AN INVESTIGATION INTO THE COSTS OF ACTIVE POWER TRANSMISSION TRANSACTIONS AND METHODS FOR EVALUATION OF COSTS

by

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SYNOPSIS

The power supply industry of South Africa is currently engaged in the process of restructuring, in a move from traditional vertically integrated and regulated structures to the unbundled, deregulated marketing of electric energy and power. Since this is a new process for South Africa, the investigation was commissioned with the aim of introducing this new area of research, to get an international perspective on the topic, and to build up a theoretical background for further studies.

In this new deregulated environment, the transmission segment of the supply industry is seen as an independent business, which can provide services at the appropriate terms and conditions. A transmission utility offers services at costs that can be evaluated by various methods. In this context, the thesis has three objectives. The first objective of the thesis is to consider different types of transmission services and costs associated with these services. The second objective is to analyse existing methods for evaluation of costs of transmission transactions and to define advantages and drawbacks of these methods. The third objective of the thesis is to test selected methods for illustration by means of case studies.

The literature survey on the topic was completed to obtain an overview of the international experience in the field of Transmission Economics, and to analyse the existing methods for evaluation of costs of transmission transactions. Two groups of methods were identified and analysed: Incremental and Accounting. After the investigation, six methods were recommended for further computer simulations. For this purpose an eighteen-bus network was selected which is the equivalent of the South African transmission grid.

The operating cost of a transmission transaction was calculated using the optimal power flow (OPF) program. The capital cost of a transmission transaction was calculated by simplified accounting procedure.

The results of the simulations show that the rates calculated by the Incremental methods are sensitive to the operating conditions of the system. The Short-Run

Marginal Cost (SRMC) method gives more realistic results with no transmission constraints in the system. When transmission constraints are present, the rates calculated by the SRMC method are unrealistically high. The Short-Run Incremental Cost (SRIC) method gives reasonable values for all cases considered. The investigation further demonstrates that the SRMC and the SRIC rates do not reflect revenue requirements.

The Accounting methods are based on a simplified calculating procedure. The common disadvantage of the Accounting methods is that the accounting rates do not reflect the changing conditions of the system. Furthermore, the calculations for the Accounting methods are performed for the peak load only. However, as the capital portion of the total cost of a transmission transaction is usually the largest, the Accounting methods have a very important advantage: they allocate the capital costs of the network and thus reflect the revenue requirements.

None of the above mentioned methods covers the operating and the capital costs at the same time. The combined Incremental/Accounting methods appear to give the best result in terms of preserving economic efficiency and providing the revenue requirements. The combined rates are more accurate than incremental or accounting rates calculated separately. They reflect the capital costs of transmission facilities, captured by the Accounting methods, and the operating costs, captured by the Incremental methods.

On the basis of theoretical analysis and computer simulations, guidelines for the application of the methods considered are provided and the foundation is laid for further research in this field.

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CHAPTER 1

INTRODUCTION

1.1 BACKGROUND AND STATEMENT OF THE PROBLEM

The power supply industry started with central control of production and transmission of electric power, which resulted in vertical integration of the structure of the electric utilities. Generation, transmission and distribution segments of power systems were integrated within the same company. Electric utility pricing has not been concerned with identifying the separate costs of various services. All services offered by the generation, transmission and distribution were bundled together and billed as a single charge to the customers. The introduction of competition and deregulation of supply industry requires that services be offered and priced separately.

The electrical industry of South Africa is going through the process of moving from traditional vertically integrated regulated structures to the deregulated market of electric energy and power. Due to the fact that this is the new process for South Africa, the investigation was commissioned with the aim to introduce the new area of research, to get international perspective on the topic and to build up the theoretical background for further studies. From the perspective of the supply industry it is very important to know and to foresee problems experienced by other countries and utilities engaged in similar processes.

In the new deregulated environment, transmission is seen as an independent business, which provides services at an appropriate price, terms and conditions. A transmission utility can offer a wide range of services. Different types of transmission services involve different costs. To evaluate the cost of a transmission transaction several methods can be applied. The existing methods for evaluating costs of transmission transactions fall into one of two groups: Incremental and Accounting methods. In order to analyse these methods and to compare them, the computer simulations are undertaken.

1.2 OBJECTIVES AND METHODOLOGY OF THE INVESTIGATION

The overall objective of the thesis is to introduce the new area of the research of Transmission Economics and Transmission Services. The particular objectives are the following:

1. To consider different types of transmission services provided by a transmission utility and to identify costs involved in providing these transmission services, in particular, in providing transmission transactions.
2. To analyse the existing methods for evaluating costs and to define and advantages and drawbacks of these methods.
3. To test selected methods on the case study.

The investigation is performed by means of literature review and computer simulations. The literature survey on the topic is completed to obtain an overview of the international experience in the field of Transmission Economics, and to analyse the existing methods for evaluating costs of transmission transactions. Two groups of methods are identified and analysed: Incremental and Accounting. After the theoretical analysis, several methods are selected for further computer simulations. For this purpose an eighteen-bus network is chosen which is the equivalent of the South African transmission grid.

Several study cases are specified to illustrate the findings of the theoretical analysis. The simulations are undertaken to demonstrate the sensitivity of the selected methods to reflect the cost of transactions in the various system conditions, such as different load profiles and the presence of transmission constraints.

The operating cost of a transmission transaction is calculated using the optimal power flow (OPF) program. The capital cost of a transmission transaction is calculated by simplified accounting procedure.

1.3 LIMITATIONS AND ASSUMPTIONS

1. This thesis is not meant to discuss the issues related to the price of a transmission service or to transmission tariffs.
2. Neither does it debate various regulation policies or their advantages or disadvantages.
3. The thesis focuses on costs of primary transmission services, i.e. transmission transactions.
4. The thesis analyses and examines the costs of transactions only in a static, not a dynamic sense. The costs are calculated for a particular hour (snap-shot). The variations of the costs over time are not considered in the research.
5. Only active power transmission transactions and associated costs are considered. Transmission of reactive power is beyond the scope of this thesis.

1.4 PLAN OF THE DEVELOPMENT

This thesis consists of six chapters. Chapter 2 of the thesis gives an overview of the transmission services in the power supply industry. In the beginning there is a brief introduction to power system and transmission networks. Then Chapter 2 introduces the objectives of the transmission utility. After a transmission service is defined, the economic problems associated with providing services are discussed in the chapter. Various types of transmission services are also presented and key factors for transmission services are discussed. Particular attention is paid to wheeling as a special type of transmission service. A summary of the international experience in the implementation of Transmission Open Access and the cost evaluation of transmission services is also presented in Chapter 2. Finally, Chapter 2 gives an overview of the South African supply industry.

Chapter 3 begins with an identification of cost components associated with providing transmission services and transmission transactions. The main part of Chapter 3 is the literature survey on costs of transmission services and methods for evaluating these costs. The literature is examined with the aim of analysing the international experience in this field and to investigate the existing methods for evaluating costs of services. Two groups of methods are identified and analysed here: the Incremental methods, the Accounting methods. The third group of methods is identified as the group of composite methods. The composite methods are the combinations of the Incremental and Accounting methods.

The purpose of Chapter 4 of the thesis covers the case studies where the findings of the previous theoretical analyses are confirmed and illustrated. For this purpose the 18-bus network is chosen, which is an equivalent of the South African transmission grid. Six methods are selected for computer simulations to calculate the costs of transmission transactions. The simulations are performed using SC-OPF software package. Chapter 4 presents the results and the analysis of the simulations for two Incremental methods and four Accounting methods.

Chapter 5 presents conclusions of the research and guidelines for the application of the selected methods. The final part of the thesis, Chapter 6, gives recommendations for the application of the selected methods. In Chapter 6 ideas are also presented for further research.

CHAPTER 2

OVERVIEW OF TRANSMISSION SERVICES IN THE POWER SUPPLY INDUSTRY

2.1 INTRODUCTION TO POWER SYSTEMS AND TRANSMISSION NETWORKS

The structure of electric power systems is commonly described as having three segments: generation, transmission and distribution. The purpose of generation is to convert a primary energy source into electric power. Once generated, the power flows over high-voltage transmission lines to the system loads. Transmission lines interconnect generating units with load centres so that the electricity generated can reach the demand. Transmission lines also interconnect utilities, allowing for the transmission of power between utilities. Delivery of the electric power at the desired voltage level is made in the distribution segment of supply of electricity.

The bulk power system must be designed and operated according to physical principles. In particular, two technical factors dictate the features of power systems.

1. Electricity flows at nearly the speed of light with virtually no storage of power in the system. Electricity must be generated, as it is needed. In order for a power system to be in static electrical equilibrium, the sum of power supplied at generation buses must equal the sum of power demanded at load buses and the amount of power lost in transmission. Power flow through any transmission line in a power system depends on the amount of power generated or demanded at each bus.

2. Secondly, every flow of power from a power plant to a distribution system affects the entire transmission network, not just the most direct path. The tight physical interconnectedness of an electric power system is what makes it differ the most from other systems that supply goods and services. All components of an electric

power system are physically connected, and all can be affected by events elsewhere in the system.

Power flows on the transmission network are physically determined by the electrical characteristics of the electrical components, by generation and demand levels and by the structure of the transmission network. A bulk power transmission network is at the highest voltage level, at or above 138 KV.

A transmission network can be seen as a physical and business entity. As a physical entity the network is composed of various electrical components such as transmission lines, capacitors, transformers, circuit breakers, etc., which are designed to function within a specific range of operating conditions. As a business entity the transmission network is represented by a transmission utility, which usually owns and operates the transmission system.

Historically, a transmission network was developed on an integrated basis for the primary purpose of reliable delivery of generation output to the loads. Taking operating and accounting expenses into account, the transmission segment of the electric power system is the least significant of the three principal segments. As P. Joskow and R. Schmalensee stress that “a transmission plant accounts for only about 15 percent of a total utility plant. Transmission expenses account for less than 2 percent of total electricity operating and maintenance expenses” [1].

However, with the introduction of competition in the supply industry and due to the fact that the transmission business is a natural monopoly, the role of the transmission network becomes very important. Transmission networks have a variety of functions such as [2]:

- delivering power from generators to consumers
- providing for interutility exchanges of energy and capacity
- integrating non-utility generation
- wheeling power.

Within power systems, performing these functions involves "moving" power from a large number of generators to a large number of loads through a transmission network. The necessary condition for competition in the supply industry is access to a transmission network for the generators and consumers.

Transmission Open Access (TOA) means that a buyer or a seller of electric power can be electrically connected to the transmission network and can obtain transmission services under reasonable terms and conditions. Transmission access can be granted to some, or to all participants in the electricity business. TOA is a concept stressing that economic, regulatory and implementation aspects are very specific to each network.

With the transmission business characterised as a natural monopoly, the need for regulation is coupled with the need for providing adequate returns as well as with economic incentives for the business to operate efficiently and to expand. In the new competitive environment there are several objectives of a transmission utility that have to be met.

2.2 OBJECTIVES OF A TRANSMISSION UTILITY

The overall objective for a transmission utility is to provide efficient, reliable and secure transmission services. As a separate commercial entity, the transmission utility must operate as a successful business, earning an adequate rate of return, having regard to the risk of business. Finally, the transmission utility must comply with the public policy to supply services on a non-discriminatory basis to existing and potential customers [6].

Generally, five main objectives for a transmission utility can be identified [7,8]:

1. Economic efficiency: true economic costs
2. Revenue requirements: financial requirements of business
3. Technical standards: quality of supply and security criteria
4. Social policy: equity and fairness considerations; transparency, simplicity and stability of transmission charges

5. Management of external factors: e.g., environment, health.

To meet these objectives, the following considerations are of importance for the transmission utility:

- *Economic efficiency.* The charges for transmission services should:
  - ⇒ reflect the true economic cost of the service provided
  - ⇒ send correct cost messages to all participants thereby avoiding cross subsidisation between different users
  - ⇒ encourage competition in electricity generation through open access to loads
  - ⇒ encourage competition in electricity distribution through non-discriminatory access to generation and
  - ⇒ promote efficient operation of the network by correctly signalling the variable costs of transmission.

- *Revenue requirements.* A transmission utility must obtain sufficient revenue to:
  - ⇒ meet its contractual obligations for the supply of power
  - ⇒ encourage new investment decisions in transmission
  - ⇒ provide a commercially appropriate return on funds and
  - ⇒ yield appropriate financial reward to the transmission utility.

- *Technical standards.* In providing services a transmission utility must:
  - ⇒ maintain reliability and security criteria
  - ⇒ comply with requirements on public safety, environmental protection and quality of supply
  - ⇒ promote system development up to the optimal transmission circuit capacities but to discourage overinvestment.

- *Social policy.* Different customers have different views on what is fair, based to a large extent on the different impacts of prices on them. However, it is considered fair that:
  - ⇒ the individual charges for a customer should reflect the actual costs of supplying services. These charges should take into account the distance

which power has to be transmitted, the number and type of circuit and the condition or age of the assets used. They should represent variations in operating conditions and network changes due to maintenance. Finally, the transmission charges should reflect the demand that the customer places on the system.

⇒ when new investment is required, those customers who obtain the benefit should be required to pay for it

⇒ the charges for transmission services need to be transparent and simple to all users and participants. They should provide reasonable stability and predictability. The move from lumped charges to separate charges for unbundled transmission services should be introduced gradually [1].

- *Management of external factors*

  There are other objectives such as management of external factors, e.g., environment, health. For the present analysis they are beyond the scope of interest.

It is important to note that in a classical vertically integrated structure these economic, technical and social objectives interact and are usually addressed jointly. However, in a competitive industry the interaction is more critical than in a monopolistic industry, and more often the objectives contradict each other.

2.3 DEFINITION OF A TRANSMISSION SERVICE

According to the interpretation of the Electric Power Research Institute (EPRI), "transmission service may be defined as any service needed to deliver, or provide the capacity to deliver, real or reactive power from one or more supply points to one or more delivery points" [4]. Such services may be provided by vertically integrated utilities or by one or more separate companies that provide the necessary transmission service components. However, the cost of transmission services is independent of the industry structure, whether there is a separate transmission company, or whether there is a vertically integrated utility that is providing the transmission services.

2.4 ECONOMIC PROBLEMS ASSOCIATED WITH PROVIDING TRANSMISSION SERVICES

To maintain economic efficiency, transmission utilities need to be fully aware of the economic impact of providing transmission services. Major economic problems to be considered are:

- the economic impact of usage on the transmission network
- evaluating the actual cost of the transmission service
- evaluating the price of the transmission service.

It is logical that the owners of a transmission network providing the electrical interconnection will demand compensation for use of the network and will establish conditions for that usage. The price paid for usage and the conditions of usage must be correct and fair.

There are many different approaches to pricing and costing transmission services. The main difference between price and cost of a product or a service is that price can be negotiated and regulated and involves several explicitly political and social considerations, whereas the cost shows the actual objective value of a product or a service.

The owners of a transmission system must know the cost of transmission usage in order to make correct economic decisions about transactions and to expand and upgrade transmission facilities in an optimal manner. They also should know the actual cost of transmission usage in order to set transmission prices correctly. The issues of pricing and costing of the transmission usage are interdependent; however the present analysis focuses on cost considerations only. Transmission pricing is a separate issue and requires independent analysis.

2.5 TRANSMISSION PRODUCTS AND SERVICES

In the classical vertically interconnected utility the main product is energy (kWh). However, in a competitive market, a wider range of services can be of interest. Transmission services can be offered under many different conditions and as suited to the interests and needs of involved parties. These conditions define different types of transmission services.

2.5.1 TYPES OF TRANSMISSION SERVICES

Transmission services can be categorised in a number of ways. The services can be separated into basic transmission services and ancillary services [9]:

- *basic transmission services or transmission transactions.* According to the definition of Reference [10] "a transmission transaction is referred to as the transmission component of the service provided by an electric utility -e.g., the transmission service associated with a power sale, a power purchase or a wheeling transaction".

- *ancillary services.* Ancillary services[1] are usually provided by the utility and required within the service territory to allow the transactions to take place. The ancillary services may include, but are not limited to:

a) supplying real losses
b) load following
c) reactive support
d) unit commitment
e) economic dispatch
f) operating reserve level

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[1] Federal Energy Research Council (FERC) defined *ancillary services* in the following way [11]: "*Ancillary services are needed to provide basic transmission service to a customer. These services range from actions taken to effect the transaction (such as scheduling and dispatching services) to services that are necessary to maintain the integrity of the transmission system during a transaction (such as load following and reactive support). Other ancillary services are needed to correct the effects associated with undertaking a transaction (such as energy imbalance service)*".

g) frequency control
h) back-up support
i) spinning reserve.

D. Shirmohhamady [12] distinguishes between different types of transmission transactions in the following way:

- *Firm transmission transactions*: These are the transactions, which are not subject to interruptions. Many contracts specify the level of priority under which the firm service is provided.

- *Non-firm transmission transactions*: These transactions are subject to interruptions and they do not assure continuity of service. The non-firm transaction may be curtailable or as-available. Curtailable transactions are ongoing transactions that may be curtailed at the utility's choice. As-available transactions are usually interruptible with very little notice. They are short-term transactions that take place when transmission capacity becomes available at specific areas of the system at specific times.

- *Long-term transmission transactions*: Long-term transactions must be contacted well in advance and may have duration ranging from weeks to several years.

- *Short-term transmission transactions*: A short-term transmission transaction may be as short as a few hours or as long as a year or two.

According to the Reference [13] there are also:

- *Emergency transactions:* They are supplied when the producer, due to causes beyond its control, is temporarily unable to supply capacity and energy for all of its customers. Emergency transactions can be seen as a special type of non-firm short-term transactions.

Reference [14] makes a distinction between transmission services in the following way:

- *wheeling,* which is a point to point transmission service[2] and
- *network service,* which is a service where the whole network rather than its particular part is considered to be involved in a service.

Wheeling can be categorised according to types of parties involved [15]:

- *Utility to Utility*: Through the transmission network of one or more interconnected utilities.
- *Utility to Private User*: Where the private user may or may not be located within the wheeling utility.
- *Private Generator to Utility*: Where the private generator may or may not be located inside the wheeling utility.
- *Private Generator to Private User*: Both, one or none of the involved parties are within the wheeling utility.

The next fundamental classification is whether the transactions are physical or monetary ones [16]:

- *Physical transactions* are realised as scheduled by the transaction agents, except when these transactions are in conflict with security criteria.
- *Monetary transactions* are simply commercial agreements that are ignored by the generation dispatch and do not imply any special priority for the contracted load. Many transactions have both physical and monetary features.

Generally, the difference between various transmission services consists in their characteristics such as the frequency with which services occur, the uncertainty and complexity to which services are subject, and the degree to which services are supported by the fraction of specific assets and the economic importance of the associated investments. All of these characteristics of transmission services can be described as a combination of various key factors, which are identified and analysed in the next section.

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[2] Due to its importance and popularity, the concept of wheeling is discussed separately in Section 2.5.3 "Wheeling as a special type of transmission service".

2.5.2 KEY FACTORS FOR TRANSMISSION SERVICES

As was shown in the previous section there are many different types of transmission services. Each type of service can be described by a set of key factors. It is important to identify them [17,18]:

- amount of a contracted transmission service (transmission capacity)
- degree of firmness of a transmission service
- time profiles of a transmission service
- duration of a transmission service
- distance of a transmission service
- responsibility for losses
- facilities used to provide a transmission service
- particular ancillary services.

Two of the most important key factors are the amount and firmness of a service. They determine the impact of a service on capacity requirements and possible system expansion needs. The amount can refer either to a reserved-capacity level (MW) or to the total energy (MW/h) to be transferred.

The firmness of service implies firm (non-interruptible) service. The firm transmission transactions are usually called block sales and give a utility considerable flexibility in how and when to transmit the electricity. The non-firm service can be as-available, curtailable (see Section 2.5.1) or interruptible for specific reasons.

The time profile of a service outlines the expected loading pattern, such as off-peak or peak load, due to the fact that for different users peak load and off-peak load conditions occur at different seasons and hours.

The duration of a service describes the initial date and length of a service. Some transmission users may prefer longer term contracts of 10 to 20 years, while others may prefer services for a short-time period. Longer-term arrangements are more likely to affect the transmission network and investment of a transmission utility.

The distance of a transmission service identifies receipt and delivery points of a service. The location of source and delivery points can significantly affect the costs of providing transmission services.

The other attributes, such as responsibility for losses , facilities used to provide a transmission service and particular ancillary services identify the responsibility for energy losses incurred as the service is provided, particular transmission facilities involved in provision of the service and a miscellaneous "other" category. This includes specifically negotiated arrangements for provision of ancillary services.

2.5.3 WHEELING AS A SPECIAL TYPE OF TRANSMISSION SERVICE

Various arrangements have been worked out between the utilities to facilitate interutility transactions that involve wheeling. In analysing wheeling F. Schweppe [19] noted, that "complications associated with wheeling are due to the difference between contractual path and physical path".

Generally, there are two ways of defining wheeling. The contractual definition is the simultaneous purchase and sale of electricity of non-adjacent parties. Because the parties are not adjacent, one or more utilities in between them must provide a transmission service, which is referred to as wheeling.

The physical definition is the following: "Wheeling is the transmission of electrical energy from a buyer to a seller, through transmission or distribution lines owned by a third party" [20]. Wheeling occurs in an electric power transmission system when electric utilities transfer power for others to use.

The contractual and physical definitions of wheeling can be quite different. It is possible for wheeling to take place contractually, yet no physical effect occurs. It is also possible to have effects of physical wheeling with no contractual agreement.

As was discussed in Section 2.5.1 there are four types of wheeling depending on the number of parties involved and the relationships between these parties. According to these relationships wheeling can be wholesale or retail. Wholesale wheeling occurs when utilities purchase the power for resale. Retail wheeling occurs when sales are made directly to consumers.

There are also six forms of wheeling. T.W. Berrie in [16] defines them in the following way:

- *"Mandatory*, e.g. forced, negotiated prices, controlled by regulatory bodies or by published tariffs.
- *Money*, e.g. generators run in merit order with wheeling costs worked out afterwards.
- *Contract*, e.g. money wheeling under specific contract of the rights to supply or buy electricity; or electricity supplied under arbitrage without contract, because of difficulties of proving contracts in practice.
- *Energy*, e.g. suppliers agree to start up generators, for example, from 7 a.m. to 5 p.m. of 100 MW, while consumers agree to load the grid to 100 MW for the same period.
- *Marketmaker*, e.g. grid utility acts as marketmaker for all supplies and consumption.
- *Regulatory*, e.g. in unregulated, competitive marketplaces; can be similar to market maker wheeling, or to the single generator and area distribution utilities situations".

To summarise, wheeling is the third party use of the transmission system. It can be seen as an isolated transaction between three parties, a buyer, a seller, and a wheeling utility. In a context of transmission services, wheeling is considered as a point to point transmission service.

2.6 INTERNATIONAL EXPERIENCE IN TRANSMISSION OPEN ACCESS AND THE COST EVALUATION OF TRANSMISSION SERVICES

Transmission Open Access is receiving increasing attention by utilities and regulatory state bodies around the world. Many countries have considered or are considering deregulating their electric power sectors to allow for competition among generators. It is argued that deregulation is creating such market conditions in the electric sectors that will promote the efficiency of electrical energy production and distribution and will offer a lower price, higher quality and more secure product. Table 2.1 shows a summary of legislative actions towards competitive electric energy systems [21].

Table 2.1: Summary of critical legislative actions towards competitive electric energy systems world-wide

Country	Date
Argentina	1991
Australia	1995
Brazil	1993
Chile	1982
Colombia	1994
England, Wales	1990
Finland	1995
Mexico	1992
Netherlands	1989
New Zealand	1988
Northern Ireland	1992
Norway	1991
Sweden	1995
USA	1992

An overview of the most interesting and successful cases of implementing the Transmission Open Access policy in different counties is presented in Appendix I. Table 2.2 shows a summary of transmission structures in these countries, as well as the methods used for evaluation of costs of transmission services [3,5].

Table 2.2: Summary of the international experience in transmission services and the cost evaluation

Country	Transmission Structure	Methods
Argentina	grid company	Composite: SRMC + fixed connection fee + extended MW-Mile
Australia	National Grid company owned by several utilities	SRMC + the charges based on network load flow model
Chile	grid company	Composite SRMC + "complementary term": MW-Mile
Colombia	grid company	Incremental: nodal LRMC
England	grid company	Incremental: SRMC + nodal LRMC
New Zealand	grid company	Composite: SRMC + Postage Stamp + network charges, based on distance
Norway	grid company	Composite: SRMC + Postage Stamp
Peru	grid company	Composite: SRMC + Postage Stamp
Sweden	State owned independent grid company	Composite: SRMC + network charges, based on location
US	voluntary pools	Embedded: Postage Stamp, Contract Path

Restructuring and deregulating the electricity industry are not easy tasks. Lessons need to be learned from others who have undergone such changes. The experience considered beforehand and taken into account, can lead to a more sustainable solution that is right for the particular system in question.

2.7 OVERVIEW OF THE POWER SUPPLY INDUSTRY OF SOUTH AFRICA

South Africa has unique opportunities in the power supply sector to provide low-cost electricity to a growing economy, and to provide access to electricity for most of its population. South Africa also has a large surplus of generating capacity on the national grid and generates some of the cheapest electricity in the world.

The regulation of electricity supply in South Africa is determined by the Electricity Act. It defines the structure, function and responsibilities of the Electricity

Control Board. The Electricity Act also assigns the sole right of electricity supply within municipal boundaries to local government. There is also the Electricity Council which consists of representatives of Government, organised labour and customers' interests. The Electricity Council determines policies regarding Eskom operation, planning and development [36].

Eskom is an independent, self-financing utility managed on business principles for the benefit of its customers. According to the reference [37], "Eskom is a consumer co-operative and therefore has no shareholders. It is a separate legal entity and is funded entirely from debt and accumulated reserves". Eskom is operated under the Eskom Act of 1987 and the Electricity Act of 1987 by the Management Board. The Management Board is appointed by the Electricity Council and it is the executive body responsible for the day-to-day running of the Eskom business.

Eskom produces more than 95% of South Africa's electricity [36]. It has 19 power stations with a nominal capacity of 37 840 MW [38]. Eskom generates more than half of the total electricity consumed in Africa. As can be seen from Table 2.3, almost half of the electricity generated by Eskom is supplied to distributors, such as local authorities and municipalities [37].

Table 2.3: Allocation of electricity generated by Eskom among the distributors

Industrial	50%
Municipalities and other re-distributors	44.8%
Agricultural	2.9%
Residential	2%
Commercial	0.3%

Eskom is actively involved in the establishment of a regional transmission grid to encourage and accelerate economic development in Southern Africa. The total transmission network comprises 239.457 km of power lines around the country and across neighbouring countries [25].

Eskom is a vertically integrated utility that connects load centres to the generating plants located mainly in the Eastern Transvaal. Historically, Eskom transmission pricing has not been concerned with identifying the separate costs of various service elements. All services have been bundled together and billed as a single charge to the customer. From January 1996 Eskom implemented the new power pool model. As a basis for the pool rules the UK Power Pool and its rules were taken. For more information on the England and Wales Power Pool see [27,39,40]. According to this model the main transmission system (MTS) is supposed to be institutionally and financially independent from generation and distribution.

2.8 SUMMARY

An understanding of a transmission service and subsequently the cost associated with this service, requires a knowledge of what a transmission network is, what functions it performs, and the manner in which the network is planned and operated by the transmission utility.

Two technical factors define the features of the power systems and transmission networks: that electricity flows at nearly the speed of light and the tight physical interconnectedness of a power system. Transmission networks have several functions such as delivering power, providing interutility exchanges, integrating non-utility generation and wheeling of power. With the transmission business characterised as a natural monopoly, the need for regulation is coupled with the need to implement the following transmission utility's objectives, such as economic efficiency, revenue requirements, technical standards, social policy and management of external factors.

There are various economic problems associated with providing transmission services, such as the impact and the cost of a service. The necessary condition for competition in bulk power markets, is non-discriminatory Transmission Open Access (TOA) to a transmission network. Under TOA conditions the transmission utility can offer a wide range of transmission services, which can be described in terms of their specific key factors. Briefly, there are firmness, amount, time profiles, duration, distance of a transmission service, as well as loss responsibility, facilities for providing of a transmission service and set of associated ancillary services.

Chapter 2 has outlined the international experience in TOA and in approaches to evaluation of costs of services. The supply industry of South Africa is also briefly discussed in Chapter 2.

To summarise, Chapter 2 has overviewed the electric power industry, transmission networks and services supplied by a transmission utility. This chapter has provided a context in which the problems related to costs of transmission services can be discussed. This information may be used as a basis for the identification and evaluation of costs of transmission services, in particular of active power transmission transactions.

CHAPTER 3

COSTS OF TRANSMISSION SERVICES AND METHODS FOR EVALUATING THESE COSTS

3.1 INTRODUCTION

The main goal of the present chapter is to identify and to evaluate the costs of transmission services. The purpose of this chapter is also to analyse the existing methods for evaluating costs and to compare these methods.

Transmission charges determine payments by a consumer, or a supplier, or both, to compensate for the utility's total costs incurred due to services provided. Different types of transmission services involve different costs. There are various cost components associated with providing transmission services.

3.2 COST COMPONENTS FOR TRANSMISSION SERVICES

A transmission utility provides transmission services at charges that should permit the recovery of all the costs incurred in connection with these services. There are eleven major cost components that can be considered for inclusion in the total costs of transmission services [10,18,41]. They are:

1. operating cost
2. opportunity cost
3. reinforcement cost
4. existing system cost
5. transmission maintenance cost
6. cost of transmission losses
7. cost of economic dispatch
8. cost of spinning reserves

9. cost of reactive support/voltage control
10. congestion cost
11. administrative and general costs.

- *Operating cost*

  The operating cost reflects the production (fuel) cost of the transmission utility associated with provision of the transmission service due to generation redispatch and the rescheduling resulting [10].

- *Opportunity cost*

  The opportunity cost of a transmission service is associated with the unrealised benefits that the transmission utility foregoes due to operating constraints that are caused by the service provided [12].

- *Reinforcement cost*

  The reinforcement cost refers to the capital costs of new transmission facilities needed to accommodate the transmission service [12].

- *Existing system cost*

  The existing system cost is the capital cost of existing transmission facilities necessary for the provision of the transmission service. This cost includes insurance, taxes, the rate of return on the investments in transmission facilities, etc. [1].

- *Transmission maintenance cost*

  The transmission maintenance cost is the cost of maintenance of transmission facilities, i.e., transmission lines, needed for providing a transmission service. This cost should be clearly distinguished from reinforcement cost because it does not increase the life of the line or does not add to the value of the line. The identification of this cost should eliminate the possibility of double payment by charging for the maintenance and for the reinforcement at the same time.

- *Cost of transmission losses*

  The cost of transmission losses is part of the operating cost of the transmission system. This cost is based on the fuel costs of the generating units that supply power to the network to cover the losses.

- *Cost of economic dispatch*

  Economic dispatch enables generators to minimise the total cost of production. The cost of economic dispatch is the cost that the transmission utility incurs in order to accommodate the economic dispatch. It should be noted, however, that in a new competitive environment there could be some technical and institutional complexities associated with implementing economic dispatching as an unbundled transmission service.

- *Cost of spinning reserves*

  Spinning reserves are generally provided to cover an outage of generating capacity. The cost of spinning reserves includes the operating and maintenance costs of generating units providing spinning reserves.

- *Cost of reactive support / voltage control*

  Supplying adequate reactive power is required to keep bus voltages within acceptable limits. The cost of reactive support is the cost that the transmission utility pays for operating and maintaining generating and transmission facilities providing reactive support. The cost of reactive support can also be associated with cost of the installation of reactive support equipment on the network.

- *Congestion cost*

  Congestion cost is associated with thermal limits on lines and voltage constraints on buses. This cost is part of the operating cost of the transmission system. This cost is based on the fuel costs of the generating units that supply power to mitigate congestion on the network. The congestion cost can be seen as a signal for new transmission investments.

- *Administrative and general costs*

  Administrative and general costs are associated with services such as arranging the requested services, billing for services and collecting revenue.

In the technical papers the costs of some services, such as reactive support/voltage control, spinning reserves, frequency control, economic dispatch, billing, transaction scheduling, security assessment, and switching are often grouped as *ancillary services cost* [11]. Definition of ancillary services by FERC is given in Section 2.5.1.

It is should also be noted that in the literature some of the cost components are characterised as extensions of others. For example, the operating cost component sometimes includes the congestion cost and cost of losses [10]. In other cases two cost components can be associated with the same concern in a power system. Thus, the congestion cost component represents the effect of approaching the operating limits of the network, whereas the opportunity cost component represents the benefits unrealised due to congestion. Therefore, the identification of cost components should be done carefully to eliminate the possibility of double charging.

Due to the fact that only the basic transmission service, i.e. a transmission transaction, is considered in detail in the thesis, only the costs associated with a transmission transaction will be investigated from now on.

3.2.1 COST COMPONENTS FOR TRANSMISSION TRANSACTIONS

Transmission services and the eleven cost components considered in the context of transmission transactions can be regrouped in the following way.

The operating cost of a transmission transaction includes the cost of losses and the cost of congestion and the opportunity cost. The existing cost of a transmission transaction includes the maintenance cost. The administrative and general costs components are ignored in the thesis because of the insignificance of their impact on the costs of transmission transactions. The other of cost components, such as the costs of reactive support, spinning reserves, economic dispatch, etc., are groped as the ancillary services cost associated with a transmission transaction.

The total cost a transmission transaction consists of:

$$TC_t = OP_t + RF_t + EXT_t + ANC_t \tag{1}$$

where,

t -	the index for transmission transactions
OP_t	the operating cost of a transmission utility in order to accommodate the transaction t
RF_t	the reinforcement cost is the capital cost of new transmission facilities, needed to accommodate the transaction t
EXT_t	the existing system cost is the capital cost of transmission facilities used by the transaction t
ANC_t	the cost of ancillary services, such as reactive support, spinning reserves, etc. associated with the transmission transaction t
TC_t	the total cost of the transmission transaction t.

There are some cost components that are applicable to all types of transactions, while the others are relevant to a few types. Table 3.1 shows the relationships between different cost components and types of transmission transactions [10].

Table 3.1: Cost components for different types of transmission transactions

Transaction Type	Firm	Non-firm, Curtailable	Non-firm, As-available
Long-term	Operating cost Reinforcement cost Existing system cost	Operating Cost	-
Short-term	Operating cost Reinforcement cost Existing system cost	Operating cost	Operating cost

All types of transactions incur the operating cost of the transmission utility. All firm transactions incur the existing system cost. If the long-term transactions require reinforcement of the transmission system in order to relieve operating constraints, they usually incur reinforcement cost. Short-term curtailable transactions do not usually incur reinforcement cost.

The ancillary services cost component is present in the total cost of a transmission transaction depending on individual negotiations. If all the services are bundled together for a particular customer as a transmission transaction, the cost of the ancillary services is usually lumped with other costs of the transaction. If the services are unbundled, the costs of required ancillary services are identified and presented separately. Once the relevant cost components have been identified, an appropriate method for cost evaluation must be chosen.

The total cost of a transmission transaction consists of four main cost components (see equation (1)). The total cost can also be separated into the fixed part and the variable part. In the context of transmission services the fixed cost or accounting cost is associated with the capital cost of transmission facilities, and is represented mainly by the existing system cost component. The variable or incremental cost is the cost associated with the operating cost of a transmission utility as well as the cost of new investments. Thus, the incremental cost is represented by the operating and the reinforcement cost components.

The cost of an ancillary service may also be divided into fixed and variable costs. The fixed or accounting cost of the ancillary service is the capital cost of facilities associated with providing this ancillary service. The variable or incremental cost is the operating cost that a transmission utility would incur in order to accommodate the ancillary service.

3.3 GROUPS OF METHODS FOR EVALUATING COSTS OF TRANSMISSION TRANSACTIONS

There are several methods for evaluating costs of transmission transactions. Depending on the costs that are considered, the existing methods can be divided into two main groups: Incremental and Accounting methods. The methods that cover the variable costs of transmission services fall into the group of Incremental methods. Accounting methods cover the fixed costs of transmission services. There is the third group which was developed recently: the group of the composite methods. The methods belonging to the third group combine the algorithms and the principles of Incremental and Accounting methods.

3.4 LITERATURE REVIEW OF THE METHODS FOR EVALUATING COSTS OF TRANSMISSION TRANSACTIONS

A number of papers concerning Transmission Open Access, transmission services and wheeling were reviewed in order to analyse the existing methods for evaluating costs of transmission transactions.

3.4.1 INCREMENTAL METHODS

By applying the Incremental methods only the variable costs of transmission services can be covered. The cost of investments is assumed to be fixed and is not evaluated by Incremental methods. There are short-run and long-run Incremental methods. The short-run is defined as that period of time, in which changes in demand cause only changes in the utilisation of existing capacity and during which capacity is treated as fixed.

The short-run Incremental methods cover the variations of the operating cost in a short period of time, e.g., from one hour to one year. The other costs such as those associated with reinforcements of the transmission system are not included.

The long-run Incremental methods cover both the operating and reinforcement costs. These methods consider the costs of present and future operations and the costs of future investments that are required to support the examined transaction.

There are four Incremental methods [26]:

1. the Short-Run Marginal Cost method (SRMC)

2. the Short-Run Incremental Cost method (SRIC)
3. the Long-Run Marginal Cost method (LRMC)
4. the Long-Run Incremental Cost method (LRIC).

The difference between the marginal and incremental costs consists in the size of the increment of a transmission transaction. The marginal cost of a transaction is associated with a unit increment (1 MW) in transmitted power. The incremental cost of a transaction is associated with an increment equal to the size of the transaction [19].

3.4.1.1 THE SHORT-RUN MARGINAL COST METHOD (SRMC)

The mathematical formulation of the Short-Run Marginal Cost method and the areas of application have been extensively described in the technical literature. K.L. Lo in [20] presents the Marginal Cost based approach for setting wheeling rates:

"The short-run costs of wheeling are the marginal costs of the last MWh of energy wheeled: Ideal Wheeling Rates = Marginal Costs of Wheeling

If $\varpi(t)$ is the marginal operating cost of transmission utility at hour t (\$/MWh), then the basic formula for definition $\varpi(t)$ is:

$$\varpi(t) = \frac{\partial(operating\ cost\ of\ wheeling\ utility)}{\partial(amount\ of\ powerbeing\ transferred)} \quad \text{"} \qquad (2)$$

The derivative (2) is evaluated subject to constraints, such as energy balance, Kirchhoff's laws and line flow limits, which are described in Appendix II "Spot pricing methodology"[1]:

H. M. Merrill [42] develops the concept of the short-run wheeling cost based on the spot price:

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[1] The spot pricing methodology was originally developed by F. Schweppe [19]. The definition of spot prices and a brief analysis are given in Appendix II.

"Since wheeling is physically indistinguishable from a simultaneous purchase -sale by the wheeling utility , the short-run marginal wheeling costs can be computed from the marginal costs (spot prices) of electricity at the buses where it enters and leaves the wheeling utility."

In the context of transmission services, the Short-Run Marginal Cost method evaluates the cost that a transmission utility incurs due to a one-unit change in power transfer. In Figure 3.1 the Marginal Cost is represented by the slope to the cost curve estimated for the transaction in MW [43]. In the literature the SRMC method is also referred to as the Sensitivity approach [10].

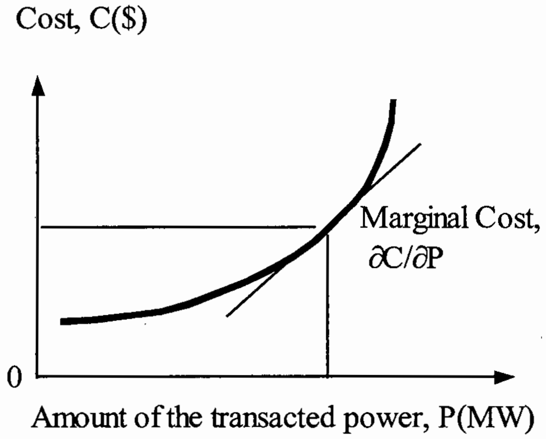

Figure 3.1: The cost curve of a transaction and the Marginal Cost

Within a network the SRMCs reflect the impact of losses and congestion on the system [66]. For network transactions with multiple points of injection and delivery the SRMC can be calculated as the difference between the marginal costs at all points of delivery and the marginal costs at all points of receipt for that transaction.

By applying the SRMC method the cost of a transaction is [44]:

$$C_t = \sum_{i \in B_t} SRMC_i \cdot P_{i,t} \tag{3}$$

where,

t the index for transactions

i the index for buses

C_t	the cost of the transaction *t*
$SRMCi$	the Short-Run Marginal Cost at bus *i*
Pi,t	the power injected at bus *i* due to transaction *t*; negative for generation, positive for load
Bt	the set of transmission buses which are the delivering and receiving points for the transaction *t*.

The SRMCs for the buses are also called spot prices. In literature they also can be referred as the Bus Incremental Costs (BICs). A. Wood and B. Wollenberg define the BIC as “the incremental cost to deliver power at a bus” [45].

3.4.1.2 THE SHORT-RUN INCREMENTAL COST METHOD (SRIC)

The Short-Run Incremental Cost, like the SRMC, is also associated with the operating cost of a transmission utility. The cost of a transaction by the SRIC method is the difference in the operating cost caused by the entire transaction [26]. This difference is evaluated by simulating the system operation with and without the transaction. In the literature this method is also called the Differencing approach [10].

In Figure 3.2 the Incremental Cost is represented by the $\Delta C/\Delta P$ value. ΔC is the change in the operating cost of a transmission utility due to the transaction, and ΔP is the change in the amount of the transmitted power which is equal to the amount of the entire transaction.

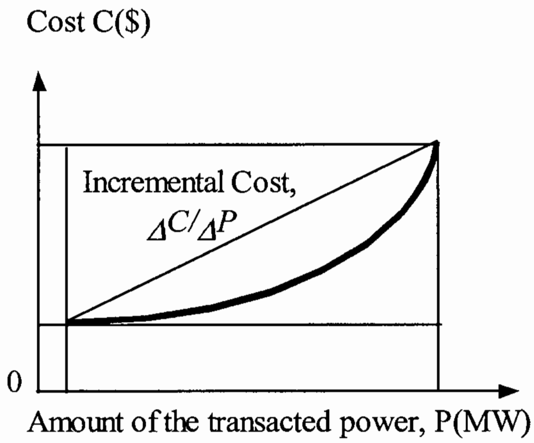

Figure 3.2: The cost curve of a transaction and the Incremental Cost

The basic formula for the SRIC method is:

$$C_t = C_{2t} - C_{1t} \tag{4}$$

where,

t	the index for transactions
C_t	the cost of the transaction t
C_{2t}	the operating cost of the transmission utility with transaction t
C_{1t}	the operating cost of the transmission utility without transaction t.

3.4.1.3 THE LONG-RUN MARGINAL COST METHOD (LRMC)

The Long-Run Marginal Cost is the sensitivity of the total cost with respect to operating and investment constraints of the transmission system.

R. D. Tabors [22] gives the following definition of Long-Run Marginal Cost: *"The Long-Run Marginal Cost (LRMC) is defined as the marginal cost of supplying an additional unit of power when the installed capacity of the system is allowed to increase optimally in response to the marginal increase in demand."*

The Long-Run Marginal Cost method covers the operating and reinforcement costs that a transmission utility incurs due to a one-unit change in power transfer. In other words, the LRMC at any point in the system is the value of the cost of present and future operations and investments required to support a marginal increase in the amount of a transaction [46]. Long-Run Marginal cost consists principally of the cost of expanding transmission capacity and the network losses. The calculation of the LRMC is performed based on a scenario of future demand and supply growth in the system.

3.4.1.4 THE LONG-RUN INCREMENTAL COST METHOD (LRIC)

H.H. Happ defines the Long-Run Incremental Costs of wheeling [47]:
"Long-run incremental transmission costs for wheeling account for the change in total costs incurred by the wheeling companies in providing wheeling service. The change in total costs includes:

- *the investment costs for reinforcement to accommodate the wheeling, or credit for delaying or avoiding reinforcements*
- *the change in operating (production) costs and incremental operation and maintenance costs incurred due to the wheeling."*

The LRIC method estimates the variation in the total cost caused by the entire transaction. The difference in the total cost is evaluated by simulating the system operation and expansion with and without that transaction. The LRIC values are calculated based on future demand and load growth forecast.

There are two basic LRIC approaches [47]:

- *The Standard approach*
- *The Long Run Fully Incremental approach.*

The Standard approach determines the system reinforcements to accommodate the transmission transaction over the term of the contract. System studies are performed with and without the transaction increment, using a long-term forecast of future load growth. The changes in investment and operating costs required over the entire contract period are determined.

The Long Run Fully Incremental approach assumes that excess transmission capability cannot be used for the transaction in consideration and that system reinforcements and corresponding investments have to be made specifically to accommodate the specific transmission transaction.

The LRIC method is similar to the SRIC method. According to the SRIC and the LRIC methods the operating cost difference caused by the transaction is evaluated by simulating the system operation with and without that transaction. In the SRIC method only the operating cost is taken into account, whereas in the LRIC method both the operating cost and the cost of reinforcements are counted.

The LRIC method is also similar to the LRMC method. The similarity between the LRIC and the LRMC methods appears from the fact that both methods involve the solving of a transmission expansion model and require forecasting loads and operating scenarios. However, in contrast to the LRMC method, instead of estimating the operating and investment cost differences caused by a one-unit increase in power transmitted, for the LRIC method these differences are evaluated by simulating the system with and without the entire transaction.

3.4.2 ACCOUNTING METHODS

Accounting methods evaluate the capital or existing system cost of the transmission system. The existing system cost component for the transmission service (see Section 3.2) corresponds to the capital cost of the transmission facilities that is to be allocated to that transaction. The capital cost of the transmission system is the cost associated with the investments made in buildings and transmission facilities. Thus, the Accounting methods evaluate the costs that were incurred in the past and which values are largely determined by accounting considerations. In the literature the accounting methods are also referred as embedded cost methods.

There are six principal Accounting methods which will be covered in the next sections 3.4.2.1 through 3.4.2.6:

- the Postage Stamp method
- the Contract Path method
- the Boundary Flow method
- the MW-Mile method
- the Extended MW-Mile method
- the Usage method.

Each of the Accounting methods has a specific calculation procedure. However, the Accounting methods also have a common routine in the calculation, which is outlined in the following way:

1. The first step is the estimation of the capital cost of assets involved and revenue requirements. The value of the assets can be estimated on the basis of the acquisition cost, or replacement value cost. [1,47]. Most of the approaches for estimating the capital cost take into account the age and depreciation of the assets, required maintenance, etc. [48].

   Then the capital cost is converted into a per year base by using the fixed charge rate (FCR). The FCR is a fraction between 0 and 1 that expresses the sum of annual demands for return, taxes, depreciation, and other fixed overhead costs.

   Therefore, the annual capital cost is associated with [21]:

- return requirements on investments
- depreciation of transmission facilities
- taxes, and
- administrative and general expenses.

2. The second step is the selection of the base for the allocation of annual capital cost. The standard base for allocating the capital cost is the user's peak demand. Since the increase of the peak demand drives new investment, the users that contribute

most to peak loads should bear the capital cost in proportion to their contribution. There are several options for the selection of system peaks [43]:

- the single annual peak
- an average of 12 monthly peaks
- the monthly peaks.

3.4.2.1 THE POSTAGE STAMP METHOD

The Postage Stamp method assumes that the entire transmission system is used for the transmission transaction. The method considers system-wide average capital costs rather than the costs of specifically selected facilities. It results in the same costs of transactions irrespective of distance or location.

The cost of the transmission transaction as determined by this method is independent of the distance of the transaction, which is the reason why the method is called the Postage Stamp method. According to the Postage Stamp method, the capital transmission costs are allocated in proportion to the user's served load, usually measured at the time of system peak load condition [26].

By averaging system transmission costs and recovering them from all system users, Postage Stamp rates have the practical attribute of administrative simplicity. Due to its simplicity the method is the most popular and has been extensively employed in practice [5,26]. However, the main shortcoming of this method is that it ignores the actual system operation.

The Postage Stamp method does not require the execution of the power flow program. As a result, it is likely to send incorrect economic signals to transmission users. A transaction that utilises the system lightly would subsidise the other transactions which utilise the system heavily.

3.4.2.2 THE CONTRACT PATH METHOD

The Contract Path method assumes that the power flows along a specified path through the transmission utility. The capital costs of only selected facilities that lie along this assumed path are allocated to the participants [47]. The Contract Path rate is calculated based on the capital cost and capacity of the selected path.

The path is selected by the transmission company and the user of the system, usually without regard for the actual transmission facilities that would be involved in the transaction. The path chosen must have sufficient unused capacity to carry the amount of power to be transmitted over it. If new transmission facilities are to be built as a result of the transaction, they may be included in the contract and all or part of their charges is allocated to the users. However, the upgrades of the transmission systems outside of the contract path will not be included in transmission costs.

This method has been adopted by the utilities because of its relative simplicity and the ease of drawing up the required contracts. The Contract Path method has the principal disadvantage of neglecting the fact that part of the transacted power may actually flow on transmission facilities outside the contracted path and even on neighbouring utilities. Therefore, the main shortcoming of this method is that it ignores the actual system operation. It does not require the executions of the power flow.

3.4.2.3 THE BOUNDARY FLOW METHOD

The Boundary Flow method measures the impact of a transaction on the transmission utility's boundaries [26]. The method allocates the capital costs of the transmission utility in proportion to the overall changes in inter-tie flows. According to the Boundary Flow method the incremental power flows resulting from the specific transmission transaction are estimated and transmission capital costs are assigned in proportion to the change in flow. The incremental flows due to a transaction are estimated through the use of a power flow program.

As the Boundary Flow method examines the impact of the transaction only on the transmission lines that tie one utility to another, the method does not reflect the distance and location of the transaction, the individual line changes and the line flow limit violations. The Boundary Flow method is useful when there are several owners of a transmission system and it is easy to identify the ties between utilities involved in the transaction. For the present analysis the case with multiple transmission owners is beyond the scope of interest.

3.4.2.4 THE MW-MILE METHOD

The MW-Mile method uses power flows as a measure of the utilisation of a transmission line. According to the MW-Mile method, the maximum transaction-related real power flows on all network lines are calculated for every transaction, using the power flow algorithm. In order to calculate the MW-Mile rates the magnitude of the maximum transaction-related MW flow on every line is multiplied by its length, N_l, and a predetermined weighting factor reflecting the cost of capacity of the line per unit, W_l [49]. The factor W_l is estimated according to the line voltage class, date of construction, material used, etc.

Then the *MW-Mile* value for the transmission transaction *t* would be:

$$MW\text{-}Mile_t = \sum_{l \in L} W_l \cdot MW_{t,l} \cdot N_l \qquad (5)$$

where

t - the index for the transmission transactions

l - the index for the transmission lines

L - the set of all network lines

$MW\text{-}Mile_t$ - the MW-Mile value of the transaction t

W_l, the weighting factor reflecting the cost per unit capacity of the line l.

$MW_{t,l}$ - the power flow on the line 1 due to the transaction t

N_l, - the length of the line l.

The total value of the *MW-Mile* for the entire transmission system is:

$$\sum_{t\in T} MW-Mile_{t,cap} = \sum_{t\in T}\ \sum_{l\in L} W_l \cdot MW_{l,cap} \cdot N_l \qquad (6)$$

where

$MW_{l,,cap}$ - the capacity of the line *l*.

T - the set of all transactions considered

This process is repeated for every transaction by considering only the generations and loads associated with that transaction. Then the cost of the transaction *t* by MW-Mile method will be equal:

$$C_t = C_{tolal} \cdot \frac{MW-Mile_t}{\sum_{t\in T} MW-Mile_{t,cap}} \qquad (7)$$

where

C_t - the cost allocated to the transaction *t*

C_{total} - the total capital cost of the network

By establishing the MW loading and the distance associated with a transaction, the MW-Mile quantity provides a measure of the effect of the transaction on a transmission system. The method allocates the total capital cost in the proportion of affected MW-Mile of a transaction to the total value MW-Miles of the whole network.

The total value of MW-Miles for the network is calculated based on the capacities of the lines. However, the total power flow is usually smaller than the line capacities. Therefore the MW-Mile method recovers only a part of the capital cost. As M. V. Pereira highlights "the MW-Mile method is only charging for a 'base-case" network, but not for the "transmission reserve", given by the difference between circuit capacity and actual flow" [26].

3.4.2.5 THE EXTENDED MW-MILE METHOD

The Extended MW-Mile method was developed as the expansion of the MW-Mile method. The method is based on the same principle as the MW-Mile method. The basic formulas for the Extended MW-Mile method are similar to the formulas of MW-Mile method. However, the calculation for the Extended MW-Mile method are performed based on the total power flows through the lines instead of the lines capacities as with the MW-Mile method. The basic formulas of the Extended MW-Mile method are the following [26].

The total value of the *MW-Mile* for the entire transmission system is:

$$\sum_{t} MW - Mile_{t,total} = \sum_{t \in T} \sum_{l \in L} W_l \cdot MW_{l,total} \cdot N_l \qquad (8)$$

where:

l	the index for the transmission lines
L	the set of all network lines
t	the index for the transmission transactions
T	the set of all transmission transactions considered
$W_{l,}$	the weighting factor reflecting the cost per unit capacity of the line l
$MW_{l,total}$	the total power flow on the line 1
$N_{l,}$	the length of the line l.

The cost of the transaction t by the Extended MW-Mile method is:

$$C_t = C_{total} \cdot \frac{MW - Mile_t}{\sum_{t} MW - Mile_{t,total}} \qquad (9)$$

where

C_t - the cost allocated to transaction t

C_{total} - the total capital cost of the network

$MW\text{-}Mile_t$ - the MW-Mile value of transaction t calculated according to the equation (5) from Section 3.4.2.4.

The Extended MW-Mile method, as well as the MW-Mile method, provides a measure of the usage of the transmission system by establishing the MW loading and the distance associated with a transaction. However, for the transmission facilities that do not have a physical mileage, such as transformers or shunt transmission facilities, the extent of their use can not be determined in this fashion. The Usage method covered in the Section 3.4.2.6 solves this problem by establishing different measures of the network usage.

3.4.2.6 THE USAGE METHOD

R. Kovacs [50]defines the Usage method as one that "estimates the usage of each transmission facility and calculates the rate on a per facility basis". The method allocates the capital costs for each facility based on the ratio of MW flow through that facility due to a transaction to the total flow through that facility.

The basic formula for the Usage method is:

$$U_f = \frac{MW_{f,t}}{\sum_t MW_{f,t}} \qquad (10)$$

where:

t the index for the transmission transactions

f the index for the transmission facilities

U_f the usage per facility f

$MW_{f,t}$ the magnitude of MW flow on facility f due to transaction t

$\Sigma MW_{f,t}$ the total flow through facility f.

Then the cost of the transaction t is :

$$C_t = \sum_{f \in F} C_f U_f \qquad (11)$$

where:

C_t - the cost for the transaction t

F - the set of all transmission facilities

C_f - the capital cost of facility.

3.4.3 COMPOSITE INCREMENTAL/ACCOUNTING METHODS

The methods belonging to the composite group were developed recently [26,51]. They are based on the combination of the Incremental and the Accounting methods. The composite Incremental/Accounting methods appear to give better results than the Accounting methods or Incremental methods applied separately. For this reason, the composite methods have been proposed in several countries and are becoming popular among electrical utilities world-wide.

3.5 DISCUSSION OF METHODS FOR EVALUATING COSTS OF TRANSMISSION TRANSACTIONS

INCREMENTAL METHODS

Short-run incremental methods

The SRMC and the SRIC methods cover the variations in the operating cost of a transmission utility due to a transaction. The SRMC of a transaction is presented by the marginal costs of transmission losses and constraints. At times of low demand when the transmission system is unconstrained, there is little if any difference in marginal cost within the system. At times of high demand when constraints do exist, there is a significant difference in marginal costs at the buses within the sytem. Similarly to the SRMC, the SRIC of a transaction depends on the level of demand on the system.

However, there is no guarantee that the revenue gained by the SRMC and the SRIC methods will be sufficient to recover an appropriate share of the capital investment in facilities used for transmission transactions. Reference [29] clearly demonstrates that the SRMC fails to generate sufficient revenue to keep the transmission company financially viable. The network charges based on the SRMC are highly variable and uncertain. As B. L. Pereira highlights, “the percentage of total network cost recovery by SRMC generally does not exceed 30 %” [29].

For an industry dominated by capital costs, the Incremental methods are not appropriate and lead to poor revenue returns in relation to invested capacities. In other words, if the network charges are based on the SRMCs, then the return to the utility would be too low if the SRMC is below average cost, and too high if it is above average cost. An attempt, referred to as revenue reconciliation, may be made to adjust the SRMC and final prices to achieve an appropriate level of capital recovery. For more information on the Revenue Reconciliation see [14,19].

The SRMC concept is becoming popular among electric utilities. The advantage of the SRMCs is that they correspond to the actual condition of the generation and network facilities. The variable network charges based on the SRMCs are seen as economic signals to generators and consumers for short-term operation. The important advantages of the SRIC method is that the SRIC also reflects the variation in the operating cost of the transmission utility. Based on these considerations, the SRMC and the SRIC methods are selected for further numerical studies which will be covered in Section 5.3.

Long-run Incremental methods

The cost of a transaction by the LRMC method and by the LRIC method is associated with the operating and reinforcement cost of a transmission utility. The successful use of the LRMC and the LRIC methods depends upon the long-term assessment of transmission facilities costs, capacities, demand profiles and geographical data.

In order to apply the LRMC and the LRIC methods, the transmission utility makes decisions to invest in alternatives for efficient system operation, maintenance and expansion. However, there is no simple formula expressing how transmission investment must change as usage changes. Moreover, investments are often lumpy, and intermittent. Transmission additions tend to be less loaded in early years, because they are often made in response to overall system needs rather than for a specific transaction or load. The high uncertainties associated with these factors, result in highly volatile LRMCs and LRICs , which have little practical value. Different assumptions can significantly affect the resulting long-run costs. Therefore the conclusion is drawn that it is inefficient to apply the methods for a study case. For the present analysis both the LRIC and the LRMC methods will not be considered.

ACCOUNTING METHODS

According to the Accounting methods, all capital costs of the system are summed up into a single number, which is then allocated among the system users. The capital costs of the network relate to the investments that have already been made. These costs are incurred regardless of the utilisation of the grid.

The rates for transmission services based on accounting or embedded costs fail to provide accurate price signals. Transmission transactions based on these costs do not promote greater economic efficiency. The Accounting methods do not consider changes in operating costs, and therefore do not represent the conditions of the system. However, the Accounting methods are simple and have a very important advantage. The charges that are calculated by these methods reduce the amount of information which participants must absorb.

Two of the Accounting methods are left without numerical evaluation: the Boundary Flow method and the MW-Mile method. The Boundary Flow method is useful when there are multiple transmission owners and it is easy to identify the ties between utilities involved in the transaction. For the present analysis this case with multiple transmission owners is not considered. The MW-Mile method is not considered because the Extended MW-Mile method is based in general on the same principle as the MW-Mile method. Only the Extended MW-Mile method is chosen for the case study. Therefore, four Accounting methods are selected for further studies and will be covered in Section 5.4.

After the theoretical analysis of the Incremental and the Accounting methods, the conclusion is drawn that there is a basic conflict between accounting and economic points of view, which objective and associated costs are to be given dominant consideration. On the one hand, the accounting objective is to evaluate the transmission service in such a way that the transmission utility will get enough revenue to support the system. On the other hand, from the economic point of view, the product or service should be priced on a marginal cost basis to be effective. The blending into a two-part rate is an advance over the Incremental and the Accounting schemes that rely solely on variable charges or solely on fixed charges. The numerical studies which cover the composite methods will be presented in Section 5.5.

3.6 OVERVIEW OF THE COST EVALUATION PROCESS

The process of the cost evaluation for a transmission transaction can be summarised in the flowchart presented on Figure 3.3. The first step is to identify the main objectives of a transmission utility. Two of the objectives play the crucial role in selecting the appropriate method: Economic Efficiency and Revenue Requirements. According to these objectives the Incremental, the Accounting or the composite methods can be selected.

If the main objective of a transmission utility is to collect enough revenue then the Accounting methods should be chosen. If the transmission company is not under burden of debts and economic efficiency is the main objective, then the Incremental methods may give the best results. It should be noted, however, that in reality both of these objectives are of equal importance for utilities. In that case, the combination of Incremental and Accounting methods can deliver better results.

For the short-run Incremental methods the operating costs of the transactions can be calculated using the OPF program. For the SRIC method two runs of the OPF should be executed for each transaction: one run with the transaction and one run without the transaction. The SRMCs for the transactions can be calculated using the Bus Incremental Costs (BICs) for entry and exit buses of the transactions.

In case of the Accounting methods the first step is to determine the Revenue Requirements by calculating the capital costs of transmission facilities on an annual basis. These annual capital costs are then allocated to the users on different bases. The standard base is the user's peak. After that the appropriate Accounting method can be selected. Transmission costs by the Postage Stamp method are calculated as average and flat rates based on the peak of the system. For the Contract Path method the selection of the contract path of the transaction is made as the most direct way between receipt and delivery points. For the Boundary Flow, the MW-mile, the Extended MW-Mile and for the Usage methods the power flows can be estimated using a power flow program.

Finally, the cost of a transaction is calculated in the following way. For the SRIC method it is the difference in total cost with the transaction and without. For the SRMC method the cost is calculated as the difference in the BICs at exit and entry buses multiplied by the amount of the transaction. For the Accounting methods the cost of the transaction is the cost of capacity used per unit multiplied by the amount of the transaction.

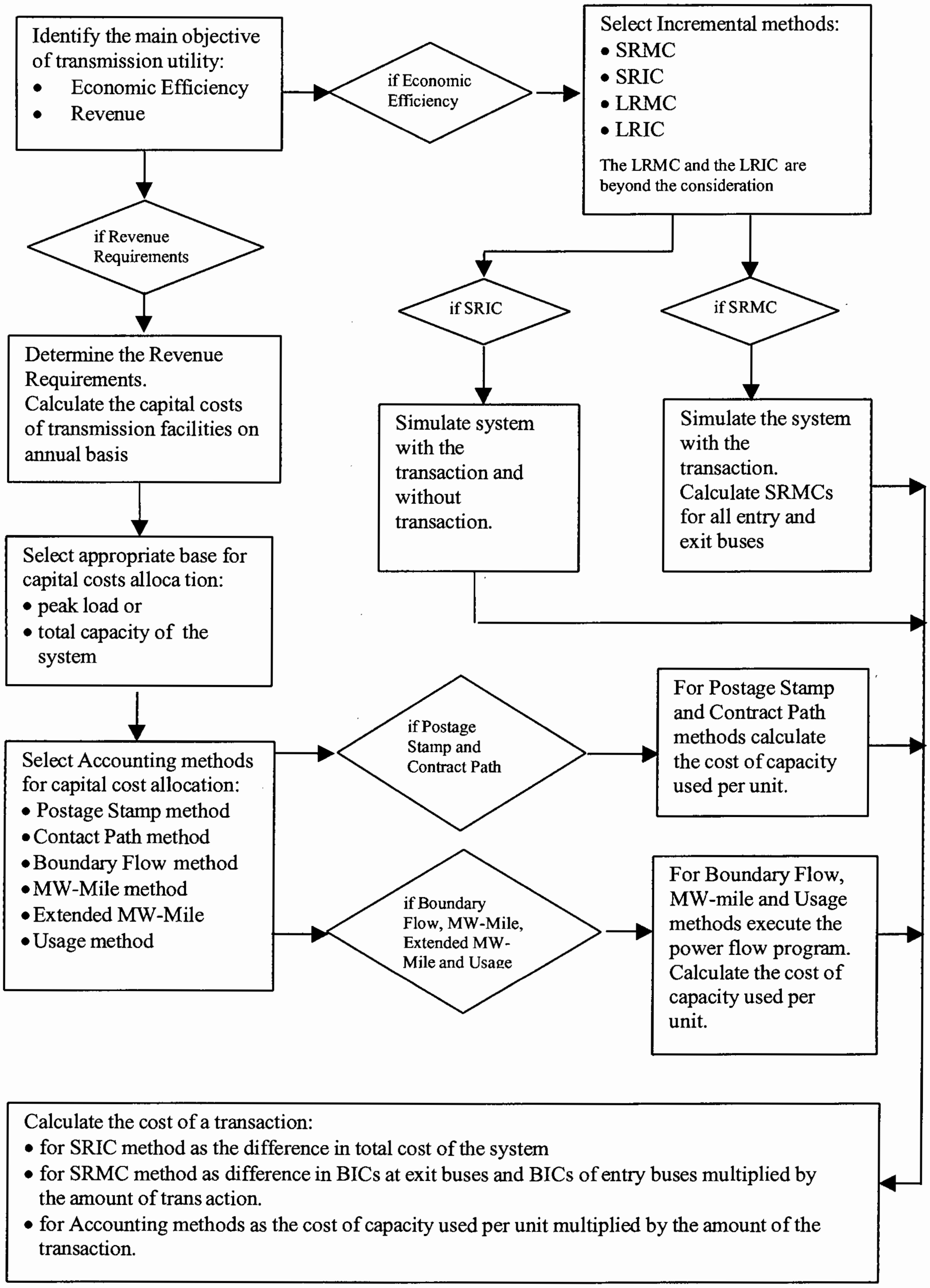

Figure 3.3: Summary of the cost evaluation process for a transmission transaction

3.7 SUMMARY

When the transacted energy flows through the transmission utility, it affects the flows in the network. Transmission charges determine payments for the use of the network to compensate for the utility's total costs incurred due to services provided.

The total cost of a transmission transaction consists of four main components: Operating cost, Reinforcement cost, Existing cost and Ancillary Services cost. There are several methods for evaluating transmission transactions. According to the costs that are considered, the methods are divided into the following groups: Incremental, Accounting and composite Incremental/Accounting methods.

Among several institutional and economical factors, which affect the choice of a method for evaluating the transmission services, the objectives of a transmission utility are of great importance. Depending on the priority of the transmission utility's objectives, the appropriate method for the cost evaluation can be selected.

The Incremental methods, such as the SRMC and the SRIC methods, evaluate the change in the operating cost of the transmission utility due to the transaction. The SRMC method uses the Bus Incremental Costs (BICs) which reflect loading and congestion of the transmission system. The availability of efficient SRMCs can provide a powerful tool for guiding the use of the electric power system. SRMCs can be seen as signals for efficient operation of the network. However, transmission charges based on the incremental costs do not reflect the Revenue Requirements. Thus they do not finance the system operation and development, as the incremental costs are usually lower than average costs.

Transmission charges based on the accounting costs cover the cost of investments, but they do not provide economic incentives for efficient operation of the transmission system. They do not reflect the operating conditions of the network, such as variations in operating cost as a result of redispatch, additional losses or congestion on the system. Although the operating costs of the transactions are small compared to the accounting costs, the operating costs should be taken in account.

Studies undertaken by many researchers and international experience show that each method alone actually is incapable of covering the total costs of the transmission transactions, while the combination of several methods can give better results. The task is to find and to apply the method that provides the correct, market based economic signals to all users of the grid. Besides ensuring the economic efficiency of the network operation, this method should provide enough revenue to compensate for the existing transmission investments and incentives for economic expansion.

Based on this consideration, six methods are selected for further numerical studies in order to define the best suitable method. They are the SRMC and the SRIC methods as well as four Accounting methods. The composite methods will be also tested on the case study.

CHAPTER 4

CASE STUDIES AND RESULTS OF SIMULATIONS

4.1 INTRODUCTION

Several study cases are specified to illustrate the findings of the theoretical analysis completed in section 3.5 of the thesis. The simulations are undertaken to demonstrate the sensitivity of the selected methods to the various system conditions, such as different load profiles and the presence of transmission constraints.

The economic analysis of the costs of transmission transactions must be done in the context of the operation of power systems. The evaluation the costs of transactions requires the utilisation of the analytical tools which take into account such attributes of power systems as losses, transmission constraints, system security, etc. Appendix VII presents the Optimal Power Flow model employed in the present analysis and describes the software tool SC-OPF utilised in the computer simulations. The OPF is formulated as a constrained optimisation problem with the exact representation of the power flows and losses in the system.

The 18-bus network is selected for computer simulations. The network is tested for three different load profiles: minimum, average and peak. Transmission transactions are specified to represent the following characteristics:

- direction of a transaction: One transaction is specified along the main flow and the other one is specified in the opposite direction.
- distance of a transaction: One transaction is specified as short-distance and the other one is specified as long –distance.
- amount of power transmitted: Transactions are considered with various amounts of power transmitted.

Transmission costs are calculated and allocated in accordance with six methods:

1. The Short-Run Marginal Cost method
2. The Short-Run Incremental Cost method
3. The Contract Path method
4. The Postage Stamp method
5. The Extended MW-Mile
6. The Usage method.

4.2 DESCRIPTION OF THE 18 BUS NETWORK AND TRANSACTIONS DATA

For the study the 18-bus network is used which is the equivalent version of the South African transmission system[1]. The system configuration is presented in Figure 4.1.

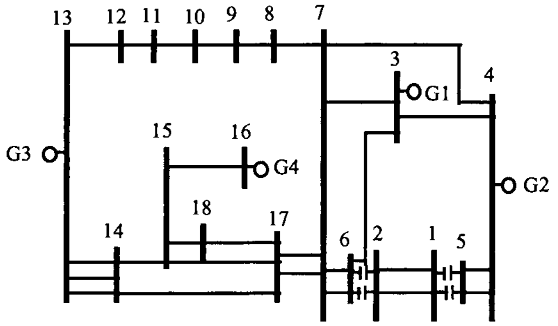

Figure 4.1: 18-bus network

Data are provided regarding load, generation, and transmission characteristics in Appendix III. Data and the study cases are simplified and are meant to illustrate the findings of the research. The limitations and assumptions associated with the network and study cases are the following.

1. Only the active power transmission and associated costs are considered. Transmission of reactive power requires special attention. This issue is beyond the scope of the thesis.

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[1] The network and its parameters are supplied by Eskom.

2. The load data are selected and adjusted in such a way that the total peak load of 7455 MW is approximately 90% of the total available generation of 8150 MW. The average and minimum load figures represent 75% and 50% of the peak load respectively.
3. The annual capital cost data for transmission lines have been converted on a per hour base. This was done by dividing the total annual capital costs by 8760 hours per year.
4. The capital costs of transformers are not considered.
5. For each transaction there are points of injection and delivery, marked "from bus and to bus", specified to represent four different types of transactions:

- Transaction 1 (T1): from bus 11 to bus 17, a long-distance transaction in the direction of the main flow[2]
- Transaction 2 (T2): from bus 17 to bus 11, a long-distance transaction in the opposite direction to the main flow
- Transaction 3 (T3): from bus 11 to bus 8, a short-distance transaction in the direction of the main flow
- Transaction 4 (T4): from bus 8 to bus 11, a short-distance transaction in the opposite direction to the main flow.

6. For these transactions the amount of 100 MW up to 1000 MW with 100 MW increments has been injected into the bus marked "from", and has been withdrawn from the bus marked "to" under peak, average and minimum load conditions respectively. The base case for all three load profiles is considered without any transaction.

The input and output data files are tabulated and the results of the simulations for each transaction can be found in Appendixes III - VI.

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[2] The main flows in the thesis are defined as base case flows.

4.3 EVALUATION OF TRANSACTION COST BY THE INCREMENTAL METHODS

The operating costs of the system are calculated using an industrial grade software package Security Constrained Optimal Power Flow (SC-OPF). Tabulated results for all transactions for the SRMC and the SRIC methods are given in Appendix IV and V. As an example, Table 4.1 presents a summary of the results of simulations for the transaction T1, minimum load, for the SRMC and the SRIC methods.

The columns in the Table 4.1 show:

- Case: each considered case is represented by the amount of the active power transmitted , starting from 0 MW for the base case and up to 1000 MW
- Generation: the power generated in MW
- Loss: the losses due to a transaction in MW
- Total Cost: the total cost of production with a transaction
- Transaction Cost: this cost is the difference between the total cost of production with a transaction and the total cost of production for the base case, i.e. without the transaction
- SRIC : the Short-Run Incremental Cost for a transaction
- BIC_i : the Bus Incremental Costs for the point of injection for a transaction
- BIC_d : the Bus Incremental Costs for the point of delivery for a transaction
- SRMC: the Short-Run Marginal Cost for a transaction

Table 4.1: The results of OPF simulations for T1 under minimum load conditions

Case	Generation, MW	Loss., MW	Total cost, $[3]/h	Transaction cost, $/h	SRIC, $/MWh	BIC$_{11}$, $/MWh	BIC$_{17}$ $/MWh	SRMC, $/MWh
Base	3764.7		53366.92					
100	3767.3	2.6	53411.36	44.44	0.4444	15.65	16.25	0.6
200	3770	5.3	53469.5	102.58	0.5129	15.52	16.26	0.74
300	3775.2	10.5	53542.2	175.28	0.5843	15.39	16.28	0.89
400	3780.5	15.8	53630.05	263.13	0.6578	15.26	16.29	1.03
500	3785.8	21.1	53764	397.08	0.7942	1410.43	11735.88	10225.45
600	3792.8	28.1	53878.8	511.88	0.8531			
700	3800.7	36	54009.93	643.01	0.9186			
800	3809.6	44.9	54156.96	790.04	0.9876			
900	3819.3	54.6	54318.27	951.35	1.0571			
1000	3830.2	65.5	54497.31	1130.39	1.1304			

The numbers under losses in Table 4.1 and in other tables of the thesis represent only the additional transmission losses owing to the transaction under consideration. The thermal losses for the base case are included in the amount of generation of 3764.7 MW and considered the starting point for calculating the additional losses.

The additional losses due to a transaction are calculated as the difference between the power generated with that transaction and the power generated for the base case. For example, for the transaction of 100 MW the additional losses are 2.6 MW. They are calculated as the difference between the power generated with this transaction, 3767.3 MW, and power generated for the base case of 3764.7 MW.

Analogously the cost of a transaction is calculated as the difference between the total cost of production with that transaction and the total cost of production for the base case, i.e. without the transaction. In our example of T1 the cost to transmit 100 MW is 44.44 $/h, which is the difference between the total cost of production for this transaction 53411.36 $/h and the total cost of the base case 53366.92 $/h.

The Short-Run Incremental Cost (SRIC) of a transaction is calculated by dividing the cost of the transaction by the amount of power transmitted. The SRIC of

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[3] The costs in Table 4.1 and in the rest of the thesis are given in the units, which are specified in SC-OPF: $/h or $/MWh.

T1 for 100 MW is 0.4444 \$/MWh, which is the result of division the cost of the transaction of 44.44 \$/h by the amount of 100 MW of power transmitted.

The Short-Run Marginal Cost (SRMC) of a transaction is calculated as the difference between the Bus Incremental Cost (BIC) for the point of delivery and the BIC for the point of injection. For the transaction T1 from bus 11 to bus 17 the SRMC is the difference between BIC_{17} and BIC_{11}. For 100 MW the SRMC is calculated as the difference between BIC_{17} of 16.25 \$/MWh and BIC_{11} of 15.65 \$/MWh. It is equal to 0.6 \$/MWh.

Due to the fact that the base case is without any transaction, in Table 4.1 the base case is represented by two figures only: the MW produced (second column) and the total cost of production (fourth column).

As can also be seen from Table 4.1, the Bus Incremental Costs (BICs), as well as the Short-Run Marginal Costs (SRMCs), are specified only for the cases of up to 500 MW. With transmission of 500 MW and bigger amounts, transmission lines become congested. This leads to distorted signals of the BICs and thus to unrealistically high values of the SRMCs, which can be seen in Table 4.2. Table 4.2 shows the BICs and the SRMCs for the cases with transmission constraints and for the cases without transmission constraints.

Table 4.2: The BICs and the SRMCs for T1 under minimum load conditions

Case	BIC_{11}, \$/MWh	BIC_{17}, \$/MWh	SRMC, \$/MWh	Lines congested
400	15.26	16.29	1.03	None
500	1410.43	11735.88	10225.45	Line 115: 2 % overloaded Line 116: 8 % overloaded
600	2124.32	17615.87	15491.55	Line 114: 1% overloaded Line 115: 4 % overloaded Line 116: 19 % overloaded
700	2008.6	27120.88	25112.28	Line 111: 10 % overloaded Line 114: 11 % overloaded Line 115: 25 % overloaded Line 116: 30 % overloaded Line 119: 2 % overloaded Line 120: 3 % overloaded Line 122: 1% overloaded

As can be seen from Table 4.2, transmission of 500 MW and higher results in more congested lines in the network and thus, in more distorted signals of the BICs, which consequently results in unrealistic values of the SRMCs. To simplify the analysis, the BICs for transactions are specified only up to the initial point of congestion. In the example of T1 under minimum load conditions the BICs are specified up to the 500 MW. The calculations of the SRMCs are also performed up to the point of congestion.

4.3.1. EVALUATION OF TRANSACTION COST BY THE SRMC METHOD

The results of simulations of the SRMC method are given in Tables 4.3 – 4.6. In order to highlight the transactions that congest the network, their cells are marked with a star *. It should also be noted that some of the cells in Tables 4.3 - 4.6 are empty, because, as was mentioned in the previous section, the calculations of the SRMCs are performed up to the first point of congestion only.

As can also be seen from Tables 4.4 and 4.6, some of the SRMCs are negative. This means that the transaction with a negative cost causes the reduction of the losses and the total cost of production. The explanation and the analysis of this and other results of the simulations follow.

Table 4.3: SRMC for T1, $/MWh

Case	Min Load	Average Load	Peak Load
100	0.6	0.44	0.16
200	0.74	0.59	0.38
300	0.89	0.75	0.59
400	1.03	0.9	0.81
500	10225.45*	1.06	1.03
600	*	2.47	1.25
700	*	10326.06*	1.71
800	*	*	3.98
900	*	*	6259.97*
1000	*	*	*

Table 4.4: SRMC for T2, $/MWh

Case	Min Load	Average Load	Peak Load
100	-0.31	-0.11	0.28
200	-0.16	0.04	0.52
300	0.71	0.21	0.77
400	4071.22*	0.39	1.03
500	*	0.57	1.32
600	*	3825.18*	1.65
700	*	*	14150.74*
800	*	*	*
900	*	*	*
1000	*	*	*

Table 4.5: SRMC for T3, $/MWh

Case	Min Load	Average Load	Peak Load
100	0.7	0.52	0.23
200	0.86	0.68	0.44
300	1.01	0.84	0.66
400	13735.6*	1	0.88
500	*	6867.71*	1.12
600	*	*	1.39
700	*	*	6867.66*
800	*	*	*
900	*	*	*
1000	*	*	*

Table 4.6: SRMC for T4, $/MWh

Case	Min Load	Average Load	Peak Load
100	-0.42	-0.21	0.2
200	-0.27	0.06	0.42
300	-0.13	0.1	0.65
400	0.02	1.26	0.89
500	0.16	0.43	32.37
600	0.31	0.6	6870.7*
700	1.71	9.75	*
800	2120.61*	8979.79*	*
900	*	*	*
1000	*	*	*

From the results of the simulations the following observations are made.

- *The effect of transmission constraints*

  As can be seen from Tables 4.3 –4.6 the SRMCs of all transactions have shown a sharp increase at a certain point. For example, for transaction T1 the congestion occurs for minimum load - at 500 MW, for average load – at 700 MW and for peak load – at 900 MW. For transaction T2 these figures are 400 MW, 600 MW and 700 MW for minimum, average and peak loads respectively.

The reason for this sharp increase of the SRMCs lies in the transmission constrains on the system. The SRMC method uses the Bus Incremental Costs (BICs), which reflect loading and congestion of the transmission system. With no transmission constraints the BICs and the SRMCs for different amounts are fairly small and change smoothly. For example, the SRMC of T1, minimum load, does not exceed 1.03 $/MWh for up to 400 MW transmitted.

When transmission lines are reaching their limits, the BICs increase drastically for most of the buses reflecting the penalties for violating the constraints. The transmission of 500 MW causes the congestion of two lines: line 115 (102 % of loading), and line 116 (108 % of loading). The SRMC for this amount is increased to as much as 10225.45 $/MWh[4].

- *The effect of different load profiles*

The next important observation is about the sensitivity of the SRMC method to different load profiles. Figures 4.2 - 4.5 show the SRMC curves for each transaction for minimum, average and peak loads.

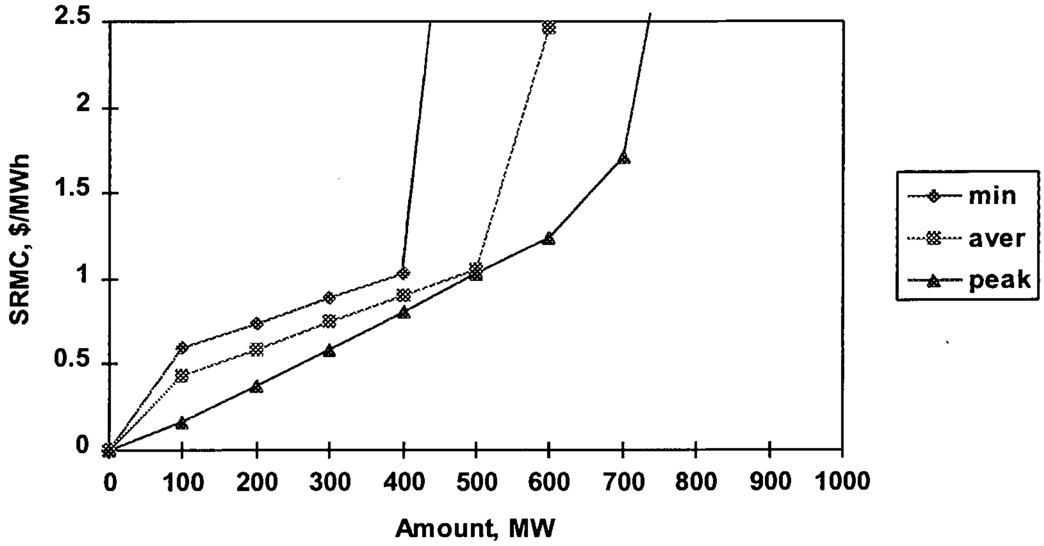

Figure 4.2: The SRMC curves for T1

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[4] The figure of 10225.45 $/MWh as well as other unpractically high values of SRMCs are obtained using SC-OPF. The operating constraints in SC-OPF are modelled in such a way that any violations of constraints are penalised with a quadratic penalty function, giving these unrealistic SRMCs. For more information see SC-OPF User Manual [60].

As one can see from Figure 4.2 for transaction T1, the SRMC curve for minimum load is placed above the SRMC curves for average and peak loads. This means that the SRMCs for minimum load are higher than the SRMCs for average and peak loads. This contradicts common sense, according to which the closer the system gets to its peak loading, the higher should be the cost of a transaction. The explanation of this fact follows.

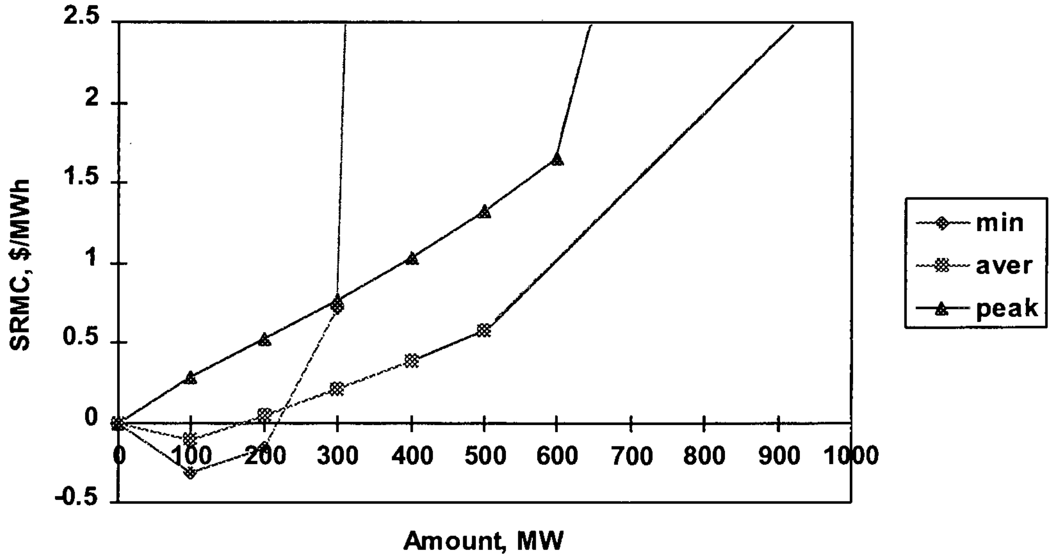

Figure 4.3: The SRMC curves for T2

Figure 4.3 shows that the SRMCs for T2, as expected, are higher for peak load than for average and minimum loads for up to 200 MW transmitted. The transactions over that amount become more expensive under minimum load conditions, which contradicts common sense. The explanation of this also follows.

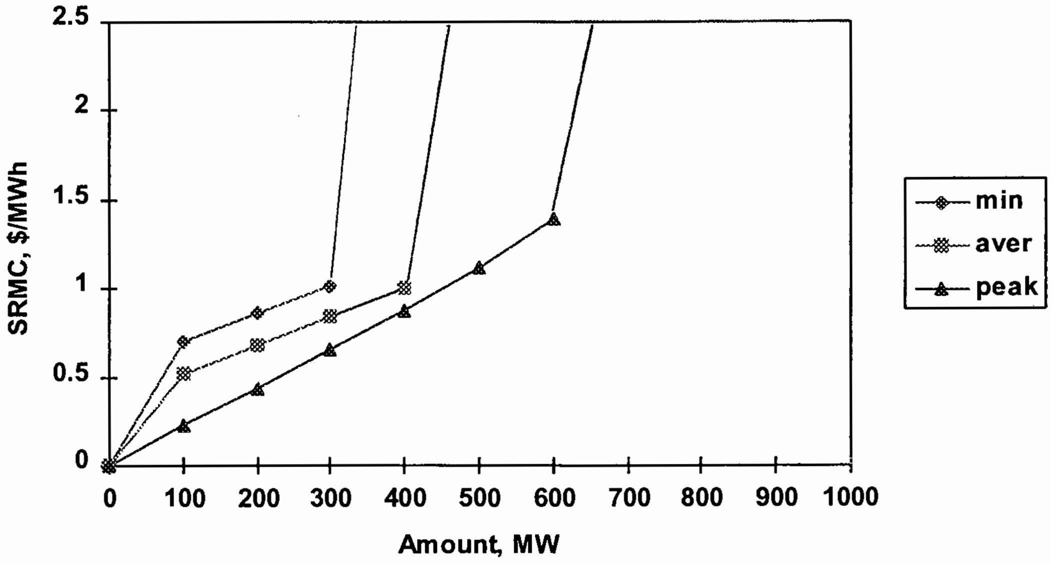

Figure 4.4: The SRMC curves for T3

According to Figure 4.4, transaction T3, similar to transaction T1, is the most expensive under minimum load conditions for all amounts of power transmitted.

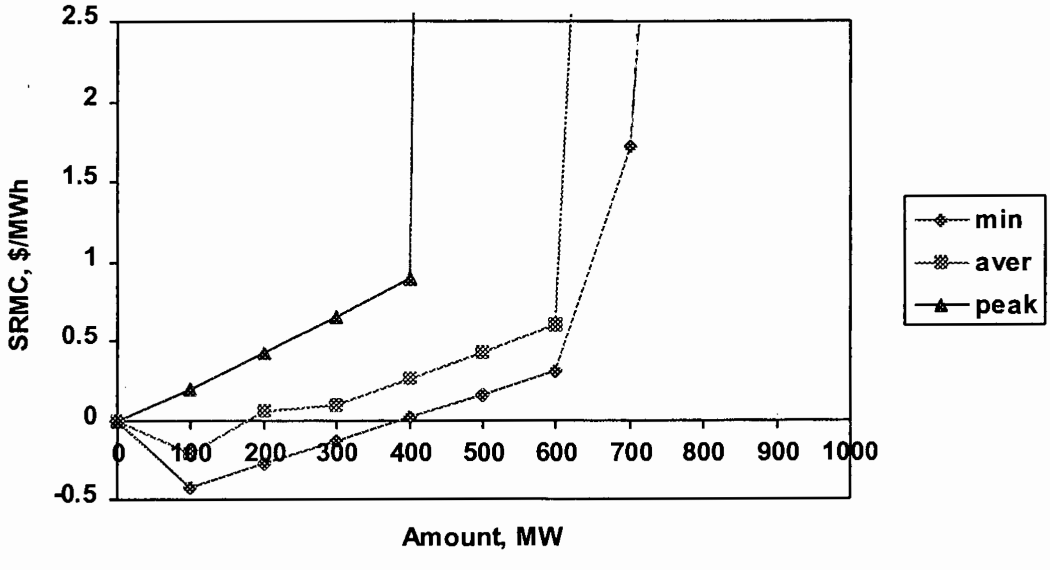

Figure 4.5: The SRMC curves for T4

Figure 4.5 shows that the SRMC curves for T4 are placed in the following way: the curve for peak load is above the curves for average and minimum loads. This means that the transaction under peak load conditions is the most expensive for all amounts of power transmitted.

Therefore, the SRMCs for transactions T1, T2 and T3 exhibit unusual behaviour. The reason for this lies in the system dispatch. The power flows of transaction T1 for the amount of 100 MW are presented on Diagrams 4.1, 4.2 and 4.3 for minimum, average and peak loads respectively.

The amount of 100 MW for a transaction is selected for illustrative purposes. The arrows along each transmission line on the diagrams show the direction of power flow. The numbers next to the arrows indicate the amount of active power in MW flowing along that particular line.

The thick arrows pointed down from the buses show the location of the loads. The transaction is indicated by two arrows ↑ and ↓: one arrow is pointed in to the bus of injection and the second arrow is pointed out from the bus of delivery. The figure of 100 MW next to these arrows shows the amount of the transaction.

By comparing Diagrams 4.1-4.3, it is observed that the main difference in power flows for minimum, average and peak loads is in the flows towards buses 6 and 7.

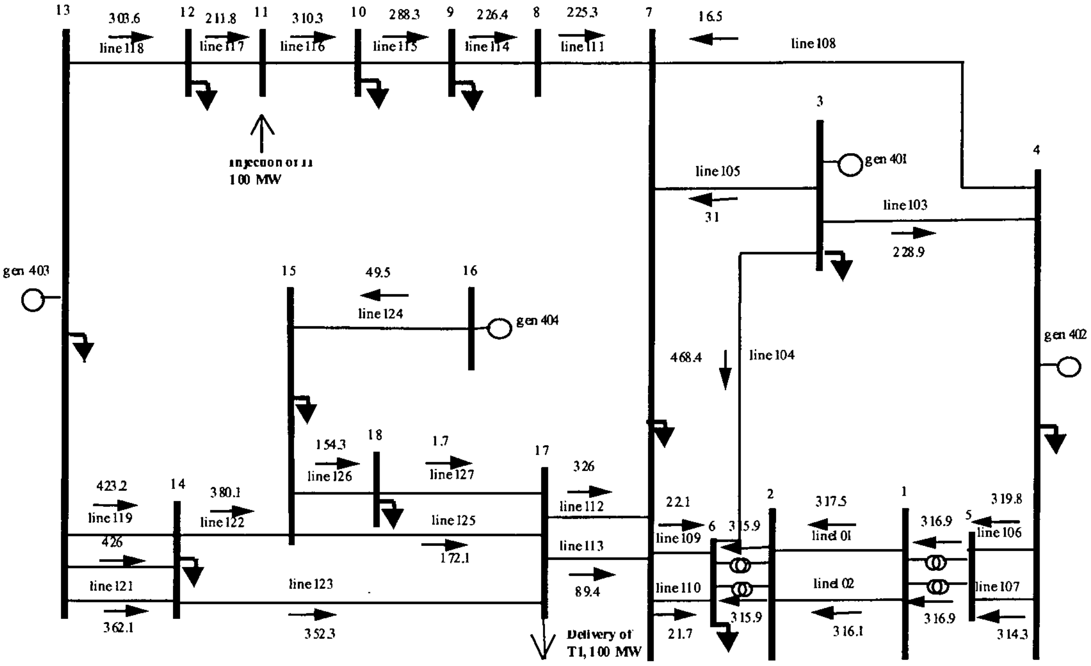

Diagram 4.1: Power flows for T1 under minimum load conditions for 100 MW transmitted

As can be seen from Diagram 4.1 for minimum load, generator 403 supplies loads not only at the nearby buses (9,10, 12, 13, 14, 15, 18) but also at the distant buses 6 and 7.

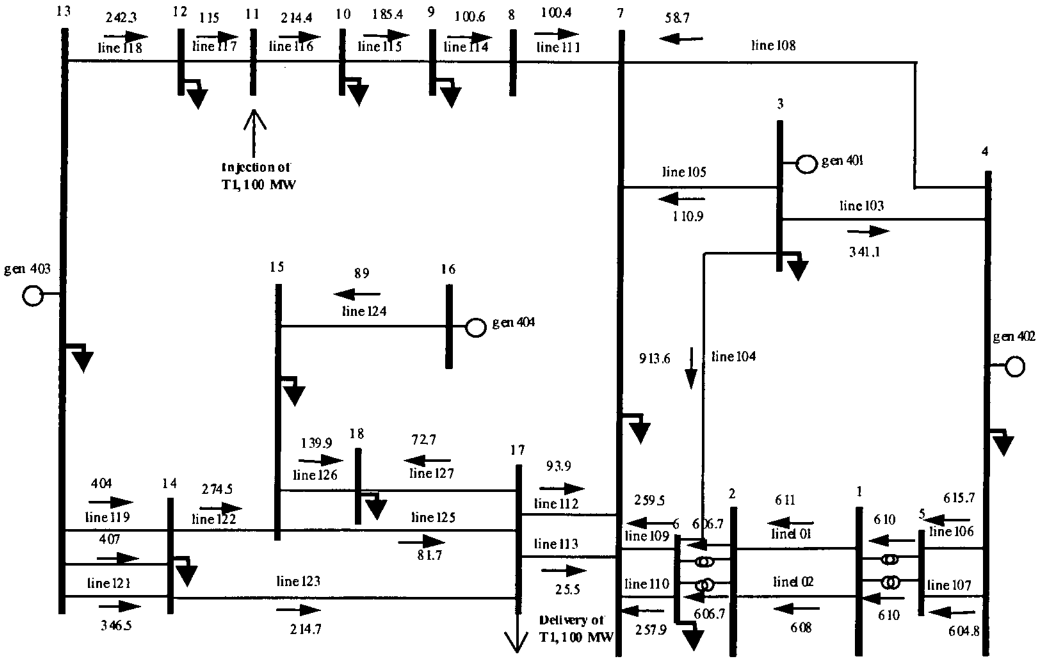

Diagram 4.2: Power flows for T1 under average load conditions for 100 MW transmitted

Diagram 4.2 shows that under average load conditions the load at bus 6 is supplied by generators 401 and 402, while the load at bus7 is still partially supplied by generator 403.

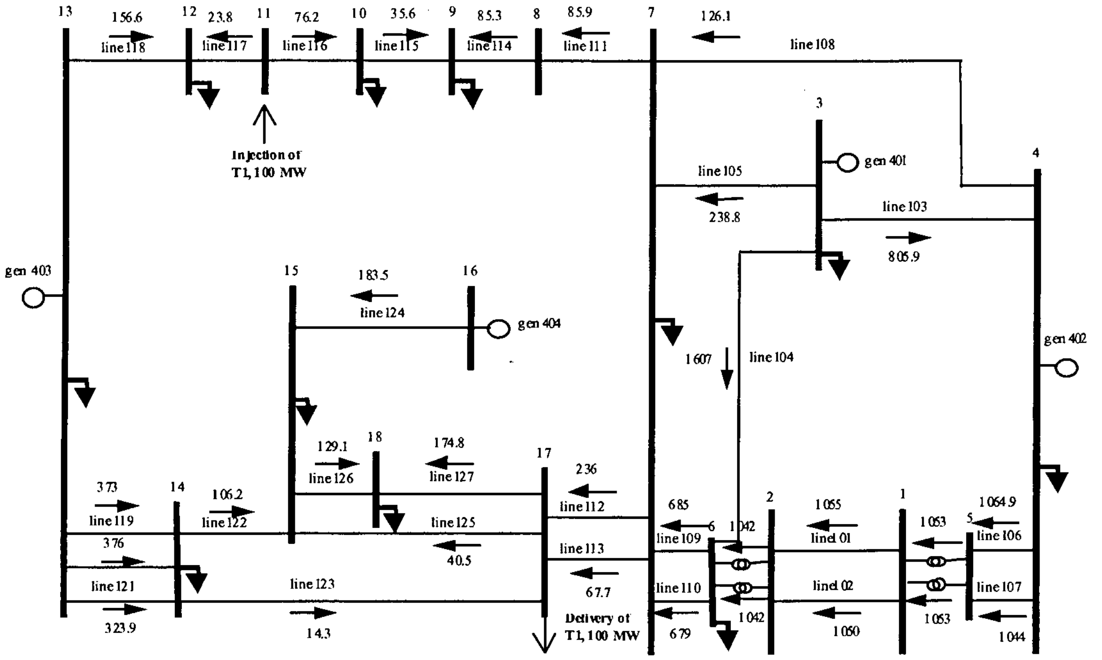

Diagram 4.3: Power flows for T1 under peak load conditions for 100 MW transmitted

Diagram 4.3 shows the power flows under peak load conditions, according to which the loads at buses 6 and 7 are supplied by generators 401 and 402. Generator 403 supplies only nearby loads at buses 14 and 12.

All loads in the network are supplied by four generators. One of the generators, G 403 is modelled as nuclear with constant output of 1800 MW. In other words, the minimum and the maximum output levels of active power for that generator are the same and are equal to 1800 MW. Therefore, under peak load conditions, generator G 403 supplies the nearby loads, while the other three generators supply the rest of the total load of 7455 MW.

Under average load conditions the generation is shifted in the OPF solution to supply the total load of 5220 MW and to keep G 403 at a constant output of 1800 MW. Now the generator G 403 supplies the nearby loads and the distant load at bus 7. Therefore the SRMCs under average load conditions are increased to reflect extra losses due to that change.

Under minimum load conditions, generation shifts are again required to supply the total load of 3727 MW and again to keep generator G 403 at constant output. The OPF results show the redistribution of flows and the new generation schedule, according to which the total operating cost and the losses under minimum load conditions are higher than under average load and peak load conditions.

- *The effect of the direction of a transaction*

  Figures 4.6 through 4.8 show the SRMC curves for all transactions under minimum, average and peak load conditions respectively.

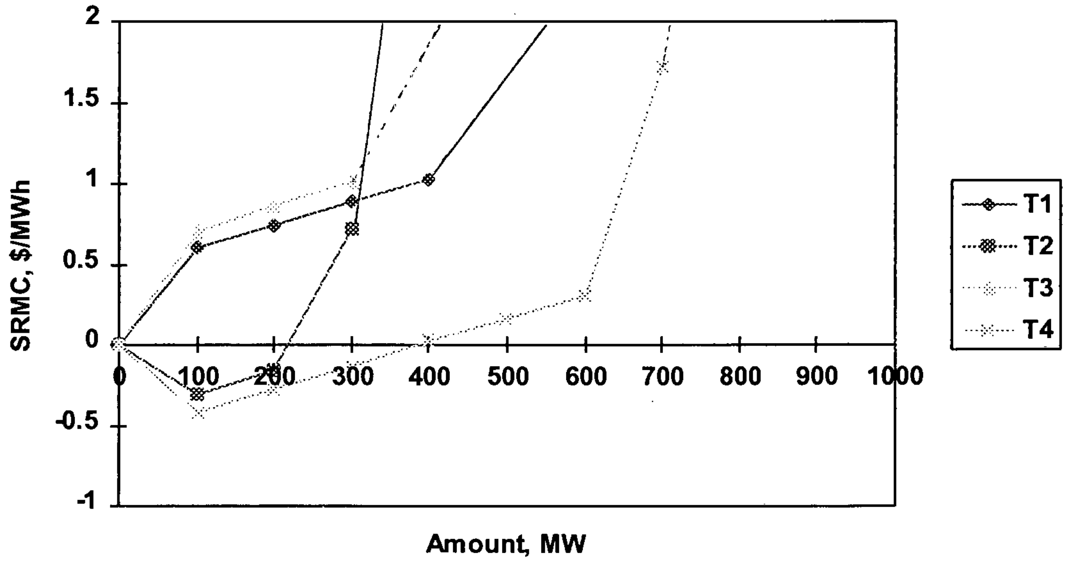

Figure 4.6: The SRMC curves for all transactions under minimum load conditions

As can be seen from Figure 4.6 for minimum load, the SRMC curves for transactions T1 and T3, which are along the main flow, are placed above the curves of transactions T2 and T4, which are in the opposite direction. It means, as expected, that the SRMCs for the transactions in the direction of the main flow are higher than the SRMCs for the transactions in the opposite direction. Furthermore, Figure 4.6 also shows that the SRMCs for T2 are negative for up to 200 MW transmitted. The SRMCs for T4 are negative for up to 400 MW transmitted.

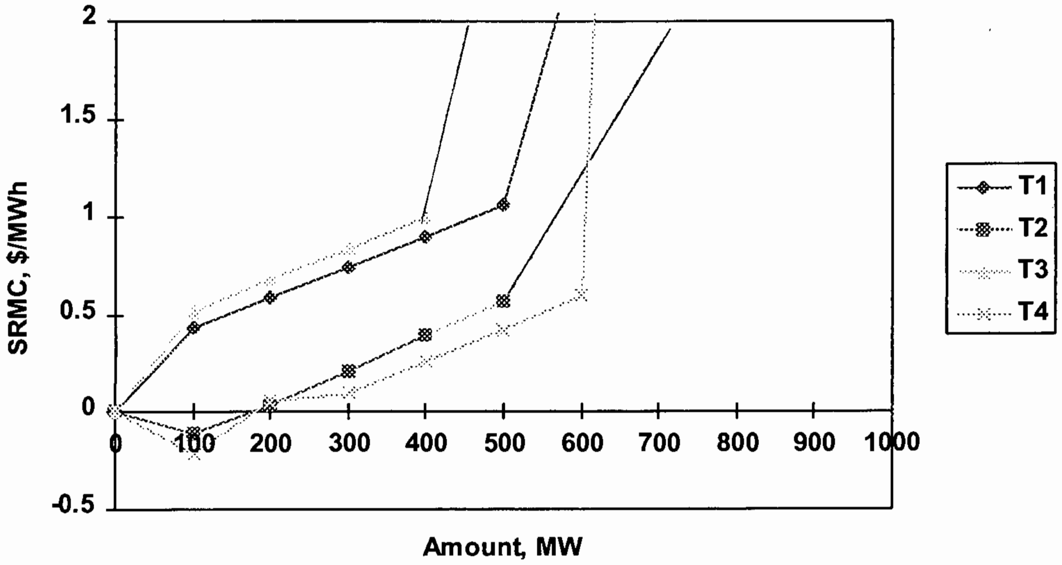

Figure 4.7: The SRMC curves for all transactions under average load conditions

According to Figure 4.7, the observations made for the transactions under minimum load conditions are also true for the transactions under average load conditions. The transactions, which contribute to the main flow on the network, T1 and T3, have higher SRMCs than the transactions that are in the opposite direction to the main flow, T2 and T4. The SRMCs are negative for T2 and T4 for up to 200 MW transmitted.

Figure 4.8 below shows the SRMC curves for all transactions under peak load conditions. As one can see from Figure 4.8, the cost curve of T1 for all amounts of power transmitted lies below the cost curves of other transactions. This means that the transaction T1 along the main flow costs less than the transactions in the opposite direction. This contradicts common sense, according to which a transaction contributing to the main flow on the network should be more expensive than the transaction in the opposite direction. The explanation of these observations follows.

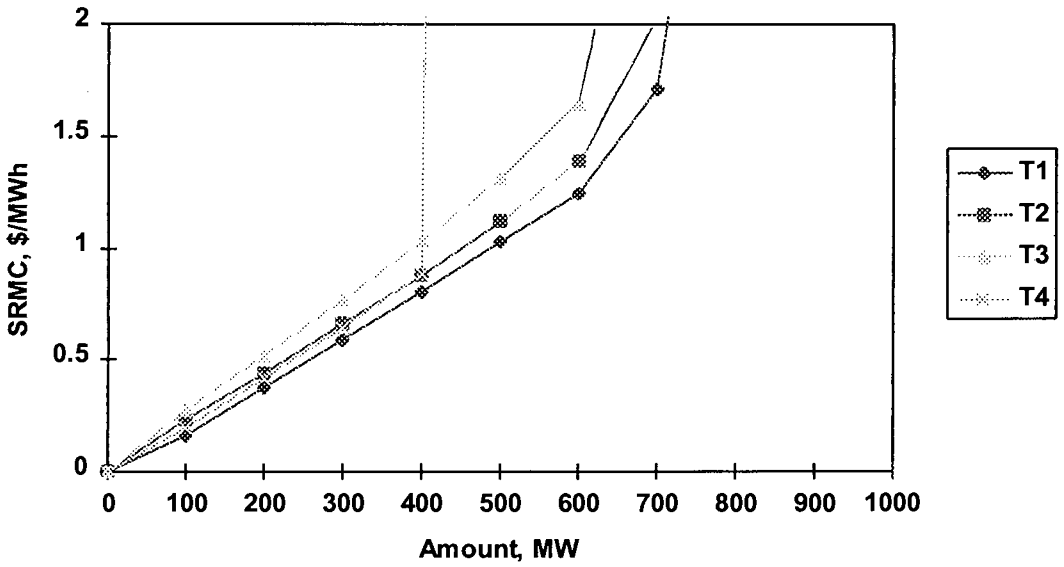

Figure 4.8: The SRMC curves for all transactions under peak load conditions

Transactions T1 and T3 are in the direction of the main flow, and thus they contribute to the main flow. The SRMCs for T1 and T3 under minimum and average load conditions, as expected, are always positive and higher than for transactions T2 and T4. Transactions T2 and T4 are in the opposite direction to the main flow and thus, they reduce the losses on the system. Tables 4.7 and 4.8 show the additional losses and the SRMCs for T2 and T4.

Table 4.7: Losses and SRMCs for T2

	Losses, MW			SRMC, $/MWh		
Case	Min	Average	Peak	Min	Average	Peak
100	-1.7	-0.8	1.2	-0.31	-0.11	0.28
200	-2.2	-0.6	3.6	-0.16	0.04	0.52
300	-2.9	0.7	7.3	0.71	0.21	0.77
400	-2	3	12.8	4071.22	0.39	1.03
500	-0.2	6.2	19.8		0.57	1.32
600	3.1	13.1	28.5		3825.18	1.65
700	7.3	19	7.9			14150.74
800	12.8	26.3	19.7			
900	19.7	35.2	34.3			
1000	30.9	45.9	52.3			

As can be seen from Table 4.7 under minimum load conditions, the additional losses for T2 are negative for up to 500 MW of power transmitted. Under average load conditions the additional losses are negative for up to 200 MW transmitted. The negative additional losses for a transaction indicate that the transaction causes a reduction of the total thermal losses in the system, which are always positive. The reduction of the losses is reflected in the negative SRMCs for certain amounts of power transmitted.

It should be noted, however, that in some of the cases the reduction of the losses is not necessarily associated with a negative SRMC. For example, transaction T2 of 400 MW under minimum load conditions reduces the losses on the network by 2 MW, but the SRMC for this amount is 4071.22 $/MWh. The reason for such high values of the SRMCs, as was explained earlier, is transmission constraints on the system.

Table 4.8: Losses and SRMC for T4

	Losses, MW			SRMC, $/MWh		
Case	Min	Average	Peak	Min	Average	Peak
100	-2.1	-1	0.9	-0.42	-0.21	0.2
200	-3.4	-1.5	2.9	-0.27	0.06	0.42
300	-3.8	-0.4	6.3	-0.13	0.1	0.65
400	-3.4	1.4	11	0.02	1.26	0.89
500	-1.9	4.1	-9	0.16	0.43	32.37
600	0.3	7.9	-6.1	0.31	0.6	6870.7
700	3.6	11	2.2	1.71	9.75	
800	7.8	13.4	12.4	2120.61	8979.79	
900	13.2	18.8	24.8			
1000	21.8	26.5	40			

According to Table 4.8, the same observations as for transaction T2 can be made for transaction T4, which is also in the opposite direction to the main flow. As expected, under minimum load conditions the additional losses of T4 are negative for up to 500 MW of power transmitted. Under average load conditions the additional losses are negative for up to 300 MW of power transmitted. The SRMCs of T4 are also negative for certain amounts of the transaction only under minimum and average load conditions.

However, under peak load conditions the SRMCs of T2 and T4 are higher than the SRMCs for transaction T1, which is in the direction of the main flow. To explain this, the power flow diagrams of T1 and T2 are compared. Again, the amount of 100 MW is selected for illustrative purposes. The power flows for T1 under peak load conditions for 100 MW transmitted are given in Diagram 4.3. The power flows for T2 under peak load conditions for 100 MW transmitted are given in Diagram 4.4.

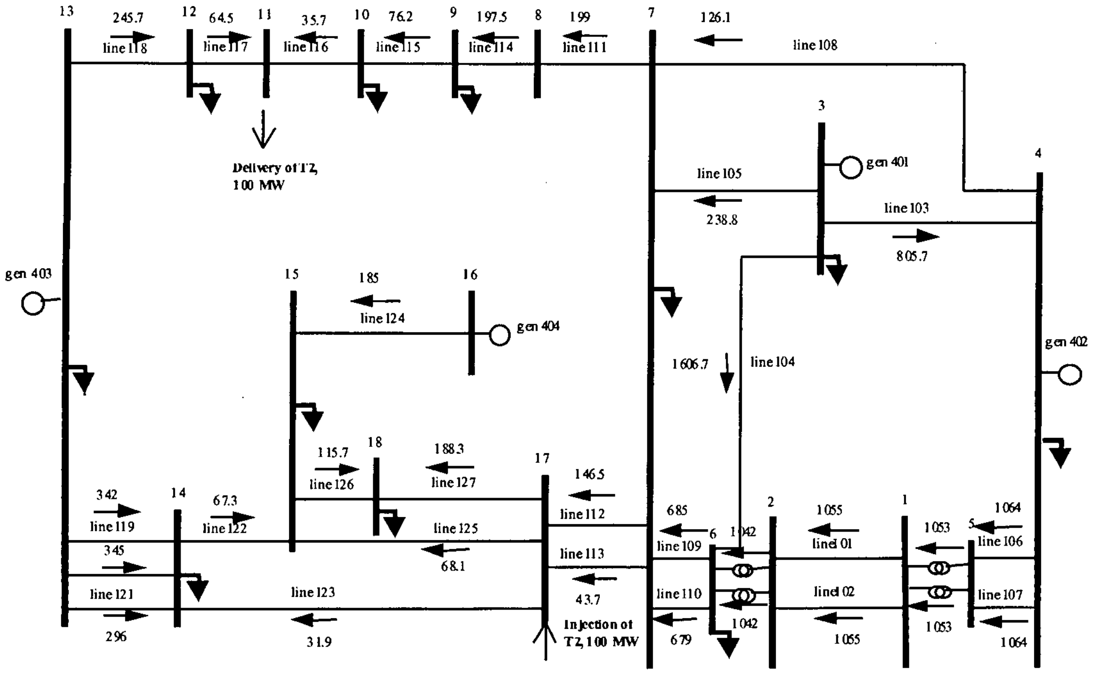

Diagram 4.4: Power flows for T2 under peak load conditions for 100 MW transmitted

By comparing the diagrams for T1 and T2 under peak load conditions, important observation can be made. Although transaction T1 is specified from bus 11 to bus 17 and transaction T2 is specified from bus 17 to bus 11, the actual power flows of both transactions do not follow the contractual routes.

As can be seen from Diagram 4.3 for transaction T1, the power injected into bus 11 is used by the system's local loads, while the load at bus 17 is supplied by generators G 401 and G 402. Diagram 4.4 for transaction T2 shows that the power injected at bus 17 is also used by local loads, while the load at bus 11 is supplied by the distant generators G 401 and G 402. This causes extra losses for T2 and explains the difference in the SRMCs for T1 and T2.

- *The effect of the distance of a transaction*

Figures 4.6 through 4.8 above show that the SRMCs of the long-distance transaction T1 for all amounts of power transmitted are less than the SRMCs of the short-distance transaction T3. This contradicts common sense, according to which the longer the distance of power transmitted, the higher should be the losses and the bigger the cost of a transaction.

The answer, again, can be found in redistribution of power flows for T1 and T3, which is reflected on Diagram 4.1 for transaction T1 and Diagram 4.5 for transaction T3. The power flows are again presented for 100 MW and for minimum load only for illustrative purposes. As was mentioned earlier, Diagram 4.1 for T1 shows that the actual flow of power does not follow the contractual long-distance route from bus 11 to bus 17. Power injected into bus 11 was used by the system's local loads, while the load at bus 17 was supplied by the system's generators. Diagram 4.5 demonstrates the power flows for T3 under minimum load conditions.

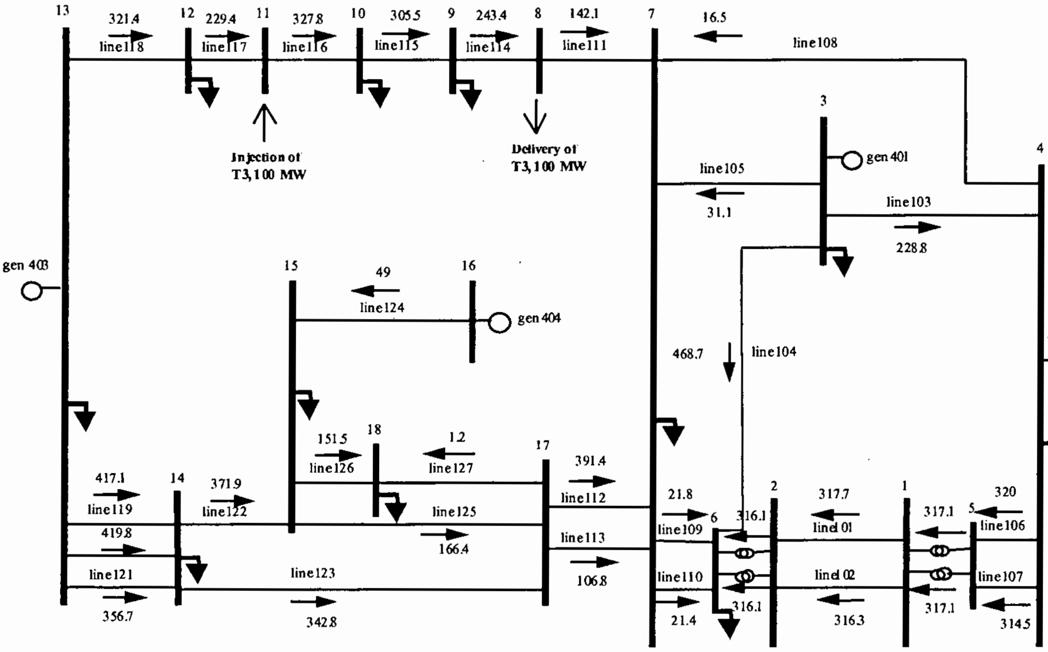

Diagram 4.5: Power flows for T3 under minimum load conditions for 100 MW transmitted

Transaction T3 is specified from bus 11 to bus 8. As can be seen from Diagram 4.5, the power injected to bus 11 flows directly to bus 8, which is the delivery point of transaction T3. Therefore by comparing Diagrams 4.1 and 4.5, it is observed that the main difference in the flows of two transaction T1 and T3 is in the power flow from bus 13 to bus 8. This flow is more substantial on Diagram 4.5 for T3 than on Diagram 4.1 for T1.

Therefore, the power flows of the long-distance transaction T1 are distributed in the system in a such way that the total losses of the system are smaller than the total losses with the transaction T3. Tables 4.9 and 4.10, which show the losses and the SRMCs for transactions T1 and T3, clearly prove this.

Table 4.9: Losses and SRMC for T1

	Losses, MW			SRMC, $/MWh		
Case	Min	Average	Peak	Min	Average	Peak
100	2.6	1.6	0.3	0.6	0.44	0.16
200	5.3	4.1	1.7	0.74	0.59	0.38
300	10.5	7.6	4.4	0.89	0.75	0.59
400	15.8	12	8.3	1.03	0.9	0.81
500	21.1	17.3	13.5	10225.45	1.06	1.03
600	28.1	23.6	19.9		2.47	1.25
700	36	31.8	26.5		10326.06	1.71
800	44.9	39.8	24.7			3.98
900	54.6	49	25.7			6259.97
1000	65.5	59.2	30.3			

Table 4.10: Losses and SRMC for T3

	Losses, MW			SRMC, $/MWh		
Case	Min	Average	Peak	Min	Average	Peak
100	2.9	1.8	0.5	0.7	0.52	0.23
200	6.7	4.6	2.2	0.86	0.68	0.44
300	11.5	8.3	4.9	1.01	0.84	0.66
400	16.3	12.9	9.1	13735.6	1	0.88
500	22.9	19.6	14.6		6867.71	1.12
600	30.4	25.9	21.5			1.39
700	38.9	33.5	64.5			6867.66
800	48.7	42.3	77			
900	59.8	52.3	93			
1000	72.2	63.8	114			

According to Tables 4.9 and 4.10, the losses are 2.6 MW, 1.6 MW and 0.3 MW for T1 of 100 MW transmitted, under minimum, average and peak load conditions. For T3 these figures are 2.9 MW, 1.8 MW and 0.5 MW respectively.

- *The effect of the amount of a transaction*

  The effect of the amount of power transmitted on the SRMCs, observed for all transactions, is as expected: the bigger the amount - the higher the losses on the system and, respectively, the greater the values of the SRMCs. The exception is the case for the transactions in the opposite direction for some amounts of the power transmitted under the minimum and average load conditions. As can be seen from Tables 4.7 and 4.8 for transactions T2 and T4, the SRMCs for certain amounts are negative. However, the SRMCs for both transactions increase constantly with transmission of 200 MW and bigger amounts.

4.3.2. EVALUATION OF TRANSACTION COST BY THE SRIC METHOD

The results of the simulations for the SRIC method are given in Tables 4.11-4.14. In order to highlight the transactions that congest the network, their cells are marked with a star *.

As can be seen from Tables 4.12 and 4.14 some of the SRICs are negative. As was mentioned previously, the negative operating cost of a transaction indicates that the transaction causes the reduction of the losses and the total cost of production in comparison to the base case. The explanation of these results follows.

Table 4.11: SRIC for T1, $/MWh

Case	Min	Average	Peak
100	0.4444	0.2772	0.0508
200	0.5129	0.3556	0.1558
300	0.5843	0.4410	0.2725
400	0.6578	0.5222	0.3922
500	0.7942*	0.6008	0.5147
600	0.8531*	0.6937	0.6331
700	0.9186*	0.9595*	0.7466
800	0.9876*	1.0140*	0.9326
900	1.0571*	1.1119*	1.3728*
1000	1.1304*	1.1483*	1.9088*

Table 4.12: SRIC for T2, $/MWh

Case	Min	Average	Peak
100	-0.2902	-0.1383	0.2560
200	-0.2180	-0.0512	0.3654
300	-0.0440	0.0385	0.4885
400	0.0381*	0.1275	0.6352
500	0.1010*	0.2134	0.7850
600	0.1669*	0.5762*	0.9429
700	0.2422*	0.6415*	2.1223*
800	0.3253*	0.7185*	2.1363*
900	0.4148*	0.8112*	2.2035*
1000	0.5091*	0.9166*	2.3229*

Table 4.13: SRIC for T3, $/MWh

Case	Min	Average	Peak
100	0.5018	0.3175	0.0797
200	0.5637	0.4019	0.1939
300	0.6425	0.4850	0.2991
400	0.7954*	0.5617	0.4205
500	0.8544*	0.9165*	0.5459
600	0.9184*	0.9479*	0.6768
700	0.9876*	1.0023*	2.1525*
800	1.0667*	1.0685*	2.1863
900	1.1513*	1.1423*	2.2870
1000	1.2418*	1.2292*	2.4672

Table 4.14: SRIC for T4, $/MWh

Case	Min	Average	Peak
100	-0.3489	-0.1855	0.2052
200	-0.2836	-0.1271	0.3061
300	-0.2135	-0.0245	0.4322
400	-0.1492	0.0587	0.5583
500	-0.0715	0.1410	1.6903
600	-0.0003	0.2264	2.0379*
700	0.0791	0.3461	1.9711*
800	0.2209*	1.2021*	1.9647*
900	0.2353*	2.4245*	2.0059*
1000	1.0145*	2.3149*	2.0907*

- *The effect of transmission constraints*

  For all transmission transactions the SRIC changes gradually and the values are fairly close to each other, whether with or without transmission constraints in the system. For example, for T1 under minimum load conditions the SRIC is 0.4444 $/MWh for 100 MW transmitted with no violation of transmission constraints. For 500 MW transmitted the SRIC is 0.7942 $/MWh, although seven lines of the network are congested. The Short-Run Marginal Costs, in contrast to the SRIC, increase drastically in the presence of transmission constraints. In the example of

T1, minimum load, the SRMC for 100 MW is 0.6 $/MWh and for 500 MW it is 10225.45 $/MWh.

Figure 4.9 presents the curves of the SRICs and the SRMCs for transaction T1 under minimum load conditions.

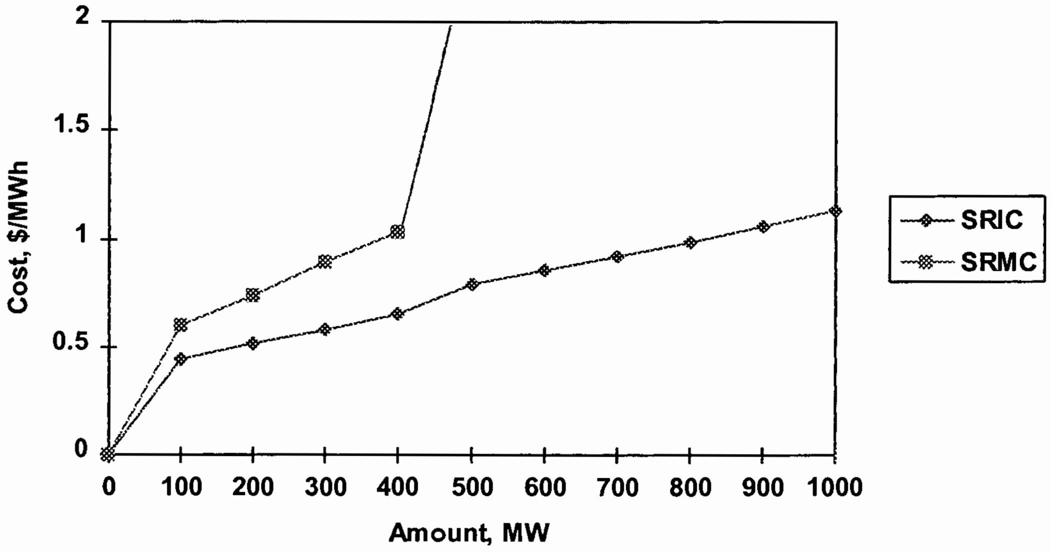

Figure 4.9: The SRIC and the SRMC curves for T1 under minimum load conditions

As can be seen from Figure 4.9 for T1 under minimum load conditions, with no congestion in the system for up to 400 MW of power transmitted, the SRICs and the SRMCs are quite close to each other. Transmission of 500 MW congests the network, hence the SRIC and the SRMC for that amount differ considerably.

It is further observed that with transmission constraints in the system, the SRIC increases more rapidly. For example, the SRIC for T3, peak load, is 0.5359 $/MWh to transmit 500 MW, 0.6768 $/MWh to transmit 600 MW. For 700 MW with transmission constraints in the system, the SRIC is 2.1525 $/MWh.

Figure 4.10 shows the SRMC and the SRIC curves for transaction T3 under peak load conditions.

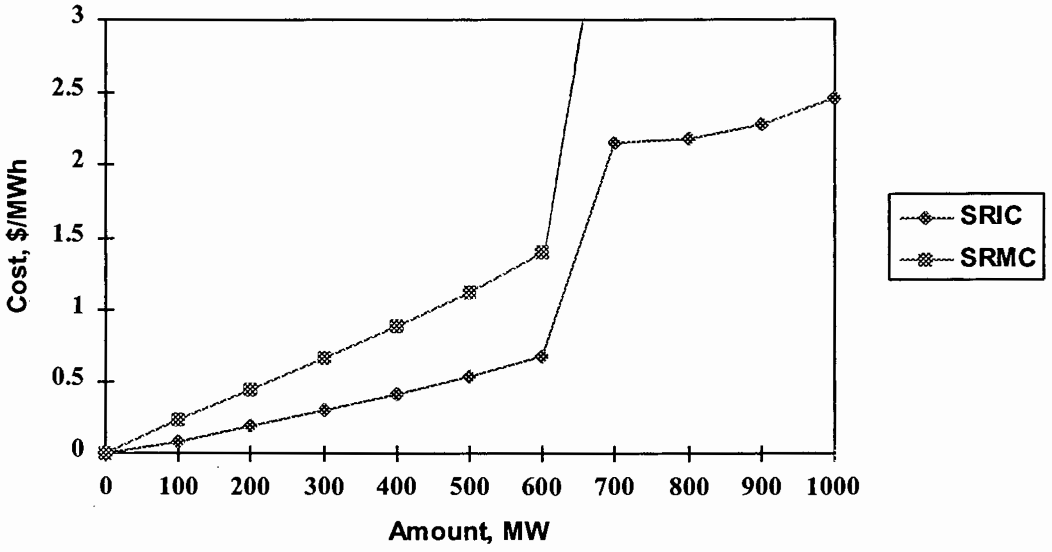

Figure 4.10: The SRIC and the SRMC curves for T3 under peak load conditions

As one can see from Figure 4.10 the SRIC and the SRMC for up to 600 MW transmitted are close to each other. Transmission of 700 MW congests the network. Figure 4.10 shows that the SRIC curve from 600 MW to 700 MW has a steeper rise, which reflects the effect of the congestion in the network.

- *The effect of different load profiles*

The effect of different load profiles on the SRIC is similar to the effect of load profiles on the SRMC. The SRICs for T1 and T3 under minimum load conditions are higher than under average and peak load conditions.

For example, Table 4.11 for T1 shows that the SRICs for the amounts up to 800 MW under peak load conditions are less than under average and minimum load conditions. The SRIC for 100 MW is 0.4444 $/MWh under minimum load conditions. Under average and peak load conditions these figures are 0.2772 $/MWh and 0.0508 $/MWh respectively.

Figure 4.11 shows the SRIC curves for transaction T1 under minimum, average and peak load conditions.

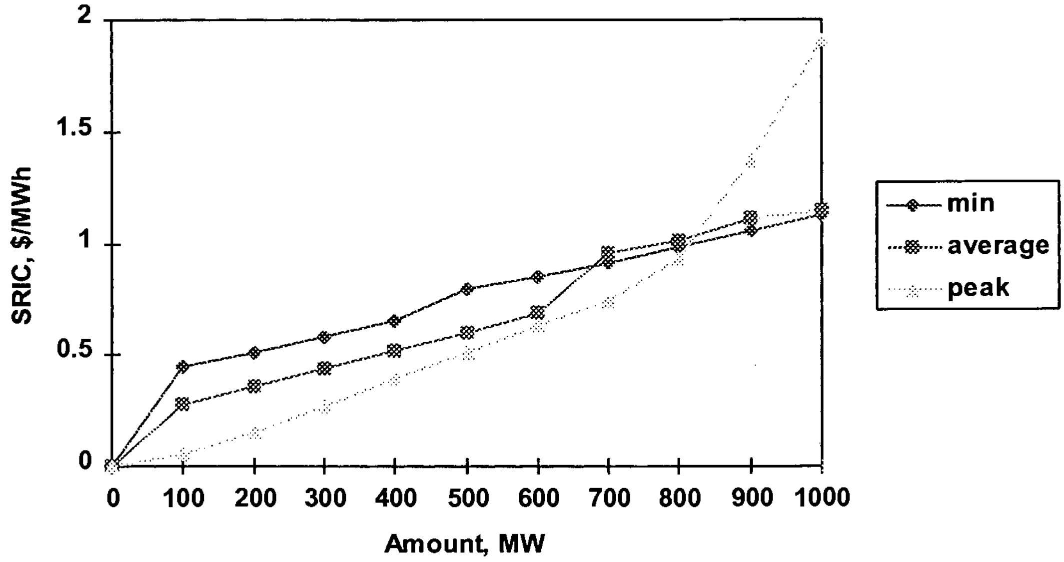

Figure 4.11: The SRIC curves for T1

As can be seen from Figure 4.11 the curve for peak load is below the curves for minimum and average loads for up to 800 MW transmitted.

According to Table 4.13, the SRICs for T3 under minimum load conditions are also higher than under average and peak load conditions for the amount of up to 600 MW. Transmission of 100 MW by the SRIC method would cost 0.5018 $/MWh for minimum load, 0.3175 $/MWh for average load and 0.0797 $/MWh for peak load.

Figure 4.12 shows the SRIC curves for T3 under minimum, average and peak load conditions.

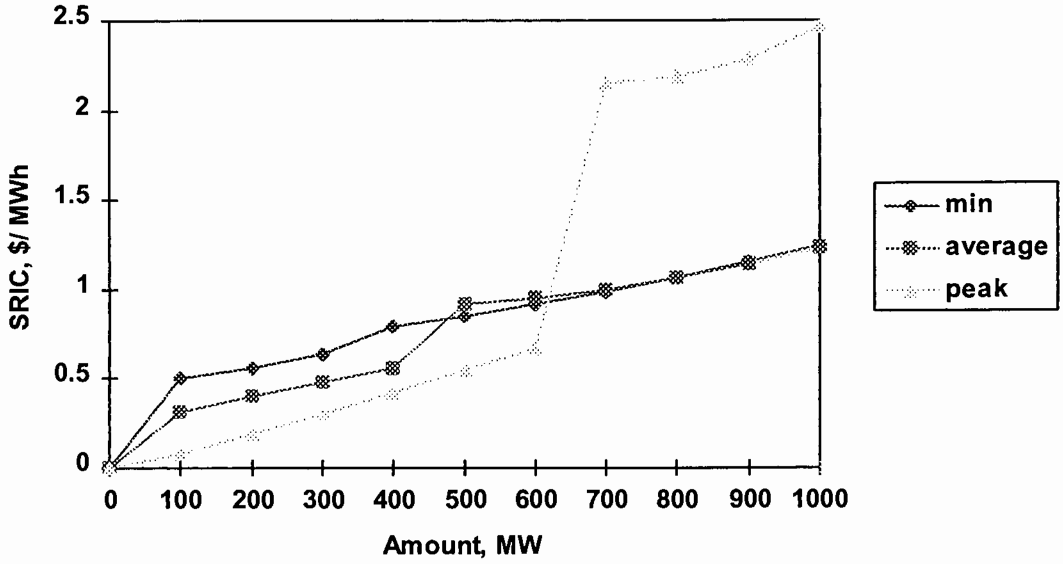

Figure 4.12: The SRIC curves for T3

According to Figure 4.12, the cost curves for transaction T3 for the amounts up to 600 MW cost less for peak load, than for average and minimum loads by the SRIC method. This contradicts common sense: the closer the system is getting to its peak loading, the more expensive it becomes to transmit power. The reason for such behaviour of the SRIC is in one of the generators, G 403, which is modelled as a nuclear one with a constant output level of 1800 MW.

- *The effect of the direction of a transaction*

The effect of the direction of a transaction on the SRIC can be seen on Figures 4.13 and 4.14, which show the SRIC curves for all transactions under minimum, average and peak load conditions respectively.

Again as with the SRMC, Figure 4.13 shows that under minimum load conditions, the SRIC curves for T1 and T3 are above the curves of T2 and T4. Therefore, as expected, the SRICs for the transactions in the direction of the main flow are higher than the SRICs for the transactions in the opposite direction.

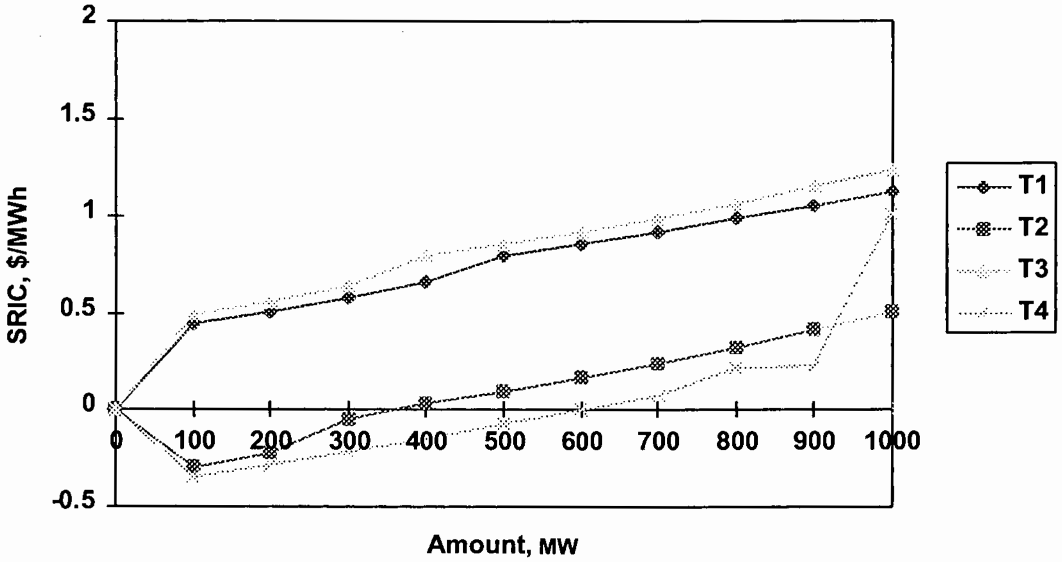

Figure 4.13: The SRICs for all transactionsunder minimum load conditions

Figure 4.13 also shows that the SRICs for T2 are negative for up to 400 MW transmitted and the SRICs for T4 are negative for up to 600 MW transmitted.

Figure 4.14 presents the SRICs under average load conditions.

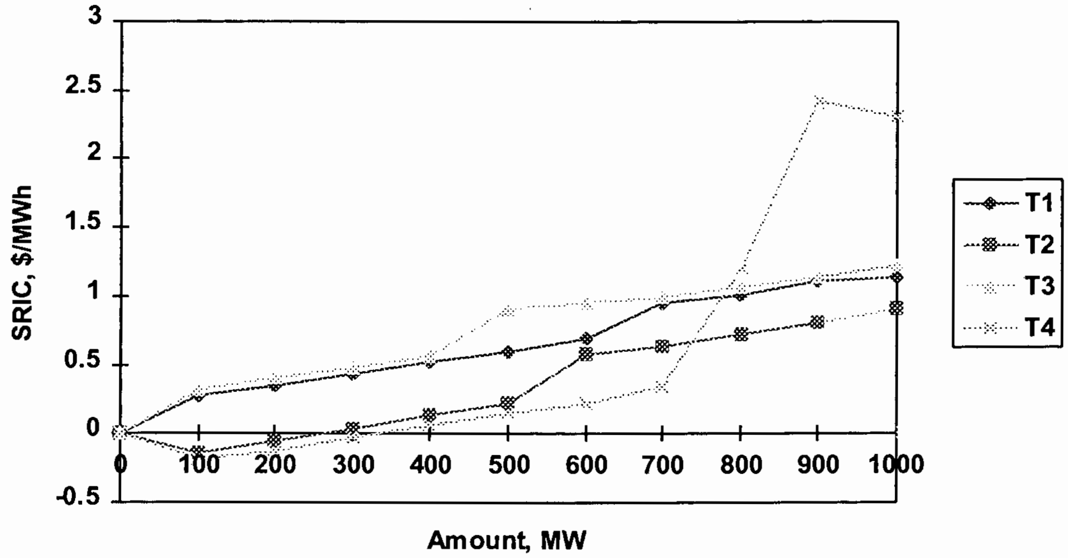

Figure 4.14: The SRICs for all transactions under average load conditions

According to Figure 4.14, the SRICs under average load conditions exhibit the same behaviour as under minimum load conditions. The SRICs for T1 and T3 are higher than for T2 and T4. For T2 and T4 the SRICs are negative for up to 300 MW transmitted.

Hence, as expected, under average load conditions the SRICs for the transactions along the main flow are higher than the SRICs for the transactions in the opposite direction. The transactions in the opposite direction for certain amounts reduce the losses in the system. They thus have negative costs by the SRIC methods.

However, for the SRICs under peak load conditions the effect is opposite. Figure 4.15 presents the SRIC curves for peak load.

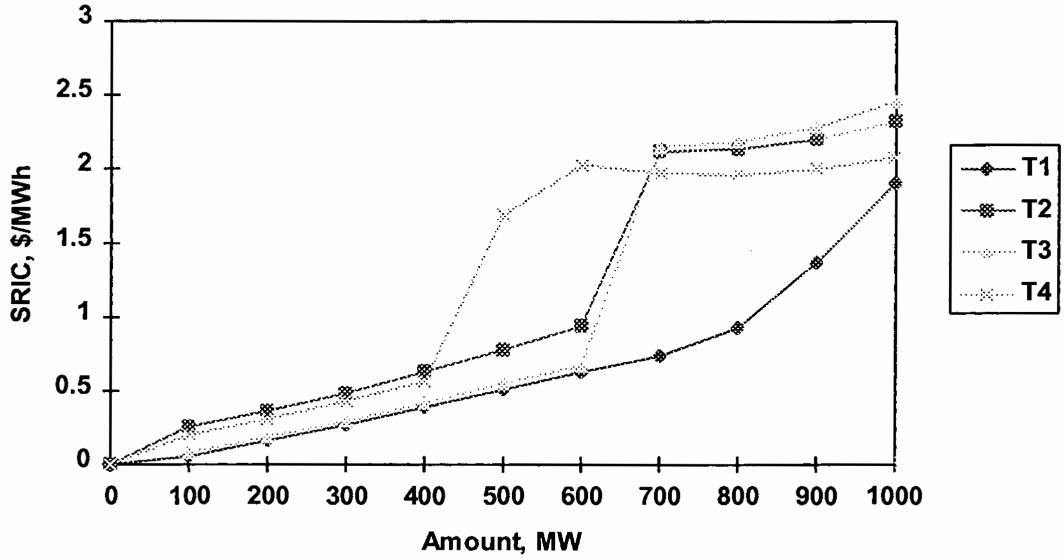

Figure 4.15: The SRICs for all transactions under peak load conditions

As can be seen from Figure 4.15, transaction T1, which is along the main flow, costs less than transactions T2 and T4, which are in the opposite direction. The reason for this lies in a system dispatch and one of the generators, G 403, modelled as nuclear with a constant output level. The power flows for transactions T1 and T2 under peak load conditions are shown on Diagrams 4.3 and 4.4. The detailed analysis and explanation of extra losses and operating costs for transactions T2 and T4 are also given in section 4.3.1.

- *The effect of the distance of a transaction*

  Figures 4.13 – 4.15 display the SRIC curves for two long-distance transactions T1 and T2, and two short-distance transactions T3 and T4. According to common sense we would expect that the longer the distance of power transmitted the higher should be the losses and the bigger the values of the SRICs.

  However, as can be seen from Figures 4.13 and 4.14, the SRIC for transaction T3 under minimum and average load conditions is higher than the SRICs for transactions T1 and T2 for all amounts of power transmitted. As was explained in the previous section, the actual power flow of the long-distance transaction T1 does not follow the contractual long route from bus 11 to bus 17. The system's local loads use power injected into bus 11, while the load at bus 17 is supplied by the system's generators. For transaction T3 the power injected into bus 11 flows directly to bus 8, contributing to the main flow and causing extra losses and higher the operating cost.

  Figure 4.15 for peak load shows that the SRICs for the long-distance transaction T1 for all amounts of power transmitted again are less than the SRICs for the short-distance transactions T3 and T4. The reason for this is in the distribution of the power flow on the system, and it was also explained in section 4.3.1.

- *The effect of the amount of a transaction*

  The SRICs are affected by the different amounts of a transaction in a similar way as the SRMCs: the bigger the amount of transaction- the greater the values of the SRICs. This effect is observed for transactions T1 and T3. The effect is opposite for transactions T2 and T4 in the opposite direction to the main flow. As can be seen from Figures 4.13 and 4.14 for minimum and average loads, transactions in the opposite direction have negative costs for certain amounts of power transmitted. For example, the operating cost for the base case is higher than for the T2 and T4 for 100 MW. However, the SRICs for T2 and T4 from 200 MW and higher increase constantly.

4.4 EVALUATION OF TRANSACTION COST BY ACCOUNTING METHODS

In the process of evaluating the transmission costs by the Accounting methods, the following considerations are taken into account:

- As all Accounting methods are not sensitive to the amount of the transaction by definition, all of them are tested with the same and only one amount of power transmitted: 100 MW
- The calculations for the Accounting methods are performed only for peak load conditions
- In order to compare the Incremental and the Accounting methods and to highlight the difference between them, the capital costs are converted on an hourly basis It is done by division of the capital costs by 8760 hours a year.

Transmission costs by the Postage Stamp method are calculated as average and flat for all transactions by division of the total capital cost of the entire system by the peak load.

The selection of the Contract Path for a transaction is made as the most direct way between injection and delivery points. The capital costs of only the transmission lines along the Contract Path are taken into account.

For the Extended MW-mile method and for the Usage method the power flows are computed using power flows.

The MW changes due to a transaction are calculated by comparing the power flows resulting from a transaction and the power flows of the base case without any transaction.

For the application of the Accounting methods various input data are required. Table 4.15 summaries the parameters of the transmission lines used in the process of calculation of the Accounting rates.

Table 4.15: Capacity, length and capital costs of transmission lines

No.	Length, Km	Capacity, MW	Cost, ml$/km	Cost, ml$	Cost $/MW	Cost $/MWh
101	437	2000	0.1	43.7	21850	2.49
102	435	2000	0.1	43.5	21750	2.55
103	38	1000	0.05	1.9	1900	0.22
104	112	2000	0.05	5.6	2800	0.32
105	1464	500	0.05	73.2	146400	16.72
106	6	2000	0.05	0.3	150	0.017
107	6	2000	0.05	0.3	150	0.017
108	2780	500	0.05	139	278000	14.59
109	284	1000	0.05	14.2	14200	1.62
110	284	1000	0.05	14.2	14200	1.62
111	188	500	0.05	9.4	18800	2.15
112	244	500	0.05	12.2	24400	2.79
113	244	500	0.05	12.2	24400	2.79
114	164	500	0.05	8.2	16400	1.87
115	168	500	0.05	8.4	16800	1.92
116	170	500	0.05	8.5	17000	1.94
117	164	500	0.05	8.2	16400	1.87
118	88	500	0.05	4.4	8800	1.
119	40	500	0.05	2	4000	0.46
120	40	500	0.05	2	4000	0.46
121	44	500	0.05	2.2	4400	0.5
122	110	500	0.05	5.5	11000	1.26
123	210	500	0.05	10.5	21000	2.4
124	82	500	0.05	4.1	8200	0.94
125	226	500	0.05	11.3	22600	2.58
126	250	500	0.05	12.5	25000	2.85
127	216	500	0.05	11.3	22600	2.58
Total	8492	22500		444.9		

4.4.1 OPTIONS FOR MW CHANGES

The Accounting methods, such as the MW-Mile, the Extended MW-Mile, and the Usage methods, use power flows in the calculation procedure. The allocation of the transmission costs is done proportionally to the MW changes on transmission lines due to the transaction under consideration. The power flows associated with a transaction may go in the same or in the opposite direction to the main flow in transmission lines. Three options exist in calculating the transaction cost depending upon how the MW changes due to the transaction are estimated [50,62]:

1. Sum of the real values

   In this case negative MW changes, whose line loading decreases due to the transaction, are subtracted from positive MW changes.

2. Only positive values

   In this case only positive MW changes are used in computing the transmission charge, and those that are negative are ignored. There is no charge for the user whose power flow is in the opposite direction of the net flow. Only customers that use the circuit in the same direction of the main flow pay transmission charges.

3. Sum of the absolute values

   In this case positive and negative MW changes are converted to absolute values and added. According to this option, all participants should pay for transmission system usage even if the transaction's flows are in the opposite direction to the main flow.

Depending on the option selected for the MW changes, the results of the calculation of transmission charges can vary. In the thesis the first two options are not considered. Sum of the absolute MW changes are taken into account for calculations.

4.4.2 EVALUATION OF TRANSACTION COST BY THE POSTAGE STAMP METHOD

The Postage Stamp rate is calculated by dividing the total annual capital cost of the network 444.9 ml$/y (or 50787.67 $/h) by the peak load 7455 MW. As a result the Postage Stamp rate for all transactions is a uniform charge of 6.79 $/WMh.

4.4.3 EVALUATION OF TRANSACTION COST BY THE CONTRACT PATH METHOD

The selection of the Contract Path for a transaction is made as the most direct way between injection and delivery points. Diagram 4.6 shows the transmission lines selected as the Contract Path for the transactions.

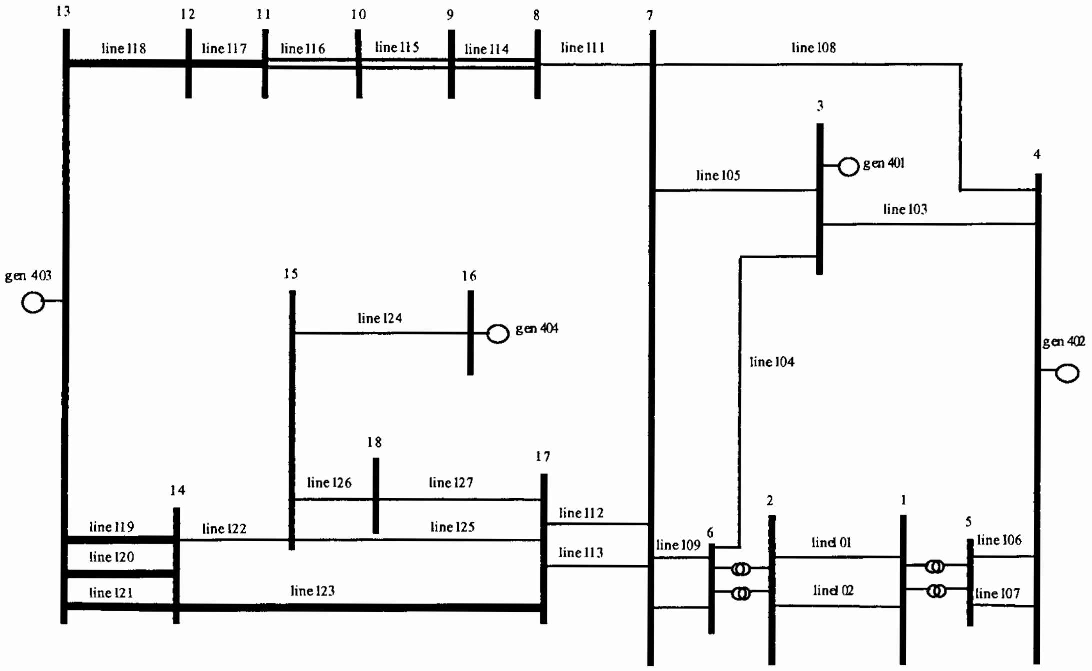

Diagram 4.6: Transmission facilities selected for the Contract Path method

For transaction T1 from bus 11 to bus 17, as well as for transaction T2 from bus 17 to bus 11, the Contract Path is assumed to be along the following transmission lines: 117, 118, 119, 120, 121 and 123. On Diagram 4.7 these lines are marked with a bold line. For transaction T3 from bus 11 to bus 8, as well as for transaction T4 from bus 8 to bus 11, the Contract Path is assumed to be along the following transmission lines: 114, 115, and 116. On Diagram 4.7 these lines are marked with a double bold line.

The Contract Path rates for the transactions are calculated by dividing the total capital cost of the selected facilities by the capacity of the Contract Path. For transactions T1 and T2 the capital cost of the Contract Path is 29.3 ml$/y, the capacity of the path 500 MW and the CP rate is 58600 $/MW or 6.7 $/MWh. For transactions T3 and T4 the capital cost of the selected path is 25.1 ml$/y, the capacity of the path is 500 MW and the CP rate is 50200 $/MW or 5.73 $/MWh.

4.4.4 EVALUATION OF TRANSACTION COST BY THE EXTENDED MW-MILE METHOD

The calculation for this method is performed using the MW changes on the lines due to a transaction. The detailed calculation procedure will be demonstrated by means of transaction T1.

Diagram 4.7 shows the changes in the active power flow due to transaction T1. The arrows along each line and numbers next to the arrows indicate the direction of power flow and the MW changes in flows due to transaction T1. The positive numbers indicate the positive contribution of the transaction to the flow. The negative numbers indicate the reduction in the flow due to the transaction. The arrows that are without any numbers, indicate that the flows on that lines are not affected by the transaction. For the present study the absolute MW changes on the lines are taken into account for the calculation of the Extended MW-Mile rates.

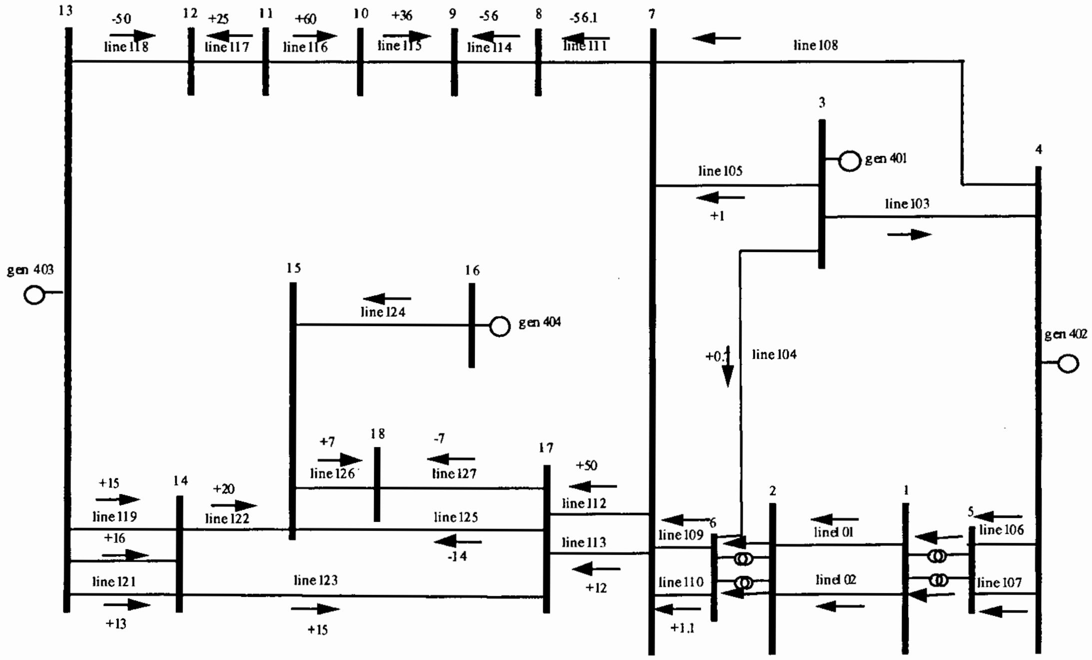

Diagram 4.7: The MW changes for T1 under peak load conditions for 100 MW transmitted

The calculation procedure for the Extended MW-Mile method consists of three steps.

1. First step is the calculation the MW-Mile value of the transaction. For this the positive MW changes on each affected line are multiplied by the length of the line and by the capacity cost. Then these MW-Mile values are summed over all affected lines. Table 4.16 shows the positive MW changes, the lengths, capacity costs used for the calculation of the MW-Mile values of the affected lines. The total MW-Mile value for transaction T1 is 175354.8 MW-Mile.

Table 4.16: The absolute values of MW changes, length, capacity cost and the MW-Miles values of the lines

Lines No.	|MW changes|	Length, km	Capacity cost, $/MWh	MW-Mile value
104	0.71	112	0.64	50.89
105	1	1464	16.72	24478.08
110	1.1	284	1.62	506.09
111	56	188	2.15	22635.2
112	50	244	2.79	30634.2
113	12	244	2.79	8169.12
114	56	164	1.87	17174.08
115	36	168	1.92	11612.16
116	60	170	1.94	19788
117	25	164	1.87	7667
118	50	88	1.0	4400
119	15	40	0.46	276
120	16	40	0.46	294.4
121	13	44	0.5	286
122	20	110	1.26	2772
123	15	210	2.4	7560
125	14	226	2.58	8163.12
126	7	250	2.85	4987.5
127	7	216	2.58	3900.96
Total				175354.8

2. The second step is the calculation of the total MW-Mile value for the entire network. Table 4.17 shows the length, capacity cost, MW flow of the lines used for the calculation of the MW-Mile value for the network. The MW-Mile value for each transmission line is calculated as a product of the length, and capacity cost of MW flow of that line. Then the MW-Mile values are summed over all lines. The total MW-Mile value for the whole network is 14560102 MW-Miles.

Table 4.17: The length, cost per MWh, MW flow and the MW-Mile values for all lines

No.	Length, km	Cost, $/MWh	Total MW flow	MW-Mile values
101	437	2.49	1055	1147977.15
102	435	2.55	1050	1164712.5
103	38	0.22	805.9	6737.32
104	112	0.32	1607	57594.88
105	1464	16.72	238.8	5845365.5
106	6	0.017	1064.9	108.62
107	6	0.017	1044	106.488
108	2780	14.59	126.1	5114641.22
109	284	1.62	685	315154.8
110	284	1.62	679	312394.32
111	188	2.15	85.9	34720.78
112	244	2.79	236	160659.36
113	244	2.79	67.7	46087.45
114	164	1.87	85.3	26159.8
115	168	1.92	36	11483.14
116	170	1.94	76.2	25130.76
117	164	1.87	25	7298.98
118	88	1.	156.6	13780.8
119	40	0.46	373	6863.2
120	40	0.46	376	6918.4
121	44	0.5	323.9	7125.8
122	110	1.26	106.2	14719.32
123	210	2.4	15	7207.2
124	82	0.94	183.5	14144.18
125	226	2.58	40.5	23614.74
126	250	2.85	129.1	91983.75
127	216	2.58	174.8	97412.54
Total				14560102

3. The last step is the calculation the Extended MW-Mile rate by multiplying the total capital cost 444.9 ml$/y (or 50787.67 $/h) by the ratio of the MW-Mile value of the transaction to the total MW-Mile value for the whole network. The ratio of the MW-Miles value of transaction T1 to the total MW-Mile value of the network is 0.012. Then the Extended MW-Mile rate for T1 is 609.45 $/h for 100 MW transmitted or 6.09 $/MWh.

The Extended MW-Mile rates for other transactions are calculated analogously. The tables used for the calculation of the other transactions are presented in Appendix VI.

4.4.5 EVALUATION OF TRANSACTION COST BY THE USAGE METHOD

The calculation for the Usage method is performed by estimation of the MW changes on the lines due to a transaction. The calculation procedure will be demonstrated by means of transaction T1.

Diagram 4.7 shows the changes in the active power flow due to transaction T1. As with the Extended MW-Mile method the sum of the absolute MW values are taken into account.

The calculation procedure for the Extended MW-Mile method consists of two steps.

1. First step is the calculation of the ratio of the MW changes due to the transaction to the total MW flow for each transmission line. Table 4.18 shows the absolute MW changes and the total MW flow for the lines affected by the transaction. This information is used for the calculation of the ratio.

Table 4.18: The absolute values of MW changes, MW flow and their ratio

Lines No.	|MW changes|	Total MW flow	Ratio of |MW changes| to the total MW flow
104	0.71	1607	0.00044
105	1	238.8	0.00042
110	1.1	679	0.00162
111	56	85.9	0.0348
112	50	236	0.651
113	12	67.7	0.112
114	56	85.3	0.176
115	36	36	1.00
116	60	76.2	0.75
117	25	25	1.00
118	50	156.6	0.3125
119	15	373	0.0402
120	16	376	0.0425
121	13	323.9	0.04
122	20	106.2	0.186
123	15	15	1.00
125	14	40.5	0.341
126	7	129.1	0.053
127	7	174.8	0.04

2. The second step is the calculation of the Usage rate. For that the ratio of each line should be multiplied by the capacity cost of that line and then the results are summed for all affected lines. The final figure of 1193 \$/MWh is the Usage rate

for the transaction T1. Table 4.19 shows the ratio, the capacity cost and the Usage rates for the affected lines.

Table 4.19: The absolute values of MW changes, MW flow and their ratio

Lines No.	Ratio of |MW changes| to the MW flow	Cost, $/MWh	Usage rate for the line
104	0.00044	0.32	0.00014
105	0.00042	16.72	0.00702
110	0.00162	1.62	0.00262
111	0.0348	2.15	0.0748
112	0.651	2.79	1.816
113	0.112	2.79	0.312
114	0.176	1.87	0.329
115	1.00	1.92	1.92
116	0.75	1.94	1.46
117	1.00	1.87	1.87
118	0.3125	1.	0.3125
119	0.0402	0.46	0.0185
120	0.0425	0.46	0.0196
121	0.04	0.5	0.02
122	0.186	1.26	0.234
123	1.00	2.4	2.4
125	0.341	2.58	0.88
126	0.053	2.85	0.151
127	0.04	2.58	0.1
Total			11.92718

The tables used for the calculation of the other transactions are given in Appendix VI.

The rates obtained by the Accounting methods are summarised in Table 4.20.

Table 4.20: Transmission rates by Accounting methods, $/MWh

Transaction	Postage Stamp	Contract Path	Extended MW-mile	Usage
T1peak	6.79	6.7	6.09	11.93
T1average	6.79	6.7	6.09	11.93
T1min	6.79	6.7	6.09	11.93
T2peak	6.79	6.7	6.52	10.24
T2average	6.79	6.7	6.52	10.24
T2min	6.79	6.7	6.52	10.24
T3peak	6.79	5.73	5.44	11.28
T3average	6.79	5.73	5.44	11.28
T3min	6.79	5.73	5.44	11.28
T4peak	6.79	5.73	4.83	8.24
T4average	6.79	5.73	4.83	8.24
T4min	6.79	5.73	4.83	8.24

By analysing the results of the calculations the following observations can be made.

The Postage Stamp method allocates the total capital cost of the network equally between all transactions, despite the differences in the use of the transmission network by each of the four transactions. This means that short-distance transactions T3 and T4 cross-subsidise the long-distance transactions T1 and T2. The transactions T2 and T4 in the opposite direction would cross-subsidise the transactions T1 and T3 in the direction of the main flow.

The Contract Path rates are different for short-distance and long-distance transactions. For long-distance transactions T1 and T2 they are 6.7 $/MWh, while for short-distance T3 and T4 they are 5.73 $/MWh. The Contract Path rates, however, are not sensitive to the flow direction. Transactions T1 and T2 would cost the same, despite the fact that T2 is in a counter flow direction and reduces the losses in the system, and T1 is in a main flow direction.

As the Extended MW-Mile (EMW) method takes into account the distance of a transaction, the rates for long-distance transactions T1 and T2 are higher than for short-distance transactions T3 and T4. Concerning the direction of a transaction, there is no clear dependence of the EMW rates for transactions in different directions. For example, transaction T2 (in the opposite direction) costs 6.52 $/MWh and transaction T1 (in the direction of the main flow) costs 6.09 $/MWh.

The Usage rates are the highest among all Accounting rates. The reason for this lies in the calculation procedure of the method. The allocation of the capital costs by this method is done separately for each line in contrast to the Extended MW-Mile method, which estimates the overall ratio of the total MW-Mile value for the transaction to the total MW-Mile value of the entire network.

According to the Usage method, the ratio of the MW change to the total MW flow is calculated for each line. This ratio reflects the portion of the capital cost of the affected line, which will be allocated to the transaction. If for a particular line the MW change is equal to the total MW flow and the ratio is equal to 1, than 100 %of the capital cost of the line is allocated to the transaction. In the case of transaction T1, the ratio of the line 115, as well as 117 and 123, is equal to 1. It means that 100 % of the capital costs of these lines were allocated to the transaction, thus causing the high overall Usage rate.

4.5 EVALUATION OF TRANSACTION COST BY THE COMPOSITE INCREMENTAL/ACCOUNTING METHODS

As was shown in Sections 4.3 and 4.4, for most of the cases the SRMC and the SRIC of a transaction are much smaller than the transaction cost by the Accounting methods. However, in order to evaluate the total costs of transactions, both the operating and the accounting costs should be taken into account by applying the combination of the Incremental and Accounting methods.

Two composite Incremental/Accounting methods are applied for the case study.

1. The combination of the SRMC and the Extended MW-Mile methods
2. The combination of the SRIC and the Usage methods.

Table 4.21 shows the costs of the transactions by Incremental, Accounting and composite methods. The costs are estimated for 100 MW of power transmitted.

Table 4.21: The costs of transactions by Incremental, Accounting and composite methods for 100 MW transmitted, $/MWh

Case	SRIC	SRMC	Postage Stamp	Contract Path	Extended MW-Mile	Usage	SRMC+ Extended MW-Mile	SRIC+ Usage
T1 min	0.4444	0.6	6.79	6.7	6.09	11.93	6.69	12.3744
T1 aver	0.2772	0.44	6.79	6.7	6.09	11.93	6.53	12.2072
T1 peak	0.0508	0.16	6.79	6.7	6.09	11.93	6.25	11.9808
T2 min	-0.2902	-0.31	6.79	6.7	6.52	10.24	6.21	9.9498
T2 aver	-0.1383	-0.11	6.79	6.7	6.52	10.24	6.41	10.1017
T2 peak	0.2560	0.28	6.79	6.7	6.52	10.24	6.8	10.496
T3 min	0.5018	0.7	6.79	5.73	5.44	11.28	6.14	11.7818
T3 aver	0.3175	0.52	6.79	5.73	5.44	11.28	5.96	11.5975
T3 peak	0.0797	0.23	6.79	5.73	5.44	11.28	5.67	11.3597
T4 min	-0.3489	-0.42	6.79	5.73	4.83	8.24	4.41	7.8911
T4 aver	-0.1855	-0.21	6.79	5.73	4.83	8.24	4.62	8.0545
T4 peak	0.2052	0.2	6.79	5.73	4.83	8.24	5.03	8.4452

The results of the simulations show that the composite rates exhibit the same behaviour as the incremental rates. As can be seen from the Table 4.21, the composite rates are different for all transactions considered. The composite rates as the incremental rates reflect the operating conditions of the system. They are sensitive to the load profile of the system, as well as to the different types of transactions. On the other hand, the composite rates also have the features of the Accounting methods: they cover the capital costs of the system and thus they ensure the appropriate revenue for the system.

4.6 DISCUSSION OF THE RESULTS OF THE SIMULATIONS

The 18-bus network was simulated for the various system conditions to illustrate the points that have been made in the previous chapters of the thesis. The following factors and their effect of the cost of a transaction were investigated:

- transmission constraints
- three load profiles
- the direction of a transaction
- the distance of a transaction
- the various amounts of a transaction.

Six methods for evaluating costs of transmission transactions were applied for case study. The discussion of the results of the simulations is as follows:

INCREMENTAL METHODS

- *Effect of transmission constraints*

  With no congestion on the system, the SRICs and the SRMCs are considerably small and quite close to each other. When there is no violation of constraints, the SRMCs and the SRICs behave similarly and rise gradually. When constraints are reached, both the SRMCs and the SRICs increase.

  As the SRMCs are based on the Bus Incremental Costs (BICs), with congestion in the network the BICs increase for most of the buses. The BICs give rise to the

SRMCs, which become more volatile and show distorted, unpractically big values.

The SRICs do not rise as sharply as the SRMCs with congestion in the network. However, when transmission constraints are observed, the SRIC curves have a steeper rise than when there are no constraints.

- *Effect of different load profiles*

  Contrary to what was expected, for some of the transactions the costs are the lowest under the peak load conditions. The reason for this is in one of the generators, which is modelled as a nuclear one with a constant output level. Under minimum and average load conditions that generator supplies remote loads and thus causes extra losses.

- *Effect of the direction of a transaction*

  As was expected, the SRMCs and the SRICs for the transactions in the direction of the main flow are higher than the SRMCs and the SRICs for the transactions in the opposite direction. Some of the transactions in the opposite direction have negative costs because the power flows due to transactions reduce the losses in the system. A transaction with a negative cost indicates that the total losses are less with that transaction than of the base case.

- *Effect of the distance of a transaction*

  The SRMCs and the SRICs under minimum and average load conditions for various amounts of power transmitted are higher for short-distance transactions than for the long-distance transactions. These results contradict common sense according to which the longer the distance of the transaction - the higher the losses and the bigger the Incremental costs. The reason of this is the distribution of power flows.

  Through analysing power flows of transactions, it is observed that in some cases the actual flow of power does not follow the contractual long-distance route. While power injected into the system by the "seller" of a transaction is used by the system's local loads, the load of the "buyer" is supplied by the system's generators. Therefore, in those cases the long-distance transactions have lower costs than the short-distance transactions.

- *Effect of the various amounts of a transaction*

  The SRMC and the SRIC vary with the amount of active power transmitted. As expected, the higher the amount of a transaction - the bigger the cost. The exception is the case with the transactions in the opposite direction. For some transactions the dependence between the SRMCs and the SRICs, and the amount of power transmitted is reversed: the higher the amount – the lower the cost. The explanation of this is in the cost effect of the transactions in the opposite direction.

ACCOUNTING METHODS

The results of the simulations show that all Accounting methods have several features in common:

- They use a simple accounting procedure that can be easily verified and calculated.
- The Accounting methods allocate only the capital costs of the system to the users.
- The results obtained from the Accounting methods do not depend upon the amounts of power transmitted.
- The Accounting methods are not sensitive to the operating conditions on the system; therefore a transaction with transmission constraints in the system would cost the same as the one without transmission constraints.
- In the calculation procedure only peak load conditions are taking into account. Thus, transactions under minimum and average load conditions by the Accounting methods would cost the same as under peak load conditions.

However, each Accounting method has some differences in the calculating procedure and in the results obtained.

Postage Stamp method

- The Postage stamp rates are flat and equal for all transactions considered.
- The method ignores any path considerations.
- It is not sensitive to the direction or distance of a transaction.
- The method does not require power flow executions.

Contract Path method

- The Contract Path rates are not sensitive to the direction of a transaction. They are equal for transactions in both directions: along the main flow and in the opposite direction.
- As the Contract Path method incorporates the transaction' path considerations, it reflect the distance of the transactions. Thus, the cost of a long-distance transaction by the Contract Path method is higher than the cost of a short-distance transaction.
- The Contract Path method ignores power flows over any parallel paths.
- The Contract Path method does not require power flow executions in its computation procedure.

Extended MW-Mile method

- The Extended MW-Mile method requires the execution of the power flow program and thus reflects the impact of a transaction on transmission lines.
- The method considers the path and the distance of a transaction.
- There is no clear dependence between the Extended MW-Mile rates and the direction of a transaction.

Usage method

- The Usage method also requires the execution of the power flow program.
- The method reflects the impact of a transaction on transmission lines.
- The Usage method considers the path of a transaction but does not reflect the distance of a transaction.

COMPOSITE INCREMENTAL/ACCOUNTING METHODS

Two composite methods are applied:

1. The sum of the SRMC method and the Extended WM-mile method and
2. The sum of the SRIC method and the Usage method.

The results of simulations show that the rates obtained from composite methods exhibit the same behaviour as the rates by the Incremental and the Accounting methods. On the one hand, the composite rates are sensitive to the operating conditions of the system and different load profiles. On the other hand, they cover the capital costs of the system and thus reflect the revenue requirements.

The combination of the SRMC and the Extended MW-Mile methods (or by the combination of the SRIC and the Usage methods) appears to give more accurate results, than the separate Incremental or Accounting methods. The composite rates reflect the capital costs of transmission facilities, captured by the Accounting methods (the Extended MW-Mile or the Usage method). On the other hand, these rates are sensitive to operating conditions of the system because the SRMCs and the SRICs reflect the variations in the operating cost of the system.

4.7 SUMMARY

The objective of this chapter was to test and compare six selected methods for evaluating transmission services in the case studies. The following methods were selected:

1. The SRMC method
2. The SRIC method
3. The Contract Path method
4. The Postage Stamp method
5. The Extended MW-Mile
6. The Usage method.

The summary of the findings of the research is the following:

INCREMENTAL METHODS

The SRMC and the SRIC vary corresponding to load conditions and the state of the system. Under different conditions, the cost effects are different and sometimes contradictory.

For example, in some cases the costs of short-distance transactions calculated by Incremental methods are higher than those of long-distance transactions. Another example of contradicting results is the case with different load profiles. According to the results of simulations with three load profiles, the costs under peak load conditions for some of the transactions are lower than the costs under minimum load conditions when the system theoretically should be less congested. As was shown the reason for that lies in one of the system generators, which was modelled as a nuclear one with a constant output level.

It is also observed that the SRMCs and the SRICs for some transactions are negative. The operating cost of a transmission transaction is negative if that transaction reduces the transmission losses in comparison to the base case. Therefore, the SRMCs and the SRICs reflect the reduction of the losses.

The important advantage of the SRMC and the SRIC methods is that they are based on operating conditions of the system. The availability of efficient SRMCs and SRICs can provide a tool for guiding the use of the electric power system and can be seen as signals for efficient operation and investment in the network.

However, the study also shows that the Incremental methods have several disadvantages. The disadvantages of the SRMC method are as follows:

- The SRMCs are very dependent upon the condition of the system and are therefore unpredictable.
- With a congested network the SRMC method can give unrealistically high rates.

- The SRMCs do no reflect the Revenue Requirements.

The disadvantages of the SRIC method are:

- For the SRIC method for every transaction two runs of the OPF are necessary: with the transaction and without. This is in contrast to the SRMC method, which requires only one run of the OPF for a transaction.
- The method also does not reflect the Revenue Requirements.

ACCOUNTING METHODS

The simulations with four Accounting methods show that the Postage Stamp (PS) method is the simplest one, as the method ignores any path considerations and does not require power flow execution. Therefore, the PS rates are flat and equal for all transactions, all load profiles and all conditions of the system.

The Contract Path (CP) method is the second simplest method as it also does not require power flow execution. However, the CP method has an important advantage over the Postage Stamp method as it reflects the transaction's path.

The Extended MW-Mile method and the Usage method incorporate the power flows in the computation procedure and are the most advanced among the Accounting methods. For these methods the MW changes on transmission lines due a transaction should be estimated. The difference between these two methods is that the Extended MW-Mile method considers the distance of a transaction, while the Usage method does not take into account the distance of the transmission transaction.

The Accounting methods use a simple accounting procedure that can be easily verified and recalculated. They allocate the capital costs of the network and thus reflect the Revenue Requirements. However, transmission transactions evaluated by the Accounting methods do not promote greater economic efficiency. The results of the simulations by the Accounting methods show that these methods do not consider changes in operating costs and therefore do not reflect the changing conditions of the system. In the calculation procedure of the Accounting methods only peak load conditions are taken into account. Thus, transactions under minimum and average load conditions by the Accounting methods would cost the same as under peak load conditions.

Therefore, none of the above mentioned methods covers the operating and the capital costs at the same time. A solution is presented for the examined cases that reconciles the conflicting objectives. The combination of Incremental and Accounting methods is found to give the best result in terms of preserving economic efficiency and providing the Revenue Requirements.

COMPOSITE INCREMENTAL/ACCOUNTING METHODS

The results of the simulations show that the rates obtained from composite methods exhibit the same behaviour as the Incremental and the Accounting rates.

- The composite rates are sensitive to the operating conditions of the system and different load profiles.
- They are different, in the same way as the Incremental rates, for various transactions.
- The composite rates reflect the capital costs of the system.

CHAPTER 5

CONCLUSIONS AND GUIDELINES

5.1 CONCLUSIONS

This thesis presents an investigation into transmission services, the cost of active power transmission and methods for evaluating costs. The literature survey on the topic focuses on analysing international experience in the field and investigating the existing methods for evaluating costs of the transmission services. Two groups of methods are identified and analysed: Incremental methods and Accounting methods. After the investigation, six methods are chosen for further computer simulations. For this purpose the 18-bus network is selected, which is the equivalent version of the South African transmission system. Study cases are specified to represent various system conditions, such as the presence of transmission constraints, different load profiles, and several types of transmission transactions.

The results of the simulations show that the short-run Incremental rates are sensitive to the operating conditions of the system, as well as to different types of transactions. In particular, the presence of transmission constraints contributes to the increase in the SRMCs and the SRICs. However, the SRMC method gives more realistic results with no transmission constraints in the system. When transmission constraints are present, the rates calculated by the SRMC method are unpractically high. The Short-Run Incremental Cost (SRIC) method gives reasonable values for all cases considered, whether with transmission constraints or without.

The simulations with transactions of various distances, directions and amounts showed that under different conditions, the effects on the SRMCs and the SRICs of transactions are different and sometimes conflicting. For example, the cost of a long–distance transaction is not necessarily higher than that of a short-distance transaction. The cost of the transaction in the opposite direction is not always less than that of the transaction in the direction of the main flow.

Therefore, the conclusion is drawn that the effects of operating conditions of a system and various types of transactions for the short-run Incremental methods depend on the configuration of the system. In order to investigate the effect of operating conditions on the SRMC and the SRIC, a system should be simulated for each operating scenario. The study further demonstrates that the SRMC and the SRIC rates do not reflect revenue requirements.

Based on this, the SRMCs and the SRICs can be seen as signals for guiding the use of the electric power system, for efficient operation and investment in the network.

The simulations with the Accounting methods show that the methods are based on a simple computation procedure that can be easily verified. Two of the Accounting methods, the Postage Stamp and the Contract Path methods do not require power flows execution. The other two considered methods, the Extended MW-Mile and the Usage methods need two power flows with and without a transaction for the calculating procedure.

The next conclusion about the Accounting methods is that they do not reflect the changing conditions of the system, as the calculations for all Accounting methods are performed for the peak load only. Thus, all transactions, whether during the off-peak load or during the peak load, would cost the same. Furthermore, the accounting rates would be equal for the transaction that causes the congestion of the system and for the transaction that does not congest the system. However, as the capital cost of a transmission transaction is usually the largest, the Accounting methods have a very important advantage: they allocate the capital costs of the network and thus reflect the revenue requirements.

Finally, the conclusion is drawn that none of the above mentioned methods cover the operating and the capital costs at the same time. The solution that reconciles the conflicting objectives of economic efficiency and revenue requirements, is presented for the study cases.

The combined Incremental/Accounting methods are found to give the best result in terms of preserving economic efficiency and providing the Revenue Requirements. The combined SRMC/MW-mile rate and the SRIC/Usage rates are more accurate since they reflect the capital costs of transmission facilities, captured by the MW-mile method and the Usage method. On the other hand these rates are sensitive to operating cost variations because the SRMCs and the SRICs represent the operating conditions of the system. Therefore, the thesis provides the foundation for calculating transmission costs that can be used to develop efficient combined tariffs for transmission services.

As a result of the investigation two papers were published. The first paper "***Overview of the methods for the determination of the cost of transmission transactions***" was presented at the South African Universities Power Engineering Conference in January 1996 at the University of the Witwatersrand. The second paper ***"An Analysis of the Existing Methods for Transmission Services Evaluation"*** was presented at the National Science Foundation Conference in November 1996 in Florida, USA.

Finally, it can be said that while the findings of this thesis have not addressed all the issues concerning transmission services, their costs and the methods for the cost evaluation, it is hoped that a step has been made in the right direction. It is also hoped that the analysis of the discussed issues will increase understanding of the operational, economic and other considerations related to transmission services. It is recommended that further studies should be carried out to answer the questions that this thesis did not cover. The recommendations for further studies follow in the Chapter 6.

5.2 GUIDELINES FOR THE METHODS CONSIDERED

The guidelines are provided for two Incremental and four Accounting methods which are analysed and numerically tested in the thesis. The guidelines for each method consist of the short description of the method, the basic input data that are necessary for the calculation, and a summary of a computational procedure. It should be noted that the description of the calculating procedures is simplified for purposes of clarity.

Incremental methods

The SRMC and the SRIC methods consider the variation in the operating cost due to a transaction. The SRMC and the SRIC are computed using the OPF.

SHORT-RUN MARGINAL COST METHOD

Description	The Short-Run Marginal Cost method evaluates the operating cost that a transmission utility incurs due to a one-unit change in power transfer.
The basic information	1. Standard network data required by a power flow programme, including line parameters, transformers and generators parameters, bus load 2. Standard generating units data required by an economic dispatch, such as incremental heat rate curves, fuel cost 3. Transaction data: points of injection and delivery, amount of a transaction in MW
Calculation Procedure	1. The OPF program is run with a transaction. The standard economic dispatch is used to calculate the Bus Incremental Costs (BICs) for the injection and delivery points of a transaction 2. The SRMC for a transaction is calculated as the difference between the BICs for all points of delivery and the BICs for all points of injection for that transaction

SHORT-RUN INCREMENTAL COST METHOD

Description	The SRIC method evaluates the difference in the operating cost of a transmission utility caused by the entire transaction.
The basic information	1. Standard network data required by a power flow programme, including line parameters, transformers and generators parameters, bus load 2. Standard generating units data required by an economic dispatch, such as incremental heat rate curves, fuel cost 3. Transaction data: points of injection and delivery, amount of a transaction in MW
Calculation Procedure	1. The OPF program is run. The standard economic dispatch is used to calculate the total operating cost without a transaction 2. The OPF program is run again. The standard economic dispatch is used to calculate the total operating cost with that transaction 3. The SRIC for a transaction is calculated as a difference in the total operating cost with and without that transaction

Accounting methods

All Accounting methods require some common computation steps, which are described briefly.

1. All capital costs for transmission facilities should be collected and tabulated.
2. A fixed charge rate (FCR) is calculated as a sum of the following elements: the cost of capital, taxes, depreciation expenses, insurance, administrative and general expenses.
3. The acquisition capital costs of the transmission facilities are multiplied by the FCR to obtain the annual capital costs.

The following are the guidelines for the four Accounting methods.

POSTAGE STAMP METHOD

Description	The PS method is based upon the assumption that the entire transmission system is involved in all transactions and that all users pay the same flat charge
The basic information	1. Annual capital cost of all transmission facilities, such as transmission lines, transformers, etc. 2. Peak load
Calculation Procedure	1. Determine the total annual capital cost as a sum of the annual capital costs of all transmission facilities 2. Calculate the Postage Stamp rate by division of the total annual capital cost by the peak load

CONTRACT PATH METHOD

Description The CP method is based upon identification of a single continuing path along which power is assumed to flow from a generating source to a load

The basic information

1. Diagram of the network: generators, loads, buses, transmission lines
2. Annual capital cost of the selected transmission facilities, such as transmission lines, transformers, etc.
3. Capacity parameter of the selected contract path
4. Transaction data: points of injection and points of delivery

Calculation Procedure

1. Select the contract path for the transaction. This should be the most direct and electrically closest way between the power receipt and delivery points
2. Determine the total annual capital cost of the selected path which is the sum of the annual capital costs of the selected transmission lines
3. Determine the capacity of the contract path which is the lowest capacity parameter among the capacities of the selected lines
3. Calculate the Contract Path rate by division of the total annual capital cost of the selected path by the capacity of the selected contract path

EXTENDED MW-MILE METHOD

Description The Extended MW-Mile method examines the impact of a transaction on all transmission line flows and allocates the capital costs of the network in proportion to the changes in line flows as measured by MW-Miles. The method employs a power flow model to project the detailed impact of system changes resulting from a transaction.

The basic information

1. Diagram of the network: generators, loads, buses, transmission lines
2. Length of the lines
3. Annual capital costs of the transmission facilities
4. Transaction data: points of injection and delivery, amount of a transaction in MW
5. Standard network data required by a power flow programme, including line parameters, parameters for transformers and generators, and bus loads (for the peak hour of the year)

Calculation Procedure

1. Simulate two power flows, with and without that transaction for the peak hour of a year
2. Estimate the MW changes due to the transaction for every affected line in the network by comparing the two power flows
3. Calculate the MW-Mile values for every affected line in the network by multiplying the value of the MW changes on that line by the length of the line in miles
4. Calculate the total MW-Mile value for the transaction by summing the MW-Miles for every affected line
5. Calculate the MW-Mile values for all lines of the network by multiplying the power flow in MW on each line by the length of that line in miles
6. Calculate the total MW-Mile value for the entire network which is the sum of the MW-Miles for all lines, calculated in step 5.
7. Calculate the ratio of the total MW-Mile value for the transaction

to the total MW-Mile value for the entire network

8. Determine the total annual capital cost of the network which is the sum of the annual capital costs of all transmission lines
9. Calculate the Extended MW-Mile rate by the multiplying the ratio, calculated in step 7, by the total annual capital cost

USAGE METHOD

Description

The Usage method examines the impact of a transaction on all transmission facilities and allocates the capital costs of the network in proportion to the changes in line flows as measured by MW values. The method employs a power flow model to project the detailed impact of system changes resulting from a transaction.

The basic information

1. Diagram of the network: generators, loads, buses, lines
2. Annual capital costs of the transmission facilities
3. Transaction data: points of injection and delivery, amount of a transaction in MW
4. Network data required by a power flow programme, including line parameters, parameters of transformers and generators, and bus loads (for the peak hour of the year)

Calculation Procedure

1. Simulate two power flows, with and without that transaction for the peak hour of the year
2. Estimate the MW changes due to the transaction for every affected facility in the network by comparing two power flows
3. Calculate the ratio of the usage for each affected line by division of the MW change by the total MW flow on that line
4. For each affected line determine the portion of the line capital cost allocated to the transaction, by multiplying the ratio, calculated in step 3 by the capital cost of the line
5. Calculate the Usage rate as a sum of the portions of the capital costs of the lines, calculated in step 4.

CHAPTER 6

RECOMMENDATIONS

6.1 RECOMMENDATIONS FOR THE METHODS CONSIDERED

Short-run Incremental methods

The SRMC and the SRIC can be used as signals for guiding the operation and the investments in the electric power system. They provide the natural measure of the price of transmission. In particular, the SRMC method reflects the cost of violating transmission constraints. When transmission constraints are present, the SRMCs increase dramatically.

The SRIC reflects the cost of additional losses incurred due to a transaction. The SRIC method can be used to estimate the cost of the additional losses and the operating cost incurred due to a transaction. For this purpose the OPF is used to compute an economic dispatch with and without the transaction.

Accounting methods

The Accounting methods are based on a simple calculating procedure. Depending on the configuration of the network, one of the Accounting methods should preferably be applied.

As the Postage Stamp method is based on an assumption that the entire transmission system is used for any transaction, the method can be usefully applied in a highly meshed power system with a load dispersed throughout the utility's service territory and with integrated generation and transmission facilities.

The Contract Path method is based upon the assumption that the power due to a transaction flows through a specified path. Thus, the method can preferably be used in a radial system with well-defined borders.

The Extended MW-Mile and the Usage methods need a power flow program to estimate the MW changes in their calculation procedure. These methods more closely reflect the actual usage of the network than the Postage Stamp and the Contract Path methods. However, it is expected that the costs of administering the Extended MW-Mile and the Usage methods will be higher than those of the other Accounting methods. These methods are applicable to any system, whether meshed or radial. The calculation of MW changes for the Extended MW-Mile and the Usage methods in a complex meshed system, though, can be a time-consuming procedure.

The Extended MW-Mile method uses the MW-Mile values as a measure of the utilisation of the network. The methods allocate the capital costs of transmission lines only. The capital costs of other transmission facilities, which do not have physical mileage, such as transformers, substations, etc., can not be allocated by the Extended MW-Mile method. This can be done by the Usage method, which allocates the capital costs on a per facility basis and considers the MW flows through facilities.

6.2 RECOMMENDATIONS FOR FURTHER INVESTIGATION INTO METHODS FOR EVALUATING COSTS OF TRANSMISSION SERVICES

Short-run Incremental methods

1. To estimate the variations in the SRMC and in the SRIC for a particular transaction, several operating scenarios should be studied to define the condition of the system, which will be the base for service charging.

2. The calculation of the SRMC and the SRIC is performed using the OPF program. The final results obtained from the OPF depend on the complexity of the model. For example, the incorporation of reactive power and voltage constraints would

improve the overall results but would make the OPF problem more complex. In order to investigate these issues further studies should be performed with the OPF program.

3. Load profiles of the network users should be studied in order to determine daily and seasonal load variations. This can be done by dividing the year into time periods so that load variations and operating conditions within each period are more or less homogeneous. Therefore, the SRMC and the SRIC of each of these operating scenarios and specified load profiles should be calculated using the OPF model.

4. In order to promote correct operating decisions for a transaction, the SRMC and the SRIC should be evaluated in real- time using the on-line OPF program.

5. Due to the unpredictability of costs obtained by the SRMC method, either under- or over-recovery of revenue requirements is possible. Transmission rates can be adjusted to achieve the appropriate level of capital recovery through revenue reconciliation. The issue of revenue reconciliation was not covered in the present research and therefore also should be addressed in future studies.

Long-run incremental methods

The Long-Run Marginal Cost method and the Long-Run Incremental Cost method, which were not numerically tested in the present study, need to be investigated in future. All methods considered in the present research allocate either operating or capital costs to users of the transmission network. The reinforcement cost of a transaction, which is evaluated by the LRMC and the LRIC methods, was not considered in this thesis and requires special attention.

Accounting methods

The Accounting methods allocate the total capital cost to the users of the transmission network. In the present study hypothetical simplified capital cost data were used to facilitate the analysis.

1. For the Accounting methods the capital costs of all transmission lines, transformers and other equipment are lumped together. However, the average capital costs can be very different from the actual capital costs. Voltage class, land, construction, material used, and the year of construction can make big differences in estimating the capital cost of the network. Therefore, future attention should be concentrated on estimating the actual capital costs of the network

2. There are several approaches to computing the capital cost. The computation can be made on the base of acquisition cost, on the base of current replacement value, and on the base of future projected cost data. Depending on the option selected the value of the capital cost can vary. Thus, each option for computation of the capital costs needs further investigation.

3. According to the Accounting methods the annual capital costs can be allocated on different bases, such as user's peak demand data, total installed capacity, etc. Present studies were completed using a single annual peak as a base. There are other options, such as the monthly peaks, an average of 12 monthly peaks, etc., which also need investigating.

4. There are various methods of breaking down annual transmission capital costs into short-term ones. For the present study the capital costs were divided by 8760, to obtain the hourly capital costs. This approach implies full capacity usage of the transmission lines around the year and does not consider the fact that for different hours of the year, the flows across transmission lines are different. Therefore other approaches, which consider the above-mentioned fact, should also be studied.

5. There are three options for estimating the MW changes due to a transaction: sum of the real values, only positive values and sum of the absolute values (for more information see Section 4.4.1). For the present study the last option was applied. Depending on the option selected, the calculation results can vary. Therefore the other two options should also be applied to case studies.

6.3 RECOMMENDATIONS FOR FURTHER STUDIES IN OTHER RELEVANT AREAS

The network and input data selection

More realistic and bigger networks should be selected for further investigation. A more realistic representation of the power system elements, such as generation units and their operating limits, capacity of transmission lines, etc., is needed. However, it is recommended that a restricted size rather than the real size of the network should be selected in order to avoid difficulties in the analysis and interpretation of results in a large, complex real system.

Reactive power

Reactive power flow is another complex and difficult aspect of evaluating transmission services that needs investigation. Reactive power and associated costs were beyond the consideration in the thesis, though it is recognised that reactive power flow affects both real line losses and voltage magnitudes. Special attention in future studies should be paid to reactive power transmission and to the analysis of associated costs. The SC-OPF software package again can be used in the proposed studies as it incorporates both active power and reactive power optimisation.

Voltage constraints

The present research analysed the cost effect of transmission constraints in the network. The transmission constraints can arise in two principal forms. The first form, which was investigated in this thesis, is the limit on the power flow on an individual line. The thermal capacity of a transmission line sets an upper limit on the power flow at that line. A second major source of congestion in a power network arises from voltage magnitude constraints at buses.

Even when power flows do not approach the thermal limits of the system and the transmission lines appear to have excess capacity, the voltage limits can constrain the transfer capacity and must be taken into account in the calculation of transmission costs. Therefore, voltage constraints inevitably require attention and further investigation for both the real and reactive power.

Security consideration

The present analysis does not explore the effect of transactions on the security of a power system. The costs of transmission transactions, beyond what is calculated from the considered methods, should also include consideration for operational and system security concerns.

Study tools

The effect of any change in the topology of the system (as a result of switching action or the outage of the system components) on the cost of transactions should be studied. The SC-OPF software package can be used again as it incorporates Switching analysis and Contingency analysis.

In order to estimate the actual cost of a transaction it is recommended that the SC-OPF be used in real time. It is also recommended that further studies should be done in using OPF from other programs such as Power System Simulator for Engineers (PSS/E).

Ancillary services

Ancillary services are those services necessary for the operation of a power system. Ancillary services, mandatory or voluntary, can be offered separately and priced individually. The present study considers only the primary transmission service – a transmission transaction. Ancillary services were beyond the scope of this thesis. However, as electric utilities unbundle their services and deregulate their structure, the important issue arises: how to provide and to price the ancillary services. These aspects need special investigation.

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APPENDIX I

IMPLEMENTATION THE TOA POLICY IN SELECTED COUNTRIES

AI.1 ARGENTINA

Argentina is a country with a 9000 MW peak demand and over 40 % of installed capacity as hydro capacity. In 1992, Argentina passed a new electricity law that incorporated an open access scheme for the transmission system and competition on generation supply levels. Thus, the electricity industry in Argentina has undertaken a very deep restructuring from a 100 percent state owned integrated activity to a true market of electricity, in which more than 70 free private agents operate, such as generation, transmission and distributions companies and big customers [22].

In Argentina, according to the established procedure for access, any third-party request is analysed by the dispatching body. The dispatching body is an association of generators, transmission company, distributors, large consumers and the State. The regulator, based on studies, submits the request to a public hearing and finally is responsible for approving it [3].

The transmission business is paid on a cost-plus basis through a two-part tariff [5]. The first part is the marginal cost based for the transmission system. It is evaluated using an hourly model analysis. Since the marginal cost pricing recovers less than the full revenue required, the remainder is raised through a supplementary charge. The second part of the tariff supplements the revenue to finance the network. The allocation scheme defined for this supplement uses the "area of influence" concept. The area of influence is determined by identifying the transmission facilities physically affected by each power plant, irrespective of the commercial use of the network.

The supplement payment is distributed among those sharing areas of influence in accordance with the flows during peak system times. Charges are made only for the positive contributors to the power flow. The users whose flows are in the opposite direction do not pay. They are not rewarded for their contribution either.

AI.2 CHILE

It is considered that Chile is a world-wide leader in deregulating the power industry. The country establishes competition and creates such conditions in the electricity industry that allow an open access to the transmission system [23].

Chile is a country with a 3000 MW peak demand and over 80 % installed capacity as hydro capacity. It started a restructuring process in 1979 that led to a new electricity law in 1989, incorporating an open access that was a basic tool of the deregulation of the electric power sector. Now over 85% of generation facilities and almost 100% of the transmission and distribution systems are privately owned in Chile, forming an essentially decentralised power sector. The competition and decentralisation policy applied in Chile for the electricity generation sector is based on free entry of generators, distributors and big customers [5].

The regulation establishes a fee structure for transmission pricing based on a two-part tariff scheme. A first part of the tariff is short-run marginal cost based and takes into consideration only the marginal cost of losses. It does not represent the cost of network constraints.

The tariff based on the marginal cost gives the transmission systems' owners a yearly income which is not sufficient to cover the total cost of these systems. A study done by H. Rudnick showed that income obtained through short-term marginal costs in the Chilean system is about 14 % of the required annual revenue for financing the transmission network [14]. To solve this problem, supplementary payments are applied. These payments correspond to the difference between the total yearly cost of the transmission system and the net income yielded by tariffs. The supplementary payments are calculated based on the area of influence of each individual generator [3].

According to the approach of the influence area, any agent of the system must participate with its proportional part in financing a facility if it modifies the operating conditions of that facility. Zones of influence are determined by the load flow simulations [14].

The Chilean law indicates that supplementary payments for each line should be allocated among generators, in proportion to the maximum transported power [5]. In this case the payments are made only by the customers that contribute to the positive direction of flow at maximum flow pay. The customers that contribute in the negative direction do not pay, nor they are rewarded for their contribution.

AI.3 COLOMBIA

The Colombian electricity sector was deregulated in 1994 with plans to incorporate transmission open access to the transmission system, which is partially owned by the State company and partially owned by regional utilities. According to a new electricity law, the transmission company provides the transmission service, investing when no capacity is available. Transmission business is regulated with the purpose of financing the development of the network [3].

Transmission pricing in Colombia is based on long-range marginal cost methodology [5]. It is based on the current use of the network and the transmission capacity that is needed when the transmission system is most heavily used. Transmission charges are calculated at times of peak flow.

AI.4 NEW ZEALAND

The New Zealand power system is dominated by hydro generating capacity. The government in New Zealand deregulated and privatised the Electricity Supply Industry in 1987 [3]. At the time of privatisation, the industry was divided into a transmission company TransPower and a generation and distribution company.

TransPower is a National Grid company and is responsible for system operations and for maintenance and investment in the system. TransPower, as an independent party, acts as National Reconciliation Manager. It contracts with distributors for connection to the grid. Energy traders gain access to transmission and distribution through use of system agreements with distributors. All transmission and distribution contracts have to be disclosed.

In order to provide an environment within which private generation can enter the electricity market, market based pricing has been established, which includes a marginal cost based approach to transmission services. TransPower pricing policy is based on cost recovery and the philosophy of "user pays". Costs are identified with specific assets and services provided by TransPower. A large portion of TransPower revenue requirement is not directly attributable to specific users and it is allocated between all users of the network.

The transmission tariff is based on the three elements or charges: the network charge, the capacity charge and the energy charge [5].

1. <u>The network charge</u>

   It is a fixed charge intended to recover the fixed costs of the existing network on a historical usage basis. This charge is calculated based on the distance between load and generation, and on the power flows at times of system peak. It is payable by distributors and direct supply customers.

2. <u>The capacity charge</u>

   This charge reflects "the common good aspects" of the grid, regardless of the location. Capacity charge is calculated on the two highest half an hour peaks occurring at any time in each day during the winter weekday.

3. The energy charge

   This is a variable transmission charge. The energy charge comprises mainly the charge for marginal losses at each connection point. Presently, TransPower calculates transmission losses over typical scenarios to give average transmission losses.

Other transmission related charges, reflecting the network constraints, dispatch, spinning reserves and reactive support, are currently under revision.

AI.5 NORWAY

The Norwegian generating system is exclusively hydro-electric. More than half of the generated power is fed directly into the main grid. There are about 30 owners of the main grid and only one operator, the Norwegian Power Grid Company which owns about 80 % of the Main Grid [24].

The Norwegian Power Grid Company is also the owner of the Norwegian power pool, which is an important centre in the electricity market. The power pool is a separate company through which power is bought and sold on an hourly basis [25]. In 1993 about 17 % of total sales in Norway were traded in this market. The remaining sales are conducted through bilateral contracts. Therefore, wholesale operators can purchase electricity through free contracts with producers or in a pool where prices are based on bids.

The new Norwegian Energy Act came into force in 1991, providing one of the most extensively deregulated electricity markets in the world. The new Energy Act has provided an open access to the network. A deliberate division has been established between the service of transporting electricity and the product electricity as such. Accordingly, the new pricing principles for transmission of electricity have been introduced, such as [24]:

- Both generators and consumers have to pay for the use of the network system.

- The price, which gives access to the network, refers to the connection point where the individual user is connected to the system.
- Typical power flows and the loading of the system are taken into account when tariffs are calculated.

The objectives of deregulation in Norway are to improve utilisation of the resources of the electricity sector and to ensure that investment signals are adequate. The system is now working as a competitive market in both generation and supply with new players such as brokers and traders in electricity.

The transmission grid is managed by a public company and its costs are shared among users through a tariff with fixed and variable terms. The fixed elements are the connection element and the power element. The variable elements are the energy element and capacity element.

1. The connection element

   It is a fixed element, based on the consumption for the whole country, peak demand and available generating capacity. The connection element is particularly intended to reflect costs related to the reliability of the main grid and operating co-ordination.

2. The power element

   This element constitutes the power exchange for each connection point during the peak load hour. The measured amount of power is adjusted for available (unused) capacity.

3. The energy element

   It is based on marginal losses. In order to determine marginal losses, the country is divided into several areas with a surplus and deficit for power. For each of the areas there are special energy tariffs.

4. The capacity element

   This element is applied when bottlenecks occur in the network. Such bottlenecks can occur due to operating interruptions, such as maintenance. The capacity charge is calculated as the difference between two spot prices: one is based on unlimited capacity, the other on real available capacity.

AI.6 PERU

In Peru the peak demand is around 2000 MW and over 70 % of installed capacity is hydro capacity. In 1993 the Peruvian electricity sector was deregulated and competition was introduced at the generation level, with open access at the transmission level. The ownership of the main grid was assigned to an independent utility, with distributors or generators forbidden to control it [5].

According to a new law, the transmission company must provide the transmission service, investing where no capacity is available. Transmission business is regulated with the purpose of financing the development of the network and assuring the competitiveness of the market. The payments for the usage of the transmission system are determined through marginal cost pricing and a global allocation of network costs. The transmission pricing scheme is based on marginal short-term cost of transmission services with a supplement charge [3].

The supplement charge is paid as a connection charge, based on firm power capacity of each generator. The supplementary charge is calculated using the Postage Stamp concept. It is independent of commercial contracts [26]. The charge allocation is determined by the pool, with participation of generators and main transmission line owners. Transmission assets and related costs are evaluated by the regulatory agency.

AI.7 SWEDEN

In Sweden the existing generating capacity is mainly hydroelectric. There are a few large producers, dominated by the state-owned Vattenfall with around 50% of the annual generation [5].

The entire Swedish utility industry is in the early stages of a restructuring process toward greater competition and less government control. The process was initiated in 1990 and since then several Electricity Acts have been implemented by the Swedish Parliament. A new state authority, Swedish National Grid, was formed with the objective to own and operate the grid. Further directives were given by the government to allow open access to the National Grid and to support competition.

Therefore, the main points of the new policy are:

- all networks within the country are opened for access by paying fees.
- the network service is unbundled from generation and sales.
- Swedish National Grid is designed as the System Operator with responsibility for system security and frequency control.

The National Grid is paid through tariffs, which are designed as point charges. The regional grid owners that are directly connected to the main transmission system carry the costs of the National Grid.

The principal cost elements of the National Grid are:

- depreciation and financial expenses
- contracted operation and maintenance expenses
- purchase of power to cover for losses
- operational costs due to transmission constraints and reserves.

The tariff structure is mainly designed to cover capital and other costs to operate and maintain the grid in a secure and reliable manner. The transmission tariff is a combination of two elements: the capacity element and the energy element.

1. The capacity element

   It is charged according to the nominal maximum power level that is fed into or drawn from the main grid at the connection points. It is also related to the geographical location of the point in the grid.

2. The energy element

This element is charged according to the measured energy that is fed into or drawn from the grid. It is meant primarily to cover the costs of the grid losses that must be purchased from producers. The energy element is calculated based on the marginal loss factor in each point.

AI.8 UK: ENGLAND AND WALES

On 31 March 1990 the structure of the electricity supply industry in England and Wales underwent a radical change. Prior to that date the electricity supply industry was nationalised. The 1990 Electricity Act introduced privatisation and provided for competition in generation and supply [27,28].

The National Grid Company (NGC) was formed to link generators, distributors and consumers both physically and commercially. NGC is an independent transmission company which owns and operates the main 400 kV and 275 kV transmission system in England and Wales. National Grid is not allowed to buy or sell electricity and is not therefore a player in the primary energy market [29].

NGC provides services to the market in England and Wales, that can be broadly classified as 'hardware' services, i.e. provision and maintenance of the transmission lines, transformers, voltage control devices etc., and 'software' services such as voltage and frequency control, economic dispatch, information and data provision for settlements and the organisation of ancillary services.

The National Grid is a commercial company providing a monopoly service that is subject to regulation. The transmission grid is paid on a cost-plus basis using the Long Run Marginal Cost approach [30]. The transmission costs are shared among users through two categories of charges: the connection charges and the use of system charges.

1. The connection charges

   The connection charges are the Entry Charges and the Exit Charges. The Entry and Exit charges are calculated for the entry and exit points. An entry point is defined as a location in the system where a customer exports power to the grid. An exit point is defined as a location in the system where a customer takes power from the grid. These charges reflect the capital costs of providing the equipment required for each connection.

2. The use of system charges

   The use of system charges are the System Service Charges and the Infrastructure Charges.

   System service charges reflect the base costs of operating and maintaining a "skeletal" network of NGC assets, which are deemed to ensure stable voltage and frequency standards as prescribed by the Electrify Act of 1989. The charge is calculated by reference to actual peak demand.

   Infrastructure Charges reflect the cost of installing, operating and maintaining the transmission system, according to the standards prescribed by the NGC licence, for the purpose of accommodating bulk power transfer and providing system security. The calculation of the Infrastructure Charge, especially with respect to the location of demand and supply is based on typical patterns of power flows in the network.

Transmission charges set by the NGC are given for 14 zones, rather than the 249 nodes on the system. They are based on the customer's maximum level of demand throughout the winter months. Electricity in England and Wales is traded through the Power Pool. The National Grid Company, which owns the transmission wires, has several roles in the Pool:

- it performs the dispatch of energy as Grid Operator.

- it supplies operational information to the Pool.
- it computes and publishes the Pool prices.

AI.9 UNITED STATES

The electric power industry in the USA is mainly privately-owned. Some 230 investor-owned utilities (IOUs) produce about 75 % of electricity generated [31]. The IOUs are vertically-integrated with generation, transmission and distribution functions. The large synchronised transmission networks in North America are owned by multiple parties. There are more than 200 owners of transmission systems in five North American networks and more than 150 dispatch centres [1]. The networks are interconnected by tie lines for overall system security purposes and trade in power.

J. Casazza, in describing the history of Transmission Open Access, pointed out that "third-party access has been practised for almost 85 years in the USA, where there are almost 200 owners of transmission systems in five North American synchronous networks, and for almost 50 years in western Europe, where there is also a large number of transmission owners in a single network" [32]. The annual saving from the co-operative development and use of the transmission is approximately $20 billion annually. Two-thirds of these savings have resulted from reduction in the investments required and one-third from fuel cost saving.

Table A.1 shows that more than 71 % of the transmission system belongs to IOUs [31]. However, there have been trends away from the traditional prevalence of the IOUs in generation ownership. Although the federal, co-operative and non-federal systems account for a relatively small share of total generation, there has been growth in their relative size in recent years. The transmission services provided to third parties by utilities grew 195 % from 1976 to 1989 [33].

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[1] In Canada, most of the utilities are publicly-owned. Eight provincial-owned utilities produce more than 80% of electricity generated, and IOUs about 7.5%. As a result, there are a few Independent Power Producers [31].

Table AI.1: Breakdown of ownership of transmission in USA electric industry

Investor-owned utility	71%
Federal (National) Government State or Province Municipality Co-operatives Other	29%

In 1992 Congress amended the Energy Policy Act (EPACT) requiring transmission utilities to provide wholesale transmission services. Regarding electricity transmission, the EPACT provides that the Federal Energy Regulatory Commission[2] (FERC) can order a utility with transmission to transmit power for a wholesale seller or buyer and order an expansion of transmission facilities if needed to comply with the service applied for [34]. However, for retail transactions, the FERC does not have power to order retail access (non-firm services), so that only the states have the authority to order it.

The FERC accepted marginal cost based pricing in principal, however many utilities still utilise embedded (accounting) cost based pricing. Some utilities still employ the Contract Path approach for pricing transmission services. They are paid for the contracted power transfer, regardless of whether the power is actually transported through the contacting companies or not. The other practice used by the FECR for wheeling transactions are the rules "OR" and "AND". The rule "OR" allocates the cost of a transaction as the highest of the embedded and the incremental cost. The rule "AND" allocates the sum of embedded and incremental costs to a wheeling transaction.

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[2] FERC regulates interstate transmission transactions and retail sales of electricity in the USA.

APPENDIX II

SPOT PRICING METHODOLOGY

Spot pricing is an approach to electricity pricing, reflecting the underlying physical and engineering properties of electricity supply systems. The main assumption of the theory of spot pricing is that the supplier can set and communicate prices instantly, and can set a different price for each customer location at each moment of time.

AII.1 DEFINITION OF HOURLY SPOT PRICE:

The hourly spot price is determined by the supply-demand conditions that exist at that hour's:

- Demand (in total and by location)
- Generation availability and costs
- Transmission/distribution network availability and losses.

An hourly spot price can be quantified in various ways. The basic approach, given by Schweppe is [19]:

$\rho_k(t)$ Marginal (or incremental) cost of providing electrical energy to customer κ during hour t taking into consideration both operating and capital costs ($/MWh).

The hourly spot price (without revenue reconciliation) is given by the marginal cost:

$$\rho_k(t) = \frac{\partial\left[\text{Total cost of providing electric energy to all customers}\right]}{\partial d_k(t)} \qquad \text{(AII.1)}$$

where:

$d_k(t)$ demand of customer k during hour t

The derivative (A.1) is evaluated subject to constraints such as:

- Energy Balance: Total generation equals total demand plus losses.
- Generation Limits: Total demand during hour t cannot exceed the capacity of all the power plants available at hour t.
- Kirchhoff's Laws: Energy flows and losses on a network are specified by physical laws.
- Line Flow Limits: Energy flows over a particular line cannot exceed specified limits without causing system operating problems.

AII.2 COMPONENTS OF HOURLY SPOT PRICE

The hourly spot price associated with the *k* customer during hour *t* is viewed as the sum of individual components defined by:

$$\begin{aligned}
\rho_k(t) \quad = \quad & \gamma_F(t) && \text{[Generation Marginal Fuel]} \\
+ \quad & \gamma_M(t) && \text{[Generation Marginal Maintenance]} \\
+ \quad & \gamma_{QS}(t) && \text{[Generation Quality of Supply]} \\
+ \quad & \gamma_R(t) && \text{[Generation Revenue Reconciliation]} \\
+ \quad & \eta_{L,k}(t) && \text{[Network Marginal Losses]} \\
+ \quad & \eta_{QS,k}(t) && \text{[Network Quality of Supply]} \\
+ \quad & \eta_{R,k}(t) && \text{[Network Revenue Reconciliation]} \qquad \text{(AII.2)}
\end{aligned}$$

The components of (AII.2) are often combined into groups such as:

$$\begin{aligned}
\lambda(t) &= \gamma_F(t) + \gamma_M(t) && \text{[System Lambda]} \\
\gamma(t) &= \lambda(t) + \gamma_{QS}(t) && \text{[Marginal Value of Generation]} \\
\eta(t) &= \eta_{L,k}(t) + \eta_{QS,k}(t) && \text{[Marginal value of Network Operation]} \qquad \text{(AII.3)}
\end{aligned}$$

AII.3 APPLICATION OF SPOT PRICES FOR TRANSMISSION PRICING

Given the spot price for each bus, the marginal cost of a transmission transaction *k* between buses *b* (buyer) and *s* (seller) may be computed as [63]:

$$MC_k = (\rho_b - \rho_s)P_k \tag{AII.4}$$

where

MC_k the marginal cost of the transaction from bus *s* to bus *b*

P_k the amount of the transmission transaction from bus *s* to bus *b*

ρ_b the spot price at bus *b*

ρ_s the spot price at bus *s*

For a transaction with multiply points of injection and supply the marginal cost may be computed as [44]:

$$SRMC_k = \sum_{i}^{n} \Delta P_i \, \rho_i \tag{AII.5}$$

where:

k the index for transactions

n the number of buses engaged in the transaction

ΔP_i the change in injection at bus i.

APPENDIX III

INPUT DATA FOR 18-BUS SYSTEM

Table AIII.1: Line data

No.	Bus No	kV.	R p.u.	X p.u.	Cap.MW	Length km	Cost, ml$/km	Cost, ml$	Cost $/MW	Cost $/MWh
101	1-2	765	0.00088	0.01995	2000	437	0.1	43.7	21850	2.4
102	1-2	765	0.00088	0.02004	2000	435	0.1	43.5	21750	2.5
103	3-4	400	0.00028	0.00776	1000	38	0.05	1.9	1900	0.22
104	3-6	400	0.00166	0.02272	2000	112	0.05	5.6	2800	0.32
105	3-7	400	0.04415	0.29664	500	1464	0.05	73.2	146400	16.02
106	4-5	400	0.0006	0.00108	2000	6	0.05	0.3	150	0.016
107	4-5	400	0.0006	0.0011	2000	6	0.05	0.3	150	0.016
108	4-7	400	0.08126	0.56332	500	2780	0.05	139	278000	14.49
109	6-7	400	0.00221	0.04854	1000	284	0.05	14.2	14200	1.42
110	6-7	400	0.00152	0.01295	1000	284	0.05	14.2	14200	1.42
111	7-8	400	0.00286	0.0141	500	188	0.05	9.4	18800	2.15
112	7-17	400	0.0038	0.04799	500	244	0.05	12.2	24400	2.79
113	7-17	400	0.00182	0.01287	500	244	0.05	12.2	24400	2.79
114	8-9	400	0.00243	0.00917	500	164	0.05	8.2	16400	1.87
115	9-10	400	0.00251	0.0102	500	168	0.05	8.4	16800	1.92
116	10-11	400	0.00253	0.01079	500	170	0.05	8.5	17000	1.94
117	11-12	400	0.00249	0.03134	500	164	0.05	8.2	16400	1.89
118	12-13	400	0.0013	0.017	500	88	0.05	4.4	8800	1.92
119	13-14	400	0.0006	0.0081	500	40	0.05	2	4000	0.47
120	13-14	400	0.00062	0.00804	500	40	0.05	2	4000	0.47
121	13-14	400	0.00119	0.01329	500	44	0.05	2.2	4400	0.51
122	14-15	400	0.0017	0.0217	500	110	0.05	5.5	11000	1.26
123	14-17	400	0.00594	0.0417	500	210	0.05	10.5	21000	2.92
124	15-16	400	0.00131	0.01597	500	82	0.05	4.1	8200	0.94
125	15-17	400	0.00597	0.03827	500	226	0.05	11.3	22600	2.58
126	15-18	400	0.00742	0.04229	500	250	0.05	12.5	25000	2.85
127	17-18	400	0.0068	0.0393	500	216	0.05	11.3	22600	2.58
Total					22500	8492		444.9		

Table AIII.2: Generation data

Generar No.	Bus No.	Pmin MW	Pmax MW	Qmin MVAR	Qmax MVAR	a	C.cff b	c
401	3	345	3450	-1500	1300	1.05	1.5	0.0015
402	4	250	2500	-450	1085	1.05	1.5	0.0015
403	13	1800	1800	-1260	666	2.25	1.6	0.0014
404	16	0	400	-250	300	1.3	1.35	0.004
	Total		8150					

Table AIII.3: Load data

Load No.	Bus No.	P Peak MW	Q Peak MVAR	P Average MW	Q Average MVAR	P Min MW	Q Min MVAR
501	3	465	50	325	35	232	25
502	4	1070	100	750	75	535	50
503	6	2280	200	1596	160	1140	100
504	7	1280	120	896	90	640	60
505	9	120	12	84	8	60	6
506	10	40	4	28	3	20	2
507	12	180	18	126	12	90	9
508	13	570	57	400	40	285	28
509	14	950	95	665	66	475	47
510	15	200	20	140	14	100	10
512	18	300	30	210	21	150	15
	Total	7455	759	5220	505	3727	250

APPENDIX IV

OUTPUT DATA FOR 18-BUS SYSTEM

OUTPUT DATA FOR BASE CASE

Table AIV.1: Generation and total cost

	Min		Aver		Peak	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	958.7	10236.02	1689.5	22605.45	3116	48595.91
402	956	11590.9	1687.8	23977.86	2500	38477.5
403	1800	31073	1800	31073	1800.1	31074.03
404	50	467	89.5	1110.46	184	2903.12
Total	3764.7	53366.92	5266.8	78766.76	7600.1	121050.56

Table AIV.2 Bus incremental cost, $/MWh

Bus N.	Min	Aver	Peak
1	16.51	17.42	19.22
2	16.58	17.64	19.9
3	16.49	17.36	19.08
4	16.49	17.37	19.08
5	16.49	17.38	19.11
6	16.59	17.68	20.07
7	16.51	17.82	21.13
8	16.34	17.74	21.25
9	16.19	17.67	21.35
10	15.99	17.53	21.31
11	15.78	17.37	21.24
12	15.58	17.22	21.14
13	15.44	17.08	20.99
14	15.53	17.17	21.09
15	15.67	17.26	21.08
16	15.51	17.09	20.86
17	16.23	17.65	21.18
18	16.11	17.69	21.57

OUTPUT DATA FOR T1, MIN. LOAD

Table AIV.3 Generation and total cost

	100MW		200MW		300MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	960.3	10263.47	962.3	10296.37	964.7	10335.56
402	957.5	11615.63	959.5	11648.61	965.0	11689.85
403	1800	31073	1800	31073	1800	31073
404	49.5	459.26	49	451.52	48.5	443.8
Total	3767.3	53411.36	3770	53469.5	3775.2	53542.2

	400MW		500MW		600MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	968	10389.34	984.3	10659.28	987.8	10716.26
402	965	11739.34	981.5	12011.72	985	12069.54
403	1800	31073	1800.	31073	1800	31073
404	47.5	428.38	20	20	20	20
Total	3780.5	53630.05	3785.8	53764	3792.8	53878.8

	700MW		800MW		900MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	991.7	10781.29	996.1	10853.94	1001	10935.03
402	989	12135.63	993.5	12210.02	998.4	12290.24
403	1800	31073	1800	31073	1800	31073
404	20	20	20	20	20	20
Total	3800.7	54009.93	3809.6	54156.96	3819.3	54318.27

	1000MW	
Bus N.	**MW**	**Cost, $/h**
401	1006.4	11025.34
402	1003.7	12378.98
403	1800	31073
404	20	20
Total	3830.2	54497.31

Table AIV.4 Bus Incremental Cost, $/WMh

Bus N.	**100MW**	**200MW**	**300MW**	**400MW**	**500MW**	**600MW**	**700MW**
1	16.51	16.51	16.51	16.52	16.54	16.54	16.55
2	16.59	16.59	16.59	16.6	16.62	16.63	16.53
3	16.49	16.49	16.49	16.5	16.52	16.52	16.53
4	16.49	16.49	16.49	16.5	16.52	16.52	16.53
5	16.49	16.5	16.5	16.5	16.52	16.53	16.53
6	16.6	16.6	16.6	16.61	16.63	16.64	16.65
7	16.51	16.52	16.52	16.53	16.55	16.56	16.57
8	16.31	16.27	16.24	16.21	1998.51	2990.37	6158.8
9	16.12	16.06	15.99	15.92	3287.40	4060.84	13318.55
10	15.89	15.79	15.69	15.59	4264.81	10899.5	20277.5
11	15.65	15.52	15.39	15.26	1410.43	2124.32	2008.6
12	15.51	15.43	15.35	15.26	7329.88	11005.21	20867.48
13	15.39	15.34	15.29	15.24	4939.85	7419.26	17475.32
14	15.49	15.44	15.4	15.35	4544.23	6825.74	10649.16
15	15.64	15.62	15.59	15.57	3120.32	4689.45	1820.65
16	15.48	15.46	15.43	15.41	3120.48	4689.61	1820.82
17	16.25	16.26	16.28	16.29	11735.88	17615.87	27120.88
18	16.11	16.11	16.1	16.1	2233.89	3359.72	1917.91
Lines Overloaded					Line 115 2% Line 116 8%	Line 114 1% Line 115 14% Line 116 19%	Line 111 10% Line 114 11% Line 115 25% Line 116 30% Line 119 2% Line 120 3% Line 122 1%

OUTPUT DATA FOR T1, AVERAGE LOAD

Table AIV.5 Generation and total cost

	100MW		**200MW**		**300MW**	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	1690.5	22622.83	1692.	22648.94	1694.	22683.61
402	1688.9	23996.73	1690.4	24022.54	1692.4	24057.57
403	1800	31073	1800.0	31073	1800	31073
404	89	1101.92	88.5	1093.4	88	1084.88
Total	5268.4	78794.48	5270.9	78837.88	5274.4	78899.06

	400MW		**500MW**		**600MW**	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	1696.5	22726.98	1699.5	22778.71	1707.5	22918.14
402	1694.8	24099.29	1697.6	24147.58	1705.7	24289.43
403	1800	31073	1800	31073	1800	31073
404	87.5	1076.38	87	1067.88	77.1	902.42
Total	5278.8	78975.64	5284.1	79067.17	5290.4	79182.99

	700MW		**800MW**		**900MW**	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	1740.1	23485.86	1744.1	23555.69	1748.8	23636.81
402	1738.5	24859.52	1742.5	24929.23	1747	25007.69
403	1800	31073	1800	31073	1800	31073
404	20	20	20	20	20	20
Total	5298.6	79438.38	5306.6	79577.93	5315.8	79737.49

	1000MW	
Bus N.	**MW**	**Cost, $/h**
401	1753.5	23719.21
402	1752.5	25102.87
403	1800	31073
404	20	20
Total	5326	79915.08

Table AIV.6 Bus Incremental Cost, $/MWh

Bus N.	100MW	200MW	300MW	400MW	500MW	600MW	700MW
1	17.42	17.42	17.43	17.43	17.43	17.44	17.48
2	17.64	17.65	17.65	17.66	17.66	17.68	17.72
3	17.36	17.37	17.37	17.37	17.38	17.38	17.42
4	17.37	17.37	17.37	17.37	17.38	17.39	17.43
5	17.38	17.38	17.39	17.39	17.39	17.4	17.44
6	17.68	17.68	17.69	17.7	17.7	17.72	17.76
7	17.82	17.83	17.84	17.85	17.86	17.88	17.93
8	17.7	17.67	17.64	17.61	17.58	17.8	1999.97
9	17.6	17.53	17.46	17.4	17.33	17.67	3288.27
10	17.43	17.32	17.22	17.12	17.02	17.5	4263.27
11	17.23	17.1	16.96	16.83	16.7	15.15	1408.96
12	17.14	17.06	16.98	16.9	16.82	15.86	7228.67
13	17.03	16.98	16.94	16.89	16.84	16.2	4938.46
14	17.13	17.09	17.05	17.01	16.96	16.38	4542.81
15	17.24	17.22	17.20	17.18	17.76	16.77	3118.84
16	17.07	17.04	17.02	17.00	16.98	16.59	3119.02
17	17.67	17.69	17.71	17.73	17.76	17.62	11735.02
18	17.69	17.69	17.69	17.7	17.7	17.45	2232.33
Lines Over-loaded							Line 115 2% Line 116 9%

OUTPUT DATA FOR T1, PEAK LOAD

Table AIV.7 Generation and total cost

	100MW		200MW		300MW	
B.N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	3116.8	48611.41	3118.8	48647.9	3121.4	48698.5
402	2500	38477.5	2500	38477.5	2500	38477.5
403	1800.1	31074.03	1800.1	31074.03	1800.1	31074.03
404	183.5	2892.7	183.0	2882.28	183	2882.28
Tot.	7600.4	121055.64	7601.8	121081.71	7604.5	121132.3

	400MW		500MW		600MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	3125.3	48773.65	3130.1	48863.68	3135.9	48975.77
402	2500	38477.5	2500	38477.5	2500	38477.5
403	1800	31074.03	1800.1	31074.03	1800.1	31074.03
404	183	2882.28	183.5	2892.7	184	2903.12
Total	7608.4	121207.46	7613.6	121307.9	7620	121430.41

	700MW		800MW		900MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	3134	48939.71	3060.6	47539.86	2989.1	46184.51
402	2500	38477.5	2500	38477.5	2500	38477.5
403	1800.1	31074.03	1800.1	31074.03	1800	31073
404	192.5	3081.93	264.2	4705.28	336.7	6551.05
Total	7626.6	121573.17	7624.8	121796.67	7625.8	122286.05

	1000MW	
Bus N.	**MW**	**Cost, $/h**
401	2930.4	45076.05
402	2500	38477.5
403	1800	31073
404	400	8332.8
Total	7630.4	122959.35

Table AIV.8 Bus Incremental Cost, $/MWh

Bus N.	100MW	200MW	300MW	400MW	500MW	600MW
1	19.22	19.22	19.23	19.23	19.24	19.25
2	19.9	19.91	19.22	19.93	19.94	19.96
3	19.08	19.08	19.08	19.09	19.09	19.1
4	19.08	19.08	19.09	19.09	19.1	19.1
5	19.11	19.12	19.12	19.12	19.13	19.14
6	20.08	20.08	20.09	20.11	20.12	20.15
7	21.14	21.16	21.18	21.22	21.27	21.33
8	21.2	21.16	21.13	21.12	21.11	21.11
9	21.25	21.16	21.08	21.02	20.97	20.92
10	21.17	21.03	20.91	20.8	20.7	20.61
11	21.05	20.87	20.71	20.55	20.41	20.28
12	21.03	20.93	20.85	20.77	20.71	20.65
13	20.92	20.87	20.83	20.8	20.78	20.76
14	21.04	20.99	20.96	20.94	20.92	20.92
15	21.06	21.04	21.04	20.05	21.06	21.09
16	20.84	20.82	20.82	20.82	20.84	20.87
17	21.21	21.25	21.3	21.36	21.44	21.53
18	21.58	21.59	21.62	21.67	21.72	21.79

Bus N.	700MW	800MW	900MW
1	19.25	19.16	19.98
2	19.97	19.89	19.82
3	19.1	19.01	18.92
4	19.1	19.01	18.93
5	19.14	19.05	18.96
6	20.16	20.09	20.03
7	21.4	21.39	21.39
8	21.16	21.47	1222.55
9	20.95	21.46	2003.64
10	20.61	21.35	2872.4
11	20.27	21.26	1063.74
12	20.82	22.77	2524.96
13	21.03	23.48	1076.01
14	21.2	23.74	836.1
15	21.44	24.29	27.12
16	21.21	24.06	26.89
17	21.98	25.24	7323.31
18	22.2	25.27	564.92
Lines Overloaded			Line 116 8%

OUTPUT DATA FOR T2, MIN LOAD

Table AIV.9 Generation and total cost

	100MW		200MW		300MW	
Bus N.	MW	Cost, $/h	MW	Cost, $/h, $/	MW	Cost, $/h
401	957.5	10216.21	956.6	10202.09	969	10407.29
402	954.5	11566.17	954	11557.93	966	11755.83
403	1800	31073	1800	31073	1800	31073
404	51	482.52	51.5	490.3	26.8	117.61
Total	3763	53337.9	3762.1	53323.32	3761.8	53353.73

	400MW		500MW		600MW	
Bus N.	MW	Cost, $/h	MW	Cost, $/h	MW	Cost, $/h
401	972.7	10467.31	973.8	10486.1	975.3	10510.95
402	970	11821.84	971.0	11838.34	972.5	11863.1
403	1800	31073	1800	31073	1800	31073.00
404	20	20	20	20	20	20
Total	3762.7	53382.15	3764.8	53417.44	3767.8	53467.06

	700MW		800MW		900MW	
Bus N.	MW	Cost, $/h	MW	Cost, $/h	MW	Cost, $/h
401	977.5	10546.94	980.0	10588.55	983.6	10646.88
402	974.5	11896.5	977.5	11945.65	980.8	12000.33
403	1800	31073	1800	31073	1800	31073
404	20	20	20	20	20	20
Total	3772.0	53536.44	3777.5	53627.2	3784.4	53740.22

	1000MW	
Bus N.	MW	Cost, $/h
401	987.6	10713.48
402	985	12069.54
403	1800	31073
404	20	20
Total	3792.6	53876.01

Table AIV.10 Bus Incremental Cost, $/MWh

Bus N.	**100MW**	**200MW**	**300MW**	**400MW**	**500MW**
1	16.5	16.5	16.52	16.52	16.52
2	16.58	16.58	16.59	16.6	16.6
3	16.48	16.48	16.5	16.5	16.5
4	16.48	16.48	16.5	16.5	16.51
5	16.49	16.49	16.5	16.51	16.51
6	16.59	16.59	16.6	16.61	16.61
7	16.51	16.51	16.52	16.53	16.53
8	16.37	16.41	16.33	765.16	225.82
9	16.26	16.33	16.19	1273.54	361.95
10	16.09	16.2	16.00	1839.06	513.32
11	15.91	16.05	15.78	6508.53	673.43
12	15.66	15.74	15.1	4175.1	1138.43
13	15.49	15.53	14.7	5117.81	7597.59
14	15.57	15.61	14.75	5273.7	7555.77
15	15.69	15.71	14.73	5835.02	7405.43
16	15.53	15.55	14.57	5835.18	7405.59
17	16.22	16.21	15.07	2437.31	7224.6
18	16.11	16.12	15.05	6183.97	7311.56
Lines Overloaded				113 109%	Line 113 18% Line 118 7%

OUTPUT DATA FOR T2, AVERAGE LOAD

Table AIV.11 Generation and total cost

	100MW		200MW		300MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	1688.5	22588.72	1688.5	22588.23	1689	22596.97
402	1687	23963.66	1686.7	23959.16	1687	23963.66
403	1800	31073	1800	31073	1800	31073
404	90.5	1127.56	91	1136.12	91.5	1144.7
Total	5266	78752.93	5266.2	78756.52	5267.5	78778.32

	400MW		500MW		600MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	1689.8	22610.44	1691	22631.53	1730.9	23325.43
402	1688	23981.03	1689.5	24007.04	1729.0	24694.02
403	1800	31073.	1800	31073	1800	31073
404	92	1153.28	92.5	4461.88	20	20
Total	5269.8	78817.75	5273	78873.44	5279.9	79112.46

	700MW		800MW		900MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	1733.8	23376.53	1737.1	23432.6	1742	23518.16
402	1732.	24746.27	1736	24815.96	1740	24885.66
403	1800	31073	1800	31073	1800	31073
404	20	20	20	20	20	20
Total	5285.8	79215.8	5293.1	79341.56	5302	79496.82

	1000MW	
Bus N.	**MW**	**Cost, $/h**
401	1747.2	23608.79
402	1745.5	24981.53
403	1800	31073
404	20	20
Total	5312.7	79683.33

Table AIV.12 Bus Incremental Cost, $/MWh

Bus N.	100MW	200MW	300MW	400MW	500MW	600MW
1	17.42	17.42	17.42	17.42	17.42	17.47
2	17.64	17.64	17.64	17.64	17.65	17.7
3	17.36	17.36	17.36	17.36	17.37	17.41
4	17.36	17.36	17.36	17.37	17.37	17.41
5	17.38	17.38	17.38	17.38	17.38	17.43
6	17.68	17.68	17.68	17.68	17.68	17.73
7	17.82	17.82	17.82	17.82	17.83	17.88
8	17.77	17.81	17.86	17.9	17.95	1009.15
9	17.74	17.82	17.9	17.98	18.07	1653.88
10	17.64	17.75	17.87	18.00	18.13	2370.95
11	17.52	17.66	17.82	17.99	18.16	4520.89
12	17.3	17.39	17.48	17.57	17.66	5331.17
13	17.13	17.18	17.23	17.28	17.34	2459.71
14	17.22	17.26	17.31	17.35	17.40	2262.14
15	17.28	17.3	17.33	17.35	17.38	1550.39
16	17.11	17.13	17.16	17.18	17.21	1550.56
17	17.63	17.62	17.61	17.6	17.59	695.71
18	17.69	17.69	17.69	17.7	17.71	1107.17
Lines Overloaded						Line 118 3%

OUTPUT DATA FOR T2, PEAK LOAD

Table AIV.13 Generation and total cost

	100MW		200MW		300MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	3116.3	48600.63	3117.7	48627.19	3119.9	48669.2
402	2500	38477.5	2500	38477.5	2500	38477.5
403	1800.1	31074.03	1800.1	31074.03	1800.1	31074.03
404	185	2924.00	186	2944.92	187.5	2976.38
Total	7601.3	121076.16	7603.7	121123.64	7607.4	121197.1

	400MW		500MW		600MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	3123.3	48734.64	3128.3	48830.83	3134.1	48940.43
402	2500	38477.5	2500	38477.5	2500	38477.5
403	1800.1	31074.03	1800.1	31074.03	1800.1	31074.03
404	189.5	3018.46	191.5	3060.7	194.5	3124.36
Total	7612.9	121304.63	7619.9	121443.05	7628.6	121616.31

	700MW		800MW		900MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	2907.9	44651.86	2919.8	448875.28	2934.3	45149.36
402	2500	38477.5	2500	38477.5	2500	38477.5
403	1800.1	31074.03	1800.1	31074.03	1800.1	31074.03
404	400	8332.8	400	8332.8	400	8332.8
Total	7608.0	122536.19	7619.8	122759.61	7634.4	123033.69

	1000MW	
Bus N.	**MW**	**Cost, $/h**
401	2952.3	45489.09
402	2500	38477.5
403	1800.1	31074.03
404	400	8332.8
Total	7652.4	123373.42

Table AIV.14 Bus Incremental Cost, $/MWh

Bus N.	100MW	200MW	300MW	400MW	500MW	600MW	700MW
1	19.22	19.22	19.23	19.23	19.24	19.25	18.97
2	19.9	19.91	19.91	19.92	19.94	19.96	19.69
3	19.08	19.08	19.06	19.08	19.09	19.1	18.83
4	19.08	19.08	19.08	19.09	19.09	19.1	18.83
5	19.11	19.12	19.12	19.12	19.13	19.14	18.86
6	20.07	20.08	20.09	20.10	20.12	20.14	19.88
7	21.13	21.15	21.17	21.21	21.26	21.33	21.11
8	21.31	21.38	21.47	21.58	21.7	21.86	8017.12
9	21.46	21.59	21.73	21.9	22.1	22.33	16359.15
10	21.47	21.65	21.85	22.08	22.34	22.65	15642.79
11	21.44	21.67	21.92	22.2	22.53	22.91	14884.9
12	21.25	21.39	21.54	21.71	21.9	22.13	12681.73
13	21.06	21.14	21.24	21.35	21.49	21.64	2498.19
14	21.15	21.23	21.32	21.43	21.55	21.7	2300.55
15	21.12	21.16	21.22	21.29	21.39	21.5	1588.73
16	20.9	20.94	21.00	21.07	21.16	21.27	1588.5
17	21.16	21.15	21.15	21.17	21.21	21.26	734.16
18	21.58	21.6	21.63	21.67	21.74	21.83	1146.24
Line Over-loaded							Line 111 4% Line 114 2% Line 118 9%

OUTPUT DATA FOR T3, MIN LOAD

Table AIV.15 Generation and total cost

	100MW		**200MW**		**300MW**	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	960.6	10268.7	962.9	10305.46	966	10357.14
402	958	11623.88	960.5	11665.11	963.2	11708.84
403	1800	31073	1800	31073	1800	31073
404	49	451.52	48	436.08	47	420.68
Total	3767.6	53417.1	3771.4	53479.65	3776.2	53559.66

	400MW		**500MW**		**600MW**	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	982	10620.73	985.1	10672.9	989	10737.09
402	979.1	11971.35	982.5	12028.23	986.1	12087.88
403	1800	31073	1800	31073	1800	31073
404	20	20	20	20	20	20
Total	3781	53685.08	3787.6	53794.13	3795.1	53917.97

	700MW		**800MW**		**900MW**	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	993.1	10804.84	998	10885.65	1003.5	10976.58
402	990.5	12160.42	995.4	12241.6	1001.0	12333.54
403	1800	31073	1800	31073	1800	31073
404	20	20	20	20	20	20
Total	3803.6	54058.26	3813.4	54220.24	3824.5	54403.12

	1000MW	
Bus N.	**MW**	**Cost, $/h**
401	1009.9	11082.44
402	1007	12433.31
403	1800	31073
404	20	20
Total	3836.9	54608.75

Table AIV.16 Bus Incremental Cost, $/MWh

Bus N.	100MW	200MW	300MW	400MW
1	16.51	16.51	16.51	16.53
2	16.59	16.59	16.6	16.62
3	16.49	16.49	16.5	16.51
4	16.49	16.49	16.5	16.52
5	16.5	16.5	16.5	16.52
6	16.6	16.6	16.61	16.63
7	16.51	16.52	16.52	16.55
8	16.37	16.41	16.44	15734.57
9	16.17	16.16	16.14	3287.93
10	15.93	15.86	15.79	4264.93
11	15.67	15.55	15.43	1998.97
12	15.51	15.42	15.34	7330.39
13	15.38	15.32	15.26	4940.23
14	15.48	15.42	15.36	4544.23
15	15.63	15.58	15.54	3120.62
16	15.47	15.43	15.38	3120.78
17	16.22	16.2	16.19	1410.69
18	16.09	16.06	16.03	2234.17
Lines Overloaded				Line 115 5% Line 116 10%

OUTPUT DATA FOR T3, AVERAGE LOAD

Table AIV.17 Generation and total cost

	100MW		200MW		300MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	1690.6	22625.2	1692.5	22657.55	1695.0	22701.05
402	1689	23998.39	1690.9	24031.7	1693.1	24070.31
403	1800	31073	1800	31073	1800	31073
404	89	1101.92	88	1084.88	87	1067.88
Total	5268.6	78798.51	5271.4	78847.13	5275.1	78912.25

	400MW		500MW		600MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	1697.7	22747.51	1734	23379.29	1737.2	23435.27
402	1696	24119.99	1732.4	24752.73	1735.5	24807.25
403	1800	31073	1800	31073	1800	31073
404	86	1050.92	20	20	20	20
Total	5279.7	78991.42	5286.4	79225.02	5292.7	79335.51

	700MW		800MW		900MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	1741	23500.83	1745.5	23580.19	1750.5	23666.17
402	1739.4	24874.54	1743.6	24948.35	1748.6	25035.65
403	1800	31073	1800	31073	1800	31073
404	20	20	20	20	20	20
Total	5300.3	79468.38	5309.1	79621.54	5319.1	79794.82

	1000MW	
Bus N.	**MW**	**Cost, $/h**
401	1756.1	23764.48
402	1754.5	25138.49
403	1800	31073
404	20	20
Total	5330.6	79995.97

Table AIV.18 Bus Incremental Cost, $/MWh

Bus N.	**100MW**	**200MW**	**300MW**	**400MW**	**500MW**
1	17.42	17.42	17.43	17.43	17.48
2	17.65	17.65	17.65	17.66	17.71
3	17.36	17.37	17.37	17.37	17.42
4	17.37	17.37	17.37	17.38	17.42
5	17.38	17.38	17.39	17.39	17.43
6	17.68	17.69	17.69	17.7	17.75
7	17.82	17.83	17.84	17.85	17.91
8	17.78	17.82	17.86	17.91	7876.86
9	17.65	17.64	17.63	17.63	1653.39
10	17.46	17.4	17.34	17.27	2369.97
11	17.26	17.14	17.02	16.91	1009.15
12	17.14	17.06	16.99	16.91	3655.6
13	17.03	16.97	19.91	16.86	2460.63
14	17.12	17.07	17.02	16.97	2262.78
15	17.22	17.19	17.15	17.11	1550.79
16	17.05	17.01	16.98	16.94	1550.97
17	17.64	17.63	17.62	17.61	695.72
18	17.66	17.64	17.62	17.6	1107.36
Lines Overloaded					Line 116 5%

OUTPUT DATA FOR T3, PEAK LOAD

Table AIV.19 Generation and total cost

	100MW		200MW		300MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	3117.5	48624.73	3120.2	48676.32	31235	48737.66
402	2500	38477.5	2500	38477.5	2500	38477.5
403	1800.1	31074.03	1800.1	31074.03	1800.1	31074.03
404	183	2882.28	182	2861.48	181.5	2851.1
Total	7600.6	121058.53	7602.3	121089.33	7605.0	121140.28

	400MW		500MW		600MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	3128.1	48826.52	3133.6	48931.24	3140.6	49064.4
402	2500	38477.5	2500	38477.5	2500	38477.5
403	1800.1	31074.03	188.1	31074.03	1800.1	31074.03
404	181	2840.72	181	2840.72	181	2840.72
Total	7609.2	121218.76	7614.7	121323.49	7621.6	121456.64

	700MW		800MW		900MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	3344.6	52986.8	3357.1	53229.1	3373.1	53538.32
402	2500	38477.5	2500	38477.5	2500	38477.5
403	1800	31073	1800	31073	1800	31073.0
404	20	20	20	20	20	20
Total	7664.6	122557.3	7677.1	122799.62	7693.1	123108.82

	1000MW	
Bus N.	**MW**	**Cost, $/h**
401	3394.1	53947.22
402	2500	38477.5
403	1800	31073
404	20	20
Total	7714.1	123517.72

Table AII.20 Bus Incremental Cost $/MWh

Bus N.	**100MW**	**200MW**	**300MW**	**400MW**	**500MW**	**600MW**	**700MW**
1	19.22	19.23	19.93	19.24	19.25	19.26	19.5
2	19.91	19.91	19.92	19.94	19.95	19.97	20.25
3	19.08	19.08	19.08	19.09	19.1	19.1	19.35
4	19.08	19.08	19.09	19.09	19.1	19.11	19.35
5	19.12	19.12	19.12	19.13	19.14	19.14	19.39
6	20.08	20.09	20.10	20.12	20.14	20.16	20.45
7	21.14	21.17	21.2	21.25	21.31	21.39	21.75
8	21.31	21.39	2148	21.58	21.71	21.87	7881.04
9	21.34	21.34	21.35	21.38	21.43	21.49	1657.45
10	21.23	21.16	21.1	21.05	21.02	20.99	2373.78
11	21.08	20.95	20.82	20.7	20.59	20.48	1013.38
12	21.04	20.95	20.87	20.81	20.75	20.7	3651.25
13	20.92	20.86	20.81	20.77	20.74	20.72	2456.3
14	21.03	20.97	20.93	20.9	20.87	20.86	2258.43
15	21.04	21.00	20.98	20.97	20.96	20.97	1546.53
16	20.82	20.79	20.76	20.75	20.74	20.75	1546.76
17	21.17	21.17	21.18	21.2	21.23	21.28	691.7
18	21.55	21.53	21.53	21.53	21.55	21.59	1102.98
Line Overloaded							Line 116 3%

OUTPUT DATA FOR T4, MIN. LOAD

Table AIV.21 Generation and total cost

	100MW		200MW		300MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	957.1	10210.34	956	10192.22	955.4	10183
402	954.5	11566.17	953.3	11546.9	952.5	11533.2
403	1800	31073	1800	31073	1800	31073
404	51	482.52	52	498.08	53	513.68
Total	3762.6	53332.03	3761.3	53310.2	3760.9	53302.88

	400MW		500MW		600MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	955	10175.95	955.3	10179.95	956	10191.6
402	952.2	11528.98	952.5	11533.2	953	11541.45
403	1800	31073	1800	31073	1800	31073
404	54	529.32	55	545	56	560.72
Total	3761.3	53307.25	3762.8	53331.15	3765	53366.76

	700MW		800MW		900MW	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	957.7	10220.55	977.5	10546.95	961	10274.65
402	955	11574.42	975	11903.69	958.4	11630.86
403	1800	31073	1800	31073	1800	31073
404	55.6	554.31	20	20	58.5	600.2
Total	3768.3	53422.27	3772.5	53543.63	3777.9	53578.71

	1000MW	
Bus N.	**MW**	**Cost, $/h**
401	866.8	8726.58
402	864.0	10079.16
403	1800.1	31074.03
404	255.7	4501.64
Total	3786.5	54381.4

Table AIV.22 Bus Incremental Cost, $/MWh

Bus N.	**100MW**	**200MW**	**300MW**	**400MW**	**500MW**	**600MW**
1	16.5	16.5	16.5	16.5	16.5	16.5
2	16.58	16.58	16.58	16.58	16.58	16.58
3	16.48	16.48	16.48	16.48	16.48	16.48
4	16.49	16.48	16.48	16.48	16.48	16.48
5	16.49	16.49	16.49	16.49	16.49	16.49
6	16.59	16.59	16.59	16.59	16.59	16.59
7	16.51	16.51	16.51	16.51	16.51	16.51
8	16.31	16.28	16.26	16.23	16.21	16.19
9	16.21	16.23	16.25	16.27	16.3	16.32
10	16.06	16.13	16.2	16.27	16.34	16.42
11	15.89	16.01	16.13	16.25	16.37	16.5
12	15.66	15.74	15.81	15.89	15.97	16.05
13	15.49	15.55	15.6	15.66	15.71	15.76
14	15.58	15.63	15.68	15.73	15.78	15.83
15	15.71	15.74	15.78	15.82	15.85	15.89
16	15.55	15.59	15.62	15.66	15.7	15.73
17	16.25	16.26	16.28	16029	16.3	16.32
18	16.14	16.16	16.19	16.21	16.24	16.26
Lines Overloaded						

Bus N.	**700MW**	**800MW**
1	16.5	16.53
2	16.58	16.61
3	16.49	16.51
4	16.49	16.51
5	16.49	16.52
6	16.59	16.62
7	16.51	16.54
8	16.19	1007.27
9	16.39	1652.07
10	16.56	2369.24
11	16.72	3127.88
12	16.26	5330.14
13	15.76	2461.48
14	15.83	2263.68
15	15.89	1551.86
16	15.73	1552.02
17	16.32	696.96
18	16.26	1108.6
Lines Overloaded		Line 118 3%

OUTPUT DATA FOR T4, AVERAGE LOAD

Table AIV.23 Generation and total cost

	100MW		**200MW**		**300MW**	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	1688.5	22588.08	1680	2244.04	1687.9	22578.24
402	1686.8	23959.58	1678.8	23821.36	1686	23946.3
403	1800	31073	1800	31073	1800	31073
404	90.5	1127.56	106.5	1406.6	92.5	1161.88
Total	5265.8	78748.21	5265.3	78741.35	5266.4	78759.41

	400MW		**500MW**		**600MW**	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	1688.2	22583.19	1689	22596.7	1690.5	22622.51
402	1686.5	23954.98	1687.4	23971.22	1688.7	23993.43
403	1800	31073	1800	31073	1800	31073
404	93.5	1179.1	94.5	1196.36	95.5	1213.66
Total	5268.2	78790.26	5270.9	78837.28	5274.7	78902.6

	700MW		**800MW**		**900MW**	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	1666.2	22200.71	1597.9	21019.56	1543.5	20083.54
402	1664.5	23573.27	1596	22388.47	1542.0	21458.44
403	1800.1	31074.03	1800.1	31074.03	1800.1	31074.03
404	147.1	2161.05	286.3	5246.35	400	8332.8
Total	5277.8	79009.06	5280.2	79728.41	5285.6	80948.81

	1000MW	
Bus N.	**MW**	**Cost, $/h**
401	1547.5	20152.05
402	1545.7	21522.82
403	1800.1	31074.03
404	400	8332.8
Total	5293.3	81081.7

Table AIV.24 Bus Incremental Cost, $/MWh

Bus number	**100MW**	**200MW**	**300MW**	**400MW**	**500MW**	**600MW**	**700MW**	**800MW**
1	17.42	17.42	17.42	17.42	17.42	17.42	17.39	17.31
2	17.64	17.68	17.64	17.64	17.64	17.64	17.62	17.53
3	17.36	17.35	17.36	17.36	17.36	17.36	17.34	17.25
4	17.36	17.35	17.36	17.36	17.36	17.37	17.34	17.26
5	17.38	17.37	17.38	17.38	17.38	17.38	17.35	17.27
6	17.68	17.73	17.68	17.68	17.68	17.68	17.65	17.57
7	17.81	17.97	17.81	17.81	17.82	17.82	17.8	17.72
8	17.7	17.88	17.64	17.62	17.59	17.57	16.23	12.61
9	17.68	17.95	17.73	17.75	17.78	17.81	27.43	8998.94
10	17.6	17.96	17.75	17.82	17.91	18.00	26.74	8995.77
11	17.49	17.94	17.74	17.88	18.02	18.17	25.98	8992.4
12	17.3	17.74	17.46	17.55	17.63	17.73	22.6	8981.13
13	17.14	17.58	17.25	17.31	17.37	17.43	20.71	29.47
14	17.23	17.67	17.33	17.38	17.44	17.5	20.51	28.57
15	17.3	17.81	17.37	17.41	17.45	17.5	19.56	25.08
16	17.12	17.77	17.2	17.24	17.28	17.33	19.39	24.91
17	17.66	17.93	17.69	17.71	17.73	17.75	18.67	21.14
18	17.71	18.09	17.76	17.79	17.82	17.85	19.32	23.26
Lines Overloaded								Line 114 12%

OUTPUT DATA FOR T4, PEAK LOAD

Table AIV.25 Generation and total cost

	100WM		**200MW**		**300MW**	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	3115.5	48585.09	3116	48594.38	3117.3	48620.76
402	2500	38477.5	2500	38477.5	2500	38477.5
403	1800.1	31074.03	1800.1	31074.03	1800.1	31074.03
404	185.5	2934.46	187	2965.88	189.0	3007.21
Total	7601.0	121071.08	7603.0	121111.78	7606.4	121180.21

	400MW		**500MW**		**600MW**	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	3120.0	48672.22	2923.5	44946.41	2893.9	44388.97
402	2500	38477.5	2500	38477.5	2500	38477.5
403	1800.1	31074.03	1800.1	31074.03	1800.1	31074.03
404	191	3050.12	367.5	7397.77	400	8332.8
Total	7611.1	121273.87	7591.1	121895.71	7594	122273.29

	700MW		**800MW**		**900MW**	
Bus N.	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**	**MW**	**Cost, $/h**
401	2902.3	44546.02	2912.5	44737.99	2924.9	44971.56
402	2500	38477.5	2500	38477.5	2500	38477.5
403	1800.1	31074.03	1800.1	31074.03	1800.1	31074.03
404	400	8332.8	400	8332.8	400	8332.8
Total	7602.3	122430.35	7612.5	122622.32	7624.9	122855.89

	1000MW	
Bus N.	**MW**	**Cost, $/h**
401	2940	45256.96
402	2500	38477.5
403	1800.1	31074.03
404	400	8332.8
Total	7640.1	123141.29

Table AIV.26 Bus Incremental Cost, $/MWh

Bus N.	100MW	200MW	300MW	400MW	500MW	600MW
1	19.22	19.22	19.22	19.23	18.99	18.96
2	19.9	19.9	19.91	19.91	19.68	19.65
3	19.07	19.07	19.08	19.08	18.84	18.81
4	19.08	19.08	19.08	19.08	18.85	18.81
5	19.11	19.11	19.12	19.12	18.88	18.85
6	20.07	20.07	20.08	20.09	19.85	19.83
7	21.13	21.13	21.15	21.18	20.95	20.96
8	21.2	21.16	21.13	21.12	16.34	970.72
9	21.37	21.4	21.45	21.52	54.76	7375.18
10	21.41	21.52	21.64	21.79	51.86	6658.35
11	21.4	21.58	21.78	22.01	48.71	7841.48
12	21.24	21.36	21.5	21.66	38.26	3695.64
13	21.06	21.15	21.25	21.37	32.5	2499.8
14	21.16	21.25	21.34	21.45	31.68	2302.05
15	21.13	21.2	21.27	21.37	28.33	1589.81
16	20.92	20.98	21.05	21.14	28.11	1589.59
17	21.20	21.23	21.27	21.33	24.37	734.82
18	21.61	21.65	21.72	21.79	26.72	1147.1
Lines Over-loaded						Line 114 15%

APPENDIX V

THE RESULTS OF SIMULATIONS WITH THE SRMC AND THE SRIC METHODS

Table AV.1: Summary of the results of the simulations for T1, minimum load

Case	MW	Loss.	Total Cost	Cost of tr.	SRIC	BIC_{11}	BIC_{17}	SRMC
base	3764.7		53366.92					
100	3767.3	2.6	53411.36	44.44	0.4444	15.65	16.25	0.6
200	3770	5.3	53469.5	102.58	0.5129	15.52	16.26	0.74
300	3775.2	10.5	53542.2	175.28	0.5843	15.39	16.28	0.89
400	3780.5	15.8	53630.05	263.13	0.6578	15.26	16.29	1.03
500	3785.8	21.1	53764	397.08	0.7942	1410.43	11735.88	10225.45
600	3792.8	28.1	53878.8	511.88	0.8531	2124.32	17615.87	15491.55
700	3800.7	36	54009.93	643.01	0.9186	2008.6	27120.88	25112.28
800	3809.6	44.9	54156.96	790.04	0.9876			
900	3819.3	54.6	54318.27	951.35	1.0571			
1000	3830.2	65.5	54497.31	1130.39	1.1304			

Table AV.2: Summary of the results of the simulations for T1, average load

Case	MW	Loss.	Total Cost	Cost of tr..	SRIC	BIC_{11}	BIC_{17}	SRMC
base	5266.8		78766.76					
100	5268.4	1.6	78794.48	27.72	0.2772	17.23	17.67	0.44
200	5270.9	4.1	78837.88	71.12	0.3556	17.1	17.69	0.59
300	5274.4	7.6	78899.06	132.3	0.4410	16.96	17.71	0.75
400	5278.8	12	78975.64	208.88	0.5222	16.83	17.73	0.9
500	5284.1	17.3	79067.17	300.41	0.6008	16.7	17.76	1.06
600	5290.4	23.6	79182.99	416.23	0.6937	15.15	17.62	2.47
700	5298.6	31.8	79438.38	671.62	0.9595	1408.96	11735.02	10326.06
800	5306.6	39.8	79577.93	811.17	1.0140			
900	5315.8	49	79767.49	1000.73	1.1119			
1000	5326	59.2	79915.08	1148.32	1.1483			

Table AV.3: Summary of the results of the simulations for T1, peak load

Case	MW	Loss.	Total Cost	Cost of tr..	SRIC	BIC_{11}	BIC_{17}	SRMC
base	7600.1		121050.56					
100	7600.4	0.3	121055.64	5.08	0.0508	21.05	21.21	0.16
200	7601.8	1.7	121081.71	31.15	0.1558	20.87	21.25	0.38
300	7604.5	4.4	121132.3	81.74	0.2725	20.71	21.3	0.59
400	7608.4	8.3	121207.46	156.9	0.3922	20.55	21.36	0.81
500	7613.6	13.5	121307.9	257.34	0.5147	20.41	21.44	1.03
600	7620	19.9	121430.41	379.85	0.6331	20.28	21.53	1.25
700	7626.6	26.5	121573.17	522.61	0.7466	20.27	21.98	1.71
800	7624.8	24.7	121796.67	746.11	0.9326	21.26	25.24	3.98
900	7625.8	25.7	122286.05	1235.49	1.3728	1063.74	7323.71	6259.97
1000	7630.4	30.3	122959.35	1908.79	1.9088			

Table AV.4: Summary of the results of the simulations for T2, min load

Case	MW	Loss.	Total Cost	Cost of tr..	SRIC	BIC$_{17}$	BIC$_{11}$	SRMC
base	3764.7		53366.92					
100	3763	-1.7	53337.9	-29.02	-0.2902	16.22	15.91	-0.31
200	3762.5	-2.2	53323.32	-43.6	-0.2180	16.21	16.05	-0.16
300	3761.8	-2.9	53353.73	-13.19	-0.0440	15.07	15.78	0.71
400	3762.7	-2	53382.15	15.23	0.0381	2437.31	6508.53	4071.22
500	3764.5	-0.2	53417.44	50.52	0.1010			
600	3767.8	3.1	53467.06	100.14	0.1669			
700	3772	7.3	53536.44	169.52	0.2422			
800	3777.5	12.8	53627.2	260.28	0.3253			
900	3784.4	19.7	53740.22	373.3	0.4148			
1000	3795.6	30.9	53876.01	509.09	0.5091			

Table AV.5: Summary of the results of the simulations for T2, average load

Case	MW	Loss.	Total Cost	Cost of tr..	SRIC	BIC$_{17}$	BIC$_{11}$	SRMC
base	5266.8		78766.76					
100	5266	-0.8	78752.93	-13.83	-0.1383	17.63	17.52	-0.11
200	5266.2	-0.6	78756.52	-10.24	-0.0512	17.62	17.66	0.04
300	5267.5	0.7	78778.32	11.56	0.0385	17.61	17.82	0.21
400	5269.8	3	78817.75	50.99	0.1275	17.6	17.99	0.39
500	5273	6.2	78873.44	106.68	0.2134	17.59	18.16	0.57
600	5279.9	13.1	79112.46	345.7	0.5762	695.71	4520.89	3825.18
700	5285.8	19	79215.80	449.04	0.6415			
800	5293.1	26.3	79341.56	574.8	0.7185			
900	5302	35.2	79496.82	730.06	0.8112			
1000	5312.7	45.9	79683.33	916.57	0.9166			

Table AV.6: Summary of the results of the simulations for T2, peak load

Case	MW	Loss.	Total Cost	Cost of tr.	SRIC	BIC$_{17}$	BIC$_{11}$	SRMC
base	7600.1		121050.56					
100	7601.3	1.2	121076.16	25.6	0.2560	21.16	21.44	0.28
200	7603.7	3.6	121123.64	73.08	0.3654	21.15	21.67	0.52
300	7607.4	7.3	121197.1	146.54	0.4885	21.15	21.92	0.77
400	7612.9	12.8	121304.63	254.07	0.6352	21.17	22.20	1.03
500	7619.9	19.8	121443.05	392.49	0.7850	21.21	22.53	1.32
600	7628.6	28.5	121616.31	565.75	0.9429	21.26	22.91	1.65
700	7608.0	7.9	122536.19	1485.63	2.1223	734.16	14884.9	14150.74
800	7619.8	19.7	122759.61	1709.05	2.1363			
900	7634.4	34.3	123033.69	1983.13	2.2035			
1000	7652.4	52.3	123373.42	2322.86	2.3229			

Table AV.7: Summary of the results of the simulations for T3, min load

Case	MW	Loss.	Total Cost	Cost of tr.	SRIC	BIC_{11}	BIC_8	SRMC
base	3764.7		53366.92					
100	3767.6	2.9	53417.1	50.18	0.5018	15.67	16.37	0.7
200	3771.4	6.7	53479.65	112.73	0.5637	15.55	16.41	0.86
300	3776.2	11.5	53559.66	192.74	0.6425	15.43	16.44	1.01
400	3781.0	16.3	53685.08	318.16	0.7954	1998.97	15734.57	13735.6
500	3787.6	22.9	53794.13	427.21	0.8544			
600	3795.1	30.4	53917.97	551.05	0.9184			
700	3803.6	38.9	54058.26	691.34	0.9876			
800	3813.4	48.7	54220.24	853.32	1.0667			
900	3824.5	59.8	54403.12	1036.2	1.1513			
1000	3836.9	72.2	54608.75	1241.83	1.2418			

Table AV.8: Summary of the results of the simulations for T3, average load

Case	MW	Loss.	Total Cost	Cost of tr..	SRIC	BIC_{11}	BIC_8	SRMC
base	5266.8		78766.76					
100	5268.6	1.8	78798.51	31.75	0.3175	17.26	17.78	0.52
200	5271.4	4.6	78847.13	80.37	0.4019	17.14	17.82	0.68
300	5275.1	8.3	78912.25	145.49	0.4850	17.02	17.86	0.84
400	5279.7	12.9	78991.42	224.66	0.5617	16.91	17.91	1
500	5286.4	19.6	79225.02	458.26	0.9165	1009.15	7876.86	6867.71
600	5292.7	25.9	79335.51	568.75	0.9479			
700	5300.3	33.5	79468.38	701.62	1.0023			
800	5309.1	42.3	79621.54	854.78	1.0685			
900	5319.1	52.3	79794.82	1028.06	1.1423			
1000	5330.6	63.8	79995.97	1229.21	1.2292			

Table AV.9: Summary of the results of the simulations for T3, peak load

Case	MW	Loss.	Total Cost	Cost of tr..	SRIC	BIC_{11}	BIC_8	SRMC
base	7600.1		121050.56					
100	7600.6	0.5	121058.53	7.97	0.0797	21.08	21.31	0.23
200	7602.3	2.2	121089.33	38.77	0.1939	20.95	21.39	0.44
300	7605.0	4.9	121140.29	89.73	0.2991	20.82	21.48	0.66
400	7609.2	9.1	121218.76	168.2	0.4205	20.7	21.58	0.88
500	7614.7	14.6	121323.49	272.93	0.5459	20.59	21.71	1.12
600	7621.6	21.5	121456.64	406.08	0.6768	20.48	21.87	1.39
700	7664.6	64.5	122557.3	1506.74	2.1525	1013.38	7881.04	6867.66
800	7677.1	77	122799.62	1749.06	2.1863			
900	7693.1	93	123108.82	2058.26	2.2870			
1000	7714.1	114	123517.72	2467.16	2.4672			

Table AV.10: Summary of the results of the simulations for T4, min load

Case	MW	Loss.	Total Cost	Cost of tr.	SRIC	BIC$_8$	BIC$_{11}$	SRMC
base	3764.7		53366.92					
100	3762.6	-2.1	53332.03	-34.89	-0.3489	16.31	15.89	-0.42
200	3761.3	-3.4	53310.2	-56.72	-0.2836	16.28	16.01	-0.27
300	3760.9	-3.8	53302.88	-64.04	-0.2135	16.26	16.13	-0.13
400	3761.3	-3.4	53307.25	-59.67	-0.1492	16.23	16.25	0.02
500	3762.8	-1.9	53331.15	-35.77	-0.0715	16.21	16.37	0.16
600	3765	0.3	53366.76	-0.16	-0.0003	16.19	16.5	0.31
700	3768.3	3.6	53422.27	55.35	0.0791	16.19	16.72	1.71
800	3772.5	7.8	53543.63	176.71	0.2209	1007.27	3127.88	2120.61
900	3777.9	13.2	53578.71	211.79	0.2353			
1000	3786.5	21.8	54381.4	1014.48	1.0145			

Table AV.11: Summary of the results of the simulations for T4, average load

Case	MW	Loss.	Total Cost	Cost of tr.	SRIC	BIC$_8$	BIC$_{11}$	SRMC
base	5266.8		78766.76					
100	5265.8	-1	78748.21	-18.55	-0.1855	17.7	17.49	-0.21
200	5265.3	-1.5	78741.35	-25.41	-0.1271	17.88	17.94	0.06
300	5266.4	-0.4	78759.41	-7.35	-0.0245	17.64	17.74	0.1
400	5268.2	1.4	78790.26	23.5	0.0587	17.62	17.88	0.26
500	5270.9	4.1	78837.28	70.52	0.1410	17.59	18.02	0.43
600	5274.7	7.9	78902.6	135.84	0.2264	17.57	18.17	0.6
700	5277.8	11	79009.06	242.3	0.3461	16.23	25.98	9.75
800	5280.2	13.4	79728.41	961.65	1.2021	12.61	8992.4	8979.79
900	5285.6	18.8	80948.81	2182.05	2.4245			
1000	5293.3	26.5	81081.7	2314.94	2.3149			

Table AV.12: Summary of the results of the simulations for T4, peak load

Case	MW	Loss.	Total Cost	Cost of tr.	SRIC	BIC$_8$	BIC$_{11}$	SRMC
base	7600.1		121050.56					
100	7601.0	0.9	121071.08	20.52	0.2052	21.2	21.4	0.2
200	7603.0	2.9	121111.78	61.22	0.3061	21.16	21.58	0.42
300	7606.4	6.3	121180.21	129.65	0.4322	21.13	21.78	0.65
400	7611.1	11	121273.87	223.31	0.5583	21.12	22.01	0.89
500	7591.1	-9	121895.71	845.15	1.6903	16.34	48.71	32.37
600	7594.0	-6.1	122273.29	1222.73	2.0379	970.72	7841.42	6870.7
700	7602.3	2.2	122430.35	1379.79	1.9711			
800	7612.5	12.4	122622.32	1571.76	1.9647			
900	7624.9	24.8	122855.89	1805.33	2.0059			
1000	7640.1	40	123141.29	2090.73	2.0907			

APPENDIX VI

THE TABLES USED FOR THE CALCULATION OF THE EXTENDED MW-MILE AND THE USAGE METHODS

TRANSACTION 2

Extended MW-Mile method

Table AVI.1: The absolute values of MW changes, length and the MW-Miles of the lines for T2

Lines No.	|MW changes|	Length, km	Capacity cost, $/MWh	MW-Mile value
104	0.6	112	0.64	43.01
105	1	1464	16.72	24478.08
110	1	284	1.62	460.08
111	57	188	2.15	23039.4
112	50	244	2.79	34038
113	13	244	2.79	9530.64
114	57	164	1.87	17480.76
115	56	168	1.92	18063.36
116	36	170	1.94	11872.8
117	45	164	1.87	13800.6
118	50	88	1.0	4400
119	16	40	0.46	294.4
120	16	40	0.46	294.4
121	26	44	0.5	572
122	22	110	1.26	3049.2
125	15	226	2.58	8746.2
123	23	210	2.4	11592
126	8	250	2.85	5700
Total				187454.93

Table AVI.2: The length, cost per MWh, MW flow and the MW-Mile values for T2

No.	Length, km	Cost, $/MWh	MW flow	MW-Mile values
101	437	2.49	1055	1147977.15
102	435	2.55	1050	1164712.5
103	38	0.22	805.9	6737.32
104	112	0.32	1607	57594.88
105	1464	16.72	238.8	5845365.5
106	6	0.017	1064.9	108.62
107	6	0.017	1044	106.488
108	2780	14.59	126.1	5114641.22
109	284	1.62	685	315154.8
110	284	1.62	679	312394.32
111	188	2.15	199	80435.8
112	244	2.79	146	99390.96
113	244	2.79	43.7	29749.21
114	164	1.87	197.5	60569.3
115	168	1.92	76.2	24579.07
116	170	1.94	35.7	11773.86
117	164	1.87	64.5	19780.86
118	88	1.	246	21648
119	40	0.46	342	6292.8
120	40	0.46	345	6348
121	44	0.5	296.9	6531.8
122	110	1.26	63.7	8828.82
123	210	2.4	31.9	16077.6
124	82	0.94	185	14259.8
125	226	2.58	68.1	39707.75
126	250	2.85	115.7	82436.25
127	216	2.58	174.8	97412.54
Total				14590615.218

Usage method

Table AVI.3: The absolute values of MW changes, capacity cost and the Usage rate for T2

Lines No.	|MW changes|	MW flow	Capacity cost, $/MWh	Usage rate
104	0.6	1607	0.64	0.0002
110	1	679	1.62	0.00239
111	57	199	2.15	0.6158
112	50	146	2.79	0.9554
113	13	43.7	2.79	0.83
114	57	197.5	1.87	0.54
115	56	76.2	1.92	1.415
116	36	36	1.94	1.94
117	45	64.5	1.87	1.314
118	50	246	1.0	0.203
119	16	342	0.46	0.0215
120	15	345	0.46	0.0213
121	14	296.9	0.5	0.0439
122	22	63.7	1.26	0.44
123	23	32	2.4	1.0725
125	15	68.1	2.58	0.53
126	8	115.7	2.85	0.1971
127	7	188.3	2.58	0.096
Total			31.68	10.23809

TRANSACTION 3

Extended MW-Mile method

Table AVI.4: The absolute values of MW changes, length and the MW-Miles of the lines for T3

Lines No.	|MW changes|	Length, km	Capacity cost, $/MWh	MW-Mile value
104	1	112	0.64	71.68
105	1	1464	16.72	24478.08
110	1.3	284	1.62	598.1
111	25	188	2.15	10105
112	18	244	2.79	12253.68
113	5	244	2.79	3403.8
114	80	164	1.87	24534.4
115	56	168	1.92	18063.36
116	78	170	1.94	25724.4
117	3.6	164	1.87	1104.05
118	25	88	1.0	2200
119	8	40	0.46	147.2
120	8	40	0.46	147.2
121	10	44	0.5	220
122	12	110	1.26	1663.2
125	8	226	2.58	4664.64
123	36	210	2.4	18144
126	3	250	2.85	5700
127	5	216	2.58	353872.8
Total				507095.59

Table AVI.5: The length, cost per MWh, MW flow and the MW-Mile values for T3

No.	Length, km	Cost, $/MWh	MW flow	MW-Mile values
101	437	2.49	1055	1147977.15
102	435	2.55	1050	1164712.5
103	38	0.22	805.9	6737.32
104	112	0.32	1607	57594.88
105	1464	16.72	238.8	5845365.5
106	6	0.017	1064.9	108.62
107	6	0.017	1044	106.488
108	2780	14.59	126.1	5114641.22
109	284	1.62	685	315154.8
110	284	1.62	679	312394.32
111	188	2.15	167	67501.4
112	244	2.79	173	117771.48
113	244	2.79	50.8	34582.61
114	164	1.87	65.2	19995.54
115	168	1.92	55.7	17966.59
116	170	1.94	96.7	31891.66
117	164	1.87	3.6	1104.05
118	88	1.	176.9	15567.2
119	40	0.46	366.4	6741.76
120	40	0.46	369.1	6791.44
121	44	0.5	317.7	6989.4
122	110	1.26	96.8	13416.48
123	210	2.4	36	18144
124	82	0.94	183	14105.64
125	226	2.58	47.1	27463.07
126	250	2.85	125.9	89703.75
127	216	2.58	178	99195.84
Total				14553724.708

Usage method

Table AVI.6: The absolute values of MW changes, capacity cost and the Usage rate for T3

Lines No.	|MW changes|	MW flow	Capacity cost, $/MWh	Usage rate
104	0.6	1607	0.64	0.00023
110	1	679	1.62	0.00239
111	25	167	2.15	0.3218
112	18	173	2.79	0.2902
113	5	61	2.79	0.2287
114	65	65	1.87	1.87
115	55	55	1.92	1.92
116	78	96	1.94	1.5762
117	3.6	3.6	1.87	1.87
118	25	176	1.0	0.142
119	8	367	0.46	0.0097
120	8	369	0.46	0.0099
121	8	317	0.5	0.0126
122	12	97	1.26	0.01558
123	36	36	2.4	2.4
125	8	41	2.4	0.468
126	3	126	2.85	0.0678
127	5	178	2.58	0.0724
Total			31.68	11.2775

TRANSACTION 4

Extended MW-Mile method

Table AVI.7: The absolute values of MW changes, length and the MW-Miles of the lines for T4

Lines No.	|MW changes|	Length, km	Capacity cost, $/MWh	MW-Mile value
104	0.2	112	0.64	14.34
105	0.8	1464	16.72	19582.46
110	0.7	284	1.62	322.06
111	24	188	2.15	9700.8
112	18	244	2.79	12253.68
113	5	244	2.79	3403.8
114	77	164	1.87	23614.36
115	76	168	1.92	24514.56
116	56	170	1.94	18468.8
117	25	164	1.87	7667
118	26	88	1.0	2288
119	9	40	0.46	165.6
120	8	40	0.46	147.2
121	7	44	0.5	154
122	12	110	1.26	1663.2
123	13	210	2.4	6552
125	7	226	2.58	4081.56
126	3	250	2.85	2137.5
127	4	216	2.58	2229.12
Total				138960.04

Table AVI.8: The length, cost per MWh, MW flow and the MW-Mile values for T4

No.	Length, km	Cost, $/MWh	MW flow	MW-Mile values
101	437	2.49	1055	1147977.15
102	435	2.55	1050	1164712.5
103	38	0.22	805.3	6732.31
104	112	0.32	1606.5	57576.96
105	1464	16.72	238.2	5830678.66
106	6	0.017	1063.9	108.518
107	6	0.017	1044.5	106.539
108	2780	14.59	126.1	5114641.22
109	284	1.62	684.9	315108.79
110	284	1.62	678.7	312256.3
111	188	2.15	118.5	47897.7
112	244	2.79	209.5	142619.22
113	244	2.79	60.6	41254.06
114	164	1.87	217.8	66794.9
115	168	1.92	96.3	31062.53
116	170	1.94	55.7	18369.86
117	164	1.87	44.9	13769.93
118	88	1.	225.6	19852.8
119	40	0.46	349.5	6430.8
120	40	0.46	352	6476.8
121	44	0.5	303	6666
122	110	1.26	73.1	10131.66
123	210	2.4	21.2	10684.8
124	82	0.94	185.5	14298.34
125	226	2.58	61.4	35801.11
126	250	2.85	119	84787.5
127	216	2.58	185	103096.8
Total				14609893.757

Usage method

Table AVI.9: The absolute values of MW changes, capacity cost and the Usage rate for T4

Lines No.	|MW changes|	MW flow	Capacity cost, $/MWh	Usage rate
104	0.6	1607	0.64	0.00023
110	1	679	1.62	0.00027
111	24	118	2.15	0.437
112	18	209	2.79	0.24
113	5	60	2.79	0.2325
114	77	217	1.87	0.6635
115	76	96	1.92	1.52
116	56	56	1.94	1.94
117	25	45	1.87	1.038
118	26	226	1.0	0.115
119	9	350	0.46	0.0118
120	8	352	0.46	0.0104
121	7	303	0.5	0.01155
122	12	74	1.26	0.2043
123	13	22	2.4	1.418
125	7	62	2.4	0.270
126	3	119	2.85	0.072
127	4	185	2.58	0.0554
Total			31.68	8.23995

APPENDIX VII

OPF MODEL AND STUDY TOOL

AVII.1 THEORY OF OPTIMISATION

Mathematically, the optimisation process involves finding a maximum or minimum for a function. Of interest to power system optimisation is to find a minimum of an objective function without violating the constraints of the system [45].

The general optimisation problem can be defined in terms of a set of control variables U and dependent variables X as [56]:

$$\begin{aligned} &\text{minimise} && f(U,X) \qquad (12)\\ &\text{subject to} && G(U,X) = 0\\ &\text{and} && H(U,X) \geq 0. \end{aligned}$$

where:

$f(U,X)$	the objective function to be minimised
$G(U,X)$	the equality constraint functions
$H(U,X)$	the inequality constraint functions

The Optimal Power Flow model can be defined by specifying the following attributes:

- the objective function
- the independent variables or controls
- the dependent variables
- the equality constraints
- the inequality constraints.

In the OPF model, the objective function is usually the cost of the generation of power or the cost of losses. The independent variables or controls are quantities that can be adjusted to help minimise the objective function and satisfy the constraints. These are the variables over which the user has direct control in the real system. The independent variables are voltage magnitude at a generator bus, active power generation, etc. All variables in the model that are not associated with controls are classified as dependent variables. These variables are free to assume values that solve the problem, within operating limits. The dependent variables are the bus voltage magnitudes, voltage angles, etc [45].

The equality constraints must be satisfied unconditionally for a solution to be feasible. The power flow equations are the most important constraints that must be met. This requires that the loads and the losses be balanced exactly with the power produced in the network.

The inequality constraints have lower and upper limits. These limits are due to physical limitations on the power system equipment that cannot be changed or operating limits that can be changed under certain conditions.

AVII.2POWER FLOW

A power system acting under steady state balanced three-phase conditions, requires that [57]:

- the power being generated supplies the load and the losses of the system
- bus voltage magnitudes remain within limits
- synchronous sources operate within their real and reactive limits
- transmission lines and transformers are not overloaded.

The tool used to investigate these requirements is the power flow or load flow. The following four variables are associated with each bus: voltage magnitude V_i, phase angle δ_i,, real power P_i, and reactive power Q_i supplied to the bus. At each bus, two of these variables are specified as input data, and the other are unknowns to be computed by the power flow program [45].

Power flow equations are the set of equations, determined by Kirchhoff's laws, that characterise the flow of power throughout the system. Care is taken in the solution of the power flow to ensure that the energy balance between the generation and load is correct. Therefore the power flow problem is specified by the set of the following equations [58]:

$$P_{ij} = |V_i||V_j||Y_{ij}|\cos(\theta_{ij} + \delta_j - \delta_i) - |V_i|^2 |Y_{ij}|\cos\theta_{ij} \qquad \text{for all } i,j \in N \qquad (13)$$

$$Q_{ij} = |V_i||V_j||Y_{ij}|\sin(\theta_{ij} + \delta_j - \delta_i) - |V_i|^2 |Y_{ij}|\sin\theta_{ij} \qquad \text{for all } i,j \in N \qquad (14)$$

$$P_{Gi} - P_{Di} - \sum_{j \in N} |V_i||V_j||Y_{ij}|\cos(\theta_{ij} + \delta_j - \delta_i) = 0 \qquad \text{for all } i,j \in N \qquad (15)$$

$$Q_{Gi} - Q_{Di} + \sum_{j \in N} |V_i||V_j||Y_{ij}|\sin(\theta_{ij} + \delta_j - \delta_i) = 0 \qquad \text{for all } i,j \in N \qquad (16)$$

$$P_{Gi,\min} \le P_{Gi} \le P_{Gi,\max} \qquad \text{for all } i \in NG \qquad (17)$$

$$Q_{Gi,\min} \le Q_{Gi} \le Q_{Gi,\max} \qquad \text{for all } i \in NG \qquad (18)$$

$$P_{ij} \le P_{ij,\max} \qquad \text{for all } i,j \in NB \qquad (19)$$

$$V_{i,\min} \le V \le V_{i,\max} \qquad \text{for all } i \in N \qquad (20)$$

where:

N -	set of bus indices
NG -	set of generation bus indices
NB -	set of transmission lines indices
P_{ij} -	the active power flow at transmission line between buses i and j
Q_{ij} -	the reactive power flow at transmission line between buses i and j
V_i	voltage magnitude at bus i
Y_{ij} -	element of i row and j column in admittance matrix of the network
θ_{ij} -	phase angle of $Y_{i,j}$
δ_i -	voltage angle at bus I

P_{Gi} and Q_{Gi} - active and reactive power generation at bus i

P_{Di} and Q_{Di} - active and reactive power demand at bus i

$P_{Gi,min}$ and $Q_{Gi,min}$ - minimum active and reactive power output at generation at bus i

$P_{Gi,max}$ and $Q_{Gi,max}$ - maximum active and reactive power output at generation at bus i

$P_{ij,max}$ - maximum active power flow at transmission line between buses i and j

$V_{i,min}$ - minimum voltage level at bus i

$V_{i,max}$ - maximum voltage level at bus i

Power flows are an important part of power systems operation and planning. They are used as a central element in the scheduling of generation, monitoring of the system, and development of interchange transactions.

AVII.3OPTIMAL POWER FLOW

In Reference [56] there is the following definition of OPF: "*Optimal power flow is an optimisation problem which attempts to provide power flow solution that satisfies all of the constraints related to a feasible steady-state operation of a power system. Additionally, OPF seeks feasible load flow solution which at the same time optimise a user-selected objective*".

The OPF model includes:

- DC or AC representations of the network ,
- generating unit cost characteristics, and
- power flow and generating unit constraints.

The OPF model incorporates an exact representation of a power system. It involves no approximations to line flows or power losses and therefore provides excellent information about the operation of power systems and associated costs. This representation of the power system is obtained by using constrained equations, which determine the power flows throughout the power system. In the OPF model there can be many objective functions, the most common are the generation cost or the economic dispatch and loss minimisation. For the present analysis, which covers only the active power optimisation, the economic dispatch is of interest.

The objective function to be minimised in the economic dispatch problem is the generation production cost. The general form of the function is [45]:

$$f(P_G)=\sum_{i=1}^{N} C_i\left(P_{Gi}\right) \tag{21}$$

where:

i	the index for generators
N -	the number of generators
P_{Gi} -	the active power generated at generator i.
$C_i(P_{Gi})$	the cost of production associated with generator i.

The production cost is generally modelled in a quadratic polynomial form [56]:

$$C_i(P_{Gi}) = a_i+b_i\,P_{Gi}+c_i\,P_{Gi}^2 \tag{22}$$

where:

a_i, b_i, and c_i - known constants.

Then the OPF model is [59]:

$$Min\sum_{i=1}^{N} C_i\left(P_{Gi}\right) \tag{23}$$

subject to: $h(v,\theta,P_G,P_D)=0,$ (24)

$g(v,\theta,P_G,P_D)\geq 0,$ (25)

where:

P_G -	the vector of power generations with i element P_{Gi}
P_D -	the vector of bus loads
v -	the vector of bus voltages
θ -	the vector of bus power angles

The equality constraints in the formulation of the OPF model (24) include the physical laws governing the power system, i.e., power flow equations. The inequality constraints (25) represent the operating limitations of the power system equipment employed. These constraints of the OPF model are specified in Section AVII.3 (see equations 13-20).

AVII.4ECONOMIC DISPATCH

Operation of the power system requires that all loads and losses of the system are balanced by the power being generated in the system. This power is usually supplied by many generating plants at various locations in the system. Each generating plant has a different efficiency of converting fuel into electrical power and due to the location of the plant, power must be transmitted over transmission lines to the load centres [57].

Economic dispatch is concerned with the amount of active power that each of these generating plants must output in order to supply the system loads most economically. This is achieved by considering each plant's efficiency and the active power losses incurred over the transmission lines.

The cost of active power generation can be expressed by a generating plant's input-output function. This relates the active power output of the plant to the fuel input of the plant. Generally, the input-output function for a thermal generating plant can be simplified to a quadratic function of the form as shown in equation (21) in the previous section.

AVII.5DESCRIPTION OF SC-OPF PACKAGE

Simulations in the thesis are performed using an industrial grade software package called Security Constrained Optimal Power Flow (SC-OPF). The program was written in Fortran 77 and developed for on line (real time) and off line (study mode) applications. SC-OPF can be run in a PC Windows environment.

SC-OPF performs the following main calculations [59,60]:

- Power Flow
- Optimal Power Flow

The program provides efficient full-featured solutions for power flows. A power flow solution is needed before running OPF. The OPF calculations incorporate both active power and reactive power optimisations. However, in the thesis, only the active power transaction transactions are considered and reactive power optimisation is beyond the scope of interest. For active power optimisation the program utilises an economic dispatch routine and applies a linear programming approach to determine the most economic dispatch of active power.

AVII.5.1 EXECUTION COMMANDS OF SC-OPF PACKAGE

SC-OPF uses 3 letter mnemonic commands and options entered by the user in order to complete a task, such as to perform an input, calculation or output. This system of commands and options, offers the user a wide choice of algorithms and allows the output data to be arranged in many different ways. Data entries in input data files are column specific and may be entered in IEEE common format [59,60].

The specific commands used to obtain power flow solutions are listed below.

Command:	DAT	*[call input data file]*
Options:	NON	*[no options for the input data file]*
Command:	PFL	*[run power flow program]*
Options:	NON	*[no options for the power flow program]*

The commands used to obtain the OPF solutions are:

Command:	AOP	*[perform active power optimisation]*
Options:	EDC	*[perform economic dispatch]*
Command:	OUT	*[request for output]*
Options:	ALL GEN BRA COS BIC	*[select only specified options for output]*

Explanation of the output options:

ALL	*output all the options indicated*
GEN	*generator power output*
BRA	*branch power flows*
COS	*system operating costs of all generators*
BIC	*bus incremental cost*

The documentation supplied with SC-OPF has all the information needed to use the package.

AVII.6UTILISATION OF SC-OPF FOR EVALUATING COSTS OF TRANSMISSION TRANSACTIONS

As was defined in Section 3.4.1.1 the cost of a transaction between two buses by the SRMC method is the difference in the Bus Incremental Costs (BICs) at each bus (3). These BICs are readily available from the OPF model, because the OPF algorithm uses partial derivatives to minimise the objective function [59]. If the objective function is production cost, the partial derivatives of the cost with respect to real power are the BICs (see Section 3.4.1.1). In order to obtain the Bus Incremental Costs from SC-OPF, the option 'BIC' should be selected with the 'OUTPUT' command.

The cost of a transaction by the SRIC method is computed by performing an economic dispatch with and without that transaction (see Section 3.4.1.2). The Short-Run Incremental Cost is the difference in the total production cost. The total production cost for each run of economic dispatch can be obtained by specifying the option 'COS' with the command 'OUTPUT'.

For evaluating the costs of transactions by some Accounting Cost methods, such as the Extended MW-mile and the Usage methods, the power flow studies are performed. In order to estimate the MW flow changes caused by transactions real, power flows are calculated by using AC power flow algorithm. In SC-OPF the power flows are calculated by choosing command 'PFL'.

AVII.7SUMMARY

In this Appendix, the OPF model, which is used for determining the costs of transactions, has been described. The characteristic of the OPF model is that it uses an exact representation of power flows and losses. The OPF accounts for operating constraints, such as transmission system constraints, and generation operating limits.

The Appendix has also described the software package SC-OPF used during the study. The package utilises an economic dispatch and applies a linear programming approach to determine the most economic dispatch of active power.

The application of SC-OPF to determine the SRMC and the SRIC of a transaction has been also presented. For the SRMC method the BICs are used. For the SRIC method the cost of a transaction is evaluated by running the OPF with and without that transaction. In order to calculate transaction costs by the Accounting methods the power flow is run to estimate the MW changes due to a transaction.