Regional Electricity Cooperation and Integration (RECI)
Foreword
The E7 was born in April 1992 when the chairpersons and chief executive officers of some of the largest electric utilities in the Group of Seven (G7) industrialized nations agreed to meet once a year at an E7 Annual Summit to discuss major global issues related to the electric utility industry. Their common goal: “to play an active role in protecting the global environment and in promoting efficient generation and use of electricity.”

To that end, they created the E7 Network of Expertise for the Global Environment to act as a *pro bono* environmental, technical and industrial advisory group for electric utilities and governments in developing and Eastern European countries. The E7 Network has already provided in-kind services in more than thirty projects in Asia, Latin America, Africa, and Eastern Europe.

Furthermore, E7 Working Groups are mandated on an ad hoc basis to examine specific policy issues relevant for the global electricity industry and develop E7 proposals, position papers and policy statements to bring the E7’s voice to the international community and facilitate exchanges with international organizations and electric utilities in developing countries.

One of the E7’s active Working Groups took an in-depth look at the issue of *regional electricity cooperation and integration (RECI)*, both as a specific tool for the development of the electricity supply industry in developing countries, and as an effective means of enhancing the industry’s contribution to the sustainable development of those countries.

Developing countries are specifically targeted here, considering the relatively low level of power system integration between those countries and the large potential offered by RECI to optimize their development in a more profitable manner.

This document and its accompanying CD-ROM provide a comprehensive examination of the conditions necessary to the successful implementation of regional electricity cooperation and integration, through the pooling of resources and the interconnection of electric power systems. It draws largely on the expertise and experience of E7 members, and on practical examples from both developed and developing nations.

The E7 and the E7 Network of Expertise for the Global Environment are confident that the information, ideas and guidelines put together by the RECI Working Group will contribute in a timely and practical manner to the full realization of the benefits – political, social, economic and environmental – which can accrue from sharing electric power resources.
## World Regional Indicators of Electricity Consumption Growth 1995-2020

<table>
<thead>
<tr>
<th>Region</th>
<th>Capacity (GW) (1995)</th>
<th>GDP growth (%)</th>
<th>Electricity growth (%)</th>
<th>Additional capacity (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>OECD</td>
<td>1,814</td>
<td>2.0</td>
<td>1.9</td>
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</tr>
<tr>
<td>China</td>
<td>227</td>
<td>5.5</td>
<td>5.4</td>
<td>550</td>
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<td>East Asia</td>
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<td>4.5</td>
<td>5.0</td>
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<td>4.2</td>
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<td>97</td>
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<td>4.1</td>
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</tbody>
</table>

Source: IEA, World Energy Outlook, 1998
The development of electric power systems is an essential component of a country’s sustainable development. Indeed, the state of development of electric power systems is often considered to be an indicator of a country’s overall development.

In developing countries around the world, this varies widely; nonetheless, several countries share some specific features which are important when considering the opportunity and feasibility of furthering the development of regional electric power systems and, hence, the countries’ overall development. These are:

- a high actual or potential growth rate of consumption of electric power;
- significant unexploited hydroelectric resources;
- complementary forms of primary energy; and
- a lack of national financial resources to develop the electric power system.

Furthermore, given that most electric utilities in developing countries are state-owned monopolies, they have been assigned ambitious electrification objectives, particularly for rural areas. Considering that many customers are subsidized by national governments through lower rates, however, electric utilities in developing countries are faced with deteriorating financial performances due to their incapacity to fully recover the costs they incur. In turn, this impedes their investment capacity and their efforts to provide the population with access to electricity services.

To address these issues, among others, most developing countries, encouraged by the leading international organizations, are presently reforming their electric power systems and moving towards liberalization and the introduction of private independent electricity generators.

These reforms, as several developing countries are currently experiencing, can be optimized through the pooling of resources, from engineering expertise to electricity generation capacity, on a regional basis. The pooling of resources further offers unique, value-added advantages. It:

- allows optimum use of available resources,
- enhances environmental protection efforts,
- facilitates a sustainable development approach,
- reduces the cost of electricity services to customers,
- increases the ability to meet potential customers’ demand, and
- constitutes a lever for the country’s economic development.

The development of electric power systems is an essential component of a country’s sustainable development. Indeed, the state of development of electric power systems is often considered to be an indicator of a country’s overall development. Therefore, the actual implementation of such resource pooling is made possible by the interconnection of electric power systems. Interconnecting isolated electric power systems also offers unique, value-added advantages. It:

- allows sharing power generation sources throughout a larger area,
- brings forth new revenue opportunities, and
- reduces the risks of power shortages.

The interconnection of electric power systems however may likely bring forth new constraints in planning, and increase the complexity of operations. The development of regional electricity cooperation and integration (RECI), through the implementation of a RECI organization on a regional (bi- or multinational) basis, will help circumvent these difficulties and will be instrumental in fulfilling the necessary conditions for the pooling of resources and the interconnection of electric power systems.

Regional electricity cooperation and integration involves:

- partnerships between electric utilities;
- the concerted implementation of interconnections;
- harmonized regional design and operation criteria; and, in the long term,
- the concerted operation of electric power systems;
- a regional approach to resource planning.

Above and beyond the physical pooling of resources and interconnection of electric power systems, regional electricity cooperation and integration is expected to yield:

- significant social, economic and environmental benefits;
- more reliable and stable electric power systems;
- an extended market; and
- important new business opportunities.

The business opportunities offered through regional electricity cooperation and integration (increased market scale, cross-border opportunities, complementarities, etc.) will be further enhanced in a context of deregulation and liberalization.
The development of regional electricity cooperation and integration
From an exchange of expertise to full integration of electricity markets, regional electricity cooperation and integration is a long-term process. Consequently, a step-by-step approach to the implementation of a RECI organization will prove to be the most effective and efficient manner of reaping the full benefits of the pooling of resources and the interconnection of electric power systems.

Above all, it is fundamental to ascertain and enhance the political will for cooperation. This may actually be considered a preliminary condition to the entire implementation process. Until now in fact, regional electricity cooperation and integration has developed first and foremost in countries with political cooperation experience.

1. Pooling experience and expertise
The exchange of experience and expertise between electricity utilities in developing countries will foster greater cooperation, and could therefore be considered the first step towards the successful implementation of a RECI organization.

The electricity supply industry requires considerable diversified expertise. In many developing countries however, that industry is too small and cannot afford to hire and train a critical mass of engineers and economists, notwithstanding the efforts of international institutions to that effect. Accordingly, there is a strong case for pooling expertise from the electricity supply industry into regional entities.

2. Exchanging information on the development and operation of power systems
In a region where countries use the same river basin, for instance, the development and operation of hydroelectric dams must be coordinated both to optimize electric generation in the river basin, and to take into account other possible uses of water resources (navigation, irrigation) by the countries situated downstream.

The use of water resources must be agreed upon by the countries of the river basin; the plan for operation of the dam must be conveyed in advance by upstream to downstream countries, etc. This type of information exchange is highly recommended, particularly when the national power systems are physically interconnected.

In a given region, moreover, countries may wish to share information on load patterns, the operation of the generation mix, as well as the location of the load and power generation plants, and possibly on the expansion plans of neighboring countries.
3. Pooling resources for the development of power supply

In developing countries, most interconnection projects (both on-going and realized) originate from the development of hydroelectric resources. The location of the reservoir, the maximum surface of the reservoir, the capacity of the power plant, the type of power supplied (firm power versus energy), the transmission requirements and investment cost, the water use rights, the assessment of the project’s environmental impact – all of these parameters should be agreed upon in the planning phase.

The cost and benefits of a power generation plant may have to be shared, leading to the implementation of different structures and institutional schemes and requiring, accordingly, varying pricing policies. It may take the form of a joint venture between neighboring countries, an independent power producer, or a long-term supply agreement with one of the countries, one country being responsible for the development of the generation power plant.

4. Sharing the investment in interconnection lines

Interconnection lines may involve two or more countries. Such interconnections are instrumental in enhancing an economic dispatch of power generation between participants. Additionally, the interconnections can improve the operating reliability of the combined systems, reduce participants’ capacity reserve margins, allow power pooling opportunities and provide environmental benefits through the reduction of airborne emissions. In turn, these benefits can improve the project’s cost effectiveness and help to mitigate any perceived risk of participants not recovering their investment cost. Consequently, in implementing a RECI organization, the most efficient organizational, cost control and pricing structures must be established to ensure those benefits.

The primary objective of regional electricity cooperation and integration is to enhance the regional electric power industry’s contribution to sustainable development objectives – which basically are economic, environmental and social objectives – and make the best use of the region’s energy resources for the benefit of the countries involved.

This implies:

• planning the development of the resources needed for national power systems as part of the development of the resources available for the regional electric power system, in a sustainable development perspective;
• setting up the legal frameworks, rules, protocols, coordination and regional mechanisms and bodies responsible for the reliable, secure and cost-effective operation of the regional interconnected power system;
• managing the transition towards a regional electricity market;
• implementing mechanisms and structures for the development and operation of regional electricity power projects; and
• setting up a RECI organization that will be responsible for the implementation of those actions, and for the operation of the regional interconnected power system.

Furthermore, the institutional framework needs to be sufficiently appealing for private investors, while keeping electrification objectives and sustainable development objectives in sight.
A collaborative process

In this regard, the actual establishment of a RECI organization could be considered the starting point of true regional electricity cooperation and integration. With the active collaboration of all participants in the electric power industry of the region’s countries, the establishment of a RECI organization would unfold according to the following process:

- the creation of a regional forum for the exchange of information,
- the drafting and signing of a protocol between the governments of the region,
- the proposal of a process for designing and implementing regional integration,
- the establishment of executive bodies to coordinate actions, and
- the creation of an independent Regional Transmission Operator, a key element in the success of RECI.

A critical role

The RECI organization will have to manage a group of local subsystems while pursuing its own primary objectives:

- least-cost operation of the regional electric power system,
- secure and reliable operation of the regional electric power system,
- promotion of the electric power system’s optimal development,
- development of regional training, and
- market regulation in an efficient, non-discriminatory manner.

Its tasks can be defined as follows:

- provide coordination between national works;
- harmonize technical operating rules and the institutional structure of national power systems or electric utilities;
- develop a schematic model of a regional resource development plan;
- define criteria, processes, rules, contracts and organization; for the management and operation of regional generation and transmission facilities;
- ensure secure and reliable operation of the regional power network; and
- define the mandate of the Regional Transmission Operator.

A development plan

The regional resource development plan will arguably provide the groundwork for the pooling of resources and the interconnection of electric power systems. It should be carried out in two steps:

- a draft master plan of the current and long-term ideal energy and electric power flows, designed to:
  - promote the idea of regional electricity cooperation and integration within the political arena,
  - provide support for organizing the following steps of the study,
  - help undertake any action that requires information on the development of the electric power systems,
  - focus on existing and potential synergies between the different energy systems in the region;
- a thorough regional generation and transmission expansion plan.
3. Project Financing

The scarcity of adequate financial resources at a national level and the considerable financial risks perceived by private investors are readily acknowledged as the major impediments to the development of electric power systems in developing countries. Financing an interconnection project will therefore likely prove to be a complex process requiring many years of effort and involving a large number of people.

Project financing (as opposed to corporate financing based on the utilities’ financial strengths) is deemed the most appropriate financing method for developing countries, as it rests on the financial strength of the project itself, requires the establishment of a dedicated entity, and raises funding through equity and loans dedicated to the interconnection project. The project financing process would unfold as follows.

1. Commitment from decision-makers

A clear commitment from the decision-makers involved in the development of an interconnection project is crucial in order to secure the support of international investors. Moreover, strong "political" support from all public and private participants is considered the single most important element for a successful interconnection project.

2. Project definition

The definition of the interconnection project will yield a project definition document, which will be instrumental in providing basic information for risk assessment, establishing preliminary financial and operational structures, and obtaining grants and support from international economic development organizations.

3. Risk analysis

Risk analysis is one of the key criteria used by lenders and investors to evaluate large infrastructure projects. This analysis will provide the basis for the definition of a risk management strategy designed to successfully complete and operate the interconnection project according to plan. The risk analysis should specifically address those risks, as perceived by capital markets, that are related to the following issues: construction, operations, markets, contractual obligations, the political and legal context, and finances.

4. International interest and support

Energy infrastructure projects in developing countries are considered as especially risky by private bankers: equipment and construction costs have to be paid in hard currencies while revenues will be obtained in local currencies. The support of an international organization – which may involve grants to pay for independent reviews and to confirm the project’s viability in a convincing way – is likely therefore to be a prerequisite to obtain financing in capital markets.

5. Financial and operational structures

Project definition and risk analysis will provide the basis for exploring various alternatives in order to establish an ownership and capital structure, an operating structure, and contractual agreements designed to mitigate risks. The definition of corporate ownership and operating responsibility will be instrumental in establishing the economic and financial viability of the project.
6. Legal commitment by participants

The definition of the legal framework which will govern the participants' relationships and commitments to the project is essential to secure international financing. This step in the financing process should lead to a Shareholders Agreement.

7. Independent review of the project

Prepared by independent experts – and usually financed by international organizations – an independent review will be instrumental in confirming the feasibility of the project and assuring its completion on schedule and on budget. This review will lead to the finalization of all information to be included in an Information Memorandum.

8. Information Memorandum

The Information Memorandum is an exhaustive, legal document compiling all the information provided in the documents produced and revised throughout the previous steps of the project financing process. It includes a description of the contracts between participants and sponsors, and will be used as a prospectus for financial institutions, investors and contractors.

9. Testing financial markets

Testing financial markets will enable the project's stakeholders to identify potential investors and lenders, to confirm financial conditions, to prepare presentations for lending institutions and to secure letters of interest from investors and lenders. These approaches are likely to result in a lead institution putting together a consortium of lending institutions which will share the loan.

10. Debt and equity proposals

To obtain equity proposals from investors-and/or operators, and to negotiate with the best parties and secure a preliminary agreement, the best approach will be determined by the degree of interest raised by the project. Should there be a great deal of interest, bids can be called among pre-qualified investors or lenders; if there is limited interest, the participants will seek potential offers and then negotiate the contractual conditions.

11. Negotiation and contractual agreements

The negotiation process is generally long and usually focused on risk mitigation, loan guarantees and loan conditions such as rates, reimbursement term, etc. This step should result in one or several signed financing agreements.

12. Meeting loan disbursement conditions

The financing agreements will set several conditions on loan disbursements to make sure that all the conditions required by the lenders and/or investors are met, in accordance with the agreements, and to safeguard the good reputation of the participants and the sponsors. Moreover, lenders are likely to ask that an independent trustee be appointed to control cash disbursements and monitor overall project realization.
In most developing countries, on the one hand, the implementation of a RECI organization will involve a group of national electric power systems, generally self-sufficient, operated by a control center, and either poorly or not at all interconnected.

On the other hand, regional electricity cooperation and integration entails, among other things, the concerted operation of electric power systems, the concerted implementation of interconnections and the establishment of harmonized regional design and operation criteria.

To foster that essential dialogue, the step-by-step process leading to true regional electricity cooperation and integration would start, at the operational level, with a limited coordination of the operation of regional electric power generation resources, and lead to the creation of an interconnected regional transmission network. Throughout the process, the region must participate in the operation and management of the national electric power systems involved, with the foremost objective of improving their secure, safe, reliable and cost-effective operation.

Accordingly, the responsibility of the RECI organization should be to:

• set common operation and management rules requiring compliance by the national electric power systems; and
• coordinate and monitor operation of the regional electric power systems.

Upon achieving a more in-depth integration, the RECI organization’s responsibilities would extend to real-time operation of the regional interconnected system, in close collaboration with the national load (power output or consumption) control centers.

Meanwhile, every electric power system should protect its customers against loss of service. In order to achieve such an objective, all parties must commit to regional agreements on the operating conditions of the RECI organization, focusing on:

• the security of the interconnected system;
• the adequacy of supply; and
• the day-to-day operation.

Regional agreements

Regional agreements establish the rules that all electric utilities within the region must obey for secure and reliable operations. Consequently, they must be signed by the utilities as well as by all the other participants.

The items to be considered in regional agreements are:

• adequacy of generation (adequate quantity and quality of generation are essential to reliable electric supply);
• adequacy of transmission (reliability cannot be achieved by adequate generation alone; adequate transmission is also essential to reliable electric supply); and
• operation planning (with specific consideration for operation organization, information sharing, power exchange schedule, maintenance coordination, emergency operation, restoration, and operating personnel and training).
Grid codes

With the progress of deregulation in the electric energy market and open access to transmission, it is increasingly important to assure non-discriminatory treatment for all participants in the market. Hence, grid codes – describing the technical requirements for transmission operators, generators and customers – must be established, and all participants must agree to comply with them.

Given the strong and complex interactions in electric networks, however, current technology dictates the need for a system operator to coordinate the use of the transmission system. The RECI organization could utilize a market model known as Regional Transmission Operators (RTO) which can manage the electric power grid on a regional basis, leading to greater efficiency and reliability and enhanced market performance while removing occasions for discrimination.

The Benefits

In developing countries, regional electricity cooperation and integration, fostered through a RECI organization and built on the pooling of resources and the interconnection of electric power systems, constitutes a significant lever for sustainable economic development.

As such, it will deliver valuable benefits – ranging from technical to economic, environmental and social – to all participants in the process, beginning with utilities and customers. Moreover, as the long-term process unfolds and the proper mechanisms are fine-tuned, such benefits as accrue from pooling and interconnection should be maximized.

Technical

The pooling of resources and the interconnection of electric power systems, on a regional basis, should foster enhanced reliability, enhanced emergency support, and better generation capacity utilization. Moreover, they should lead to more transparent processes, broader competitive markets and potential energy price reductions.

Each local electric power system will benefit from improved reliability in long-term supply-demand balance – reduction in reserve capacity – through the interconnection of electric power systems.
The pooling of resources should allow for the use of more efficient power generation. Moreover, considering that the interconnection will be instrumental in minimizing power generation losses and optimizing network management efficiency, it can lead to lower supply costs.

The cost of an interconnection consists primarily of the investment cost of transmission line(s), which is far less substantial than an investment in power generation.

The creation of larger, more reliable and stable electric power systems should facilitate economies of scale and bring forth new opportunities for revenues.

**Economic**

The pooling of resources and the interconnection of isolated electric power systems allow optimum use of available resources.

They will be instrumental in achieving reductions in the operating cost of the generation mix, increasing the generation capacity margin and, conversely, reducing the need for investment in peak capacity.

Lower production costs and/or lower investments in generation, achieved through the interconnection of electric power systems, should have an impact on rates to the customers’ advantage.

Improved electric power systems reliability will foster an increase in quality of service and a reduction in power interruptions that too often lead to productivity losses in the commercial and industrial sectors, affecting average regional manufacturing costs and, finally, the national gross domestic product (GDP).

Pooling electricity resources is crucial if the electric power systems are to fully contribute to sustainable development.

**Environmental**

True regional electricity cooperation and integration will make it possible to further optimize the use of generation resources.

Better exploitation of hydroelectric resources and reduced consumption of non-renewable primary energy (fossil fuels) may result in significant reductions of CO₂ and other airborne emissions.

The pooling of resources and the interconnection of electric power systems will offer a region development choices that respect the principles of sustainable development and avoid the use of highly polluting energy sources.

**Social**

Optimized electric power systems should improve reliability and quality of service, while allowing lower tariffs.

Lower electricity rates, achieved through regional electricity cooperation and integration, will foster increased regional growth.

The interconnection of isolated electric power networks throughout a region will enhance rural electrification programs.

Local needs of individuals, families, communities and businesses will be better met through the increased availability of electricity.
Regional electricity cooperation and integration is a multi-faceted, multi-layered process involving engineers as well as administrators, and investors as well as politicians, over an extended period of time and through a series of significant hurdles.

Its contribution to the development of electric power systems is likely, on the one hand, to generate a ripple effect that will be felt throughout the social, political and economic fabric of developing countries and impact on their current situation and future development.

On the other hand, the pooling of resources and the interconnection of electric power systems have to be taken up with all due consideration for an important series of technical, financial and practical questions.

The E7 and the E7 Network of Expertise for the Global Environment are keenly aware of the complex and sensitive nature of these issues. Accordingly, the RECI Working Group, drawing from the experience of utilities in E7 countries and from the experience of several developing countries involved in the implementation of a RECI organization, has prepared a series of guidelines designed to provide practical information to all professionals and decision-makers.

Consequently, they should consider the accompanying CD-ROM as a useful guide to help them understand the issues, assess the situation, perform the necessary studies and make efficient decisions regarding the pooling of resources and the interconnection of electric power systems, and their commitment to regional electricity cooperation and integration.

The Guidelines
The guidelines to regional electricity cooperation and integration, offered on this CD-ROM, represent a systematic approach to the planning and implementation of a RECI organization, giving some indications as to the best way to proceed at each step of this long-term process.

**Long-term strategic planning**

The first section of the guidelines examines how best to determine the opportunity to implement a RECI strategy in view of the development of power systems. **Module 1** analyzes the conditions and implications of the implementation of regional electricity cooperation and integration, in order to assess its feasibility. **Module 2** is concerned with the viability of regional electricity cooperation and integration in a target region, which can be assessed through a market analysis. **Module 3** also examines viability through the study of a region's available resources and their optimum development. **Module 4** outlines the winning conditions under which the partners in a RECI organization will share the benefits of regional electricity cooperation and integration.

**Medium-term project implementation**

A second section deals with the development of the physical means necessary to the implementation of a RECI organization. **Module 5** examines the technical feasibility of a RECI organization, or how to implement the pooling of resources through the interconnection of electric power systems, while **Module 6** examines its financial feasibility, or how to secure the financing to build interconnection facilities.

**Short-term operational planning**

The third and final section of the guidelines is concerned with the constraints resulting from the operation of an electric power system within a large international interconnected grid. **Module 7** examines the RECI's organizational viability, while **Module 8** analyzes the operating conditions of a RECI organization.
UNDERSTAND THE ISSUES

ASSESS THE SITUATION

MAKE EFFICIENT DECISIONS
Regional Electricity Cooperation and Integration (RECI)

E7 Guidelines for the pooling of resources and the interconnection of electric power systems

1. An Introduction to Regional Electricity Cooperation and Integration
2. RECI Feasibility Module 1
3. Market Analysis Module 2
4. Resource Development Module 3
5. Integrated Operational Planning: Optimal Conditions Module 4
6. Pooling Resources: Technical Conditions Module 5
7. Financing Interconnection Facilities Module 6
8. Market Operational Structures Module 7
9. A RECI Organization: Operating Conditions Module 8
10. Glossary of Technical Terms
11. Acronyms and Symbols
The significant hydroelectric potential offered by South America (16.8% of the world’s potential) has already led to bilateral projects and realizations such as Itaipu (Brazil – Paraguay), Yacireta (Argentina – Paraguay) and the Garabi (Brazil – Argentina) project.

The Comisión de Integración Eléctrica Regional (CIER), a non governmental organization linked with the national electric sectors of ten South American countries, seeks to foster electricity network integration in the Southern Cone and has already conducted two studies: “Assessment of the hydroelectric potential and its complementarity” and “Main markets and feasibility of interconnections.” The two studies (a third one is underway) have confirmed the important benefits that would accrue from the integration of national electric power systems.

RECI Development Potential

Other regions of South America may be identified as offering conditions favorable to medium or long-term regional electricity cooperation and integration:

• The Southern Cone, with Rio Parana and Rio Paraguay;
• The Andean community: Venezuela, Colombia, Ecuador.

ASIA

The Greater Mekong subregion of East Asia includes Cambodia, the province of Yunnan in the People’s Republic of China, the Lao People’s Democratic Republic, Myanmar, Thailand and Vietnam.

With the assistance of international organizations – the Asian Development Bank, ASEAN, the ASEAN Center for Energy (ACE), the Mekong River Commission and the World Bank – a structure for the development of power trade and interconnections is currently active through:

• yearly ministerial meetings;
• a coordinating body, the Electric Power Forum (EPF);
• the Experts Group on Power Interconnection and Trade (EGP).

A Policy Statement on Regional Power Trade, adopted by the EPF and endorsed at a ministerial meeting has become effective. In line with the Policy Statement, the GMS countries recognize power trade, the importance of harmonization of transmission technical standards and of information exchange, and the desirability of foreign investment. They also agree on best practices for private sector participation and the need to protect the environment.

RECI Development Potential

Other areas in Asia, including neighboring countries, may be considered as potential RECI regions:

• Egypt, Jordan, Israel, Lebanon, Iraq and Turkey;
• The Caspian Sea region, including Kyrgyzstan
• South Asia, including Nepal.
In 1972, the governments of Mali, Mauritania and Senegal set up the Organisation pour la Mise en Valeur du Fleuve Sénégal (OMVS) in order to promote irrigation, power generation and navigation in the Senegal valley. Building a dam in Manantali (Mali) was considered as a multipurpose project of regional interest for the three countries.

Consequently, a key of repartition for the costs of the project was proposed and adopted, leading to the construction of the dam (completed in 1989), and eventually of an hydroelectric power plant and of the associated transmission lines. An independent company will be in charge of building and operating the power plant and transmission lines, and will sell the electricity to the three national electric utilities, allocating each of them a share of the energy corresponding to the approved key of repartition.

The South African Power Pool (SAPP) was established in 1995 with the structure of a loose pool, where participants are allowed to contract bilaterally. The pool was developed under the aegis of the regional political organization, the South African Development Community (SADC).

SADC welcomed the South African Republic after the end of apartheid. SADC member countries had been used to cooperating for some time and when the South African Republic entered the Community, it created strong momentum for the development of a regional energy plan.

RECI Development Potential

- North of the Sahara,
  - the Maghreb (Morocco, Tunisia, Algeria, Libya) with connections to Egypt, and Europe;
- South of the Sahara,
  - West Africa from Mauritania up to Chad and Nigeria, including the sub-region of OMVS;
  - South West Africa, from the Democratic Republic of Congo to Nigeria;
  - South Africa, up to the Democratic Republic of Congo;
  - The Great Lakes region and East Africa.
Acknowledgments

The E7 and the E7 Network of Expertise for the Global Environment wish to acknowledge the dedication and contribution of all the members of the RECI Working Group towards the production of this document and the accompanying CD-ROM.

Ervine Helm
Edison International (USA)

Frédéric Boujot
François Verneyre
Électricité de France (France)

Marcella Molinaro
ENEL (Italy)

Pierre Deschamps
Gaëtan Guertin
Yvon Hotte
Nathalie Noel
Réal Paul-Hus
Serge Robin
Hydro-Québec (Canada)

Shuji Tajimi
Yasuo Taku
Kansai Electric Power (Japan)

Tony Petrella
Ontario Power Generation (Canada)

Torsten Knop
RWE (Germany)

Shinichi Furutsuka
Hideo Suzuki
TEPCO (Japan)

Additional information on Regional Electricity Cooperation and Integration (RECI) and other issues of interest pertaining to the contribution of electric utilities to worldwide efforts towards sustainable development may be obtained at:

E7 Network of Expertise for the Global Environment
1010 St. Catherine Street West, 6th floor
Montréal, Québec H3C 4S7
CANADA

Telephone: (514) 392-8876
Fax: (514) 392-8900
E-mail: e7secretariat@hydro.qc.ca

The E7 Web site – http://www.e7.org/ – will also give you access to the contents of the RECI CD-ROM and to other information on E7 initiatives and activities.
An Introduction
to Regional Electricity Cooperation and Integration
(RECI)
Regional electricity cooperation and integration (RECI) may be the most promising and the most profitable avenue for developing countries to further the development of their electric power systems, to reap the environmental, social and economic benefits accruing from a more efficient use of power resources, and to enhance their sustainable development.

The E7 member companies, drawing from past and ongoing experiences in OECD and non-OECD countries, mandated an ad hoc Working Group to analyze both those experiences and the conditions under which developing countries, in particular, may benefit the most from the pooling of their resources on a regional basis, the interconnection of their electric power systems and the implementation of a RECI organization.

The E7 Guidelines for the pooling of resources and the interconnection of electric power systems present the RECI Working Group’s studies and analyzes as a comprehensive examination of regional electricity cooperation and integration in the context of developing countries and a critical analysis of the optimal conditions and inevitable barriers for its implementation, as well as a series of practical information to help understand the issues, assess the situation, perform the necessary studies and make the appropriate decisions.

Regional cooperation and integration is a long-term process and a step-by-step approach may prove to be the most effective and efficient manner of reaping the full benefits accruing from to the implementation of a RECI organization. The Guidelines are organized, accordingly, as a series of eight modules, outlining a three-phase strategic planning program, from long-term strategic planning (modules 1 to 4) to medium-term project implementation (modules 5 and 6) and short-term operational planning (modules 7 and 8).

Long-term Strategic Planning

Module 1 examines the social, political, economic and technical conditions that will enhance the feasibility of regional cooperation and integration and offers specific recommendations on the management of true regional cooperation and integration. Module 2 outlines the conditions under which the partners in a RECI organization will share the benefits of regional electricity cooperation and integration, and offers a detailed description of the methodology for forecasting regional electricity load and the techniques used to comprehend consumers behavior. Module 3 also examines RECI’s viability through the study of a region’s available resources and their optimum development. Its focus is on vertically structured organizations, responsible for planning resources. Module 4 utilizes the cooperative game theory, specifically, to demonstrate that a method of surplus sharing can be determined to benefit all national electric power systems involved.
Medium-term Project Implementation

Module 5 examines the technical feasibility of the pooling of resources through the interconnection of electric power systems. From basic technical issues, such as power supply reliability and system planning criteria, it follows through to a presentation of advanced multiple interconnection technologies and an actual interconnection project. Module 6 offers guidelines on how to carry in-depth evaluations to demonstrate the economic and financial viability of a power system interconnection and, considering the substantial amounts of money involved in infrastructure projects, on how to secure the financing to build interconnection facilities.

Short-term Operational Planning

Module 7 studies the viability of a RECI organization through the detailed presentation of an electric power market and of a specific structure model, considered as a medium or long-term objective for the electric power industry. Module 8 analyzes the RECI organization’s practical, day-to-day operating conditions, and outlines the regional agreements necessary for the secure and reliable operation of the interconnection network.

A Timely and Practical Resource

It is estimated, today, that more than 2 billion people around the world still do not have access to electricity. Demand is on the rise, nonetheless, and the global electricity industry is faced with a unique challenge: how to meet such a demand, further the access to a major source of energy and achieve these goals while adhering to the principles of sustainable development and contributing to the social and economic development of developing countries around the world.

Regional electricity cooperation and integration (RECI) will play a significant, even determining role in meeting that challenge. Fostered through a RECI organization and built on the pooling of resources and the interconnection of electric power systems, it will deliver valuable benefits to all participants in the process, beginning with utilities and customers. Moreover, as the long-term process unfolds and the proper mechanisms are fine-tuned, such benefits should be maximized.

The pooling of resources on a regional basis allows optimum use of available resources, enhances environmental protection efforts, facilitates a sustainable development approach, reduces the cost of electricity services to customers, increases the ability to meet potential customers’ demand, and constitutes a lever for the country’s economic development.
The interconnection of electric power systems, moreover, allows sharing power generation sources throughout a larger area, brings forth new revenue opportunities, and reduces the risks of power shortages.

Regional electricity cooperation and integration, under favorable conditions, will thus yield significant social, economic and environmental benefits, ensure more reliable and stable electric power systems, open up an extended market, and offer important new business opportunities.

The E7 Guidelines for the pooling of resources and the interconnection of electric power systems should contribute, in a timely and practical, manner to the promotion of regional electricity cooperation and integration and the full realization of the benefits accruing from the implementation of a RECI organization.

back/forward to
Module 1
Module 2
Module 3
Module 4
Module 5
Module 6
Module 7
Module 8
Glossary of Technical Terms
Acronyms and Symbols
Acronyms
and Symbols
Acronyms

ADB  Asian Development Bank
AfDB  African Development Bank
BOAD  Banque Ouest Africaine de Développement
BOO  Build – Own – Operate (see Glossary)
BOOT  Build – Own – Operate – Transfer (see Glossary)
BTL  Build – Transfer – Lease (see Glossary)
CABEI  Central American Bank for Economic Integration
CDM  Clean Development Mechanisms (see Glossary)
DSM  Demand-side Management
EBRD  European Bank for Reconstruction and Development
EIB  European Investment Bank
EUR  Euro (currency adopted by the European Union) symbol:
GTO  Gate Turn-Off (thyristor)
IBRD  International Bank for Reconstruction and Development
IDA  International Development Association
IDB  Inter-American Development Bank
IFC  International Finance Corporation
IGBT  Isolated Gate Bipolar Transistor
IRP  Integrated Resource Planning (see Glossary)
ISDB  Islamic Development Bank
kgoe  Kilogram of oil equivalent
MIGA  Multilateral Investment Guarantee Agency
NERC  North American Electric Reliability Council
NGO  Nongovernmental organization
O&M  Operation and Maintenance
OASIS  Open-Access Same-Time Information System (see Glossary)
PWM  Pulse Width Modulation
PX  Power Exchange
toe  Metric ton of oil equivalent

back/forward to
Module 1
Module 2
Module 3
Module 4
Module 5
Module 6
Module 7
Module 8
Glossary of Technical Terms
Module 1
RECI Feasibility
Module 1
RECI Feasibility

Foreword

Chapter I Integration of National Power Systems: the General Case

1.1 Interconnecting the Electric Networks: the Technical and Economic Case
  1.1.1 Pooling the load of customers
  1.1.2 Economies of scale in power supply
  1.1.3 Reliability of the power system
  1.1.4 Overall benefits of interconnecting isolated power systems
  1.1.5 Electric interconnection and the transmission of energy
  1.1.6 Economies of scale and distributed generation
  1.1.7 Cost/benefit analysis of an interconnection project

1.2 Regional Electricity Cooperation and Integration: the Various Steps
  1.2.1 Capacity building and pooling experience and expertise
  1.2.2 Exchanging information on the development and on the operations of the power system
  1.2.3 Pooling resources for the development of power supply
  1.2.4 Sharing the investment cost of interconnection lines

1.3 Interconnecting Electric Networks: the Political, Institutional and Financial Case
  1.3.1 Energy security and political relationships with neighboring countries
  1.3.2 Possible impacts of interconnection projects on the structure of the regional electric power industry
  1.3.3 Choosing the adequate structure to overcome financial barriers
  1.3.4 Interconnection, pooling resources and competition: a complex interaction

1.4 Experience of the E7 Network Utilities
  1.4.1 Development of the electric power system in E7 countries
  1.4.2 Ongoing reform of the electric power industry
  1.4.3 Conclusion

1.5 Possible Leverage for Pooling Electricity Resources
  1.5.1 Clean Development Mechanisms in the Kyoto Protocol: an important incentive for interconnecting power systems
  1.5.2 Fostering political dialogue under the aegis of international institutions
Chapter II  Electric Power Sector in Developing Countries: an Analytic Overview

II.1 Technical and Economic Characteristics of the Power Systems of Developing Countries
   II.1.1 Demand
   II.1.2 Supply

II.2 Political, institutional and financial characteristics of the electricity supply industry
   II.2.1 Most common paradigm: state-owned companies
   II.2.2 Financial capacity: call for institutional lenders
   II.2.3 Ongoing reforms
   II.2.4 Relations with neighboring countries

II.3 Taxonomy of the Electric Power Systems Relevant to Interconnection Issues
   II.3.1 Economics of power generation
   II.3.2 Financial, political and institutional features

Chapter III  Organizing and Implementing Regional Electricity Cooperation and Integration

III.1 Regional Integration: How to Proceed?

III.2 Planning the Development of Resources for the Electric Power System in a Regional Perspective
   III.2.1 Simplified master plan of the regional electric power system accounting for the energy system
   III.2.2 Setting the framework for the regional resource development plan
   III.2.3 Electricity demand forecast
   III.2.4 Planning the development of the generation capacity and associated transmission network

III.3 Setting the Framework for the Technical Operation of a Regional Electric Power System

III.4 Transition Towards a Regional Electric Power Market
   III.4.1 Background
   III.4.2 Conditions for and structure of the electric power market in developing countries
III.5 Evaluation and Development of Regional Projects
   III.5.1 Background
   III.5.2 Role of the RECI organization
   III.5.3 Steps in the evaluation and development of a power project
   III.5.4 Emergence and identification of the project, and control of its contribution to sustainable development objectives
   III.5.5 Development of the institutional framework of the project

III.6 RECI Organization
   III.6.1 Main features of the RECI organization
   III.6.2 Basic structure and functions of the RECI organization
   III.6.3 Recommendations for the design, implementation and development of Regional Electricity Cooperation and Integration (RECI)

III.7 Role of International Institutions in Fostering Regional Integration
   III.7.1 Background
   III.7.2 Categories of international institutions
   III.7.3 Areas for support from international institutions in the RECI process

Chapter IV Regions for Cooperation and Integration of Electric Power Systems
   IV.1 Principles for Identification of Regions
   IV.2 Identified Regions for Potential Regional Integration
      IV.2.1 Africa
      IV.2.2 Middle East
      IV.2.3 South America
      IV.2.4 Central America and Antilles
      IV.2.5 South Asia
      IV.2.6 Southeast Asia
      IV.2.7 Northeast Asia
   IV.3 Some Regions with an Ongoing Integration Process
      IV.3.1 CIER (South America) studies
      IV.3.2 Greater Mekong Subregion (GMS)
      IV.3.3 Organisation de Mise en Valeur du Fleuve Sénégal (OMVS)
      IV.3.4 The South African Power Pool (SAPP)
      IV.3.5 The Mediterranean-ring
List of Tables

Table 1: World regional indicators of electricity consumption growth for 1995-2020
Table 2: 1990 electricity balances, imports, exports, of various regions of the world
Table 3: 1998 electricity balances, imports, exports, of various regions of the world
Table 4: Africa, domestic supply of electricity (GWh)
Table 5: Middle East, domestic supply of electricity (GWh)
Table 6: South America, domestic supply of electricity (GWh)
Table 7: Central America and Antilles, domestic supply of electricity (GWh)
Table 8: South Asia, domestic supply of electricity (GWh)
Table 9: South Asia, domestic supply of electricity (GWh)
Table 10: 1998 electricity balances of countries ranked by descending order of imports dependence

References

foward to
Module 2
Module 3
Module 4
Module 5
Module 6
Module 7
Module 8
Glossary of Technical Terms
Acronyms and Symbols
Foreword

For a given region, the integration of the electricity supply industry of the member
countries, in its final stage, may be defined by two objectives. First of all, the national
electricity networks should be interconnected enough to enable substantial energy and
capacity exchanges between countries. Then, having agreed on a certain level of quality
of supply, the operators and the developers of the region’s power systems have to
coordinate in order to minimize the regional cost of electric power, while contributing to
environmental and social objectives.

To achieve these goals, none of the possible institutional structures of the electricity
supply industry, at both the regional and national levels, is precluded. The current trend
for reforming the industry towards increasing competition at the supply side will,
however, have to be considered since its technical feasibility is eventually linked to the
interconnection of national networks.

Generally speaking, regional electricity cooperation and integration enhances the
contribution of the electricity sector to sustainable development. In OECD countries,
further integrating large and mature electric power industries may yield important
environmental and economic benefits. In developing and emerging economies, pooling
electricity resources (notwithstanding political obstacles) is crucial for the development of
the electricity supply industry, as well as for the contribution of the industry to
economic, environmental and social objectives, which are the three pillars of sustainable
development.

Regional electricity cooperation and integration ranges from sharing experience and
expertise on the operation and planning of the electric power system, to pooling activities
such as training electric engineers, research and development, integrating parts of or the
entire structure for operating and developing the electric power systems. The electric
interconnection of national power systems is considered as a very important step towards
regional electricity integration, and a decisive step towards the implementation of a
regional competitive power market. There is, in every sector of the economy, particularly
sectors of mass production, a clear case for pooling resources. This is all the more true in
the electricity supply industry: as electricity is not storable, there is a strong incentive for
pooling supply and consumption through the interconnection of electricity networks.
Throughout the last century, the experience of utilities in the E7 countries has indicated that the interconnection of isolated electricity networks usually results in pooling generation resources and eventually, if the institutional structure permits, in integrating electric utilities into larger structures. Conversely, the existence of separate political and/or institutional structures may be an obstacle to technically and economically feasible electric interconnections, and may lead to the development of suboptimal power systems at the expense of sustainable development objectives.

In developing countries, the important financial risk perceived by private investors combined with the scarce domestic financial resources force the electric power industry to call for the support from international funding institutions. These international funding institutions tend to favor regional cooperation projects versus separate national projects. They also urge the governments to reform their power sector towards more regulatory and financial independence, and to promote competition, wherever feasible. Interconnection projects will find the required funds more easily if they benefit financially independent and internationally accountable electric utilities. Conversely, an efficient electric power wholesale competition requires a minimum level of interconnection.

Last but not least, true regional integration will help to further optimize the use of generation resources. Through more efficient exploitation of hydroelectric resources and fossil fuels savings, it can also allow significant reductions of CO$_2$ and other airborne emissions. Accordingly, integration projects may benefit from the Clean Development Mechanisms (CDM), one of the flexible measures outlined in the Kyoto Protocol.

The *E7 Guidelines for the pooling of resources and the integration of electric power systems* are aimed at fostering the regional integration of electric power systems for its contribution to sustainable development objectives. It is made up of three sections, reflecting the successive phases of cooperation and integration, generally implemented through the construction and operation of an interconnection network between formerly isolated power systems. **Section I** explains how to plan the interconnection project, **Section II** presents how to develop the project, and especially how to finance it, and **Section III** provides the conditions of operations in order to optimize the benefits of the interconnection project.

Module 1 makes the case for regional integration in developing countries, and provides recommendations on how to manage a true regional integration.

- In Chapter I, the general case for interconnecting power systems will be made.
- In Chapter II, the main characteristics of electric power systems in developing countries will be presented; this will pertain to technical, economic, environmental, and financial issues relevant to regional integration.
- In Chapter III, the E7 views on how to proceed with the integration of electricity supply industries in developing regions of the world are presented. This chapter draws from previous chapters the following:
There is a huge potential for development of the electric power systems. This makes a strong case for the integration of the national electricity supply industry. In other words, the economic surplus resulting from cooperation is generally so considerable that political barriers should be overcome.

The investments required for the development of the electric power system exceed the financing capability of incumbent electric utilities. Accordingly, the stakeholders will have to resort to external financial sources, mostly private. Private participation will develop more easily in a corporatized and liberalized framework.

Development plans, however, even if their determinism shall be mitigated, are crucial for the regional integration of developing electric power systems and, as such, are a primary step in the regional integration process.

- In Chapter IV, some regions where regional integration may yield some surplus are presented, and three regions where the integration of electricity supply industries is underway are given more emphasis.

A Memorandum of Understanding has been signed in Paris on May 22, 1998, with regard to the cooperation between the E7 Network of Expertise for the Global Environment and the Joint United Nations Development Programme (UNDP) / World Bank Energy Sector Management Assistance Program (ESMAP) in “providing technical assistance to governments of developing countries and economies in transition to improve the performance of their electric power sector and reduce environmental consequences of electricity production, transmission, distribution and use.” Dealing with energy trade, the objective of ESMAP is “to provide support to government interested in transnational energy projects, either natural gas or electric power interconnections.” Accordingly, much reference will be made to the steps taken by ESMAP to develop regional electricity integration.

Regional integration means the integration of the electric power industry of a given region. In its final step, this means that the electric power system is operated and developed at a regional level, irrespective of national features such as borders. Most of the time, regional integration goes with the development and operation of an interconnected regional transmission network; that is why in these Guidelines, the two notions may be used equally. On the one hand, the electric power industry of a given region may be integrated while its electric power systems remain isolated. On the other hand, electric power systems may be interconnected while being very loosely integrated.

The regions for which electric integration will be considered cannot easily be defined; obviously, they should originate from existing political regions but they should also take into account geographical features, such as river basins, economic development zones, and of course, integrate, if politically feasible, countries with very cheap energy resources. Some very large countries may include several electric regions; this is the case for the US. This could be the case for India or for China. The main regions offering a potential for electric integration will be presented in Chapter IV.
The main lessons from recent ongoing experience in regional integration are twofold:

- The exchange of information on the development and operation of national power systems has to be fostered, at first.
- Considering that the main barriers are political ones, it is crucial that governments realize the benefits of the integration of national power systems.
Chapter I

Integration of National Power Systems: the General Case

Generally speaking, the economic and technical rationale for integrating isolated power systems is twofold:

• achieve reductions in the operation cost of the generation mix;
• increase the generation capacity margin and, conversely, reduce the need for investment in peak capacity.

This economic rationale should be decisive when the expected benefits in operation cost and capacity margin are greater than the costs, the investment and operation cost, of the interconnection.

A power system naturally develops through an iterative and continuous interconnection process which can be optimized by planning. This process can be biased, impeded and even stopped by natural and technical barriers such as geography, right-of-ways and environment, or political and institutional ones such as political borders, national security, public opposition, financing, or such as an improper institutional structure. The electric power industries of the E7 Network are trying to overcome some of these barriers. They are currently challenging institutional barriers with electricity market reforms, but are now confronted to public opposition to transmission lines. Most developing countries, in addition to geographical barriers, have to tackle important political issues when considering the integration of their electric power systems.

The geographical barriers, which mostly pertain to the technical and economic feasibility of interconnection lines relative to the distance, are sometimes decisive. On the contrary, the political and institutional barriers can and have to be overcome. Security of supply issues should not be overlooked but the political, economic, environmental and social benefits of interconnecting networks and pooling resources are such that establishing the institutional framework for fostering regional electricity integration while pursuing legitimate security of supply objectives is of value.

The main criteria for evaluating the potential benefits of regional electricity cooperation and integration is assumed to be economic efficiency, that is to say to minimize the cost of supply of electricity for a given region and for a given reliability level.
The national objectives of energy security, the global objective of sustainable development and, in developing countries, the foremost objective of electrification will also be considered when assessing the institutional framework for pooling resources of the electricity supply industry. The potential regional interconnected network will be studied with the help of technico-economic models. These models estimate the economic surplus that stems from an ideal integration of the region’s electric power systems. An adequate structure of the regional electricity supply industry, integrating in particular the interconnection investments and operations, is crucial for the region to exploit in the most efficient manner this potential surplus, as estimated by the technico-economic models.

I.1 Interconnecting the Electric Networks: the Technical and Economic Case

The technical and economic case for interconnecting isolated electric networks is very easy to make. A very significant example is that a 1,000 kilometer-long 400 kV line is as cheap as the cheapest peak load generation units, the combustion turbines. Some experts estimated at 10 GW the capacity at which these economies can be fully realized. In Europe, it is estimated that a full integration of national electric power systems would save 10% of generation capacity. In any case, in the absence of cheap generation sources such as hydroelectric sources, the expansion of electric power systems by interconnection is limited by the remoteness of load centers. The current section analyses the various advantages of the interconnection of electric networks. The case for distributed generation is acknowledged. Two other arguments for the interconnection of electric power systems are to be mentioned although, strictly speaking, they do not pertain to the economic case:

It may help to compensate for planning uncertainty, thereby reducing the risk of overcapacity of the generation mix.

It may enhance the feasibility of bulk power supply competition by increasing the number of players.
I.1.1 **Pooling the load of customers**

Electricity is consumed by a large number of customers with very different load patterns. The load factor of a power system generally increases with the number of customers. Pooling customers with different load patterns through an electricity network reduces the relative fluctuation of the resulting load. The load factor of the interconnected power system is always higher than the weighted average of the load factor of the two formerly isolated power systems. As generation must follow the load over time, other things being equal, the greater the number of customers interconnected, the easier load following will be.

Actually, the customers are not concentrated in a single node. They may be distributed in different cities or all over the countryside. Their spatial distribution may bring about transmission losses and expenditures that may offset the benefits yielded by the increase of the overall load factor resulting from their interconnection.

I.1.2 **Economies of scale in power supply**

The issue of central generation versus isolated or distributed generation dates back to the birth of the electricity industry. Edison in the 19th century already broached the issue. During the 20th century, the electricity industry has gradually evolved towards increased size and centralization of generation means. This general trend is currently challenged by the commercial deployment of small efficient combustion turbines and by the reemergence of the heat and power cogeneration market. It should be recognized in any case that electricity generation is subject to economies of scale.

As is the case with every transformation activity — from raw material to manufactured products — the electric power sector presents a strong economic case for pooling the transformation of primary energy into electric power (horizontal concentration). This economic gain may be obtained at three levels:

a. the power generation unit;
b. the power plant;
c. the power generation company.
At the level of the power generation unit, for a given technology (diesel engines, steam turbines, combustion turbine, wind turbine, etc.), increasing the unit size reduces the unit investment cost, increases efficiency and reduces labor cost per kWh generated by the unit. The capacity at which these economies of scale are exhausted depends on the technology: around 1,000 MW for nuclear units, 600 MW for steam turbines, 300 MW for combined cycle units, and 50 MW for diesel engines\(^1\). For a given technology, increasing the size of a unit generally entails technical barriers that will challenge the R&D department of electric plant manufacturers.

Economic gains may also arise from the operation of several units on the same site. For hydroelectric power plants, these gains arise from the fact that civil works for the dam account for most of the investment cost of the hydroelectric power plant. Spending the additional investment cost of a turbine is not commensurate with the up-front cost of civil works. Hence, the full exploitation of a hydroelectric potential is often an important incentive for interconnecting isolated networks.

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1. The case for hydro turbines is very dependent on the river flow and on the head.
Finally, one can mention economies at the level of the power generation company, arising from the construction and operation of similar power plants, sometimes referred to as “the series effect.” These types of economies are very difficult to assess because very few electric power companies are not integrated into power pools or coordination arrangements. The same company, moreover, may own several identical power plants but in different power systems. Historically, this series effect has been very important. It does not pertain, however, to the economic case for interconnecting isolated power systems.

I.1.3 Reliability of the power system

To be considered reliable, a power system should be operated so that it can continue satisfactory operations when forced outages of a power generation unit occur. This implies that the spinning units do not operate at full load, and provide a capacity reserve equal to the capacity of the largest unit. Another cold reserve, made of units with short start-up times such as combustion turbine or hydroelectric power units, shall also be available to restore a spinning reserve. The reserve criteria vary from one power system to another but a proxy of the reserve capacity is twice the largest unit operating. In addition to this, a unit may have to stop for maintenance. All in all, a rule of the thumb indicates that the maximum size of a power generation unit should not exceed 10-15% of peak load of the power system.

Conversely, the larger the power system is, the bigger the size of the units it can use and — through economies of scale in generation — the smaller the generation cost, or if the unit size does not increase, for some reason, the share of capacity reserve can be reduced.

I.1.4 Overall benefits of interconnecting isolated power systems

Once the former isolated power systems are interconnected, the overall load and the load factor increase: the load curve is flattened. Flattening the load curve will make it possible, in the short term, to maximize the use of the low fuel cost units, thus decreasing the overall fuel cost. At the same time, it will increase the capacity margin of the overall power system. In the long term, it may permit the introduction of bigger size units in the power system, thereby capturing economies of scale.

Not accounting for the possible economies of scale in the generation sector, flattening the load curve is per se a strong incentive for interconnecting isolated networks.
I.1.5 Electric interconnection and the transmission of energy

These incentives for interconnecting isolated power systems are very strong: it is estimated, for instance, that the full integration of the European power system would save 10% of the overall generation capacity. In most regions of the world, however, the interconnection of electric networks originated in the existence of cheap and abundant primary energy sources, and especially hydroelectric sources.

The electric load centers may be remote from the oil or gas fields, from the coal mine or from the hydroelectric dam or the wind farm. Accordingly, either the primary energy has to be transported to the power plant site, or electric power has to be transmitted from the power plant (if it is sited close to the primary energy source) to the load center. The choice between these two options depends on various parameters and, among the economic ones, on the relative transport cost of the primary energy versus electricity. There are some examples, such as mine mouth power plants, where the transmission of electricity has been preferred to the transport of fossil fuels. Most long electric power transmission lines are justified, nevertheless, by the exploitation of hydroelectric resources.

a) Hydroelectricity and associated transmission lines

If hydroelectricity, as a virtually nontransportable energy source, requires high voltage transmission lines, the integration of formerly isolated power systems will, conversely, favor the development of hydroelectric resources for the following reasons:

1. Hydroelectric power plants may be very cheap generation options, provided that the economies of scale on a given hydroelectric site are adequately exploited. Economies of scale arise from the fact that the civil works for the dam account for most of the investment cost of the hydroelectric power plant, and that the expenditure of an additional turbine is not commensurate with the up-front cost of civil works. Hence, to fully exploit the economies of scale of a given hydroelectric site, the maximum generation capacity has to be installed and used as quickly as feasible. It is unlikely that the quickest pace of development an hydroelectric site’s capacity will match the development requirements of the power system; most of the time, it will result in an overcapacity of the power system for years. One way to reduce the time duration of the overcapacity period is to increase the size of the power system by connecting it with others.

2. They are listed by J.P. Charpentier as: (1) emergency support, (2) savings on operating costs, as a result of the structural differences of load profiles and (3) savings in investment (and operating) costs from complementary means of production. [see WB 95(1)].

3. The same logic will apply if renewable energy sources are to play an important role in the energy supply balance: due to their high space intensity, solar and wind resources, in particular, will have to be developed in remote areas, requiring long distance interconnection lines.
2. The water flow at the hydroelectric power plant varies from dry to wet years, and also during the year. Even with a large pluriannual reservoir, the output of the hydroelectric plant may be very uncertain. The risk associated with dry years is better shared by several power systems.

3. The important variations of the hydroelectric power plant’s output throughout the year also mean that the associated transmission line is not always fully loaded. Therefore, if this transmission line connects two formerly isolated systems, it may also be used for other interconnection purposes.

4. It may happen that, in the same region, the variations of hydroelectric schemes complement each other; this seems to be the case in South America. The interconnection of these two complementary hydroelectric schemes should be very profitable.

b) Transport of primary energy versus electricity transmission

When developing energy systems with primary energy sources remote from the load centers, it must be decided either to transport the primary energy or to transport electricity. This issue has to be dealt from many aspects, among them energy security, marketing opportunities of the primary energy, existing infrastructure and industry organization. In the absence of a regional energy development plan, the most dynamic and integrated energy sector will win the transmission market. This represents an important reason for the national electric power industry to integrate.

I.1.6 Economies of scale and distributed generation

There is an overall trend to promote distributed generation in lieu of centralized generation. Does this pertain to the interconnection issue?

The concept of distributed generation is to place distributed resources (small generators or storage units) at critical locations in a grid. The technologies of choice for distributed generation are renewable technologies, or efficient or climate-friendly technologies such as combined heat and power or combustion turbines. Instead of generating power with centralized units, and subsequently paying for a transmission service, transmission investment, O&M, and losses⁴; one can take advantage of possible synergies, at the consumer’s end, for instance to combine the production of generation with the production of heat.

This concept is promoted by environmentalists as a means for substituting coal, nuclear and hydroelectricity for natural gas, combined heat and power, and renewables.

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4. Worldwide transmission and distribution losses, according to the World Bank [see WB 00], averaged 8% (6% in high-income countries and 15% in low-income countries) in 1995. Distributed generation, however, does not address the nontechnical losses that account for most of the losses in developing countries.
At first glance, this concept may appear as being favored by market liberalization which makes the electricity supply industry more reluctant to capital intensive and huge projects, and open to private initiative. It provides flexibility to the electric power system, moreover, and may relieve some transmission constraints in countries of the Organisation for Economic Co-Operation and Development (OECD) where it is politically difficult to extend the electricity transmission network. Distributed generation takes advantage of the fact that some generation technologies are less sensitive to effects of scale than others, this being the case for combustion turbine and combined heat and power.

The present Guidelines are intended to promote regional electricity cooperation and integration. One possible outcome could be the development of a liberalized integrated electricity market which, according to some experts [see RIIA, 96], would in turn favor the development of decentralized and dispersed generation. It should be noted, however, that the implementation of a centralized power system has been furthered by the development of transmission networks.

The issue of distributed generation depends on the potential scale economies of the technology: the more the technology is sensitive to economies of scale, the less interesting it will be to distribute the generation facilities. It also depends on the transmission constraint development possibilities, development cost and transmission losses. However that may be, the case for pooling electricity demand is not challenged; there are still strong incentives for pooling the loads of customers, which will enable increasing the load factor and reducing the uncertainty of the load. Additionally, distributed generation may help to increase the load factor of the transmission network. All these features can be measured and evaluated within the least-cost utility planning process [presented in Module 3], which accounts for the costs of uncertainty and gives premium, accordingly, to flexible generation technologies.

To account for environmental externalities, the least-cost criteria should be combined with a criteria measuring the emissions of carbon dioxide that would have been released in the absence of distributed generation. In the end, a value will have to be given to CO₂ emissions so that a trade-off can be made between scenarios with distribution generation technologies, and scenarios where centralized generation prevails.

Distributed generation and electric integration are not opposites; they are, rather, complementary means for the electric power industry to contribute to sustainable development goals.

### 1.1.7 Cost/benefit analysis of an interconnection project

At a very early stage, the technical and economic costs and benefits of the interconnection have to be analyzed and compared, so that the difference between these two — the economic surplus — can be estimated.
It will be very difficult to determine and implement the institutional structure that will capture most of the economic surplus. In addition to the lack of coordination usually encountered among electric utilities in a country, energy security issues and different (or inconsistent) regulations can further prevent the players from capturing the surplus. This issue will be dealt hereafter in sections 1.2 and 1.3. At this point, only technical and economic issues are considered.

**a) Estimation of the economic benefits of the interconnection**

Many methodologies have been already developed to assess the benefits of interconnection projects; they have been implemented in various software models. It is very difficult to account simultaneously for every characteristic of the power system that may have an impact on this issue, such as quadratic transmission losses, optimal operation of the hydroelectric resources, interconnection capacity and availability. Most of the time, a sequence of software models will have to be used with increasing focus on transmission.

From the outset, the upper bound of the economic benefits of interconnection may be estimated by assuming that the two formerly isolated power systems are integrated in a single power system, and that the power generation units are dispatched by merit order with the objective of minimizing the overall operation cost, their power system of origin notwithstanding. The difference between the sum of the operation cost of the two isolated power systems and the operation cost of the integrated power system will give an upper bound of the estimation of the economic benefits. The capacity, the losses and the availability of the projected interconnection line(s) will, of course, limit these economic benefits.

The benefits of the interconnection will be fully exploited in the long run, actually, when the temporary overcapacity brought by the interconnection line is offset by the load growth of the integrated power system.

**b) Costs of the interconnection project**

In developing countries, as the load is relatively disperse over the region, the investment cost of the interconnection line may be an important barrier to interconnection. Moreover, a common set of technical rules for the operation of the interconnection line has to be adopted. Finally, if a significant integration of the power systems is sought, an harmonization of technical standards, as well as some measurement, control, and command equipment will have to be provided.
b.1) Investment cost of interconnection project

The cost of the interconnection is mostly made up of the investment cost of the transmission line(s). This cost is a linear function of the distance. Significant scale economies are linked with the capacity of the transmission line which, incidentally, and among other things, accounts for the fact that transmission is considered as a natural monopoly. The investment cost of a transmission line is far smaller than the investment cost in power generation; the unit investment cost of a combustion turbine, for instance — US$250/kW — is of the same order of magnitude as the investment cost of a 1000 kilometer-long Direct Current (DC) transmission line with a 3000 MW capacity. This could explain that, when a generation project is associated with a transmission project, the transmission project (even if it serves other purposes than the transit of the power supplied by the project) will not be priced as such.

Right-of-ways for the transmission line may be an important part of its cost and, most of the time, are difficult to obtain in developed countries. Right-of-ways are partly an economic issue (what is the economic cost of booking the way for the transmission of electricity?) and a financial one (what is the bargaining power of the owner of the way?).

All in all, in OECD countries, building new transmission lines is an environmental issue linked with the right-of-ways and public acceptance; in developing countries, the distances are greater and the loads smaller, thereby increasing the relative importance of technical and financial issues.

b.2) Harmonization of operation principles and technical standards

The parallel or synchronous operation of formerly isolated power systems will require a lot of coordination between the operators and, of course, agreement on, and compliance with common operation principles and rules. The details of these agreements may differ from one power system to the other. They require, however, the adoption of some common rules such as the maintenance of the value of frequency, within limits, and the compliance with criteria for network security such as the N-1 criteria [see Modules 5 and 8 for further details].

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5. Actually, economies of scale in transmission are far more important than in generation.

### Economies of scale in transmission lines

<table>
<thead>
<tr>
<th>Voltage transfer capability for 200 km</th>
<th>kV</th>
<th>110</th>
<th>220</th>
<th>380</th>
<th>500</th>
<th>750</th>
</tr>
</thead>
<tbody>
<tr>
<td>line cost in % of 380 kV (single circuit)</td>
<td>%</td>
<td>47</td>
<td>68</td>
<td>100</td>
<td>135</td>
<td>175</td>
</tr>
<tr>
<td>cost/MW in % of 380 kV</td>
<td>%</td>
<td>888</td>
<td>289</td>
<td>100</td>
<td>62</td>
<td>39</td>
</tr>
</tbody>
</table>

Source: IAEA 1985

6. For the transit of electric power over distances exceeding 1,000 km, the Direct Current (DC) technology is better than the Alternative Current (AC) technology, and is not demanding in terms of synchronism requirements (back-to-back stations are used to transit power from UCPTE to CENTREL, the regional group of four power companies from the Czech Republic, Hungary, Poland and Slovakia.). DC technology, however, presents some restrictions. Intermediate picking stations, as well as the inverter and converter stations, are very expensive.
Assuming these agreements have been reached, an harmonization of some technical standards and equipment will have to be managed, and some measurement, control and command equipment will have to be provided to fully integrate the interconnected power system and to capture most of the technical and economic benefits. A common dispatch center will have to be built, possibly. This will add to the investment cost of the transmission lines for the interconnection.

1.2 Regional Electricity Cooperation and Integration: the Various Steps

Regional electricity cooperation and integration is a long-term process which may be implemented in a stepwise manner, from an exchange of expertise and information on the operation and development of the electric power system, to joint-venture, asynchronous interconnection, interconnection limited at sharing emergency reserve, to the full integration of the electricity markets. Prior to market integration, the European system was at a level of integration in between sharing emergency reserve and full integration [see UCPTE 98]. In some regions, the integration process could stop in its early steps [see Joskow, 83]. Some of the possible steps are presented below.

1.2.1 Capacity building and pooling experience and expertise

In many developing countries, as the electricity supply industry is to small, it cannot afford to hire and train many specialists. This issue is not specific to the electricity supply industry and pertains to the overall economy of developing countries; it is crucial, however, for the electricity supply industry which requires a lot of diversified expertise. This issue is tackled by international institutions, such as the World Bank or the International Atomic Energy Agency of the United Nations (IAEA), or regional organizations, such as the Union des Producteurs et Distributeurs d’Électricité d’Afrique (UPDEA), through the organization of seminars, discussion and training on methodologies. Most of the time, however, the electricity supply industry of developing countries cannot afford the critical mass of engineers and economists to maintain and develop the expertise initiated by the international institutions.

There is a strong case, accordingly, for pooling in regional entities some of the expertise of the electricity supply industry; an early step would be the exchange of experience and expertise among the electricity utilities.
1.2.2 Exchanging information on the development and operation of the power system

In a given region, countries may wish to share information on the load patterns and the operations of the generation mix, as well as on the location of the load, the power plant generation and, possibly, the expansion plans of the neighboring countries.

When countries use the same river basin, for instance, the development and operation of hydroelectric dams have to be coordinated not only to optimize the electricity generation of the river basin, but also to take into account the other possible uses of the water by the downstream countries (navigation, irrigation, etc.) and to mitigate the risk of flooding the downstream countries. The use of the water has to be agreed upon by the countries of the river basin. The operation plan for the dam has to be communicated in advance by upstream to downstream countries.

This type of information exchange is strongly recommended when the national power systems are physically interconnected.

1.2.3 Pooling resources for the development of power supply

A review of the interconnection projects in developing countries (on-going and realized) would show that most of interconnection projects originated in the development of hydroelectric resources. The location and maximum surface of the reservoir, the capacity of the power plant, the type of power supplied (firm power versus energy), the transmission investment cost, the water use rights, all these parameters should be agreed upon during the planning phase. These parameters, however, are generally reviewed during the negotiations between the stakeholders (banks, governments, electric utilities, and, possibly, private customers).

a) The project

Two countries may share the cost and the benefits of a power generation plant. In European countries, this is mostly the case for nuclear power plants. In developing countries, hydroelectric power plants may be targeted for joint ventures; this has been the case for Itaipuh, on the Parana river, on the border between Paraguay and Brazil.
There could be no transmission of power between the two countries. The capacity of the transmission lines is sufficient, most of the time, to accommodate power transfers from one country to the other when that power is not used, temporally, by the associated country. There is also a strong incentive to oversize the transmission lines to allow additional exchange of power between the two countries. The case of a hydroelectric scheme on the border of two countries is very common. The exploitation of regional hydroelectric resources may be complicated if the dam is situated in one country: the transmission lines will have to cross that country in order to supply the other country.

b) Institutional and pricing issues

The process for sharing the cost and benefits of power generation projects, and the associated transmission lines, may be implemented by various structures and institutional schemes and, accordingly, by various pricing policies. This can be a joint venture, an independent power producer, or a long-term supply agreement from one of the country to the other, one country being responsible for the development of the power generation plant. All these issues will be detailed in Chapter IV.

I.2.4 Sharing the investment cost of interconnection lines

Interconnection lines not directly associated with power generation projects are increasingly studied. They generally involve more than two countries. An efficient institutional and pricing structure has to be implemented in order to capture most of the benefits that have been estimated in the economic feasibility study (generally based on merit order dispatching), and to mitigate the perceived risk of not recovering the investment cost of the interconnection transmission line.

I.3 Interconnecting Electric Networks: the Political, Institutional and Financial Case

Once the economic and technical benefits of regional integration have been assessed, the capability of the current regional organization to capture these benefits will have to be examined. Changes to this regional organization — namely its political, institutional, and financial aspects — will, moreover, have to be proposed and, if agreed upon, implemented.

Technically and economically viable interconnection projects may be faced with political, institutional, and financial barriers. Conversely, the institutional structure of the interconnection project should be designed in such a way that the stakeholders are incited to capture most of the economic and technical benefits of the interconnection project.
As a start-up in the integration process, interconnection projects may, finally, induce changes in the structure of the national electricity supply industry; pooling the power generation capacity is likely to foster true bulk power competition at both the regional and national levels.

The electricity supply industry is part of the core of modern economies. Changes in the structure of this industry, accordingly, will eventually infer changes in the other sectors of the economy, and counteract on the political organization of the society, particularly on the political integration of the region.

The foremost barriers to regional integration are political ones. Politicians are concerned about self-sufficiency, energy security issues, possible asymmetries in the cross border trade of electricity, and by the impact of regional exchanges on the price of the commodity in domestic markets.

Once these political barriers are properly addressed, the rules and standards of operation have to be harmonized, and a regional operator — or an efficient coordination between national power markets — shall be devised in such a way as to recover most of the potential surplus accruing from regional integration.

Once a sound political and institutional framework for regional integration has been set, the financial barrier to developing interconnections should be overcome, and the perceived risks usually linked with such projects in developing countries will be significantly mitigated. In order to attract private investment, then, the following pricing issue has to be settled: how to ensure a given return to independent power transmitters?

I.3.1 Energy security and political relationships with neighboring countries

Part of the political stakeholders’ concerns, outlined above, are not specific to the electricity sector but pertain to the international trade of any commodity, which is ruled as such by the World Trade Organization / General Agreement on Trade and Tariffs (GATT) agreements. The specificity of the issue arises from the fact that electricity is a nonstorable, crucial intermediate product, and requires a dedicated network to be traded. There are few such products, actually; water, also less costly to store, has very similar features.
Before getting to the rationale of the issue, it is of value to consider that the United States have let the state-owned utilities of their northern neighbor, Canada, obtain good conditions for marketing their hydroelectric resources\(^7\) but that, in 1998, these exports represented less than 2% (45 TWh over 3,558 TWh) of the US production of electricity. Considering their proximity, perhaps, members of the Union for the Coordination of Transmission of Electricity (UCTE) rely more on each other for their electricity supply. Among the E7 countries, Italy (along with Netherlands) is the most dependent on electricity imports which represented about 15% of its domestic consumption (39 TWh, out of 272 TWh) in 1998. This stems from a century-long, nation-centric development of its power systems. Can developing countries afford such autarkic development?

**a) Self-sufficiency, asymmetries and the theory of comparative advantages**

Self-sufficiency — to balance demand with domestic supply — and potential asymmetries in market access are legitimate and common concerns, although not specific to electric power. They have been addressed, as such, from the outset of international economy and the theory of comparative advantages. The limitations to this theory are numerous; these limitations will not be detailed herein; rather, the generic types of cross border electricity trade will be analyzed with regard to these two concerns. As the vehicle of cross border trade, transmission activity will not be analyzed either in this section.

In the short term, after exchanging information on the marginal cost structure of their national power systems, the operators realize that one country benefits from a comparative advantage in a given period of the year, that is to say that the economic marginal generation cost\(^8\) of a power system is lower. The two electric power systems will then exchange power until the difference between the economic marginal costs of the two systems is minimized.

What could be the barriers to this type of cross border trade?

On average, the operation cost of the exporting power system will increase since it will have to increase generation through a greater use of marginal units. The value of electricity exports, however, shall be higher than the operation cost increase.

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7. One could argue on the relevance of a political distinction between Canada and the US rather than a distinction between a given state of the US and a given province of Canada. It is a well-known fact that most Canadian provinces have stronger commercial links with cross-border states of the US than with neighboring Canadian provinces. One could also mention the factor of magnitude between the two markets; does Brazil really care if 25% of its electricity supply depends on a bilateral agreement with Paraguay?

8. This economic marginal generation cost is assumed as the highest variable cost (operation and maintenance) of the operating units; “economic” means that any national tax or subsidy shall be excluded. In the case of reservoir-type (as opposed to run-of-river) hydroelectric power plants, water may have a value depending upon the water level in the reservoir, and on the date (future likely load patterns and water inflows). The decision to “turbine” it or not will depend on this value, expressed in monetary unit per kWh, as compared to the operation cost of thermal power plants.
These exchanges would not have happened otherwise. This surplus is easy to allocate when there is no allocation to be made, that is when the electric utility and its generation capacity and operation are owned by the community. It is another matter altogether in the case of a competitive pool market if, actually, generation assets are not owned by the community. If no compensation mechanism is set up, the pool price should increase, hereby increasing the price of electricity for customers of the exporting country. Shall the customers be compensated for that rate increase? And if yes, how?

The importing power system will have to stop its most costly generation units and, consequently, reduce the demand for the fuel and revenues of the local fuel supply chain. As the fuel concerned would be fuel oil — which is very easily storable — it should not be an issue: the fuel supply chain can adapt to this reduced demand. This could be different, however, if the fuel concerned is less easily storable, such as natural gas if sold with take-or-pay conditions.

If this comparative advantage lasts in the long term, the developers of the two power systems have to analyze it. This can result in one country importing electric power on a constant (firm contract) basis. The need to establish a strong regional organization that reduces the risk of one country breaking the agreed power exchanges will then come to light. The risks of long-term dependence will be mitigated if the regional power grid balances the generation means between the countries, if there is, in other words, some mutual dependence or complementarity, as it is the case in South America.

**b) Barriers to reducing national reserve capacities**

In the course of the development of interconnected electric power systems, some generation capacity has to be saved, actually, in order to pay off the investment in interconnection capacity. National stakeholders shall accept, consequently, that their national security of supply may be threatened by once cooperative foreign utilities. Energy security may be threatened even more if the electricity supplied transits through a third country. Actually, most countries agree to develop interconnections only as an addition to their existing national development plan.

To overcome this barrier — the lack of confidence in the neighboring electric power systems to provide reserve capacity — the Union for the Coordination of Production and Transmission of Electricity (UCPTE, now known as UCTE) was created in Europe. It is very difficult to assess whether this regional organization has been successful in this respect, since most of the European electric power systems, were and still are in a situation of overcapacity.
1.3.2 Possible impacts of interconnection projects on the structure of the regional electric power industry

Developing international interconnection projects provides incentives for reforming the institutional framework of the electric power systems. The electricity supply industry would, consequently, gain more independence from governments and offer better accountability. Many experiences can justify such statement. The creation of an entity responsible for the economical supply of electricity in the country, distinct from the entity responsible for the country’s self-sufficiency, is clearly an advantage as it allows a transparent and unbiased assessment of the economic cost of self-sufficiency.

Interconnecting national power systems will foster the implementation of the mechanisms of true regional electricity cooperation and integration. The development of interconnections will, in turn, foster the emergence of a true competitive power market.

1.3.3 Choosing the adequate structure to overcome financial barriers

For most developing countries, the available capital for investment projects is very limited. Again, this is not specific to the energy sector but applies to all sectors of the economy. In a context of scarce financial resources, interconnection projects will not be considered as priorities by governments unless they are associated with the exploitation of hydroelectric resources or other primary resources. In fact, it is very difficult for an engineer to make benefits materialize, as these benefits will depend on the willingness of the neighboring country’s utility to cooperate.

As most investment projects in the electricity supply industry of non-OECD countries, part of the works will be made by foreign companies and, accordingly, priced in US dollars or other foreign currency; the electric utility, however, is paid by its customers in local currency. The ability of the utility to finance the investment depends a lot, therefore, on the stability of the national currency. Generally speaking, the political and financial risks perceived are so important that 1) local governments will have to guarantee the loans, 2) high interest rates will be used, so that the project will need to be supported by institutional development funds.

The risk is even higher for interconnection projects since it involves two different electric utilities in two different countries. The individual risks combine with the risk of dispute either between the two utilities or the two countries. An interconnection project is perceived, accordingly, as very risky thereby raising important financial barriers. To overcome these, one must agree on an institutional structure (or structures) to build and operate the interconnection, and minimize the financial risk.
1.3.4 Interconnection, pooling resources and competition: a complex interaction

A priori, international cooperation between the operators of power systems has no direct influence on the structure of their respective power systems. Increasing the interconnection capacity, however, will favor the feasibility of wholesale power supply competition.

On one side, a political statement from the European Community outlines the role of interconnections in contributing to the effectiveness of internal energy markets. On the other side, in its latest statements, UCPTE expressed some concern that competition could threaten the reliability of the interconnected European system, and aimed at maintaining a balance between competition and technical cooperation 9.

According to the World Bank [see WB 93 (2)], the feasibility of wholesale power competition depends on the size of the power system. In Introducing Competition to the Power Sector, it concluded that “the size of both market and system is an important factor in determining whether competition would be feasible. Such factors as technological mix used for generation and degree of interconnection are also important.”

All in all, increasing regional interconnection of electric power systems, if politically feasible, should favor the emergence of an integrated power system and, in some cases, may bring into question the prevailing structure of the electricity supply industry. Most of the time, however, even after implementing these interconnections, the potential economies of scale of power generation technologies will not be exhausted, and the hydroelectric resources will not be fully exploited, so that the conditions for a competitive power market will still not be met.

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9. According to the European Community, the development of trans-European electricity networks will contribute to:
   - Effective operation of the internal market in general, and of the Internal Energy Market in particular
   - Strengthening economic and social cohesion by reducing the isolation of the less-favored regions of the Community.
   - Reinforcing security of energy supply.

The European Community considers that the development of interconnections between Member Countries will result in effective operation of the internal electricity market. The underlying assumption is that a developed interconnection network will help promoting electricity wholesale competition.

At the same time, the Union for the Co-ordination of Production and Transmission of Electricity (UCPTE) aims at maintaining a balance between competition and technical cooperation:

“the UCPTE will have to ensure that the opening up of the market do not jeopardize the benefits of co-operation, namely:
   - The reliability and security operation of the interconnected network,
   - The continuity of the intensive ion information exchanges,
   - The use of ecologically attractive generation technologies.”
I.4 Experience of the E7 Network Utilities

A priori, there are many reasons for not applying the interconnection experience of the E7 Network directly to developing countries\(^\text{10}\); these will be discussed in Chapter II, as it outlines the characteristics of the power sector in developing countries. A primary reason, although not specific to the electricity sector, is that power systems of the E7 Network have evolved, over one century, along with advances in technology and the growing purchase power of the population, whereas the developing countries may benefit from the most up-to-date technologies.

This raises two questions:

- Is the current electricity technology affordable by developing countries? In most developing countries, the reliability and security requirements of the electric power system are less significant than those in the countries of the E7 Network; this is usually expressed in the planning process by considering a cost of unserved energy 5 to 10 times higher in developed countries than in developing countries.

- Why does the natural development of an energy electricity network have to be fostered? Some experts hold the view that the electric networks of developed countries have expanded by a natural iterative process, progressively integrating the nearby loads, then commissioning bigger size generation units. Whether this was really the case is not obvious; and if it were the case, would it be the less costly development path for developing countries?

I.4.1 Development of the electric power system in E7 countries

The E7 is composed of eight electric power companies covering three regions of Europe, North America and Japan. In terms of network integration, the three regions have so far promoted the interconnection of power transmission networks with different objectives linked to geography, resources, economy and scale characteristics. The various interconnection patterns of the E7 member companies can serve as a reference for those regions intending to promote system interconnection as they proceed to make institutional and technical choices.

\(^{10}\)It is not difficult to comprehend that, both in concept and design as well as within the framework of a profitability analysis, the standards that must be applied (to developing countries) are completely different from those of deregulating, industrialized countries.
a) The past and current evolution of the European electricity networks

In European countries, in the past, electricity networks have been reinforced — where they needed to be — within the franchise of a given utility and, in a lesser extent, with the neighboring utilities. Further extension of the interconnected system to Western Europe was officialized in 1951, when the UCPTE was established at the instigation of the Organization for European Economic Cooperation (OEEC), forerunner of the OECD. This shows that fostering the integration of national electricity networks is also viewed as a step towards political integration.

In 1998, nevertheless, electricity exchanges between countries of the UCTE and with third countries only account for 186 TWh over a consumption of 1742 TWh. Energy exchanges represented only 10% of the UCTE countries consumption. The European community dedicates a lot of efforts to the development of the Trans-European Energy Networks, with the stated objective to make effective the Internal Energy Market. All in all, the existence of a community of states is justified by the promotion and regulation of interstate activities and trade. Although authorized by law, cross border exchanges are limited by several factors, such as 1) overcapacity in most European countries, 2) limited capacity of cross border lines.

b) The past and current evolution of the North American electricity networks

The US electricity supply industry is made up of 3,300 companies, including 342 so-called investor-owned utilities which represent 73% of electric generation, non-utility generators (11%) and federally owned utilities, as well as publicly owned state and municipal utilities. Federal involvement in hydroelectric power is justified by the multiple uses of the dams.

The transmission system in the United States lists almost 200 owners. Third Party Access (TPA) has been practiced for 85 years. No real nationwide market exists but the geographic market area for bulk power sales is increasing. The market structure is made up of 157 energy control centers (dispatch centers), 20 cooperative power pools (from loose power pools to tight power pools) that typically coordinate maintenance schedules and may engage in joint capacity planning, and 10 regional reliability councils that are part of five synchronous networks, interlinked by direct current transmission lines except for the main network from Mexico which is isolated from the others.

11. “Co-operation within the energy sectors of the Baltic States is a tool in promoting general economic development and strengthening the efforts of the Baltic countries accession to the European Union.” from a document issued in March 1999 by the Energy Committee of the Baltic Council of Ministers (The Baltic Energy Strategy).

12. This paragraph draws heavily from the IEA/OECD 1998 Review of the Energy Policy of the United States [see IEA, 98 (2)], and from a booklet issued in late 1999 by the IEA Competition in electric markets [see IEA, 99(1)].
Regulation governance is shared between the Federal Energy Regulatory Commission (FERC) and state regulatory commissions. The federal government should, theoretically, be responsible for interstate trade, whereas the state keeps responsibility of intrastate trades. Intrastate trade impacts on interstate trade, in practice, so that the federal government should be able to oversee somewhat intrastate trade. In fact, FERC has jurisdiction over transactions involving the transmission grid. FERC Orders 888 and 889, issued in April 1996, create a generally competitive interstate market for electricity. To reduce the incumbent utility’s incentive to discriminate, it encourages the creation of independent system operators. For the time being, FERC has to prove that there is no other way to assure a true competitive market and, in doing so, force separation of the grid from generation and supply.

All things considered, the North American electric power system moves towards better regional integration; this is the most prominent result of the reform process which was initiated in 1978 through the Public Utility Regulatory Policies Act (PURPA).13

**c) The past and current evolution of the Japanese electricity networks**

As Japan started to achieve high economic growth in the 1960s, Japanese electric utility companies were required to secure ample supply capacity to meet a growing demand, and to do this through the adoption of interconnected systems.

Although each utility company operates independently and, basically, maintains supply-demand balance in their respective areas, it is possible for the utilities to cover capacity shortages in urban areas by utilizing the generating capacity of the other companies.

The objective of promoting interconnections was not only to make up for capacity shortages in densely populated and industrialized areas, but also to: a) utilize facilities effectively by taking advantage of time and seasonal variations in regional load demand; b) reduce reserve capacity; c) acquire merit of scale through large-scale resource development projects, as well as upgrading generator capacity and introducing joint projects for the development of nuclear and other large power plants.

In order to achieve these objectives, Japanese utility companies promoted interconnections through the use of overhead transmission lines, submarine cables and frequency converters [see details in Module 5].

With these interconnections, electricity exchanges between electric utilities in Japan accounted for 65 TWh of a total consumption of 898 TWh, in 1999.

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13. The Public Utility Regulatory Policies Act (PURPA), passed in 1978, forced incumbent utilities to buy power from “qualifying facilities”, its main objective being to promote cogeneration and renewables.
I.4.2 Ongoing reform of the electric power industry

Nearly all OECD countries are now embarked, at various stages, in the reform of their power sector. The rationale for embarking into such reform is not very clear, and varies from one region to the other.

In the United States, it was justified by problems encountered with the former regulation for bulk power purchase, triggered by the deployment of cheap natural gas fired, combined cycle, power plants. It may be also have been justified by very important retail price gaps between states. In 1996, with a US average of 6.9 US cent/kWk, many eastern states had to pay more than 10 US cent/kWk, whereas others in the Northwest paid less than 5 US cent/kWk. Such a huge difference cannot be justified by technical and economic factors alone, and it would not last long if interstate trade was really significant.

In the European Union, there is a strong political pressure to integrate the various nationwide concessions of generation, transmission and distribution in the internal European market. Although many regions — such as Scandinavia (NORDEL) and, to a lesser extent, Western Europe (UCPTE) — were well integrated, the reform led by the European Commission is mostly intent on creating a European power market.

All in all, the motivations for reforming the structure of the electricity supply industry in the three E7 regions are very diverse but every region is intent on promoting interstate trade and regional integration. The various features adopted to this end — changes in ownership, horizontal and vertical restructuring, market type (bilateral or mandatory power pool) transmission pricing — should not hide the fact, however, that the success of the reforms will be measured, ultimately, by the level of regional integration attained.

I.4.3 Conclusion

All the above considerations on the technical features and economics of power generation as well as the spatial dispersion of primary resources and load centers helped shape the development of interconnected networks and the integration of electricity markets in developed countries.

The North American experience proves, however, that the political organization of a given region is a strong determinant of the level of integration of the electric power industry. At the other end of the spectrum, the political centralism of France — considering all its drawbacks — is certainly responsible for one of the largest integrated electric power system.
In the last 15 years, the development of the combustion turbine technology with (or without) combined cycle, together with cheap fossil fuel resources particularly natural gas) and the stagnation of electricity demand, made it possible for the development of electricity supply in E7 countries to be ensured, in the medium to long term, through small size power generation units that could be owned by other stakeholders than incumbent utilities such as oil and gas companies. The new combustion turbine technology, furthermore, does not require as much specialized and trained staff as nuclear power plants or even coal-fired power plants, and is not as capital intensive, so that industrial heat and power producers can also develop and sell their own electric power generation.

It can be argued, accordingly, that the model of a state-regulated franchised electric company is not adequate any more: there is no more need for studying and combining transmission and generation expansion plans as the growth of electric demand is expected to be moderate\textsuperscript{14}. There is also no urgent need for solving the institutional and pricing issues of the generation and transmission sectors since the expansion of the power systems is not a priority. The main challenge is to integrate the market, moving it from state to federal or union regulation and control, and to put the electricity supply industry in the best position to uphold these changes.

In developing countries, the situation is quite different. Economies of scale have not been captured, the hydroelectric potential is not harnessed, and the demand for electricity is expected to double or triple over the next 25 years. There is an urgent need for organizing the expansion of the energy system at a regional level. The corresponding investment to be made in the electric sector is generally out of reach of the governments’ financial capability. The experience of E7 countries shows that the development of transnational electricity trade — a key component of the least-cost process for developing the electricity sector — will not be “naturally” favored by state-owned and controlled electricity utilities\textsuperscript{15}. If a high level of regional integration is to be achieved, a strong political push needs to be given, either through political regional organizations or by international institutions.

\textsuperscript{14} OECD countries should have to make up the existing capacity of the electric power system with one half of it in the next 25 years, whereas all the other regions except for economies in transition will have to double or triple the existing capacity [see IEA, 98 (1)].

\textsuperscript{15} The volume of energy traded in Europe could contradict this statement. Aside from Scandinavia (where the hydroelectric resources of Norway as well as the geography naturally lead to integration) and Switzerland (which is endowed with important hydroelectric resources) the bulk of the energy trade in Europe originates in planning errors that resulted in unsuited national generation capacity, such as the nuclear overcapacity in France.
1.5 Possible Leverage for Pooling Electricity Resources

There are many political and social barriers to true regional electricity cooperation and integration. To overcome these barriers requires, basically, building political trust among countries in the region, which will, in turn, facilitate the creation of new institutions mandated with regional objectives. Regional electricity cooperation and integration, if based on sustainable development objectives, may be levered by the global environmental objective of mitigating CO₂ emissions as well as by its contribution to regional economic development.

1.5.1 Clean Development Mechanisms in the Kyoto Protocol: an important incentive for interconnecting power systems

Clean Development Mechanisms (CDM) are one of the flexible mechanisms of the Kyoto Protocol. They concern the investments from countries committed to a maximum level of CO₂ emissions in developing countries that reduce CO₂ emissions in relation to a given baseline. Many of the investments involving an interconnection line should qualify since either they will favor a better dispatch of the generation mix — likely to reduce the consumption of fossil fuels and, thereby, reduce CO₂ emissions of the power system — or facilitate the development of hydroelectric power plants that will replace thermal power generation.

However, the current stand among the experts devising these CDMs is project-wise, irrespective of the project’s contribution to the emissions of the whole power system. For the time being, these experts have not devised anything relative to the baselines for qualifying transmission lines that would permit a better dispatch of the generation mix.

1.5.2 Fostering political dialogue under the aegis of international institutions

There are political barriers to market integration, mainly the absence of political trust, as well as political concern that international trade would jeopardize the social objectives assigned to the electricity supply industry. On the contrary, giving higher profile to the economic, social and environmental benefits that electricity market integration could yield and spending efforts to persuade political actors to meet and agree on common rules may be a starting point for regional electricity cooperation and integration.
In fact, integration is a self-feeding process; this is quite clear in the European Community, as it started developing to coordinate coal and steel production, then was implemented as an integrated body, and now fosters the integration of electric power markets in a single market.

The financial lever of international institutions is, in this regard, an opportune start-up for regional electric integration.
Chapter II

Electric Power Sector in Developing Countries: an Analytic Overview

The development of the electric power sector is an essential component of the sustainable development of a country. The electrification rate and the average national electric construction per capita, moreover, are indicators of a country’s development level. The category “electric power systems of developing countries” actually covers a wide range of development levels, from the power systems of Latin America’s Southern Common Market (MERCOSUR) to the power systems of the Sahel countries in Africa. Some regions liable to proceed to regional electric integration are made up of countries at very different levels of development\(^{16}\). But, all in all, many developing countries share, at various degrees, the following features that may be of importance when addressing the integration issue:

- very dispersed load, but high actual or potential growth rate of consumption of electric power, partly due to partial electrification, and partly due to the average low income of customers;
- significant untapped hydroelectric potential\(^{17}\);
- lack of national financial resources to develop electric power systems.

These three features are encountered, mostly, in developing parts of the world, and render a true and efficient integration of the national electric power systems of these regions even more crucial than in mature electric power systems of Western Europe or North America.

This chapter draws a lot from papers, notes of international organizations, and particularly the World Bank’s *Power Supply in Developing Countries: Will Reform Work?* [see WB 93 (2)], as well as from the Energy Research Group [see ERG, 90].

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\(^{16}\) Conversely, some developing countries who share common borders with developed countries, Mexico for instance, are integrated in the electricity power markets of these developed countries.

\(^{17}\) In 1995, John Besant-Jones [see WB 95 (2)] stated that developing countries have exploited an average of 10% of their technically usable hydroelectric resources. Because most developing countries are situated in the tropics, the hydroelectric potential is relatively more important than in E7 countries’ regions.
II.1 Technical and Economic Characteristics of the Power Systems of Developing Countries

OECD countries present a relatively homogenous range of electricity consumption, estimated at around 7,000 kWh/capita\(^{18}\). The large majority of developing countries presents consumption per capita ranging from 20 kWh in the less electrified countries (such as Ethiopia), to 380 kWh in India, 822 kWh in China and 1403 kWh in Latin America. It would be valuable to compare these figures with Gross Domestic Products (GDPs), population density, and percentage of population living in cities. This, however, is outside the scope of this section; the objective herein is, rather, to assess the technical and economic feasibility of regional integration of the electricity supply industry of developing countries, and to identify which type of institutional framework will be the most conducive to that end goal.

II.1.1 Demand

In most developing countries, part of the demand for electricity cannot be met, and an important part of the population does not have access to electricity. Even if the overall energy bill of households would be reduced by substituting traditional fuels for electricity, the up-front cost for supplying and distributing electric power remains a barrier to the penetration of electricity. In many developing countries, actually, two major issues face the development of electricity consumption\(^{19}\):

- the absence of financial capability to develop electrified zones, on the part of electric utilities;
- the large number of households situated in electrified zones that cannot afford electricity.


\(^{19}\) For a considerable amount of time already, this has put into question the objective of rural electrification assigned by politicians to utilities benefiting from franchises for transmission and distribution. Kilometers of medium voltage lines are built in the country with negative rates of return. Solutions with smaller up-front investment, such as so-called decentralized electrification should be preferred.
a) Volume and concentration of overall electricity consumption

The consumption of electricity per capita is usually very low compared to standards in developed countries. Considering that several developing countries are situated in the subtropical zone, air conditioning and air fans represent a significant share of the consumption of the residential and services sectors; the load factor of such use is very low, at around 30%.

The overall consumption of electricity relative to the surface of the country (kWh/ square meter) is very low, moreover, compared to the same indicator in developed countries.

b) Electrification objectives and growth rates

The electrified zones are often limited to the larger cities. Most governments of developing countries express very ambitious electrification objectives. These objectives, however, are contradicted by the lack of financial resources and the absence of economic viability of electrification, particularly within rural areas.

The combination of ambitious electrification programs and strong economic growth perspectives can result in strong growth rates of electricity consumption. The World Energy Outlook [see IEA 98(1)], for one, assumes stronger growth rate for electricity demand in non-OECD countries than in OECD countries over the next 25 years. The growth rate of electricity consumption, furthermore, is higher than the growth rate of GDP, except in Latin America and China.

Table 1: World regional indicators of electricity consumption growth for 1995-2020

<table>
<thead>
<tr>
<th>Region</th>
<th>1995 Generation Capacity (GW)</th>
<th>GDP Growth</th>
<th>Electricity Growth</th>
<th>Additional Generation Capacity (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>OECD</td>
<td>1,814</td>
<td>2%</td>
<td>1.9%</td>
<td>1295</td>
</tr>
<tr>
<td>China</td>
<td>227</td>
<td>5.5</td>
<td>5.4</td>
<td>550</td>
</tr>
<tr>
<td>East Asia</td>
<td>126</td>
<td>4.5</td>
<td>5.0</td>
<td>321</td>
</tr>
<tr>
<td>South Asia</td>
<td>106</td>
<td>4.2</td>
<td>4.5</td>
<td>218</td>
</tr>
<tr>
<td>Middle East</td>
<td>89</td>
<td>2.7</td>
<td>4.0</td>
<td>127</td>
</tr>
<tr>
<td>Latin America</td>
<td>187</td>
<td>3.3</td>
<td>3.4</td>
<td>325</td>
</tr>
<tr>
<td>Africa</td>
<td>97</td>
<td>2.5</td>
<td>4.1</td>
<td>118</td>
</tr>
</tbody>
</table>

II.1.2 Supply

Electric power supply is considered as a crucial issue by governments. They promote the development of electric power systems, both as a requirement for, and an important criteria of economic development. They also put great emphasis on self-sufficiency of electricity supply and energy security. The above table shows that in all non-OECD regions, the generation capacity will more than double during the 1995-2020 period.

a) Primary resources

In OECD countries, the electric power systems can rely on a very important existing infrastructure for its fuel procurement. The natural gas network is well developed. There are many efficient oil refineries, and coal transport infrastructure. In many developing countries, the situation is quite different. Fuels for thermal power generation are expensive and not abundant enough; this is the case in China where many provinces cannot benefit from cheap and good quality coal because of transport bottlenecks. This suggests the need for integrating the regional electric power resource development planning process and regional energy strategies through integrated energy resource planning procedures.

b) Generation mix unit size, operation cost

In many developing countries, the small size of the power systems prevents operators from benefiting from economies of scale at the unit level, as well as at the plant level and at the firm level. Due to the absence of efficient infrastructure for fuel procurement, moreover, fossil fuels are generally expensive. Despite the low cost of manpower, furthermore, operation costs are rather high. Important savings could be realized by developing natural gas and electricity supply simultaneously; but the market potential is often not important enough for developing the minimum infrastructure for natural gas procurement. As a consequence, the electricity supply industry has to rely on heavy fuel oil burnt in diesel engines or in boilers for base load generation.

The availability of cheap fuel for power generation is an important determinant and, from this perspective, the electric power systems of developing countries may be ranked in categories according to their long-run generation costs and their short-run marginal costs. It is of course crucial to integrate countries which may benefit from cheap long-run generation costs into regional organizations.
c) Rural electrification

In most developing countries, the population is located outside the cities; the transmission and distribution cost of electricity, obviously, is higher there than in urban areas. The cost of centralized electric supply solutions has to be compared with decentralized solutions such as motors, small diesel engines or intermittent power sources such as photovoltaic power systems, small hydro, and other renewable power systems. In small rural communities, the trend is to determine the basic collective needs — such as small communication units, refrigeration for drugs, very limited lighting use and, possibly, water pumps — and see whether intermittent sources of power could meet those needs. In larger rural centers (1,000 to 5,000 inhabitants, depending on the region’s GDP per capita), the economic rationale for interconnection, outlined above, should apply and centralized solutions should eventually replace decentralized solutions.

Financing rural electrification highlights the issue of public service versus commercial activity. Whatever the type of technology or its level of centralization, electric service is and will certainly remain too costly for customers with low income, disseminated in rural areas. It should be noted in passing that part of the rationale for creating public utilities was the need to conduct huge rural electrification programs.

Regional electricity cooperation and integration may impact on rural electrification programs at different levels:

- Integration requires the interconnection of national electric power systems. This will result in the interconnection of the main electric nodes of the region through long distance high voltage transmission lines. The villages situated close to the route of the line could - and should\(^\text{20}\) - be electrified at reasonably low costs.

- Regional integration is expected to reduce the average cost of electricity and, accordingly, favor decreases in electricity rates and further electrification.

- It may make the funding of rural electrification programs more complex by making it more difficult to recover the costs of these programs through higher rates for large consumers. In an advanced stage of regional integration, actually, these large consumers should be eligible to choose their supplier among all of the region’s electric utilities. Cross-subsidization will be threatened by the emergence of regional markets.

- Regional electricity cooperation shall also impact on rural electrification issues. Rural electrification will surely never be a place for competition between electric utilities of a region. The analyses of potential rural uses of electricity, and of social acceptance of electricity, are generally regional rather national issues. Pooling technology expertise and sharing best practice at a regional level, moreover, will surely accelerate rural electrification.

\(^{20}\) The electrification of villages situated close to the route of the line is one the best means for getting the line accepted by the public. It may, however, considerably increase the cost of the project by foreclosing the DC technology option.
To sum up, rural electrification is a crucial component of true regional electricity cooperation and integration of electricity supply industries, and a significant aspect of the contribution of electricity to sustainable development objectives. With regard to rural electrification, the mandate of the regional electricity cooperation and integration (RECI) organization could include:

- A review of national rural electrification programs and possible options for their enhancement in a regional electric market context;
- Assessment of associated rural electrification possibilities, within any regional generation or transmission project;
- Conducting a forum for capacity building and sharing of best practice and experience, and possibly creating an agency for rural electrification.\(^{21}\)

II.2 Political, Institutional and Financial Characteristics of the Electricity Supply Industry

In developing countries, most electric utilities are state-owned monopolies. Their organization generally dates back to the 1960s and was built on the model prevailing in OECD countries at that time. Generally speaking, their features correspond to what Kellow [see Kellow 96] described as distributive agencies. They are assigned electrification objectives by governments. Most of the time, the electricity consumption of the domestic sector is highly subsidized and, furthermore, distribution supports high levels of nontechnical losses. Consequently, many of these utilities hardly recover their operation cost through revenues from sales, and have to rely partly on international aid or on funding by their governments for the development or maintenance of their facilities.

Most of the time, there is no clear separation between governments and electric utilities. The electric utility, typically, is administered by the energy ministry and, as such, jeopardized by noneconomic objectives such as welfare and political goals. Its investment budget, moreover, is generally merged with those of other ministries, and the bulk of its payment arrears originate from the administration itself. In addition to these issues, encountered in countries where the government is in a poor financial situation, these electric utilities may have to face the usual issue (common in rich countries) of distributive policies. Under such conditions, the first step on the long way towards viability of the electricity supply industry is obviously corporatization.

\(^{21}\) It is to be mentioned that the South African Power Pool (SAPP) puts a fixed percentage of revenues from energy trades into a fund for rural electrification.
The financial and funding institutions involved in the electric sector of developing countries have been analyzing these issues for a long time, and urge the states to liberalize the electricity supply industry. “Most countries cannot afford to keep the status quo of poorly performing (technically and financially) power suppliers, especially under pressure for general economic reform and protection of the environment.” [see WB 93 (1)]

II.2.1 Most common paradigm: state-owned companies

In developing countries, most electricity supply industries have a national scope and are owned by the state. The poor creditworthiness of such a feature — assuming, of course, that the state has very poor financial capabilities — does not affect the integration issue, in any particular manner, and will not be commented upon herein. It is interesting to consider, instead, which type of governance is the more favorable to regional integration.

In most developing countries, the governance is such that the decisions on large investments belong to the minister of energy and/or electricity, who is in fact the chief executive officer of the state-owned company which, often, is not corporatized at all. The investments are part of the government’s budget, as are those of other infrastructures such as roads, etc. For political reasons, this budget has to be spent on high visibility investments. Power plants will always be preferred to transmission lines. It is also very difficult to avoid distribution of the budget throughout the various administrative units of the country.

State-owned companies will place high focus on rural electrification objectives and on investments in generation development. In federal states, there could be competition between states to attract federal funds so that it will be difficult for a state to participate in a generation investment in another state.

II.2.2 Financial capacity: call for institutional lenders

Very few electric utilities in developing countries are capable of financing their own development. The financial indicators, moreover, are not good enough to attract private investors under normal conditions — that is if the accounting system allows for measuring these indicators. The perceived country and institutional risks are so high, furthermore, that capital is far more costly for many electric utilities in developing countries than for those in developed countries. Most of the time, they have to resort to institutional funding, and need the support and guarantee of these institutions to raise financing.
II.2.3 Ongoing reforms

All international organizations, and especially the World Bank, are encouraging governments to disengage from day-to-day operations in the energy sector. Most developing countries are reforming their energy sector towards liberalization and the introduction of private independent generators, the objective being to attract private funding and to increase the sector's efficiency.

The ongoing reforms of the electricity supply industry will be discussed in further detail in Chapter IV. Aside from reforms towards bulk power competition, however, the removal of subsidies and the introduction of cost-reflective pricing may be considered as abandoning social policy objectives. These subsidies, nonetheless, reduce the investment capacity of electric utilities by deteriorating their financial performance and, when all is said and done, prevent these utilities from giving most of the population access to electricity services.

Describing the ongoing reforms of the electricity supply industries of developing countries is not per se within the scope of these Guidelines. It is quite clear, however, that a move towards a corporate structure for the electricity supply industry will be beneficial to the development of the electric sector, and that the removal of subsidies\(^{22}\) will help to make electric utilities financially viable.

II.2.4 Relations with neighboring countries

Good relations with neighboring countries are of course a prerequisite to regional integration of national electric power systems. Most of the time, a political regional organization may help. Conversely, regional integration of electric networks should favor the emergence of regional organizations that, in turn, will enhance the region's political integration.

Regional integration often originates in countries sharing the same river basin, and will depend on the exploitation of the hydroelectric potential of this river. There are several issues pertaining to the use of a river for hydroelectric generation: change of the river flow, navigation, flooding of areas, displacement of population, fishing, etc. These issues will have to be dealt with at a political level.

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\(^{22}\) The case for the removal of subsidies has been made by the IEA in *World Energy Outlook*, 1999 insights. *Looking at energy subsidies: getting the price right* [see IEA, 1999 (4)]. Actually, most international institutions support the removal of any subsidy because price distortions lead to misallocation of resources. If electric supply is seen as a public service, they recommend that the state subsidizes electricity consumption.
II.3 Taxonomy of the Electric Power Systems Relevant to Interconnection Issues

A taxonomy of the electric power systems relevant to regional integration shall be established in parallel with the identification of the relevant regions. Ideally, this taxonomy should mainly focus on the technical and economic aspects of the energy and electric system, rather than on their political and institutional aspects. In practical terms, since political barriers to regional electric integration are very important, countries that have initiated some form of regional economic cooperation or integration will be in the best position to enter the process of integrating their electric power sectors.

II.3.1 Economics of power generation

When considering the economics of power generation as well as the energy system, three categories of countries/regions may be identified. These three categories represent a growing order of economic interest for regional integration. This order is linked to the existence of what economists call a comparative advantage for production of electric power commodity.

a) National electric power system and effect of scale

This first category shall include electric power systems that have no particular inexpensive power resources. They could, however, profit from the conventional benefits of electric integration which are:

- reducing the cost of long-term uncertainty linked to the adequacy of supply to demand;
- sharing reserve capacity;
- benefiting from load diversity,
- benefiting from the effect of scale at the generation unit level, at plant level or at the level of the company (series effect);
- increasing bargaining power with fuel suppliers and, generally speaking, for equipment.

As in E7 countries, particularly in the former UCPTE, this category does not ask for a strong regional integration. What is to be done, instead, is to provide a forum where the electric utilities will exchange information on their load, maintenance programs and marginal cost. A possible issue is paying for the investment in the interconnection network, which could be more important — although surely still modest compared to an investment in generation — than in more densely populated regions of E7 countries. The second issue is that the larger is the network, the more complex will be the operation.
b) Difference in access to transportable primary resources

Some countries in the region may have cheap access to fossil fuel resources or may offer better site conditions for a power plant. In some cases, it could be cheaper to transport electricity rather than fuel; this is generally the case for coal and, under certain conditions, for natural gas or oil products.

b.1) Transport of electricity versus transport of natural gas

In its studies of natural gas and electricity networks in the Mediterranean basin, the Office Méditerranéen de l’Énergie (OME) has been comparing, over an extended period of time, the respective economics of natural gas and electricity transport for electric power generation [see Hafner 95 & Hafner 00]. Its latest conclusions show that up to 1,500 km, and for capacity under 1,300 MW, electric transmission might be a better option.

The economics with regard to that issue are rarely decisive; in theory, there is no clear advantage for one or the other solution. Other energy policy factors will decide the issue: in addition to the transit of electric power, the interconnection line can also be used to capture the benefits described for the first category, and the interconnection line can feed distribution networks, on its way between the two load centers. From another point of view, natural gas transport can benefit from economies of scope, considering that natural gas may be used for other purposes than electric power generation. If transported, natural gas may be stored for utilization in combustion turbines in case of emergency or of peak load, or for security reasons. Finally, the import expenditure for electricity transport will be more important.

In both cases — electricity or natural gas transport — an important investment may be required. For this investment to be realized, the countries of the region shall trust each other; if they do, regional integration will be very advanced.

Throughout the world, regional natural gas networks develop more quickly than electric networks. This is the case in South America. Even if natural gas production and transmission projects cannot be viable without the certainty of a substantive electric market, and even if electricity will be the only market for many years, the options of electric versus gas transmission are rarely studied.
c) **Existence of an important hydroelectric potential or other primary resources that cannot be transported**

The current trend towards electric power competition certainly offers several positive aspects. It should be recognized, however, that it puts capital-intensive and large size investments (such as hydroelectric schemes) at a disadvantage. Although they may present important benefits, hydroelectric projects cannot easily be managed in a strict competitive framework. To implement a structure enabling the emergence of large hydroelectric schemes — pursuant to sustainable development objectives — is crucial.

Most of the current efforts are spent on developing regional integration on this basis and, in the absence of political issues or financial constraints, this category will develop naturally. This is the case for countries where rivers are used as political borders: the two neighboring countries have to cooperate to build and operate the common hydroelectric dam. This is also the case for river basins where upstream countries generally own most of the hydroelectric potential but do not have the financial capacity to assure its development.

### II.3.2 Financial, political and institutional features

The financial, political and institutional features of the countries of the region will mostly determine the challenges faced when integrating the region’s electric power system.

For developing countries, the primary incentive to follow international organizations’ calls for better cooperation between countries is, obviously, the lack of money for economic development. The commitment of a region is a better guarantee for investors than the commitment of isolated countries; the country’s risks will be reduced, and it will be impossible (or more difficult) for a given country in the region to cancel an agreement if the neighboring countries are part of the same agreement. To attract investments, the regional organization will have to devise an institutional framework that will consider international participation, primarily, and, as such, will depend on laws, protocols, charters, and codes of conduct that are recognized at an international level. To sum up, the mere fact that countries meet to devise a regional organization will reduce the risk perceived by potential investors.

Regional integration will be facilitated, obviously, if the countries of the region have similar political and institutional structure for their electric power industry.

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23. At least three regions out of four where the World Bank spends some effort towards developing regional integration belong to this category [see IV.3, CIER, Great Mekong Sub region, and SAPP]. Only ECOWAS is not one of them.
When the structure of the national electricity supply industry is already significantly liberalized — up to the Third Party Access model — the emphasis has to be put on the development of new investments rather than on trade matters. When this structure is still vertically integrated with at most a Single Buyer model, on the contrary, countries will surely recognize the benefits of coordination and planning, but they will also be more reluctant to liberalize trade. To sum up, the steps taken by the countries towards liberalization of their national electricity supply industry will impact on the initial mandate — and the challenges — of the regional organization.
Chapter III

Organizing and Implementing Regional Electricity Cooperation and Integration

These Guidelines should constitute a useful resource for those responsible for planning, or supervising the planning, of the development and operation of a power system. It specifically addresses the concerted implementation of interconnections in regions where energy development has not reached full maturity and where local markets alone cannot justify the construction of large-scale facilities capable of minimizing the cost of electricity service to all customers and promoting sustainable development.

Before the implementation phase, generally speaking, the development of regional interconnection projects should be managed in two main phases.

(i) The development of the region’s electricity power system should be studied in a sustainable development perspective, notwithstanding, as much as possible, institutional, political and financial barriers or incentives. This phase should be managed by regional organizations with the possible funding and expertise of international institutions.

(ii) Once some interconnection project(s) have been proved sustainable, the institutional, political and financial stakeholders have to enter the project(s) and, if agreed upon between them, proceed with their implementation. These two phases do combine, actually, because the possible interconnection projects undergoing economic and technical feasibility studies generally benefit from the support of a group of participants that will also be involved in the institutional and financial studies.

Finally, regional integration will consist of:

- the creation, under the governance of the governments of the region, of a regional organization responsible, partly or entirely, for the coordination of the actors of the electric power industry, the harmonization of the planning and operating rules, and for the minimization of the overall cost of supply;

- the management of power generation and transmission projects that are justified from the perspective of sustainable regional development.
Most electric power industries are undergoing a reform of their structure to enable the emergence of a competitive electric power market. This market is dedicated to cost-effective electricity supply and cost-reflective electricity pricing. In some OECD countries, it leads to departing from cost-plus or rate of return pricing of electric supply and numerous electric power systems, to a few integrated power markets were pricing is based on competitive bidding mechanisms.

In developing countries, most of the electric power industries are publicly–owned and have a vertically integrated monopolistic structure, self sufficient for electric power supply, with weak if not absent interconnections with neighboring countries. They are faced, moreover, with the issue of financing their own development, as well as the maintenance and refurbishment of the existing power systems. They are under pressure from international financing institutions and (mostly foreign) investors or lenders who will advocate the liberalization of their electric power industry as a precondition for granting loans or/and for investing directly. The minimum scope for these private investments should be operation franchises for generation and transmission facilities, or new power plants, or significant transmission projects.

Regional integration is a lengthy process, it may develop over decades. The structure of the regional electricity market may evolve according to the development needs and the financial capability of the countries of the region. Some experts, arguing that transition periods are very long, hold the view that the structure of the regional market shall be, from the outset, similar to that of a competitive power market.
III.1 Regional Integration: How to Proceed?

The primary objective of regional electricity cooperation and integration is that the target and transitional regulation and structure of the regional electric power industry shall facilitate its contribution to sustainable development objectives and, particularly, to make the best use of the regional energy resources.

This implies:

• Planning the development of resources for the national power systems, in a sustainable development perspective, as part of the development of resources for the regional electric power system, taking into account the regional energy system and regional energy policy and strategy;

• Setting up legal frameworks, rules, protocols, coordination and regional mechanisms and bodies responsible for:
  1. the reliable, secure and cost-effective operation of the regional interconnected network,
  2. the introduction, if deemed useful, of a regional electricity power market (bulk power market, free access to the transmission network);

• Implementing mechanisms and structure for the development and the operation of regional electric power projects;

• Setting up a regional organization that will be responsible for the implementation of these actions, and for the operation of the regional interconnected power system.
III.2 Planning the Development of Resources for the Electric Power System in a Regional Perspective

Ideally, regional integration shall be based on sustainable development objectives, which are economic, environmental and social objectives. The operation and development of the regional electric power system has to be optimized, accordingly, with regard to these three objectives/criteria, notwithstanding the current political, institutional and financial features and issues. The regional organization of national power systems has to be devised to help pursue these optimal operation and development objectives. Conversely, some suboptimal (but more robust and feasible from a political, institutional and financial standpoint) operation and development plans shall be devised.

These development plans shall indicate, for the facilities of regional interest, the technology, the capacity and the location of the power generation facilities together with the time schedule for commissioning these facilities. Given the location of the supply and demand nodes, the development of the regional transmission network — and especially the cross-border transmission lines — will also be scheduled.

This regional electric power development plan should be considered as a reference for all national and/or independent power projects. Furthermore, it should contribute to estimating the economic, environmental and social surplus accruing from the full regional integration of the electric power industries.

The experience of E7 countries lead us to express some reservations about conventional electricity planning procedures: these reservations stem from both the uncertainty of the future, and the possible subjectivity of planners which can be characterized as “reverse adaptation.” In a noncompetitive framework, the organization tends to adapt the ends to the means. Module 3 (Resource Development) provides the reader with many details on how the “system resource planning” concept introduces flexibility in the development plan to deal with uncertainty.

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24. Even if it is increasingly questioned in OECD countries, the reference to a development plan will be assumed in these Guidelines without any further justification.

25. In these Guidelines, from now on, “surplus” will designate the economic, environmental or social cost reduction that may accrue from regional electricity cooperation and integration (RECI). The economic surplus will be understood, generally, as the difference in the cost of electricity for the region without and with a given level of regional cooperation and integration.

26. Ansley Kellow [see Kellow, 96] addressed the issue encountered with conventional — often deterministic — electricity planning methods, and proposed the so-called Least Cost Utility Planning concept, which is quite similar to the “System Resource Planning” concept presented in Module 3 of these Guidelines. In the glossary of his referenced book, he defines reversed adaptation as the “tendency for inflexible sociotechnical systems to adapt ends to suit the means at their disposal”.

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The terminology chosen — “resource development plan” rather than “expansion plan” — bears witness to our adherence to this concept which is aimed at avoiding overinvestment and rigid options, as far as possible, and at resorting primarily to demand-side options and energy conservation to balance demand and supply. The features of the electric power systems of developing countries — which often require an increase of electric supply at a very sustained pace — are not being underestimated in these Guidelines.

The current section aims at focusing on the main issues encountered when seeking a regional agreement on a regional resource development plan; the methodology for planning the development of national resources is presented in Module 3.

This regional resource development plan could be conducted in two steps:

- As a first step, a draft and very simplified master plan of the current and long-term ideal energy and electric power flows could be studied. The objectives of such a study would be (i) to promote the idea of regional electricity cooperation and integration in the political arena, (ii) to provide support for the organization of the following steps of the study, (iii) to help engage any action that requires information on the development of the electric power system, (iv) to focus on the existing and potential synergies between the different energy sectors of the region.

- As a second step, the regional generation and transmission expansion plan will be studied more thoroughly. It should start by setting the framework and the main assumptions of the study. Several of these assumptions should have already been discussed when drafting the simplified master plan. The load forecast should be carried out and, thereafter, the generation and transmission master plan will be elaborated.

The results of the first step will be presented and, most of the time, the decision to continue with the second step should have already been taken. The simplified master plan, however, should help the planners present the main options of the regional plan for discussions at a political level and open the planning process to nonexperts.

It is crucial to show, from the outset, that each country will win from regional electricity cooperation and integration. At each of these steps, accordingly, the surplus has to be estimated. With the help of game theory, Module 4 demonstrates that a formula for sharing surplus can be found that will satisfy all the national electric power systems.

27. In these concepts, coordinating and trading electricity with neighboring electric power systems is usually ranked as one of the least cost options [see Kellow 96, British Columbia 1990 Plan]. This is a benefit of RECI which is commonly recognized, but our aim is to go beyond this agreement and to plan the development of the national electric power systems in a regional perspective.
III.2.1 Simplified master plan of the regional electric power system accounting for the energy system

From the outset of the RECI process, it is important to get a schematic idea of the current and long-term energy and electric power flows. The following questions need to be examined:

- What will be the national loads in a 5-year to 20-year time frame, and where will they be located?
- Where are and where should be situated the main primary energy sources and the main sources of inexpensive electricity?
- What are the main electric power links that could be built?

In the course of the planning process, detailed models of the electric power system will have to be used. A draft simplified model, however, should help figure out the main issues to be addressed in the development of a regional electricity power system, as well as the expected surplus to be shared between the stakeholders. It should help, in particular, to coordinate the development of the national energy systems, together with the various options for the regional electric power system. This simplified study should help answer questions such as: where to build the power plants, what to develop, natural gas or electricity transmission links? It could contribute, furthermore, to convincing politicians of the potential benefits of regional integration, and of the necessity of fostering the regional integration process.

There is no precise methodology to be recommended for this step; very few software programs should be used, the primary objective being to convince politicians of all the advantages of regional electricity cooperation and integration. Most of the required information will be provided by the system operator of each country. This step will also help harmonize national data, including existing electric power master plans.

The national electric power systems could be represented by a very limited number of nodes. These nodes should represent either:

- Existing and already committed power plants, or group of power plants, with their net capacity and operation and fuel cost, excluding every subsidy or tax. Plant retirements will be accounted for.
- Demand expressed by a peak demand and a load factor\(^\text{28}\).

\(^{28}\) The various demand nodes considered for a given country will not be necessarily comparable in terms of electricity power (MW); they should be of interest, rather, for cross-border interconnections.
On the same model, the future primary energy sources should be located. Existing, planned and potential gas transmission networks, pipelines, and large power transit links should be represented. Candidate power plants will be represented by size, capacity, operation cost and maximum yearly generation. This simplified master plan will help estimating the electric power balance by node for several horizon years, the power plants to be added, and the main transit of electric power, either national or regional.

It will not permit, however, to estimate the full benefits accruing from the coordination of the formerly isolated power systems since the load diversity, the improvement in reliability, and the reduction in operation cost (which may, in itself, justify interconnection projects) cannot be quantified. It will, nevertheless, give a rough idea of the surplus that may arise from regional power projects and important electric power or energy transits, and it is crucial for devising a true regional development plan.

### III.2.2 Setting the framework for the regional resource development plan

When setting the framework for the regional electric power system development plan, the countries will have to refer to the objectives of sustainable development. This will result in communication, discussions and, if need be, agreements on specific issues relating to economic, environmental, and social objectives. It is likely that these discussions have already taken place in other arenas. As far as the framework for the resource development plan of the regional electric power system is concerned, the following issues will have to be addressed:

#### a) Economics

The following macroeconomic assumptions will have to be agreed on between the countries of the region.

**Common currency.** A common currency will simplify the study. The US dollar will generally be the currency of choice. Countries will have to provide an exchange rate between their domestic currency and the US dollar. If there is any difficulty in getting such data, or if this data appears to be very inconsistent with actual rates — and considering that regional integration should not be based on any price distortion — all the costs could be expressed directly in the agreed common currency.

**Discount rate.** One of the agreed values should be consistent with the expected Weighted Average Cost of Capital (WACC), resulting from the financial evaluation of the regional projects, if any\(^\text{29}\). Another value could reflect sustainable development objectives.

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\(^{29}\) Some authors argue [see Kellow, 96] that it is important to consider a discount rate consistent with the cost of capital for the private sector in order not to “bias the analysis in favor of supply-side approaches to electricity planning at the expense of demand-side management.”
Fossil fuel prices (delivery cost at plant)
It is very important to analyze the price of fossil fuels, delivered at plant border. The different elements — taxes and subsidies, transport cost, refinery cost and margin if any, and import price (Free On Board, and Cost, Insurance and Freight) — have to be identified. Some in-depth inquiries have to be made to capture the cost for transmission and distributing fossil fuels in the region.

Cost reflectiveness of fossil fuel prices. Even if national price distortions (taxes or subsidies) could be of some interest for a given country, they may lead to uneconomic decisions at the regional level. Economic costs, rather than prices for fuel procurement, shall be considered.

Finally, the regional organization will have to consider forecasts for international prices of fossil fuels.

b) Balance of service, balance of trade
Notwithstanding the current trend towards globalization of the economy, there is still some sense for developing countries to value domestic expenditure versus imports. True regional integration should lead them to consider the balance of trade and the balance of service at a regional level. This could be expressed by a multiplier for imports and exports services, equipment and commodities. This multiplier may be not explicitly assessed; countries will rather prefer to define a minimum domestic share. In any case, the premium given to domestic input has to be discussed and clearly assessed by the countries of the region.

c) National energy policy
It is important that, from the outset of the regional integration process, all stakeholders understand the national energy strategies; this is particularly true in the case of the existing national development plans of the electric power systems.

The national objectives related to energy independence — especially the requirements, if any, for a minimum share of domestic electric power generation capacity — will have to be expressed to the other stakeholders.

A common agreement on the value given to the quality of service has to be reached. At this planning stage, it may be expressed by cost of unserved energy or loss of load probability.
d) Environment

The emphasis put on environmental issues such as airborne pollutants, carbon dioxide emissions or other releases from power plants, is less important in developing countries than in OECD countries. Environment, nevertheless, has already been acknowledged as a very important issue in non-OECD countries such as China, Mexico and Brazil.

Most of the power generation technologies make an important use of water resources; this is obviously the case for hydroelectric power plants. Many hydroelectric power projects are discontinued or rejected because their environmental impact is too negative. Apart from the displacement of population, the most important of these impacts are the reduction of the river flow, either by evaporation or by derivation, and the change in the monthly pattern of the river flow. This could be very detrimental for countries where water resources are scarce.

In developing countries, regional integration may start with the exploitation of common water resources; this is currently the case for the river Senegal in Western Africa, among others. The use that will be made by the upstream countries of the region will impact on the use of the water that can be made by downstream countries; this often raises disputes between countries. The simplest way to avoid these disputes is to account for the environmental cost burden of downstream countries in the sharing of the surplus.

Even though the issue may be less crucial than in OECD countries, the power projects must pass an environmental impact assessment to obtain environmental clearance. Given the number of independent stakeholders involved in regional projects, that may delay the commissioning of regulation electric power projects, it is recommended to proceed to site banking.

e) Social objectives

When dealing with social objectives, the contribution of the electric sector is considered as crucial. That everybody shall have access to the electricity service is a common and widely accepted objective. By pursuing cost savings in electricity generation, regional integration should contribute to achieving that goal. The national policies and measures aimed at giving access to the electricity service, however, will need to account for regional integration. This will be discussed in Module 2.
III.2.3 Electricity demand forecast

The methodology for forecasting the regional electricity load is described in detail in Module 2. A starting point will be the existing national electricity demand forecasts; they are to be harmonized and combined to assess the regional electricity demand (MW and GWh). This regional demand forecast is to be split between the different nodes identified in the simplified master plan of the regional electric power system.

a) Unbiased evaluation of the electricity market

The basic data will have to be collected from the national electric utilities which, most of the time, are state-owned. National decision-makers have a natural tendency to put too much emphasis on the social objectives of the development plan, at the expense of its economic viability and to overestimate future demand growth. Opposite, institutions responsible for the financial evaluation of the interconnection project will hold a conservative position on the demand growth rates, in order to minimize their risk. To facilitate a consensus on load forecasts, these forecasts should be elaborated with a very transparent and clear methodology, in which the main determinants of the demand growth (population, GDP, electrification rate/off grid electrification) will be analyzed very thoroughly. These determinants will be subject to review by the officials of the regional organization.

Harmonization of the main determinants of electricity consumption

Most of the time, the identification of regions for electric cooperation will come from regions with existing commercial flows and comparable macroeconomic features. It would be very surprising that, in the long-term, the demographic and GDP determinants evolve independently for neighboring countries; accordingly, the macroeconomic determinant of the load forecast will have to be harmonized. The combination of different values for these determinants — which will set the scenarios for demand growth — will, similarly, have to be harmonized by the countries of the region.

b) Ability to pay

In most developing countries, the consumption of electricity is subsidized; this applies particularly to domestic customers. There could be three ways of subsidizing electricity consumption: 1) not recovering the supply cost through the tariff; 2) not recovering the electricity bills and nontechnical losses; 3) expanding the distribution network to zones with very low return on investment. It has to be considered whether and/or how these subsidies can be maintained in an integrated market.
c) Collecting and forecasting the evolution of national load curves

One of the foremost rationales for interconnection is the savings that may accrue from load diversity. To fully address load diversity, the yearly load curve (usually with hourly values) of each country has to be collected. Ideally, this data should be analyzed by sector and main use, in order to forecast their evolution in the most accurate way. If, currently, there is load shedding, the actual load curve may be very different from the one where there is no generation capacity constraint.

d) Demand-side measures

In the concept of resource development, demand-side options, such as load management and energy conservation, are considered as primary options to be used for balancing demand and supply.

III.2.4 Planning the development of the generation capacity and associated transmission network

The methodology for elaborating a national resource development plan is described in detail in Module 3. For the region, a resource development plan has to be proposed. Compared to the simplified master plan of the regional power system described above, it should enable:

- the proposal of an optimal electric power generation and transmission development plan for the region, and the proposal of some suboptimal plans, that should account either for uncertainty and for different levels of regional integration;
- the assessment and analysis of the surplus of regional integration;
- the setting of a framework for detailed feasibility studies of regional investment, transmission studies most likely: feasibility study of the line, and load flow, short circuit and stability studies;
- preliminary study of the transmission line(s): route, assessment of environmental impact, main characteristics.

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30. At a regional level, these options should not have to be considered, as they should have been accounted for as primary options at the national level. This highly depends, of course, on the integration level of the region.
a) Some modeling characteristics

As part of the surplus will come from the diversity of national load patterns, the load curves at each node will have to be represented with sufficient details.

In a development plan, optimizing the daily operation of the power system is out of the question; the existing power plants will be represented by their variable cost, their forced outage rates given as a percentage, and the required average period for maintenance.

If an optimal management of the existing and potential hydroelectric resources is of importance, the management of the hydroelectric resources will have to be modeled in great detail; for reservoirs, monthly inflows shall be considered.

At this stage, transmission losses can be neglected. The availability of long interconnection links, on the contrary, is a parameter of value to dimension the reserve capacity.

b) The regional development plan

Finally, the regional development plan will consist of a schedule for the commissioning of power plants with their technology, unit size and location, and of a corresponding schedule for commissioning interconnection lines and for the reinforcement of national transmission systems. In the absence of any constraint on international power exchanges, this associated transmission development plan will probably include new transmission lines of a higher capacity than those necessary were the national power systems to remain self-sufficient.

c) Assessment of the surplus arising from regional integration

The maximum surplus accruing from regional integration will be assessed by comparing the overall generation and transmission cost31 of the regional electric power system with the sum of the overall generation and transmission costs of the electric power systems of each country, considered as isolated.

In between these two extreme scenarios — full integration versus isolated development — several intermediate scenarios will be studied: the interconnection lines can be limited in capacity; the lines can be used as an emergency supply before loss of load; national electric power systems may wish to remain self-sufficient, etc.

The corresponding national electricity balance have to be assessed by comparing the national demand with the power supplied by domestic power plants, for each time period.

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31. This overall generation and transmission cost shall consist of operation, maintenance and capital cost of generation and transmission facilities.
This should also be helpful in analyzing how the interconnection lines are used. It is very important to characterize the surplus in order to implement the organization which will, probably, recover most of the surplus: is there a need for regional coordination of national planning; is there a need for a central dispatch of the regional generation means; or will some exchange of information between the national dispatch centers be sufficient?

A thorough analysis of the nature of the surplus will help determine how to share the costs of the investments dedicated to regional integration, and how to ensure that the subsequent benefits will be recovered by the investors. An issue before sharing the surplus will be to reach an agreement on the value of environmental and social surpluses.

d) Remarks
The assessment of generation and transmission means should include an environmental impact study.
The proposed interconnection transmission network will have to prove stable in the most severe operating conditions, and capable of supplying the load in normal conditions as in N-1 conditions, that is in case of the loss of a generation or transmission unit.

e) Conclusion
The regional generation and transmission development plan shall be considered as the baseline, and as optimal according to economic, environmental and social criteria.

It should be flexible enough to facilitate the periodic reviews that may be required to adapt to the actual load, to the existing generation and transmission capacity, and to the actual power market conditions. In this regard, some suboptimal development plans will have to be studied to allow for deviation from the economic optimum.
III.3 Setting the Framework for the Technical Operation of a Regional Electric Power System

In most developing countries, the region will be defined as a group of national power systems, generally self-sufficient, operated by a national control center (NCC), and not or poorly interconnected.

It is to be remembered that the main objective of the electric power system is to ensure continuity of service of load demands and, consequently, to ensure secure, safe and reliable operation of the system. This objective shall be pursued at both the national and the regional levels.

Regional integration of national electric power systems is a step-by-step process, starting with a limited coordination of the operation of regional generation resources and resulting in the setting up of an interconnected regional transmission network. The integration process shall improve the secure, safe, reliable and cost-effective operation of the power system. To make that process work, the region has to participate in the operation and management of the national electric power systems.

To this aim, the responsibility of the regional organization should, at least, be to:

- set common operation and management rules to be complied with by the national electric power system;
- coordinate and monitor the operation of the regional electric power system.

In the context of a more in-depth integration, the responsibility of the regional organization should extend to the real-time operation of the regional interconnected system, in close collaboration with the national control centers.

Liaison between the regional and national levels could be implemented through the following actions:

- agreements between the parties;
- setting rules and guidelines, and a grid code;
- the establishment of a regional coordination center (RCC) which, in close collaboration with the national control centers, will ensure the technical operation of the regional interconnected system.
The agreements between the parties, as far as the safe and reliable operation of the system is concerned, should deal with generation, transmission, and system operation criteria and rules.

The main criteria and rules are presented here below.

a) Generation criteria and rules

These criteria should account for the capability of the generation capacity to supply the load, in normal conditions as well as in “emergency” conditions, such as forced outage of generation and/or transmission means.

This mainly consists in assessing:

- the availability of the generation capacity and its type of use (base load, intermediate load or peak load);
- the reserve capacity (automatic generation control, spinning and not spinning reserve, replacement reserve), the conditions for which this capacity should be used to face the hazardous variations of load and the risk of losing one or several generation units;
- the capability of supplying reactive power.

b) Transmission criteria and rules

The capability of an electric power system to supply the load depends on generation, in the first place, but also on the capability of the interconnected transmission system to ensure load transits, at any time, in normal as well as in “emergency” conditions, such as forced outage of generation and/or transmission means.

This mainly consists in agreeing, on a regional level, on:

- voltage deviation limits and conditions related to the supply of the corresponding reactive power;
- conditions for the transmission system to sustain loss of transmission or generation means;
- agreement on the N-1 rule, as far as the transmission is concerned.
c) System operation criteria and rules

To ensure a safe and reliable operation of the regional electric power system, the regional organization shall coordinate and manage other basic functions of system operation such as:

- information exchange;
- operational planning studies;
- maintenance coordination of interconnection between countries;
- schedules and monitoring of electric power exchanges between subsystems;
- control of the demand-supply balance at the regional level;
- management of the overall generation reserve capacity of the region;
- measures to be taken in emergency situations attributable to a network incident (load shedding, system separation, generation tripping) and to restore the network afterwards;
- common training for the operating staff of the regional and national electric power systems.

Module 8 gives more details on the functions of the Regional Operation Control Center of the regional organization.

III.4 Transition Towards a Regional Electric Power Market

III.4.1 Background

Most of electric power industries are undergoing a reform of their structure to enable the emergence of a competitive electric power market. This market is dedicated to cost-effective electricity supply, and cost-reflective pricing of electricity.

Generally speaking, the types of institutional structure targeted or implemented in a transition phase can be characterized as follows:

1. the single buyer model, where a single entity purchases power from all producers on a contractual basis;

2. the Third Party Access (TPA) or open access model, where access to transmission system is given to independent power producers. That model can be divided into two sub-models:
• the pool model, where suppliers have to sell their supplies to a power pool market;
• the bilateral contracts model, where the suppliers sell directly to customers, the power pool being used to ensure the balance between supply and demand.

Virtually all electric power industries are in transition; moreover, the target structure for the industry is still shifting: nobody can say when this target will be reached and it is virtually impossible to meet an unstable and ideal objective, such as true competition.

III.4.2 Conditions for and structure of the electric power market in developing countries

Third Party Access models have been devised for large size and mature electric power systems with numerous and diversified generation facilities and large interconnected transmission networks supplying numerous large customers. Many of the electric power systems in developing countries do not present such characteristics.

The current size of most of the electric power systems in developing countries does not allow for the implementation of a true competitive electric power market with a Third Party Access model which requires:

• generation means, numerous and diversified enough to enable merit order ranking;
• transmission networks large enough to enable a merit order dispatching of generation facilities;
• a substantial number of large customers.

Presently, most electric power systems are supply-constrained, either at the generation or at the transmission level; consumption is mainly made of small customers and electric power exchanges with neighboring countries are very limited by the capacity of cross-border interconnection lines. The viability of a competitive electric power market is very limited, accordingly, and, most of the time, the Single Buyer model (the nearest to the current vertically-integrated structure of the electric power industry) is the only model practicable. This model may evolve towards more competition as it increases in size. This is true at a national level, but all the more true at a regional level: there is a clear link between regional integration, implemented through an interconnected network, and the introduction of competition in the regional electric power industry. Without any or very little interconnection capacity, regional market competition is only wishful thinking.

• The region increases the size of the market for independent power producer, hereby reducing the market risk.
• A regional market enables the introduction of large size generation means that would not be viable in national markets.
Potential large industrial customers would be better attracted by electricity supply from large regional systems rather than from isolated national systems with restricted supply capacity. They would also be interested by the possibility to choose a supplier located in another area than their own.

As outlined in section 4.6, however, the regional organization should offer the necessary liabilities to potential investors.

To sum up, the liberalization process is likely to be longer and more incremental in developing countries than in industrialized countries, considering its dependence on the size of the electric power systems. Conversely, this dependence of the market on the size of the systems should be conducive to regional integration. A stable and enhanced regional organization may offer better liabilities for independent power projects, and the size of a regional electric market may be more appropriate to a Third Party Access model.

The regional organization will have to put in place mechanisms and structure — which are presented in detail in section 4.6 — to initiate the cooperation and integration process on the basis of the current structure of the national electric power industry and its ongoing reform, and to gradually evolve to the target market structure presented below.

a) **Current structure ongoing reforms of the electric power industries in developing countries**

Virtually all electric power industries in developing countries were state-owned and structured — many still are — as vertically-integrated monopolies, self-sufficient and autonomous for electric power supply, with weak if not absent interconnection with neighboring countries.

In most of these countries, reforms of the industry’s structure towards liberalization are ongoing or planned. The main features of the reforms may be summarized as follows:

- single buyer model;
- public utility or privatized company (owner or operation franchise);
- vertically integrated system in some countries or, in others, unbundling in various ways;
- unbundling of generation (in one or several entities), transmission and distribution (in one or several entities);
- integrated generation and transmission activities, and separation of the distribution activity (in one or several entities);
- separation of the transmission activity from generation and distribution which are merged in several geographical entities;
- transmission activity is generally maintained as an integrated entity;
• independent power producers (IPP) that sell their electric power to the integrated system or to the transmitters;

• each country constitutes an autonomous and self-sufficient control area managed by a national control center (NCC), owned by the transmission entity;

• bilateral contracts for electric power exchanges between countries through interconnection lines.

The usual features of the reforms outlined above do not allow for a true competitive power market but prepare the ground for it. At the regional level, the issue is similar: there is no true competitive electric power market but bilateral contracts (signed before the start of reform process) for power exchanges between countries. It is worthwhile mentioning that some countries in South America have already radically reformed their industry to introduce a true electric power market.

b) Medium-term structure of the regional power market

The implementation of a regional electric power market could target a Third Party Access model: bilateral contracts or power pool or a mixed option. This is a very long-term target, however. In the medium term, accordingly, the regional organization will have to manage a transition structure allowing for different national market structures.

A transition structure that could be devised for a medium to long-term period (10-15 years), could be the following:

Structure of national electric power industries for:

• Countries where the three activities of the national or subnational electric power systems should be separated entities: generation, in one or several entities; transmission; distribution, in one or several entities;

• Countries where the three activities are unbundled but remain in an integrated structure.

Generation

• Most countries have one or a few national private suppliers. Some countries have a principal state-owned supplier. Some of these suppliers could form an integrated generation system.

• There should be a possibility for IPPs in every country, even with different types of market: 1) contract with a single national buyer; 2) contracts with customers at a national level (TPA); 3) large IPPs that could contract outside the country, at a regional level.

32. The following section does not nor could not exhaust all the different possibilities. Apart from the options already adopted in western countries, some more could be devised. These Guidelines advises on the objectives to be realized but the decision about the best means should be left to the concerned parties.
Transmission

- Typically, one transmission entity (one system operator) for each national or subnational system;
- Possibility for private transmission entities in the case of large interconnections.

Consumers of two kinds:

- Domestic consumers supplied by a distribution entity. In some countries, these distribution entities would be part of a national integrated system; in other countries, they would be allowed to choose their supplier at the national level as well as at the regional level.
- Large consumers eligible for contracting directly with suppliers at the national level as well as at the regional level.

Technical management and operation of the regional power system

- Each national or subnational power system will be managed and operated in real time by the control center, under the guidelines, rules, coordination and real-time instructions of a regional coordination center (RCC).

Market

The regional market will be an aggregation of countries, each with its own market. The national markets could be classified into four categories:

- Single Buyer — Vertically integrated power system (few countries at the intermediate state);
- Single Buyer — Nonintegrated power system
- Third Party Access — Bilateral contracts (most of the countries at the intermediate state);
- Third Party Access — Pool model (few countries at the intermediate state).

Even at an intermediate state, the regional market should be efficient. It will be the aggregation of the kinds of national markets outlined above, with a likely predominance of the “TPA — Bilateral contracts” model.

A typical competitive market, regional as well as national, could be similar to the market presented in the following paragraph.
c) Typical structure of a competitive electricity market

A quick review of the structure of liberalized or liberalizing electric power industries showed that the electric power industries are all structured with the following elements. With the exception of the regulator who shall remain independent, these elements may be grouped (or not) in a single entity:

- competing power generators;
- a system operator financially independent of markets participants (producers, distributors, customers). The system operator will operate the transmission network. The system operator can be the owner of the network (or of part of the network), or some other entity, such as the transmitters\(^{33}\);
- one or several distribution utilities, benefiting from a franchise in a given geographical zone;
- eligible customers (eligibility is generally defined by a given level of consumption of electricity) that can contract with any of the suppliers;
- a market regulator.

The regional organization, at least, will have to coordinate the system operators as well as the regulators.

This module presents briefly [see Chapter III.6] the possible functions and structure to be implemented at the regional level during this transition stage, as well as the main features of the process towards the progressive implementation of a RECI Organization.

\(^{33}\) In order to ensure that it has no other interest than the optimal management of the grid, the system operator may be different from the owner of the network.
III.5 Evaluation and Development of Regional Projects

Regional electricity cooperation and integration is dedicated to the optimal operation of existing generation assets and to ensuring that the required regional generation or transmission investments are developed in due time and in an optimal way with regard to sustainable objectives.

How is it possible to ensure that optimal investments are actually developed, and that investments that are not part of the optimal portfolio do not lock out optimal investments? The answers mainly rest on the role and efficiency of the RECI Organization with regard to the evaluation and development of regional projects.

III.5.1 Background

In virtually all regions, regional power projects — defined as projects that will affect the electric power systems of more than one country of the region — have already been developed or, at least, have been scheduled, or are currently underway. The RECI Organization shall be positioned to manage and, when commissioned, make the best use of these regional investments.

Ideally, the RECI implementation process shall be deeply engaged before proceeding to the evaluation and development of regional projects so that investors can appreciate that RECI originated in a true willingness to cooperate and was not specifically created to attract investors to a specific project. Conversely, if politicians are not appealed by the implementation of high visibility projects, their support for the RECI process will surely be more difficult to enlist.

Finally, the RECI process and, particularly, the setting up of a RECI Organization shall parallel the development of “prototype” interconnection projects. Most probably, since the RECI Organization is not yet finalized, the development of these “prototype” projects will have to be handled by institutional funds.

If OECD countries are accumulating experience in cross-border energy trade, there is very little experience in international projects in the electricity sector intended for regional integration in developing countries. Most of the time, one investor (private or public) will take the risk and negotiate with potential customers. In the context of developing countries with very limited financial resources, such risk sharing may be impossible. Other solutions, therefore, have to be devised.
III.5.2 Role of the RECI Organization

If a regional organization already exists and has its sights on a RECI Organization, its involvement in the evaluation and development of power projects would depend on the structure of the regional electric power market. Conversely, the role of the regional organization may vary with the type and size of the projects, and obviously with its place in the optimal investment portfolio assessed through the resource development plan studies.

As discussed above, the regional resource development plan should probably result in the identification of regional — that is multinational — projects. Quite often, these projects exceed the financial capabilities of the countries involved and, consequently, financial resources need to be found on the international market. The RECI Organization should develop the expertise to ensure and, possibly, contribute to the promotion, evaluation and overview of the development of regional projects.

Depending on the institutional structure and the type of project, the RECI Organization will manage some of the following actions: financing; risk assessment; call for bids; business plan; conditions of operation; international financing (if the size of the project is important enough); control of the viability of the offer shortlist [see Module 6].
III.5.3 Steps in the evaluation and development of a power project

Whatever the role of the RECI Organization with regard to the development of a project, the following steps have to be implemented:

- assessment of the technical feasibility of the project, through a review of the regional resource development plan, and assessment of its contribution to sustainable development objectives, with particular emphasis on its economic viability;

- development of the institutional framework for the project (ownership, liabilities, risk coverage, operation, power pricing) and setting up the organization that will develop the project;

- establishment of the financial simulations of the project, and financing.

Some of these actions are described in Module 6. The first step is to determine the institutional form of the project: will it be part of or a subsidiary of one or more incumbent utilities, or will it be a new entity such as an IPP? The choice will depend, mostly, on the prevailing institutional structure in the countries that will host the project.

III.5.4 Emergence and identification of the project, and control of its contribution to sustainable development objectives

The scope of this specific step will vary, according to the role of the RECI Organization and the contribution of the project to the regional resource development plan.

a) Project absent from the reference regional development plan

If it not included in the portfolio of “optimal” investments, this power project shall, at least, be assessed with regard to social and environmental criteria of sustainable development objectives. In any case, an impact assessment study — with regard to the environment and also to the project’s impact on the regional power system — has to be provided by the project developer to the RECI Organization. The project may infer operation constraints on the existing transmission network; its impact on the existing power system has to be studied and priced by the RECI Organization.
b) Project part of the reference resource development plan

If the project is part of the regional resource plan, the RECI Organization will be interested, naturally, in promoting it. The higher the risk, the more critical the role of the RECI Organization shall be and, accordingly, the stronger the guarantees offered to investors.

The resource development plan shall already have taken into account the environmental, economic and technical risks of the project, as estimated under several scenarios. These risks must be outweighed by the expected benefits if the project is to be selected. Other risks — such as, in the case of an hydroelectric power plant, the uncertainty of the cost and the duration of civil works, the risk of drought, etc. — are to be more precisely assessed, while still others, inherent to the structure of the regional power market, are to be classified as institutional risks.

The role assigned to the RECI Organization depends on the importance and the type of risk incurred when implementing the resource development plan. If the plan includes several hydroelectric schemes, for instance, everything shall be done to minimize the institutional risk and to charge the technical risk to adequate organizations. Considering that, in developing countries, RECI is mainly designed for the exploitation of regional hydroelectric resources, the RECI Organization should take a substantial part of the burden of risks specific to hydroelectric projects, such as construction cost overruns and uncertain water flows.

To sum up, in the case of hydroelectric projects, the RECI Organization shall try to reduce the burden placed on the project developer.

Assuming that a project is part of the regional plan, the RECI Organization shall meet the conditions for this project to be actually developed; if need be, it will have to ensure that the region supports part of the risk or, if not, that the contract between the parties does not lock out some possibilities of further development. In that perspective, bilateral contracting on long-term basis shall be carefully controlled by the RECI Organization.

Whether the RECI Organization shall delegate part of the project’s development to the country or countries where the facility is located is an issue which has not been resolved.
III.5.5 Development of the institutional framework of the project

Choosing the institutional framework, and pricing the transmission service of the interconnection project, are decisions that must be guided by these foremost objectives:

- mitigate and manage the risks supported by the investors;
- maximize the exploitation of the economic, social and environmental surplus by the integrated electricity system, and agree on sharing this surplus;
- minimize the likelihood of future disputes;
- ease additional common investments and actions.

Maximizing the effective use of the interconnection and minimizing future disputes will help minimize the risks.

The following phases have to be implemented:

- Development of an institutional framework for the interconnection and the interconnected system, with the recommendations of the institutional study. Setting up this institutional framework will be part of the mandate of the RECI Organization.
- Development of financial studies, especially financial simulations of the companies taking part of the interconnection. This phase will be implemented in parallel with a tariff study\(^\text{34}\) (if a tariff is needed) and builds on the agreed institutional framework towards the financing close.
- Agreement on common operation rules between the transmission system operators (TSO). This should already have been set up by the Regional organization.

\(\text{a.1) Choosing the best institutional framework}\)

\(^{34}\) In the case of hydroelectric power plant projects, it will be perceived as very risky for the private investor to rely on the market price. Conversely, an hydroelectric power project may be extremely profitable at market price.
Ideally, the structure of the RECI Organization should have already been set up, at least partially. Developing an institutional framework for a specific project risks lengthening the lead time between the moment when the need for such a regional project comes to light, and the commissioning date. The institutional framework should be designed in such a way that the transmission or generation facilities are actually developed and provide a service at a “sustainable” price.

In any case, the institutional framework shall answer the following questions:

- Who will own the common investment and, particularly, the interconnection line? It could be a group of private companies and state-owned companies. The RECI Organization shall manage the attribution of the ownership.

- Which type of sale agreement will be adopted: only bilateral exchanges on a long-term contract basis, or market prices?

- Is there a need for further harmonization of regulations between countries?

a.2) Implementing the institutional structure: sharing the benefits and the costs

Once the institutional structure has been agreed upon by the stakeholders (banks, investors, electric utilities and governments), the pricing of the transmission service (and possibly of the common power generation) has to be agreed upon by the parties.

- If a tariff has been agreed upon, there are three main objectives for the tariff:
  - to be cost reflective;
  - to recover the costs;
  - to share the benefits and cost equally between the countries.

If there is no tariff but only a market price, the stakeholders shall devise some flexible mechanisms so that the risk they do not want to support is covered by the region.

The financial objectives for the investors, the funding institutions and commercial banks will be to ensure, even in the worst cases, a minimum cost recovery. It is often done at the expense of cost-reflectiveness which generally allows to capture most of the potential surplus estimated in the feasibility study.

The information provided here is very general. Module 5 presents in greater details how to arrive at an agreement on the sharing of the surplus.
III.6 RECI Organization

Effective regional electricity cooperation and integration requires the creation of a permanent organization of all the stakeholders of the electric power industry of all the countries in the region. No dedicated integration project could be implemented in the absence of a formal regional organization. Setting up such an organization will be the starting point of regional integration. The RECI Organization will be responsible for coordinating, planning, monitoring, and possibly regulating the operation and development of the regional power system.

A RECI Organization is understood herein as a formal organization in charge of implementing the commitment of countries towards the integration of their national electricity supply industries.

Actually, the mandate of the RECI Organization should be twofold: 1) to operate the regional electric power system and organize the corresponding bulk power market; 2) to implement the different steps of the integration process, that is to say to establish and gradually implement the necessary rules, standards, guidelines, procedures and corresponding practices to develop regional electricity cooperation and integration.

The RECI Organization will be implemented in two different phases: in the preparatory phase, the basic principles for agreement by the governments (represented, ideally, by the energy ministers) will be set. Once the agreement is finalized, the operational phase will unfold with the implementation of these basic principles, and the design and development of the RECI Organization [see below, Chapter III.6.2].

As far as the integration of the electric power systems of developing countries is concerned, two types of regions may be identified:

1. Regions where no substantive interconnections are being currently operated, but where multinational generation projects, with associated interconnection networks and export contracts, are being studied;

2. Regions where limited cooperation and/or bilateral exchanges already exist, and where the development of the interconnected network is scheduled or already initiated.

35. Whether or not to create a formal regional regulator is an open question.
In type 1 regions, the RECI implementation process could be prepared, at least partially, in parallel with the evaluation of multinational projects. The operational phase, however, will not start before these projects begin to operate. In type 2 regions, the operational phase will start as soon as the preparatory phase is finalized.

The following section deals with type 2 regions.

Special tribute should be paid, particularly for this section, to the experts of the World Bank who tried to foster the emergence of power markets in developing countries, drawing from the ongoing experience of power pools in OECD countries. The organization outlined in this section draws a lot, accordingly, from the organizations that are being implemented or scheduled for implementation in the southern part of Africa, in South Asia and in South America.

The proposed RECI Organization is only one of the options to be considered when devising an organization for the integration of national electricity supply industries within a region. The organization outlined below, moreover, does not imply any position by the E7 members as to the ideal (if any) institutional structure of the electricity supply industry. This section should be considered as a review — based on the experience of E7 members — of the methodology currently in use in several developing regions of the world.
III.6.1 Main features of the RECI Organization

The design and implementation of the RECI Organization should be achieved on the basis of the following features:

1. Whatever the type of the regional power system may be, the mandate of this organization will be to monitor a group of local subsystems, each with its own structure, while pursuing its primary objectives:
   - least-cost operation of the regional power system with a special focus on transmission constraints;
   - ensuring a secure and reliable operation of the regional power system;
   - promoting an optimal development of the regional power system with special emphasis on interconnection possibilities. To this end, one of the foremost objective of the reform towards the liberalization of the electric power industry in developing countries will be to create an institutional framework, appealing enough for private investors while adhering to sustainable development objectives, and particularly electrification objectives;
   - developing regional energy trade and running the electric power market in an efficient and nondiscriminatory manner.

2. Due to the fact that the region, most of the time, will consist of sovereign states, the RECI Organization, at least in its initial phase, should adopt the structure of a loose power pool. Its role will be limited to the coordination and monitoring of national power systems, and to ensuring that national power systems consider regional integration in their operation and development strategy.

3. Every stakeholder of the electricity supply industry, particularly customers’ associations, has to be represented in the RECI Organization which should not discriminate between the stakeholders and monitor the application of established rules.

4. At the beginning of the implementation process, the RECI Organization shall be placed under the authority of the governments of the countries in the region.

5. The implementation of the RECI Organization will be prepared during the Preparatory Phase during which the basic principles, as well as all the requirements and conditions for regional electricity cooperation and integration, will be specified and formalized.

6. The RECI Organization should be flexible enough to permit its gradual evolution from the current state-owned vertically integrated monopoly (as described in Chapter III.4.2.a) to the medium-term situation of a more liberalized market (as described in Chapter III.4.2.b).
This evolution should account for the current reforms of national power systems which are oriented towards the privatization and unbundling of state-owned public utilities and the organization of bulk power markets, including Independent Power Producers (IPP) and possibly, in a near future, Third Party Access for eligible consumers. It has to be repeated here that, in the United States, one of the main reasons for reforming the electric power industry was imperfect regional integration [see Joskow, 1985]. In Europe, the governments mandated the European Commission to organize a single market which, in the electricity sector, led to directives that had to be reflected in the national regulations. For a given region, the integration of electric power industry will be facilitated if countries harmonize their national regulations of the electric power industry. The RECI Organization should, to some extent, overview national reforms.

An external consulting expertise will be needed, most probably, particularly in the preparatory phase and at the beginning of the operational phase.

### III.6.2 Basic structure and functions of the RECI Organization

**a) Basic structure of the RECI Organization**

The RECI implementation process should be set up in such a way as to manage the two following phases: 1) a preparatory Phase, 2) an operational Phase with a) the initiation of regional electricity cooperation and integration, and b) the enhancement and deployment of cooperation and integration.

The RECI process may be initiated with a restricted number of countries in the region, and then spread to include the whole region.

**a.1) Phase 1: the preparatory phase**

In this phase, the main organizational and operational features of regional electricity cooperation and integration will be determined. This will result in countries of the region committing themselves, through signed agreements, to policies, rules, standards and procedures for the operation and development of a regional interconnected power system, for the corresponding electric bulk power market, and for the setting up of a RECI Organization.

For this preparatory phase, it would be efficient to create an Informal Working Group, made up of representatives of the utilities of the region. This group would benefit from external expertise. The works of this group should cover all the components (political, institutional, technical, commercial and financial) of regional electric cooperation and integration.
a.2) Phase 2: the operational phase

Starting the RECI implementation process

The objective of this first operational phase will be to implement a permanent RECI Organization, as specified in the agreements signed by the countries. The expertise of the Working Group should be used as much as needed.

Allowing for the features described here above, the RECI Organization should be structured as described below or in a similar manner. In its initial structure, it should adapt to the conditions of cooperation between national electric power systems.

Governance of the RECI Organization:

The regional electricity supply industry will broadly consist, most likely, of state-owned utilities. The Governing Board of the RECI Organization, accordingly, will mainly (if not exclusively) consist of high level representatives of these utilities.

The Governing Board should adhere to efficiency objectives based on the following:

1. Not to be controlled by any single (or group of) market stakeholders;
2. Non-discriminatory access to market and market efficiency;
3. Achieve the targeted reliability and expansion of the electric power system, and further the development of the market;
4. Transparency of the decision-making process;
5. Changes in the operating rules within a reasonable period of time.

Among other external constraints, the Governing Board of the RECI Organization will have to take into account the fact that the electric power system is only a part of the energy system, and that the policy for the electricity sector has to be in line with the energy policy of the countries. Some of the projects scheduled for the development of the regional electric power system will, moreover, significantly affect the budget of the governments, and will then have to undergo a prioritization process, along with major projects from other sectors.

Upper level of authority

The national political and institutional levels have to be involved in any regional electricity cooperation and integration; this is particularly in the case of a commodity, such as electricity, which considered as a strategic commodity. Accordingly, the RECI Organization shall be placed under the authority of an Energy Ministers Council.
The major decisions related to the national reforms in the areas of policies, legislation, institutions, financing and market regulation should be taken at this early stage. They are the prerogative of the governments. Consequently, they will be directly involved, through the Energy Ministers Council, in the operation of the RECI Organization throughout this initial period.

**Management and operational levels of the RECI Organization**

As stated above, the mandate of the RECI Organization is twofold: 1) to operate the regional electric power system and organize the corresponding bulk power market 2) to implement the different steps of the integration process, that is to say to establish and gradually implement the necessary rules, standards, guidelines, procedures and corresponding practices in order to develop regional electricity cooperation and integration.

To carry out this twofold mandate, the RECI Organization should be very flexible. It should be made up of a permanent staff, responsible for the operation of the regional power system and the management of the bulk power market. It would organize and overview the **Working Groups** who would elaborate on the evolution of the regional power market, item per item. These Working Groups would be staffed by experts, through temporary assignment, and assisted by the participating utilities and, if need be, external experts. The permanent staff would be appointed by the Governing Board with the approval of the Energy Ministers Council.

During the implementation phase of the RECI Organization, the works could be carried out by a scaled-down permanent staff consisting of: a **General Manager**; **operational branch managers** — possibly one for each of the three main branches (policy/institutional, technical, and commercial/financial) — and a **Regional Coordination Center manager** who would be responsible for the day-to-day operation of the regional power system and regional market.

All management and operational activities could be overseen by a **Management Committee** appointed by the Governing Board.

**Regulation**

Section 4 of this chapter described the likely evolution of the structure of the electricity supply industry. In a given region, integration of the electricity supply industries does not entail that all the national electricity supply industries share the same institutional structure. State-owned vertically integrated monopolies may be side by side with fully competitive national power markets. The case made by Kellow [see Kellow 96] on distributive versus regulatory policies will not be reopened.

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36. On the issue of the regulation of the electricity supply industry: if it is structured as a power market, the regulatory body should be involved in licensing new players, new market rules or rules changes, market behavior assessment, and recommendations of appropriate remedies in case of violation of the rules or abuses of the market.
Whatever the prevailing institutional structure, each country should be represented, at the regional level, on a Committee whose mandate is to coordinate the regulations of national power systems for the operation of the regional market. The participants to this Committee should be independent from national political powers and industrial interests. This Committee should assess the compatibility of national regulations with RECI requirements and, if necessary, require countries to adjust their regulations.

Depending on the political will of the region and/or on the importance of the regional power market (number of players and volume traded), this Committee could form a regulatory body. The implementation of a formal regional regulatory body, however, is not an urgent matter.

**Dispute resolution**

Mechanisms for dispute resolution should be defined. It could be a two-level dispute resolution system, mandatory before arbitration. The first level could be the responsibility of the Management Committee, the second level that of the Committee of national regulators. The arbitration procedures could be managed by an international court of law or by one of the countries of the region.

**Emergence and evolution towards a regional interconnected power system and a regional electricity market**

A regional interconnected power system and a regional electricity market should emerge and evolve gradually towards a model of the type outlined, as an example, in section III.4.2.b. Regional organizations of this type exist in some regions of the world. Some are briefly presented in these Guidelines [see Chapter IV, and Module 7 for the northeastern American market]. The South African Power Pool (SAPP) [see section IV.3.4], although it faces many difficulties, also provides an interesting example.

This gradual evolution towards an interconnected power system and a regional electric market should be characterized as follows:

- The group of market participants should be enlarged to include private or public entities, either the operators of the facilities developed for the regional power system, or the national generation, transmission or distribution entities emerging from the unbundling of vertically integrated utilities, or eligible large consumers who could be granted free access to the regional bulk power market, or, possibly, wholesale buyers and retailers. The composition of the Governing Board will have to be adapted accordingly.

- The market will evolve from few power exchanges under bilateral contracts (mostly between countries) to an important market with numerous players and increasing trade volumes. The consequences for the RECI Organization are the following:
• The operation, management and control of the regional power system, as well as the management of the regional power market, will be complicated. To tackle this increased complexity, the RECI Organization should be reinforced: some additional staff and expertise will be required, particularly in the organization’s commercial, financial and legal components. The role of the RECI Organization should evolve from the coordination of a group of rather independent national power systems, to the operation (including monitoring, coordination and, possibly, the management of some functions) of a regional interconnected network and of a regional market.

• Considering the increasing number and diversification of players, it will become crucial that the RECI Organization does not discriminate among them. Its behavior should not be biased by any given group of players such as the incumbent utilities or one of the governments of the region. The RECI Organization, consequently, shall become independent from governments.

To sum up, the role of the RECI Organization will have to evolve towards the role of a Regional Independent System Operator (RISO), as it is generally defined in power markets in OECD countries.

At this phase, the main reforms will have been implemented, and the regional character of the operation of the regional power system and of the regional power market should be widely accepted. The governments may be less involved, accordingly, than in the first preparatory phase. They will, however, retain their crucial role of ascertaining that the regional interconnected power system and the associated regional power market remain consistent with national energy policy and financial, legal and institutional objectives. They also have to ascertain that the work of the RECI Organization is consistent with the objectives defined at the outset.

The increase in the types and volumes of trade, and in the number of players, will require that 1) the role of monitoring and controlling the regional market as well as the role of harmonizing national regulations be enhanced, and 2) these roles shall be carried out independently from the players and from the RISO. These roles could be delegated to a Regional Independent Regulatory Commission. This regulator could be appointed by the Energy Ministers Council. It should be an upper-level body, replacing the previous committee and overseeing the RISO and other participants. It could also be mandated to submit, for approval by the Energy Ministers Council, new licensed participants, new members of the Governing Board, as well as amendments to the rules of the market. It should also be entrusted with market monitoring and with a second level of dispute resolution, the first level remaining with the Management Committee.
b) Basic functions of the RECI Organization

The principal bodies of the RECI Organization could be the following:

b.1) Energy Ministers Council

It will be responsible for approval of major policy issues and for admitting new members on the Governing Board.
It will appoint a committee for the second level of dispute resolution.

b.2) Governing Board

The Governing Board will be the executive body for strategic issues (the major policy issues being submitted for approval by the Energy Ministers Council), approval of the budget of the RECI Organization, and control of the performance and of the operation of the RECI Organization.

b.3) RECI Organization, management and operation

The Management Structure will be responsible for the day-to-day coordination and monitoring as well as for the expansion of the regional interconnected power system and electricity market. It will, therefore, have to govern the operational structure, and to prepare and implement the decisions of the Governing Board.

The Operational Structure will have to coordinate and monitor the operation, and plan and develop the regional interconnected power system. It will, therefore, have to design and implement the recommendations presented in section III.6.3.

The Management Committee will oversee the Management Structure and the Operational Structure, and help the latter to prepare and implement the objectives of the RECI Organization. The members of this Committee will represent the member countries before the Management Structure and to the Operational Structure.

It will be the first level of dispute resolution.

b.4) Regulatory and dispute resolution system

The structure and functions of this system are described in section III.6.2.a).
III.6.3 Recommendations for the design, implementation and development of Regional Electricity Cooperation and Integration (RECI)

As for any international initiative, the political, institutional and energy policy aspects of RECI are crucial. Considering the importance of these aspects, RECI is expected to proceed on a long-term basis and in a step-by-step manner. This section provides some recommendations for appropriate actions on specific items of these various aspects. The guiding principles for these actions will, generally, have to be agreed upon at a political level. These actions will then be designed, implemented and developed at technical and financial levels. It appears more efficient to seek agreement from the political arena on a comprehensive set of principles before implementing the RECI Organization. It is recommended, accordingly, to divide the RECI process into two phases: the Preparatory Phase, where basic principles are prepared for agreements by governments, and the Operational Phase, where the RECI Organization is designed, implemented and developed according to the basic principles agreed upon in the Preparatory Phase.
a) Actions in the Preparatory Phase

<table>
<thead>
<tr>
<th>RECOMMENDATIONS</th>
<th>PRIORITY</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 - To establish a draft and very simplified regional master plan outlining some scenarios for the development of generation and transmission means to demonstrate the benefits accruing from an interconnected system as compared to the development of national autonomous systems, aimed at convincing governments to promote and support regional integration, so that political and institutional barriers can be removed.</td>
<td></td>
</tr>
<tr>
<td>2 – Agreements between countries: to conduct the necessary studies, to specify the contents of agreements, to draw the draft and then to establish the final formal Agreements to be signed by the concerned parties:</td>
<td></td>
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<tr>
<td>_ intergovernmental policy agreement to be signed by energy ministers,</td>
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<tr>
<td>_ interutilities management agreement to be signed by the executive officers of utilities,</td>
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<tr>
<td>_ interutilities operating agreement to be signed by the operating managers of utilities.</td>
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<tr>
<td>These agreements should specify:</td>
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<tr>
<td>_ the basic principles of regional cooperation;</td>
<td></td>
</tr>
<tr>
<td>_ the basic operating and planning criteria and the basic rules for the regional electric power market;</td>
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<td>_ the items to be developed during the operation phase;</td>
<td></td>
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<tr>
<td>_ and the basic organization and functions of the permanent regional organization.</td>
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<tr>
<td>These agreements shall cover all the items presented here below in section 2, and all the basic policy principles.</td>
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<tr>
<td>3 – Signature of the Agreements by the parties involved</td>
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<tr>
<td>4 – Implementation of the formal permanent RECI Organization</td>
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</tbody>
</table>
The preparation may be eased by setting up some informal forums between top-level executives, experts from the governments and utilities of the countries of the region, independent senior experts, international bodies, and the Working Group in charge of the Preparatory Phase. In these forums, the operating experience of the participants should be presented and discussed. Views should be exchanged on the possible options for coordinating, operating, managing, regulating, structuring, and developing the planned integrated electric power system and the corresponding regional market.

The Preparatory Phase will be formally terminated when all the agreements are signed. At that time, the Operational Phase shall begin. A transition phase for the implementation of the basic organization of the RECI Organization will, in fact, separate the two phases.

b) Actions in the Operational Phase

The policy and basic principles for action on the following items will have been agreed on at the end of the Preparatory Phase. Thereafter, these actions will have to be specified and operating rules should be defined. Their implementation in the Operational Phase will be prioritized as “immediate”, “short term”, “medium term”, and “long term”.

Policies, processes, rules, criteria, guidelines and procedures for the operation, management and development of generation and transmission facilities in a regional perspective should be set.

Most of the corresponding studies that should have been initiated during the Preparation Phase should be finalized in the short term for the Operational Phase and updated continuously.
### RECOMMENDATIONS

<table>
<thead>
<tr>
<th>Area</th>
<th>Priority</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Political, legislative, and institutional area</strong></td>
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<tr>
<td>Module 6 provides some details about the actions that could be</td>
<td></td>
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<tr>
<td>taken relative to this area.</td>
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<tr>
<td><strong>Regional integration</strong></td>
<td>Immediate to short term</td>
</tr>
<tr>
<td>In the energy policy of each country, regional integration must</td>
<td></td>
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<tr>
<td>appear as one of the major factors for the development of the</td>
<td></td>
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<tr>
<td>power system. This should be acknowledged and enforced by each</td>
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<tr>
<td>country.</td>
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<tr>
<td><strong>Laws and regulations</strong></td>
<td>Short term</td>
</tr>
<tr>
<td>The compatibility between national legislation and RECI requirements should be examined. Appropriate recommendations should be made, and measures should be taken to achieve the necessary level of compatibility.</td>
<td>Short term</td>
</tr>
<tr>
<td>A credible and clear regulatory framework, in compliance with a future competitive market and compatible with RECI requirements, should be set up in each country.</td>
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<tr>
<td><strong>Transmission</strong></td>
<td>Short term</td>
</tr>
<tr>
<td>- <strong>Ownership</strong>: National policies relative to the ownership and</td>
<td></td>
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<tr>
<td>operation of national transmission facilities as well as to the</td>
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<tr>
<td>bulk regional interconnection links should be clearly defined and</td>
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<tr>
<td>harmonized.</td>
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<tr>
<td>- <strong>Unbundling</strong>: Each country commits itself to separate the</td>
<td>Short term</td>
</tr>
<tr>
<td>transmission function of the national power system from the</td>
<td></td>
</tr>
<tr>
<td>generation and distribution functions.</td>
<td></td>
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<tr>
<td>- <strong>Electricity wheeling</strong>: Each country commits itself to allow the</td>
<td>Short term</td>
</tr>
<tr>
<td>wheeling of capacity and/or energy through its system, provided it is technically and economically feasible.</td>
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<tr>
<td>A distinction between different priority levels as well as different wheeling charges will be established.</td>
<td>Short term to medium term</td>
</tr>
<tr>
<td>- <strong>Open access</strong>: Policies of open access to the transmission</td>
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<tr>
<td>network for use by all generators on a nondiscriminatory basis</td>
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<tr>
<td>should be established, taking into account RECI requirements</td>
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<tr>
<td>relative to the electricity market.</td>
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<tr>
<td><strong>RECI ORGANIZATION</strong></td>
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<tr>
<td>-----------------------</td>
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</tr>
<tr>
<td>Definition and implementation of the organization, and of institutional rules and functions [see section III.6.2 for an organization model]</td>
<td></td>
</tr>
</tbody>
</table>

**Initial organization of the technical RECI Organization** to be designed and implemented  
- Bodies of the organization  
- Initial membership  
- Arrangements for membership change  
- Voting arrangements  
- Budgeting and source of funds  
- Management: appointment of key staff  
- Procedures for dispute resolution and for arbitration  
- Responsibilities, obligations, rights and functions of each body  
  
**Evolution of the organization** to be designed and implemented  
- Membership change: new stakeholders; new voting arrangements  
- Changes in the bodies of the organization: to set up a Regional Independent System Coordination Operator and a Regional Coordination Regulator [see section III.6.2]. At this stage, the expansion of the regional electricity market, as well as the increasing number and diversity of market participants, increase the importance of the role of the RECI Organization for the operation of the regional power system, as well as for the management of the regional power market. The increasing need for independence from the participants and the governments will prompt the RECI Organization to evolve towards a RISO organization, and bring to light the need for a regional regulator.  
- APPOINTMENT OF THE CORRESPONDING MANAGEMENT KEY STAFF  
- Changes in provisions on dispute resolution  
- Responsibilities, obligations, rights, functions of new bodies  

<table>
<thead>
<tr>
<th><strong>ENVIRONMENTAL IMPACT</strong></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>A regional approach should be set up through a regional environmental unit that will address environmental issues:  -/ To create and update a set of rules, criteria, guidelines and regulations to be applied by each country  -/ To establish or to strengthen national environmental institutions  -/ To coordinate their policies in compliance with the requirements of the RECI Organization  -/ To incorporate environmental issues in national and regional planning</td>
<td>Short term to medium term</td>
</tr>
</tbody>
</table>
2 **Technical area**

**PLANNING**

- A simplified master plan  
  Preparatory Phase
- A flexible regional generation and transmission master plan (to be updated every 2-3 years) determining the least-cost scenario  
  Immediate

See section IV.2 of this module

**OPERATING**

**Operating guidelines**, including detailed requirements relative to the planning, design and operation of a multinational interconnected power system as well as the consequent procedures, should be established. They may include, in particular, the following items:

- definition of data to be gathered at a regional level; guidelines for data collection;
- definition of operating criteria [See section IV.3];
- procedures for routine and emergency operation;
- reliability standards;
- implementation and use of ancillary services (See section IV.3 of this module and Module 8);
- lines protection coordination;
- procedures for outages analysis.

To set up and operationalize a **Regional Coordination Center** and implement the following responsibilities and functions:  
Immediate to short term

- to establish a central data base including information about outages;
- to analyze outages affecting regional operation;
- to perform operational planning studies at the regional level to identify possible constraints in normal and deteriorated situations, transfer limits on interconnection lines, wheeling limits through countries, reliability or stability problems;
- to continuously monitor and coordinate, if necessary, the routine, degraded, emergency operation of the regional interconnected power system, implementation and use of ancillary services, lines protection system performance, compliance of the National Control Centers (NCC) operation with the regional requirements and reliability standards, use of operational guidelines by the NCC;
- to coordinate, monitor and disseminate the generation and transmission maintenance schedules.
### Development of New Projects

National standards could be harmonized and guidelines established in the technical area for feasibility and detailed design studies, tender documents, construction contracts and construction follow-up.

### 3 Commercial/Financial

<table>
<thead>
<tr>
<th>Category</th>
<th>Timeframe</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Transmission Pricing</strong></td>
<td>Immediate to medium term</td>
</tr>
<tr>
<td>To introduce in each country a mechanism for calculation of transmission prices which will reflect the fixed and variable costs of transmission. The prices should be compatible among the countries, transparent and nondiscriminatory in order to provide a firm basis for investors interested in the development of transmission and generation facilities, and for operation of the regional interconnected network.</td>
<td></td>
</tr>
<tr>
<td>Transmission prices and priority to wheel should be determined to make open access fully effective</td>
<td></td>
</tr>
<tr>
<td><strong>Generation Tariff</strong></td>
<td>Short term</td>
</tr>
<tr>
<td>To introduce in the each country a mechanism of calculation of generation tariffs, based on two parts: one part relative to the capacity available and the corresponding fixed costs, and another part relative to the actual energy supplied and the variable energy costs.</td>
<td></td>
</tr>
<tr>
<td><strong>Taxes and Royalties</strong></td>
<td>Immediate to short term</td>
</tr>
<tr>
<td>Each country should review and ensure the compatibility of taxes and royalties policy with RECI requirements</td>
<td></td>
</tr>
<tr>
<td><strong>Ancillary Services</strong></td>
<td>Short term</td>
</tr>
<tr>
<td>To develop procedures for payment of ancillary services that should be compatible among countries.</td>
<td></td>
</tr>
<tr>
<td><strong>Valuation of Capacity and Energy Settlement of Payments</strong></td>
<td>Short term</td>
</tr>
<tr>
<td>To establish procedures compatible with regional requirements for valuation of capacity and energy, metering, billing and settlements.</td>
<td></td>
</tr>
<tr>
<td><strong>Existing Contracts</strong></td>
<td>Short term</td>
</tr>
<tr>
<td>To assess how existing contracts could be accommodated within the new institutional and commercial framework.</td>
<td></td>
</tr>
</tbody>
</table>
### INVESTMENTS

See section IV.5 of this module and Module 6 which gives some detailed data on actions.

Actions should be taken by the countries and coordinated at the regional level to facilitate and promote private investments, particularly by mitigating risks supported by investors:

- to ensure that a market is established;
- to address market entry barriers;
- to establish clear policy relative to regulatory framework, pricing mechanism, taxes and royalties, convertibility of currency and open access to regional transmission network;
- to develop a clear process for construction;
- to address environmental issues;
- to allocate risks allocation.

To establish guidelines, procedures, models for project definition, business plan, risk analysis, financial and operation structure definition, commitments, contractual agreements.

<table>
<thead>
<tr>
<th>Financial Support</th>
</tr>
</thead>
<tbody>
<tr>
<td>Contacts should be made with multilateral and bilateral financing institutions (World Bank, etc.) with the objective of assessing their cofinancing and their guarantee capabilities in order to catalyze private investment.</td>
</tr>
</tbody>
</table>

### 4 Other actions

#### TRAINING

A training program should be established in different areas for the staff working in the RECI Organization. The operators of the regional power system should be the first to benefit from training.

#### ASSISTANCE OF MULTILATERAL INSTITUTIONS

At the various phases of the preparation, design and implementation of the RECI Organization, the assistance of multilateral and/or bilateral financing institutions should be sought (see section III.7).
5 Items for action marked as “immediate”

The corresponding actions should belong to one of two categories:

1. Actions with the limited objective of improving in the short term the operation and volume of regionally traded energy. The accruing benefits should be given high visibility so that the regional integration components of national energy policies will be further enhanced. In other words, the RECI process should build on electric power exchange short-term potentials.

2. Launch the working groups that will work on the long-term structure of the RECI Organization and, generally speaking, all the studies that are required to achieve true regional integration.

An indicative list of examples of immediate actions is given here below. It should not be considered as exhaustive.

- To establish working groups with some countries having already embarked in the reform process on items such as:
  - unbundling;
  - introduction of independent power producers;
  - setting up of a national regulation;
  - tentative transmission pricing;
  - existing wheeling charges contracts;
  - study of a transmission project with private investment;
  - taxes & royalties legislation reform underway;
  - establishment of an environmental institution underway;
  - existing interconnected subsystem: how is it operating? Is it possible to improve the operation and management of the subsystem? What are the benefits?

- To identify and remedy possible stability or reliability issues of the existing transmission system, or network congestion.

- To identify one of the less expensive interconnection project and develop it, possibly with funds from the private sector and guarantees from multilateral institutions.

- To identify companies or international institutions capable of providing assistance and training.
III.7 Role of International Institutions in Fostering Regional Integration

The RECI implementation process will be supported (if not led) by international institutions. This support will be even stronger should it come to light that sustainable development objectives are being pursued. If such is the case, it should be possible to get the support of worldwide funding institutions dedicated to sustainable development.

III.7.1 Background

Up to the early 1990s, actually, the support of international funding institutions was focused on feasibility studies of interconnection schemes. In Africa, for instance, the African Development Bank, together with the Union des Producteurs et Distributeurs d'Électricité d'Afrique (UPDEA), established regionwide generation and transmission development plans. The interconnection study of UPDEA, zone D, showed how far to the north the hydroelectric power from river Congo could flow. Even if these studies show important surpluses, very few interconnection projects came out finally. Most of these interconnection plans were associated with large hydroelectric schemes and, considering the associated high risk level and the emerging concern about the adequacy of large hydroelectric schemes’ development with sustainable development objectives, most of these projects were discontinued.

With the recent collapse of the Soviet Union, OECD countries do not manifest the same need to fund developing countries. The budget allocated to development funds such as the World Bank has consequently been reduced, and development funds have to rely increasingly on the private sector to alleviate poverty.

III.7.2 Categories of international institutions

The international institutions that can help in the regional electricity integration process are ranked by category, and these categories cover all the types of barriers that are to be removed for achieving true regional electricity integration. Some political organizations may also have a funding role.

A good combination of these organizations within the RECI process will be a key to success.
a) Political organizations

The Southern African Development Community (SADC), MERCOSUR, the Association of South East Asian Nations (ASEAN), the federal government of the United States, the European Commission, etc.

All these organization should benefit from the RECI process. A crucial political choice has to be made from the outset however: shall the RECI process be put under the umbrella of the political organization of the region, or shall the energy ministers create a stand-alone organization? The answer to this question may depend on the type of regional electricity integration that is being sought. If it is based on the exploitation of river basins, and considering that these are multipurpose rivers, other ministers than energy ministers will be concerned. This is particularly true in light of the fact that the forthcoming worldwide challenge is water supply. If the regional political level is already important, or is likely to be of importance compared to the national level, the issue may be different.

b) Information exchange regional organizations

This category consists of all the organizations that gather and exchange information on the electricity supply industries of the region. They are regional associations of electric utilities and, generally, at the forefront of a regional integration process. Some of these instances are the Regional Electrical Integration Commission (CIER) in Latin America, UPDEA in Africa, and OME in the Mediterranean basin.

As they do not have important budgets, nor any governance over national electric utilities or the electricity supply industry, it is very difficult for them to push the RECI process further than some specific studies during the Preparatory Phase. Considering their expertise, however, they are good partners for funding institutions.

Their ability to give high visibility to the benefits of RECI, within the political sphere, and to plan the Preparatory Phase of the RECI process up to the agreement on basic principles by the delegates of governments of the region, is crucial.

c) Funding institutions

These are limited to funds that extend beyond short-term profitability; accordingly, these funds also pursue objectives of sustainable development. Sustainable development is usually characterized according to the following three components:

- Economics — not only short-term profitability of capital, but also long-term economic viability for humankind;
- Environment — at regional and global levels. The most prominent issue is greenhouse gas emissions.
- Social objectives — such as poverty alleviation, access to electricity service for all, etc.
Funding institutions that are concerned about CO₂ emissions reduction — such as Global Environmental Facility (GEF) and Partitioned Carbon Fund (PFC) — are not fully aware and/or do not acknowledge the savings that can accrue from regional electricity integration. There is a case to be made in international circles for the probable benefits of regional integration. When devising the Clean Development Mechanisms of the United Nations Framework Convention on Climate Change, for instance, environmental experts do not take into account the benefits that could accrue from interconnection lines.

The World Bank group, which is particularly concerned about poverty alleviation and economic development, is primarily active in the RECI process. For the time being, a technical body — the Energy Sector Management and Assistance Program (ESMAP) — is providing funds for studies and in-kind technical advice during the Preparatory Phase of the RECI implementation process. The World Bank considers funding interconnection investments as a means of giving momentum to the RECI implementation process and is seeking partnerships with other funds.

The E7, with its own fund, is certainly in a good position to enter a partnership with the World Bank on this issue. As a nonprofit association of eight of the largest electric utilities, it is interested, first and foremost, in offering evidence of the benefits accruing from regional electricity cooperation and integration.

d) Legal or trade institutions

The World Trade Organization (WTO) and the Energy Charter are included in this category.

III.7.3 Areas for support from international institutions in the RECI process

During the Preparatory Phase, the support of international institutions could translate into the organization and the financing of meetings. These meetings would be designed to promote the benefits of regional integration in the political arena as well as to the key players in the electric power industry, and to explain the conditions for integration.

Funding for consultancy services or direct financial support could then be allocated throughout the various phases of the regional integration process. The following issues could be addressed.

- Study of the regional development plan for generation and transmission;
- Dissemination of cross-regional electricity experience;
- Assistance to draft policy, management and operating agreements;

37. PFC and GEF are managed by the World Bank.
• Study and implementation of a regional organization and of the reform of the structure of national entities, establishment of regional dispatching, which is the core of the regional organization, study of the organization of a procedure for member countries to contribute to the regional organization.

• New regional projects: assistance to perform feasibility and detailed design studies (including environment issues, financial study, risk evaluation, business plan) and to draft guidelines, models for tender documents, contractual agreements on purchase, fuel, implementation;

• To bring all the national facilities that will be part of the regional network up to the same technical level: support and assistance for studies, call for bids, provide liabilities for potential investors;

• For facilities that will provide returns only in the long-term, specific support to attract private investors.
Chapter IV

Regions for Cooperation and Integration of Electric Power Systems

In this chapter, some regions that may potentially benefit from cooperation and the integration of their national electric power systems will be identified. More emphasis will be given to three regions: South America, the southern part of Africa and the Great Mekong Subregion in Asia. In these three regions, the integration process is currently underway. A subregion of West Africa, composed of countries along the Senegal river basin is also presented. Finally, some consideration will be given to the electric network of the Mediterranean basin.

The rationale and the major technical, economic and institutional features of regional integration will be reviewed for each of these examples.

The following tables present the electric energy imports and exports within the countries of the region or with neighboring regions. Some discrepancies may come to light due to the fact that some countries are in transition. The share of imports in domestic supply has increased in most regions of the world during the 1990-1998 period.

The last column indicates the imports as a percentage of domestic supply. OECD Europe is the region where countries rely most on imports. A similar table, with a country-by-country listing, is to be found as an appendix to this module.
**Table 2: 1990 electricity balances, imports, exports, of various regions of the world**

<table>
<thead>
<tr>
<th>Region</th>
<th>Domestic Supply</th>
<th>Imports</th>
<th>Exports</th>
<th>Imports</th>
</tr>
</thead>
<tbody>
<tr>
<td>OECD Total</td>
<td>7,596,990</td>
<td>248,254</td>
<td>(230,241)</td>
<td>3.3%</td>
</tr>
<tr>
<td>OECD North America</td>
<td>3,802,354</td>
<td>40,863</td>
<td>(40,601)</td>
<td>1.1%</td>
</tr>
<tr>
<td>OECD Pacific</td>
<td>1,152,296</td>
<td>-</td>
<td>-</td>
<td>0.0%</td>
</tr>
<tr>
<td>OECD Europe</td>
<td>2,642,340</td>
<td>207,391</td>
<td>(189,640)</td>
<td>7.8%</td>
</tr>
<tr>
<td>Non-OECD Total</td>
<td>4,273,168</td>
<td>60,091</td>
<td>(78,427)</td>
<td>1.4%</td>
</tr>
<tr>
<td>Africa</td>
<td>319,673</td>
<td>2,429</td>
<td>(4,244)</td>
<td>0.8%</td>
</tr>
<tr>
<td>Latin America</td>
<td>490,693</td>
<td>28,306</td>
<td>(28,219)</td>
<td>5.8%</td>
</tr>
<tr>
<td>Asia Excluding China</td>
<td>647,335</td>
<td>2,236</td>
<td>(1,737)</td>
<td>0.3%</td>
</tr>
<tr>
<td>China (Region)</td>
<td>650,179</td>
<td>1,930</td>
<td>(1,889)</td>
<td>0.3%</td>
</tr>
<tr>
<td>Former USSR</td>
<td>1,692,000</td>
<td>-</td>
<td>(35,000)</td>
<td>0.0%</td>
</tr>
<tr>
<td>Non-OECD Europe</td>
<td>238,075</td>
<td>25,190</td>
<td>(6,882)</td>
<td>10.6%</td>
</tr>
<tr>
<td>Middle East</td>
<td>235,213</td>
<td>-</td>
<td>(456)</td>
<td>0.0%</td>
</tr>
<tr>
<td><strong>World</strong></td>
<td><strong>11,870,158</strong></td>
<td><strong>308,345</strong></td>
<td><strong>(308,668)</strong></td>
<td><strong>2.6%</strong></td>
</tr>
</tbody>
</table>

**Table 3: 1998 electricity balances, imports, exports, of various regions of the world**

<table>
<thead>
<tr>
<th>Region</th>
<th>Domestic Supply</th>
<th>Imports</th>
<th>Exports</th>
<th>Imports</th>
</tr>
</thead>
<tbody>
<tr>
<td>OECD Total</td>
<td>9,134,155</td>
<td>278,927</td>
<td>(269,480)</td>
<td>3.1%</td>
</tr>
<tr>
<td>OECD North America</td>
<td>4,577,583</td>
<td>58,517</td>
<td>(57,667)</td>
<td>1.3%</td>
</tr>
<tr>
<td>OECD Pacific</td>
<td>1,515,934</td>
<td>-</td>
<td>-</td>
<td>0.0%</td>
</tr>
<tr>
<td>OECD Europe</td>
<td>3,040,638</td>
<td>220,410</td>
<td>(211,813)</td>
<td>7.2%</td>
</tr>
<tr>
<td>Non-OECD Total</td>
<td>5,262,982</td>
<td>137,196</td>
<td>(152,552)</td>
<td>2.6%</td>
</tr>
<tr>
<td>Africa</td>
<td>414,606</td>
<td>11,656</td>
<td>(13,317)</td>
<td>2.8%</td>
</tr>
<tr>
<td>Latin America</td>
<td>717,730</td>
<td>47,862</td>
<td>(47,877)</td>
<td>6.7%</td>
</tr>
<tr>
<td>Asia Excluding China</td>
<td>1,108,963</td>
<td>3,652</td>
<td>(1,898)</td>
<td>0.3%</td>
</tr>
<tr>
<td>China (Region)</td>
<td>1,197,610</td>
<td>7,777</td>
<td>(7,784)</td>
<td>0.6%</td>
</tr>
<tr>
<td>Former USSR</td>
<td>1,210,439</td>
<td>57,849</td>
<td>(71,885)</td>
<td>4.8%</td>
</tr>
<tr>
<td>Non-OECD Europe</td>
<td>204,401</td>
<td>7,746</td>
<td>(8,732)</td>
<td>3.8%</td>
</tr>
<tr>
<td>Middle East</td>
<td>409,233</td>
<td>654</td>
<td>(1,059)</td>
<td>0.2%</td>
</tr>
<tr>
<td><strong>World</strong></td>
<td><strong>14,397,137</strong></td>
<td><strong>416,123</strong></td>
<td><strong>(422,032)</strong></td>
<td><strong>2.9%</strong></td>
</tr>
</tbody>
</table>
IV.1 Principles for Identification of Regions

The main technical and economic criteria for integrating countries in a region are:

1. small national power markets with high growth potential;
2. the existence in some countries of the region of a comparative advantage for power generation — this comparative advantage of some countries of the region over the others generally originates from the existence of cheap and abundant hydroelectric resources;
3. limited distances between national electric power systems.

The main limits to interconnection are deep and large bodies of water, large deserted areas, large forests, or mountains. These limits, obviously, are always to be weighted against the cost of the primary source for generating electricity; the shorter the distance between two isolated power sitemaps, the less important the comparative advantage.

Most of the time, these technical and economic criteria are not discriminating enough. Political, cultural or social similarities may, therefore, help identify the regions. The existence of a political organization should be an important advantage.

IV.2 Identified Regions for Potential Regional Integration

It should be of interest to establish a tentative list of the main candidate regions for integration of electric networks. In this list, some regions may be interconnected in the longer term, as happened in North America and Europe. The list presented below is not exhaustive. In the regions identified, some interconnections may already exist.

IV.2.1 Africa

The Sahara desert splits Africa in two parts that may be connected in the long term through the eastern border. Even without taking the Sahara desert into account, Africa has a very low population density, which does not favor the development of important electric power systems. The next table ranks, in descending order, the domestic supply of electricity of the major African countries.

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38. The wording “comparative advantage” refers to international economy; it is used to bring the reader to reflect upon the fact that electric power may be considered as a mere commodity, subject to international trade.
Table 4: Africa, domestic supply of electricity (GWh)

<table>
<thead>
<tr>
<th>Country</th>
<th>1990</th>
<th>1998</th>
<th>Growth Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>South Africa</td>
<td>165,963</td>
<td>203,217</td>
<td>3%</td>
</tr>
<tr>
<td>Egypt</td>
<td>42,256</td>
<td>62,966</td>
<td>5%</td>
</tr>
<tr>
<td>Algeria</td>
<td>16,045</td>
<td>23,608</td>
<td>5%</td>
</tr>
<tr>
<td>Libya</td>
<td>16,800</td>
<td>19,496</td>
<td>2%</td>
</tr>
<tr>
<td>Nigeria</td>
<td>12,564</td>
<td>15,716</td>
<td>3%</td>
</tr>
<tr>
<td>Morocco</td>
<td>9,731</td>
<td>14,841</td>
<td>5%</td>
</tr>
<tr>
<td>Zimbabwe</td>
<td>9,693</td>
<td>11,757</td>
<td>2%</td>
</tr>
<tr>
<td>Tunisia</td>
<td>5,807</td>
<td>9,087</td>
<td>6%</td>
</tr>
<tr>
<td>Ghana</td>
<td>4,970</td>
<td>7,741</td>
<td>6%</td>
</tr>
<tr>
<td>Zambia</td>
<td>4,850</td>
<td>6,376</td>
<td>3%</td>
</tr>
<tr>
<td>Democratic Republic of Congo</td>
<td>5,645</td>
<td>5,535</td>
<td>0%</td>
</tr>
<tr>
<td>Kenya</td>
<td>3,215</td>
<td>4,950</td>
<td>6%</td>
</tr>
<tr>
<td>Côte d’Ivoire</td>
<td>2,315</td>
<td>3,399</td>
<td>5%</td>
</tr>
<tr>
<td>Cameroon</td>
<td>2,697</td>
<td>3,285</td>
<td>2%</td>
</tr>
<tr>
<td>United Republic of Tanzania</td>
<td>1,628</td>
<td>2,200</td>
<td>4%</td>
</tr>
<tr>
<td>Sudan</td>
<td>1,515</td>
<td>1,966</td>
<td>3%</td>
</tr>
<tr>
<td>Ethiopia</td>
<td>1,202</td>
<td>1,627</td>
<td>4%</td>
</tr>
<tr>
<td>Mozambique</td>
<td>620</td>
<td>1,537</td>
<td>12%</td>
</tr>
<tr>
<td>Senegal</td>
<td>901</td>
<td>1,286</td>
<td>5%</td>
</tr>
<tr>
<td>Angola</td>
<td>841</td>
<td>1,063</td>
<td>3%</td>
</tr>
<tr>
<td>Gabon</td>
<td>915</td>
<td>1,027</td>
<td>1%</td>
</tr>
<tr>
<td>Togo</td>
<td>402</td>
<td>522</td>
<td>3%</td>
</tr>
<tr>
<td>Congo</td>
<td>507</td>
<td>470</td>
<td>-1%</td>
</tr>
<tr>
<td>Benin</td>
<td>217</td>
<td>317</td>
<td>5%</td>
</tr>
<tr>
<td>Other Africa</td>
<td>8,374</td>
<td>10,423</td>
<td>3%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>321,663</strong></td>
<td><strong>416,410</strong></td>
<td><strong>3%</strong></td>
</tr>
</tbody>
</table>

Source: IEA 1999
The following regions may be identified:

- **North of the Sahara**
  - the Maghreb countries (Morocco, Tunisia, Algeria, Libya), with connections to Egypt and Europe (Spain and possibly, in the future, Italy). Virtually all these countries are interconnected and a 500 kV interconnection is planned [see OME, 00].

- **South of the Sahara**
  - West Africa from Mauritania up to Chad and Nigeria, including the subregion of the *Organisation de Mise en Valeur du Fleuve Sénégal* (OMVS). Some of these countries are already interconnected via an hydroelectric power plant on the Volta river in Ghana (Ghana, Côte d’Ivoire, Togo, Benin). The World Bank is initiating a RECI implementation process with the Economic Community of West Africa (ECOWAS) as a starting point. A feasibility study of a 330 kV interconnection of these countries has been carried out.
  - Southwest Africa: from the Democratic Republic of Congo (DRC) to Nigeria
  - South of Africa up to the DRC, under the policy umbrella of the South African Development Community
  - The Great Lakes and East Africa

It is to be underlined that extraordinary inexpensive and abundant hydroelectric resources may justify intracontinental interconnection such as the one studied between the Democratic Republic of Congo (DRC) and Egypt. For the time being, and even if it is considered as very efficient with regard to sustainable development objectives, such a huge project (the investment amounts to US$10 billion [see Swidan 98]) is faced with significant financial and political barriers, given the up-front cost and the number of countries involved.

The Mediterranean ring that is being built [see OME, 00] will be a key complement to exports of natural gas from North Africa to Europe.
IV.2.2 Middle East

Middle East is a very unique region insofar as most countries are endowed with natural gas and or oil resources, and are among the world’s major fossil fuel exporters. There is no large hydroelectric potential. The interconnection rationale belongs, thereby, to the first category identified in Chapter II, section 3.1 b. There are no other incentives for regional integration than those linked to potential increase in the size of power systems.

As of 1999, there were several natural gas and oil pipelines connecting Iraq, on the Persian Gulf, with Syria, Jordan and Lebanon. The region, nevertheless, may be divided into two isolated electric power subsystems: Mediterranean countries, on the one side, and Persian Gulf countries on the other side.

**Persian Gulf countries**
The GCC interconnection: a study of a 400 kV/220 kV interconnection project of the six countries, members of the Gulf Cooperation Council (GCC) — Saudi Arabia, United Arab Emirates, Oman, Kuwait and Bahrain — has been performed, and the establishment of a supervisory body for the scheme should be imminent.

**Mediterranean countries**
A 500/400 kV interconnection between Egypt, Iraq, Jordan, Syria and Turkey (EIJST) is underway: the 500/400 kV link between Egypt and Jordan was commissioned in 1999; a 500/400 kV link between Egypt and Jordan is being considered. The benefits accruing from the interconnection should largely compensate for the corresponding investment. The feasibility study evidenced, in fact, that the possibility of sharing the reserve margin compensated, in itself, for the interconnection investment. Lebanon, the only country of the region (aside from Israel) to be deprived of oil and gas resources is interconnecting with Syria.
### Table 5: Middle East, domestic supply of electricity (GWh)

<table>
<thead>
<tr>
<th>Country</th>
<th>1990</th>
<th>1998</th>
<th>Growth Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Persian Gulf countries</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kuwait</td>
<td>18,477</td>
<td>29,984</td>
<td>6%</td>
</tr>
<tr>
<td>Bahrain</td>
<td>3,482</td>
<td>5,773</td>
<td>7%</td>
</tr>
<tr>
<td>Iraq</td>
<td>24,000</td>
<td>30,346</td>
<td>3%</td>
</tr>
<tr>
<td>Islamic Republic of Iran</td>
<td>59,102</td>
<td>103,413</td>
<td>7%</td>
</tr>
<tr>
<td>Oman</td>
<td>4,501</td>
<td>8,198</td>
<td>8%</td>
</tr>
<tr>
<td>Qatar</td>
<td>4,818</td>
<td>8,125</td>
<td>7%</td>
</tr>
<tr>
<td>Saudi Arabia</td>
<td>64,899</td>
<td>116,519</td>
<td>8%</td>
</tr>
<tr>
<td>United Arab Emirates</td>
<td>17,080</td>
<td>33,392</td>
<td>9%</td>
</tr>
<tr>
<td>Yemen</td>
<td>1,663</td>
<td>2,507</td>
<td>5%</td>
</tr>
<tr>
<td><strong>Mediterranean countries</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Iraq</td>
<td>24,000</td>
<td>30,346</td>
<td>3%</td>
</tr>
<tr>
<td>Israel</td>
<td>20,442</td>
<td>36,909</td>
<td>8%</td>
</tr>
<tr>
<td>Jordan</td>
<td>3,638</td>
<td>6,741</td>
<td>8%</td>
</tr>
<tr>
<td>Lebanon</td>
<td>1,500</td>
<td>9,011</td>
<td>25%</td>
</tr>
<tr>
<td>Syria</td>
<td>11,611</td>
<td>18,315</td>
<td>6%</td>
</tr>
<tr>
<td>Egypt</td>
<td>42,256</td>
<td>62,966</td>
<td>5%</td>
</tr>
<tr>
<td><strong>Total (excluding Egypt)</strong></td>
<td>235,213</td>
<td>409,233</td>
<td>7%</td>
</tr>
</tbody>
</table>

*Source: IEA*
### IV.2.3 South America

The following figures give an overall picture of the South American electric power industry.

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Population</strong></td>
<td>332,386,000</td>
</tr>
<tr>
<td><strong>Surface</strong></td>
<td>17,347,150 km²</td>
</tr>
<tr>
<td><strong>Electricity generation</strong></td>
<td>635,103 GWh</td>
</tr>
<tr>
<td><strong>Generation capacity</strong></td>
<td>147,199 MW</td>
</tr>
<tr>
<td><strong>Customers</strong></td>
<td>74,187,000</td>
</tr>
<tr>
<td><strong>Electricity / capita</strong></td>
<td>1.911 kWh.</td>
</tr>
</tbody>
</table>

*Source: CIER*

The main features of the South American power systems are a small load density and a significant hydroelectric potential (16.8% of the world’s hydroelectric potential), a large part of which is situated on the Parana and Uruguay basins. These rivers also constitute the borders between Brazil, Paraguay, Uruguay and Argentina. This situation has led to bilateral hydroelectric projects and realizations such as Itaipu and Yacireta, as well as the Garabi project on the Uruguay river. Private financing is being sought for the latter.

Two subregions seem to offer characteristics for medium-term integration:

- The South Cone, with Rio Parana and Rio Paraguay: there is a political umbrella, the Common Market of the South (MERCOSUR), composed of Argentina, Brazil, Paraguay and Uruguay, with Bolivia and Chile as associated members, which considers energy integration as an important issue.

- The Andes community: Venezuela, Colombia, Equator

The natural gas resources in the South Cone were exploited with the help of private financing in gas network interconnection. The integration of the gas market is ongoing.

As for electric power exchanges, the capacity exchanges (some 10 GW) are concentrated around the hydroelectric schemes of the Parana and Paraguay rivers. Other interconnections between Colombia and Venezuela, and Colombia and Ecuador, are operating.

The regional electricity cooperation and integration process is led by CIER, a regional organization.
Table 6: South America, domestic supply of electricity (GWh)

<table>
<thead>
<tr>
<th></th>
<th>1990</th>
<th>1998</th>
<th>Growth Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brazil</td>
<td>249,540</td>
<td>360,992</td>
<td>5%</td>
</tr>
<tr>
<td>Argentina</td>
<td>51,826</td>
<td>82,170</td>
<td>6%</td>
</tr>
<tr>
<td>Venezuela</td>
<td>59,321</td>
<td>80,904</td>
<td>4%</td>
</tr>
<tr>
<td>Colombia</td>
<td>36,357</td>
<td>45,967</td>
<td>3%</td>
</tr>
<tr>
<td>Chile</td>
<td>18,372</td>
<td>35,509</td>
<td>9%</td>
</tr>
<tr>
<td>Peru</td>
<td>13,163</td>
<td>18,584</td>
<td>4%</td>
</tr>
<tr>
<td>Ecuador</td>
<td>6,373</td>
<td>9,897</td>
<td>6%</td>
</tr>
<tr>
<td>Uruguay</td>
<td>4,906</td>
<td>7,412</td>
<td>5%</td>
</tr>
<tr>
<td>Paraguay</td>
<td>2,215</td>
<td>5,536</td>
<td>12%</td>
</tr>
<tr>
<td>Bolivia</td>
<td>2,142</td>
<td>3,717</td>
<td>7%</td>
</tr>
<tr>
<td>Total</td>
<td>444,215</td>
<td>650,688</td>
<td>5%</td>
</tr>
</tbody>
</table>

Source: IEA 1999
### IV.2.4 Central America and Antilles

An interconnection from Mexico to Panama is being planned.

*Table 7: Central America and Antilles, domestic supply of electricity (GWh)*

<table>
<thead>
<tr>
<th></th>
<th>1990</th>
<th>1998</th>
<th>Growth rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cuba</td>
<td>15,025</td>
<td>14,145</td>
<td>-1%</td>
</tr>
<tr>
<td>Dominican Republic</td>
<td>3,698</td>
<td>7,555</td>
<td>9%</td>
</tr>
<tr>
<td>Jamaica</td>
<td>2,016</td>
<td>6,480</td>
<td>16%</td>
</tr>
<tr>
<td>Costa Rica</td>
<td>3,631</td>
<td>5,723</td>
<td>6%</td>
</tr>
<tr>
<td>Trinidad and Tobago</td>
<td>3,577</td>
<td>5,169</td>
<td>5%</td>
</tr>
<tr>
<td>Guatemala</td>
<td>2,316</td>
<td>4,418</td>
<td>8%</td>
</tr>
<tr>
<td>Panama</td>
<td>2,985</td>
<td>4,387</td>
<td>5%</td>
</tr>
<tr>
<td>El Salvador</td>
<td>2,262</td>
<td>3,921</td>
<td>7%</td>
</tr>
<tr>
<td>Honduras</td>
<td>1,985</td>
<td>3,515</td>
<td>7%</td>
</tr>
<tr>
<td>Nicaragua</td>
<td>1,465</td>
<td>2,262</td>
<td>6%</td>
</tr>
<tr>
<td>Netherlands Antilles</td>
<td>790</td>
<td>1,116</td>
<td>4%</td>
</tr>
<tr>
<td>Haiti</td>
<td>597</td>
<td>663</td>
<td>1%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>40,347</strong></td>
<td><strong>59,354</strong></td>
<td><strong>5%</strong></td>
</tr>
</tbody>
</table>

*Source: IEA 1999*
IV.2.5 South Asia

At first sight, this region presents highly favorable features for regional integration. Considering its population density, its large area surface and its central position, India should be a natural leader in initiating an integration process.

In 1997, there seemed to be some prospects for an energy confederation composed of India, Pakistan and Bangladesh. Plans were said to be afoot, at that time, to tap the vast hydro potential in the neighboring nations and import power to India.

India, which can be considered as a region in itself, has still to go through an integration process, from its state electricity boards to the regional and national levels. For now, a nationwide interconnected system is being devised [see CEA, 97], but the integration of state electricity boards into an Indian energy system faces strong opposition. A committee, formed to consider the changeover from a regional to a national concept in power planning, concluded that, taking into account the poor quality of system operation at the regional level, the time was not ripe for the changeover. In June 1999, however, the Central Electricity Authority of India made a “first attempt to carry out studies for transmission development on an “All India” basis, with the objective of developing a “National Power Grid”, and it proposed “to achieve the objective of forming a national Power Grid in a phased manner by the year 2012.” [see CEA, 99]

In South Asia, there is a large hydroelectric potential with the river basins of Brahmaputra, Indus and Ganges still untapped. For India alone, this potential is estimated at 500 TWh — as compared to an existing hydroelectric generation capacity of some 100 TWh — 83% of which is located in the northern and northeastern regions, close to the Himalayas.

39. Actually, the basic unit in India is made up of the 18 State Electric Boards and 11 other utilities (roughly one by state). In the 1960s, a first integration step was taken when six regions were identified for planning and operation. In 1975, the central government of India created two generation companies, one for thermal power plants and another for hydroelectric power plants. Later on, a National Power Grid company was created.

40. There is need for an eventual change from a regional to a national concept in planning for power development. However, this has to be an evolutionary process. A critical analysis of the present level of consolidation of regional grids, the projected power supply position, adequacy of transmission and load dispatch facilities and the trend towards private sector participation in power development indicate that the time is not yet ripe for the change over. The Committee, therefore, considers that planning on the basis of a regional concept may be followed for the 9th Plan period. In the meantime, efforts should be continued to further consolidate the regional grids and evolve a viable National Power Grid. The progress made in this regard may be reviewed towards the end of the 9th Plan period. Keeping this in view, as well as the picture that would have emerged by then with regard to private sector participation in power development, a decision for a changeover to a national concept in power planning for the 10th Plan and beyond could be made.
As mentioned by the World Bank in an appraisal document on a loan for restructuring the power system of an Indian state, Andhra Pradesh [see WB, 99(7)], the national restructuring program of India's power transmission and system operation would proceed in parallel with state-level reforms of the energy sector.

Table 8: South Asia, domestic supply of electricity (GWh)

<table>
<thead>
<tr>
<th>Country</th>
<th>1990</th>
<th>1998</th>
<th>Growth Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>India</td>
<td>290,815</td>
<td>495,513</td>
<td>7%</td>
</tr>
<tr>
<td>Pakistan</td>
<td>37,673</td>
<td>62,154</td>
<td>6%</td>
</tr>
<tr>
<td>Bangladesh</td>
<td>7,732</td>
<td>12,882</td>
<td>7%</td>
</tr>
<tr>
<td>Sri Lanka</td>
<td>3,150</td>
<td>5,683</td>
<td>8%</td>
</tr>
<tr>
<td>Nepal</td>
<td>838</td>
<td>1,436</td>
<td>7%</td>
</tr>
<tr>
<td>Total</td>
<td>340,208</td>
<td>577,668</td>
<td>7%</td>
</tr>
</tbody>
</table>

Source: IEA 1999

41. In this document, the World Bank noted that “To encourage private investment in the transmission business, the Central government enacted the Electricity Laws (Amendment) Act 1998, in August 1998. This act provides for the establishment of a central transmission utility, state transmission utilities and transmission licensees and thereby facilitates private investment in power transmission. POWERGRID, India’s national transmission utility (designated as the Central transmission utility under the new act), is developing modern system coordination and control facilities (including load dispatch system for state utilities) and regional power pools. These facilities and the emerging regional electric power markets with availability-based bulk power tariffs and frequency-linked power pool rates will enable generators and utilities to improve the efficiency of system operations and trade power under scheduled and unscheduled interchange arrangements, supplementing power supplied under long-term PPAs. Over time, POWERGRID plans to interconnect these regional systems towards a national power grid. POWERGRID is also involved in facilitating power imports from neighboring countries.”
IV.2.6 Southeast Asia

The countries in this region have GDPs per capita, ranging from less than 1,000 to more than 10,000 in Thailand and Singapore; the electrification rate and the electricity use of the countries vary in a similar manner. The potentially largest exporter of hydroelectricity — the Lao People's Democratic Republic (Lao PDR) — is one of the smallest and poorest country of the region.

South Asia is the region of the world where electric consumption has increased the most during the 1990-1998 period. The hydroelectric potential of the Mekong river basin is significant and mostly concentrated in the province of Yunnan in China, Lao PDR and Myanmar.

The history of interconnection dates back to 1968 when the first interconnection line between Thailand and Lao PDR was commissioned. This line was designed to facilitate hydroelectric power exports from Laotian dams to Thailand.

Thailand, given its central position, is the most interconnected country of the region. As of 1998, however, Thai imports from Lao PDR and Peninsular Malaysia represent only 1.8% of its domestic supply; even though these imports are increasing, they still only represent a very modest share of the country’s power supply.
Table 9: South Asia, domestic supply of electricity (GWh)

<table>
<thead>
<tr>
<th></th>
<th>1990</th>
<th>1998</th>
<th>Growth Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thailand</td>
<td>44,796</td>
<td>91,539</td>
<td>9%</td>
</tr>
<tr>
<td>Indonesia</td>
<td>36,951</td>
<td>77,903</td>
<td>10%</td>
</tr>
<tr>
<td>Malaysia</td>
<td>22,942</td>
<td>60,664</td>
<td>13%</td>
</tr>
<tr>
<td>Philippines</td>
<td>25,245</td>
<td>41,192</td>
<td>6%</td>
</tr>
<tr>
<td>Singapore</td>
<td>15,714</td>
<td>28,557</td>
<td>8%</td>
</tr>
<tr>
<td>Vietnam</td>
<td>8,722</td>
<td>21,665</td>
<td>12%</td>
</tr>
<tr>
<td>Myanmar</td>
<td>2,478</td>
<td>4,579</td>
<td>8%</td>
</tr>
<tr>
<td>Brunei</td>
<td>1,172</td>
<td>2,503</td>
<td>10%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>158,020</strong></td>
<td><strong>328,602</strong></td>
<td><strong>10%</strong></td>
</tr>
</tbody>
</table>

Source: IEA 1999

With a hydroelectric potential estimated at 837 TWh (more than twice the 1998 overall South Asian domestic supply), only 2% of which is being tapped, there are very impressive perspectives for regional integration. Nam Teun II — an hydroelectric power plant project that would be located in the Lao PDR for exports to Thailand and operated by an independent power producer — has been discussed for at least 10 years. A RECI Organization would surely facilitate the project.

The Great Mekong Subregion is proceeding with the establishment of such an organization [see section 2.2 of this chapter].

### IV.2.7 Northeast Asia

<table>
<thead>
<tr>
<th></th>
<th>1990</th>
<th>1998</th>
<th>Growth Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>People's Republic of China</td>
<td>623,040</td>
<td>1,159,043</td>
<td>8%</td>
</tr>
<tr>
<td>Chinese Taipei</td>
<td>90,479</td>
<td>166,179</td>
<td>8%</td>
</tr>
<tr>
<td>Hong Kong (China)</td>
<td>27,139</td>
<td>38,567</td>
<td>4%</td>
</tr>
<tr>
<td>DPR of Korea</td>
<td>53,500</td>
<td>30,989</td>
<td>-7%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>794,158</strong></td>
<td><strong>1,394,778</strong></td>
<td><strong>7%</strong></td>
</tr>
</tbody>
</table>

Source: IEA 1999

China’s electric power industry is composed of provincial companies whose development plans have to be approved at the central level. The bulk of its power supply comes from coal-fired power plants. The cheapest and more abundant coal reserves are situated in the province of Shanxi, some 1,000 kilometers east of Beijing.
The promotion of electric interconnections between provinces, as opposed to the transport of low quality coal through a saturated railway network, is ongoing. An interconnection project (specifically directed towards Shanghai) should be designed, with the Three-Gorge project as centerpiece. Along the borders, there are plans to interconnect with the Kyrgyz Republic in order to benefit from its inexpensive hydroelectric potential.

A northeastern Asian ring is being planned, from China to Korea, to Japan, from Japan (Hokkaido) to Russia (Sakhalin) and back to China [see APERC, 00].

IV.3 Regions with an Ongoing Integration Process

The integration process in four regions is presented in more details below. The OMVS is by far the smallest, its peak load cumulating at only 0.35 GW as compared with the Greater Mekong Subregion’s 20 GW, the more than 100 GW in South America, and the South African Power Pool (SAAP). All four regions can count on hydroelectric resources, whose development, however, cannot be managed by a country alone. Most of the time, the best hydroelectric resources are situated in the mountains, that is in the less populated and poorer parts of the region. In each of the region, the integration process is spurred by the richest and/or most populated country which, considering the current state of its electric power systems, can manage market competition and is keen on reinforcing the commercial links with its neighbors. The Republic of South Africa is the best example.

In the southern region (SADC) as well as in the western region (ECOWAS) of Africa, in the Greater Mekong Subregion of Asia, and in South America (CIER), the integration process is strongly supported by international organizations and particularly by the World Bank.

In all these regions, the World Bank supports the creation of a regional power market, analogous to those emerging in E7 countries’ regions. The European Commission is funding a study of an electric ring of the Mediterranean sea, the so-called “Med-Ring” project; although there is currently no formal integration process, the Mediterranean basin region is also presented below.

IV.3.1 CIER (South America) studies

The Regional Electrical Integration Commission (CIER) was created on July 10, 1964, on the basis of a proposition approved during the First Regional Electrical Integration Congress, held in Montevideo, at the instigation of the Uruguayan Electric Sector Authorities. The foremost objective of this nonprofit international organization is to promote and foster the integration of the regional electric power systems.
Among the studies undertaken by this commission, three are aimed at fostering the integration of the electricity supply industries of the region:

1. Assessment of the hydroelectric potential and of its complementarity (CIER 1);
2. Main markets and feasibility of interconnections (CIER 2);
3. Identification of institutional and political barriers to the integration of electricity markets and recommendation for overcoming these barriers (CIER 3).

The first two studies have already been conducted, and confirm the important benefits that would accrue from the integration of the national electric power systems. In addition to the conventional economic benefits accruing from interconnections, the more efficient use of hydroelectric resources (if CO₂ emissions were priced at US$30/ton) could finance the construction of some 20,000 km of 400 kV AC transmission lines. The impact of international trade would be a price increase for the exporting country’s national customers. This impact has been carefully studied.

It should be mentioned here that, at this time, no state has manifested its intention to commit itself to an integration process.

IV.3.2 Greater Mekong Subregion (GMS)

The integration of the Greater Mekong Subregion, in East Asia region, can be considered as an ongoing process, and has been qualified by Enrique Croustillat [see WB, 95 (2)] as a “long-term process” whose most important benefits will accrue after 2010. The delay is attributable to the long lead times for the construction of hydroelectric schemes.

The GMS includes Cambodia, the province of Yunnan in China, LAO PDR, Myanmar, Thailand and Vietnam.

The integration process seems to have been assisted, since 1992, by the Asian Development Bank under a GMS program. Other international organizations involved are the ASEAN, with the ASEAN Centre for Energy (ACE), the Mekong River Commission, and the World Bank. The existing structures for the development of the energy trade and interconnections in the GMS are the following:

1. Yearly ministerial meetings: the 9th GMS Ministerial Meeting was held in Manila on January 2000;
2. The Electric Power Forum (EPF), meeting once a year, whose role is to coordinate all matters relative to the Policy Statement;
3. The Experts Group on Power Interconnection and Trade (EGP), whose role is to promote and administer energy trade. The EGP, composed of two experts from each country (one from the electric utilities, the other from the government) was created more recently and meets twice a year.
Under a GMS program, the following statements, understandings, protocols and workshops are being developed by the EGP:

- an intergovernmental Memorandum of Understanding;
- a Policy Statement on Regional Power Trade has become effective, after it was adopted by the EPF and endorsed by the Ministerial Meeting. With this agreement, GMS members acknowledge power trade, the importance of harmonization of transmission technical standards and of information exchange, the desirability of foreign investment, and agree on best practice for private sector participation, as well as the need to protect the environment;
- a regional protocol on regional power trade, the principle of which has been agreed in the Policy Statement, as well as on the establishment of formal bodies for technical and nontechnical trade matters: November 2000;
- a regional indicative master plan, due date: October 2001;
- a regulatory and institutional framework: October 2002;
- and some workshops dealing with coordination of technical issues, institutional, regulatory and commercial issues, and project financing.

These activities are financed by the Asian Development Bank and the World Bank.

Enrique Croustillat identified the following barriers to full power trade. Institutional barriers are leadership and priorities; the absence of a Regional organization capable of promoting and managing the development of trade; long-term contracting, too rigid to allow for international exchanges; transmission ownership which is not fixed; and the absence of open access transmission rules and of an independent regulation. Technical barriers are the absence of a transmission master plan and of harmonization of operation standards. Commercial and financial barriers are the absence of transmission tariff, construction uncertainty, country and cross border risks.
IV.3.3 Organisation de Mise en Valeur du Fleuve Sénégal (OMVS)

The Senegal and Niger rivers are the most important rivers of Western Africa. These rivers share the same mountain (the Fouta Djalon) as their source, and practically the same water flow regime: maximum flow in August and September during the rain season, and virtually no water during the preceding period. Most of the hydroelectric potential of the basin of the Senegal river is situated in the western part of Mali. After leaving Mali, the river flows to the west and serves as a border between Mauritania, on the right bank, and Senegal, on the left bank. The river was used for agriculture (in what is called “culture after the fall of the river”); it could be use for navigation all year long, if a minimum flow could be maintained; and diverting some of the water is being planned in order to meet the water requirements of the region of the capital of Senegal, Dakar.

Building a dam in Manantali, in Mali, has for long been considered as a multipurpose project of regional interest. Based on an assessment of the benefits for the three countries — navigation, agriculture and electric power generation — a key of repartition of the costs of the project was proposed and adopted by the three countries. The project was estimated at some US$1 billion, with a 4 x 50 MW hydroelectric power plant situated in Manantali, and connected through 1,200 km long 225 kV lines, the main loads of Mali, Senegal and Mauritania.

Surprisingly, ten years passed between the completion of the dam in 1989, and the beginning of construction of the hydroelectric power plant and the associated transmission lines. Why so much time, considering that this project could yield the most easily measurable benefits and recoverable returns, and that the bulk of the investment, the dam, had already been spent?

One can mention the political disputes between Senegal and Mauritania, the inability of the beneficiaries (the state-owned companies) to present financial statements and, accordingly, the absence of any guarantee for the institutional lenders, the absence of an agreement on the route of the line, and some questioning about the certainty of an average hydroelectric generation attributable to a seemingly decreasing trend of the yearly river flow over the 1970-1990 period, as compared with the 1900-1970 period. It is also to be acknowledged that the three countries did feel the same urgency to complete the hydroelectric part of the project, and used the fact that the upstream country (namely Mali) had stronger incentives, particularly higher avoided costs of thermal generation, to demand extra transmission facilities.
Finally, an appraisal mission of the project was held in December 1996, and nearly all the financing was obtained in mid 1997. An independent company will be in charge of building and operating the hydroelectric power plant and the associated transmission lines, and will sell the electricity to the three national electric utilities, allocating to each of them a share of the energy corresponding to the aforementioned key of repartition. Over the counter energy sales between utilities are possible.

**IV.3.4 The South African Power Pool (SAPP)**

The South African Power Pool (SAPP) was inaugurated in 1995 [see 26, WB 98(4)] with the structure of a loose pool (where participants are allowed to contract bilaterally). This pool has been developed under the umbrella of the region’s political organization, the South African Development Community (SADC). This organization welcomed the Republic of South Africa (RSA) after the end of apartheid. SADC member countries were used to cooperating for a long time already. When the RSA entered the Community, it gave a very strong momentum to the development of a regional energy plan.

This region of some 9 million square kilometers, and 180 to 200 million inhabitants, is made up of 12 countries, from RSA to DRC and Tanzania. Electric energy consumption is more than 200 TWh, with a peak load of 30 to 35 GW to be supplied by a capacity totaling some 45 GW, RSA producing the bulk of it, that is 85 to 90%.

SAPP is the first formal international power pool to be established outside Europe and North America. It came into effect in September 1995, and moved towards implementation in December 1995 when two Memorandum Of Understanding — intergovernmental and interutilities — were signed by a majority of SADC members. These Memorandum Of Understanding are complemented with a ban agreement between operating members.

The southern part of Africa offers good features for regional electricity cooperation and integration:

Under the aegis of the South African Development Community (SADC), countries of the region have been cooperating in various sectors, such as telecommunications, transport and energy, for several decades and, consequently, have developed a “regional culture”. Virtually all the countries of the region are interconnected, with interconnection capacity varying from 100 to 1,400 MW. The transactions between countries are characterized by long-term bilateral contracts.

The region is endowed with diversified primary energy resources: hydroelectricity, coal, oil and natural gas. These resources are distributed in such a way that the countries’ capacity complement each other: coal in the RSA and Zimbabwe; hydroelectric energy in Mozambique, Zambia, Zimbabwe, Angola and the Democratic Republic of Congo (DRC); natural gas in Namibia and Mozambique; oil in Angola.
RSA, an industrialized country accounting for 90% of the region's production and consumption, is very proactive in the development of a regional electric network. This network would enable RSA to benefit from diversified energy sources (particularly hydroelectric energy) for its electric supply.

From an institutional point of view, most SAPP countries have embarked on or are moving ahead with power sector reforms:

- separation of accounts, or accounts unbundling for generation, transmission and distribution;
- development of investment policies in the power sector to facilitate private investments for Independent Power Producers (IPPs);
- experience of private companies:
  - a part of the Zambian transmission system has been privatized.
  - ESKOM, the state-owned monopoly from SAR, has initiated an internal competitive power pool for its own generation.
- HCB is the owner and operator of the of a 2,075 MW Cabora-Bassa hydroelectric power plant located in Mozambique, and of a 1,400 kilometer-long HVDC interconnection link with SAR to supply electric to ESKOM.
- A large consumer, MOZAL, located in one country, Mozambique, will be supplied the electric utility of another country, ESKOM from RSA.
- A wheeling charge contract has been signed between DRC and Zambia for transiting electric power from DRC to Zimbabwe through Zambia.
- Some countries, Botswana, Namibia and Mozambique (the southern area), have opted for greater degrees of importing over building new national generation capacity.

The RECI implementation process, with the support of the World Bank, is underway, and the most immediate issues that need to be addressed in the near future are:

- to operationalize the Regional Coordination Center;
- to develop regional generation and transmission planning (a preliminary study conducted during the Preparatory Phase of SAPP has led to a schematic diagram of the possible main interconnection links for the region);
- to organize training for system operators;
- to conduct an assessment of the National Control Centers;
- to initiate studies on transmission pricing;
- to form a Working Group to assess preconditions for private sector participation;
- to perform a study for the harmonization of the SAPP rules with the ESKOM competitive generator's pool.
The consequent activities are underway, but works are less advanced than initially scheduled when the agreements were signed. This is particularly attributable to the fact that the implementation of an international power pool is complex, and that countries are reluctant to accept a loss of autonomy. The implementation of the Regional Coordination Center, which is crucial for achieving an efficient South African Power Pool, has been delayed.

**IV.3.5 The Mediterranean-ring**

The Mediterranean-ring, even though it is not a RECI Organization as modeled in these Guidelines, should develop very quickly. There are several reasons for this prognostic:

- the political willingness of the European Union to integrate the Mediterranean basin in its sphere of influence — the European Commission is studying the possibility to extend the Trans-European energy networks to the southern part of the Mediterranean sea;
- the opposition in European countries to the construction of power plants;
- the emergence of power markets in European countries, open to imports, and therefore giving the possibility for the Maghreb countries to export thermal electric power;
- the European Union’s strategic and commercial interest in combining natural gas and electricity imports from the Maghreb countries;
- the need for the Maghreb countries to provide some stability and redundancy to an electric network system which is currently linear along the Mediterranean sea — in general a ring is a very secure electric system.

The interconnection investments are not that important as compared with the financial capacities of the countries, and the integration of European electricity supply industries is already underway, giving momentum to the development of the Mediterranean ring. The organization to be put in place for pooling resources, accordingly, need not be identical those planned or implemented in other regions.

The *Observatoire Méditerranéen de l’Énergie* (OME), a nongovernmental organization of energy companies of the Mediterranean basin, is the foremost party with an interest in the development of electric networks in the Mediterranean basin.
Table 10: 1998 electricity balances of countries ranked by descending order of imports dependence

<table>
<thead>
<tr>
<th>Domestic Supply</th>
<th>Imports</th>
<th>Exports</th>
<th>Imports</th>
<th>Exports</th>
<th>Net Imports</th>
</tr>
</thead>
<tbody>
<tr>
<td>GWh</td>
<td>GWh</td>
<td>GWh</td>
<td>%</td>
<td>%</td>
<td>GWh</td>
</tr>
<tr>
<td>Luxembourg</td>
<td>6,712</td>
<td>6,338</td>
<td>924</td>
<td>94.4%</td>
<td>13.8%</td>
</tr>
<tr>
<td>Togo</td>
<td>522</td>
<td>426</td>
<td>-</td>
<td>81.6%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Benin</td>
<td>317</td>
<td>255</td>
<td>-</td>
<td>80.4%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Kyrgyzstan</td>
<td>10,889</td>
<td>6,399</td>
<td>7,125</td>
<td>58.8%</td>
<td>65.4%</td>
</tr>
<tr>
<td>Zimbabwe</td>
<td>11,757</td>
<td>5,149</td>
<td>-</td>
<td>43.8%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Switzerland</td>
<td>56,923</td>
<td>23,607</td>
<td>29,561</td>
<td>41.5%</td>
<td>51.9%</td>
</tr>
<tr>
<td>Belarus</td>
<td>32,699</td>
<td>10,009</td>
<td>2,610</td>
<td>30.6%</td>
<td>8.0%</td>
</tr>
<tr>
<td>Republic of Moldova</td>
<td>6,500</td>
<td>1,916</td>
<td>-</td>
<td>29.5%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Tajikistan</td>
<td>14,667</td>
<td>3,969</td>
<td>3,724</td>
<td>27.1%</td>
<td>25.4%</td>
</tr>
<tr>
<td>Congo</td>
<td>470</td>
<td>126</td>
<td>428</td>
<td>26.5%</td>
<td>3.0%</td>
</tr>
<tr>
<td>Croatia</td>
<td>14,252</td>
<td>3,782</td>
<td>428</td>
<td>26.5%</td>
<td>3.0%</td>
</tr>
<tr>
<td>Mozambique</td>
<td>1,537</td>
<td>350</td>
<td>5,677</td>
<td>22.8%</td>
<td>369.4%</td>
</tr>
<tr>
<td>Hong Kong (China)</td>
<td>38,567</td>
<td>7,760</td>
<td>610</td>
<td>20.1%</td>
<td>1.6%</td>
</tr>
<tr>
<td>Austria</td>
<td>57,274</td>
<td>10,304</td>
<td>10,467</td>
<td>18.0%</td>
<td>18.3%</td>
</tr>
<tr>
<td>Nepal</td>
<td>1,436</td>
<td>239</td>
<td>60</td>
<td>16.6%</td>
<td>4.2%</td>
</tr>
<tr>
<td>Bosnia-Herzegovina</td>
<td>2,762</td>
<td>423</td>
<td>199</td>
<td>15.3%</td>
<td>7.2%</td>
</tr>
<tr>
<td>Turkmenistan</td>
<td>6,307</td>
<td>950</td>
<td>4,059</td>
<td>15.1%</td>
<td>64.4%</td>
</tr>
<tr>
<td>Latvia</td>
<td>6,267</td>
<td>914</td>
<td>385</td>
<td>14.6%</td>
<td>6.1%</td>
</tr>
<tr>
<td>Italy</td>
<td>300,518</td>
<td>41,633</td>
<td>901</td>
<td>13.9%</td>
<td>0.3%</td>
</tr>
<tr>
<td>Kazakhstan</td>
<td>52,955</td>
<td>7,252</td>
<td>3,441</td>
<td>13.7%</td>
<td>6.5%</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>62,651</td>
<td>8,383</td>
<td>10,844</td>
<td>13.4%</td>
<td>17.3%</td>
</tr>
<tr>
<td>Uzbekistan</td>
<td>46,800</td>
<td>6,000</td>
<td>5,100</td>
<td>12.8%</td>
<td>10.9%</td>
</tr>
<tr>
<td>Finland</td>
<td>79,475</td>
<td>9,582</td>
<td>276</td>
<td>12.1%</td>
<td>0.3%</td>
</tr>
<tr>
<td>Netherlands</td>
<td>102,979</td>
<td>12,234</td>
<td>420</td>
<td>11.9%</td>
<td>0.4%</td>
</tr>
<tr>
<td>Ghana</td>
<td>7,741</td>
<td>912</td>
<td>422</td>
<td>11.8%</td>
<td>5.5%</td>
</tr>
<tr>
<td>Brazil</td>
<td>360,992</td>
<td>39,412</td>
<td>8</td>
<td>10.9%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Hungary</td>
<td>37,928</td>
<td>4,042</td>
<td>3,302</td>
<td>10.7%</td>
<td>8.7%</td>
</tr>
<tr>
<td>Country</td>
<td>Installed Capacity</td>
<td>New Capacity</td>
<td>Peaking Capacity</td>
<td>Unit Commitment</td>
<td>Unit Reserve</td>
</tr>
<tr>
<td>---------------------------------</td>
<td>--------------------</td>
<td>--------------</td>
<td>------------------</td>
<td>------------------</td>
<td>--------------</td>
</tr>
<tr>
<td>Portugal</td>
<td>39,259</td>
<td>3,974</td>
<td>3,700</td>
<td>10.1%</td>
<td>9.4%</td>
</tr>
<tr>
<td>Argentina</td>
<td>82,170</td>
<td>8,000</td>
<td>-</td>
<td>-9.7%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Belgium</td>
<td>84,634</td>
<td>7,828</td>
<td>6,435</td>
<td>9.2%</td>
<td>7.6%</td>
</tr>
<tr>
<td>Denmark</td>
<td>36,763</td>
<td>3,280</td>
<td>7,600</td>
<td>8.9%</td>
<td>20.7%</td>
</tr>
<tr>
<td>Georgia</td>
<td>7,971</td>
<td>698</td>
<td>796</td>
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<td>10.0%</td>
</tr>
<tr>
<td>Other Africa</td>
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<td>858</td>
<td>124</td>
<td>8.2%</td>
<td>1.2%</td>
</tr>
<tr>
<td>Lebanon</td>
<td>9,011</td>
<td>654</td>
<td>-</td>
<td>-7.3%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Germany</td>
<td>555,762</td>
<td>38,315</td>
<td>38,953</td>
<td>6.9%</td>
<td>7.0%</td>
</tr>
<tr>
<td>Norway</td>
<td>120,617</td>
<td>8,046</td>
<td>4,412</td>
<td>6.7%</td>
<td>3.7%</td>
</tr>
<tr>
<td>Former Yugoslavia</td>
<td>76,263</td>
<td>4,911</td>
<td>3,527</td>
<td>6.4%</td>
<td>4.6%</td>
</tr>
<tr>
<td>Slovenia</td>
<td>11,820</td>
<td>706</td>
<td>2,630</td>
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<td>22.3%</td>
</tr>
<tr>
<td>Ukraine</td>
<td>172,150</td>
<td>10,056</td>
<td>10,728</td>
<td>5.8%</td>
<td>6.2%</td>
</tr>
<tr>
<td>Slovak Republic</td>
<td>26,755</td>
<td>1,447</td>
<td>157</td>
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<td>0.6%</td>
</tr>
<tr>
<td>Greece</td>
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<td>2,500</td>
<td>890</td>
<td>5.2%</td>
<td>1.9%</td>
</tr>
<tr>
<td>Azerbaijan</td>
<td>18,240</td>
<td>903</td>
<td>648</td>
<td>5.0%</td>
<td>3.6%</td>
</tr>
<tr>
<td>Morocco</td>
<td>14,841</td>
<td>705</td>
<td>-</td>
<td>-4.8%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Spain</td>
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<td>8,964</td>
<td>5,562</td>
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<td>2.8%</td>
</tr>
<tr>
<td>Sweden</td>
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<td>6,102</td>
<td>16,799</td>
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<td>11.4%</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>370,714</td>
<td>12,630</td>
<td>162</td>
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<td>0.0%</td>
</tr>
<tr>
<td>Lithuania</td>
<td>11,549</td>
<td>384</td>
<td>6,466</td>
<td>3.3%</td>
<td>56.0%</td>
</tr>
<tr>
<td>Poland</td>
<td>139,315</td>
<td>4,608</td>
<td>8,082</td>
<td>3.3%</td>
<td>5.8%</td>
</tr>
<tr>
<td>Canada</td>
<td>534,439</td>
<td>17,299</td>
<td>44,665</td>
<td>3.2%</td>
<td>8.4%</td>
</tr>
<tr>
<td>Kenya</td>
<td>4,950</td>
<td>146</td>
<td>-</td>
<td>-2.9%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Turkey</td>
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<td>3,298</td>
<td>298</td>
<td>2.9%</td>
<td>0.3%</td>
</tr>
<tr>
<td>Albania</td>
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<td>100</td>
<td>500</td>
<td>2.1%</td>
<td>10.7%</td>
</tr>
<tr>
<td>Other Asia</td>
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<td>114</td>
<td>1,547</td>
<td>2.1%</td>
<td>28.0%</td>
</tr>
<tr>
<td>United Republic of Tanzania</td>
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<td>43</td>
<td>-</td>
<td>-2.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Thailand</td>
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<td>1,623</td>
<td>153</td>
<td>1.8%</td>
<td>0.2%</td>
</tr>
<tr>
<td>Honduras</td>
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<td>60</td>
<td>16</td>
<td>1.7%</td>
<td>0.5%</td>
</tr>
<tr>
<td>Estonia</td>
<td>8,131</td>
<td>138</td>
<td>528</td>
<td>1.7%</td>
<td>6.5%</td>
</tr>
<tr>
<td>El Salvador</td>
<td>3,921</td>
<td>61</td>
<td>(23)</td>
<td>1.6%</td>
<td>-0.6%</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>38,064</td>
<td>564</td>
<td>4,211</td>
<td>1.5%</td>
<td>11.1%</td>
</tr>
<tr>
<td>Costa Rica</td>
<td>5,723</td>
<td>77</td>
<td>148</td>
<td>1.3%</td>
<td>2.6%</td>
</tr>
<tr>
<td>Country</td>
<td>kWh</td>
<td>GWh</td>
<td>TWh</td>
<td>%</td>
<td>%</td>
</tr>
<tr>
<td>-------------------------</td>
<td>-----</td>
<td>-----</td>
<td>-----</td>
<td>------</td>
<td>------</td>
</tr>
<tr>
<td>Romania</td>
<td>53,883</td>
<td>724</td>
<td>337</td>
<td>1.3%</td>
<td>0.6%</td>
</tr>
<tr>
<td>Panama</td>
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<td>57</td>
<td>23</td>
<td>1.3%</td>
<td>0.5%</td>
</tr>
<tr>
<td>South Africa</td>
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<td>2,375</td>
<td>4,532</td>
<td>1.2%</td>
<td>2.2%</td>
</tr>
<tr>
<td>Algeria</td>
<td>23,608</td>
<td>255</td>
<td>262</td>
<td>1.1%</td>
<td>1.1%</td>
</tr>
<tr>
<td>Uruguay</td>
<td>7,412</td>
<td>78</td>
<td>2,234</td>
<td>1.1%</td>
<td>30.1%</td>
</tr>
<tr>
<td>United States</td>
<td>3,859,365</td>
<td>39,513</td>
<td>12,730</td>
<td>1.0%</td>
<td>0.3%</td>
</tr>
<tr>
<td>Russia</td>
<td>809,124</td>
<td>8,261</td>
<td>26,275</td>
<td>1.0%</td>
<td>3.2%</td>
</tr>
<tr>
<td>France</td>
<td>453,330</td>
<td>4,590</td>
<td>62,152</td>
<td>1.0%</td>
<td>13.7%</td>
</tr>
<tr>
<td>Democratic Republic of Congo</td>
<td>5,535</td>
<td>56</td>
<td>188</td>
<td>1.0%</td>
<td>3.4%</td>
</tr>
<tr>
<td>Mexico</td>
<td>183,779</td>
<td>1,705</td>
<td>272</td>
<td>0.9%</td>
<td>0.1%</td>
</tr>
<tr>
<td>Ireland</td>
<td>21,234</td>
<td>152</td>
<td>73</td>
<td>0.7%</td>
<td>0.3%</td>
</tr>
<tr>
<td>India</td>
<td>495,513</td>
<td>1,675</td>
<td>130</td>
<td>0.3%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Nicaragua</td>
<td>2,262</td>
<td>7</td>
<td>11</td>
<td>0.3%</td>
<td>0.5%</td>
</tr>
<tr>
<td>Other Latin America</td>
<td>7,688</td>
<td>17</td>
<td>-</td>
<td>-0.2%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Bolivia</td>
<td>3,717</td>
<td>7</td>
<td>1</td>
<td>0.2%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Colombia</td>
<td>45,967</td>
<td>85</td>
<td>64</td>
<td>0.2%</td>
<td>0.1%</td>
</tr>
<tr>
<td>Peru</td>
<td>18,584</td>
<td>1</td>
<td>-</td>
<td>-0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Malaysia</td>
<td>60,664</td>
<td>1</td>
<td>8</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>People's Republic of Congo</td>
<td>1,159,043</td>
<td>17</td>
<td>7,174</td>
<td>0.0%</td>
<td>0.6%</td>
</tr>
<tr>
<td>Australia</td>
<td>194,834</td>
<td>-</td>
<td>-</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Iceland</td>
<td>6,281</td>
<td>-</td>
<td>-</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Japan</td>
<td>1,046,294</td>
<td>-</td>
<td>-</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Korea</td>
<td>37,240</td>
<td>-</td>
<td>-</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>New Zealand</td>
<td>37,566</td>
<td>-</td>
<td>-</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Angola</td>
<td>1,063</td>
<td>-</td>
<td>-</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Cameroon</td>
<td>3,285</td>
<td>-</td>
<td>-</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Côte d'Ivoire</td>
<td>3,399</td>
<td>-593</td>
<td>0.0%</td>
<td>17.4%</td>
<td>(593)</td>
</tr>
<tr>
<td>Egypt</td>
<td>62,966</td>
<td>-</td>
<td>-</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Ethiopia</td>
<td>1,627</td>
<td>-</td>
<td>-</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Gabon</td>
<td>1,027</td>
<td>-</td>
<td>-</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Libya</td>
<td>19,496</td>
<td>-</td>
<td>-</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Nigeria</td>
<td>15,716</td>
<td>-</td>
<td>-</td>
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Module 2
Market Analysis
Module 2
Market Analysis

Introduction

Chapter I  Economic Appraisal of the Interconnection Project: the Case of Pooling Generation Resources
  I.1 Evaluating Management Cost Reductions
  I.2 Other Benefits and the Investment Costs

Chapter II  Economic Appraisal of the Interconnection Project: the Case of Access to New Markets
  II.1 Energy Demand Modeling
      II.1.1 Econometric models
      II.1.2 Technico-economic models
      II.1.3 General equilibrium models
  II.2 Forecasting the Future: Limits and Precautions
      II.2.1 Scenario approach
      II.2.2 Some recommendations

Chapter III  Ability to Pay and Tariff Setting

List of Figures
  Figure 1: Energy modelling
  Figure 2: Structure of the “MEDEE-S” model
  Figure 3: Structure of PRIMES

Appendix

back/forward to
Module 1
Module 3
Module 4
Module 5
Module 6
Module 7
Module 8
Glossary of Technical Terms
Acronyms and Symbols
Introduction

The preliminary phase of an interconnection project has the strategic objective of producing a picture, as detailed as possible, of the characteristics and expectations of the market (market analysis) and, on the supply side, of the available resources. In this preliminary phase, demand and supply information is collected to properly target the project according to the market characteristics and, consequently, to evaluate the expected costs and benefits in order to compare project appraisals.

The foremost rationale for the interconnection of systems is linked to the advantages of increased market scale which opens new opportunities for electricity production and for demand management and which may even induce some advantages from the aggregate management of the same, previously separate, electric power systems. This basic case is examined in Chapter I, evaluating the benefits of the pooled management of generation resources.

The relevant market information refers to the demand characteristics (regional load profile) and the potential revenues such load will yield (the benefits of an aggregate load management). The project appraisal compares this information with the costs required to accomplish the project (i.e. the investment costs required to adapt the existing system to higher electricity exchanges).

As explained in module 1, the interconnection project may be related to other guiding rationales (economic, social, political, etc.), have different dimensions (national, regional or related to selected demand segments) and perspectives (macroeconomic, microeconomic, either at the utility, agency or private operators’ level). The purely economic and technical objectives of increasing market scale have sometimes been interwoven with broader objectives, such as strengthening economic cooperation or a political will to support increased regional trade. Sometimes interconnections have been pursued as a means for developing the distribution system and supplying unconnected areas. In many non-OECD countries, energy consumption (particularly electricity) is constrained by a lack of infrastructures rather than a lack of consumer demand, and socioeconomic analysis of the territory may indicate “suppressed demand.”

These project characteristics help determine the market analysis characteristics: the further the project progresses from a particular to a general dimension, from a micro to a macro perspective, from a single to multiple objectives, the more detailed and complex the information required to conduct market analysis (Chapter II).

When an interconnection project is justified essentially on political or social grounds, the market analysis could, in principle, be disregarded. Projects in the electricity sector have significant social impacts that, in developing countries, compete with the satisfaction of other essential needs of the population, such as education, public health, economic infrastructures, etc. In this case, economic viability is not the predominant consideration because the choice is a matter of ranking different social objectives that eventually depend on political considerations. In such case, the market analysis is not essential for the decision-makers. The economic appraisal is important, however, since it will make decision-makers aware of the economic burden of undertaking a costly project.

The market analysis may suggest, in some cases, coupling the interconnection project with a thorough reappraisal of the present customer policy, such as the tariff structure and payment arrangements in force. Very often, the problem of non-technical losses must also be properly addressed. While these policies are not directly linked to interconnection, they may share the same objective (a more efficient electricity market) and/or aid in collecting larger financial resources for the interconnection project.
Chapter I

Economic Appraisal of the Interconnection Project: the Case of Pooling Generation Resources

1.1 Evaluating Management Cost Reductions

The interconnection of two or more electric power systems may produce significant benefits due to a better management of resources and to an increased market scale. If the interconnecting countries have different marginal costs of electricity production and/or complementary country load profiles, the pooled management of generation resources leads to savings in production costs.

To begin with, a rough estimate of these benefits may be made. Consider a very simple electric power system in which the country’s domestic electricity network is represented by a single point that also represents the country’s total production and consumption. This clearly describes the interconnection grid between countries and their relevant capabilities. In this system, the benefits of interconnection are essentially related to:

- savings in kWh costs, due to dissimilar generation costs among countries. These differences may be caused by the use of different technologies or, more importantly, different input costs, due to access to primary fuels/energy sources;
- more efficient generation management, due to structural differences, and in particular, complementary load profiles;
- reduced risk of power supply interruption due to greater system reliability. ²

² If one region’s electricity system is particularly unreliable, however, the overall reliability of the interconnected system may be diminished as a result.
The interconnection is beneficial if the management costs of the interconnected system are lower than the management costs of the isolated ones.

In order to evaluate and compare these costs, operation planning of both the isolated and the interconnected systems is optimized by minimizing an economic function whose components are:

- generation costs (essentially, “fuel costs”);
- costs of unserved load (“failure costs”);
- transmission costs.

This implies that the attractiveness of interconnection is valued in terms of reduced generation costs and reduced unserved load, adjusted by a parameter taking into account the potential higher cost of network losses, in case of longer transmission distances in the interconnected system.

In the case of multiple interconnection projects, relative management costs may be evaluated and compared in order to rank projects according to the efficiency improvements they will allow.

The maximum hypothetical economic benefits of interconnection are indicated by the difference in management costs in two extreme and purely speculative situations: a “no interconnection” scenario, where all regional electric power systems are isolated, and another scenario in which all the countries or regions are interconnected and unlimited interconnection capacity tie is assumed. Such an estimate of the upper limit of the economic interest of interconnection in the situation under consideration is a purely theoretical reference parameter, since the costs implied by this hypothesis are not taken into account; unlimited interconnection capacities, for instance, do require huge amounts of resources.
I.2 Other Benefits and Investment Costs

The above estimate should be completed with an evaluation of the full benefits accruing from a coordinated management of generation resources.

These advantages are attributable to:

- investments in generation capacity being avoided. The interconnection and the corresponding possibility for exchange of electricity between the interconnected countries or regions may reduce the need for new capacity;
- reduced reserve capacity for emergency support;
- economic impact of improved system reliability. Beyond the increase in quality of service, other direct benefits are also generated, considering that power interruptions lead to productivity losses in the commercial and industrial sectors, which affect the average regional manufacturing costs and, finally, gross domestic product (GDP). Unstable frequency has a less perceptible impact on the economy, as the consumers are usually not aware of small frequency drifts; nevertheless, it does influence the lifetime of electrical equipment;
- cooperation benefits. Increased joint venture potential, or at least coordinated planning, is possible with interconnection. The physical and organizational tightening on the grid can lead to lower supply costs.
- other benefits. More efficient utilization of capacities might, for example, reduce CO2 emissions, as suggested by the Kyoto protocol, or reduce the consumption of nonrenewable primary energy.

In the analysis above, the national systems have been modeled as a single bus bar. It was assumed that in each country the main generation and load centers are connected on the same bus, without the network mean. In order to correctly evaluate the attractiveness of interconnection, however, it is also necessary to evaluate the investment costs required. As a result, an appropriate network study must be conducted, taking into account the overall systems structure within each country. This makes it possible to evaluate the reinforcement, in terms of lines, stations and so on, required to accomplish the project and actually benefit from the improvements indicated by the economic analysis.
The resulting investments depend on several factors: the amount of power to be exchanged; the length of the interconnection; the presence of natural obstacles; other technical aspects related to frequency and power regulation policies on the systems to be interconnected, and voltage profile control.

From that viewpoint, some of the interconnection projects that have passed the first operational savings assessment may turn out not to be feasible, due to excessively high investment costs. In fact, the financial requirements of these projects are quite often too considerable for the utility and even for the countries involved.
Chapter II

Economic Appraisal of the Interconnection Project: the Case of Access to New Markets

While the opportunity of larger market scale is the main rationale for interconnecting electric power systems, in practical experience, the interconnection is also undertaken with the goal of pursuing a wide range of other benefits, such as:

- better efficiency and coordination of initiatives to target a common electricity market (Balkans);
- better system management (industrialized countries, particularly in the past);
- exploitation of common resources (Mekong);
- tightening and further meshing of the electricity grid, and electrification of new areas;
- transfer of electricity from one country to another;
- exploitation of (selected) market opportunities (western countries, particularly in recent years);
- other political objectives, such as strengthening political stability through regional electricity cooperation and integration.

In some of those cases, interconnection deeply affects the market through the creation of new markets or the reshaping, in varying degrees, of existing markets. Then, as much information as possible on all aspects of the market affected by the interconnection project is needed for an economic appraisal.
In the case analyzed in Chapter I, the countries are interconnected in order to manage the generation resources as if it was a single area. The main benefits arise from a rationalization of the generation resources, while the network and the dimension of the aggregate market are presumed unchanged. Customers benefit from interconnection through the impact on tariffs of the lower production costs and/or avoided investments in generation. Thus, the market analysis is limited to the definition of a country’s or a region’s load profile in order to estimate the management improvements allowed by a pooled load management. No larger market analysis is required, unless interconnection leads to exceptionally high changes of cost of service, with subsequent demand variations.

When broader objectives are pursued through the interconnection project, the market analysis must be based on a more complex set of information. This may include demand analysis and forecasts at the national/regional level, as in the case of international exchanges or exploitation of common resources, or their evolution in selected segments of the market, in the case of exploitation of market opportunities or electrification of new areas, for instance. It may be interesting to assess the customers’ ability to pay, as well as the sensitivity of electricity demand to price changes, for instance in the case of market opportunities exploitation, electrification of new areas, or the quality of electricity (frequency of admissible variations) requested by customers or by the relevant sector of the economy, for instance in the case of better system management.

The project may also be affected by considerations regarding the region’s economy. Electricity demand is clearly related to the level and type of economic activity developed in the region. However, economic activity is, in turn, strongly affected by the availability of electric energy. This consideration is of some relevance when the interconnection project also involves the electrification of new areas, and the benefit that can be derived from the project depends on the economic potential of the area. In this case, the evaluation of “suppressed” demand is of particular importance, and ad hoc methods should be adopted to estimate it.

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3. See, for instance, International Atomic Energy Agency (IAEA), *Expansion planning for electrical generating systems, a guidebook*, Technical Reports Series No. 241; or International Atomic Energy Agency, *Energy and Nuclear Power Planning in Developing Countries* Technical Reports Series No. 245. The major objective of this publication is to familiarize energy specialists in developing countries with the fundamental elements of comprehensive national energy planning. The book examines the various technical and economic factors which are involved in energy planning in general, and which also have to be taken into account when considering the utilization of nuclear power in a national energy network. It is further intended for use as a training manual or textbook.
Sometimes the interconnection project involves major externalities that cannot be disregarded. In such a case, the market analysis may be fairly complicated, requiring evaluation of social or nonmonetary parameters. This is the case for big power plants, built to serve a whole region. In this case, market analysis must include an evaluation of noneconomic costs and benefits, for instance the environmental impact of the project, and the burden distribution among countries and over human generations should be taken into account.

As indicated in the previous chapter, a complete evaluation of the impact of the project requires a comparison of the costs and benefits involved both in the case of separate electricity systems and in the case of an interconnected system. This latter case could actually be split into several subcases with different combinations of countries and different hypotheses regarding exchange of electricity and level of electricity integration.

In what follows, different methodologies for demand analysis and forecast are examined, and the implications of each methodology in the context of developing countries are also evaluated.

II.1 Energy Demand Modeling

The specific features of electricity demand analysis emerge from the observation that no one wants electricity for its own sake. Electricity demand is a “derived” demand, in that it appears when people seek the services provided by electrical appliances. Electricity demand is, thus, the result of a number of interactions between people’s tastes and preferences (which in turn are related to socioeconomic variables) and the existing energy technologies.

In developing countries, two additional elements have to be taken into account: this demand arises only when people have reached the level of disposable income at which they can afford the electricity; electricity demand may be constrained by a lack of distribution infrastructures so that, in fact, demand depends on supply, that is on the amount of electricity that the local infrastructures and supply capabilities are capable of delivering. In extreme cases, there is no connection to the grid and the electricity demand cannot be expressed (it is then referred to as “suppressed” demand).
The link between socioeconomic data and the electricity demand is captured through a demand model that indicates the mechanism through which electricity demand is supposed to be driven by the explicative factors. Each market is characterized by a proper set of explanatory variables whose relevance relies in its ability to induce reliable hypothesis for the future, i.e. a reliable forecast of the market, in terms of which a decision may be made. Thus the demand model expresses the analysts’ perception of the socioeconomic determinants of energy demand. It is essential that the countries involved in the project share this perception. This prerequisite may imply an additional effort to reach the necessary consensus.

At the macroeconomic level, the driving factors of energy demand are expressed in terms of the economic profile of the region (GDP per capita, GDP per economic sector and per region, added value per sector, income distribution over the territory) and information on social variables (population growth and density; growth rate). The economic data is collected on a sectorial basis, if possible, because of the sectors’ different energy requirements and the varying impact of sectorial trends on energy demand.

If subnational data is also available, it is then possible to identify regions with homogeneous socioeconomic characteristics. Demand trends and market characteristics are often quite different from one region to another, and consequently the project should be targeted to the area’s context and needs. Very often, these regions are not limited by national political boundaries but extend over subnational or transnational areas. Generally, however, the smaller the area, the greater the uncertainties in demand forecasts, since smaller areas intensify the importance of particular local conditions that are difficult to capture in the model.

An important characteristic of the market, especially when dealing with specific market segments, is the reactiveness of demand to a change in price. Electricity demand models often include, as explicative variables, not only the price of electricity but also the price of other fuels that may be a substitute to electricity, for instance carbon for heating. This reactiveness of electricity demand to price changes is synthetically expressed by the price elasticity of electricity demand. The direct price elasticity measures, in percentage, the variations in quantity of the electricity demand, as determined by a one percent (1%) variation in electricity price. The cross-price elasticity measures the reactiveness of electricity demand to other fuel price variations. This information is very useful but should be carefully examined. The reaction to price changes is closely related to the socioeconomic context, individuals’ lifestyles and available technologies. The information content of elasticities is limited therefore to the specific context in which it was calculated and cannot be transposed in time and space.

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There is a wide variety of demand models available. They generally differ in terms of target time span and economic or technical relations. They may be grouped according to their formalization mode:

1. classic econometric models;
2. technico-economic models, combining economic and technical analysis;
3. macroeconomic general equilibrium models, analyzing in detail energy demand and supply.

**II.1.1 Econometric models**

On the basis of a set of socioeconomic indicators which are supposed to give a synthetic representation of the economy (GDP, national income, added value per sector, population, etc.), these models calculate the level of energy demand, globally or per sector (residential, tertiary, industrial, agriculture, transport), or per energy form.

The link between the explicative variables and electricity demand is outlined by a functional relationship expressed in mathematical terms. This link may stem from an empirical evaluation of past relationships (empirical models) or from a suitable development of microeconomic theory.

Very different models have been developed within this methodology, from a highly simplified relationship among variables representing large aggregations, for instance linear regression, to elaborate models based on complex sectorial demand functions, for instance, the Almost Ideal Demand System, applied to sectorial demand.

These models are limited by the set of statistical data available. For instance, the possibility of breaking down the information (such as a demand analysis for selected market segments or smaller regional areas) depends upon the availability of reliable detailed data, for instance present and perspective added value for the selected segments, regional GDP, etc. Moreover, the quality of this relationship is directly linked to the ability of the socioeconomic indicators to explain variations in electricity demand. Finally, the extrapolation may fail to capture structural shifts in demand growth that are particularly important in developing countries as a result of changing lifestyles and the introduction of new technologies.

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II.1.2 Technico-economic models

These models rely on the observation that energy sources (oil, gas, electricity etc.) are not in demand of themselves, but are needed for energy consuming equipment. Thus, demand for energy sources and energy consuming equipment demand are strongly interrelated. Energy consuming appliances are durable goods whose market generally adapts slowly to changes in the determinants of demand, producing more stable and manageable demand models and more reliable predictions.

These models determine changes in energy demand through the evolution of demand for appliances. Their foremost characteristic is thus the importance they ascribe to technology in the creation and development of energy demand. Energy prices are significant in energy demand determination because of their impact on the choice of technologies or on energy substitution.

The limits of these models are linked to the huge amount of information required (both technical and economic), the challenge of identifying the most suitable set of explicative parameters, and the complexity of the treatment of this type of information.

The MEDEE energy model

The MEDEE methodology’s relevance lies in its ability to overcome some of the main problems of the traditional long-term energy modeling by using a simulation procedure instead of the optimization one which is largely used in traditional models. Simulation procedures, in fact, simplify the structure of energy modeling and makes hypotheses more transparent. This also makes it possible to compare the effects of different energy programs and policies on the demand for energy sources.

The MEDEE demand-side methodology (Figure 1) is “engineering style” which implies that the economy is considered as a machine which is composed of the activities of individuals and community, and whose driving power is energy.

Accordingly, energy source demand is induced by the level and the type of economic activity, as well as by the intensity and quality of social needs (e.g., mobility of persons, temperature in rooms, etc.). This energy source demand is in practice a demand for useful energy (e.g., process heat, mechanical energy, etc.). The demand for energy commodities, or final energy (e.g., coal, electricity, gas), can be calculated from the level of useful energy demand and will depend upon the efficiencies of the equipment (e.g., furnaces, boilers, engines) used to convert the final energy into useful energy.
Thus the energy demand can be inferred from the economic structure of a region, taking into account its technical parameters, such as the penetration rate of appliances, the specific consumption of products and the energy intensities, where other parameters are not available.

In principle, these models consider all energy inputs in order to capture substitution phenomena.

This approach is flexible enough to accommodate changes in demand determinants and the occurrence of periods of crisis. It is also a quite stable model because it uses the structural evolution of the socioeconomic variables (value-added, types and modes of transport, etc.) as input variables. These variables in general do not have sudden changes in value, even in periods of crisis, thus assuring a certain stability to the model. Therefore, past experience provides useful information for the future.
Energy Modelling

- National and International Scenario (economy, population, technologies)
  - General and Sectoral Policies

- Macroeconomic Model

- Energy Demand Model
  - Demand Coverage Model

- Energy Market Dynamic Model

- Input and Output Policies:
  - Demand Policies (incentive, tariffs, taxation, legislation, environment, etc.)
    - Data Banks
  - Supply Policies (security, independence, evaluation of geographic coverage, etc.)
    - Data Banks

- Simulation of Demand Alone

- Price Feedback

- General Optimization Model

- Inputs
- Outputs
- Operators
The MEDEE methodology is part of the scenario methodology (see section 2.3), which identifies the most likely future trends and, most importantly, the possible futures within which the real future is likely to fall. Such a feature qualifies this methodology for sensitivity studies aimed at testing different development hypotheses and energy policy alternatives.

Figure 2 (Structure of the ‘MEDEE-S’ Model) schematizes the structure of MEDEE-S,6 a model that belongs to the set of energy demand models developed within the framework of the MEDEE method. It is designed especially for application in developing countries, thanks to its flexible structure and specifications which can cope with numerous different situations in terms of energy end uses, economic activities and information availability.

It consists of five standard modules, identifying the energy requirements of the main activity sectors: agricultural, industrial, transport, tertiary and residential. Supplementary sub-modules can be added, provided that data is available and the economic structure is applicable.

The simulation of the energy demand evolution, worked out through the MEDEE-S energy model, is based on a set of hypotheses defining the socioeconomic, demographic, economic and technical context over a long-term period. Scenario hypotheses (see section 3.3) are formulated for those variables whose evolution is subject to wide variations during the period of simulation, since they are related to the strategy of the main actors (public authorities, companies, etc.) or to changes in the international environment (external trade characteristics).

The formulation of scenario hypotheses is mainly based on a country’s economic prospects: GDP growth, sectorial and subsectorial added value, etc. These indicators define the macroeconomic context of the different policy options (external policy, sectorial policy, energy policy, transport policy, etc.), depending on the strategies of the decision-makers. Each of these policies entails different modalities for national development and has significant impact on the future energy demand of the country.

II.1.3 General equilibrium models

These models originate from the observed strict interdependence between energy and economy. They combine a macroeconomic and a technical approach to analyze the behavior of detailed energy demand and supply. The aim is to analyze the macroeconomic consequences of alternative energy policies, and project future levels of energy demand.

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6. For detailed information, see UNDP/Economic and Social Commission for Asia and Pacific/CEC, MEDEE-S, 1989.
The approach combines a central, macroeconomic model with a certain number of side models, breaking down the most interesting parts of the central model (industrial processes; household space heating; energy saving measures, etc.) in great detail and focusing on the evolution of the technical coefficient.

The specificity (and weakness) of these models is that they combine the coherence of the economic theory and an adherence to the concrete reality of the technical analysis. As in the group of models mentioned above, moreover, another limitation stems from the amount of detailed data required and the complexity of the treatment of the whole model.

**Figure 2**

<table>
<thead>
<tr>
<th>Standard Sub-Models</th>
<th>Supplementary Modules</th>
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<tbody>
<tr>
<td><strong>Industry</strong></td>
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<td>Analysis by branch and end uses:</td>
<td>Steel</td>
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<td></td>
<td>Other energy intensive products (by type of products)</td>
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<tr>
<td><strong>Household</strong></td>
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<tr>
<td>Distinction urban/rural and according to classes:</td>
<td>1. Heating</td>
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<td>2. Water heating</td>
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<td>3. Electrical appliances</td>
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<td>4. Cooking</td>
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<tr>
<td><strong>Tertiary</strong></td>
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<tr>
<td>Analysis by subsector:</td>
<td>5. Heating</td>
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<td>6. Cooking</td>
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<td>7. Public lighting</td>
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<td><strong>Transport</strong></td>
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<td>Distribution between:</td>
<td>8. Urban transport</td>
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<tr>
<td><strong>Agriculture</strong></td>
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<tr>
<td>Analysis by end use or by equipment</td>
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The PRIMES energy model

The European Commission (EC) has a lengthy tradition in the field of energy models, a tradition sustained, especially in the past, through significant efforts aimed at developing methods for energy forecasting.

During this time, energy models that can be considered as milestones in the energy modeling history have been adopted by EC (EFOM, MEDEE, MIDAS, etc.). Many of these models, or later updated versions, are still topical and widely used.

For its energy forecasts, the European Commission currently uses the PRIMES model. This model is specially designed to examine current and future trends of energy markets across the European Union and the implications of energy use on the environment.

Although PRIMES is a completely new model, it represents a natural evolution from the European Commission’s previous energy models. It draws on the experience gained from the development and application of existing models and databases used by the European Commission. At the same time, the PRIMES model requires a level of technological and environmental detail and a market-based approach unknown in any existing energy model.

The PRIMES model thus combines the detailed “bottom-up” technological approach conventionally used in energy models with an accurate representation of the different energy markets and the feedback between supply and demand as determined by market prices. At the same time, PRIMES incorporates a substantial amount of environmental data that enables analyzing the effects of different energy policies.

The major differences between PRIMES and previous energy models available to the European Commission are that:

- PRIMES explicitly considers the formation of energy prices, and calculates price equilibrium in each energy market. This makes it possible to test the effects of price and market-related policy instruments such as carbon taxes and emission permits;
- it relies on the market clearing mechanisms and related behavior of operators. Consequently, given the increasing trend towards the liberalization of European energy markets, it enables the user to draw realistic forecasts of energy supply and use;
- PRIMES contains a high degree of detailed information about technologies in both the supply and demand sectors.

PRIMES is modeled on the hypothesis that there is a market for each fuel, and that producers and consumers respond to changes in prices. It is organized in two blocks, for demand and supply respectively. Several demand and supply markets are analyzed, each represented in separate independent sub-modules. This allows using the mathematical formulation that best represents the functioning of each market. This mixture of different mathematical specifications is highly desirable since it gives the model a high degree of realism. The relationship between the sub-models is shown in Figure 3.

On the demand side, four sub-models are considered: industrial, residential, tertiary and transport. Demand forecasts in these sectors depend on the level of economic activity, and consumer energy prices as derived by the supply module. On the supply-side, the sub-models analyze electric power generation, refineries, and natural gas. Each fuel market is modeled taking into account the factors determining supply and demand, assuming that prices for alternative fuels remain constant. The model determines the economic equilibrium in each market through an iterative process.

The electricity supply module, in particular, is developed as a logical unit that can operate autonomously. It incorporates considerations on capacity expansion planning, system operations, trade and sale. Sales are made by merchant companies to a set of market segments in each EC country. All parties involved (electricity generators, end consumers and transmission companies) are explicitly considered. The formulation adopted for the electricity module, moreover, is flexible so that the changing market conditions in this sector can easily be reflected.

The mathematical form for this module minimizes total system cost for expansion, operation and trade under the constraints deriving from: demand for electricity, generation capacities, transmission capacities, fuel and electricity contracts, and environmental and standards reliability. The outcome of the model sets the selling price and the amount of electricity to be purchased from autoproducers.

Typical applications of the PRIMES might include:

- the analysis of technological options and the effect of different policies on technology innovation;
- the energy/environment interface, and related policy instruments, including taxation;
- the internal market for energy, including the consequences of third party access for electricity and alternate market regimes.
The PRIMES model needs a large amount of data in order to produce meaningful results (i.e. explicit representation of technologies, multiple sectors and full environmental formulation). For example, the data required for the electricity model consists of:

- demand of electricity addressed to generators by sector/process and time-segment;
- technico-economics of plants: nominal power with given fuel, investment costs, fixed costs, variable costs, technical and economic life-time, efficiency etc.;
- existing park and commitments, decommissioning;
- electricity and fuel contracts;
- water reservoir changes;
- system reserve margins.

II.2 Forecasting the Future: Limits and Precautions

The decisions concerning an interconnection project need to be based on information on the future characteristic of the market. Whatever the demand model chosen, this extrapolation of information about the future may be based either on a punctual forecast approach or on a scenario approach.

The punctual forecasting process generates the future value of demand, using a single future value of the explicative variables. However, the uncertainty of the events the forecasters are trying to predict unavoidably produce a forecast which is uncertain to a greater or lesser degree, thus limiting the reliability of punctual forecast, in general, and for developing countries, in particular.

Uncertainty increases when dealing with developing countries, where the economic and energy policy environment undergoes rather rapid structural changes. Any change in the socioeconomic context is likely to affect the “mechanism” through which electricity demand is linked to the explanatory variables. The parameters of the model function which represent this linking “mechanism” have been identified from past data so that forecast reliability is retained for the socioeconomic context, and thus the linking “mechanism” remains unchanged. This hypothesis is often very restrictive in the evolving context of developing countries.

In the previous paragraph some limits of demand models have been underlined. In the context of developing countries, these limits may become even more stringent.
Any forecasting methodology relies strongly upon the availability of a reliable, detailed time series of data. However, many developing countries lack reliable data on fundamental variables, including input data such as industrial production, GDP, and sectorial price and consumption data. The very concept of gross domestic product is less adequate to measure national economic activity in the context of a production system that is poorly organized and lacks economic infrastructures.

Furthermore, sectorial demand changes in developing countries, resulting from specific policies such as rural electrification programs or industrial policy, can have a very substantive influence on consumption relative to existing demand levels. If the country’s electricity demand is largely attributable to the demand of a single economic sector or, at the limit, of a small number of large consumers (large factories, for instance), any event or any policy affecting this sectorial demand or these large consumers will determine the evolution of national electricity demand. It is important that these effects be captured in the model.

In developing countries, electricity demand is actually underestimated by the available data because part of the demand is “suppressed”, i.e. it cannot be expressed because people have no access to the electricity market, since the network infrastructure is poorly developed, making the electricity supply unavailable for entire regions. Part of this suppressed demand may be carefully extracted from the demand for close substitutes for electricity services (for example, demand for kerosene for space heating and cooking), but a large part is potential or replaced by non commercial fuels such as biofuels.
Figure 3: Structure of PRIMES

- **Demand Model**
  - Function of energy prices
  - Six Industrial Demand Modules (non-linear optimisation)
  - Commercial Demand Module (qualitative response model)
  - Residential Demand Module (qualitative response model)
  - Transport Demand (econometric model)

- **Electric Power Generation**
  - Load Curves Projection (from sectoral demand)
  - Capacity Expansion Planning (linear program per country, multi-period)
  - Dispatching (linear program, Europe, network)
  - Electricity Prices (accounting)

- **Refineries**
  - Expansion and Operation (linear programs per refinery type)
  - Oil products Prices (shadow prices, world oil)

- **Natural Gas**
  - Supply, Transport, Distribution (linear program, Europe, multiple gas fields)
  - Natural Gas Prices per Country (cost curves, transportation)

- **Solid Fuels** (based on imports)
This calls into question the validity of past experiences in forecasting future trends in the greatly varying environment of developing countries. Moreover, it also raises doubts as to the reliability of the hypothesis of homogeneous consumption patterns among countries, on the basis of which a country’s prospective demand trend is extracted from observation of the demand behavior of similar, more advanced countries.

In short, the relevance of the punctual forecasting approach should be questioned (or disqualified altogether) in case of:

- expansion of the time horizon in a socioeconomic context that is rapidly changing;
- use of the model in different socioeconomic systems;
- change in the spatial scale (e.g., regionalization);
- inability to capture the “suppressed demand.”

Demand forecasts based on statistical evaluation and projections of past consumption trends are usually more appropriate for developed countries, in which data coverage is excellent and changes from observed trends are slow due to a highly stable lifestyle and the use of mature techniques.

**II.2.1 Scenario approach**

The above mentioned problems may be overcome, or at least reduced, with the adoption of a “scenario approach.” In the scenario approach (unlike the forecast methodology which is based on a single value for the explicative variables), the available information is exploited to arrive at different hypotheses about the values of the explicative variables and/or different conjectures as to the occurrence of relevant events or implementation of policies affecting demand.

Whatever the demand model, the scenario approach is geared not so much to pinpointing the most likely future trends (i.e., a forecast using what is considered to be the most realistic set of parameters, given present expectations for the future), but rather to generating a range of possible futures under which the real future is expected to fall.\(^8\) In turn, these sets of different “futures” or “scenarios”, applied to the chosen demand model, produce different demand forecasts.

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In order to have a manageable prediction, a set of “futures” is reduced to its most significant cases. It is common practice to consider the two extreme cases, characterized respectively by “high” and “low” estimates of the explicative variables, and a medium one, leading to the so-called “high,” “low” and “medium” scenario forecasts. It should be noted that although the median estimate generally results in the most likely forecast, this is not always the case, and the framework may well suggest that the most probable scenario is located at one of the extremes.

It is not an easy task to assign a probability value to each scenario. This is very often a subjective evaluation based on all the information available, including technical data, informal exchange of opinions, other evidence and the individual wisdom of the technicians.

The scenario approach qualifies for sensitivity studies designed to test and measure the effects of development options, or different policies or hypotheses as to the value of the relevant variables. The scenario methodology also allows enough flexibility to take new facts into account as soon as they come to light.

The most significant weakness of the scenario approach consists in the difficulty of defining a consistent and plausible set of scenario assumptions. In developing a new scenario, it is absolutely necessary that a reasonable relationship between explanatory variables be assured. Judgment must be exercised to ensure that the explanatory variables used to build a scenario form a consistent and internally coherent set. For example, if a high rate of construction of new buildings is assumed, it cannot be associated with low production growth for the building materials industry (unless, of course, significant importing of building materials, etc., is assumed). The quality and pertinence of projections of long-term energy demand depend on the quality of the scenario assumptions. Consequently it is necessary to pay as much attention to the design procedure for the scenario assumptions as to the model itself.
II.2.2 Some recommendations

Consequently, when arranging a demand analysis and forecast for developing countries, it is important to take into account some provisions:

- modular models are to be preferred because they allow running each section model independently. In this way, the data problem of each module may be addressed separately (MEDEE-S is one of those models);
- models should be flexible, allowing for different degrees of detail, according to the detail of the available data;
- as far as possible, data collection should be completed with all the available information. Missing data could be inferred from other available information or estimated *ad hoc*. The soundness of the technician’s judgment in this operation may be critical to the quality of the results;
- in some cases, the available model should be modified and adapted to the data set at hand. It could be required to set *ad hoc* models.
Chapter III

Ability to Pay and Tariff Setting

That analysis sought to highlight the relevant characteristics of the market targeted for an interconnection project, their evolution, and the possible impact of the project. This information is essential to properly target the project and evaluate its costs, revenues and possible returns.

The expected return on the project is one of the most important variables the investor needs to know, since this determines the project’s viability and the burden associated with nonviable projects. Any decision regarding project implementation can thus be made in full awareness of the costs and returns involved.

The revenue that accrues to the investor depends on expected sales volume and the expected price on the relevant market. In short, it depends on the demand curve the investor faces on the market.

When the investor is also entitled to make decisions about the tariff system in place, the sensibility of the revenue to a change in tariff level and structure may be questioned. Any revision of tariff policy has socioeconomic consequences that must be evaluated and balanced against the socioeconomic impact of the project. This implies that the project should be considered not only from the point of view of the financial analysis of the electricity operator, but from the point of view of the socioeconomic benefits accruing to the whole region as well.

A different tariff structure may allow a more significant recovery of costs incurred in the interconnection project.9 On the one hand, this is often the case in a developing country since the tariff system is often subsidized and inefficiently implemented, which can affect the viability of the project or the ability of the electricity company to operate in a sound financial environment.

On the other hand, tariffs are very low and electricity is largely subsidized, because consumers’ ability to pay is also very low and the tariff policy is more closely related to socioeconomic objectives than to electricity market policy. A change in pricing policy impacts on these socioeconomic objectives with costs that should be carefully evaluated.

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It also implies fine tuning between economic efficiency and electricity affordability. This consideration is of some relevance. Economic efficiency would suggest setting higher tariffs in order to cover marginal costs, at least. But if the price is too high for the customer’s ability to pay, it depresses the electricity market. Demand cannot be expressed in full and consequently, market dimension and profitability are reduced.

Other events reduce the flow of revenues that can be collected on the market, and hence the profitability of the investment. In developing countries, particular attention is paid to the problem of nontechnical losses, which can have a significant impact on project profitability. Technical losses of between 3-4% are normal in a distribution system, owing to its design. In developing countries, where load densities are much lower, “normal losses” amount to 8-10%. However, in those countries, the electricity system very often suffers losses of more than 30% (and close to 50% in some cases), the more important losses being “nontechnical”—mostly a result of theft by meter hampering or illegal connections, for instance. In other cases, the electricity consumed is metered, but bill payment is disregarded.

Policies aimed at reducing these revenue losses generally focus on the improvement of metering arrangements and the identification of appropriate conditions of payment. These policies may not be effective enough if not enough attention is paid to the rationale for such customers’ behavior. High nontechnical losses show that the electricity price is much higher than the price customers are willing to pay. In developing countries, this low evaluation of electricity may be related to customers’ lack of appreciation of the benefits of electricity. In this latter case, an effort should be made to ensure customers are aware that the benefits they derive from the availability of electricity exceed the costs they are asked to pay.

In some cases, this attitude also results from the country’s attitude towards government services, which are viewed as “belonging to the public” and thus free of charge. Since electricity companies in developing countries are often government owned, investments in this sector, particularly by international organizations, may depend upon the privatization of electricity companies. Proper attention to local culture has also proved effective, for instance when local authorities are relied upon to collect bill payments.
Appendix

An Application of MEDEE-S Model: Energy Demand Forecast for Armenia

Introduction

This report describes the methodology adopted for, as well as the results of a study carried out in the framework of the TACIS project EAR 9801 “Armenia-Assistance to the Energy Strategy Centre.” The study is aimed at developing consistent energy demand scenarios for the Republic of Armenia. These scenarios represent the basis and the starting point for the identification of a set of viable options/projects on which to found an adequate energy supply plan.

The main objectives of this exercise can be resumed as follows:

- definition of economic development scenarios for the Republic of Armenia;
- setup of an energy model, including collection and updating of needed input data; and
- elaboration of consistent energy demand scenarios.

1 Background

Armenian energy economic future is affected by a high level of uncertainty, mainly related to the capacity of the productive (mostly industrial) system to survive — and with what kind of structure — through the transition period since the country gained its independence from the former Soviet Union, and the subsequent economic crisis.

Though imprecision is inherent in any forecasting process, uncertainty increases when dealing with countries where the economic and energy policy environment undergoes rather rapid structural changes. Any changes in supply-demand configuration can require a restructuring of the energy system representation.
The methodology used to deal with these situations, and also adopted in our analyses, is usually the Scenario Approach. This methodology implies the development of some alternative scenarios, each characterized by a different set of assumptions for the explanatory variables.

2 The MEDEE-S Model

The model adopted for the energy demand forecasts is the MEDEE-S, a model that belongs to the set of energy demand models developed within the framework of the MEDEE method (see Module 2, section 1.2). It is particularly fitting within the scenario methodology. MEDEE-S, moreover, has been designed especially for application in developing countries: its flexible structure and its specifications allow for coping with numerous different situations in terms of energy end uses, economic activities and information availability.

It is characterized by a techno-economic accounting approach to main energy uses. This implies an analysis consisting in identifying the economic, demographic, social and technical determinants of the final energy demand by use and sector, evaluating them in term of physical units (industrial and agricultural production, number of vehicles, stocks of equipment, traffic, number of households, etc.). A simulation of their development is worked out then, either through model calculations or through exogenous variables and scenarios.

Among various input data, the MEDEE-S model needs an economic development scenario as a starting point to developing energy demand forecasts. A simple and flexible macroeconomic module has been developed, which generates an internally consistent economic future setting based on defined assumptions for the economic growth of the productive sectors. The de-aggregation level of the productive sectors depends on the availability of data and on the depth required for the analysis.

The simulation of the energy demand evolution, worked out through the MEDEE-S energy model, is based on a set of hypotheses defining the socioeconomic, demographic, economic and technical context over a long-term period. These hypotheses are formulated by means of scenario variables. These are variables whose evolution is subject to wide variations during the period of simulation since they are related to the strategy of the main actors (public authorities, companies, etc.) or to changes in the international environment (external trade characteristics).
The formulation of scenario hypotheses is mainly based on the country’s economic prospects: GDP growth, sectorial and subsectorial shares in value-added structure, etc. These indicators define the macroeconomic context within which different policy options (external, sectorial, policy, transport, etc.) — depending on the decision-makers’ strategies — may be considered. Each of these policies entails different modalities for the national development, and has significant impacts on the future energy demand of the country.

In addition to the scenario variables, the MEDEE-S model requires three other types of input variables: exogenous variables, constant or initial variables, and command variables.

Exogenous variables (e.g. annual use of farm vehicles, COP of industrial heat pumps, etc.) have a range of variation, which seems to be more limited than that of the scenario variables. They are projected through the extrapolation of current trend and remain unchanged for different sets of scenario variables (i.e. for different scenarios).

**Figure A.1: MEDEE-S - General analysis of final energy demand**
Constant variables define the situation of the base year. This group of variables also includes some parameters whose value is assumed to remain constant over the period examined in the study.

Finally, command variables define the structure of the model as adapted by the user: general operating characteristics (simulation period, energy unit to express the results), choice of sectors, calculation variants, annex models, etc.

MEDEE-S gives its results in terms of final energy demand, even though what people really require is the set of services that can be assured through the use of energy. These services can be related to social needs (moving, cooking, adequate temperature level, lighting, etc.) or economic activities (industrial/agricultural production, supply of services, etc.). The satisfaction of this demand of services requires a certain amount of energy in a certain physical and technological context (climate, equipment or appliance, type of industrial process). The evolution of this quantity of (useful) energy strictly depends on the assumed evolution of the socioeconomic environment (scenario hypotheses), but is relatively independent of the used energy vector.

Final energy, on the contrary, though it depends on the amount of useful energy it is called to meet, also depends on the form of energy used to run the equipment and on the relative efficiencies of different equipment in competition (if any).

In order to transform useful energy in final energy, therefore, assumptions have to be made concerning either the expected technological evolution, or the effects of existing or considered policies which could interfere in the competition among energy sources or technologies.

For the estimation of electricity demand, it should be remembered that electricity has a peculiarity: it must be produced at the same instant it is required by the customers. A significant consequence is that, when it comes to electricity, any energy demand forecast must be translated into a capacity demand forecast. The capacity demand should be met, in principle, at any instant. In this context, the projection of the likely internal peak demand acquires a critical importance.

Figure A.1 outlines the logical process MEDEE-S adopts in order to work out final energy.
3 Energy Demand Forecasts

3.1 Base assumptions

In order to develop sound energy demand forecasts, some economic scenarios for Armenia have been considered. Two of these scenarios (Scenario A and Scenario B) have been more developed in greater depth and are described in this section. They are expected to define the borders of the most likely future area where the Armenian economy may move over the next 10-20 years.

In Scenario A, GDP is expected to grow by 6% per year over the 2000-2010 period, and by 3% per year during the following decade. The scenario assumes that the government’s economic reform program for the 1998-2001 period (financial, structural, sectorial and institutional policies aimed at consolidating the macroeconomic stabilization that has been achieved to date) fully meets the targets. Achieving these goals is expected to foster the Armenian productive system, thereby creating the basis for a sustained economic growth that is assumed to last throughout the 2000-2010 period. This growth is mainly driven by the industrial sector. The realization of these scenario hypotheses implies an adequate development of the needed infrastructures (road, railways, telecommunication networks, energy infrastructures, etc.). The favorable economic trend creates new business opportunity and reduces the emigration flow. Population is projected to increase by 1% per year on average over the 2000-2010 period. Over the following decade, population increases by 0.8% per year.

In Scenario B, it is assumed that the short-term objectives set by the government’s economic reforms program are only partially realized. Policies aimed at attracting foreign investments obtain results below expectations, a situation also attributable to further delays in the admission of Armenia in the WTO. The Russian crisis lasts (in alternate phases) well beyond the year 2000, thus contributing to the depression of regional trade. Low investments delay the industrial recovery as well as the process of modernizing the sector. GDP is assumed to grow by 3.0% per year on average over the 2000-2010 period, and by 2.0% per year during the following decade. Population is projected to decrease by 0.6% per year on average during the 2000-2010 period, and remain substantially stable (-0.05% per year) over the 2010-2020 period.

A population level of 3.1 million, in 1999, is assumed in this study. This value is lower than the official statistic by about 700,000 units. The real population level, however, has not officially been verified for a long time. The assumed value, based on unofficial experts estimates, has been considered more reliable as a reference in our analyses.
3.2 Main results

Both scenario A and scenario B foresee a significant increase in energy consumption over the next twenty years, after a troubled decade in which overall energy consumption fell down by 16% per year on average.

Electricity demand is expected to increase at a pace that, though significant, is slower than that of the overall energy consumption. This is mainly due to the fact that, during the past decade, energy forms, other than electricity, recorded a tremendous drop: in 1999, the consumption level was ten times lower than in 1988.

The overall energy consumption in Scenario A, at final level, is expected to increase by 20.0% per year over the 1999-2005 period, by 9.9% per year during the following five-year period, and by 3.8% per year over the 2010-2020 period. In Scenario B, the respective yearly average growth rates are expected to be +17.2% per year, +7.5% per year and +2.9% per year.

With regard to energy per capita consumption, a slight upward trend is expected for both total energy and electricity. It should be noted that the expected values remain below the levels already registered in Armenia during the late 1980s, with the sole exception of electricity per capita consumption foreseen in Scenario A in 2020.
### Table A1: Armenia energy consumption and related indicators

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<tr>
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<th>Scenario A</th>
<th>Scenario B</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total final energy consumption (Mtoe)</td>
<td>6,402 1,15 0,960</td>
<td>2,86 4,60 6,69</td>
</tr>
<tr>
<td>Electricity consumption (TWh)</td>
<td>9,3 4,3 3,6</td>
<td>5,8 8,0 10,9</td>
</tr>
<tr>
<td>Electricity demand on the grid (TWh)</td>
<td>11,1 5,4 5,1</td>
<td>6,9 9,3 12,4</td>
</tr>
</tbody>
</table>

#### Energy intensities:

1. total final energy (kgoe/US$) |
   - 1988 | 0,63 | 0,50 | 1,06 | 1,27 | 1,38 | 1,06 | 1,31 | 1,43 |
2. electricity consumption (kWh/US$) |
   - 1988 | 2,73 | 2,32 | 1,90 | 2,14 | 2,22 | 2,24 | 2,08 | 2,09 |
3. Per-capita energy consumption:
4. total final energy (kgoe/ab.) |
   - 1988 | 1854 | 371 | 310 | 884 | 1343 | 1804 | 830 | 1227 | 1641 |
5. electricity consumption (kWh/ab.) |
   - 1988 | 2696 | 1377 | 1171 | 1789 | 2345 | 2936 | 1627 | 1953 | 2397 |

<table>
<thead>
<tr>
<th>(%)/year</th>
<th>'88/'99</th>
<th>'99/'05</th>
<th>'05/'10</th>
<th>'10/'20</th>
<th>'99/'05</th>
<th>'05/'10</th>
<th>'10/'20</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total final energy consumption</td>
<td>-15,8</td>
<td>20,0</td>
<td>9,9</td>
<td>3,8</td>
<td>17,2</td>
<td>7,5</td>
<td>2,9</td>
</tr>
<tr>
<td>Electricity consumption</td>
<td>-8,2</td>
<td>8,1</td>
<td>6,7</td>
<td>3,1</td>
<td>5,0</td>
<td>3,1</td>
<td>2,0</td>
</tr>
<tr>
<td>Electricity demand on the grid</td>
<td>-6,9</td>
<td>5,3</td>
<td>6,2</td>
<td>2,9</td>
<td>2,3</td>
<td>2,6</td>
<td>1,8</td>
</tr>
</tbody>
</table>

#### Energy intensities:

1. total final energy (kgoe/US$) |
   - 1988 | -11,3 | 13,2 | 3,7 | 0,8 | 13,3 | 4,4 | 0,9 |
2. electricity consumption (kWh/US$) |
   - 1988 | -3,3 | 2,1 | 0,7 | 0,1 | 1,5 | 0,1 | 0,0 |

#### Per-capita energy consumption:

1. total final energy (kgoe/ab.) |
   - 1988 | -15,0 | 19,1 | 8,7 | 3,0 | 17,8 | 8,1 | 2,9 |
2. electricity consumption (kWh/ab.) |
   - 1988 | -7,3 | 7,3 | 5,6 | 2,3 | 5,6 | 3,7 | 2,1 |

(*) Preliminary

(**) Net of non-energy uses
The expected trends of energy intensities (energy consumption per unit of GDP) show slight differences between overall energy consumption and electricity consumption (Table A1). Total energy intensity, as a matter of fact, shows a slight increase over the 2000-2010 period, followed by a saturation trend in the following decade. Electricity intensity, on the contrary, records a substantially stable level throughout the 2000-2020 period, just below the 1980s value and well below the peak of the early 1990s. No significant differences exist, either for total energy or for electricity intensities, between Scenario A and Scenario B.
Module 3

Resource Development
Module 3
Resource Development

Chapter I   Overview of Resource Planning
I.1   Application of Generation Planning
I.2   Interconnection Systems

Chapter II   Process for Developing a Generation Resource Plan
II.1   Resource Plan Development Process
II.2   Resource Plan Factors
II.3   Resource Plan Models
   II.3.1   Load forecasting and load shape models
   II.3.2   Reliability analysis models
   II.3.3   Generation resource and capacity expansion models
   II.3.4   Production or operation simulation models
   II.3.5   Transmission and interconnection planning models
   II.3.6   Economic or financial analysis models
   II.3.7   Commercially available models

Chapter III   Planning for Uncertainty
III.1   Historical Perspective
III.2   Key Features of Scenario Planning
III.3   Scenario Planning Process

List of Figures
   Figure 1:   Overview of integrated resource plan development
   Figure 2:   Examples of commercially available electricity
                production simulation and price forecast models

Appendix
Chapter I

Overview of Resource Planning

I.1 Application of Generation Planning

The resource planning process involves developing a resource plan that provides sufficient flexibility to develop the resources needed, in a timely manner, and also to adapt to the uncertainties of the future. This planning approach allows a transition from resource planning, focused on the development of long lead time central base-load power plants, to a planning strategy that emphasizes regional electricity cooperation, energy diversification and resource flexibility. Such a strategy enables utilities and regions to develop resources when needed, respond to changes in the operating environment and take advantage of cost reducing opportunities as they appear.

Designing an entire power system is dependent on the long-range view as well as on immediate needs. The overall goal is for the utility or region to produce a long-term plan that is reasonable, prudent, and consistent with the goal of providing a reliable, cost competitive and environmentally sound energy supply in an uncertain environment.

The concept of system resource planning includes generation, interconnections and load management. The requirements of resource planning vary with the size of the electric system or systems, and expected future customers load requirements. In some cases, a small utility may consist of building a generation plant with transmission feeders to a proposed load. As areas grow, they may begin to overlap and, upon merging, start forming an electric system. Such smaller systems require careful design and, in early stages, it may be difficult to determine that, in a few years, a larger integrated system will develop.

Generation planning involves the evaluation of a region resource adequacy, its system reliability, and the development of an economic, efficient, environmentally sensitive resource plan. The utility or region’s resource plan, when implemented, should provide the lowest rates for their customers within the constraints of maintaining adequate and reliable service.
As smaller utilities are able to deliver more and more dependable service to meet increasing load, customers will continue expanding their electricity usage and will increasingly depend upon service reliability. During the 1960s, 1970s and 1980s, utilities began to realize that, as unit sizes became larger for efficiency reasons, they tended to operate at higher capacity factors for overall dispatching efficiency while the older units were increasingly being used for load following and peaking purposes.

During the late 1980s and 1990s, as new units became more efficient and economic, generation planning was able to focus on environmental concerns, as well as on the middle portion of the system load duration curve and on the generation needed during maintenance outages. Such efforts focused on the development of cogeneration and renewable resources. Developing countries still focused mainly on the development of efficient large base-load resources. Low oil prices in the 1990s also fueled use of gas burning combined cycle systems. Generation planning is best approached by considering different types of resources, such as base-load units, mid-range units and peaking units.

In recent years, there has been more emphasis on using competition between suppliers to meet customer’s load requirements. As described in Module 7 (Market Operational Structures), a number of countries now adopt competitive market structures using Regional Transmission Organizations (RTOs), that is Independent System Operators (ISOs) and Transmission Companies (Transcos). As the traditional vertically integrated utility is unbundled, the responsibility for providing adequate power supply is gradually transferred to the market. Market participants develop generation or purchase power to meet customer needs. This Module focuses on vertically structured organizations responsible for planning resources (including interconnections) that meet customers’ future load requirements.

### 1.2 Interconnection Systems

In recent years, there has been greater emphasis by utilities and regions on interconnection for mutual benefits or on the formation of larger utility pools. Such interconnections and the attending market structures rely on regional cooperation and system integration.

These interconnections will be based on partnerships between adjacent systems, other regions, or, in some cases, between neighboring countries. Pooling electric resources is essential to both developed countries, as well as developing countries to allow the electricity industry to continue to contribute to sustainable development.
The goal of the interconnected system is to create favorable conditions allowing optimum integrated use of a region’s available resources, in turn allowing benefits for both the utilities and the customers. While these interconnections improve economic operation of the electric systems however, they also complicate system planning and design.

With interconnected systems and pools, planning additions and interconnections requires taking into consideration the future load requirements of the individual utilities as well as the load requirements and potential reliability impacts of other interconnected members. For instance:

1. Should the utility supply energy for itself and/or other pool members?
2. Should unit additions be rotated between pool members or should they be offered for participation?
3. How large a generation unit does the utility or the pool needs?
4. What is the forecast load growth of the pool?
5. What are the effects on reliability during normal operation and during emergency conditions?
6. What are the cost/benefits of such an interconnection?
Chapter II

Process for Developing a Generation Resource Plan

II.1 Resource Plan Development Process

Traditionally, the resource planning process follows a simple, straightforward pattern, as illustrated in Figure 1. It consists of the following elements:

- Area demand forecast;
- Alternative demand management options;
- Supply side resource options;
- Political, environmental and cultural issues and constraints;
- Utility goals;
- Evaluation of alternatives;
- Integrated resource plan selection and approval.
This process might be adequate if the resource planner is developing resources for a remote or isolated region. However, most regions are composed of politically, socially and economically diverse sub-areas, which might also have different environmental sensitivities and natural resource availabilities. This simple process can only be used as a systematic manner of keeping track of the pros and cons of many complicated parameters.

In preparing the resource plan, the resource planner reviews the area’s demand forecast based on maximum and minimum economic growth conditions. System load shape and industrial, commercial and residential load characteristics should also be reviewed.

Based on the expected load growth, the resource planner assesses alternative demand management and supply resource options, taking into account the technical requirements of the electric systems and any political, environmental or cultural factors worth considering.
Upon evaluating the alternatives, the resource planner develops an overall integrated resource plan (IRP) which will yield a system capable of serving the load, employing least-cost resource and demand options, and addressing relevant environmental issues and transmission needs. In the process, the resource planner evaluates resource plan risks, quantifies the cost/benefits of the recommended plan, and identifies any required environmental mitigation measures.

Finally, the resource planner conducts a planning for uncertainty assessment with planning scenarios, as described in Chapter III, herein. The uncertainties facing the utilities affect both the demand and supply aspects of resource planning. Many of these uncertainties can be characterized as changes in trends or perceptions on how the business environment will evolve over time. It is the unpredictable occurrences, however, that cause marked or abrupt changes in these trends and change the long-term needs or methods of electricity service.

In addition, the possibility of pooling with other neighboring utilities, or interconnecting with a country with a different political environment or different social structures, raises many new uncertainties as well as opportunities.

During the development of the alternative expansion plans, the resource planner should look for generation and economic tradeoffs that might affect the overall efficiency and cost-effectiveness of the proposed resource plan. Any differences between expansion alternatives should be identified and integrated, as much as possible, in order to develop the optimum resource plan.

### II.2 Resource Plan Factors

As previously stated, one of the primary objectives of the resource plan is to maintain the system’s flexibility in order to efficiently respond to change. Depending on the size of the electric system, the plan might consist of strategic elements that combine to meet a reasonable, foreseeable future scenario. The resource plan may consist of a mix of various cost-effective options, including the following:

- Load management / Energy conservation;
- Generation resources by independent power producers;
- Utility sponsored resource additions;
- Existing generating unit life extensions/retirements;
- New transmission interconnections and power purchases from neighboring utilities or regions.
The particular concern is the need for planning a system that can be efficiently and reliably operated. For instance, adding a base-load resource to the system may result in some smaller oil/gas units being placed in a retired or inactive status. Thus, additional load following capabilities may be needed to meet power requirements that fluctuate throughout the day.

Pursuing additional interconnections, or utilizing existing capacity with other regions or neighboring utilities, may provide access to dispatchable peaking capacities with low incremental costs from those sources. In addition to the direct benefits of capacity and energy, there are other possible strategic benefits, including:

- Improved operating reliability of the combined transmission system interconnecting the utilities, regions or countries;
- Reduction in the utilities’, regions’ or countries’ capacity reserve margin due to increased interconnection support;
- Power pooling opportunities, including energy exchanges, generating unit commitment, and perhaps transmission service revenues for transmitting utilities;
- Increased competition between the utilities, regions and perhaps countries, leading to lower overall purchased power costs and customer costs;
- Long-term fuel cost planning benefits;
- Environmental benefits, i.e. reduced emissions in environmentally sensitive load areas or regions.

II.3 Resource Plan Models

To help planners formulate and evaluate the many and lengthy expansion alternatives and develop an integrated resource plan, computer-implemented planning and simulation models are involved. The various types of computer programs used could include (but not be limited to) the following categories:

- Load forecasting and load shape models;
- Reliability analysis models;
- Generation resource and capacity expansion models;
- Production or operation simulation models;
- Transmission and interconnection planning models;
- Economic or financial analysis models;
Each program may be used separately or in combination with any of the others as required by a given problem. For the development of a robust integrated resource plan, however, the planner would implicitly utilize several of these analysis tools. These models are merely convenient tools to facilitate planning analyses, and they will produce useful results only if the planner does set up the evaluation with realistic and comprehensive input assumptions.

II.3.1 Load forecasting and load shape models

Many factors affect the forecast of a region’s demand requirements. For example, high fuel costs have a direct and negative impact on rates and, therefore, electricity consumption. Non-fuel related components of electricity rates, such as capital, operation and maintenance costs, are also significant variables. The region’s economic growth, however, is by far the most significant factor in demand forecast. Other factors, e.g. environmental constraints, electricity market structure, self generation or bypass, and technological innovations for appliances and generation, will all play a part in the forecast of load and load shape for the region.

Macroeconomic and/or end use models are traditionally used to perform long term forecast. For regions with a market structure allowing capacity and energy exchanges, statistical analysis tools are now also applied to perform short-term forecasts.

II.3.2 Reliability analysis models

Another key parameter that a planner has to take into consideration is the definition of an acceptable reliability target for the system. A reliability analysis model takes into account load forecast, load shapes, sizes and outage characteristics of generation units in the region to evaluate the probability of the system not being able to serve a certain amount of load, for an acceptable duration. The loss-of-load probability (LOLP) method has been the most commonly used.

In a regulated electricity market, the reliability target is most likely set by regulatory agencies. With deregulation and the restructuring of the electricity industry, eventually, customers’ willingness to pay will dictate reliability targets sustained by a competitive market mechanism. These models, nevertheless, convert a reliability target index into a reserve margin requirement, commonly used in planning studies.
II.3.3 Generation resource and capacity expansion models

A generation capacity expansion model seeks to develop a plan for resource additions that will adequately serve the forecasted loads. In other words, the model will yield a capacity expansion program for the system by comparing the load forecast and system reserve margin requirement with the total installed capacity of all existing generation units. However, this simplified method can only be used as a preliminary indicator. Planners and decision-makers would likely require a more comprehensive evaluation. Among many more other questions, they might be asking:

- What kind of generation should be added next?
- What if the fuel cost doubles?
- What are the financial implications, should the interest rate increase?

Hence, probabilistic simulation models with forward-looking capability or iterative algorithm are commonly used to determine the timing, quantity and characteristics of the capacity expansion program.

Parameters, such as the efficiency of the generation option as well as the fuel cost projection, are crucial to the analysis. Uncertainties of load growth and fuel availability, as well as generation potentials from hydroelectric units, also require additional attention.

Public policy incentives, e.g. demand-side management projects (DSM), renewable resources and environmental constraints, will also influence the resulting integrated plan.

II.3.4 Production or operation simulation models

One of the selection criteria for a viable integrated resource plan is to determine if the plan yields the least total system cost. The capital cost required for building new plants, the labor and materials cost of plant maintenance, the cost of fuel depending on the type of units, the environmental monitoring and mitigation costs, the interest rate and the financing costs are all part of this cost equation.

Resources with low fuel costs, such as coal, nuclear and hydroelectric plants, will be dispatched to a greater degree during operation, thus running as base-load resources. They are more likely, however, to have higher initial capital requirements and they might incur more maintenance costs if operated in cycling mode in order to follow the load. Gas turbines are cheaper to build, lower in routine maintenance costs, and they can follow the load very efficiently. However, they generally have higher heat rates and bigger fuel costs.
Combined cycle units are very efficient, with very low heat rates if running as a base-load resource. They can also be operated as a simple cycle gas turbine to follow load fluctuations. In regions where oil or gas is abundant and cheap, a combined cycle unit is the favorite choice of most utilities and investors.

Depending on the source of the information, net design heat rate quotes might vary significantly.

The following table illustrates performance data used by the American Society of Mechanical Engineers in their training material for a course titled “Steam Turbine Fundamentals”.

<table>
<thead>
<tr>
<th>Net Heat Rate</th>
<th>Conventional Fossil Unit</th>
<th>Simple Cycle</th>
<th>Combined Cycle</th>
<th>Jet Engine</th>
<th>Diesel</th>
</tr>
</thead>
<tbody>
<tr>
<td>Btu/kWh</td>
<td>Gas/Oil Fuel</td>
<td>Coal Fuel</td>
<td>Gas Turbine</td>
<td></td>
<td></td>
</tr>
<tr>
<td>20 MW</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>8300</td>
</tr>
<tr>
<td>100 MW</td>
<td>9400</td>
<td></td>
<td></td>
<td>11000</td>
<td></td>
</tr>
<tr>
<td>150-200 MW</td>
<td></td>
<td></td>
<td>9500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>200 MW</td>
<td>9300</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>300 MW</td>
<td>9100</td>
<td></td>
<td>7500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>500 MW</td>
<td>9000</td>
<td>9200</td>
<td>6500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1000 MW</td>
<td></td>
<td></td>
<td></td>
<td>8800</td>
<td></td>
</tr>
</tbody>
</table>

Real life operating heat rates are also influenced by the location of the plant, the ambient conditions at the site, the auxiliary system load requirements and many other factors. Be that as it may, the relative efficiencies shown in the above table provide planners with a preliminary assessment of the preferred technology.
Resources with high initial capital requirement might be able to generate with very little O&M and fuel costs, while resources with low initial costs might require higher O&M and fuel costs. The evaluation of tradeoffs among different generation types can be very complex. Production simulation models are therefore developed to aid in these types of complex analyses. These programs simulate the operation of future systems, computing fuel, start-up, operation, and maintenance costs. In addition to the annual operating and maintenance cost summaries, they can also calculate the present cost value for the investment requirements of the resource plan. These models will generally take the results from load forecasting models, reliability models, and economic and financial analysis models, and work in an iterative fashion in order to offer a least-cost resource plan. With the advancement of computer technology, new models today can even optimize a lot of these complicated tradeoff options simultaneously.

II.3.5 Transmission and interconnection planning models

Transmission and interconnection expansion planning utilizes a study of long-range load and generation forecasts to determine a preferred network growth pattern.

This study examines the bulk power transmission network throughout the expansion period to determine the voltage level, location, and installation date for future network additions using a Horizon Planning approach. Alternative designs for a horizon year condition are developed first as a guide for scheduling each transmission facility addition. The Horizon Year approach determines the facilities needed at the horizon year. The specific schedule of addition is then determined by conducting analyses of earlier years.

Upon completion of a generation expansion study, system planners will study the need for transmission expansions, which include the necessary circuits, the transformers and the circuit breakers. These results may apply to one or several different voltage levels.

The traditional method for transmission expansion planning is heavily dependent upon the system design engineer. Typically, a system design engineer would undertake the study by sketching out some preliminary designs for load levels several times above historical system peak load conditions.

Using the prevailing growth rates, horizon years can then be determined, indicating when the load levels will be reached. If the growth patterns change, the facilities requirements will generally be similar to those determined for the same load levels but the time frames will need to be adjusted.
A preliminary network modification study will be required to meet various conditions of peak load, light load, generation outages and transmission circuit outages. This requires an experienced power system planner who will determine the critical conditions that need to be studied to ensure that an adequate system is developed in order to provide the desired level of reliability of service to the load. In almost all cases, the primary objective is to provide reliable service to customers. A separate analysis is usually performed to ensure that enough resources are available with enough reserves to serve peak demand at all times including outages of generation units.

Optimization in Transmission Planning is accomplished through the investigation of alternative developments of the transmission system to meet the requirements of a given horizon year, e.g. 20 years from today. Once alternative systems are verified and deemed technically adequate, economic cost comparisons are performed using discounted cash flows or present worth analysis.

In the traditional approach to expansion planning, the digital computer is vital for the engineer to check his designs. The results of these checking calculations indicate whether and when these network modifications should be made. The advancement of computer technology has also made it possible to test the system in many different ways. Where, traditionally, the main requirements used to be steady state thermal loading and voltage conditions, the typical transmission assessment now includes transient stability, posttransient voltage, and reactive margin analysis.

The engineer’s input data required for a typical transmission network expansion program is generally based on the following assumptions:

1. The existing transmission network will be used as a starting point.
2. The location and magnitude of all future loads and generation are known.
3. The permissible transmission line loading and voltage levels are specified.

As system planners have learned from the traditional approach to transmission expansion planning, a long-range study is necessary in examining the impact of different plant sizes and locations, the introduction of a new voltage level of transmitting energy, and/or the changes in the contingency protection costs. Long-range planning is necessary because of the long lead time needed to plan, design, get necessary permits, procure materials and equipment, construct and test the new facility. Long-range studies also enable the system planner to optimize the benefits of today’s construction decisions into the future network.
Once a basic generation/transmission expansion plan is established, a more complete transmission system representation is used to define in more detail the nature of the circuits to be added. A large-scale load flow program is used to determine the adequacy of the proposed detailed transmission system design from the standpoint of voltages and overloads.

Because of the severe consequences of a stability problem on the transmission system, moreover, stability studies are performed to minimize the potential for widespread disturbances resulting in an interruption of service to customers on a massive scale, or even in a total blackout.

Finally, when the preferred alternative expansion program is selected, the next step is the implementation of the expansion plan. The optimal system is not necessarily the lowest cost system. There are other factors to be considered when adopting an expansion plan, for instance the flexibility to make changes in response to other factors such as abnormal line loading (heat waves, cold winters), shortages in resources, higher or lower load growths, etc. Flexibility in operating the system is also of prime importance in making final recommendations, and requires close consultation with operation personnel.

### II.3.6 Economic or financial analysis models

A financial modeling program is generally used to evaluate and predict the effects of investment decisions on the organization’s balance sheet, income statement and cash flows. Investments, including those for yearly generation, transmission and production costs, are input, along with a detailed description of the organization’s financial structure, accounting data, and management policy information. This type of program can simulate the organization’s financial activities on a monthly basis and provide forecasts of necessary capital acquisition to finance required system expansions. A financial modeling program is a useful addition to the traditional economic evaluation methods involving the present worth of revenue requirements.

The investment costs of generation and transmission projects in future years are normally computed using an investment cost program, once the expansion pattern and individual investments have been specified. This type of program uses fixed-charge rates and present worth mathematics to combine the series of payments into an equivalent present worth of future revenue requirements.
II.3.7 Commercially available models

Over the last 25 years, many computer models have been developed to assist planners in their pursuit of an optimum long-term resource plan. Depending on the desired planning objectives and/or criteria, these models could be different in their operating structures, simulation techniques, transmission modeling capabilities, emission analyses and several other parameters.

The simplest model for determining capacity needs is probably the deterministic model using predefined reserve margin requirements and long-range load forecast to identify the quantity of new generation resources required in order to reliably serve the growing demand. This method, even though very primitive, still provides the planner with a quick outlook. It is generally used as a reality check of the result obtained from more complex model analyses.

Most of the planners would also perform a basic production simulation to verify that the long-range plan is operationally adequate to serve the load with reasonable production costs. Sufficiently detailed information about existing resources and the proposed new additions are required therefore to perform this simulation. Analytical probabilistic dispatch and/or hourly Monte Carlo simulation techniques are commonly used to simulate the effect of minimizing the operation cost for a given plan. However, they would not be able to optimally select the most cost-effective additions for the system.

The next level of complexity is introduced when the planner asks the model to determine the most cost-effective plan, given necessary resource characteristic of existing resources as well as those of the options available in the future. Dynamic/linear programming techniques are used to perform this type of analysis. Additional assumptions on the financing of the project, the interest rates in the market and the initial capital requirement of the new resource options are not only essential but also crucial to the production of a reasonable expansion plan.

To complicate matters, most planners have to deal with the fact that the system they are studying is not isolated. Neighboring utilities and their excess resources are great alternatives to adding new power plants. In order to evaluate the availability and the cost of such excess resources, models were developed, offering the capability of evaluating many regions interconnected by a transmission network. Most of them model the transmission network with simple line loading limitations. During the simulation analysis, the model will check to see if the power flow from region A to region B (calculated based on a least-cost dispatch) would violate the constraints of the transmission line linking region A to region B. In the affirmative, the model will readjust the dispatch of units in region A, B and/or other regions in the network until this violation is avoided.
As any electric power engineer would tell, however, line ratings are dynamically varied, instantaneously. The demand of the system, the generation pattern of all resources in the network, as well as the condition of all of the interconnected transmission lines will contribute to the power flow of the system and the constraints of each line. Consequently, models with DC/AC power flow approximations began to surface in the market. They require additional input data and assumptions about the system under evaluation, as well as bigger and faster computing capabilities to perform the calculations.

As the electricity market began to open up to competition, most of the models started to incorporate more resources from outside the region as wholesale competitors. Sophisticated market dynamics simulation models began to develop, with various degrees of capacity expansion capabilities, different levels of transmission system representations and simulation. They have become the tools used for fundamental analysis in long-range strategic planning studies. They are used to predict regional market equilibrium prices. These price projections are in turn used in the decision-making process for new power plant investments and in the negotiation process of power purchase and/or price hedging contracts. They are also used, sometimes, in identifying market behavior abnormalities.

Commercially available electricity market simulation and price forecast models are generally accessed by planners through annual licenses. Depending on the complexity of the model, as well as the completeness of its input database, the annual license fee could range from US$30,000 to over US$200,000. Companies would, moreover, have to allocate staff and computer resources to operate these models and maintain the most current/realistic databases necessary. Some choose to benefit from these models by hiring consulting firms who have the requisite licenses and the expertise to perform the necessary analyses.

Some of these commercially available models and their characteristics are summarized in Appendix A.
Chapter III

Planning for Uncertainty

III.1 Historical Perspective

The resource planning process has traditionally been dominated by a single-load forecast that defined the resource requirements. This process worked quite well during decades of steady growth with few unforeseen events. As the business environment started changing in the late 1960s, however, the increasing frequency of unexpected occurrences made long-term planning more complicated and challenging.

The initial response to this increasingly complex planning environment was more sophisticated forecasting and simulation models, more extensive databases, and more emphasis on optimized resource planning. Even though these models and databases helped in the development of sound resource plans, they did not address the main underlying reason for the growing complexity of resource planning. In order to incorporate properly frequent unforeseen events and plan for an uncertain future, many planners began to use sensitivity analyses, decision tree methodology and scenario planning techniques to capture those continually changing conditions.

In the mid-1960s, following years of steady and rapid growth, most of the utilities in the United States were forecasting a sustained load growth of 8-9% annually for at least another ten (10) years. In this rapid growth environment, resource requirements would double before the end of the decade. Resource plans developed at the time included a significant number of new power plant projects, high voltage transmission/interconnection systems and natural gas or oil pipeline projects.

A few major unforeseen events changed some of the underlying assumptions, however, and many of those plans were never carried out.

The 1965 blackout in the northeast of the United States demonstrated the importance of the electric power system reliability. The North American Electric Reliability Council (NERC) was formed as a result of this incident.

The 1970 Earth Day demonstration and the passage of the California Environmental Quality Act ushered in the environmental movement of the 1970s.
The 1973 oil embargo by members of the Organization of Arab Petroleum Exporting Countries led to a quadrupling of oil prices and to concerns about energy supply vulnerability. In the United States, the National Energy Policy Act and, in several states, energy conservation legislation were passed in response to the need for lower energy usage.

The impact of the 1973 energy crunch resulted in lower economic growth, higher inflation and unemployment, and lower energy consumption. At the end of the 1970s, the electricity demand growth rate was reduced to nearly half of the previous estimate, at approximately 5% on an annual basis.

Another set of unforeseen events happened in the late 1970s, leading to further changes in the rules and regulation under which the electricity industry operated:

- amendments to the 1970 EPA Clean Air Act (1973 and 1976);
- California’s Nuclear Initiative (Proposition 15) (1976);
- West Coast drought (1976-1977);
- passing of the National Energy Policy Act (PURPA and Fuel Use Act) (1978);
- Three Mile Island nuclear incident (1979);
- oil and gas industry deregulation (1981).

By 1980, the US economy was going through its worst post-World War II recession with double-digit inflation, 20% prime rate, and high unemployment. With a doom and gloom outlook for the future, policy makers initiated many energy conservation and load management programs; utility management began to focus further on capital minimization strategies and utility planners cut the demand growth forecast to merely 3% in the early 1980s, and later to 2% in mid/late 1980s and throughout the 1990s.

Even though resource plans were drastically changed several times to reflect the most current information available at the time of their development, utilities in California, for instance, found themselves in a position of high reserve margin, high electricity rates and low load growth in the early 1990s. With the passing of the new 1992 National Energy Policy Act, including Transmission Open Access and privatization of utility assets around the world, the wave of electricity industry deregulation swept the nation.

As we look back on the events which changed our business environment, it is clear that no one could have predicted with any degree of accuracy the nature or timing of those events. The lesson learned is that we should prepare ourselves for future uncertainties by considering a number of alternative scenarios and developing the appropriate strategies.
III.2 Key Features of Scenario Planning

Historical perspective demonstrates that, more often than not, long-term forecasts are more. The focus in developing a robust resource plan should therefore be on the identification of alternative futures. How can this be best accomplished? A promising approach is scenario planning.

Under that approach, and instead of trying to predict the future, a set of plausible futures is postulated. Every one of these plausible futures is described by a set of internally consistent assumptions. Some of the assumptions in the set are the economic condition of the region, the rate of electricity demand growth, and the regulatory, environmental, technological, social, political and business environments. Each of these alternative futures is possible but not assured.

Scenario analysis has successfully helped many industries better prepare themselves for future uncertainties. Some of the key features of scenario analysis are as follows:

- It looks at many alternative futures as opposed to a single one.
- It encourages the examination of underlying assumptions and allows planners to change the assumptions.
- It allows decision-makers to ask “what if” questions.
- It evaluates alternative strategies or options, and tests the robustness of different resource plans under different alternative futures.
- It emphasizes the significance of planning flexibility, and develops plans with built-in on and off ramps to quickly response to changing conditions.

III.3 Scenario Planning Process

Scenario planning analysis generally starts with an all-encompassing effort to identify how the future could unfold under a wide range of assumptions. The process of developing future scenarios is a creative exercise involving a broad range of specialists in the industry. Scenarios consisting of plausible combinations of assumptions for economic conditions, environmental considerations, and regulatory, social and business conditions are postulated. They are characterized by a theme or an initiating event.
Through preliminary analysis, planners will find that many scenarios result in similar consequences with regard to the need for new resources, even though those consequences may be determined by different factors. Consolidating some of the scenarios based on their consequences will reduce the number of cases for detailed study, yet still encompass a wide range of potential futures.

Examples of scenarios that may be considered include:

- Resource Plan Reference Case;
- High Growth Scenario – Economic Boom;
- Low Growth Scenarios – Economic Bust;
- Facility Shutdown Scenarios – Loss of Major Resources;
- Extreme Environmental Condition Scenario;
- Regional Political Conflict Scenario;
- Customer Self-generation Scenario;

While it is conceivable that events outside the bounds of the scenario might occur, the probabilities are considered sufficiently low not warrant formal consideration.

The next step in analyzing future scenarios is to identify and quantify those major factors or variables affecting the resource requirements. As a starting point, one might consider the following factors:

- economic growth of the region – higher economic growth would result in higher energy consumption, hence high resource requirements;
- fuel cost and availability – higher fuel costs have a direct and negative impact on rates and consumption; fuel availability will not only influence fuel cost but also affect the selection of new resources;
- base rates – the non-fuel component of utility rates (capital requirement and non-fuel O&M) is also a significant factor influencing energy sales;
- environmental constraints – changes in environmental regulations could affect both the cost of electricity service and the demand for electricity;
- regulatory or market structure – this changes the fundamental structure of the industry; it could drastically change the way electricity is generated, transmitted and distributed.
- technological innovations – technological innovations could increase load, as in the case of new appliances, reduce load, as in the case of more efficient capital stock and equipment, and improve the efficiency of new resources.
Since it is impossible to know which of these plausible scenarios may unfold, the future Resource Plan should focus on developing a flexible action plan covering the entire set, which can be rearranged in a number of ways to respond to changes in real life.

To meet the resource requirements of each scenario, planners would need a set of strategic elements for the development of a flexible planning strategy. Strategic elements, viewed as building blocks, can be put together in a number of ways to accommodate different system designs. The utility will select the right resource combination in order to accommodate projected growth rates, either increasing or decreasing over a specific planning horizon, i.e., 5, 10 or 15 years. Strategic elements might include options, such as:

- refurbishment or retirement of utilities’ existing generating units;
- new utility generation resources;
- independent power producers or merchant plants;
- load management and energy conservation options;
- transmission and interconnection system expansions.

The result of this planning process is a sound resource plan that allows sufficient flexibility in the management of resources to be able to respond and adapt to future uncertainties. The planning approach further provides a transition from a resource plan focused on long lead time power plants to a planning strategy emphasizing regional electricity cooperation, energy diversification and resource flexibility.

The problems resulting from a significant change in needs, costs or business environment are generally the result of a utility or region’s inability to make adjustments to its plans, rapidly and in an efficient manner. Using a flexible resource planning process and planning for uncertainty involves the continued balancing and re-balancing of numerous supply and demand side resource options in order to meet and respond to changing conditions in a reliable manner.
Figure 2: Examples of commercially available electricity production simulation and price forecast models

<table>
<thead>
<tr>
<th>Vendors</th>
<th>General Description</th>
<th>Simulation Techniques</th>
<th>Transmission Modeling Capabilities</th>
<th>Capacity Addition Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>AURORA EPIS, Inc.</td>
<td>A Windows-based software package, with capabilities to forecast prices, and value resources and strategies</td>
<td>Chronological hourly dispatch</td>
<td>Transport modeling of transmission network constraints, losses and wheeling costs</td>
<td></td>
</tr>
<tr>
<td>EGEAS EPRI Model</td>
<td>Model developed to assist utilities in IRP, can run on many platforms</td>
<td>Probabilistic simulation</td>
<td>Limited</td>
<td>Performs dynamic programming analysis to add most cost effective units</td>
</tr>
<tr>
<td>MAPS General Electric</td>
<td>Has complete transmission system modeling capable of estimating locational marginal prices</td>
<td>Chronological hourly dispatch</td>
<td>Extensive, uses load flow analysis with DC approximation</td>
<td>User specified capacity expansion plan</td>
</tr>
<tr>
<td>PMDAM New Energy Associates</td>
<td>Has capability to estimate hourly energy and monthly capacity prices, run on PC platform using Microsoft Access</td>
<td>Analytical probabilistic dispatch or Monte Carlo simulation</td>
<td>Extensive, uses transport modeling technique to capture transmission constraints, losses and wheeling costs</td>
<td>Performs probabilistic simulation to add new generation units</td>
</tr>
<tr>
<td>PROMOD New Energy Associates</td>
<td>Has capability to estimate hourly energy and monthly capacity prices, run on PC platform using Microsoft Access</td>
<td>Probabilistic simulation or chronological Monte Carlo simulation</td>
<td>Extensive transport modeling, may have some capability of DC approximation</td>
<td>Capacity expansion through iterative analysis</td>
</tr>
<tr>
<td>Tool</td>
<td>Company/Group</td>
<td>Description</td>
<td>Methods/Techniques</td>
<td>Required Actions</td>
</tr>
<tr>
<td>--------</td>
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</tr>
<tr>
<td>PROSYM</td>
<td>HESI, Inc.</td>
<td>Has capability to estimate hourly market prices, run on PC platform, using Microsoft Access</td>
<td>Many techniques available: Monte Carlo, convergent Monte Carlo, or probabilistic simulation</td>
<td>Transport modeling of transmission network constraints, losses and wheeling costs. User must carry out this analysis separately and input the expansion plan.</td>
</tr>
<tr>
<td>UPLAN</td>
<td>Lotus Consulting Group</td>
<td>Has ability to forecast market cleaning prices, transmission congestion charges and ancillary service prices</td>
<td>Multiarea chronological model, dispatch based on demand bids and suppliers’ offers</td>
<td>Uses AC power flow analyses to determine transmission flow, losses and wheeling charges. User must carry out this analysis separately and input the expansion plan.</td>
</tr>
<tr>
<td>WPMM</td>
<td>ICF</td>
<td>Has capability to estimate hourly energy and capacity prices, PC platform, Microsoft Access user interface</td>
<td>Chronological dispatch of each region and economic exchanges between regions</td>
<td>Interregional transmission modeling permissible. Model determines the capacity expansion plan using an iterative technique.</td>
</tr>
</tbody>
</table>
Module 4

Integrated Operational Planning: Optimal Conditions
Module 4
Integrated Operational Planning: Optimal Conditions

Introduction

Chapter I Joint Planning
I.1 Costs of Joint Planning
I.2 Benefits of Joint Planning

Chapter II Distribution of Surpluses
II.1 Initial Distribution
II.2 Solution Concepts
II.3 The Core
   II.3.1 Example
II.4 Stable Sets
II.5 The Nucleolus
II.6 The Shapley Value
II.7 Application of the Concepts
II.8 Measurement of Payoffs
II.9 Design of Transfer Payments
II.10 Costs of Implementation

Chapter III Trust
III.1 Iterative Processes
III.2 Trust and Reciprocity
III.3 Conflicts and Compliance

Conclusion

back/foward to

Module 1
Module 2
Module 3
Module 5
Module 6
Module 7
Module 8
Glossary of Technical Terms
Acronyms and Symbols
Introduction

The objective of this module is to identify optimal conditions for the success of a joint project. A project can only be successful in the long term if a stable solution is found that convinces every contributor to the project that his particular effort is worthwhile. Ignoring this requirement will inevitably lead to frictions that might jeopardize the project.

A stable solution requires the consensus of all parties involved in the project. This module seeks to facilitate the process of finding solutions that will prepare the ground for consensus. After a brief look at how the benefits and costs — and the resulting surplus, i.e. the difference between the two — of a joint project can be identified, the main part of the module examines different possibilities for distributing that surplus.

There are various possibilities as to how a stable distribution of the surplus can be achieved in a particular project. A Transmission System Operator that would otherwise refuse to cooperate might be compensated through higher tariffs for the use of its grid. A distribution company may retain a share of captive retail customers while at the same time being given access to a liberalized wholesale market with lowered prices. An enterprise operating less efficient generation facilities may receive direct payments in order to compensate for the stranded investments. These are but a few examples.

All of the measures have to be designed, of course, to achieve a certain goal, a certain final distribution that will provide sufficient incentive for every participant to participate in the project. It will become readily obvious that the methods described in this module are not meant to be applied directly to a particular project. Their purpose is different.

By working with these methods and transferring them to a real world setting, the reader can discover the effects described here in the situation he is facing. This will enable him to gain a deeper understanding of a particular problem and an awareness of the requirements and demands of the different parties involved. A more meaningful understanding should translate into a more stable distribution of the benefits of the project and may, in some cases, enable a joint effort for the realization of the project.
Chapter I

Joint Planning

It is important that all these costs and benefits be quantified. If this cannot be done directly, estimates must be used to arrive at a quantifiable result. A correct identification and evaluation of the costs and benefits (to whomever they accrue) is important for several reasons.

Among those reasons is the necessity to obtain a correct understanding of the impact of the project and thus to understand if the project should be undertaken at all. Such a process also facilitates the bargaining among the parties involved, and makes it possible to obtain the consensus of the parties that are not directly involved. The whole process of achieving optimal conditions for Integrated Operational Planning could be made more transparent through the extensive collection of information on the impact of the project. It may also simplify the agreement process as well as the bargaining involved in that process.

Yet, this evaluation of costs and benefits may remain incomplete if all the concerned parties cannot be interviewed. An example may be the impact on future generations. Another possibility would be that the relevance of available information may not be obvious at a given moment, e.g. environmental effects were thought to be less relevant three decades ago. Still, even in these cases it will often be helpful to draw on the best estimates available.

It is also important to remember that the costs and benefits for all parties involved in the project must be taken into account. Consequently, the evaluation is not limited to parties participating directly in the joint project, but must necessarily extend to those who are affected by the project, e.g. the consumers of electricity within the region.
1.1 Costs of Joint Planning

Completion of a joint project to promote regional electricity cooperation and integration entails a range of costs. One way to identify these costs is simply to take a look at all costs that are usually incurred. These might include any or all of the following:

Planning Costs

Among the various costs of a joint project, planning costs will normally be the lesser. Apart from purely technical planning — which will be subsumed under construction costs — lowering those costs may be realized through a clear understanding of what is to be achieved, who should benefit and how. The purpose of this module is to help advance this process.

Construction Costs

A joint project for regional electricity cooperation and integration usually requires the construction of electric installations such as generation facilities, transmission lines or distribution grids. These obviously entail certain costs.

Loss of Monopolies

Under certain circumstances, monopolistic behavior is obviously less than optimal in terms of benefits to society, assuming that there are feasible alternative ways to provide the commodity supplied by a monopolist. Besides, monopolists would not tend to behave the way they do if it was not to their advantage.

Regional electricity cooperation and integration, achieved by a joint project, generally brings together previously separate markets. This means that the monopolists involved in the joint project will lose at least some of their monopoly rents, i.e. the profit derived from setting prices above marginal cost. Even if, in a setting with perfect regulation, a monopolist would not garner any specific rents, it can only be assumed that the introduction of competition will be accompanied, usually, by a loss of monopoly rents.

Of course there should be sufficient benefits for other parties involved to compensate the monopolists. However, this has to be accomplished with side payments. Side payments are the transfers modifying the initial distribution. They are not a result of the joint project per se, but are designed to ensure the stability of the arrangement. To begin with, the costs for the monopolists have to be recognized, identified and acknowledged if their voluntary participation in the joint project is to be secured.
Loss of Customers

Apart from the loss of monopolistic rents due to lower prices, the revenues of the parties involved in a joint project may also be eroded by lower sale volumes, i.e. by loss of customers. This possibility entails, of course, that other parties will gain customers — an aspect that will be examined in the next chapter. Again, even these parties can be motivated to participate in the joint project, but they have to be compensated by transfer payments. In this case the first step in setting proper compensation is to identify the losses.

The loss of monopoly rents and customers must be quantified by means of estimates. This requires careful analysis of future market developments (without being excessively elaborate), in order to design a sound mechanism for the joint project. The added benefits of a more precise estimation, particularly in this case, have to be weighed against the extra costs.

I.2 Benefits of Joint Planning

If the joint project is to be undertaken at all, the total benefits for all parties involved must, of course, exceed total costs. The greater the surplus — the difference between benefits and costs — a project produces, obviously, the more interesting that project will appear. Still, the benefits must be identified in detail before we can arrive at the initial distribution. The initial distribution is the distribution of payoffs to all parties concerned, the payoffs accruing from the joint project per se, i.e. before taking any side payments into account.

Use of Efficient Generation

A major factor is the use of the most efficient generating facilities in the region. This can be achieved by complete closure or reduced utilization of obsolete plants, better use of renewable sources of energy or, in some cases, even reduced need to transport primary fuels through areas with a transport network that is not yet fully developed.

Lowering of Reserve Capacity

One of the main technical benefits of enlarging a synchronous electric system is lowered overall reserve capacity by means of reserve pooling. This effect, of course, applies only if the joint project is designed to link two or more formerly separate systems to form a single synchronous area. The reason for this effect is mainly that the size of the largest block that can fail will remain unaffected by the link between the two systems.
As the failure of the largest block influences the probably necessary reserve to a large extent, the required reserve capacity will usually be lowered drastically by the synchronous link of the two formerly separate systems. Additional benefits may be realized, however, if two regions with different peak loads — e.g. between summer and winter, or for other reasons — are linked.

It should be borne in mind, however, that altered generation patterns can change the probability of power failure. Any differences in supply security and the corresponding risk of power failure must be quantified and taken into account.

**Gain of Customers**

If some participants in the joint project should lose customers, other participants will, of course, gain customers and sell more electricity after the project is completed. It should also be mentioned, however, that the overall result does not necessarily have to be zero. Generally increased efficiency due to completion of the joint project may lead to an overall increase in electricity consumption, although the increase will usually come from the producers offering the less expensive energy.

In addition to reduced prices, the joint project might also bring an increase in the electricity consumption through increased power availability and the corresponding end of rationing, as well as through the connection of previously unconnected areas which enables the realization of previously suppressed demand. These last two effects may be of particular relevance in the concerned countries. Consequently, there could be gains in electricity sales without other parties suffering corresponding losses.

As in the case of loss of customers, the costs arising directly from the methods used to estimate this effect can easily exceed the added benefits accruing from an enhanced stability of the project.¹

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¹ These techniques of demand forecast and the description of consumer behavior are considered in more detail in Module 4.
Chapter II

Distribution of Surpluses

II.1 Initial Distribution

After the decision to initiate joint planning, the different parties involved in the process (or other parties who are interested and can influence those who are directly involved) usually bear their own costs and reap the benefits themselves. Nongovernmental organizations (NGOs), regulatory authorities and environmental groups, as well as large customers, may be among those other parties. All of them are important, in one way or another, to the power companies or financial institutions directly involved with the joint project, and can exert considerable influence. This, in turn, could indirectly affect the costs and benefits for one of the parties working on the project and, for that reason, it has to be taken into account.

This situation where no side payments are made and no party is compensated in any way is called the initial distribution. Of course, the initial distribution may include fundamentally different situations. Situations in which all parties involved in the joint project are better off than they were before the project are substantially different from those configurations where some parties have improved their situation, while others obtain worse results compared to the situation before the project. It should be noted, however, that the case where everyone involved receives a worse payoff than they would have had without the joint project is not possible. Should such a situation occur, the project would be abandoned completely and the problem of identifying optimal conditions becomes irrelevant.

---

2. A payoff is the difference between benefits and costs for each of the various parties involved in the joint project.
II.2 Solution Concepts

After the initial distribution has been determined, transfer payments still remain possible. The easiest way to determine the transfer payments, however, is to look at the final distribution of the net benefits for each party involved in the joint project. The transfer payments, then, simply represent the difference between the initial and the final distribution.

This implies that all that is required is to have an idea about a “good” final distribution after the initial distribution has been determined. A more detailed look at possible problems associated with both the measurement of the payoffs, as well as the design of transfer payments, will be provided in the next chapter. In this section, meanwhile, we will take a closer look at different solution concepts, i.e. different notions of what constitutes a “good” final distribution.

II.3 The Core

The Core is the most popular and most convincing solution concept in cooperative game theory. It has a number of drawbacks, however, the most disturbing of which is that it usually either delivers no solutions at all or an indefinite multitude of different solutions. For all practical purposes, this reduces the Core to the function of narrowing the vast amount of imaginable solutions down to a set of plausible ones.

The Core, precisely stated, is the set of undominated imputations. Imputations are those payoff vectors\(^3\) that are both individually and collectively rational. Individual rationality requires that every participant in the game, i.e. in the joint project, gets at least what he would also get if he did not participate, i.e. if he did not cooperate with anybody and simply proceed on his own. Collective rationality, on the other hand, demands that the efficient solution for all participants be obtained. This simply means that the joint project is realized if it is viable.

---

3. A payoff vector lists all individual payoffs and thus describes the results of the game completely.
Unfortunately a definition of domination cannot be avoided. One imputation dominates another over a certain subset of the participants if this subset can, on its own, realize a different payoff vector that has at least the same payoff for all members of the subset, and at the same time a larger payoff for at least one element of the subset. It is interesting to note that individual rationality is simply the absence of domination for all subsets with only a single element.

The Core, in other words, requires that every subset of participants in the joint project will not be able to improve the situation of its members by abandoning the project and realizing an alternative solution that it also has the power to implement.

II.3.1 Example

The concept of the Core becomes more understandable as we study the following example. Its basic structure was presented as early as 1975 when Gerald Faulhaber demonstrated that the set of subsidy-free prices, i.e. sustainable solutions in our context, are those prices for which the resulting revenue vector lies in the Core of the underlying cost allocation game.

The example focuses on the search for a stable scheme of contributions to a joint project in cases where the production of the goods concerned is subject to subadditive costs. For our purposes, subadditivity of costs is equal to the existence of economies of scope, and implies that the joint or common production of all or any subset of the goods concerned is cheaper than the separate production of the elements of that set. Economic efficiency, in other words, requires joint or common production, in our case through a project of regional electricity cooperation that encompasses all relevant participants.

The objective is to determine individual contributions to the joint project that ensure both stability and efficiency by making it unattractive for any subset of participants to divide the production of the goods in question by leaving the joint project. A system of contributions to the joint project is, accordingly, stable and efficient (i.e., collectively rational) if the payoff vector is in the Core of the underlying noncooperative game which models the costs and revenues of the joint project.

Let us now address the project in our example. There are four different areas to be supplied with electricity. Two areas are situated in the western part of the region (labeled 1 and 2) while the other two are located in the eastern part (labeled 3 and 4). Each of the areas will be assumed to consume 100 GWh a year. The cost of distributing the electricity is the same in each area, namely EUR 5 million a year.

It is obvious that one large power plant will be sufficient to supply the whole region. For simplicity sake, the assumption is made that there only is a single size and version of power plant available, the total cost of which is EUR 10 million a year. If only a single power plant is constructed, the areas in the western half and eastern half must be linked by a transmission line. The line is assumed to incur total costs of EUR 5 million annually.

These relations are displayed in the following diagram:

Subadditive costs — which are the same as superadditivity\(^5\) of the profit functions — imply that the efficient solution has all four different areas supplied by a single power plant. The agreement on this solution has to be voluntary, however, i.e. every subset of the set of four areas, including single areas, has to agree to this solution. This efficient solution implies annual costs of:

\[ c(\{1,2,3,4\}) = \text{EUR 35 million} \]

which is the requirement of collective rationality or efficiency.

However, alternative arrangements with the following costs \( c \) are possible:

\[
\begin{align*}
    c(\{1,2,3\}) &= c(\{1,2,4\}) = c(\{2,3,4\}) = c(\{1,3,4\}) = \text{EUR 30m} \\
    c(\{1,3\}) &= c(\{1,4\}) = c(\{2,3\}) = c(\{2,4\}) = \text{EUR 25m} \\
    c(\{1,2\}) &= c(\{3,4\}) = \text{EUR 20m} \\
    c(\{i\}) &= \text{EUR 15m} \quad \text{for all single-area arrangements.}
\end{align*}
\]

\(^5\) Superadditivity implies that the joint result (in this case the profit in the case of cooperation) exceeds the sum of the single elements if these were pursued separately. It is the opposite of subadditivity where the joint result obviously amounts to less than the sum of the parts.
Again, subadditivity of costs, which implies that the costs of joint production do not exceed that of separate production of the individual products, is evident, i.e.

\[ c(K) + c(J) \geq c(K+J) \] provided that K and J are disjoint sets, i.e. do not have common elements.

We are thus dealing with a relevant game, i.e. a game where a real positive surplus can be realized through cooperation and then be distributed. 6

It will also be assumed that the total revenue \( r \) covers the exact total cost of the project, i.e.:

\[ r(K) = c(K) \text{ where } r(K) = \sum r_i \forall i \in K \]

This means that the overall contribution has to be equal to the cost of the project. This overall contribution is defined as the sum of the individual contributions of all participants.

The scheme to distribute the revenues is in the Core if no subset of the grand coalition, i.e. the set of all participants in the project, has an incentive to pursue a separate solution, i.e.:

\[ c(K) \geq r(K) \forall K \in N \]

In the event this condition is not fulfilled, there would be a subset which would benefit from leaving the joint project and setting up an electricity supply on its own. This is a particular form of a stand-alone test applied to cost distributions.

An alternative to this is the additional cost test that yields the same result, namely the Core:

\[ r(K) \geq c(N) - c(N - K) \forall K \in N \]

6. It is interesting to note -- as Faulhaber did -- that these cost relations are equal to the conditions of a natural monopoly. The important question is whether any subset has an incentive to pursue a separate solution. This obviously is not the case if the distribution of costs is in the Core, i.e. a natural monopoly is stable if the corresponding allocation is in the Core.
For the realization of the joint project, in other words, the additional cost test requires that each subset contribute at least the amount covering the additional cost that the grand coalition would incur without that subset. If this were not the case, the other members of the joint project would subsidize the subset in question, which would in turn provide an incentive for them to leave the project.

Accordingly, a system of contributions is stable, which means that the joint project will be completed if the allocation of contributions is in the Core. For our example, this implies:

\[
\begin{align*}
  r_1 + r_2 + r_3 + r_4 &= 35 \\
  r_i &\geq 5 \quad \forall i \in \mathbb{N} \\
  r_1 + r_2 &\geq 15 \\
  r_3 + r_4 &\geq 15
\end{align*}
\]

All cost allocations that fulfill these four conditions are in the Core, and the result is thus stable.
II.4 Stable Sets

Stable Sets are an alternative solution concept that avoids many of the disadvantages associated with the Core.

A major disadvantage of the Core is that in many cases it will be empty. This implies that a stable final distribution does not exist. One option in this case would be to simply abandon or modify the joint project. Another possibility, however, is to search for “less unstable” solutions. Although this approach might be problematic because even “less” unstable solutions are still unstable, it may nonetheless help to find payoffs that can pave the way to completion of the project.

Unfortunately, there exist no definite criteria for differentiating unstable solutions. Different concepts lead to different results. For the purposes of these Guidelines, we shall discuss only the concept of Stable Sets (also called Von-Neumann-Morgenstern-Solutions) and the Nucleolus.\footnote{Other concepts -- such as the Bargaining Set and the Kernel -- will not be examined at all, as their relation to practical problems is strictly limited in a context of regional electricity cooperation and integration.}

Stable Sets are internally stable, i.e., they include no payoff vector that is dominated by any other payoff vector also included in the same Stable Set. The Stable Sets also have to be externally stable, in that every payoff vector not included in the particular Stable Set has to be dominated by at least one payoff vector that is an element of the Stable Set in question. It should be noted that this fails to preclude that some payoff vectors not included in the Stable Set may dominate payoff vectors that are, indeed, elements of the Stable Set.
By contrast, the Core is not necessarily externally stable, while on the other hand it is impossible for any element of the Core to be dominated by a payoff vector that is not included in the Core. Of course, the Core is always internally stable as well.

The idea behind this concept is that any social order or distribution of benefits that is mutually agreed on has to be without internal contradictions. There is also the additional requirement that any external challenge to the social order or distribution of benefits must be met with an argument that is superior to that particular challenge. In the case of a joint project, this means that the participants can, as a first step, agree on a whole set of possible solutions provided that this set does not contradict itself.

II.5 The Nucleolus

Both of the above solution concepts have a severe disadvantage as regards practical application: they usually present the parties involved in the joint project with a whole set of different solutions from which to choose. Admittedly, the Core can sometimes be limited to a single element. Usually, however, it merely narrows the set of solutions to a smaller set. Although this vagueness is a fitting reflection of the complexity of the underlying cooperative game, it is of little help in providing applicable recommendations.

The advantage of the Nucleolus and the concept of Shapley Value is that both reduce the set of solutions to a single element.

For the Nucleolus, let us define the excess of a coalition as

$$e(K,u) = v(K) - \sum_{i \in K} X_i, \forall i \in K$$

In other words, the excess is the difference between what a particular subset — or “coalition” in the terms of cooperative game theory — can achieve on its own and what it really yields, given certain payoffs. Of course, this value is different for each subset and each payoff vector. A positive excess would mean that the subset in question gets less than it could get alone; a negative excess means that it gets more than it could get if it would not cooperate with anybody else.

The Nucleolus is the payoff vector that minimizes the excess of all possible coalitions. As mentioned before, the Nucleolus will very often include only a single element.

To be more precise, minimization of the excesses over payoffs is accomplished lexicographically. In other words, the Nucleolus gives us the set (with only a single element most of the time) of payoff vectors that minimize the maximum excess.
This can be interpreted as the solution that minimizes the incentive to leave the joint project for that party whose incentive to do so is the strongest.

It is interesting to note that the Nucleolus will always be a subset of the Core—provided the Core is not empty. In fact, it will point to the innermost element of the Core. Should the Core be empty, the Nucleolus will contain the payoff vector that is closest to the (nonexistent) Core. This relation can be understood more easily if one realizes that the Core is characterized by the fact that the excesses of all coalitions of all payoff vectors that form part of the Core are necessarily non-positive.

Our example will be slightly modified, as the manual calculation of the Nucleolus is significantly easier if the number of participants is reduced. For this reason, we will assume that the contribution of the fourth participant in the project is fixed at EUR 5 million for external reasons, i.e. the area will only pay for its own distribution, but still be connected to the joint project.

This leads to the following reduced specific cost function:

\[
\begin{align*}
c(\{1,2,3\}) &= \text{EUR 30m} \\
c(\{1,3\}) &= c(\{2,3\}) = \text{EUR 25m} \\
c(\{1,2\}) &= \text{EUR 20m} \\
c(\{i\}) &= \text{EUR 15m} \text{ for all single-area arrangements (except } c(\{4\}) = \text{EUR 5m of course)}
\end{align*}
\]

The Nucleolus of this reduced game is thus a simple equal division of the remaining EUR 30 million — the original cost of EUR 35 million, minus the fixed contribution of the fourth participant of EUR 5 million — that must be contributed to the joint project. The Nucleolus is the payoff vector that reads:

\[(10m; 10m; 10m)\]

It can be seen immediately that the maximum (cost) excess here is EUR 5 million which applies both to all subsets with only a single element (again excluding \{4\}, of course), and to the subsets with two elements \{1,3\} and \{2,3\}. Any deviation from the Nucleolus would have to increase the excess of at least one of the participants in the project above EUR 5 million.

The excess is positive in a stable situation due to the fact that we are dealing with costs, i.e. the payoff would be the negative value of the costs, and the true excess would then be negative.
II.6 The Shapley Value

The Shapley Value is a power index. It is, nevertheless, the only solution that fulfills all the criteria of collective rationality or efficiency, symmetry and additivity.

For a participant \( i \) in a joint project, it is calculated as

\[
\phi_i(v) = \sum_{K \subseteq N} \frac{(k - 1)! (n - k)!}{n!} \frac{v(K) - v(K - \{i\})}{[v(K) - v(K - \{i\})]}
\]

where \( v(K) \) is the value of a project to the set of participants in the project \( K \), \( k \) is the number of participants in the project \( K \), \( N \) is the set of potential participants and \( n \) the number of potential participants.

The Shapley value is the payoff for each participant in the joint project. It is calculated as the sum of additional value the participant provides for an existing hypothetical project if he joins this project as the last participant. All existing projects that the participant may hypothetically join as the last participant are weighted by the share of this coalition among all possible permutations of all potential participants in the project.

As in the case of the Nucleolus, calculation of the Shapley Value is vastly simplified if the number of players is reduced. The reduced three-player game, where the fourth area is paying for its own distribution costs, is therefore used as an example:

8. Other power indices are the Deegan-Packel-Index or the Banzhaf-Index.
For area 1, the parts of the sum that form the Shapley-Value read as

$$
\phi_i(v) = \frac{2}{6} \times 15 + \frac{1}{6} \times 10 + \frac{3}{6} \times 5 = 9,1 \overline{6}
$$

where the first element is arrived at by taking the additional necessary contribution of area 1 to an existing coalition with no elements. This is the case where area 1 would go it alone. The second element is the additional necessary contribution if area 1 were to join area three. The third element then sees area 1 joining either area 2, or both areas 2 and 3 which are already cooperating.

As areas 1 and 2 are symmetrical, the same applies to area 2, of course.

The contribution of area 3 is then calculated as

$$
\phi_i(v) = \frac{2}{6} \times 15 + \frac{4}{6} \times 10 = 11,6
$$

The first element sees area 3 joining nobody, i.e. it is seeking its own supply, while the second element sees area 3 cooperating with any combination of areas 1 and 2.

The resulting sum is EUR 30 million, since, in any case, the sum of the individual Shapley Values must yield the total cost of the joint project.

It is interesting to note, however, that the payoff vector derived from the calculation of the Shapley Values

$$(9,167m; 9,167m; 11,667m)$$

differs from the Nucleolus. The “just” Shapley-Value, obviously, is not the same as the “stable” Nucleolus. Both solutions are part of the Core, as they must be as long as the Core is not empty. This ensures a reasonable amount of stability, even for the Shapley Value-derived payoff vector. This may change, on the other hand, if there is some uncertainty about the true payoffs. One reason might be that it is too costly to quantify the benefits and costs precisely. In that case, it might be safer to opt for the Nucleolus.
In our example, area 3 (which is the reason for building the transmission line) must pay more if the costs are allocated fairly than if the most stable solution is sought. Taking the particular characteristics of the joint project into account, the participants must judge which solution is most appropriate for their specific problem.

It should be borne in mind that some of the participants in the project might benefit from having a “just” distribution, or might be harmed and thus receive disutility from payoffs that are considered “unfair.” The reason for these preferences might be given by the fact that many people weigh relative utility much higher than absolute benefits. In other words, you might prefer to receive less rather than more if this is compensated by the fact that your neighbor does not receive more than you do. If this is the case, a “fair” payoff vector, like the Shapley Value used in the example, might prove to be more stable than the inherently “stable” Nucleolus.

II.7 Application of the Concepts

The crucial question concerning the application of concepts taken from cooperative game theory, as presented above, is, of course, how they can be implemented for particular projects of regional electricity cooperation and integration.

The application can, basically, be quite straightforward if the factors involved have been clearly identified. Most importantly, this applies to the payoffs for both the initial and final distribution. Then there is the question of how the transfer payments can be designed. Finally, we will take a brief look at the cost of implementing a particular system.

II.8 Measurement of Payoffs

The measurement of payoffs is not as straightforward as it might seem. In the first chapter, the various costs and benefits associated with the joint project were identified. If these are to be compared, however, they must first be quantified. At times, this can pose serious difficulties or give rise to significant additional costs.

Quantifying the costs directly related to the project — e.g. construction costs — might still be the easier operation. Estimating the monetary effect of loss of monopoly rents, i.e. lower prices, or direct loss of customers, i.e. loss of sales will prove more difficult. The same applies to the benefits incurred by the joint project. All benefits and losses must be quantified, however, in order to arrive at a final distribution that ensures the continuing participation of all parties in the project.
II.9 Design of Transfer Payments

As shown above, transfer payments may be required in order to arrive at a stable solution that will ensure the feasibility of the joint project. However, the issue of how these transfer payments might be designed was not discussed in detail. And yet, this is one of the most important questions facing anyone wishing to implement a joint project.

Of course the easiest way to make transfer payments would be to simply consider direct monetary transfers from one party to another. This procedure, however, might meet with serious resistance from some of the parties involved. The reason might be a loss of face or simply the legal impossibility of transferring convertible currency.

For this reason, it might be more appropriate to look for other ways to implement transfer payments, which would be more in line with the general idea of the joint project and, possibly, directly linked to the other effects of the project. In this regard, two possibilities are of particular interest.

The first possibility involves issues of transmission pricing. It is obvious that a Transmission System Operator (TSO) has to be remunerated for the use of the system. This, of course, includes any costs incurred directly to complete the project. Depending on who is charged with these costs, however, there are many different ways to design transfer payments: either only the users of the specific project can be charged, or the costs may be spread over all users of the network.

If the TSO is linked to an electric power producer or a supply business through a vertically integrated company, other possibilities emerge, as extra revenues for the integrated company may be generated through the TSO’s part of the business. Special care must be taken to ensure that inflated transmission charges do not jeopardize the success of the whole project by distorting the optimal allocation of generation capacity.

The other major possibility for designing transfer payments has to do with different degrees of market openness. It should be noted that this is not necessarily linked to liberalization: a wholesale open market for large interconnected electric power producers has always existed. An integrated electric power supply company which is compensated in order to make a project feasible could, for example, be given access to cheaper electricity while retaining certain groups of captive customers during a transition period.
If these arrangements are the only way to carry out a joint project, a regulatory authority can generally be expected to approve the scheme. It is important, however, to involve the regulator at an early stage as a party in the project, representing a specific interest, e.g. captive customers. This illustrates the fact that third parties must be considered, even if they can influence the joint project only indirectly.

II.10 Costs of Implementation

Is the implementation of a particular system worth the cost associated with the project? That question, as always, must be asked.

First of all, even the costs of negotiations must not be underestimated. Reaching agreement on one of the concepts presented above can be a lengthy process that might delay completion of the joint project. This, in turn, could deprive all parties of the surplus yielded by the project, for a certain period of time. It might be better, in some cases, to opt for a less favorable solution rather than bargain longer.
Chapter III

Trust

III.1  Iterative Processes

Many of the procedures described above will be repeated over time. The project might actually be completed, but the benefits and some of the costs will be incurred repeatedly. In technical terms, partial games are played in iteration. This does not apply to the initial planning and construction, but is almost certain to surface in operations.

This eventuality brings to light the need to arrive at stable final distributions that will, from the outset, satisfy all participants. Long-term relationships cannot be established, otherwise. Yet, there may still be some problems.

These may stem from the fact that the final distribution after the first phase, i.e. direct completion of the joint project, must be stable. Meanwhile, there may also be several minor games that differ from the first one, all of which must also reach stable solutions. This is especially the case if long-term irreversible investments are made. The partners are then locked because the investments have a substantially higher value within the project than outside. This paves the way for opportunistic behavior by some of the parties if no proper safeguards are installed beforehand.

There are basically two different ways to deal with this situation if it arises. The first would be to incorporate all future effects into the first and only evaluation of the joint project by depreciating them accordingly. This would require, above all, that all parties be able to make binding commitments for the future. If they can, then, this also is the procedure by which a solution should be found: the other possibility would be much more complicated. Then again, this absolutely requires binding contracts for all parties contributing to the joint project. This requirement could, however, be difficult to meet if international relations are involved.

In this case it may be necessary to agree on arrangements that are inherently stable and will not provide an incentive for some parties to abandon earlier agreements, even if this appeared beneficial to them in the first place. In other words, the structure would have to be modeled as an iterative game.
III.2 Trust and Reciprocity

Yet the theory of iterative games is much too complicated to be applied rigorously to the distribution of benefits from a joint project. The most that can be done is to recognize specific effects, and try to take these into account when looking for a stable solution.

The most important of these effects is iteration, which implies that the same game is played again and again over several periods of time. Noncooperation by some of the participants may then be countered by the threat that, in the long term, the other parties may as well refuse to cooperate. The solution agreed upon should, therefore, make allowance for a lower payoff to all parties if some refuse to cooperate. The design of such mechanisms, however, is rooted in noncooperative game theory, and is usually quite complex. It is thus beyond the scope of these Guidelines.

III.3 Conflicts and Compliance

In the absence of an enforceable contract, a substitute solution might be the designation of a party to settle conflicts. This may, indeed, be the only solution to long-term relationships. It should be stressed that this is usually not a third party. Instead, one of the parties involved in the project is given the power to decide on gaps in necessarily incomplete contracts.

This authority, together with access to information required to monitor compliance, can be granted to one of the parties by selling the resources of the other parties and, in effect, forming a single firm. This solution would also simplify the design of transfer payments, which could be transferred by the purchase of one or more of the firms involved. The formation of a single entity would, in fact, solve many of the problems addressed in this module. It is not the ultimate solution, however, as it is bound to create other difficulties.

All the participants in any joint project of regional electricity cooperation and integration should give serious consideration to the formation of single legal entities. This needs to be emphasized over and over again. These entities may encompass all, or just part of, the activities related to or influenced by the project.

The formation of a single firm will not, usually, automatically solve the problem of a stable distribution that would motivate all relevant parties to participate in the project. The question of who will own which share in the single firm will remain.
It will drastically facilitate, and in many cases eliminate altogether, the necessity to design mechanisms to compensate certain parties. In other words, the need to find a stable solution will remain while, at the same time, the problem of the design of transfer payments will disappear.

Another question concerns the scope of the single entity, should one be formed. Shall it be restricted to the assets built by the project? Shall it encompass only a single buyer in order to control the market? Or shall it extend to all facilities of electricity supply in the region? The other modules provide a number of examples of how this question has been addressed in projects already completed.

It should be made clear, however, that integration may defuse the problem of devising side payments but, at the same time, it will usually contradict the opening of the markets. A major factor in the liberalization process is the unbundling of different activities that were formerly integrated. Even more importantly, a number of different competitors have to supply the market in order to gain the benefits of a market opening. Integration is clearly against these trends. Still, the careful examination of different possibilities, even in this respect, can improve the understanding of the project and may provide solutions to problems that would otherwise render the realization of the joint project impossible.
Conclusion

Early identification and distribution of the benefits of a joint project in the field of regional electricity cooperation and integration represent a central requirement for the success of the project. Only if a stable solution is found, i.e. a solution where the incentive for any participant to leave the project is minimized, will all parties participate in and contribute to the project. A stable solution is a precondition for completing the project, which in turn will benefit the whole region.
Module 5

Pooling Resources: Technical Conditions
Module 5
Pooling Resources: Technical Conditions

Introduction

Chapter I  Technical Conditions Required to Interconnect Power Systems
  I.1 Power Supply Reliability
     I.1.1 Power Supply Adequacy
     I.1.2 Power Supply Security
  I.2 System Planning Criteria
  I.3 System Interconnection Technologies
     I.3.1 Comparison between AC and DC power transmission technologies
     I.3.2 Frequency control methods

Chapter II  Nature of Technical Studies to be Conducted
  II.1 System Adequacy Studies
     II.1.1 A Study of optimum reserve capacity
     II.1.2 A Study of possible effects of system interconnection on reserve capacity
  II.2 System Security Studies
  II.3 Improvements on Transmission Capacity
  II.4 Metering
  II.5 System Simulation and Analysis
     II.5.1 Power flow analysis
     II.5.2 Fault current analysis
     II.5.3 Stability analysis
     II.5.4 Voltage stability analysis

Chapter III  Advanced Technologies Applicable in Interconnected Power Systems
  III.1 HVDC Technology
     III.1.1 Multi-terminal HVDC system
     III.1.2 Self-commutated AC/DC converters
     III.1.3 Power modulation control
  III.2 Technologies for Improvement of AC System Stability
     III.2.1 Countermeasures based on conventional equipment
     III.2.2 Countermeasures based on flexible AC transmission systems (FACTS)
     III.2.3 Countermeasures based on generator excitation control systems
Chapter IV    Overview of Interconnected Power Systems Around the World

IV.1 Japan
IV.2 North America
IV.3 Europe
   IV.3.1 NORDEL power systems
   IV.3.2 UCTE power systems
IV.4 Southeast Asia

List of Tables and Figures
   Table 1: Data input and output of power flow calculation
   Table 2: Comparison between line-commutated and self-commutated converter
   Table 3: Outline of typical FACTS equipment
   Table 4: Technical features of Southeast Asian interconnection systems

   Figure 1: Metering system outline
   Figure 2: Nose curve (P-V curve)
   Figure 3: Configuration of multi-terminal HVDC system
   Figure 4: Power modulation control
   Figure 5: Power systems in Japan
   Figure 6: Power systems in Europe
   Figure 7: Power exchange among NORDEL countries
   Figure 8: Locations of Southeast Asian interconnection systems

Appendix    Study Approaches for Interconnection Planning and Basic Considerations for Technical Issues (Constraints)

References

back/foward to
Module 1
Module 2
Module 3
Module 4
Module 6
Module 7
Module 8
Glossary of Technical Terms
Acronyms and Symbols
Introduction

The following economic and technical benefits can generally be derived from the planning and operation of electric power facilities through the interconnection of regional electric power systems:

- reduction in reserve capacity;
- scale merit from large electric power facilities;
- economical exchange of electric power between regional systems;
- suppression of frequency and voltage fluctuations; and
- improvement of the load factor, due to load diversity.

It should be noted that these benefits are available to regional electric power systems only if they are technically properly interconnected. If technical conditions are not satisfied, some unfavorably positioned regional power systems may be adversely affected. If one power system develops a failure, it may have a ripple effect and cause major electrical outages throughout the entire interconnected network.

In order to prevent these adverse effects, it is necessary to incorporate new technical constraints when building a network of interconnected regional power systems. These constraints are not necessary in isolated power systems. Specifying and examining technical conditions that must be satisfied in interconnecting regional power systems is of considerable importance. This task must be performed with utmost care.

It is difficult, moreover, to standardize a system’s interconnection configuration because there are many different conceivable designs, which depend on numerous factors such as system size, interconnection scale, geographical considerations, construction of power sources and transmission systems, and reliability levels. There are so many elements involved that it is difficult to adopt a uniform approach to studying technical requirements for system interconnection.

With all this in mind, Chapter I outlines basic technical issues that must be examined and resolved in creating a network of interconnected power systems — namely, power supply reliability, system planning criteria, and interconnection technologies, among others. Chapter II extends these basic issues to discuss more specific technical aspects of system interconnection planning. Chapter III focuses on trends in direct-current equipment and their stabilization technologies (including the AC network) which are some of the advanced technologies used to interconnect multiple power systems. Finally, Chapter IV illustrates an actual interconnection project.
Chapter I

Technical Conditions Required to Interconnect Power Systems

I.1 Power Supply Reliability [1] [3]

Power supply reliability is defined by the North American Electric Reliability Council (NERC) as “the performance level of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired.” Hence, reliability is expressed in terms of the frequency, duration and magnitude of adverse effects on the electric supply.

Reliability is an essential concept related to the planning and operation of a power system. System interconnection may affect the reliability of regional power systems. The reliability of an entire network of interconnected power systems must, therefore, be assessed in planning for system interconnection. This assessment is required generally to determine the benefits of improved reliability through system interconnection. At the same time, this assessment is needed in order to examine possible drops in reliability and adopt the requisite corrective measures.

I.1.1 Power supply adequacy

Adequacy means reliability, defined by NERC as “the ability of an electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.” This term is used when reliability is under discussion. A question may arise, for instance, as to whether, in an accident such as unexpected demand increases, partial or local service interruption can be evaded by automatic control or by a system operator performing operations such as uneconomical operation, power supply interruption, or load shedding. Adequacy can be defined, more specifically, as reliability within a range of events which can be controlled by operators, such as load shedding due to an overload or tight supply conditions in a local power system.
Adequacy is best understood as a concept corresponding to the reliability of ordinary supply-demand matching activities, or reliability as seen from a lower voltage local power system. In a network of interconnected regional power systems, the reliability of supply-demand control activities is considered as a primary element of adequacy. In such a network, an intersupply of electricity between different power systems can be achieved, and the reliability of supply-demand matching will generally be improved. In this case, the benefits of improved reliability in supply-demand matching — reduction in reserve capacity — accruing to each local power system must be properly reflected in the allocation of costs related to system interconnection.

If there is a large disparity in adequacy levels between regional power systems, moreover, some power systems may have to bear a drop in supply-demand matching reliability as a consequence of interconnection. The following solutions to this problem can be devised, although the actual measure chosen depends on the purpose of the planned system interconnection.

- Power interchange support rule between network operators, i.e. an interchange of electricity may not be made if it results in a decline in the supply-demand matching reliability of a given power system.
- Possible drop in the supply-demand matching reliability will be accounted for in the allocation of costs involved in system interconnection.
- Improving reliability of less reliable power systems by means of reinforcement of the power sources or transmission systems.

## I.1.2 Power supply security

Security means reliability, defined by NERC as “the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system elements.” In other words, security may be considered as dynamic reliability, such as the capability to maintain stability. More specifically, security is a concept used when considering reliability against overload or system instability beyond the control of operators.
Security is a reliability concept of a higher level than adequacy. Security involves localizing outages resulting from a short circuit fault or loss of power source in order to ensure survival of the system as a whole. In other words, if a fault on one power system spreads and causes an outage throughout a network of interconnected power systems, then the security of that network is deemed low. Interconnected power systems form a large network so that, for instance, the effects of a major power source dropout will be mitigated, depending on fault conditions, because of a decreased ratio of system-scale-to-power-source capacity. In this case, it is possible to develop large-scale power generation units that cannot be produced due to security reasons when a local power system is operated independently. Interconnection may allow significant scale merit to be acquired from large-scale power generation units. This benefit must also be reflected in the distribution of system interconnection costs, as noted above.

System interconnection, nevertheless, brings with it certain disadvantages, depending on scale, method and fault conditions. While a fault can be localized in independently operated regional power systems, it may spread over the entire network of interconnected power systems, resulting in a decline in security. A possible solution to this problem is the adoption of a direct-current interconnection scheme that will isolate power systems in terms of faults, or the use of protective devices to isolate power systems in an alternating current interconnected network. In either case, system interconnection must essentially be designed so as to localize a fault, utilizing protection and control technologies, which is the rule for avoiding accidents in interconnected power systems.

Because security problems, such as an outage throughout an interconnected network, are usually due to a complicated combination of factors, merely reinforcing facilities (such as transmission lines alone) will not be a realistic measure to improve security in light of a cost-benefit analysis. Once a fault has spread over the entire network, moreover, it will result in serious damage.

When interconnected power systems are isolated in the event of a fault, some power sources and loads must be shut off in order to maintain the balance between supply and demand, depending on the power flow pattern in the interconnected power system network at that time. To achieve this, protective systems must be built. Considering that a load shutoff will have a considerable impact on people's lives, however, the scale of system interconnection (the maximum interconnection power flow) might be limited to a level at which a load shutoff would not be necessary to isolate the power systems, or at which a significant load shutoff would be unnecessary.
I.2 System Planning Criteria

System planning criteria are applied to secure power supply reliability while achieving economic efficiency in the planning of facilities. Because reliability is influenced by system planning criteria, the criteria must be considered from the standpoint of security, which demands particular attention when planning a system interconnection.

The system planning criteria used in building power systems vary from one regional power system to another, depending on the voltage classes of transmission facilities in each power system. For optimum power system security, attention must be focused on the system planning criteria for trunk power systems. It is difficult, however, to apply uniform planning criteria to the planning of regional power systems because these criteria are set to reflect many factors, such as historical background, system configuration, social impacts of power failure, and cost and benefits of security improvement.

Details will be discussed in the following section. It can be said, however, that a deterministic approach is usually used to assess security, and that the (N-1) or (N-2) criteria are generally employed in system planning. In these criteria, various assumptions, such as demand cross-section, short-time allowable overload, fault conditions affecting system stability, are applied in different possible combinations.

Given, however, that system interconnection involves the possibility of a fault spreading throughout a network, as mentioned earlier, care must be taken when one bulk power system is to be interconnected with another power system built on system planning criteria which are so weak that there is a strong possibility of security being affected.

This being the case, once the system planning criteria adopted in regional power systems have been confirmed, security must be examined using the generally accepted reliability assessment method, i.e. by determining whether frequency can be maintained in the event of a major power source dropout, and whether stability can be sustained in the event of a fault in a bulk power system. If this examination finds that there are any regional power systems that may suffer a significant decrease in security as a result of system interconnection, then some measures to improve security must be taken. These measures may involve reinforcing weaknesses in the power systems that have an adverse effect on security, or coordinating the system planning criteria of different regional networks wholly or in part, in what might be called a drastic measure. This coordination is useful not only in the planning stage, but also in the formulation of a rational operating plan for interconnected power systems.
1.3  System Interconnection Technologies

1.3.1  Comparison between AC and DC power transmission technologies

A precise comparison of alternating-current (AC) and direct-current (DC) system interconnection technologies is very difficult because these technologies have a number of advantages and disadvantages, while economic and technical efficiency as well as other factors must be taken into consideration. A selection of appropriate interconnection technology must be made on a case by case basis.

AC power transmission technology has been widely used because it offers the following strong points.

- Voltage can be raised and dropped easily and efficiently with a transformer.
- Since large capacity circuit breakers can be manufactured, the AC transmission technology allows a high level of latitude in making up a variety of system configurations, such as a multiple terminal structure.
- Since AC power transmission technology makes it possible to serve loads on a branch of a line, it allows more flexibility in the design of the future system's expansion.

AC power transmission systems — which are contiguous and compatible in terms of operating patterns — can, moreover, be interconnected with each other, easily and economically. AC power transmission systems have thus formed an extensive worldwide network, as can be seen today.

As AC power systems developed, however, the following problems emerged, making it necessary to take measures to guard against them.

- Short-circuit and ground-fault currents on the system have increased.
- A local fault tended to spread over the entire network of interconnected power systems.
- Due to the need for total operation of interconnected systems, system operations, such as control of frequency, voltage and reactive power, have been become complicated and sophisticated.
DC power transmission is an alternative technology that can solve the problems encountered in the AC power transmission system. DC power transmission is now adopted in numerous power transmission projects.

DC power transmission has, in general terms, the following advantages:

A. Because transmitting electricity is not affected by system stability, DC power transmission is suitable for delivering large power over a long distance, and makes it easy to regulate the power flow. Stability between synchronous equipment due to reactance need not be considered in DC power transmission itself, while stability of the interconnected AC system at both ends should be examined.

B. In submarine interconnections, DC power transmission technology is suitable because DC power transmission is free from dielectric loss and, contrary to AC power transmission, does not require compensation for line-charging current. Insulators are also more durable against DC voltage than against AC voltage.

C. The longer the transmission routes, the lower the cost of construction. DC power transmission requires only two conductors and, if the ground or seawater is used as a return circuit, a single conductor can be used. Therefore, DC power transmission lines can be constructed at lower cost. Because converter stations must be set up at both ends of a DC interconnection, however, the cost of building these converter stations should be taken into consideration, in addition to the cost of constructing transmission lines.

In general, the break-even distance is used as a yardstick by means of which the cost of DC power transmission is compared with that of AC power transmission. DC technology is believed to provide a lower cost system than AC transmission if transmission distance is longer than the break-even distance [4], although that may be influenced by several factors.

Both DC and AC power transmission technologies have their own options, however, such as the use of FACTS in AC systems and the installation of series capacitors designed to maintain voltage in the event of an AC side fault in DC power transmission systems. Some problems, moreover, have yet to be solved. The ground return circuit configuration, for instance, may cause electrolytic corrosion of underground equipment. Therefore, one should avoid comparing both transmission technologies by the break-even distance alone.

D. Considering that attention need not be paid to frequency, DC power transmission technology makes it easy to provide asynchronous interconnection of power systems and allows power systems to be interconnected without increasing short-circuit capacity.
By means of the back-to-back (BTB) or other interconnection configurations, DC power transmission technology makes it possible to interconnect power systems in locations where it is necessary to take measures to cope with problems (such as short circuit current) and where it is difficult to interconnect using AC transmission technology, and also between AC systems with different rated frequencies.

On the other hand, DC transmission technology has its counterbalancing disadvantages. Low-grade harmonics produced in a converter station, for example, may cause inductive disturbance in nearby radio installations and communications lines. As reactive power is consumed, DC power systems may become unstable when they are connected with AC power systems with small short-circuit capacity. In order to solve these problems, filters need to be installed, and appropriate types of reactive equipment and proper control devices must be set up in converter stations [5]. Another solution to these problems is a self-commutated converter, which is expected for commercial introduction in DC power transmission systems.

In addition, DC power transmission technology cannot serve loads on a branch of a line. Therefore, a DC multiple terminal structure and other technologies need to be developed, so as to form a DC power transmission network similar to an AC system.

A comparison has been made, thus far, between AC and DC power transmission technologies. Like AC and DC hybrid power transmission, AC and DC system interconnection is possible and has come to be one of the options for interconnecting systems.

### 1.3.2 Frequency control methods

An attempt must be made to determine a way to control frequencies when interconnecting regional power systems.

In system interconnections, the frequency of each regional power system varies both with load fluctuations in the power system, and with the power flow in interconnection lines. It is necessary, therefore, not merely to adjust supply capacity corresponding to load fluctuations, but to maintain an interconnection line power flow at a base level. In system interconnections, therefore, frequency control can be made with consideration of an interconnection line power flow.
The following three methods are usually applied when controlling frequency in a network of interconnected power systems:

- **flat frequency control (FFC);**
- **tie-line load frequency bias control (TBC);** and
- **flat tie-line control (FTC).**

FFC is a method that is also adopted in independent power systems. It controls frequency in order to stay at a base level, regardless of tie line load flow. Generator output is controlled in response to frequency deviation.

TBC is a technique that controls generator output in response to frequency deviation and deviation of a tie-line load flow from the base level. It controls load imbalances in the power system. This method is widely used in interconnected power systems.

Finally, FTC is a method that controls generator output in proportion to deviation of a tie-line load from the base level. It may be adopted in small power systems.

When considering the frequency control approaches that should be adopted in each interconnected regional power systems, TBC is a rational method, as it enables load imbalance in the power system to be covered by generators in the same power system. In the event TBC is adapted to the entire system, and for all the interconnected power systems, frequency control errors may result.

The general practice, therefore, is to adopt the FFC approach in the largest capacity system of all the interconnected power systems, while applying the TBC method in other regional power systems. In this case, because the regional power systems operating on the FFC method must make up for frequency control errors, corresponding frequency adjustment capacity must be secured by the regional power system.
Chapter II

Nature of Technical Studies to be Conducted

II.1 System Adequacy Studies

As discussed in the previous chapter, power supply reliability is one of the basic considerations that should be taken into account in system interconnection planning. System adequacy constitutes one of the essential components of this service reliability.

This is a definition of adequacy, or a range covered by the term adequacy. Adequacy assessment methods vary in some aspects with power source planning or power system planning, and can be classified into deterministic and probabilistic methods. Power source planning mainly uses the probabilistic method, while the deterministic method is the mainstream of power system planning. This is chiefly because the former method deals with a relative magnitude, not a plane distribution of the supply capacity of the entire power system and demand, so probabilistic events can easily be considered.

The deterministic approach is commonly used worldwide in planning for power transmission systems. It is used, for instance, to assess the possibility of service interruption in the event of a shutdown of single equipment, based on assumptions such as a demand cross-section, short-time allowable overload and fault conditions affecting stability. This approach is also known as the (N-1) criteria. When significant effects of a fault are anticipated, the (N-2) criteria may be applied. N symbolically represents the number of components of an entire power system. In some countries, the probabilistic method is applied as a supplementary approach in power system planning. Various probabilistic proposals have been put forward by researchers. These proposals, however, are not commonly employed.

From the perspective of adequacy, attention must be given, generally, to the effects of system interconnection on reliability, in terms of supply and demand. In order to examine these effects, the probabilistic assessment technique can be applied to power source planning (power supply-demand planning). Reserve capacity is closely connected with this supply-demand reliability (adequacy). How to determine reserve capacity is described below.
In power supply-demand planning, it is essential to provide safeguards to prevent service interruption attributable to various events such as repairs on power source facilities, accidents, supply capacity deficiency caused by water shortage, and a gap between demand projection and actual demand. In order to prepare for future contingencies, therefore, it is necessary to provide supply facilities with greater capacity than is actually necessary to meet anticipated demand.

Reserve capacity is derived from surplus supply facilities installed to prepare for future contingencies. If reserve capacity is insufficient, service interruption may occur more often, whereas excess reserve capacity will result in a reduction of service interruption, though it may affect the effective use of supply facilities and lead to overinvestment. In determining optimum reserve capacity, therefore, an important consideration is to anticipate the frequency of service interruption, or to establish a proper level of power supply reliability (adequacy), while taking the cost of investment into account.

II.1.1 Study of optimum reserve capacity [6]

A. Definition
A typical indicator of power supply reliability is the loss-of-load probability (LOLP). LOLP denotes the probability of supply capacity falling short of demand and causing service interruption. It is often expressed by the number of anticipated power shortage days per year. Thus, reserve capacity depends on a level of LOLP to be established.

B. Determination of reserve capacity
Demand data used in calculation include a maximum demand duration curve (showing daily maximum demand levels) and a power demand duration curve (showing hourly demand levels in order of size). Supply capacity, moreover, will be determined from a total number of supply facilities, excluding those shut down during repairs. In determining required supply capacity, the following variables will be taken into consideration in a probabilistic manner.

- Demand fluctuations: demand fluctuations due to temperature change, among other things, will be expressed by normal distribution and, after reversing signs are used, these fluctuations will be added to supply capacity.

- Fault outages of supply facilities: a generator fault probability distribution will be expressed by a binomial expression or Poisson distribution, depending on the number of generator units installed.

- Variation in supply capacity of hydroelectric power plants: a probability distribution, based on past water flow records, will be used to determine this variation.
Based on a probabilistic distribution of these variables of demand and supply capacity, the supply and demand situation will be simulated using the Monte Carlo method to determine reserve capacity required to meet target reliability.

C. Setting of target reliability
In order to determine a desired level of power supply reliability, it is important to make a comprehensive study of all the factors involved. These include a socially required level of power supply reliability, a level of investment needed to improve reliability (its effects on electricity rates), and the reliability of distribution facilities.

II.1.2 Study of possible effects of system interconnection on reserve capacity
Reserve capacity is provided to prepare for future contingencies, such as fluctuations in demand or supply capacity beyond prediction. Because these contingencies are normally characterized by their diversity, a network of interconnected power transmission systems will usually need less reserve capacity than independent power systems in order to acquire the same level of power supply reliability, as long as proper power interchange rules are in place to deal with these contingencies.

In system interconnection planning, it is essential to examine interconnection capacity between interconnected power systems. To determine this capacity, normal economical power interchange and supportable capacity will be taken into consideration. Although there is an inverse proportionality between interconnection capacity and reserve capacity needed to meet the required power supply reliability (LOLP), a saturation tendency is observed in a decrease in secured reserve capacity when interconnection capacity is increased.

On the one hand, therefore, if small power systems are interconnected with independent power systems mainly to provide mutual support, required reserve capacity may decrease significantly, depending on how these power systems are interconnected. On the other hand, in a network of interconnected power systems where large economical power interchange occurs at all times, the reduction in reserve capacity derived from system interconnection may reach a saturation point, so that reserve capacity will be less sensitive to increases in interconnection capacity.
A data set pertaining to each power system is needed to look into the reserve capacity reducing effect of system interconnection. The main data include the following:

- interconnection capacity;
- maximum demand duration curve;
- power generating mix and power fault rate;
- load diversity and demand fluctuations;
- hydroelectric power plant water flow fluctuations; and
- power interchange rules.

In a study using interconnection capacity as a parameter, reserve capacity that meets the LOLP requirement will be determined, and the effect of interconnection capacity on a reduction of reserve capacity will be assessed.

II.2 System Security Studies

Unlike adequacy, security is assessed only by deterministic methods, because there are doubts as to the appropriateness of applying the probabilistic approach in evaluating security. The (N-1) and (N-2) criteria are adopted as criteria for an assessment of security.

The following factors (faults) are assessed in evaluating security:

- transient and small signal stability during power transmission line faults;
- a drop or rise in frequency owing to a major power source dropout or a load dropout;
- voltage instability, which makes it difficult to maintain voltage on the load side; and
- overload, which results in over current cascading an excess of transmission capacity of a transmission line.

Once these problems have surfaced, they are likely to result in complex cascading, causing a system-wide blackout in the entire power transmission network. In the planning stage, therefore, these factors must be carefully assessed in accordance with system planning criteria, and facility reinforcements as well as protective control measures based on the results of an assessment should be taken. Because it is impossible to consider all the possible system conditions at this stage, including maintenance and operation requirements, it is normal, on the one hand, to conduct a detailed study using power system simulation technology (to be described later) under a certain set of assumptions.
On the other hand, a study of actual daily operations must be carried out, and this should allow for shutdown of facilities for maintenance and modifications to system configuration. The assumptions used in this study may be more rigorous than those used in the planning stage. This can result in more severe conditions than the conditions used during the planning stage, so some measures to maintain security, including power supply interruption, load shutdown or rejection, must be examined in order to avoid a system-wide blackout.

The main feature of a study and assessment of security in system interconnections is the principle of power system separation using interconnection configuration and schemes of protective control measures. As mentioned in the preceding section, in order to prevent a system-wide blackout in the event of a localized fault, care must be taken to avoid too tight an interconnection of regional power systems. Still, there is no definitive method for interconnection configuration and protective control measures for separating power systems. Power system separation should, instead, be implemented on a case-by-case basis. The actual method of power system separation must be determined based on an analysis of the aforementioned events. For example, protective control measures for power system separation include monitoring the frequency of interconnected power systems and performing interconnection cutoff operations upon the detection of an unusual frequency drop, as well as installing step-out isolation relays as a normal transient stability measure.

II.3 Improvements on Transmission Capacity

This section describes actual measures that are applied to increase transmission capacity when facility improvements are considered necessary, in accordance with the system planning criteria. There are two different sets of measures that can be taken to increase transmission capacity. One set of measures is intended to cope with relatively direct transmission capacity shortages resulting from shortages of current capacity or system instability. The other set of measures is concerned with sustaining voltage and frequency levels, suppression of a fault current, and other matters affecting the quality of electric supply service and constraints on system makeup. Yet, these measures are connected with one another. In other words, one measure may serve the purposes of two or more measures, while some measures may conflict with others and bring about adverse effects. As a result, technical factors that affect power transmission, such as power flow, system stability, a fault current, and stable voltage levels, must be subjected to comprehensive examination.

Focus here is on measures designed to enhance transmission capacity and guard against system instability that may cause a major power failure. Measures to meet a current capacity short will also be discussed.
With reference to system stability, attention is usually directed to synchronous instability between power generators resulting from transient stability or small signal stability. Attention must also be paid to voltage stability, which will become an essential consideration when power sources and loads are located at different distances. As mentioned above, the (N-1) and (N-2) criteria are basically employed to assess system stability. In addition, a single-line three-phase ground fault and a two-line six-phase ground fault at the same point are examined to assess transient stability. A single-line shutdown, a two-line shutdown, and a shutdown of main power sources, among other things, are taken into consideration as conditions for assessing voltage stability. To guard against a severe accident, a general practice is to provide “controlled” security measures, such as limited power source interruption.

The following concrete measures are taken to improve transmission capacity. Before implementing these measures, a comprehensive study must be conducted to check whether a fault current will be increased and to take into account operational and maintenance requirements.

A. Reduction in reactance of series equipment such as generators and transformers
   Stability will be improved by shortening electrical distances between components in a power system.

B. Adoption of high-initial-response exciter and power system stabilizer (PSS) in generator excitation systems.
   Reinforcing the synchronizing and damping abilities of generators will alleviate synchronous instability.

C. System interconnection reinforcements (increasing the number of lines and transmission routes).
   Stability will be improved as with measure (A).

D. Construction of intermediate switching stations.
   Decreasing the length of the affected section will reduce the effects of a fault.

E. Adoption of high-speed protective relays and high-speed circuit breakers.
   Shortening the duration of the fault will mitigate the effects of a fault.

F. Installation of Static Var Compensators (SVC) and synchronous capacitors.
   Stability can be improved, as voltage levels will be maintained at middle points of the power system.

G. Installation of series capacitors.
   Stability will be improved as with measure A.

H. Adoption of braking resistors.
   Transient stability will be improved by absorbing acceleration energy during a fault.
I. Adoption of high-response speed governors.
   Transient stability will be improved, as mechanical input will be controlled quickly during a fault.

J. Adoption of power system voltage regulators (PSVR) on the high-voltage side of generators.
   Reactive power of generators can be used effectively by regulating voltage on the high-voltage side of a generator step-up transformer (an electrical distance of the power system can be shortened equivalently).

Of the above, measures A, C, F (synchronous capacitors) and G may result in an increase in fault current levels. With regard to series capacitors, continuous control types with switching elements like thyristors (so-called FACTS equipment) have been developed.

Measure C is intended to reinforce existing interconnected power systems. It should be noted that new system interconnections may significantly affect security. This is because when power systems are newly interconnected with one another, there is a possibility of a fault in one power system spreading across the interconnection to the other system. A careful study must be made, therefore, of all aspects of the system interconnection, including operational requirements.

Turning to measures to deal with a shortage of current capacity in power transmission lines and transformers, the common assessment method is to examine continuous capacities and excessive short-time capacities of equipment, based on the assumption of events (N-1 and N-2). When adopting short-time capacity, it is essential to assess a possible impact of this capacity on equipment life and examine service restoration patterns. Measures to make up for a shortage of current capacity include adoption of thicker conductors in power transmission lines, increase in the number of circuits, construction of new bypass routes, installation of additional transformers, increase in the capacity of transformers and construction of new substations. Consequently, reinforcing series equipment is a relatively simple measure.
A current capacity shortage must be examined carefully, however, in connection with protective equipment (protection against overload). This is because, although a current capacity shortage will not pose a serious problem in a fully interconnected system in a meshed configuration, the overload protection system may cause a cascading shutoff and eventually bring about a major power failure in a radial interconnected power system network over several routes. In an actual operating environment, a power outage caused by cutoff due to protection against overload (resulting from a current capacity shortage) is often associated with a maintenance outage of facilities. Installing series equipment that may come within the limits of capacity, even if some components of the power system are being shut down, is often not rational in terms of economic efficiency and benefits.

The adoption of a proper design in the system’s configuration — based on detailed prior simulation and proper timing coordination of overload protection relays — as well as the reinforcement of series equipment, may therefore be considered important factors in avoiding a cascade accident resulting from a shortage of current capacity.

II.4 Metering

When two or more different business entities are involved in power system operations, a control method designed to obtain data for all of these entities must be developed and incorporated into systems, and a precise procedure to determine the price of services must be put in place [7]. As needs for these features expand, data acquisition, exchange and centralized processes must be provided. Metering plays an important role in services (such as power purchase and wheeling service) that utilize such interconnected power systems.

How data should be managed is an essential consideration in metering for system interconnection. The system makeup is such that metering outfits (MOFs) are installed at individual entities, and an automatic transmitter transmits data measured at every predetermined sampling time to control stations, where data is controlled. It is desirable, generally, to have a unified controller to manage all such data. Another approach is for entities to add up and check measured values for each other. It is also essential that divisions should communicate with each other in order to collect the data necessary for system operations in accordance with operation procedures that have been agreed upon beforehand. When wheeling service is provided in different interconnected power system networks, adjustments must be made to loads measured in the respective networks. In a power system configuration as shown in Figure 1, for instance, it is usually impossible to measure loads at each delivery point of wheeling service. Moreover, loads from customers become larger than wheeling power. Therefore, given the power at a receiving point (Po) and the customer load (Lo), power purchased by customer is equal to Lo-Po.
Another important consideration is to make rules for power purchases, wheeling service and potential problems arising from the nonperformance of system service and other contracts.

Net Purchase and Sale, and Net Metering are two of the protocols used in determining electricity rates which are applicable when utilities supply electricity to nonutility generators, or when utilities purchase surplus power from nonutility generators.

The former method measures net consumption and net power output with different watt-hour meters and, based on the measured values, determines electric charges for each customer.

The latter approach is designed to determine electric charges by measuring a difference between the total energy consumption and the total power output during a billing period, using one watt-hour meter, which turns in both directions, normal and reverse.
Net amount metering has a number of advantages, in that simple and inexpensive measuring instruments can be used and manpower necessary for management can be economized. Yet, it has its counterbalancing disadvantages, such as reduced revenues for utilities and a lack of information on customer loads. In order to deal with these problems, therefore, operational and technical requirements and other details of net metering must be studied and established.

In general, problems involved in metering increase with the number of entities participating in power systems. Hence, the construction of a computerized system capable of processing data for system control (including electricity rates) on a real time basis is needed.

II.5 System Simulation and Analysis [8]

In system interconnection, as in an individual power system plan, a comprehensive study must be conducted on system technical factors such as power flow, fault current, system stability and voltage stability. This section touches upon approaches to analyzing these system technical factors.

II.5.1 Power flow analysis

Permissible voltage and power flow limits are established for electrical equipment such as transmission lines and transformers. In plans to build power systems, therefore, the examination should be carried out on the basis of voltage and power flow.

Typical examples requiring power flow calculations are given below:

- check on equipment overload (constantly and in the event of a fault);
- check on inappropriate voltage (constantly and in the event of a fault);
- plans to install reactive equipment.
Power flow calculations are generally conducted using the Newton-Rhapson formula. Power flow is calculated, using computers, in order to clarify active power, reactive power, voltage, phase angle and other parameters in each section of the power system. The main items of input data for power flow calculation and output are shown below.

In recent years, more attention has been given to optimal power flow calculations, and various research projects are under way to develop this method in a practical manner. Optimal power flow calculation is a method intended to minimize transmission loss and power cost, with due consideration for constraints such as upper and lower voltage limits.

**Table 1: Data input and output of power flow calculation**

<table>
<thead>
<tr>
<th>Slack bus data</th>
<th>Input Data</th>
<th>Output of Calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Bus voltage, V</td>
<td>Active power, P</td>
</tr>
<tr>
<td></td>
<td>Phase angle, $\theta$</td>
<td>Reactive power, Q</td>
</tr>
<tr>
<td>Generator bus data</td>
<td>Active power, P</td>
<td>Reactive power, Q</td>
</tr>
<tr>
<td></td>
<td>Bus voltage, V</td>
<td>Phase angle, $\theta$</td>
</tr>
<tr>
<td>Load bus data</td>
<td>Active power, P</td>
<td>Bus voltage, V</td>
</tr>
<tr>
<td></td>
<td>Reactive Power Q</td>
<td>Phase angle, $\theta$</td>
</tr>
</tbody>
</table>

When power systems are interconnected with one another at a single point, power flow can be examined easily by treating components on the sending end as a new power source, and components on the receiving end as a new load, with capacities equal to the power flow. When power systems are interconnected with one another at multiple points, however, a power flow will avalanche into the remaining interconnected lines once interconnected lines are broken at one point. This event is called the “loop-flow phenomenon.” When this occurs, the accident may be spread due to overcurrent. When this happens, some measures must be taken, such as increased capacity of equipment and protective control enhancement. Hence, power flow calculation is an important component of plans for multiple-point system interconnections.

**II.5.2 Fault current analysis**

Fault current calculations are conducted in order to calculate short-circuit current which will flow in from the power station if a fault develops on the transmission line of a power system or the bus bar of a substation. The impedance matrix and the admittance matrix are used to analyze fault current and, based on these matrices, analytical programs have been developed.
The greater the system capacity and the denser system interconnections become, the
greater the fault current becomes. The following problems will arise in this case:

- insufficient breaking capacity of circuit breakers;
- insufficient momentary capacity of series equipment such as disconnecting switches
  and CT, and transformers and transmission lines;
- communications disturbance due to the production of electromagnetic induced
  voltage on communications lines.

Because of the interconnection, system capacity will expand and, consequently, fault
current will increase as well. The possible effects of faults in other power systems must also
be taken into account. In system interconnection plans, therefore, a system
configuration must be established based on the results of an analysis of fault current in all
the power systems to be interconnected with one another, and a set of measures must be
taken, such as equipment reinforcements and protective control. When small power
systems are interconnected with large power systems, fault current calculation is an
important measure that must be taken to protect the small power systems, which will be
greatly affected by a fault in the large power systems.

II.5.3 Stability analysis

Analysis of power system stability is designed to check whether generators can be
operated synchronously. This analysis can be classified into small signal stability analysis,
designed to check stability after the outbreak of small disturbance, and transient stability
analysis, aimed at checking whether generators have stepped out or not after the
outbreak of a severe disturbance.

Stability analysis is basically built on the generator power swing equation. Most of the
new technologies and their analyses are based on this equation.

A. Small signal stability analysis

Analysis of small signal stability is performed to check stability, not by tracing hourly
changes in individual parameters but by obtaining certain indicators. This method is also
known as the indirect process. The small signal analysis is checked by linearizing the
generator motion equation at an operating point, compounding the system control
equation, and using stability analysis techniques, such as the eigenvalue analytical
approach. In this method stability is judged by obtaining the eigenvalues of the state
matrix and checking whether the real eigenvalue components are negative or positive.
When a network of interconnected power systems is built, a new problem of interarea mode oscillation may sometimes emerge. This phenomenon occurs with a low frequency of once every few seconds, the damping characteristic of oscillation is weak and it takes a long time to attenuate. Because the interarea mode oscillation may lead to loss of intersystem synchronism, conducting small signal stability analysis and examining measures such as interconnection breaking to guard against possible problems are the most important tasks which must be performed. System interconnection planning may also be used for the optimal tuning of power system stabilizers on generators with a view to improving the damping of the various oscillation modes, i.e. those within a power system and those originating from the interconnection.

**B. Transient stability analysis**

Transient stability analysis is designed to check the stability of power systems against significant disturbances, such as line switching during a line fault, power source dropout, and abrupt change in load. This analysis is usually made by digital simulation of events lasting several seconds. The method is called the direct process. The direct process obtains hourly changes in state of generator and load by directly solving the differential equation for generators and the algebraic equation for a power flow.

In digital simulation, it is necessary to simulate a power system based on detailed data, such as power flow, generators, control equipment and protective relays.

Because a local disturbance may likely develop into cascading outage on the entire network of interconnected power systems, detailed simulation must be conducted in advance so that measures can be taken to minimize the spread of a minor event.

**II.5.4 Voltage stability analysis**

In order to make receiving-end voltage stable, the production of reactive power (e.g. generator output, which is reactive, output of reactive equipment, and line charge) must be properly balanced against its consumption (e.g. load, which is reactive, output of reactive equipment, and line loss). Unless this reactive power balance is properly maintained, voltage will deviate from the standard value, producing a situation unfavorable for system operations.

Unlike active power, reactive power is characterized by localization. This is attributable to the fact that the reactance component of a power transmission system is greater than its resistance component. In other words, while active power can be transmitted to the entire power system with small loss, transmitting reactive power involves great losses in transit, causing a drop in receiving-end voltage as a result.
To solve these problems, voltage stability analysis must be carried out in order to draw up a plan to install reactive equipment in the power system with long-distance or heavily stressed transmission line, an economical solution that maintains voltage stability.

While the main purpose of stability analysis, as discussed in the preceding section, is to retain the synchronous operation of power sources, voltage stability analysis is conducted in order to maintain load voltage.

In voltage stability analysis, the nose curve (P-V curve) is generally used as a basic characteristic for demand and voltage at a receiving end. The nose curve at a certain receiving end is illustrated below. In this curve, two voltage values (a higher solution, V2, and a lower solution, V1) can be obtained relative to a certain load, PL. The higher solution represents a stability point, while the lower solution indicates an instability point. The tip of the nose shows a stability threshold point.

*Figure 2: Nose curve (P-V curve)*

In facility planning, input from reactive equipment, line impedance, and load power factor, among others, must be adjusted so as to ensure that an operational point will stay within the stability region during heavy load hours. To accomplish this, power flow calculation must be performed over and over again as parameters — generator operating voltage, transformer tap, and inputs from reactive equipment — are changed. In large power systems, computer-assisted automatic calculation is indispensable. VQC (the voltage stability simulation system in TEPCO), for example, is one of the simulation systems used for this calculation.
Chapter III

Advanced Technologies Applicable in Interconnected Power Systems

III.1 HVDC Technology

III.1.1 Multi-terminal HVDC system

The multi-terminal HVDC system is a HVDC system for interconnection between AC systems at three locations or more, using AC/DC converter terminals. DC voltages or DC currents are controlled coordinately by the multiple terminals. This system is capable of collecting and distributing energy along DC lines.

The multi-terminal HVDC has several types. In any case, however, the HVDC and AC systems should be reliable and cost-efficient as a whole. The HVDC system should be well coordinated with configuration and characteristics of the interconnected AC systems.

Figure 3 shows a configuration of the multi-terminal HVDC system.
**Figure 3 Configuration of multi-terminal HVDC system**

**Characteristics**

Loads can be distributed by changing DC current references.

Even when a permanent fault occurs at a branch DC line, power can still be transmitted by disconnecting the affected branch line with switch gears provided at branch points.

**Examples**

- Sardinia-Corsica-Italy three-terminal HVDC system
- Quebec-New England five-terminal HVDC system

**III.1.2 Self-commutated AC/DC converters**

Line-commutated thyristor converters need AC voltages for commutating operations.

HVDC systems composed of line-commutated converters are widely employed around the world, and have long-standing operating experience. The line-commutated converters, however, have problems such that these converters may fail commutation and are forced to stop due to voltage drops or waveform distortions in the AC systems.
On the other hand, progress has been made recently in high-power controlled turn-off devices, such as GTO, Si thyristor, and IGBT. The self-commutated converters composed of these devices can solve the problems mentioned above, and offer a promising solution for interconnections in developing countries where relatively low short-circuit capacity may handicap the use of line-commutated thyristor converters. Efforts have been made to use self-commutated converters in practical power system applications.

The self-commutated converters are classified into two types: voltage sourced converters and current sourced converters. The voltage sourced converter can be considered as a voltage source when viewed from AC systems, and the current sourced converter can be considered as a current source. Table 2 shows a comparison between line-commutated and self-commutated (voltage sourced) converters.

**Examples**

- Directlink HVDC Light project between New South Wales and Queensland in Australia
- Gotland HVDC Light project in Sweden
Table 2: Comparison between line-commutated and self-commutated converter

<table>
<thead>
<tr>
<th>Line-Commutated Converter</th>
<th>Self-Commutated Converter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Schematic of main circuits</td>
<td>schematic of main circuits</td>
</tr>
<tr>
<td>Operational region</td>
<td>Operational region</td>
</tr>
<tr>
<td>Control</td>
<td>Control</td>
</tr>
<tr>
<td>Reactive power supply</td>
<td>Reactive power supply</td>
</tr>
<tr>
<td>AC network conditions</td>
<td>AC network conditions</td>
</tr>
<tr>
<td>Harmonics</td>
<td>Harmonics</td>
</tr>
</tbody>
</table>

### Table 2: Comparison between line-commutated and self-commutated converter

<table>
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<tr>
<td>Schematic of main circuits</td>
<td><img src="image" alt="schematic of main circuits" /></td>
<td><img src="image" alt="schematic of main circuits" /></td>
</tr>
<tr>
<td>Operational region</td>
<td><img src="image" alt="Operational Region" /></td>
<td><img src="image" alt="Operational Region" /></td>
</tr>
<tr>
<td>Control</td>
<td>AC and DC voltages are controlled (active and reactive power cannot be controlled independently).</td>
<td>Active and reactive power can be controlled independently.</td>
</tr>
<tr>
<td>Reactive power supply</td>
<td>Converters always act as reactors (reactive power must be compensated by static capacitor banks, etc.).</td>
<td>Both reactor and capacitor load can be emulated.</td>
</tr>
<tr>
<td>AC network conditions</td>
<td>In a power system with a small short-circuit capacity ratio, stable operation is difficult. Converters cannot be operated without AC system voltages.</td>
<td>Applicable to a weak AC system. Power can be supplied to loads without AC system voltages.</td>
</tr>
<tr>
<td>Harmonics</td>
<td>Harmonic filters must be equipped.</td>
<td>By high-frequency PWM control, harmonics can be reduced (filters can be much reduced or even cancelled).</td>
</tr>
</tbody>
</table>
III.1.3 Power modulation control

Power Modulation Control, which is a countermeasure to suppress oscillation phenomena such as phase oscillations between synchronous generators during an AC system fault, has been developed in AC-DC hybrid power systems. In this control scheme, DC power is modulated for power damping at high speed, corresponding to acceleration and deceleration of synchronous generators during an AC system fault.

At Pacific Intertie in the United States, for instance, Power Modulation Control has been applied to DC interconnected power systems in order to suppress long-term oscillation phenomena between interconnected AC systems.

Figure 4: Power modulation control
III.2 Technologies for Improvement of AC System Stability

To improve AC system stability, countermeasures have been taken from the viewpoint of system planning (uprating of system voltage or multiplying of transmission line routes), control and protection (high speed fault clearing and reclosing) and equipment, as follows:

III.2.1 Countermeasures based on conventional equipment

A. Series capacitor
Series capacitors are inserted to transmission lines in series to compensate for line reactance, and consequently reduce the electrical length of the line.

Benefit: Power system impedance can be reduced without constructing new transmission lines.

Problem: Possibility of Sub-Synchronous Resonance (SSR) increases.

B. Braking resistor
During a fault in a transmission line, such as a power source transmission line, the generator power output is consumed by braking resistor forcibly to reduce acceleration of generators.

Benefits: Braking resistor can improve transient stability and is specially effective in suppressing the first wave of power swing just after a fault. Since braking resistor is not connected with AC systems in normal operations, the power system voltages and currents are not affected.

Problem: Braking resistor needs high-speed and highly reliable control for closing and opening.
III.2.2 Countermeasures based on flexible AC transmission systems (FACTS)

FACTS is a concept that was proposed by the Electric Power Research Institute (EPRI) of the United States to make AC systems, incorporating power electronic-based and other static controllers in order to enhance controllability and increase power transfer capability.

Thanks to recent advances in power electronics technologies, high-voltage and high-power thyristors and GTOs are available for power system applications. By incorporating these switching devices, high-performance power system control facilities and equipment can be built.

FACTS equipment can be installed at various points in power systems, and can be controlled independently or coordinately. FACTS equipment can control phase angles, voltages or impedance at a high speed, corresponding to power system operating conditions. The following benefits are expected from FACTS:

- increase in power transfer capability;
- improvement of system stability;
- power flow control involving loop flow between transmission lines.

Table 3 shows an outline of typical FACTS equipment.
### Table 3: Outline of typical FACTS equipment

<table>
<thead>
<tr>
<th><strong>SVC</strong> Static Var Compensator</th>
<th><strong>TCSDR</strong> Thyristor Controlled Static Damping Resistor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Outline</td>
<td></td>
</tr>
<tr>
<td>• Component: Power Capacitor, Shunt Reactor, Thyristor</td>
<td>• Component: Breaking Resistor, Thyristor</td>
</tr>
<tr>
<td>• Control: Reactive Power by Thyristor</td>
<td>• Control: Power Consumption of Damping Resistor by Thyristor</td>
</tr>
<tr>
<td>• Improvement: Small-signal Stability, Transient Stability and Voltage Stability</td>
<td>• Improvement: Transient Stability</td>
</tr>
</tbody>
</table>

**Schematic**

- **SVC**
  - Bus
  - Transmission Line
  - Thyristor
  - Shunt Reactor
  - Power Capacitor

- **TCSDR**
  - Bus
  - Transmission Line
  - Thyristor
### STATCOM
Static Synchronous Compensator

- **Component:** DC Capacitor, Self-Commutated Converter, Converter Transformer
- **Control:** Reactive Power by Self-Commutated Converter
- **Improvement:** Small-signal Stability, Transient Stability and Voltage Stability

### TCSrC
Thyristor Controlled Series Capacitor

- **Component:** Series Capacitor, Reactor, Thyristor
- **Control:** Transmission Line Reactance by Thyristor
- **Improvement:** Small-signal Stability, Transient Stability and Voltage Stability

#### Outline

- **Component:** DC Capacitor, Self-Commutated Converter, Converter Transformer
- **Control:** Reactive Power by Self-Commutated Converter
- **Improvement:** Small-signal Stability, Transient Stability and Voltage Stability

#### Schematic

- **STATCOM**
  - **Bus:**
    - Converter Transformer
    - Self-Commutated Converter
    - DC Capacitor

- **TCSrC**
  - **Bus:**
    - Series Capacitor
    - Reactor
    - Thyristor
    - CB
III.2.3 Countermeasures based on generator excitation control systems

In order to improve the transient stability of AC power systems, stabilization measures using the high-initial-response excitation of synchronous generators are generally applied.

The transient stability problem basically consists of phase oscillation or loss of synchronism between synchronous generators. When the electrical power output declines due to a voltage drop during a transmission line fault, generators will accelerate and phase angle will expand. In order to solve this problem, a high-initial-response excitation is needed to maintain voltage and electrical power output.

However, although this system increases synchronization torque and thus improves transient stability, damping torque may become negative, and small-signal stability may deteriorate, thereby resulting in increased oscillation of generators. Therefore, the high-initial-response excitors should be equipped with power system stabilizers (PSS) to restore and even improve the damping torque. At the 1999 Summer Meeting of the Power Engineering Society of the Institute of Electrical and Electronics Engineers (IEEE/PES), the following conclusions on PSS were reached [9]:

- Power system stabilizers are a very cost-effective and proven means of providing damping of low frequency electromechanical power system oscillations (local and interarea modes).

- PSS with input signals from speed, frequency or power have been used successfully and can be tuned to provide significant damping to the power system. Accelerating power-based PSS, however, have several significant advantages over single-input speed, frequency, or electric power-based PSS. Accelerating power PSS may have dual inputs (electric power and speed/frequency) or accelerating power may be derived from terminal voltage and current measurements.

- Modern digital-based PSS can be installed on existing equipment or can be an integral part of a digital voltage regulator. Digital PSS provide additional flexibility and ease of tuning, besides being significantly cheaper than their analog counterparts. Digital control offers many other advantages and few disadvantages.
Chapter IV

Overview of Interconnected Power Systems Around the World

IV.1 Japan

In Japan, the power systems consist of two regions with different frequencies — 50 Hz and 60 Hz — in the eastern and the western regions respectively.

In the eastern region, the 50 Hz power systems are operated by three utilities: Hokkaido Electric Power Company, Tohoku Electric Power Company and Tokyo Electric Power Company. In the western region, the 60 Hz power systems are operated by six electric utilities: Chubu Electric Power Company, Hokuriku Electric Power Company, Kansai Electric Power Company, Chugoku Electric Power Company, Shikoku Electric Power Company and Kyushu Electric Power Company. In each region, the power systems are interconnected with one another by AC (and partially by DC) so that utilities can exchange power with each other from economical or power preserve points of view.

AC interconnection between the eastern and western regions is impossible because of different frequencies. BTB frequency converter stations, therefore, interconnect the utilities of both regions, mainly for emergency power exchange purposes.

Two frequency converter stations are in commercial operation. One is the Sakuma Frequency Converter Station (300 MW) and the other is the Shin-Shinano Frequency Converter Station (600 MW). The third one — the Higashi-Shimizu Frequency Converter Station (300 MW — is presently under construction.

In case the system frequency decreases due to a fault on either side of the 50 Hz or 60 Hz system, emergency power of a previously determined amount is provided from the power system on the other side. This emergency power exchange has made great contributions to the prevention of decreases in the system frequency and effects on the whole systems.
Two other BTB DC links for interconnection between power systems with different frequencies are in operation in South America:

- **Aquarey Interconnection (50 MW)**

Paraguay (50 Hz) and Brazil (60 Hz) have been interconnected since 1981. The main purpose of this interconnection is to transmit surplus hydroelectric power from Paraguay to Brazil.

- **Uruguayana Interconnection (50 MW)**

Argentina (50 Hz) and Brazil (60 Hz) have been interconnected since 1995.

*Figure 5: Power systems in Japan*
IV.2 North America [10]

The US power system is interconnected with Canada and Mexico. Most power exchange has occurred between the United States and Canada.

The US-Canada interconnection was begun in 1901 in order to take advantage of seasonal variations in power demand and utilize both Canadian hydro resources and US coal resources effectively. Today, both countries are providing seasonal power exchange, emergency power exchange and economical power exchange.

Total interconnection capacity is 18,900 MW (as of 1994). Major interconnection lines are Quebec-New York 765 kV 1 cct, Quebec-New England ±450 kV DC 1 cct, Ontario-New York 345 kV 2 cct and 230 kV 4 cct, Ontario-Michigan 345 kV 2 cct and 230 kV 2 cct, British Columbia- Washington 500 kV 2 cct and 230 kV 2 cct.

The largest exchange was 45,000 GWh, from Canada to the US in 1987.

IV.3 Europe [10] [11]

The European power systems are classified into four parts: NORDEL power systems in Northern European countries, UCTE power systems in Western European countries, Interconnection of Power Systems (IPS) in Eastern European countries and the former Soviet Union, and finally independent power systems in Britain, Ireland and Iceland. All the AC power systems are being operated at 50 Hz. All the systems, excluding those in Ireland and Iceland, are interconnected through HVDC transmission lines.

IV.3.1 NORDEL power systems

NORDEL consists of the five Northern European countries: Denmark, Finland, Norway, Sweden, and Iceland. Power exchanges are made among NORDEL countries, very often utilizing differences in the generation mix of each country. Because of differences in the timing of peak demand, seasonal power exchanges are also made between NORDEL and UCTE.
Figure 6: Power systems in Europe
Figure 7: Power exchange among NORDEL countries (1996, GWh value) [11]

- Typical power exchanges among NORDEL countries:
  Norway has many hydroelectric power stations, and Denmark mainly depends on thermal power plants. Denmark delivers power to Norway during a water shortage season, and Norway supplies power to Denmark during a high-water season.

- Typical seasonal power exchanges between the NORDEL and UCTE systems:
  In summer, power generated by hydroelectric power stations in Sweden is delivered at moderate prices to Germany. When power demand increases in winter in Sweden, Germany provides power to Sweden.
IV.3.2 UCTE power systems

UCTE consists of fourteen countries, including Germany, France and Italy. The total transmission capacity of international interconnections is 93,350 MVA, and the total power exchange is 173,200 GWh, which represents 10.6% of the total energy consumption of the UCTE (as of 1995).

The aims of the UCTE are to secure power supply in emergency, provide mutual support in operating power stations, and reduce investment for facilities. Switzerland is responsible for planning daily power exchanges and constant monitoring of the system frequency. The UCTE systems have no central load dispatching station.

France has a system interconnection with the UCTE network. The power systems in France are interconnected and synchronized with those of Belgium, Germany, Switzerland, Italy and Spain through 400 kV 14 cct, 225 kV 12 cct, 130 kV 2 cct, 110 kV 1 cct, and DC ±100 kV 2 cct. French power systems are also interconnected through DC ±270 kV 1 cct (2,000 MW) submarine cables with Britain, which is not a member of the UCTE.
IV.4 Southeast Asia [12]

Figure 8 illustrates locations of Southeast Asian interconnection systems. The technical features of these systems are shown in Table 4.

Figure 8: Locations of Southeast Asian interconnection systems
Table 4: Technical features of Southeast Asia interconnection systems

<table>
<thead>
<tr>
<th>System Description</th>
<th>Utility</th>
<th>Technical Features</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Malaysia – Singapore (Sultan Iskandar P/S – Senoko P/S)</td>
<td>TNB, SP</td>
<td>AC 230 kV 250 MW 2 cct Overhead transmission line and submarine cable</td>
<td>In operation since 1985.</td>
</tr>
<tr>
<td>2 Malaysia – Thailand</td>
<td>a) AC interconnection (Sadao - Bukit Keteri)</td>
<td>TNB</td>
<td>a) AC 132 kV 117 MVA 1 cct</td>
</tr>
<tr>
<td></td>
<td>b) HVDC interconnection (Gurun - Khlong Ngae)</td>
<td>EGAT</td>
<td>b) DC 300 kV 300 MW 110 km (85 km TNB, 25 km EGAT) Monopole (1st stage) 600 MW Bipole (2nd stage)</td>
</tr>
<tr>
<td>3 Sarawak - Peninsular Malaysia (Bakun Hydro - Kuala Lumpur)</td>
<td>SESCO, TNB</td>
<td>DC submarine cable 2,100 MW 650 km</td>
<td>Target completion 2003.</td>
</tr>
<tr>
<td>4 Inter-Philippines interconnections a) Luzon – Leyte</td>
<td></td>
<td>a) DC 350 kV 400 MW 443 km (cable length: 23 km)</td>
<td>a) In operation since 1998.</td>
</tr>
<tr>
<td></td>
<td>b) Negros – Panay</td>
<td></td>
<td>b) AC 138 kV 100 MW 185 km (cable length: 18 km)</td>
</tr>
<tr>
<td></td>
<td>c) Negros – Cebu</td>
<td></td>
<td>c) AC 138 kV 100 MW 100 km (cable length: 16 km)</td>
</tr>
<tr>
<td></td>
<td>d) Leyte – Cebu</td>
<td></td>
<td>d) AC 230 kV 200 MW 362 km (cable length: 32 km)</td>
</tr>
<tr>
<td></td>
<td>e) Leyte – Bohol</td>
<td></td>
<td>e) DC 138 kV 100 MW 198 km (cable length: 18 km)</td>
</tr>
<tr>
<td></td>
<td>f) Leyte – Mindanao</td>
<td></td>
<td>f) DC 350 kV 400 MW 475 km (cable length: 56 km)</td>
</tr>
</tbody>
</table>
Appendix

Study Approaches for Interconnection Planning and Basic Considerations for Technical Issues (Constraints)

Preconditions: Benefit evaluation on power source development and supply-demand balancing.

1 Timing for the Implementation of the Interconnection

a. The interconnection planning must be consistent with power source development and demand forecast.

b. Anticipated difficulties (urbanization and other infrastructure planning) involved in the construction of new interconnection facilities must be taken into consideration.

2 Interconnection Approaches

A study should be conducted to develop optimal interconnection facilities with due consideration to future planning of regional power systems and interconnection systems. Although an overall assessment is necessary, the following steps must be carried out:

- interconnection capacity;
- selection of AC or DC and transmission voltage (at the interconnected point);
- frequency control method after interconnection.

2.1 Interconnection capacity

a. When the interconnection is designed mainly to develop power sources and power transmission, consideration must be given to future power source development.
b. When the interconnection is designed mainly for power exchanges, consideration must be given to the scale of relative regional power systems and the possible effects of system interconnection on reserve capacity.

[Examples]
- To reduce the amount of generator tripping and load shedding to within the permissible level in order to maintain the system frequency when the system is disconnected.
- To grasp saturation trends of reserve capacity when the interconnection capacity is being increased.
- To specify the increase and decrease of required reserve capacity and reflect these in the allocation of costs.

2.2 Selection of AC or DC and transmission voltage (at the interconnected point)

Comprehensive case studies and evaluation should be conducted in the following areas.

a. System Analysis
   Factors to ensure stable system operation, including power flow, fault current and system stability, and their countermeasures should be studied.

[Examples]
- The possibility of overload in the existing power systems should be confirmed. (If the power systems are also interconnected through other routes, the fault current that might be transmitted through that route should be confirmed.) Upgrading of transmission capacity should be taken into account, if necessary.
- The possibility of breaking capacity shortages should be confirmed. Breaking capacity should be upgraded if necessary, or an HVDC system should be adopted.
- The ability to maintain stable operation during major transmission line faults should be confirmed. Countermeasures to improve system stability and prevent fault expansion should be adopted.
b. **System Design**
Configuration of the transmission line and kinds of conductor, including relevant facilities, should be designed.

[Examples]
- The need for the new transmission line branching off from the existing transmission line should be considered. (This will affect the selection of AC or DC.)
- Economic evaluation should be conducted on transmission system construction costs and transmission losses.
- Aside from its technical aspects, the choice of the appropriate voltage level for interconnection transmission grids generally depends on several factors such as:
  - the foreseen power exchange between interconnected systems;
  - need of voltage profile support and VAR control equipment;
  - cost benefit analysis of investment, including operation;
  - geographical and economic area to which interconnection belongs.
- When the routes of transmission lines are selected, it is necessary to sufficiently consider their environmental influences and regulations as well as the routes themselves. In the case of DC power systems in particular, ground return circuit configuration should be avoided to prevent electrolytic corrosion of underground equipment.
- Telecommunications facilities are indispensable for the interconnection of systems for various reasons. Their applications relate to, for instance, power flow control of DC interconnection, metering and system protection. A telecommunications system with multiplex configuration is adopted, generally, in order to maintain reliability by multi-routes and/or multi-formula.

### 2.3 Frequency control method after interconnection
Adoption of a frequency control method, which is adjusted to the scale of regional power systems, is essential.
References


9. System Reliability as Affected by Power System Stabilizers, Summary of a Panel Session on PSS application, PES Summer Meeting, Edmonton, Canada.


11. NORDEL Annual Report 1996

Module 6
Financing
Interconnection
Facilities
Module 6
Financing Interconnection Facilities

Introduction

Chapter I Commitment from Decision-Makers
Chapter II Project Definition
Chapter III Risk Analysis
Chapter IV International Interest and Support
Chapter V Financial and Operational Structures
Chapter VI Legal Commitment by Participants
Chapter VII Independent Review of the Project
Chapter VIII Information Memorandum
Chapter IX Testing Capital Markets
Chapter X Debt and Equity Proposals
Chapter XI Negotiation and Contractual Agreements
Chapter XII Meeting Disbursement Conditions
Chapter XIII Special Considerations

Conclusion

Table 1: Project financing process

Appendix A Example of Power Infrastructure Project
Appendix B Project Definition Document: Example of Table of Contents
Appendix C Example of an Interconnection Project
Appendix D Business Plan
Appendix E Main Financial Ratios
Appendix F Risk Analysis

back/forward to

Module 1
Module 2
Module 3
Module 4
Module 5
Module 7
Module 8
Glossary of Technical Terms
Acronyms and Symbols
Introduction

This module focuses on how to raise financing successfully. This is not a trivial issue, since infrastructure projects require substantial amounts of money, which usually is not available in local capital markets. Consequently, international capital markets will be called upon to fill these needs. In order to convince international lenders, in-depth evaluations of the project will be needed to prove the economic and financial viability of a power system interconnection.

Infrastructure financing is a complex process that requires years of effort and constant support (renewed and reiterated) from all participants. The term “participant” is used broadly, and includes stakeholders from the different countries involved in the project; the term “sponsors,” on the other hand, is used in a limited sense to describe the promoters, which could be private or public entities. The complexity is largely due to the number of parties as well as the underlying risks involved in interconnection systems which are built across many jurisdictions. Appendix A provides an example of the structure and the parties that may be involved in a power infrastructure project.

Experts and Advisors

It need not be stressed that such a complex process requires solid financial expertise. It is very important, consequently, to select strong financial leaders and experienced financial advisors.

The complexity of the task at hand is such that it is virtually impossible to secure financing without a team of experienced technical, legal and financial experts. It is important, moreover, to point out that the type of experts that are needed will change at each stage of the project. For the preliminary studies, financial advisors should have proven economic and social awareness and be familiar with international financial organizations. Various stakeholders (referred to herein as participants) may also wish to have their own advisors. As the project definition progresses (see Table 1), the participants should bring in very competent legal advisors and investment bankers to help with risk assessment and project structuring. These experts should be retained by the participants as a group, and should be forbidden from working for other sponsors at a later date. Their role is to design and bring together the best project in the best interest of the stakeholders.
This module does not presume public or private ownership, nor specific operating structures (BOO, BOOT, BTL, co-ownership, pooling, etc.). It is thus likely that once the participants have selected the sponsors to carry out the project, these sponsors will hire their own advisors. In order to finalize the financing, the sponsors are likely to ask the participants (governments, agencies, regulatory bodies) for their support. As negotiations progress, the role of the participants’ experts is to protect the interests of stakeholders, while the sponsors’ advisors will try to shift potential risks toward the participants. In this important phase, the advisors for the participants must be as shrewd as the advisors for the sponsors.

Admitting financial advisors as part of the project team at an early date will bring better results in terms of risk allocation and international support to the project.

**Financing Process**

Financing an interconnection project is a complex process that requires many years of effort and involves a large number of people.

Two methods of financing are available: corporate financing and project financing.

**Corporate financing** involves the existing electric utilities. Each utility will take its financial share of the project on its own balance sheet. The funding will be put together by each utility through equity, bond issues or loans that will not be dedicated to a particular project. This kind of financing will be issued, generally, on the credit rating of the firm, published by agencies such as Moody's and Standard & Poor's. Corporate financing rests on the financial strength of the participants, who share the risks of the project. If the cash flow from the project is not sufficient to cover reimbursement of the loans, the participants must make up the shortfall. Corporate financing allows funding an interconnection project entirely by loans, but this can downgrade some financial ratios of the sponsors, such as debt service, coverage ratio and gearing.

**Project financing** rests on the financial strength of the project itself. It requires the establishment of a dedicated entity. Funding is raised by the entity through equity from the sponsors and from loans dedicated to the project. Financing is usually made non-recourse to the sponsors: reimbursement of the loans comes only from the cash flow generated by the project and no guarantees are provided to the lenders by the sponsors. During the construction phase, the banks will generally have some recourse on the sponsors if the project is never completed. During the operation period, the revenue stream will normally be subject to a Purchase Agreement which may be guaranteed by sovereign governments if the utilities’ financial strength is not sufficient. Project financing requires equity funding, generally 20-40% of total investment. Debt is not included in the balance sheet of the sponsors. Interest rates required by the lenders, however, tend to be higher than in a corporate financing framework.
In developing countries, public utilities, generally not rated by agencies and often highly indebted, may have difficulty accessing the international capital markets to finance large infrastructure projects. Moreover, a dedicated entity will usually be created when an infrastructure project (such as an interconnection project) is too large for a single country, but is relevant to a whole region.

The participant or sponsor companies, moreover, may not be interested in integrating the project specific risks into their firm’s overall risk. As a result, project financing is widely used in developing countries. Project financing offers an interesting alternative for a large infrastructure project, as the funding is based on the strength of the cash flows of the project. A specific entity is created to undertake the project with limited or no recourse to the underlying balance sheets of the participant and sponsor companies. Each participant or sponsor company is able to restrict its financial risks to its contribution in equity of the project company.

Chapters I to XIII describe the different stages in the financing process (see Table 1). These stages apply to both, corporate and project, modes of financing.
Table 1: Project financing process

- **Stage I**: Commitment from Decision Makers
- **Stage II**: Project Definition
- **Stage III**: Risk Analysis
- **Stage IV**: International Interest and Support
- **Stage V**: Financial and Operational Structures
- **Stage VI**: Legal Commitment by Participants
- **Stage VII**: Independent Review of the Project
- **Stage VIII**: Information Memorandum
- **Stage IX**: Testing Financial Markets
- **Stage X**: Debt and Equity Proposal
- **Stage XI**: Contractual Agreements and Documentation
- **Stage XII**: Meeting Disbursement Conditions

Interactive process if decided by potential sponsor(s)
Chapter I

Commitment from Decision-Makers

Objective

⇒ To confirm the full commitment of the decision-makers in all participating countries (participants).

A full commitment from all participants is crucial in order to secure the support of international investors. Though the commitment must be present at the very beginning of the project, it is essential to make sure that no events have occurred in previous stages of the project to diminish that support.

Since the objective is to build an interconnection system between several countries, the decision process must have strong political support from all participants. This is the single most important element for a successful project. This political commitment implies that:

• the objectives of the participants have been determined;
• the benefits for each participant are understood;
• the roles and responsibilities of each participant are clarified, and everyone’s concerns are understood;
• a tasks schedule for short-term actions has been defined;
• the leadership of the project is determined, and the support (logistic, technical, financial) that each participant will bring to the project is identified;
• the gaps between available expertise and expertise needed to start the project are identified.

Results

⇒ Letters of commitment from political leaders; or
⇒ Clear public support.
⇒ Memorandum of Understanding.
Tips / Recommendations

⇒ Each participant should be met personally to build trust. If possible, all participants should be invited to a launch meeting in order to create a good relationship between the parties.

⇒ The project leader should provide each participant with a sample letter of support to harmonize commitments.

⇒ Funding may be available from international sources for preliminary studies and project definition.

⇒ Assistance (financial and technical) should be obtained from international sources, and a consultant should be appointed to pursue the project.
Chapter II

Project Definition

Objectives

To produce a working document explaining the goals and issues, and describing the project in order to:

- provide basic information for risk assessment;
- establish preliminary financial and operational structures;
- obtain grants and support from international economic development organizations (such as The World Bank and OECD), if available.

The first aim of the financing process is to produce a Project Definition Document (PDD) which summarizes the preliminary studies made by the engineering, marketing and financial experts. Used as a communications tool, this document is an important input for the next three steps of the process.

The PDD is a preliminary but comprehensive assessment of all aspects of a project. It must allow a rapid understanding of the project and specifically cover the following aspects:

- a short description of the project and its goals in business terms;
- identification of the participants, their commitments and their responsibilities;
- description of the electricity sector and infrastructure in each country and the importance of the transmission project to future growth, tariffs structure, supply, security, etc.);
- overview in each country involved of the legal framework(s) and tariff regulation(s) which will have a bearing on the interconnection project;
- technical description: feasibility, location, etc.;
- Business Plan, including projected financial statements, revenue streams, estimates of costs and benefits (economic, social, environmental, etc.), see Appendix D;
- Schedule.

A table of contents of a PDD is provided as an example in Appendix B.
Actually, the Project Definition Document is a preliminary version of the Information Memorandum, which will provide much more detailed information for bankers and investors. The content of the Project Definition Document will then be completed in the following steps of the financing process up until the Information Memorandum stage is completed (see Chapter VIII).

Results
⇒ Project Definition Document (PDD).

Tips / Recommendations
⇒ The project leader is responsible for supervising the writing of the PDD. Financial experts must make sure, however, that the content of the document will satisfy financial markets and be consistent with the Information Memorandum which is to come at a later date.

⇒ The participants may have to harmonize or simplify their regulatory framework in order to make the project feasible.

⇒ The PDD will be used to prepare a road show to interest potential stakeholders (utilities with track records, engineering firms with a strong background, independent power producers, etc.).

⇒ The PDD will be used to prepare call-for-tenders documentation.
Chapter III

Risk Analysis

Objective

⇒ To formulate a risk management strategy in order to successfully complete and operate the project according to plans.

One of the key criteria used by lenders and investors to evaluate large infrastructure projects is risk management. Consequently, the lending decision and underlying terms (rate, guarantees, reimbursement schedule, etc.) are closely tied to the quality of the participants’ risk management strategy.

Risk analysis is an essential step, whether corporate financing or project financing is used. The main difference between the two modes of financing is the allocation of risks.

When corporate financing is used, the risks are supported by the utilities undertaking the project. The risk analysis will delineate the extent to which the utilities are able to withstand adverse conditions and outline ways to lessen the impact on their financial situation.

When project financing is used, a single entity does not have to support all the risks. These risks are allocated to the various participants. A key to successful project financing is the proper allocation of risks. The risk management strategy is broken down into three different steps:

• risk identification and identification of impacts on the project;
• risk allocation to the parties “best able” to bear such risk, i.e. the party which can best exercise control over risk or realize the greatest reward if the risk does not materialize;
• risk mitigation actions to reduce the impact of risks.

In large and complex infrastructure projects, the risks are multiple. The table below shows a non-exhaustive list of risks, as perceived by capital markets. See Appendix F.
General Risk Category | Sub Categories of Risk
---|---
Construction Risk | Technology, partnerships, contractors and subcontractors, infrastructures, availability of materials, delay on schedules
Operation Risk | Technology, partnership, operation costs
Market Risk | Demand, competition, price, regulation
Contractual Risk | Terms and conditions of all contractual obligations
Political and legal Risk | War, rebellion, confiscation, expropriation
Financial Risk | Currency, financing costs, taxation, inflation

These risks should be assessed in terms of likelihood of occurrence and potential impact in case of occurrence. Appropriate mitigation measures should then be appraised to reduce their impact and/or probability.

Mitigation measures to reduce qualitative risk might include political risk insurance, a loan in the same currency as revenues, and due diligence performed on all contractual aspects to ensure that all contractual risks are taken into consideration.

Other technico-economic risks could be assessed through various sensitivity analysis scenarios. Each technico-economic parameter is increased/decreased by 10%, one after another, and impacts are introduced into the financial model and measured via project financial ratios. The importance of the results for each parameter makes it possible to identify the main risks. Mitigation measures for these major risks can be integrated into the financial model.

Results
⇒ Risk Management Strategy
⇒ Risk Management Plan
⇒ Partnership agreements

Tips / Recommendations
⇒ It is recommended that this stage be completed before finalizing stage 5 (Financial and Operational Structures). In fact, risk-related issues frequently require specific structures in order to mitigate them.
⇒ The risk allocation process may create tensions among participants and result in protracted negotiations. Make sure there is a good mediator at the table.
Chapter IV
International Interest and Support

Objectives

⇒ To secure international interest and support for the project;
⇒ To secure financing from international economic development organizations (such as the World Bank and OECD) to proceed with independent reviews of the project.

Capital markets are very sensitive to risk, and private bankers usually see higher risks in projects in developing countries. This is particularly true for energy infrastructure projects where equipment and construction costs are mainly paid with strong currencies and revenues mainly come from low-income consumers in local currencies. This is why capital markets will often ask that infrastructure projects be supported by international organizations. They will find some comfort in the fact that an international organization has overseen the project and participant governments are committed to implementing the project.

Securing the interest of these organizations will open the doors for public and private funding. Without this support, the project will certainly be more difficult, if not impossible to finance.

Interest from international organizations is often accompanied by grants to pay for independent review. Feasibility studies may be quite expensive, but are needed to convince investors and lenders that the project is viable. At even the early stage of preliminary studies, financial support can be obtained from multilateral institutions through grants from continental development banks (ADB, AfDB, BOAD, CABEI, EIB, EBRD, IDB, ISDB) or advances from the Project Preparation Facility of the World Bank. These institutional lenders can provide a follow-up of the interconnection project from the identification stage to the financing close.

The World Bank comprises four entities:

- The International Bank for Reconstruction and Development (IBRD) provides governments, public agencies or corporations, and private bodies or corporations with government guarantee, with loans for development projects. The interest rate of the loans is adjusted periodically in relation to the Bank’s cost of borrowing.
- The International Development Association (IDA) makes soft loans to governments of eligible countries, i.e. very indebted poor countries. These loans can be passed on to sponsors, generally at market rates.
• The Multilateral Investment Guarantee Agency (MIGA) provides credit insurance.

• The International Finance Corporation (IFC) makes loans to the private sector in developing countries. A Loans are made for its own account. IFC also acts as an aggregator: it makes B Loans for the account of commercial banks and other financial institutions. IFC activities are increasing due to the involvement of the private sector in infrastructure projects.

Continental development banks have the same kind of instruments.

Tips / Recommendations

⇒ It is preferable to make early contacts with international organizations in order to ascertain their requirements for information and include them in the project definition document.

⇒ Before meeting with representatives of these organizations it is preferable (but not mandatory) to obtain formal agreement among the participants on the financial and operational structures of the project.

Results

⇒ Letters of interest;

⇒ Subsidies from international economic development organizations;

⇒ Preliminary risk assessment;

⇒ Partnership agreement.
Chapter V

Financial and Operational Structures

Objectives

⇒ To define corporate ownership and operating responsibility for the project;

⇒ To establish the economic and financial viability of the project.

Project definition (see Chapter II) and risk analysis (see Chapter III) will provide the basis for exploring various alternatives in order to establish:

• an ownership and capital structure;

• an operating structure and contractual agreements in order to mitigate risks (e.g. operating responsibilities between the participants and the sponsors; BOO; BOOT; BTL, etc.).

• The economic and financial viability of the project.

This module, again, does not presume that public or private ownership will be chosen, nor that the system will be operated by an independent entity or an agency of the participants. For private sector ownership and operation, the financing will be arranged mainly by the sponsors, with limited involvement from the participants. In the case of an agency corporation or a pooling of systems, the participants must expect to play a more active role in the financing.

The final scenario will be used to define:

• the contractual liens between participants and sponsors (see Chapter VI – Legal Commitment from Participants) and modifications to regulations in order to accommodate the project;

• the types of contracts and the content of calls for tenders for operators or others parties (construction contract, Power Purchase Agreement, O&M contract, Insurance, Site lease, etc.);

• a list of pre-qualification criteria (financial, technical and ownership restrictions) to select potential lenders and equity investors.
Tips / Recommendations

⇒ Use the output to obtain indications of interest.

⇒ Operators must have a substantial stake in BOO, BOOT or BTL if one of these approaches is chosen.

⇒ An example of the financial and operating structure of an interconnection project is given in Appendix C.
Chapter VI
Legal Commitment by Participants

Objectives
⇒ To make the commitment of each participant official;
⇒ To give the group of participants “legal status”.

In order to secure international financing, the participants will have to clearly define the legal framework which will govern their relationships and commitments to the project. The legal documentation will vary depending upon the ownership and operating structures of the project. There may be several agreements: a Shareholders’ agreement, a Concession agreement, etc. The content of the agreements will be developed progressively throughout the negotiations about the financial and operational structures in stage 5. This requires political understanding, legal knowledge and interpersonal savvy on the part of the negotiators. Each participant should:

A. appoint key negotiators and personal advisors;
B. state clearly their objectives and expected benefits;
C. clarify their roles and responsibilities;
D. acknowledge the major risks and agree on how, when, and who will assume the ultimate risks (alternatively, how settlement and negotiations are to take place);
E. give their approval in principle to the draft agreement.

The draft agreement is then reviewed by a larger group of legal, financial and technical advisors representing each participant. The document should be finalized and approved by each participant.

If it is decided to create an agency to carry on the project, the participants should appoint a steering committee to secure financing.

Should private ownership and/or private operating structures be adopted, then the financing process will be carried out by the sponsors with limited involvement from the participants. On the other hand if the sponsors are corporations owned by one or more participants, then it will be difficult to prevent the funding institutions from asking for government support.
Results
⇒ List of the key negotiators and personal advisors;
⇒ Shareholders’ agreement.

Tips / Recommendations
⇒ The legal commitment is not mandatory before contacting international organizations. Their support, however, is usually conditional upon such a legal agreement being signed.
⇒ Reaching a legal commitment could require protracted negotiations, since risks have to be allocated between the parties.
Chapter VII

Independent Review of the Project

Objective

To select independent experts who will bring value to the project in terms of knowledge and credibility.

International financing is usually available to public sponsors in order to hire independent experts to review the projects. The independent experts must be well recognized and able to confirm the feasibility of the project. Furthermore, independent engineers' reports are seen as convincing means to confirm the feasibility of the project and assure its completion on schedule and on budget.

Experts should be selected from firms with proven track records and successful financing achievements. Lists of experts and advisors are available from international organizations and countries that finance feasibility studies.

The following steps must be completed in order to deliver the results expected at this stage:

A. Obtain lists of recognized experts when securing the support of international financial organizations (The World Bank, EBRD, African Development Bank, Asian Development Bank, etc.);

B. Select technical, financial and legal advisors based on the lists of experts;

C. Mandate these experts to perform an independent analysis of the project;

D. Review, complete and finalize the different sections of the PDD (which will become the Information Memorandum), i.e.

   - Technical description and benefits analysis (by the technical and financial advisors);
   - Projected financial statements based on financial hypothesis and relevant information if financing is raised by public sponsors (by the financial advisors);
   - Corporate and fiscal structures (by the legal and financial advisors);
   - Risk analysis (the legal, financial and technical advisors should review the allocation of risk between participants and sponsors);

E. Obtain approval and commitment from all the participants (including legal and financial).
Results

⇒ Mandate independent advisors (financial, technical and legal);

⇒ Review and finalize all information to be included in the Information Memorandum (see Chapter VIII);

⇒ Complete the risk management strategy (identification, allocation and management).

Tips / Recommendations

⇒ Using independent experts with an international reputation is a key success factor because of the strong mitigation effect perceived by capital markets.

⇒ Even if the feasibility studies and/or the Information Memorandum have been reviewed by independent experts, future sponsors may decide to do other detailed studies.
Chapter VIII

Information Memorandum

Objective

⇒ To prepare an exhaustive document with all the information required by lenders and investors.

⇒ The Information Memorandum is compiled from the different documents produced and revised throughout the previous stages. It must include the following:

- Purpose and description of the project (technical, organizational, legal, etc.);
- Review of the host countries, their power sectors, their tariffs, regulatory framework, etc.;
- Support from international organizations;
- Risk analysis, including risk identification, allocation and management;
- Financial structure of the project;
- Description of the contracts between participants and sponsors.

The Information Memorandum will be used as a prospectus for financial institutions, investors and contractors.

Results

⇒ Information Memorandum.

Tips / Recommendations

⇒ The Information Memorandum should be exhaustive;

⇒ It is a legal document and must not contain any misleading information.
Chapter IX

Testing Capital Markets

Objectives

⇒ To identify potential investors and lenders;
⇒ To confirm financial conditions;
⇒ To prepare presentations to lending institutions.

At the very beginning of the financing process, the project leader will delegate responsibility to his financial experts to keep track of capital markets in order to update loan conditions. The following activities are to be performed by the sponsors (whether they are public or private) and their advisors. The support from participants may be limited.

The official steps in contacting capital markets really begin here. With multiple phone calls followed by presentations of the project, the financial expert will build up two different lists: the first includes potential operators, and the second is a list of potential investors and lenders. Throughout the process, the financial expert will attempt to confirm his initial hypothesis about borrowing conditions and investment markets. This will ensure he is in a good position to suggest the appropriate financial structure.

The following steps must be completed in order to deliver the expected results from this stage:

A. Identify and evaluate potential investors;
B. Identify and evaluate potential lending institutions (public and private);
C. Gather information relative to financing conditions on the market;
D. Prepare a financing plan with a detailed funding schedule and calculated financial ratios (see Appendix E);
E. Prepare a road show;
F. Obtain indications of interest.
Results
⇒ List of potential investors and lenders;
⇒ Terms and schedule for pre-qualification;
⇒ Presentation for road shows;
⇒ Letters of interest from investors and lenders.

Tips / Recommendations
⇒ A lender will seldom take the full risk of financing an infrastructure project. More often, a lead institution will put together a consortium of lending institutions which will share the loan.
Chapter X

Debt and Equity Proposals

Objectives

- To obtain equity proposals from investors-operators;
- To obtain loan offers from international institutions or private sources;
- To negotiate with the best parties and secure a preliminary agreement.

Based on the indications of interest expressed by investors and lenders, the participants will choose one of the following two approaches:

- Should there be a great deal of interest in the project, bids can be called among pre-qualified investors or lenders;
- On the other hand, if there is limited interest in the project, the participants will seek potential offers and then negotiate the contractual conditions.

The selection process is longer, obviously, for public tenders. The following steps must be performed in order to obtain the expected results:

A. Rely on financial advisors to set proper process and procedures for two different calls for tenders:
   - One for investors or investors/operators,
   - One for lenders;

B. Establish prequalification and qualification conditions;

C. Obtain approval from participants and appoint an independent committee to evaluate the offers and proposals;

D. Prepare final drafts for the major contracts and other information needed for a call for tenders;

E. For investors and operators:
   - Ask for bids from pre-qualified investors/operators and obtain bid bonds with individual offers;
   - Evaluate the offers and select the one (or two) best offer(s);
   - Require performance bonds and/or a minimum investment from operators.
F. For lenders

- Obtain financing proposals from international institutions and private sources that meet pre-qualification criteria;

Evaluate the offers and select one (or two) offers.

Results

⇒ List of individuals to form the evaluation committee;
⇒ Prequalification and qualification criteria;
⇒ Calls for tenders (for investors-operators and lenders);
⇒ Financing proposals from international institutions and private sources;
⇒ Selection of one or two investors, and one or two lenders.

Tips / Recommendations

⇒ It is desirable to arrange a question period before closing the bids; make sure to distribute all questions and answers to all bidders.

⇒ All public tenders should allow bidders to ask for copies of all contracts. If contracts are too voluminous to be distributed, they should then be made available in the data room (where all information on the project is made available to bidders).

⇒ Public tenders must be a transparent process. A specific timetable and complete information must be provided, therefore, to all bidders.

⇒ Both investors (operators) and lenders might choose to go through steps 7 to 9 before making a bidding decision.

⇒ An investor-operator must be evaluated jointly by the financial experts and engineers, since operating skills and experience are at least as important as the financial capability of the operator.

⇒ Loans may be for short or long periods; they may be with or without liens on the assets if government guarantees are provided.

⇒ Leasing is a form of loan in which the ownership of the assets is vested in the name of the lenders until full repayment is made.
Chapter XI

Negotiation and Contractual Agreements

Objectives
⇒ To secure the best financial conditions possible;
⇒ To obtain legal commitments.

Following step 10, negotiations will start with the winning bidders (for both investors/operators and lenders). The negotiation process is generally long, and usually focused on risk mitigation, loan conditions (rate, reimbursement term, etc.), loan guarantees, etc.

In order to deliver better results, the following steps must be performed:

A. Appoint one negotiator and agree not to interfere;
B. Select the winning bidder (again for both investors/operators and lenders) with whom the participants would like to close a deal;
C. Negotiate and finalize the business conditions for both investment/operation and loan;
D. Finalize legal and contractual documentation with legal advisors of proven reliability;
E. Obtain authorization and sign agreement.

Results
⇒ Signed financing agreement(s).

Tips / Recommendations
⇒ It is preferable to keep a second runner-up just in case negotiations with the winning bidder fail;
⇒ Make sure to specify to bidders that lobbying must not be done for any consideration; this interference could adversely affect the bargaining power of the sponsors.
Chapter XII

Meeting Disbursement Conditions

Objectives
⇒ To make sure that all the conditions required by the lenders/investors are met, in accordance with the agreements;
⇒ To safeguard the good reputation of the participants and the sponsors.

Although it is very good news when the loan agreement is signed, there is more to do before the money is disbursed. In fact, the financing agreements will set many conditions on loan disbursements. The lenders will often ask that an independent trustee be appointed to control cash disbursements and monitor overall project realization.

Likewise, sponsors should make sure to appoint someone who will be responsible for meeting disbursement conditions.

The following steps must be completed in order to deliver the expected results for this stage:
A. Verify and track disbursement conditions (before signing the loan agreement);
B. Provide required information and certificates in a timely manner;
C. For BOO, BOOT or BTL, make sure that all contractual terms are met;
D. Meet completion and/or performance test criteria;
E. Issue disbursement requests;
F. Pay the agreed fees.

Results
⇒ Requests for disbursement;
⇒ Payment of fees;
⇒ Cash funds.
Chapter XIII

Special Considerations

In countries eligible for loans from the International Development Association (IDA), infrastructure financing cannot be obtained through either equity or loans from commercial banks. The World Bank and the continental development banks (ADB, AfDB, IDB, EIB, EBRD) usually finance such projects. Some institutions make soft loans, for instance, with 40-year duration, 10-year grace period and 0.75% commission per year.

For utilities in these countries, a public service criteria can be used instead of the usual financial ratios: average tariff level is adjusted to recover exactly the operating expenditure, plus debt service, plus provision for replacement of equipment (set at a low level, for instance 1% of total investment per year, during the first ten years of operation of the network).

Tips / Recommendations

⇒ Contact the multilateral institutions at the identification stage of the project.
Conclusion

Infrastructure financing requires substantial investments that are usually beyond the capabilities of local capital markets. In order to convince international markets to support interconnection systems, the project must meet technical and financial criteria acceptable to investment bankers.

In fact, identifying major risks at an early stage will provide more time for the project team to develop appropriate approaches to secure the available financing.

Therefore, making financial advisors part of the project team should bring better results in terms of risk allocation and financial support from international markets.
Appendix A

Example of Power Infrastructure Project

[Diagram showing the flow of resources and interconnections in a power infrastructure project, including key stakeholders and agreements like Concession Agreement, Construction Contract, Operating Contract, Equity Dividends, Deed of Trust, Trust Agreement, Trustee, Insurers, Energy Suppliers, Equipment Suppliers, Contractor, Sponsors, Shareholders Agreement, Concession Company, Loan, Revenue Collection, Debt Service, Guarantees, Export Credit Guarantee Agencies.]
Appendix B

Project Definition Document: Example of Table of Contents

Executive summary

Project overview
  Background
  Goals and objectives
  Description
  Participants and sponsors
  Project benefits
  Project costs
  Time schedule

Description of electricity sector by country
  Power sector organizations
  Existing power facilities
  Access to power service and consumption trends
  Legal and regulatory framework

Business model
  Description of electricity activities
  Organizational structure
  Participants’ and sponsors’ responsibilities
  Building and operating responsibilities
  Legal framework and requirements
  Tariff and revenues (assumptions and determination method)
  Detailed project costs
  Other assumptions

Technical aspects
  Description
  Alternatives
  Feasibility
Appendix C

Example of an Interconnection Project

THE OMVS/SENEGAL RIVER AUTHORITY ENERGY PROJECT

The Manantali dam is situated in Mali on a tributary of the Senegal river, around 1000 km from the sea. This dam was built between 1982 and 1988 and it has been used to regulate river flow for irrigation purposes. From 2001, a power plant located nearby will generate electricity for Mali, Mauritania and Senegal. Water inflows are uneven and concentrated during the rainy season, from July to September, so that may be a major risk. OMVS Energy Project deals mainly with building a 200 MW power plant and a 225 kV transmission line, which is 1200 km long and connects the networks of Senegal, Bamako and Nouackchott. Total amount of investing expenses for the Manantali dam and Energy Project is around US$1 billion, with a 20% share for transmission.

After an appraisal mission conducted in December 1996, nearly all the financing was obtained in mid-1997 from multilateral institutions, including the IDA, by the three states involved, using the following key of repartition: Mali 52%, Mauritania 15% and Senegal 33%. An independent company (IPP) is in charge of building the facilities (currently ongoing). At a later date, it will also be in charge of managing reservoir, plant and network. This IPP is owned jointly by the three participant states. An O&M company will be selected through an international tender. The IPP will sell generated energy on a long-term basis to electric utilities of the three states, according to the aforementioned key of repartition. Over-the-counter energy sales between utilities are possible.
Appendix D

Business Plan

1 THE OBJECTIVES OF THE BUSINESS PLAN

A business plan has three main functions.

- First, a business plan is a document designed to map out the course of a company over a specific period of time. It is a plan that can be used to develop ideas about how the business should be conducted. It is a chance to refine strategies and “make mistakes on paper” rather than in the real world, by examining the project from all perspectives, such as constructions, operations, and finance.

- So it translates the main management decisions (investments, debt repayment, purchases, expenses, wages, etc.) into financial terms. It projects into the future the cumulated effects of decisions made in the past, present and in the future. It ensures that the company has at its disposal financial means for its decisions, and that these means will be preserved in the future.

- Second, a business plan is a retrospective tool, a yardstick against which to measure the project’s actual performance. For example, the financial part of a business plan can be used as the basis for an operating budget. After some time has elapsed, the business plan should be examined to see where and why the business is not adhering to that budget. Examining the business actual performance against the business plan can help pinpoint strengths and weaknesses in the organization.

- The third reason for writing a business plan is to raise money. Most lenders or investors will not put money into a business without seeing a business plan. The business plan is really only the beginning of the money-raising process. It is the first in a series of documents a reviewer will receive.
Because the business plan is a hybrid document -- part pragmatic projection and part sales tool -- the information must be accurate, yet must convey a sense of optimism and excitement. Although risks must be acknowledged, they should not be dwelled upon. Professionals -- consultants, accountants, and lawyers who work with business people in writing business plans and securing financing -- often advise their clients to make realistic projections. The business plan must be clear and well organized, written at a level of complexity the reviewer will understand.

The business plan is a confidential document. It should be distributed only to those who have a need to see it, such as members of the management team, professional advisors, and potential sources of money.

The preparation of a business plan must be seen as an iterative process, as both the assumptions and the projections must be refined.

## 2 NECESSARY INPUT FOR THE BUSINESS PLAN

The financial assessment is based on the prior definition of one or more sets of assumptions grouped into consistent scenarios. A scenario represents a set of assumptions concerning:

- the macroeconomic environment (inflation and exchange rates, etc.);
- sales forecast;
- the definition of the corresponding optimum investment program;
- the basic operating costs, such as maintenance and operating expenses, purchases, wages and other expenses;
- the financing conditions (equity, loans, grants etc.) and targets (for instance rate of return on equity, etc.).

## 3 OUTPUT OF THE BUSINESS PLAN

- A synthesis of the hypothesis outlined above
- Projected income statements (see next figure) inducing:
  - Average Selling Price => Percentage increase
It shows the pricing policy, the possibility of increasing or the necessity of decreasing the tariff in order to increase the sales volumes or net income.

- **Operating Income (pre-tax)**
  The first objective is to check that the core business is profitable. The second objective is to identify the main components of the operating income and to analyze their development over many years, in order to optimize the operating income.

- **Net Income (post tax)**
  As the net income takes into account the financial, exceptional results and taxes, it is important to analyze their respective contributions. The variation of the Net Income should be analyzed and compared to the business plan.

- **Internal Cash Generation**

  \[ \text{Net Income} + \text{Depreciation} \]

At the beginning of the project, the net income of the first years may be negative due to depreciation related to a new major investment. Depreciation is just a calculated -- and not payable -- charge, so it is more appropriate and important to measure the net internal cash generation than the net income in the first years of the project.

- Projected balance sheets (see figure below)
- Projected cash flow statements (refer to IAS 7, published by the International Accounting Standards Committee)
- Financial ratios
- Sensitivity of results corresponding to major risks: construction, market and operating, political, environmental, legal.
Income Statement

<table>
<thead>
<tr>
<th>Cost of Goods Sold</th>
<th>Net Sales</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Margin</td>
<td></td>
</tr>
<tr>
<td>Selling, General and Administrative Expenses</td>
<td></td>
</tr>
<tr>
<td>Operating Income</td>
<td>Other Expenses</td>
</tr>
<tr>
<td>Net Income Before Tax</td>
<td>Income Tax</td>
</tr>
<tr>
<td>Net Income</td>
<td>Other Revenue</td>
</tr>
</tbody>
</table>

Balance Sheet

<table>
<thead>
<tr>
<th>Current Assets</th>
<th>Total Assets</th>
<th>Total Liabilities and Stockholders' Equity</th>
<th>Stockholders Equity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plant and Equipment (Tangible Assets)</td>
<td>Cash</td>
<td>Accounts Payable</td>
<td>Long Term Liabilities</td>
</tr>
<tr>
<td></td>
<td>Marketable Securities</td>
<td>Notes Payable</td>
<td>Capital Stock</td>
</tr>
<tr>
<td></td>
<td>Accounts Receivable</td>
<td>Accrued Expenses</td>
<td>Additional Paid-in Capital</td>
</tr>
<tr>
<td></td>
<td>Notes Receivable</td>
<td>Income Tax Payable</td>
<td>Retained Earnings</td>
</tr>
<tr>
<td></td>
<td>Inventories</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Prepaid Items</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other Assets and Deferred Charges</td>
<td>Intangible Assets</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Deferred Charges</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Appendix E

Main Financial Ratios

The ratios are divided into three financial categories: Profitability, Solvency and Debt.

PROFITABILITY

- Operating Ratio (%)
  \[ = \frac{\text{Operating Charges} + \text{Depreciation}}{\text{Operating Revenues}} \]

  The ratio should be lower than 1; otherwise it reflects an operating deficit. In this case, the depreciation should be separated in order to check that the operating revenues are higher than the operating charges; otherwise corrective action must be taken to ensure that the business is profitable.

- Rate of Return on net revalued fixed assets (%)
  \[ = \frac{\text{Operating Income after Tax}}{\text{(2-year average revalued fixed assets)}} \]

  The ratio should be compared to the interest rate of the Treasury Bond (T-Bond). The question is: is it worth investing in the project if at the end the rate of return is about the same as the interest rate of T-Bond which is guaranteed and safer?

  So the rate of return must be at least the interest rate of the T-Bonds plus a prime risk which depends on the nature and the risks of the project.

- Return on Equity (%)
  \[ = \frac{\text{Net Income}}{\text{(year average total equity)}} \]

  The ratio should be superior to cost of debt.
SOLVENCY

- **Current ratio (%)**
  \[ \text{Current ratio} = \frac{\text{Current Assets}}{\text{Short Term Debt}} \]
  This ratio indicates the level of working capital needs.

  Working Capital Needs = Inventories + Accounts receivable – Accounts Payable.
  The objective is to have the lowest level of working capital needs in order to reduce the debt carrying the current assets and generating interest charges.
  The ratio should be lower than 1.

- **Self Financing ratio (%)**
  \[ \text{Self Financing ratio} = \frac{\text{Internal Cash generation} - \text{Debt service} - \text{Variation in working capital}}{\text{Capital Expenditure}} \]
  The debt service includes interest payment and principal repayment.
  This ratio can be calculated on a period of one to three years. The target value should be 25-40 %.
  In this case, it means that the investment expenditure is self-financed by the company about 25 to 40%, after the operating cycle and debt service.

- **Debt Service Coverage**
  \[ \text{Debt Service Coverage} = \frac{\text{Internal Cash Generation} + \text{Interest Charges}}{\text{Debt Service}} \]
  This ratio indicates the capacity of the company to face the repayment of the debt and its interest charges, after having paid all the operating expenses. The target value should be 1-1.5.

- **Accounts receivable (months of sales)**
  \[ \text{Accounts receivable (months of sales)} = \frac{\text{Accounts receivable} - \text{Sales revenue including VAT}}{12} \]
  This ratio represents the accounts receivable in term of sales months. The objective is to reduce the accounts receivable, and the maximum value accepted by IBRD is about 3 to 3.5 months.

- **Accounts payable (months of purchases)**
  \[ \text{Accounts payable (months of purchases)} = \frac{\text{Accounts payable} - \text{Purchases including VAT}}{12} \]
  This ratio measures the credit accepted by the suppliers to the company in term of purchase months. Although accounts payable make it possible to avoid short-term debt toward banks, a large amount of accounts payable may mean that the company is unable to pay its suppliers.
  If the accounts payable are too substantial, the suppliers may suspend deliveries, and cause a disruption in the operating cycle.
• Inventories (months of purchases)
  = (Inventories - purchases) x 12
For an electric utility, this ratio is not appropriate due to the fact that electricity cannot be stored. If enough data is available, the following ratios should be calculated:

  (Fuel inventory - Fuel purchases) x 12
or
[(Equipment inventory and spare parts) - (Equipment & spare parts purchases)] x 12

**DEBT**

• Gearing
  = Long Term Debt - (Long Term Debt + Total Equity)
This ratio is important for the banks that recommend the following structure:
Long Term Debt is between 60% and 80% of (Long Term Debt + Total Equity).
Total Equity is between 20% and 40% of (Long Term Debt + Total Equity).

The higher the ratio, the more the company depends on financial backers.
Appendix F

Risk Analysis

COUNTERPARTY RISKS

In order to ensure the success of the project and the reliability and solvency of the different parties, the following points should be evaluated.

• The borrowers and any guarantor
  If guarantees or other cash deficiency arrangements are available during the project construction and development phase or thereafter.

• Contractors
  If some level of bonding exists in order to secure payment of liquidated damages for failure to perform.

• The project sponsors and other participants in the project
  If the sponsors have a key role in the project management.

• Product purchasers
  If medium- to long-term sales contracts are in place.

• Project suppliers
  If medium- to long-term supply contracts are anticipated.

• Project operators
  If the project is of a nature requiring advanced technical operation skills.

• Insurers, re-insurers and insurance brokers
  For their ability to pay under the insurance policies and brokers’ undertakings which make up the insurance arrangements.
CONSTRUCTION, DEVELOPMENT AND OPERATING RISKS

- Delays in completion
- Involves additional interest expense and lengthening of repayment profile.
- Cost overruns
- In supplies and transport of energy and/or in the cost of contractors and labor.
- Availability of work force, management personnel and reliable contractors
- Shortfalls in expected capacity, output or efficiency
- If performance does not achieve equipment rated output or anticipated efficiency (because of defects in the engineering, design or technology).
- Soil mechanics
- May involve construction difficulties, exceeded deadlines, cost overruns in supply and transport, etc.
- Force majeure
- Force majeure risks are particularly acute during the construction and development phase of the project, but also apply during the operating phase. This essentially refers to factors beyond the control of the parties, such as natural disasters—fire, flood, earthquake—and war, revolution and strikes, affecting the project itself or affecting contractors, suppliers etc.
- Some of these risks can be minimized through:
  - requiring that performance bonds and completion guarantees are given on behalf of suppliers, contractors and subcontractors and assigned to the lenders;
  - taking out commercial insurance;
  - incorporating strict provisions in the underlying documentation, for example, with contractors and suppliers, to penalize and fix costs and performance and efficiency criteria;
  - ensuring that the project company has entered into binding and forcible long-term fixed price contracts for supplies, energy and transport with creditworthy and reliable counterparties.
ECONOMIC RISKS

- Fluctuations in exchange rates
- Inflation and increases in interest rates
- Increases in world commodity prices, especially for energy supplies
- Some of these risks can be minimized in various ways:
  - hedging facilities against exchange rate and interest rate risks by way of currency and/or interest rate swaps, interest rate caps, collars and floors and other techniques;
  - the debt service and repayment profile can be formulated with reference to a matrix of factors including market prices, inflation rates, energy costs, tax rates, etc.;
  - pass through contracts or indexation against increases in fuel prices;
  - protection against a fall in the tariff through forward sales options contracts.

POLITICAL AND LEGAL RISKS

In any cross-border financing, borrowers and lenders take a political risk in the sense that a collapse of the existing political order in the borrower’s country or the imposition of new taxes, exchange transfer restrictions, nationalization, restructuring of the electricity sector or other laws and regulations might jeopardize the success of the venture, the security of the investment and the prospects of repayment and recovery.

Political risks might be mitigated in a number of ways:

- Licenses granted to the project sponsors should be checked and clarified with the regulator;
- Project lenders will undertake a thorough review of the political and legal risk at an early stage. They should familiarize themselves with the tax and tariff laws of the host country and structure the project and its financing in such a way to limit the risks. In some cases, it might be necessary to predicate the financing on a change in the law itself;
- World Bank guarantees.
ENVIRONMENTAL RISKS

Greater costs to project completion due to environmental requirements can impact on a lender’s assessment of the project profitability.

In order to protect against these risks, some general suggestions are:

• Become familiar with the legal framework governing environmental liability in the host country as part of the general assessment of the project feasibility. Lenders should ensure they have experts to evaluate the information that is gathered;

• Evaluate the risk of environmental liability associated with the project site;

• Documentation should contain representations, warranties and covenants on the borrower’s part to ensure that the borrower focuses on these issues and complies with all applicable regulations and recommended practices.
Module 7
Market Operational Structures
Module 7
MARKET OPERATIONAL STRUCTURES

Introduction

Chapter I  Market Operational Issues

Chapter II  Assumptions and Market Principles
  II.1  RTO Minimum Characteristics
    II.1.1  Independence
    II.1.2  Scope and regional configuration
    II.1.3  Operational authority
    II.1.4  Short-term reliability
  II.2  RTO Minimum Functions
    II.2.1  Transmission tariff administration and design
    II.2.2  Congestion management
    II.2.3  Parallel path flow
    II.2.4  Ancillary services
    II.2.5  OASIS, TTC, and ATC
    II.2.6  Market monitoring
    II.2.7  Planning and expansion
    II.2.8  Interregional coordination

Chapter III  Market Model Description

Chapter IV  Participant Obligations and Responsibilities
  IV.1  Regulator
  IV.2  Licensed Participants
  IV.3  Responsibilities of the RTO
  IV.4  Responsibilities of Market Participants

Chapter V  Market Operation
  V.1  Market Rules
  V.2  Dispatch Process
  V.3  Determining Market Prices
  V.4  Physical Bilateral Contracts
  V.5  Ancillary Services
  V.6  Suspension of Market Operations
  V.7  Transmission Service
  V.8  Settlements and Billing
Chapter VI  Interregional Coordination

List of Tables and Figures

Table 1: Summary of ISO and Transco differences
Table 2: Summary of NERC-defined ancillary services
Table 3: Summary of international transmission pricing

Figure 1: Electricity market model example
Figure 2: Real-time spot price determination

References

back/foward to
Module 1
Module 2
Module 3
Module 4
Module 5
Module 6
Module 8
Glossary of Technical Terms
Acronyms and Symbols
Introduction

For nearly 100 years, and all over the world, the electricity industry has been considered as a natural monopoly. The premise was that efficient production of electricity required reliance on public or private monopoly suppliers subject to government regulation of prices, entry, investment, and quality of service. Today, as evidenced in many countries, dramatic changes are taking place in the structure of electric power sectors. These changes are designed to foster competition in the generation segment of the industry and to reform the regulation of the monopoly transmission and distribution systems. Key restructuring issues include reliability, market efficiency, value to all participants and incentives for investments and expansion. It is acknowledged that a supportive political, legal, and social framework is a prerequisite for a competitive market to flourish.

Regulatory and structural reform of the electricity sectors is following the basic model previously applied to network industries such as telecommunications and natural gas. The competitive segments of the industry (generation) are being separated, structurally or functionally, from the monopoly segments (transmission and distribution). Prices for the competitive segments are being deregulated and consumers are given the opportunity to choose among competing suppliers. Services provided by the monopoly segments are being unbundled from the supply of competitive services and nondiscriminatory access to “lines” facilities is being mandated. Transmission rates, moreover, are being determined by new regulatory mechanisms such as performance based regulation. These new mechanisms are designed to control costs better than traditional cost of service regulation.

As markets evolve in individual provinces, states, and countries, it would be beneficial to all regions to develop mechanisms to coordinate their interregional activities to ensure integration of both reliability and market practices. These benefits include enhanced reliability, enhanced emergency support, better generation capacity utilization, transparent processes, thereby fostering broader competitive markets and potential energy cost reductions.

The purpose of this module is to highlight the issues and options relating to how Regional Electricity Cooperation and Integration (RECI) organizations would operate their systems to facilitate interregional trade. The objectives of regional integration are to enhance interregional reliability through coordinated operations, facilitate broader competitive markets, implement mutually beneficial system enhancements, and improve the flow of information to market participants and the public. The term RECI Organizations refers, herein, to the individual markets that are physically connected to each other.
Chapter I

Market Operational Issues

In developing a market operational structure, there are many issues to address including governance, capacity market, energy market, ancillary services, transmission access, congestion management, and interregional trade. The following briefly outlines some of the issues relating to the operational aspects of the market.

Governance

- Allocation of governance and regulation between government (regulator) and industry
- Types of committees and structures
- Method of selection of Board and committee members
- Authority of Board and committee to propose, adopt, and amend market rules — voting rights
- Membership requirements: eligibility, application process, and fees
- Which entities are required to meet financial security requirements?

Capacity Market

- Is there a bilateral or centrally administered market for capacity, or a combination of both?
- Is installed capacity differentiated from operating capacity?
- Are capacity obligations imposed on a periodic basis, e.g. yearly, monthly?
- Is mandatory offering of available capacity required?
- Which entity determines minimum capacity standards?
- Who is responsible for settlement and billing for generation-based capacity?
Energy Market

- Over what time frame are energy offers/bids excepted?
- What flexibility does a participant have to change their price or amount of energy bid?
- Will portfolio generation offers be permitted?
- Transparency of bids/offers, or balanced schedules
- How are prices set when the Regional Transmission Operator (RTO) intervenes during emergency conditions?
- Centralized regional real-time dispatch or self-dispatch (bilateral trading)
- Is regional unit commitment based on receipt of price bids or balanced schedules?
- Is centralized commitment based on sum of demand bids or centrally forecast demand?
- Are there penalties for over scheduling generation or under forecasting demand?
- What are the external transaction procedures?
- Who is responsible for settlement and billing for energy-based service?
- Is settlement a Pool or bilateral basis, or a combination of both?
- Is settlement ex-ante, real-time, ex-post, or other pricing?
- What is the compensation for out-of-merit generation?

Ancillary Services

- Who is the entity responsible for determining the minimum service standard?
- What entity may provide the service?
- Which entity is the provider of last resort for the service?
- Which entity schedules and dispatches the service?
- Who is responsible for monitoring and auditing dispatch and delivery of service?
- Is the service priced at a cost basis or on a market basis?
- What are the penalties for deviations from the schedules?
- What is the form of bid for each ancillary service?
- Who is responsible for settlement and billing for ancillary services?
Transmission Access

- Which entity receives application for service?
- Which entity performs analysis and responds to requests?
- Which entity is obliged to provide transmission service?
- What is the pricing methodology for network and in/out/through?
- What entity pays for network reinforcements for connecting new generation and loads?
- What entity pays for network reinforcements for general system expansion?
- How are proceeds allocated among transmission owners if a single transmission tariff is used?
- Which entity files transmission service charges with the regulator?
- Which entity bills for transmission service?

Congestion Management

- What method is used for managing congestion, financial or physical rights?
- What method is used for managing intra-control area and intra-market congestion?
- What method is used to manage intermarket congestion?
- How is payment and hedging for congestion handled?

Interregional Trade

- How will neighboring operators perceive other operators’ rules?
- How will neighboring operators match buyers and sellers for scheduling purposes?
- What happens if a transaction clears in one market and not in the adjacent markets?
- How will transmission be allocated over the interties?
Chapter II

Assumptions and Market Principles

To have meaningful competition in an open electricity marketplace, it is necessary to have a reliable and secure interconnected transmission system that provides nondiscriminatory access to all market participants. The rates, terms and conditions of service for the transmission system should be regulated independently of all power suppliers and customers. Given the strong and complex interactions in electric networks, current technology dictates the need for a system operator that coordinates the use of the transmission system.

Regional system operations can be handled using a number of market models. These include:

- Vertically integrated utility (VIU) model — a single VIU covering a geographic area;
- Pool Model — multi-VIU covering several states;
- Competitive Market model.

Typically, VIU and Pool models thrived in noncompetitive utility structures. They planned and operated their systems for their own benefit and limited wholesale trading competition. A Competitive Market model, on the other hand, provides nondiscriminatory access to all market participants and facilitates competition in an open electricity marketplace. One method to achieve a competitive market is to utilize Regional Transmission Operators (RTO). RTOs can be defined as independent transmission organizations that maintain the operation of a reliable transmission system. It should be noted here that the term RTO is a term currently used exclusively in the United States, and applies to US circumstances that may differ from the systems and functions in use in other countries.

The Federal Energy Regulatory Commission (FERC), in the United States, acknowledged that the vertical integration of transmission, distribution and generation offered a lot of potential for transmission owners to discriminate in favor of their own generation. Through its Order 2000, FERC is attempting to create RTOs that can manage the electric power grid on a regional basis, leading to greater efficiency and reliability, and enhanced market performance while removing opportunities for discrimination. FERC aims at unifying as many as 130 transmission control areas that would be formed into 3 to 12 RTOs for the purpose of efficient transmission use. Order 2000 provides details relating to four minimum characteristics and eight minimum functions for RTOs. They include:
II.1 RTO Minimum Characteristics

II.1.1 Independence

To be independent of market participants, the Regional Transmission Operator, its employees and non-stakeholder directors can have no financial interest in energy market participants. The decision-making process must be independent of any market participant or class of participants, meaning that no one class of market participants can veto a decision made by the rest of the Board and no two classes can force an action opposed by the rest of the Board.

II.1.2 Scope and regional configuration

The Regional Transmission Operator must serve an appropriate region, of sufficient size and scope to effectively perform its functions. Functions include making accurate and reliable available transmission capability (ATC) calculations, resolving loop flow issues, managing transmission congestion, eliminating pancaked transmission rates, improving operation and planning, coordinating system expansion, and supporting efficient competitive energy markets. The Commission stressed that since the goal of its Final Rule is to promote competitive markets, regions should be configured to accommodate trading patterns as well as operational interconnections. An appropriate region should “be capable of supporting trade over a large region, and not perpetuate unnecessary barriers between energy buyers and sellers.” FERC did not provide any ruling on the appropriateness of the scope and regional configuration of existing RTOs. FERC, however, sets forth factors to be used as guidance in determining RTO scope and configuration. These factors are:

1. The ability to perform essential RTO functions and achieve RTO goals;
2. Encompass one contiguous geographic area;
3. Encompass a highly interconnected portion of the grid;
4. Deter the exercise of market power;
5. Recognize trading patterns;
6. Take into account existing regional transmission entities;
7. Encompass existing control areas;
8. Take into account international boundaries.
II.1.3 Operational authority

The Regional Transmission Operator must have operational responsibility for all transmission facilities under its control. The RTO can operate the facilities directly or delegate certain tasks, or a combination of both. While the RTO need not be a single control area, it must be the security coordinator for its region.

II.1.4 Short-term reliability

The RTO must have exclusive authority for maintaining short-term reliability, including receiving, confirming and implementing all interchange schedules, ordering generation redispatch if needed for reliable operation, and approving scheduled transmission outages.

II.2 RTO Minimum Functions

II.2.1 Transmission tariff administration and design

The Regional Transmission Operator must administer its own tariffs and employ a pricing regime that promotes the efficient use and expansion of the transmission system and eliminates pancaked rates. The RTO must be the sole provider of transmission services over facilities under its control, the sole administrator of its FERC-approved open access tariff, and the sole authority to receive, evaluate, approve or deny requests for transmission service or new interconnections.

II.2.2 Congestion management

The Regional Transmission Operator must develop and operate market mechanisms that manage congestion in a manner that provides all transmission customers with efficient price signals. The Commission concludes that market mechanisms to manage congestion are preferable to the use of administrative curtailments or other approaches that do not take into account the relative value of the impacted transactions. RTOs are well suited to implement these approaches because market-based congestion management mechanisms must be closely coordinated with an RTO’s day-to-day operational activities.
II.2.3  Parallel path flow

The Regional Transmission Operator must develop and implement procedures to address parallel path flows within its region and with other regions. In adopting this requirement, the Commission conceded that the ability of transmission customers to choose among different contract paths will be diminished or eliminated. The Commission concludes, however, that the ability of transmission customers to move power anywhere within an RTO at a single rate and under a single set of terms and conditions will provide sufficient competitive benefit to offset any concerns.

II.2.4  Ancillary services

The Regional Transmission Operator must serve as the provider of last resort for the ancillary services, defined in Order No. 888 as the responsibility of the transmission provider, and must allow participants the option of self-supply or third-party acquisition of appropriate ancillary services. The RTO can fulfill its ancillary service obligations through contractual arrangements, direct or indirect control of specific generation resources, or market mechanisms. The option of self-supplying ancillary services is intended to provide a competitive check on the RTO’s provision of ancillary services.

II.2.5  OASIS, TTC and ATC

The Regional Transmission Operator must be the single Open Access Same-Time Information System (OASIS) site administrator for all transmission facilities under its control. To ensure accurate information and consistent assumptions, the RTO must independently calculate Total Transmission Capability (TTC) and Available Transmission Capability (ATC), based on data developed partially or totally by the RTO. Data supplied by others must be subject to a system of checks designed by the RTO to ensure coordinated and unbiased information.

To promote interregional trading, the Commission envisions the development of standardized methods of moving power into, out of, and across RTOs, including standardized communications protocols to schedule power movements.
II.2.6 Market monitoring

The Regional Transmission Operator must objectively monitor the energy markets it operates to identify design flaws, market power abuses and opportunities for improved efficiencies, providing reports to FERC and other appropriate regulatory authorities. The RTO must also propose appropriate remedial actions. The underlying goal is to provide the Commission with additional means of detecting market power abuses, market design flaws and opportunities for improvements in market efficiency.

The Commission recognizes that since the RTO serves as a provider of last resort for certain ancillary services, which it must procure efficiently in competitive markets, the RTO itself may have an interest in taking actions to lower prices in those markets. All RTOs, therefore, must propose an objective monitoring plan to assess whether the RTO’s involvement in the markets favors its own economic interest over those of its customers or members.

II.2.7 Planning and expansion

The Regional Transmission Operator must have responsibility for planning and directing needed transmission additions and expansions to provide efficient, reliable, nondiscriminatory service. RTOs are expected to encourage market-motivated operating and investment action to prevent and relieve congestion. Pricing mechanisms used for transmission planning and expansion should be compatible with pricing signals for shorter-term congestion management, so that market participants can choose the least-cost solution. Where feasible, the RTO should encourage market approaches to relieving congestion.

II.2.8 Interregional coordination

This function requires Regional Transmission Operators to develop mechanisms to coordinate their activities with other regions, whether or not RTOs exist in those regions. The goal is to ensure integration of both reliability and market practices. While RTOs are not required to have uniform practices, reliability and market interface practices must be compatible, particularly at the seams. RTOs are specifically charged with ensuring that market activity is not limited because of differing regional practices.

FERC does not have a preference relating to the type of RTO — i.e. Independent System Operator (ISO), Transmission Company (Transco), or a combination of the two — as long as the RTO meets the minimum characteristics and functions, as well as other requirements.
Table 1 provides a summary of the main differences between an ISO and a Transco. An ISO can be defined as an independent entity that operates and controls the transmission assets of all transmission owners in the region. ISOs are normally nonprofit though for-profit is possible. Transcos can be defined as an independent entity which owns/leases all the transmission assets in the region. Profit is primarily a regulated rate of return on the capital investment. Both ISOs and Transcos would operate the energy market. Advantages and disadvantages of ISO and Transco organizations are summarized below.
### Table 1: Summary of ISO and Transco differences

<table>
<thead>
<tr>
<th>ISO</th>
<th>Transco</th>
</tr>
</thead>
<tbody>
<tr>
<td>Divestiture of functions, rather than assets of the vertically integrated utilities.</td>
<td>All transmission assets in the region have to be divested and combined into a single entity.</td>
</tr>
<tr>
<td>Being primarily nonprofit removes investment conflicts and enhances neutrality. Requires a less rigorous process because the governing structure represents all stakeholders and acts in the public interest.</td>
<td>Decisions could reflect ownership interest and compromise independence. Requires stronger regulatory process.</td>
</tr>
<tr>
<td>Lack of financial interest may compromise operating efficiency.</td>
<td>Incentive to be efficient.</td>
</tr>
<tr>
<td>Weak in forcing capital investment decisions since the ISO only has responsibility for planning and directing needed transmission additions and expansions.</td>
<td>The RTO and the Transco relation is internal, thus less complex contractual agreements. No need to separate operating and asset functions. Takes longer to achieve due to unbundling of generation from transmission.</td>
</tr>
<tr>
<td>Easier to form because a utility does not have to divest its transmission, only transfer operational control.</td>
<td>Having owner and operator functions permit decisive operating authority.</td>
</tr>
<tr>
<td>Large ISO area and appropriate regional shape provides increased reliability to users and can better eliminate pancaked rates across the region.</td>
<td>Divestiture complicates matters.</td>
</tr>
<tr>
<td>Easier for public power to join an ISO than a Transco.</td>
<td>Better able to ensure comparability of service by amalgamating all transmission uses into one tariff.</td>
</tr>
<tr>
<td>Market monitoring is better fit with the ISO governing structure.</td>
<td>Market monitoring may be inappropriate if the Transco does not perform the functions being monitored.</td>
</tr>
<tr>
<td>Rate-making may be complex.</td>
<td>Can simplify rate-making by implementing performance-based rates and developing innovative transmission pricing proposals.</td>
</tr>
<tr>
<td>Difficult to ensure comparability of service since each entity has its own tariff.</td>
<td>Nonaffiliated Transco may have a greater potential for independence.</td>
</tr>
</tbody>
</table>

It is anticipated that Regional Transmission Operators will have the function of managing the real-time energy market as well as a forward energy exchange. Although the forward energy exchange function could be managed by any third party exchange type entity, RTOs will probably include this function to meet the early financial needs of market participants. The RTO/PX debate, however, will not be discussed in this module. As markets mature, there is an expectation that alternative financial markets will develop outside of the RTO domain.
Chapter III

Market Model Description

Common attributes for an open market model are as follows:

• Non-discriminatory access to transmission and distribution systems;
• Open, voluntary market place that facilitates bilateral and spot market transactions;
• Transmission Operators that operate the market independent of market participants;
• Spot market integrated with regional, physical dispatch;
• Bid-based spot market with the capability of allowing physical bilateral contracting;
• Visible, transparent market clearing prices;
• Congestion management via centralized real-time (re)dispatch;
• Independent regulator for approval of transmission service rates;

It is assumed, herein, that the control areas participating in the RECI Organization will utilize an RTO approach for interregional trade transactions.

Under wholesale competition, generators/wholesalers from within and outside of the RTO will compete to sell electricity to purchasers of bulk power such as distribution utilities, industrial customers, aggregators, brokers and marketers. Purchasers will be able to buy energy in the RTO market or through physical bilateral contracts. All participants in the RTO-administered markets will have to be licensed by the regulator, authorized by the Regional Transmission Operator, and their facilities will have to be registered with the RTO, including the installation of appropriate wholesale metering at their connection points to the grid.

The diagram below illustrates one potential market model for the flow of electricity and transactions associated with the physical markets administered by the RTO — real-time (spot) and procurement ancillaries — and physical bilateral contracting. Transactions are between licensed participants (consumers do not need a license, unless they want to buy from the RTO-administered market). End use consumers have been split between those that want to participate in the wholesale market and those who do not. Those that do participate in the wholesale market will require a wholesale license.
Flow of electricity assumes that a generator is a net producer of energy. Generators will need a wholesale license to sell to wholesale buyers or through the RTO-administered markets, and a retail license to sell to a consumer.

Physical bilateral transactions can occur at the wholesale level between wholesale buyers, wholesale sellers and retailers, and at the retail level between retailers and retail customers.

*Figure 1: Electricity market model example*
Chapter IV

Participant Obligations and Responsibilities

IV.1 Regulator

The regulator for the electricity industry typically will license generators, transmitters, distributors, wholesalers, retailers and the Regional Transmission Operator. It will set rates for transmission and distribution utilities. It will also, with the assistance of the RTO, monitor the market for abuse of market power. If the regulator finds an abuse of market power, it can amend the license of a market participant or order the RTO to make a change to the market rules. The regulator will also function as an appeal body for market participants seeking an amendment to a market rule made by the RTO or an order of the RTO. Finally, the regulator will review certain transactions related to the sale or acquisition of generation, transmission and distribution facilities.

IV.2 Licensed Participants

The Regional Transmission Operator is licensed to direct the operation of transmission systems and operate the market established by the market rules. A consumer is not require to have a license. The following classes of persons may apply for authorization to participate in the RTO-administered markets, or to cause or permit electricity to be conveyed into, through or out of the RTO-controlled grid:

- **Generator** - a person who owns or operates a generation facility which generates electricity or provides ancillary services for sale through the RTO-administered markets or directly to another person.

- **Wholesale buyer** - a market participant who purchases electricity or ancillary services in the RTO-administered markets or directly from a generator.

- **Wholesale seller** – an entity that sells electricity or ancillary services through the RTO-administered markets or directly to another person, other than a consumer.

- **Retailer** - an entity that retails electricity.

- **Transmitter** - an entity that owns or operates a transmission system.

- **Distributor** - an entity that owns or operates a distribution system.
IV.3 Responsibilities of the RTO

The Regional Transmission Operator will be charged with maintaining the operation of a reliable and secure transmission system. Its responsibilities include:

- The RTO is bound to comply with all applicable government standards and requirements.
- The RTO will ensure market participant compliance with the rules through licensing and enforcement of the market rules.
- The RTO will define transmission operating procedures, instructions and reliability-related information.
- The RTO will enter into agreements with transmission owners who will be required to operate their equipment and otherwise act in a manner that is consistent with the reliable operation of the RTO-controlled grid.
- Transmission service agreements will be formed with customers. In its settlement process, the RTO will collect transmission service charges and disburse these revenues to transmission owners.
- The RTO will determine the available capacity of the system, schedule energy transactions, dispatch electricity and manage congestion and losses using established market rules.
- It will administer the grid connection requirements and will identify any projected transmission system security and adequacy issues.
- Each year, the RTO will publish a report containing forecasts of the adequacy of the generation and transmission facilities to meet expected loads. These adequacy forecasts are intended to inform the market and government officials of the potential magnitude, duration and location of expected shortages.
- As a general rule, the RTO will rely on market responses to solve grid and market problems. While the RTO has the clear authority to intervene in the market and indeed suspend market operations if necessary to preserve system security and reliability, its first option must be to rely on market responses.
- During periods of emergency and market suspensions, the market rules will allow the RTO to use market mechanisms whenever practical to resolve system conditions and help the system return to normal market operations. When market mechanisms fail, the market rules provide that the RTO will have adequate and clear authority to take whatever measures it deems necessary to maintain or restore system security and safety. The RTO will, of course, coordinate its emergency activities with asset owners and other market participants.
IV.4 Responsibilities of Market Participants

Wholesale market participants include: generators, transmitters, distributors, wholesale buyers and sellers, and retailers (including aggregators, brokers and marketers)

Market participant responsibilities include:

- Operate and maintain their equipment in a manner that is consistent with the reliable operation of the RTO-controlled grid and to assist the Regional Transmission Operator in the discharge of its responsibilities to maintain reliability.

- Participants must provide the RTO with equipment function descriptions, ratings, and restrictions and promptly inform the RTO of any change or anticipated change in the capability of its facilities or the status of its equipment or facilities.

- Participants must promptly comply with RTO directions, including instructions to disconnect equipment from the grid for reliability purposes and in emergency situations. Such directions may be declined if they would result in equipment damage, endanger the safety of employees or the public, or damage the environment.

- Each participant shall carry out its obligations in accordance with applicable reliability standards.

- Generators, wholesale loads, and distributing companies will enter into a connection agreement with the transmitter or distributor. These agreements shall specify the physical and operational requirements for a reliable connection between the RTO-controlled grid and transmission facilities or distribution facilities.
Chapter V

Market Operation

The following provides an outline of how an RTO-type market would function based on the above principles and responsibilities.

V.1 Market Rules

The objective of the market rules is to govern the RTO-controlled grid and to establish and govern efficient competitive and reliable markets for the wholesale sale and purchase of electricity and ancillary services. The market rules should contain provisions for:

- Governing the making, amendment and publication of the market rules;
- Governing the conveying of electricity into, through or out of the RTO-controlled grid and the provision of ancillary services;
- Governing the terms and conditions pursuant to which persons may be authorized by the Regional Transmission Operator to participate in the RTO-administered markets;
- Governing the manner, in which electricity and ancillary services are sold, purchased and dispatched in the RTO-administered markets;
- Governing standards and procedures to be observed in system emergencies;
- Authorizing and governing of directions and making of orders by the RTO;
- Providing mechanisms for the resolution of disputes and monitoring, surveillance and investigation of market participant activities.
V.2 Dispatch Process

As mentioned above, the Regional Transmission Operator should determine the available capacity of the system, schedule energy transactions, dispatch electricity, and manage congestion and losses using established market rules. A common dispatch approach is as follows. Every generator that wants to participate in the market would submit dispatch data to the RTO for each hour regardless of whether the generator is participating in the spot market or has a physical bilateral contract. The dispatch data would be in the form of offers to provide energy and/or reserves. These offers include MW quantities for each hour and US$/MWh prices for the quantities. The offers would also include physical descriptions of each units abilities to provide the offered service such as how much, how fast, limits, etc., and location of injections and connection points.

Offers can be submitted a day ahead or several hours ahead. The closing time of this market depends on the time required to perform security assessments, finalize the generation schedule, and issue dispatch instructions. This can be from one or more hours ahead, down to 15 minutes ahead for minor changes. To allow system security and ancillary service requirement assessments to be completed, advance indications (not commitments) of supplier and consumer intentions must be provided to the RTO. These indications are used to create a provisional day-ahead generation schedule, which may have to be modified if there are significant changes in the status of the grid or in market participants’ intentions prior to closing of the real-time market. These preliminary schedules would be shared with all market participants in advance of real-time operations.

The RTO would then rank the generator offers (spot and physical bilateral) according to their offers and develop a dispatch schedule based on economic merit order. The RTO will then dispatch by directing the real-time operation of dispatchable generators and loads to cause a specified amount of electric energy to be provided to, or taken off the system. The dispatch process takes into account the capabilities of the transmission grid, which may be constrained by congestion. Should congestion occur on the system, the RTO would adjust the merit order dispatch, based on offer prices, to relieve the congestion. That is, lower cost units are backed off to relieve congestion and higher cost units are constrained on to meet loads. All generators that are dispatched based on their offers get access to the grid.

With regard to loads, customers would have a choice of being non-dispatchable or dispatchable. Non-dispatchable loads would always be served and be willing to buy at any price. Dispatchable loads would provide hourly bids to the RTO and as long as the energy price is at or below their bids, they will be served. If the real-time energy price is above their bid, they would be dispatched off by the RTO.
V.3 Determining Market Prices

Figure 2 below illustrates a common method to determine spot market energy prices for a typical dispatch interval. The market clears at the point where the supply and demand curves intersect. The supply curve is fixed for one hour (last generator offers), while actual demand is changing with each five-minute dispatch interval. As demand moves up or down the supply curve, the spot market energy price changes. It should be noted that although all generators offer into the market, generators with physical bilateral contracts will not be paid the spot market energy price. The customer counterparty of the physical bilateral contract will pay the generator directly. The offers from generator participating in physical bilateral contracts are only used by the RTO to determine the most economic system dispatch.

The demand curve is composed of bids for dispatchable loads, line losses and forecasts of non-dispatchable load.

A dispatch algorithm will be used to determine the various schedules, dispatch instructions, and prices that market participants receive from the RTO to guide the actual physical operations of the electricity system and to be used in settlements. The algorithm balances load, based on forecast demand from non-dispatchable loads and the bids from dispatchable loads, with energy based on offers and forecasts from generators. Energy and operating reserve (10-minute and 30-minute) is optimized to ensure that electricity is delivered to loads, reliably and at the lowest cost. The algorithm also ensures there is enough spinning reserve within the classes of operating reserve, and it determines limits on intertie flows.

*Figure 2: Real-time spot price determination*
V.4 Physical Bilateral Contracts

Physical bilateral contracts involve commercial arrangements between market participants. A typical RTO-type market design would support both spot trading and bilateral trading. Sellers and buyers would arrange bilateral deals between themselves that cover prices, quantities, term, conditions, etc. The seller would inform the RTO of their bilateral quantities but not of their bilateral prices. As mentioned earlier, the associated contract quantities are not considered part of the spot market for RTO settlement purposes. Physical bilateral quantities do not affect the RTO dispatch. Generators have to submit offers for all their intended production to allow the RTO to conduct merit order dispatch. The bilateral quantities are only needed by the RTO for settlement purposes in order to separate spot market transactions from physical bilateral transactions.

V.5 Ancillary Services

Ancillary services are the means by which system operators manage generation and transmission in an integrated manner to maintain frequency, voltage and reliability within prescribed levels while meeting customer demands. Part of the integration involves acquiring and deploying services that are neither pure transmission nor pure generation but combine the features of both. Although classified as ancillary services, they are essential to the proper functioning of the grid. Ancillary services also tend to be “system” services; they are not easily amenable to procurement or deployment on a transaction by transaction basis. They must be coordinated, instead, on a system-wide basis, and can be more easily acquired through a central market mechanism.

The North American Electric Reliability Council (NERC) has identified a total of eleven ancillary services, which it refers to as Interconnected Operations Services. These are listed in Table 2 below. The first six of these services are consistent with the six ancillary services articulated by the US Federal Energy Regulatory Commission (FERC) in its Open Access Order 888.
Table 2: Summary of NERC-defined ancillary services

<table>
<thead>
<tr>
<th>NERC-Defined Interconnected Operations Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scheduling, System Control and Dispatch</td>
</tr>
<tr>
<td>Reactive Supply and Voltage Control from Generation Sources</td>
</tr>
<tr>
<td>Regulation</td>
</tr>
<tr>
<td>Energy Imbalance</td>
</tr>
<tr>
<td>Operating Reserve — Spinning</td>
</tr>
<tr>
<td>Operating Reserve — Supplemental</td>
</tr>
<tr>
<td>System Black Start Capability</td>
</tr>
<tr>
<td>Network Stability Services from Generation Sources</td>
</tr>
<tr>
<td>Load Following</td>
</tr>
<tr>
<td>Real Power Transmission Losses</td>
</tr>
<tr>
<td>Dynamic Schedule</td>
</tr>
</tbody>
</table>

In specifying these Interconnected Operations Services, NERC has endeavored to ensure system reliability in both current and future possible market structures.

- **Scheduling, System Control and Dispatch** service encompasses the scheduling, confirmation and implementing of interchange schedules between control areas that may be providing transmission service. This service also ensures operational security during the interchange transaction. These services are dealt with in NERC’s Operating Policies and Standards. Theoretically, all flows of electricity between control areas should be scheduled. Unscheduled loop or parallel flows, however, are often present. Such flows are not easily controlled, and are often not compensated for. Unless otherwise agreed, each control area must endeavor to operate its system in such a manner that there is no unscheduled flow across any of its interconnections.
• **Reactive Supply and Voltage Control from Generation Sources** provides the capability to control voltages across the transmission system in a control area and maintain them at acceptable levels. This service is also used to support interconnected system operations, and to facilitate electricity transfers between one control area and another. Reactive supply is achieved through changes to generators’ reactive power output.

• Certain reactive supply requirements can be addressed through conditions of connection or through connection agreements rather than procured as ancillary services. For instance, generating units may be required to supply specified amounts of reactive power while generating energy, or load customers may be required to maintain their ‘power factor’ at agreed levels, with the result that neither unreasonably reduces transmission system voltages through their operations.

• **Regulation** and frequency response service is used to balance generation resources with minute-to-minute local variations, and to maintain desired frequency levels within and between control areas. Both generation and loads may provide this service if they are equipped to respond to automatic control signals issued by the RTO. This response can include changes in capacity, energy, and plant maneuverability.

• **Energy Imbalance** service addresses mismatches between a generator’s scheduled energy supply and the amount of energy actually provided. In the market operating structure outlined above, imbalances will be covered by the RTOs dispatch, i.e. in the spot market settlement, generators (and loads) will be charged for deviations from schedules at spot prices.

• Operating Reserve is extra generating or load reduction capability held in reserve to allow the RTO to respond to unforeseen changes or contingencies on the power system. **Operating Reserve — Spinning** service provides reserve capacity from facilities synchronized to the system, which can be either unloaded or ramped up immediately. Such capability must be fully available within 10 minutes in order to qualify as spinning reserve. Generators that are on-line, but loaded to less than their maximum output, typically provide this service.

• **Operating Reserve — Supplemental** service is an additional level of operating reserve, beyond the spinning reserve that is immediately available to the system. It is capable of being synchronized to the system and fully available to serve load within 10 minutes. This service may be provided by generating facilities or by interruptible load that can be removed from the system within 10 minutes.

• **System Black Start Capability** service is used to restart or restore power after a system-wide blackout. It is provided by generators that can start up without the assistance of electrical supply from the grid. This capability can be achieved using standby or emergency generators at the plant site. It is sufficient for this service to be provided at a limited number of plants within a control area.
• **Network Stability Services from Generating Sources** are provided by special equipment, devices, software and systems in order to enable the system operator to meet NERC regional, subregional, or local reliability requirements. They are generally provided by special equipment on specific units, and provide benefits such as increased transfer capability or improved reliability of the transmission network. Examples of the equipment used to provide this service include generation rejection or runback schemes. In certain instances, this service can be provided by loads that have special stability enhancement controls.

• This service is separate from that provided by equipment that may be required of most generators in a region or control area as a condition of connection to the system, such as governors, excitors and voltage regulators.

• **Load Following** service is the provision of generation and load response capability that can be dispatched within a scheduling period by the RTO. This service is provided through the RTO’s dispatch.

Two additional services are referred to by NERC as “individual services,” as they are required by, and provided to individual transactions within or through the power system. **Real Power Transmission Losses** service is the provision of capacity and energy to replace energy losses associated with a scheduled bilateral transaction or the capacity to do so. The **Dynamic Schedule** service allows a generator within a host area to be operated and controlled as if it were part of another control area. This service requires that real-time monitoring, telemetering, computer software, hardware, communications, engineering, and administration required to electronically move a portion or all of the real energy services associated with generation or load out of its host control area be in place.

It is common for the operating reserve (10-minute and 30-minute) ancillary to be part of the real-time bidding markets. Ancillaries such as regulation (automatic generation control), voltage control and reactive power, black start capability and must-run facilities would be procured through contracts with the RTO.
V.6 Suspension of Market Operations

The Regional Transmission Operator (RTO) has the authority to suspend the RTO-administered market if certain emergency circumstances, such as a failure of the market system or a major blackout, exist or are imminent. The market cannot be suspended solely because the market price has reached the maximum market clearing price or some demand has been curtailed. Each market participant is required to file its emergency plans with the Regional Transmission Operator in order to assist the RTO in dealing with an emergency operating state. The RTO will endeavor to restore market operations as soon as the conditions requiring suspension are resolved.

V.7 Transmission Service

The terms of access to the transmission system are fundamental to the development of competition in the electricity marketplace. A reliable and secure interconnected transmission system that allows nondiscriminatory access to all market participants must be maintained and priced appropriately for an open electricity marketplace to exist.

Transmission pricing can be complex since electricity does not travel along predetermined paths that respect the terms of a supply contract. Electricity flows along the path of least resistance. In an integrated network, this means that power may flow through many parallel paths according to network status which can change from one moment to another and which is influenced by all users of the network. This phenomenon is commonly referred to as loop flows. Loop flows can cause increased losses and congestion.

In order to reflect transmission costs and network externalities correctly, transmission costs can be separated into three distinct components: sunk transmission costs, variable transmission costs (losses and congestion), and new investment recovery costs. There are two main categories of charging structures — historical cost charging and marginal cost charging. Historical cost mechanisms base prices on costs that have already occurred and include postage stamp pricing, contract path pricing, and megawatt-kilometer pricing. Postage stamp pricing is the simplest approach and is based on the simple division of total network cost by total connected load. This yields a price that is based on the premise that the network provides similar service to all users. Congestion and loss costs would be charged to all users on a load-ratio share basis. Contract path pricing is similar to postage stamp but only uses the total cost of assets along the path between producer and consumer. The contract path approach does not take into account loop flows resulting in inefficiency problems.
The megawatt-kilometer pricing method is based on the assumption that the length of the transmission route and the amount of power transmitted provide a reasonable proxy for transmission cost including losses and congestion.

There are two marginal cost approaches in use — incremental cost related pricing and locational marginal pricing (LMP). The incremental cost related pricing approach calculates transmission costs by comparing total system costs before and after the transaction. The calculated costs could include or exclude investment costs associated with the transaction.

The LMP or nodal pricing approach is used in the United States, New Zealand and Australia. Nodal pricing is based on the theory of optimal electricity pricing: the efficient spot price for energy delivered at a given electrical node should be the sum of (a) marginal energy cost at the swing bus, (b) marginal line loss, and (c) marginal congestion cost of transmission. As (a) is identical at all nodes, the efficient transmission rate should capture (b) and (c). If there is no transmission congestion, all nodes would pay the same energy cost plus marginal line losses. When congestion occurs, higher cost generation may have to be substituted for lower cost generation that would otherwise be used. Under the LMP approach, energy pricing would differ from place to place whenever congestion occurs, reflecting the real-time marginal cost of supplying energy at each point on the network. The energy price difference between two nodes can be considered to be the marginal congestion cost of transmission.

It is widely recognized that marginal cost pricing will not recover the total revenue requirement of the transmission owners. Therefore, a common approach is to use a postage stamp charge in addition to marginal cost pricing. Table 3 below summarizes the international experience with the different transmission charging methodologies.
Table 3: Summary of international transmission pricing

<table>
<thead>
<tr>
<th>Country</th>
<th>Losses</th>
<th>Congestion</th>
<th>Cost Recovery</th>
<th>Investment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Australia NEM (National Electricity Market)</td>
<td>Nodal Pricing – one node per region</td>
<td>Price breaks between regions</td>
<td>Combination of location-specific charges and postage-stamp charges</td>
<td>Planning by system operator subject to public benefit test before incorporation into asset base.</td>
</tr>
<tr>
<td>Brazil</td>
<td>Zonal pricing – application of loss factor at each node</td>
<td>Price breaks between zones</td>
<td>Use of zonal charges calculated using long run incremental costs. Inter-regional interconnectors subject to postage-stamp charges.</td>
<td>10-year plans prepared by Independent System Operator. Investments subject to competitive tender.</td>
</tr>
<tr>
<td>Colombia</td>
<td>Metered quantities scaled up to allow for losses</td>
<td>Additional costs recovered through uplift to pool price</td>
<td>Use of zonal charges calculated using long run incremental costs</td>
<td>Planning by Ministry of Energy. Competitive tendering for construction</td>
</tr>
<tr>
<td>England and Wales</td>
<td>Metered demand scaled up to allow for losses</td>
<td>Additional generation costs recovered through uplift to pool price</td>
<td>Use of zonal charges calculated using long run incremental costs</td>
<td>Planning by system operator. Published plan allows participants to assess capability availability</td>
</tr>
<tr>
<td>MAPP (Mid-Atlantic Power Pool in the USA)</td>
<td>No explicit provision</td>
<td>No explicit provision although discounted charge applied to non-firm transactions</td>
<td>Historical cost base recovered through MW-mile charges.</td>
<td>Planning by system operators, integrated into one region-wide plan. Utilities required to construct facilities as per the plan</td>
</tr>
<tr>
<td>New Zealand</td>
<td>Nodal Pricing</td>
<td>Nodal Pricing</td>
<td>Use of locational specific transport and access charges</td>
<td>Participants or system operator identifies and funded by coalitions of beneficiaries</td>
</tr>
<tr>
<td>PJM (Pennsylvania, New Jersey, Maryland power pool in USA)</td>
<td>Metered demand scaled up to allow for losses. Moving towards application of loss factor at each node</td>
<td>Nodal Pricing</td>
<td>Mixture of postage stamp charges to recover fixed costs and location specific charges</td>
<td>Planning by system operator. Published plan allows participants to assess capability availability</td>
</tr>
<tr>
<td>CA-ISO (California ISO in USA)</td>
<td>Zonal pricing—application of loss factors at each node</td>
<td>Price breaks between zones</td>
<td>Use of locational specific transport and access charges</td>
<td>Coordinated planning by system operator, integrating utilities plans into one region-wide plan</td>
</tr>
</tbody>
</table>
The Regional Transmission Operator will enter into operating agreements with transmission owners, who will continue to operate the system subject to appropriate regulation. The RTO will determine the available capacity of the system, schedule energy transactions, and manage congestion and line losses using established market rules. It will also administer the grid connection requirements applicable to market participants connected to the transmission system and will identify any long-run security and adequacy requirements for the transmission system. In addition, the RTO will advise the regulator and participate in regulator proceedings that consider new transmission investment proposals. Market participants will be free to present transmission investment proposals to the regulator at any time, with or without a supporting assessment from the RTO. The cost of new transmission system investments will be included in the basic use service charge unless the regulator determines that there is an identifiable beneficiary who should pay.

The RTO will charge consumers for transmission services based on rates approved by the regulator. In its settlement process, the RTO will collect the transmission service charges designed to recover the transmission owners’ revenue requirements and will disburse these revenues to the transmission owners. All customers are entitled to non-discriminatory, firm transmission service.

V.8 Settlements and Billing

Settlement is the accounting process whereby the Regional Transmission Operator determines the amounts that each market participant should pay or be paid to compensate for the energy supplied or used, transmission charges, competitive transition charges and RTO administration costs. In the case of spot market transactions, billing and collection is carried out by the RTO. In the case of a physical bilateral contract, the supplier will bill and collect from the customer. For bilateral contracts, the wholesale seller will have the option of having the RTO direct all charges to it in order to allow it to render one bill to the customer. Financial payments will include the following:

- Real-time markets: energy and operating reserve;
- Congestion;
- Transmission rights;
- Capacity reserve market;
- Operating deviations (OR and capacity reserve);
- Procurement ancillaries and must-run contracts;
• Transmission tariffs and connection charges;
• RTO administration charge;
• Other penalties and fines (if applicable);
• Forward energy market (if applicable).

The RTO will collect meter data, which will be subject to a validating, estimating and editing process that will convert the raw meter data into settlement-ready data. Any erroneous or missing data is corrected utilizing error correction techniques with operational and historic data. A validation and dispute resolution process will deal with disagreements over settlement information.

Although all energy settlement functions resulting from physical bilateral contracts are carried out by the contracting parties, contract quantities are needed by the RTO for settlement purposes in order to separate spot market transactions from physical bilateral transactions.

Contract energy quantities will be deducted from the buying market participant’s metered quantities for energy to determine the spot market sales. The RTO will pay a selling market participant the energy market price for the net difference between the seller’s actual metered injections and the total physical bilateral contract quantities sold to all buyers at each location in an hour. Contract quantities are also subject to the other RTO settlement charges.
Chapter VI

Interregional Coordination

It is widely accepted that there are significant technical and economic benefits to interregional coordination and trade. The goals for interregional coordination should include:

- enhance interregional reliability through coordinated operation and planning;
- facilitate broader competitive markets;
- improve flow of information to market participants and the public.

To accomplish this, the control areas, regardless of whether it is an RTO or a vertically integrated utility, should work together with the market to achieve the following objectives:

- implement uniform procedures for confirming transactions and schedules among control areas that maximizes markets’ efficiencies while protecting bulk power system reliability and security;
- establish protocols for coordinating real-time operations and planning activities among control areas;
- investigate feasibility of increasing intertie capacity;
- establish technical processes to strengthen coordination between each control area’s planning and assessment procedures;
- identify rules and practices that need to be addressed to promote seamless markets at the interties;
- identify and coordinate regional redispatch opportunities;
- identify and provide consistent information required to support the marketplace in each control area.
Specific interregional coordination issues that need to be addressed include:

- ramping across the hour and day ahead scheduling;
- reserve sharing and contingency restoration;
- emergency purchases;
- pricing models at the boundaries (proxy buses);
- improved tie-out procedures and curtailment notification;
- common energy market closing and posting times;
- common market interfaces;
- information sharing;
- standardization of interconnection rules for new generation;
- sharing of inter-RTO technical expertise and systems;
- interregional dispatch;
- role of market monitoring;
- long-term reliability; and
- inter-RTO transmission hedging.
References


Module 8

A RECI Organization: Operating Conditions
Module 8
A RECI Organization:
Operating Conditions

Introduction

Chapter I  Items Considered in Agreements
I.1 Adequacy of Generation
I.2 Adequacy of Transmission
I.3 Operation Planning

Chapter II  Adequacy of Generation
II.1 Operating Reserve
  II.1.1 Basic concepts
  II.1.2 Regulating reserve
  II.1.3 Contingency reserve
  II.1.4 Required amount of operating reserve
II.2 Generation Controls
  II.2.1 Basic Concept
  II.2.2 UCTE
  II.2.3 NERC

Chapter III  Adequacy of Transmission
III.1 Criteria of Transmission System
  III.1.1 Basic concept
  III.1.2 N-1 criteria
  III.1.3 Transfer capability
  III.1.4 UCTE
III.2 Voltage Controls
Chapter IV  Operation Planning

IV.1  Basic Concept
IV.2  Operation Organization
IV.3  Information Sharing
IV.4  Power Exchange Schedule
IV.5  Maintenance Coordination
IV.6  Emergency Operations
IV.7  Restoration
IV.8  Operating Personnel and Training

Chapter V  Recommendation

References

back/forward to

Module 1
Module 2
Module 3
Module 4
Module 5
Module 6
Module 7
Glossary of Technical Terms
Acronyms and Symbols
Introduction [1] [2] [3]

The objective of this module is to present the operating conditions of a RECI organization.

Compliance of service with load demands is the primary objective of all power systems. Although a 100% reliable power supply is impossible, every system should protect its customers against loss of service.

In order to achieve the above objective, all parties in an interconnected system must agree upon the operating conditions.

Generally, operations consist of two elements. The first is ensuring reliability, and the second is pursuit of economies. In this module, only the former aspect of system operations will be discussed.

Even in smaller interconnections, the methods used in operating systems in a reliable manner show many similarities with methods used in larger systems. It is obvious, nevertheless, that every system also has specific operating methods because of its own unique characteristics. In this module, similarities between operating conditions will be introduced through the experiences of various interconnected systems.

In order to operate a system in a reliable manner, it is necessary to establish rules that incorporate planning and operating criteria. It is also important for every entity in the interconnected system to agree upon the rules, because every subsystem of an interconnected system can affect the others, and these effects cannot be ignored for reliable system operations.

Certain types of rules and agreements are required for secure and reliable operations, such as:

- Regional (International) Agreements;
- National Grid Codes;
- Agreements on specific tie-lines;
- Agreements on specific generators or customers.
The regional agreements that will be discussed in this module might be defined as the rules to obey for all electric utilities within the region for secure and reliable operations.

The Western System Coordinating Council (WSCC), for example, was established to promote the reliable operations of the interconnected bulk power system of the western part of the United States, through coordination of planning and operation of generating and interconnected transmission facilities. WSCC has its own Reliability Criteria. These Reliability Criteria consist of Reliability criteria for transmission system planning, Power supply design criteria, Minimum operating reliability criteria and Definitions. As indicated in this example from the WSCC, reliability in system operations cannot be achieved by system operations alone; it also requires adequate system planning, as described in a previous module.

As regards the WSCC Reliability Criteria, only Minimum operating reliability criteria will be discussed in this module.

Electric utilities only complied with regional agreements before open access became the issue. With the progress of deregulation in the electric energy market, and open access to transmission, it is increasingly important to consider two things. One is to define technical requirements for all participants in the market in order to operate a secure and reliable system. The other is to assure nondiscriminatory treatment for all participants. Hence, agreements must be signed by the utilities as well as by all other participants in the electric energy market.

Agreements for all participants are often called grid codes.

A grid code might generally be defined as the rules that all market participants (such as electric utilities, independent power producers, customers and any other entity that participate in a deregulated market, must obey for reliable operations.

The DVG (Deutsche Verbund Gesellschaft), for example, has two kinds of grid codes.

In these grid codes, technical requirements for transmission system operators as well as for generation and loads are described. Only the operational requirements for transmission system operators will be discussed in this module even though these requirements also include requirements for planning. Furthermore, even though it is important to determine the requirements for generation and loads for reliable system operations, they are beyond the scope of this module because these requirements may vary with each system’s characteristics.

In Japan, where the new rules started in 2000, the system operations design for each utility company are open to the public in order to guarantee nondiscriminatory treatment for all participants in the deregulated market. The generation and load requirements are described in the wheeling tariffs of each utility company.

On the other hand, since the agreements on specific tie-lines and the agreements on specific generators or customers are unique in nature, only the content of regional (international) agreements and national grid codes will be discussed in this module.

Naturally, every agreement on specific tie-lines, generation or customers must satisfy the conditions set out in the grid codes or regional agreements.
Chapter I

**Items Considered in Agreements**

In this section, the items to be considered in grid codes or regional agreements are discussed, using examples from various interconnections.

### I.1 Adequacy of Generation

Naturally, adequate quantity and quality of generation are essential to reliable electric supply. The following should be considered:

- Operating reserve;
- Generation controls.

### I.2 Adequacy of Transmission

Reliability cannot be achieved by adequate generation alone. Adequate transmission is also essential to reliable electric supply. For reliable transmission, the following should be considered:

- Criteria of the transmission system;
- Voltage controls.
1.3 Operation Planning

Coordinated operation planning between utilities or control areas is also essential to the operation of interconnected systems. The items to be considered are as follows:

- Operation organization;
- Information sharing;
- Power exchange schedule;
- Maintenance coordination;
- Emergency operation;
- Restoration;
- Operating personnel and training.
Chapter II

Adequacy of Generation [1] [4] [5]

II.1 Operating Reserve

II.1.1 Basic concepts

The control area is identified, generally, as the primary entity in assuring secure and reliable operations. The concept of a control area is purely technical and is not necessarily equivalent to a physical region. The control area can be defined as a part of an interconnected system which is responsible for controlling generation to meet load demands. Within a control area, load demand should be supplied by generation within the area and imports from other areas.

In order to avoid loss of load, adequate generating capacity should always be available to cover forced outages of generation or transmission resulting in loss of generation. Moreover, the generating capacity should cover load demand variations in order to maintain nominal system frequency.

For reliable operation, each control area should have enough generating capacity in excess of the load demand to cover forced outages and load demand variations. This surplus generating capacity is called operating reserves.

There are basically two ways to categorize operating reserves. As mentioned above, one way is for regulation and contingencies. In this case, the functions of the operating reserve are considered. The other way is to categorize the reserves as spinning reserve and non-spinning reserve. The characteristics of operating reserves are considered here.WSCC, for example, uses the former category, and the Union for the Coordination of Transmission of Electricity (UCTE) uses the later. There is no essential difference between these two categories. In this module, the former category will be used.
II.1.2 Regulating reserve

A mismatch between generation and load demand causes frequency deviation. To maintain nominal frequency, generation control (regulation) is required. Operating reserves should include the capacity for regulating reserve.

The regulating reserves include a spinning reserve and a non-spinning reserve.

Spinning reserve is defined as unloaded generation that is synchronized and ready to serve additional demand. It can serve loads almost instantaneously.

Non-spinning reserve is defined as reserve not connected to the system but capable of serving demand. It would take some time before it could serve loads.

The amounts of these reserves are closely related to the system’s characteristics and generation control requirements or frequency deviation requirements.

WSCC’s requirement in terms of the amount of regulating reserve, for instance, is “Sufficient spinning reserve, immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the control area to meet NERC’s Control Performance Criteria.”

Within the UCTE, the spinning reserve (or “Primary Control”) is 3000 MW as a whole-interconnected system. It should be noted that this 3000 MW of spinning reserve includes reserves for contingencies.

These reserves will be discussed in detail later, since they are closely related to the quality of generation control.

II.1.3 Contingency reserve

As mentioned before, although a 100% reliable power supply is impossible, load demands must be supplied even during forced outages of generation or transmission. Although it is advisable to have large amounts of contingency reserve for reliability, too high a reserve level can mean loss of economies. Therefore, adequate amounts of contingency reserve should be set, with due consideration for the credibility of forced outages.

In the case of a system not interconnected to other systems, for instance, it might be desirable to have contingency reserves equal to the largest generating unit in the system, because a forced outage of a single generating unit is sufficiently credible.
In general, the loss of a single element is considered as credible enough, and the system is operated so as to withstand the loss of any single element.

The loss of transmission lines that connect to generation stations is obviously less credible, but it may be regarded as credible in some special cases, such as two lines on the same towers or lines close to airports. In such cases, contingency reserves should be at least equal to the generation capacity of the largest station.

The advantage of interconnection is that these contingency reserves need not be supplied by the affected system alone, even if the contingencies are considered as credible enough, since the other interconnected systems can compensate partially for the generation deficiency.

The required amount of contingency reserve should be kept within a whole-interconnected system. Accordingly, the amount of contingency reserve required from each system would be smaller.

A forced outage of generation or transmission is not the only factor that determines the required amount of contingency reserve. In determining that amount, load uncertainty should be considered as well. When electricity is used for air conditioning, load demands may vary depending on temperature. As a result, errors in load forecasting cannot be avoided. When hydroelectricity is used as an energy source, moreover, availability of hydro resources should be also considered. With these considerations, contingency reserves might be determined by means of a probabilistic approach, such as Loss of Load Probability (LOLP).

**II.1.4 Required amount of operating reserve**

Based on the above considerations, each interconnected system determines the required amount of operating reserve.

Within the UCTE, 3000 MW of operating reserve is adequate for the whole system.

At NERC, the criteria used for operating reserves is that: “Each control area shall operate its MW power resources to provide for a level of operating reserve sufficient to account for such factors as errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and regional and system load diversity. Following loss of resources or load, a control area shall take appropriate steps to reduce its Area Control Error (ACE) to meet the Disturbance Control Standard (DCS). It shall take prompt steps to protect itself against the next contingency.”
The Disturbance Control Standard (DCS) states that “the ACE must return either to zero or to its pre-disturbance level within ten minutes following the start of the disturbance.”

In Japan, 8 to 10% of operating reserve in yearly planning is considered as adequate.

II.2 Generation Controls

II.2.1 Basic concept

Even in normal conditions, load demand varies continuously. In order to maintain nominal frequency, generation should be regulated to meet the varying demand.

The required amount of capacity for regulation depends on the characteristics of load variations. For adequate regulation, not only the amount but also the speed of the variations should be taken into consideration. For faster variations with a cycle of less than one minute, the regulation achieved by speed-governor control of generators is considered as effective. A variation with a cycle of a few minutes is typically regulated by spinning reserve via Automatic Generation Control (AGC). For relatively slower variations, non-spinning reserve might be effective.

As described above, in determining the required amount of regulating capacity, several factors should be considered. At first, the required quality of frequency; such as the standard deviation of deviations from nominal frequency, should be established. At the same time, the characteristics of load variations should be identified. Given these requirements and characteristics, the required amount of spinning reserve and the total amount of regulating reserves would be determined.

II.2.2 UCTE

Within the UCTE, generation controls are categorized as primary control and secondary control. The required amount of primary control is 3000 MW as a whole-interconnected system. Each control area contributes to primary control in accordance with its respective contribution coefficient Ci (Ci=EI/Eu, where EI is the annual electricity generation of area i, and Eu is the total sum of annual electricity generation in all control areas). In addition, the minimum requirement for activation of the primary reserve is determined by the curve below.
The primary control reserve for each area must be capable of full deployment in response to a generation outage of less than 1500 MW, within 15 seconds and within time limits to be calculated on a linear basis for outages ranging from 1500 MW to 3000 MW.

The functions of secondary control are:

- Maintenance of scheduled power exchange;
- Takeover from the primary control deployed by all members; the secondary control will only be activated in the control area where the imbalance appears;
- Restoration of frequency to nominal value.

The secondary control is required to begin within 30 seconds of the disturbance and be fully deployed within 15 minutes.

**II.2.3 NERC**

As another example, NERC has established Control Performance Standards (CPS1 and CPS2). Each control area is required to monitor its control performance on a continuous basis against two standards.

The first measure of CPS is a measure of the control area’s performance. This measure is intended to provide the control area with a frequency-sensitive evaluation of how well the area has met its demand requirements.
The second measure of CPS is designed to limit ACE ten-minute averages and provides an oversight function to limit excessive unscheduled power flow that could result from ACEs.

These measurements of control performance apply to all (normal and disturbance) conditions.
Chapter III

Adequacy of Transmission [5]

III.1 Criteria of Transmission System

III.1.1 Basic concept

Adequate generation alone cannot achieve secure and reliable delivery of electricity. Adequate generation and transmission combined can achieve secure and reliable delivery.

An interconnected system should be operated to avoid system instability, uncontrolled separation, cascading outages or voltage collapse as a result of credible contingencies. Typically, single contingency is considered as “sufficiently credible contingencies.” These criteria are usually called “N-1” criteria.

III.1.2 N-1 criteria

The N-1 criteria mean that the loss of any single element (line, transformer, generating unit, etc.) will not cause overload of any equipment in the interconnected system, instability, uncontrolled separation, or voltage collapse.

This means that the loss of any single element will not cause any operating constraints in the interconnected system, so that the system can remain stable. But the loss of two or more elements might cause certain constraints, and countermeasures would be required to stabilize the system.

It is desirable to assure operating security in case of more serious contingencies, such as loss of two or more circuits or loss of a bus in a substation. It is not economical, however, to consider the loss of two or more elements as criteria. Hence, the comparative analysis of technical and economic factors should be considered when determining criteria for an interconnected system.
Among those factors:

- probability of contingencies;
- effects of contingencies;
- cost of protective measures against contingencies.

As a result of these considerations, emergency control might be adopted in the event of the loss of two or more elements. The chance of losing two or more elements is very small, but not zero. Since we cannot say it will never happen, some countermeasures against this kind of severe contingency are necessary.

Automatic load shedding, for instance, can be adopted in the event an entire generation plant is lost as a result of multiple transmission outages. Naturally, adopting emergency controls may be an economic, but less reliable choice because it can increase the probability of losing loads. When emergency control is adopted, the balance between economy and reliability should be considered in detail.

All entities in the interconnected system should agree on the criteria for the interconnected system. In the case of an existing interconnected system, there is no major difference on this point. Possible differences might concern which contingencies are to be considered as single contingency or as credible.

### III.1.3 Transfer capability

The transfer capability between control areas should be determined based on the criteria defined, and be agreed upon within the interconnected area. Scheduled exchanges between control areas never exceed the transfer capabilities.

In the operation planning stage, each system should supply data for analysis, such as network topology, load distribution, generation dispatch and information on generation and transmission, to determine the transfer capability.

More detailed analyses might be required, especially in a meshed network, since any exchange can theoretically affect any power flow in the meshed interconnected system.
III.1.4 UCTE

Within the UCTE, a forecast analysis for a whole-interconnected system is performed. In the analysis, the following are considered using a simulation of an N-1 outage on an international interconnection:

- The effects of generation outage on power flow, both in national networks and on the interconnection;
- Power flow transfers associated with the outage of lines or other elements of national networks, taking the influence of other networks into account.

For network security, the UCTE has developed a technique to improve the accuracy of real-time analysis of the network.

Since the problem of the stability of the whole UCTE has come to light only very recently, a stability analysis has been completed on the basis of regional coordination. The UCTE has recently been considering the possible need for a stability analysis of the whole-interconnected UCTE system.

III.2 Voltage Controls

Each control area should be responsible for adequate system voltage. In other words, each control area should be responsible for reactive power management in the area. Since reactive power transmission causes voltage drop and transmission loss, it is preferable to maintain the balance between reactive power supply and demand on a local basis.

In order to maintain the balance of reactive power, each system should be equipped with voltage control equipment. In normal conditions, shunt compensation is an effective means of maintaining balance. Rapid voltage regulation is necessary, however, in forced outages of transmission or generation. For this purpose, generating units should be equipped with automatic voltage control equipment. The installation of voltage control equipment is generally considered at the planning stage.

In operations, scheduling and setting of voltage control equipment should be considered. In particular, the voltage and reactive power flow of interconnection lines should be coordinated. The system characteristics of both ends of interconnection lines should be considered in the coordination process.

As mentioned above, voltage control is considered as a local issue. As a result, this issue may be discussed in general terms only in regional agreements.
Chapter IV

**Operation Planning** [4] [6]

### IV.1 Basic Concept

Coordination in all phases of operation is essential within the interconnected system for secure and reliable operations.

### IV.2 Operation Organization

In order to coordinate operation planning and real-time operations, an organization governing the reliability of operations should be established.

In general, there are two types of organization. One is an organization for operation planning and the other is an organization for real-time operations. The first type of organization includes NERC and UCTE, which handles only the system planning and operation planning of each region. The second type of organization includes PJM Interconnection, LLC.

PJM Interconnection, LLC is responsible for the real-time operations of the largest centrally dispatched electric system in North America. It is interesting to note that this kind of organization often handles not only the coordination of real-time operations, but also coordination and planning of transmission and generation. In fact, PJM Interconnection LLC manages coordinated operations, which includes system operations and market operations, and coordinated planning, which includes coordination of generation planning and the interconnected bulk power transmission system.

These organizations are very effective at coordinating and exchanging information at the planning stage and in real-time operations.
IV.3 Information Sharing

The information needed for operations should be shared within the interconnected system routinely. The information includes real-time information and operation planning information.

The real-time information is based on system monitoring, which provides the system operators with up-to-date information on the conditions on the power system, using telemetry systems. Typically, the real-time information system can monitor voltages, current, power flows and the status of circuit breakers and switches in substations in the power system. In addition, other critical information such as frequency, generator outputs and transformer tap positions can also be monitored. In order to ensure that all the information can be checked in a reasonable time frame, computer systems are usually installed in operations control centers.

Not all the information that is gathered at each control center needs to be exchanged. The minimum requirement in information exchange depends on the form of system operations. If the system configuration is relatively simple and each control area can operate its own system independently, the status of circuit breakers and interconnection power flows might be considered as sufficient. If some control areas are operated as a single power pool, however, each area cannot operate its own system independently. In this case, accordingly, information on major transmission lines in each area as well as information on generations should be exchanged.

Operation planning information includes interconnection capabilities under normal and emergency conditions, short-term load forecasts, generating capabilities and any other information that can affect the operations of an interconnected system.

The procedures for information sharing should be established within the interconnected system.
IV.4 Power Exchange Schedule

All exchange schedules should be confirmed and implemented between the control areas involved in the power exchange. “Control areas involved” means control area(s) from which the scheduled power originates, control area(s) to which the scheduled power is delivered and control area(s) who provide transmission for the schedule.

In scheduling the power exchange, all the power flow should be kept within the transfer capability limits that have been agreed upon.

The power flow distribution attributable to power exchange is determined by the laws of physics. In a meshed system, every exchange can, theoretically, affect any transmission flow. For this reason, the power flow attributable to a power exchange should be calculated by a common network model which includes network topology and parameters. This network model should be agreed upon and maintained within the interconnected system.

IV.5 Maintenance Coordination

Maintenance outages of power system facilities are necessary for secure and reliable operation. An outage that may affect the reliability of an interconnected system’s operations should be planned and coordinated by the control areas affected. For adequate maintenance outage coordination, procedures and responsibility for disseminating information about scheduled outages should be established.

IV.6 Emergency Operations

During emergencies, all entities should cooperate and take appropriate actions based on emergency plans that have been agreed upon within the interconnected system. Under emergency conditions, maintaining the interconnection should be regarded as a prime consideration, in order to provide maximum assistance to the systems in trouble.

To meet this requirement, each area should establish a program of manual or automatic load shedding which arrests frequency or voltage decays. The program shall be coordinated throughout the interconnection to prevent unbalanced load shedding which may cause high transmission loading and extreme voltage deviations.
A control area with a generation shortage should promptly balance supply and demand without regard to financial cost in order to avoid prolonged use of the assistance provided by emergency reserves of other areas.

The emergency reserve is meant to be used only as a temporary source for emergencies, and is to be promptly restored for the next contingency. If the area doesn't have enough generating capacity to balance, assistance from other areas can be scheduled. If it is impossible to balance even with this assistance, the area is responsible for removing sufficient load to maintain balance between supply and demand.

Even though maintaining the interconnection is the prime consideration, as mentioned above, if the whole-interconnected system is endangered by remaining interconnected, appropriate action such as system separation (“islanding”) must be taken to protect the entire system.

If a portion of the interconnection becomes separated from the remainder of the interconnection, abnormal frequency and voltage deviations may occur. To permit re-synchronizing, relief measures should be taken by those separated systems that contribute to the frequency and voltage deviations.

### IV.7 Restoration

In abnormal conditions, adequate actions — such as load shedding, system separation or generator tripping — may be required to avoid system collapse. Following the abnormal condition, immediate restoration steps should be taken to return the system to normal. These restoration steps should be determined and agreed upon within the interconnected system.

It is impossible to determine the restoration process for all possible abnormal conditions, since these abnormal conditions result from complex processes which are difficult to estimate beforehand. Accordingly, some numbers of basic scenarios that can be combined or modified to approximate actual conditions should be established.
In NERC, the following steps are required in the Operation Manual:

- A restoration plan should be established for each system, and include necessary operating instructions and procedures to cover emergency conditions, including the loss of telecommunications.
- The restoration plan should be updated to reflect changes in the network and correct deficiencies found during the simulated restoration exercise.
- Operating personnel should be trained in implementing the plan.
- Restoration procedures should be verified through actual testing or simulation.

### IV.8 Operating Personnel and Training

Although rules and agreements are necessary for reliable system operations, it is impossible to establish perfect rules for all situations. It is impossible, for instance, to establish the restoration process for all abnormal conditions, as described in the previous section.

This means that the task of the system operating personnel is not only to obey the rules, but also to make appropriate decisions in actual situations. Hence, in order to maintain a high degree of system reliability, training is necessary for system operating personnel.

Training should be conducted regularly in order to ensure that all personnel involved in operating the interconnected system are knowledgeable and skillful. In the training process, staff should acquire knowledge (such as changes of operational conditions, and equipment of interconnected systems) and practice operation skills (such as restoration procedure), using training simulators.
Chapter V

Recommendation

This module describes the (mainly technical) aspects of system operations through experiences in E7 countries.

When an interconnection is implemented, other factors aside from purely technical ones should be considered, such as the economy, geographical constraints and so on.

It should be noted that the operating conditions of an interconnected system must be established based on an existing system, which may have its own unique characteristics.

Accordingly, it is very difficult to determine how to establish the operating conditions of interconnected systems in a “universal” manner.

One possible recommendation might be to improve coordination between planning and operations since, as described above, operations cannot be established in isolation.

In other words, operations must be considered in the planning stage; otherwise it might be difficult to establish reliable and adequate operations for each system.

Another recommendation is that experience might be effective in establishing adequate and reliable system operations.

The operating conditions could be modified and refined by comparison with prior experiences of interconnections. The requirements for electric utilities will vary, depending on social conditions. At some point in time, for example, greater reliability might be required as electrification progresses. At another time, lower-cost electricity might become important. These processes could even be repeated alternately. As a result, a balance between reliability and cost might be attained, under adequate conditions. At the same time, adequate and reliable operating conditions could be established for the interconnected system.
References

4. UCTE, Summary of the current operating principals of the UCPTE. http://www.ucte.org
Glossary of Technical Terms
**Glossary**

**Aggregator**
An entity responsible for planning, scheduling, accounting, billing, and settlement for energy deliveries from the aggregator's portfolio of sellers and/or buyers. Aggregators seek to bring together customers or generators so they can buy or sell power in bulk, making a profit on the transaction.

**Autoproducer**
Autoproducer undertakings generate electricity and/or heat, wholly or partly for their own use as an activity that supports their primary activity. They may be privately or publicly owned.

**Base-Load Unit**
A generating unit that normally operates at a constant output to take all or part of the base load of a system. (The minimum load experienced by an electric utility system over a given period of time.)

**Build – Own – Operate (BOO)**
An infrastructure project (such as a power transmission system) is a “BOO” project when a special-purpose company is created to assume responsibility for a) having the infrastructure built according to specifications, b) paying for it and c) managing the infrastructure project according to a concession agreement, the laws and regulations of the countries, etc.

**Build – Own – Operate – Transfer (BOOT)**
A BOOT is a BOO project with an understanding from the special-purpose company to transfer ownership of the assets to the host countries (or their nominee(s)) at the end of the concession period.

**Build – Transfer – Lease (BTL)**
A BTL project is a Build – Transfer – Lease project. The special-purpose company assumes responsibility for building the infrastructure according to specifications and transferring its ownership to the host countries at a predetermined price. The project company then leases the assets and operates the system in accordance with the concession contract.
Clean Development Mechanisms
Flexible mechanisms of the Kyoto Protocol (see Kyoto Protocol). CDMs enable industrialized countries to finance emissions-avoiding projects in developing countries and receive credit for doing so.

Cogeneration
The generation of electricity as a by-product of another process in the industry. It involves the recovery of heat or primary energy that would otherwise be wasted.

Combined cycle
A two-stage electrical generation process. In the first stage electricity is generated by a gas turbine. The waste heat is then used to generate more power by steam turbine.

Control Area
An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

Corporatize (to)
The corporatization of a state-owned agency or enterprise consists in its reconstitution as an independent legal entity, subject to commercial law, commercial accounting and reporting practices.

Counterparty
A counterparty is a party -- individual or organization -- with whom one transacts business.

Cross-price elasticity
The cross-price elasticity of demand is a measure of the responsiveness of a change in the price of a good to a change in the price of some other good.

Demand-Side Management (DSM)
The term for all activities or programs undertaken by an electric system or its customers to influence the amount or timing of electricity use.

Distribution
The process of transferring electricity from the transmission system to final users. Electricity is distributed along local networks of overhead and/or underground power lines.

Disutility
Disutility is dis-satisfaction resulting from the consumption of a product or service. The presence of disutility reduces the total utility of the consumer.
Integrated Resource Planning (IRP)
A process to control electric power planning through both demand-side management (to reduce the need or demand for electricity) and supply side management (to redistribute the types of needed electric generation among fuel types, location, etc.) to accomplish specified social and environmental goals.

Intertie
An interconnection permitting passage of current between two or more electric utility systems.

Kyoto Protocol
At a conference held in December 1997, in Kyoto, Japan, the Parties to the United Nations Framework Convention on Climate Change agreed to a Protocol to reduce greenhouse gas emissions.

Open-Access Same-Time Information System (OASIS)
An electronic posting system for transmission access data that allows all transmission customers to view the data simultaneously.

Peaking Unit
A power generator used by a utility to produce extra electricity during peak load times.

Spinning Reserve
Electric power available from generating units connected to the system and ready to deliver power promptly.

Tacis
The Tacis Programme, launched in 1991, is a European Union initiative to provide grant-financed technical assistance to support the process of transition to market economies and democratic societies in countries of the former Soviet Union, including Russia.

Tie Line
A circuit connecting two or more control areas or systems of an electric system.

Unbundling
Disaggregating electric utility service into its basic components and offering each component separately for sale with separate rates for each component. For example, generation, transmission and distribution could be unbundled and offered as discrete services.

Unserved Energy
The expected amount of energy curtailment per year due to demand exceeding available capacity. It is usually expressed in megawatthours (MWh).
Uprating
Increasing the rating or stated measure of generation or transfer capability.

Wheeling
The contracted use of electrical facilities of one or more entities to transmit electricity for another entity.

back/forward to
Module 1
Module 2
Module 3
Module 4
Module 5
Module 6
Module 7
Module 8
Acronyms and Symbols