be traced back to the 1940s when the government of the Federal Republic of Germany divested itself of the Volkswagen company.

3.2.1 DEFINITIONS AND CONCEPTS

One of the main questions in the privatisation debate is: what exactly do we mean by privatisation? In the words of Donahue (1989): "Privatization is not only an inelegant term; it is also lamentably imprecise" (p.5). The literature on privatisation provides no agreed single definition of this term, but most of the definitions emphasis the meaning of handing-over ownership from the public to the private sector. Most sources show that privatisation is a process with the ultimate aim of improving performance of the different economic sectors of the economy. Thus, the criterion in judging the different definitions is not which is right and which is wrong, but rather that each definition should be judged on its usefulness for a particular purpose.

Ward (1999) believes that privatisation has no strict legal definition. It could include the involvement of the private sector in operating or investing in publicly owned assets and also the involvement of the private sector in the provision of services previously provided by the public sector. Cowman (1990) includes in his definition the transfer of activities of public enterprises, which produces and sell industrial, commercial, or financial goods, to the private sector.

Jackson and Price (1994) give a breakdown of activities, which could be included under privatisation. These were the sale of public assets, deregulation, opening up of state monopolies to greater competition, contracting out, the private provision of public services, joint capital projects using public and private finance, and reduction of subsidies. Prager (1992) indicates that privatisation can mean the transfer of ownership, but he points out that ownership and control are not necessarily synonymous, and it is control which usually determines results. He asserts that it is possible for ownership to remain with the state and control to be privatised, such as in the case of long-term rental contracts. It is also possible for ownership and fundamental decision-making to remain with the state, but for production to lie in private hands, such as in management contracts and contracting out. According to him, the most substantial improvement in efficiency results when private ownership is introduced without restrictions on entry into the industry concerned. This means that for privatisation to succeed it has to be combined with the introduction of competition.

Cavandish and Mistry (1992) consider privatisation as a process designed to broaden the scope of private sector activity and to encourage the public sector to adopt some of the efficiency-enhancing techniques normally used by the private sector. Kay and Thompson (1986) believe that privatisation introduces changes into the relationship between government and the private sector in the forms of deregulation, denationalisation, and contracting out. Thus, it could be said that these authors regard privatisation as a dynamic process with the ability to redraw the frontier between the public and the private sector. Such views lead us to differentiate between privatisation and other related concepts such as liberalisation, commercialisation, corporatisation and deregulation (or more accurately re-regulation). According to Roberts et al. (1991), privatisation is the transfer of ownership of assets from the public to the private sector and liberalisation is the introduction of competition into regulated and monopolistic industries, which can be public or private. Vickers and Yarrow (1988) emphasise an important difference between liberalisation and privatisation. That is public ownership does not necessarily mean the lack of competition and private ownership does not necessarily imply competition.

A conflict can arise between the policies aimed at introducing privatisation and those aimed at introducing liberalisation. Kay and Thompson (1986) have identified the 'paradox of privatisation' whereby the management of industries subject to privatisation resist the introduction of liberalisation. As a result, concessions are made by the government to ensure management support for the smooth introduction of privatisation causing liberalisation to diminish. In addition, a government interested in reducing the public sector borrowing requirements may have a disincentive to liberalise as a monopoly results in a higher market price (and revenues) than an industry subject to competition.

Hunt and Shuttleworth (1996) draw some distinctions between the three terms: commercialisation, corporatisation and privatisation. Commercialisation introduces changes in government behaviour through more focus on profitability rather than through introducing changes in organisation. Corporatisation is the formal move from direct government control to a legal corporation with separate management. At this stage, economic regulation could be introduced for the purpose of guiding pricing and investment policies. Privatisation is the move from a publicly- to a privately-held corporation.

Horsnell (1999) sees commercialisation as an alternative to full or partial privatisation where commercialisation of the state enterprise makes the enterprise try to imitate the behaviour of private companies. This process includes measures such as full accounting for each subdivision of the company, ending cross-subsidisation between its different activities, and enhancing the ability of the company to raise funds from the international capital market on its own. Hence, this view focuses on the behaviour dimension of the comparison rather than on ownership transfer per se. On the other hand, Kessides (1993) sees commercialisation as the status of a public enterprise which is financed mainly by internal revenues and operates as a autonomous business and its has very limited access to public funding. Corporatisation turns a public enterprise into a legal entity subject to company law, with formal separation of ownership and management responsibilities.

According to MacKerron (1999), liberalisation is very general concept, but it is normally taken to mean a process in which trade restrictions are reduced and subsidised arrangements are removed. This may or may not have any direct connection with the process of privatisation. Privatisation means the transfer of the ownership of an enterprise from public to private, but some governments use the term 'privatisation' when they actually mean corporatisation. The term corporatisation is used to describe the process of transforming utility activities from those which are part of government to those of a corporate structure, using the accounting and managerial techniques generally used by private corporations. Deregulation demands a high level of effective competition between a significant number of participants, and requirement of the absence of natural monopoly characteristics which is difficult to meet. Thus, the real challenge in privatisation is effective re-regulation involving new agencies which have to be greatly independent from the government's direct influence.

3.2.2 PRIVATISATION METHODS

Savas (1992) believes that the methods of privatising public enterprises could involve three strategies: divestment of enterprises or assets, displacement through the government's gradual withdrawal and delegation by contracts and franchises. Ward (1999) indicates that privatisation could include the unbundling of a vertically integrated public monopoly, the

sale of shares through public offerings, the financing and operation of infrastructure projects and the introduction of private sector management to a public enterprise.

Ramananadham (1989) categorises the measures which the privatisation process can include. The first measure relates to ownership and includes total denationalisation and liquidation; the second relates to organisational changes to holding company structures and changes within monolithic structures such as leasing competition and restructuring; the third is operational and comprises contracting-out, pricing principles, resorting to the capital market and the rationalisation of government control.

Wright and Thompson (1994) listed three main forms of sales which privatisation could take: sale to the public through flotation, sale to incumbent management and employees and sale to a third party. Jones et al (1990) draw attention to the fact that the distribution of the proceeds from the divestiture depends greatly on the timing, before or after flotation, of the restructuring of the firms to be privatised. In this case the government may be tempted to sell firms with monopoly power intact for the purpose of maximising its flotation proceeds and then restructure afterwards. Stevens (1989) believes that the other temptation, for some governments, is to sell enterprises which are considered a burden on their budgets. However, this approach may not result in reducing this burden as selling a loss maker would involve a lump sum, which would reflect the expected negative cash flow. In addition, other costs for selling public enterprises should be considered, such as the lost opportunity to promote liberalisation which is much easier prior to privatisation than afterwards.

According to Kuczynski (1999) the process of privatisation involves through three main steps: setting up the commercial structure of the industry, deciding on the regulatory framework, and selling off the industry. He indicated that there are choices at each step as in the case of electricity where transmission can be treated as the only component to be left whole while everything else is decentralised, or it can be influenced by the merits of vertical or horizontal integration. Also there is the issue of how to reconcile adequacy of investment with regulation of price or profitability.

Ilwan et al (1999) believe that the privatisation of an enterprise can be categorised as either a one-step, two-step or multi-step process. In one-step privatisation, the ownership of a public enterprise is divested through the sale of all the equity to the general public. In two-step privatisation, the 'controlling block' of shares is sold to strategic investors who assume management control of the enterprise, followed by the placement of shares in the capital market. In multi-step privatisation, gradual corporatisation is implemented while the deregulation framework is being put in place and new investments, such as Build-Own-Operate (BOO) or other similar schemes, are undertaken by the private sector. Thus, Multi-step privatisation is particularly suitable for politically sensitive activities such as those of electricity or gas.

3.2.3 OWNERSHIP AND EFFICENCY

In the privatisation literature, the discussion of efficiency focuses the attention on the issue of public versus private ownership. According to Veljanovski (1989), Adam Smith favoured the 'privatisation'[1] of Crown Lands on efficiency grounds as he observed that publicly owned land was 25 per cent less efficient than privately owned land. This has been explained by way in which private ownership was able to provide the owners with strong incentives to use resources efficiently. In his *Prolegomena* or *Introduction to History*, Ibn Khaldoun, the fourteenth century Arab thinker, raised doubts about the usefulness of the state involving in activities which were supposed to be in private hands. He observed that commercial and agricultural activities on the part of the government were ruinous to tax revenues (i.e. the economy) and harmful to the subjects (i.e. social welfare).

In contemporary economics, the attitudes towards public and private ownership may have been shaped by the theories of property rights and public choice. Lindblom (1977) looks at property rights as the granting of authority to control assets to persons and organisations, both private and public. He explains that well-defined rights to profit in the private sector makes this sector perform better than the public sector. However, the public choice theory is concerned more with behaviour in the public sector, where bureaucrats pursue their

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[1] As the term privatisation is a recent term it is not expected that Adam Smith used it as such, but his preference for private over public ownership is very well recognised.

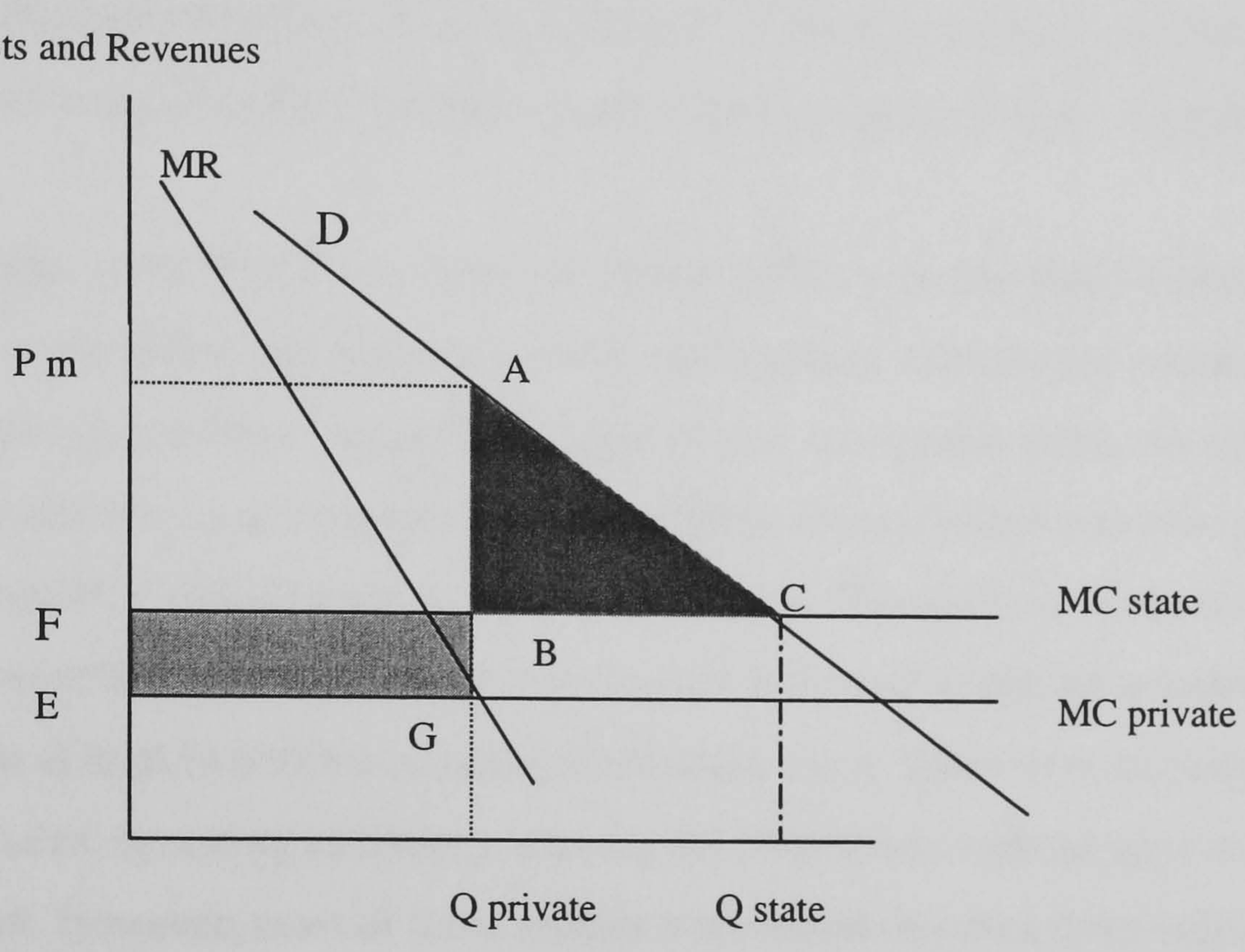
own utility rather than the public interest. This approach to public and private ownership acknowledges that there are agent-principal problems in all forms of ownership. However, the literature on the subject indicates that these forms of ownership differ in their performance due to the difference in incentives in the face of asymmetric information.

Rees (1985) argues that privatisation could change the nature of the agent-principal relationship by reducing the distortion of the information flow between principals and agents through the introduction of more effective incentive systems that tie agents to the principals' objective. However, De Fraja (1993) believes that even in the public sector the introduction of the appropriate incentives to the managers, such as in the form of higher payments may encourage a higher effort level. He also indicated that the public enterprise is not necessarily less efficient than private enterprise, but can in some cases, be more efficient.

Like many researchers who agree that privatisation is a means and not an end in itself, Parker and Wu (1998) consider that the main objective of privatisation is the improvement of economic performance through the increase in productivity. Although Hemming and Miranda (1991) recognise the fact that privatisation does not necessarily guarantee an increase in economic efficiency, they believe that the increase in competition will ultimately produce gains in allocative and productive efficiency. They assert that gains in allocative efficiency will result from more efficient allocation of resources to better economic and social objectives, and that gains in productive efficiency will result in producing the same level of output at a lower cost. According to these authors, the strongest incentive for this improvement in economic efficiency is due mainly to the introduction of the risk of bankruptcy or take-over, which implies that the cost of production is lower for a firm in the private sector than in the public sector.

However, as Ferguson and Ferguson (1994) explain (as illustrated in Figure 3.1), privatisation can improve productive efficiency but it may also reduce allocative efficiency.

Figure 3.1: Gains and Losses from Privatisation



Source: Ferguson, P. and Ferguson, G. (1994) Industrial Economics: Issues and Perspectives.

Figure 3.1, above, is based on the assumption that privatisation could put the management under greater pressure from shareowners, causing costs to decline (i.e. lower marginal costs) and prices to rise to monopoly levels. In this case, the presumed positive impact of privatisation on economic efficiency occurs as the gains from productive efficiency (area EFBG) outweigh the loss in allocative efficiency (area ABC). They also believe that the profit incentives would give managers the reason to introduce new products and processes. As a result, the short-run allocative loss would be offset by the successful innovation which would advance the welfare of society over time. These positive outcomes from privatisation could be even higher if privatisation was combined with competition which results in lower competitive prices associated with higher output.

Vickers and Yarrow (1988) reported on the empirical studies of the importance of property types (public or private), but the results were less informative than expected. They

criticised the focus in many of these studies of the ownership variable and their failure to take proper account of the effects on performance of differences in market structure, regulation, and other relevant economic factors. They particularly criticised the methodology used by some of the studies which may have led to a bias in favour of private ownership. Pollitt (1995) studied the performance of over 275 electricity utilities mainly from the US. He found that there was no significant difference in the performance of publicly-owned companies in comparison with that of privately-owned companies.

The World Bank, in its World Development Report 1996, indicates that an extensive empirical literature shows generally that private enterprises, in industrial countries, exhibit higher productivity and better performance than public enterprises. Also, the report presented the outcome of comparative studies of performance before and after privatisation in eighteen countries including six developing countries. The analysis of the sixty-one privatised companies indicated stronger conclusions in favour of private ownership. It showed that in at least two-thirds of post-privatisation cases, there were increases in profitability, sales, operating efficiency, and capital investment without any increase in unemployment. However, most of these studies were based on cases from industrial economies where advanced capital markets and infrastructure exist, which diminishes their relevance to developing economies.

Martin and Parker (1997) reviewed several empirical studies from developed as well as developing countries, which deal with the relationship between efficiency and ownership type. They reported that some of the studies support the notion that private ownership leads to higher performance, while others show no statistical significant difference. Their conclusion is that even if private firms are more profitable than public enterprises, profit should not be the only indicator of efficiency. This is particularly true as these firms operate in monopolistic markets and consequently are able to overcharge. Majumdar (1998) conducted a cross-sectional study consisting of 67 Indian state-owned, 63 privately-owned and 27 foreign-owned enterprises. He analysed the performance of these enterprises and found that the state-owned enterprises exhibited poor performance despite the fact that all firms operated in an equally competitive environment. The conclusion of his study was

that institutional factors such as protection of firms from failure and cheap capital provided by the government should be eliminated as they are sources of soft-budget constraints.

Nellis (1999) found from the case of the transition countries that the evidence of good results from privatisation comes mainly from Central and Eastern Europe, but evidence from Russia and Ukraine shows less promising results. He noticed that private ownership in these latter countries often does not lead to restructuring and competition and even some partially state-owned enterprises perform better than privatised enterprises. In these and other transition countries, clear performance improvements occur only in cases where the companies were sold to foreign investors, while there is very little difference between the performance of public and private enterprises. However, Havrylyshyn and McGettigan (1999) surveyed a selection of similar empirical studies from these countries and reported that privatised enterprises performed much better than public enterprises.

Tittenbrun (1996) put forward the argument that even if most studies suggest that public enterprises are less efficient than private ones, there are some studies which indicate the opposite conclusion. Hence, the existing evidence is insufficient to show that public enterprises are inherently less efficient than private ones. Abu Shair (1992) believes that the market mechanism is the single most important determinant in improving efficiency and minimising agency costs. Hence, in his view, it is market structure, and not ownership, which brings about the success or failure of privatisation.

Hemming and Manssor (1988) believe that the efficiency of privatised enterprise results from economic and financial liberalisation, which allow market forces to influence the performance of enterprise. Bishop and Thompson (1992) indicate that most economists are generally agreed that simply changing the ownership type is not sufficient, and that this is not even necessary, for efficiency improvement. What is important, in their view, is that competition, or at least the threat of it, is present and credible.

Waterson (1995) believes that the preference for competition shown by most economists is solely related to attaining efficiency as they consider inequity as a separate issue. Crew (1986) argues that while economists either suppress or purposefully ignore this issue,

equity seems to be a main concern of the public and of the regulators. Nicholson (1998), using the social welfare function, illustrates that this separation is not always socially optimal. He demonstrates that efficiency is necessary for maximising social welfare, but is not sufficient. This means that society sometimes accepts a trade-off between the goals of efficiency and equity if the true optimal outcome, by the Pareto criterion, is unattainable. Zajac (1993) emphasises that the debate on this issue should take into account the fact that economic efficiency is not unique but depends on the initial distribution of income or resources, and it is at best only a necessary condition for justice.

3.2.4 PRIVATISATION, RESTRUCTURING AND REGULATION

The explanation for government economic intervention in the market is justified by the presence of market failure. Sherman (1989), Bös (1994), and Cooter and Ulen (2000) summarise the sources of competitive market failure as follows: the existence of 'public goods', externalities, severe informational asymmetries and technical conditions such as economies of scope and economies of scale which create a natural monopoly. Thus, it has become common in the literature to find many writers such as Fine (1990) who believe that the original rationales for the existence of public enterprise are based on the problems of natural monopoly and externalities.

When an industry exhibits the characteristics of natural monopoly, it becomes more useful for a single firm to solely occupy it. According to Vickers and Yarrow (1985), obtaining the benefits of productive efficiency without the disadvantages of monopolistic behaviour is possible if policy initiatives include public ownership, competitive forces, regulation, or franchising. Kessides (1993) cautions that although market failures make government intervention acceptable, this does not necessarily justify government involvement in all aspects of the service provisions. In addition, she draws attention to the fact that new technologies would alter what is traditionally considered a natural monopoly and would introduce more competition. The best example of this is the technical changes in electricity generation which have made it possible for an efficient level of production to be reached by much smaller power plants than in the past.

Many authors such as Zank (1991) and Walters (1989) have raised concerns about public monopolies being replaced by private monopolies which require the creation of a regulatory agency. Salvatore (1996) indicates that the public interest theory supposes that regulation is introduced to deal with market failures and to ensure that the economic system works in a manner consistent with the public interest. However, he points out that the capture theory claims that regulation may result in laws and policies that restrict competition and promote the interest of the firms that they are supposed to regulate.

Price (1994) argues that regulatory intervention is undertaken to overcome market failures with the objective of improving the outcome of free markets. This implies that even if private markets are preferred in most of the privatisation debates, they are not necessarily superior to public ownership. Hence, there is a need for economic regulation due to the presence of monopoly power. She considers this regulation inevitable and may even be desirable in industries providing services through a common network, such as electricity transmission.

According to Jackson and Price (1994), the appropriate form of regulation depends on the structure of the privatised industry. Some industries are unbundled prior to privatisation, such as electricity and water, while others are privatised as vertically and horizontally integrated monopolies, such as telecom and gas. In the first case, the natural monopoly element can be isolated and regulated, which makes it easier to encourage entry and competition in the other elements. Newbery (1995) indicates that it is not necessary for privatisation to be preceded by industry restructuring and regulatory reforms. He uses Chile as an example where regulatory reforms were introduced prior to privatisation, in contrast to the US, UK and Norway where privatisation was shown to occur before industry restructuring and regulatory reforms.

Waldeman and Jensen (1998) and Stelzer (1989) argue that the vertical unbundling of the electricity industry would be likely to result in lower industrial prices relative to residential prices. One of the reasons behind this outcome is that generating companies would compete for large commercial accounts. Hence, for deregulation to benefit captive small customers, a certain level of regulation is necessary to prevent this cross-subsidisation.

However, this regulation is less necessary when the industry is restructured to introduce competition in as many aspects of the industry as possible. Weyman-Jones (1989) believes that the generation segment is expected to form a competitive market, transmission and distribution are to remain as regulated network monopolies, and the supply services could become a contestable market. The success and the workability of this system depend greatly on the availability of and access to the transmission and distribution networks.

The distinction between fixed costs and sunk costs is crucial in this discussion. Vickers and Yarrow (1985) argue that even if an industry is a natural monopoly, it is possible that the threat of entry would be sufficient to deter an incumbent firm from exercising its monopolistic power. The theory of contestable markets attributed to Baumol (1982) considers that the main condition for this entry to be credible is that sunk costs are completely absent. As a result, all entry costs are recoverable and exit is costless, which makes it possible for a natural monopoly market to be contestable without further need for regulation. Martin (1993) believes that the possibility for sunk costs to be zero is very limited as that depends on the nature of resale markets for capital assets. The degree of sunkenness not only depends on the specificity of the assets, but also (to a lesser degree) on the costs of resale of the assets, including transportation costs.

Weyman-Jones (1994) points out that dealing with the problem of sunk costs in the natural monopoly aspects of the electricity industry can be achieved through keeping the network either as a private but regulated company or as a publicly-owned company while guaranteeing open access to encourage competition. This way the company incurs sunk costs without threat of entry, but it remains subject to either rate of return (RoR) regulation or a price-cap using the price-setting rule, RPI– X, where the first term is Retail Price Index and X represents a productivity factor.

Averch and Johnson (1962) believe that a regulated company under RoR has no incentive to invest in technology to improve operational efficiencies. In addition, they believe that such regulation would lead to excess capitalisation, which is known as the Averch-Johnson effect. Crew and Kleindorfer (1992) criticise the rate of return regulation for its failure to effectively protect the firm from entry, and its rigid price and cross-subsidised price structure. Laffont and Tirole (1993) see price-cap regulation as a reasonable alternative to

RoR because it gives better incentives for efficient production by the regulated natural monopoly. However, Banks (1996) criticised the process of setting the efficiency factor (X) and he considers price-cap regulation no more than a variant of rate of return regulation.

Thompson (1992) cautions that the centrality of the productivity factor (X) in the price cap regulation creates some problems. In addition to the political nature of the selection of this factor, productivity changes are difficult to predict and the choice of the factor affects the allocation of benefits, due to increase in productivity, between shareholders and customers. Alexander and Irwin (1996) compared the effect of rate of return and price-cap regulations on the risk that affects the regulated utilities' capital cost. They concluded that a price-cap raises the firms' capital costs, which implies that regulators using a price-cap should permit these firms to earn a higher return in order to attract new investment capital and improve the quality of their service. Burns and Weyman-Jones (1998) indicate that the impact of the X factor on productive efficiency is related to whether the profit maximising utility is risk averse or risk neutral. While the value of this factor is critical for productive efficiency in the first case, it is less so in the second where the utility will try to beat any price cap to obtain the profit.

Beesley and Littlechild (1989) have suggested that the choice between the two regulatory regimes of price cap and rate of return could be determined by the characteristics of the industry concerned. An industry moving towards a competitive structure may be regulated by a price cap, partly because the problem of incentive is reduced by the industry itself having both the opportunity, through changing technology, and the reason to reduce cost, due to potential competition. Price (1994) argues that these two forms of regulations differ, in that price cap applies only to monopolistic sectors while rate of return covers the entire industry. However, the application of rate of return regulation is more difficult in an integrated industry, where costs and infrastructure are shared by different sectors, than in a unbundled industry.

In general, the form that regulation would take is influenced by the structure of the monopolies concerned. Shleife (1985) gives the example of using yardstick competition to

regulate the performance of electricity regional distribution companies. The horizontal separation of the electricity industry makes it possible to evaluate the performance of each company in relation to the average. Weyman-Jones (1995) considers yardstick competition as a special case of incentive regulation as it decouples a utility's price structure from its own reported costs. In addition, he argues that this form of regulation has the advantage of helping the regulator to deal with the problem of asymmetric information.

3.2.5 PRIVATISATION IN DEVELOPING COUNTRIES

Privatisation is a reform policy that has been recommended to many developing countries by the International Monetary Fund (IMF), the World Bank (WB), the United States Agency for International Development (USAID) and most donor countries. Prager (1992) argues that the movement of third world countries toward privatisation is influenced by two factors: firstly, the conviction that public sector performance was less than expected; secondly, external pressure from the IMF and WB, especially on these countries who rely on structural adjustment loans to reduce the role of the public sector in their economies.

The discussion of privatisation in developing countries draws attention to the necessity of examining the factors which have led to the growth of the public sector in these countries in the first place. Zini (1992) believes that the main reason for government involvement in economic development is related to the fact that the private sector has not delivered as expected. Also, the governments in these countries have access to costly information and are more able to undertake risks than the private sector. In addition, due to the weak development of capital markets in these countries the government is more capable of mobilising savings than the private sector. However, Ghafoor and Weiss (1999) argue that this intervention has its drawbacks as it affects pricing and investment decisions in public enterprises, particularly in the infrastructure. The combination of subsidisation and the rapidly growing demand for these services increase future investment requirements to a level which is beyond the ability of the government.

According to Bouin and Michalet (1991), the degree of government involvement varies in developing economies. The government may take control of activities which it considers are strategic industries making public enterprises widespread. Alternatively, the

government may adopt policies which encourage private sector to play a crucial role in the economy. Finally, some governments may selectively use state-controlled industries to serve special interests. Chaudhry (1992) believes that the scope of government intervention in the economy in developing countries is not necessarily based on ideology. He gives the example of the governments of Saudi Arabia and Iraq where, despite the differences in their ideological inclination, the public sectors in both countries play major role in the economy.

According to Ali (1996), ideology as well as politics and economics has had a major impact on the extent of government involvement in the economic development of some Arab countries including Saudi Arabia, Iraq and Tunisia. However, he argues that the relative influence of the factors composing the triad in this involvement varied from one country to another and within the same country over time. He believes that not only does the economic factor come third in importance as far as the role of the three governments in economic development is concerned, but also that it is greatly influenced by the political factor. Most of the participants in a conference, organised by the Arab Monetary Fund (AMF) in 1988, about privatisation in Arab countries, concluded that ideology has some effect on the extent of the state intervention in these economies.

The conference participants classified these countries into three groups based on the rationale for government intervention in the economy. The first group included countries which had experienced a socialist transformation during the 1960s, such as Egypt, Sudan, Syria, Iraq, Algeria and South Yemen. In these countries, the public sector involvement was considerable and was not limited to strategic industries, but included economic activities such as the retail sectors, contracting, book publishing and even hotels and restaurants. The second group included Jordan, Tunisia and Morocco, which are countries that did not adopt the socialist ideology, but had development strategies based on interventionism. This development may be rooted in historical factors where the colonising power departed but left foreign projects, which then had to be given national certification. The third group included the Gulf States, such as Saudi Arabia which officially adheres to the philosophy of free-market economy. In this group, the public sector controls the oil sector due to its strategic nature and some strategic industries such as petrochemicals. The

private sector has a major role in other sectors, even though the partnership with the public sector remains very considerable.

For all practical purposes the two different points of view, mentioned above, come to the same conclusion that there is extensive involvement in the economy by the government regardless of the ideology or the rationale behind this intervention. The conference participants concluded that privatisation was necessary in the first group, but it was less so for the second group and was not very urgent for the oil-dominated group. This observations also implies that the extent of government intervention reflects the potential and scope of privatisation programmes.

Cassese (1992) finds it ironic that the process of privatisation, which is supposed to reduce the government's role, requires considerable government involvement and a strong bureaucratic structure. He asserts that the promotion of some industries and the weakness of the private sector due to the lack of entrepreneurial initiatives or the shortage of private capital makes this sector in need of government support. Also, he finds that public enterprises, especially in less developed countries, are entrapped in a vicious circle. They are in charge of performing unprofitable activities, which make them dependent on financial aid from the government. This dependency results in more bureaucratic and political involvement in the activities of the enterprises, which reflects further links to the government and more demand for such enterprises to carry out unprofitable activities.

Chang and Singh (1992) indicate that not only economic but also institutional and political factors have a direct impact on the performance of public enterprises. They argue that another approach to dealing with the problems of the public sector in developing economies is through promoting the private sector rather than going through the complex process of privatisation. El-Naggar (1989) disagrees with this approach as it ignores the dynamics of change in an economy with a large number of state-owned enterprises. Instead, he suggests incremental privatisation where these enterprises are to be privatised, but in gradual phases.

Jackson and Price (1994) caution that the actual experiences of privatisation in these economies show that the process may have helped the government with its finances (though not by as much as is often assumed) but failed to produce the dynamic efficiency gains that had been hoped for. They attribute this outcome to two causes: firstly, the fact that in many cases the privatised firms are sold back to their original owners who lack the managerial skills; and, secondly, the rent-seeking behaviour of managers of privatised industries who demand subsidies and legal protection rather than working on improving the competitiveness of their firms. Thobani (1999) believes that misallocation of risks, between government and investors, is another cause of failing to benefit from privatisation especially in the infrastructure. Guarantees from governments, such as in the case of purchasing power at a predetermined price regardless of demand or guaranteeing a minimum revenue for BOT contracts, may reduce the efficiency incentives for private investors and increase liabilities for the government.

According to Berrie (1992), the central issue in understanding the limited progress in pursuing the privatisation policy is not desirability but feasibility. The main obstacles are the private sector's high dependency on government subsidies, undeveloped capital markets and work-force opposition. Bayliss and Fine (1998) believe that the success and even just the implementation of privatisation depend upon complex economic and political preconditions. For example, Abu Shair (1997) indicates that the argument for private ownership is based on the assumption of the existence of financial markets, which facilitate the transfer of property ownership. However, most developing countries do not have developed markets and if they do they are inefficient and lack the codes and institutional arrangements to protect property rights.

Cassese (1992) explains the lack of success in privatisation in developing countries in terms of two paradoxes: firstly, there must be a well-developed private sector and a strong financial market, but the existence of a large public sector in these countries is the very reason that the private sector is weak; secondly, in more recently independent countries, the public enterprises are the result of a process of confiscation of foreign capital and this contradicts the need to put the control of some privatised sectors back under the management of foreigners. For the implementation of privatisation to be successful it has

to recognise the fact that privatisation is a political process rather than a social one. Hence, the report by the United Nations Development Program (1993) identifies the 'sins' that developing countries need to avoid in the implementation of this process. These sins include the attempt by the government to maximise its revenues rather than creating competition, public monopolies being replaced with private monopolies, and the procedures used in the process which may lack transparency and lead to corruption and nepotism.

Irwin (1997) draws attention to one of the challenges facing privatisation in developing countries, which is that of dealing with the social and political implications of changing price structures. Economic efficiency requires that prices vary between different consumers according to their price elasticity and different times of use. He calls for an end to price subsidies, as this policy in developing countries is unsuccessful in achieving its main objective of assisting the very poor. Stevens (1998) agrees that distortion of prices, such as in the case of price subsidies, is not a good way to redistribute income, although in developing countries it may be the only way.

Walters (1989) accepts that the existence of a capital market makes the process of privatisation much easier, administratively and politically, but he does not consider it a necessary condition. He cites the case of Chile, where the government has carried out an extensive and successful privatisation programmes despite the limitations of the capital and financial markets. Young (1992) believes that the limited nature of capital markets is not an intractable problem. He suggests that privatisation could be used to develop a capital market by adopting a privatisation programme that creates widespread ownership. This could be done through sale to the general public through flotation of shares, sale to the employees or management of the enterprise concerned, and sale to the consumers of its services. According to Robinson (1991) this is in line with the argument by most economists that the prime aim of privatisation is to liberalise markets so as to obtain the benefits from more competition.

Yoder et al. (1991) conducted an empirical research study of the correlation between privatisation, as measured by the share of private sector spending of Gross National

Product (GNP), and some development indicators for forty-five developing countries. The study concluded that there is no significant correlation between privatisation and economic development and it emphasised the importance of the institutional factors that may affect development rather than just private sector growth. However, Abu Shair (1997) argues that given an appropriate framework of institutional reform, the process of privatisation has the potential to contribute to the economic and social development in these countries.

3.2.6 PRIVATISATION IN INFRASTRUCTURE

The speed and the scope of the movement toward privatisation vary between developing countries. Malaysia, along with Turkey, the Philippines, Bangladesh, and most of the Eastern European countries followed broad schemes of privatisation. Hensley and White (1993) consider the Malaysian case different from the others as in this case the country was viewed as a corporate entity. The government provided the policy parameters and support while the private sector provided commercial expertise and ingenuity. This privatisation experience was based on the encouragement of projects initiated by the private sector itself, especially in infrastructure projects. Malaysia utilised innovative tools of privatisation such as of Build-Operate-Transfer (BOT) and Build-Own-Operate (BOO) which became the vehicles for the execution of ambitious infrastructure plans.

Malhotra (1997) points out that developing countries have to create the necessary investment climate which encourages the use of these arrangements in infrastructure projects in general, and in electricity in particular. This environment should include, among other factors, a transparent process, competition in bidding, fair allocation of risk, and predictable policies. Roseman and Malhorta (1996) believe that private power producers could play a dynamic role, which would demand their involvement in the restructuring process of the electricity industry. In addition to their role in increasing the generation capacity and reducing public spending, these producers could enhance the potential of competition in the generation segment of the industry. Dunkerley (1995) indicates that this trend in developing countries is a departure from the traditional, public-sector-dominated methods. These new methods also have the advantages of providing a vehicle for private investment, especially for international investors who could introduce know-how and new financing and management techniques.

Hawdon (1998) explains that in some variants of the BOT scheme, the power plant is owned and operated by a private foreign company for a substantial period. The site and fuel are provided by the host country, which also buys the electricity generated. The clear advantage of such an arrangement is that capital to build the plant is provided by the private generator, so there is no foreign exchange requirement for the government. The nature and the structure of BOT schemes vary from project to project, but they are highly complex. Although David and Wong (1994) admit this complexity, they argue that seeing these schemes as unnecessarily risky is unjustified. They explain that under theses schemes there are inevitable sources of risks such as borrowing and investment is on a limited recourse basis, a sovereign guarantees from the host government are limited to the initial stage of the project and uncertainties associated with exchange rates and inflation.

David and Fernando (1995) stress that negotiating a successful BOT project should clearly resolve the following issues which include:

- the debt-equity ratio and how the equity is allocated between the host country and the private power developer;
- the formation of the company which will implement and operate the project;
- agreements for power purchase and fuel procurement as well as agreements covering construction and operation stages;
- agreement on the energy pricing formulae which should include a basic price and adjustments for fuel prices, exchange rate fluctuation and inflation;
- technical procedures and standards such as start-up frequency, reserve allocation and plant dispatch; and
- the financial model showing reasonable cash flows for the project and a fair rate of return on equity to the developer.

In the electricity industries of developing countries, where the objective of increasing generation capacity is very much needed, these schemes have become more relevant than ever before. One of the advantages of BOT, especially for developing countries, is that the ownership of a project which is considered to be strategic would return to the government at the end of the agreed period. Hensley and White (1993) draw attention to another advantage from adopting the BOT or BOO schemes in project financing. These schemes

separate the project risks from the (host) country risk because lenders advance money against the cash flow of the project rather than the government's guarantee. The project company or consortium raises the debt financing from commercial sources, while members of the consortium provide equity which usually amounts to 30 per cent of the total project cost. This equity reflects the level of commitment to the project and presents a protection against bankruptcy.

Pollio (1998) emphasises the importance of requiring sponsors and operators to take a direct equity stake in the project. This requirement leads to financial efficiency because it creates a strong linkage between the profits of the different parties and the overall performance of the project. However, these schemes are highly beneficial, but are not sufficient for sustainable financing. According to Jechoutek and Lamech (1995) the elegantly engineered financial instrument or transactional modality should not to be seen as an end in itself, but rather has to be combined with sector and corporate reforms. Sustainable financing of the sector concerned requires the introduction of more corporate financing and not just the reliance on project financing.

In addition, the opening up of the electricity industry for these schemes of private generation should be approached with some prudence, not only because it is a relatively new concept for most developing countries but also because it may create problems of its own. For instance, Albouy and Bousba (1998) indicate that the overall positive impact of IPPs on economic development, especially in Asian countries, came with some significant effects. These effects included higher exposure to foreign exchange risks and over-capacity in cases such as Indonesia and Malaysia, where too many programmes were implemented too soon.

3.3 THE CASE OF THE ELECTRICITY INDUSTRY

Most of the traditional literature on the electricity economics focuses primarily on the issue of regulation, while the more recent literature explores issues related to the increasingly debated alternatives for restructuring the industry. This due to the fact that the institutional transformations of the industry, in developed and developing countries alike, have had

reaching effects on the different aspects of the industry in terms of ownership, operation, regulation and pricing.

This section reviews the changing structure of this industry, with special attention given to the evolving role of the transmission segment within this new environment. The focus is on the contentious issue of transmission pricing, which is an indispensable element in any restructuring scheme. In particular, having the efficient and implementable transmission pricing is critical for facilitating the evolution of a competitive electricity market.

3.3.1 RESTRUCTURING AND PRIVATISATION OF THE INDUSTRY

Restructuring and privatisation are not synonymous, as restructuring does not necessarily imply changes in ownership and privatisation does not necessarily imply changes in structure. In the case of the electricity industry, however, restructuring usually comprises the elements of restructuring, privatisation and deregulation (i.e. re-regulation). There is wide agreement, in the literature, that restructuring should begin with legal and institutional reforms; to be followed by the liberalisation of the industry, before any substantial privatisation is achieved.

Although different countries may have the same objectives of the establishment of efficient markets and the introduction of competition, Hadjilambrinos (1999) emphasises that political and institutional traditions influence the restructuring direction that each country takes. Some governments may view privatisation not as a part of a broad restructuring programme with competition as an objective, but as a way of improving the government's fiscal position through maximising privatisation proceeds.

Lock (1995) and others suggest that prior to privatisation, the electricity industry should be broken up into separate generation, transmission and distribution companies, and that such companies must be turned into more viable and economically efficient entities through corporatisation. However, Arocena et al. (1999) argue that corporatisation of the industry, instead of involving its initial disintegration would amount to the government's raising money through an implicit tax on future electricity consumption. This caution is well founded but the dilemma is that if the electricity industry is losing money, it is unlikely to

be sold easily. Thus, it is worth trying to privatise such companies, exposing them to the pressure of competition at an early stage of the process.

3.3.1.1 INTRODUCTION OF COMPETITION

Most restructuring cases involve, simultaneously, a horizontal as well as a vertical break-up of the electricity industry. Klein (1998) describes horizontal restructuring as the situation where two or more entities are created in a single area of economic activity (i.e. power generation), while vertical restructuring involves the separation of different stages of the production chain, such as electricity transmission, from the competitive segments of generation. In his view, vertical separation has the advantages of facilitating less regulation, by isolating natural monopolies from competitive segments, and reducing the monopolistic power of vertically integrated utilities.

In the literature on economic regulation, there is an implicit conviction that the best regulators are the free-market forces themselves. Newbery (1995) argues that competition is more effective than regulation in promoting efficiency. Therefore, he maintains, it is considered a good public policy to regulate only the natural monopoly aspects of the electricity industry. Also, the reform should include an open transmission system, even under public ownership, and create competition in generation and possibly distribution through privatisation.

In the opinion of Lock (1995), what is more important is that comprehensive regulation and an independent regulator should be part of the broad restructuring strategies for the electricity industry. Jackson and Price (1994) consider the separation of the electricity supply into a service distinct from distribution to be an innovative concept. However, this needs to be coupled with more selective and specific forms of regulation to those parts, which are natural monopolies, and permitting the introduction of competition wherever possible.

3.3.1.2 TRANSITION COSTS OF RESTRUCTURING

Despite the changing organisation of the industry, co-ordination within and among the generation, transmission, and distribution segments remains necessary. Herriott (1989)

believes that co-operation under the new structure should cover both commercial and technical aspects. This would include economy power transactions, unit commitment, joint planning in generating and transmission, co-ordinated maintenance, spinning and capacity reserve transactions.

However, the move towards more market mechanism in the industry has created its own sceptics. Baxter et al. (1997) argue that restructuring involves considerable transition costs, such as stranded investments. These costs include physical assets and financial liabilities, to which the industry has committed itself prior to the introduction of competition into the market. Joskow and Schmalensee (1983) expressed some doubts that the introduction of competition into electricity markets could accommodate, without loss of some economic efficiency, the organised co-operation that is necessary for least-cost planning and operation.

Vickers and Yarrow (1988) find that there is a contradiction between creating a central co-ordination, to overcome the externalities resulting from full decentralisation, and the objective of promoting greater competition through the introduction of more independent decision making. Banks (1996, 1999) believes that the unbundling of the electricity industry might have only created uncertainty without being able to introduce successful financial instruments to minimise the risks. Thus, he thought it is unwise for countries with successful electricity industries to rush into this process with no guarantees that it would be correctly applied.

This argument could be accepted if the industry exhibited a good performance in terms of low prices for consumers and reasonable profit for producers. In reality, however, many countries have had to reform their industries precisely because of the failure in achieving these desirable outcomes. The policy dilemma, then, is to consider the expected benefits resulting from restructuring versus the problems and the costs associated with such a complicated process. Hence, the question of how this trade-off should be resolved is becoming one of the most interesting issues in electricity economics.

3.3.2 THE NEW ELECTRICITY INDUSTRY

3.3.2.1 CHANGING GENERATION TECHNOLOGIES

Although claims about natural monopoly have influenced public policies and academic discussions for many years, these claims have become less relevant to some activities of the modern electricity industries. There is a general recognition that this industry consists of at least two distinct businesses: production (i.e. generation) and delivery (i.e. transmission and distribution). While the delivery business retains the characteristics of a natural monopoly, the generation business is no longer considered a natural monopoly.

Primeaux (1986) was one of the writers who strongly challenge the theory of natural monopoly and its application to electricity utilities. Arocena et al. (1999) argue that both static and dynamic (e.g. 'learning by doing') economies of scale do not exist in power generation. In addition, many empirical studies, such as Bernstein (1988) examined the investment costs of power projects which are in the range between 40 and 600 MW, and reached the same conclusion. More recent studies, such as those conducted by Doyle and Maher (1992) and Bayless (1994) reveal that the new technology of Combined Cycle Gas Turbines (CCGT), has made it possible for efficient production in generation to be reached on a much smaller scale than ever before.

According to Berrie (1992) the prospects for Independent Power Producers (IPP) are greatly improved as these new technologies point downwards in scale, price and optimum size, away from 2000 MW and towards 200-500 MW power generators. This trend has made market competition more possible especially with the faster installation of smaller generators. For example, Meade (1987) reported that generation facilities under 10 MW were allowed, in the US, to sell power to end users under bidding contracts without any official approval.

3.3.2.2 COMPETITION IN GENERATION

Klein (1998) observed that, in recent years, the notions about which segments are truly natural monopolies have been challenged strongly and repeatedly. Thus, the potential for competition has been expanded and the extent of regulation has become limited. Trebing (2000) believes that restructuring would make it possible to introduce competition into the

generation segment while the natural monopolies of transmission and distribution would have remain regulated. Robinson (1991) argues that competition in genertaion is necessary for achieving higher economic efficiency. The gains in productive efficiency can happen through lower costs, and the gains in allocative efficiency can be achieved by bringing prices into closer alignment with these costs.

The reduction in monopoly power of the traditional utilities is, according to Flavin and Lenssen (1994), due to the recent technological changes in electricity generation and the introduction of IPPs as competitors. The developments in generation technologies, such as co-generation or distributed generation, have made it possible for small generation facilities to be strategically located near the consumption centres. These developments not only have a positive impact on competition but are also a contributing factor in cost reduction. According to Hoff et al. (1996), these small sources of generation can relieve capacity constraints on the system, which reduce variable costs and investment requirements.

Cardell and Ilic (2000) recognise that the growing popularity of these technologies is due to their short construction time and low capital costs. However, the authors caution that these changes introduce uncertainties, such as the impact on the technical operations and control of the system. In addition to this technical uncertainty, financial complexity is also introduced. Kim and Ahn (1990) point out that purchasing electricity from independent co-generators and reselling it to consumers raises concerns regarding pricing and payments, which need to be addressed.

3.3.2.3 TRANSMISSION AND DISTRIBUTION

Both transmission and distribution are considered to be naturally monopolistic activities, subject to regulation, in the sense that duplication of lines between two locations is inefficient. Armstrong et al. (1997) point out that the distinction between these two activities is that the transmission network is high-voltage and national in scope, whereas the distribution network is low-voltage and local. When the electricity industry consists of vertically integrated utilities, this distinction is less critical, but restructuring and privatisation have highlighted some significant practical and regulatory issues such as third

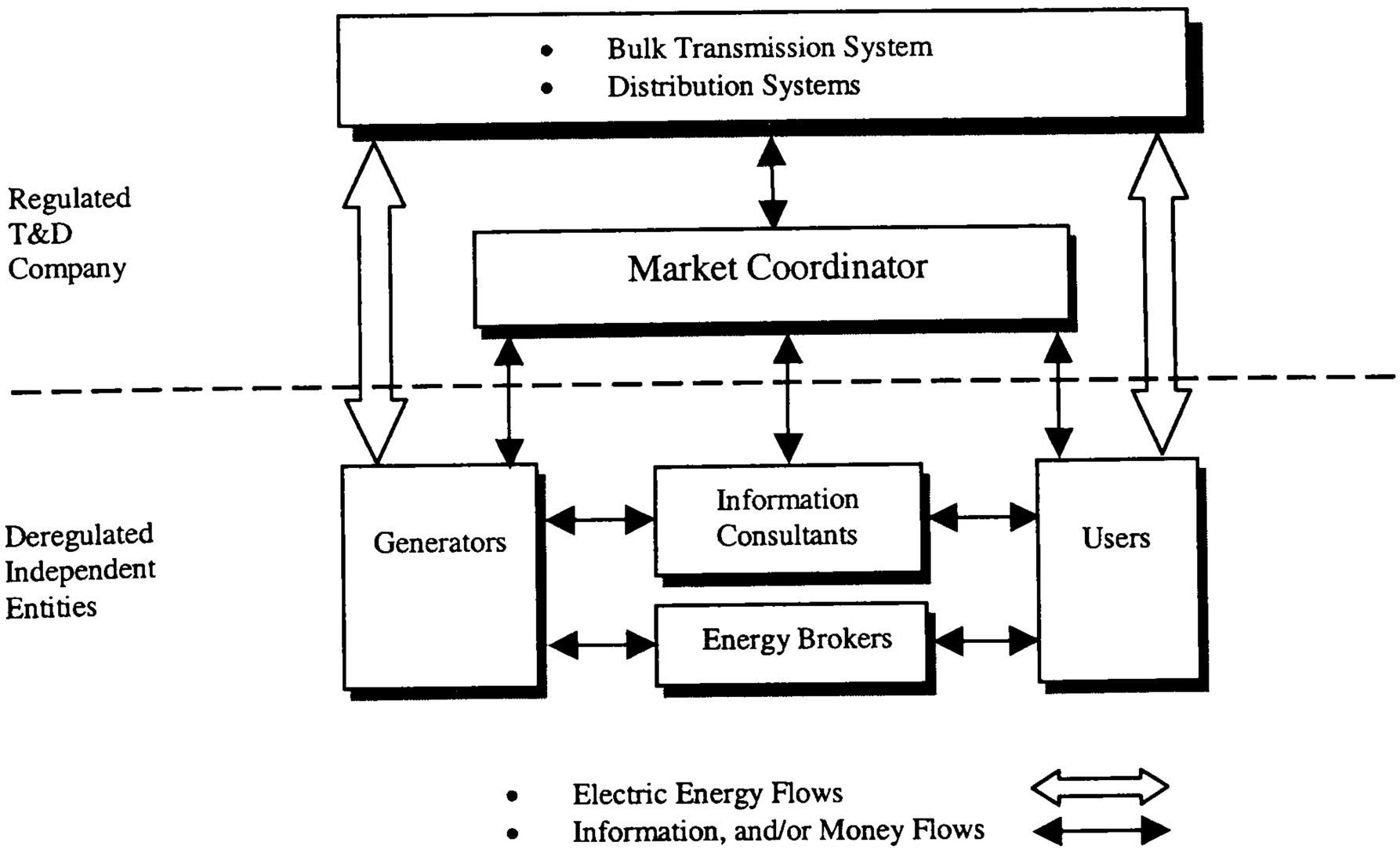
party access. In a wholesale market, trading (i.e. 'wheeling') can be conducted not only across the competing utilities distribution network but also over the transmission lines.

Sansom (1995) argues that it is not economically nor technically necessary to have transmission and distribution operated by single company in an unbundled structure. The option of regional separation is essential for yardstick competition, especially as there are very limited economies of scope between distribution activities in different regions. Since transmission is naturally monopolistic over large areas that contain several regions, vertical integration between transmission and distribution is incompatible with the regional separation of distribution companies. Also, another advantage of this separation is that retail supply competition between regional companies become possible.

3.3.3 TRANSFORMATIONS IN THE ELECTRICITY INDUSTRY

In the 1980s, Fred Schweppe and other colleagues at Massachusetts Institute of Technology expected a considerable transformation in the industry's structure which would not take very long to materialise. They envisioned the ideal unbundled (i.e. deregulated) marketplace for electricity to consist of three main segments as in the following figure:

Figure 3.2: Schweppe's Vision of an Unbundled Electricity Market



Source: Schweppe et al. (1988), Spot pricing of electricity, p.76

Figure 3.2, above, shows that the participants in the electricity industry can be grouped within three main segments. The first segment is a regulated transmission and distribution company which operates physically and financially as an intermediary. This company can be a public company but if it is a private one it should be regulated on the basis of a rate-of-return framework The second segment consist of many independent, private generating companies which sell electricity to the transmission and distribution company. The third segment comprises the electricity consumers who buy electricity from the transmission and distribution company.

Although Joskow and Schmalensee (1983) expected the electricity industry to be restructured along similar lines to those outlined above, they did not agree that the transmission and distribution segments should necessarily be integrated into one company. These two visions conform to what it is called a single-buyer structure, which is nowadays considered a temporary and a transitional stage. Hence, these early works did not foresee the enormous restructuring and divestiture currently progressing in the electricity industries of many countries, which went beyond this vision.

3.3.3.1 ELECTRICITY RESTRUCTURING MODELS

The increasing public concern about efficiency in the electricity industry and recent technological innovations, especially in generation, have led to calls for abandoning the traditional model of a vertically integrated industry. Tenenbaum et al. (1992), and Hunt and Shuttleworth (1996) are well-known authors in the literature who take a similar normative approach in presenting a comprehensive analysis of the ways to structure an electricity industry.

Tenenbaum et al. (1992) gave a broad review of the different structures and regulations of the electricity industry. Four restructuring models were presented and each one of them differed by the extent to which it introduced privatisation, as in the following:

> **Model 1:** This model consist of one or more vertically integrated, privately owned companies with each one in a franchised market. In this model privatisation is introduced without competition.

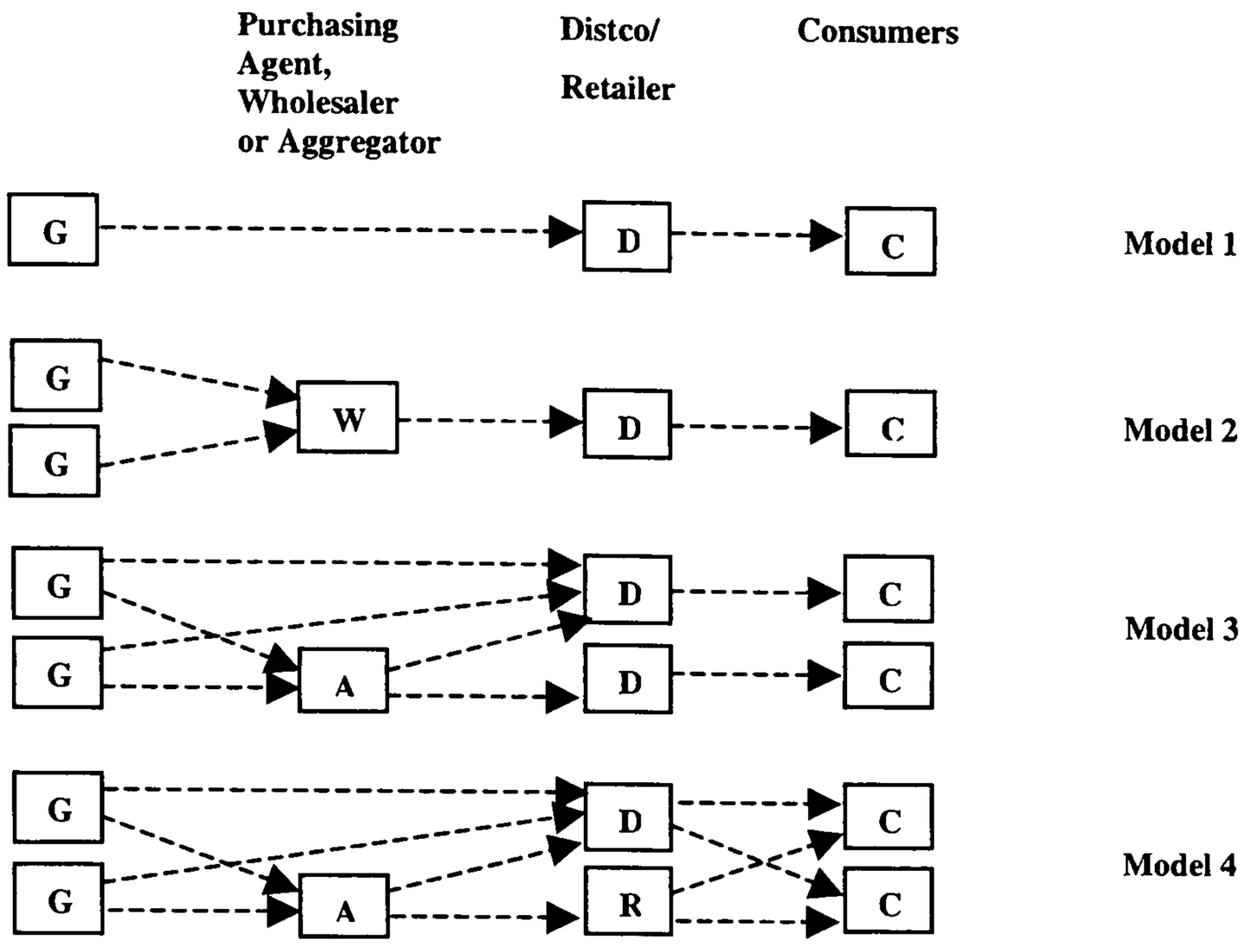
Model 2: This model maintains the traditional structure of Model 1 but allows competition in generation, with continued regulation of transmission and distribution.

Model 3: This model expands on Model 2 by stressing the role of the transmission segment in the form of a 'common carrier' which must transmit electricity in a non-discriminatory way. In this model, the transmission owners are obliged to provide transmission access to competitors and to other wholesale buyers and sellers.

Model 4: This model assumes that the whole industry is privatised and vertically separated. In this model, the independent transmission company owns the network and controls the dispatch function. Regional distribution companies are obliged to provide access to competitors and to their own consumers.

Hunt and Shuttleworth (1996) identified four similar restructuring models. These models are not differentiated on the basis of ownership, but rather in terms of the degree of competition and choice that each model provides to the participants. The first model is described as monopoly model, the second as a purchasing agency (i.e. monopsony) model, the third as a wholesale competition model and the fourth as a retail competition model. The following figure illustrates these four models:

Figure 3.3: Restructuring Models for Electricity Industry



Source: Hunt, S. and Shuttleworth, G. (1996), Competition and Choice in Electricity, p. 24

The models in the figure are not based on ownership; for example, government-owned or private monopolies can fit into the first model. The most important characteristics of each model are those of competition among generators, choice for retailers and choice for final consumers. Hunt and Shuttleworth (1996) believe that restructuring an electricity industry to allow full competition is technically and economically feasible. They conclude that the fourth model is the most economically efficient model, because it has the most competitive market structure.

When one comes to apply these models to the real world, there is no single model that can conform to the structure of a particular country, and in reality the distinction between these models is not always straightforward. Tenenbaum et al. (1992) indicated that the electricity market of England and Wales has some features which are not necessarily found in Model 4. This market has retail competition, but also allows distribution companies to own equity interests in generation (i.e. backward vertical integration).

The dynamic nature of electricity industry restructuring would ultimately introduce many choices and possibilities. Hyman and West (1989) believe that competition in the electricity industry could exist in a number of ways. Vertically integrated utilities can

choose between using their own generation or buying it from other utilities or independent power producers. Many regional utilities or independent producers can sell in the wholesale market, and customers can choose between self-generation, or purchase from the local utility or even from external sources.

3.3.3.2 TRADING MECHANISMS IN ELECTRICITY MARKETS

The important cornerstone in promoting competition in generation and in the wholesale electricity market is the structure of the market itself. Newbery (1999) points out that this market consist of both a spot (physical) market and a market for risk sharing through trading in financial instruments. Sioshansi and Morgan (1999) argue that the type of generation mix is a determining factor in choosing the suitable market mechanism. While it is more suited for a system where the bulk of generation is thermal to choose a pool mechanism, a system where the majority of its generation is hydro-based has good reason to select the long-term contract mechanism.

Mork (2001) emphasises that the decision to choose between a pool or bilateral contract should be based on factors such as price volatility and security of supply on the one hand, and prices transparency and market liquidity on the other. The emphasis is on the argument that the price transparency associated with pool-based markets can produce more competition and (allocative) efficiency. Murray (1998) also favours this approach over bilateral contracts, which, while they benefit the involved parties individually, these contracts produce suboptimal outcomes and the overall costs may generally be higher.

However, the price transparency of the pool requires information availability, which, due to the repetitive nature of the electricity market, can create an incentive for collusion among generators. This problem has introduced calls for keeping some details confidential in order to make it harder for the bidders to guess the actions of their rivals. Cramton and Schwartz (2000) believe that information about bidder identity associated with each bid is especially vulnerable to collusive use. Bower and Bunn (2000) reviewed the relevant literature on the auction theory and draw attention to suggestions for combating these collusion problems, such as by delaying the release of information about bids and auction

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Due to the longer-term nature of CFDs, Lowrey (1997) believes that the Electricity Forward Agreements (EFAs) provide the market participants with much greater flexibility. Bower and Bunn (2000) indicate that a vital part of an electricity spot market is the forward market where consumers and generators meet voluntarily to trade bilateral contracts, but in a mandatory day-ahead market, both CFDs and EFAs must be financially settled against prices set in this market.

3.3.3.4 ELECTRICITY POOLS

Barker et al. (1997) compared the governance and regulation of new style power pools in different countries and categorised these pools into 'tight' and 'loose' pools. The tight pool is a pool that has a centralised dispatch based on the marginal generation costs, and specified capacity and operating reserve requirements, which are subject to financial penalties for non-compliance. The loose pool is a pool with some co-ordination of operations and planning but with no central dispatch and usually no specific reserve obligations. What distinguishes these new style pools from the old ones are that the former are created to maximise competition in generation (subject to reasonable reliability standards), to compete on price, and to be open to all market participants.

Murray (1998) provided an overview of the alternative market structure and mechanisms that have been established or are being considered to realise competition in generation and supply. He presented three different types of pools; gross, net and zonal pools, which are outlined as follows:

> **The gross pool** is where all energy is traded between generators and suppliers and where the market clearing price is set in advance based on estimated marginal generation costs with the objective of minimising the total cost of production. Participants in this pool hedge against the volatility of pool prices by striking two-way hedging contracts to adjust pool payments to a pre-agreed contract price.

> **The net pool** is where most of the energy is traded directly between generators and suppliers through bilateral contracts. The difficulties surrounding the prediction of the actual demand and generation availability make this type useful in clearing the

residual supply and any uncontracted demand. However, this arrangement does not create full competition because bilateral contracts lack the necessary transparency.

The zonal pools become possible when different areas of the system have different prices due to transmission constraints. Thus, the price differentials and level of interconnection capacity create 'bid' zones for the trading between the pool authorities or directly between generators in the different zones. This arrangement introduces further complexity but highlights the importance of investment in additional transmission capacity.

3.3.3.5 NEW PLAYERS IN THE ELECTRICITY MARKET

The new electricity industry has introduced new entities and an innovative trading climate. The treatment of electricity as any other commodity has given rise to new institutions and players. With the creation of electricity spot and futures markets, marketers, brokers, and resellers have become visible participants in these markets. The significance of these transformations is in the ability of these players to provide a number of highly-valued products and value-added services.

The marketers, through their involvement in electricity markets, attempt to co-ordinate different power sources through bilateral contracts with generators. Sioshansi and Altman (1999) attribute the growth of demand for the services provided by such players to three factors. Firstly, the presence of market price volatility has made it necessary to manage risk. Secondly, there is the participation of small players who need to rely on marketers for important trading, brokering, and information services. Thirdly, the considerable locational and temporal price differences create considerable arbitrage opportunities.

Thus, it is not surprising that the continuous evolution of the electricity markets could reach new highs. It has been suggested that the auction approach to electricity pricing and trading might become possible in the near future. Sheble (1999) envisions that the implementation of auctions in the electricity industry would be accomplished through a computerised market. This would require generation and transmission players to submit offers that reflect system operating conditions and demand centres need to submit bids that

represent their valuation of requested demand. The only caveat is that the auction centre would have to assign only contracts that do not violate system security and reliability.

3.3.4 THE ROLE OF TRANSMISSION

3.3.4.1 TRANSMISSION IMPACT ON COMPETITION

The function of electricity transmission is considered of vital importance in the efficient planning and operation of the electricity industry in both vertically integrated and unbundled structures. Weyman-Jones (1995) points out the economies of massed reserves which could result from having one interconnected system. This advantage is caused, according to him, by the fact that "the risk of failing to meet demand on a system of nodes is less than the sum of the separate risks of failing to meet demand at individual nodes" (p. 426). Joskow and Schmalensee (1983) believe that the transmission network has positive effects, which include the realisation of plant-level scale economies, production efficiency, reduction in total capacity requirements and increased reliability of supply.

These benefits could also be realised in an unbundled structure where power trade could occur between vertically integrated (though monopolistic) companies or in trading through an electricity spot market. The move toward disaggregation of the industry has enhanced the role of transmission not only in terms of exchange of power but also in facilitating competition in the power trade. Yarrow (1994) argues that introducing competition especially in generation is one of the major direct benefits from substantial investment in transmission.

Bornstein et al. (1997) examined the competitive impact of transmission on competition in generation, in the context of a model of two geographically separated markets, each dominated by a single supplier. The main finding of this investigation was that the availability of increased transmission capacity enhanced the potential for competitive entry, in the form of electricity imports. More importantly, the mere presence of this threat discouraged monopolistic behaviour in each market, even though the entry was not realised. Hence, it could be concluded that having some excess transmission capacity, even if unused, is useful in keeping prices low.

These findings reflect the role of transmission networks in creating competition between different sources of generation as well as providing the consumers with choices. However, this positive role might be lost depending on the structural as well as the regulatory approach to dealing with this monopolistic segment. Tenenbaum and Henderson (1991) emphasise that market power in the electricity industry lies in the ownership or control of the transmission network. For example, a combined generation and transmission utility wishing to sell power could use its transmission control to block lower-priced suppliers from competing. This could be overcome, according to Doyle and Maher (1992), if there is open access where the transmission company operates as a common carrier and the generation segment is competitive.

Flavin and Lenssen (1994) believe that restructuring the industry should extend retail wheeling even to residential consumers, who otherwise could become captive to the distribution companies and, hence, subsidise large consumers. According to Tenenbaum et al. (1992), industry reforms should include both a competitive wholesale electricity market and open access transmission. They emphasise that the key to healthy competition is knowing who has access and who has the right to use the network. This then requires conduct regulation to ensure that competitors get comparable transmission services.

3.3.4.2 THE TRANSMISSION COMPANY

The transmission of electricity is basically a service provided by ' a transporter' which is the entity responsible for transmitting the power between different points on the network. This service is provided to match instantly the generation of electricity with any changes in demand. This entity can be a publicly owned company, but in a privatised structure it should be regulated like any other natural monopoly. In electricity industries where a competitive market has been adopted, separate companies usually own the generation and transmission segments. Thus, restructuring usually puts transmission and generation under separate ownership, which eliminates the incentive for the transmission company to manipulate the competitive market.

Herriott (1989) is of the view that the transmission company should be a provider of a transportation service rather than a buyer-reseller of electricity. The access of this company

to the cost and demand information makes it able to account for all transactions and optimise the investments in generation and transmission capacity. Trebing (2000) discusses two alternatives for organising transmission segment. The first alternative is the creation of a non-profit administrator, or independent system operator (ISO), who is responsible for scheduling electricity transfers and establishing transmission prices. The second alternative also involves an independent administrator but here the transmission company is a regulated for-profit company. The proponents of this approach argue that it has a performance incentive that makes it preferable to the first alternative, which is in any case a transitional step toward the creation of the for-profit company.

According to Berrie (1992), the owners of this company can be the generation companies, the distribution companies or both, or it could remain as an unaffiliated company. He classifies the transmsission entity into three categories: common carrier, market-maker or purchasing agent. In the case of the common carrier, an independent company operates the transmission network, while both generators and distributors are able to contract directly with each other. In the case of the market-maker, an autonomous transmission company could buy and sell electricity from generators, and sell to distributors. This case induces economic efficiency, as purchasing policy is based on the merit order of generators rather than on long-term contracts. In the case of the purchasing agent, the transmission company accepts the contracts made between generators and distributors and dispatch them in terms of the cheapest offered price. This case has the advantage of eliminating the ability of generators to manipulate and game the market, but this comes at the expense of market transparency.

3.3.4.3 THE COST OF TRANSMISSION SERVICES

According to Chao and Peck (1996), there are three cost components in electricity transmission: losses, congestion costs and costs of ancillary services, which include the provision of reactive power and spinning reserve. Thus, transmission costs can be split into two parts: fixed costs, which include infrastructure assets, operating and maintenance charges and ancillary services, and variable costs, which include losses and congestion.

Since electricity is a demand-driven industry, this makes it imperative to consider also how much demand centres, especially large consumers, are using the transmission network. Thus, it has been suggested by Weedy (1998), among others, that reactive power, as a source of transmission losses, is priced and charged to large consumers. He argues this is a natural step as these consumers have direct impact on transmission costs, including, reactive losses, through the fluctuations in their demands.

Hunt and Shuttleworth (1993a) like Church and Ware (2000), consider that purchasing power by the transmission company is no different from buying capital and labour as factors of production. The transmission company needs to buy active and reactive power to compensate for the transmission losses incurred in transporting energy. This makes the transmission company liable for these losses, which induces efficiency in the network operations as the company has the incentive to optimise transmission expansion. However, this company is normally subject to regulation, which aims at distancing its profit from its operation of the system, for when losses are considered part of income, there is an incentive to increase rather than reduce losses and congestion on the system.

Electricity transmission involves high economies of scale where the increase in the transmission capacity is unavoidably higher than the increase in demand. Thus, the nature of transmission investment would create excess capacity, even in expansion planning which is optimal. Hence, a high proportion of the transmission costs is fixed, and these costs are sunk even in the long run. According to Ring and Read (1996a), electricity transmission has high sunk costs because transmission assets have no economic alternative use other than transporting electricity. Dismukes et al. (1998) were able to show the existence of increasing return to scale in the provision of electricity transmission over all relevant ranges of capacity and distance. This confirms the presumption that this segment is a natural monopoly and should be regulated.

3.3.4.4 THE IMPORTANCE OF TRANSMISSION PRICING

The ultimate objective of restructuring the electricity industry is to give the retail customer direct access and choice between competing power sources. Hence, the identification and separate pricing of the electric service components is necessary to allow customers to

choose their preferred generators. The uncertainty introduced by the unbundling of the industry and the rapid development of competitive bulk power markets has increased the importance of transmission pricing. According to Hughes and Felak (1996), the unique nature of a transmission network has made such pricing more difficult than pricing systems for generating capacity and energy.

Bornstein et al.(1997) point out that when one considers the unusual physical attributes of electricity transmission, this trade problem exhibits some interesting characteristics. Electricity can be easily 'reshipped', which gives the marketers the ability to buy electricity at one point and have it delivered to another point at very little or no cost to themselves. Also, electricity is a perfectly homogenous commodity which means that price differences can be easily arbitraged. This implies that trading in electricity requires the pricing of transmission costs and the determining of who should pay for transmission services.

The transmission pricing issue increases in importance as the industry advances further toward more competition. With the exception of Model 1 (vertically integrated monopoly), transmission pricing becomes vital for all the models discussed in Tenenbaum et al. (1992) and Hunt and Shuttleworth (1996). In Model 2 (purchasing agency or monopsony), the competition in generation makes transmission prices a factor in the evaluation of bids. The contracts for purchasing power, for example, should determine which party is responsible for the transmission costs. Obviously, transmission prices become more central to Model 3 (wholesale competition) and Model 4 (retail competition), where generators can trade directly with distribution companies, retailer or consumers.

Bushinell and Stoft (1996) argue that the vexing issue of transmission pricing is one of the major consequences of electricity industry restructuring. These prices affect the socially optimal decisions made by the different users as well as facilitating smooth transformation of the process itself. Bamoul (1996), and Bamoul and Sidak (1995) argue that when the transmission owner provides the transmission service to itself and to its competitors, then transmission pricing becomes even more necessary for economic efficiency. They suggest that access to this service be priced under the efficient component pricing rule, which

requires this service provider to charge itself exactly the same price (i.e. marginal cost) for its use that it charges its competitors.

The importance of dealing with the issue of transmission pricing is due to the fact that transmission prices have a direct impact on allocative efficiency, by feeding into electricity retail prices, and on productive efficiency. According to King (1996), private investors in generation incorporate the comparison between transmission prices and fuel costs into their investment decisions. Thus, a good transmission pricing method is one that encourages, or at least is not inconsistent with, efficiency in the expansion of generation and transmission capacity. It should give the optimal signal for new generation with an efficient level of transmission use.

The trend, especially in developing countries, has been toward variants of BOOT type private investments and independent power producers. Winning contracts for these projects from the host utility or purchasing company usually depends on the advantage of the proximity to consumption centres. Since primary fuel sources usually exist far from locations where electricity is consumed, the transportation costs of fuel as well as electricity become an essential determining factor. Transmission costs are normally integrated into a composite unit charge, but the introduction of these private projects has increased the demand for transparency of accounting and separation of electricity cost into its different components.

Notwithstanding the general recognition of the importance of transmission pricing in the industry's restructuring, setting charges for transmission remains a complex and contentious issue. The complexity is due to the fact that electricity is homogeneous and non-storable on large scale. This makes it impossible to determine physically which generator's output is supplied to a particular load. The conflicting interests of system users make their acceptance of a common pricing rule for transmission very difficult.

Green (1998a) concluded from his investigation of the UK electricity market that transmission pricing must be set prior to privatisation to limit disputes. He showed that even a good transmission pricing scheme, such as marginal cost pricing, can be rejected

when some generators or distribution companies, especially in an oligopolistic market, find it disadvantageous. These findings highlight the necessity to introduce transmission pricing method which achieve economic efficiency and, also, can be implemented.

CONCLUSION

Even though there is no agreement on a single definition for privatisation, most of the definitions in the literature emphasise the transfer of assets from the public sector to the private sector. Thus, the criterion in judging the different definitions is not what is right and what is wrong, but rather each definition to be judged based on its usefulness for a particular purpose.

Much of rationale for privatisation is based on the assumption that private ownership is superior to public ownership. However, the empirical studies regarding the impact of ownership on the performance of privatised industries remain inconclusive. More importantly, the performance of such industries is related to market liberalisation and the presence of competition, or at least the threat of entry.

Improving performance as one of the objectives from privatisation of other industries has been sought in electricity industry. The change in generation technologies came at the time when restructuring and privatising of electricity became a policy objective in many parts of the world. This made it possible to introduce horizontal restructuring, by allowing a number of private companies to operate in the generation segment. It also introduced vertical restructuring through the separation of competitive activities, such as generation, from the monopolistic segments, such as transmission and distribution. Hence these two sides of restructuring can increase competition and facilitate regulation by isolating the relevant activities which need to be regulated.

The different models for restructuring the electricity industry emphasise the central role that transmission services could play in facilitating competition in the privatised segment of the industry. In addition to facilitating plant-level scale economies by generators, consumers can benefit from the ability to purchase power from competing sources of

generation. The costs of these services introduce the spatial element into the price of electricity, but also become source of disputes among the users such as generation and distribution companies.

The elimination of this contentious issue would enhance the movement toward further restructuring and competition in the industry, which should benefit the consumers at the end. However, at this stage the existing methods of transmission pricing unsuccessfully tried to satisfy the conflicting objectives of economic efficiency, transparency, fairness and implementation. The difficulties with the current methods demand the introduction of another alternative, which try to strike a balance between these desirable objectives.

CHAPTER FOUR
Transmission Pricing Methods

4.1 INTRODUCTION

A transmission service is no longer just the service of moving power between different points on the network (i.e. the transmission grid). This service has been transformed, with vertical separation of the industry, to include facilitating the instant trading and dispatching of electricity between separate points on a single system and also between a number of interconnected systems.

The transmission company is the entity which has the responsibility of transporting the power from generation sources to demand centres. The revenues of this company are supposed to be based on the services it provides and priced accordingly. In setting these charges, attention has to be balanced between the objective of economic efficiency and other objectives such as transparency, fairness and acceptability of the charges by the participants.

The transmission pricing methods have evolved over the past decade due to the increase in electricity trading and the institutional transformation of this industry in many parts of the world. Several methods have been developed to address the issue of charging for transmission services, which are necessary services for trading in electricity markets. The following section 4.2 provides a general introduction to four methods; contract path, 'postage stamp', marginal cost pricing and electricity 'tracing'. Section 4.3 elaborates on the marginal pricing method because it is the standard reference in the literature of transmission pricing and also it is the benchmark for the most desirable attribute of economic efficiency. Section 4.4 presents in details the main features of the new method of electricity tracing.

4.2 GENERAL REVIEW OF TRANSMISSION PRICING METHODS

4. 2.1 CONTRACT PATH METHOD

The contract path method is a very simple method, which was developed in the early days of the electricity industry in the United States (Perera, 1994). According to this method the contracting parties assume a specific path from a generation source to a consumption point on the transmission network. This is done in a similar fashion to the transportation of conventional commodities where a buyer and a seller choose between different paths for delivering the product. The charge for the transaction in an electricity contract is usually allocated on the basis of the relative size of the user (i.e. *pro rata*).

While electricity flows follow the laws of physics (i.e. electricity travel along the lines with least resistance), the path of the financial contract does not necessarily follow the physical path of the electricity. According to Chao and Peck (1996), this misalignment between the contract path and the physical paths results in no compensation being given to the owners of the transmission facilities which are actually used. This divergence is not only unfair, but also causes private costs and social costs to be different which results in a gross distortion to economic efficiency.

The acceptability of this method, in the past, was due to the fact that electricity was traded between clearly determined parties over a limited number of tie-lines. However, this method which is obviously not compatible with the complexity of today's electricity markets. Hogan (1992) considers this method too simplistic and thus unsuitable for efficient electricity trade, because it has little to do with the actual cost of electricity transmission. Ilic et al. (1997) believe that this method also leads to a 'pancake effect', where a electricity travelling over number of intervening networks in series may be charged at multiple rates.

4.2.2 POSTAGE STAMP METHOD

This method differs from the contract method in that it considers the average transmission costs of the system rather than the costs associated with a particular contracted transaction.

With this method, every user pays a postage stamp charge, which is a uniform pro-rata charge according to the participant's usage as measured by the participant's size. Ilic et al. (1997) indicate that a postage stamp transmission rate is usually based on the annual system transmission costs divided by the peak system MW capacity. The simplicity of this method has caused it to be very commonly used and preferred by electricity authorities due to the ease of its implementation.

However, this method is subject to considerable criticisms mainly on the grounds that the postage stamp charges give incorrect economic signals. Baldick (1998) believes that with this method the charges distort the operational and capital planning decisions of the system. Hughes and Felak (1996) argue that these charges do not send efficient pricing signals to competing generators. For example, these charges cause a generator that heavily uses the transmission network to have a lower delivered price than otherwise. This can lead to an incorrect mix of generators, which makes the overall costs higher than necessary.

4.2.3 MARGINAL COST PRICING METHOD

This method is a great improvement on the previous methods as it joins economic principles with the laws of physics which govern power flows. With this more sophisticated method, the price for one extra MW at a delivery node should equal to the marginal cost of generating and transmitting (transporting) this unit to that node. This concept has evolved into what is currently known as the nodal spot prices, which were developed by Bohn et al. (1984b) and Scheweppe et al. (1988) from the Massachusetts Institute of Technology (MIT).

Despite the advantage of this method on the grounds of economic efficiency, its usefulness in practice is limited by factors mostly associated with the decentralised aspects of an unbundled electricity industry. In a vertically integrated utility, the complexity of the algorithm is eased with the availability of all necessary information to the dispatcher who has the objective of meeting the instant demand with the lowest total costs (generation, transmission and distribution). The separation between these different functions, as well as the introduction of market rules into the industry, increase the complexity of using this method. Also, the conflicting interests of the participants make disclosure of essential

information very difficult and even create the incentive to resist any rules which jeopardise these interests (Kwok, 1997). A more detailed account of these limitations of the marginal cost pricing method of transmission in a deregulated structure is presented in section 4.3.6.

4.2.4 ELECTRICITY TRACING METHOD

The complexity of pricing electricity transmission in comparison to conventional commodities is due to its unique physical characteristics. The fact that electricity cannot be stored on large scale, and its homogeneity, make it impossible physically to determine which generator's output is supplied to a particular load. However, the electrical engineering literature of the last a few years has witnessed attempts to trace, albeit notionally, the flow of electricity on the transmission lines. Bialek (1996) and Kirchen et al. (1997) independently were able to develop two approaches to tracing electricity. These two approaches of the tracing method aim at allocating the flows and consequently the transmission losses between the users (i.e. generators and/or demand centres) of the network.

The matrix-based approach of Bialek and the graph-based approach of Kirschen et al. are based on the same main assumption of the Proportional Sharing Rule (PSR). The essence of this rule is that nodal inflows are shared proportionally by the nodal outflows. The main difference between the two approaches is that Bialek's approach is more general, as it applies even to networks with circular power flows which makes it more suitable to systems with meshed networks. Also, it applies to both networks with and without losses, while Kirschen's approach applies only to networks without losses. This means that Bialek's approach can directly allocate transmission losses (resulting in more accurate charges), and according to Acha et al. (1997) this approach has been proven to be mathematically sound.

The simplicity, transparency and fairness of the tracing method in allocating transmission costs are generally acknowledged in the literature (see, for example, Hogan (1997) and Pan et al. (2000)). However, the question of how this method scores on the issue of economic efficiency remains an open one. This thesis aims at examining this issue by studying how the tracing charges would compare with charges based on the ideal marginal cost pricing.

4.3 MARGINAL COST PRICING OF TRANSMISSION

Marginal cost pricing of transmission is an optimality problem, which is considered in microeconomic theory as a resource allocation problem. The analysis of the concept of optimum output for a multi-plant firm goes back to the discussion and debate by Patinkin (1947) and Leontief (1947). George et al. (1949) was the first to work out the solution for this optimisation problem in the production of electricity by taking into account the transmission costs (losses). This effort has been also explored further by Westfield (1955) who included an application of marginal cost analysis to a real case from electricity industry, namely the American Gas and Electric Company System with its over forty power plants. Thus, the relevant framework for this problem is that of a multi-plant firm with an objective of allocating its inputs between its different plants taking into consideration transportation costs. In the 1980s, Scheweppe and his colleagues from MIT were able to extend this framework even further with their development of nodal spot prices for electricity in a deregulated industry structure.

There is a trade-off between the economies of scope gained from vertically integrated utilities and the gains from unbundling the electricity industry due to the opening for competition. When transmission is operated under the deregulated structure, especially in pool arrangements, the system operator needs to rely on the information provided to him by the different generators regarding their respective bids, assuming they reflect their marginal operational costs. The operator has the responsibility of maintaining the stability of the system by co-ordinating the actions of the generators. The objective of electricity industry within an unbundled and deregulated structure is to maintain, as much as possible, the economic dispatch applied by the operator in a vertically integrated utility.

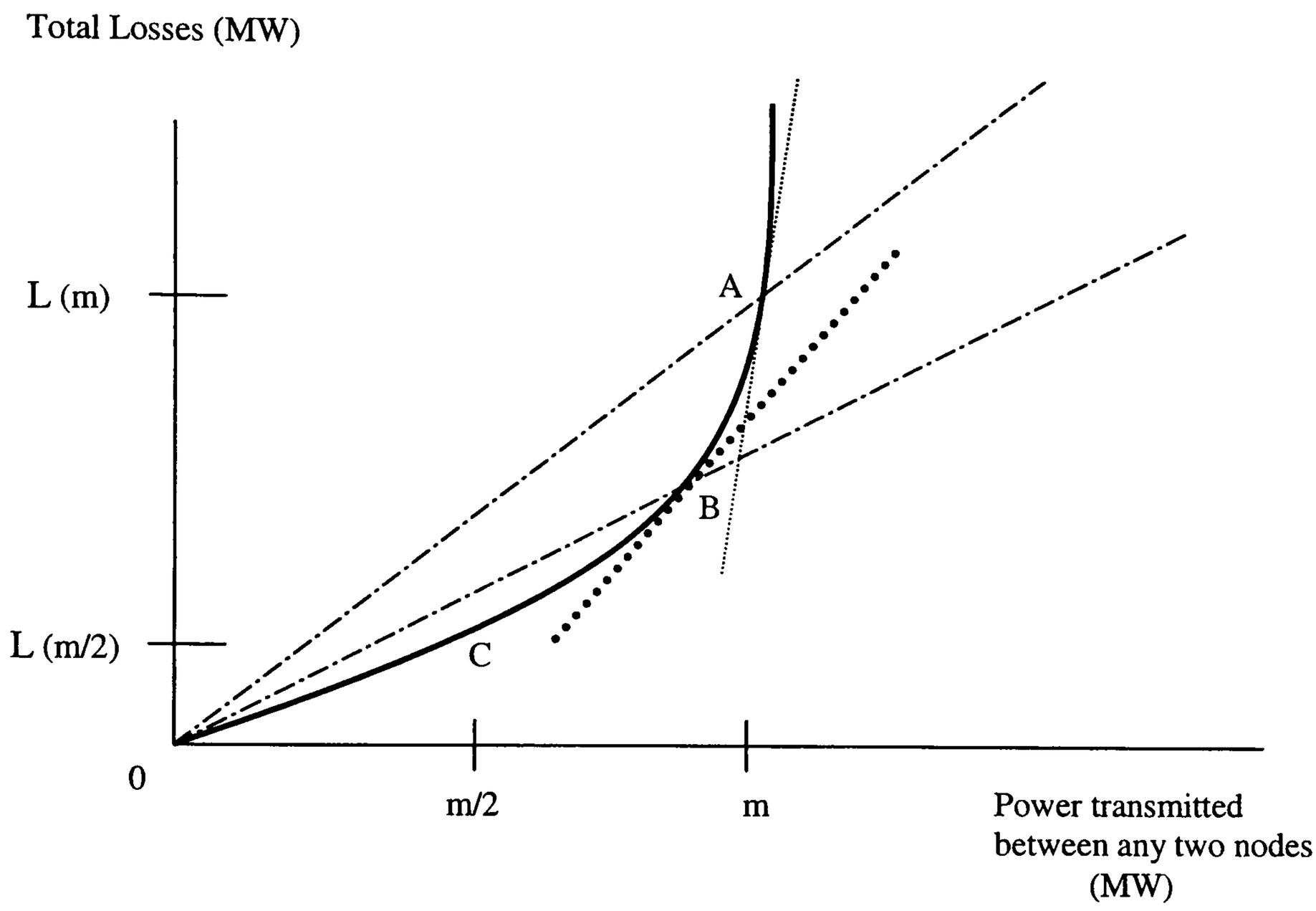
4.3.1 THE NATURE OF TRANSMISSION LOSSES

What makes pricing the electricity transmission differ from pricing other transported commodities is the non-linear nature of transmission losses. Transmission losses over the lines are shown (George et al.1949, Scherer 1977) to be an approximately quadratic function of the transmitted power. For a line with a given voltage:

Transmission Loss (mw/mile) = $R \cdot I^2 \approx R \cdot (\text{Power})^2$ (Equation 4.1)

Where;
I is the current over the line, and
R is the resistance coefficient for the line.

Figure 4.1: Transmission Losses and Line Flow



Source: Adapted (with considerable modifications) from Scherer, C. (1977), Estimating Electric Power System Marginal Costs, P. 215

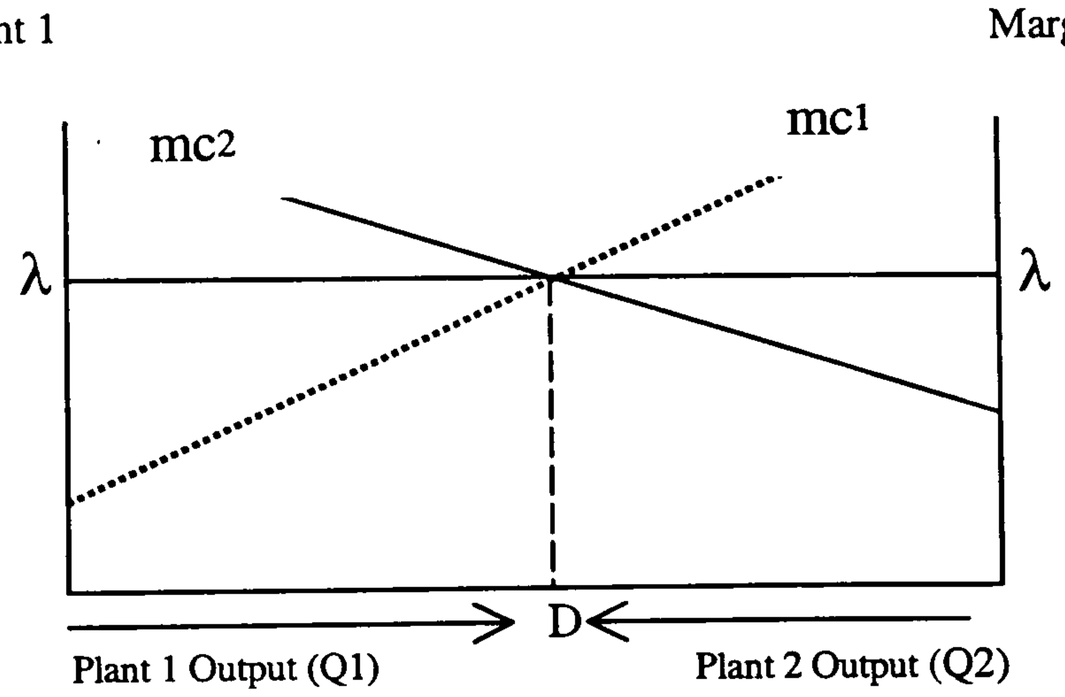
The above equation indicates that marginal losses (the first derivative) are twice the average losses. This is confirmed by Figure 4.1, which shows the relationship between the slope of each of the rays and the slope of the (relevant) tangent lines. The slope of the radiance line OA through point A is lower than the slope of the tangent line at the same point. This means the marginal losses are higher than the average losses at the associated level of power transmitted on the network. A similar relationship results from the slopes of the line OB and the tangent line at point B. The figure shows that the marginal and the average losses at a higher level of transmitted power are higher than those at a lower level of power. This is consistent with the fact that transmitting a higher level of power would be

at a higher cost because of the non-linear nature of electricity transmission. This is illustrated by the figure, where a certain percentage increase in the power transmitted results in an increase in transmission losses by a higher percentage.

4.3.2 ECONOMIC DISPATCH IN MULTI-PLANT UTILITY

Marginal analysis is a fundamental principle and useful tool for the allocation of resources for a vertically integrated utility as well as for an unbundled industry. Figure 4.2, below, shows that the objective of the operator in the short run is to allocate total demanded output between the different plants with different capacities at the least total costs. The dispatcher or the operator in this utility is required to allocate the output among these plants to minimise costs by equating the marginal costs for each dispatched plant.

Figure 4.2: Marginal Analysis Application to Load Scheduling



Total Demand (D)= Q1+Q2

Source: Westfield, F. (1955) 'Marginal Analysis, Multi-Plant Firms, and Business Practice: An Example', Quarterly Journal of Economics, vol. 69, May, pp. 253-268.

Assuming no transmission losses, the above figure shows that the optimal output of the multi-plant utility is set where the marginal generation costs of the different plants equal the system marginal cost, λ. Thus, the welfare-optimal price would equal marginal production cost (as in non-spatial commodities) and this would be the same for the spatial case of electricity when there is no transmission cost.

In the case of the optimisation problem when there are transmission losses, the dispatcher equates the marginal delivered costs and not just the marginal generation costs. The marginal delivered cost from each plant is the marginal generation cost plus the marginal transmission cost allocated to the plant. This means that each plant must be operated at a rate such that their respective marginal delivered costs are equal. When there are transmission costs, price is greater than marginal cost, and the difference is the marginal cost of transmission (Dansby, 1980).

When the utility is vertically integrated, the transmission costs are internal to the firm and that makes the allocation of these costs among the plants merely an element of economic dispatching rather than a joint cost allocation. The allocation of these costs is an issue of conflict and dispute when the industry is unbundled and generation, transmission and distribution are vertically separated. It is one of the major contentious issues that a deregulated structure has to deal with, if the expected benefits from restructuring and competition of electricity industry are to be realised.

Regardless of the institutional transformation introduced into this industry, the operational side of the system must be run according to the same principles as apply in a vertically integrated utility. In both cases there is a need to have a central controller with an objective of matching the generation instantly with the demand and that has to be at a minimum cost. In an unbundled structure the society replaces the utility, the system operator replaces the dispatcher of the utility and the objective is to maximise social welfare rather than the utility's profit.

4.3.3 THE THEORY OF NODAL SPOT PRICES

The objective of the system operator is to maximise the social net welfare, subject to the limits imposed by the physical nature of the electricity network. This is an optimisation problem not very much different from that of the multi-plant firm which tries to minimise its costs (or maximise its profit) subject to some generation and transmission constraints. Vickrey (1971) is considered the first to have proposed nodal spot pricing, which he called 'responsive pricing'. However, the optimisation problem in obtaining nodal prices was introduced explicitly by Bohn et al (1984b) and Schweppe et al (1988).

Hsu (1997) and Green (1998b) represented this problem, where the system operator uses the standard welfare criterion of maximising the social net welfare (W), that is benefits (B) minus costs (C), from consuming electricity subject to the following set of constraints:[2]

- *Energy Balance Constraint*: the generation must equal the demand plus transmission losses where any violation of this constraint causes a blackout of the whole system;
- *Transmission Line Flow Constraints*: the flow (z) on a line i must not exceed its designed maximum capacity;
- *Individual Generation Constraints*: the output of a generator can not exceed its capacity; and
- *Total Generation Constraint*: the sum of output from all generators does not exceed the total generation capacity for the system.

Thus, it is necessary to

$$\underset{d,g}{Maximise} \qquad W = \sum_k B(d_k) - \sum_j C(g_j)$$

$$Subject\ to \qquad \sum_k d_k + Losses - \sum_j g_j = 0 \qquad (Energy\ Balance\ Constraint)$$

$$|z_i| \le z_i^{\max} \qquad (Line\ Flow\ Constraints)$$

$$g_j \le g_j^{\max} \qquad (Individual\ Generation\ Constraints)$$

$$\sum_j g_j \le g_{crit} \qquad (Total\ Generation\ Constraint)$$

---

[2] Bohn et al. (1984a) and Wu et al. (1996) cited an additional set of operational constraints, such as the limits for voltage deviations.

where:

dk is the demand at node k,

g_j is the generation at node j,

z_i is the flow along line i,

$z_i^{\max}$ is the maximum flow allowed on line i

$g_j^{\max}$ is the generation capacity at node j, and

g_{crit} is the total amount of generation available (critical capacity).

The basic assumption of the model is that the network has n nodes and net injection at $n-1$ of them. The residual injection occurs at the last node (i.e. the known in Power Systems jargons as the swing bus) where the marginal generator is normally assumed to be located. Hence, the marginal generator has no impact on the total losses which make the marginal losses at this node are zero.

Rewriting the above optimisation problem as a Lagrangian:

$$\begin{aligned} \underset{d,g}{Maximise} \quad & \sum_k B(d_k) - \sum_j C(g_j) \\ & - \mu_e \left(\sum_k d_k + Losses - \sum_j g_j \right) \\ & - \mu_i^{QS} \left(|z_i| - z_i^{\max} \right) \\ & - \mu_j^{\max} \left(g_j - g_j^{\max} \right) \\ & - \gamma \left(\sum_j g - g_{crit} \right) \end{aligned} \qquad \text{(Equation 4.2)}$$

The first order conditions are;

$$\frac{\partial B}{\partial d_k} - \mu_e \left[1 + \frac{\partial Losses}{\partial d_k} \right] - \sum_i \mu_i^{QS} \frac{\partial z_i}{\partial d_k} = 0 \ , \qquad \text{(Equation 4.3)}$$

and

$$-\frac{\partial C}{\partial g_j}-\mu_e\left[\frac{\partial Losses}{\partial g_j}-1\right]-\sum_i \mu_i{}^{QS}\,\frac{\partial z_i}{\partial g_j}-\mu_j{}^{\max}-\gamma=0 \qquad \text{(Equation 4.4)}$$

where:

μe is the shadow price on the energy constraint,

$\mu_i{}^{QS}$ is the shadow price on the line flow constraint (Quality of Supply),

$\mu_j{}^{\max}$ is the shadow price on the individual generation capacity constraint, and

γ is the shadow price on the total generation capacity constraint (Curtailment Premium)

Assuming that the consumer at node k maximises his utility if the price he is willing to pay (Pk) equals his expected marginal benefits, then we obtain the following equation:

$$Pk=\mu e\left[1+\frac{\partial Losses}{\partial dk}\right]+\sum_i \mu i^{QS}\,\frac{\partial zi}{\partial dk} \qquad \text{(Equation 4.5)}$$

Assuming that dk and g_j are located at the same node, then

$$\frac{\partial Losses}{\partial dk}=-\frac{\partial Losses}{\partial gj}\text{, and }\frac{\partial zi}{\partial dk}=-\frac{\partial zi}{\partial gj}$$

This means that increasing dk by 1 MW has the same effect on losses and congestion over line i as decreasing g_j by 1 MW. So, the first order condition for generation can be rewritten as:

$$\frac{\partial C}{\partial g_j}+\mu_j{}^{\max}+\gamma=\mu e\left[1-\frac{\partial Losses}{\partial gj}\right]-\sum_i \mu_i{}^{QS}\,\frac{\partial z_i}{\partial g_j}$$

$$=\mu_e\left[1+\frac{\partial Losses}{\partial dk}\right]+\sum_i \mu_i{}^{QS}\,\frac{\partial z_i}{\partial dk}=Pk \qquad \text{(Equation 4.6)}$$

Hence, the nodal price is the same for generator and load that are located at the same location on the network.

Define P^* as the price at the swing bus. If there is no shortage of capacity at the marginal generator, then there is no over all shortage of capacity and $\mu_j{}^{\max} + \gamma = 0$. So, at the swing bus, the price equals the marginal generation cost: $p^* = \mu_e$. The marginal generating cost of the marginal generator becomes the system marginal generation cost (λ). The price for other nodes, such as node k is:

$$Pk = P^*\left[1 + \frac{\partial Losses}{\partial dk}\right] = (\lambda + \gamma)\left[1 + \frac{\partial Losses}{\partial dk}\right] \qquad \text{(Equation 4.7)}$$

When there is no shortage of capacity (i.e. $\gamma = 0$), the price at node k equals the system marginal cost (λ) plus the marginal losses given value by P^*. So, an increase in demand by 1 MW at node k increases the system losses by l MW, the generation level has to increase by $(1+l)$ MW, and the price at node k should be $(1+l)$ times the price at the swing bus.

The impact of an increase in demand on total losses is not always positive because it depends on how this additional demand is met and how it affects the net flow on the lines. When the increase in demand is supplied from a generator at the same bus and the net flow remains unchanged, then marginal losses are zero. Also, the marginal losses are positive when the line net flow increases due to the increase in demand. Inversely, the marginal losses are negative when the line net flow decreases due to the increase in demand.

Thus, the sign and the value of these losses depend on the location of the source of the additional generation. The nodal prices and transmission charges are directly influenced by the choice of the marginal generator. For some systems, the choice of the marginal generator changes considerably when there are more than one potential marginal generator at any point in time. As a result, the human judgement of the system operator, according to Wu et al. (1996), is needed at least for the selection of the thermal constraints and contingency constraints which have influence over the directions of the line flows.

Even if the marginal generator of the system is fixed, the volatility of the nodal prices will remain when transmission constraints are active. So, in the case of line constraint, a more

expensive generator on the demand side of the constraint is dispatched and a cheaper one on the generation side is constrained off.

$$P_k = (\lambda + \gamma)\left[1 + \frac{\partial Losses}{\partial d_k}\right] + \sum_i \mu_i^{QS} \frac{\partial z_i}{\partial d_k} \qquad \text{(Equation 4.8)}$$

So, the price at node k can be different from the marginal generation cost (λ) depending on the losses and/or the existence of congestion over the transmission line.

4.3.4 THE MARGINAL LOSSES AND PENALTY FACTORS

By assuming that the transmission constraints are not active ($\mu_i^{QS} = 0$), the nodal price for a demand node, such as k, is

$$P_k = \lambda\left[1 + \frac{\partial Losses}{\partial d_k}\right] \qquad \text{(Equation 4.9)}$$

The increase in demand by one extra unit may cause an increase (decrease) in the net flow on the lines, which in turn leads to an increase (decrease) in losses. Consequently, the price at this node will be higher (lower) than the price at the node where the marginal generator is located. These two nodal prices will be the same when the increase in demand has no effect on net line flows. One more observation from equation 4.9 is that for the nodal price to be non-zero, it is necessary that $\frac{\partial Losses}{\partial d_k} \neq -1$. When $\frac{\partial Losses}{\partial d_k} = -1$, the consumers at this node obtain their demand free of charge, such that $P_k = 0$, which is obviously unrealistic.

For a generation node, such as j, the nodal price when there is no congestion is:

$$P_j = \lambda\left[1 - \frac{\partial Losses}{\partial g_j}\right] \qquad \text{(Equation 4.10)}$$

The increase in generation may cause an increase (decrease) in the net flow on the lines, which in turn leads to an increase (decrease) in losses. Consequently, the price at this node will be lower (higher) than the price for the marginal generator. These two nodal prices will be the same when the increase in demand has no effect on net line flows.

Rewriting the previous equation gives us the following:

$$\lambda = P_j\left(\frac{1}{1-\frac{\partial Losses}{\partial g_j}}\right) \qquad \text{(Equation 4.11)}$$

where $\frac{1}{1-\frac{\partial Losses}{\partial gj}}$ is called the penalty factor (Wood and Wolleneberg, 1996).

The penalty factor is an essential in economic dispatching. For example, assuming all generators have equal marginal generating costs, the generator with a penalty factor near unity is expected to be dispatched first because it has the lowest on losses.

It is necessary that $\frac{\partial Losses}{\partial gj} \neq 1$. If $\frac{\partial Losses}{\partial gj} = 1$, an increase of generation by 1MW causes the losses to increase by the same amount and the price at this node would be zero. This indicates that the generator is producing at no charge, which is unlikely to happen in practice because there is no incentive for this generator to supply this extra MW.

For the marginal generator, the price (P_j) equals its marginal operation costs (λ). In this case, the penalty factor is one and the marginal losses are zero. The values of the penalty factors are important elements in economic dispatching. These values show how each generator's additional output affects the system total losses. The impact of the sign and the value of marginal losses on the values which the penalty factor can take show how

influential the choice of the marginal generator is in allocating the system transmission costs among the participants such as generators and loads.

4.3.5 THE REVENUES OF THE TRANSMISSION COMPANY

Hunt and Shuttleworth (1993b) showed how the principles of transportation economics are very much applicable to electricity transmission. The demand for the transport service is derived from the market conditions of that product. In addition, price differential between any two locations can be explained by the transportation costs between them, which is equal to the marginal cost of transport. The authors analysed similar issues related to transporting electricity and conventional commodities, but overlooked the issue of incentives for the transport company. The quadratic relation between the volume of power transmitted and transmission losses (see equation 4.1) gives the transmission company (TC) a perverse incentive to increase losses rather than to reduce them. This means that this company can increase its revenues by operating the network inefficiently.

The revenues of the TC are generated from the difference between its payments to generators and the payments it receives from demand centres. These revenues are based on the differences in nodal prices, which depend on losses and line constraints. The sum of these differences is called Network Revenues (NR) or Merchandise Surplus (MS) (Bialek and Kattuman, 1999):

$$MS = \sum_{k \in \Omega} Pk(dk - gk) > 0 \qquad \text{(Equation 4.12)}$$

where Ω is the set of all network nodes.

Both demands and generators contribute to the Merchandise Surplus (MS) depending on their impacts on the losses and congestion of the network. The demand centres in the areas where demand exceeds generation (net importer area) contribute positively to the MS because $\frac{\partial Losses}{\partial dk}$ and $\frac{\partial zi}{\partial dk}$ are positive. Similarly, the generation in the net exporter areas contributes positively to the MS because $\frac{\partial Losses}{\partial gj}$ and $\frac{\partial zi}{\partial gj}$ are positive.

On the other hand, if the areas are net exporters, demand centres reduce losses by increasing their demands. In this case, the TC pays the consumers for increasing their demand, which is unrealistic and unlikely to be implemented. In addition, the MS is an insufficient source of revenues for the TC. For example, Bråton (1997) has reported from the experience of Norway that the transmission company raised no more than 34 per cent of its revenues from charges for energy losses.

Another disadvantage of the transmission charges based on marginal pricing is that the TC charges the demand centres more than their actual costs. These charges for marginal losses can be illustrated in the following:

$$Loss = RD_B^2 \qquad \text{(Equation 4.13)}$$

where;
D_B is the demand at node B; and
R is the line resistance coefficient.

This means that

$$\text{Marginal Loss} = \frac{\partial(Loss)}{\partial D_B} = 2RD_B \qquad \text{(Equation 4.14)}$$

The price at this node P_B should cover two components: the energy price (P^*) and the value of marginal losses at this node ($P^* \frac{\partial(Loss)}{\partial D_B}$).

Hence,

$$P_B = P^*(1 + \frac{\partial(Loss)}{\partial D_B}) = P^* + P^*(2RD_B) \qquad \text{(Equation 4.15)}$$

The total payment by the demand at this node is equal to the price times the quantity demanded such that the total payment by load B is as follows:

$$P_B\ D_B = P^*(1+2RD_B)D_B$$

$$= P^*(D_B + 2RD_B^2) \qquad \text{(Equation 4.16)}$$

Since $Loss = RD_B^2$,

Then; $P_B\ D_B = P^*(D_B + 2(Loss))$. (Equation 4.17)

From the above, it is obvious that the payment by the customer at this node equals the payment for the load plus additional payment equals twice the value of actual losses. In this case, the payment by load *B* is double its actual transmission cost, and the difference becomes part of the MS collected by the TC.

4.3.6 LIMITATIONS ON MARGINAL COST PRICING

Even though this method is based on short run marginal cost pricing, which is known in economic theory to guarantee economic efficiency, it faces serious practical limitations. Oren et al. (1995) and Hughes and Felak (1996) point out that this method is much more suitable for radial electric systems, because in some cases electricity can travel from points (i.e. nodes) with high costs to points with low costs, which is in contrast to the economics of transportation. However, this observation overlooks the fact that this occurs when electricity flows travel toward more expensive nodes through these low cost nodes due to the presence of line congestion. Green (1997) points out that marginal pricing of transmission costs leads to large spatial differentials in charges which, although desirable from an economic point of view, result in strong objections from distant users.

The other limitation associated with this method is an institutional one, where the application of the method is based on a number of assumptions and a considerable amount of information, which diminishes its practicality in an unbundled structure. Shuttleworth (1996) and Christie et al. (2000) believe that the marginal pricing method cannot be implemented on a non-discriminatory and transparent basis due mainly to the considerable complexity of the algorithm used.

Khan and Baldick (1994) point out that in an unbundled industry the dispatcher does not have direct access to the necessary information, especially that of generation costs, which is available to his counterpart in a vertically integrated industry. Thus, they doubt that the resulting transmission prices are efficient, because there is no guarantees that the dispatch of generators is optimal and that it incorporates all system constraints. This indicates that the desirable outcomes from marginal pricing may not necessarily materialise in an unbundled industry.

Bushnell and Stoft (1996) and Wu et al. (1996) point out that the presence of line losses and constraints increase the revenues collected by the transmission company, which feeds into the criticism of this method on institutional grounds. Hence, this company would have a perverse incentive to increase rather than decrease the transmission losses and congestion in the transmission system. However, this criticism ignores the fact that this incentive for inefficiently operating the system is minimised when the revenues of this company is regulated, as a natural monopoly.

Due to the quadratic nature of transmission losses, marginal cost pricing results in the transmission company over-recovering the short-run transmission costs, as the payment to generators is lower than the payments by demand centres. One way of dealing with this issue is for the difference to be distributed to the demand centres, but this is not usually done on the basis of marginal pricing. Another way is for this net revenue to be used to remunerate part of the fixed costs, with and the remainder raised through additional surcharges, such as access charges. However, many authors such as Bohn et al. (1984a) emphasise that these charges would have negative effects on the economic efficiency of pricing at the margin.

There is an agreement in the literature on transmission pricing that nodal spot prices are very volatile as the supply of electricity has to be matched instantly with any change in demand, and because of the dependency on the marginal node. Chapter Six of this thesis will illustrate how the sign (positive, negative or zero) and the value for marginal transmission loss depend on the choice of the marginal generator in the system. For

example, marginal transmission losses can be negative, which implies that end-users ought to be paid for an increase in their consumption in a market based on spot prices.

4.4 THE ELECTRICITY TRACING METHOD

In conventional, transported commodities, it is relatively easy to trace a particular shipment to a particular producer or a particular distributor (or even a consumer). Unfortunately this is not the case with electricity, where it is impossible to distinguish between homogenous electrons. Thus, the electricity transmission costs in deregualted market can be considered joint costs, which must be allocated in a fair and efficient manner between the different users of the network. The new method of electricity tracing is an attempt to overcome this problem by its ability to trace the power flows and the losses associated with them, and consequently identify who is responsible for these costs.

This section, which is based on Bialek(1996, 1997, 1998) and Bialek and Kattuman (1999), aims at explaining the method's basic assumption of the Proportional Sharing Rule. The method's matrix formulations are introduced by initially presupposing a network with no transmission losses and then a network with losses. The section ends by presenting the rational for the method in the context of co-operative game theory.

4.4.1 THE PROPORTIONAL SHARING RULE

The main assumption of the tracing method (in both Bialek's and Kirchen's approaches) is that the power travelling through a node (inflows) is proportionally shared by the power leaving the node (outflows). Figure 4.3, below, illustrates this rule.

Figure 4.3: Proportional Sharing Rule

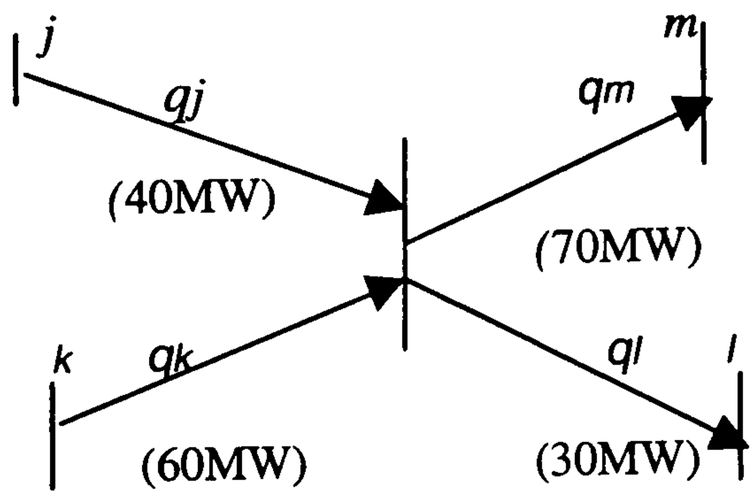


Figure 4.3 shows a segment of the network where four lines are connected to a node denoted *i*. Two of these lines carry inflows of 40 MW (*qj* in line *j-i)*, from generator j, and 60MW (*qk* in line *k-i*), from the generator *k*. The other two lines carry outflows of 70MW (*qm* in line *i-m),* to load *m,* and 30MW (*ql* in line *i-l*), to load *l*. The total inflows through this node are 100MW, 40 per cent of which are supplied by line *j-i* from generator *j* and 60 per cent by line *k-i* from generator *k*.

The rule is then used to apportion the outflows on each line leaving node *i* and supplied to loads *m* and *l*. For example, the 70 MW supplied to load *m* consist of (70x 40)/100 = 28MW from generator *j* through line *j-i* and (70x60)/100 = 42 from generator *k* through the line *k-i*. This could be done in a similar fashion for load *l*. Inversely, the same rule can be applied for generators where, for example, 42 MW (or 70 per cent) of the 60MW produced by generator *k* go to load *m* and the rest goes to load *l*.

Thus, this assumption underlining the PSR means that the tracing method deals with the share of the load (or generator) in transmission flows and costs rather than the impact on them. This is a major feature which needs to be considered in the comparison with the marginal cost pricing. Another distinction is that while the marginal pricing makes both loads and generators pay for their impact on costs, the tracing charges recover these costs either from loads or generators. The only way that both loads and generators can pay is for the total losses to be split by a certain percentage such as 50:50.

4.4.2 THE APPORTIONING OF POWER FLOWS BETWEEN LOADS

This section generalises the PSR, as applied above to individual node, to a network with *n* number of nodes by utilising the network incidence and adjacency matrices (see Appendix B for the derivation of these matrices). This section uses the average line flows (i.e. no losses) to trace where the electricity of a particular demand centre comes from.

The total nodal flow is the sum of inflows (or outflows) through node *i* and takes the symbol P_i (in the sections on tracing method). By considering the inflows, the nodal power flow is expressed as:

$$P_i = \sum_{j \in \alpha_i^{(u)}} \left| P_{i-j} \right| + P_{Gi} \qquad \text{for } i = 1,2,\ldots,n \qquad \text{(Equation 4.18)}$$

where;

$\alpha_i^{(u)}$ is the set of upstream nodes which directly supply node i,

$P_{i\text{-}j}$ is the line flow into node i in line j-i, and

P_{Gi} is the generation at node i.

Since $\left|P_{j-i}\right| = \left|P_{i-j}\right|$, the line flow $\left|P_{i-j}\right| = \left|P_{j-i}\right|$ is related to the nodal flow at node j by substituting $\left|P_{i-j}\right| = c_{ji} P_j$, where $c_{ji} = \left|P_{j-i}\right| / P_j$, and rewriting equation 4.18 such that

$$P_i = \sum_{j \in \alpha_i^{(u)}} c_{ji} P_j + P_{Gi} \qquad \text{(Equation 4.19)}$$

Moving the $\sum_{j \in \alpha_i^{(u)}} c_{ji} P_j$ term to the left-hand-side, gives us:

$$P_i - \sum_{j \in \alpha_i^{(u)}} c_{ji} P_j = P_{Gi} \quad \text{Or} \quad \mathbf{A_u P = P_G} \qquad \text{(Equation 4.20)}$$

where;

$\mathbf{A_u}$ is the $(n \times n)$ upstream distribution matrix,

$\mathbf{P}$ is the vector of nodal through-flows, and

$\mathbf{P_G}$ is the vector of nodal generations.

The matrix $\mathbf{A_u}$ is called upstream because the set $\alpha_i^{(u)}$ corresponds to all nodes which are upstream from node i. The (i,j) element of $\mathbf{A_u}$ is equal to

$$\left[\mathbf{A_u}\right]_{ij} = \begin{cases} 1 & \text{for } i = j \\ -c_{ji} = -\left|P_{j-i}\right| / P_j & \text{for } j \in \alpha_i^{(u)} \\ 0 & \text{otherwise} \end{cases} \qquad \text{(Equation 4.21)}$$

If $\mathbf{A_u^{-1}}$ exists then $\mathbf{P = A_u^{-1} P_G}$ and its i-th element is

$$P_i = \sum_{k=1}^{n} \left[\mathbf{A_u^{-1}}\right]_{ik} P_{Gk} \quad \text{for } i = 1,2,\ldots,n \qquad \text{(Equation 4.22)}$$

This is an important equation as it shows the contribution of the k-th generator to i-th nodal power (i.e. $\left[\mathbf{A}_{\mathbf{u}}^{-1}\right]_{ik} P_{Gk}$). Since P_i is equal to the sum of the load demand (P_{D_i}) and other outflows in lines leaving node i, the proportional sharing rule makes it possible to calculate the outflow in line i-l from node i as

$$|P_{i-l}| = \frac{|P_{i-l}|}{P_i} P_i = \frac{|P_{i-l}|}{P_i} \sum_{k=1}^{n} \left[\mathbf{A}_{\mathbf{u}}^{-1}\right]_{ik} P_{Gk} \quad \text{for all } l \in \alpha_i^{(d)} \qquad \text{(Equation 4.23)}$$

where α_i^d is the set of downstream nodes which are directly supplied from node i.

Similarly, the load demand P_{Di} can be calculated as

$$P_{Di} = \frac{P_{Di}}{P_i} P_i = \frac{P_{Di}}{P_i} \sum_{k=1}^{n} \left[\mathbf{A}_{\mathbf{u}}^{-1}\right]_{ik} P_{Gk} \qquad \text{for } i = 1,2,\ldots,n \qquad \text{(Equation 4.24)}$$

This is an important equation as it shows the contribution of the k-th generator to the i-th load. This contribution is equal to $P_{Di} P_{Gk} \left[\mathbf{A}_{\mathbf{u}}^{-1}\right]_{ik} / P_i$ and is useful in determining where the electricity of a particular load comes from.

4.4.3 THE APPORTIONING OF POWER FLOWS BETWEEN GENERATORS

This section uses the average line flows (i.e. no losses) to trace where the electricity of a particular generator goes to. By considering the outflows, the nodal power flow is expressed as:

$$P_i = \sum_{l \in \alpha_i^{(d)}} |P_{i-l}| + P_{Di} = \sum_{l \in \alpha_i^{(d)}} c_{li} P_l + P_{Di} \qquad \text{for } i = 1,2,\ldots,n \qquad \text{(Equation 4.25)}$$

where $c_{li} = |P_{l-i}| / P_l$.

Rewriting equation 4.25:

$$P_i - \sum_{l \in \alpha_i^{(d)}} c_{li} P_l = P_{Di} \quad \text{or} \quad \mathbf{A_d P = P_D} \qquad \text{(Equation 4.26)}$$

where;

$\mathbf{A_d}$ is the $(n \times n)$ downstream distribution matrix,
$\mathbf{P}$ is the vector of nodal through-flows, and
$\mathbf{P_D}$ is the vector of nodal demands.

The matrix is called downstream because the set $\alpha_i^{(d)}$ contains all nodes which are downstream from node i. The (i,l) element of $\mathbf{A_d}$ is equal to

$$[\mathbf{A_d}]_{il} = \begin{cases} 1 & \text{for } i = l \\ -c_{li} = -|P_{l-i}|/P_l & \text{for } l \in \alpha_i^{(d)} \\ 0 & \text{otherwise} \end{cases} \qquad \text{(Equation 4.27)}$$

Adding $\mathbf{A_u}$ and $\mathbf{A_d}$ gives a symmetric matrix, which has the same structure as the nodal admittance matrix (i.e. the matrix used in load flow solution).

If $\mathbf{A_d^{-1}}$ exists then $\mathbf{P = A_d^{-1} P_D}$ and its i-th element is equal to

$$P_i = \sum_{k=1}^{n} \left[\mathbf{A_d^{-1}}\right]_{ik} P_{Dk} \quad \text{for} \quad i = 1,2,\ldots,n \qquad \text{(Equation 4.28)}$$

This is an important equation as it shows how the nodal power, P_i, is distributed between all the demand centres in the network. Since P_i is equal to the sum of generation at node i and all the inflows in lines entering the node i, the proportional sharing rule makes it possible to calculate the inflow to node i from line i-j *to* node i as

$$|P_{i-j}| = \frac{|P_{i-j}|}{P_i} P_i = \frac{|P_{i-j}|}{P_i} \sum_{k=1}^{n} \left[\mathbf{A_d^{-1}}\right]_{ik} P_{Dk} \quad \text{for all} \quad j \in \alpha_i^{(u)} \qquad \text{(Equation 4.29)}$$

Similarly, the generation P_{Gk} can be calculated as

$$P_{Gi} = \frac{P_{Gi}}{P_i} P_i = \frac{P_{Gi}}{P_i} \sum_{k=1}^{n} \left[\mathbf{A}_{\mathbf{d}}^{-1}\right]_{ik} P_{Dk} \quad \text{for} \quad i = 1,2,\ldots,n \qquad \text{(Equation 4.30)}$$

This is an important equation as it shows the share of the i-th generator output which is used to supply the k-th load demand. This share is equal to $P_{Gi} P_{Dk} \left[\mathbf{A}_{\mathbf{d}}^{-1}\right]_{ik} / P_i$ and is useful in determining where the electricity of a particular generator goes to.

By considering both equation 4.24 and 4.30, we have

$$\frac{P_{Di} P_{Gk} \left[\mathbf{A}_{\mathbf{u}}^{-1}\right]_{ik}}{P_i} = \frac{P_{Gk} P_{Di} \left[\mathbf{A}_{\mathbf{d}}^{-1}\right]_{ki}}{P_k} \quad \text{or} \quad \frac{\left[\mathbf{A}_{\mathbf{u}}^{-1}\right]_{ik}}{\left[\mathbf{A}_{\mathbf{d}}^{-1}\right]_{ki}} = \frac{P_i}{P_k} \qquad \text{(Equation 4.31)}$$

The network has n nodes where each node could have a generation, load or both. Thus, assuming that there is n_g generators and n_l loads in the system, it is necessary to determine $n_g n_l$ elements of matrix $\mathbf{A}_{\mathbf{u}}^{-1}$ or $\mathbf{A}_{\mathbf{d}}^{-1}$.

4.4.4 ALLOCATION OF LOSSES TO LOADS

This section provides the allocation of the transmission losses to loads. This requires modifying the section 4.4.2 to include losses by assuming that the network is fed with the actual generation. This also assumes that there is no power is lost in transmission which implies that the nodal power at each node is adjusted upwards (i.e. to include losses over upstream lines). Thus, the unknown gross nodal power at node i is $P_i^{(gross)}$ and the unknown gross flow in the line i-j entering this node is $P_{i-j}^{(gross)}$.

Since $\left|P_{i-j}^{(gross)}\right| = \left|P_{j-i}^{(gross)}\right|$, the gross nodal power can be expressed as

$$P_i^{(gross)} = \sum_{j \in \alpha_i^{(u)}} \left|P_{i-j}^{(gross)}\right| + P_{Gi} \quad \text{for } i = 1,2,\ldots,n \qquad \text{(Equation 4.32)}$$

And since $c_{ji}^{(gross)} = \left|P_{j-i}^{(gross)}\right| / P_j^{(gross)}$, the flow $P_{i-j}^{(gross)}$ can be replaced by $c_{ji}^{(gross)} P_j^{(gross)}$.

The only approximating assumption of the method is that $\left|P_{j-i}^{(gross)}\right| / P_j^{(gross)} \cong \left|P_{j-i}\right| / P_j$ where $P_{j\text{-}i}$ is the actual flow from node j in line j-i and P_j is the actual total flow through node j. This assumption implies that the distribution of gross flows at any node is the same as the distribution of actual flows. Hence, equation 4.32 can be re-written as

$$P_i^{(gross)} - \sum_{j \in \alpha_i^{(u)}} \frac{\left|P_{j-i}\right|}{P_j} P_j^{(gross)} = P_{Gi}$$

$$\text{or} \qquad \mathbf{A_u P_{gross}} = \mathbf{P_G} \qquad \text{(Equation 4.33)}$$

where;

$\mathbf{A_u}$ is the upstream distribution matrix calculated from the actual flows,

$\mathbf{P_{gross}}$ is the unknown vector of gross nodal flows, and

$\mathbf{P_G}$ is the vector of the actual nodal generations.

Since $\mathbf{A_u}$ and $\mathbf{P_G}$ are known, solving equation 4.33 will give the unknown gross nodal flows, $\mathbf{P_{gross}}$. As a result, the proportional sharing principle can be used to determine the contribution of generators in the gross line flows and gross loads.

Hence, the gross outflow from node i in line i-l is

$$\left|P_{i-l}^{(gross)}\right| = \frac{\left|P_{i-l}^{(gross)}\right|}{P_i^{(gross)}} P_i^{(gross)} \cong \frac{\left|P_{i-l}\right|}{P_i} \sum_{k=1}^{n} \left[\mathbf{A_u^{-1}}\right]_{ik} P_{Gk} \qquad \text{for all } l \in \alpha_i^{(d)} \qquad \text{(Equation 4.34)}$$

and the gross demand at node i is

$$P_{Di}^{(gross)} = \frac{P_{Di}^{(gross)}}{P_i^{(gross)}} P_i^{(gross)} \cong \frac{P_{Di}}{P_i} P_i^{(gross)} = \frac{P_{Di}}{P_i} \sum_{k=1}^{n} \left[\mathbf{A_u^{-1}}\right]_{ik} P_{Gk} \qquad \text{(Equation 4.35)}$$

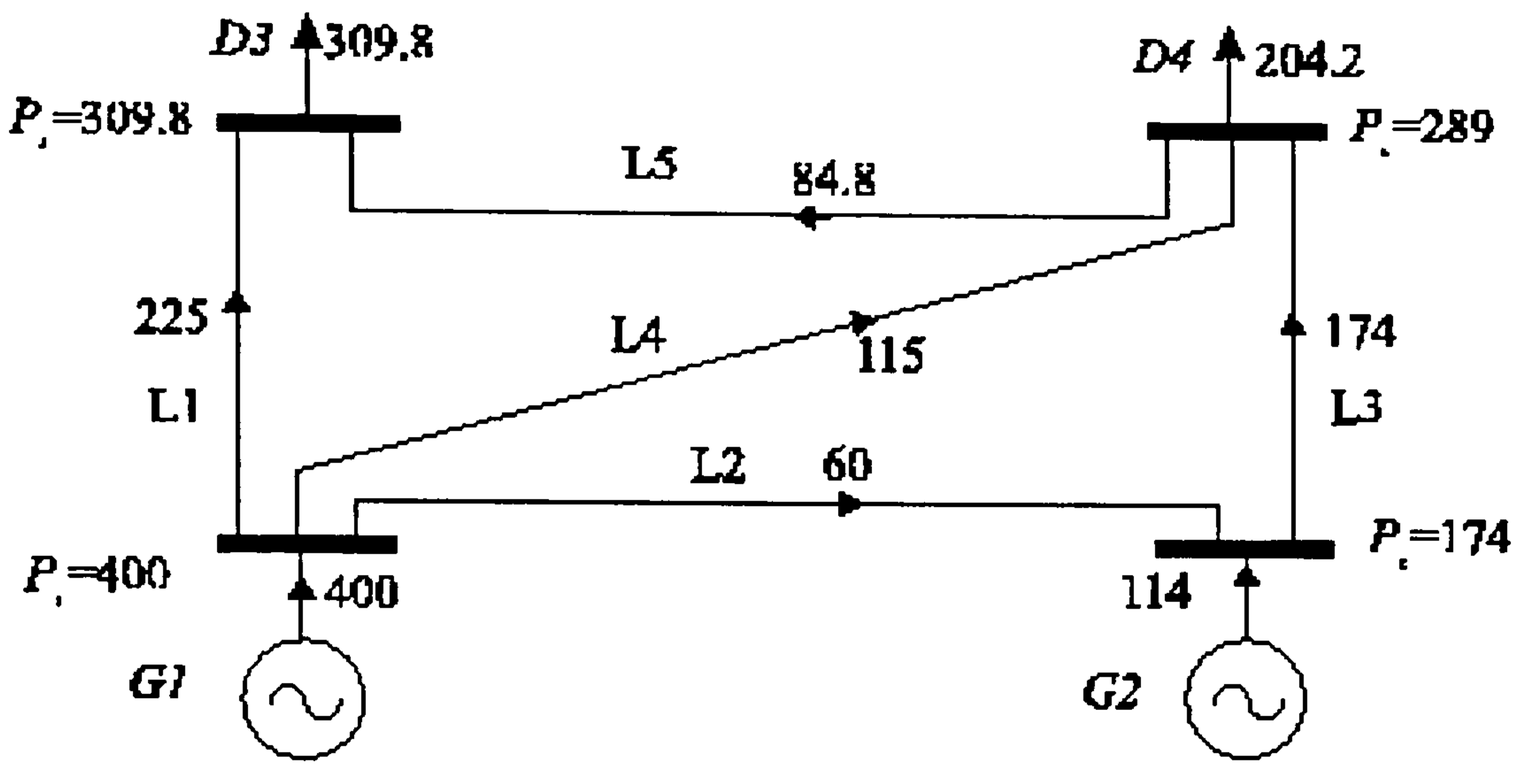
The importance of this equation is that it shows what would be the gross load at a given node if the network were fed with the actual generation.

Consequently, the losses allocated to the load at node i are the difference between the gross demand and the actual demand at this node such that

$$\Delta P_{Di} = P_{Di}^{(gross)} - P_{Di} \qquad \text{(Equation 4.36)}$$

The following figure, Figure 4.4, is a numerical example for applying the method to a network with gross flows.

Figure 4.4: A Network with Gross Power Flows



The following equation, equation 4.37, is constructed on the basis of Figure 4.4 and equation 4.33.

$$\begin{bmatrix} 1 & 0 & 0 & 0 \\ -60/400 & 1 & 0 & 0 \\ -225/400 & 0 & 1 & -83/283 \\ -115/400 & -173/173 & 0 & 1 \end{bmatrix} \begin{bmatrix} P_1^{(gross)} \\ P_2^{(gross)} \\ P_3^{(gross)} \\ P_4^{(gross)} \end{bmatrix} = \begin{bmatrix} P_{G1} = 400 \\ P_{G2} = 114 \\ 0 \\ 0 \end{bmatrix} \qquad \text{(Equation 4.37)}$$

Solving this equation gives the following values of gross nodal powers:

$\mathbf{P}_{\mathbf{gross}} = [400 \;\; 174 \;\; 309.8 \;\; 289]^T$.

The share of actual demand in actual nodal power flow is equal to the share of gross demand in gross nodal power flow. And since the actual demand at node 3 and node 4 is

300MW and 200MW, respectively, the gross load demands at these two nodes are simply calculated as

$D_3^{(gross)}$ = (300/300)×309.8 = 309.8MW, and

$D_4^{(gross)}$ = 289x(200/283) = 204.2MW

Hence, by applying equation 4.36, the loss apportioned to D_3 is equal to 9.8MW while the loss apportioned to D_4 is 4.2MW.

Since $\mathbf{A}_u^{-1} = \begin{bmatrix} 1 & 0 & 0 & 0 \\ 0.15 & 1 & 0 & 0 \\ 0.6907 & 0.293 & 1 & 0.293 \\ 0.4375 & 1 & 0 & 1 \end{bmatrix}$,

and applying Equation 4.35 and the usage of $\mathbf{A}_u^{-1}$ relevant elements makes it possible to show where the power supplied to each load comes from. For example, D3 receives from G1 (gross) load equal $(300/300)\times 0.6907\times 400 = 276.3$MW. which is multiplying the share of actual demand of D3 in power flow at node 3 by (3,1) element of $\mathbf{A}_u^{-1}$ by the generation at node 1. The following table, Table 4.1, summarises these results.

Table 4.1 Allocation of Losses to Loads

Generators	Loads		Total
	D3	D4	
G1	276.3	123.7	400
G2	33.5	80.5	114
Total	309.8	204.2	514
Loss	9.8	4.2	14

4.4.5 ALLOCATION OF LOSSES TO GENERATORS

This section provides the allocation of the transmission losses to generations. This requires modifying the section 4.4.3 by assuming that the transmission losses are completely removed from the line flows. This also assumes that there is no power is lost in transmission which implies that the nodal power at each node is adjusted downwards without violating the Kirchhoff's Current Law. Hence, the unknown net nodal power at

node i is $P_i^{(net)}$ and the unknown net flow in the line i-j entering this node is $P_{i-j}^{(net)}$. Similar to the process of using the gross flows in the algorithm in section 4.4.4, this section uses the net flows instead.

Since $\left|P_{i-j}^{(net)}\right| = \left|P_{j-i}^{(net)}\right|$, the net node power balance equation can be expressed, when looking at the outflows as

$$P_i^{(net)} = \sum_{l \in \alpha_i^{(d)}} \left|P_{i-l}^{(net)}\right| + P_{Di} = \sum_{l \in \alpha_i^{(d)}} c_{li}^{(net)} P_l^{(net)} + P_{Di} \quad \text{for} \quad i = 1,2,\ldots,n \quad \text{(Equation 4.38)}$$

where $c_{li}^{(net)} = \left|P_{l-i}^{(net)}\right| / P_l^{(net)}$.

As the transmission losses are small, it can be assumed that $\left|P_{l-i}^{(net)}\right| / P_l^{(net)} \cong \left|P_{l-i}\right| / P_l$ so that equation 4.38 can be re-written as

$$P_i^{(net)} - \sum_{l \in \alpha_i^{(d)}} \frac{\left|P_{l-i}\right|}{P_l} P_l^{(net)} = P_{Di}$$

$$\text{or} \quad \mathbf{A_d P_{net} = P_D} \qquad \text{(Equation 4.39)}$$

where;

$\mathbf{P_{net}}$ is the unknown vector of net nodal flows,

$\mathbf{A_d}$ is the downstream distribution matrix, and

$\mathbf{P_D}$ is the vector of the actual nodal demand

Since $\mathbf{A_d}$ and $\mathbf{P_D}$ are known, solving equation 4.39 will give the unknown net nodal flows, $\mathbf{P_{net}}$. Using the proportional sharing rule, the net inflow to node i in line i-j can now be calculated as

$$\left|P_{i-j}^{(net)}\right| = \frac{\left|P_{i-j}^{(net)}\right|}{P_i^{(net)}} P_i^{(net)} \cong \frac{\left|P_{i-j}\right|}{P_i} \sum_{k=1}^{n} \left[\mathbf{A_d^{-1}}\right]_{ik} P_{Dk} \quad \text{for all} \quad j \in \alpha_i^{(u)} \qquad \text{(Equation 4.40)}$$

while the net generation at node i can be calculated as

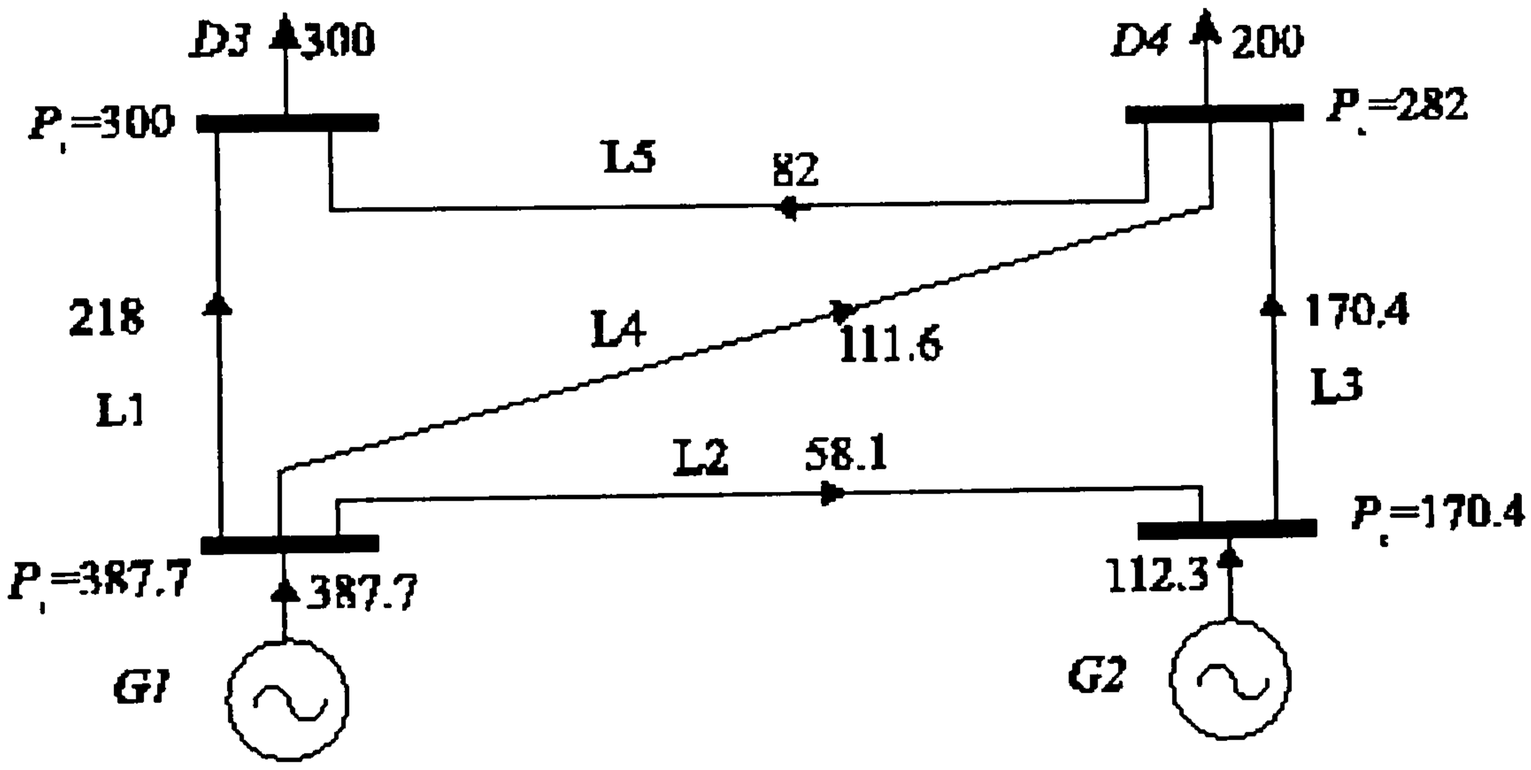
$$P_{Gi}^{(net)} = \frac{P_{Gi}^{(net)}}{P_i^{(net)}} P_i^{(net)} \cong \frac{P_{Gi}}{P_i} P_i^{(net)} = \frac{P_{Gi}}{P_i} \sum_{k=1}^{n} \left[\mathbf{A}_{\mathbf{d}}^{-1}\right]_{ik} P_{Dk} \qquad \text{(Equation 4.41)}$$

The importance of this equation is that it shows what would be the net generation at a given node necessary to cover the system demand if we assume the network without any power lost. Thus, the losses allocated to the generator at node i are the difference between the actual and the net generation

$$\Delta P_{Gi} = P_{Gi} - P_{Gi}^{(net)} \qquad \text{(Equation 4.42)}$$

at this node. The following figure, Figure 4.5, is a numerical example for applying the method to a network with net flows.

Figure 4.5: A Network with Net Power Flows



The following equation, equation 4.43, is constructed on the basis of Figure 4.5 and equation 4.39.

$$\begin{bmatrix} 1 & -59/173 & -218/300 & -112/283 \\ 0 & 1 & 0 & -171/283 \\ 0 & 0 & 1 & 0 \\ 0 & 0 & -82/300 & 1 \end{bmatrix} \begin{bmatrix} P_1^{(net)} \\ P_2^{(net)} \\ P_3^{(net)} \\ P_4^{(net)} \end{bmatrix} = \begin{bmatrix} 0 \\ 0 \\ P_{D3} = 300 \\ P_{D4} = 200 \end{bmatrix} \qquad \text{(Equation 4.43)}$$

Solving equation 4.43 gives the vector of net nodal flows:

$\mathbf{P}_{net} = [387.7 \;\; 170.4 \;\; 300 \;\; 282]^T$.

The share of actual generation in actual nodal power flow is equal to the share of net generation in net nodal power flow. And since the actual generation at node 1 and node 2 is 400MW and 114MW, respectively, the net generations at these two nodes are simply calculated as

$G_1^{(net)} = (400/400)\times 387.72 = 387.7$ and

$G_2^{(net)} = (114/173)\times 170.4 = 112.3$.

Hence, by applying equation 4.42, the loss apportioned to G_1 is equal to 12.3MW while the loss apportioned to G_2 is 1.7MW.

Since $\mathbf{A}_d^{-1} = \begin{bmatrix} 1 & 0.341 & 0.8909 & 0.6017 \\ 0 & 1 & 0.1648 & 0.604 \\ 0 & 0 & 1 & 0 \\ 0 & 0 & 0.273 & 1 \end{bmatrix}$,

and applying equation 4.41 and the usage of $\mathbf{A}_d^{-1}$ relevant elements makes it possible to show where the power produced by each generator goes to. For example, G1 supplies D3 with (net) power equal $(400/400)\times 0.8909\times 300 = 267.4$MW. Which is multiplying the share of actual generation of G1 in power flow at node 1 by (1,3) element of $\mathbf{A}_d^{-1}$ by the demand at node 3. It is worth noting that the amount supplied from G1 to D3 of 267.4 is less than one shown in Table 4.1 because in the former case net rather than gross flows are used. The following table, Table 4.2, summarises these results.

Table 4.2 Allocation of Losses to Generators

Loads	Generators		Total
	G1	G2	
D3	267.4	32.6	300
D4	120.3	79.7	200
Total	387.7	112.3	500
Loss	12.3	1.7	14

4.4.6 THE PSR AND CO-OPERATIVE GAME THEORY

The usage of co-operative game theory is common in the context of joint cost allocation problems, such as in the cases investigated in Littlechild (1970) for telecommunication industry and Young (1994) for roads and dams projects among others. The previous sections have demonstrated the centrality of the Proportional Sharing Rule in the recovery of transmission losses as joint costs. This rule is fair as it does not discriminate against any particular nodal inflow or outflow, which makes it acceptable by the generators (or loads). This aspect of the tracing method is examined, within the framework of co-operative game theory, in Bialek and Kattuman (1999), who showed that this rule leads to a cost allocation solution that meets the relevant requirements for an equilibrium. This examination is summarised in this section.

As shown in Figure 4.3, the PSR treats all inflows equally with respect to outflows by considering node *i* as a perfect mixer of flows. This means that each MW of inflows has an equal chance of flowing to each line leaving this node. In this example, the flow in *i-m* (as well as the flow in *i-l*) consists of a share (*qj/q*) from the inflow from *j-i* and a share (*qk/q*) from the inflow from *k-i*. The quadratic function of losses means that loss per MW is much higher in line *i-m* than in line *i-l*. If generator *k* is assumed to supply most of its output to line *i-l*, it will be expected to bear a much lower loss charge than if it is assumed to supply most of its output to line *i-m*. Thus, it is necessary that all generators are willing to co-operate in the assignment of these joint costs and they find it advantageous to accept it.

4.4.6.1 THE COST ALLOCATION GAME

The aim of this section is to define the appropriate game for examining the proportionality assumption. A general cost allocation game, represented in characteristic function form, is a pair (N,c), where $N:=\{1,2,\ldots,n\}$ is the set of participants and c is a cost function called the characteristic function. The symbol N can be thought of as the set of generators, but it is possible to consider it as the set of MWs that flow through the node. The characteristic function (c) specifies the minimal cost that will be assigned for each possible coalition of players arranging matters to suit its members.

Coalitions are one of the main aspects of co-operative games that are central to the determination of the solution. While it is reasonable to assume that each player will compare any proposed allocation with the pay-off it can obtain by working alone, any group of players may also find that they can do better for themselves by co-operating only among themselves and excluding others from the arrangement. With respect to each coalition possible, these players can be expected to hold out for their worth, that is for what they can bring to the coalition. The prospect of this coalition formation must be respected by the solution of the game. Thus, the worth of any player, which is the share it can be expected to get in the game as a whole, must have some relation to its worth to all possible coalitions.

As each subset of $\{1,...,R\}$ is a potential coalition, there are 2^R coalitions and the cost function (c) attaches a real number to each one of them. If an allocation is such that no coalition can do better by themselves, the allocation can be considered a good candidate to be in the core of the game and hence acceptable by all players.

In the case of transmission loss allocation, these players (or MWs) could be labelled. For example, the lth unit of power generated by the generator j is labelled as jl and the output of this generator can be denoted by the set $\{jl\}$, where l runs over natural numbers from 1 up to and including M, if j generates M units of power (MW).

Assuming that there is only one line leaving node i in Figure 4.3, instead of two. In this case, an alternative labelling system is used to refer to the players, by considering a one-to-one mapping from the set of MWs flowing through the node to the set of natural numbers, running from 1 to R. It is worth noting that these numbers are just labels, which makes it possible to consider the flow from the node to the outflow line as a process whereby players are 'toted up' as fed to the line, one at a time, in the order in which they have been labelled, 1 to R. Hence, each MW is charged with the incremental transmission loss when it joins its predecessors in the outflow line. With a convex cost function, this charge is unfair as it depends on the order in which players are entering the line. Although this procedure is efficient, it needs adjustment to ensure fair treatment to all players.

4.4.6.2 THE SHAPLEY VALUE

The Shapley value is an acceptable solution because it has a stable (unique) set equilibrium and hence it lies in the core of the game. So, as no coalition can do better, the allocation will be acceptable to all players. The cost allocation in this case is symmetric, monotonic and additive. The Shapley value looks at the game on the basis of the characteristic function alone rather than the identity of the players. It also captures the idea that the worth of an individual player is the average of his worth in all possible coalitions. In this context of the co-operative game, each coalition is considered to be one permutation of the possible ordered set of players that can be accounted to have increased the flow (and loss) in the line. With a convex loss function, fair treatment of the players requires the consideration of all possible orders which are equally likely.

Each $\pi \in \Pi_R$ can be thought of as a coalition, where π is a permutation of the set $\{1,...,R\}$, with the players accounted as flowing out in the sequence $\pi(1), \pi(2), ..., \pi(R)$. Also, each $i \in \{1,...R\}$, can be considered as determining its worth relative to permutation π, based on its marginal cost when the accounting is done in this order.

The marginal cost vector relating to permutation π is given by:

$$m_i^{\pi}(c) \equiv c\left(P(\pi,i)\mathrm{Y}\{i\}\right) - c\left(P(\pi,i)\right) \qquad \text{(Equation 4.41)}$$

where $P(.)$, in this section only, is the set of predecessors of i with respect to π,
$P(\pi,i) \equiv \left\{ j \in \{1,\ldots,R\} \middle| \pi(j) < \pi(i) \right\}$.

Marginal cost is increasing in the number of predecessors, |P|, or more precisely:

$$m_i^{\pi}(c) = r(((|P+1|)^2 - (|P|)^2) \qquad \text{(Equation 4.42)}$$

This means that i places highest value on that permutation where it is the first to be accounted to flow out, as this allocates the smallest marginal transmission loss. The set of all possible permutations of $\{1,...,R\}$ is denoted by Π_R .

The Shapley value of the game is defined by

$$\phi(c) \equiv \frac{1}{R!} \sum_{\pi \in \Pi_R} \sum_{i \in \{1,...R\}} m_i^{\pi}(c) = \frac{1}{R!} \sum_{\pi \in \Pi_R} \sum_{i \in \{1,...,R\}} (c(P(\pi,i) \cup \{i\}) - c(P(\pi,i)))$$ (Equation 4.43)

This value represents the average of the additive marginal vectors of the game. The symmetric property of the Shapley value means that it is consistent in treating all players equally. The monotonicity property ensures that transmission charges are non-negative and that they do not fall with the increase in generation, which means that the charges to each player are proportional to its costs. As a result, this value allocates to each MW of power generated by each generator its fair share in total transmission losses. The additivity property is more relevant when the charges need to be decomposed into their components.

Finally, the discussion should be extended to include the case where there is more then one line leaving node *i* as illustrated in Figure 4.3. With a convex loss function, allocating to any generator a larger share of the power flow in a line that carries more power than others will attribute to it a much larger share of transmission loss, which would be unfair. The outflow from the node to the different lines can be, in a notional manner, 'toted up', MW by MW, in the order in which they have been labelled, 1 to *R*. This process can be done by having successively numbered MWs which are accounted for as fed to different lines, till all inflows have been disbursed. Another scenario is that these MWs are accounted for as fed through in blocks to a line till its power flow target is met, before the next line is fed, and so on, until all inflows are accounted for. The Shapley value considers equally all possible permutations of the set {1,...R}. If each has the same probability (1/R!), this implies that each MW has equal probability of leaving the node on any of the outflow lines. In short, the PSR is implicit in the determination of the Shapley value, which justifies it on the grounds of co-operative game theory.

CONCLUSION

The transformation of the electricity industry into a decentralised structure has highlighted the need to rethink the means by which are generation and transmission segments are co-ordinated. This co-ordination can be achieved through a price mechanism that should lead to efficient outcomes. The close link between transmission and generation means that the design of good transmission pricing schemes has to incorporate the appropriate costs of both, otherwise the incentives for efficient use and development of the system are distorted. Thus, the unbundling of the industry and the introduction of competition have put the issue of transmission pricing at the heart of the restructuring and privatisation process. As a result, this evolution has focused the debate on the very critical issue of selecting the correct transmission pricing method.

This chapter has explained how the traditional pricing methods such as the contract path and the postage stamp are no longer keeping up with, and are ill suited to, the changes in the industry. It has also presented the theory of transmission pricing which finds its roots in the well-established marginal analysis, specifically in the marginal cost pricing of a multi-plant firm with transportation costs. The marginal method has shown its advantage of incorporating the laws of physics governing electricity with the principles of economics guiding efficient markets. However, in addition to the complexity of its assumptions, there are some obstacles that diminish the usefulness of the method in a decentralised structure. For example, full implementation of the method requires very detailed data, which cannot be sufficiently available to the system operators without commercially sensitive information being compromised.

The chapter has also reviewed the electricity tracing method and its assumptions as well as demonstrated, in considerable details, its linear algebraic foundations. In addition to being mathematically sound, the method is simple and transparent with very limited data requirements. The economic efficiency of the method is an open question, but this research study aims at exploring this issue empirically in the following chapters.

CHAPTER FIVE
The Tracing Allocations of Variable Costs (Losses) of Transmission

5.1 INTRODUCTION

Regardless of the structure and the institutional arrangement of an electricity industry, the laws of physics governing electricity remain the same. This is especially the case with transmission losses, which occur as a result of transporting power from generation sources to loads (demand centres). The longer the distance between generators and demand centres in a network, the higher the energy losses on its transmission lines. So transmission losses must be accounted for and allocated fairly among the different users of the system.

The unique nature of electricity makes it impossible to determine physically which generator's output is supplied to a particular load. What complicates this transportation problem even further is that additional power produced or consumed at a node instantly affects the flows for the other nodes in the network. Thus, it has been difficult to develop any transmission pricing rule that not only economically efficient but also simple, fair and transparent.

The method of electricity tracing is able to apportion the power flow and consequently the transmission costs between the network's users. This chapter illustrates the allocation of the variable costs[3] (i.e. losses) by applying the tracing method to real transmission data. A general description of these data is presented in section 5.2; section 5.3 shows the allocation of these costs to the 109 demand centres, while section 5.4 shows the allocations to the 16 generators in the network.

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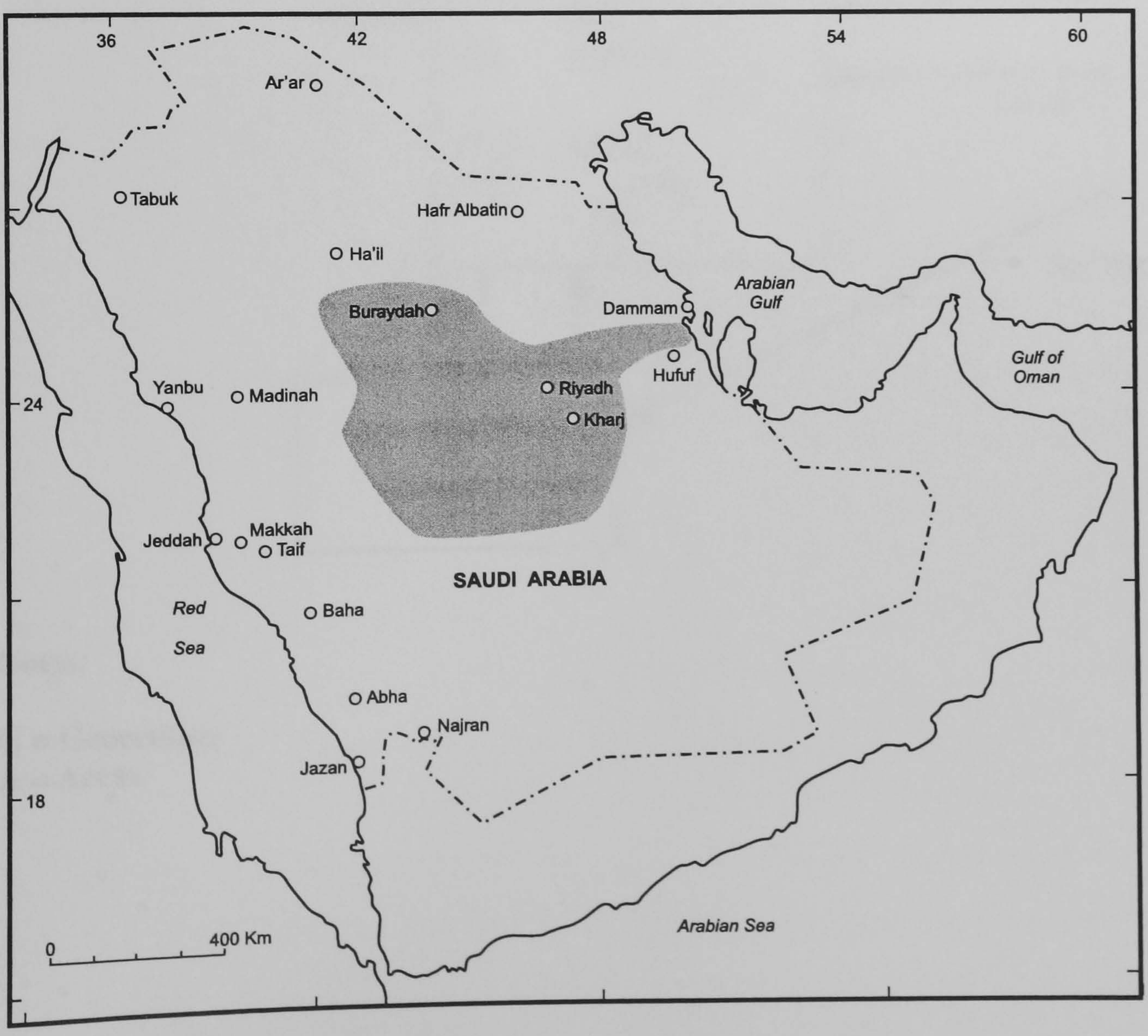
[3] Due to the non-existence of line congestion, this thesis concentrates on transmission losses as the variable costs. The allocation of fixed costs will be dealt with in Chapter Eight.

5.2 THE MATHEMATICAL PACKAGE AND DATA USED

The allocation of transmission costs using the tracing method is based on the formulation of incidence and adjacency matrices and the use of linear algebra tools (see Appendix B). Thus, it is fitting to use mathematical package software such as Gauss or MATLAB (Matrix Laboratory), which are specially designed packages for numerical computations. The availability of the MATLAB package was the factor determining its usage, in this thesis, for obtaining the tracing results.

This chapter uses the output data from the Load Flow Program (LFP) of the Saudi Consolidated Electricity Corporation in the central province (SCECO-Central). This program contains detailed information about the company's connected high voltage transmission lines of 380kV, 230kV and 132kV. These 215 double-circuit lines, which link 151 nodes that include 109 loads and 16 generators. The areas of this network, which are included in the company's LFP, are presented by the shaded region as shown in Figure 5.1.

Figure 5.1: The Network Included in LFP Results



The LFP divide the network into six areas: the capital Riyadh (A1) and its suburbs, the part of the eastern region (A2) which exports power to the central region, the Qassim region (A3), the Kharj region (A4), rural areas outside Riyadh (A5) and the Dwadmi region (A6). The topological links between these six areas are shown in Figure 5.2. The figure also illustrates the geographical positions of the 16 generators of the network.

Figure 5.2: Transmission Network Connecting the Six Areas (numbers in MW)

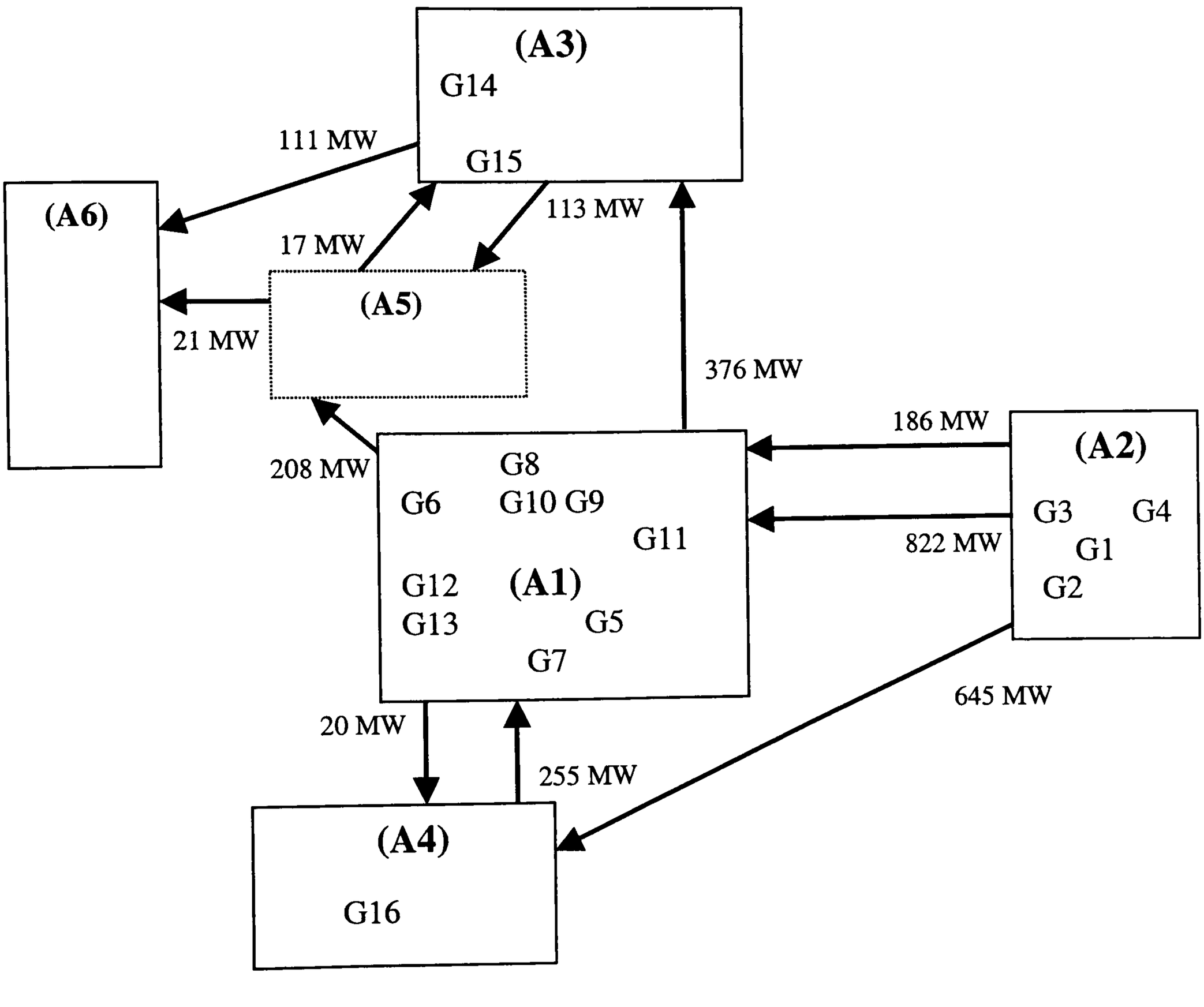


Table 5.1shows the generation, demand and imported power for each one of these areas.

Table 5.1: Peak Generations and Loads for SCECO-Central in1998

Network Areas	Generation		Load		Imports
	MW	%	MW	%	MW
A1: Riyadh-City	3995	62.2	4405	70	-410
A2: Eastern*	1787.7	27.8	117.8	1.8	1669.9
A3: Qassim	535	8.3	890.3	14	-355.3
A4: Kharj	101	1.6	499.2	7.8	-398.2
A5: R-Rural	0	0	277.6	4.4	-277.6
A6: Dawadmi	0	0	130.7	2	-130.7
Total	6418.7		6320.5		98

Source: SCECO-Central, Load Flow Program (3.15 p.m., 9 June 1998)
* part of SCECO-Eastern's network

The table clearly demonstrates the concentration of most of the system in area A1, which is the capital city, Riyadh. This area has 70 per cent of the demand and 62.2 per cent of the generation, including the generation capacity imported from the eastern province (A2) which requires additional power to satisfy 410 MW or 9.3 per cent of its load. The table also shows that all the areas (except A2) are net importers of electricity, which indicates the importance of transmission for this network. The total for the last column is 98 MW which is the total transmission losses over for this network or about 1.5 per cent of generation at the peak hour.

This is a relatively low percentage in comparison with the usual percentage for international systems, which in developed countries is in the range of 2 to 5 per cent. This low percentage in the case of SCECO-Central is due to the over-capacity in transmission that resulted from the availability of government funds during the oil boom of the 1970s and through the 1980s. While this may have created a modern transmission system, it may also have resulted in an over-investment in transmission and inefficient planning. Obviously, this is not expected to persist as the industry is entering into the privatisation stage. At any rate, these losses are costly if we consider that they are roughly equal to the amount of electricity generated by the sixteenth generator (G16) with 101 MW and even twice the electricity produced by the seventh generator (G7) with 50 MW. The significance of these costs is even greater as these two generators have the highest genertion costs in the system and hence are supplying the power needed to meet the additional demand during peak periods.

It is not expected that there would be line flows (and thus losses) on all lines, as that depends on the role of each line in terms of linking generators to demand centres. This network contains 215 transmission lines but naturally the flows, and thus the losses, on each line are not the same. This means that the users of lines with higher flows and losses (implying higher capacity) are expected to have a higher share in the overall system costs than the users of less costly lines. The following figure illustrates the relation between the number of the transmission lines and losses on them.

Figure 5.3: Losses on the Transmission Lines

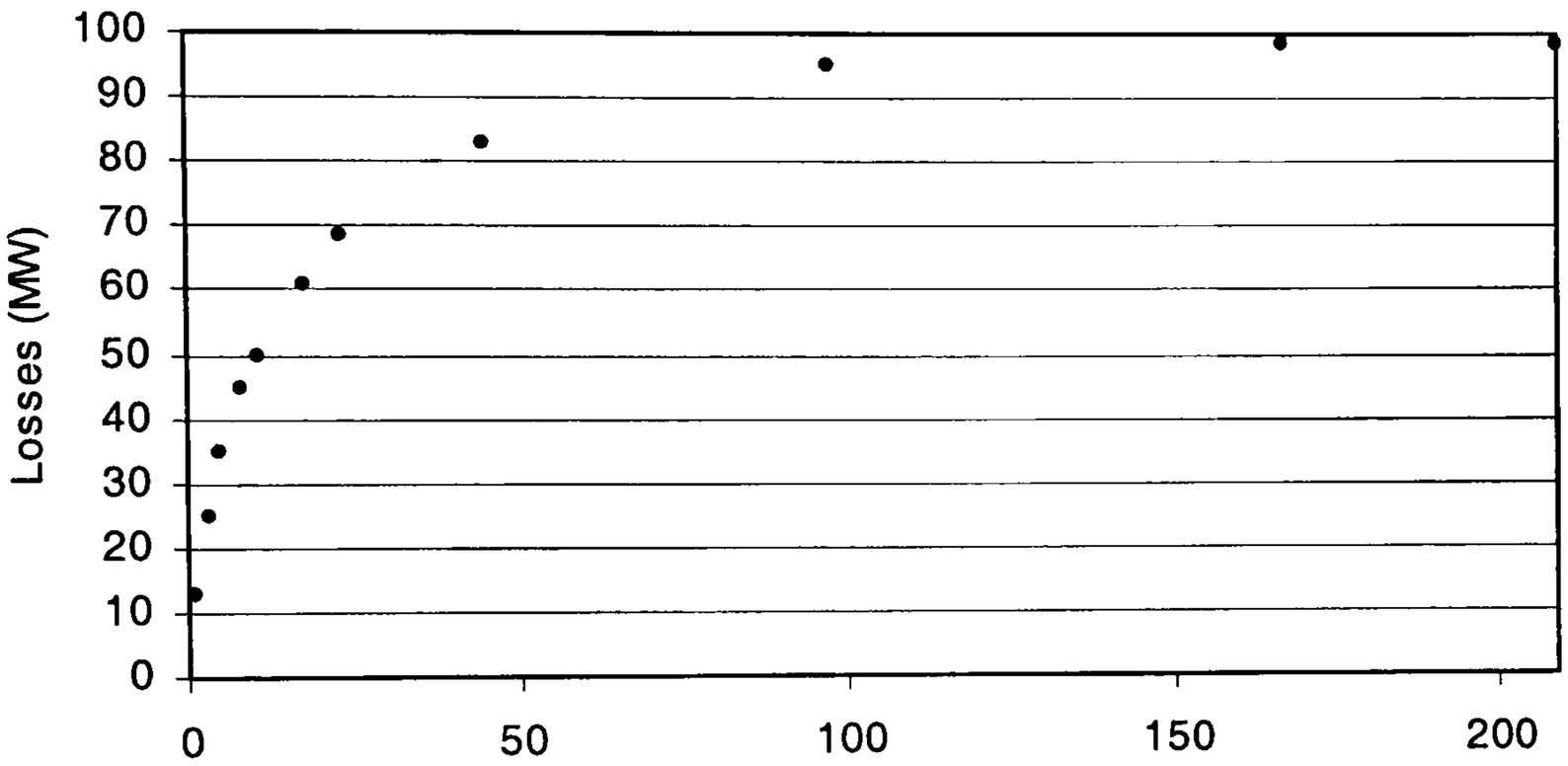
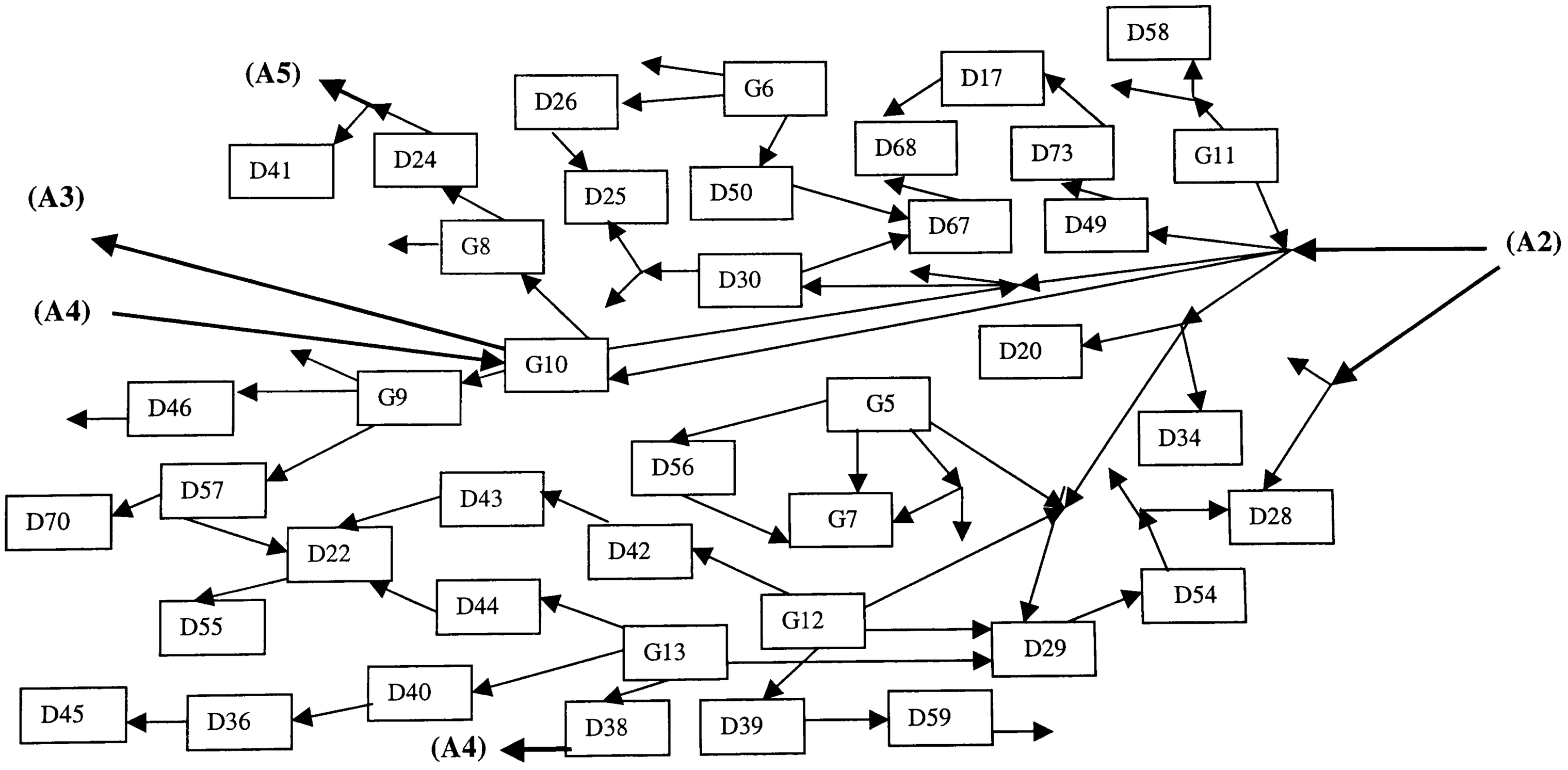


Figure 5.3 shows that most of the losses (68 MW) of this network result from the power flowing over a limited number of lines (23), which account for only 11 per cent of the total number of lines. The explanation for this is that these losses occur on lines with high power flow such as the interconnecting lines (i.e. tie-lines) between the six areas. In addition, the concentration of generation (62.2 per cent) and demand (70 per cent) in A1 means that a large number of lines are used to supply this demand. Figure 5.4, below, is a simplified version of the actual network in A1 but reasonably illustrates both the proximity of generation and load centres to each other as well as the link of this area with outside sources of generation. Figure 5.4 shows that the lines in this area are relatively short. Consequently have lower losses than losses over the tie-lines which are long and transmit a large volume of power.

Figure 5.4: The Transmission Network in Area 1



The high density of this network as in the case of area A1 contributes to this discrepancy as what affects losses is net power flow; that is, the more demand centres there are sharing a line the more its losses are reduced than increased. Thus, having more demand centres sharing the same lines results in lower losses in area A1 despite its being the largest area in terms of demand. In addition, the generators in this area have benefited for a long time from below international fuel prices. This has resulted in generators locating near demand centres, which has also reduced losses on most of these lines. This is expected to change as the industry becomes more market oriented and less dependent on subsidisation, with the result that more private generators will have the incentive to locate in cheap fuel areas in the eastern region of the country.

5.3 ALLOCATION OF TRANSMISSION COSTS TO LOADS

5.3.1 THE RATIONALE FOR CHARGING LOADS

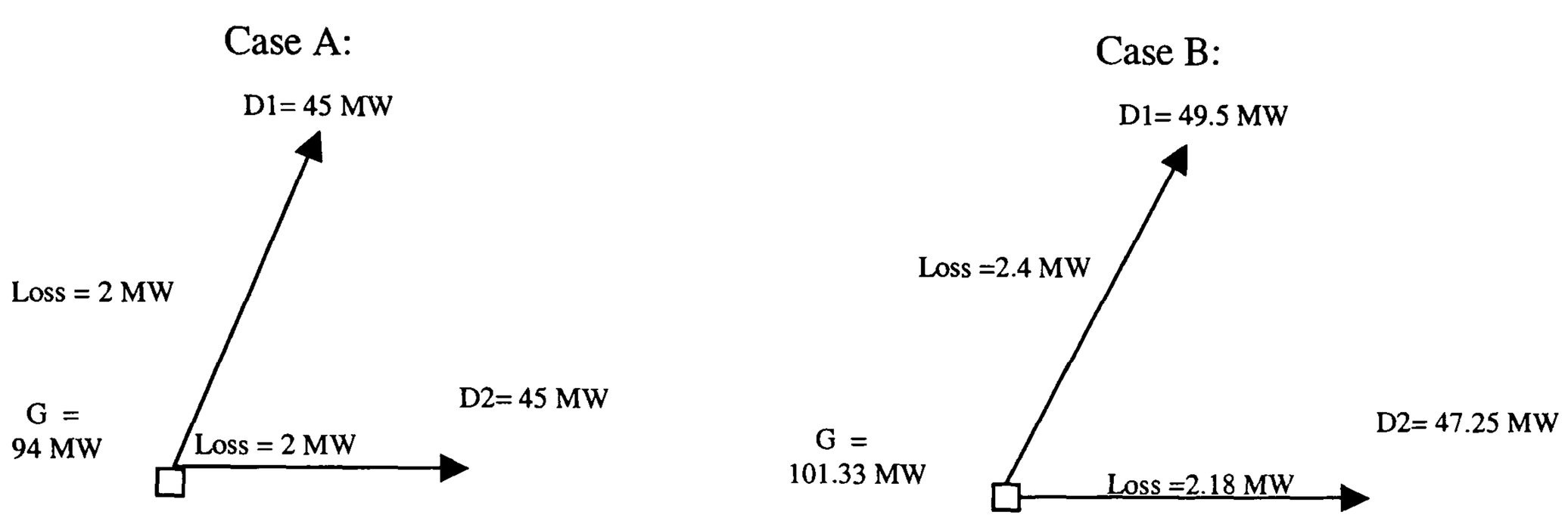
A society is considered inefficient when using its scarce resources if costs are not reflected in prices. In the case of electricity, the price of one MW at a consumption point should reflect not only the cost of producing it but also the cost of receiving it at that point. When transmission losses are ignored, the market price of electricity is lower than the socially optimal price. Therefore, this commodity, from a social point of view, is overproduced and the allocation of resources is inefficient.

The extent of the losses depend on the net power flows on the lines, which means that the addition of demand at a line will reduce the net flow and losses. As a result, the location of loads, especially of large consumers, has impact on transmission costs and hence charges. The reduction in unnecessary transmission losses results in productive efficiency by saving in generation costs, as the generation capacity for the system is normally designed to cover both demand and losses.

The transmission costs are not only affected by where the consumption occurs but, equally as important, by when it occurs. At peak hour, one MW costs more to transmitted than at an off-peak because it is given a higher value due to a higher marginal generation cost (λ) and can be associated with line constraints, which occur at peak rather than off-peak times. Thus, these losses during peak time can be avoided when some loads are encouraged to

alter their consumption pattern. The following example, in Figure 5.2, illustrates how any change in demand has a direct impact on the generation costs due to the change in transmission costs

Figure 5.5: Impact of Changes in Demand on Generation and Transmission Costs



(Assumption: Line Resistance coefficient (r) = .001)

Figure 5.5 illustrates the impact of an increase in demand on line losses. This impact is a direct result of the quadratic relationship between line losses and the power flows on the line. Assuming that the line resistance is 0.001 per unit (p.u.), the increase in demand at D1 by 10 per cent (or 4.5 MW) causes the losses on the transmission line to increase by a higher rate of 20 per cent. Since both nodes are the same distance from the generation source (G), the impact on the transmission losses is due only to the rise in the demand. In this case, the increase in the demand at D2 by 5 per cent (or 2.25 MW) causes the losses on the transmission line to increase by 9 per cent. So, on average the increase in demand by 7.5 per cent leads to a 14.5 per cent increase in losses. Hence, generation has to increase by 7.8 per cent, which is more than the increase in demand.

5.3.2 THE RESULTS FOR LOADS

5.3.2.1 ALLOCATION OF LINE FLOWS AND LOSSES

The share of a generator (or load) in the flows over each line in the transmission network is the basis for determining the share of this generator (or load) in the cost of the line. Thus, the share of the user in the total system flows is the sum over its share in all the flows over the network lines, as determined by the tracing method. Two of the largest demand centres, D5 and D126, are chosen here to illustrate how the tracing method is able to apportion, for each load, the line flows and the losses over these lines. These allocations are presented in

Table 5.2 and Figure 5.6, below, and in Table 5.3, for each load respectively.

Table 5.2: D5's Share in Transmission Flows and Losses

Flows over Lines		D5 share in line flows		Line Loss	D5 share in line loss	
Line	(MW)	(MW)	(%)	(MW)	(MW)	(%)
L21	19.21	11.027	57.4	0.01	0.0057	57.4
L22	32.3	18.54	57.4	0	0	57.4
L24	168.07	14.93	8.89	1.8	0.1599	8.89
L25	163.16	14.49	8.89	1.64	0.1457	8.89
Total	382.74	58.987	15.41	3.45	0.3113	9.02

In accordance with the tracing method, Table 5.2 shows that the share of D5 in line flows and line losses are the same. The table also shows that D5 has about 9 percent of the total losses on these lines, despite the fact that D5's share in the total flows on the same lines is 15.4 percent. The reason for this difference is that allocated losses from each line are not necessarily equal when the shares in the line flows are the same. For example, D5 shares the same percentage of the flows on both lines L24 and L25 but it has a different share of the losses. This indicates the advantage of the method in allocating directly the losses over the lines which produces more accurate allocation. Figure 5.6, below, demonstrates how this load has low losses despite its being the largest of the demand centres.

Figure 5.6: D5's Usage of the Transmission Network (in MW)

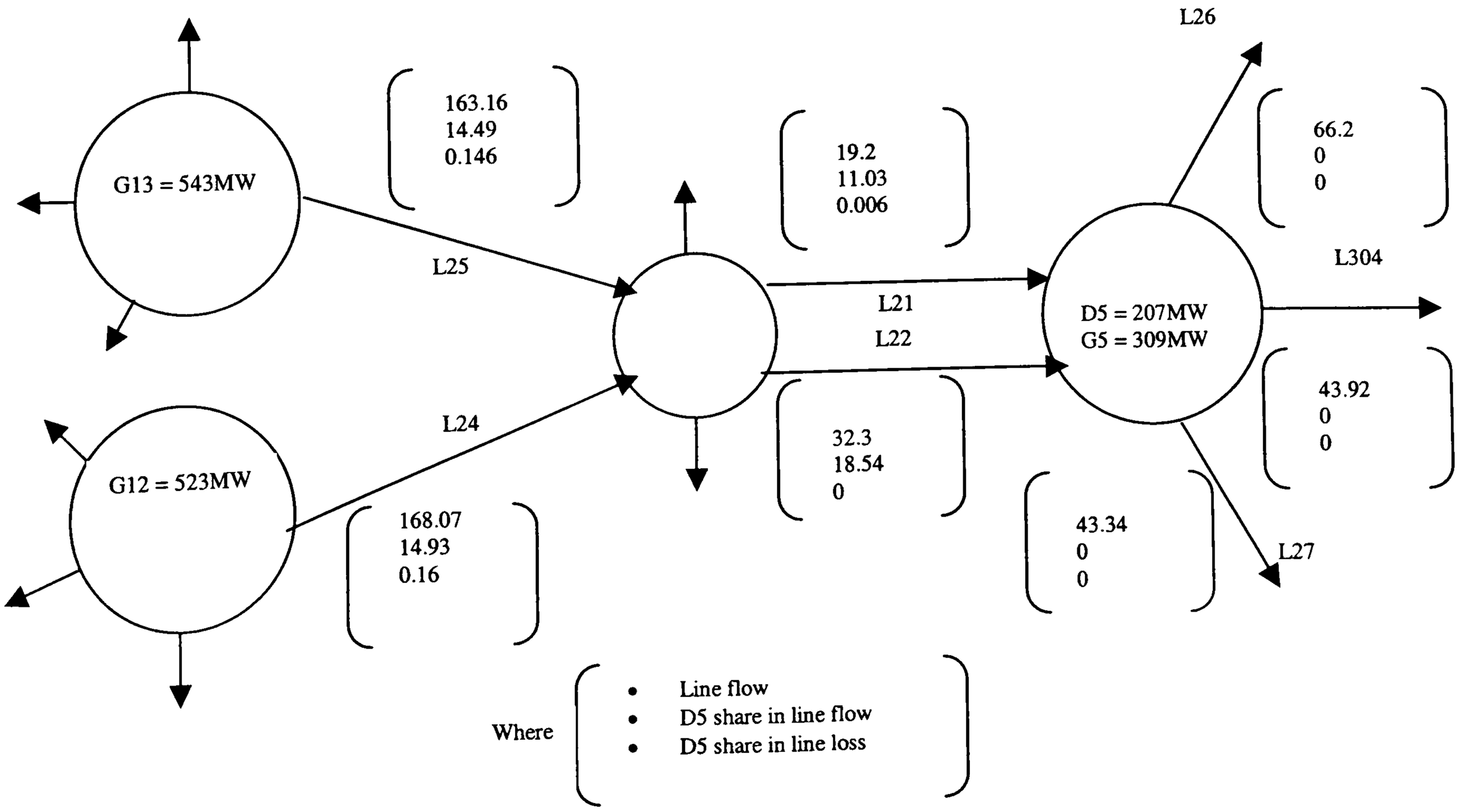


Figure 5.6 shows that Kirchhoff's current law is satisfied where the nodal inflows and outflows are equal. For example, at node D5, the inflows of 360.5 MW (including generation from G5 and flows on lines L21 and L22) are equal to the outflows which are also 360.5 (including the load of D5 and flows on lines L26, L27 and L304). Figure 5.6 also shows that the low losses allocated to D5 are a direct result of its usage of nearby generators including the generation at the same node, G5. Even though the load at this node (D5) is 207 MW, which is less than the generation level of 309 MW at G5, the method is able to show that only 177.4 MW are supplied from G5,15 MW from G12 and 14.6 MW from G13.

Table 5.3 confirms that the share of a generator in total losses on the transmission lines is not necessarily equal to the share in the total flows on these lines although the relative share in losses and flows over a particular line is the same. For example, what makes the case of D126 different from the case of D5 is that the share in losses is higher, rather than lower, than the share in the flows. This again illustrates the need to allocate the losses directly, as the share in total flows does not necessarily reflect the share in the total losses.

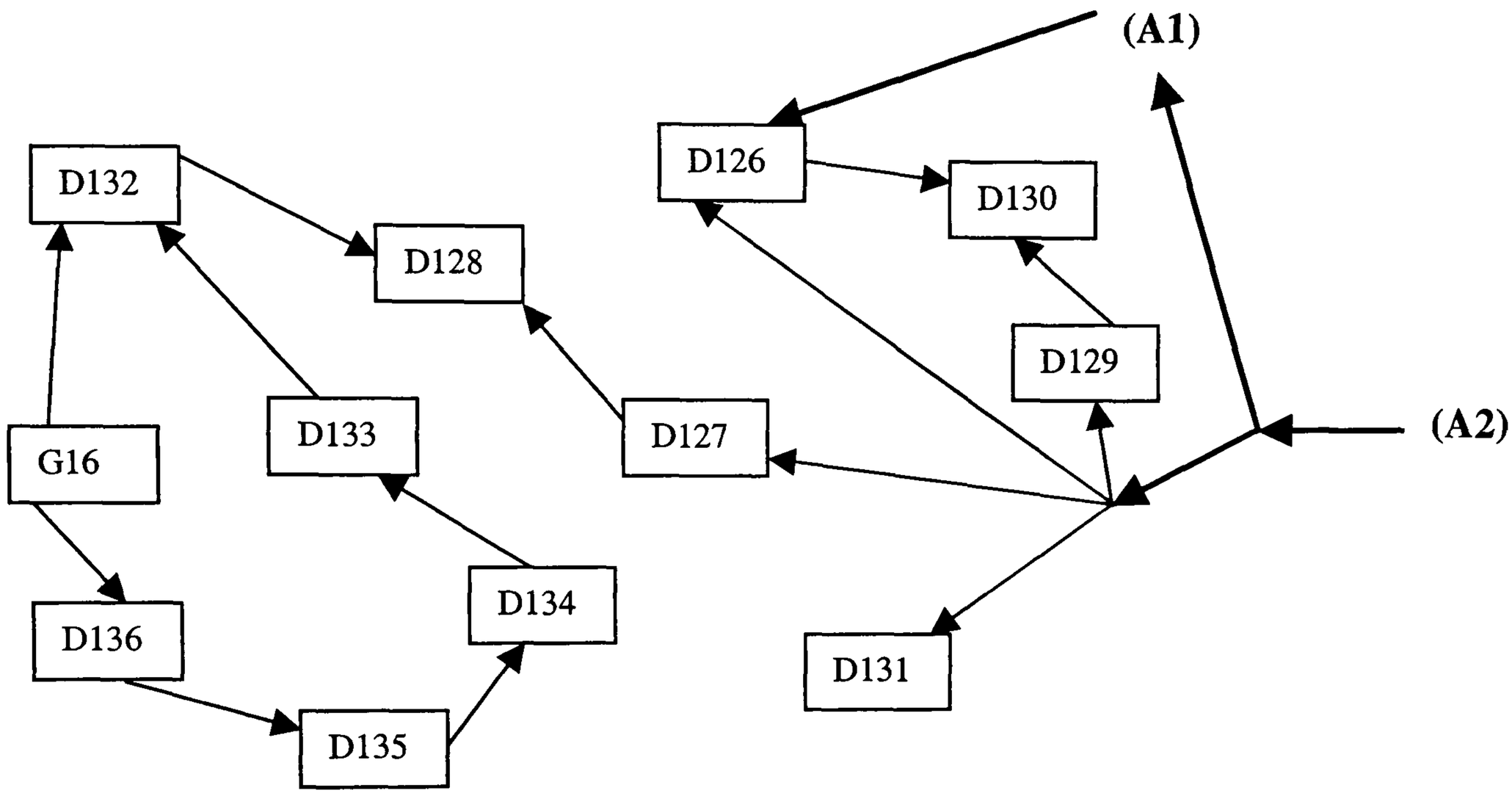
Table 5.3: D126's Share in Transmission Costs

Flows over Lines		D5 share in line flows		Line Loss	D5 share in line loss	
Line	(MW)	(MW)	(%)	(MW)	(MW)	(%)
L72	178.25	167.9645	94.22	0.78	0.734992	94.22
L187	642.6	167.4927	26.06	6.44	1.678576	26.06
L189	384.04	168.332	43.83	0	0	43.83
L217	523.41	135.6823	25.92	3.54	0.917666	25.92
L222	91.925	6.800604	7.39	0.67	0.049567	7.39
L223	92.63	6.85276	7.39	0.68	0.050306	7.39
L224	124.18	32.19088	25.92	0	0	25.92
L225	175.37	12.95567	7.39	0.26	0.019208	7.39
L227	125.53	9.273154	7.39	0	0	7.39
L228	950.52	9.251935	0.97	4.36	0.042438	0.97
L236	62.335	9.656354	15.49	0.15	0.023237	15.49
L237	9.96	9.385283	94.23	0.6	0.565379	94.23
Total	3360.75	735.8383	21.89	17.48	4.081368	23.35

Table 5.3 shows that D126 has been allocated about 4.08 MW in losses, which is 2.29 per cent of this load or 4.16 per cent of the total network losses. The inspection of Figure 5.7,below, for the network in A4 shows that this node meets all of its demand from

generators which are located in A1 and A2. As a result, it has to use some of the tie-lines linking these areas together and thus has a large share in the losses. Although D126 uses 12 lines, most of the losses (63.5 per cent) on these lines come from the tie-lines, L187 and L217. This indicates that tracing allocations are reflective the usage extent of the network.

Figure 5.7: Topology of Transmission Network in Area 4



5.3.2.2 DEMAND CENTRES' USAGE OF THE NETWORK LINES

Table 5.4 compares the largest 10 loads in the system, which account for 34 per cent of the total load of the network. The table shows that the allocation of transmission costs should not be based on the size of the load (or the generator for that matter) but rather on the extent of usage of the network. This is reflected in the tracing charges in the fourth column in Table 5.4 which are the represented in the loss per MW of load for each one of the largest ten demand centres.

Table 5.4: The Largest Ten Demand Centres

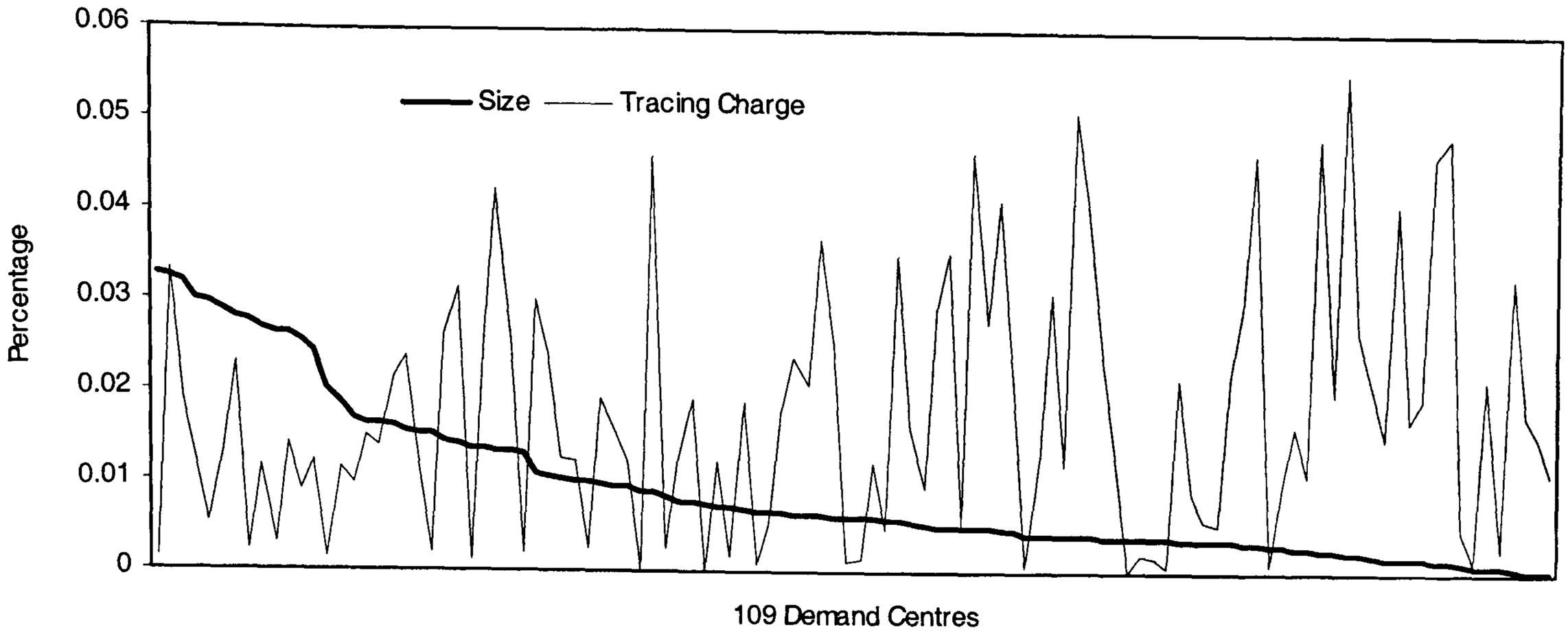
Demand Centre	Load Size (in MW)	Losses (in MW)	Tracing Charge (loss per MW)	Number of Used lines
	A	B	C = B/A	
D5	207	0.311321	0.001503966	4
D17	182	2.44	0.013406593	17
D20	202	3.828028	0.018950634	22
D22	175	0.382684	0.002186766	6
D24	167	0.522071	0.003126174	15
D25	187	1.004307	0.005370626	26
D28	205	6.815117	0.033244473	29
D41	171	1.981734	0.011589088	21
D68	189	2.291936	0.012126646	33
D126	178	4.081368	0.022929034	12
Total	1863	23.6	0.013	185

It could be said that the number of lines used does not give an indication of usage of the transmission network. For example, as shown in Table 5.4, D25 has low losses and ranks seventh among the ten nodes in terms of losses but third in terms of lines used. It uses 26 lines and the line with the maximum loss is only 0.4 MW, which indicates that this load relies on the nearby generator (G6) and other generators through short lines. The usage of a large number of lines does not imply large losses as shown in the case of D68, which uses thirty-three lines even though it does not have a large amount of losses.

D5 has the largest demand with 207 MW, but it has only 0.31 MW, or 0.15 per cent of its load in losses. This low ratio is an indication of low usage of the transmission network, as this load depends heavily (about 85.5 per cent) on generation at the same node, G5 (see Table 5.8 in section 5.4.1.3). On the other hand, D28 has the second largest demand with 205 MW but it has the highest losses at 6.8 MW or 3.3 per cent of its load. This demand centre relies on the transmission network to receive its load, which results in its sharing a larger portion of transmission losses, especially those on tie-lines. The important observation from these examples is that tracing allocations are reflective of a load's usage of the network which is determined by its share in line flows and losses on the lines rather than the number of lines used or even the size of the user.

This observation is confirmed by Figure 5.8, below, which demonstrates that the allocated losses for a demand centre are not based on the size of its load but rather on the extent of usage of the transmission network, which depends on its position on the network.

Figure 5.8: Demand Centres' Usage of the Transmission Network



The declining line, in Figure 5.8, represents the ranking of demand centres sizes from the largest to the smallest (i.e. in terms of its percentage in total network load). The tracing charge for each demand centre, as expressed in terms of allocated losses per MW of its demand (i.e. a percentage of load at each demand centre), is represented by the fluctuating line. The comparison of these two lines indicates that any two loads may have different charges despite having the same size. This reflects the ability of the tracing method to factor the geographical element into these charges in contrast to the charges of the postage stamp method. This figure indicates that higher charges are for the demand centres with small loads and mostly located in remote rural areas.

The above observation would have a direct implication for the policies of subsidising those consumers in rural areas who are mostly in the lower income bracket. Although the intention is to remove the industry completely from government subsidisation, this observation indicates a need for continuous subsidisation for these areas and less developed (and poorer) regions. This subsidisation could continue at least in the short term, as full benefits from competition could take a while to reach such consumers. The market distortion of this subsidisation could be minimised as the basis for it becomes much clearer. This would be in contrast to the situation in the past when a considerable number of consumers, regardless of their location, benefited from a subsidised nation-wide tariff system.

5.4 ALLOCATION OF TRANSMISSION COSTS TO GENERATORS

The common justification for allocating transmission costs to generators is that generators need the transmission network to reach their potential consumers. This justification used to prevail because the achievement of economies of scale, on the plant level, required that electricity systems to be designed in such a way that large central stations could supply dispersed and distant loads.

However, changing generation technologies and the unbundling of the industry have highlighted the necessity to charge generators for transmission costs. The objectives are to maintain the least-cost dispatching of generators, as in an integrated structure, and to produce efficient decisions regarding long-term generation and transmission investments. The following sections present the allocation of transmission costs to the 16 generators in this network.

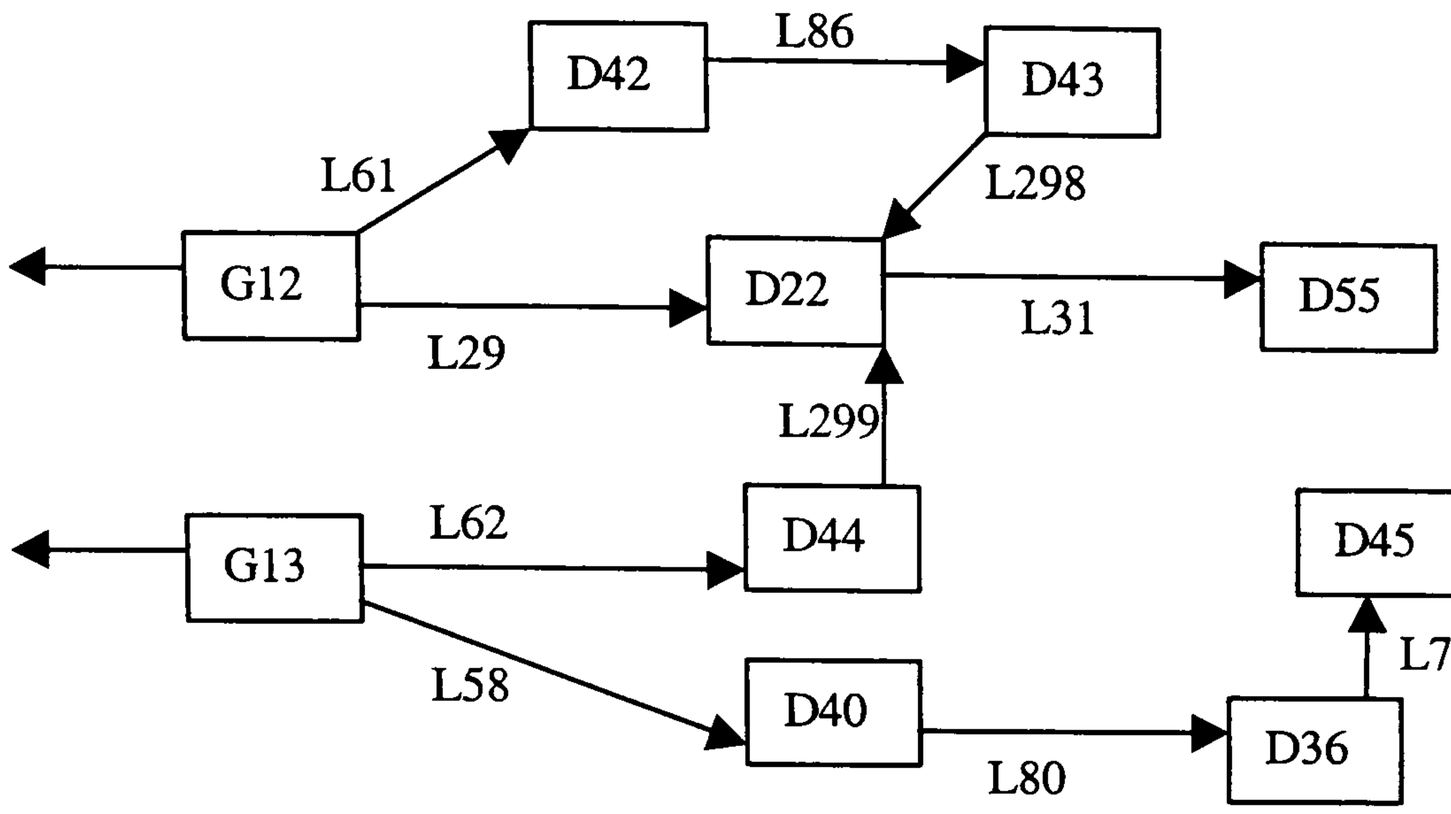
5.4.1 THE RESULTS FOR GENERATORS

This section presents the main results of using the tracing method to allocate losses to the 16 generators of this network. The method was also used to allocate the losses on the tie-lines, which are used by some of the generators and have a considerable amount of flows and losses on them. Finally, the section shows the contribution of each generator to the loads of the largest 10 demand centres in the network or conversely it shows where the load of each demand centre comes from.

5.4.1.1 THE TRACING PATH

The following figure provides an example of how to trace the power transmitted between two generators (G12 and G13) and some of the supplied demand centres. This example is also useful in highlighting the main difference between the tracing method and the contract path method in terms of how much these two paths are in accordance with the actual operation of the system.

Figure 5.9: The Tracing of Electricity Flows



In considering the numbered lines in this example, it is clear which generator is supplying which line and by what percentage as each line is supplied by only one generator. However, the exception to this is line L31, which is shared by both generators because D22 operates as a perfect mixer of their flows. The proportionality rule makes it possible to apportion the flows on this line between the two generators. It is calculated that G12 shares 70 percent of the flows (and losses) while G13 is responsible for the remaining 30 per cent. Thus, it becomes possible to determine the lines which are supplied by each generator and to be able to allocate the line costs accordingly. This same rule can also be applied to determine the usage and the costs for the demand centres in the network.

As a result, the tracing charges takes into consideration as much as possible the actual flows over the transmission system. This is clearly different from the method of the contract path where the path of the transaction is determined by the contracting parties with no reference to the actual power flows. For example, in a contract path arrangement, D55 can purchase electricity from G12 and pay the transmission costs associated with the direct link along the two lines, L29 and L31. This, however, ignores the important fact that part of this electricity is transmitted over many other lines as well. Also, this contract path ignores the fact that the electricity generated not only by G12, but also G13 is supplied to Line 31 (as explained above). As the contract path normally uses the postage stamp method to allocate the transmission cost of the transaction between the contracting parties, the criticism of the postage stamp (i.e. that it ignores spatial signalling) is similarly valid here.

Another important observation is that the tracing charges for transmitting electricity from G12 or G13 to any one of the loads could involve either positive or zero charges. This obviously results in less efficient outcomes in comparison with marginal pricing which could also include negative charges. The siting of more generation near loads reduces line flows (and losses) and consequently has a positive effect on competition. However, the tracing outcomes remain preferable over those of postage stamp charges, which are always positive regardless of the user's location or the direction of the contracted power flows.

5.4.1.2 ALLOCATION OF LOSSES TO GENERATORS

The procedure for allocating transmission losses to the demand centres is repeated here for the allocation of these costs to the network generators, as shown in Table 5.5. The tracing charges in the fourth column in Table 5.5 are the represented in the loss per MW of generation output for the network 16 generators.

Table 5.5: Comparison of the Network's Generators

Generators	Output (in MW)	Losses (in MW)	Tracing Charge (loss per MW)	Number of used lines	Share in Total Output (%)	Share in Total losses (%)
	A	B	C = B/A			
G1	249.9	7.162	0.028659	138	3.89	6.96
G2	9.99	0.357	0.035736	140	0.16	0.35
G3	49.98	1.8604	0.037223	141	0.78	1.84
G4	1477.87	41.5347	0.028104	145	23	42.23
G5	309	0.0548	0.000177	6	4.8	0.07
G6	511	1.4884	0.002913	19	7.96	1.54
G7	50	0	0	None	0.78	0
G8	378	3.4703	0.009181	20	5.9	3.52
G9	378	1.7703	0.004683	9	5.9	1.82
G10	759	10.9116	0.014376	89	11.8	10.99
G11	543.99	8.2452	0.015157	118	8.5	8.38
G12	543	5.8223	0.010722	40	8.46	5.93
G13	523	5.9754	0.011425	36	8.15	6.08
G14	444.99	8.0316	0.018049	13	6.93	8.19
G15	90	0.7998	0.008887	9	1.4	0.81
G16	101	1.27	0.012574	7	1.6	1.29
Total	6418.72	98.1		930	100	100

The largest generator in this system is G4 with 23 per cent of total generation and it shares over 42 per cent of the transmission losses in this network. Having the same level of output does not necessarily imply the same share in losses; for example, G8 and G9 have the same output but share different amounts of losses because G8 uses more of the grid by

transporting power over a longer distance. This shows the aspect of fairness in the tracing allocation where transmission charges are set according to the extent of grid usage by each generator.

The number of lines used by a generator is not the factor which determines how much this generator is using the grid. For example, G3 uses 141 lines (67.5 per cent) but it is among the lowest of the generators in terms of the grid usage because this ranking depends on the size of the losses allocated to this generator. This is a direct outcome of the symmetric way in which a unit (i.e. 1 MW) of power flow is treated in the tracing method regardless of who produces it. Also, a generator such as G7 has no losses because its generation does not go to the grid lines but directly supplies the demand at the same node. The interesting point is that the tracing charge (i.e. the losses-generation ratio) gives a very useful spatial signal to generator G2 that it is very costly to be at its current location. This is because G2 is located in the eastern region but supplies distant loads mainly in the central region.

5.4.1.3 GENERATORS' USAGE OF TRANSMISSION LINES

The tracing method allocates the losses on each line to the generators that have used the line. The losses allocated depend on the losses on the particular line. It is expected that tie-lines would a have high volume of power and thus large losses. This means that generators which use these lines are expected to have most of their losses attributed to these lines.

As explained in section 5.3.2.1 (for allocating line losses to demand centres), the tracing method can apportion the flows and the losses over each line to the user. This allocation is presented again here for the 16 generators with more details of the usage of the tie-lines which interconnect the different areas of the network. The usage of these lines is an indication of the magnitude of power exchange between these areas.

Table 5.6: Losses over Lines Supplied by Generators

Generators	Loss per generator (MW)	Max loss over a line (MW)	Min loss over a line (MW)	Standard Deviation	Mean	Coefficient of variation
G1	6.83	2.52	2.64E-06	0.288	0.04947	5.821768
G2	0.3452	0.10042	1.05E-07	0.01223	0.002466	4.960224
G3	1.801	0.5024	5.26E-07	0.0613	0.012774	4.798805
G4	41.45	12.84	9.47E-05	1.39	0.285853	4.862646
G5	0.069	0.0343	0.00857	0.0105	0.011428	0.918778
G6	1.506	0.54	0.00125	0.131	0.079286	1.65225
G7	0	0	0	0	0	0
G8	3.458	1.0154	0.00113	0.273	0.172905	1.578901
G9	1.78	1.530086	0.00722	0.522	0.198153	2.634328
G10	10.78	3.201	0.00031	0.412	0.121172	3.400118
G11	8.22	3.313	8.98E-05	0.355	0.069648	5.09706
G12	5.82	1.64	0.00054	0.377	0.145414	2.592592
G13	5.97	1.8	0.00073	0.419	0.165837	2.526574
G14	8.036	3.333	0.021095	0.939	0.618118	1.519127
G15	0.797	0.248	0.0049	0.0778	0.088526	0.878837
G16	1.27	0.68	0.02	0.2465	0.181429	1.358661

Table 5.6 illustrates how line losses are allocated among the sixteen generators. It shows the maximum and minimum losses on a line and the level of loss dispersion on these lines for each generator. The generator with the highest allocated losses is G4, which is the largest power plant (with steam turbines) in the eastern province. The distance and the high power transmitted over the interconnecting lines are expected to result in a high transmission loss. The generators from A2 have high dispersion; for example, the dispersion between G4's maximum and minimum line losses is a result of supplying 145 lines or 70 per cent of the network total lines. The next generators are those in A1 where G10 has a loss of 10.78 MW, but the line's maximum losses of 3.2 MW are slightly lower than the maximum losses for similar generators such as G11 and G14.

In considering the losses allocated to generators on an area by area basis, it is clear that the generators located in A2 have the largest share of losses (51 per cent or 50.43 MW). These losses result from transmitting the power from the eastern region (i.e. generators in A2), including G4, to the central province. The generators located in A1 have 37.6 MW or 38 per cent of the losses, which could be higher if these generators were not located in the vicinity of the demand centres.

In addition, a number of generators in this area, such as G8, G10 and G11, supply other areas with power, which makes them share part of the losses over the interconnecting lines. Generator G14 in area A3 has higher losses than G15 because it is the major power plant in that area and therefor has to use a larger number of the lines with a higher power flow to supply loads. As Table 5.7 illustrates, G14 is not among those generators which use interconnection lines, confirming the observation that this generator's losses are due to the fact that it supplies all of its output to its own area.

Table 5.7: Interconnection Losses

Area	Generators	Share in Interconnection Losses	
		(%)	MW
A1	G6	0.7	0.23
	G8	3.1	1.01
	G10	15.6	5.065
	G11	1.4	0.46
A2	G13	3.1	1.01
	G1	5.4	1.76
	G2	0.2	0.072
	G3	1.1	0.35
	G4	69.3	22.465
Total		100	32.42

Table 5.7 indicates that only nine of the sixteen generators have their output transmitted over interconnection lines in the network. It is important to distinguish between the generators that supply only their own vicinity and those generators that provide power to remote areas. Generators can be categorised into three groups: the first group consists of generators which have no demand at their node, such as generator G4; the second comprise generators which supply only the demand at their node, such as G7; the last group contains those generators which supply demand in their own area as well as demands in other areas.

Table 5.7 also illustrates that the generators in A2 are the dominant source of power for all areas, which makes them to share 76 per cent of the interconnection losses. The other generators using the interconnection lines are those from A1 and they share only 24 per cent of these losses. Determining the generator shares of the losses over interconnection lines is relevant when these areas are under different franchised distribution companies.

5.4.1.4 THE CONTRIBUTION OF GENERATORS TO LOADS

Any network may have nodes where generation and load are balanced, but when a node needs to import or export power it could be described as 'resource deficient' or 'resource concentrated' (Hassnik and Jones, 1996). In the last two cases there is an explicit impact on the grid which requires a pricing mechanism to reflect the efficient charges for using the system by generators and/or loads. Table 5.8, below, shows the contribution of each one of the 16 generators of the network to the loads of the highest 10 demand centres.

Table 5.8 The Contribution of Generators to the Largest Ten Loads

Generators	Demand Centers									
	D5	D17	D20	D22	D24	D25	D28	D41	D68	D126
G1		0.028	0.02		1.088	0.67	52.87	2.21	0.038	18.49
G2		0.001	0.001		0.044	0.027	2.1	0.088	0.001	0.74
G3		0.006	0.004		0.217	0.14	10.56	0.442	0.008	3.69
G4		83.25	60.9		14.19	9.26	26.92	77.32	68.51	145.4
G5	177.4									
G6		75.72				84.78			99.56	
G7										
G8					113.1	68.15			1.49	
G9									0.406	
G10					29.88	18.56			18.99	
G11		23	16.8		8.53	5.42	48.21	60.28		
G12	15		63.06	121.1			32.6	30.66		
G13	14.6		61.19	53.93			31.69			9.67
G14										
G15										
G16										
Total Load (MW)	207	182	202	175	167	187	205	171	189	178

This table shows the contribution of generators to the nodes with the highest loads, which are located in the first area (A1). Besides the provision of the information on how much each generator is contributing to these loads, the table is more useful for calculating how much it would cost each generator to supply these loads with power. For example, G12 contributes 15 MW (or 7.25 per cent) to the load at D5 but this costs G12 about 1.81 MW as transmission losses. These costs are calculated by identifying the lines through which G12 supplies D5 and the amount of these losses which is allocated to this generator. A similar calculation for G13 shows that this generator is responsible for 1.65 MW in losses which makes the total power supplied to D5 cost 3.45 MW. On the other hand, its nodal generation, which is G5, does not need to use the transmission grid and consequently has

no transmission costs in this case. Similarly, the cost for supplying the other demands can be calculated, but due to the complexity of the network the above example is sufficient to explain the point for the purpose of this chapter.

Table 5.8 indicates that the node D126 imports 145.41 MW or 82 per cent of its load from G4 (located at A2). It also imports the reminder not from the generator (G16) in its area but from G13, which is located in A1.The dependency of D126 on generation sources from other areas suggests, that A4 needs an additional generation capacity. The above figure and table show that the demand centre with the third highest losses is D20, which happens to be also the third in terms of load level. However, it has been established that it is not the load level that causes a node to have large losses, but rather its extent of usage of the transmission grid. This means that D20 has a loss of 3.83 MW or 1.89 per cent of its load as a result of being dependent on power transmitted from six generators from two different areas.

Table 5.8 shows that nine out of the highest ten loads are located in A1, the capital city of Riyadh. This indicates the concentration of the demand in this area, which accounts for 70 per cent of the total network demand. With more power imported from the eastern province, this concentration imposes additional transmission losses on the system. The magnitude of transmission losses is related not only to the level of demand but also to the density of the demand itself (Dansby,1980).

CONCLUSION

Viewing electricity as a commodity requires the costs of its different stages to be accounted for. This is more critical for transmission segment of the industry, where there is an issue of joint cost allocation between different and usually competing users. However, ignoring transmission losses leads to inefficiency in the allocation of resources and increases unnecessary consumption. In addition, society may find it desirable to subsidise some consumers, such as rural consumers, (or even some generators) with minimal distortion to market prices. This would require that the government's subsidisation policy be guided by the actual economic costs.

Thus, the importance of the transmission segment of electricity goes beyond the mere linking of generators with loads to induce efficiency and promote competition in the industry. These advantages are difficult to materialise if there is no agreed transmission pricing rule which is simple, transparent and also economically efficient. This chapter contributes to this discussion by applying the tracing method to the available real data. Despite some limitations of these data, such as the relatively small number of generators, from which to generalise the results, it could be concluded that the tracing charges have the advantage of being simple, fair and transparent.

The main finding of these results is that the tracing charges confirm that the extent of usage rather than the size of the generator (or the demand centre) should be the determining factor for transmission prices. This is clearly different from the postage stamp charges which ignore locational factors and consider the user's size as the only factor in setting transmission charges.

This chapter has also demonstrated that the tracing path is reflective of the actual power flows in the system, indicating a major advantage over the contract path method, which is based only on the financial agreement of the contracting parties. Although this chapter has been able to show the simplicity and transparency of the tracing charges, there is no guarantee that these charges are of relevance to economic efficiency. For this objective, the following chapter aims at examining how these charges compare with the ideal charges of the marginal cost pricing of transmission.

CHAPTER SIX
Marginal Cost Pricing of Transmission Losses

6.1 INTRODUCTION

The privatisation debate usually emphasises the issue of productive efficiency, because privatisation is expected to improve performance and thus lead to production at the lowest costs possible. However, less attention has been directed to the issue of allocative efficiency, which is more concerned with how far the price of a good is actually reflective of its marginal costs. Two practical factors could explain this. Firstly, it is widely believed that the long-term gains from privatisation are significant enough to minimise the short-term loss in allocative efficiency that is caused by the departure from marginal costs prices. Secondly, the production and sale decisions for most commodities are usually based on average costs rather than on marginal costs, as in any case they are considered impractical if not almost impossible to measure.

The production and transmission (and distribution) of electricity is much better suited as an illustrative example for marginal analysis than any other commodity. The electricity system must be managed to reflect minute-by-minute changes in the operating conditions, using very sophisticated technologies. Obviously, this requires an extensive set of information that has to be available for the system operator to run the system economically and reliably. The system is operated by engineers who apply optimisation techniques which are familiar to economists, such as the concepts of minimization of total costs or maximisation of profit (or net social welfare). Thus, the theory evolved by economists, with the development of marginal analysis in the late nineteenth century has been put into practice by electrical engineers since the first half of the twentieth century.

The recent deregulation of the electricity industry and the parallel separation between the financial and operational sides of the industry has revived this common issue between economists and engineers. This is especially true in the area of transmission pricing, which is currently subject to an unsettled debate which aims at providing a solution that is economically efficient but also acceptable by competing parties. The preference is for the

prices which are based on the marginal costs of transmission due to the obvious advantages of this method on the grounds of economic efficiency. However, as discussed in Chapter Four, there are serious difficulties, which have been reviewed in the literature, regarding the implementation of this method in an unbundled industry structure.

The following section of this chapter aims at presenting an empirical illustration of the main features of the marginal cost pricing method. The focus is on the transmission losses, as they are the major variable costs of electricity transmission especially if we consider that the network data used in this research do not exhibit line congestion. The subsequent sections draw important comparisons between the first-best situation, presented by the marginal method, and the tracing and postage stamp methods as alternatives. This comparison was helped enormously by access to some generation data, such as that of marginal generating costs, which were very useful in examining the effects on economic efficiency of the departure from the marginal pricing of transmission.

6.2 AN EMPIRICAL ILLUSTRATION

The results throughout this section are obtained from the Optimal Power Flow (OPF) computations. Wood and Wollenberg (1996) show that this program is an algorithm of optimisation (economic dispatching) which can calculate the marginal cost of power (generation and transmission) at any node in the network. It tells us which generator is supposed to be chosen to supply the additional increase in load. When the marginal generation cost is the same for each generator, the generator which has the lowest impact on transmission losses is dispatched.

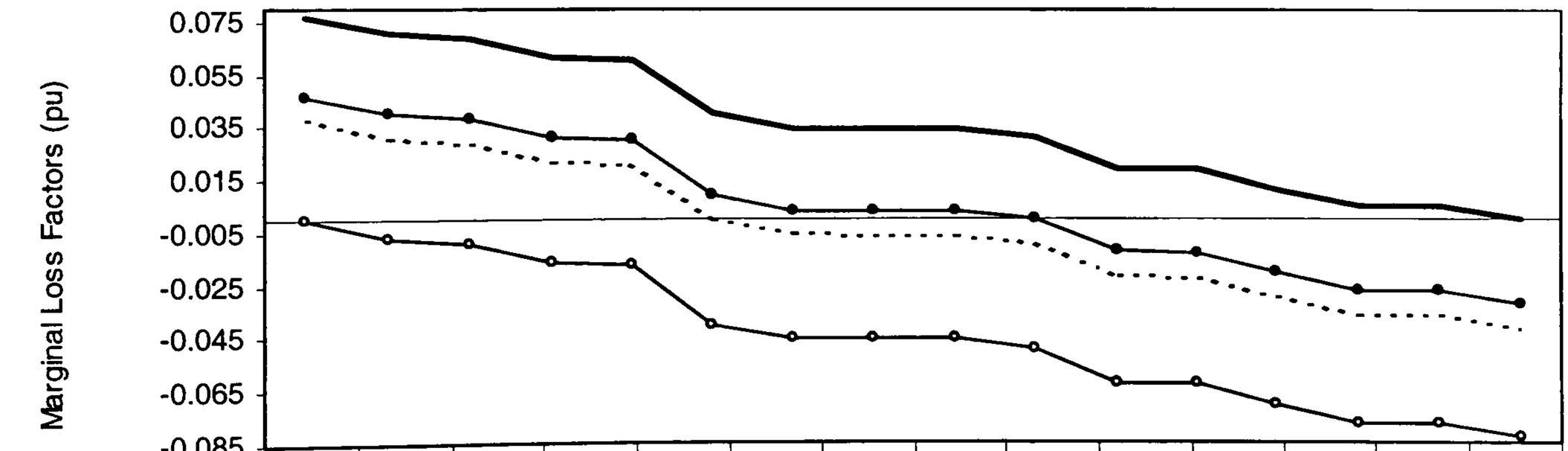
The data necessary for obtaining the marginal losses from the output of this program are gathered from the electricity company (SCECO-Central). These data include node data, which include demand and generation level at each node, and the transmission network per unit line parameters (resistance and reactance). The results give us the marginal losses for each node when the chosen marginal generator can be any one of the sixteen generators in this network. The Marginal Loss Factor (MLF) is used to express how much the change in generation (or load) by 1 MW at a particular node affects the total losses. Thus, the MLF indicates the marginal loss per unit (i.e. pu) of generation (or load) at this node.

6.2.1 THE INFLUENCE OF THE MARGINAL GENERATOR

As shown in Equation 4.9 (in Chapter Four), additional demand may increase, decrease or have no effect on the line net flows, which affect the losses associated with these flows. This impact is linked to the location of the additional source of generation, which depends on the location of the marginal generator. The impact of each generator (or demand centre) on total losses depends on the choice of the marginal generator. This, however, does not alter the relative ranking of each generator (or demand centre), as changing the marginal generator causes the curves to shift vertically upward or downward.

In Figure 6.1, four marginal generators (G6, G14, G11 and G4) are selected to show how the marginal losses for each generator in the network vary according to where the marginal generator is located. It is very clear that the value and sign of marginal losses change with a different marginal generator. For example, G11 could have positive, zero or negative marginal losses, depending on which generator among the four generators is chosen to be the marginal one. The MLFs are shown in the Figure 6.1, below.

Figure 6.1: The Impact of Marginal Generator on Marginal Losses



	G4	G3	G2	G1	G11	G9	G8	G10	G6	G13	G12	G5	G7	G14
G6 (A1)	0.047	0.04	0.038	0.031	0.009	0.003	0.003	0.003	0	-0.012	-0.013	-0.027	-0.028	-0.032
G14 (A3)	0.077	0.07	0.069	0.062	0.04	0.035	0.035	0.035	0.031	0.02	0.019	0.005	0.005	0
G11 (A1)	0.039	0.032	0.03	0.023	0	-0.006	-0.006	-0.006	-0.009	-0.021	-0.022	-0.036	-0.037	-0.042
G4 (A2)	0	-0.007	-0.009	-0.017	-0.04	-0.046	-0.046	-0.046	-0.049	-0.062	-0.063	-0.078	-0.078	-0.083

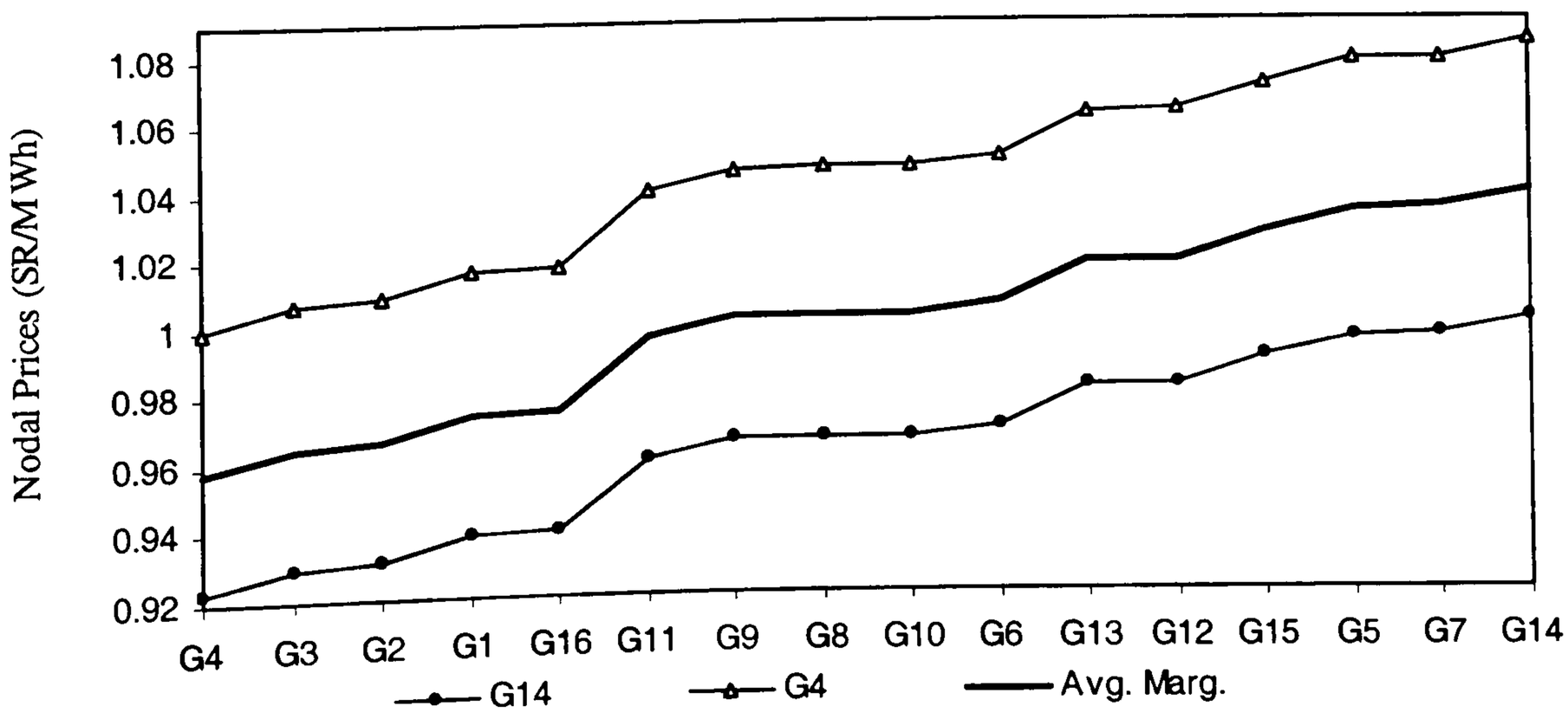
Figure 6.1 reveals that regardless of which generator is designated as the marginal generator, G14 always has the lowest marginal losses. This means that it is the most efficient generator in terms of its impact on total transmission losses and that G4 is the

least efficient. The rest of the sixteen generators are ranked in between the two, from the least efficient on the left-hand end of the x-axis to the most efficient on the right-hand end.

Being the most efficient in terms of losses is an important factor in economic dispatching where both generation costs and transmission costs are incorporated in the decision of which generator will meet the additional increase in demand. However, in decentralised structure some generators have an incentive to prevent the pricing of transmission losses at the margin when there is very large differences in charges. For example, this figure illustrates that while G14 has zero charges, G4 pays 0.077 (pu) and this difference could be even higher for a network which is spread over larger area. Thus, in such situations, what is considered economically desirable is not necessarily can be implemented especially when powerful players find it disadvantageous to them.

Figure 6.1, above, and the associated table illustrates how the choice of the marginal generator clearly influences the marginal losses for each one of the sixteen generators. The upward and downward shifts in marginal losses will naturally result, as can be seen in Figure 6.2, below, in very high volatility in nodal prices. This again will not alter the relative ranking of the different generators, as shown by the vertical and identical shift in prices.

Figure 6.2: The Impact of Marginal Generator on Nodal Prices



This figure shows the shifts in the nodal prices as a result of the fluctuations in marginal losses. For example, the nodal prices for each generator increase, on average, by about 8.4

percent as the marginal generator changes from G14 to G4. On the other hand, if G14 is the marginal generator instead of G4, the nodal prices for the generators decline, on average, by about 7.7 percent.

The choice of the marginal generator not only has impact on generators in the network, but, as Figures 6.3 and Figure 6.4 show, it also affects the other users (i.e. the demand centres). In these figures, the nodes are arranged starting with the marginal generator, to be followed by the generators without demand centres at the same bus, then by generators with demand centres and finally by demand centres without genertion as ranked in charges from the lowest to the highest. The objective of this figure is to illustrate how the generators and the demand centres are affected as a separate group by the choice of the marginal generator.

Figure 6.3: Marginal Losses for all Nodes (G4 as Marginal)

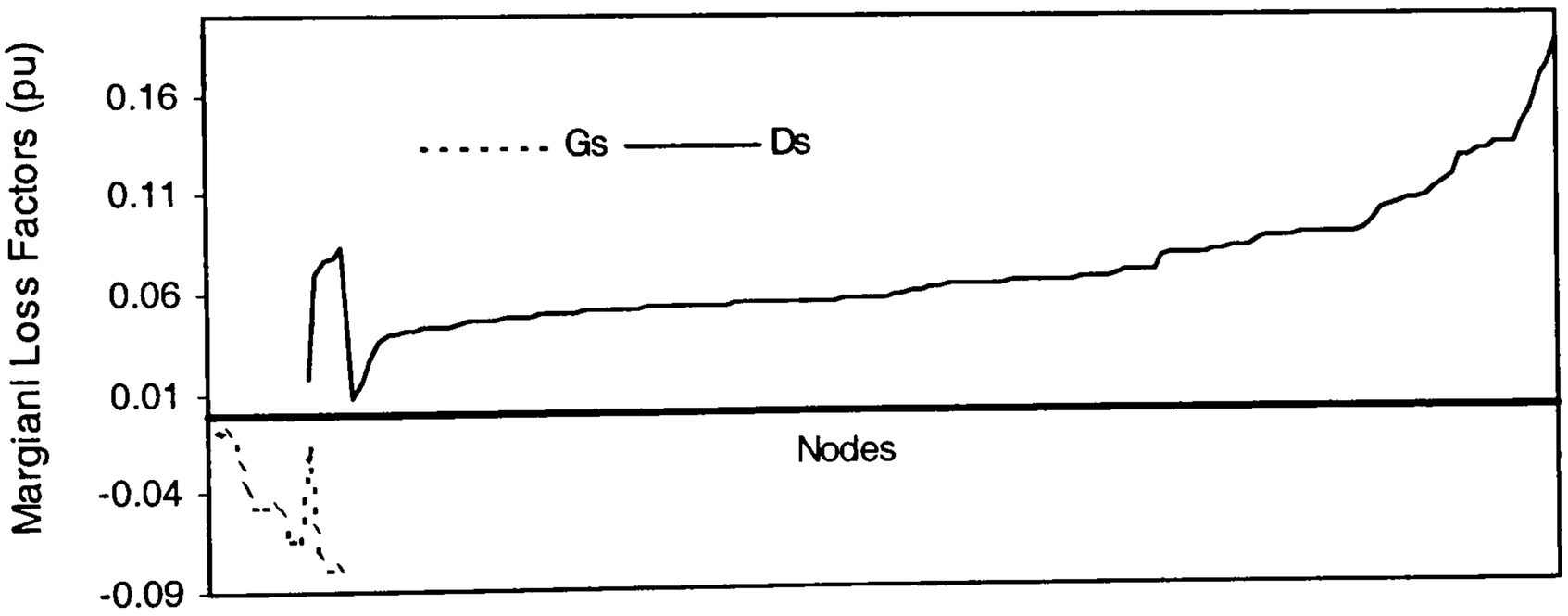
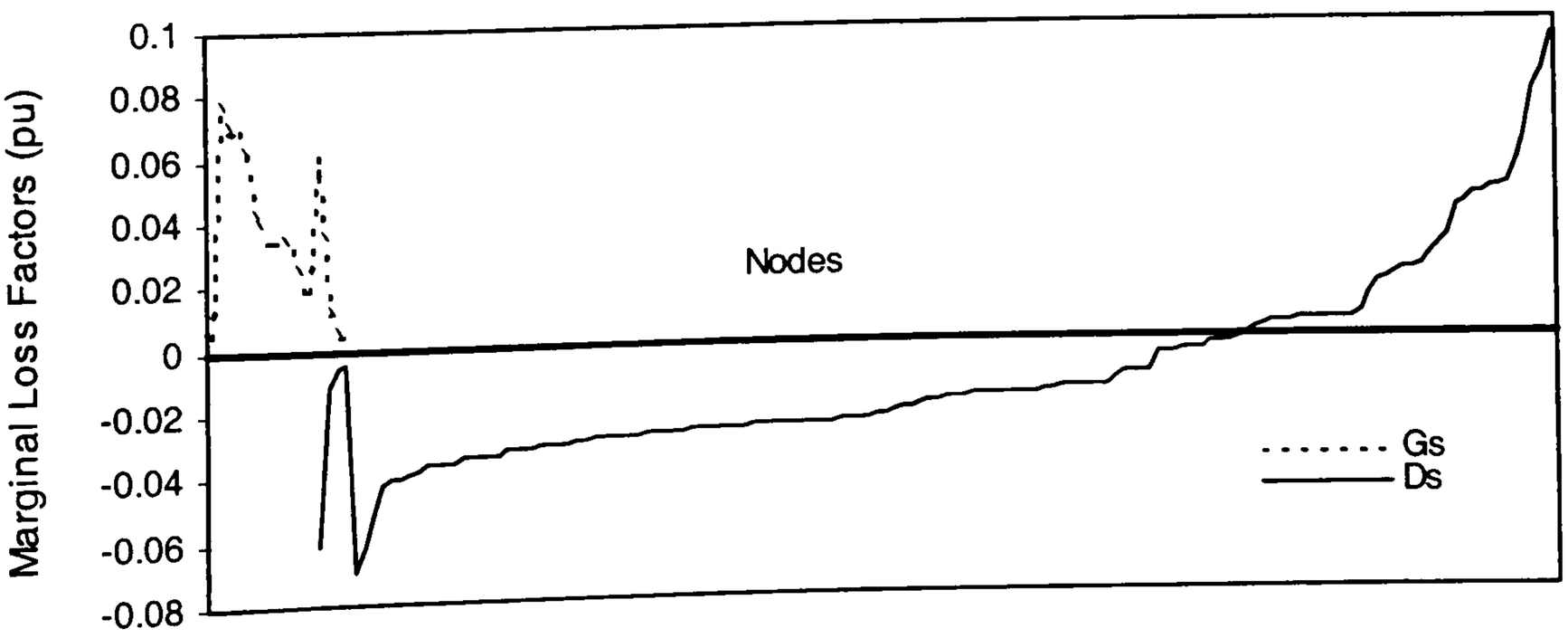


Figure 6.4: Marginal Losses for all Nodes (G14 as Marginal)



These two figures show how the choice of marginal generator influences the value and the sign of marginal losses for both the generators and the demand centres. For example,

choosing G4 makes all generators contribute negatively (i.e. reducing) to total losses while it makes all demand centres contribute positively (i.e. increasing losses). This is a natural outcome since G4 is the least efficient generator, which means that any one of the other generators would reduce the net flows and losses. On the other hand, choosing G14 will give completely different charges where all generators contribute positively to the losses and most of the demand centres contribute negatively. This reflects the impact of the marginal generator on the direction of the line net flow, which results in a different allocation of losses to the generators (or the demand centres). Thus, the charge levied on any generator (or any demand centre) is not a result of the increase in its generation (or demand) but rather because of the location of the designated marginal generator.

This shows the high volatility feature associated with this method as marginal losses (and consequently prices) vary with changing marginal generator. The volatility of these prices is further exacerbated by the nature of electricity, which is non-storable in large quantity. This requires that generation continuously must keep-up with the instant changes in demand. As shown above, a relatively small network of sixteen generators has a considerable degree of uncertainty, which can be considerably higher for larger networks or for a system consisting of interconnected networks.

Obviously when the trading arrangements are made on the basis of *ex post* prices, there is only one set of prices to consider and there is no room for guess work. The main advantage of these prices is that they are economically efficient, as they should reflect the actual optimal dispatching of the system. However, the price volatility, which results from changing the marginal generator, introduces risk and hedging costs into the process. In addition, trading in electricity as a commodity makes it necessary, especially in a pool-based structure, to make use of *ex ante* prices. The parties to the contracts have to agree on the strike price based on certain assumptions about future dispatching conditions. Consequently, the choice of a generator as the marginal generator makes the contract (exercise) price predictable but not necessarily unique. The main disadvantage of such prices are that these assumptions can be open to dispute and the prices are less efficient as they are not based on the actual operation of the system. This uncertainty introduced with unbundling may reduce the potential for further trade and restructuring of electricity

industry, particularly in developing countries with newly developed financial markets. This requires to limit such sources of uncertainty and to provide more predictable environment to encourage more private participation in the industry.

6.2.2 THE TRANSMISSION COMPANY NET INCOME

As shown in Figure 6.3 and Figure 6.4, above, the groups of participants in the system, such as generators and distribution companies, are affected by the choice of the marginal generator. Table 6.1, below, illustrates how the contribution of each one of these two groups to the transmission losses can vary with the location of the marginal generator.

Table 6.1: Contribution of Generators and Demand Centres to Losses

Gs	Output (MW)	Marginal (G4)		Marginal (G14)	
		M. losses (p.u.)	Value (MW)	M. losses (p.u.)	Value (MW)
G4	1477.87	0	0	0.0771	113.9438
G3	49.98	-0.0073	-0.364854	0.0704	3.518592
G2	9.99	-0.0092	-0.091908	0.0686	0.685314
G1	249.9	-0.0165	-4.12335	0.0618	15.44382
G16	101	-0.0176	-1.7776	0.0609	6.1509
G11	543.99	-0.0401	-21.814	0.0401	21.814
G9	378	-0.0458	-17.3124	0.0348	13.1544
G8	378	-0.0459	-17.3502	0.0347	13.1166
G10	759	-0.0459	-34.8381	0.0347	26.3373
G6	511	-0.0494	-25.2434	0.0314	16.0454
G13	543	-0.0624	-33.8832	0.0195	10.5885
G12	523	-0.0627	-32.7921	0.0192	10.0416
G15	90	-0.0709	-6.381	0.0116	1.044
G5	309	-0.0777	-24.0093	0.0053	1.6377
G7	50	-0.0783	-3.915	0.0048	0.24
G14	444.99	-0.0834	-37.11217	0	0
Contribution of Gs to Losses			-261.0086		253.7619
Contribution of Ds to Losses			446.3293		-75.0738
Net Contribution			185.3207		178.6881

This table shows that the choice of the least efficient generator (G4), in terms of losses, makes generators, as a group, contribute negatively to the transmission losses of the system by reducing them. On the other hand, it makes the other group, the demand centres or distribution companies, contribute positively by increasing the losses. The opposite case is true when the most efficient generator (G14) is the marginal generator. Also, as the table shows, the net contribution of the two groups taken together produces additional revenues

to the transmission company which is a net income for this company. The difference between revenues collected by generators from the transmission company and payments from the demand centres to the transmission company is called the Network Revenue or Merchandise Surplus (MS). This company pays the generators for their output, including transmission losses, at the nodal price of the injection (production) point and receives payment from the demand centres at the nodal price of the delivery (consumption) point.

Table 6.2: Transmission Company's Net Income

Gs	Output (MW)	G4(A2)		G14(A3)	
		*Nodal Price	Revenues	*Nodal Price	Revenues
G4	1477.87	1	1477.87	0.9229	1363.926
G3	49.98	1.0073	50.34485	0.9296	46.46141
G2	9.99	1.0092	10.08191	0.9314	9.304686
G1	249.9	1.0165	254.0234	0.9382	234.4562
G16	101	1.0176	102.7776	0.9391	94.8491
G11	543.99	1.0401	565.804	0.9599	522.176
G9	378	1.0458	395.3124	0.9652	364.8456
G8	378	1.0459	395.3502	0.9653	364.8834
G10	759	1.0459	793.8381	0.9653	732.6627
G6	511	1.0494	536.2434	0.9686	494.9546
G13	543	1.0624	576.8832	0.9805	532.4115
G12	523	1.0627	555.7921	0.9808	512.9584
G15	90	1.0709	96.381	0.9884	88.956
G5	309	1.0777	333.0093	0.9947	307.3623
G7	50	1.0783	53.915	0.9952	49.76
G14	444.99	1.0834	482.1022	1	444.99
Total Generators' Revenues			6679.729		6164.958
Total Loads' Payments			6766.709		6245.306
Merchandise Surplus			86.98073		80.34814

* Assuming, for simplification, marginal operating cost (λ) equals one SR

This table shows the revenue received by each generator in the cases of two designated marginal generators: G4 and G14. These two generators represent (in terms of transmission losses) the least efficient generator (G4) and the most efficient generator (G14) of all sixteen generators. Since G4 is the marginal generator, its nodal price is SR1, while the other fifteen generators have nodal prices greater than SR1 as they reduce transmission losses and, hence, should be rewarded. This means the dispatching of the least efficient generator will give higher nodal prices (for generators) than the dispatching of the most efficient generator. As a result, the generators' total revenues are higher (SR6679.7) than if G14 were the marginal generator, with total revenues of SR6164.958. Similarly, as the

marginal generator is the least efficient one, the total payments by the demand centres increase from SR6, 245.3 to SR6, 766.7.

Table 6.2, above, raises three important issues which need to be considered when the marginal cost pricing method is used. Firstly, The positive difference between the generators' revenues and the demand centres' payments is the net income collected by the transmission company, which is almost equal to the actual losses. This means that the transmission company has a disincentive to operate the system efficiently, as higher losses mean higher revenues. Dealing with this problem requires the income of this company to be regulated to reflect its actual costs and to guarantee fair return on its investments either using price cap or rate-of-return regulations. In addition, the over-recovered revenues can be used to remunerate and finance, albeit partially, the transmission network's fixed costs, as refunding the loads is not economically efficient.

Secondly, regardless of the type of ownership of this company (i.e. private or public), the separation between ownership and operation may become necessary. This is especially warranted when the transmission company is owned partially or completely by generation or distribution companies. This would minimise the potential for self-dealing and conflict of interests, which could make operating the system done on merely costs grounds.
Thirdly, this table focuses only on transmission costs by assuming that the marginal costs of both generators have the value of SR1. The data for this network (see Table 6.6) show that G4 and G14 have marginal generating costs of SR3.75 and SR53.7, respectively. Since, the marginal generating costs of the marginal generator give the transmission losses (and MS) their monetary values, the unregulated transmission company has an interest in the choice of which of the two costs is used. This is an important issue to consider as using the average of marginal losses for allocation entails a choice between the different values for the system marginal generating cost, λ, (further discussion in Chapter Seven, Section 7.5).

6.3 THE COMPARISON OF THE MARGINAL AND TRACING METHODS

6.3.1 CHARGING FOR TRANSMISSION LOSSES

The importance of the comparison between the two methods is that it shows if there is any similarity or pattern in the charges of these two methods.

Figure 6.5: Marginal and Tracing Charges for Generators (Nodal)

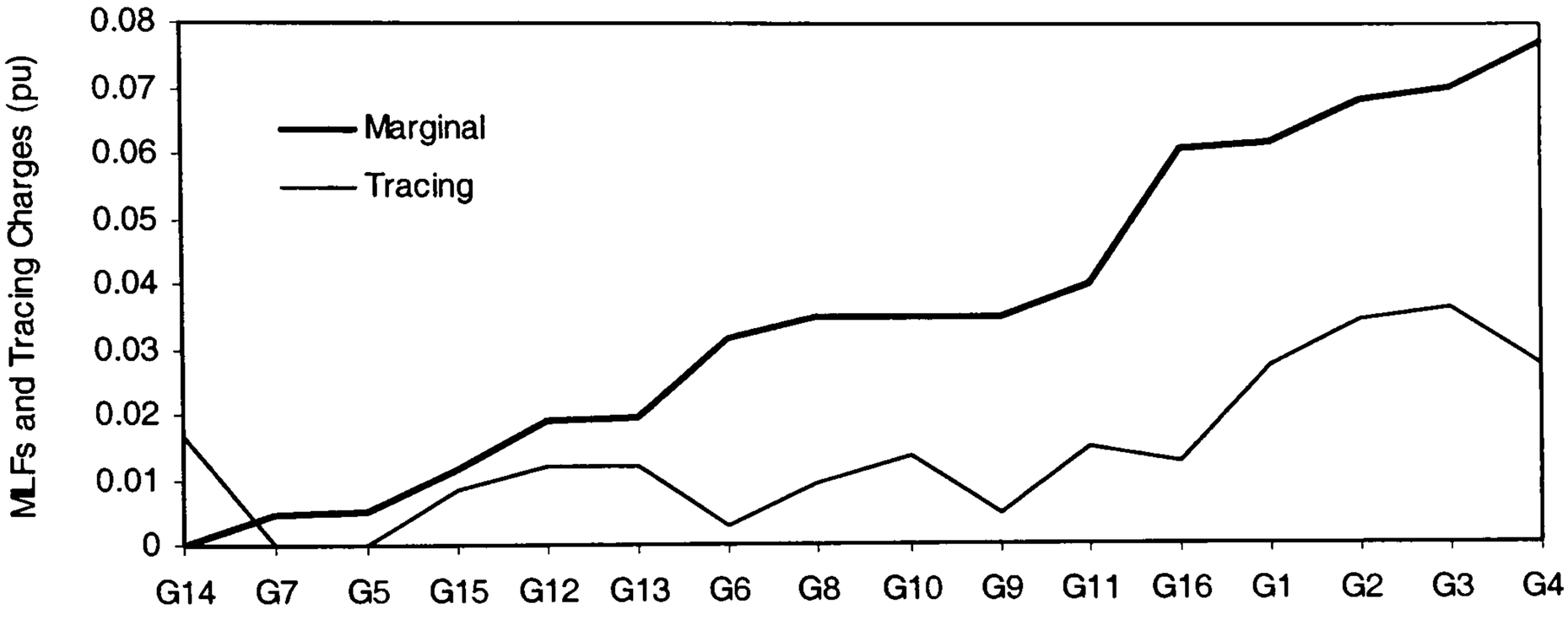
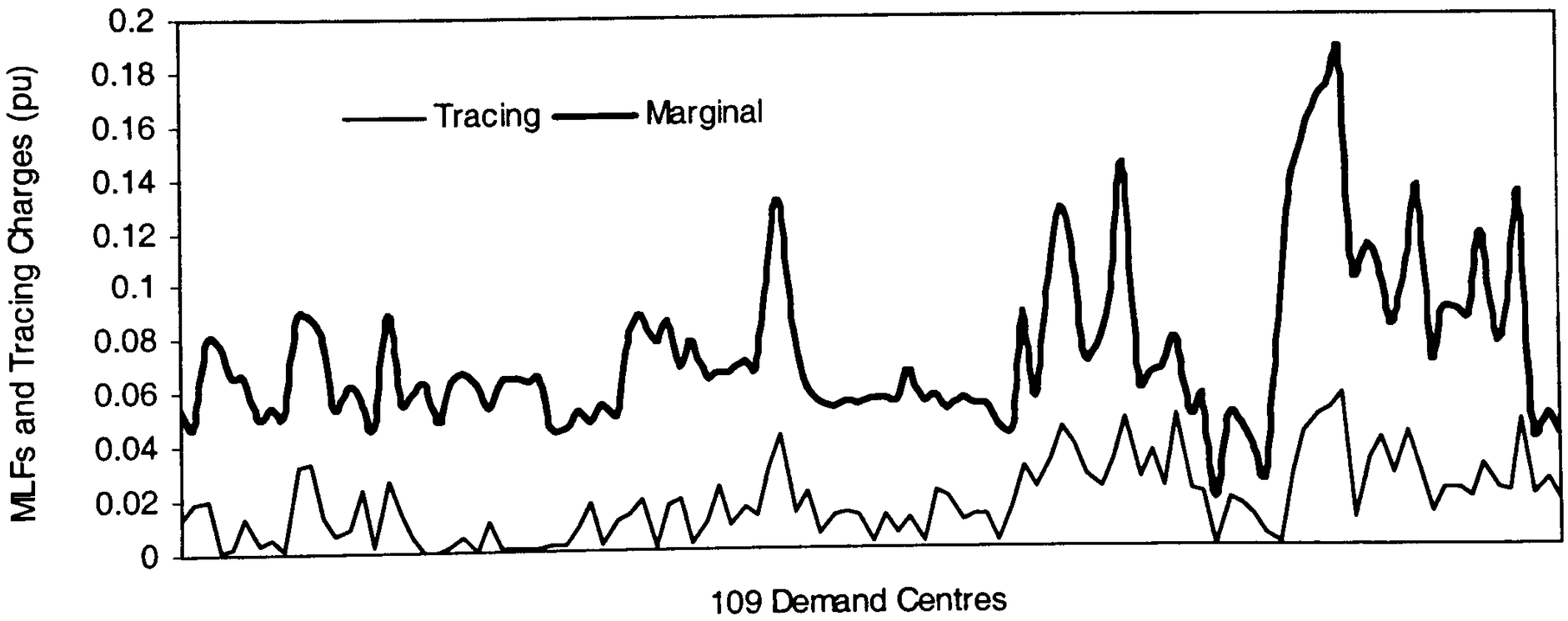


Figure 6.6: Marginal and Tracing Charges for Loads (Nodal)



Figures 6.5 and 6.6,above, show how losses are allocated to generators and demand centres according to the marginal and the tracing methods. It seems, from an inspection of these figures that the two methods show a similar pattern, but not the same charges. The value and the sign of the marginal losses vary with the choice of the marginal generator while, the allocation of the traced losses is independent of this choice. So, the comparison

between the two methods should focuses on the pattern (which reflects the ranking) of the charges rather than on their respective values.

One observation from Figure 6.5 is that the differences in charges between the most efficient and the least efficient generator are larger using the marginal method, which shows the advantage of this method in giving a stronger spatial message. However, this large differential in charges would make the marginal method more difficult to implement as some of the generation and distribution companies may find it disadvantageous and unacceptable.

Figure 6.6 gives more confirmation of the similarity in pattern between the two methods. It shows that the marginal and the traced losses are very similar for those demand centres with very high and those with very low losses. Also, it shows that the demand centres with very low charges according to the marginal method have been given even lower charges according to the tracing method. The possible explanation is that the tracing method has a very strong local effect, where demand centres (generators) which are located near generators (demand centres) would have lower charges than what economically warranted.

In addition, Figure 6.6 shows that the dissimilarity between the two methods is for those demand centres with moderate charges according to the marginal method. The marginal method is able to reflect the small geographical differences between nodes, while the tracing method needs a larger distance between the nodes to give a significant difference in charges. Thus, the tracing method gives a strong spatial message when the network is spread over a relatively large geographical area and it has relatively low load density, as measured in MW/square miles (Scherer, 1977). When there is high load density, it is expected that many demand centres and generators will be relatively close to each other within the same area. In such a case, it is more fitting that the marginal rather than the tracing method is used for the purpose of nodal pricing. Figures 6.11 and 6.12 showing zonal charges (in section 6.5) illustrate further how the tracing method may give very similar results to those obtained from the marginal method. Therefore, the usefulness of the tracing method could be greater for zonal rather than for nodal pricing.

6.3.2 MEASUREMENT OF SIMILARITY BETWEEN THE METHODS

The above discussion shows that there is a reasonable degree of similarity between the prices using the marginal and the tracing methods. To quantify these similarities, or their lack, we can utilise the concept of the simple correlation coefficient (r). This coefficient can have a range of values: r = +1, r = -1 or any value in between (including r = 0, i.e. no correlation exists). According to Thiessen (1997), a high positive correlation exists between two variables when r = + 0.9 and a low positive correlation exists when r = + 0.6. In general, this correlation coefficient is a useful tool for testing the cause-and-effect relationship or measuring the degree of linear association between any two variables. The latter usage is more relevant to the present objective of this research, for which we need to examine the extent to which the tracing charges resemble (or depart from) the ideal, efficient marginal charges. The following two figures, Figure 6.7 and Figure 6.8, aim at demonstrating the pattern which might exist between the marginal and tracing charges, by plotting the co-ordinate points of these charges, as shown below.

Figure 6.7: Comparison of Marginal and Tracing Charges for Generators (p.u.)

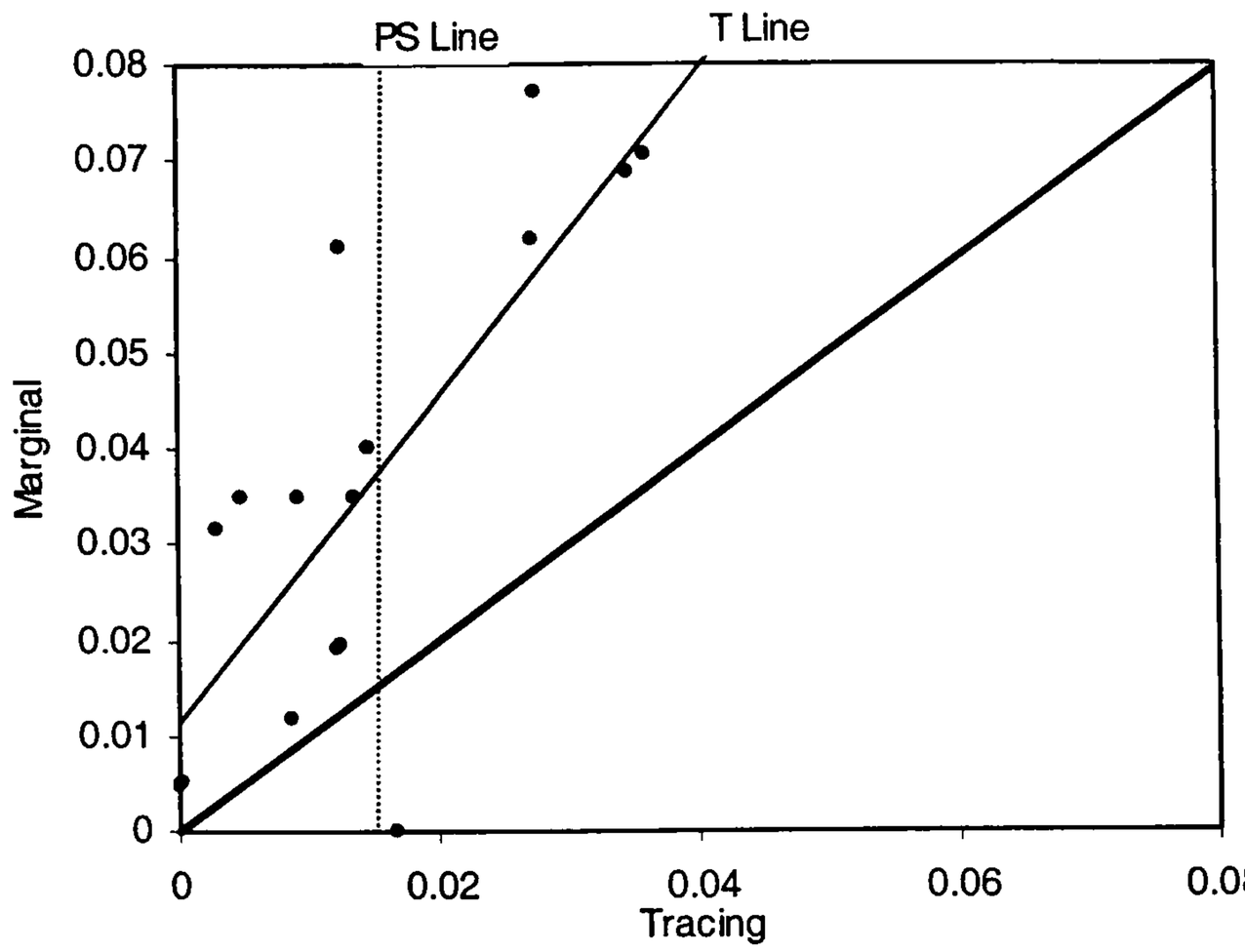
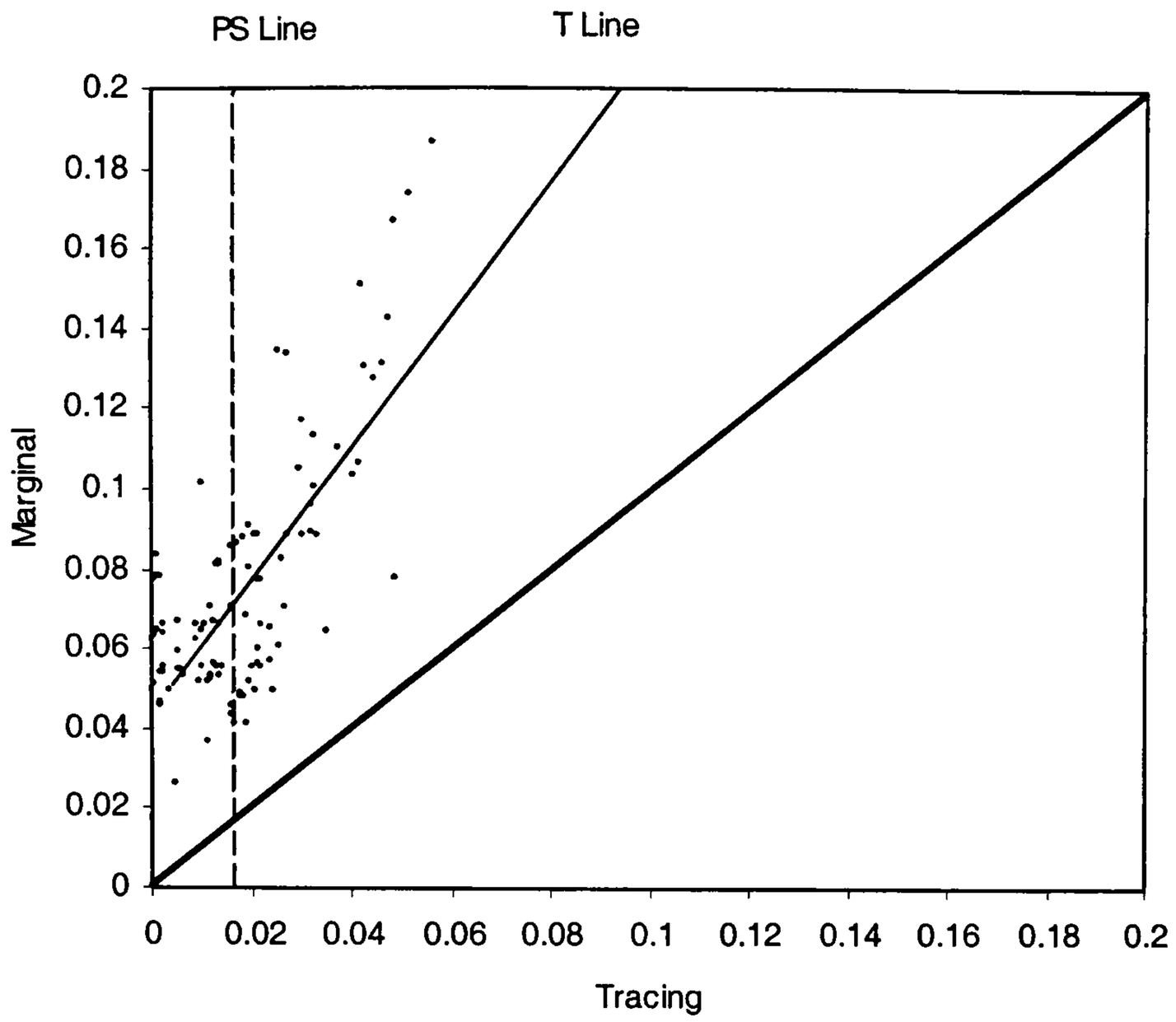


Figure 6.8: Comparison of Marginal and Tracing Charges for Loads (p.u.)



Using R-square values is helpful in examining the best-fit line for the plotted marginal and tracing co-ordinated points in Figure 6.7. The degree of association between the marginal and tracing charges indicates that the linear relationship is a reasonable approximation, especially if the latter do not include local effect or are used for charging zones rather than individual nodes. The R-square value for generators shows that the linear line has a value of 0.59, which is slightly lower than the quadratic line with 0.594. This could be considered an insignificant difference, especially in the light of the fact that the nodal charges of the tracing method undercharge generators that are located near demand centres (see section 6.6 and Chapter Seven (section 7.3.2) for the problem of local effect).

Similarly, the R-square value for loads, in Figure 6.8, shows that the linear line has a value of 0.564, which is slightly lower than the quadratic line with 0.568. However, ignoring the charges for most of the loads, which benefit from the local effect, increases these values to 0.662 and 0.664, respectively, which reduces the difference. Using the zonal charges instead of the nodal charges increases the correlation coefficient to 0.825 and 0.833 for both the linear and the quadratic lines. This implies an R-square value of 0.681 and 0.694, respectively, which means that the difference is decreasing further. This indicates that the degree of association between the tracing and the marginal charges are the highest when

the tracing zonal charges are used. While the small number of generators has been acknowledge as a limitation, even these results for the demand centres cannot be broadly generalised unless a much larger network is used.

In Figure 6.7 and Figure 6.8, above, the 45-degree line, as well as the vertical line for postage stamp charges, provides helpful reference points for the purpose of comparison. The line (T) represents the linear line, which could describe the relationship between the charges according to the tracing and the marginal methods for each generator (or demand centre) in the network. The positive slope of this line provides a support for the conclusion that both methods give similar spatial charges for transmission. The position of the tracing line to the left of the 45-degree line indicates that the tracing charges are lower than the marginal charges. The vertical line for postage stamp charges reflects the fact that this method is not suitable for spatial signalling as it treats all the generators and all the demand centres as if they were located at the same point on the network. Table 6.3, below, summarises the correlation coefficients between the marginal, the tracing and the postage stamp charges.

Table 6.3: Correlation Coefficients for Loss Charges

Correlation Coefficients	Nodal		Zonal	
	Demands	Generators	Demands	Generators
r (T,M)	0.751203	0.768396	0.8247992	0.616087
r (T,PS)	-6.2E-17	-4.9E-17	2.077E-17	4.95E-17
r (M,PS)	-4.5E-16	1.77E-16	-4.65E-16	2.37E-16

where
T is the tracing charges,
M is the marginal charges, and
PS is the postage stamp (pro rata) charges.

The above table presents the results for the correlation coefficients that measure the strength and the direction of the linear relationship between the charges of any combination of the three sets of charges. These results for the tracing and the marginal combination shows that on average the coefficient value is 0.74, which indicates a reasonably strong and positive relationship between these two charges. The very low (almost zero) value for the correlation coefficient in the case of postage stamp charges, with either marginal or tracing charges, highlights the lack of any spatial signal that the postage stamp method can provide.

The correlation coefficients for nodal charges in the case of tracing and marginal charges are not different for demand centres (0.751) and generators (0.768). This is obviously not the case for the zonal charges where the coefficients are 0.825 and 0.62 for the demand centres and generators, respectively. Thus, it could be concluded that the two methods give similar zonal charges as confirmed by the relatively high correlation coefficient of 0.825, for the demand centres.

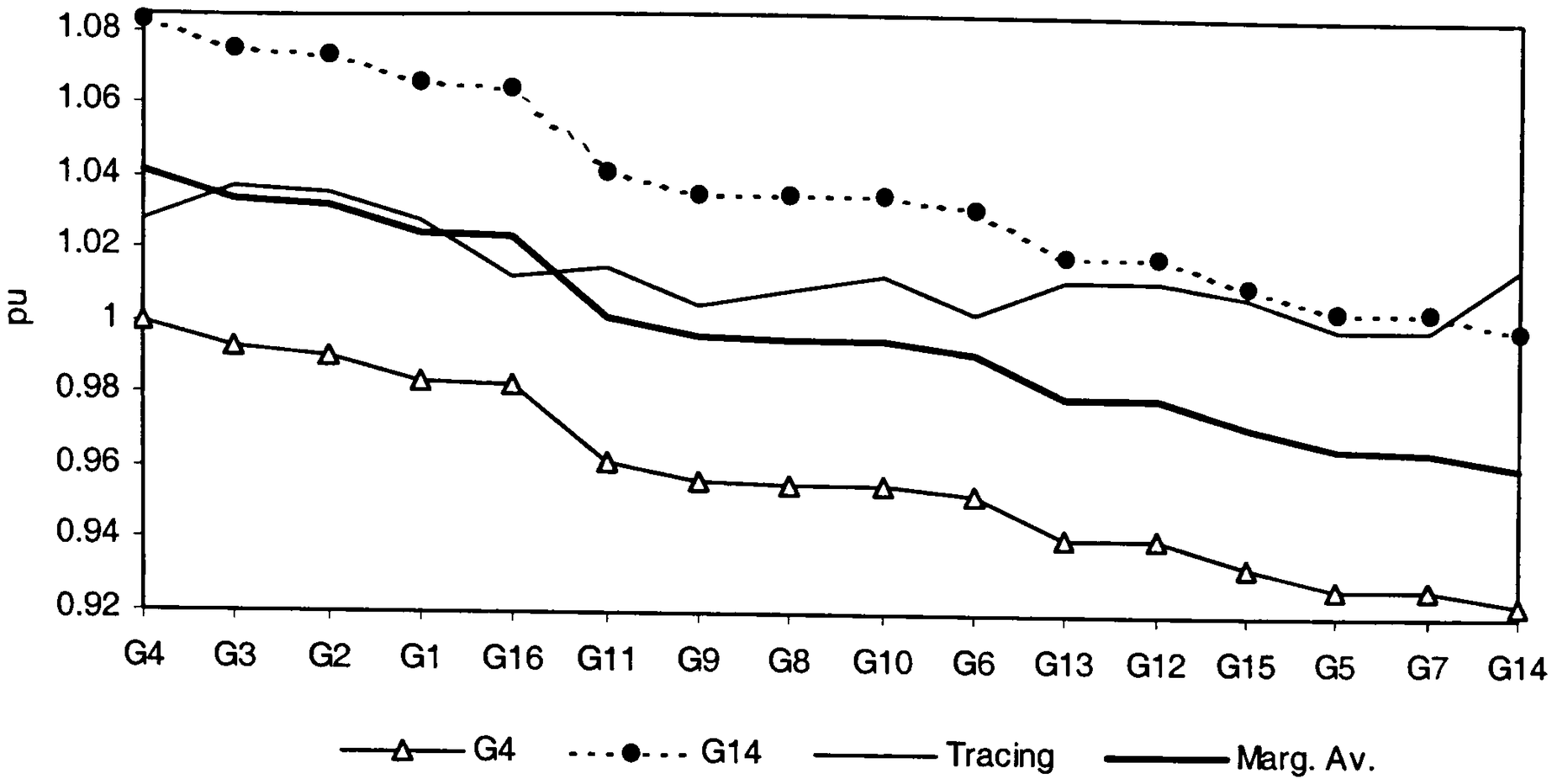
The unexpected result is that zonal charges for generators dropped below the average with a correlation coefficient value of only 0.62. This could be explained arithmetically, where a discrepancy for one co-ordinate point has more influence on the value of the correlation coefficient for a set of points consisting, for example, of two rather than ten points. This means that the coefficient value is very sensitive when the number of co-ordinate points is small, which in turn means that the results for the demand centres (in this case only) can be more useful for generalisation than the results for the generators. In short, the limitations associated with the data used in this research may not make it possible to reach a definite conclusion, but the results so far point to the potential of the tracing method.

6.4 A LEAST-COST ECONOMIC DISPATCHING

6.4.1 THE PENALTY FACTORS

Figure 9 illustrates the penalty factors as calculated for the sixteen generators. As shown in Chapter Four, equation 4.11, these factors are related to the marginal losses for each generator. The importance of these factors is in ranking generators in terms of their generation and transmission costs, which is a major requirement for a least-cost economic dispatching.

Figure 6.9: Penalty Factors under the Marginal and Tracing Methods



According to the marginal method, G14 always has the lowest penalty factor regardless of the designated marginal generator. This is expected because, as shown previously, it is the most efficient generator due to its lowest impact on total losses (i.e. no losses). On the other hand, G4 is the least efficient generator because it has the highest increase in total losses. The other generators are ranked in between G14 and G4 from left to right on the x-axis. The lowest line represents the penalty factors when G4 is designated as the marginal generator, which gives the lowest values to these factors, because in this case the nodal prices are the highest. The highest line represents the penalty factors when G14 is designated as the marginal generator, which gives the lowest values, because in this case the nodal prices are the lowest. These two cases represent the minimum and maximum cases; the other fourteen sets of penalty factors are not presented here for simplification.

The bold line in the figure, which is positioned approximately at the middle point between the two (minimum and maximum) cases, shows the average for the sixteen sets of penalty factors. The least efficient generators, or five (including G4) out of the sixteen generators, are distant generators which means that designating any one of them as marginal generator would result in penalty factors under the bold line. On the other hand, designating any one of the other eleven (more efficient) generators would result in penalty factors that are above the average. It is worth mentioning that the penalty factors given by the tracing method tend to be closer to those which result from dispatching the efficient generators rather than from dispatching the less efficient ones.

6.4.2 SHORT RUN MARKET-CLEARING PRICE

6.4.2.1 THE SYSTEM MARGINAL PRICE (SMP)

Economic dispatching modifies generation costs by taking into account the penalty factors. Table 6.4, below, shows how the merit order of generators is adjusted to reflect the transmission cost allocated to them using marginal and tracing method.

Table 6.4: Adjusted Merit Order using Marginal and Tracing Methods (in SR/MWh)

Merit Order Curve		Marginal (G16)		Marginal (G14)		Tracing	
Generators	Operating Cost	Gs	Adjusted OC	Gs	Adjusted OC	Gs	Adjusted OC
G4	3.75	G4	3.821	G4	4.063	G4	3.856
G1	5.63	G1	5.644	G1	6.001	G1	5.787
G2	5.63	G2	5.685	G2	6.044	G2	5.831
G3	5.63	G3	5.696	G3	6.056	G3	5.84
G10U1	37.17	G10-U1	36.221	G10-U1	38.506	G10-U1	37.681
G12U1	38.02	G12-U1	36.463	G12-U1	38.764	G12-U1	38.491
G11	38.13	G5-U1	36.618	G5-U1	38.926	G11	38.698
G5U1	38.72	G11	37.364	G11	39.722	G5-U1	38.725
G8	42.11	G10-U2	41.035	G10-U2	43.623	G9	42.315
G9	42.11	G8	41.035	G8	43.623	G8	42.504
G10U2	42.11	G9	41.038	G9	43.628	G10-U2	42.689
G6	42.67	G6	41.439	G6	44.053	G6	42.795
G12U2	44.03	G12-U2	42.226	G12-U2	44.891	G12-U2	44.575
G13	44.03	G13	42.239	G13	44.905	G13	44.578
G5U2	44.75	G5-U2	42.321	G5-U2	44.988	G5-U2	44.756
G15	46.24	G15	44.004	G15	46.782	G15	46.64
G5U3	53.43	G14	50.517	G14	53.7	G5-U3	53.437
G14	53.7	G5-U3	50.529	G5-U3	53.714	G14	54.62
G7	55.16	G7	52.136	G7	55.426	G7	55.16
G16	56.79	G16	56.79	G16	60.472	G16	57.501

The merit order column, in Table 6.4, is based on the merit order data which obtained from both electricity companies: SCECO-Eastern (for G1, G2, G3, and G4); and SCECO-Central for the other generators. This data show that the highest operating (generation) cost for the eastern region is only SR5.63/MWh while the lowest for the central region is SR37.17/MWh. The significant difference in generation costs between the two regions can be explained by two factors. Firstly, the generators in the eastern region use thermal (steam) turbines while those in the central region use gas turbines. Secondly, the dominant fuel in the eastern region is natural gas while the generators in the central region rely on crude oil and/or diesel, which are transported from the eastern region. The System Marginal Price (SMP), the market-clearing price, is set by the operating cost of the most expensive generator, G16, as shown in Figure 6.10 and Figure 6.11, below.

Figure 6.10: Short-Run Electricity Market

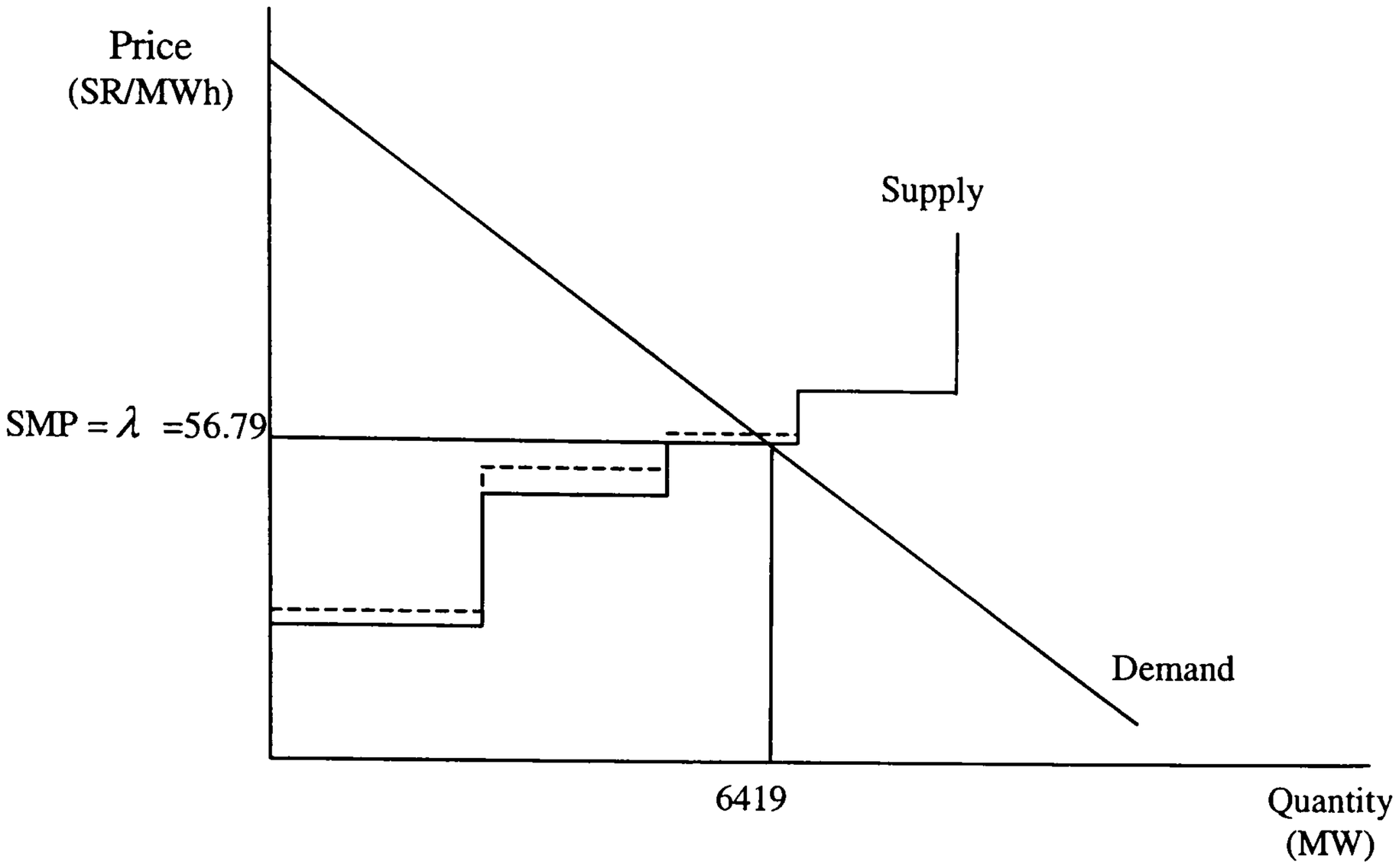
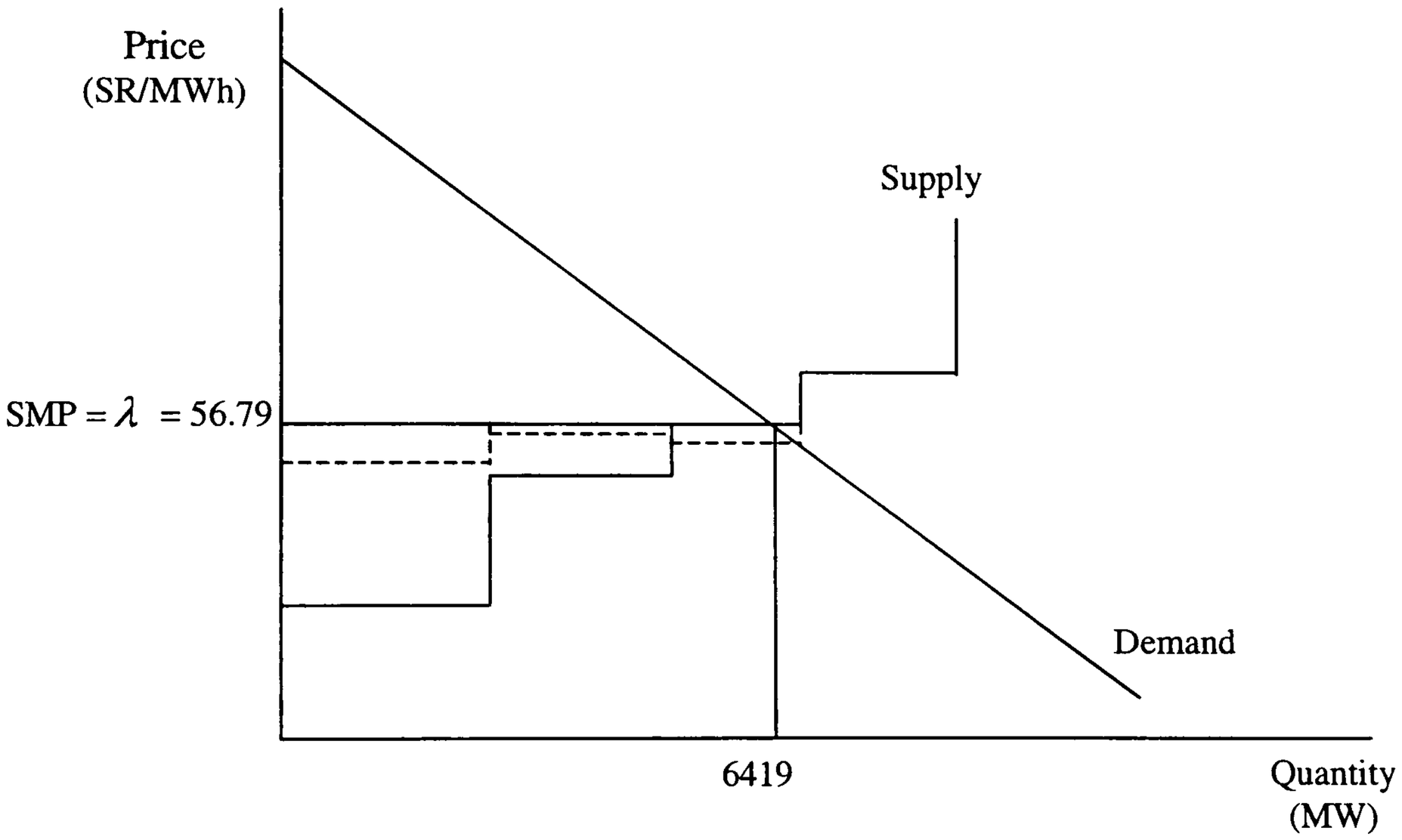


Figure 6.11: Nodal Spot Prices



In economic dispatching the generator with the lowest marginal production (generation and transmission) cost is dispatched first. The generator with the next lowest cost is then dispatched, and this continues until the total demand (including losses) is met. In Figure 6.10, each generator has a constant marginal operating cost, and the horizontal summation of these marginal costs results in the short-run supply curve for the system. Hence, the marginal generator determines the market price, which is the System Marginal Price (SMP).

According to Hogan (1998), the outcome of economic dispatching and the competitive market for electricity are the same at any given level of demand. This analysis obviously assumes that the generators bid their marginal operating cost. In practice, however, the generators' bids should reflect the cost of losses. This means that the generators must know the loss charge ex ante because they bid the marginal generating cost modified by the marginal (or tracing) loss charge in order to recover their costs. In an ideal situation, the marginal generator G16 should receive a nodal price of SR56.79/MWh, which is equal to its marginal generating costs plus zero marginal losses. Under ex ante charging, however, loss charges are determined by assuming any generator to be the marginal generator which means that the nodal price might be different from the actual one.

Instead of G16, choosing G14 (see Table 6.4) causes an upward shift for the supply curve as indicated by the dotted line in Figure 6.10. This shift does not change the economic dispatching outcomes, as the ranking of the generators in terms of losses remains the same. However, including loss charges results in lower nodal prices than the SMP, as indicated by the dotted line in Figure 6.11. This means that due to positive marginal losses (Figure 6.4) the generators' revenues are reduced which leads to lower producer surplus. On the other side of the market, due to negative marginal losses (Figure 6.4) the loads' payments are reduced which leads to higher consumers' surplus. Since at any particular node the price is the same for the generator and load, the reduction in generators' revenues (ie. reduction in producers' surplus) equals the reduction in loads' payments. Thus, these transfers offset each other which keeps the net welfare unchanged.

In the case of tracing charges, the positive loss charges shift the supply curve upward (see Figure 6.10) which result in lower nodal prices as shown in Figure 6.11. The reduction in generators' revenues result in lower producer surplus, but the consumer surplus and loads' payments remain unchanged which reduces the net social welfare. Regardless of which generator is assumed as the marginal generator, ex ante marginal charges preserve the efficient dispatching but the serious effects of such allocations on both generators' revenues and loads' payments can be disputed. Although the tracing charges would slightly reduce economic efficiency, its independence from the marginal node and lower charging differentials would make it much acceptable for competing users.

6.4.2.2 ADJUSTED SYSTEM MARGINAL PRICE

The last two columns of Table 6.4 illustrates how the adjustment of generation costs by transmission costs would result in similar ranking of generators using the marginal and tracing methods. As SMP dependes on the cost of the most expensive generator, the difference in ranking for low cost generators is less significant than that for high cost generators. Even for high cost generators, generation costs have more influence over the generators ranking than transmission cots do. For this reason, any dissimilarity between the marginal and tracing methods is likely to have a very limited impact on the overall ranking of the generators.

An important question to raise is how much a change in the ranking of expensive generators can influence the SMP. For this purpose we consider two cases: in the first case the generators operate with some of the capacity kept as a reserve; and in the second case lowest cost generators are operated at full capacity until the total demand is met. The actual data obtained for our system in the first case show that it operates below full capacity with an average 5% in reserve. Meeting the system load and losses requires 6419 MW of generation, which makes it necessary to have all sixteen generators (or twenty units) operating. Table 6.4 shows that, in this case, generator G16 sets the System Marginal Price (SMP) at SR56.79/MWH for the marginal method and SR 57.50/MWH for the tracing method. However, if G14 is chosen to determine charges ex ante, the SMP is set at SR60.5/MWH. This case indicates that even the marginal method can give charges that are different from the actual (ex post) charges.

In the second case, the operator of this system dispatches cheaper generators at their full capacity (i.e. no reserve) to meet the same generation level of 6419 MW. In this case, the calculation indicates that this target is met at the point where G14 is the most expensive generator for both methods. Consequently, generator G14 sets the adjusted SMP at SR53.7/MWH for the marginal and at SR54.62/MWH for the tracing method. An important conclusion that can be drawn from the above is that the generator which sets the adjusted SMP remains the same according to the marginal and tracing methods with some slight difference in ex ante charges. In short, these examples imply that tracing charges for transmission do not cause a significant distortion to the actual marginal charges and consequently have small impact on economic efficiency.

Table 6.5: Adjusted SMP using Different Pricing Methods

Methods		Case 1 (with reserves)	Case 2 (without reserves)
		Adjusted SMP	Adjusted SMP
Marginal	G16	56.79	
	G14	60.47	53.7
	G4	55.81	49.56
	M. Average	58.26	51.75
Tracing		57.5	54.62
Postage Stamp		57.65	54.5

The previous discussion shows that there is a trade-off between the objective of cost minimisation and that of system reliability. Also, Table 6.5 shows that the SMP is lower in the second case (no reserve) across all the different methods. This means that the SMP is not only influenced by the actual costs of generators but also by the priority given by the system operator to these two objectives.

More importantly, the table shows the deviation of the adjusted SMP, using the different methods, from the optimal SMP as determined by the marginal method (i.e. when G14 is the marginal generator). This deviation even occurs with the marginal method when one of the generators other than G16 is designed as the marginal generator. Thus, the issue is not which method to follow, but rather which method can be useful with the least departure from the ideal situation. Table 6.5 shows that both tracing (SR 57.50/MWH) and postage stamp (SR 57.65/MWH) method give values closer to the ideal situation (SR 60.47/MWH) than the other marginal cases. The lack of any spatial message of the postage stamp method gives the tracing method an edge over the former when a comparison is drawn between them. This leads us to focus not on the departure from the ideal situation *per se* but rather on whether there is a net gain would arise from such a departure.

6.4.3 THE COST OF DEPARTING FROM MARGINAL PRICING

At the outset, it is important to emphasise that the following discussion does not attempt to justify using the tracing method (or any other method for that matter) instead of the marginal method in the actual dispatching. Rather, the analysis is concerned with 'what if' the marginal method is replaced by the tracing method. The objective is to investigate how much it costs to depart from the optimal marginal pricing of transmission losses.

Economic theory stipulates that net social welfare is maximised using marginal pricing. However, in reality there is a departure from such an ideal solution. Then the important issue is how much society would loses from such a departure. According to Green (1998b), paying uniform price (i.e SMP), while transmission losses are charged postage stamp rates, leads to a minimal loss in economic efficiency. He estimated that such a departure from optimal marginal pricing will reduce the net social welfare, as measured by the sum of consumers and producers' surpluses, by only 0.6 per cent. As previously shown in section 6.3.2 that tracing prices have an advantage over postage stamp prices in terms of providing the necessary spatial signals making it more desirable from the social point of view.

Table 6.4 illustrates how the tracing method gives a similar short-run economic incentive as reflected in the dispatching of generators. The issue, then, is how much extra costs would results when the tracing method alters the ranking of generators from the ideal. To investigate this situation, an extreme case is used where the tracing charges do not lead to having the most efficient (in term of losses) generator dispatched. Table 6.6 is usefully illustrates the operating costs for each generation unit and at different levels of output.

Table 6.6: Generators' Operating Costs (in SR/MWh)

Generators	Generation Cost (SR)	Output (MW)	Total Generation Cost (SR)
G4	3.75	1478	5542.5
G1	5.63	250	1407.5
G2	5.63	10	56.3
G3	5.63	50	281.5
G10-U1	37.17	570.5	21205.485
G12-U1	38.02	345	13116.9
G11	38.13	578.2	22046.766
G5-U1	38.72	215	8324.8
G10-U2	42.11	208	8758.88
G9	42.11	416	17517.76
G8	42.11	416	17517.76
G6	42.67	588	25089.96
G12-U2	44.03	200	8806
G13	44.03	600	26418
G5-U2	44.75	30	1342.5
G15	46.24	90	4161.6
Sub-Total		6044.7	181594.211
Case One:G14	53.7	104	5584.8
Total		6149	187179.011
Case Two: G5-U3	53.43	104	5556.72
Total		6149	187150.931

This scenario is feasible when the assumption is that the total generation, which includes losses, is 6,148.7MW. The first 6,044.7 MW will be supplied by generators G4 through to G15 inclusive using either the tracing or the marginal method. The additional 104 MW can be supplied by either G5-U3 or G14 depending on whether the tracing or the marginal method is used. Table 6.4, in section 6.4.2.1, shows that with the marginal method G14 would have to be dispatched immediately following G15, while the tracing method would dispatch G5-U3 instead. Table 6.7, below, demonstrates in numbers the comparison between these two cases.

Table 6.7: Increase in Total Production Costs due to Tracing (in SR/MWh)

Case	Generation Cost	Transmission Cost *	Total Costs
One (Marginal)	187179.011	6658.8	193837.811
Two (Tracing)	187150.931	7593.18	194744.111
Difference	-28.08	934.38	906.3

* Using the operating cost of G14 (SR53.7) to price losses

In case one, the ideal, G14 is the marginal generator with an operating cost of SR53.7. The total system's losses in this case is 124MW which is the lowest level of losses, as G14 is the most efficient generator in term of losses. The total transmission cost is SR6,658.8, which is the value of these losses. Adding the operating cost of producing 104MW by G14 (i.e. SR5,584.8) to the operating costs of the first 6,044.7MW which is SR181,594.2, gives a total operating cost of SR187,179.011. Therefore, the total production cost, which is the sum of total operating cost and total transmission costs, is SR193,837.811.

A similar procedure can be calculated for the second case, where the total transmission cost increases to SR7,593.2 due to the increase in losses to 141.3MW. Table 6.7 shows that this increase in transmission costs outweighs the reduction in generation costs. Three important findings can be drawn from this table. Firstly, it confirms the advantage of marginal pricing in cost minimisation and attaining economic efficiency. Secondly, the tracing method deviation from this ideal case is very small accounting for only an increase of SR906.3 MW/h, which is 0.47 % of total production costs. Thirdly, the minimisation of costs should simultaneously include both the generation and transmission costs.

6.5 THE PROBLEM OF FREE RIDING

Section 6.3.2 gives a presentation of the general similarity in pattern between the marginal and tracing methods. These results provide a chance to compare how losses are allocated for individual generators (or demand centres). This is especially useful in investigating the issue of local effect which creates free riding problem, as explained in Chapter Five.

The ranking of generators (from the most efficient to the least efficient, in term of losses) is as follows:

- for the marginal method:

  G14, G7, G5, G15, G12, G13, G6, G8, G10, G9, G11, G16, G1, G2, G3, G4

- for the tracing method:

  G7, G5, G6, G9, G15, G8, G12, G13, G16, G10, G11, G14, G1, G4, G2, G3

It is worth noting that G7 (and to some extent G5) is identified, in Chapter Six, as a free rider under the tracing method. The reason is that it is located at the same bus as D7. The ranking of G7 and G5 shows that both are considered efficient generators according to the marginal and the tracing methods. The location of a generator near a demand centre (or vice versa) would give low charges according to both methods. However, the fact that G7 has no charges is a confirmation of the conclusion reached in Chapter Five (Section 4.1.1) that the tracing method has a very strong local effect. This means that the problem of free riding is a direct result of this effect. Consequently, the solution to the problem of free riding is in fact to minimise the local effect of the method. One way of doing this is to use zonal charges and by taking into consideration the relative size of each generator (or demand centre) in setting the charges.

The most notable difference in the ranking of the two methods is that G14 dropped from being the most efficient under the marginal method to be ranked as number twelve (out of the sixteen) under the tracing method. The generator is the central generator in area A3 where it supplies most of the power to the demand centres, including some remote rural towns and locations. This would naturally allocate, under the tracing method, higher losses to this generator. The central role of this generator in supplying the area's demand centres reduces the flow of electricity from areas A1 and A2 which are located to the south of area

A3. Ironically, the same reason which placed this generator at the top of the ranking for the marginal method placed it in a lower position for the tracing method.

The reason for this conflicting result is probably related to the fact that the marginal method considers the impact on losses rather than the share of the generator (or demand centre) in total losses. This fundamental difference between the two methods gives further support to the suggestion that the tracing method is suited better for zonal rather than nodal charging. In this case, nodes at similar locations are grouped under one zone which makes each zone represent a super node. The above ranking provides an illustration of the role of zonal pricing in reducing the differences between the two methods. The following two figures show the comparison of the zonal charges.

Figure 6.12: Marginal and Tracing Charges for Generators (Zonal)

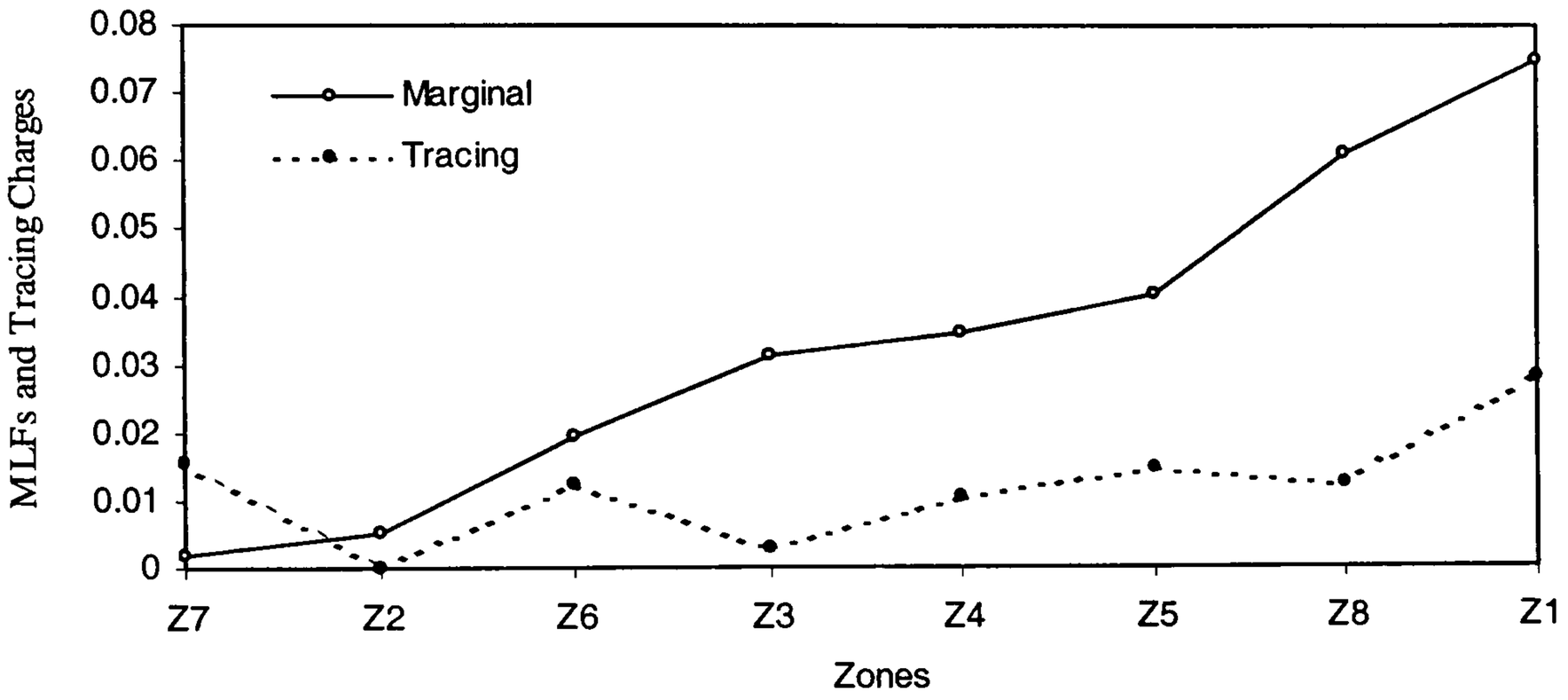
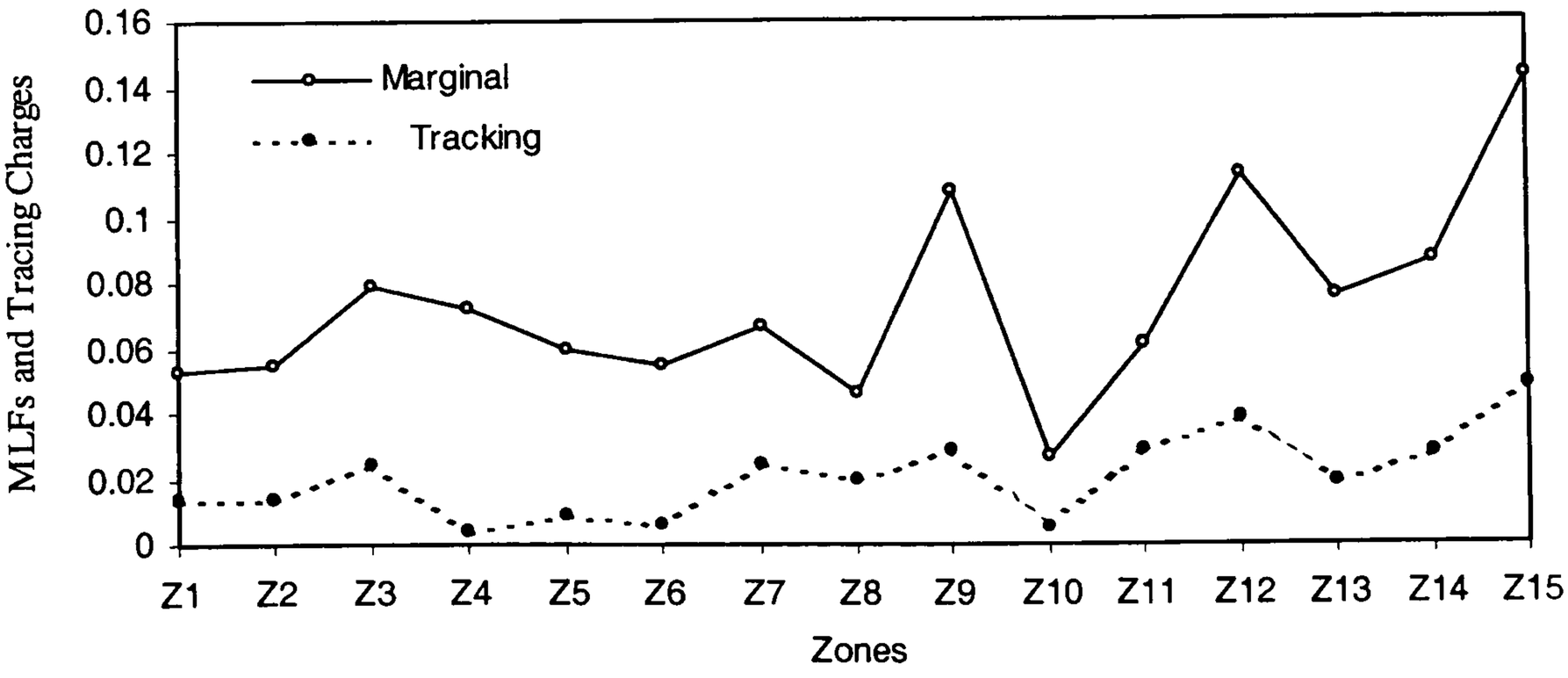


Figure 6.13: Marginal and Tracing Charges for Demand Centres (Zonal)



The grouping of generators is easier than that of demand centres. The researcher benefited from the company's own division of the network, in particular the demand centres, into zones. These figures show the similarity between the two methods, especially for the generators located at the extreme ends of the network. For example, the distant generators (G1, G2, G3, and G4) are grouped under zone Z1, and generators G5 and G7 under zone Z2. The two methods differ for the other zones and this is a confirmation of the ability of the marginal method to reflect small distances between nodes or zones. This grouping has also been done for the other generators (as well as for the demand centres). The comparison of the two methods on the basis of zonal charges gives further similar charges. This is more so in the case of demand centres than that of generators for the same reason that was mentioned in section 6.3.2. The following two figures, Figure 6.14 and Figure 6.15, illustrate an approximate topology of the generation and load zones of the network.

Figure 6.14 Topology of the Generators Zones

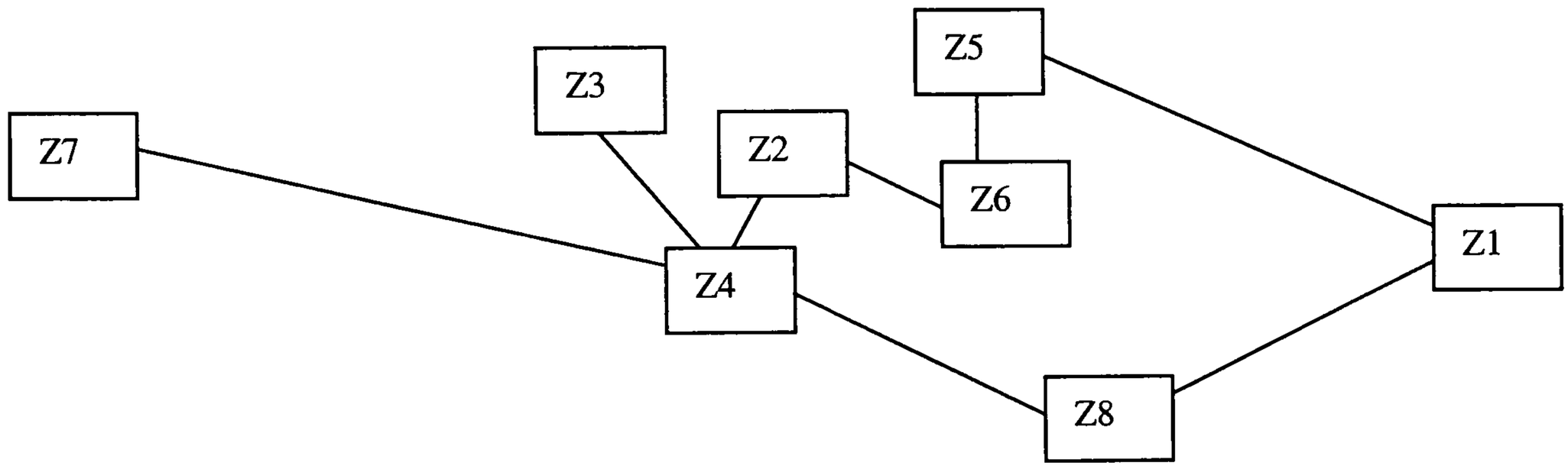
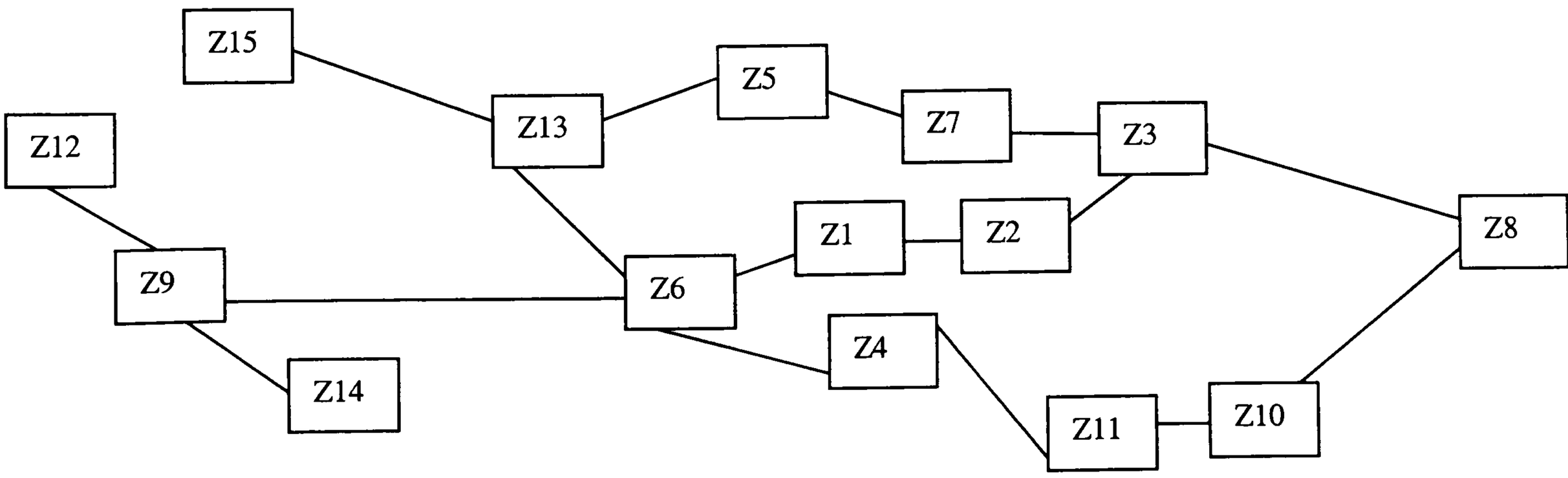


Figure 6.15: Topology of the Demand Centres Zones



CONCLUSION

The restructuring of the electricity industry and the separation of generation from transmission and distribution has made transmission pricing vital to the functioning of wholesale power markets, in either a bilateral or pool mechanism. There are different methods of transmission pricing that range from the ideal in the form of marginal cost pricing to the very simple in the form of average or postage stamp pricing. This chapter has reviewed the marginal method and has provided an empirical presentation of its main features as well as its limitations. Also, it has contributed to the debate on the issue of transmission pricing by conducting, for the first time, a comparison between this method and both the postage stamp and the new method of electricity tracing.

The chapter has demonstrated graphically and statistically the inability of the pro rata charges to allocate the transmission costs in a manner which incorporate the spatial dimension of transporting electricity between generation sources and consumption centres. This severe disadvantage of the postage stamp method can lead to inefficient decisions about electricity consumption, generation and transmission capacity expansion as well as the siting of new generators.

The comparison of the tracing charges with the marginal charges are based on a network which is not large enough to allow generalisation of the results. What is more certain, however, is that the tracing method is more suited for zonal rather than nodal charges and for a large system that is spread over a large geographical area. For example, this chapter illustrated that the tracing charges are very similar to the marginal charges when the comparison is for the zonal charges for demand centres. This observation implies a potential for the tracing method in the light of the present trend of integrating networks of different regions of the same country and even between networks from different countries.

The important point is that this research study considers that marginal cost pricing is preferable even in a modified form, which could be possible for a restructuring process that is in its initial stages. However, some caution is warranted as the simplicity and the practicability of the postage stamp method may prove to be too attractive to resist by the electricity authority or the regulator. Thus, the tracing method could provide a reasonable

alternative, which is worth consideration especially if its distortion to optimal prices is confirmed to be minimal.

The departure of the tracing prices from the first-best outcome is not significant enough to disregard it, but on the contrary these charges could introduce some stability and fairness into this vexing issue. This advantage is very much needed for developing countries which are in the process of privatising their electricity industries. This is relevant to the electricity industry in Saudi Arabia where further regional (and international) interconnection of grids and more reliance on distant sources of generation would increase the uncertainty of electricity trading.

The minimisation of risks is an essential element in speeding up the move toward privatisation and competition in the electricity industry. The decisions regarding private investments in the industry are based, among other factors, on the expected future cash flows of participants. The following chapter examines the advantage of the tracing method in introducing some predictability into the price volatility of electricity bulk markets. Although this stability might come with some loss of economic efficiency, this loss is expected to be small as more competition and cheaper sources of generation can create sufficient benefits to offset any efficiency loss that would come from the departure from marginal prices.

CHAPTER SEVEN
The Impact of Demand Variations on Transmission Charges

7.1 INTRODUCTION

The production of electricity has to match instantly the change in demand, otherwise the system will have blackouts. Each level of demand is associated with a different set of generators with various generation and transmission costs. As a result, the system marginal generation cost (λ) is expected to be different at every market-clearing price for every hour of the day. The changes in the loading conditions of the electricity system are caused by the continuous fluctuations in electricity demand, which impact the power flows and losses over the transmission network. Thus, the demand side of the electricity market has complementary influence, over the outcomes and the full functioning of the market, to that of the supply side.

The marginal pricing of transmission losses is able to reflect accurately the variations in demand but produces volatile charges. From an economic efficiency point of view, this volatility is desirable and also necessary to reflect the instant changes in the generation and transmission costs. The challenge, then, is to have a transmission pricing scheme which minimises this volatility and provides stable charges that reflect the actual hourly operations of the system. The crucial point is that stability should not be the sole objective desirable by itself, as it is possible to have transmission charges that are very stable but have no relation whatsoever to economic efficiency. This chapter illustrates, with real data, how the allocations of transmission costs are influenced by the changes in the system demand. The aim is to examine how the tracing, postage stamp and the marginal pricing methods are able to accommodate these two desirable objectives. For this purpose, the chapter uses the demand levels of an off-peak hour as the initial case and the peak hour as the case when the system is at its maximum loading condition.

7.2 THE IMPACT OF CHANGES IN DEMAND

The results for the tracing (and postage stamp) charges are calculated on the basis of the data output from the Load Flow Program (LFP) of SCECO-Central for off-peak and peak hours. The off-peak hour occurred at 6 a.m. on 1st June 1998 while the peak hour occurred at 3:15 p.m. on 9th June1998. The results for the marginal charges are calculated from the Optimal Power Flow (OPF), which is based on the data obtained from the same company for the same hours. Table 7.1, below, presents these two loading conditions at these two hours.

Table 7.1: Network Generation and Demand

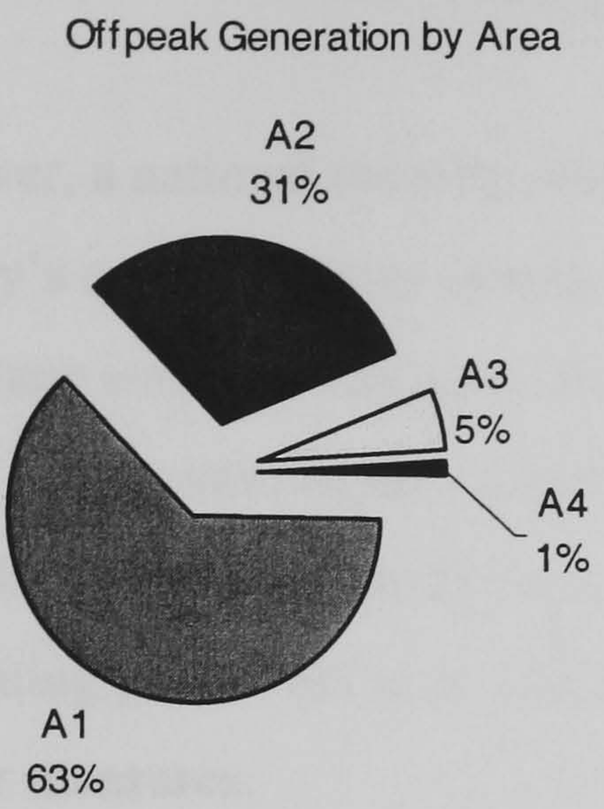
	Off-peak	Peak	Change	
	MW	MW	MW	%
Generation	4298.11	6418.72	2120.61	49.34
Demand	4252.95	6320.5	2067.55	48.6
Losses	45.16	98.22	53.06	117.5
(% of Generation)	1.05	1.53		

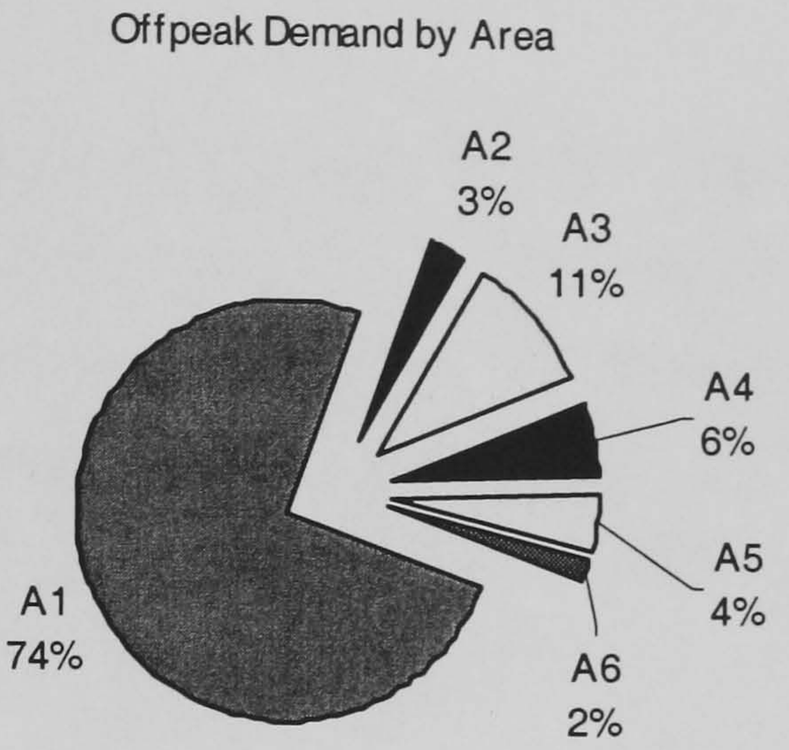
Source: SCECO-Central, Load Flow Program

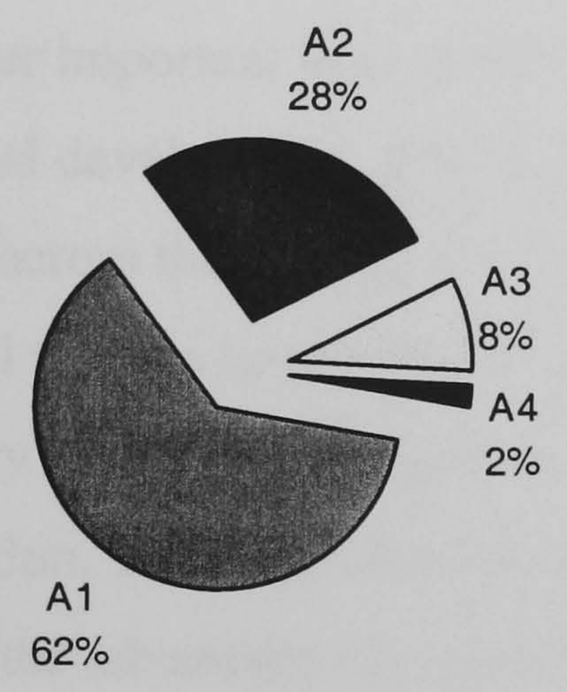
This table shows that generation had to increase by a higher rate than the increase in demand in order to take account of the increase in losses. The increase of 49.34 per cent in generation came with a 117.5 per cent increase in losses, which demonstrates the (approximate) quadratic relationship between power flow and losses on the network lines. This indicates that the peak demand imposed additional costs on the system through an increase in losses of more than 53 MW.

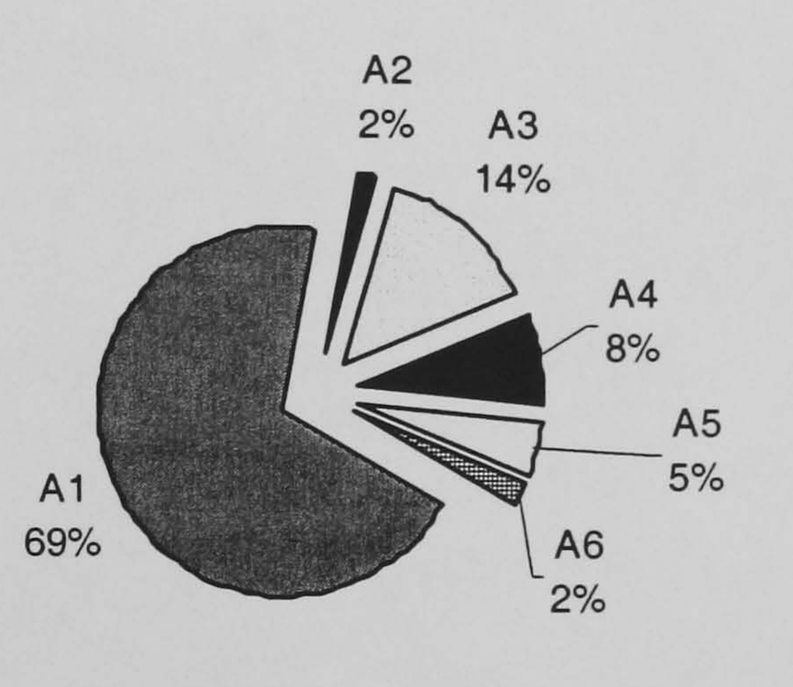
The increase in demand has additional transmission costs resulting from this relationship between the power transmitted and the losses associated with it. This resulted in an increase in the ratio of losses to generation from 1.05 per cent to 1.53 per cent. Figure 7.1 shows the breakdown of the network into its six areas, which are set in the LFP and represent very clearly defined geographical areas (i.e. sub-regions). The figure also shows each area's generation and demand at the off-peak and the peak hour.

Figure 7.1: Generation and Demand of the Network Areas









Peak Generation by Area

Peak Demand by Area

Figure 7.1, above, clearly shows that the concentration of the generation and demand of this network is in area A1 which is the capital city, Riyadh, and its suburbs. The generation of the net exporting area, A2, is important to this network even at the off-peak hour with 31 per cent share in total generation. The slight decline in the share of this area (as well as of A1) in total generation at the peak hour was due to the relative increase in generation of the areas; A3 and A4.

Obviously, this increase in generation in these two areas was necessary to meet the increase in their demand. This is useful in reducing the pressure on the transmission network, especially for the tie lines with the net exporting area (A2), which is the eastern region. However, as the industry moves into a market-based structure, most of the new generators are expected to locate in A2. This means that more demand centres in these

areas, and in most of the regions of the country, will become increasingly dependent on imported power from the eastern region.

However, a national security consideration, such as avoiding a concentration of the country's energy sources in one region, would require incentives through subsidisation to encourage some generators to locate elsewhere. This would be a clear distortion to market prices, but it could be minimised if the subsidies were limited in scope and have some link with efficient prices. Similarly, environmental considerations, such as the negative impact of locating generators near demand centres, especially residential areas, could involve similar measures.

Another important issue to be considered, in the broader context of pursuing a balanced regional development, is that of the advantages from having regional variations in peak hours across the country (see Chapter Two, section 2.3.3). For example, it is not very helpful that the largest area in this network, A1, has the highest population growth in the country with an annual growth of 8 per cent, most of which (5 per cent) is due to internal migration. This, naturally, increases the demand on the services, including electricity, and limits the advantage of reserve sharing between interconnected areas with their different peak hours.

7.3 THE TRACING CHARGES

This section investigates the impact of changes in demand from the off-peak to peak hour on transmission losses and, hence, charges. It is expected that changes in magnitude and/or the direction of line flows would result in different transmission charges. Table 7.2, below, presents the tracing charge, which is per unit (i.e. MW) or the ratio of losses allocated to each generator (or demand centre) to its generation output (or load).

Table 7.2: Charges for Generators at Off-Peak and Peak Hours

Generators	Output		Losses		Tracing Charges (pu)	
	Off Peak	Peak	Off Peak	Peak	Off Peak	Peak
G1	249.9	249.9	4.604784	7.162	0.018427	0.028659
G2	9.99	9.99	0.2481	0.357	0.024835	0.035736
G3	49.98	49.98	1.2866	1.8604	0.025742	0.037223
G4	1025.24	1477.87	19.7185	41.5347	0.019233	0.028104
G5	185	309	0.0226	0.0548	0.000122	0.000177
G6	511	511	1.299951	1.4884	0.002544	0.002913
G7	0	50	0	0	0	0
G8	180	378	0.8184	3.4703	0.004547	0.009181
G9	180	378	0.32	1.7703	0.001778	0.004683
G10	490	759	3.6031	10.9116	0.007353	0.014376
G11	184	543.99	1.7749	8.2452	0.009646	0.015157
G12	498	543	4.8165	5.8223	0.009672	0.010722
G13	465	523	4.5186	5.9754	0.009717	0.011425
G14	180	444.99	1.3065	8.0316	0.007258	0.018049
G15	40	90	0.2453	0.7998	0.006133	0.008887
G16	50	101	0.2563	1.27	0.005126	0.012574
Total	4298.11	6418.72	45.16	98.22		

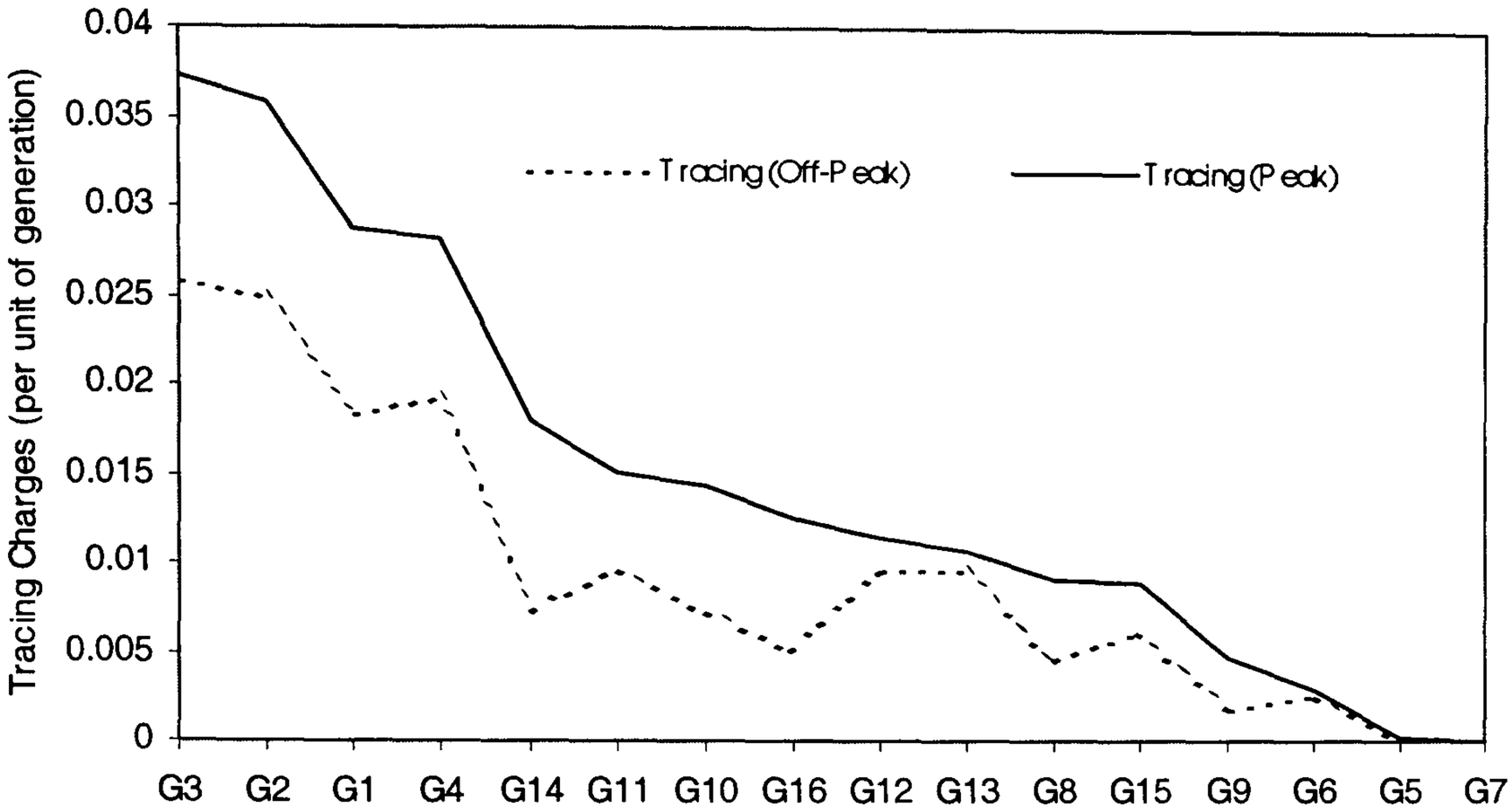
This table shows the comparison of the charges for the sixteen generators at the off-peak and peak hours. Some generators had no change in generation but their losses have increased, which in turn increased their charges. It is worth noting that despite the fact that the output of G1, G2, G3 and G6 did not change, their transmission charges increased at peak hour by 55 per cent, 44 per cent, 45 per cent and 16 per cent, respectively. This might indicate that externalities, which usually exist during peak hour, are reflected in these charges.

As usage of the existing capacity is expected to increase more at the peak hour than at the off-peak hour, it is reasonable to have an increase in the transmission cost of one MW from the same generator. This confirm the ability of the tracing charges to reflect network externalities. In addition, the generators G11 and G12 had the same charges at the off-peak hour but had different charges at the peak hour and these charges increased at different rates, by 57 per cent and 11 per cent respectively. Since both generators had the same output at the peak hour, it could be concluded that the generator size has no direct link to its transmission charges using this method.

7.3 .1 THE STABILITY OF TRACING CHARGES

It is very important to introduce stability and predictability into transmission pricing without losing sight of locational factors. This is especially true for investments in future generation and transmission capacity, which require predictable spatial signals. The results in Table 7.2 can be represented more clearly in Figure 7.2, below.

Figure 7.2: Tracing Charges for Generators at Off-Peak and Peak Hours



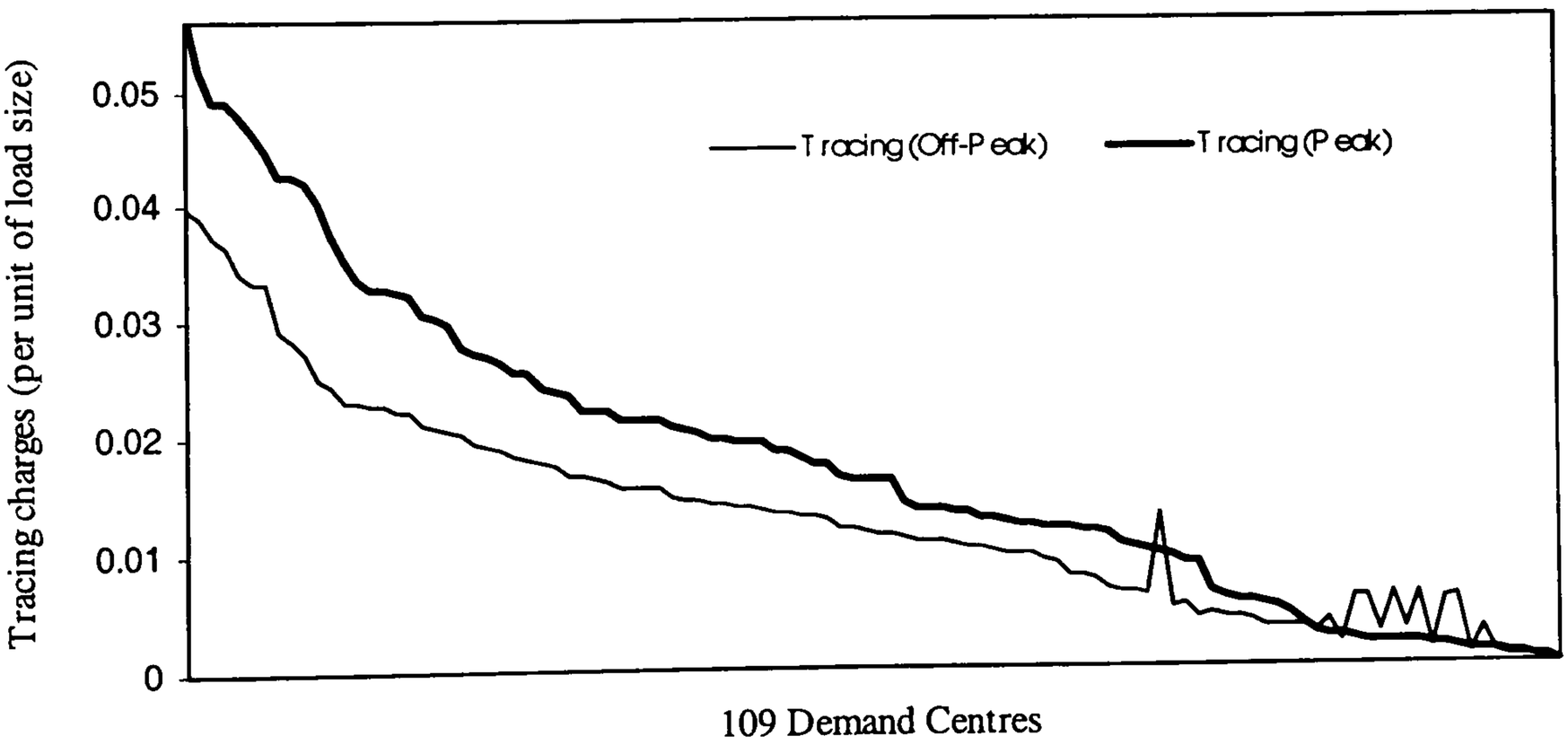
In Figure 7.2, the generators are ranked from the highest to the lowest in accordance with charges at the peak hour; this is represented by a steadily declining line. The figure shows that distant generators, such as G1, G2, G3 and G4, had a similar pattern of charges at both the off-peak and peak hours. This was also the case for generators with the lowest charges, including G9, G6, G5 and G7. The charges for the eight remaining generators had some fluctuation, which could become less subject to controversy if zonal charges were used instead. Although the peak charges increased the price differential between the distant generators and the other generators, this differential remains acceptable because it is much lower it would be than if the marginal charges were used.

It is clear from these examples that the charges at the two demand levels have a very similar pattern especially for distant generators in the eastern region. This confirms the conclusion that the tracing charges are able to better reflect the actual transmission costs when the system is spread over large geographical areas. In addition, the high correlation coefficient of $r = 0.981$ indicates a large degree of association between the charges at different levels of demand.

The tracing charges are also consistent with the actual operation of the system where the standard deviation of these charges is higher for peak (0.014) than that for off-peak (0.0079) hours. This indicates that the relative usage of some of the distant generators becomes higher than that of the much nearer generators, which implies an uneven increase in the extent of network usage by individual generators. These observations indicate that the stability of the tracing charges does not preclude charging for actual usage of the network by generators.

Figure 7.3, below, shows the tracing charges for the 109 demand centers of this network. The overall pattern of the charges, in this figure, illustrates that demand centres with high and moderate charges during the off-peak hour continue to pay high charges at the peak hour. Also, the charges at these two hours remain reasonably stable where the correlation coefficient of these charges is 0.95 and is reflective of fluctuations of the charges, where the standard deviation has increased from 0.008 at the off peak to the 0.014 at the peak hour. However, it is worth noting that although most of these loads pay higher charges at the peak hour, some are actually benefiting at this hour. This is reflected in the line for off-peak charges, which rises above the peak charges line. The following section will examine this observation in more details.

Figure 7.3: Tracing Charges for Demand Centres at Off Peak and Peak Hours



7.3.2 THE PROBLEM OF LOCAL EFFECT

The above discussion has pointed out that some of the nine demand centres have higher charges at the off-peak hour than at the peak hour. This is a surprising result and could be explained by the increase in the loads of these demand centres, which is higher than the increase in losses, leading to lower peak charges. However, this explanation is not completely satisfactory, as Table 7.3 illustrates that some of these demand centres (with higher charges at the off-peak hour) have lower transmission losses (costs) even though their loads have increased.

Table 7.3: Demand Centre with Lower Charges at Peak Hour

Demand Centres	Load (MW)		Losses (MW)		Tracing Charges (loss per MW of Load)	
	Off Peak	Peak	Off Peak	Peak	Off Peak	Peak
D5	186.3	207	1.0387	0.3154	0.0055	0.0015
D7	77.4	128	0.452	0.1503	0.0058	0.0012
D14	43.81	86	0.1718	0.0935	0.0039	0.001
D33	52.2	82	0.1524	0.1724	0.0029	0.0021
D45	34.2	38	0.0391	0.0428	0.0011	0.0011
D47	40.5	45	0.1305	0.0781	0.0032	0.0017
D56	22.5	25	0.1309	0.0439	0.0058	0.0018
D74	10.8	19	0.1387	0.1891	0.0128	0.0099
D77	87.3	97	0.2882	0.1802	0.0033	0.0018

Table 7.3 shows that all the nine demand centers pay lower charges at the peak hour than at the off-peak hour, which means that the increase in demand results in lower tracing charges. The tracing charges for the demand centres at D33, D45 and D74 declined at the peak hour despite the increase in their allocated losses. The reason for this is that the loads at these demand centres increased at a higher rate than in their traced losses.

As regards the remaining six demand centres (D5, D7, D14, D47, D56 and D77), the increase in their loads came with a reduction in their losses, which caused charges to decline. This reduction in the peak charges for both groups could be explained by the fact that these demand centres benefit from being located at, or at least very close to, generation sources. However, this reduction is inconsistent with the loss allocation under the marginal cost pricing method, which confirms the local effect problem associated with the tracing method.

So far the discussion has considered transmission losses in MW units rather than in monetary value which is given by the system marginal genertion cost, λ. As the marginal generation cost at the peak hour is higher than the marginal generation cost at the off-peak hour, the value of the allocated losses is expected to be higher during the peak hour. However, Table 7.4, below, illustrates that this is not the case with most of the nine demand centres discussed, where very high value for λ.is required to make the peak charges higher than the off-peak charges. This clearly highlights the significance of the local effect and the free riding problem associated with it. Thus, there is a need for some remedies, such as using zonal-based charges to overcome these discrepancies in nodal tracing charges.

Table 7.4: Tracing Charges at Different Values for System Marginal Price

Demand Centers	Off-Peak	Peak						
	for λ = 100	for λ = 110	for λ = 150	for λ = 200	for λ = 300	for λ = 350	for λ = 400	for λ = 500
D5	0.5575	0.16764	0.2286	0.3048	0.4572	0.5334	0.6096	0.762
D7	0.584	0.12914	0.1761	0.2348	0.3522	0.4109	0.4696	0.587
D14	0.3921	0.11957	0.16305	0.2174	0.3261	0.38045	0.4348	0.5435
D33	0.292	0.23122	0.3153	0.4204	0.6306	0.7357	0.8408	1.051
D45	0.1143	0.12386	0.1689	0.2252	0.3378	0.3941	0.4504	0.563
D47	0.3222	0.19096	0.2604	0.3472	0.5208	0.6076	0.6944	0.868
D56	0.5818	0.19316	0.2634	0.3512	0.5268	0.6146	0.7024	0.878
D74	1.28	1.09483	1.49295	1.9906	2.9859	3.48355	3.9812	4.9765
D77	0.3301	0.20438	0.2787	0.3716	0.5574	0.6503	0.7432	0.929

where λ is the system marginal generation cost (in SR),
SR100 = $27

Table 7.4 uses the marginal cost of generation to give a monetary value to the transmission losses. For a system with no line congestion, the marginal cost of producing an additional MW is expected to be lower at the off-peak hour than at the peak hour. So it is reasonable to assume that the transmission cost of delivering one MW to a demand centre has a much higher value at the peak hour. The above table shows that this is not the case for these nine demand centres, with the exception of D45 and to some extent D33 and D74, which happen to be the loads allocated higher losses at the peak hour.

The table shows that if the price at the peak hour is assumed to be SR110, only D45 pays higher charges than at the off-peak hour. So the shaded area shows the assumed value of λ

at which each centre is paying higher charges at the peak hour. It is clear that D5, D7 and D14 require very high λ to reach that point. It is worth noting that these three demand centres are located at the same generation nodes of G5, G7 and G14, respectively. An inspection of the position of the other demand centres on the actual network indicates that they are located very near generation sources and in areas with more available generation capacity at peak than at off-peak hours.

7.3.3 THE SIGNIFICANCE OF THE LOCAL EFFECT PROBLEM

The above discussion, as well as the analysis in Chapter Six, highlights the problem of free riding and its occurrence in both the generation and the demand side of the system. Table 7.2, section 7.3, for example, shows that G7, which supplies all of its output to D7, has the same (zero) charge whether it produces or not. However, this is unfair as G7 benefits from just being connected to the transmission grid without even having to use it directly which provides some kind of insurance.

This generator has the advantage of using the available transmission capacity at any moment in time, which is a benefit that must be paid for. In addition, the homogeneous nature of electricity makes it possible that some of the power produced by this generator uses the network and consequently impact other users. This usage is confirmed by the fact that G7 has positive marginal charges, indicating its impact when the marginal generator is located in the same area, A1, or G14 (as in Figure 7.6 in section 7.5). Thus, it is reasonable to consider that the tracing allocation of these variable costs makes G7 a free rider in this system. Consequently, it is necessary to eliminate the cross-subsidisation among generators by addressing this problem without altering the locational signaling.

In short, the problem of local effect, and the free riding problem that results from it, could be more easily avoided if the system transmission costs were allocated on the basis of the zonal rather than the nodal prices. This also confirms the suitability of the tracing method for systems with low demand density. This is obviously is in the case of Saudi Arabia where the geographical nature of the country shows dispersed urban centres containing almost 90 per cent of the population. As a result, it becomes easier to identify the zones clearly (for both generators as well as for demand centres). In addition, the sheer length of

distances between zones makes the ranking of charges more accurate and thus more acceptable.

7.3.4 TRACING CHARGES FOR THE NETWORK AREAS

In the previous sections, the discussion was focused on individual charges for either generators or demand centres. Now it turns to charges based on area, as shown in Table 7.5, below.

Table 7.5: The Charges for Generation (by Area)

Area	Percentage Increase in		Tracing Charges (loss per MW of generation)		
	Generation	Losses	Off-peak	Peak	Increase (%)
A1	48.4	120	0.0064	0.0094	46.8
A2	33.9	97	0.0194	0.0285	46.9
A3	143	470	0.0071	0.0165	132
A4	102	395	0.0051	0.0126	147

This table shows that the increase in losses allocated for each area is larger than the increase in generation, which means that the increase in transmission charges might be influenced by the location of the generators. For example, the generation in A1 increased by 48.8 per cent and the losses by 120 per cent even though its demand increased by only 37 per cent. This indicates that this area exports part of its power to other areas, especially A5 and A6 that do not have their own local generation sources. This means that power flows have increased on the lines supplying A1 as well as those supplying these two areas from A1, which results in higher losses over the lines.

Table 7.5 shows in the second and third columns that the relative increase in losses for each area is similar to the relative increase in generation. However, the increase in generation comes with an increase in losses, but not necessarily with an increase in charges by the same percentages, as shown in the last column. For example, area A3 has the highest increase in generation by 143 per cent and the highest increase in losses by 470 per cent, but the tracing charge increased by 132 per cent.

These examples illustrate that the tracing charges are flow-based and are quite closely related to the system operations, which is an advantage over the postage stamp method (and the contract path method for that matter). This is not the case with respect to the

marginal cost pricing method but, as shown in Chapter Six, the tracing charges are not considerably dissimilar to the marginal charges. Table 7.8, below, shows the case when charges are levied on the loads of the areas in this network.

Table 7.6: The Charges for Demand (by Area)

Area	Percentage Increase in		Tracing Charges (Loss per MW of Load)		
	Load	Losses	Off-peak	Peak	Increase (%)
A1	37	79	0.0088	0.0115	31
A2	0	49	0.0162	0.0241	48.8
A3	96	214	0.0151	0.0242	60.3
A4	107	221	0.0159	0.0246	54.7
A5	68.8	191	0.0151	0.026	72.2
A6	71	193	0.0197	0.034	72.6

This table shows that the change in transmission charges are not necessarily proportional to the change in the size of load. For example, the demand at area A2 did not change but its losses and charges increased by an equal percentage of 49 per cent. The table also shows that area A4, which has the highest increase in demand, has the highest increase in losses but not necessarily the highest increase in charges. The importance of these findings is that they confirm the ability of the tracing allocation to reflect in a stable and transparent manner the principle that it is more expensive to deliver one MW at peak rather than at off-peak time. As a result, it is reasonable to assume that charges at peak times to be higher.

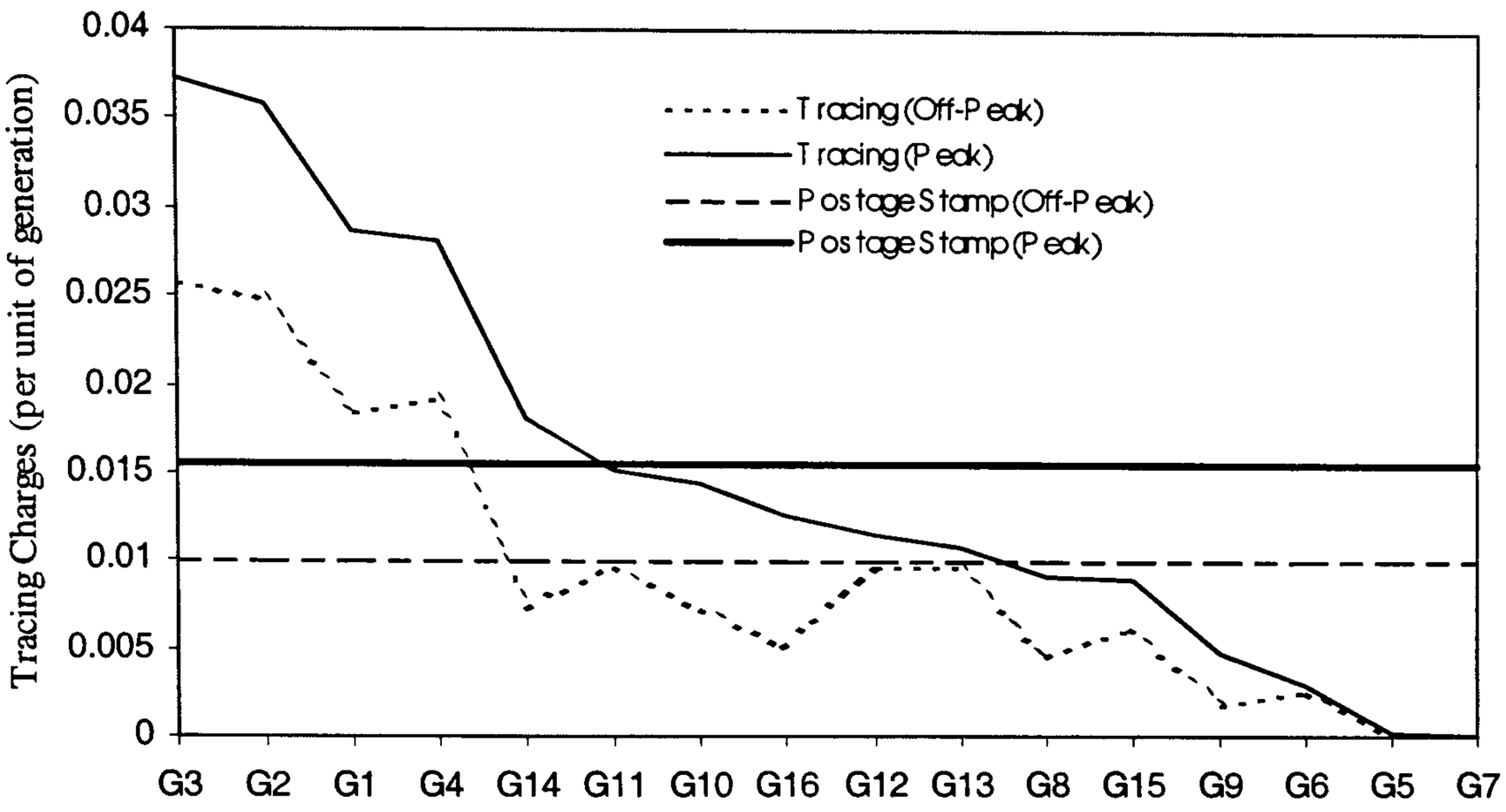
7.4 THE STABILITY OF POSTAGE STAMP CHARGES

The advantage of the postage stamp method over the other methods is in its very stable charges, which for a certain level of transmission losses are calculated on the basis of the user's size. For example, at the off-peak hour, every generator pays 1.05 per cent of its generation for losses and 1.53 per cent at the peak hour. This advantage of stability, however, does not eliminate the criticism directed at this method that its charges do not incorporate locational differences.

Obviously, ignoring these costs has direct negative implications for aspects of both productive as well as allocative efficiency. Thus, the choice is whether the priority should be given to the advantage of stability at the expense of economic efficiency considerations.

Figure 7.4 provides a comparison between the charges using the tracing method and the postage stamp method at the off-peak and peak hours.

Figure 7.4: Postage Stamp and Tracing Charges for Generators



This figure illustrates that different generators would have different preferences for the two methods. While distant generators prefer postage stamp charges, some generators which are located near demand centres, such as G5 and G7, may have enough reasons to object to these charges. The acceptance of these methods by any one of the other generators depends on how much their charges are reflective of the changes in the load level. For example, G11 can be indifferent to a choice between the two methods as it pays the same charges regardless which one of the methods is used in this example at least.

Figure 7.4, above, shows that the postage stamp makes distant generators, such as G1, G2, G3 and G4, pay the same charges as the generators that are located near consumption centres. This clearly distorts the necessary spatial message that a good transmission pricing method should provide. The negative implication of adopting a non-spatial transmission pricing method is that the opportunity to provide a level playing-field for the competing generators would be lost.

Figure 7.5: Postage Stamp and Tracing Charges for Demand Centres

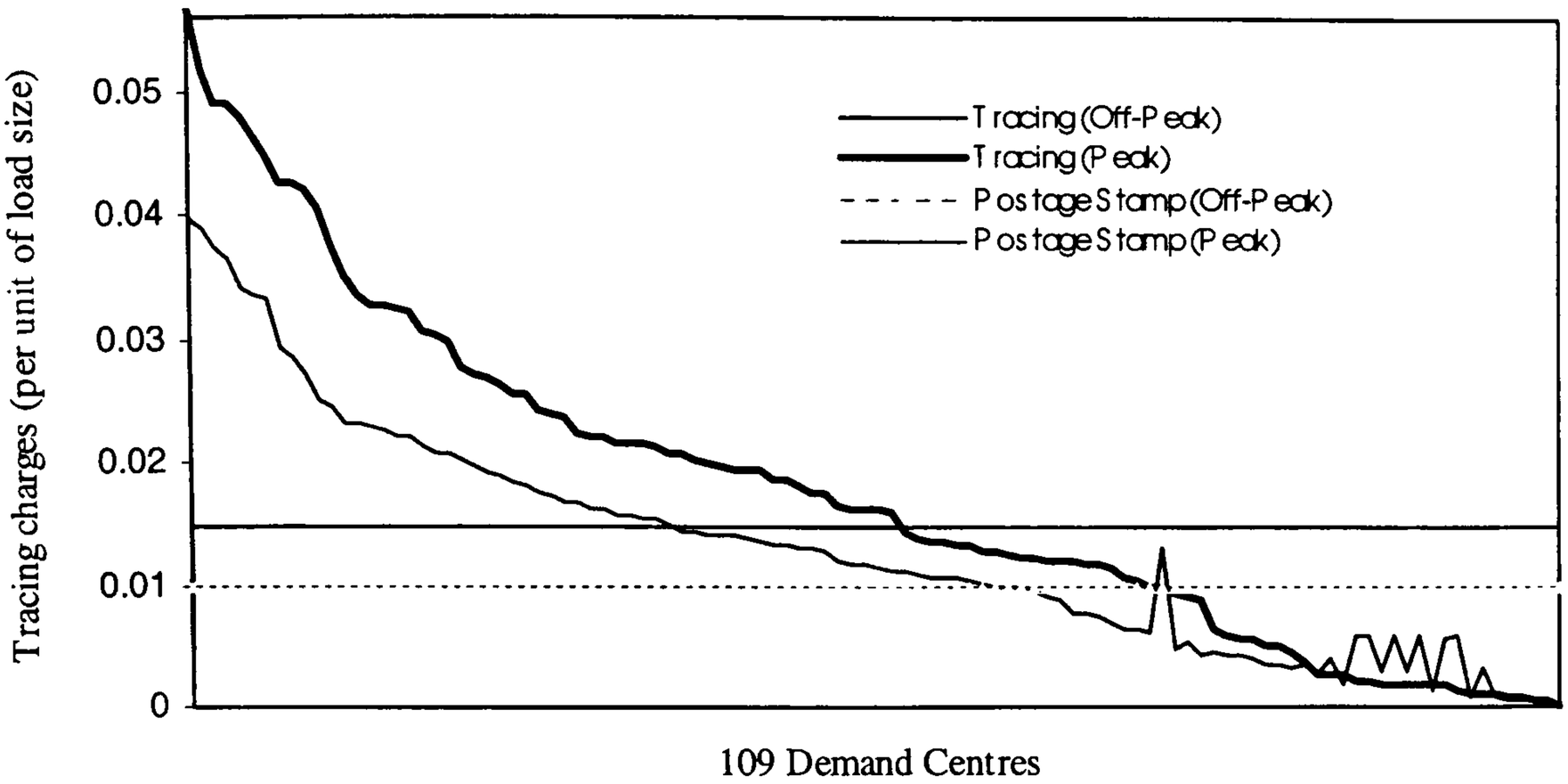


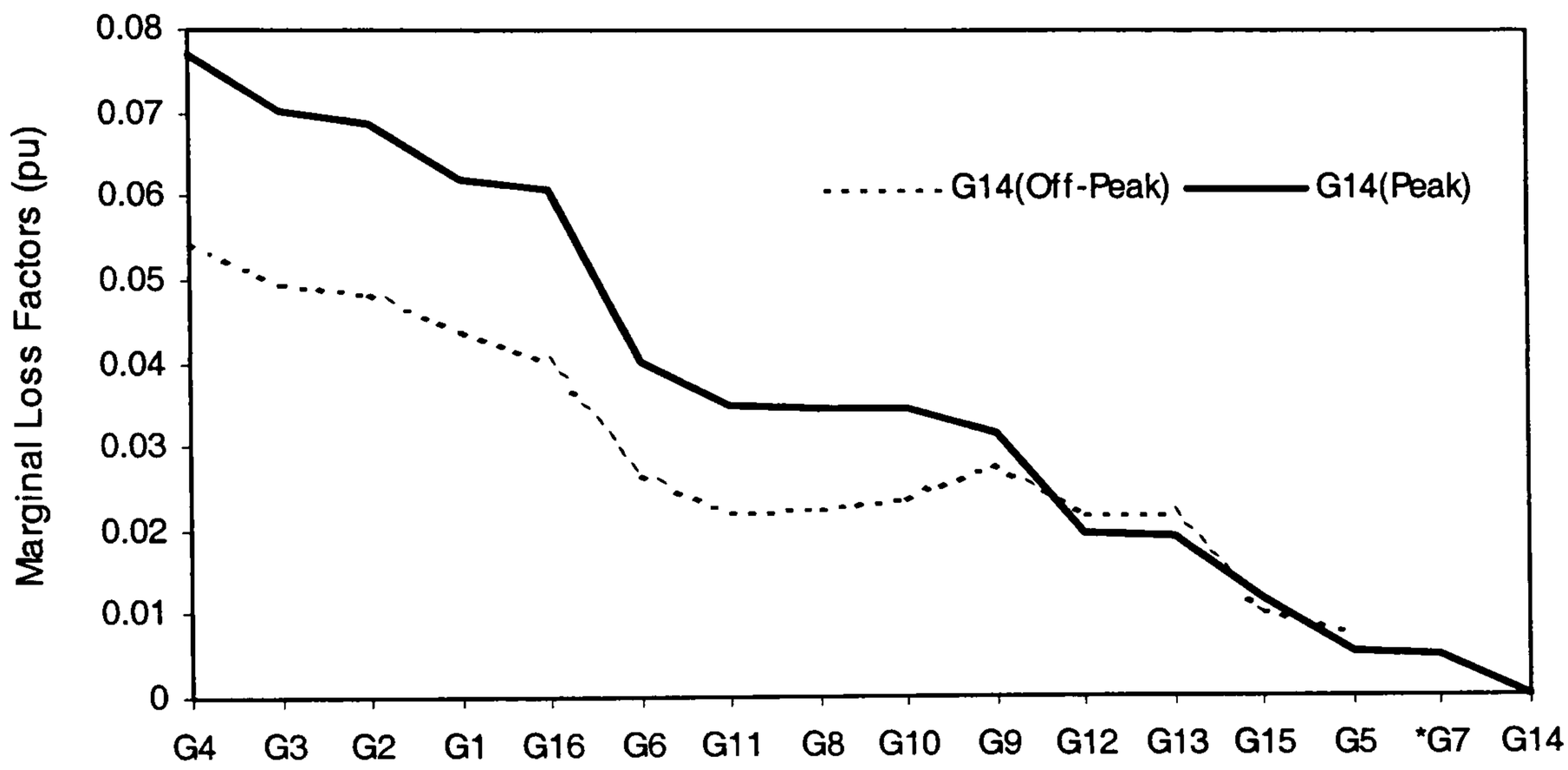
Figure 7.5 gives similar results to those of the generators in Figure 7.4, which confirms the comparison points raised in the above discussion. It could be argued, however, that allocating transmission costs between demand centres instead of generators will counterbalance the disadvantages of the postage stamp charges. The basis for this argument is that the demand for electricity is insensitive to spatially differentiated prices. However, the counter-argument to this reasoning is that this is true for small consumers but not necessarily for large ones, such as industrial consumers. Also, small consumers do not usually change their location in response to change in retail prices, but they can shift part of their consumption from peak to off peak periods. Thus, the adoption of real time prices, or at least time-of-use prices, that include the generation and delivery costs could alter this consumption pattern in line with their willingness to pay.

7.5 THE VOLATILITY OF MARGINAL CHARGES

The marginal cost pricing of transmission losses has the advantage of reflecting accurately the actual operation of the system at different levels of demand. However, the choice of the marginal generator introduces volatility and, hence, the difficulty of predicting the transmission charges that vary with fluctuations in demand. This is caused by the fact that the marginal charges depend directly on the choice of the marginal generator at each level of demand and also on the changes in the pattern of the power flows over the transmission network.

One of the solutions for dealing with this issue is to fix a particular generator as a reference point. This generator is usually chosen from the generation sources that are more likely to be located in the area where most of demand centres are concentrated. Figure 7.6 shows the marginal charges for losses at the off-peak and peak levels of demand. These charges are based on the assumption that the marginal generator is fixed at the node where G14 is located, which is the most efficient generator in terms of transmission losses.

Figure 7.6: Marginal Charges at Off-Peak and Peak Hours (Assuming G14 as the Marginal Generator)



This figure illustrates that marginal charges at both levels of demand have a similar pattern of charges. This is confirmed with a correlation coefficient of 0.98 between the two sets of charges, which indicates the identical ranking of generators in both loading conditions. The standard deviation for the off-peak and peak hours are 0.015 and 0.24 respectively, which shows that at the peak hour some generators use the transmission network more extensively than others. This also confirms the similar results in section 7.3.1 for the tracing charges, indicating the similar ability of this method to reflect the changes between the two loading conditions.

Figure 7. 6 also shows that the charges for the distant generators G1, G2, G3 and G4 are more predictable than those for the other generators which are mostly located in areas of demand concentration. This observation points to the potential for the latter generators to

reject the calculation of their charges on the basis of the fixed generator. This rejection could occur if some generators in these areas considered such charges higher than they would be with no fixed generator. This would be particularly so if other competing generators within the same areas had much lower charges. As Figure 7.6 illustrates, this is possible where the designation of the same generator as the marginal alters the ranking of generators in these areas. Obviously, this rejection may be less likely if the charges are set for zones rather than nodes even when the marginal cost pricing method is used.

Another similar solution is that of using the annual average of marginal losses. This solution aims at preserving the spatial signal of the marginal charges without having to choose a particular generator. However, this solution raises two problems that could prevent its implementation. Firstly, some generators are dispatched only at peak hour, as is the case with G7 (see Figure 7.6). Also, this is the case for generators which are gas-fired and those that are built for meeting peak demand. Such generators may consider these charges disadvantageous if the ex ante charges are considered lower when the ex post marginal generator is used at the peak hour.

The second problem facing this solution comes from the fact that the monetary value of transmission losses depends on the marginal generation costs of the last generator that makes it to the merit order schedule at a particular hour. Thus, the critical question is which λ to choose, especially as there is very likely to be a different λ for each hour of the day. Obviously, the success of allocating transmission losses either on this basis or using the concept of a fixed generator depends mainly on the acceptance by all participants of these modifications prior to implementation.

These problems highlights the likelihood that an electricity industry which is in the process of developing its wholesale market would find it easier to introduce such modifications than an industry with an already established market. In the latter case, some of the players have reason to object to or even block the implementation of any changes which they consider disadvantageous. The lesson for the electricity industry of Saudi Arabian is that the attempt to introduce marginal cost pricing of transmission requires clarification of these issues before the introduction of the wholesale power market. This is very important

for potential generators who need transparent rules to guide their decisions with regard to plant siting and the choice of generation technology.

CONCLUSION

What is relevant to the cost of producing and transmitting (and distributing) electricity are the issues of not only where but also when electricity is delivered (consumed). The electricity system as a whole is designed to ensure that sufficient generation, transmission and distribution capacity is available for meeting the peak demand when it occurs. Thus, economic efficiency requires that end users face the retail prices that reflect the actual cost components. This is possible in a decentralised industry structure if the wholesale market prices incorporate the spatial and temporal factors influencing these prices.

This chapter has demonstrated that the transmission losses are generally higher in absolute and in relative terms at the peak hour than at the off-peak hour. However, the allocation of these costs runs into some difficulties because the charges for any individual user are influenced directly by the variations in demand and changing power flows over the whole network. Thus, the challenge is to have a good transmission pricing scheme that can reflect the spatial costs associated with different loading conditions in a predictable and stable manner. The important point, though, is that stability of charges should not be sought for its own sake when the resulting transmission prices have no relation to economic efficiency.

The charges of the postage stamp method are very stable, in the sense that a pro rata charge for each generator (or each load) is always higher at peak than in the off-peak hours. However, this high degree of stability comes with complete disregard for locational signaling at both time periods. At the other end are the marginal charges, which accurately reflect the costs associated with both the time and the location of use. The volatility and the large differentials of these charges can obstruct their adoption unless some modifications are introduced early enough in the restructuring process to ensure acceptance by the participants. The tracing charges do not have exactly the same advantages as the marginal charges, especially for nodal charges. Nevertheless, the independence of tracing charges

from the choice of marginal generator facilitates transmission costs' allocation with a higher degree of predictability.

In summary, this chapter has illustrated the additional difficulty facing the selection among the different transmission pricing methods. There is a need for the selected method to reflect efficiently the impact of demand changes on transmission costs. Although the marginal method is preferable, even in a modified form, the tracing method is worth consideration if more extensive research shows that its departure from the first best situation is minimal. Having the correct transmission charges helps not only in the siting of generators and the technologies used but also in guiding investment decisions regarding generation and transmission capacity.

Another important implication is that benefits from the wholesale market cannot materialise if wholesale prices do not feed into retail prices. The decisions of final consumers should be based on the actual costs associated with their consumption. Thus, consumers need to be able to observe and react to changes in prices by using real-time pricing. This implies that the demand side of the market is directly involved and should be considered as an essential part of designing a successful electricity market. However, this could lead to direct exposure of consumers to price fluctuations which cannot be politically feasible unless significant competition as well as choice is introduced. Real competition in generation, and even in supply, can help in keeping wholesale and retail prices as low as possible.

CHAPTER EIGHT
Potential Applications of Tracing Pricing

8.1 INTRODUCTION

Saudi Arabia, like many countries around the world, is going into the process of liberalising its electricity industry. In addition, the country is involved in another process of integrating its national transmission network with that of the GCC countries and, at a later stage, with other regional interconnections. These developments make transmission pricing a critical issue, which needs to be addressed at an early stage in the creation of markets for electricity. Although there are different methods for pricing transmission, agreement on a unified method between different participants with conflicting interests is difficult to achieve.

Chapters Six and Seven provided a comparison of the new method of electricity tracing with the marginal and average (in the form of postage stamp) pricing methods. This chapter has the aim of presenting two potential applications of the tracing method. These applications are essential in facilitating successful market liberalisation of electricity industries both nationally and internationally. The first application deals with the issue of international trade in electricity where the complexity of the process requires transmission pricing which is transparent and easy to implement with a minimum distortion of economic efficiency. The second application deals with the issue of designing access charges to the transmission network. This is very necessary for cost recovery in electricity transmission which is characterised by economies of scale due to its large fixed (sunk) costs. The usefulness of this chapter, and this thesis in general, is that its relevance is not limited to the network of a certain country or geographical region, but can be applicable to any network or region which has embarked on market liberalisation.

8.2 APPLICATION ONE: CROSS-BORDER TRADE IN ELECTRICITY

The first international power interconnection was that between the United States and Canada at the beginning of the twentieth century. The European experience of international interconnections began in the early 1930s. Since then many regions in the developed and the developing world have realised the advantages of interconnection and begun to welcome power exchange between countries. If the twentieth century was the century of interconnection and electricity exchange between countries, the twenty-first century may become the century of integration and trade between networks. The new century may bring with it innovations and some technological advancements which would change existing arrangements of trading in electricity over transmission networks[4]. However, new arrangements resulting from new technologies would, in turn, raise new and unexpected issues.

8.2.1 BENEFITS AND PROBLEMS OF INTERCONNECTIONS

The justifications for interconnection between countries are not dissimilar to those for interconnecting utilities and regions of the same country. There is a broad agreement in the literature such as Joskow and Schmalensee (1985), Pechman (1993), Andrews (1995) and Badawi (1997) on the main benefits (and problems) that can arise from interconnection. The benefits of interconnecting of different electricity networks could be summarised as follows.

(1) The interconnection lines (tie-lines) between different networks function as additional sources of generation. The advantage of the interconnection is not only in the reduction in the substantial generation investments, but also in the increase in the system's reliability.

(2) Interconnection reduces the spinning reserve, which is the capacity that has to be maintained to keep the system functional. In this case, all interconnected networks would share the available reserve without jeopardising the security of the system.

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[4] The Financial Times (6-9-2000) reported the development of a new technology (called Regensys) for storing large quantities of electricity. If this technology is feasible, the belief in the natural monopoly of electricity transmission will require rethinking.

(3) Interconnection makes it possible to take advantage of the differences in the marginal generation costs between generation units, which induces more efficient utilisation of the available capacity.

(4) Interconnection of generation plants to the same grid would result in considerable economies from maintenance co-ordination. The costs of planned outages would be lower than the case when isolated plant requires maintenance and consequently higher cost replacement power is needed.

(5) Interconnection makes it possible to take advantage of the variations in seasonal, weekly and even daily load peaks between the different networks. This would reduce the generation costs by allowing the most efficient generation unit to be chosen to meet the increase in demand.

(6) Power generation stations may be optimally located in areas with excess cheap fuel sources. Once transportation costs are considered, it might be more economical to transmit electricity rather than transporting fuel in its original form.

(7) In a deregulated market, the transmission grid will become the physical market where electricity is traded. Hence, more interconnections would increase the market size and provide more alternatives to buyers (such as distribution companies) and sellers (such as generators). This notion of the electricity market means that higher trade would result in better utilisation of the grid.

Despite the above advantages, the integration of separate networks into one complex system is not expected to function without some problems, although the international experiences indicate that the overall economic argument for grid interconnections is very strong. The potential problems could include the following.

(1) The interconnection of a number of networks can make system control a formidable task. This can be more so when the stability of the whole system is affected by an accident at one of the networks.

(2) There can be higher costs for the construction of tie-lines between two networks when these lines are too long in comparison with the internal lines of one or both networks. This means that the economics of interconnection should consider the electricity consumption density within each network, as the geographical proximity of countries does not necessarily imply that major centres of consumption are close to each other.

(3) If the usage of the tie-lines is limited, the operational (transmission losses) and capital costs will be high in relation to the volume of the transferred power. Thus, it may become more difficult to reach a favourable cost/benefit ratio from interconnection.

(4) Viability studies of grid interconnection should consider the transmission losses which can be very high for a distance over 1500-2000 km even with lines of high voltage as high as 700 kV level (MacKillop, 1989).

8.2.2 THE CASE OF THE ARAB COUNTRIES

In this section, which is partially based on the work of Badawi (1997), Marconato (1999) and McKie (1999), a review of the Arab world experience of electricity interconnection is presented. The aim is to explore how far the region is from establishing the infrastructure which is necessary for creating a interregional market for electricity in the future. This experience started in 1952 with the building of a transmission line between Tunisia and Algeria. However, the real interest in interconnection began in the 1980s when the Arab Fund for Economic and Social Development (AFESD) was given the responsibility of studying and financing interconnections between the Arab countries. Subsequently, the Fund provided sixteen countries with over $3.3bn in loans, until 1998, with the objective of promoting such projects across the region.

This effort was considerably enhanced after the creation, in 1987, of the Arab Union of Producers, Transmitters and Distributors of Electricity (AUPTDE). AUPTDE has the responsibility of implementing interconnection projects and harmonising the existing systems to facilitate the establishment of a unified grid across the Arab world. Although many pan-Arab political and economic projects have, in the past, failed to materialise, it seems that this project may have a better chance of succeeding. For this reason, the official objective is to have all 22 Arab countries linked by the grid by 2015. This optimistic scenario clearly assumes that the weak networks of the Sudan and Djibouti are also included, which is not feasible unless the project to link Egypt and Congo becomes a reality.

8.2.2.1 ARAB COUNTRIES OF THE *MASHREQ* AND *MAGHREB* REGIONS

The Arab world's experience of power interconnections can be divided into two main groups according to region. The first group comprises the Maghreb which are North African countries of Morocco, Algeria, Tunisia, Libya, and Egypt. The second group comprises the Mashreq, that is, those countries in the eastern Mediterranean and Arabian Peninsula including Syria, Lebanon, Jordan, Iraq, Yemen and the GCC countries (Bahrain, Kuwait, Oman, Saudi Arabia and Qatar). Table 8.1 shows the different existing interconnections in these two regions as of 1999, although some are not commissioned yet.

Table 8.1 Power Interconnections in the Arab World as of 1999

Regions	Interconnection	Capacity (kv)	Status
Maghreb	Morcco-Spain	400	Operational
	Morcco-Algeria	225	Operational
	Alegeria-Tunis	225	Operational
	Tunis-Libya	225	Operational
	Libya-Egypt	220	Operational (400kV Underconstruction)
Mashreq	Jordan-Egypt	400	Operational
	Jordan-Syria	230	Operational (400kV Underconstruction)
	Syria-Lebanon	230	Operational
	Syria-Turkey	400	Underconstruction
	Iraq-Turkey	400	Built but not Commercially Operational
	GCC (phase 1)	400	Scheduled to be Operational in 2001

Sources: Badawi (1997), MaKie (1999), Marconato (1999) and George (2000).

The interconnection between countries in the Arab Mashreq came later than that between countries in the Arab Maghreb. This delay may have been useful, as interconnecting well-developed networks with sufficient generation capacities and using advanced technologies would create an efficient and robust system in the long term. On the other hand, the case of some Maghreb countries shows that most of the recent investments were directed toward upgrading previously-established links and the completion of internal networks. The interconnection of Egypt and Jordan has made it possible to link the two groups together, which makes possible the aim of having a unified grid across the Arab world.

Interconnection between Syria and Turkey would make the *Mediterranean Power Ring* project, which aims to link Spain to Turkey via North Africa and the Middle East, achievable if the political will is there to implement it. The completion of this project

would make the existence of a trans-continental electricity grid possible, even if the Turkish section does not materialise. The long distance of 5000km between Morocco in the west and the Arabian Gulf in the east, the seasonal differences between the countries involved and some differences in their weekend holidays present a considerable advantage.

The average growth rate of electricity load in most Arab countries is expected to exceed 6 per cent for the next decade, which according to AFESD will require over $73bn in new generation capacity. Table 8.2 shows that 26 per cent of the installed generation capacity of these countries is held as a reserve. This percentage is the capacity that has to be kept in reserve for unexpected outages. Assuming a 50 per cent saving on this reserve, a unified grid would reduce the installed capacity by 10,206 MW or an equivalent saving of about $9bn (or $900,000 per MW as assumed in a similar estimation by the GCC (see section 8.2.2.2)). This is the only benefit factored into the equation, which means that other advantages of electricity exchange would clearly increase these benefits.

Table 8.2 Installed Reserves in Arab Countries in 1996

Country	Installed Capacity (MW)	Peak Load (MW)	Installed Reserves	
			(MW)	(%)
Jordan	1,266	928	338	27
UAE	7,004	4,996	2,008	29
Bahrain	1,307	1,023	284	22
Tunis	1,624	1,184	440	27
Algeria	5,602	3,760	1,842	33
Djibouti	90	64	26	29
Saudi Arabia	21,895	18,506	3,389	15
Sudan	518	428	90	17
Syria	4,784	2,970	1,814	38
Somalia	60	57	3	5
Oman	1,613	1,508	105	7
Qatar	1,347	1,327	20	1.5
Kuwait	6,898	5,312	1,586	23
Lebanon	1,670	1,662	8	0.4
Libya	4,204	1,983	2,221	53
Egypt	13,346	8,333	5,013	38
Morocco	3,137	2,193	944	30
Mauritania	180	114	66	37
Yemen	810	555	255	31
Total	77,335	56,923	20,412	26.4
Maghreb	14,897	9,356	5,541	37
Mashreq	62,438	47,567	14,871	24
Total	77,335	56,923	20,412	26.4

Source: Calculated from Badawi (1997)

Since the GCC interconnection is not currently linked with either the Jordanian or the Egyptian networks, the objective of having one Arab grid needs a few more years to become a reality. The linking of Yemen with Saudi Arabia via the southern region of Saudi Arabia is in effect linking the GCC with Yemen. This is more likely to occur than a link between Oman and Yemen, as the great distance between consumption centres in these latter countries could make a link between them less economically viable. The large size of Saudi Arabia makes it possible to link the GCC and Yemen with the already operational link between the Maghreb and the rest of the Mashreq region.

The above points show that these interconnections would create a suitable infrastructure for the development of international markets for electricity in the region. As this would include many networks, the benefits from having such markets are expected to be higher in this case than in the case where the links between countries are used only for power exchange. As most of the countries in the region have embarked on liberalising and privatising their electricity industries, the dynamics of the electricity industry would make the establishment of such markets a possibility in the Middle East.

8.2.2.2 THE GCC INTERCONNECTION PROJECT

Although the accomplishments of the GCC have been so far below expectations, Kopper (1995) indicated that establishing joint projects such as the GCC grid interconnection might reflect a commitment on the part of member governments. This commitment could be viewed as manifested in the payment of these governments of their share of the project despite the constraints on their budgets during the 1990s. This project, which costs more than $2bn, was approved in 1997. The first phase of the project is to link Bahrain, Kuwait, Qatar and Saudi Arabia and was scheduled to be commissioned by 2001, while the second phase will include linking Oman and UAE by 2003. The GCC grid is owned by Gulf States Interconnection Authority (GSIA) with its headquarter in Saudi Arabia but its stocks will be floated in all stocks markets of the GCC countries. The authorised capital of this entity is $1.1bn, which has been shared between member governments who have paid $385m (35%) with $715m (65%) still to be raised from private sources.

The idea of the GCC interconnection started in the 1980s, with the objective being limited to the sharing of generation reserves among the six members of the GCC. However, the 1990s witnessed a rethinking of the long-term objectives of the project. The new perspectives of the role of the electricity market has shifted the focus toward economic and commercial objectives. According to McKie (1999), running this project on a commercial basis includes the objective of creating an electricity market with pool mechanism fully functioning by 2010.

The GCC study of the interconnection project estimated that the project will reduce the generation reserves of all six countries by 3,027 MW before the year 2010, which is an equivalent saving of over $2.7bn (or $900,000 per MW) during the same period. The intra-GCC trade in electricity may be one of the benefits from the GCC interconnection, but these benefits will be even greater when the region is linked with the other Mashreq countries and Turkey. The obvious benefit lies in taking advantage of the significant differences in their load profiles. While the peak loads in the GCC countries occur usually during the summer months of June to August, the peak loads in Egypt, Syria and Turkey occur in the winter months of December to January. Hence, these differences will benefit both groups by increasing the load factors and higher utilisation of their generation capacities.

8.2.2.3 IMPLICATIONS OF THE INTERCONNECTION

There are some structural implications of the interconnection of the different regions of the Middle East. The interconnection of the GCC with the rest of the Arab countries would make the Gulf region a net exporter of thermal-generated electricity in addition to being a net exporter of oil (and natural gas). This development would increase the diversification of the generation mix for the unified grid where the systems of Egypt and Syria, which rely on hydroelectric sources, can be complemented by thermal sources from the Arabian Gulf. This may become even more relevant during times of natural drought or other shortages or of other kinds of water problems which could be caused by 'hydro-politics'.

In the GCC countries, power generation accounts for 50 per cent of the demand for natural gas which is expected to grow even further in the coming years (MEES 43:22 8th May

2000 and MEES 43:22 29th May 2000). Also gas-fired generation is becoming a new option in other neighbouring countries, such as Egypt. However, the study by Abdallah (1999) asserts that Egypt has reached its potential for hydroelectricity production and, given the country's population growth and other factors, domestic natural gas sources will not suffice for future energy load. The study even predicts that these factors will make Egypt a net importer of energy by 2012 or 2017 at the latest. The implication of this prediction is that Egypt would become a good market for electricity as well as gas produced in the Gulf, especially if the Egypt-Congo link fails to materialise.

The linking of the GCC by another grid for natural gas and the potential for the region to export both primary energy sources and electricity would highlight the importance of the costs of transportation for future generation sites. In addition, the interest in combined cycle generation technologies, because of their technical and environmental advantages, as well as the interest in utilising gas sources, would make the inter-link between the electricity and gas industries more significant than ever before. For instance, transportation cost is an important factor to consider in the comparison between gas and electricity as alternatives. Some countries may find it more beneficial to export electricity rather than export natural gas. Such a preference has been justified on two grounds: firstly, producing and the exporting electricity may have higher value-added than exporting natural gas and, secondly, there is a considerable growth in domestic demand for gas especially for industrial purposes and as fuel for power generation.

The long-term benefits of interconnecting countries should also be taken into consideration in the appraisal of the economic viability of interconnection projects. Amundsen et al. (1999) investigated the impact of interconnection on competition in electricity markets and found that cross-border trade would enhance the prospect of competition not only between countries but also between firms within each country. Their study also found that the integration of electricity markets would equalise prices across national borders. Such an outcome could be of relevance in the case of the GCC countries. In addition to the introduction of competition, the similarity in their generation costs may induce more gains in productive efficiency and could result in lower prices for consumers.

8.2.3 THE ROLE OF THE TRACING METHOD IN CROSS-BORDER TRADE

8.2.3.1 PRICING ISSUES

Charpentier and Schenk (1995) argue that the liberalisation and privatisation of the electricity industry in many countries have introduced two new elements into the operation of international interconnections. Firstly, private distribution companies that aim at minimising their costs will look for the cheapest generation sources regardless of their national origin. The same rationale can apply to generators who have the incentive and the means to supply customers in other countries. Secondly, transforming the process from a power exchange to trade will make market prices based on marginal costs, profit-sharing, or avoided costs difficult to use. The reasons for this are that pricing and cost information become more commercially sensitive in trade-based systems than in exchange-based systems. Hence, electricity pricing in international competitive markets needs to be based on market bids in a similar way to that of trade in electricity in national power pools. Therefore, transmission pricing of electricity becomes a vexing issue, which could hinder trade if there is no agreement upon a unified transmission pricing method.

There are considerable difficulties facing the implementation of marginal pricing of transmission, not least due to its extensive data requirements. These limitations would make the method even more difficult to adopt in a system which integrates different networks from different countries. The use of average pricing in the form of pro rata (i.e. postage stamp) is a very practical solution considering the complexity of the process and the need to facilitate more trade across national borders.

However, this solution would have its drawback for economic efficiency, as international interconnections extend over long distances, which means that ignoring transmission losses would result in sub-optimal decisions regarding location of generators. The use of postage stamp rates, in effect, ignores the opportunity cost of transmitting electricity, by neglecting the relevant comparison with the transportation cost of other sources of energy such as gas. Hence, the practicality of average pricing may come with a large loss in economic efficiency as it ignores completely the spatial factor in electricity trade.

8.2.3.2 THE CONTRIBUTION OF THE TRACING METHOD

As shown in Chapters Five, Six and Seven, transmission pricing by the tracing method preserves significantly the practicality advantage of average pricing together with a reasonable reflection of spatial signals as in marginal pricing. The shortcomings of tracing, such as its inability to reflect small differences in distance and the problem of free-riding by some of the system users, does not diminish its usefulness for international trade in electricity.

On the contrary, the first point may become irrelevant considering that short distances must be reflected when nodal rather than zonal pricing is used. The long distances involved in international interconnections would make this shortcoming immaterial. Also, this argument could be supported by the claim put forward by Hunt and Shuttleworth (1997) that having price at each node (nodal prices) may be considered redundant. Consequently, the issue of free-riding would not be likely to become a problem considering that in cross-border trade the charges would be allocated between national networks (i.e. large zones) and each network would have its own method of allocating charges between its members. The remainder of this section gives an example of how these charges are determined using the tracing pricing. This will be done in two stages. The first stage deals with allocating losses over interconnection lines (tie-lines) while the second stage deals with determining the charges for using the system by the different networks.

8.2.3.2.1 Stage One: Allocation of Interconnection Losses

For the objective of illustrating how transmission costs[5] (losses) are allocated between different networks that belong to separate countries, the original network of this research has been used. To simplify the calculation with no effect on the integrity of the outcomes, two of the six sub-networks of the original network were incorporated with the others according to their actual geographical proximity. As a result, the original network is transformed into four sub-networks which will be used in this section (Figure 8.1, below) to resemble an interconnection system consisting of four networks which belong to four separate countries.

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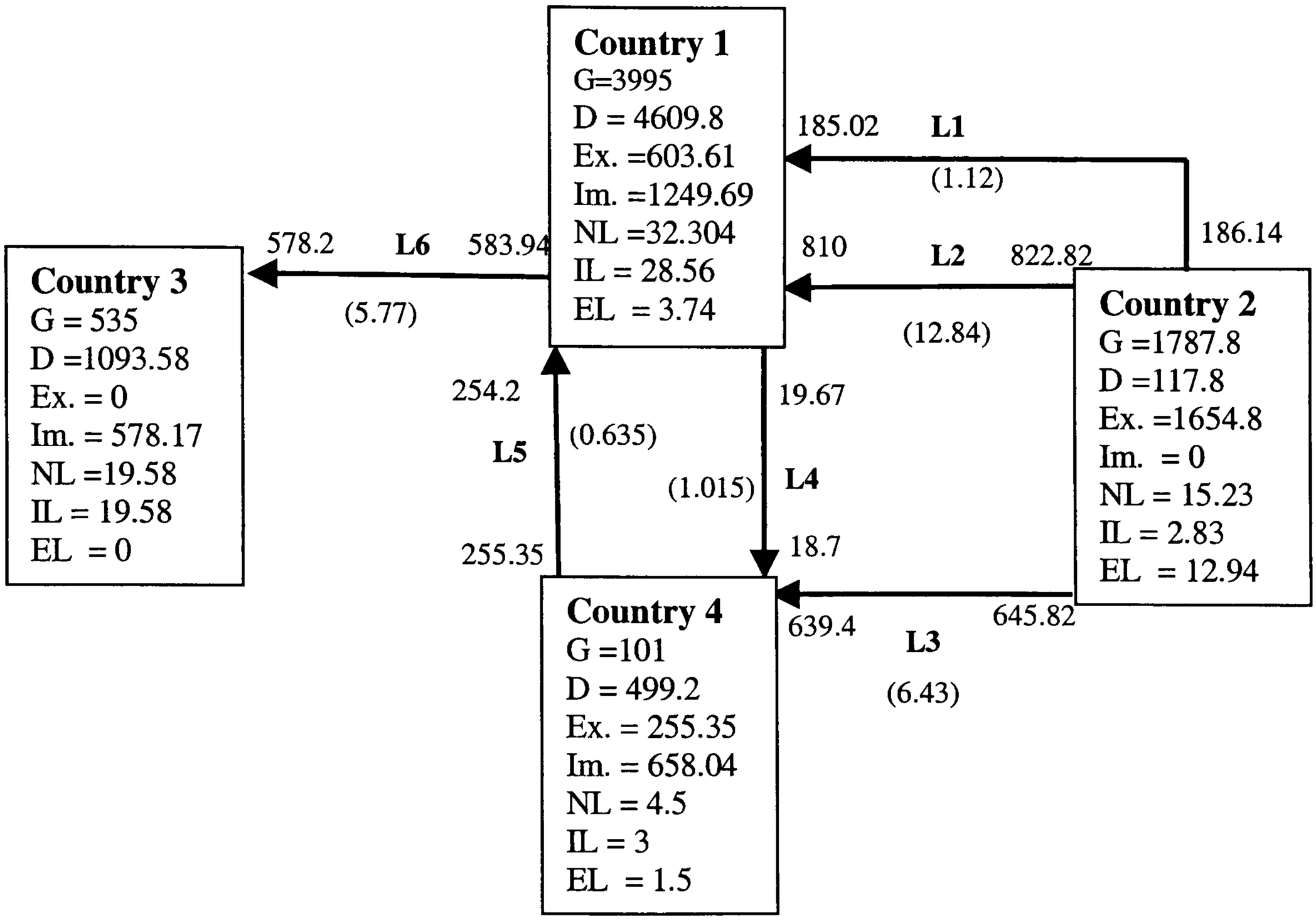
[5] Here the focus is on variable costs, but fixed costs can be dealt with in a similar fashion as in Application Two: Access Charges, in Section 8.3.

The calculation of the following results is based on a similar procedure used in Bialek (1999) and Bialek and Kattuman (1999). However, the calculations in this section provide more realistic results as it is based on actual power flows data.

Figure 8.1: Interconnected Networks (numbers in MW)



NOTES:

1) Kirchhoff's Current Law (nodal inflows = nodal outflows) is satisfied.
2) Network Losses = Generation – Demand – Export + Import
3) Losses on interconnection lines are in parentheses

Figure 8.1, above, shows for each network the relevant information regarding generation (G), load (D), exports (EX), imports (IM). Losses over each network (NL) are calculated by subtracting load and net exports from generation. By using the Proportional Sharing Rule, the determination of the share of outgoing[6] flows (exports) in NL gives us the value of external losses (EL), and the share of flows supplied to load centres within the network in NL gives us the value of internal losses (IL).

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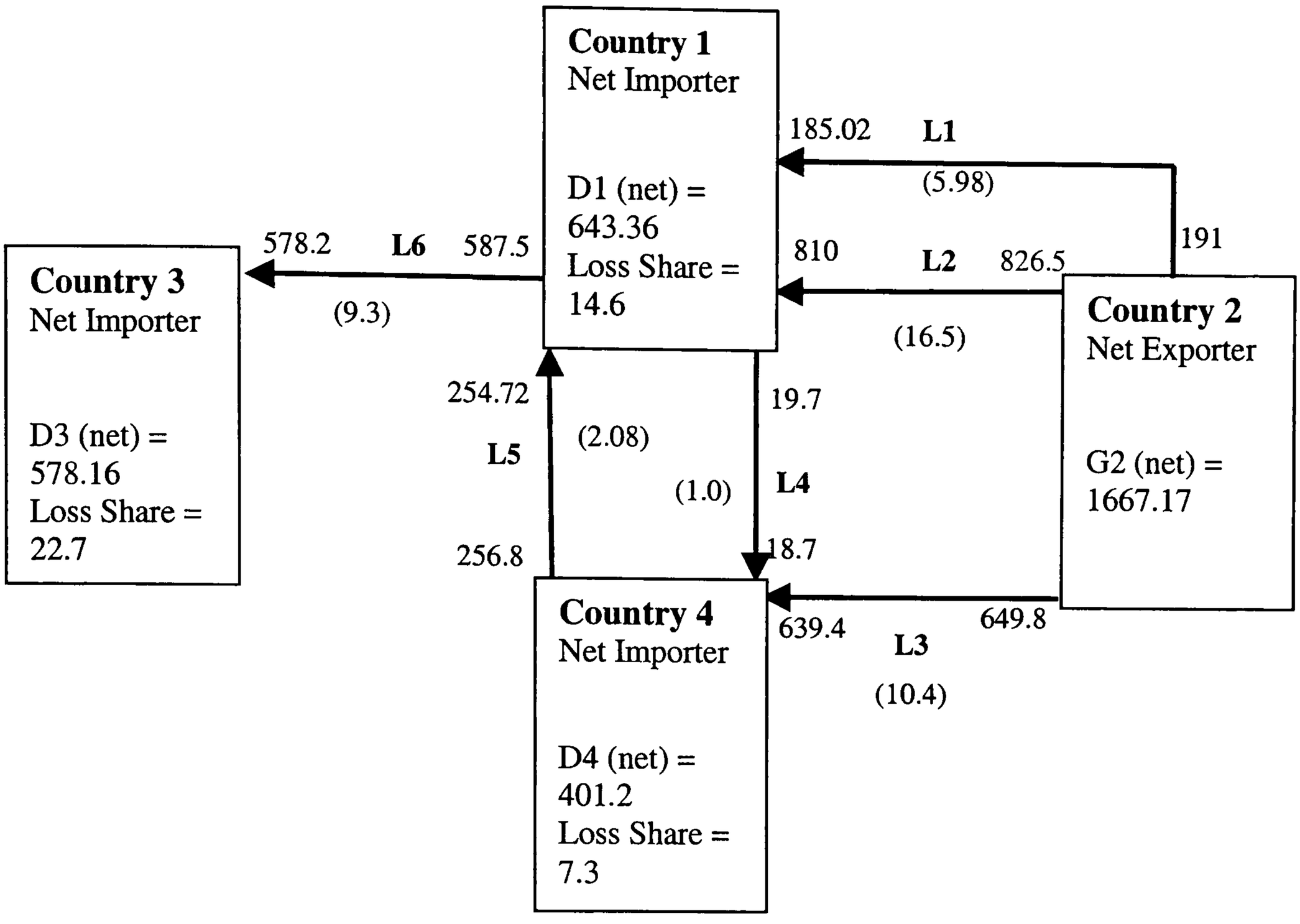
[6] This could easily be done for incoming flows (imports), but for simplicity we have limited our case to only outgoing flows (exports).

The method used to allocate network losses between internal and external losses is a matter to be decided by the Transmission System Operator (TSO) of each network. This would make the tracing method more politically acceptable, as it takes into consideration the issue of sovereignty, allowing each country to choose the method it wishes. For example, in the interconnected system of Figure 8.1 we assumed that networks of countries 1 and 4 use the postage stamp method while the networks of countries 2 and 3 use the tracing method. However, for the tracing method to work for cross-border allocation it has to be accepted by all networks involved as the only method of allocating the over the six tie-lines of the interconnected system.

For the purpose of allocating the cost of trade over these lines, it is necessary to transform this system into a network with four supernodes, by netting out inflows from outflows at each network. In this way, each network becomes a net exporter, a net importer or a balanced node. The charges will not be levied on users of a network with balance generation and load (plus losses) as it is unfair to charge a load for losses on tie-lines while this load is supplied by internal generation. In addition, some of the losses over lines in this network are partially caused by power flows from other networks. However, our case does not contain a balanced network, which means that we have one net exporter network (Country 2) and three net importer networks (Country 1,3 and 4) as shown in the following figure, Figure 8.2.

Figure 8.2: Networks as net exporters or net importers (numbers in MW)



NOTES:

1) Kirchhoff's Current Law (nodal inflows = nodal outflows) is satisfied.
2) For Net Exporter: G (net) = G – D – IL
3) For Net Importer: D (net) = D – G + IL

Applying the tracing method assumes that the four networks agree, at least, on who should pay the charges for cross-border trade: the loads (and exports) or generators (and imports). In our case, we assumed that it has been agreed that loads (and exports) would pay these charges. For this reason, the flow at the sending end of each one of the six tie-lines increased, causing the losses over these lines to increase, as shown in Figure 8.2. This means that external losses are incorporated into the flows involved in the cross-border trade and not in the internal transactions within each network. Hence, the total losses on tie-lines increased from 27.9 MW in Figure 8.1 to 45.26 MW in Figure 8.2.

The allocation of these losses arising from using the tracing method results in 14.6 MW (or 0.0226 pu), 22.7 MW (or 0.0393 pu) and 7.3 MW (or 0.0179 pu) for D1, D3 and D4, respectively. However, the allocation of the losses from using the Postage Stamp results in 0.0275 pu for each load. The implication of using the latter method is that distant load D3

is allocated 15.89 MW while D4 is allocated 11.03 MW, which reconfirms the shortcoming of the postage stamp method in its lack of any spatial signalling. This means that the benefits induced by the simplicity of average pricing should be weighted against its distortion to economic efficiency. On the other hand, the ability of the tracing method to reflect the locational differences indicates that it has less distortion to economic efficiency than that of the postage stamp method.

8.2.3.2.2 Stage Two: Calculation of Charges

As we have seen from Chapter Four, Equation (4.28) shows how the nodal power, P_i, is distributed between all the loads in the system. In this section, the same concept can be used for interconnected system where P_i becomes a network (i.e. a supernode).

$$P_i = \sum_{k=1}^{n} \left[\mathbf{A}_{\mathbf{d}}^{-1}\right]_{ik} P_{Dk} \qquad \text{for } i = 1,2,\ldots,n \qquad \text{(Equation 4.28)}$$

This equation is very helpful in computing how much each load should pay for cross-border transmission. These charges should equal the sum over all the i networks for the contribution to load k multiplied by the transfer price Ti of each network, as follows:

Allocation to load k =

$$= \sum_{i=1}^{n} \left[\mathbf{A}_{\mathbf{d}}^{-1}\right]_{ik} P_{Dk} Ti = P_{Dk} \sum_{i=1}^{n} \left[\mathbf{A}_{\mathbf{d}}^{-1}\right]_{ik} Ti \qquad \text{(Equation 8.1)}$$

Similarly the revenues collected by the TSO in network i are the sum of k loads which are supplied through network i multiplied by the transfer price Ti, as follows:

Revenues for transits in network i

$$= \sum_{k=1}^{n} \left[\mathbf{A}_{\mathbf{d}}^{-1}\right]_{ik} P_{Dk} Ti = Ti \sum_{k=1}^{n} \left[\mathbf{A}_{\mathbf{d}}^{-1}\right]_{ik} P_{Dk} \qquad \text{(Equation 8.2)}$$

Substituting (Equation. 4.28) into (Equation. 8.2) shows that revenues collected by TSOi is equal to

$Pi\ Ti$, which assures the recovery of costs in each network.

The following tables (Table 8.3 and Table 8.4) present the calculation results, which are based on the data in Figure 8.1 and Figure 8.2, and provide the charges for cross-boarder and internal transmission of electricity over the system. To make our case even more realistic, we can reasonably assume that each network charges different transfer prices for using its lines for transmitting electricity. It is expected that the Transmission System Operator (TSO) of a modern and well-developed network will charge higher transfer fees than the TSO of an old and poorly maintained network. In the following example, the assumption is that the TSOs in N1, N2, N3 and N4 charge 4, 5, 2 and 3 SR/MW, respectively.

Table 8.3 Charges due to Cross-Border Trade

Network	Loads				Total (SR)
	D1	D2	D3	D4	
N1	(643x 4=) 2573	0	(587x 4=) 2350	(19.79x 4=) 79.16	5003
N2*	(658x 5=) 3287.7	0	(601)x 5=) 3005.3	(408.4x 5=) 2041.8	8335
N3	0	0	(578x 2=) 1156	0	1156
N4	(257x 3) 770	0	0	(401x 3=) 1204	1974
Total	6631	0	6512	3325	16468
Per MW	(6631/ 643=) 10.2		(6512/ 578 =) 11.3	(3325/ 401=) 8.3	

* Collected charges include the payments of Ds for load and cross-border losses.

Table 8.3 shows how much each load in Figure 8.2 pays the different networks for using their lines in order to receive this amount of load. For example, D1 pays SR2,573 to N1, which is the transfer fee 4 SR/MW multiplied by the size of the load (643.36 MW). As the same load (plus 15MW for the share of D1 in cross-border losses) came from network N2, then D1 pays N2 658MW multiplied by 5 SR/MW (the transfer fee in N2), which is SR3290. A similar explanation applies to the payment of D1 to N4 where the former imports 257 MW which is transmitted over the lines of the latter. Thus, Table 8.3 shows how much each TSO collects in revenue from the transfer of power over its lines due to cross-border trade. Also, the table shows how much each load pays (per MW) for using tie-lines. Obviously D3 pays the highest charges per MW, which is expected for two reasons: firstly, it is the furthest geographically from the sources of generation and, secondly the power received by D3 has travelled over the lines of the other three upstream networks (i.e. a pancaking effect).

Table 8.4 Total Revenues Collected by TSOs (in Million SR)

TSO in Network	Transfer Price (A)	Internal Transfer Fees	Cross-border Transfer Fees	TSO's Revenues (B) = (C) x (A)	Total Flows (MW) (C)
N1	4	15977	5003	20980	5245
N2	5	603	8335	8938	1787.6
N3	2	1070	1156	2226	1113
N4	3	303	1974	2277	759
Total		17953	16468	34421	

Table 8.4 shows the total amount collected by the TSOs not only from cross-border trade (total in Table 8.3), but also the amounts collected from internal trade from loads (or generators). Hence, the table shows that the total revenues of a particular TSO are equal to the transfer price multiplied by the power transmitted over its network, which means that each TSO recovers exactly its revenues as indicated in equation 8.2, above.

Table 8.5 Average Transport Charges for Demand Centres

Charges	Loads				Total Payments
	D1	D2	D3	D4	
Internal transfer fees	15,977	603	1,070	303	17,953
Per MW	*3.47*	*5.12*	*0.98*	*0.6*	
Cross-border transfer fees	6,631	0	6,512	3,325	16,468
Per MW	*1.43*	*0*	*5.95*	*6.67*	
Total	22,611	608.12	7,583	3,628	34,431
Per MW	*4.9*	*5.12*	*6.93*	*7.27*	

Table 8.5 looks at these revenues from the point view of demand centres as per MW charge. It shows that, with no exception, all loads pay internal charges because each network has internal transactions. However, while D1, D3 and D4 pay both internal and cross-border charges, D2 does not pay any cross-border charge as it is completely supplied from internal generation. This table shows the per MW transfer charge for the loads in this system. This charge is clearly influenced by all the following three factors: the dependency of the load on external sources, the extent of using the system (due to its geographical position in the network), and the internal transfer price of the used networks. For example, although D2 receives its entire load from local generation, it pays slightly more than D1 in per MW because the transfer price charged by TSO in N2 is very high. On the other hand, most of the payments from D3 and D4 are due for their dependency on power which is imported from abroad.

The above illustration shows the suitability of the tracing method for international trade in electricity. As international markets naturally would use loose pool (i.e. where no central dispatcher is needed) rather than tight pool mechanisms, the limited information requirement of the tracing method makes it suitable for such arrangements. This also would make the tracing method a practical alternative to marginal pricing which is complex and requires very detailed information, some of which is commercially sensitive.

However, the above discussion has to take into consideration that there is a potential for some objections when tracing is used in cross-border trade. For example, in figure 8.2, how external losses are allocated between the tie-lines L1, L2 and L3 depends on which pricing method is used by N2. Hence, the charges that calculated in table 8.5 would be different, albeit only slightly, depending on which pricing method is used in N2. However, since cross-border trading is usually small in comparison with the trade volume within each country, the choice of the pricing method is not likely determined by cross-border trade considerations alone. In addition, the implementation of the tracing method assumes a prior agreement among the networks, which implies some acceptance of such possibility. This is based on the assumption that networks are joining the interconnection with the objective of maximising the benefits from the electricity trade.

8.3 APPLICATION TWO: ACCESS CHARGES

The ideal transmission pricing method must achieve some important objectives including economic efficiency, adequacy of revenues, transparency, easy implementation and fairness. However, in practice there is no single method which could satisfy this requirement, as there are some inherent contradictions between these objectives. This makes it necessary to compromise, and a trade-off between these objectives is usually accepted depending on the priority given to each one individually.

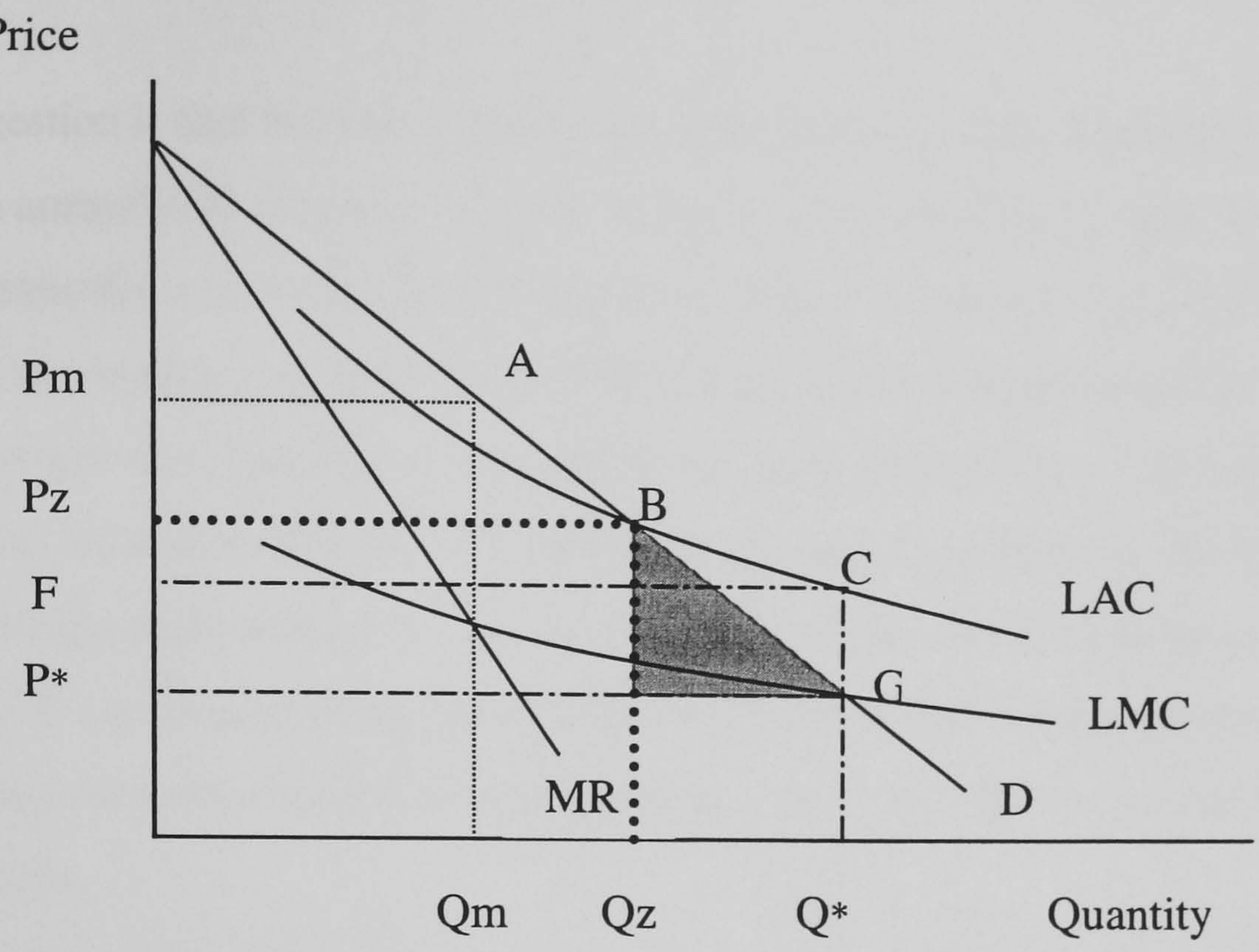
The first two objectives are clearly impossible to reconcile for industries with significant economies of scale. This could be demonstrated by the case of the electricity transmission which involves high fixed (sunk) costs, low marginal costs and excess capacity. As pricing based on marginal transmission costs alone fails to recoup the total revenues, other pricing methods have been suggested (and some used) to deal with recovering the fixed costs. This section provides a brief review of some of these methods, followed by a presentation of how the tracing method would contribute to the recovery of the fixed costs of electricity transmission.

8.3.1 THE PROBLEM OF NATURAL MONOPOLY

8.3.1.1 ECONOMIES OF SCALE

In economic theory, the concept of natural monopoly refers to an industry where the technological advantages of large-scale production preclude efficient competition among smaller companies. Thus, one of the major topics in the economics of public utility is how to deal with the problems resulting from the existence of economies of scale. As illustrated by Figure 8.3, the marginal cost price fails, in the case of increasing return to scale, to raise sufficient revenues to keep the firm operational in the long run. The challenge, therefore, is how to recover the total costs with the least distortion to economic efficiency.

Figure 8.3: The Problem of Natural Monopoly



This figure illustrates the position of a natural monopoly where the average cost is falling throughout the relevant range of output. As the demand is always less than the minimum efficient scale (MES), which is the lowest point on the long-run average cost (LAC) curve, only one firm can efficiently serve the market. In the case of unregulated monopoly, the firm maximises its profit at point (A) where marginal costs equal marginal revenues. This solution is socially undesirable as it results in too low an output and too high a price in comparison with the ideal output (Q*), where the LMC intercepts the demand curve at point G. However, at this point marginal cost is lower than average cost which means that the firm encounters a loss equal to the rectangular FCGP*. Thus, marginal cost price does not satisfy the necessary condition for economic efficiency, which is the recovery of total costs.

It is usually suggested that the firm may need a subsidy from the government which can be raised through a lump-sum tax. Viscusi et al. (1998) object to this subsidy on the following grounds. Firstly, this loss reflects the fact that consumer expenditures (and benefits) are lower than the total costs, which may indicate that the products should not be produced at all. Secondly, such subsidies would create a disincentive for the firm to be efficient.

Thirdly, this lump-sum tax is not necessarily collected from people who benefit from the subsidy, which makes such a suggestion unacceptable on a distributional basis.

Another suggestion is that the firm could be privately operated and regulated in such a way that it earns a normal rate of return on its investment. Thus, total costs equal total revenues which, geometrically, occur at point (B) where the long-run average cost curve (LAC) intercepts the demand curve (AR). This solution leads to insufficient output and increases the price above the marginal cost, which results in the *deadweight loss* (see Appendix A). This loss comes from the reduction in consumer and producer surplus by the amount which is equal to the area of the shaded triangle in Figure 8.3. Thus, the acceptance of this solution depends on the size of the deadweight loss. Braeutigam (1989) argues that this loss is very high and unacceptable if there are large fixed costs and the demand for the product is elastic.

8.3.1.2 DEALING WITH FIXED COSTS

The following is a review of the pricing schemes from the literature, which are suggested for dealing with the issue of allocating the fixed costs in the context of a natural monopoly.

8.3.1.2.1 Linear Prices

a) Marginal Cost Prices

These prices guarantee efficiency and satisfy the revenue requirement when the firm is operating in the region where there is a decreasing return to scale. However, as we have seen in Figure 8.3, this form of pricing fails to produce sufficient revenues when economies of scale exist or when the market demand is smaller than the minimum efficient scale. Thus, this method of pricing needs to be complemented by supplementary charges.

b) Ramsey Prices

These are based on the mark-up of price over marginal cost in inverse proportion to the elasticity of demand. These prices are considered the second best linear prices as they satisfy the revenue requirement with the least distortion to marginal price. Although the Ramsey rule was originally designed for pricing final goods, Laffont and Tirole (1996) argue that the same principle could be extended to include intermediate goods such as

network access. The main criticisms of Ramsey prices are that they discriminate between classes of consumers and that the calculation of these prices is very information-intensive. In addition, some writers such as Church and Ware (2000) emphasise the point that these prices are optimal only if there are no price distortions anywhere else in the economy.

c) Simple Average Price

In this case, every user pays the same average cost per unit. This method has no or, at least, only very small, transaction costs as the computations are simple and straightforward. However, the presence of large fixed costs causes marginal users to find the average price to be too high and to stop buying the product. This distortion to the optimal price makes intra-marginal users postpone buying the product when they find that they have to pay a higher price than they were willing to pay initially.

8.3.1.2.2 Non-linear Prices

a) Price Discrimination

The monopolist can depart from linear pricing by charging different prices for each consumer based on his/her willingness to pay. As the price of the last unit sold is equal to its marginal cost, this form of non-linear pricing is considered efficient. However, such a pricing scheme is inequitable due to the fact that there is a complete transfer of consumers' surplus to producers.

b) Two-parts Tariffs

This is the most common form of multi-part pricing and occurs when the enterprise charges two different prices to a single customer. The tariff consists of a usage charge based on the marginal cost of the last unit consumed and a fixed (access) fee per unit, for some specific period, during which the consumer has the right to use the product. This fee is normally expected to be independent of the amount used by the consumer and is intended to cover his share in the fixed (capital) costs through a lump-sum charge.

The main concerns with two-part prices are that they would weaken the efficient message of the usage charge, and that the marginal users may be driven away if they perceive the access fee is too high in comparison with what they are willing to pay at the margin. The

solution to the latter concern could be to make marginal users pay only the marginal cost price while less price-sensitive consumers pay a higher access fee in addition to the variable charge. However, this solution implies a cross-subsidisation between the different classes of users.

8.3.2 THE CASE OF ELECTRICITY TRANSMISSION

Investments in electricity transmission are usually characterised as being very specific and indivisible (lumpy) which causes a large proportion of total transmission costs to be sunk. This section is concerned with how access fees would recover these costs in the context of electricity transmission.

8.3.2.1 IMPORTANCE OF ACCESS FEES

Nodal spot prices, which are based on marginal cost prices, make the revenues collected from operating the network insufficient to cover current investments and reinforcement of the system. The transmission company collects the net marginal cost income (merchandise surplus), which is the difference in marginal cost prices at the different points over the network. Rudnick et al. (1995) state that this income varies between systems but usually covers only 15 per cent of the required revenues of a typical transmission system with no line constraints. Bråtonn(1997) reported that the presence of line constraints would increase this percentage to 25-30 per cent of the total required revenues for the transmission company.

As a result, the main problem in financing the provision of transmission services is in dealing with the allocation of capital costs between generation and distribution companies. The literature contains a broad array of recommendations and practices, which are employed by many transmission systems for the designing of access fees. The most widely used is the simple method of the postage stamp where the fixed cost is averaged per unit of capacity for each user. However, this method ignores the optimal economic signal of the marginal cost price and its charges do not relate to the actual use of the transmission network.

The other alternative is to use the MW-Mile method for determining transaction-related power flows. This method considers the impact of a certain transaction on the network flows by taking account of the magnitude, the path and the distance travelled by the transacted power. Lima (1996) indicates that the main criticism of this method is that it could be considered as 'a base case' where it does not account for the transmission reserve, which is the difference between the network capacity and the maximum (peak) power flows.

The advantage of the MW-Mile method in reflecting the transmission effects of a transaction is diminished by the limitation on its usefulness and practicality for systems with a large number of transactions. Some countries such as Argentina, Bolivia and Chile have adopted a toll charge based on the concept of 'area of influence' which corresponds to the lines and substations that are directly affected by the generator's output (or demand's load). Rudink et al. (1995) point out that this concept has a vague definition and the implementation of the charges has created a free-riding problem, as some companies do not pay any access charge while benefiting from being connected to the network. Also, the authors point out that generators in Chile have refused in the past to supply distant distribution companies as that would involve paying very high access charges.

8.3.2.2 ECONOMIC IMPLICATIONS OF ACCESS FEES

8.3.2.2.1 Distortion to Marginal Cost Price

Regardless of which method is used, the optimal economic signal of nodal spot prices is weakened by the inclusion of access fees as part of the payments of network users. The concern then is not whether the access fees would distort economic efficiency but rather whether the magnitude of this distortion is acceptable. As indicated above, this obviously would depend on the method chosen for setting the access charges. The Ramsey prices are shown to have the least deadweight loss, but the considerable information requirement of this method and its apparent discrimination between different users prevent its acceptability by regulatory bodies.

The two-part tariffs scheme is common practice by many transmission systems, where usually the fixed costs are recovered by the postage stamp charge on the basis of per unit

of capacity (or maximum demand). The immediate problem with recovering fixed costs by using this simple scheme is that it would affect marginal decisions. This form of charging may be acceptable in the regulation of public utilities, but in the case of a business with a spatial dimension, such as the provision of transmission services, fairness considerations may require that access charges be spatially differentiated. The average charge would clearly obscure the locational signal provided by the marginal cost price. On the other hand, spatially differentiated access fees may strengthen this signal if the method used for designing the access fees provides charges which give similar signals to those of marginal prices.

8.3.2.2.2 Impact on Economic Decisions

Whether or not the access fee is spatially differentiated, it would still impact on the economic decisions of the network users, especially those related to investment in generation. For example, large distortion may discourage a generator from investing in new capacity even if there is sufficient transmission capacity. Thus, the regulatory framework should address the important issue of who should pay the access fee. In this regard, there are two opposing points of views each with compelling arguments.

The first argument, which is presented by Rudnick (1995), is that generators should pay the access fees, as the only way for them to reach consumers and compete is by using the transmission grid. This argument is also based on the reasoning that the combination of the generation and transmission segments of the industry has no economies of scale, which makes marginal cost price able to provide sufficient revenues for the combined two businesses. The second argument, which is presented by Green (1995), is that distribution companies and not generators should pay for access fees, especially if the charges are spatially differentiated. The reason is that generators are more responsive to spatial price signals and, as such, it is sufficient that they should face only the short-run marginal transmission costs (losses). As a result, distribution companies should pay the fixed charges as they are able to pass it on to final consumers, who are not expected to relocate.

The minimisation of distortion to efficient decisions would be related to economic usage of the network as measured by capacity and energy usage. According to Baldick (1998), the

charges for recovering capital costs could be levied on a variety of measurable quantities such as peak power generation (or demand) during a billing period, and the energy produced (or consumed) over a billing period. He considers peak power usage is more price elastic than energy usage because a user has flexibility in scheduling his peak demand but not in curtailing his demand over a period of time. Thus, he asserts that access fees based on the energy usage will produce less distortion than access fees for peak generation (or demand). Rudnick (1999) presented the counter argument that transmission assets are designed for peaking conditions, which make it reasonable to charge on the basis of capacity rather than energy usage. However, he also favours a scheme based on energy usage as a better reflective of economic use of the transmission network.

8.3.2.2.3 Impact on Investments and Expansions

The generation and transmission of electricity are very closely related segments of the electricity industry. In a vertically integrated industry, the co-ordination between the two segments is normally done as part of one integrated investment plan. These decisions are more difficult to achieve in a decentralised and unbundled environment. The capital expansion of generation and the location of new generation capacity depend on the (dis)incentives which are provided by the optimal transmission prices.

According to Hunt and Shuttleworth (1993b), the (expected) short run marginal cost (SRMC), which includes losses and cost of constraints, would reflect the long run cost of marginal addition to the transmission capacity. Thus, in an ideal situation the SRMC equals the long run marginal cost (LRMC) at a level of output where the fixed cost choice associated with the SRMC is the optimal choice and the marginal cost pricing would produce investment and expansion decisions which are optimal. However, in practice this outcome may be complicated by the fact that the SRMC could be understated which means it would not necessarily equal the LRMC.

In addition, the indivisibility of transmission investments would make setting access fees a source of friction between current and future users. Spiller (1995) points out that the economies of scale in transmission would make efficient expansion exceed the capacity which is required by the current users. It is, thus, possible that future users will free ride,

which may cause some of the current users, such as generators, to delay building new generation capacity until transmission expansion takes place. One of Spiller's suggestions, which is unlikely to be implemented in practice, is that future expansions be tailored to the needs of the current users. Assuming this suggestion is possible, it would result in investment which is sub-optimal. Thus, Spiller believes that the only way that fixed cost recovery to be de-coupled from investments is by making the expansion of the transmission network is fully pre-subscribed.

8.3.3 THE CONTRIBUTION OF THE TRACING METHOD

The homogeneous nature of electricity makes it physically impossible to link a user to a particular transmission asset. Hence, it is difficult to determine the exact usage of each generator or distribution company for the purpose of allocating the capital costs of transmission system. According to Hogan (1997), the best application of the tracing method is in the allocation of fixed costs as a supplement to the marginal cost price[7]. As shown in this section the tracing method contributes to the allocation of fixed costs by its ability to portion out, albeit in a notional manner, the flows on every line in the network. Thus, this flow-based approach would identify the usage of each generator or distribution company in the system's assets (i.e. transmission lines and associated overheads).

8.3.3.1 STRATEGIES FOR SETTING ACCESS CHARGES

Due to the presence of economies of scale in electricity transmission, the application of marginal cost pricing does not recover the total (variable and fixed) costs of transmission. It is known that marginal pricing produces a surplus which is collected by the transmission company and used to cover part of its fixed costs. However, this surplus is insufficient and, as a result, the remaining fixed costs have to be paid for through access charges. Figure 8.4, below, shows three possible strategies, similar to those in Bialek (1998), which the regulated transmission company can choose in setting these charges. The access charge could be based on postage stamp charges (strategy A), on tracing charges (strategy B), or on a combination of both (strategy C).

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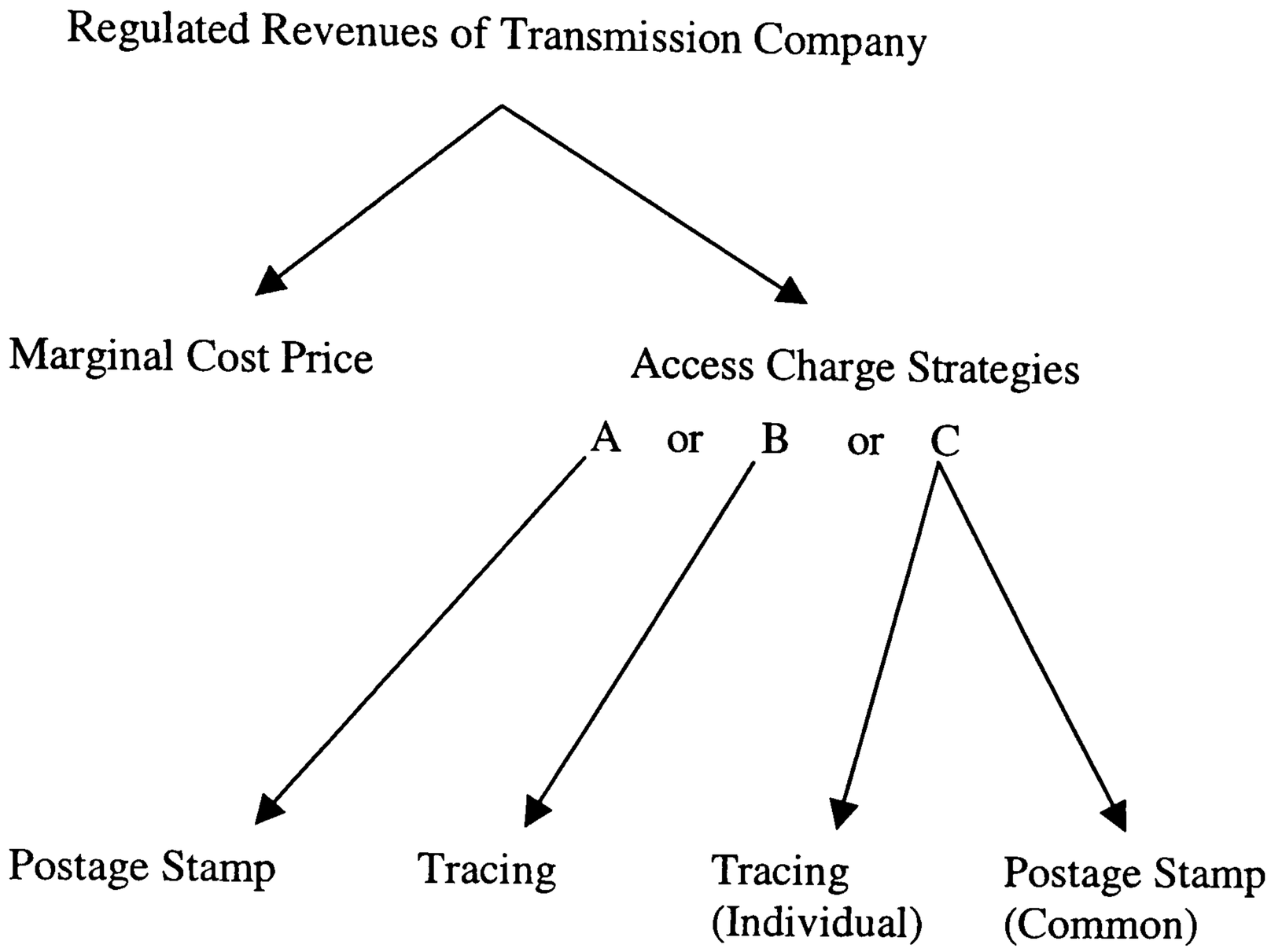
[7] Although Hogan's comment referred to the tracing method as in Kirchen's approach, it is also valid for the more general approach of Bialek.

Figure 8.4: Strategies for Setting Access Charges



Strategy A is consistent with the argument that the access charge should be independent of the actual usage, but this strategy distorts the locational signal of the marginal cost price. Strategy B would preserve the locational signal (assuming tracing gives similar charges to those for marginal cost pricing), but this strategy implicitly assumes that spare capacity of the system should also be paid for through locational charges. Strategy C addresses this concern by dividing the access charge into two components: a tracing-based individual (locational) charge and a common charge, for spare capacity, based on the postage stamp.

The tracing charge (in Strategies B and C) is based on the share of each generator in the peak power flows of each line. Since the capacity of all the lines is designed for peaking conditions, the individual charge would reflect the generators' maximum usage of the network assets. In addition, any transmission system keeps spare capacity which benefits all users by preserving the security of the network and meeting demand increases without the need for continuous system expansion. Thus, paying for these common benefits would require charges for the spare capacity to be non-spatial and postage stamp based. As a result, in strategy C, the costs allocated to a generator could be divided into two components. The first component is an individual cost component, or the maximum usage

of the lines by each generator, which is allocated on the basis of the tracing charge, and the second component is a common cost component which is allocated on the basis of the postage stamp charge.

For strategy A (postage stamp charges), all the information that is required is the fixed cost, which needs to be allocated to the generators, and also the maximum generation capacity of each generator (i.e. the generator's size). Since this information is available to the transmission company, applying strategy A is straightforward where the network fixed costs are allocated between generators based on their relevant size. For strategies B (and C), equation 8.3 implies that knowing the cost of each line is necessary for calculating the share of each generator in the cost of each line. In strategy B, the access charge for a generator is calculated according to equation 8.3, below, where this charge is equal:

$$\sum_{\text{all lines}} \frac{\text{Generator's share in a line peak power flow (in MW)}}{\text{Total peak power flow over the line (in MW)}} \text{ X cost of the line (in SR),}$$

(Equation 8.3)

In strategy C, the cost of each line is divided into used and unused (spare capacity) parts. The individual charge covers the share of the generator in the cost of the used part of the line. This charge can be calculated by applying equation 8.3 using, in this strategy, line cost which is proportional to the used part of the line instead of the total cost of the line, as in strategy B. The sum of the individual charges over all generators equals the costs of the used part of the network, which leaves the costs of the unused (spare capacity) part unrecovered. Recovering the costs of this part can be done in the same fashion as in strategy A by using postage stamp charges, which is based on the size of the generator.

Since the transmission company is expected to have the information regarding the cost of each line and thus the fixed cost of the network, calculating the access charges for either one of the three strategies is, in practice, straightforward. In this research study, however, constructing Table 8.6 on the basis of actual data was impossible as the cost of each transmission line was not available. To overcome this difficulty, the researcher used the available data for line resistance as a proxy for the line cost. This is an acceptable solution because the cost of transmission line is proportional to both the line resistance and length (Bialek and Kattuman, 1999).

Using the coefficient for line resistance, instead of line cost, in equation 8.3, resulted in the number 2930 which is the sum over all lines as indicated by the equation. To make this number more relevant to the issue of cost allocation; this number can be thought of as a monetary value (i.e. 2,930bn SR) for the fixed costs. Assuming 2,930bn SR as a value for these costs is a reasonable assumption considering that the financial statement of SCECO-Central company in 1998 indicates that its combined transmission and distribution fixed assets were worth 8,802bn SR.

It is important to emphasis that the figure 2,930bn SR is not intended to estimate the actual value for the transmission fixed cost of SCECO-Central company. The general objective here is to provide a realistic example of how the access charge could be calculated using the tracing and postage stamp schemes for a transmission network. Using each one of the three strategies outlined above, table 8.6 shows how 2,930bn SR is allocated between the sixteen generators. (The same calculation can be carried out for the 109 load centres.)

Table 8.6 Access Charges for the Usage of the Network (in Million SR)

Gs	Maximum Generation Output (MW)	Strategy (A): Postage Stamp (SR)	Strategy (B): Tracing (SR)	Strategy (C):		
				Individual (Tracing) (SR)	Common (Postage Stamp) (SR)	Total (SR)
G1	250	107.94	56.42	12.13	84.72	96.85
G2	10	4.31	2.43	0.52	3.38	3.91
G3	50	21.58	12.41	2.66	16.94	19.61
G4	1478	638.18	333.55	71.72	500.86	572.58
G5	349	150.69	1.08	0.23	118.27	118.50
G6	588	253.89	623.30	134.02	199.26	333.28
G7	52	22.45	0	0	17.62	17.62
G8	416	179.62	132.97	28.59	140.97	169.56
G9	416	179.62	31.22	6.71	140.97	147.68
G10	778	335.93	525.37	112.96	263.65	376.61
G11	578	249.57	223.93	48.14	195.87	244.02
G12	545	235.32	45.23	9.72	184.69	194.41
G13	600	259.07	43.85	9.43	203.32	212.76
G14	486	209.84	586.45	126.09	164.69	290.79
G15	90	38.86	166.27	35.75	30.49	66.25
G16	101	43.61	146.03	31.40	34.22	65.62
Total	6787	2930	2930	630	2300	2930
%		100	100	22	78	100

It is worth noting that obtaining the figure 2,930bn SR from applying equation 8.3 means that the construction of table 8.6 should begin with strategy B rather than strategy A. In strategy B (as well the individual charge in strategy C), the relevant share of each generator in the flow on each line determine how the cost of the line is allocated between the sixteen generators. In strategy A, dividing the fixed cost of 2,930bn SR by the total generation capacity of 6787 MW requires each generator to pay 431,708 SR per MW of capacity as an access fee. Multiplying this number by the generation capacity of each generator results in the total access charges (as shown in the third column of the table), which each generator is supposed to pay over the years it is remains connected to the grid.

This access fee is usually paid on an annual basis, which makes it possible to adjust the charge depending on the increase or decrease in the existing total generation capacity. This means that the entry of a new generator may reduce the share of already connected generators, making it much easier to finance the investments in the network expansion with more generators rather than less. In addition, it enhances competition where the incumbent generators can benefit from the entry of new generators.

Clearly, the access fee in the case of strategy A is based on the relative size of each generator, which means that two generators with the same generation capacity would pay the same access charge. This charge would ignore the generators' locations in the network and their actual use of the network, as their output may reach different loads at different points on the network. For example, G3 (located in the eastern region) and G7 (located in the central region) have similar generation capacity and pay similar access fees despite the fact that G3 uses the network more extensively to reach the load centres which are mostly located in the central region. The acceptability of these charges is based on the assumption that access charges should not be spatially differentiated, as such fees are intended to charge the generator only for having the right to access the network, regardless of location.

Strategy B, in the fourth column of the Table 8.6, shows that the access charges are related to location rather than size. For example, G6 pays the highest access charge even though this generator is not the largest generator. Although this strategy provides a spatial signal, the allocation of the entire fixed costs based only on location ignores spare capacity as a

common benefit. Also, this strategy would benefit free riders such as G7, unless the regulatory rules require such users to pay a fee that is compatible with that paid by other generators within the same area or zone. So obviously this strategy is highly suitable for a system with very low spare capacity and no free riding problem.

The advantage of strategy C is that the combination of individual and common charges would also require that a free-rider, such as G7, to pay at least for the benefits of being connected to the grid. The last column of the table indicates that charges in both strategies C and B are similar when common charges are included. This is obviously a direct result of the fact that this network is over-built (or under-utilised) with 78 per cent of the total capacity of the network being largely unused. This means that strategy C is useful for the more common case of having systems with a reasonably acceptable level of spare capacity. Thus, using this strategy will in effect transform the transmission pricing from two-part tariffs to three-part tariffs (i.e. variable charge, individual fixed charge and common fixed charge).

The choice between the three strategies for setting the access charge could be partly influenced by the existence, or the lack, of large excess spare capacity. Although some generators may find these charges to be too high, having an over-built network has the advantage of providing some assurance to private generators that they will not be constrained-off due to line congestion. This would give private investors a higher degree of certainty in predicting their future cash flows, which means that the presence of an over-built network could be useful, especially during the early years of restructuring and privatisation.

8.3.3.2 DISCUSSION AND EVALUATION

The important implication of the existence of large excess capacity in the transmission network is that the tracing method might be unsuitable for setting access charges. However, a qualification to this conclusion needs to be made by noting that the existence of large excess transmission capacity is the exception rather than the norm. In the case of this network, which represents most of the transmission networks in Saudi Arabia, such excess capacity is expected to be temporary.

The completion of these regional transmission networks is recent, taking place only from the mid 1980s onwards. These modern systems benefited greatly during the oil boom period from direct government funding, which is unlikely to reoccur. Notwithstanding the continuous growth in electricity demand, the privatisation of the electricity industry would cause future investment decisions to be based more on commercial considerations than before. Hence, whether the tracing method is chosen depends on how much of the existing capacity would be utilised. This would indicate that the postage stamp might become the preferable choice, especially in the early years of the industry's privatisation.

The simplicity of the average (e.g. postage stamp) charges is clearly a very attractive advantage, but we should be wary of methods whose simplicity would come at the expense of economic efficiency. In the context of choosing cost allocation methods, Baumol and Willig (1983) caution that " one is driven to the suspicion that (apparent) ease of calculation threatens to become an over-riding consideration taking precedence over any consequences for social welfare and economic efficiency" (p. 21). This concern needs to be taken seriously when choosing simple charges such as those based on the postage stamp method in setting access fees, because such fees could have an adverse impact on the marginal users' willingness to pay.

The marginal users' willingness to pay is expected to be affected by any cost allocation method. The issue is, then, whether the tracing method has a less distorting effect on users' decisions than the postage stamp. It is possible that some users, especially intra-marginal users, may find the charges based on the tracing method more acceptable as they reflect fairly the usage of the system. Hence, these charges would be considered higher, but fairer, by users who would otherwise either leave the market or, at least, bypass the transmission network[8]. The tracing method is not immune from criticisms such as those raised by Ring and Read (1996b) against methods which recover fixed costs by using charges which are related to the operational (i.e. variable) usage of the network.

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[8] As regards this latter choice, Rudnick and Raineri (1997) reported that some generators, in Chile, decided to bypass the transmission network through building their own transmission lines.

This criticism extends to tracing charges where such charges are clearly related to the day-to-day operation of the system. In this case, the access fees would be directly linked to the flow patterns over the network. This is in contradiction with the objective of setting access fees, which is to grant the user the *right* to use the grid regardless of whether he actually uses it or not. This would imply that the introduction of a two-part tariffs create two different and complementary types of product: usage and access. However, Laffont and Tirole (1996) believe that access charges which are related to the use that is made of the access, have the advantage of reflecting demand considerations.

CONCLUSION

Beyond the usefulness of the tracing method in the allocation of variable costs (losses) of electricity transmission, the method has two potential applications. The first application is related to trade in electricity between networks of different countries. The second is a contribution to the issue of allocation of fixed costs in electricity transmission. Some of the advantages of the method, such as transparency and practicality with limited distortion to economic efficiency, would make it an alternative worth serious consideration.

The application to cross-border trade shows that the tracing method is very useful in presenting more unifying transmission pricing method among different international networks. The ideal marginal pricing method is impractical because of its information requirements, especially those which are commercially sensitive. Also, the method faces additional difficulty in facilitating international trade between countries due to national sovereignty considerations. The simple method of the postage stamp may serve the purpose of practicality, but it grossly ignores the concerns for allocative economic efficiency.

The application of the tracing method to the design of access fees to recover fixed cost shows that the method is able to link the charges of users with a fair approximation of their usage of the transmission assets. However, the method faces two objections: firstly, its access charges are directly linked to the day-to-day operation of the system; and secondly, the method is less useful for a transmission system with very large excess capacity. These

objections and the inability of marginal cost pricing to recover capital cost of transmission would make it likely that in practice access fees will be based on postage stamp charges.

In sum, the main rationale behind using tracing in transmission pricing is that its practicality would promote more trade, which offsets the minimum loss in economic efficiency. The over-simplicity and practicality of average pricing (e.g. postage stamp) may still cause it to be preferred over the tracing method, and over the marginal method for that matter. The bottom line in passing judgement on which method to choose depends on which would result in the highest net benefits from more trade in electricity, that could offset any shortcoming it may have.

CHAPTER NINE
Conclusions and Summary

"Good economics is a balance of theory and abstraction on the one hand against hard reality on the other" (Christopher Huhne, 1990, p. 14).

9.1 INTRODUCTION

The philosophy of the free market is one of the official principles guiding Saudi Arabia's economic development strategies, but despite this there has been much emphasis on the need for economic planning. In addition to market failure rationale, the argument for economic planning has been based on the necessity to develop the country's human and physical capital. Planning has also been beneficial in redistributing oil revenues, which are the main source of national wealth, and prioritising the government's own spending commitments.

The reduction in the reliance on oil revenues and diversification of the economic-base, mainly through industrialisation, have become the cornerstones of the development plans. Paradoxically, achievement of these objectives remains dependent on the availability of revenues from oil itself, which are subject to fluctuation and long-term uncertainties. However, the developments in domestic and global economic conditions have led to serious reconsideration of the extent of the public sector role in the economy.

In the face of high population growth and competing priorities, greater private sector participation could assist the country in allocating its resources more efficiently. Thus, it is not surprising that privatisation has become a government 'strategic option' in the move to increase the efficiency of the economy and reduce the size of the public sector. However, the success of the process depends not only on how seriously the private sector is in taking the initiative, but also on the official commitment to it. The recent government efforts which aim at introducing legal and institutional reforms, and the (so far) disciplined public spending, despite the upsurge in oil revenue seem very encouraging.

In the following sections, the focus is on the case of electricity industry, which is already undergoing the process of restructuring and privatisation. Particularly, these sections deal with electricity transmission pricing which is one of key issues that has to be addressed during the early stage of the process. The main section provides a comparison between three transmission pricing methods and evaluates their relevance to the Saudi Arabian electricity industry. The chapter ends with a discussion of policy issues and related recommendations that need to be considered in context of the restructuring process. Finally, the chapter suggests some important topics for further research.

9.2 AN EVALUATION OF THE ELECTRICITY INDUSTRY CASE

Saudi Arabia's experience of privatisation is limited and could be described, at best, as partial privatisation. What makes the electricity industry different from the other sectors is that it is the only sector which has been officially approved for full privatisation. Also the nature of government involvement in this industry has changed considerably over the decades from very limited supervision and regulation to extensive 'partnership' with the private sector. This was due to a sudden surge in electricity demand caused by energy-intensive industrialisation and rapid urbanisation. The reversal of this situation is the ultimate objective of the current restructuring plan, which aims at making the industry operates again as a profit-making enterprise.

The choice between different paths to privatising an industry is a critical factor in the success of the whole process. The Saudi Arabian electricity industry has had to choose between two proposals. The first proposal was for privatising the vertically-integrated regional companies, SCECOs. The second proposal considered privatisation, initially in the generation segment, as part of a broad and multi-stage restructuring programme. Although the second proposal requires a longer time to achieve full privatisation, choosing this approach was a prudent decision for three reasons. Firstly, the ownership mix and the actual operation of the SCECOs make the privatisation of each one separately impractical. Hence, the second proposal is, in fact, a gradual privatisation of these regional companies on an activity-by-activity rather than on a region-by-region basis. Secondly, the first proposal makes the introduction of competition and choice more difficult, the contentious

issue of third party access being a case in point. Thirdly, the second proposal provides the necessary time to introduce the appropriate institutional and legal reforms, which are very much needed.

Thus, the plan anticipates that the industry's new structure will include vertical separation of generation, transmission and distribution. The aim of the plan is to transform the industry from a single-buyer model to a power pool model, where electricity would be traded on an hourly basis in a spot market. This over-ambitious plan, especially for a developing country, is a formidable challenge, as its success would depend on many factors including the consistency and continuity of the implementation.

Opening up the generation and distribution activities to private companies requires the introduction of fair and transparent rules for solving cost allocation problems. More specifically, the issue of transmission pricing increases in importance as the industry is further unbundled and moved closer to a market-based structure. Transmission pricing is essential for facilitating the emergence of competitive electricity markets as well as promoting efficient trade-offs between the expansion of the transmission network and the siting of new generation capacity.

Thus, the correct transmission price not only encourages competition through the provision of a level playing field but also enhances productive and allocative efficiency. These are important factors especially for a vast country such as Saudi Arabia where most of the electricity demand is in regions which are far from primary energy sources. Also, the completion of a nation-wide natural gas network, in parallel to that of electricity, will highlight the significance of transportation costs for both power generators and industrial consumers.

9.3 OBJECTIVES OF TRANSMISSION PRICING METHODS

The recent increasing interest by theorists and practitioners alike in the issue of transmission pricing developed from the necessity to find an efficient and practicable way of allocating transmission costs. In contrast to the case of a vertically-integrated industry, these two objectives are difficult to reconcile in an unbundled structure, as transmission

9.3.1 Promotion of the efficient day-to-day operation of the bulk power market

This objective implies that any proposed transmission pricing scheme should be judged not only by how much its charges reflect optimal dispatching, but also by how these charges are incorporated into the trading mechanism of the electricity market. Thus, the practical question in a liberalised structure is whether it is possible to create a competitive electricity market that induces optimal dispatching of generators.

This research has illustrated how marginal cost pricing of transmission losses results in efficient dispatch where it modifies the generation cost of each generator to minimise total costs. Also, it has illustrated how the tracing and postage stamp charges impact on the merit order of the generators. The postage stamp charges are weak in incorporating transmission costs into economic dispatching as all generators are considered as if they were at the same location.

The tracing method produces charges which are similar to those of the marginal pricing method, especially for zonal charges. Since transmission losses are small, in comparison with generation costs, the likelihood that the tracing charges would result in incorrect dispatching is very limited. In fact, this research has illustrated that even when the tracing charges have altered the optimal dispatch, the increase in total production costs was very small, amounting to only 0.47 per cent. This is equivalent to an increase of only 0.27 per cent in the cost of delivering one MW of electricity to consumption centres.

Three important issues are relevant to this discussion. Firstly, the actual practices in electricity markets show that the dispatcher relies on generators bids which are not necessarily reflective of their real marginal operating costs. Secondly, when trading arrangements are made on an *ex ante* basis, both the marginal and tracing charges do not necessarily reflect the actual dispatch. Conversely, the *ex post* marginal charges reflect the actual operating conditions, but are volatile. Hence, it could be argued that the slight departure of tracing charges from the actual dispatch can be accepted as long as their stability induces higher trade liquidity in the market. Thirdly, in an ideal situation, competition is enhanced when generators are rewarded with negative marginal charges as a result of the reduction in power flows and consequent losses due to their trading with loads

in expensive areas. Although tracing charges are zero in this case, this is more preferable than the positive charges of postage stamp which do not provide any incentives for such generators.

9.3.2 Signalling of locational advantages for investment in generation and demand

Generation companies and energy-intensive customers have partially determine their long-term investments on the relative cost of transporting different energy sources including electricity itself. It is expected that transporting gas is cheaper than transmitting electricity (Newbery, 1999). However, incorrect accounting of these costs would lead to suboptimal decisions by both generators and large industrial consumers.

Generators may locate near consumption centres as that would reduce their transmission costs, but this is not always economically efficient as the cost of the alternative, which is to locate near fuel sources and transmit electricity to consumption centres, must be considered. Assuming the cost of transporting these sources is efficiently priced, the appraisal of these decisions depends on the usage of correct transmission prices for electricity.

Obviously, marginal cost pricing of transmission has the advantage of reflecting the exact differences in the transmission cost between locations. The postage stamp charges, on the other hand, fail to reflect any spatial signal and may even give the opposite signal. Thus, it is unfair that generators pay the same transmission charge regardless of their proximity to consumption centres. The tracing method may not give the exact signals as marginal pricing does, but as the research has shown, tracing gives similar signals. This is indicated by the average correlation coefficient, for marginal and tarcing charges, of 75 per cent. The research study shows that this similarity is even higher (82 per cent) for zonal charges for demand centres indicating that the tracing is more reflective of costs for a network which is spread over large geographical areas. This is obviously very relevant to the case of Saudi Arabia, especially as almost 90 per cent of the population are concentrated in cities and towns (i.e. zones) which are separated by relatively large distances.

From a regulatory point of view, there are two issues worth consideration in terms of transmission pricing. Firstly, while small generators are price-takers, large generators or generation companies with several stations have the incentives and the ability to impact on the power flows of the system which can give them favourable charges (Green, 1997). Thus, limited competition in generation gives a few companies the opportunity to game the market, which would diminish the usefulness of spatial signalling. Secondly, a location premium may become necessary to promote investment in distant generation. Remote and less developed regions with low-income populations may find it difficult to pay high retail prices that incorporate transmission charges. Conversely, generators may also find it costly to supply such regions without some kind of subsidy. Clearly such a subsidy will cause a distortion of the market signals. However, correct transmission prices will minimise this distortion as the value of the subsidy would have relevance to the actual costs and is based on a well-defined standard.

9.3.3 Signalling of the need for investment in the transmission system

The investments in generation and transmission need to be very closely co-ordinated as the available capacity of transmission influences directly the siting of new generation. Consequently, the vertical separation of transmission and generation places transmission pricing at the heart of this relationship. The presence of large differences in nodal prices would signal the need to reduce transmission losses and congestion through building additional transmission capacity.

Marginal cost pricing is able to reflect well the very small locational differences which result in optimal investment in the network. The postage stamp charges entirely ignore transmission cost differentials, which leads to incorrect investment decisions. As the tracing method understates the charges for transmission losses, the tracing prices would give weaker spatial signals than the marginal prices would. This could lead to under-investment in the transmission network and suboptimal siting of generation, which could result in more than necessary generation in the eastern region. However, this research has shown that this signal becomes stronger for zonal than nodal charges. This would also make it more suitable for signalling the need for new links between different zones (or interconnected countries) rather than signalling the need for investment within each zone.

There are three observations worth mentioning in the context of this important objective. Firstly, in practice, decisions regarding transmission investments are guided but not necessarily decided by nodal prices. Secondly, as the transmission company is normally a regulated entity, the decisions on investment expansion are based mostly on regulatory considerations. Thirdly, even if the network expansion was optimally determined, transmission investment is indivisible (King, 1996). Consequently, network expansion is done in stepwise fashion which normally results in an overbuilt transmission system.

9.3.4 Compensation of the owners of existing transmission assets

This is a crucial objective that any transmission pricing should satisfy because revenue adequacy is a necessary condition for economic efficiency. The transmission network owners are not expected to invest in more capacity if their incurred costs are not guaranteed to be recovered. Hence, the choice of transmission pricing scheme must strike a delicate balance between this objective and the other equally desirable objectives.

This research shows that while marginal pricing of transmission leads to over-recovery of variable transmission costs (Chapter Six, Table 6.2), it is widely known to under-recover fixed (sunk) costs. This makes it necessary to rely on some form of multi-part tariff, which usually involves usage (variable) and access (fixed) charges. The drawback of this two-part tariff is that the efficient economic signal of marginal prices is weakened due to the presence of significant sunk costs, which are normally recovered through postage stamp charges.

Postage stamp and tracing methods recover the exact total costs as both starts with the assumption that there is a well-defined way of allocating transmission costs (Hogan, 1997). The postage stamp allocates the total (variable and fixed) costs based on the size of the generator or distribution company. The tracing method is able to allocate the total costs based on 'the extent of use', which has the advantage of incorporating locational signals into cost recovery. This research has pointed out that the usefulness of the tracing method in recovering fixed costs is limited for an excessively overbuilt network. However, this is a temporary situation, especially in a developing country, and, hence, cannot be generalised.

9.3.5 Simplicity and transparency

The acceptability of any transmission pricing depends on how much the users understand the assumption on which charges are based. Simplicity and transparency are not considered strong features of marginal charges, which are based on many assumptions and complex calculations. This research has illustrated how transmission charges can be positive, negative or zero depending on which generator is designated as the marginal generator. So the marginal prices optimally reflect transmission costs but they also produce volatile charges, which are not always understood by the participants. The usual suggestion is that using the average of marginal charges, over some specified period (e.g. one year), might simplify the charges.

If the marginal method is known for its complexity, the postage stamp method is known for its simplicity. In addition to being straightforward, the calculation of averages has no or only a very small, transaction cost. The tracing method can also be considered simple, but it requires the initial construction of an algorithm, which takes only a very short time even for a large network. The logic behind the calculation of tracing charges is simple as it is based on the notion that nodal inflows are shared proportionally by the outflows. Nevertheless, the advantage of simplicity should not be the overriding factor above economic efficiency considerations.

9.3.6 Political implementation

The implementation of transmission pricing depends greatly on whether the pricing rules are in place prior to opening the market for competition. This may not necessarily guarantee successful implementation but it would minimise the potential for disputes. Any changes in an existing transmission pricing rule would result in winners and losers. So even if the new pricing rule is both simple and economically desirable, influential losers may succeed in blocking it (Green, 1998a).

One of the difficulties facing the implementation of transmission charges on the basis of marginal cost pricing is that this method results in charges with very large differentials. Theoretically, this indicates the advantage of the marginal pricing as it reflects the impact of the user's actions on the system costs. In practice, however, distant generation and

distribution companies, which perceive charge differential as disadvantageous, usually raise objections. Thus, it is suggested that reducing these differences by a specific factor would make it less objectionable although it likely to weaken the economic signals of the charges.

On the other hand, the postage stamp charging scheme is more politically acceptable as it is easier to enforce and more understandable. Although, this method produces uneconomic and also unfair charges, users normally do not object as the difference between what they expect to pay and what they are actually paying is relatively small. Whether the tracing method is politically implementable remains an open question. However, the fairness of the allocation of transmission costs and the low differentials in charges should make it more acceptable than the marginal. Nevertheless, it seems that charging on the basis of the postage stamp method will remain common practice unless the concern for losses in economic efficiency becomes more earnest.

To summarise, these six objectives could be categorised into two main objectives: economic efficiency (the first three) and implementation (the remaining three). It is worth noting that the marginal and postage stamp methods give almost the opposite outcomes. While the marginal is very strong in meeting economic efficiency objectives, its weakness is in implementation. The postage stamp is very strong in terms of implementation, but it is very weak on the grounds of economic efficiency. The tracing method might prove, especially with more extensive data, to be a good compromise between the two, by satisfying the condition of implementation combined with a reasonable account of economic efficiency.

The conclusion of this research is that marginal pricing should be given priority, especially as its implementation can be less difficult in a newly-restructured industry, such as that of Saudi Arabia. When transmission pricing rules are known at an early stage of the process, the system users would have less incentive to object when the electricity market is already established. As there is an inclination to choose simplicity and implementation, in the form of the postage stamp method, over complexity and economic efficiency, in the form of

marginal pricing, this research draws attention to the fact that compromise, in the form of the tracing method, could be possible.

9.4 POLICY ISSUES AND RECOMMENDATIONS

There follows a list of policy issues and recommendations which have arisen from this research study.

1) There are currently major institutional and regulatory reforms proposed for the Saudi Arabian economy. The consistency and continuity of these reforms are necessary ingredients of a suitable climate for domestic and foreign investors, as well as for the long-term success of the reform itself. More importantly, the reform of a particular sector does not take place in isolation from the rest of the reforms in the economy. For instance, progress in restructuring the electricity industry is closely dependent on the presence of a well-developed financial market and a transparent regulatory system.

2) Although privatisation has been a major reform objective for many years, the translation of this objective into reality has been less advanced than expected. Thus, privatisation initiatives need to include specific timetables, as that would establish accountability and distance the process from short-term government budgetary conditions.

3) The electricity industry is a capital-intensive enterprise which requires highly skilled labour. Hence, privatisation can have a negative impact on the employment of Saudi Arabian nationals. This would create a potential for conflict between the objectives of Saudisation and privatisation. Incremental approach to hiring and firing of employees, especially in the initial years, and well-designed training programmes, would minimise such impacts.

4) The restructuring and privatisation of the electricity industry should result in lower and cost-based prices through competition and choice in as many parts of the industry as possible. Privatisation with no credible competition may lead to higher prices which not only hinder the objective of industrialisation but also have a negative distributional effect.

5) Restructuring of the electricity industry requires regulatory involvement, as there are high incentives for rent seeking behaviour and monopolistic power in such an industry. Also, the opportunity given to large consumers to choose their suppliers should be extended as soon as possible to small consumers, who as captive consumers may end up subsidising those large consumers.

6) Although there is no shortage of domestic private wealth, foreign investment would bring to the Saudi electricity industry not only finance but also know-how, managerial skills and expertise. This investment comes in the form of IPP and variants of BOOT power projects, which have the advantage of raising cheaper sources of finance than the government or even local commercial banks would. However, these schemes are associated with high prices due mainly to their high sensitivity to the foreign exchange risk and to the uncertainty about rules for setting electricity tariffs and the legal system.

7) An important lesson that Saudi Arabia can learn from international experiences of transmission pricing is that not only should the rules be predictable and transparent, but more importantly they should be announced in advance of the electricity market becoming operational. This is necessary to limit the potential sources of dispute, as changing the rules in the middle of the game would create objections and could even impede the efficiency of the market itself.

8) The concentration of natural gas in the eastern region and the aim to link the country's regions with both electricity and natural gas networks highlights the importance of transportation costs for generators. Also, some hydrocarbon and other energy-intensive industries may find it advantageous to locate at the western coast of the country, which is nearer to their European and African markets. In addition to transportation costs, these industries may consider having their own power generators, in which case efficient decisions between these alternatives would be dependent on the availability of 'correct' transmission prices.

9) Having a single nationwide distribution company makes it politically unfeasible to have residential electricity consumers paying regionally differentiated prices. As the restructuring plan envisages that the industry will include regional private distribution companies, locational differences can feed into retail prices through transmission

prices. Ignoring these differences would lead consumers in regions with low (high) marginal transmission cost, such as the eastern (central or western) region, to face higher (lower) prices than necessary, resulting in too little (much) electricity consumption. In addition, neglecting consumers' responses to real time prices would create incomplete electricity market which could result in inefficient outcomes.

10) Saudi Arabia can benefit from the GCC interconnection on two fronts: firstly, additional sources of cheap generation could put positive pressure on the Saudi electricity industry to improve its performance. Secondly, trading in an electricity spot market requires the use of financial instruments. Thus, the establishment of a pool for GCC power would open the way for traders in the Saudi electricity industry to have access to the more liberal financial markets, such as that of Bahrain.

9.5 FURTHER RESEARCH

The following is a summary of suggested topics of relevance to this research study, which need to be explored further.

1) More definite conclusions can be drawn if similar studies are applied to other networks. Thus, the generalisation of the results can be even more reliable especially if larger networks are used.

2) As the network used in this research is excessively overbuilt, the used data reflect only transmission losses. Thus, further research may be needed to consider the impact of line congestion on transmission prices using the different pricing methods.

3) Cost-benefit analysis of whether investment in a generator near a gas field versus investment in one near a consumption centre might give different outcomes using the different electricity transmission pricing methods.

4) Introducing market rules to electricity has resulted in some calls for the pricing of ancillary services such as reactive power, which is the power supplied by generators for maintaining the stability of the transmission system. It would be useful to investigate the economics of allocating this cost using the marginal and tracing methods.

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APPENDIX A:
Glossary

This thesis focuses mainly on the subject of transmission pricing which is an area of growing interest for both economists and electrical engineers. Due to the interdisciplinary nature of this subject, it is appropriate to provide a glossary of the terms which commonly used in the fields of economics and electrical engineering. The following references were very useful in compiling this glossary:

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2) Felak, R.; Poray, A.; Sheblé, G. and Wong, P. (1996) Glossary of Terms and Definitions Concerning Electric Power Transmission System Access and Wheeling, The IEEE, New Jersey.

3) Nicholson, W. (1998) Microeconomic Theory: Basic Principles and Extensions, The Dryden Press, Fort Worth.

Allocative efficiency: the condition achieved when the prices of goods supplied to the market are equal to their marginal costs of supply, which means that goods and services are allocated to the consumers who value those goods most highly, as indicated by their willingness to pay for them. Thus, at these prices it is not possible to rearrange the outputs of an economy and make one consumer better off without making another worse off.

Ancillary services: those services provided by generators for maintaining reliable operation of the transmission system, including voltage control, frequency control etc.

Arbitrage: the act of buying an item (cheaply) in one market and selling it at a higher price in another market, resulting in a risk-free profit from the price differential between the two markets.

Asymmetric information: the difference in information held by the buyer and the seller about a potential transaction or commercial arrangement.

Averch-Johnson effect: the condition which results when the regulator sets the allowed rate-of-return above the cost of capital, causing the utility to use more capital than if it were unregulated (i.e. over-capitalisation).

***Bai al salam*:** an Islamic form of sale contract in which the price is paid in advance and the goods are delivered in the future. This deferred-delivery sale is similar to a forward contract where delivery of the product is in the future in exchange for payment on the spot market.

BOO/BOOT: acronyms for Build-Own-Operate (BOO) and Build-Own-Operate-Transfer (BOOT) which are methods for encouraging private sector participation in the electricity industry. Under these schemes, a project company is set up to plan, finance under limited recourse, design, construct, and operate generation projects for a specified period of time.

Consumer surplus: the difference between the total value consumers receive from the consumption of a particular product and the total amount they are willing to pay for the product. Consumer surplus is usually measured by the area under the compensated demand curve and above the market price.

Constrained-off generator: the generator which, despite having a favourable ranking in the merit order schedule, is excluded from being dispatched due to congestion on transmission lines.

Contestable market: a market where firms can enter or exist freely without incurring sunk costs. Thus, this market is subject to 'hit-and-run' entry and exit resulting in zero economic profit even in a natural monopoly situation.

Co-operative game: a game in which players can negotiate binding contracts that allow them to plan and employ joint strategies.

Day-ahead market: a market which involves trading of multi-hour electricity blocks for delivery during the following day.

Deadweight loss: the reduction in total surplus (i.e. consumers' surplus and producers' surplus) due to the restriction on the output of a product at a level below the optimum efficient level.

Demand-side management: the identification and implementation of initiatives that improve the use of existing generation capacity by modifying the characteristics of the demand for electricity. This usually involves a mix of pricing and conservation strategies that aim at increasing the incentives for a more efficient use of electricity.

Derivative: a financial instrument, traded on or off an exchange, the price of which is directly derived from the value of one or more underlying securities, commodities, or any agreed upon pricing index or arrangement.

Disintegration (or unbundling): the functional separation of a vertically integrated utility into smaller, individually owned business units. This means that the generation, transmission, distribution, and metering and supply become vertically separated.

Distribution company: the company responsible for constructing and maintaining the low voltage distribution lines connecting the transmission network (i.e. high voltage) to the final customer.

Economic dispatch: the allocation of total generation requirements between different power plants with the minimisation of total system costs through consideration of both marginal generating costs and marginal transmission costs as well as the system's physical constraints.

Economic profit: the difference between revenues and costs, including opportunity costs. The consideration of the opportunity costs, of the best available alternative, is very helpful in the distinguishing of economic profit from accounting profit.

Embedded cost: the total cost based on the historical cost of the factors of production used to produce a given level of output. This normally does not relate to the current market prices for the factors used, but rather to the costs that existed when the factors were actually purchased.

Ex ante/ ex post: the distinction between that which is planned (*ex ante*) and that which actually occurs (*ex post).*

Fixed costs: the costs that do not change as the level of output changes in the short run. These costs include contractual commitments and investment-related costs to which the firm is already committed.

Forward contract: a supply contract between a buyer and seller, whereby the buyer is obligated to take delivery and the seller is obligated to provide delivery of a fixed amount of electricity. The price can be determined in the present, or it can be related to the spot price at the date when the transaction is to be terminated, or just before that time; the payment is due in full at the time of, or following, delivery.

Future contract: a supply contract between a buyer and seller, whereby the buyer is obligated to take delivery and the seller is obligated to provide delivery of a fixed amount of electricity at a predetermined price at a specified location, while the payments are settled daily.

Heat rate: the number of British Thermal Units (Btu) needed to obtain one kWh of electricity in an actual system.

Hedging: a kind of price insurance operated through the use of options, futures, and swaps, which can also take place using long term contracts.

Impedance (Z): the electrical characteristic of an electricity transmission line or transformer which quantifies that factor's ability to impede the flow of electrical power.

Independent power producers: generators which deliver electricity to a system but are not owned by the utility or the transmission company, in a single-buyer model.

Installed reserve margin: the difference between the total generating capacity and the peak load. The objective of having sufficient installed reserve margin is to maintain the system's reliability by meeting unexpected circumstances such as plant outages.

Interconnected system: individually owned and operated electricity networks which are connected to each other through transmission lines, known as tie-lines, for the objective of delivering and receiving electricity.

***Istisna*:** a purchasing mechanism based on Islamic financing principles. Istisna is a contract to purchase in the present a product (e.g. generator or transmission project) which is going to be manufactured in the future against an agreed price. Payments are made to the contractor at each stage of completion of the project.

Kirchhoff's (current) laws: laws stating that the algebraic sum of all currents directed toward (and away from) a junction point is zero. This means that, at any given node in the network, the power inflows should equal the outflows.

Load (capacity) factor: the ratio of the actual amount of electricity produced to the maximum amount possible over the same period when applied to a single generator. A higher load factor means higher plant utilisation, as maximum capacity is built to meet peak demand, not average demand.

Long run: a period over which complete adjustment to changes can take place. In microeconomics, it means the length of time over which a firm can enter or leave the industry and during which all its inputs are variable.

Marginal cost: the increase in the total costs of a firm, due to the increase in its output by one additional unit. Marginal cost represents the opportunity cost, or the total sacrifice to society, for producing a given product.

Market period: a very short period over which the quantity supplied is fixed and not responsive to changes in the market price.

Marketer: an agent for generation projects who markets power on behalf of the generators and also arranges transmission and ancillary services as needed. The major difference between a marketer and a broker is that the former represents the generator while the latter acts as a middleman.

Merit order: the rank in which generators are dispatched, based on their respective marginal generating costs, as the loading condition changes from base load to peak load and back.

Monopoly: a structure of an industry in which there is only a single seller of the product, which has no close substitutes.

Monopsony: a market in which there is only one buyer (as in the single-buyer electricity model) of some factor of production or the output of many producers (e.g. generators).

Natural monopoly: the situation which results when it is cheaper for one firm to produce a product or service, at a given level of demand, than it is for two or more firms to do so.

Oligopsony: a form of buyer concentration, where a few large buyers confront many small suppliers. Thus, these powerful buyers are able to secure advantageous terms from the individual suppliers.

Opportunity cost (or economic cost): the value or worth of the next best alternative (or opportunity) to economic good, or the cost of the sacrificed resources which are used to produce this good.

Option contracts: contracts that give the owner the right but not the obligation to buy or sell a specified trading contract. These contracts allow the holder to buy (i.e. a call option) or to sell (i.e. a put option) a commodity (e.g. electricity energy) at the exercise price during a specified period of time in exchange for a one-off premium payment.

Parallel flow: the electricity flow over a utility's transmission network which is caused by the electricity flows (transactions) over other networks.

Pareto optimality: the situation which occurs when an economy's resources are allocated in such a way that no one individual can become better off without making someone else worse off.

Peak load: the maximum (usually hourly integrated) demand of all customer demands plus system losses, which are usually expressed in MW, at a given moment in time.

Perfect competition: the state of the world where there are assumed to be a large number of buyers and sellers for any product and each agent is a price taker.

Power pool: traditionally, a co-operative arrangement whereby monopoly electricity utilities exchange electricity for the purpose of backup and cost saving. In a liberalised structure, an electricity pool is the arrangement whereby competing generators bid to establish which are to be dispatched first.

Producer surplus: the area below the market price and above the respective supply curve.

Productive efficiency is concerned with the lowest cost method of producing output demanded by consumers subject to the technical constraints of production. Productive efficiency assumes that it is not possible to re-arrange the production inputs and obtain more output of one good without reducing the output of another

Rate-of-return regulation: the setting of a price that gives a firm or a utility, usually a monopoly, a competitive return on its assets.

Reactive power: the kind of electricity which establishes and sustains the electric and magnetic fields of alternating current equipment. It must also supply the reactive losses on transmission facilities.

Ready reserve: the unused capacity of generation that is not on line but can be brought on line within 15 minutes.

Real-Time Pricing: charges different retail electricity prices for different hours of the day and for different days of the year. Thus, these prices are able to capture the variations in supply/demand balances and, as such, reflective of wholesale prices.

Regulation: the supervision of the economic activities of private and public enterprises by the government in the interest of economic efficiency, fairness, and safety. Regulation may be imposed by enacting laws, by setting up special regulatory agencies, or by encouraging self-regulation through the recognition of voluntary bodies.

Reliability: a condition which, when applied to the electricity system, implies two components: adequacy and security. Adequacy is the ability of the system to meet the aggregate demand at all times, taking into account the unanticipated outages of system facilities. Security is the ability of the system to endure unexpected interruptions such as sudden loss of system facilities.

Rent seeking: the behaviour of economic actors who use the political process to gain benefits which would not be attainable by accepting market outcomes.

Resistance: is the electrical characteristic of an electricity transmission line or transformer which quantifies that factor's ability to oppose the flow of an electric current.

Spinning reserves: the difference between maximum capacity and actual output of generating units that can be operational almost instantaneously.

Spot market: a market where commodities (e.g. electricity) are traded for immediate delivery.

Stranded investments (costs): investments that have been undertaken, but have become unprofitable due to the change in the regulatory system resulting in increased competition. For example, the cost of existing facilities are not longer needed as the utility's customers can chose to buy electricity from other sources.

Strike (exercise) price: the price at which the underlying options contract is bought and sold in the event that the option is exercised.

Sunk costs: the costs that have already been incurred but cannot be recovered, even in the long run, as they are expenses of specific factor inputs (e.g. transmission and distribution assets) which cannot be used for other purposes or easily resold.

Swap market: the clearinghouse that allows contracts to be terminated with an exchange of physical or financial substitution.

Third party access (TPA): the obligation of companies operating transmission (and distribution) networks to allow third parties (e.g. consumers and distribution companies) to make use of these networks.

Transmission losses: the amount of energy dissipated in the electrical transmission network when electricity travels along the transmission lines.

Two-part tariff: the most common form of muti-part tariffs, in which purchasers of a product or service are charged both an access (entry) and a usage fee.

Value added: the difference between the value of a firm's (or industry's) output and the cost of the inputs. So the value added of a firm is the value of what this firm adds to its bought-in materials and services through its own production and marketing efforts within the firm.

Variable costs: the costs which tend to vary with the changes in the level of the firm's output.

Welfare economics: a normative branch of economics that employ value judgements and concerned with the way economic activity ought to be arranged so as to maximise the well-being of the nation by both increasing output and changing its distribution.

Wholesale wheeling: a mechanism of trading where access by a generator to the purchasing utility across the transmission lines of another utility is allowed. Retail wheeling occurs when a non-utility generator sells power to a retail customer, such as a large industrial customer, over a utility's transmission network.

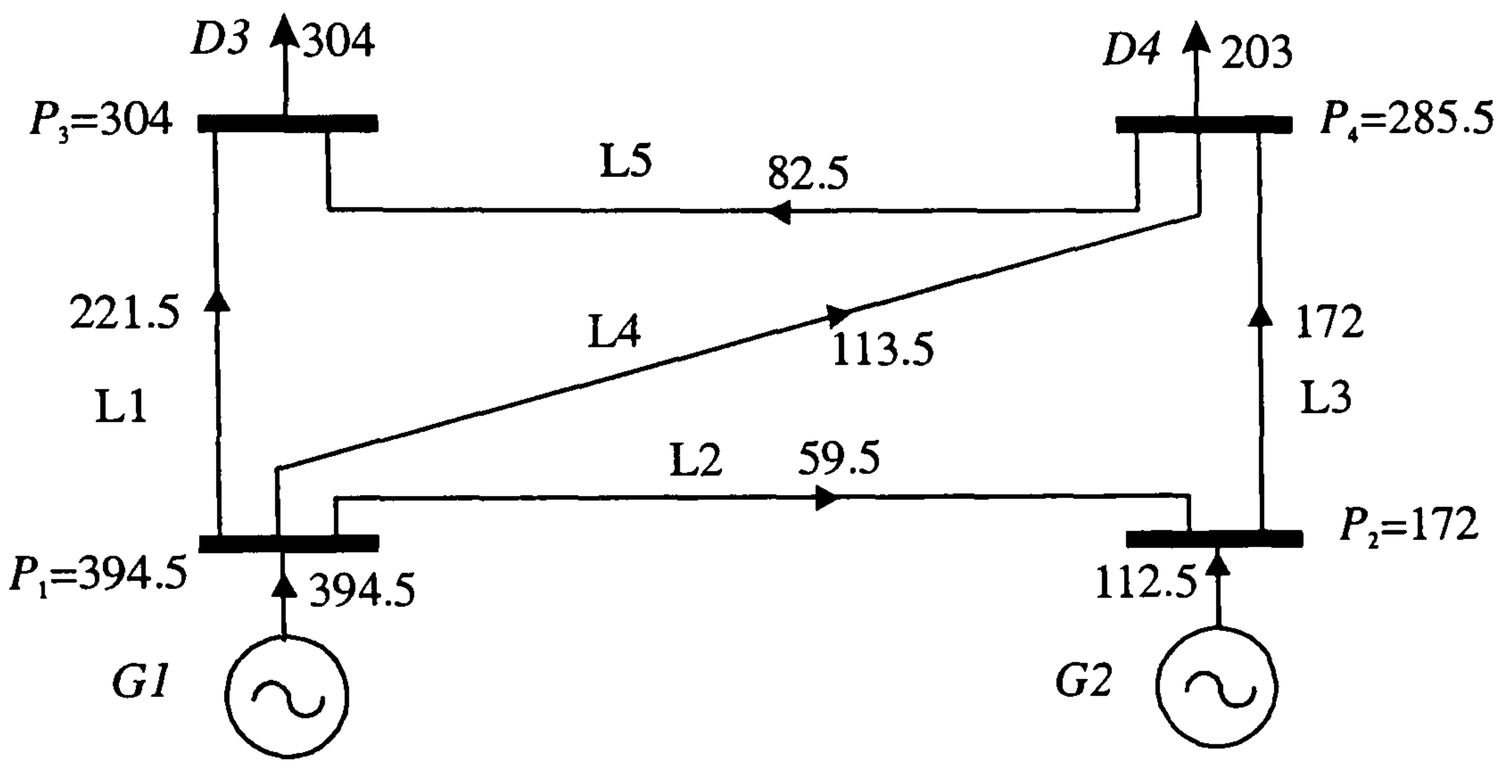
X-inefficiency: the failure to achieve productive efficiency by using resources optimally so that the lowest possible cost for each level of service provision is attained. This type of inefficiency is assumed to occur when ownership and control are separated in firms with monopolistic power.

Yardstick competition: the situation where the regulated return for an individual company depends on its performance relative to the average. The horizontal disaggregation of the electricity distribution enables the regulator to overcome the problem of asymmetric information.

APPENDIX B
Derivation of Tracing Formula Using Network Matrices

This appendix is based on Bialek and Kattuman (1999). The tracing methodology will be derived by using the incidence and adjacency matrices of a network which is consisted of *n* nodes and *m* lines. For simplification, an example of a network with average flows (i.e. no transmission losses) is used as illustrated in Figure B.1, below.

Figure B.1: A Network with Average Power Flows



Define $\mathbf{P}$, $\mathbf{P}_G$, and $\mathbf{P}_D$ as $(n \times 1)$ vectors of nodal flows, nodal generations and nodal demands, respectively, and $\mathbf{F}$ as $(m \times 1)$ vector of branch flows. For this network;

$\mathbf{P} = [394.5 \;\; 172 \;\; 304 \;\; 285.5]^T$,

$\mathbf{P}_G = [394.5 \;\; 112.5 \;\; 0 \;\; 0]^T$,

$\mathbf{P}_D = [0 \;\; 0 \;\; 304 \;\; 203]^T$,

$\mathbf{F} = [221.5 \;\; 59.5 \;\; 172 \;\; 113.5 \;\; 82.5]^T$, and

the $(m \times n)$ incidence matrix $\mathbf{B}$ is:

$$\mathbf{B} = \begin{bmatrix} 1 & 0 & -1 & 0 \\ 1 & -1 & 0 & 0 \\ 0 & 1 & 0 & -1 \\ 1 & 0 & 0 & -1 \\ 0 & 0 & -1 & 1 \end{bmatrix} \qquad \text{(Equation B.1)}$$

This matrix can be split into matrix $\mathbf{B}_u$ consisting of -1's and $\mathbf{B}_d$ consisting of 1's, as in the following:

$$\mathbf{B}_u = \begin{bmatrix} 0 & 0 & -1 & 0 \\ 0 & -1 & 0 & 0 \\ 0 & 0 & 0 & -1 \\ 0 & 0 & 0 & -1 \\ 0 & 0 & -1 & 0 \end{bmatrix}, \mathbf{B}_d = \begin{bmatrix} 1 & 0 & 0 & 0 \\ 1 & 0 & 0 & 0 \\ 0 & 1 & 0 & 0 \\ 1 & 0 & 0 & 0 \\ 0 & 0 & 0 & 1 \end{bmatrix} \qquad \text{(Equation.B.2)}$$

The *adjacency* matrix, **D**, is defined as $(n \times n)$ matrix with $[\mathbf{D}]_{ij} = 1$ if there is a flow from node i to node j. The adjacency matrix can be calculated as $\mathbf{D} = -\mathbf{B}_d^T \mathbf{B}_u$ and for the network shown in Figure B.1 it is:

$$\mathbf{D} = -\mathbf{B}_d^T \mathbf{B}_u = \begin{bmatrix} 0 & 1 & 1 & 1 \\ 0 & 0 & 0 & 1 \\ 0 & 0 & 0 & 0 \\ 0 & 0 & 1 & 0 \end{bmatrix} \qquad \text{(Equation.B.3)}$$

Let us now define $(n \times n)$ matrix $\mathbf{F}_d$ such that its (i,j) element is equal to the flow in line i-j towards node j (i.e. downstream). $\mathbf{F}_d$ has the same structure as the adjacency matrix **D** and can be calculated as

$$\mathbf{F}_d = -\mathbf{B}_d^T \text{diag}(\mathbf{F}) \mathbf{B}_u \qquad \text{(Equation.B.4)}$$

Thus, for the network shown in Figure B.1,

$$\mathbf{F}_d = \begin{bmatrix} 0 & 59.5 & 221.5 & 113.5 \\ 0 & 0 & 0 & 172 \\ 0 & 0 & 0 & 0 \\ 0 & 0 & 82.5 & 0 \end{bmatrix} \qquad \text{(Equation.B.5)}$$

where the (i,j) element of $\mathbf{F}_d^{\mathrm{T}}$ is equal to the flow in line i-j towards node i (i.e. upstream).

The Kirchhoff Current Law can be expressed as:

$$\mathbf{P} = \mathbf{P}_D + \mathbf{F}_d \mathbf{1} \quad \text{or} \quad \mathbf{P} = \mathbf{P}_G + \mathbf{F}_d^{\mathrm{T}} \mathbf{1} \qquad \text{(Equation.B.6)}$$

where **1** is $(n \times 1)$ vector of 1's.

Equation.B.6, above, can be expanded as:

$$\begin{aligned}\mathbf{P}_D &= \mathbf{P} - \mathbf{F}_d \mathbf{1} = \mathbf{P} + \mathbf{B}_d^T \mathrm{diag}(\mathbf{F}) \mathbf{B}_u \mathbf{1} \\ &= (\mathbf{I} + \mathbf{B}_d^T \mathrm{diag}(\mathbf{F}) \mathbf{B}_u \mathrm{diag}(\mathbf{P}^{-1}))\mathbf{P} = \mathbf{A}_d \mathbf{P}\end{aligned} \qquad \text{(Equation.B.7)}$$

$$\begin{aligned}\mathbf{P}_G &= \mathbf{P} - \mathbf{F}_d^{\mathrm{T}} \mathbf{1} = \mathbf{P} + \mathbf{B}_u^T \mathrm{diag}(\mathbf{F}) \mathbf{B}_d \mathbf{1} \\ &= (\mathbf{I} + \mathbf{B}_u^T \mathrm{diag}(\mathbf{F}) \mathbf{B}_d \mathrm{diag}(\mathbf{P}^{-1}))\mathbf{P} = \mathbf{A}_u \mathbf{P}\end{aligned} \qquad \text{(Equation.B.8)}$$

where $\mathbf{I}$ is the unity matrix of rank n and

$$\begin{aligned}\mathbf{A}_d &= \mathbf{I} + \mathbf{B}_d^T \mathrm{diag}(\mathbf{F}) \mathbf{B}_u \mathrm{diag}(\mathbf{P}^{-1}) \\ \mathbf{A}_u &= \mathbf{I} + \mathbf{B}_u^T \mathrm{diag}(\mathbf{F}) \mathbf{B}_d \mathrm{diag}(\mathbf{P}^{-1})\end{aligned} \qquad \text{(Equation.B.9)}$$

The $\mathrm{diag}(\mathbf{P}^{-1})$ is a diagonal matrix with its i-th diagonal element equal to the reciprocal of i-th nodal flow, $1/P_i$. Note that $\mathbf{A}_d$ has the same structure as the adjacency matrix , $\mathbf{D}$, but with addition of a diagonal, while the structure of $\mathbf{A}_u$ is the transpose of $\mathbf{A}_d$.

The elements of $\mathbf{A}_d$ and $\mathbf{A}_u$ matrices can be calculated as:

$$\begin{aligned}[\mathbf{A}_{\mathbf{u}}]_{ij} &= \begin{cases} 1 & \text{for } i = j \\ -\left|P_{ji}\right| / P_j & \text{for } j \in \alpha_i^u \end{cases} \\ [\mathbf{A}_{\mathbf{d}}]_{ij} &= \begin{cases} 1 & \text{for } i = j \\ -\left|P_{ji}\right| / P_j & \text{for } j \in \alpha_i^d \end{cases}\end{aligned} \qquad \text{(Equation.B.10)}$$

where;

α_i^d is the set of nodes supplied directly from node i (it corresponds to non-zero off-diagonal columns in the i-th row of $\mathbf{F}_d$ or $\mathbf{A}_d$), and

α_i^u is the set of nodes supplying directly node i (it corresponds to non-zero off-diagonal columns in the i-th row of $\mathbf{F}_d^{\mathrm{T}}$ or $\mathbf{A}_u$).

Since $[\mathbf{A}_u]_{ij} P_j = [\mathbf{A}_d]_{ji} P_i$, adding matrices $\mathbf{A}_u$ and $\mathbf{A}_d$ gives a matrix of a structure identical to that of the nodal admittance matrix.

As $\mathbf{A}_u$ and $\mathbf{A}_d$ are non-singular, equation.B.7 and B.8 allow calculating a nodal flow as the linear combination of components supplied from individual generators or to individual loads:

$$\mathbf{P} = \mathbf{A}_u^{-1}\mathbf{P}_G \quad \text{and} \quad \mathbf{P} = \mathbf{A}_d^{-1}\mathbf{P}_D \qquad \text{(Equation B.11)}$$

The Proportional Sharing Rule allows the presentation of individual nodal demands as the sum of components supplied from individual generators or to individual nodes:

$$P_{Di} = \frac{P_{Di}}{P_i}\sum_{k=1}^{n}\left[\mathbf{A}_u^{-1}\right]_{ik} P_{Gk}\,, \qquad P_{Gi} = \frac{P_{Gi}}{P_i}\sum_{k=1}^{n}\left[\mathbf{A}_d^{-1}\right]_{ik} P_{Dk} \qquad \text{(Equation.B.12)}$$

The inclusion of losses can be done by considering gross or net network flows. For the gross flows, the flow vector $\mathbf{F}$ used to calculate $\mathbf{A}_u$ in equation.B.9 must be replaced by the vector of flows at the sending end of each line, $\mathbf{F}_{send}$. For the net flows, vector $\mathbf{F}$ used to calculate $\mathbf{A}_d$ in equation.B.9 must be replaced by the vector of flows at the receiving end of each line, $\mathbf{F}_{rec}$. Thus, matrices $\mathbf{A}_u$ and $\mathbf{A}_d$ will be expressed as:

$$\begin{aligned}\mathbf{A}_d &= \mathbf{I} + \mathbf{B}_d^T \mathrm{diag}(\mathbf{F}_{rec})\mathbf{B}_u \mathrm{diag}(\mathbf{P}^{-1}) \\ \mathbf{A}_u &= \mathbf{I} + \mathbf{B}_u^T \mathrm{diag}(\mathbf{F}_{send})\mathbf{B}_d \mathrm{diag}(\mathbf{P}^{-1})\end{aligned} \qquad \text{(Equation.B.13)}$$

and the rest of the method will be the same as that described in Chapter Four (Sections 4.4.4 and 4.4.5).