Technical and Commercial Issues of Embedded Generation

Cases of study: Argentina and Chile

A dissertation submitted to

The University of Manchester Institute of Science and Technology

for the degree of Master of Science

JM Vignolo

Manchester Centre of Electrical Energy
Department of Electrical Engineering and Electronics
September 2000

DECLARATION

No portion of the work contained in this dissertation has been submitted in support of an application for another degree or qualification of this or any other university or other institute of learning.

ACKNOWLEDGEMENTS

The work in this dissertation could not have been completed without the help and support of others. To name each and every person who have, in some way, contributed would be a near impossible task. I would, however, like to acknowledge the advice and support received from my colleagues, in particular, Ing. Raúl Zeballos, Ing. Ventura Nunes, Ing. Jorge Alonso and Ing. Andrés Tozzo.

In addition, I am particularly grateful to my colleagues in Argentina and Chile, Ing. Ana Lia Duco, Ing. Sabino Mastrángelo, Ing. Luis Vargas, Ing. Patricio Molina and Ing. Juan C Araneda, for all the information and material they provided to make this work possible.

I would also like to thank my supervisor, Dr. Goran Strbac, for his mentoring, help and guidance.

Finally, I would like to thank my friend and colleague, Ing. Isi Haim, for his support and encouragement during all these years of my academic career.

JM Vignolo

September 2000

THE AUTHOR

Mario Vignolo graduated with an Engineer degree in Electrical Engineering from "Universidad de la República" in Montevideo, Uruguay in 1998. He has been working as Assistant Professor in the Electrical Institute of that university since November 1998. He has made publications on Power Flows and Lighting in many international conferences. In addition, he has been working in the industry since 1996 as an electrical installation and lighting designer.

TABLE OF CONTENTS

LIST OF FIGURES

ABSTRACT

In this work a review over the technical and commercial issues of embedded generation in the new Electricity Supply Industry is done. Some of the problems that the present arrangements have in recognising the real value of embedded generation are analysed and some alternatives presented, based on previous works in this area.

The particular cases of Argentina and Chile are studied. A description of the regulatory frameworks of both countries is done and a critical analysis of that frameworks with respect to embedded generation is presented.

In addition, a study of the present degree of penetration of embedded generation in the Argentine and Chilean networks is presented.

LIST OF ACRONYMS AND SYMBOLS

CAMMESA -	"Compañía Administradora del Mercado Mayorista Eléctrico Sociedad Anónima" Wholesale Electricity Market Operator Company
CDEC -	"Centro de Despacho Económico de Carga" Centre for Economic Load Dispatch
CHP -	Combined Heat and Power
CIER -	"Comisión de Integración Eléctrica Regional" Commission for the Regional Electric Integration
CNE -	"Comisión Nacional de Energía" National Commission of Energy
Distco -	Distribution company
DLC -	Direct Loss Coefficient
DUS charges -	Distribution use of system charges
EG -	Embedded Generation or Embedded Generator/s
ELL -	Expected Load Lost
EMC -	External Marginal Cost
ENRE -	"Ente Nacional Regulador de Electricidad" National Electricity Regulator

ERG - Embedded Renewable Generation or Embedded Renewable Generator/s

ESI - Electricity Supply Industry

FA - “Factor de Adaptación”
Adaptation Factor

FN - “Factor de Nodo”
Nodal Factor

GSP - Grid Supply Point

GUMA - “Gran Usuario Mayor”
Major Large User

GUME - “Gran Usuario Menor”
Minor Large User

GUPA - “Gran Usuario Particular”
Particular Large User

HV - High Voltage

IG - Isolated Generation or Isolated Generator/s

INOMEM - “Interconectado no despachado en el MEM”
Interconnected but not dispatched in the MEM

IPCONST_l - “Incremento de Precio por Confiabilidad del Sistema de Transporte”
Over-price due to transmission system reliability

LAF - Loss Adjustment Factor

LDC - Local Distribution Company

LOLP - Loss of Load Probability

LV - Low Voltage

MEM - "Mercado Eléctrico Mayorista"
Wholesale Electricity Market

MEMSP - "Mercado Eléctrico Mayorista del Sur de Patagonia"
Southern Patagonia Wholesale Electricity Market

MLC - Marginal Loss Coeficient

MV - Medium Voltage

O&M - Operating and Maintenance

PAEPRA - "Programa Argentino de Electrificación de la Población Rural Aislada"
Electricity Supply Program for Dispersed Rural Population in Argentina

PER - "Programa de Electrificación Rural"
Rural Electrification Programme

PM - "Precio Mercado"
Market Price

PMC - Production Marginal Cost

$PPAD - "Potencia Puesta a Disposición en el Mercado"
Capacity Made Available at the Market

RMC - Reduction Marginal Cost

ROCOF - Rate of Change of Frequency

SCLD_l - "Sobrecostos producidos por fallas de larga duración en alta tensión de una línea *l*"
Over-costs produced due to long duration failures in HV of a line *l*

SCCD_l - "Sobrecostos producidos por fallas de corta duración en alta tensión de una línea *l*"
Over-costs produced due to short duration failures in HV of a line *l*

SE - "Secretaría de Energía"
Secretariat of Energy

SEC - "Superintendencia de Electricidad y Combustibles"
Secretariat of Electricity and Fuels

SIC - "Sistema Interconectado Central"
Central Interconnected System

SIN - "Sistema Interconectado Nacional"
National Interconnected System

SING - "Sistema Interconectado del Norte Grande"
Great Northern Interconnected System

SMC - Social Marginal Cost

SPRF - "Sobreprecio por riesgo de falla"
Overprice due to failure risk

SRMC - Short Run Marginal Cost

U.K. - United Kindom

USD - United States Dollars

VAD - “Valor Agregado de la Distribución”
Value for the distribution service

WEM - Wholesale Electricity Market

£ - Pounds Sterling.

CHAPTER 1

BACKGROUND

1.1 FRAMEWORK: THE NEW ELECTRICITY SUPPLY INDUSTRY (ESI)

For a hundred of years electricity and its delivery were thought to be inseparable. Since the late-1980s and early-1990s things began to change. Due to diverse reasons [26] both developed and developing countries began to abandon the idea of an electricity industry vertically integrated to adopt a new model that allows competition and choice in electricity. The idea of commercial separation of electricity as a product and its delivery as a service was put in practice firstly in the U.K. The success of this change was took by other countries as an example and since that moment introduction of competition in the Electricity Supply Industry (ESI) has being taking place in many countries around the world.

The change in the ESI involves two different aspects that are very related to each other. One is *restructuring*; the other is *privatisation*.
Restructuring refers to changes in structure. It is about commercial arrangements for selling energy: separating or "unbundling" integrated industry structures and introducing competition and choice.
Privatisation is a change from government to private ownership, and is the end-point of a continuum of changes in ownership and management.

It can be considered that there are four basic ways to structure an electric industry and three different possibilities of ownership and management. [12]
In the case of structure the models are defined by the degree of competition:

- Model 1: No competition at all.
- Model 2: Requires a single buyer or purchasing agency to choose from a number of different producers, to encourage competition in generation.
- Model 3: Allows distribution companies to choose their supplier, which brings competition into generation and wholesale supply.
- Model 4: Allows all customers to choose their supplier, which implies full retail competition.

In the case of ownership and management, three different levels can be considered:

- First level: The ESI is a government department, with no separate accounts, and often with responsibilities that are only remotely connected to electricity production.
- Second level: The ESI is a distinct government-owned company, or nationalised industry.
- Third level: The ESI is a privately owned industry.

When considering the two aspects (i.e. structure and ownership) at the same time different possibilities arise. A matrix of structure and ownership/management results as shown in Fig. 1.1.

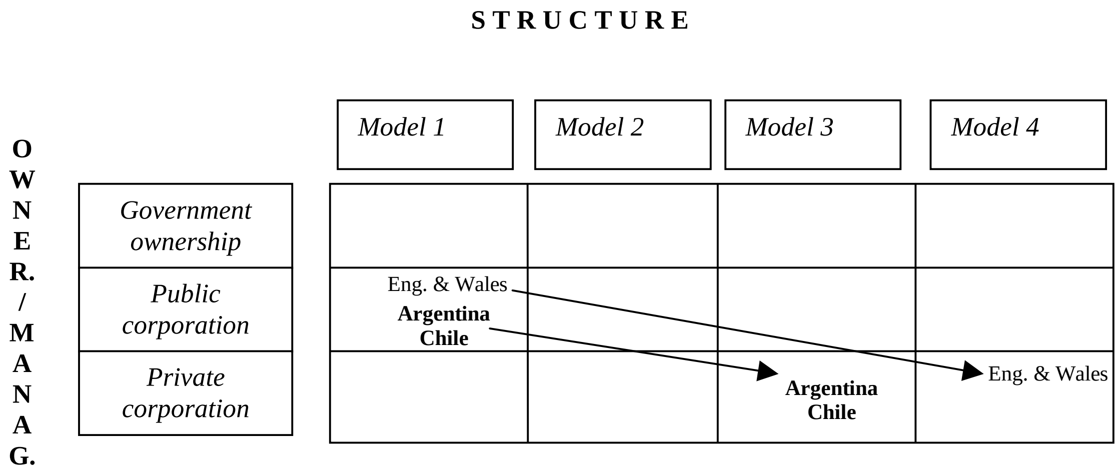


Fig. 1.1. Structure and ownership/management matrix.

The horizontal axis is competition and choice; the vertical axis is the degree of government control. Different levels of competition and choice, represented by the four models, are shown on the horizontal axis; on the left is full monopoly, on the right is full competition. On the vertical axis the dimension is the degree of government control. It starts at the top with a government department with full control, passing through a government-owned, but separate company, and ending with a privately owned company.

The countries of the world have electric industries all over this matrix. Many are moving from one place to another, but all the movement is from top to bottom, and from left to right: a reduction in government control, and an increase in competition and choice.

In Fig. 1.1 the cases of U.K., Argentina and Chile is represented.

In the whole process prices take a fundamental place as they must express real or true costs in order to make competitiveness work. If the market was perfect, the interaction of market forces would lead to setting the optimum assignment of resources. However, the characteristics of the ESI and the fact that transmission and distribution are natural monopolies makes the presence of a Regulator necessary. The Regulator has to establish the planning principles, the standards and the tariff structures that assure competition be able to work. In order to do that the true costs involved must be very well known and understood.

1.1.1 The New Electricity Supply Industry in Argentina

INDUSTRY STRUCTURE

Law Nº 24065 of January 1992 (Energy Act) [20] divides the electricity industry into three sectors: generation, transmission and distribution.

The generation sector is organised on a competitive basis with independent generation companies selling their production in the Wholesale Electricity Market (WEM) or by private contracts with certain other market participants.

Transmission is organised on a regulated basis. Transmission companies are required to provide third parties access to the transmission systems they own and are authorised to collect a toll for transmission services. Transmission companies are prohibited from generating or distributing electricity.

Distribution involves the transfer of electricity from supply points of transmitters to consumers. Distribution companies operate as geographic monopolies, providing service to almost all consumers within their specific region.

Accordingly, distribution companies are regulated and are subject to service specifications. Distribution companies may buy the electricity needed to meet consumer demand in the WEM or from contracts with generation companies.

The Energy Act also recognises a class of large users, consisting of industrial customers and other users with particular electricity supply needs. Large users are divided [2, Annexe 17] in three different groups (GUMA, GUME and GUPA) in accordance to their power needs and the amount of energy contracted in the WEM.

DISPATCH AND PRICING

The Argentine electricity dispatch system is designed to ensure that the most efficiently produced electricity reaches customers.

Generation companies sell their electricity to distribution companies and other large users in the competitive WEM through supply contracts or in the spot market at prices set by CAMMESA (“Compañía Adminsitradora del Mercado Mayorista Eléctrico Sociedad Anónima”, in english, Wholesale Electricity Market Operator Company). CAMMESA shareholders are the generation, transmission and distribution companies, large users (through their respective associations) and the SE (“Secretaría de Energía”, in english, Secretariat Energy).

All generation companies in the SIN (“Sistema Interconectado Nacional”, in english, National Interconnected System) pool electricity in the WEM. Electricity is purchased from participants in the pool by distribution companies and other large users at the contractual, seasonal, or spot price.
The contractual price is paid by distribution companies and other large users that have entered into supply contracts with generation companies. Large users who contract directly with generation companies must also pay the distribution companies a toll for the use of the distribution network (Distribution use of system charges, DUS charges).
The seasonal price is the price paid by distribution companies for electricity from the pool and is a fixed price reset every six months by CAMMESA and approved by the SE accordingly to supply, demand, available capacity and other factors. The seasonal price is maintained for at least 90 days. Thereafter, CAMMESA updates assumptions underlying the models employed to establish the seasonal price based on current data and results provided by companies that are members of the WEM. If the SE finds significant variance among current and prior data, it may modify the seasonal price through a resolution.
The spot price is an hourly price paid for energy and reflects the marginal cost of generation.

The actual operation of CAMMESA involves the dispatch of generating resources without regard to the contracts among generation companies and distribution companies or large users. Consequently, a generation company's capacity may be dispatched to provide more or less energy to the pool irrespective of its contractual commitments. Under these circumstances, the generation company will be obliged to buy or sell excess energy from or to the pool at spot prices.

In Fig. 1.2, the various possibilities of trading electricity in the WEM are shown [3]. The diagram also shows how the imbalances are traded in the market.

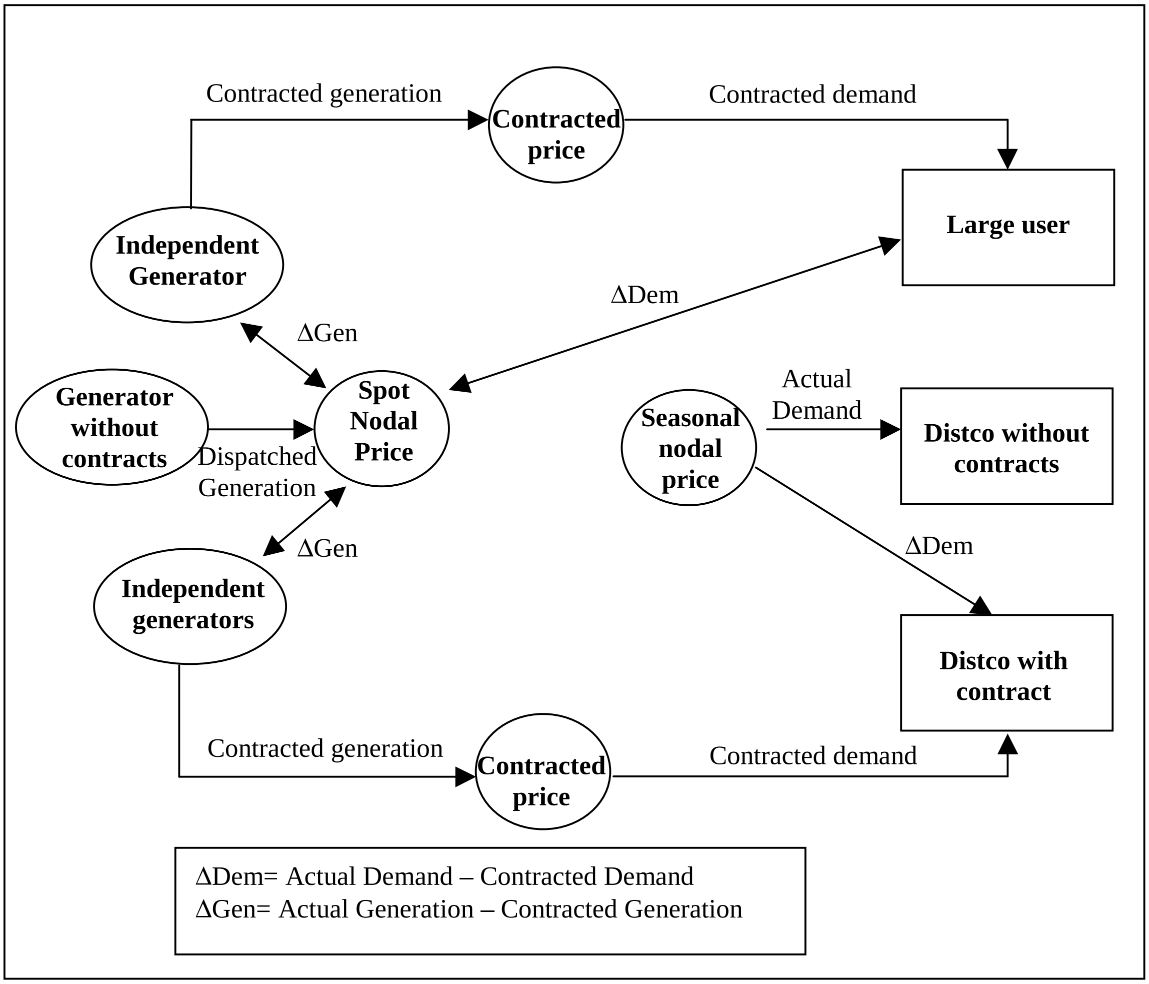


Fig. 1.2. Argentina: Trading prices in the WEM.

There is a Stabilisation Account that is constituted from the differences between the revenue due to the energy purchased to CAMMESA and the expenditure due to the energy sold to CAMMESA.

THE PRICE SYSTEM

Nodal Factors and Adaptation Factors

The type of pricing used by the Argentine WEM is nodal pricing.

At each node there is a price for the energy and a price for the capacity [2, Annexe 3].

The price for the energy at each node is calculated multiplying the price for the energy at the market, PM ("Precio Mercado", in english, Market Price) by the FN ("Factor de Nodo", in english, Nodal Factor).
The price for the capacity at each node is calculated multiplying the price for the capacity at the market, $PPAD ("Potencia Puesta a Disposición en el Mercado", in english, Capacity Made Available at the Market) by the FA ("Factor de Adaptación", in english, Adaptation Factor).

The FN at node *i* is calculated as:

$$FN_i = 1 + \frac{d(Losses)}{d(Pdi)}$$

where:

$\frac{d(Losses)}{d(Pdi)}$ is the derivative of the system transport losses (*Losses)* with respect to the power demanded at node *i* (*Pdi).*

In order to calculate the FN at node *i* a power flow programme is used simulating a unity variation of demand at *i* ($d(Pdi)$) and calculating the variation in system losses ($d(Losses)$). The slack busbar for this calculation is the WEM node (market place) or the market local node ("centre of load masses") for an area not electrically linked to the market. An area may result not linked to the market due to a system constraint. For this cases, the nodal factor of node *i* (FN_i) with respect to the WEM node is calculated multiplying the nodal factor of *i* with respect to the market local node (FNL_i) by the nodal factor of the local market node with respect to the WEM node (FNL), i.e.:

$$FN_i = FNL_i x FNL$$

where,

FN_i is the nodal factor of node *i* with respect to the WEM node.

FNL_i is the nodal factor of node *i* with respect to the local market node.

FNL is the nodal factor of the local market node with respect to the WEM node when no constraints are present (as defined in [The Procedures, Annexe 3, item 2.1).

As a result, the price for energy at node *i* is:

$$PN_i = PMxFN_i$$

CAMMESA calculates hourly nodal factors and seasonal nodal factors in accordance to [2, Annexe 3, Item 2.2]

With the previous considerations, PM results to be the generation marginal cost including transport (which is considered from contribution to system losses), evaluated at the market place. In addition, nodal factors represent the looses marginal cost associated to the link between the market place and the node.

FA is defined as the ratio between the price for the capacity at node *i* and the price for the capacity at the WEM node, when node *i* is linked to the WEM node without constraints.

The adaptation factor for a node *i* takes into account the reliability of the link between the market place and node *i*.

Due to failures in the transmission network, consumers at different nodes may experience cuts in the power supplied. This situation produces an increment in marginal prices at those nodes when considering the value of ENS (Energy Not Supplied).

The FA at node *i* considers the over-costs produced to the consumers at the receptor nodes when a failure in the transmission system occurs.

Two types of failures are considered:

- Long duration failures.
- Short duration failures.

Each type of failure has an associated over-cost defined as follows:

- SCLD_l ("Sobrecostos producidos por fallas de larga duración en alta tensión de una línea *l*", in english, Over-costs produced due to long duration failures in HV of a line *l*).
- SCCD_l ("Sobrecostos producidos por fallas de corta duración en alta tensión de una línea *l*", in english, Over-costs produced due to short duration failures in HV of a line *l*.

During the Summer Seasonal Programming, CAMMESA calculates the annual over-costs due to long duration failures and short duration failures (SCLDE_l and SCCDE_l respectively) for each line *l*. These over-costs are calculated averaging the expected over-costs for the next four seasonal periods, as follows,

$$SCLDE\_l = \frac{\sum_p SCLDE\_l,p}{2}$$

$$SCCDE\_l = \frac{\sum_p SCCDE\_l,p}{2}$$

where,

$SCLDE\_l,p$ is the over-cost due to large duration failures of line *l* during seasonal period *p* calculated in accordance to [2, Annexe 3, Item 3.1.1].

$SCCDE\_l,p$ is the over-cost due to short duration failures of line *l* during seasonal period *p* calculated in accordance to [2, Annexe 3, Item 3.1.2].

Note: Each seasonal period corresponds to a 6 month period. One is the summer seasonal period and the other is the winter seasonal period.

The over-price due to transmission system reliability (IPCONST_l) reflects the annual over-costs due to large and short duration failures per unit power linked through line *l*. IPCONST_l is calculated as follows,

$$IPCONST\_l = \frac{(SCLDE\_l + SCCDE\_l)}{(PMPT\_I)(NHFV)}$$

where,

$NHFV$ are the number of non-valley hours during the working days in the two seasonal periods considered.

$PMPT\_l$ is the average power linked through line *l*, calculated in accordance to [2, Annexe 3, Item 3.1.3].

The price for capacity at node *i* ($PPADi) is calculated adding the total over-price at node *i* due to transmission system reliability to the price for capacity at the market ($PPAD):

$$\$PPADi = \$PPAD + \sum_l IPCONSTi\_l$$

where,

$IPCONSTi\_l$ is the over-price due to transmission system reliability at node *i*. When line *l* is out of order, node *i* keeps linked to the market with constraints.

Then, using the previous definitions, the adaptation factor at node *i* is calculated as follows,

$$FAi = 1 + \frac{\sum_l IPCONSTil}{\$PPAD}$$

Payments to generators

Generators are paid for the energy produced when dispatched and also for the capacity made available and accepted by CAMMESA.

The payments the generators receive for the hourly energy is given by the marginal cost of producing and transporting the next MWh to the market place. Thus, generators receive, for the energy produced, the nodal price at the busbar they are connected to.

During the weeks with failure risk an overprice is paid (SPRF) for the energy generated during the working days at peak hours [3]:

$$SPRF = \frac{ENS}{D} x(CENS - PM)$$

where:

$SPRF$ is the overprice due to failure risk

ENS is the probable energy not supplied.

D is the forecasted demand.

$CENS$ is the cost of the energy not supplied.

PM is the market price.

The payments for capacity are done over the working days at peak hours.
During the weeks without failure risk, CAMMESA organises a price competition between generators. The result are the generators which will remain as cold reserve. The price for capacity is paid to all the available generators scheduled and to all the generators that provide reserve.

Seasonal Prices for Distcos

The prices for distribution companies are calculated for seasonal periods of 6 months duration.
One period correspond to winter-spring with high contribution of hydroelectric energy. The other period correspond to summer-autumn with low contribution of hydroelectric energy.

These prices remain fixed during the first 3 months of the period. If at the end of the trimester there are differences with respect to the original hypothesis considered in the Seasonal Programming, the SE could modify the prices for the remaining period.

In order to determine the Seasonal Prices CAMMESA uses optimisation models calculating the optimum hydrothermical energy dispatch. The database used is provided and agreed among the WEM members.
In addition, the service quality is agreed with the Distcos. From the service quality agreed, the reserve requirements and correspondent costs are obtained.

The result of the Seasonal Programming is the price of energy for each Distco, determined for each tariff period; e.g. peak, valley and remaining period. These prices are the weighted averages, for each week, of the PM plus the differences for the energy valued at a different price (local prices, operation costs, etc.), modified using the nodal and adaptation factors.
On the other hand, an estimation of the SPRF is also obtained.

Integrating the payments for the $PPAD and the SPRF over the period, the capacity payments for the Distco in the seasonal period may be calculated.

The seasonal price for the capacity of each Distco is defined as a fixed monthly payment. For the calculation, two facts are taken into account:
1. The power contracted by the Distco.
2. The total payments forecasted in one semester for the PPAD paid to generators.

The tariff for distribution companies consists in two terms:

- an unique energy price for each tariff period for the whole semester.
- a fixed charge for capacity.

TRANSMISSION TARIFFS

The transmission tariff that must be paid by entities engaged in generation and distribution activities and by large users can be broken down into:

1. A connection charge that underwrites the costs of operating the equipment that links them to the transmission system.
2. A transport capacity charge that corresponds to the payments associated to operation and maintenance of the equipment used for the electricity transport service.
3. A charge based on the aggregate amount of electric energy transported which is calculated from the difference of the value of the energy at the receiving busbar and the value of the energy at the sending busbar.

DISTRIBUTION TARIFFS FOR FINAL CUSTOMERS

Retail tariffs for the biggest distribution companies (EDENOR, EDESUR and EDELAP), which represent the 44 % of the electricity market, are established by indexed rate formulas in their concession contracts for an initial five-year period.
They are based on the sum of the nodal price and the VAD ("Valor Agregado de la Distribución", in english, Value for the distribution service).
The VAD are set to cover the distribution system operating costs, taxes, and amortisation.
The VAD incorporates a rate of return to encourage the enterprise's efficiency, as well as an investment return expected for activities with parallel levels of risk.

Penalties are applied for failure to meet established quality of distribution service criteria.

The ENRE ("Ente Nacional Regulador de Electricidad", in english, National Electricity Regulator) oversees these tariffs and will apply new tariff formulas based on defined criteria once the five-year period is over.

Provincial authorities set tariffs for distribution utilities in their jurisdiction according to economic criteria promoted by sector reforms at this level. Before the reforms, retail tariffs in the provinces have historically been subjected to a political, rather than an economic basis.

THE ELECTRIC SYSTEM

Power System overview

By the end of 1998, Argentina had an installed capacity of 23046 MW with a total electricity generation of 68460 GWh during the year [29]. Electricity consumption in that same year was 64711 GWh growing 5 % from the previous year [17].
Planners expect electricity demand will continue to grow at the same average annual rate during the next decade. The capacity additions contemplated for the coming years are mostly thermal, using natural gas-fired plants.
Electricity service covers around 95 % of the total population, but the level of electrification in isolated areas is only around 70 % [17].
The MEM ("Mercado Eléctrico Mayorista", in english, Wholesale electricity market) is the largest system in the country with a total installed capacity of 19271 MW in 1998 [29].
The MEMSP ("Mercado Eléctrico Mayorista del Sur de Patagonia", in english Southern Patagonia wholesale electricity market) operates the southern region and had an installed capacity of 831 MW in 1998 [29].

Participants and Degree of Private Sector Participation

Generation

There are currently forty generating companies in the MEM and four in the MEMSP. Except for bi-national projects (Yaciretá, Salto Grande), the commercial nuclear enterprise (ENASA), and minor plants owned by provincial utilities and co-operatives, virtually all generation in the country is in private hands. Foreign investors hold a major ownership stake in these units. There are also various co-generators and auto-generators in both regions.

Transmission

The transmission activity in Argentina is subdivided into two systems: The High Voltage Transmission System (STEEAT), which operates at 500 kV and transports electricity between regions, and the regional transmission systems (STEEDT), which operate at 132 / 220 kV and connect generators, distributors and large users within the same region.

TRANSENER is the biggest company of the STEEAT, and five regional companies are located within the STEEDT (TRANSNOA, TRANSNEA, TRANSPA, TRANSCOMAHUE and DISTROCUYO). In addition to these companies, there are also provincial transmission companies and independent transmission companies. These companies operate under a technical license provided by TRANSENER, which in turn will make their assets available in the MEM in exchange for an established fee.

Retail Distribution

The three distribution companies divested from SEGBA (EDENOR, EDESUR and EDELAP) represent 44 % of the electricity market in Argentina. Including the companies divested from some regional utilities (Entre Rios, San Luis, Córdoba, Mendoza, Formosa, Santiago del Estero, Tucumán, Río Negro, Catamarca, Misiones, Jujuy and Santafe), private participation in the distribution market has increased to 60 %. The remaining distribution companies have remained in the hands of the provincial governments, but this ownership structure is expected to change with the expansion of the new regulatory framework to the different regions of the country.

Sectors problems after de-regulation

Some observations have been made on the problems arisen after de-regulation [17]:

- Some confusion and lack of confidence regarding the ability of the current transmission pricing system´s ability to provide incentives for new investment in capacity is a critical issue of debate. The transmission system has experienced some bottlenecks, but the regulatory entity has not yet actuate to allocate the responsibility for expansion or allocate costs among the relevant interest groups. Therefore, investors are reluctant to build new facilities. The SE has established a fund to support an emergency expansion of the system to relief the immediate pressure.
- The impact of sustained, low spot prices on the wholesale market may have a negative impact on generating companies´ financial health and interest in new investments because the capacity charges may not adequately reflect long run marginal costs for supply. Nevertheless, this condition will disappear if demand increases, including export to other countries.
- Undertaking restructuring and privatisation of the provincial utilities is occurring at an uneven pace due to the local governments reluctance to lose (as they perceive it) a ready-made source of revenues.
- The prolonged blackout that has occurred in Buenos Aires have raised questions about the operating conditions of the privatised distribution companies. The overseeing and penalty procedures affecting the distribution companies should be as strict as possible, guaranteeing that the concessions are following the contracts that they signed.

1.1.2 The New Electricity Supply Industry in Chile

INDUSTRY STRUCTURE

Law DFL Nº 1 from 1982 (Energy Act) [22] divides the electricity industry into three sectors: generation, transmission and distribution.
There is competition in generation but no competition in transmission and distribution. Transmission and distribution businesses are regulated because of their inner characteristic of being natural monopolies.

The electricity companies are subject to regulation of its prices and other aspects of its business in Chile under the Chilean Electricity Law. Three government entities have primary responsibility for the implementation and enforcement of the Chilean Electricity Law.
CNE ("Comisión Nacional de Energía", in english, National Commission of Energy) has authority to set tariffs and node prices and to prepare the Indicative Plan, a 10 year guide for the expansion strategy of the electric system.
SEC ("Superintendencia de Electricidad y Combustibles", in english, Secretariat of Electricity and Fuels) sets and enforces the technical standards of the system.
In addition, the Ministry of Economy grants final approval of tariffs and node prices set by CNE and regulates the granting of concessions to electric generation, transmission and distribution companies.

The sector is almost completely unbundled vertically and horizontally, though legally the functional separation of commercial activities is not required. However, major concerns persist regarding horizontal and vertical integration [17]. The ownership of the SIC ("Sistema Interconectado Central", in english, Central Interconnected System) is under a corporate entity, TRANSELEC, which has the same shareholders as ENDESA, the largest generator in the region. In addition, ENERSIS, the holding company for the largest distribution company in Chile, owns around 25 % of ENDESA´s shares.

DISPATCH AND PRICING

The Chilean power network consists of two systems, the SIC, which includes the capital Santiago and its surroundings, and the SING ("Sistema Interconectado del Norte Grande", in english, Great Northern Interconnected System), which supplies the mining region in the north. These two systems are not interconnected to each other and the SIC has approximately three times the installed capacity of the SING. There are also various small interconnected systems in the south.

There is a CDEC ("Centro de Despacho Económico de Carga", in english, Centre for Economic Load Dispatch) for each system. The CDEC co-ordinates the operation of the corresponding interconnected system. For example, there is one CDEC for the SIC and an one CDEC for the SING. Any other electricity system with more than 100 MW of installed capacity must have its own CDEC. Each CDEC is controlled by the largest generators of the system where that CDEC operate.

The SIC and the SING are intended to be near perfect markets for the sale of electricity in which the lowest marginal cost producer is used to satisfy demand before the next lowest marginal cost producer is dispatched. As a result, at any specific level of demand, the appropriate supply will be provided at the lowest possible cost of production available in the system.

Generation companies meet their contractual sales requirements with dispatched electricity, whether produced by them or purchased by them in the spot market.

A generation company may be required to purchase or sell energy or capacity in the spot market at any time depending upon its contractual requirements in relation to the amount of electricity from such company to be dispatched. Purchases and sales made in the spot market are traded at the "spot marginal cost" of the interconnected system in which the companies are located, which is the marginal cost of the last generation facility to be dispatched.

Sales to distribution companies for resale to regulated customers (customers which demand for capacity is equal or less then 2 MW) must be made at the nodal seasonal prices. Two nodal prices are paid by distribution companies: nodal prices for peak capacity and nodal prices for energy.

Nodal prices for peak capacity and energy consumption are established every six months.

Sales to unregulated customers (customers with demand for capacity of more then 2 MW), whether directly by a generation company or through a distribution company for consumption by such distribution company's customers, are not regulated and are made at negotiated prices.

In Fig. 1.3, the various possibilities of trading electricity in the WEM are shown. The diagram also shows how the imbalances are traded in the market.

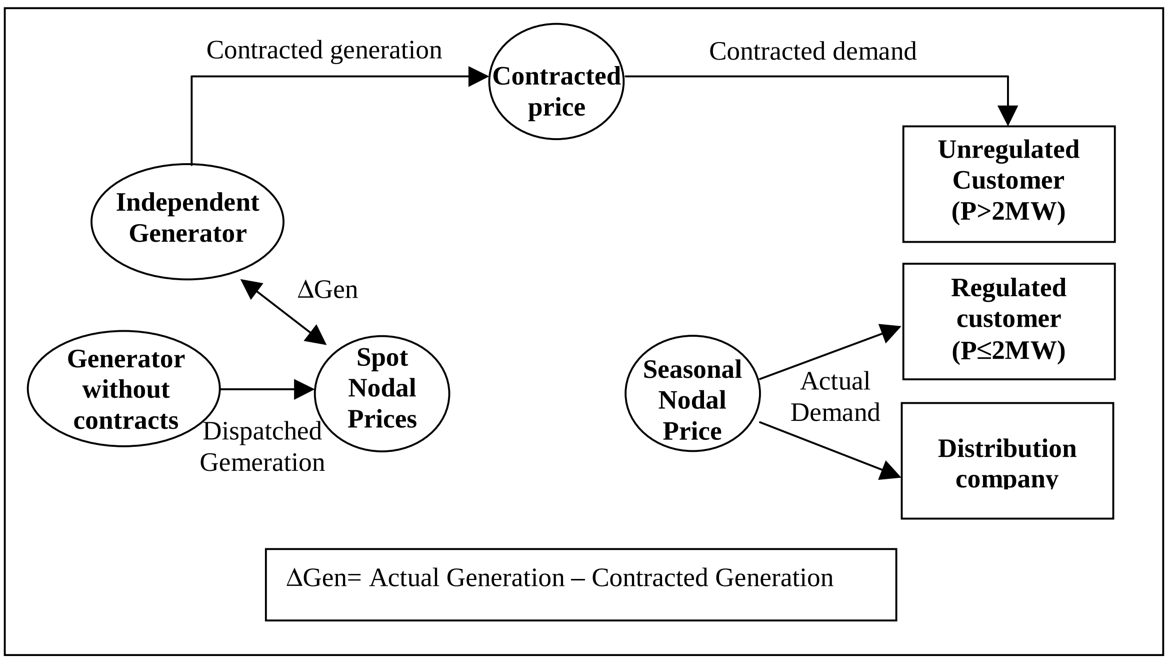


Fig. 1.3. Chile: Trading prices in the WEM.

PRICE SYSTEM

The type of pricing used in Chile is Nodal Pricing.
CNE must calculate nodal prices at each relevant substation where distribution companies are connected to the system. This calculation is done every six months.

Nodal Prices have two components: Nodal Price for Energy and Nodal Price for Peak Capacity [22].

Basic Prices for Energy

In order to calculate Nodal Prices for Energy, CNE determine Basic Prices for Energy at one or more reference substations known as Basic Energy Substations. These substations are chosen taken into account:

- Geographical location of marginal generators.
- Sectors of the transmission system where relevant transfers of power occur.
- Demand busbars (busbars where demand is greater than local offer of energy).
- Local demand at the substation compared to total demand.

Basic Prices for Energy are then calculated at the Basic Energy Substations using the expression:

$$P_b = \frac{\sum_{i=1}^{i=N} (CMG_i x D_i) / ((1+T)^i}{\sum_{i=1}^{i=N} (D_i) / ((1+T)^i} \quad \text{(Art. 275, DS Nº 327 [23])}$$

where:

N correspond to the total amount of periods of equal duration considered (which its summation results in between 24 and 48 months).

T is the equivalent rate for each period considering an annual capital cost of 10%.

CMG_i is the expected marginal cost of energy at basic energy substations at period *i* (average system cost of providing an additional unit of energy at the substation considered, with optimal system operation).

D_i is the expected demand at period *i*.

Expected marginal costs of energy result from an optimisation that minimises the summation of the actualised operation and rationing cost during the period of study.

Basic Prices for Peak Capacity

In order to calculate Nodal Prices for Peak Capacity, CNE determine Basic Prices for Peak Capacity at one or more substations. In order to achieve that, CNE determine the most economic units that could provide additional power during the hours of peak demand.

The Basic Price for Peak Capacity will be equal to the annual marginal cost of increasing system capacity using that type of units. For the calculation a percentage equal to the theoretical reserve margin is added to system capacity.

Nodal Prices

CNE calculates Nodal Prices for Energy, at the relevant substations of the electric system, multiplying Basic Prices for Energy by an Energy Penalisation Factor.

In the same way, CNE calculates Nodal Prices for Peak Capacity, at the relevant substations of the electric system, multiplying Basic Prices for Peak Capacity by a Capacity Penalisation Factor.

The calculation of the penalisation factors is done considering the marginal looses of energy and peak capacity transmission respectively using the economical adapted system.

Node prices must fall within 10 % of deregulated prices.

Trading of energy between generators

Transfers of energy between generators are done at spot prices taking into account marginal cost of energy and marginal cost of peak capacity.

The marginal cost of peak capacity (CMgP) is calculated using:

$$CMgP = \frac{CMCG}{DUPA}$$

where,

$CMCG$ is the annual marginal cost of increasing the actual generating capacity of the electric system.
$DUPA$ is the annual availability of the most economic units that could provide additional capacity during the hours of annual peak demand of the electric system.

The marginal cost of energy is the average system cost of providing an additional unit of energy at the substation considered, with optimal system operation.
It results from an optimisation that minimises the summation of the actualised operation and rationing cost during the period of study.

TRANSMISSION TARIFFS

As transmission companies´ assets were constructed through concessions granted by the Chilean government, the Chilean Electricity Law requires such companies to operate the covered transmission system on an "open access" basis. New users may obtain access to the system by participating in the investment to expand the system.

Law DFL Nº 1 [22] allows transmission enterprises to receive an income which covers the long run annualised average costs (investment, operation and maintenance) for economically adapted system operations, as well as a return.
The transmission tariff has basically, two components:

1. Marginal revenue.
2. Basic toll.

The marginal revenue is the resulting amount of money for differences between nodal prices (nodal price at the generator busbar and nodal price at the buyer busbar).

The basic toll results from the summation of the O&M costs and investment costs of the network involved in the service.

Additional tolls are paid in the case that the generator asks to withdraw electricity from nodes different to those agreed for the basic toll.

As needed, a commission comprising representatives of both transaction parties is formed to solve disputes over the service or fees.

DISTRIBUTION TARIFFS TO FINAL CUSTOMERS

Retail tariffs for regulated end-consumers are obtained by adding the VAD to the node price for energy and capacity. Periodic tariff adjustments according to established criteria are allowed for distribution companies to change nodal prices.

The VAD is based on costs for a model distribution enterprise operating in a similar type zone (i.e., of similar density and other features) established for 4 year periods through CNE authorised consultant studies.

The VAD incorporates [22, Article Nº 106]:

- Fixed costs for administration, billing and customer service expenses.
- Standard investment costs and, operating and maintenance (O&M) costs for distribution per unit of power supplied.
  The annual investment costs are calculated using the VNR ("Valor Nuevo de Reemplazo", in english, New Replacement Value) considering the facilities adapted to the demand, the network life and an annual discount rate of 10 %.
  The VNR for the installations of a distribution company given in concession is defined in Article Nº 116 of DFL Nº 1 [22] as the cost to renew all the works, facilities and physical goods dedicated to provide the distribution service in that concession. The VNR is re-calculated every 4 years.
- Mean distribution losses in power and energy.

The indicated components are calculated for a specific number of standard distribution zones determined by the CNE, previous deliberation with the companies. These standard zones represent distinctive distribution densities (high density, urban, semi-rural and rural).

In the Chilean regulation model [28], there is a hybrid-benchmarking scheme between different companies. On one hand, groups of companies of similar characteristics are compared with a model company, identified through typical zones. Then, the performance of heterogeneous companies is compared in an integrated manner, with an assessment of the global adequacy of the industry with a single standard. In the former case and through a theoretical model and through direct comparison, efforts are made to provide the efficiency signal to similar companies and in the latter case efforts are made to produce a horizontal comparison that fits the theoretical model with the average reality of heterogeneous companies.

To prevent a theoretical approach, the regulation specifies that the cost study of the model company for each typical zone will be based on an efficiency assumption in the investment policies and in the management of a distributing company operating in the country [22, Article Nº 107]. Consequently, the analysis is limited to a model company that works in an environment similar to the one existing in reality and that it faces the same restrictions.

The methodology to determine the model company and the steps to be followed in the analysis can be essentially grouped in four stages [28]:

1. In the first stage, the information of the real company is collected and validated.
2. In the second stage, the efficient company and its organisation structure is defined and dimensioned.
3. In the third stage, the costs and their allocation to three fields (high voltage, low voltage and customers) are determined.
4. In the fourth stage, the VAD and the corresponding adjustment indexes to be used in the following four years is determined, together with the identification of special circumstances.

The global rate of return is set to a level between 6 % and 14 % [17]. The pricing mechanism does not include either quality of service issues or financial penalties.

THE ELECTRIC SYSTEM

Power System overview

Total installed capacity in Chile was 7858 MW in 1998 [17]. Electricity generation and demand were 33417 GWh and 29180 GWh respectively, which represents 12.7 % in losses. Growth in electricity demand has been steady at 7 % per year. More than 95 % of the population has electricity service. Since the entrance of the new gas pipelines from Argentina, most capacity additions have been gas fired combine cycle. As it was previously said, the Chilean power network consists of two big systems, the SIC and the SING, and also various small independent systems.

Participants and Degree of Private Sector Participation

Generation

Private generators, including self-generators, represent about 90 % of the nationally installed generating capacity. There are 11 main generating companies, under private (majority) ownership.

Ten private generators supply electricity in the SIC. The largest generator, the privately owned ENDESA and its subsidiary PEHUENCHE, own over 60 % of the SIC's installed capacity and supplies 65 % or so of the system's total generation. GENER is the second largest generator, with around 1600 MW of installed (mostly thermal) capacity, holding around 24 % of the market. GENER´s affiliate GUACOLDA S.A. is building another 300 MW of capacity with COCAR. The third generator is COLBUN-MACHICURA, which owns two hydro stations with a combined installed capacity of 560 MW (15 % of the market). Smaller private generators in the SIC include the GUARDIA VIEJA, PULLINQUE and PILMAIQUEN plants.

EDELNOR is a privately owned vertically integrated utility with 277 MW of installed capacity. It also owns (with CODELCO, a copper mining company) and operates the SING.

CHILGENER´s SING affiliate, NORGENER S.A. owns the 274 MW Nuevo Tocopilla plant. The 614 MW Tocopilla plant, the largest plant in the SING, belongs to the state owned copper mining company (CODELCO) and to a holding company composed of CODELCO and a private consortium consisting of TRACTEBEL (Belgium), IBERDROLA (Spain), and ENAGAS (Chile). In early 1996, this consortium bought the controlling 26% interest in the plant through the holding company. ENDESA owns 73 MW of installed capacity in the SING. Like CODELCO, many of the major mining industries located in the SING have considerable self-generating capacity, which they developed prior to the power sector reform.

Transmission

TRANSELEC was created as an ENDESA affiliate in order to own and operate the SIC´s transmission assets when they were spun off form ENDESA in March 1993. This new entity aimed to provide more transparency and alleviate concerns about the generator's potential for self-dealing transmission access on a priority basis. TRANSELEC´s shareholders were initially the same as ENDESA´s shareholders, but are evolving independently over time with changing investor interests.

EDELNOR, through its subsidiary, SITRANOR, owns and operates the transmission system of the SING.

Retail Distribution

There are a total of 23 distribution utilities in Chile. ENERSIS is the holding company for the largest distribution utility, CHILECTRA, which serves the Santiago metropolitan area (roughly 40 % of the total retail market). CHILECTRA and CHILQUINTA are the largest of the 17 investor-owned distribution utilities operating in the SIC. There are also very important companies like CGE, EMEL and SAESA which have been growing up very fast specially geographically over their concessions. EDELNOR and two smaller distribution utilities provide distribution service in the SING.

Generally, small vertically integrated companies under private ownership provide distribution service in the smaller, isolated systems (EDELAYSEN, EDELMAG). There are also three small municipal utilities and a few electric co-operatives supplying retail electricity service in remote areas.

Sectors problems after de-regulation

Some observations have been made on the problems arisen after de-regulation [17]:

- There are doubts regarding the independence of the CNE because of Ministerial involvement, insufficient staffing and expertise, and also because the regulatory role of the CNE is not absolute depending on the Ministries and the SEC.
  In addition, the regulatory agencies face difficulties in obtaining the necessary level of detailed information from sector enterprises, particularly regarding costs, which may cause difficulties in their ability to perform effectively on issues dealing with pricing and competition.
- As the long-term projections showed a reduction in the node prices, both in the SIC and in the SING, generators began to be concerned regarding their investments.
- There is concern about competition and the feeling that greater competition could lead to decrease benefits. These limiting factors on competition ultimately have an impact on new investments, economic cost of service, quality of service, and end-consumer options and prices.
  For instance, limiting factors include:
  - ENDESA ´s market power, as a single generator has been too overwhelming, representing more than 60 % of the capacity and 65 % of the generation in the SIC.
  - The exclusion of smaller generators as members of the CDEC committee (e.g., in the SIC, only the 5 largest generators are represented) has raised other issues on fair competition, pricing and rulemaking.
  - The coupling of the ownership and operation of the main transmission system with ENDESA´s dominant generating capacity has led to major concerns about the transparency and fairness of ENDESA´s marketing and wheeling terms.

- The pricing in the de-regulated market, representing about 27 % of total demand, is seen as being constrained by the regulated bulk power prices, whereas the node prices cannot vary by more than 10 % of the de-regulated prices.

1.2 EMBEDDED GENERATION (EG)

CIGRE defines Embedded Generation [6] as the generation which has the following characteristics:

- It is not centrally planned
- It is not centrally dispatched at present
- It is usually connected to the distribution network
- It is smaller than 50-100 MW

In this project we are going to consider Embedded or Dispersed or Distributed Generation all that generation which is directly connected into the distribution network instead of the transmission network. This is the same definition that is used in [15].

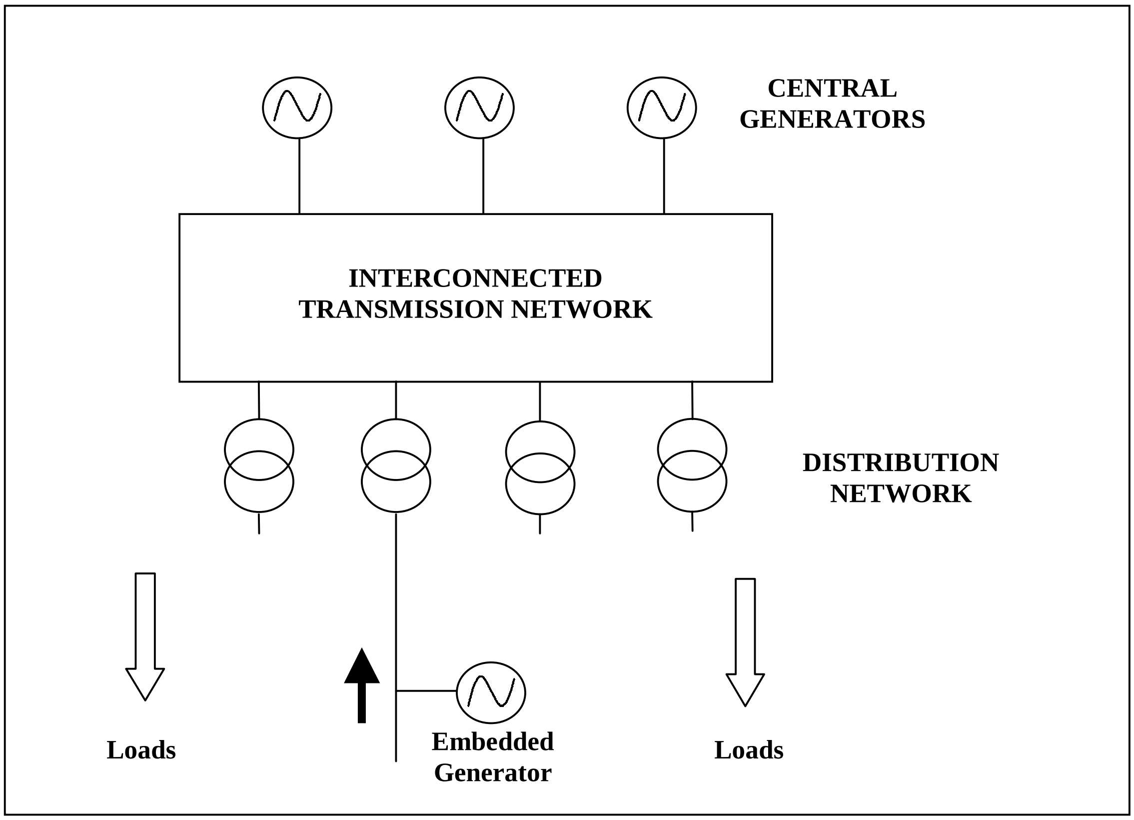


Fig. 1.4. Embedded Generation.

Examples of EG are CHP (Combined Heat and Power) plants (also known as co-generation plants), wind energy converters, hydro power stations, Photo-voltaic systems (PV), fuel cells and bio-mass plants.

Usual power levels for this plants are from 2 kW to 100 MW.

In the past, before the construction of big transmission networks covering large areas, all generation was embedded in distribution networks.

Then the situation changed, big generation plants were constructed and large transmission networks were built interconnecting generators and consumers.

Economies of scale involved in constructing large generation plants influenced this process. In addition, the presence of a transmission system gave more reliability and quality of supply.

Today we have an electricity industry which has large and strong transmission networks. However, in the last decades, the proportion of EG in the networks has been growing up.

Information provided by CIGRE shows that the percentage of EG in Denmark reach 37 % and in Netherlands 40 %. In other countries of Europe, the proportion of EG is clearly less than 15 %. See Fig. 1.5.

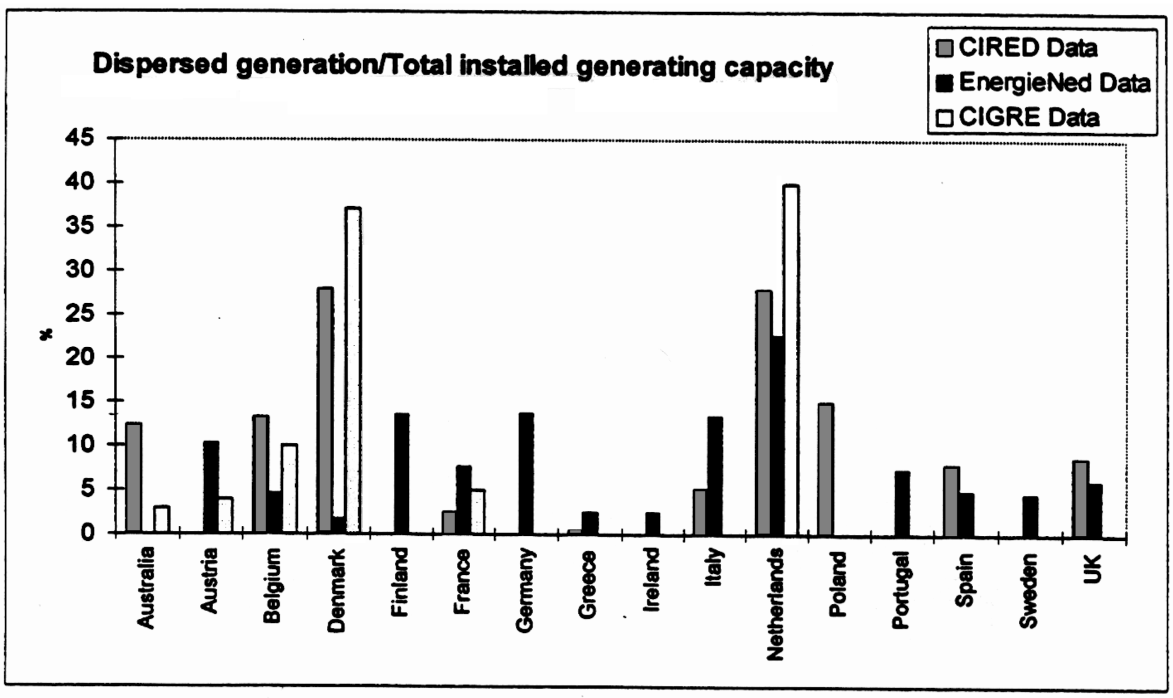


Fig. 1.5. EG in Europe.

There is an interest of governments to increase the amount of clean energy. This takes the form of government schemes which promote renewable generation. In many cases, the result are embedded renewable generation (ERG) plants.
In addition, interest in obtaining high overall efficiencies, for example through CHP plants, may be observed. The result are co-generation plants embedded in distribution networks.

The Working Group 37.23 of CIGRE [6] has summarised the reasons for an increasing share of EG in different countries. The aspects included in the report are the following:

- EG nowadays have mature technology that is readily available and modular in a capacity range from 100 kW to 150 MW.
- The generation can be sited close to customer load, which may decrease transmission costs.
- Sites for smaller generators are easier to find.
- No large and expensive heat distribution systems are required for local systems fed by small CHP-units.
- Natural gas, which is often used as fuel for EG, is expected to be readily available in most customer load centres and is expected to have stable prices.
- Gas based units are expected to have short lead times and low capital costs compared to large central generation facilities.
- Higher efficiency is achievable in co-generation and combined cycle configurations leading to low operational costs.
- Politically motivated regulations, e.g. subsides and high reimbursement tariffs for environmentally friendly technologies, or public service obligations, e.g. with the aim to reduce CO_2 – emissions, lead to economically favourable conditions.
- In some systems EG competes with the energy price paid by the consumer without contributing to or paying for system services, which leads to an advantage of EG in comparison to large generation facilities.
- Financial institutions are often willing to finance EG-projects since economics are often favourable.
- Unbundled systems with more competition on the generation market provide additional chances for industry and others to start a generation business.

- Customers demand for “green power” is increasing. (It is also interesting to read [13].)

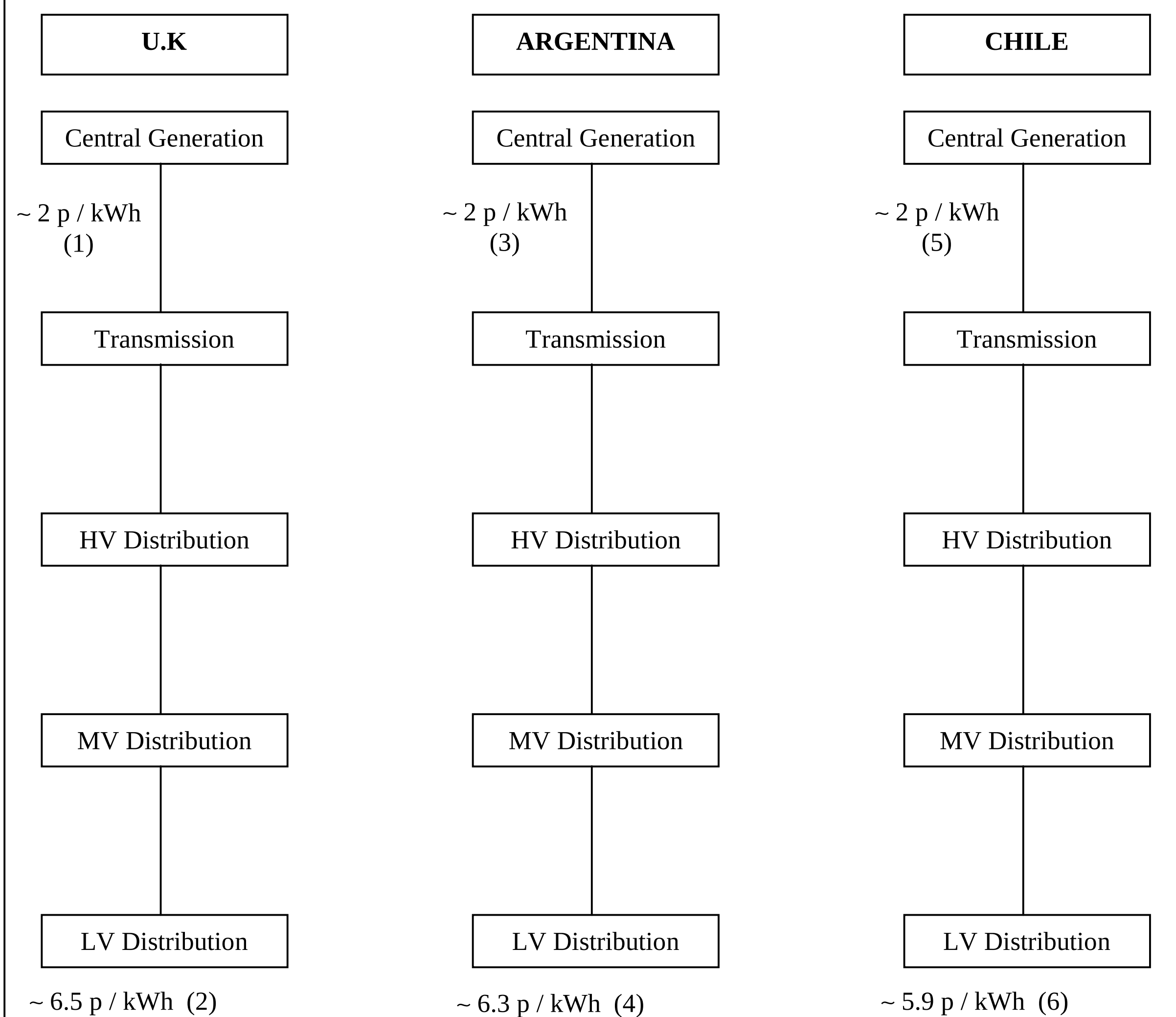
On the other hand, the growth of EG has led to concerns about the impact on the network of high levels of EG penetration. These concerns include aspects related to stability, voltage control, power quality, protection and security of the overall system. In addition, distribution companies are concerned with regard to the nature of their networks, which were designed for customers which consume electricity rather for customers which generate electricity.
These issues will be addressed in Chapter 2.

From the commercial point of view, considering the framework of a competitive ESI, EG becomes a big question. Is EG competitive? Does the present network practices and electricity tariffs structures consider the real value of EG?
In Fig. 1.6., present tariffs at different levels of the ESI in U.K., Argentina and Chile are shown.

The difference between wholesale electricity market prices and retail prices of electricity are, for the different countries considered, the following:

U.K.	$\Delta p \cong 4.5$ p / kWh
Argentina	$\Delta p \cong 4.3$ p / kWh
Chile	$\Delta p \cong 3.9$ p / kWh

The network charges directly measure the relative grade of competitiveness between central and EG.
Transmission and distribution networks, together with the supply business are responsible for the difference of prices (Δp). Electricity produced by central generation requires transmission and distribution networks to reach its consumers, while EG, often located closer to loads, requires less transporting facilities.



Notes:

(1) Source: [32].
(2) Source: [32].
(3) Source: [36].
(4) Source: [CIER]. Buenos Aires, EDESUR, taxes included.
(5) Source: [38].
(6) Source: [CIER]. Santiago de Chile, CGE, taxes included.

1 £ = 1.6 USD

Fig. 1.6. Prices at different levels of the ESI in U.K., Argentina and Chile

Consequently, electricity produced by EG may have a higher value than that produced by central generation.

However, it depends on the tariffs structures how much of that Δp is EG allowed to collect. As revealed in [32], the issue of competitiveness of EG is a network pricing problem. As a result, it is of major concern to study and know the real value (costs and benefits) of EG and to analyse how good does the tariffs structures of the ESI consider that value.

These aspects are addressed in Chapter 2.

CHAPTER 2

COMMERCIAL AND TECHNICAL ISSUES OF EMBEDDED GENERATION

In the new ESI prices take a fundamental place as they must express real or true costs in order to make competitiveness work. If the market was perfect, the interaction of market forces would lead to setting the optimum assignment of resources. However, the characteristics of the ESI, and the fact that transmission and distribution are natural monopolies, makes the presence of a Regulator necessary. The Regulator has to establish the planning principles, the standards and the tariffs structures that assure competition be able to work. In order to do that, the true costs involved must be very well known and understood.

When considering EG, the identification of the true costs mentioned above and their reflection in the planning and tariffs arrangements determines its competitiveness.

There are some aspects of EG in which it is important to think about when considering its participation in a competitive electricity market. We are going to call this aspects: commercial and technical issues of Embedded Generation.
The idea is trying to identify the true value of EG involved in all these aspects.

In this project, we are going to analyse the following commercial and technical issues:

1. Commercial issues:

- Allocation of losses
- Connection costs
- Externalities

2. Technical issues:

- Voltage regulation practice
- Power quality
- Protection and stability
- Methods and tools used in network planning and design

2.1 COMMERCIAL ISSUES OF EG

As it is revealed in [32], the actual approaches for distribution pricing have been developed for users who take power from the network rather than for users who inject power into the network. This means that EG is ignored.   The impact of EG on the networks (costs and benefits) is very site specific, it varies in time, it depends on the availability of primary sources (e.g. wind or light when considering for example ERG), on the size of the plant, the proximity of the load and the characteristics of the network where the plant is connected. That is why the use of simplistic tariff structures which for example average network charges across customer groups are not adequate to capture the spatial and temporal variations of EG costs and consequently do not reflect the economic impact of EG on the distribution network.

A complete development of new tariffs that recognise the specific location of EG and its impact on power system operating and capital costs is proposed in [32].

In addition, for the case of ERG, there is another aspect that tariffs should consider that are the environmental externalities. As discussed in [15] externalities have been defined as "benefits or costs, generated as a byproduct of an economic activity, that do not accrue to the parties, involved in the activity". Generally, no direct commercial value attaches to the clean plant as it does not receive higher payment than other more polluting plant.

In this Chapter the main questions related to the commercial issues of EG are addressed, the general practices and its inadequacies are reviewed and some alternatives are proposed based on [32].

2.1.1 Allocation of losses

INTRODUCTION

The presence of EG in the network alter the power flows and consequently the network losses. The method used for the allocation of the cost of losses will necessary have a great impact on the parties involved.

We are going to take as hypothesis that the ideal scheme for allocating losses should fulfil the following requirements [32]:

- Economic efficiency. Losses must be allocated so as to reflect the true cost that each user imposes on the network with respect to cost of losses.
- Accuracy, consistency and equity. The loss allocation method must be accurate and equitable, i.e. must avoid or minimise cross subsidies between users and between different times of use. Furthermore, the method must be consistent.
- Must utilise metered data. From a practical standpoint, it is desirable to base allocation of losses on actual metered data.

- Must be simple and easy to implement. In order for any proposed loss allocation method to find favour, it is important that the method is easy to understand and implement.

REVIEW ON CURRENT ALLOCATION OF LOSSES METHODS

Since the advent of competitive electricity markets, several schemes have been proposed for evaluating and compensating for looses.

For instance, contributions method is based on the assumption of proportionality to determine the proportion of the active power flow in a transmission line contributed by each generator. This proportion of line use is used to evaluate the losses allocated to each generator. This is the idea behind the Substitution method, which ends calculating Loss Adjustment Factors (LAFs). LAFs are then used to gross up demand or generation to the Grid Supply Point (GSP) to account for losses.
Looking to our hypothesis, this method fails to satisfy the economic efficiency objective because it determines the share rather the impact of each generator on each line flow. As a result, no messages are given to users regarding the costs they impose on the system.

There are other proposed methods, such as the Marginal Loss Coefficient method (MLC method) and the Direct Loss Coefficient method (DLC method) [32].
The first one is based on Short-Run Marginal Cost (SRMC) pricing allocating marginal losses. MLCs measure, by definition, the change in total active power losses due to a marginal change in consumption or generation of active power P_i and reactive power Q_i at each node *i* in the network. MLC method achieves economic efficiency (under the hypothesis, widely accepted, that SRMC pricing achieves that objective). On the other hand, the method needs revenue reconciliation (the losses calculated from MLCs turn out to be greater than actual losses incurred in the network).

The second method, DLC method, allocates total losses instead of marginal losses. DLC method relates losses directly to nodal injections. The objective of the method is to derive a relationship such that losses can be expressed directly in terms of injections.

Due to the complexity of AC load flow equations and their solution by iterative procedures, a closed form solution for losses is not feasible. In addition, the formula used to compute losses contains system state variables whose values are only known after the load flow solution has converged. The main idea of the method is that losses are almost quadratic function of the power flows. Hence, the losses are estimated using Taylor series expansion around the initial operating point. The operating point is defined in terms of state variables V and θ with P and Q representing the corresponding nodal power injections. The assumptions and approximations made in the computation of direct loss coefficients give rise to small differences between the losses calculated from the application of DLC ´s and those calculated from load flow. However, in contrast to MLC ´s there is no fundamental requirement for reconciliation in the case of DLC ´s.

Substitution method.

In order to clarify the idea behind the substitution method and analyse its problems, we are going to consider the same example as proposed in [32].

Let us consider the following simple distribution network:

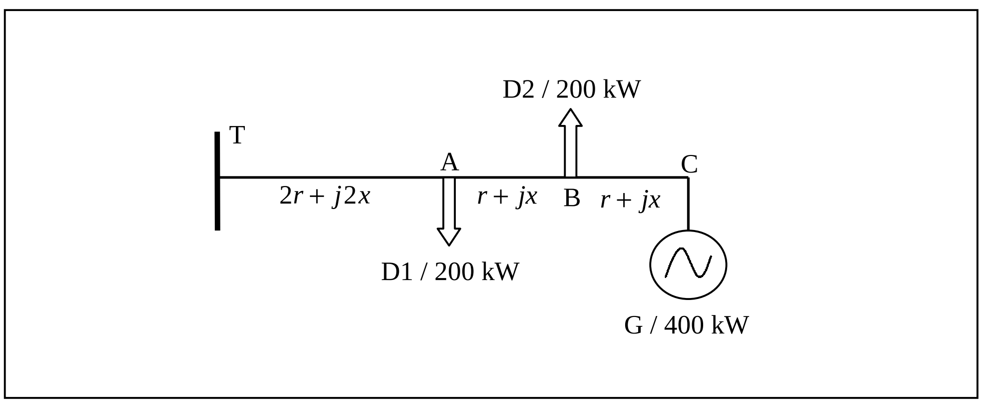


Fig. 2.1. A simple distribution network to analyse the substitution method.

Fig. 2.1 shows a radial feeder which has two loads (D1 and D2 at point A and B respectively) and a generator (G) embedded at point C. The power demanded by the loads is supposed to be constant and equal to 200 kW. The power delivered by the generator is 400 kW.

The distance between A and B is the same as the distance between B and C. In addition, the distance between T and A is twice the distance between A and B. Impedances for sections TA, AB and BC are those indicated in the diagram.

In order to simplify the calculations, the following hypothesis are made:

- All voltage magnitudes are equal to 1.0 p.u.
- Voltage drops are negligible.
- Losses have no impact on the calculation of power flows.
- $x >> r$

A base value of 100 kW is used and a value of r = 0.001 p.u. is chosen.

From the hypothesis made it is easy to demonstrate that the line looses (l) can be calculated multiplying the value of line resistance (r) by the square of the active power flow (p) through the line:

$$l = rp^2$$

For the case shown in Fig. 2.1 the power flows are the following:

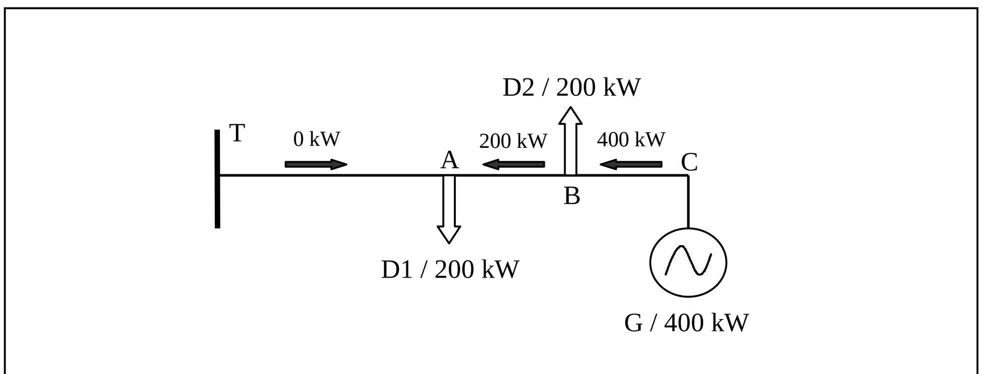


Fig. 2.2. Base Case power flow: all users connected.

This case, when all users are connected is taken as the base case.

The looses for the base case are then,

$$l = 0.001\left[2^2 + 4^2\right] = 0.02 \ p.u.$$

To apply the substitution method, each user must be disconnected in turn and the losses must be calculated for each case.

Let us disconnect the generator (G) first. The power flows for this case result:

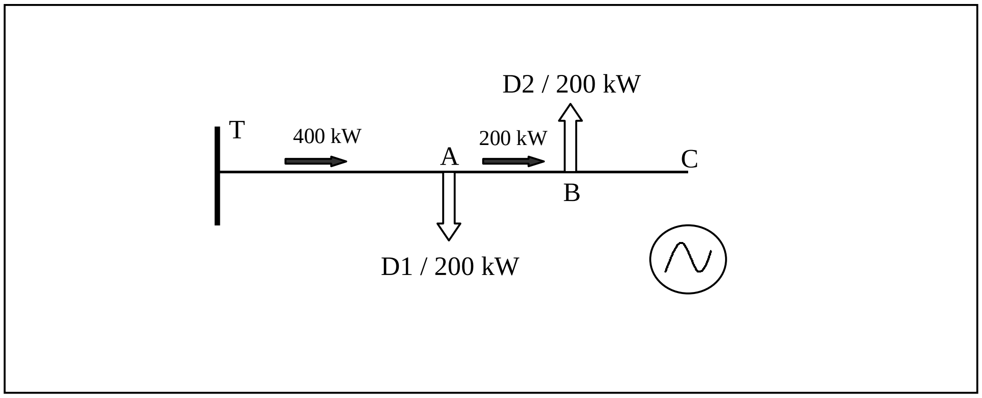


Fig. 2.3. Power flows when G is disconnected.

For this case, the looses are:

$$l = 4^2 x(2x0.001) + 2^2 x0.001 = 0.036 \; p.u.$$

As the total power losses decrease from 3.6 kW to 2.0 kW when the embedded generator G is connected, in accordance with the substitution method the embedded generator G reduces losses and therefore should be rewarded.

Now, the case when D1 is disconnected will be analysed. The resulting power flows are shown in Fig. 2.4.

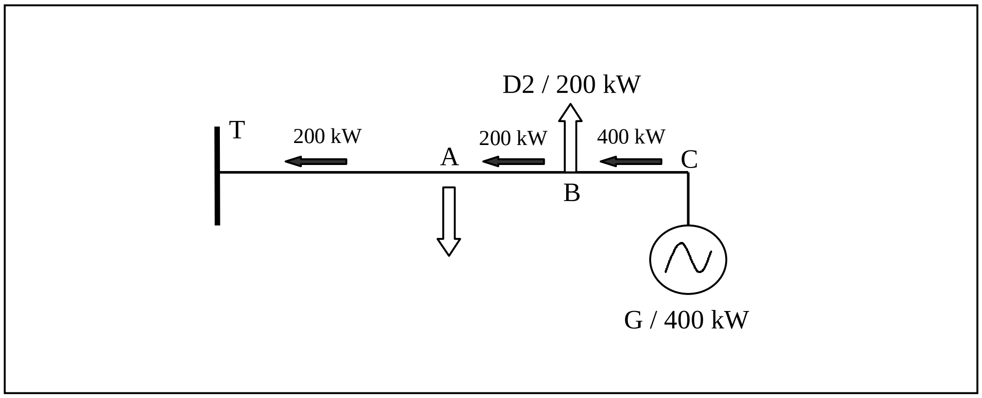


Fig. 2.4. Power flows after disconnecting the user D1.

The losses for this case result:

$$l = 2^2\, x(2x0.001) + 2^2\, x0.001 + 4^2\, x0.001 = 0.028\ p.u.$$

The total losses decrease from 2.8 kW to 2.0 kW when D1 is connected to the network. In accordance with the substitution method, the user D1 also reduces total losses and should then be rewarded.

Finally, the case when D2 is disconnected must be analysed. The power flows for this case are shown in Fig. 2.5.

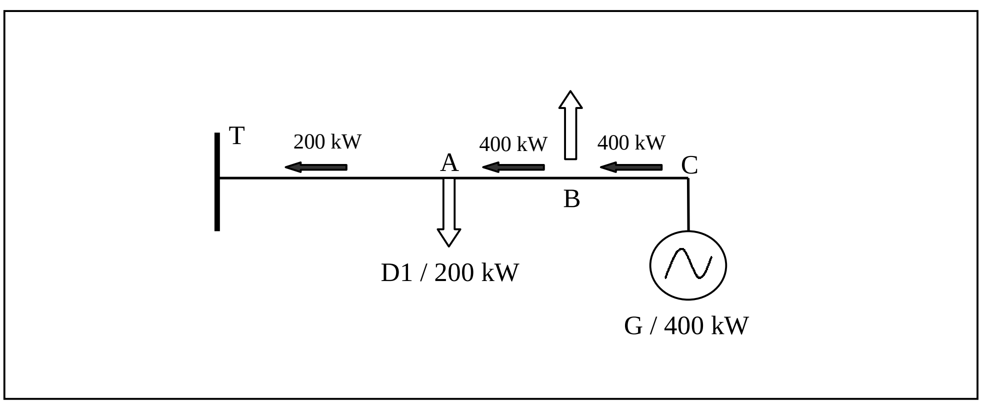


Fig. 2.5. Power flows when D2 is disconnected.

The losses when D2 is disconnected are:

$$l = 2^2 x(2x0.001) + 4^2 x0.001 + 4^2 x0.001 = 0.040\ p.u.$$

As in the other cases, D2 also reduces total losses from 4.0 kW to 2.0 kW. Consequently, in accordance with the substitution method D2 should be rewarded as well.

Clearly, by applying the substitution method it appears that each of the users in this example contributes to a reduction in the total system losses. According to the substitution method, they would all be entitled to a reward for reducing total losses. However, they are the only users responsible for creating losses. This clearly demonstrates the inconsistency of the substitution method.
Using another example, it can be also demonstrated that the substitution method produces cross-subsides.
Let us consider the same network but with another embedded generator connected at point F (see Fig. 2.6). The line impedance between T and F is indicated in the diagram.

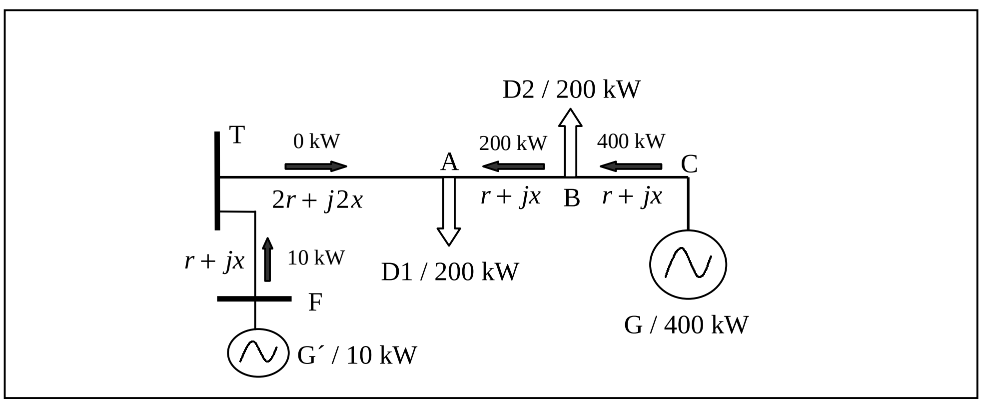


Fig. 2.6. Cross-subsides created by the substitution method.

The power flows, for this new example, are shown in the above diagram. The losses when all users are connected are calculated:

$$l = 2^2 x0.001 + 4^2 x0.001 + 0.1^2 x0.001 = 0.02001\ p.u.$$

Generator G´ does not influence the impact on losses of users A, B and C, previously calculated by the substitution method.

The losses when generator G´ is disconnected from the network are those calculated in the case shown in Fig. 2.2 (base case).

Consequently, the connection of G´ increases the losses from 2.0 kW to 2.001 kW, and therefore, accordingly with the substitution method, G´ must be penalised.

It is important to note that in a reconciliation process the cost of total system losses would have to be recovered. As G´ is the only one seen to be creating losses, it would be left to pay, not only for their own losses, but also for losses created by the other three users. In addition, G´ would also have to pay the bill rewarding the users at nodes A, B and C for their apparent contribution to system loss reduction.

As a result, in this example, cross-subsides are introduced between users when applying the substitution method.

MLC method

Using the MLC method, loss adjustment factors (LAFs) are calculated based on the concept of marginal losses. MLCs measure the change in total active power losses L due to a marginal change in consumption or generation of active power P_i and reactive power Q_i at each node i of the network.

Then, the idea is to express the losses L as:

$$L = \sum \left[\rho_{P_i} P_i + \rho_{Q_i} Q_i \right] \qquad \text{(eq. 2.1)}$$

where ρ_{P_i} and ρ_{Q_i} are LAFs which are related to the loss marginal coefficients.

Let us calculate now the marginal loss coefficients. By definition, the MLCs are,

$$\begin{aligned} \tilde{\rho}_{P_i} &= \frac{\partial L}{\partial P_i} \quad i = 1,2,\dots N \\ \tilde{\rho}_{Q_i} &= \frac{\partial L}{\partial Q_i} \quad i = 1,2,\dots N \end{aligned} \qquad \text{(eq. 2.2)}$$

where, N is the total number of nodes of the network.

$\tilde{\rho}_{P_i}$ and $\tilde{\rho}_{Q_i}$ represent the active and reactive power related MLCs.

If a user, i.e. generator, takes part in voltage control by injecting required power (PV node), there are no loss-related charges for the reactive power to be allocated. Then, it is defined,

$$\frac{\partial L}{\partial Q_i} = 0 \quad \text{if } i \text{ is a PV node} \qquad \text{(eq. 2.3)}$$

In the same way, as losses are deemed to be supplied from the slack node, the loss-related charges, for this node are zero:

$$\frac{\partial L}{\partial P_s} = \frac{\partial L}{\partial Q_s} = 0 \quad s \text{ is the slack node} \qquad \text{(eq. 2.4)}$$

Because of this assumption, the choice of slack node clearly has an impact on both magnitude and polarity of MLCs. Fortunately, in distribution systems where we are focusing, this complication need not arise as the transmission network can always be taken as the slack node.

Marginal loss coefficients are a function of a particular system operating point. As there is no explicit relationship between losses and power injections, the standard chain rule is applied in the calculation of MLCs using voltage magnitudes and angles as intermediate variables (V_i and θ_i respectively). As a result, only a load flow solution for a particular system operating point is required to compute MLCs.

Applying the standard chain rule, the following general system of linear equations can be established for calculating MLCs:

$$\left[\begin{array}{cccc:cccc} \frac{\partial P_1}{\partial \theta_1} & \frac{\partial P_2}{\partial \theta_1} & \cdots\cdots & \frac{\partial P_N}{\partial \theta_1} & \frac{\partial Q_1}{\partial \theta_1} & \frac{\partial Q_1}{\partial \theta_1} & \cdots\cdots & \frac{\partial Q_N}{\partial \theta_1} \\ \vdots & & & & & & & \\ \frac{\partial P_1}{\partial \theta_N} & \frac{\partial P_2}{\partial \theta_{N1}} & \cdots\cdots & \frac{\partial P_N}{\partial \theta_N} & \frac{\partial Q_1}{\partial \theta_N} & \frac{\partial Q_2}{\partial \theta_N} & \cdots\cdots & \frac{\partial Q_N}{\partial \theta_N} \\ \hdashline \frac{\partial P_1}{\partial V_1} & \frac{\partial P_2}{\partial V_1} & \cdots\cdots & \frac{\partial P_N}{\partial V_1} & \frac{\partial Q_1}{\partial V_1} & \frac{\partial Q_2}{\partial V_1} & \cdots\cdots & \frac{\partial Q_N}{\partial V_1} \\ \vdots & & & & & & & \\ \frac{\partial P_1}{\partial V_N} & \frac{\partial P_2}{\partial V_N} & \cdots\cdots & \frac{\partial P_N}{\partial V_N} & \frac{\partial Q_1}{\partial V_N} & \frac{\partial Q_2}{\partial V_N} & \cdots\cdots & \frac{\partial Q_N}{\partial V_N} \end{array}\right] . \begin{bmatrix} \frac{\partial L}{\partial P_1} \\ \vdots \\ \frac{\partial L}{\partial P_N} \\ \frac{\partial L}{\partial Q_1} \\ \vdots \\ \frac{\partial L}{\partial Q_N} \end{bmatrix} = \begin{bmatrix} \frac{\partial L}{\partial \theta_1} \\ \vdots \\ \frac{\partial L}{\partial \theta_N} \\ \frac{\partial L}{\partial V_1} \\ \vdots \\ \frac{\partial L}{\partial V_N} \end{bmatrix} \qquad \text{(eq. 2.5)}$$

This expression can be written in a more compact form as follows:

$$A.\tilde{\rho} = b \qquad \text{(eq. 2.6)}$$

Matrix *A* is the transpose of the Jacobian in the Newton-Raphson load flow and can be calculated on the basis of load flow results for a particular system operating point. The vector $\tilde{\rho}$ represents MLCs whereas the right-hand vector b represents sensitivities of total losses with respect to voltage angle and magnitude.

In order to calculate the vector $\tilde{\rho}$, vector b must be calculated first.
An expression of total losses *L* may be obtained from the summation of the individual losses in each branch of the network.
The square of the voltage drop between nodes *i* and *j* is given by:

$$\Delta V_{ij}^2 = V_i^2 + V_j^2 - 2V_iV_j \cos(\theta_i - \theta_j) \qquad \text{(eq. 2.7)}$$

If G_{ij} is the conductance of the branch between nodes *i* and *j*, then the losses in that branch are:

$$L_{ij} = G_{ij}\Delta V_{ij}^2 = G_{ij}\left[V_i^2 + V_j^2 - 2V_iV_j \cos(\theta_i - \theta_j)\right] \qquad \text{(eq. 2.8)}$$

Consequently, the total losses L are given by:

$$L = \frac{1}{2}\sum_{i=1}^{N}\sum_{j=1}^{N} G_{ij}\left[V_i^2 + V_j^2 - 2V_iV_j\cos(\theta_i - \theta_j)\right] \qquad \text{(eq. 2.9)}$$

where the factor $\frac{1}{2}$ appears because the double summation encounters the losses of each branch twice.

The components of vector b are the partial derivatives of L:

$$\frac{\partial L}{\partial \theta_i} = 2\sum_{j=1}^{N} G_{ij}V_iV_j\, sin(\theta_i - \theta_j) \quad i = 1,2,....N \qquad \text{(eq. 2.10)}$$

$$\frac{\partial L}{\partial V_i} = 2\sum_{j=1}^{N} G_{ij}\left[V_i - V_j\cos(\theta_i - \theta_j)\right] \quad i = 1,2,....N \qquad \text{(eq. 2.11)}$$

It is important to note that there are no equations for any voltage-controlled node as by definition the MLC with respect to reactive power for any such node is zero. In the same way, there are no equations for the slack node as by definition the MLC with respect to active and reactive power for the slack node is zero.

From eq. 2.6, vector $\tilde{\rho}$ is calculated.
The result of using $\tilde{\rho}$ for the evaluation of losses yields approximately to twice the value of actual losses [32]:

$$\sum_{i=1}^{N-1}\left[\tilde{\rho}_{P_i}P_i + \tilde{\rho}_{Q_i}Q_i\right] \approx 2L \qquad \text{(eq. 2.12)}$$

Consequently, the obtained MLCs ($\tilde{\rho}$) need reconciliation. If a constant-multiplier reconciliation factor (κ_0) is used then,

with,

$$\kappa_0 = \frac{L}{\sum_{i=1}^{N-1}\left[\tilde{\rho}_{P_i} P_i + \tilde{\rho}_{Q_i} Q_i\right]} \qquad \text{(eq. 2.13)}$$

the reconciled vector of MLCs results:

$$\rho = \kappa_0 \tilde{\rho} \qquad \text{(eq. 2.14)}$$

and

$$\sum_{i=1}^{N-1}\left[\rho_{P_i} P_i + \rho_{Q_i} Q_i\right] = L \qquad \text{(eq. 2.15)}$$

Reconciliation by a constant multiplier entails simple scaling of the MLCs so that the sum of the products of resultant MLCs and the nodal power injections at each node equals the total losses as computed by the load flow study.

On the other hand, additive reconciliation may be used. This could be motivated by the desire to preserve differentials between nodes. Therefore MLCs are shifted by constant factors rather than scaled. Because the losses due to active and reactive power flow in a system are different, it is necessary to have two reconciliation factors in the case of additive reconciliation (one for active related MLCs and another for reactive related). This is done so as to maintain the ratio of losses due to active and reactive power when the MLCs are shifted.

It is important to note that MLCs may be evaluated in an hourly basis for hourly settlement or on a year basis. In the last case, MLCs analysis can provide signals to existing and potential system users (customers, generators and suppliers) on the cost or benefits they can expect based on their impact on losses.

DLC method

As explained before DLC method relates losses directly to nodal power injections.

The expression for losses in terms of the network state variables is, as seen before (eq. 2.9):

$$L = f(\theta, V) = \frac{1}{2}\sum_{i=1}^{N}\sum_{j=1}^{N} G_{ij}\left[V_i^2 + V_j^2 - 2V_iV_j\cos(\theta_i - \theta_j)\right]$$

For a given change in operating point, the new total system losses can be evaluated using Taylor series expansion around the initial operating point. The operating point is defined in terms of state variables V and θ with P and Q representing the corresponding nodal power injections. The new loss value is therefore given by:

$$L \approx f\left(\theta^0 + \Delta\theta, V^0 + \Delta V\right) = f\left(\theta^0, V^0\right) + [\Delta\theta \quad \Delta V]\begin{bmatrix}\frac{\partial L}{\partial \theta} & \frac{\partial L}{\partial V}\end{bmatrix}^t + \frac{1}{2}[\Delta\theta \quad \Delta V][H][\Delta\theta \quad \Delta V]^t + \ldots\ldots$$

(eq. 2.16)

where $[H]$ is the Hessian matrix and, $\Delta\theta$ and ΔV represent the change in operating point.

The initial operating point is taken to be:

$$\begin{aligned} V_i^0 &= 1.0 \\ \theta_i^0 &= 0 \qquad i = 1,2,\ldots\ldots N-1 \end{aligned} \qquad \text{(eq. 2.17)}$$

Therefore,

$$f\left(\theta^0, V^0\right) = L_0 = 0 \qquad \text{(eq. 2.18)}$$

and,

$$\frac{\partial L}{\partial \theta_i}\left(\theta^0, V^0\right) = 2\sum_{j=1}^{N} G_{ij}V_iV_j sin\left(\theta_i - \theta_j\right) = 0 \quad i = 1,2,\ldots.N \qquad \text{(eq. 2.19)}$$

$$\frac{\partial L}{\partial V_i}\left(\theta^0, V^0\right) = 2\sum_{j=1}^{N} G_{ij}\left[V_i - V_j \cos\left(\theta_i - \theta_j\right)\right] = 0 \quad i = 1,2,\ldots.N \qquad \text{(eq. 2.20)}$$

As a result,

$$L \approx \frac{1}{2}[\Delta\theta \quad \Delta V][H][\Delta\theta \quad \Delta V]^t \qquad \text{(eq. 2.21)}$$

It is important to point out that $\Delta\theta$ and ΔV in eq. 2.21 represent the final deviations from flat start values of voltage angle and magnitude respectively.

In order to express losses directly in terms of nodal injections, eq. 2.21 must be expressed in terms of nodal injections. This is accomplished by using an analogy with the well-established Newton-Raphson load flow algorithm:

$$[\Delta\theta \quad \Delta V]^t = [\bar{J}]^{-1}[\Delta P \quad \Delta Q]^t \qquad \text{(eq. 2.22)}$$

where $\bar{J}$ is an average Jacobian computed from the flat start and final Jacobians, J^0 and J respectively:

$$\bar{J} = \frac{1}{2}\left(J^0 + J\right) \qquad \text{(eq. 2.23)}$$

It is important to note that ΔP and ΔQ in eq. 2.22 represent the actual nodal active and reactive power injections respectively as the initial P and Q values were assumed to be zero. That is:

$$\begin{aligned} \Delta P &= P \\ \Delta Q &= Q \end{aligned} \qquad \text{(eq. 2.24)}$$

From eq. 2.21, eq. 2.22 and eq. 2.24 we obtain:

$$L \approx \frac{1}{2}[\Delta\theta \quad \Delta V][H][\bar{J}]^{-1}[P \quad Q]^t \qquad \text{(eq. 2.25)}$$

Consequently, the vector of DLCs is given by:

$$\gamma = \frac{1}{2}[\Delta\theta \quad \Delta V][H][\bar{J}]^{-1} \qquad \text{(eq. 2.26)}$$

The assumptions and approximations made in the computation of DLCs give rise to small differences between the losses calculated from the application of DLCs and those from load flow [32]. However, in contrast to MLCs, there is no fundamental requirement for reconciliation in the case of DLCs. This is because the DLC method is based on allocation of total losses. In addition, losses are, approximately, a quadratic function of power and eq. 2.9 used as the basis for derivation of DLCs stops at the quadratic term.

Comparison of loss allocation methods

In [32] an example is presented comparing the values of constant-multiplier reconciled MLCs and DLCs for different cases. It results that values of reconciled MLCs are practically identical to values of DLCs.

It is also demonstrated, in that work, how efficient are MLCs and DLCs methods in eliminating cross-subsides. In addition, it is clear from the examples presented in the referred work that whether or not an embedded generator should be rewarded for loss reduction depends on both the amount and distribution of load as well as its generation output.

Moreover, an example using a generic distribution network is presented. This example clearly demonstrate that MLCs and DLCs vary in time consistent with the temporal nature of load and embedded generator output. It can be seen, for example, that if the EG injects a significant amount of power into the network at off-peak times, this may lead to an increase in total losses. This is explained by the fact that power must be transported over longer distances to reach the load (since local load may be low). In the extreme case, the power would have to travel as far as the bulk supply point for export into the transmission grid. On the other hand, during peak-on period, EG may be compensated for reducing losses in the system because its entire output is consumed locally. This reduces the need for centrally generated power.

As a result, it seems clear that both MLCs and DLCs methods satisfy the required characteristics exposed in the Introduction for an efficient, consistent and practical loss allocation method.

On the other hand, from which was presented here it results that the substitution method fails with those requirements because it is not economic efficient, it is not accurate and it is not simple to implement.

2.1.2 Connection costs

The connection of an embedded generator implies an agreement between the developer and the Local Distribution Company (LDC).

In countries like the U.K. where the new ESI has been working for several years and the amounts of EG are growing up this process is quite well known. The developer makes a connection application and the LDC is obliged to offer terms for providing a suitable connection for the proposed generation scheme. In [7] a procedural flow chart which depicts the general sequence of events and tasks for dealing with a request for generator connection is presented. The flow chart is based on the result that EA Technology obtained from a questionnaire that was submit to 12 companies in the U.K. Nine of the companies responded to it. In Fig. 2.7 the flow chart mentioned is reproduced.

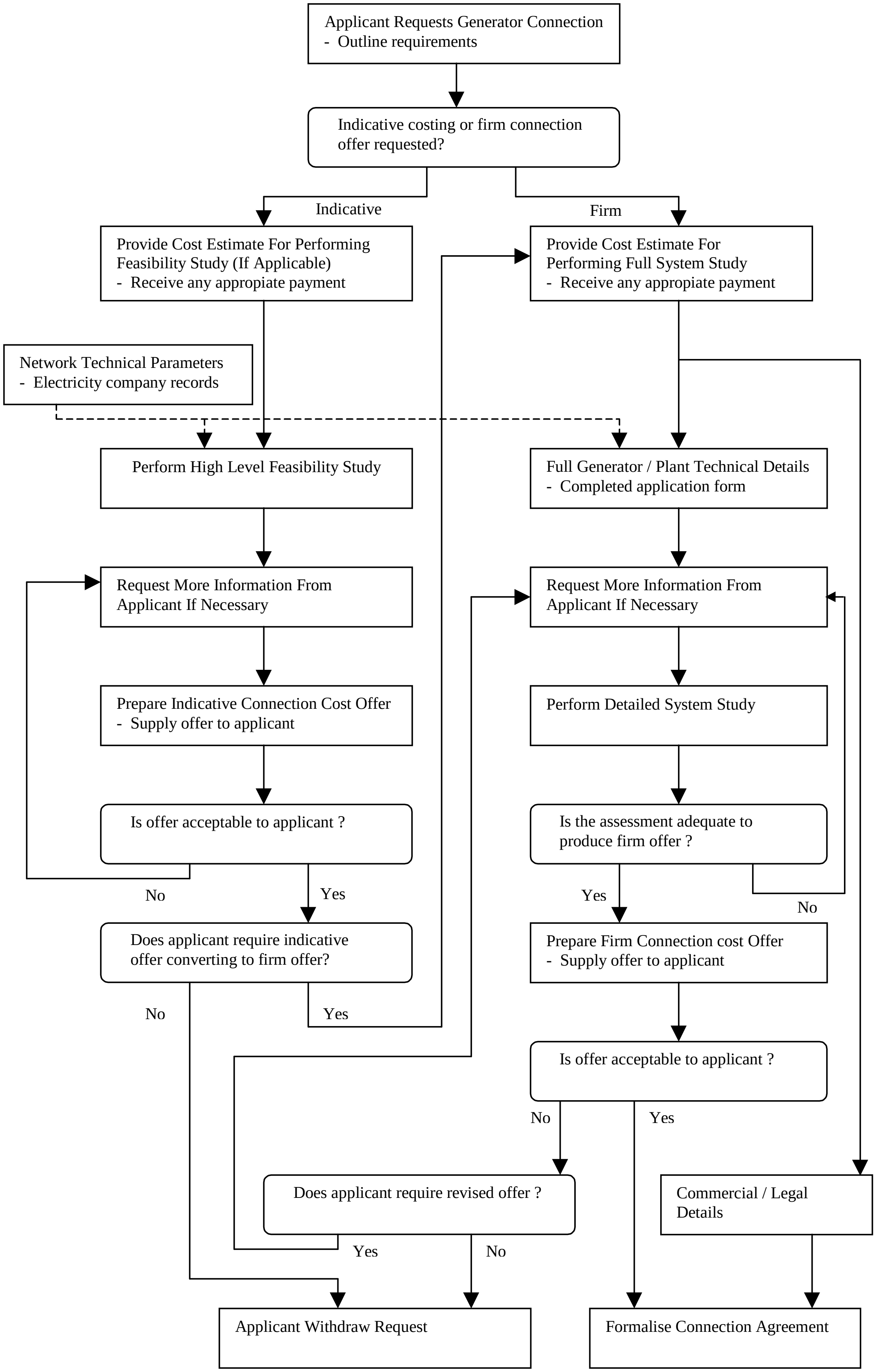


Fig. 2.7. Procedural flow chart for dealing with requests for embedded generator connection.

From Fig. 2.7. it is clear that the LDC has to study the connection costs of the proposed project. This connection costs relate only to the cost of the infrastructure on the LDC side of the point of supply. However, there can also be significant costs associated with electrical infrastructure on the developer's side of the point of supply. These two areas of cost must be considered in total when evaluating projects, and also when considering alternative connection options.

In general, the main components of the connection costs which are considered when dealing with a new EG project are the following:

- <u>Initial costs and O&M (Operating and Maintenance) costs</u>.
  Initial costs are referred to those costs associated to modify an existing connection or to provide an entirely new one.
  In addition, there are also costs associated with the operation, maintenance, repair and replacement of the new or modified connection infrastructure. These operation and maintenance costs must be considered in addition to the initial costs.

- <u>Extension costs and reinforcement costs</u>.
  The new connection provides an electrical path into the network, starting at the ownership boundary between the generator installation and the LCD's network. The work required to provide this path can be broken down into two categories. Firstly, new infrastructure must be installed in order to provide an extension of the existing network, from the point of common coupling up to the point of supply. Secondly, some reinforcement of the existing network infrastructure may be necessary in order to accommodate the planned generation capacity. These two components of the connection work are illustrated in Fig. 2.8.

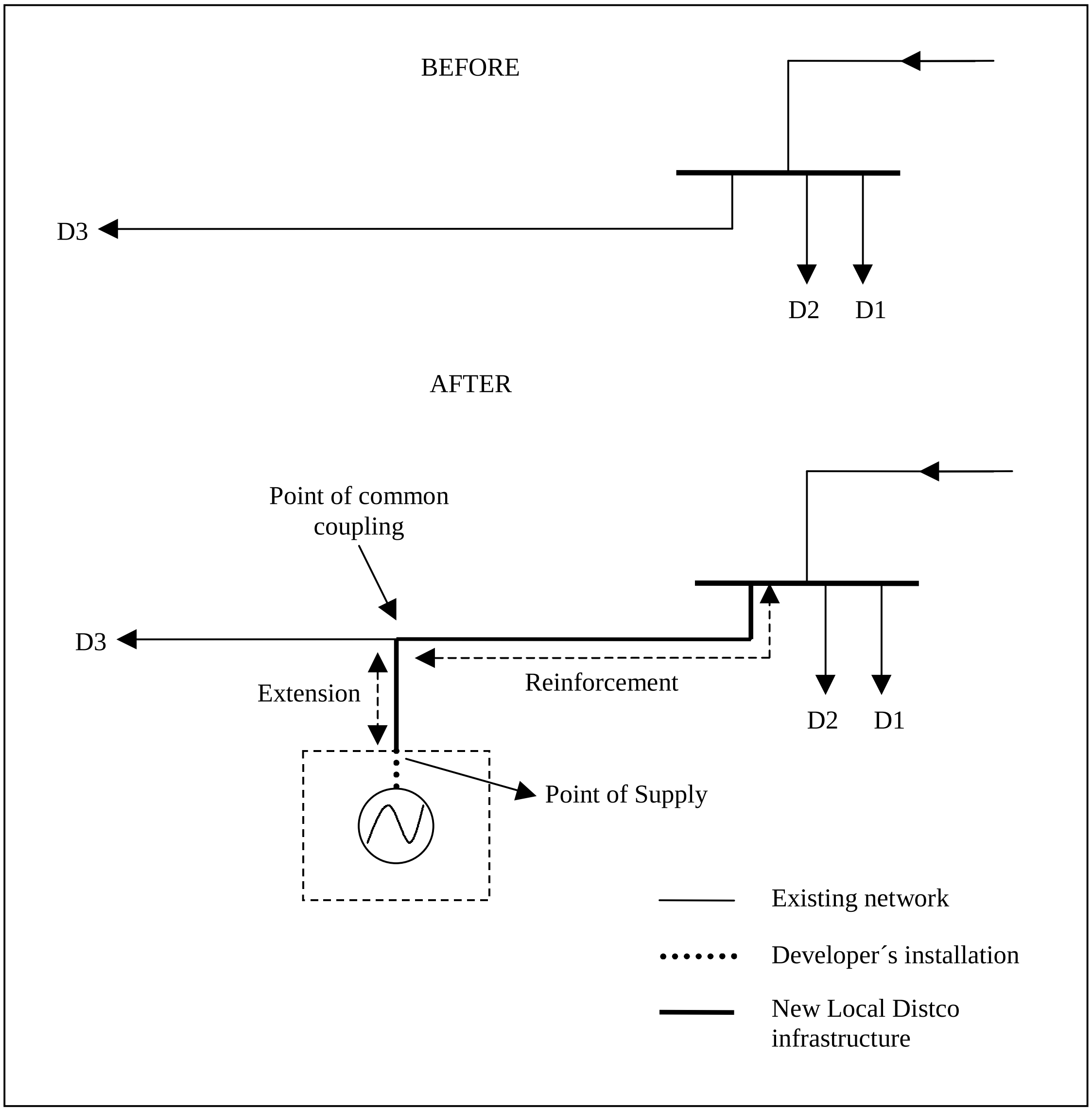


Fig. 2.8. Extension and reinforcement.

Reinforcement work is usually required to increase the electrical capacity of those parts of the network which form part of the electrical path from the generator into the network. However, some network reinforcements do not fit this pattern. For example, it may be necessary to upgrade the switchgear at a substation some distance from the proposed generation scheme, due to the increase in fault level caused by the connection of the generator (see Fig. 2.9).

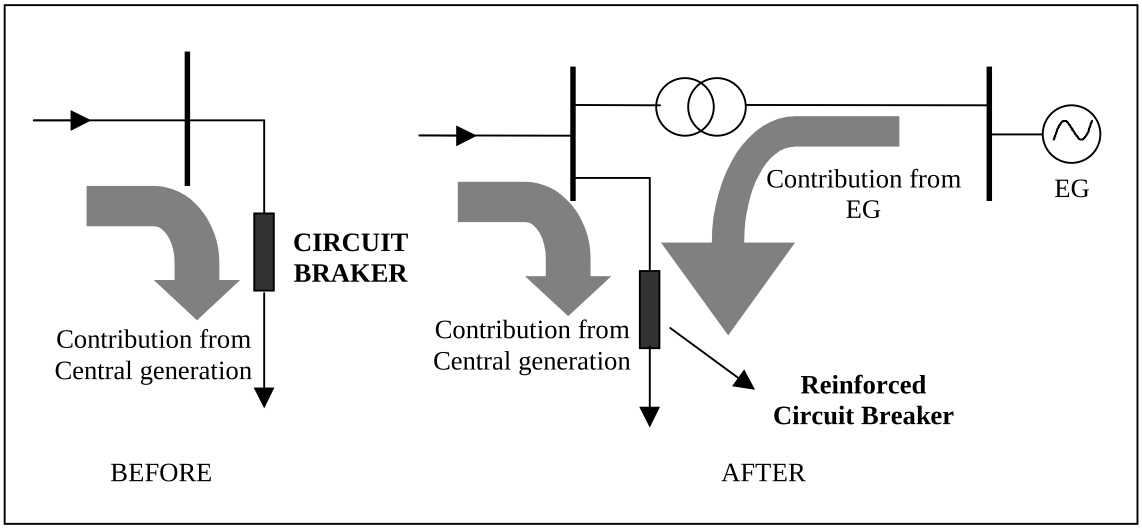


Fig. 2.9. Switchgear upgrade needed due to connection of an EG.

- Return of investment.
  In general, regulatory frameworks, enable the LDC to recover "the appropriate proportion" of both their initial costs and their O&M costs. Connection charges usually provide the LDC with a reasonable rate of return on any capital expenditure.

ALLOCATION OF CONNECTION COSTS

The big question when considering connection costs of EG is who has to pay each of the components of these costs.
As the distribution business is a monopoly, it has to be regulated. A fair pricing policy is then needed to achieve an optimal assignment of resources.
It seems clear from [32] that to achieve a fair pricing policy the real costs involved has to be very well known and understood, and the network pricing policies should reflect these costs.

There are examples of regulatory frameworks that do not achieve this target when considering the connection costs of an EG. In these cases, a set of rules is created to solve the problem of costs allocation without considering the real participation of each part in those costs. As a result, one part loses competitiveness.

For instance, it is well known the discussion of whether the new connected EG should pay only the costs associated with making the new connection ("shallow connection"), or it should pay also the additional costs which are associated with the reinforcement of the system ("deep connection"). In some cases, like the U.K. the reinforcement costs charged to the EG are limited to one voltage level above the voltage of the connection and on circuits where the new or increased load requirement is more than 25 % of the existing capacity. This kind of criteria seems to be arbitrary and not cost reflective.

The fundamental objectives of network pricing are [31]:

- To promote an efficient operation of the energy market.
- To provide location signals for investment in generation and demand.
- To provide the right signals for investment in the network, compensating owners for justifiable investments and discourage over-investment. (Cross-subsides must be avoided).
- To provide transparency.
- To provide prices stability.

The concept of Economically Adapted Network (EAN) fulfil these requirements [31]. The idea of this method is to determine the network optimal design (EAN) based on a medium term plan (e.g. 5 years) of demand and generation distribution, and then calculate the charges for the use of the EAN. These charges correspond to cost allocation with respect to users contribution to marginal investment and operating cost of this EAN.

The charges obtained from the EAN are applied on the existing network and kept over the price review period.

When designing the EAN, two aspects referred to circuit capacity must be taken into account. One refers to the capacity driven by the electricity transport requirements. The other is the capacity driven by additional, security and service quality.

The capital costs associated with the first requirement (electricity transport capacity) are balanced with the costs of losses in order to achieve the optimum. The capital costs associated with the second requirements (security and service quality) must be balanced with the cost of outages.

The concept of EAN may be used in distribution networks with EG [31]. In this case, classical issues like "deep or shallow" connection charges become no more a different issue. Using this concept, the question is to determine the contribution of each user (generation or load) to the investment and operating cost of the EAN.

Within this framework, connection charges can be dealt with as part of the use of system charges.

As an example, if we look at Fig. 2.9. it is clear that the current that flows through the circuit breaker has two components. One component is the contribution from the central generators; the other is the contribution from the EG. Using conventional short circuit analysis tools, the individual contribution of each generator (central and embedded) to the size of the circuit breaker can be computed. Then, these contributions to the short circuit current may be used to allocate the cost of replacing the circuit breaker.

If reinforcement has to be done over a line or cable due to the installation of an EG, the marginal investment and operating cost contribution of each user (central generation and EG) may also be determined. In this case the line capacity will be driven by the cost of losses and reliability costs. Both the methodology of determining the optimum capacity and cost allocation is developed in [32].

DEPENDENCE ON THE VOLTAGE LEVEL

There is an other important issue referred to connection costs that should be addressed here. This issue is the dependence of the connection costs on the voltage level.
It is well known that the higher the voltage level to which the EG is connected, the larger the connection costs. Consequently, in order to make a generation project viable, developers and operators of EG would normally prefer to be connected at the lowest possible voltage level. On the other hand, the higher the connection voltage level the lower the impact that embedded generation has on the performance of the local network. Therefore, such solutions would normally be preferred by network operators. This two conflicting objectives need to be balance appropriately, and may requiere not only an in depth technical and economic analysis of the connection design but also the presence of appropriate network pricing policy.

The determination of the voltage level where a generator should be connected is determined by its impact on the voltage profile of the local network. However, the commercial framework for the voltage regulation policy through active or reactive power control is not yet very well developed.
At present, asynchronous generators that absorb reactive power are charged by the distribution company on the basis of the demand taken by the generator. Conversely, synchronous generators are offered no incentive by the distribution company to provide reactive power to the system.
Many LDC base their DUS charges on kVA demand, which discourages consumption of reactive power. However, absorbing reactive power can be very beneficial to controlling voltage rise effect in weak overhead networks with EG. Although, this would normally lead to an increase in network losses, EG does not have the opportunity to balance the connection costs against cost of losses and make the convenient choice.

Consequently, the inability of the present reactive power pricing concept to support provision of voltage regulation may unnecessarily force generators to connect to a higher voltage level, imposing more higher connection costs.

2.1.3 Externalities

Externalities have been described as "benefits or costs, generated as a byproduct of an economic activity, that do not accrue to the parties involved in the activity" [15].
An externality defines [21] a situation in which the activities of one or more economic agents have consequences on the welfare of other agents without any transaction between them. An externality is defined to be positive if there is an increase of welfare. Conversely, an externality is defined to be negative if there is a decrease of welfare. For instance, the increase in security of electricity supply given by the installation of a new EG will be an externality of the first group while pollution produced by an old coal-fired electricity generating plant will be of the second group.

In this project we are going to consider both environmental and security of supply externalities of EG. With respect to EG environmental externalities, it is important to say that these externalities are not determined by fact that the generator is embedded in the distribution network. However, there is an important proportion of EG which is renewable or gas fuelled, and therefore they are less polluting than the older coal and oil fired stations connected into the transmission system.

ENVIRONMENTAL EXTERNALITIES

The production of electricity has many impacts on environment (air, water, soil) which affects people, animals, ecosystems, products, etc.. In addition, the intensity of these impacts is high because the production of electricity is also high and it is constantly growing up.
This leads to a high level of pollution, risk of accidents and risk of natural resources to be destroyed.
As a result, there is a social need to limit the impacts of electricity production.

The new ESI is based on the neo-classic theory which establishes that price is set at the point where the suppliers curve (marginal cost of producing one more unit) meets the demand curve (marginal utility obtained by customers). Maximum social welfare is achieved at this point (see Fig. 2.10)

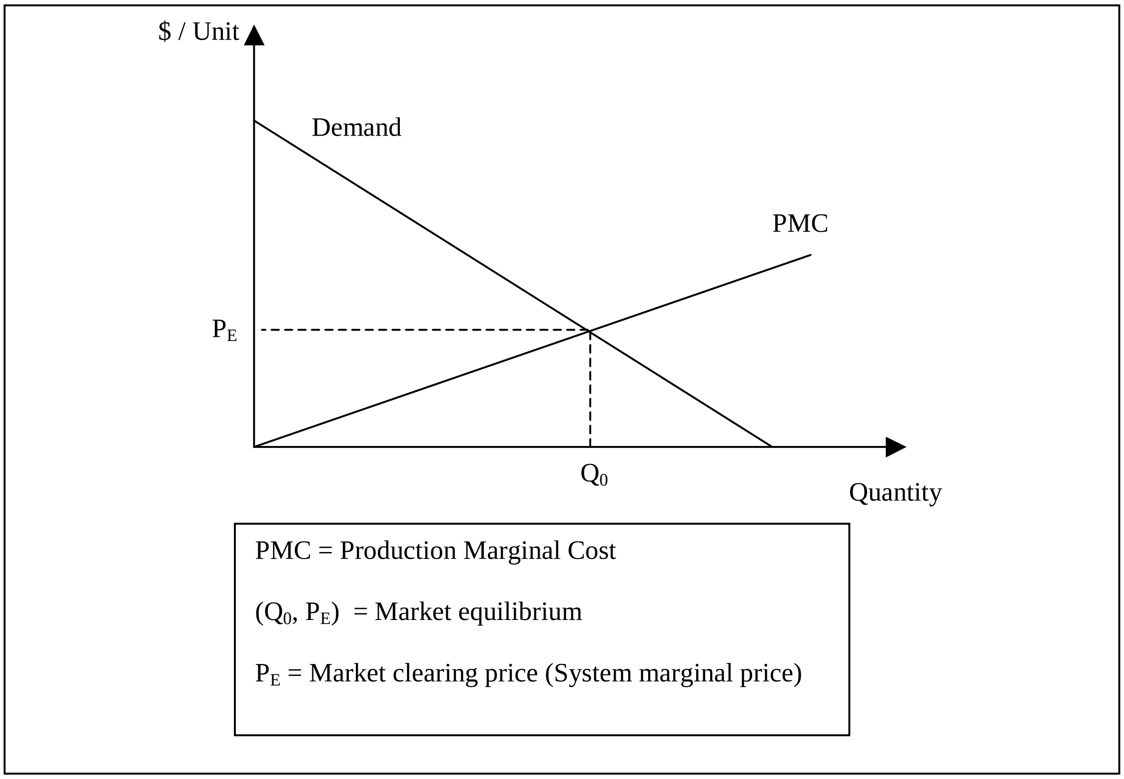


Fig. 2.10. Market equilibrium.

In Fig. 2.10 the external costs imposed by environmental externalities are not considered.

If the economic agents do not consider the external costs imposed by their activities, then the price system does not incentive the agents to adjust their activities to the level that maximum social welfare is achieved. As a result, in these conditions, the resources assignment at equilibrium does not maximise the social welfare.

In Fig. 2.11, the external marginal cost (EMC) is considered. This cost is the externalities cost. This cost increases with the quantity produced.
A social marginal cost (SMC) is defined, which includes the production marginal cost (PMC) and the EMC.

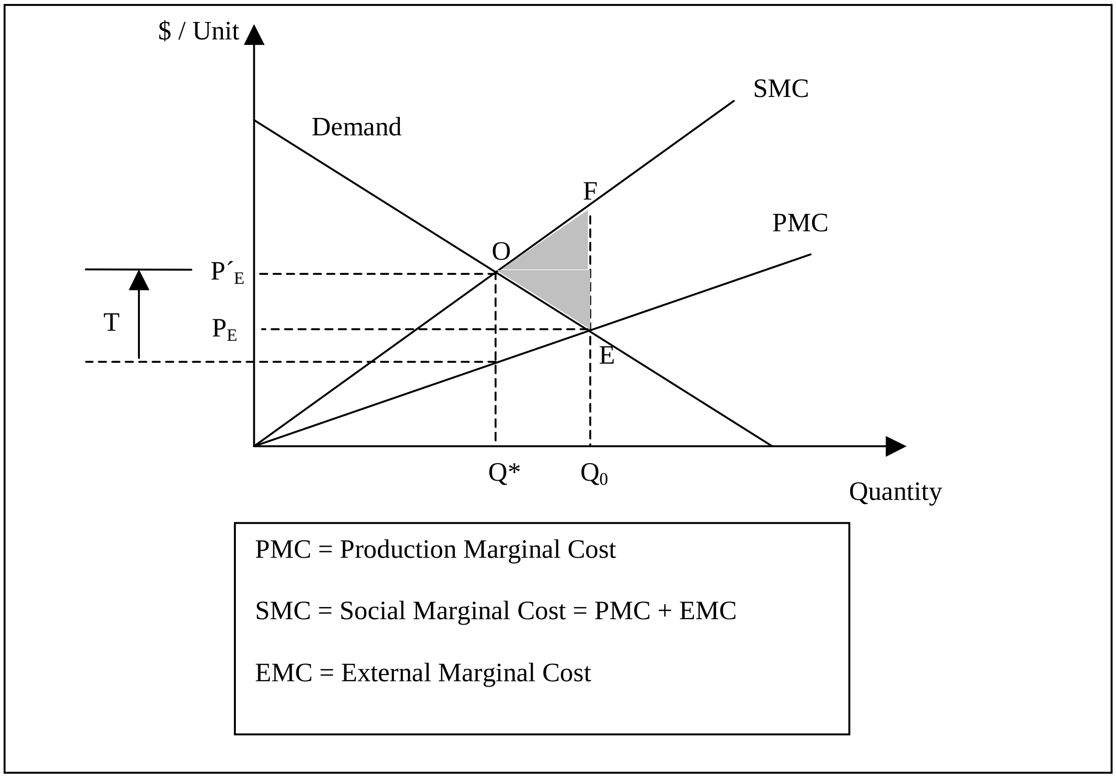


Fig. 2.11. The effect of considering the external costs in the market equilibrium.

The new equilibrium is achieved at (Q^*, P'_E) where the SMC meets the demand curve. As it can be seen, if the EMC is not considered, the market equilibrium (Q^*,P'_E) where maximum social welfare is achieved, is shifted to the point (Q_0, P_E). The difference of social welfare between the two situations is given by area OEF.

As a result, the neo-classic answer to environmental externalities is to impose a tax to the producer that equals the optimum external marginal cost, T (see Fig. 2.11). These kind of taxes are known as pigouvian taxes (it was Pigou, in 1920, who firstly proposed these taxes).

In this way, the external costs are included in the system prices and therefore the economic agents are given incentives to adjust their activity to the level that maximise their own and social welfare.

The previous statements are based on the hypothesis that producers may change the level of pollution only by changing the level of production. This is not true as producers may reduce pollution in other ways. There is a cost associated to the reduction of pollution, a reduction marginal cost (RMC).

As a result, taxes should be set at the point where RMC equals EMC [21]. See Fig. 2.12.

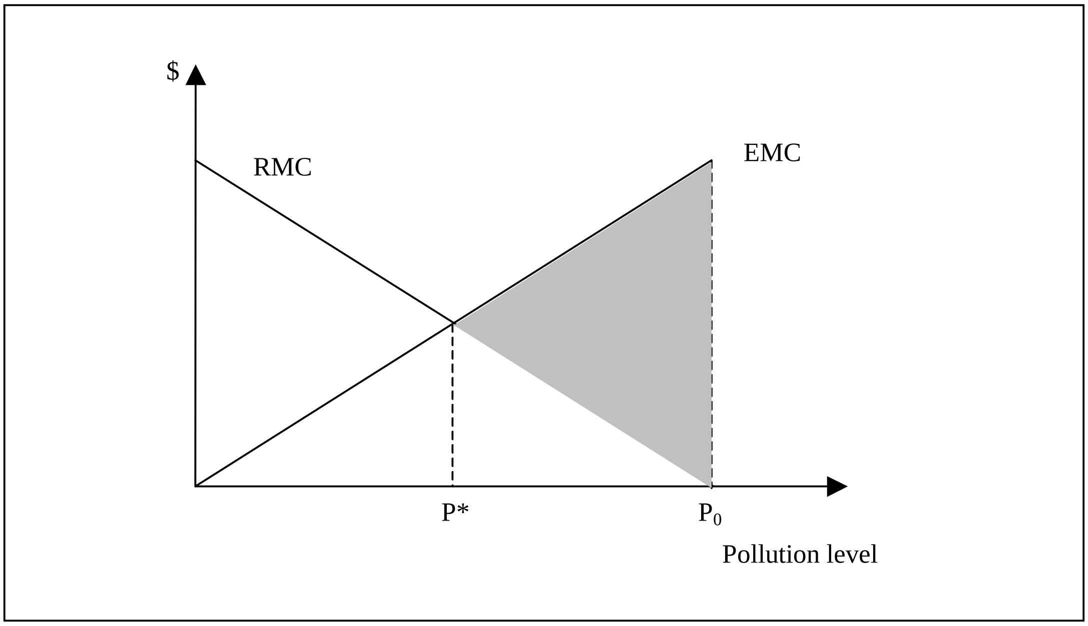


Fig. 2.12. Optimum pollution level.

Although the method achieves the optimum in accordance to the neo-classic theory, it is very difficult to implement, mainly because of the difficulties to predict and evaluate the effects of pollution in monetary terms. However, there are studies that make that kind of evaluation, which at least give a "feel" or "starting point " of the contribution of different technologies. Such studies are, for example, [27] and the environmental study included in [15].

Some of the results of [27] are summarised in Fig. 2.13, Fig. 2.14, Fig. 2.15, Fig. 2.16 and Fig. 2.17.

The pollutants that are taken into account in [27] are the following:

- Sulphur dioxide, SO_2 (linked with acid rain): a “starting point” value of the negative effects of USD 2.03 / lb has been estimated considering primarily health effects.
- Oxides of nitrogen , NO_x (linked with acid rain and urbane ozone): a “starting point” value of USD 0.82 / lb has been estimated considering also health effects.

- Particulates: a "starting point" value of USD 1.19 / lb has been found based primarily on visibility effects (USD 0.83 / lb), with a strong contribution from health effects (USD 0.36 / lb).
- Carbon dioxide, CO_2 (which is a greenhouse gas): The value of reducing CO_2 emissions was estimated to be USD Cents 2.5 / lb carbon (or USD Cents 0.068 / lb CO_2) using a mitigation cost estimate for tree planting.

Fig. 2.13. Externality costs for Coal-Fired Units.

EXTERNALITY COSTS FOR COAL-FIRED UNITS

		TYPE OF TECHNOLOGY		
EXTERNALITY	USD/lb	Existing Boiler (1.2 % sulphur coal)	AFBC[1] (1.1 % sulphur coal)	IGCC[2] (0.45 % sulphur coal)
	[A]	[B]	[C]	[D]
[1] SO_2	2.03	1.80	0.55	0.48
[2] NO_x	0.82	0.607	0.3	0.06
[3] Particulates	1.19	0.15	0.01	0.01
[4] CO_2	0.0068	209	209	209
Totals:				
[5] USD/MMBTU Input		5.76	2.80	2.46
[6] Heat Rate (BTU/KWh)				
USD/kWh Generated		**0.058**	**0.028**	**0.025**

Notes:

1 AFBC = Atmospheric Fluidised Bed Combustion.

2 IGCC = Integrated Gas Combined Cycle.

[B] [C] [D]: All emissions are expressed as lbs/MMBTU fuel input.

[1]: No SO_2 scrubbers are installed on the first three plants.

[2]: NO_x emissions are uncontrolled in each case.

[3]: Particulates emissions vary widely and are extremely dependent on the ash content and sulfur content and sulfur content of coal.

[5]: Sum of (value of X emissions for each externality) for each plant.

[6]: Assumed heat rates for each plant.

[7]: [5]x[6]/1000000

Fig. 2.14. Externality costs for Oil-Fired Units.

EXTERNALITY COSTS FOR OIL-FIRED UNITS

		TYPE OF TECHNOLOGY			
EXTERNALITY	USD/lb	Boiler #6 Oil (0.5 % sulphur oil)	Boiler #6 Oil (1 % sulphur oil)	Boiler #6 Oil (2.2 % sulphur oil)	Combustion Turbine #2 Oil (1.1% sulphur oil)
	[A]	[B]	[C]	[D]	[E]
[1] SO_2	2.03	0.54	1.08	2.38	0.16
[2] NO_x	0.82	0.357	0.287	0.357	0.498
[3] Particulates	1.19	0.055	0.09	0.174	0.036
[4] CO_2	0.0068	169	169	169	161
Totals:					
[5] USD/MMBTU Input		2.60	3.68	6.48	1.87
[6] Heat Rate (BTU/KWh)		10400	10400	10400	13600
USD/kWh Generated		**0.027**	**0.038**	**0.067**	**0.025**

Notes:

[B] [C] [D]: All emissions are expressed as lbs/MMBTU fuel input.

[1]: SO_2 emissions are uncontrolled in each case.

[2]: NO_x emissions are uncontrolled in each case.

[5]: Sum of (value of X emissions for each externality) for each plant.

[6]: Assumed heat rates for each plant.

[7]: [5]x[6]/1000000

Fig. 2.15. Externality costs for Natural Gas-Fired Units.

EXTERNALITY COSTS FOR NATURAL GAS-FIRED UNITS

		TYPE OF TECHNOLOGY		
EXTERNALITY	USD/lb	Existing Steam Plant	Combined Cycle	BACT (SCR,SWI)
	[A]	[B]	[C]	[D]
[1] SO_2	2.03	0	0	0
[2] NO_x	0.82	0.248	0.42	0.042
[3] Particulates	1.19	0.003	0.003	0.0002
[4] CO_2	0.0068	110	110	110
Totals:				
[5] USD/MMBTU Input		0.95	1.10	0.78
[6] Heat Rate (BTU/KWh)		10400	9000	9000
USD/kWh Generated		**0.010**	**0.010**	**0.008**

Notes:

[B] [C] [D]: All emissions are expressed as lbs/MMBTU fuel input.

[1]: SO_2 are zero from gas combustion.

[2]: NO_x emissions are uncontrolled in the first two cases. For the BACT case, Selective Catalytic Reduction (SCR) and Steam Water injection (SWI) are assumed.

[5]: Sum of (value of X emissions for each externality) for each plant.

[6]: Assumed heat rates for each plant.

[7]: [5]x[6]/1000000

Fig. 2.16. Starting point values for Nuclear Power Externality Costs.

STARTING POINT VALUES FOR NUCLEAR POWER EXTERNALITY COSTS

AREA	USD Cents / kWh
Routine Operations	0.11
Accidents	2.30
Decommissioning	0.50
TOTAL	**2.91**

Fig. 2.17. Summary of environmental costs for various Renewable Energy Technologies.

SUMMARY OF ENVIRONMENTAL COSTS FOR VARIOUS RENEWABLE ENERGY TECHNOLOGIES

TECHNOLOGY TYPE	USD Cents / kWh
Solar	0 to 0.4
Wind	0 to 0.1
Biomass	0 to 0.7

In the other study, included in [15] the true worth or economic value of an embedded generator is determined by the relative amount of the different pollutants that emits compared to that of the generation it displaces, and the environmental cost consequences of those pollutants.

Two cases have been considered:

- Case 1: which assumes that older coal or oil plant is displaced by CCGT (Combined Cycle Gas Turbine) plant.
- Case 2: assuming that the older plant is displaced by renewable plant such as wind or hydro.

The methodology used by [15] consisted firstly in determining the amount of pollutant emissions of different plant types (see Fig. 2.18). Secondly, the emission reduction for cases 1 and 2 was calculated (Fig. 2.19). Thirdly, the emission costs for the different types of pollutants were established based on a study undertaken by the European Union under the ExternE project (Fig. 2.20). Finally, the value of emission reductions for cases 1 and 2 were calculated (Fig. 2.21).

EMISSIONS FROM DIFFERENT TYPES IN TONNES / GWh

PLANT TYPE	PARTICULATES (3)	SO_2	NO_x	CO_2
Old Coal (1)	0.4 – 2.2	10 – 20	2 – 5	820 – 1033
Old Oil (1)	1	12	3	800
CCGT (1)		less than 0.01	0.27 – 0.29	393 – 422
Wind (5)	0	0	0	0
Hydro (5)	0	0	0	0
CHP (1,4)			less than 0.2	130 – 940 (4)
Coal with FCD (2)	0.2	1 – 2	3	878

Notes:

(1) Source PowerGen Environmental Performance Report 1995.

(2) Estimated assuming 90 % of sulphur is removed and an efficiency in the mid range of those quoted for other PG plant (this allows for some thermal efficiency reduction due to operating the FGD plant).

(3) These values are for primary particulates only. Primary particulates are those emitted directly from the power station. Secondary particulates are those created by chemical reactions in the pollution plume and are generally aerosols of sulphates or nitrates.

(4) This analysis shows the emissions per unit of electrical output, rather than combined heat and electrical output.

(5) The ExternE project quotes emissions of 7.9 % SO_2, 1.7 % NO_x and 1 % CO_2 as a proportion of the Coal with FGD emissions based on the manufacture and construction for a wind turbine together with other externalities due to noise, etc. However, this represents a small proportion of the totals quoted for other plant, and in particular the old coal and oil, above and therefore, the figures quoted assume no external costs from renewable generation (wind and hydro).

Fig. 2.18. Emissions from different plant types in tonnes / GWh.

EMISSION REDUCTION THROUGH DISPLACING PLANT IN TONNES / GWh [1]

	Particulates [1,2]	SO_2 (1)	NO_x (1)	CO_2 (1)
Case 1	1.2	14	3.1	477
Case 2	1.2	14	3.3	884

Notes:

(1) Calculated on basis of displacing mean of old coal and old oil emissions from Fig. 2.18, i.e. coal and oil plant displaced in a 2:1 ratio.

(2) Primary particulates only - see note (3) of Fig. 2.18.

Fig. 2.19. Emission reduction through displacing plant in tonnes / GWh.

DAMAGE COST IN ECU / GWh FOR WEST BURTON AND THE ESTIMATED DAMAGE COST OF DIFFERENT POLLUTANTS IN £ / TONNE OF POLLUTANT

Pollutant	Damage Cost in ECU / GWh for West Burton B	Damage Cost in £ / tonne of pollutant (based on West Burton B)
Primary particulates	580	2574
Secondary particulats	3180	see note (3), Fig. 2.18.
SO_2	850	549
NO_x	Not quantified for West Burton B. For the Lauffen reference plant the value is 350.	310 (for Lauffen reference plant – see third bullet point below)
CO_2	1500 – 770000	1 – 622

Notes:

The assumptions made in compiling this Table are set out below:

- The values in this table are extracted from European Union ExternE Project, which has made the quantification in terms of cost per GWh of generation at two reference plants. One of these reference plant, is West Burton B. The values presented in this table are specific to the West Burton B site and do not necessarily reflect the damage costs of emissions from other sites.
- SO_2 is the only contributor to acid rain and its consequential damage costs. This is not strictly accurate as acidification and its consequential damage is caused by both SO_2 and NO_x.
- NO_x is the only contributor to ozone formation and its consequential damage costs. In fact the Lauffen damage was calculated for near-field damage in close proximity to the plant where local conditions showed increased ozone formation. Normally it might be expected that NO production from the power plant would result in a local decrease in ozone and an increase in far-field ozone production.

- CO_2 is the only contributor to global warming. In fact there are other greenhouse gases such as methane and nitrous oxide which also contribute. The extreme range reflects different results from several studies quoted by the ExternE project in a literature review of global warming, but which did not directly form part of that project. These different studies show different numbers mainly because of their (often subjective) differing judgements on the valuation of mortality, and the impacts of "natural" disasters such as storms. The valuations quoted should therefore be used with extreme caution; the highest values being an extreme upper bound. A central estimate of damage cost may be closer to 2200 ECU / GWh (£1.8 / tonne). Costs quoted are Net Present Values at 1990 prices using a real discount rate of 3 %. Lower discount rates will give higher damage costs.
- 1 ECU = 71 pence (exchange rate used in ExternE).
- The effect of secondary particulates has not been quantified.
- Damage cost per tonne of pollutant has been calculated using the W. Burt. emission data of 880 CO_2, 0.8 NO_x(Lauffen Power Station), 1.1 SO_2, 0.16 primary particulates, all in tonnes/GWh.

Fig. 2.20. Damage cost in ECU / GWh for West Burton and the estimated damage cost of different pollutants in £ / tonne of pollutant.

VALUE OF EMISSION REDUCTIONS THROUGH DISPLACING COAL OR OIL PLANT NOT FITTED WITH FGD PLANT, IN PENCES / kWh

	Particulates (1)	SO_2	NO_x	Total excluding global warming	CO_2	Total including global warming
Case 1	0.3	0.8	0.1	1.2	0.04 - 29	1.2 – 30
Case 2	0.3	0.8	0.1	1.2	0.07 - 55	1.3 – 56

Notes:

The assumptions made in compiling this Table are set out below:

- Primary particulates only. The cost of secondary particulates has not been assessed as it has not been possible to quantify the change in emission levels of secondary particulates. Consequently, this analysis potentially understates the total value of emission reductions.
- The contribution of SO_2 and NO_x may be overstated and understated, respectively, due to the assumptions made over SO_2 being the only contributor to acidification damage.
- As stated in bullet 4 of the assumptions underlying in Fig. 2.20, the global warming externalities are extremely uncertain and the highest value quoted is generally regarded as an extreme upper bound.
- The CCGT on renewable plant are displacing coal or oil plant is not fitted with FGD.

Fig. 2.21. Value of emission reductions through displacing Coal or Oil plant not fitted with FGD plant, in pences / kWh.

Conclusions

The externalities method proposed by the neo-classic theory to account for environmental effects of electricity production is consistent with the philosophy behind the new ESI. However, the value of reducing environmental damage is very difficult to determine, because it depends on the environmental impact of pollutants (which are frequently location specific) and the values attached to those impacts.

Two different studies that quantify the damage costs of existing generating technologies were summarised. From both studies it is clear that renewable energy has an extra value, which should be considered by regulators when setting the tariffs structures. An ideal situation seems to be one in which market price signals were given with respect to environmental effects.

The actual situation is that other types of methods are been applied since the beginning of government environmental policies (from late 1960s). For example, limitations in the amount of pollutants that a generator plant can produce have been applied. This policy, although limiting pollution, does not give incentives to keep on reducing it.

In addition, there are policies that promote clean energy. For instance, there is the NFFO (Non Fossil Fuel Obligations) in the U.K. The obligation, within the Energy Act, requires the local distribution companies (RECs) to purchase a proportion of their electricity requirements from clean sources. Moreover, if a renewable generator is not part of the NFFO then a supplier purchasing its electricity would not have to charge the Fossil Fuel Levy on the proportion of its supply backed by that generation.

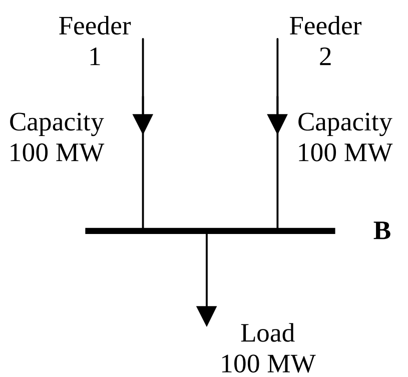
In sum, it seems to be widely agreement in considering the environmental effects of electricity production. However, the extra benefits of clean energy seems not to be considered in full yet.

A cost reflective tariff with respect to the environmental effects of electricity would have significant impacts in the degree of competitiveness of clean generators in general, and particularly, in the degree of competitiveness of ERG.

SECURITY OF SUPPLY

Users of electricity expect to have quality and reliability in their supply. The value of not having electricity is, in fact, greater than the cost of electricity [18].
In addition, providing security of supply has its costs. The greater the security the higher the costs of achieving it.

The level of security present in the network is proportional to the resources that have been assigned to the provision of that security. These resources can be either network facilities or generation resources.
It seems quite clear that the presence of EG tends to increase the level of system security. To confirm this idea, let us consider the following example:



Feeder	FOR (Forced Outage Rate)
1	0.02
2	0.02

Fig. 2.22. Security of Supply: Example (without EG).

Fig. 2.22 shows a very simple distribution network. It consists of two radial feeders of 100 MW capacity each, which feed busbar B. A constant load of 100 MW is connected to B. The FOR of the two feeders are given in the table above.

Let us calculate the LOLP (Loss of Load Probability) for the load. The outage capacity probability table for this case is:

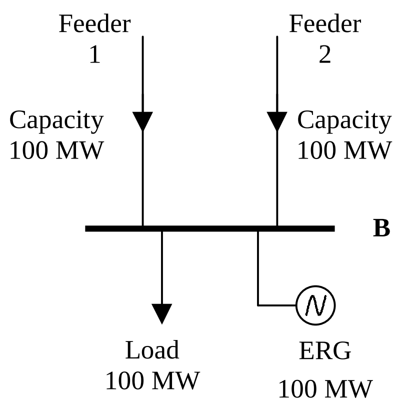
Capacity out (MW)	Capacity in (MW)	State Probability
0	200	0.98x0.98 = 0.9604
100	100	2x0.98x0.02 = 0.0392
200	0	0.02x0.02 = 0.0004

The LOLP is, by definition, the probability of not satisfying the load.
Then, the LOLP is calculated by adding the individual probabilities of those states in which the load experiences troubles:

$$LOLP = 0.0004$$

The expected number of days in which the load experiences troubles can also be calculated multiplying the LOLP by 365 which give us 0.146 days/year. If we prefer the number expressed in hours/year, we have to multiply by 24, obtaining 3.50 hours/year.

Let us evaluate now the LOLP when an embedded renewable generator (ERG) of 100 MW capacity is connected to busbar B. We will assume an availability of 50 % for the ERG. This situation is presented in Fig. 2.23.



Equipment	FOR (Forced Outage Rate)
Feeder 1	0.02
Feeder 2	0.02
ERG	0.5

Fig. 2.23. Security of Supply: Example (with EG).

The outage capacity probability table for this case is the following:

Capacity out (MW)	Capacity in (MW)	State Probability
0	300	0.98x0.98x0.5 = 0.4802
100	200	2x0.98x0.02x0.5 + 0.98x0.98x0.5 = 0.4998
200	100	2x0.98x0.02x0.5 + 0.02x0.02x0.5 = 0.0198
300	0	0.02x0.02x0.5 = 0.0002

Therefore,

$$LOLP = 0.0002$$

The expected number of days in which the load experiences troubles in this case is equal to 0.0002x365 = 0.073 days/year. This number, in hours/year is 1.75. This is 50 % of the days in which the load experiences troubles in the first case.

Another approach is to calculate the ELL (expected load lost) for the two cases.
The ELL is defined as:

$$ELL = \sum_{i=1}^{n} x_i \, p_i$$

where,

i is the capacity state.

n is the number of capacity states.

x_i is the load lost whilst in *i-th* capacity state.

p_i is the probability of the *i-th* capacity state.

Using the ELL for comparing the two cases, results,

for the first case, $ELL = 100x0.0004 = 0.04MW$, and

for the second case (with ERG), $ELL = 100x0.0002 = 0.02MW$.

Once again, the ELL for the second case is 50% of the ELL for the first case.

From this example it is clear that a generator embedded in the distribution network provides additional system security.

System security may be provided by both network or generation facilities. EG can potentially replace transmission and distribution network facilities. From this perspective, EG can be seen as a competitor to transmission and distribution in the provision of network services.
On the other hand, a significant proportion of EG does not provide firm capacity (e.g. renewable generation). In this case, generation is not available at all the time. However, it can not be say that this type of generation does not provide system security. From the probabilistic point of view the ERG has a defined level of availability that must be considered in conjunction with the availability of other equipment. The simple example that was provided below demonstrates this fact.

Security of supply is an extra value or benefit of EG. It is the responsibility of the Regulator to give fair competitiveness to EG regarding to these aspects. It seems important that security standards are included in the regulatory frameworks to define the system level of security. In addition, the probabilistic nature of the EG must be considered.

Reliability of supply has its own value and users of the network may be prepared to pay for security of supply. However, the sensitivity of different users to reliability may be different. Consequently, in an efficient pricing structure, the use of system charges must reflect the value that each user places on network performance. What is more, each user should have a choice regarding the level of security that desires, and should be charged accordingly.
In [32], a method of network pricing that includes the quality of supply driven costs is presented. Allocation of reliability driven capital is based on quantifying the impact of each network user on expected marginal outage cost. This cost corresponds to the expected increase in outage costs imposed on the rest of the customers of the system by an increment in demand.

2.2 TECHNICAL ISSUES OF EG

2.2.1 Voltage regulation and reactive power

Under the regulations of the ESI, distribution utilities must supply electricity to their customers at a voltage within specified limits.
If we consider the simple example of Fig. 2.24, voltage regulation is achieved by adjusting the taps of transformers T1 and T2.

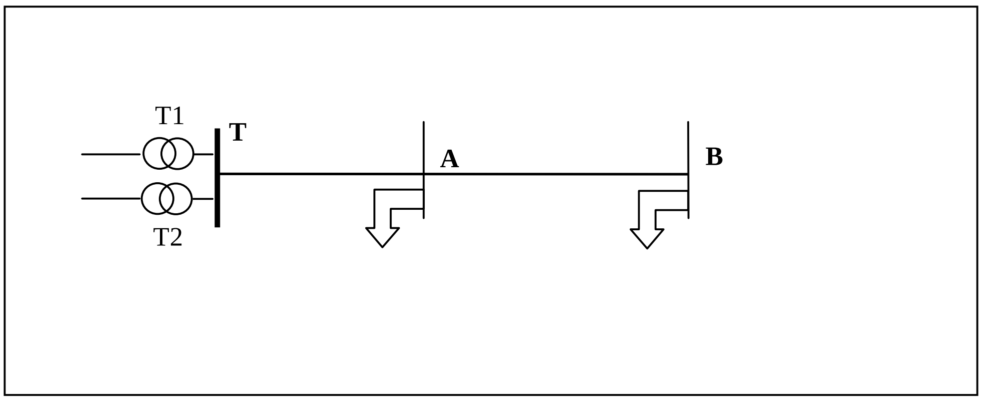


Fig. 2.24. A simple distribution network without EG.

The taps are adjusted so that the following conditions are satisfied:

- At times of maximum load the most remote customer (B) will receive acceptable voltage (above the minimum allowed).
- At times of minimum load the voltage received by the customers is below the maximum allowed.

If we now consider an EG connected to the circuit of Fig. 2.24, as indicated in Fig. 2.25, the load flows and hence the voltage profiles will change in the distribution network.

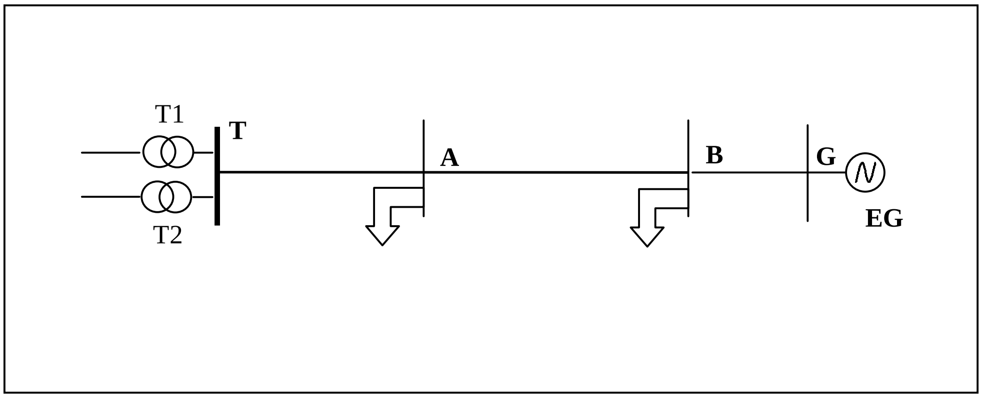


Fig. 2.25. A simple distribution network with EG.

If the generator is exporting, then this will cause the voltage to rise. The degree of the rise will depend on many factors, such as:

- Level of export relative to the minimum load on the network.
- Siting of the generator (proximity to a busbar where the voltage is regulated by the distribution company).
- Distribution of load on the network.
- Network impedance from busbar to generator.
- Type and size of generator.
- Magnitude and direction of reactive power flow on the network.

The worst case is likely to be when the customer load on the network is at a minimum and the EG is exporting.
On the other hand, if the generator is used on-site it does not adversely affect network voltages (i.e. if a load is connected to busbar **G** consuming most of the power generated by EG).

If we suppose that the line between busbar **B** and busbar **G** in Fig. 2.25, has an impedance, $R + jX$ (in per unit), then the voltage drop $\delta|V|$ (in per unit) may be calculated as follows:

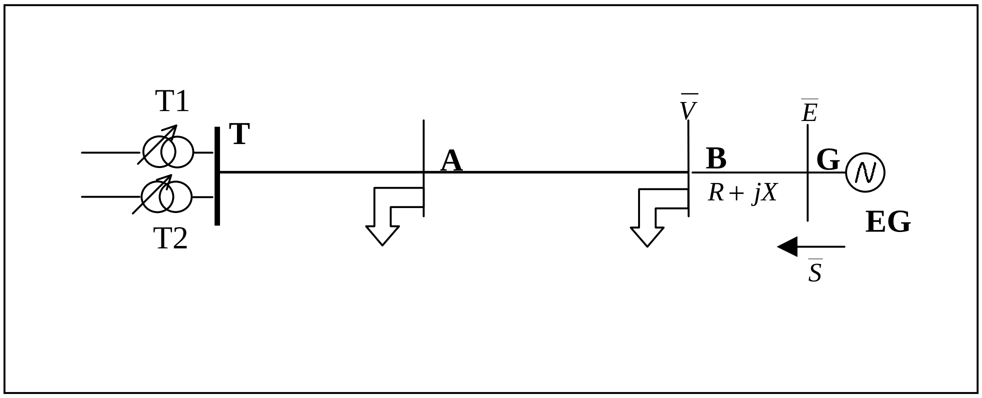


Fig. 2.26. A simple distribution network with EG.

$\delta|V| = |\overline{E}| - |\overline{V}|$

where,

$|\overline{E}|$ is the modulus of voltage $\overline{E}$ in per unit.

$|\overline{V}|$ is the modulus of voltage $\overline{V}$ in per unit.

$\overline{E}$ and $\overline{V}$, are indicated in Fig. 2.26.

In Fig. 2.27, a diagram with the magnitudes involved in our calculation is presented.

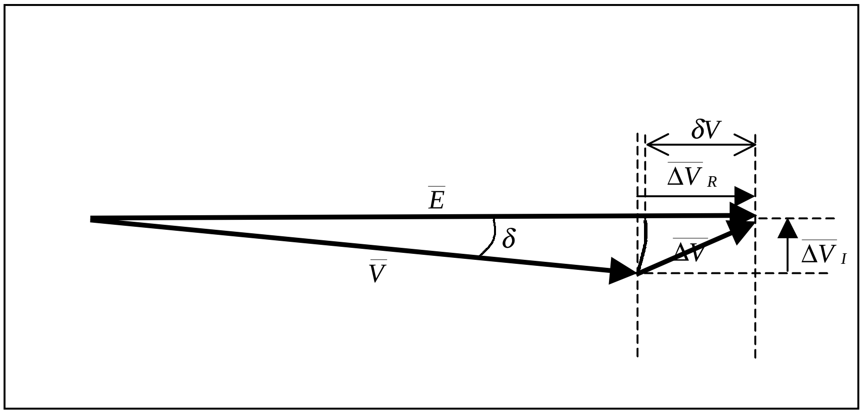


Fig. 2.27. Diagram: voltage drop calculation.

$\overline{\Delta V} = \overline{E} - \overline{V} = \Delta V_R + j\Delta V_I$

Usually, δ is small; thus it is possible to approximate $\delta|V|$ by ΔV_R,

$\delta|V| \approx \Delta V_R$

In addition, we may calculate $\Delta\overline{V}$ in the following way,

$$\Delta\overline{V} = (R + jX)\overline{I}$$

$$\overline{S} = \overline{E}\overline{I}^* \quad \Rightarrow \quad \overline{I} = \frac{\overline{S}^*}{\overline{E}^*}$$

$$\overline{S} = P + jQ$$

$$\therefore \quad \Delta\overline{V} = (R + jX)\frac{(P - jQ)}{E} = \frac{RP + XQ}{E} + j\frac{PX - RQ}{E}$$

$$\therefore \quad \delta|V| \approx \frac{RP + XQ}{E}$$

As a result, the voltage rise may be limited controlling the reactive power Q exported by the generator. In particular, for negative values of Q (i.e. generator importing reactive power), it is possible to achieve $\delta|V| = 0$. This method can be effective for circuits with high X/R ratio, such as higher voltage overhead circuits. However, for LV cable distribution circuits with a low X/R ratio, the method does not work. As a result, only very small EG can generally be connected to LV networks.

An integrated EG new approach to design and operation is proposed in [32]. This approach that enables a dynamic voltage control is summarised in Fig. 2.28.

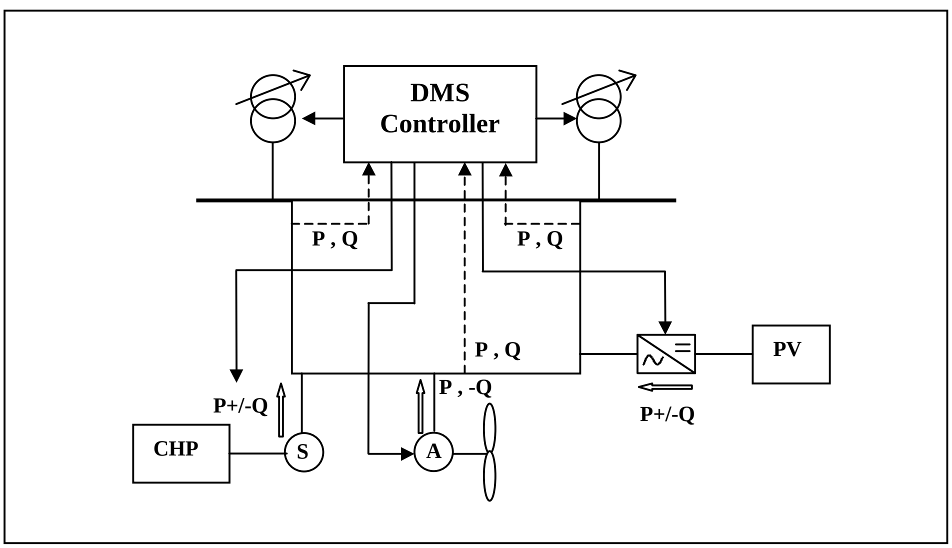


Fig. 2.28. Integrated Dispersed Generation New approach to design and operation.

Modelling has to be used to address the effects of the connection of a new EG in a particular distribution network. As a result, the mechanisms to provide voltage regulation can be determined (e.g. tap-changing transformers).

It is believed, by some authors [32], that a reactive power market should exist at distribution level to permit EG to participate in voltage regulation.

At present, loads in the distribution network are charged for reactive power consumption. On the other hand, EG are not generally paid for providing reactive power. What it is found in many countries, are regulations regarding the power factor range of the EG (e.g. in Greece the power factor of an embedded synchronous generator should vary within 0.85 and 0.95 and should not be negative).

In addition, in accordance to [32], it is desirable that regulations consider stochastic voltage limits (as it is proposed in EN 50160) instead of deterministic rules Moreover, it should be allowed EG to be constrained off in certain circumstance to limit voltage rise.

2.2.2 Power quality

One aspect that has particular importance in the new ESI is power quality. Due to the interaction of the various participants, the definition of the quality standards within the system becomes an important issue. For instance, generators will be obliged to produce an adequate voltage waveform (i.e. with limited voltage harmonics content) while consumers will be obliged not to distort too much the current waveform (i.e. small harmonics current content).

In general, standards refer to voltage harmonics and / or current harmonics.

A summary of the various standards in different countries is done in [4] based on a publication of Zamora and Macho of 1997. In Fig.2.29 this summary is presented.

Country	Standard	Subject	Brief description
Finland	Document: Limits of harmonics in electrical networks.	Voltage Current Psofometric noise	Establishes limits taken into account voltage level. Establishes THD limit.
France	Document: Regulations on converters installation considering the feeding network characteristics.	Voltage	Takes into account the shortcircuit level at the point of connection. Makes difference between LV, MV and HV.
New Zeland	Document: Limits on the levels of harmonics content, 1981.	Voltage Current Psofometric Noise	Takes into account the shortcircuit level at the point of connection.
Poland	Document from the Electrical Engineering Institute of Katowice, 1980.	Voltage	Makes difference between LV, MV and HV.
Sweden	Document from the Electric Supply Authority,1973.	Voltage	Establishes power limits of the installed equipment in accordance with the shortcircuit level at the connection point. Establishes THD limit. Makes difference between LV, MV and HV.
South Africa	Document from the Electric Supply Authority,1977.	Voltage	
U.K.	BS 5406-1976 = EN 5006	Voltage	Domestic Equipment.
U.K.	G5/2 and G5/3	Voltage Current	Industrial application. Scales in accordance with equipment power.
Australia	AS 2279, 1976.	Voltage Current	Covers U.K. and European standards.
IEEE	IEEE 519: Practice and Requirements for Harmonic Control in Electric Power Systems, 1989	Voltage Current	Establishes power limits of the installed equipment in accordance with the shortcircuit level at the connection point. Establishes limits of individual harmonics. Establishes THD limit. Makes difference between LV, MV and HV.
Russia	GOST 13109-1979	Voltage	
Germany	DIN 57160 Part 2 VDE 0160 Part 2, 10.75	Voltage	Establishes power limits of the installed equipment in accordance with the shortcircuit level at the connection point. Establishes limits of individual harmonics. Establishes commutation limits.
IEC	1000-3-2	Current	LV, I < 16 A
IEC	1000-3-3	Voltage (Flicker)	LV, I < 16 A
IEC	77	Voltage	Distribution networks.
IEC	WG CC02 (CIGRE 3.6.05/CIRED 2, 1992)	Voltage	HV. Considers individual harmonics and THD.
IEC	555-2	Voltage/Current	Standard artificial network. Domestic equipment.

Fig. 2.29. Summary of international standards on harmonics.

VOLTAGE FLICKER

Voltage flicker refers to rapid fluctuations in the voltage level (presence of harmonics in the voltage wave).
These fluctuations can be very annoying for local electricity users, as they cause light bulbs to "flicker" instead of producing steady light. Fluctuations at frequencies close to 8 Hz cause the most annoyance.
For practical purposes, a severity index (Pst) is defined based on measurements every 10 minutes. Pst = 1 is considered the limit under which no disturbance should be observed [4].

The classic "danger situation" for voltage flicker [9] is when one or two fixed-speed wind turbines are connected to a weak rural network with low fault levels. The power output of wind turbines varies rapidly due to wind turbulence, and on a system with low fault level this can result in voltage fluctuations. A wind farm with several turbines is less likely to cause flicker, as the variations in the power outputs of the different turbines tend to cancel out. Furthermore, a system with healthy fault levels is unlikely to suffer from flicker as a result of the connection of one or two of wind turbines.

The potential to cause voltage flicker is peculiar to fixed-speed wind turbines, and is due to the electrical characteristics of induction generators. Variable-speed wind turbines are less likely to cause flicker. Generator sets and other types of generators operating at constant power output do not cause flicker.
In all cases, the particular standards and regulations on flicker must be consider. They will limit the amount of EG to be connected.

HARMONICS

Ideally, the voltage and current at any point in a distribution system should have a perfectly sinusoidal, 50 Hz waveform. However, this is not the case in practice. There are various sources of harmonics connected to the networks (inverters, compact fluorescent lights, etc.).
Inverter-coupled embedded generation schemes also introduce harmonics into the network.

The standards which refer to harmonics, usually limit the value of individual harmonics and / or the value of THD (Total Harmonic Distortion).
The THD is defined as follows:

$$THD(\%) = \frac{\sqrt{\sum_{k=2}^{50} (C_k)^2}}{C_1} x100$$

where,

C_1 is the fundamental component (1st order).

C_k is the k harmonic component.

The standards regarding harmonics will be a limiting factor in the degree of penetration of EG.

VOLTAGE SAGS

A voltage sag is a decrease in the RMS ac voltage, at the power frequency, of duration from 0.5 cycles (10 ms for 50 Hz systems) to 1 minute.
In accordance to their duration voltage sags may be divided as follows:

- Instantaneous: from 0.5 cycles to 30 cycles.
- Momentary: from 30 cycles to 3 seconds.
- Temporary: from 3 seconds to 1 minute.

The process of starting an EG can sometimes produce voltage sags in the distribution network. These sags are caused by inrush currents, which may occur when transformers or induction generators are energised from the network. Synchronous generators do not give rise to inrush currents themselves, but their generator transformers may do so if they are energised from the network.
In addition, voltage sags can be produced whenever a generator is suddenly disconnected from the network due to faults or other occurrences.

Voltage sags may produce several problems in the networks such as:

- Unwanted tripping of sensitive controls
- Dropping out of relay contacts
- Malfunction of sensitive equipment (PLC, medical equipment, etc.)

There are standards which establish which voltage sags are tolerable and which ones are not in accordance to their magnitude and duration. In Fig. 2.30 and Fig. 2.31 two different tolerance curves are presented.

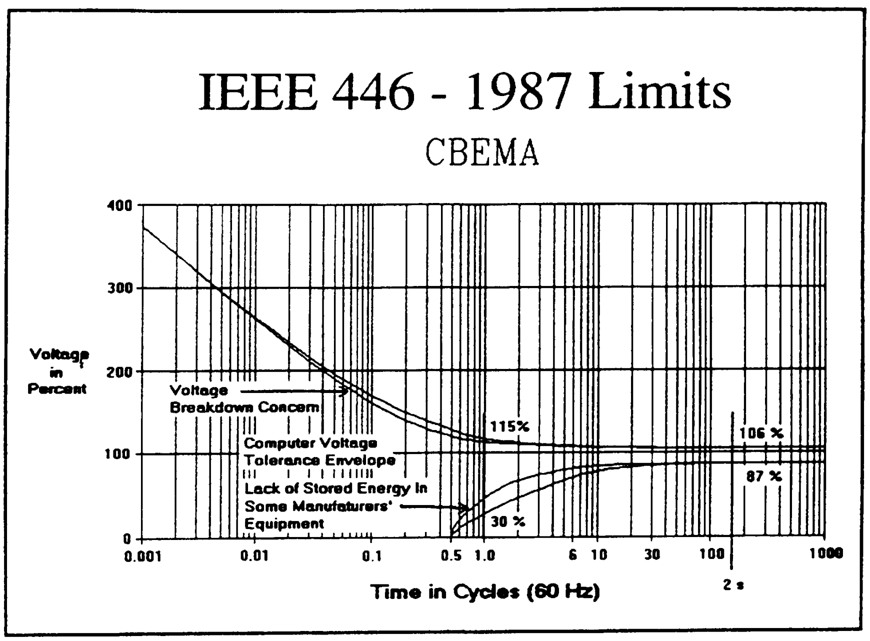


Fig. 2.30. IEEE 446 tolerance curves.

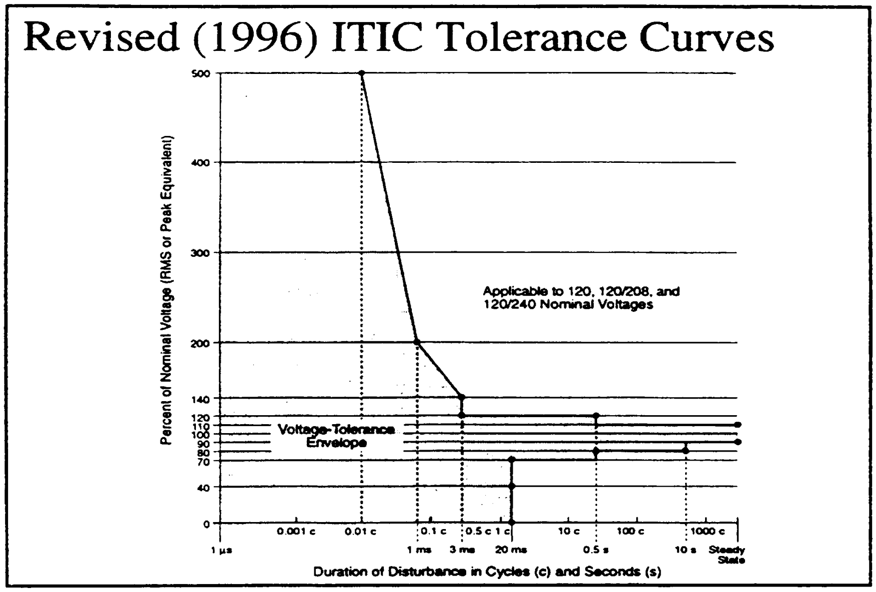


Fig. 2.31. ITIC tolerance curves.

VOLTAGE AND CURRENT UNBALANCE

The connection of unbalanced loads and generation to the distribution network can result in unbalanced currents and voltages. However, the vast majority of EG schemes use 3-phase generators or inverters, which inject balanced currents into the distribution network. Such generation schemes do not increase levels of voltage unbalance in the network. In fact, embedded generators which use 3-phase induction generators can actually reduce voltage unbalance.

On the other hand, in the particular case of some induction generator plants, the levels of voltage unbalance (negative phase sequence voltage) can cause relatively large negative sequence currents to flow [8]. This may cause overheating or tripping of the generator protection in some cases.

For each EG scheme, this issue should be assessed.

2.2.3 Protection and stability

The installation of an EG must not adversely affect the distribution network and other customers in the network. As a result, the design of the protection system is an important issue to consider.

At least, one circuit breaker must be installed at the point of supply to the generator installation to allow isolation of the EG from the distribution network. In general, the local distribution company will require that a circuit breaker is installed on their side of the point of supply to allow them to disconnect the EG from the distribution system if necessary.

Another circuit breaker could also be installed on the developer ´s side of the point of supply. This circuit breaker provides back-up to the first circuit breaker and allows the developer to provide their own isolation and earthing for maintenance of the generator installation. Both alternatives [9], one or two circuit breakers for the EG, are shown in Fig. 2.32.

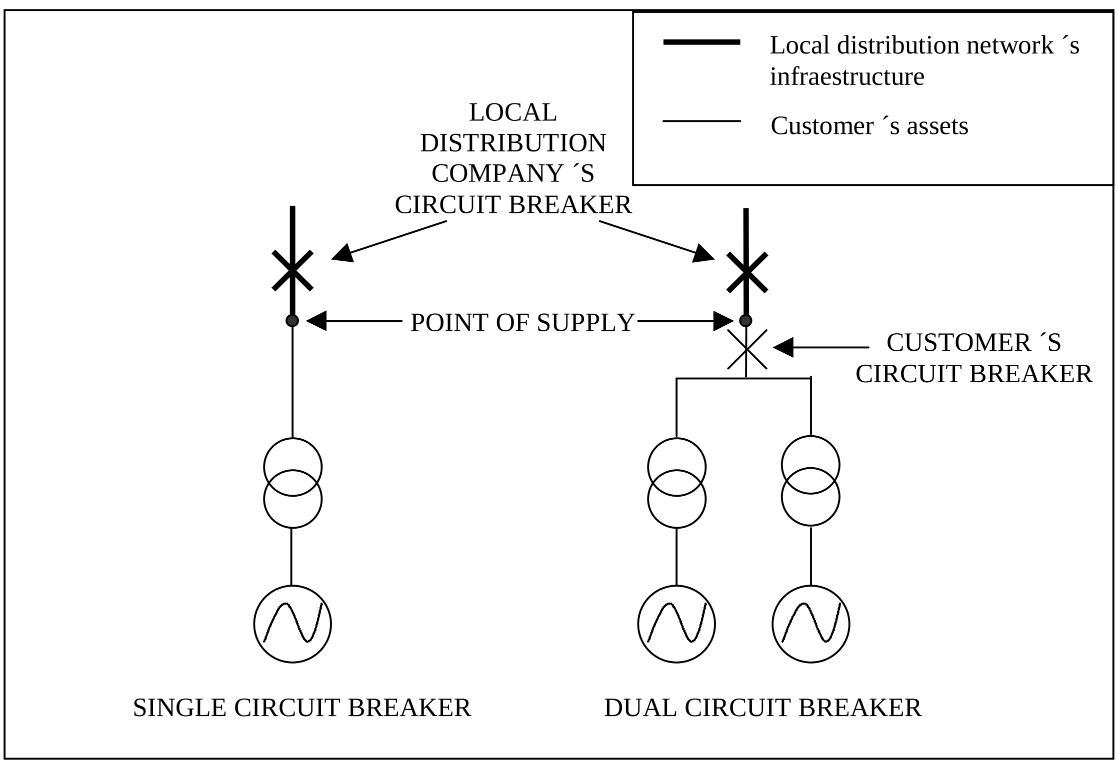


Fig. 2.32. Circuit breakers at the point of supply.

In some cases it may be possible for the developer to make cost savings by omitting the second circuit breaker. However, if there is only one breaker, local distribution company ´ s engineers have to be called out to provide isolation and earthing of the generator installation, and the local distribution company could charge for this service.

It is important to note that generator installation may include additional circuit breakers, isolators or other switchgear, to allow isolation of individual machines or transformers. An emergency trip button is usually required at the point of supply, to enable the generator to trip the local distribution company-owned circuit breaker in the event of an emergency. The emergency trip button is generally located in the substation where the local distribution company ´ s circuit breaker is installed. The button must be located in an area of the substation, which can be accessed by the developer ´s personnel.

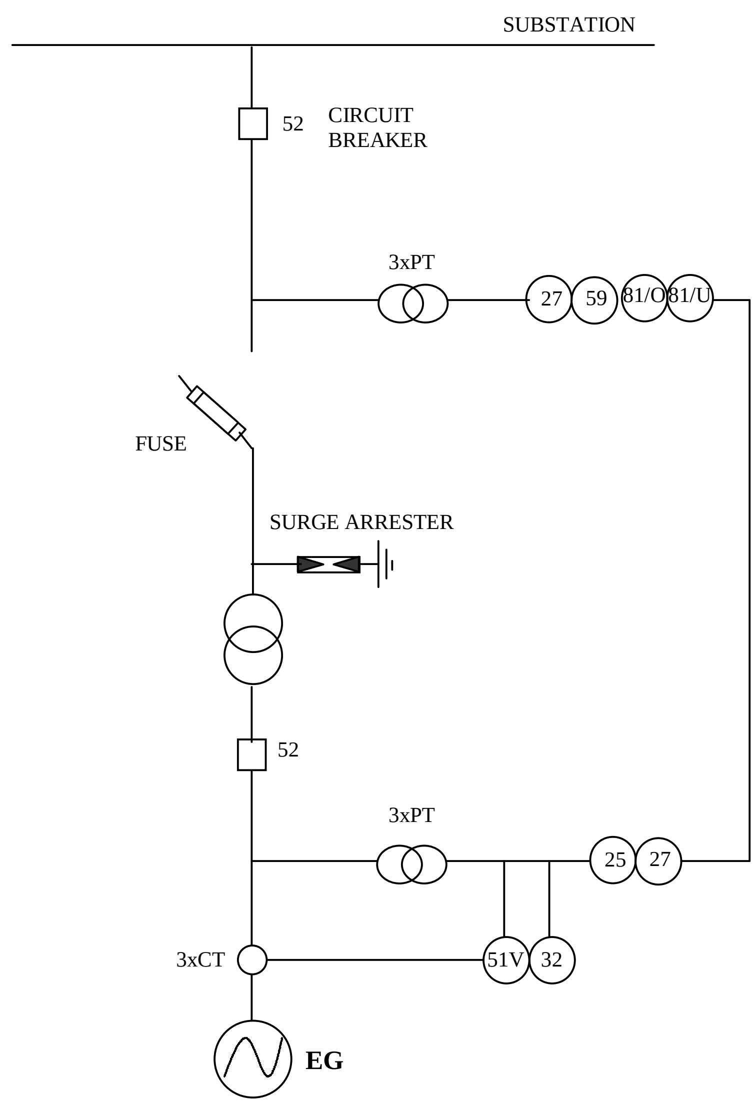
The protection system must detect and isolate faults in the generator installation. A list of the usual relays for these installations is presented below [1]. Depending on the particular case, the totality or part of this equipment will be used in the generator installation.

1. Under voltage relay. It can be instantaneous or temporised. An under voltage may occur if a circuit breaker in the distribution network that opens, produces a situation in which the system demand is higher than the generation (i.e. overloaded system or non acceptable loaded system).
2. Over voltage relay. It can be instantaneous or temporised. An over voltage may occur if a circuit breaker in the distribution network opens and the generator excitation control is not able to limit the voltage raise.
3. Under and over frequency relay. It can be instantaneous or temporised. When the generator is working in an islanding condition, the governor could not be able to keep the frequency within the statuary limits. The under/over frequency relay provides an additional way to disconnect the generator in that situation.
4. Over current, voltage controlled relay. It is generally temporised. It provides protection against short-circuits and over currents.
5. Synchronism relay. It is used for synchronic generators. It avoids the connection of the generator when the synchronism conditions are not present. It verifies if the

magnitudes and phases of the system and the generator voltages are within acceptable limits.

6. Voltage presence. An equipment is used to avoid the connection of the generator to a network that is not energised.
7. Reverse power. A relay avoids the generator to work as a motor.

In Fig. 2.33, the location of these relays in the generator installation is shown.



REFERENCES:

27 – Under voltage relay.	51V – Over current, voltage controlled relay.
59 – Over voltage relay.	25 – Synchronism relay.
81 / U – Under frequency relay.	27 – Voltage presence relay.
81 / O – Over frequency relay.	32 – Reverse power relay.

Fig. 2.33. Protection scheme for the generator installation [1].

In general, all these relays operate with temporisation in order not to open the circuit unnecessarily (e.g. in the case of transient events such as load changes). Fast re-closing in the radial network where the generator is connected should be avoided because the generator isolation cannot be guaranteed before the re-closing is done.

A possible solution is the use of synchronism relays that verify synchronism before re-closing. This is not an usual practice in distribution networks. Another possibility is to verify the presence of voltage in the generator side of the re-closer. If the voltage is less than a set value then re-closing is done.

A particular situation that requires special consideration is islanded operation. This situation is presented in Fig. 2.34 where an electrical fault in the distribution network produces the trip of circuit breakers A and B. As a result, a part of the distribution network is disconnected from the main grid supply. Generator G, continues its operation feeding the site load (SL) and the network load (NL) (islanding operation).

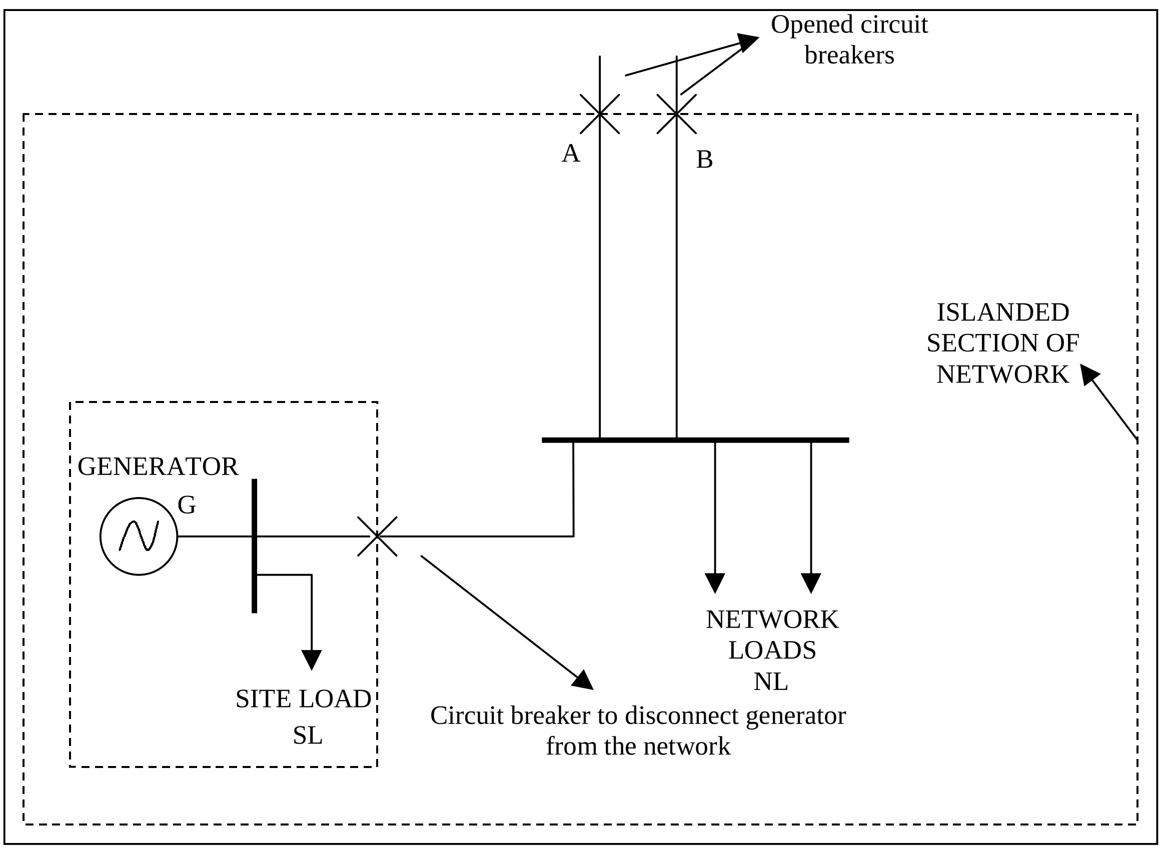


Fig. 2.34. Islanded operation of a section of network.

Islanded operation may lead to voltage and frequency fluctuations in the islanded section of the network. There are obviously consequences on quality of supply; in addition, the generator could trip. Moreover, it is a matter of concern that the islanded part does not reclose out of synchronism.

Protection against this situation is achieved by using loss of mains protection which aims to detect when the generator is islanded and to disconnect it from the network. Loss of mains protection is commonly implemented using rate of change of frequency relays, usually referred to as ROCOF relays.
Although loss of mains protection systems will detect islanding in most cases, there is no system which can guarantee to detect it in all cases [9]. Problems can arise when the islanded part of the network includes loads which closely match the output of the EG. To guarantee loss of mains protection, inter-tripping with the local distribution company ´s circuit breaker must be provided.

On the other hand, in some cases the distribution company could use islanded operation to guarantee the supply to a site load. In these cases, a study of the feasibility of such operation should be performed.

It is important to note that although it is very important to consider the protection issues, the associated costs do not affect the cost base of the EG project.

With reference to stability, studies on transient and voltage stability should be performed in systems with high degree of EG penetration.
In the past, with no EG penetration in the distribution networks, stability was not a matter of concern. As the network was passive, it remained stable under most circumstances, provided the transmission network was itself stable.
In networks with very low EG penetration, stability is still not a problem.
However, whilst the levels of EG penetration begin to increase, both transient as well as long term dynamic stability and voltage collapse studies become necessary.

2.2.4 Methods and tools used in network planning and design

EG includes stochastic sources such as wind, light or water flows. Consequently it can not be assessed using deterministic techniques such as traditional load flow analysis. New techniques which take into account the probabilistic nature of generation and loads have to be used.

For example, a realistic impression of when and where overvoltages or undervoltages occur over a whole period of study cannot be obtained by selecting combinations of consumer loads and EG power production. However, a better analysis could be made using Probabilistic Load Flow [32] or Monte Carlo Simulation based power flows.

In [32], an appropriate set of tools were designed for technical studies and pricing of networks with EG.

CHAPTER 3

CASES OF STUDY: ARGENTINA AND CHILE

3.1 ARGENTINE CASE

3.1.1 Degree of penetration of EG in Argentina

In accordance to Secretariat of Energy ´s Report 1998 [29] and [2], generation in Argentina may be split up into the following types:

- MEM: It refers to generation that is centrally dispatched by CAMMESA and sold in the Wholesale Electricity Market. It is generation connected to the transmission network.
- MEMSP: It refers to generation that is centrally dispatched by CAMMESA and sold in the Southern Patagonian Wholesale Electricity Market. It is generation connected to the transmission network.
- INOMEM: It refers to generation that is connected to the SIN but it is not centrally dispatched by CAMMESA. In general, this generation is embedded in distribution networks. It can be part of a provincial electricity company or part of a private distribution company. In the first case, the provincial company is owned by the provincial government and operates as a vertically integrated electricity industry, which buys the energy not locally produced in the wholesale electricity market. In the second case we are talking about generators that were already installed in the distribution network at the moment of concession and therefore were included in that concession.
- ISOLATED: It refers to generation that provides electricity in those areas not connected to the national interconnected system (isolated areas). We are referring to small isolated distribution networks with their own generation.
- SELF- PRODUCERS: Refers to industries that produce their own electricity but also buy electricity in the market. Moreover, in the particular case that they also sell electricity, they are called SELF-GENERATORS. In this case, SELF-GENERATORS are centrally dispatched by CAMMESA.
  SELF-PRODUCERS are installed both in the distribution and transmission system.

The case of CO-GENERATION is included in the first two types (MEM and MEMSP) because co-generation is always centrally dispatched by CAMMESA. Co-generators are industries that produce electricity for their own industrial purposes but also sell some of the electricity produced in the market. They are different from SELF-GENERATORS because they never buy electricity in the market.
In general, CO-GENERATION in Argentina is installed in the transmission system.

From our definition of EG (Chapter 2) it results that for the evaluation of the amount of EG in the argentine system we have to consider:

- The amount of INOMEM generation.
- The amount of SELF-GENERATION in the distribution networks.
- The amount of CO-GENERATION in the distribution networks.

In addition, we are going to evaluate the amount of isolated generation (IG).

From Secretariat of Energy ´s Report 1998 [29] and for the purpose of this project, the following data was obtained.

ELECTRICITY GENERATION IN MWh - YEAR 1998

SYSTEM	CC	D	W	H	NUC	GT	VT	SO	TOTAL	%
MEM	4976359	9	0	22969267	7452828	11297515	15914171	0	62610149	91.45
MEMSP	0	0	0	2267061	0	1316140	0	0	3583201	5.23
INOMEM	294	8504	2823	1191885	0	263	0	0	1203769	***1.76***
ISOLATED	0	454818	29718	75268	0	217016	0	17	776837	1.13
TOTAL	4976653	463331	32541	26503481	7452828	12830934	15914171	17	**68173956**	
SELF-GENERATORS									**286344**	***0.42***
COGEN. D *(1)*									**0**	0.00
TOTAL AVAILABLE ENERGY									**6.8E+07**	**100**
IMP. - EXP. *(2)*									**8000230**	
LOSSES BOMB. *(3)*									**-260685**	
TOTAL GEN. OFFER									**7.6E+07**	

% EG	***2.18***
% IG	1.13

REFERENCES:

CC: Combined Cycle
D: Diesel
W: Wind
H: Hydro
NUC: Nuclear
GT: Gas Turbine
VT: Vapor Turbine
SO: Solar

(1) COGEN. D. refers to CO-GENERATION connected to the distribution system.
(2) IMP. - EXP. = Imported electricity - Exported Electricity
(3) LOSSES BOMB. refers to losses due to bombing in generating plants.

Fig. 3.1. Total generation in Argentina in 1998 (in MWh).

COMPOSITION OF GENERATION IN 1998 (% of total MWh)

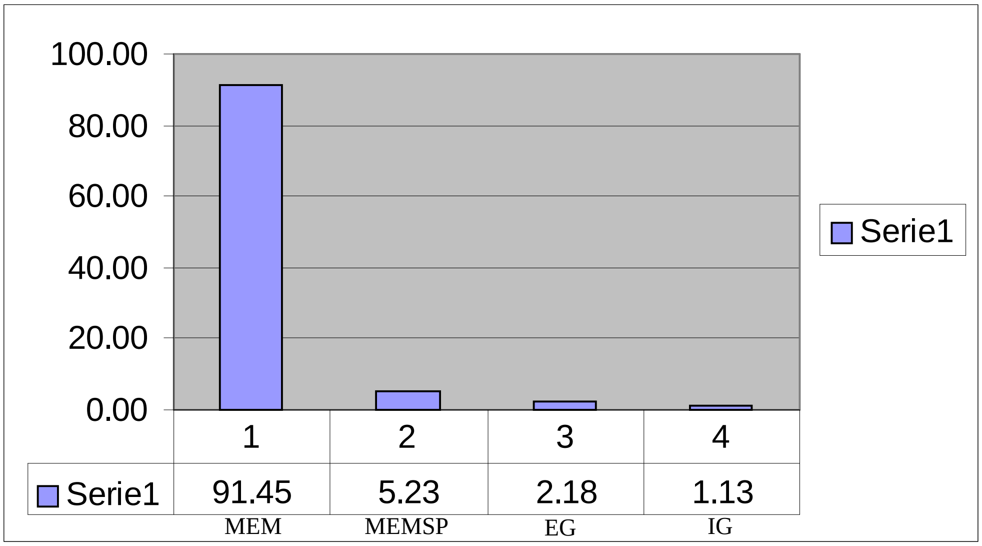


Fig. 3.2. Composition of generation in Argentina (1998).

COMPOSITION OF EG IN ARGENTINA (1998)

CC	D	W	H	NUC	GT	VT	SO	SELFGEN	TOTAL	
294	8504	2823	1191885	0	263	0	0	286344	1490113	MWh
0.02	0.57	0.19	79.99	0.00	0.02	0.00	0.00	19.22	100.00	%

REFERENCES:

CC: Combined Cycle
D: Diesel
W: Wind
H: Hydro
NUC: Nuclear
GT: Gas Turbine
VT: Vapor Turbine
SO: Solar

SELFGEN refers to SELF-GENERATION

Fig. 3.3. Composition of EG in Argentina (1998).

COMPOSITION OF EG IN ARGENTINA (% of MWh)

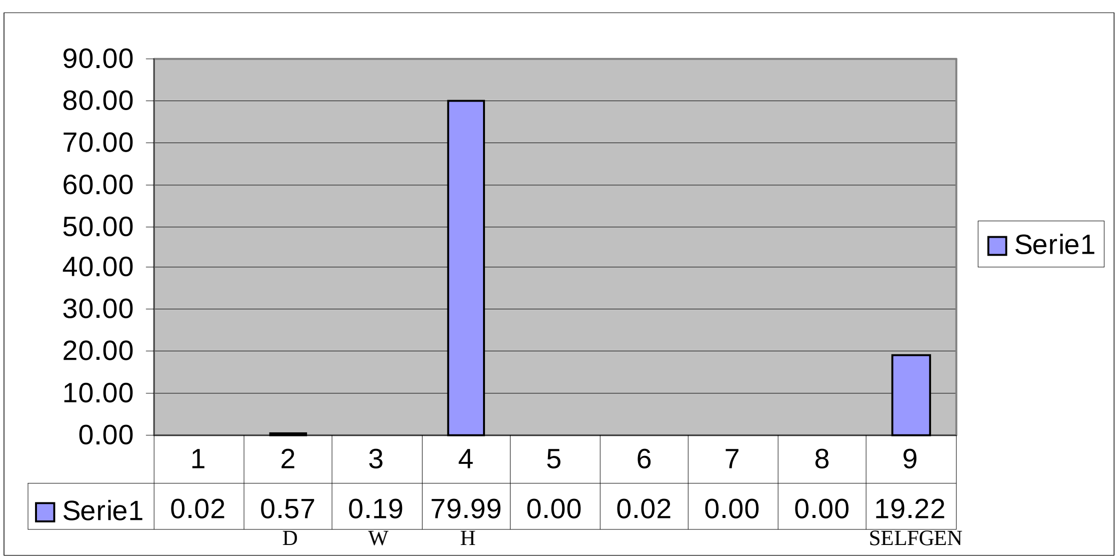


Fig. 3.4. Composition of EG in Argentina (1998).

COMPOSITION OF ISOLATED GENERATION IN ARGENTINA (1998)

CC	D	W	H	NUC	GT	VT	SO	TOTAL	
0	454818	29718	75268	0	217016	0	17	776837	MWh
0.00	58.55	3.83	9.69	0.00	27.94	0.00	0.00	100	%

REFERENCES:

CC: Combined Cycle
D: Diesel
W: Wind
H: Hydro
NUC: Nuclear
GT: Gas Turbine
VT: Vapor Turbine
SO: Solar

Fig. 3.5. Composition of isolated generation in Argentina (1998).

COMPOSITION OF ISOLATED GENERATION (% of MWh)

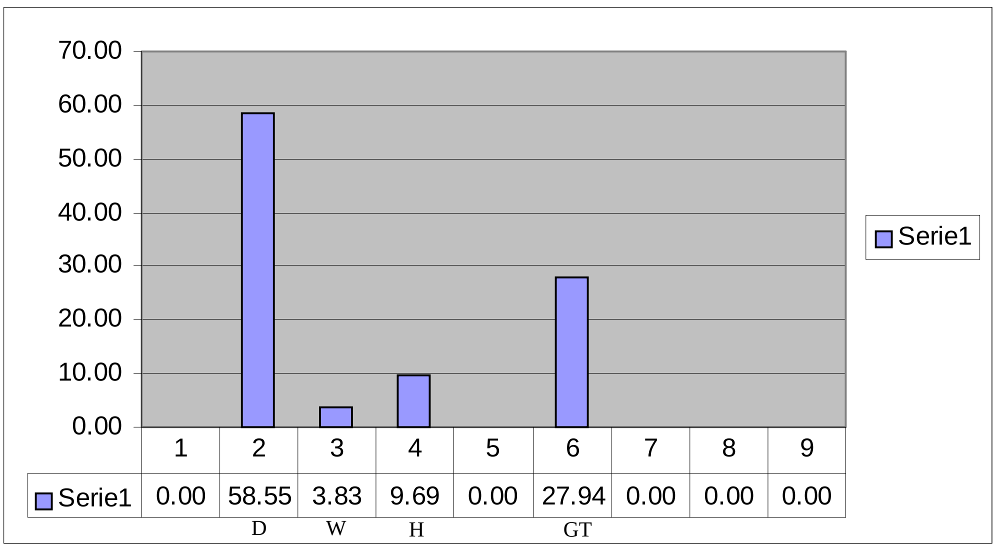


Fig. 3.6. Composition of isolated generation in Argentina (1998).

From the previous figures it results that, from the total energy production in Argentina (1998), 2.18 % comes from embedded generators. This value was obtained by adding the production of INOMEM generation plus the production of SELF-GENERATORS. It is important to note that INOMEM generators are owned by local distribution companies or provincial electricity companies. Consequently, the energy produced by INOMEM generators is used, by these companies, to decrease the amount of energy they bought in the wholesale market.

On the other hand, the production of SELF-GENERATORS considered here, is traded in the wholesale market.

From Fig. 3.4 it is clear that EG is composed basically of hydro generation (80 %) and self-generation (19.2 %). There are also small amounts of wind generation (0.2 %) and diesel generation (0.6 %).

The amount of isolated generation (IG) in the argentine system is 1.13 % (Fig. 3.2) which is composed basically of 58.6 % of diesel generation, 27.9 % of gas generation, 9.7 % of hydro generation and 3.8 % of wind generation (Fig. 3.6). There is also a small proportion of solar generation.

If we now analyse the installed generation capacity we obtain the following results.

GENERATION CAPACITY IN ARGENTINA IN 1998 (kW)

SYSTEM	GC	VC	DI	W	HB	HI	NUC	GT	VT	SO	TOTAL	%
MEM	1539800	512900	8800	0	974000	7585380	1018000	3051240	4581000	0	19271120	83.62
MEMSP	0	0	0	0	0	494720	0	336200	0	0	830920	3.61
INOMEM	48640	22400	320069	13250	0	263868	0	152200	22400	0	842827	3.66
ISOLATED	0	0	237473	2	0	8417	0	107080	0	25	352997	1.53
TOTAL	1588440	535300	566342	13252	974000	8352385	1018000	3646720	4603400	25	21297864	
SELF-PRODUCERS											1748317	7.59
TOTAL GENERATION CAPACITY AVAILABLE											23046181	100

% EG	11.24
% IG	1.53

REFERENCES:

GC: Combined Gas Cycle
VC: Combined Vapor Cyle
W: Wind
H: Hydro
NUC: Nuclear
GT: Gas Turbine
VT: Vapor Turbine
SO: Solar
D: Diesel

Fig. 3.7. Generation capacity in Argentina (1998).

COMPOSITION OF GENERATING CAPACITY (%)

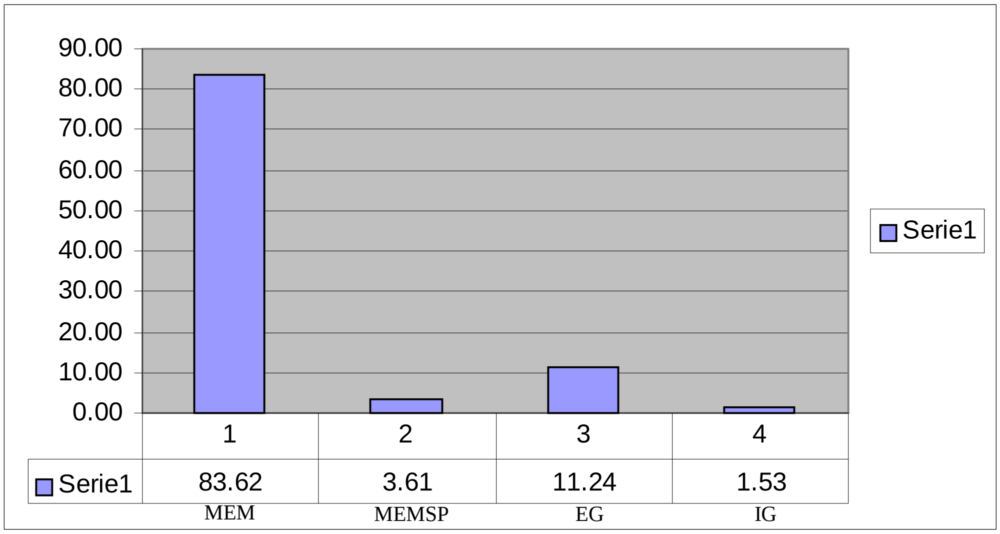


Fig. 3.8. Composition of generating capacity in Argentina (1998).

From Fig. 3.7 and Fig. 3.8 it may be seen that the proportion of EG capacity installed in Argentina (1998) is 11.24 %. This value seems to be large if we compare it with the proportion of EG energy production (2.18 % in Fig. 3.2). The reason for obtaining this number is that we are adding to the INOMEM capacity (3.66 %) the total self-producers capacity (7.59 %). The majority of the energy produced by self-producers is consumed by themselves (only 286344 MWh are traded from a total of 5995606 produced by self-producers, which represents 4.8%).

The installed capacity of IG is 1.53 %, which is close to the value of 1.13 % obtained in Fig. 3.2.

The Electricity Supply Program for Dispersed Rural Population in Argentina ("PAEPRA") promotes the IG in rural areas in Argentina, which are not reached by electricity networks.

The different areas are given in concession to private companies, which are in charge of the electricity supply to the area. The customers pay a fair tariff for the electricity consumed and the national and provincial governments make an extra payment to the company. The concession is made to the company who requires the lower subside.

In Fig.3.9 there is a list of some of the projects under this program. It is important to note that these projects involve the use of renewable energy.

PROJECTS	**TYPE**
Project Nº 1 - Thermal-electric plant using bio-mass waste	Bio-mass
Project Nº 2 - Electrification of Rural Schools in Santa Fe Province	PV
Project Nº 4 - Wind Farm in Cerro Arenales (10 MW)	Wind
Project Nº 6 - Hydro generation for Rural Areas	Hydro
Project Nº 8 - Installation of Micro-turbines at River De los Sauces	Hydro
Project Nº 10 - Installation Program of a Bio-gas plant in Mendoza province	Bio-gas
Project Nº 23 - Electricity Supply using Wind-Solar generation in San Juan province	Wind-Solar

Fig. 3.9. Some of the projects under the Electricity Supply Program for Dispersed Rural Population in Argentina [43].

3.1.2 Regulations on EG in Argentina

From the analysis of the argentine Energy Act, it results that there are no specific regulations on EG. EG is treated in the same manner as directly connected generation (generation connected to the transmission systems).

The Energy Act recognises three types of generation in Argentina:

1. MEM Generator: It is an entity which (unique) activity is selling electricity in the WEM.
2. SELF-GENERATOR: It is an electricity consumer, which generates electricity as a secondary product, but its main activity is the production of commodities or services. A self-generator may buy and sell electricity in the WEM.
3. CO-GENERATOR: It is an entity, which generates electricity, vapour or other types of energy for industrial purposes. A co-generator may only sell (does not buy) electricity in the WEM.

Consequently, a new EG which is connected to the SIN has only three possibilities:

1. Being a MEM Generator.
2. Being a SELF-GENERATOR.
3. Being a CO-GENERATOR.

It is important to note that a large amount of the present EG in Argentina (see 3.1.1) is of none of these types because, as explained before, they remained as part of provincial systems or distribution concessions at the time of deregulation.
However, for new projects only the three types explained are possible.

In all cases, a generator will need approval from the Secretariat of Energy and CAMMESA in order to become a member of the WEM and to be able to sell electricity. In accordance to the Energy Act, Self-generators and Co-generators are treated as MEM Generators. In addition, Self-generators and Co-generators must have an installed capacity of at least 1 MW and an average annual availability of 50 % in order to become members of the WEM.

There are no special tariffs for EG. A new EG in Argentina will be one of the three types of generators specified above and will be paid in accordance to the criteria establish in Chapter 1 for all generators.
This is different from the situation in countries such as Greece where EG is allowed to get 90% of the retail price of electricity.

CONNECTION COSTS

From the statistics presented in 3.1.1 it is clear that the connection of new embedded generation is not an usual practice in Argentina.

The analysis of [2] leads to the conclusion that a generator which is to be connected embedded in the distribution network must follow what is established in Annexe 28. The distribution company has to give open access to its existing network capacity. However, it is not obliged to expand the system in order the generator to be connected. For the expansion of the system, an agreement between the generator and the distribution company must be held [2, Contract between parts, Access Regulation]. Two different procedures may be followed:

- the distribution company is responsible for the construction, operation and maintenance of the expansion,

or

- the generator makes the expansion and the distribution company is in charge of the operation and maintenance.

In all cases, the generator has to pay the costs of the expansion corresponding to the capacity it will use.

As a result, the new EG has to pay for any reinforcement in the distribution network, which corresponds to what we have called as "deep connection" in Chapter 2.

DISTRIBUTION USE OF SYSTEM CHARGES

These charges should be agreed between the distribution company and the generator. However, Annexe 28 of [2] establishes maximum applicable tariffs.

The charges include the following components:

- Connection: correspond to the payments associated to operation and maintenance of all the connection and transformation equipment. The payments depend on the level of quality service.
- Transport Capacity: correspond to the payments associated to operation and maintenance of the equipment used for the electricity transport service. The payments depend also on the level of quality service.
- Transported Energy: are calculated from the difference of the value of the energy at the receiving busbar and the value of the energy at the sending busbar.

In Fig.3.10, the maximum applicable tariffs established in Annexe 28 of [2] are shown.

BASE VALUES FOR DUS CHARGES REFERRED TO MAY 1994 IN $

Connection

For each 220 kV feeder	$ 4 / hr
For each 132 kV or 66 kV feeder	$ 2 / hr
For each 33 kV (or less) feeder	$ 1.5 / hr
For each step-down dedicated transformer	$ 0.15 / hr / MVA

Transport Capacity

For 220 kV lines	$ 45 / hr / 100 km
For 132 kV (or less) lines	$ 43 / hr / 100 km
For 220 kV cables	$ 90 / hr / 100 km
For 132 kV (or less) cables	$ 85 / hr / 100 km

Note: 1 $ = 1 USD

Fig. 3.10. Distribution use of system (DUS) maximum charges.

ALLOCATION OF LOSSES

In Argentine, the method of allocating the cost of losses in the distribution systems consists in averaging them among all customers. These costs are part of the whole tariff that customers pay to the distribution company. No special consideration is given at present for individual customers such as EG, which may reduce the amount of losses in the network.

EXTERNALITIES

Environmental externalities

There is a law, in Argentina, which promotes wind and solar energy (Law Nº 25019 together with Decree Nº 1597-99). An additional payment of 0.01 USD / kWh is paid to these type of generators. In addition, a reduction of taxes that this energy pay is applied.

Security of Supply

Generators may sell electricity either in the contract market or in the spot market as explained in Chapter 2. The payments they receive are associated to the energy delivered and the capacity made available ($PPAD).

In accordance to Annexe 12 of [2], for the case of Self-generators and Co-generators, the following definitions apply:

- Firm-capacity: The capacity sold by the generator in the hourly spot market is considered firm if that sale was programmed in the Weekly Programme and if it does not exceed for more than 20 % the offered capacity for that day.
- Non firm-capacity: The capacity sold by the generator in the hourly spot market is considered non-firm if the sale was not programmed in the Weekly Programme or if programmed, the capacity exceed for more than 20 % the offered power for that day.

The firm capacity sold to the WEM by a Self-generator or Co-generator is paid for the energy at the hourly nodal energy price, and for the capacity at the hourly capacity price. The non-firm capacity sold at the WEM is only paid for the energy at the hourly nodal energy price.

Consequently, an ERG which production varies stochastically has difficulties in selling firm capacity under the argentine law. Therefore, in these cases, generators will only get paid for energy sold.

VOLTAGE REGULATION AND REACTIVE POWER

In accordance to [2], all the participants of the WEM are responsible for voltage regulation and for the control of reactive power flows.

MEM generators must inform CAMMESA the nominal P-Q capacity curve of the generator.

CAMMESA must define, together with the Secretariat of Energy, the minimum standards for new generators regarding to:

- the nominal P-Q capacity curve
- the security margins
- the network requirements

Each MEM generator is obliged to deliver:

- at any time, until 90 % of the reactive power limit of the generator at any operational point in the P-Q capacity curve, for the generator working at maximum refrigeration pressure
- 100 % of the reactive power limit for 20 minutes in intervals of 40 minutes each.

In addition, the MEM generator must control the voltage at those busbars that CAMMESA ask the generator to control.

In the case of Self-generators and Co-generators the following rules apply:

- For firm-capacity generation, the generator must follow the established P-Q capacity curve (same case as MEM generators).
- For non firm-capacity generation, the generator cosine-phi must fall between 0.85 inductive and 0.97 capacitive.

It is important to note that, in accordance to [2], generators are not paid for the reactive power delivered (*). On the other hand, they are penalised if they do not meet their reactive power flow requirements.

POWER QUALITY

ENRE resolution 99/97 defines limits of flicker and harmonic contents in current in the argentine ESI.
The resolution considers both the distribution at LV and at MV levels. In addition, the location where the measurements have to be done, the measurement equipment, the measurement period and methodologies to measure are defined. Moreover, the penalisations for the cases of non-compliance of this resolution are established.

Voltage flicker

In Fig.3.11, a summary of the argentine standard on flicker is presented. It is important to note that the limits on flicker are established in accordance to the contracted power and not to the actual current that is flowing at the moment of measure.

(*) There is an exception that corresponds to the case when a generator covers the reactive power that another generator was supposed to supply, but actually did not.

<table>
<tr><th>Tariff</th><th>Contracted Power</th><th>Measurement Impedance</th><th colspan="2">LV U ≤ 1 kV</th><th colspan="2">MV 1 kV ≤U ≤ 66 kV
HV 1 kV ≤U ≤ 220 kV</th></tr>
<tr><td>T-1</td><td>P < 10 kW</td><td rowspan="5">Reference Impedance</td><td colspan="2">Pst = 1</td><td colspan="2" rowspan="11"></td></tr>
<tr><td>T-2</td><td>10 kW ≤ P < 20 kW</td><td colspan="2">Pst = 1</td></tr>
<tr><td>T-2</td><td>20 kW ≤ P < 30 kW</td><td colspan="2">Pst = 1.26</td></tr>
<tr><td>T-2</td><td>30 kW ≤ P < 40 kW</td><td colspan="2">Pst = 1.58</td></tr>
<tr><td>T-2</td><td>40 kW ≤ P < 50 kW</td><td colspan="2">Pst = 1.86</td></tr>
<tr><td rowspan="6">T-3</td><td rowspan="6">P ≥ 50 kW

K1 = S_L / $S_{MT/BT}$

cosφ = 0.85 when calculating S_L</td><td rowspan="12">The minimum value of:

a. Network impedance.

b. The impedance that at nominal current produces a voltage drop of 3 %.</td><td>K1 ≤ 0.1</td><td>Pst = 0.37</td></tr>
<tr><td>0.1 < K1 ≤ 0.2</td><td>0.46</td></tr>
<tr><td>0.2 < K1 ≤ 0.4</td><td>0.58</td></tr>
<tr><td>0.4 < K1 ≤ 0.6</td><td>0.67</td></tr>
<tr><td>0.6 < K1 ≤ 0.8</td><td>0.74</td></tr>
<tr><td>0.8 < K1</td><td>0.76</td></tr>
<tr><td rowspan="6">T-3</td><td rowspan="6">P ≥ 50 kW

K2 = S_L / S_{cc}

cosφ = 0.85 when calculating S_L</td><td colspan="2" rowspan="6"></td><td>K2 ≤ 0.005</td><td>Pst = 0.37</td></tr>
<tr><td>0.005 < K2 ≤ 0.01</td><td>0.46</td></tr>
<tr><td>0.01 < K2 ≤ 0.02</td><td>0.58</td></tr>
<tr><td>0.02 < K2 ≤ 0.03</td><td>0.67</td></tr>
<tr><td>0.03 < K2 ≤ 0.04</td><td>0.74</td></tr>
<tr><td>0.04 < K2</td><td>0.76</td></tr>
<tr><td colspan="7">Notes:
1. $S_{MT/BT}$ is the transformer capacity where the customer is connected.
2. S_L is the contracted complex power calculated using a power factor of 0.85.
3. S_{cc} is the shortcircuit power at the customer supply point.</td></tr>
</table>

Fig. 3.11. Argentine standard on flicker (ENRE Resolution 99/97).

Current harmonics content

Once again, the limits in current harmonic content are given considering the contracted power and the voltage level. In Fig. 3.12, a summary of the argentine standard on current harmonic content is presented.

Harmonic **[n]**	**Tariff T-1** LV U ≤ 1 kV P< 10 kW	**Tariff T-2** LV U ≤ 1 kV P< 50 kW **Tariff T-3** MV 1 kV < U < 66 kV P≥ 50 kW	**Tariff T-3** HV 66 kV ≤ U ≤ 220 kV
	Maximum accepted current (A)	Maximum accepted current in per cent of $I_{measured}$ / I_{1N}	
ODD HARMONICS NON MULTIPLES OF 3			
5	2.28	12.0	6.0
7	1.54	8.5	5.1
11	0.66	4.3	2.9
13	0.42	3.0	2.2
17	0.26	2.7	1.8
19	0.24	1.9	1.7
23	0.20	1.6	1.1
25	0.18	1.6	1.1
> 25	4.5 / n	0.2 + 0.8 x 25 / n	0.4
ODD HARMONICS MULTIPLES OF 3			
3	4.60	16.6	7.5
9	0.80	2.2	2.2
15	0.30	0.6	0.8
21	0.21	0.4	0.4
> 21	4.5 / n	0.3	0.4
EVEN HARMONICS			
2	2.16	10.0	10.0
4	0.86	2.5	3.8
6	0.60	1.0	1.5
8	0.46	0.8	0.5
10	0.37	0.8	0.5
12	0.31	0.4	0.5
> 12	3.68 / n	0.3	0.5
THD (%)	----------	20.0	12.0

Notes:

1. I_{1N} is the nominal current corresponding to the contracted power (P), calculated using a power factor of 0.85.
2. All current values are RMS and in Amps.

Fig. 3.12. ENRE Resolution Nº 99 / 97. Limits on current harmonics.

Comparative study between the Argentine standard and IEEE 519

In [4] a comparative study between the argentine standard and IEEE 519 has been done considering the case of tariff T-3 in MV and for the case that I_{sc} / I_{1N} (ratio between short circuit current and maximum load current) is between 100 and 1000. The conclusion was that the argentine standard is more tolerable, in particular when considering current harmonics 5, 7 and 11. With reference to the THD, the argentine standard value is 12 % for the case of consideration while the IEEE value is 7.5 %.

METHODS AND TOOLS USED IN NETWORK PLANNING AND DESIGN

From the analysis of the Technical Procedures Nº 1 [2], it is clear that the methods and tools used in network planning and design are deterministic methods.

The requirements for the connection of new generation includes the study of:

- the effects of the new generation on the network transport capacity
- the over-voltages, over-currents, shortcircuit currents and other effects that may affect the life of installed equipment
- the effects on the service quality
- the effects on the system operational costs

These studies must be done by the developer and are revised by CAMMESA.
The studies are carried on by using power flow programmes, short-circuit programmes and stability programmes. For the analysis, a set of different scenarios are defined. These scenarios consider the actual system operation and possible particular emergency cases that are produced in accordance with a Reference Guide that is periodically actualised by CAMMESA.

In Fig. 3.13, a reference table with the studies that must be carried on in accordance with the Technical Procedures Nº 1 is shown.

		Type of installation		
Stage (*)	**Study**	**New Generation**	**New Demand**	**Increase in transport capacity**
1	Power flow	Yes	Yes	Yes
1	Short-circuit	Yes		Yes (1)
1	Transient Stability	Yes	Yes (2)	Yes (2)
1	Transport requirements	Yes	Yes	Yes
2 and / or 3	Electromagnetic transients	Yes	Yes (3)	Yes
2 and / or 3	Deep transient stability studies	Yes (2)	Yes (2)	Yes (2)
2 and / or 3	Black start	Yes	----	----
2 and / or 3	Islanding	Yes	Yes (4)	----
2 and / or 3	Regulators adjustment	Yes	----	----
2 and / or 3	Small perturbations	Yes	----	----

Notes:

(1) If there is a change ins the transport system configuration.

(2) When there are important changes in transported power or energy.

(3) When voltage perturbations are introduced (flicker, harmonics, fast load changes, etc.).

(4) When the value of the new demand imposes the study.

(*) In accordance with Technical Procedures Nº 1, three different stages are defined for new connections to the transport system:

Stage 1: Access to the transport capacity and extensions.

Stage 2: Detailed technical design.

Stage 3: Design and optimisation of the control systems.

Fig. 3.13. Reference studies table for new connections.

3.1.3 Conclusions

From the analysis made in 3.1.1 it resulted that from the total amount of energy produced in Argentina in 1998, 2.18 % came from EG. From this number, nearly 20 % came from SELF-GENERATORS and the other 80 % from INOMEM generators. INOMEM generators are, in general, part of the still vertically integrated provincial systems, owned by the provincial governments. Consequently, as mentioned before, the energy produced by INOMEM embedded generators is not traded in the market. This energy is actually used to decrease the amount of energy that provincial companies must bought in the WEM.
As a result, the amount of energy produced by EG and traded in the market is that produced by SELF-GENERATORS, and this corresponds to 0.42 % of the total production.

The analysis of the regulation framework done in 3.1.2 shows that the present arrangements in Argentina, do not consider the real value of EG.

The tariff structures consider EG as any other generation in the network not taking into account its situation with respect to the load. No additional value is placed to EG tariffs, thus making EG to compete directly with central generation.

When looking at the connection costs within the present arrangements in Argentina, it is clear that EG is obliged to pay "deep connection" charges. In Chapter 2, it was discussed that connection charges were not an issue itself, but part of the whole distribution use of system charges policy. It was discussed there that for a fair network pricing policy, each user of the network should pay in accordance to its contribution to the total costs involved in the use of the network. Therefore, "deep connection" charges, clearly make EG to lose competitiveness.

In addition, as seen in 3.1.2, DUS charges do not appropriately allocate the cost of losses. Within the present arrangements, the costs of losses are allocated by averaging them among all customers as part of the whole tariff. No special consideration is given at present for individual customers such as EG, which may reduce the total amount of losses in the system.

With reference to the environmental externalities, an additional value is placed for renewable energy. As mentioned, under the "Wind Law" in Argentina, wind and solar energy is paid an extra 0.01 USD/kWh. In addition, a reduction in the taxes is applied in the tariffs for this type of energy.
However, as seen in 2.1.3 (for instance, taking the values of Fig. 2.14) the environmental costs for an oil-fired unit are, for the best case, 0.025 USD / kWh, while for renewable energy, are, for the worst case, 0.007 USD / kWh. This means that an extra payment of 0.01 USD / kWh is not enough to encounter the environmental effects of energy production.
Under the scope discussed in Chapter 2, electricity tariffs should take into account, in accordance to the type of generating plant, the environmental costs of energy.

When looking at security of supply, it is clear that the present arrangements in Argentina only recognise firm capacity as a source of system security. The philosophy applied is deterministic and does not take into account the probabilistic availability of the energy sources. As discussed in 3.1.2 an ERG, which production varies stochastically will only get paid for the energy produced and not for providing additional system security.
It was clear, from the example proposed in Chapter 2 (when referring to Security of Supply) that an ERG with an availability of only 50 %, contributes in the system security.

With reference to voltage regulation and reactive power management, the present arrangements in Argentina usually do not consider additional payments for provision of reactive power, as seen in 3.1.2. Generators must provide the service and are penalised if they do not meet their reactive power flow requirements.
This applies to all generators, embedded or not.
Under the general philosophy of network pricing discussed in Chapter 2, this situation is not adequate as it is not cost reflective and may distort the market. However, the situation does not particularly discriminate EG.

With reference to power quality, as discussed in 3.1.2, ENRE Resolution 99/97 defines limits on flicker and current harmonics. As seen, the argentine standard is more tolerable than the IEEE 519. This could lead to a greater penetration of EG in Argentina with respect to other countries, which applies IEEE 519 or similar standards. It is clear that, for this situation to happen, the other aspects of the present arrangements, which affect EG, should change.

In sum, no special considerations have been taken into account, with respect to EG, in the present Argentine arrangements.
For EG to grow in Argentina a different pricing network policy has to be applied which recognises the real value of EG.
In addition, new methods and tools have to be defined in network planning and design, which take into consideration, for example, the stochastic nature of ERG.

3.2 CHILEAN CASE

3.2.1 Degree of penetration of EG in Chile

The analysis of CDEC-SIC Report [5] give us the following composition of the energy generated in the SIC in 1998 (Fig. 3.14 and Fig. 3.15).

COMPOSITION OF SIC GENERATION IN 1998

H	T_NOSELF	T_SELF	TOTAL	
15129900	9538400	990000	25658300	**MWh**
58.97	37.17	3.86	100.00	**%**

REFERENCES:
H: Hydro Generation
T_NOSELF: Thermal Generation which is not from Self-producers
T_SELF: Thermal Generation from Self-producers

Fig. 3.14. Composition of energy generated in the SIC in1998.

COMPOSITION OF SIC GENERATION IN 1998 (% of MWh)

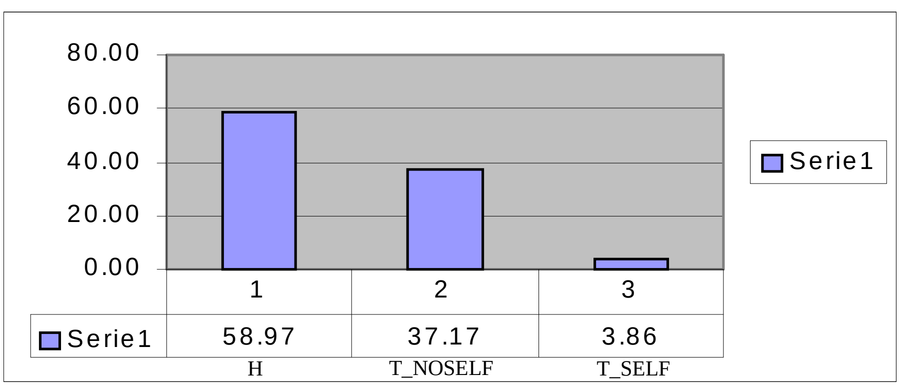


Fig. 3.15. Composition of the energy generated in the SIC in 1998.

From the previous figures it is clear that the energy generated in the SIC in 1998 is composed by hydro generation (59 %) and thermal generation (41 %). In addition, from the thermal generation, 3.86 % comes from self-producers. The Energy Act defines a self-producer as an entity which main activity is different from generating or transmitting electricity. CDEC-SIC information is that almost all the self-producers considered in these statistics are connected to the transmission network. Consequently, in accordance to our definition (Chapter 2), no one of them are EG.

No available statistics were found from the SING. However, it is important to note that:

1. The SING has three times less the capacity installed in the SIC.
2. Many of the major mining companies located in the SING have considerable self-generating capacity, which have been developed before the power sector reform. This capacity may be considered EG, although its energy is not traded but consumed internally.

On the other hand, [41] gives evidence of small amounts of isolated generation (IG) spread out in rural areas in Chile and also projects to increase the amount of IG. There is a National Rural Electrification Program ("PER") that promotes IG in areas not reached by the network. They are mainly, wind-diesel and PV systems. In Fig. 3.16, the main examples of IG are shown.

INSTALLATIONS AND PROJECTS	**TYPE**
Applications done by ENTEL	PV
National Television of Chile	PV
Army	PV
PER - 2500 individual domestic installations	PV
CNE - Project - 6000 individual domestic installations	PV
CNE - Project - 3500 individual domestic installations	W-D
CNE - Small rural town - 14.5 kW	W-D

Fig. 3.16. IG: present installations and projects in Chile.

In addition, feasibility studies for co-generation embedded in the chilean distribution networks may be found. In [33], a study is presented which evaluates a co-generation potential of 300 MW for Santiago de Chile.

3.2.2 Regulations on EG in Chile

From the analysis of the chilean regulatory framework it results that there are not special regulations for EG in Chile. EG is subject to the same regulation as any other generation.

However, for the particular case of self-generation (that may be embedded or not), DS Nº 327 [23] establishes some specific considerations. Article Nº 168 of DS Nº 327 defines a self-producer as an entity which main objective is different from generation or transmission of energy. In [33] an interpretation of this concept for the chilean electricity market is given. In accordance to [33], Self-producers includes:

- Generation of electricity using fuels obtained as sub-products of a process, e.g. waste fuels from the cellulose industry,
- Generation of electricity form non-conventional sources, e.g. renewables,
- Thermal electric generation plants that use the heat produced in other processes.

As a result, although a self-producer may not be embedded in a distribution network, EG is, in general, of one of the types of generation included in the previous concept.

Article Nº 169 of DS Nº 327 establishes that a self-generator may integrate a CDEC (which is a condition to sell electricity) only if the installed generation capacity is greater than 9 MW. As a result, the installation of small (less than 9 MW capacity) independent EG is not treated in the chilean electricity law.
What it is possible, is that a distribution company installs its own generators to reduce the electricity bought in the WEM. This is established in Article Nº 240 of DS Nº 327.

CONNECTION COSTS

In accordance to the Chilean electricity law, a generator which is going to be connected in the network has to arrange the connection costs with the company which has the concession of that network. This philosophy applies both to transmission and distribution networks. In the case that an agreement is not reached between the parties, Article Nº 51 of DFL Nº 1 [22] establishes that a referee board must be constituted. The board is integrated by one lawyer in representation of each part and a third lawyer to be chosen by both (or by the Justice in the case of disagreement).

In addition, from the statistics presented in 3.2.1 it is clear that there is no experience of connection of EG in Chile.

DISTRIBUTION USE OF SYSTEM CHARGES

Article Nº 51 B of DFL Nº 1 establishes that a generator, which is connected to a network, has to pay to the company, which has the network concession, the correspondent charges for network use. This applies both to transmission and distribution networks.

Article Nº 51 C establishes that these charges have three different components:

3. Marginal revenue.
4. Basic toll.
5. Additional toll, if necessary.

The marginal revenue is the resulting amount of money for differences between nodal prices (nodal price at the generator busbar and nodal price at the buyer busbar).

The basic toll results from the summation of the O&M costs and investment costs of the network involved in the service.

Additional tolls are paid in the case that the generator asks to withdraw electricity from nodes different to those agreed for the basic toll.

In accordance to Article Nº 51 F, the charges are proposed by the company, which has the network concession. In the case that an agreement is not achieved with the generator the referee board mentioned before (Article Nº 51 of DFL Nº 1) has to decide.

ALLOCATION OF LOSSES

In Chile, the method of allocating the cost of losses in the distribution systems consists in averaging them among all customers. These costs are part of the whole tariff that customers pay to the distribution company. No special consideration is given at present for individual customers such as EG, which may reduce the amount of losses in the network.

EXTERNALITIES

Environmental externalities

As seen before, the "PER" promotes the electrification of rural areas mainly by using renewable sources of energy. The type of generation considered under this programme is IG.

No other incentives for renewable generation were found in Chile, for instance, regarding to generation connected to the interconnected network.

Security of Supply

Security of supply is assured in the chilean electricity market through the payments for peak capacity, in accordance to what was explained in Chapter 1.

VOLTAGE REGULATION AND REACTIVE POWER

Voltage regulation and reactive power dispatch is co-ordinated by each CDEC. There are no general rules. Each CDEC has an internal agreement about the payments that have to be done to generators for provision of reactive power.

DS Nº 327 [23] defines limits on:

- Harmonic content in current.
- Voltage sags and swells.
- Negative sequence component of voltage.
- Flicker and voltage harmonics.

The Resolution considers the distribution and generation at MV and HV levels. In addition, the location where the measurements have to be done, the measurement equipment, the measurement period and methodologies to measure are defined.
The resolution is temporary until the Mining Ministry of Chile publishes a standard on this subject (Article Nº 18 of DS Nº 327).

Current harmonics content

The limits on current harmonic content are given considering the ratio I_{cc} / I_{1N} (short circuit current over maximum load current) as in the IEEE standard. In Fig. 3.17, a summary of the Chilean Resolution on current harmonics is presented.

Maximum Harmonic Current Distortion in the Electric System Expressed as a percentage of the Maximum Load Current value at fundamental frequency						
I_{sc} / I_L	**Individual Harmonic Order (Odd Harmonics)**					**THD (%)**
	< 11	11 ≤ H < 17	17 ≤ H < 23	23 ≤ H < 35	35 ≤ H	
≤ 20 (*)	4.0	2.0	1.5	0.6	0.3	5.0
20 - 50	7.0	3.5	2.5	1.0	0.5	8.0
50 - 100	10.0	4.5	4.0	1.5	0.7	12.0
100 - 1000	12.0	5.5	5.0	2.0	1.0	15.0
≥ 1000	15.0	7.0	6.0	2.5	1.4	20.0
Even harmonics are limited to 25 % of the odd harmonic limits above.						
* All power generation equipment is limited to these values of current distortion, regardless of actual I_{sc} / I_L Where: I_{sc} = Maximum Shortcircuit Current at the Point of Common Coupling. The Point of Common Coupling is the closest node in the network where two or more users demand electric energy. I_L = Maximum Load Current (RMS) of fundamental frequency at the Point of Common Coupling. It is calculated as the average current of the maximum demand for the preceding 12 months.						

For the case of customers connected at Points of Common Coupling, at voltages between 69 kV and 154 kV, the limits are 50 % of those established in the Table. For the case of customers connected at Points of Common Coupling, at voltages greater than 154 kV, the values corresponding for 110 kV are applied. If the source that produces the harmonics is a converter, with a number of pulses equal to **q,** greater than six, then the limits indicated in the Table must be increased by a factor equal to the square root of **q/6**.

Fig. 3.17. Chilean temporary Resolution on current harmonics.

Voltage sags and swells

Voltage fluctuations are divided, under Article Nº 25 of DS Nº 327, in:

- <u>Short duration fluctuations</u>: from 0.5 cycles to 1 minute duration.
  - <u>Instantaneous</u>:
    Duration: from 0.5 cycles to 30 cycles.
    Magnitude: between 10 % and 92.5 % of nominal voltage, or
    between 107.5 % and 180 % of nominal voltage.
  - <u>Momentary</u>:
    Duration: from 30 cycles to 3 seconds.
    Magnitude: between 10 % and 92.5 % of nominal voltage, or
    between 107.5 % and 140 % of nominal voltage.
  - <u>Temporary</u>:
    Duration: from 3 seconds to 1 minute.
    Magnitude: between 10 % and 92.5 % of nominal voltage, or
    between 107.5 % and 120 % of nominal voltage.

- <u>Long duration fluctuations</u>: greater than 1 minute:
  - Voltage drop: between 80 % and 92.5 % of nominal voltage.
  - Voltage increase: between 107.5 % and 120 % of nominal voltage.

Under the Chilean Resolution, the voltage drops below 10 % of the nominal voltage are considered interruptions. In accordance to their duration, they are divided as follows:

- Momentary: between 0.5 cycles and 3 seconds duration.
- Temporary: between 3 seconds and 1 minute duration.
- Permanent: greater than 1 minute duration.

Negative sequence component of voltage

Under the Chilean Resolution, the negative sequence component of voltage must not exceed 2 % of the positive sequence component, for voltages equal or less than 23 kV. For voltages greater than 23 kV, the negative sequence component of voltage must not exceed 1.5 % of the positive sequence component.

The measurements must be done over a measurement period of 1 week under the conditions specified in the Resolution.

Voltage flicker

In Fig. 3.18, a summary of the Chilean Resolution on flicker is presented. It is important to note that the limits on flicker are established in accordance to the voltage level and no consideration is done on the contracted power.

<table>
<tr><th>Voltage level (kV)</th><th>Pst</th><th>Measurement period</th></tr>
<tr><td>≤ 110 kV</td><td>≤ 1.0</td><td rowspan="2">Consecutive intervals of 10 minutes during a total measurement period of 1 week. (Short duration)</td></tr>
<tr><td>> 110 kV</td><td>≤ 0.8</td></tr>
<tr><td>≤ 110 kV</td><td>≤ 0.8</td><td rowspan="2">Consecutive intervals of 2 hours during a total measurement period of 1 week. (Large duration)</td></tr>
<tr><td>> 110 kV</td><td>≤ 0.6</td></tr>
</table>

Fig. 3.18. Chilean temporary Resolution on flicker.

Voltage harmonics

In Fig. 3.19, a summary of the Chilean Resolution on voltage harmonics limits is presented. It is important to note that the limits on voltage harmonics are established in accordance to the voltage level and no consideration is done on the contracted power.

Odd harmonics non multiples of 3			**Odd harmonics multiples of 3**			**Even harmonics**		
Order	**Voltage harmonic (%)**		**Order**	**Voltage harmonic (%)**		**Order**	**Voltage harmonic (%)**	
	≤ 110 kV	**> 110 kV**		**≤ 110 kV**	**> 110 kV**		**≤ 110 kV**	**> 110 kV**
5	6	2	3	5	2	2	2	1.5
7	5	2	9	1.5	1	4	1	1
11	3.5	1.5	15	0.3	0.3	6	0.5	0.5
13	3	1.5	21	0.2	0.2	8	0.5	0.4
17	2	1	> 21	0.2	0.2	10	0.5	0.4
19	1.5	1				12	0.2	0.2
23	1.5	0.7				> 12	0.2	0.2
25	1.5	0.7						
> 25	0.2 + 1.3x25/n	0.2 + 0.5x25/n						

Fig. 3.19. Chilean temporary Resolution on voltage harmonics.

For voltages equal or less than 110 kV, the Chilean Resolution, establishes a limit in the THD for voltage of 8 %.
For voltages greater than 110 kV, the Chilean Resolution, establishes a limit in the THD for voltage of 3 %.

Comparative study between the Chilean standard, the Argentine standard and IEEE 519

In 3.1.2 of this project a comparative study between the argentine standard and IEEE 519 has been presented considering the case of tariff T-3 in MV and for the case that I_{sc} / I_{1N} (ratio between short circuit current and maximum load current) was between 100 and 1000.

The conclusion was that the argentine standard is more tolerable, in particular when considering current harmonics 5, 7 and 11. With reference to the THD for current, the argentine standard value is 12 % for the case of consideration while the IEEE value is 7.5 %.

The Chilean Resolution for current harmonics is a copy of IEEE 519. Therefore, the same conclusions as in 3.1.2 are valid when comparing the Argentine standard with the Chilean Resolution on current harmonics. However, it is important to note that IEEE 519 establishes specific limiting values for EG, which is not done in the Chilean Resolution.

For the case of flicker, the Argentine standard makes distinction depending on contracted power and voltage level, while the Chilean Resolution considers only voltage level. However, a comparison may be made for MV and HV looking at Fig. 3.11 and Fig. 3.17. For short duration flicker the values established in the Argentine standard are between 0.37 and 0.76 while in the Chilean Resolution are 0.8 and 1.0. Consequently, the Chilean Resolution is more tolerable in this aspect.

With reference to individual voltage harmonics and THD for voltage, the Chilean Resolution considers limits, while the Argentine standard does not.

3.2.3 Conclusions

From the analysis made in 3.2.1 it is clear that there is no penetration of EG in the SIC system, in Chile. However, for the SING, it was found that many of the major mining companies have self-generating capacity, which can be considered EG. For this case, the energy produced is mainly consumed internally, by the companies, and not traded in the WEM.

On the other hand, a study that evaluates the co-generating potential in Santiago de Chile was found, which indicates some interest in EG in Chile.

From the study of the Chilean regulatory framework, done in 3.2.2, it resulted that there were not special regulations for EG, in Chile. EG, in Chile, is subject to the same regulations as any other type of generation.

However, Chilean regulations define a class of generators called self-producers, which as discussed before may include EG. With reference to self-producers, the regulations establish that they may integrate a CDEC (which is condition to sell electricity in Chile) only if the installed generating capacity is greater than 9 MW. Consequently, this gives no place for the installation of EG with capacity less than 9 MW.

With reference to connection costs, the regulations do not define who has to pay each component of the costs. On the other hand, the regulations establish that these costs have to be arranged between the parties, i.e. the distribution company and the EG developer.

As there is no experience on new EG connections, it is difficult to see who is going to pay for connection costs in the future, supposing the development of EG schemes.

It is clear from what we have discussed in Chapter 1 and 2, that the role of the Regulator is essential in this area as the distribution business is a monopoly.

In addition, as seen in 3.2.2, DUS charges do not appropriately allocate the cost of losses. Within the present arrangements, the costs of losses are allocated by averaging them among all customers as part of the whole tariff. No special consideration is given at present for individual customers such as EG, which may reduce the total amount of losses in the system.

With reference to environmental externalities, no incentives for renewable generation were found in Chile regarding to generation connected to the interconnected network. However, there are programmes, which promote renewable generation for isolated areas.

When looking at security of supply, in Chile, this is achieved through the payments for peak capacity, as seen in 1.1.2.

As seen, there is no experience in dealing with ERG. Consequently, in order to provide competitiveness to this type of generation, the aspects discussed in Chapter 2 referring to security of supply and sources that varies stochastically should be taken into account.

With reference to voltage regulation and reactive power management, the present arrangements in Chile give freedom to the CDECs to decide their policies. This is quite dangerous for the development of EG as the CDECs are dominated by the biggest generators, which may see EG as a competitor.

With reference to power quality, as discussed in 3.2.2, DS Nº 327 defines limits on flicker, current harmonics, negative sequence component of voltage, and voltage sags and swells.

As seen, the Chilean standard for current harmonics is a copy of IEEE 519 and consequently it is more strict than the Argentine standard. This could lead to a lower penetration of EG in Chile with respect to Argentina. However, for voltage flicker, the Chilean standard is more tolerable than the Argentine standard.

In sum, as for the case of Argentina, no special considerations have been taken into account, with respect to EG, in the present Chilean arrangements.

For EG to grow in Chile a different pricing network policy has to be applied which recognises the real value of EG.

In addition, new methods and tools have to be defined in network planning and design, which take into consideration, for example, the stochastic nature of ERG.

CONCLUSIONS

In the last decades, the proportion of EG in the networks of many countries has been growing up. Moreover, it is expected that this situation will continue.

There is an increasing interest of governments to rise the amount of clean energy. This takes the form of government schemes, which promote renewable generation. In many cases, the results are embedded renewable generation (ERG) plants.
In addition, interest in obtaining high overall efficiencies, for example through CHP plants, may be observed. The results are co-generation plants embedded in distribution networks.
The results of the Working Group 37.23 of CIGRE on the reasons for an increasing share of EG in different countries have been presented in Chapter 1 of this project.

On the other hand, the growth of EG has led to concerns about the impacts on the network of high levels of EG penetration. These concerns include aspects related to stability, voltage control, power quality, protection and security of the overall system. In addition, distribution companies are concerned with regard to the nature of their networks, which were designed for customers which consume electricity rather for customers which generate electricity. We have addressed these issues in Chapter 2.

When looking at the difference between wholesale electricity market prices and retail prices of electricity (Δp) in U.K., Argentina and Chile, values in a range from 3.9 p/kWh and 4.5 p/kW may be obtained.

As a result, the network charges directly measure the relative grade of competitiveness between central and EG. Transmission and distribution networks, together with the supply business are responsible for the difference of prices. Electricity produced by central generation requires transmission and distribution networks to reach its consumers, while EG, often located closer to loads, requires less transporting facilities.

Consequently, electricity produced by EG may have a higher value than that produced by central generation.

However, it depends on the tariff structures how much of that Δp is EG allowed to collect. As revealed in [32], the issue of competitiveness of EG is a network pricing problem. As a result, it is of major concern to study and understand the real value (costs and benefits) of EG and to analyse how good does the tariffs structures of the ESI consider that value.

For the cases of Argentina and Chile, these aspects were studied in Chapter 3. This project reveals that the present arrangements in Argentina and Chile do not properly address the technical and commercial issues of EG. In fact, EG is not considered under present regulations being treated in the same manner as central generation, which produces EG to lose competitiveness.

In [17], it is said that the electricity demand in Argentina is growing at a rate of 5 % per year, while in Chile at 7 % per year. This implies that more generation will be needed in these countries shortly and consequently, it seems a good opportunity for EG to develop. However, from what we have discussed in this work, it is clear that the role of the Regulator is essential to give EG fair competitiveness. Without fair regulations and an adequate network pricing policy it will be very difficult for EG to grow.

REFERENCES

[1] Alonso, J. (1995). “Consideraciones básicas sobre la protección de generadores de potencia menor o igual a 3 MVA, conectados a la red de distribución eléctrica”. (Basic considerations over the protection of generators of power equal or less than 3 MVA, connected to the distribution network), submitted as part of the activities within the Contract UTE - FI about Micro-turbines installation, 1995.

[2] CAMMESA (1998). “Procedimientos para la Programación de la Operación, el Despacho de Cargas y el Cálculo de Precios” (Procedures for the Operation Programming, the Load Dispatch and the Calculation of Prices), version XII.1.

[3] Caruso, L and Arizu, B (1992). “El Sistema de Precios en el Mercado Eléctrico Mayorista Argentino” (The Price System in the Argentine Wholesale Electricity Market), *“La Transformación de la Industria Eléctrica Argentina y la Organización del Mercado Eléctrico Mayorista” (The Transformation of the Argentine Electric Industry and the Organisation of the Wholesale Electricity Market)*, Ministry of Economy, SE, Argentina.

[4] Casaravilla, G. (2000). "Filtro activo de mínimo costo ajustado a la Carga de un Horno de Arco y a las Reglamentaciones sobre emisión armónica aplicables" (Minimum Cost Active Filter Adjusted to the Load of an Arc Furnace and to the Applicable Regulations on Harmonic Emissions), submitted to the "Universidad de la República" for the degree of Mater of Science.

[5] CDEC – SIC (1999), “Estadísticas de Operaciones 1990 - 1999” (Operation Statistics 1990 - 1999).

[6] CIGRE (1999). Impact of Increasing Contribution of Dispersed Generation on the Power System, Working Group 37.23.

[7] EA Technology (1999). The Effect of Increasing Levels of Embedded Generation on the Distribution Network, report carried out under contract as part of the New and Renewable Energy Programme, managed by the Energy Technology Support Unit (ETSU) on behalf of the Department of Trade and Industry.

[8] Econnect Ltd (1998). Increasing Levels of Distributed Generation and its Effect on Electricity Networks, report carried out under contract as part of the New Renewable Energy Programme, managed by the Energy Technology Support Unit (ETSU) on behalf of the Department of Trade and Industry.

[9] Econnect Ltd and Ilex Associates (1999). A Technical Guide to Connection of Embedded Generators to the Distribution Network, report carried out under contract as part of the New Renewable Energy Programme, managed by the Energy Technology Support Unit (ETSU) on behalf of the Department of Trade and Industry.

[10] Executive Government of Argentina (Presidency) (1992), Decree Nº 1398/1992.

[11] Executive Government of Argentina (Presidency) (1995), Decree Nº 0186/1995.

[12] Hunt, S. and Shuttleworth, G. (1996). *Competition and Choice in Electricity*, John Wiley & Sons Ltd., England.

[13] Hyde, D. (1998). Will Consumers Choose Renewable Energy, and Should You Care One Way or the Other, published in the *IEEE Power Engineering Review*, May 1998.

[14] Iannini R., Gonzalez J. and Mastrángelo S. (1999). “Energía Eólica: Teoría y Características de las Instalaciones” (Wind Energy: Theory and Characteristics of the Installations), CAMMESA.

[15] Ilex Associates (1996). Costs and Benefits of Embedded Generation, report carried out under contract as part of the New Renewable Energy Programme, managed by the Energy Technology Support Unit (ETSU) on behalf of the Department of Trade and Industry.

[16] Ilex Associates (1999). Embedded Generation: Issues Arising in Network Charging and Supply, report carried out under contract as part of the New Renewable Energy Programme, managed by the Energy Technology Support Unit (ETSU) on behalf of the Department of Trade and Industry.

[17] Inter-American Development Bank (1999). Profiles of Power Sector Reform in Latin America and the Caribbean, presented to CIER ("Comisión de Integración Eléctrica Regional", Commission for Regional Electric Integration"), 1999.

[18] Kariuki, K.K. and Allan, R. N. (1996). Factors affecting customer outage costs due to electric service interruptions, *IEE Proc.-Gener. Transm. Distrib., Vol. 143, Nº 6*.

[19] Legislative Chambers of Argentina (1960). Law Nº 15336: Electric Energy Regulations.

[20] Legislative Chambers of Argentina (1992). Law Nº 24065: Generation, Transmission and Electricity Distribution.

[21] Martin, Pierre (1996). “Energía y medio ambiente: desarrollo sostenible e internalización de costes ambientales” (Energy and environment: sustained development and internalisation of environmental costs), presented in the XVI Workshop on Energy Economics in Montevideo, 1996.

[22] Mining Ministry of Chile (1982). Law DFL Nº 1: General Law for Electric Services referring to Electric Energy.

[23] Mining Ministry of Chile(1998). DS Nº 327: Establishes the regulations of Law DFL Nº 1.

[24] Mining Ministry of Chile (1997). D Nº 300: Establishes tariff formulae for the Electric Industry.

[25] Mining Ministry of Chile (2000). D Nº 194: Establishes Nodal Prices for Electricity Supply.

[26] Newbery D. (1995). Regulation of the Electricity Sector: Comments on Some Alternative Models, presented in the International Seminar on Restructuring and Regulation of the Electric Power Sector, Buenos Aires, 1995.

[27] Pace University Centre for Environmental Legal Studies (1990). Environmental Costs of Electricity, prepared for New York State Energy Research and Development Authority, Oceana Publications, Inc.

[28] Rudnick,H. and Donoso, J. (2000). Integration of Price Cap and Yardstick Competition schemes in Electrical Distribution Regulation. Accepted for publication in *IEEE PES*.

[29] SE (1999). "Informe del Sector Eléctrico. Año 1998" (Report about the Electric Sector. Year 1998).

[30] Shropshire Energy Team (1998). The Capacity of the Electricity Network in Shropshire to Absorb Embedded Generation, report carried out under contract as part of the New Renewable Energy Programme, managed by the Energy Technology Support Unit (ETSU) on behalf of the Department of Trade and Industry.

[31] Strbac, Goran (1999). Pricing of Networks with Embedded Generation, talk given in Seminar 3: Embedded Generation – Realising the Potential for Network Benefits, organised by Econnect Ltd. under RAD 0634 ETSU PROG 02.

[32] UMIST (1999). Electricity Tariffs and Embedded Renewable Generation, report carried out under contract JOR3-CT98-0201.

[33] Vargas, L. and La Fuente V., F. (1999). "Cogeneración en Chile: Potencialidad y Desafíos" (Co-generation in Chile: Potentialities and Challenges), publication carried out under Project 198 1028 funded by FONDECYT.

[34] West Green Associates (1997). A Survey of the ESI Connection Arrangements and Sale of Power Benefits Offered to Embedded Generators in England and Wales, report carried out under contract as part of the New Renewable Energy Programme, managed by the Energy Technology Support Unit (ETSU) on behalf of the Department of Trade and Industry.

[35] West Green Associates (1998). Technical Requirements and Documentation for the Network Connection of Small-scale Generation: as applied to Embedded Generation in England and Wales, report carried out under contract as part of the New Renewable Energy Programme, managed by the Energy Technology Support Unit (ETSU) on behalf of the Department of Trade and Industry.

WEB PAGES

[36] www.cammesa.com.ar, CAMMESA, Argentina.

[37] www.cier.org.uy, CIER, Uruguay.

[38] www.cne.cl, CNE, Chile

[39] www.dti.gov.uk/renewable/index2.html, DTI, U.K.

[40] www.energia.mecon.ar/enre/, ENRE, Argentina.

[41] www.ing.puc.cl/~power/alum...Celdas%20de%20Combustible/cc.html, "Celdas de combustible y generación distribuida" (Fuel cells and distributed generation), Pontificia Universidad Católica de Chile, Chile.

[42] www.ing.puc.cl/power/southamerica, Pontificia Universidad Católica de Chile, Chile.

[43] www.mecon.ar/energy/, SE, Argentina.

[44] www.ofgem.gov.uk, Ofgem, U.K.

[45] www.sec.cl, SEC, Chile.