INSTITUTIONAL, REGULATORY AND COOPERATIVE FRAMEWORK MODEL FOR THE NILE BASIN POWER TRADE

DELIVERABLE 2: LEGAL AND INSTITUTIONAL ARRANGEMENTS OF REGIONAL POWER MARKETS (REVISED)

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LIST OF ACRONYMS

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AFC	Available Flowgate Capability
ARR	Auction Revenue Rights
BA	Balancing Authority
CAT	Curtailment Adjustment Tool (in SPP)
CEB	Communauté Electrique du Benin
CEM	Common Energy Market
CIE	Compagnie Ivoirienne d'Electricité
CIS	Commonwealth of Independent States
CoAG	Council of Australian Governments
CR	Congetion Rights (SIEPAC)
CRIE	Regional Regulatory Agency (SIEPAC)
CVT	Variable Transmission Charges (SIEPAC)
DAM	Day Ahead Market
ECOWAS	Economic Community of Western African States
EECI	Energie Electrique de la Côte d'Ivoire
EIS	Energy Imbalance Service
EOR	Independent system and market operator (SIEPAC)
EPC	Electricity Power Council (in CIS)
ESAA	Energy Supply Association of Australia
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission (US)
FTR	Financial Transmission Rights
GMS	Greater Mekong Sub Region
ICC	Information and Coordination Center (in WAPP)
ICE	Intercontinental Exchange (US)
ICT	Independent Coordinator of Transmission (SPP)
IDC	Interchange Distribution Calculator
IGA	Inter–Governmental Agreement on Power Trade in the Greater Mekong Sub–Region
IPP	Independent Power Producers/Project
IPSCIS	Interconnected Power System of Commonwealth of Independent States
JOA	Joint Operation Agreement
LIP	Locational Imbalance Prices (in SPP)
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
LSE	Load Serving Entities
LTTR	Long Term Transmission Rights
MCE	Ministerial Council on Energy (Australia)
MER	Regional Electricity Market of SIEPAC
MISO	Mid-West Independent System Operator
MO	Market Operator
MOI	Memorandum Of interest
NBI	Nile Basin Initiative
NBPTF	Nile Basin Power Trade Framework
NE - ISO	New England Independent System Operator
NEM	National Electricity Market (Australia)

NEMMCO	National Electricity Market Management Company
NERC	National Electricity Reliability Council
NSI	Net Scheduled Interchange
OMVS	Organisation pour la Mise en Valeur du fleuve Sénégal
PAC	Participant Advisory Committee (Australia)
PJM	Regional Market of Pennsylvania, New Jersey and Maryland
PMU	Project Management Unit
PPA	Power Purchase Agreement
PRSG	Planned Reserve Sharing Group (in MISO)
PTC	Power Technical Committee
PTOA	Regional Power Trade Operating Agreement (in GMS)
RPM	Reliability Pricing Model in PJM
RPTCC	Regional Power Trade Coordination Committee (in GMS)
RPTP	Regional Power Trade Project
RRO	Regional Reliability Organization
RSC	Regional State Committee (in SPP)
RTEPP	Regional Transmission Expansion Planning Process in PJM
RTN	Regional Transmission Network (in GMS)
RTO	Regional Transmission Organization (US)
RTR	Regional Transmission Grid (SIEPAC)
SADC	Southern African Development Community
SADCC	Southern African Development Co-ordination Conference
SAP	Subsidiary Action Program
SAPP	Southern African Power Pool
SCED	Security-Constrained Economic Dispatch
SCUC	Security-Constrained Unit Commitment
SERC	Southeastern Reliability Council (US)
SIEPAC	Central American Regional Electricity Market
SMD	Standard Market Design (NE-ISO)
SONABEL	Société Nationale Burkinabè d'Electricité
SPP	Southwest Power Pool
SRMC	Short Run Marginal Cost
STEM	Short Term Energy Market (in SAPP)
SVP	Shared Vision Program
TSO	Transmission System Operator
TUOS	Transmission Use of System
UES	Unified Energy System
UPS	Unified Power System (in CIS)
USSR	Union of Soviet Socialist Republics
VOLL	Value of Lost Load
VRA	Volta River Authority
WAPP	Western African Power Pool
WSPP	Western Systems Power Pool

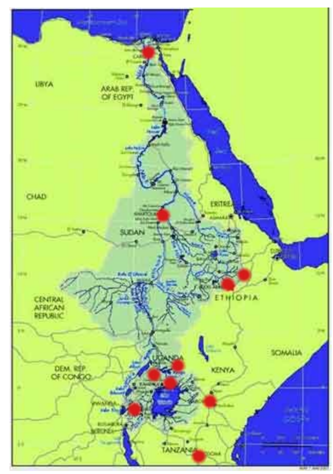
FOREWORD

The purpose of this report, named "LEGAL AND INSTITUTIONAL ARRANGEMENTS OF REGIONAL POWER MARKETS", is to present a review of several regional power trade organisations which could provide lessons to later develop the guidelines and recommendations for a regional power trade framework in the Nile Basin countries.

This report is the Deliverable 2 and corresponds to Activity 2: "*Review of other Power Trade Organisations*" of the project's reviewed terms of reference agreed during the inception mission in Dar es Salaam.

BACKGROUND AND CONTEXT OF THIS PROJECT

The Nile Basin Initiative (NBI): Formally launched in February 1999 by the Council of Ministers of Water Affairs of the Nile Basin States, the NBI provides a forum for the countries of the Nile to move forward, towards a cooperative process in order to achieve tangible benefits in the Basin and build a solid foundation of trust and confidence.



The NBI has two primary areas:

Basin-wide projects - "Shared Vision Program" (SVP) to help create an enabling environment for action on the ground

Sub-basin projects - "Subsidiary Action Program" (SAP) is aimed at the delivery of actual development projects involving two or more countries

The Regional Power Trade Project (RPTP) is one of the thematic projects to be implemented basin-wide, to help establish a foundation for trans-boundary regional cooperation and create an enabling environment conducive for investment and action on the ground, within an agreed basin-wide framework.

The RPTP aims to establish the institutional means to coordinate the development of regional power markets (such as a Power Pool) among the Nile Basin countries, through the creation of a power trade framework which can contribute to achieve poverty reduction including expanding access to reliable and low-cost power supply, in an environmentally sustainable manner.

The broad benefits envisaged from the NBI are poverty alleviation through improved, sustainable management and development of the shared Nile waters, and enhanced regional stability through increased cooperation and integration among the Nile states.

The project activities are coordinated by the Project Management Unit (PMU) at the regional level and by the PTC members at the country level. Activities include the establishment and operation of a power trade framework, the conduct of a comprehensive basin-wide analysis of long-term power supply, demand and trade opportunities, the identification of potential development projects within the NBI SAPs, the preparation of a public participation plan and stakeholder analysis, and the development of knowledge management tools. These activities are carried out through studies, consultations, workshops, seminars, and through other modalities, for which the project may seek assistance from national and regional research and training institutions, NGOs, consultants, and other public or private organizations from the Nile basin region.

The current project: "CONSULTANCY TO DEVELOP AN INSTITUTIONAL, REGULATORY AND COOPERATIVE FRAMEWORK MODEL FOR THE NILE BASIN POWER TRADE" falls within the RPTP framework. Among key project objectives are to:

1. Assist the RPTP and the NBI Power Technical Committee (PTC) in reviewing institutional arrangements adopted by regional power trade organisations, and submitting discussion papers to the RPTP, comparing and contrasting the different arrangements.

2. Conduct an information gathering tour so as to collect basic information of the countries in the region which will permit in the future develop recommendations and perform an informed decision making process.

3. Propose a model for developing Regional Power Trade at the Nile sub–basin and basin levels.

4. Draft Memoranda and legal documents as required.

SCOPE OF THE REVIEW

This activity aims at reviewing institutional and legal arrangements of Power Trade Organizations around the world. The organisations to be reviewed include:

- UCTE, CENTREL, NORDEL, BALTREL and SUDEL in Europe
- The re-creation of a regional market in the Commonwealth of Independent States
- PJM, New England ISO, South West Power Pool, Western System Power Pool, and Mid-West ISO in the US;
- The Central American regional market based on the SIEPAC transmission infrastructure
- The Southern Africa Power Pool and the Western Africa Power Pool in Africa
- The Great Mekong Subregion initiative and the ASEAN Interconnection projects in South-East Asia
- The National Electricity Market in Australia

This list represents numerous and heterogeneous institutions to review. The Consultant will proceed with this review in a systematic way, focusing in certain elements that can be useful for this TA. This methodology will also allow extracting conclusions more easily, and facilitate comparisons between those analyzed.

- The analysis of these institutions will be carried out focusing on the following points:
- Objectives of the institution
- Internal organization, to include:
- Geographic coverage area (countries, states, provinces, etc.)
- Operational structure, mechanisms
- "Size" of the market – as measured by total energy generation-demand. Secondarily by peak demand.

Other characteristics of size & level of competition: number of generators-market participants, number of customers, etc.

- Brief description of trade agreements
- Governance
- Achievements, to include:
    - products and volume traded
    - prices (values and rising/falling/stabilizing trends)
    - other

At the risk of some redundancy in the individual description, additional information is provided for some regional markets in this revised version, as per the request of the Client:

- Development path and evolution of legal and institutional structures
- Government participation and policy framework

- Key role of the power infrastructure in evolution into competitive power market
- Harmonisation of operations procedures, design criteria, electricity pricing and existing bilateral contracts
- Knowledge gaps influences
- Political challenges to be overcome
- Technical and financial real time operation:
- Short, medium and long term system planning
- Size and structure of the organization's secretariat in charge of the power market development

Those markets that are addressed in Deliverable 5 however, have not been significantly revised from the original version and this additional information (and more) is provided in the subsequent deliverable. Those include: PJM, SIEPAC, SAPP, Greater Mekong, and Nord Pool.

At the conclusion of this report, a brief comparison table of the markets covered is provided.

THE EUROPEAN POWER TRADE ORGANISATIONS

1. GENERAL ASPECTS

Historically, power systems were developed at a local and, later, at a national basis. It very soon became obvious that cooperation between electricity utilities and other stakeholders in the electricity business would be profitable and, hence, different types of cooperation schemes were developed.

The first step in this development was the creation of a loose type of power pools to set operational rules and trading rules to be followed by the members. These rules then, made it possible to optimise the usage of generation and transmission lines with sufficient reliability in the operational phase.

This kind of loose pools was developed in US areas. The organisation of the Western System Power Pool and the Southwest Power Pool can be mentioned as examples.

In Europe, similar cooperation organisations were created, at first to maintain the reliability in synchronous power systems. Such organisations are UCTE, CENTREL, BALTREL, SUDEL, NORDEL and more recently ETSO.

The focus of those organisations in the start up phase was very much towards technical requirements, but as this focus has been orientated more towards market solutions, the organisations also have to take the levelling of the playground for market solutions into account.

In USA, this has led to a stronger integration between the technical requirements and the power markets. The solution has for many areas resulted in a tight pool solution as PJM, New England ISO etc. Those regional transmission organisations have centralised market and dispatch solutions.

In Europe, the technical solutions still remain within the system operators' organisations and the market solutions are solved by a number of power exchanges. The technical solutions have to promote regional market solutions.

In Europe, new associations have been formed for cooperation within the whole European area. ETSO is formed by the TSOs in the area and EUROPEX is formed by the power exchanges. In addition the Regulators have their meetings; power traders have their association etc.

2. UCTE

2.1. OBJECTIVES OF THE INSTITUTION

The "Union for the Co-ordination of Transmission of Electricity" (UCTE) is an association of transmission system operators in continental Europe in 23 countries. It coordinates the operation and development of the electricity transmission grid from Portugal to Poland and from the Netherlands to Romania and Greece.

Whereas the NORDEL co-operation includes political and regulatory issues as well as technical and operational, UCTE focuses on the technical matters such as system adequacy and security of supply. The regulatory aspects are mainly left to ETSO, the organisation of TSOs. The two organisations attract different groups of members: Whereas UCTE members are defined by connection to the UCTE synchronous grid, ETSO includes TSOs of other European countries, e.g. Norway and Iceland.

UCTE aims to ensure efficient and reliable operation of the interconnected high-voltage grids. Thanks to the coordinated operation of the system, mutual assistance can be provided, a joint reserve can be shared and electricity can be traded internationally.

For over 50 years, UCTE has been drawing up technical standards required for coordinating the connected high-voltage grids which operate with a frequency of 50 Hz.

The key challenge of UCTE is:

To keep the quality of the UCTE system at high level and to provide a sound basis for electricity markets in a broader Europe and its enlargement to the benefit of all market players and consumers.

The main tasks of UCTE are:

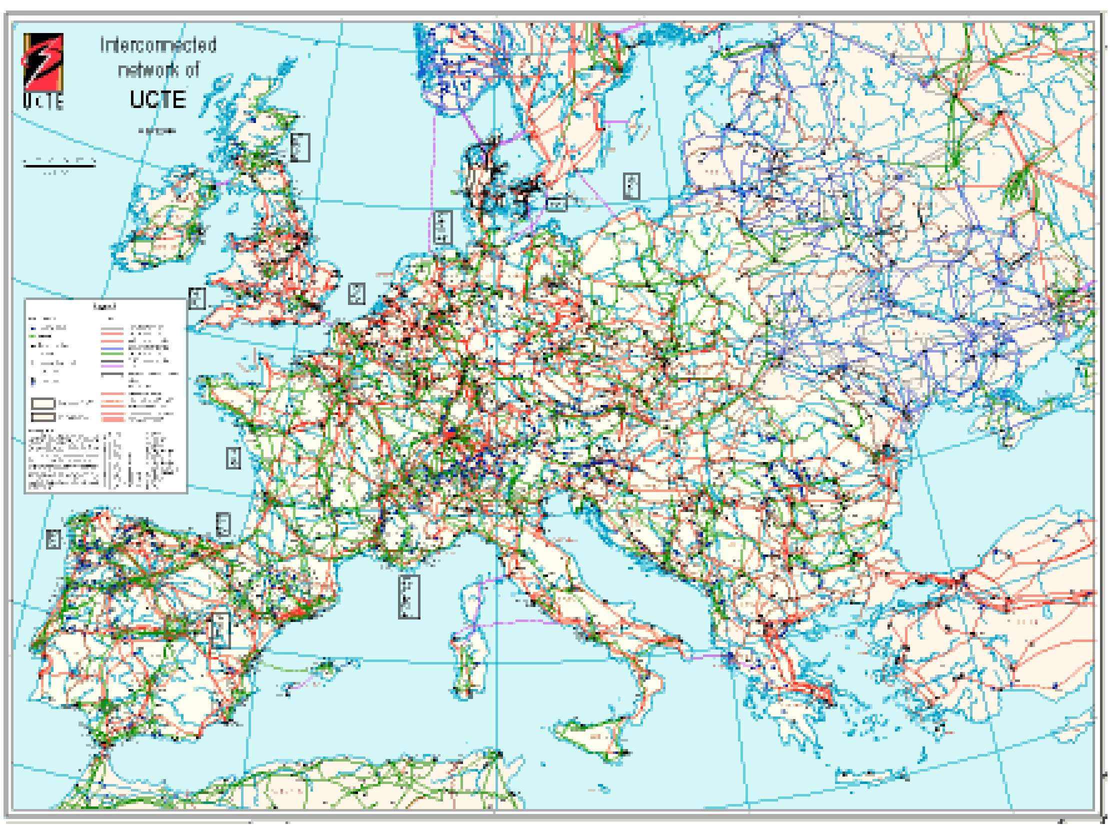
To co-ordinate the rules for operation of the synchronous area, and of the high voltage interconnections between the synchronous area and the neighbouring systems;

To analyse and evaluate the reliability and adequacy of the interconnected system;

To analyse and supervise the geographical extension of the synchronous area;

To analyse and co-ordinate the mutual technical and emergency help among the system operators;

To facilitate the dissemination of know-how and information on the interconnected system, including statistics.



2.2. INTERNAL ORGANISATION

2.2.1. GEOGRAPHICAL COVERAGE AREA

UCTE has 33 TSOs as members, from 23 countries as shown in the map below:

2.2.2. MARKET SIZE

The predecessor of UCTE (UCPTE) was founded in 1951 in Western Europe. During more than fifty years of co-operation, UC(P)TE achieved high, world-wide acknowledgement in the field of quality of the synchronous operation of the interconnected networks. Approximately 450 million consumers are supplied with electricity via UCTE networks, the annual electricity consumption in 2005 was nearly 2490 TWh, with a peak load of 390 GW and installed capacity of 607 GW. The grids of the UCTE members constitute one of the largest synchronous transmission systems in the world.

2.2.3. ORGANISATION

Organisation of UCTE:

General Assembly (see “Governance”)

Steering Committee (see “Governance”)

Working Groups

Operations and Security

System Strategy

Co-ordinated Planning

Data

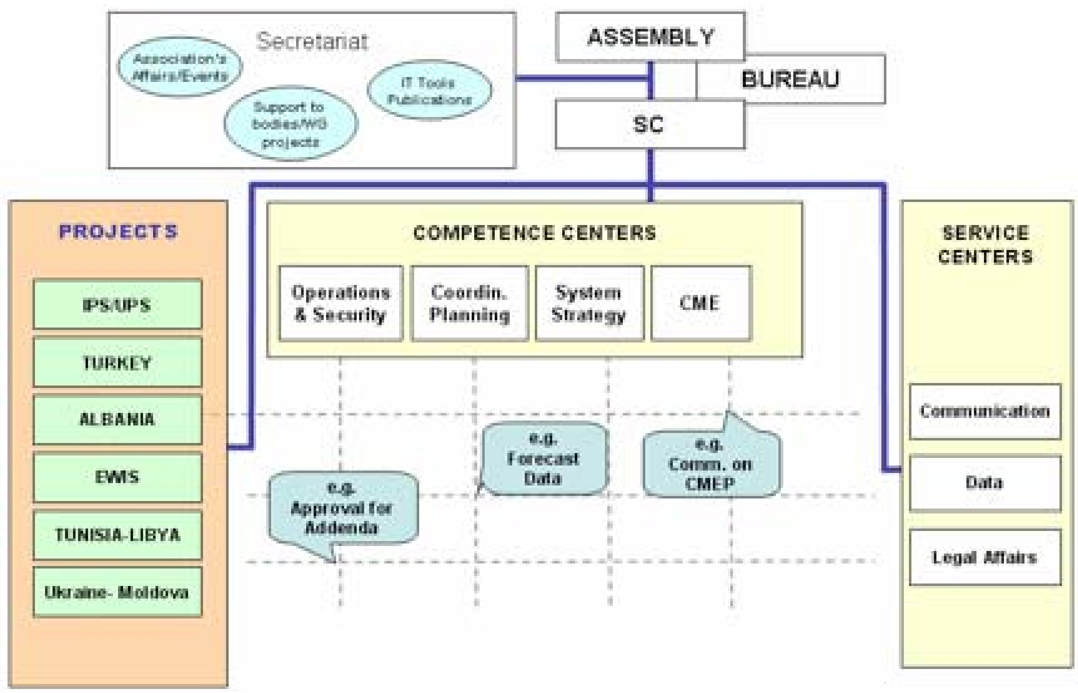
Compliance Monitoring and Enforcement

Legal Issues

Communication

The Bureau

The bureau is responsible for the internal co-ordination between the Assembly, the Steering Committee as well as for the external representation.



2.2.4. SUMMARY OF TASKS AND MEASURES

The major task of UCTE (Union for the Co-ordination of Transmission of Electricity) is to ensure the coordination and co-operation for the safe and reliable operation of the interconnected electricity systems.

The tight co-operation of the member companies is essential for the greatest possible exploitation of the benefits deriving from the interconnected operation. Therefore, UCTE has elaborated numerous **recommendations and regulations, which must be observed** by each interconnected member. This is the only way in which the strict requirements of operation safety and reliability can be fulfilled.

UCTE has been actively taking part in the development of competition rules from the beginning of European electricity market liberalisation. The objective is to create the open electricity market and competition without any impairment to the safety of supply.

2.3. GOVERNANCE

The decision-making bodies of UCTE are:

General Assembly
The supreme decision making body of UCTE is the General Assembly, which seats once a

year. Each member has representation and voting right according to the size of its power system.

Steering Committee
The Steering Committee is the decision making body of UCTE in technical issues. It has (at least) six meetings in a year, and each member country has one representative.

2.4. ACHIEVEMENTS

2.4.1. ADAPTATION TO THE DEREGULATION OF EU ELECTRICITY MARKETS

UCTE accepted and realised the unbundling of the vertically integrated electricity companies, i.e. the unbundling of the electricity generation, transmission and distribution in compliance with EU Directive 96/92/EC on the deregulation of the electricity markets.

In the first step, the amendment, effective 1 July 1999, of Articles of UCTE considers the conditions of the competitive environment. From this moment, UCTE has been focussing only on electricity transmission system operation functions, i.e. the co-ordination of the interests of the electricity generators was transferred to another organisation. This is reflected by deleting the "P" letter (production) from the former name of the organisation. Thereby, the organisation has demonstrated also externally that the electricity industry is ready to comply with all the requirements in the EU Directive and to support the fair competition.

In the second step, the renewed UCTE realised, on 17 May 2001, the organisation changes adjusted to the market economy. As the forerunner of the EU membership of former CENTREL member countries and as a result of their decade technical and diplomatic activities, these companies gained the associate membership in UC(P)TE on 1 January 1999 and became the full and founding members of renewed UCTE on 17 May 2001.

2.4.2. RECONNECTION OF THE SOUTH-EASTERN PART OF THE UCTE GRID

On October 10, 2004, the synchronous zones 1 and 2 of UCTE were reconnected. It re-established and re-strengthened the power links between Southeast Europe and the European Union that had been destroyed during the Balkan War in the 1990s.

Reconnection resulted in many positive technical effects in the South-East European part of the UCTE grid which can be summarized as follows :

increased security of grid operation,

improved voltage profile,

increased frequency stability, and

increased reliability and quality of electricity supply.

The major technical benefit of the reconnection derives from diminished technical congestion problems in the South-East European network, which is true both for tie lines and the individual grid parts of the respective TSOs in Southeast Europe.

The reconnection has allowed for a new direction for electricity flows, namely from east to west, in addition to the north–south power flows that existed already before reconnection.

The additional transport capabilities from areas with power surpluses to power deficit areas helped load management. Another important benefit after reconnection are increased opportunities for electricity trading, that stem from overall reinforced power system security and reliability.

Reconnection also had a positive effect on the process of liberalization in electricity markets in Southeast Europe, by giving an impetus and swing to the process of market opening in the region.

2.4.3. Inclusion of the former CENTREL grids

The interconnection of the Czech, Hungarian, Polish and Slovak systems with the then-UCPTE networks on 18 October 1995 took place just several weeks after resynchronization of the separated power systems of the Federal Republic of Germany and the former German Democratic Republic together with West Berlin. As a matter of course, these achievements were only made possible as a result of the political changes which happened in Central and Eastern Europe in 1989.

UCTE integrated the electrical system of the CENTREL countries, namely Poland, the Czech Republic, Slovakia and Hungary. Nine years later, in 2004, these countries joined the European Union. A similar pacemaker function was taken over by UCTE for Bulgaria and Romania connecting their electrical network to the former second synchronous zone of UCTE in advance of their future EU membership in the years to come. CENTREL operations terminated on December 31, 2006, following the integration with UCTE.

2.4.4. Rules and regulations

The UCTE security package has the following parts:

The Operation Handbook (OH),

The Multilateral Agreement (MLA).

The Compliance Monitoring and Enforcement Process (CMEP)

The Operation Handbook (OH)

The development of the Operation Handbook started before the corresponding mandate was given by the Regulatory Forum in Florence to UCTE in 2001. The former technical recommendations developed as a result of the experience gained over 50 years of interconnected operation were based on a vertically integrated industry structure and scattered in many documents. With the unbundling of the sector and liberalization of the electricity market, UCTE decided to reshape and update its operational standards and gave this task to the »Operations and Security» Working Group.

The OH consists of 8 Policies which are internally arranged into criteria, requirements, standards, guidelines and measures:

Load-Frequency Control and Performance

Scheduling and Accounting

Operational Security

Coordinated Operational Planning

Emergency Operations

Communication Infrastructure

Data Exchanges

Operational Training

The Multilateral Agreement (MLA)

The Multilateral Agreement (MLA) was selected as the most suitable legal instrument to make the technical standards of the Operation Handbook binding among TSOs. Its development started shortly after the initiation of work on the Operation Handbook.

Although the task was very ambitious, UCTE met this challenge and all UCTE members signed the Multilateral Agreement which came into force on 1 st July 2005.

The MLA primarily defines the procedure of handling alleged infringements of standards of the Operation Handbook. Since security of a synchronously interconnected system is indivisible, the MLA had to be signed by all UCTE member companies to come into force. Today, signing of the MLA is a pre-requisite for UCTE membership.

The Compliance Monitoring and Enforcement Process (CMEP)

The introduction of the Operation Handbook standards implies a procedure to monitor the compliance with the standards also to make sure that the TSO community keeps credible with regard to its commitment to a reliable operation of the interconnected system. Therefore, UCTE started the development of a new Compliance Monitoring and Enforcement Process as a platform for an efficient recurrent monitoring of the security standards as described in the UCTE Operation Handbook.

3. CENTREL

The information below is of primarily historical interest, as CENTREL is no longer an active organization, its functions being integrated in the UCTE operations from 1 January 2007.

3.1. OBJECTIVES OF THE INSTITUTION

3.1.1. CURRENT OBJECTIVES

CENTREL was the regional group of the four transmission system operators in The Czech Republic, Hungary, The Slovak Republic and Poland. The CENTREL companies were associate members of UCTE beginning in January 1999, and was fully absorbed by UCTE as of January 1st 2007. CENTREL no longer exists as an independent organization.

3.1.2. DEVELOPMENT AND TERMINATION

CENTREL was the regional association of four transmission system operator companies - the Czech ČEPS, a.s., the Hungarian MAVIR ZRt., the Polish PSE-Operator SA, the Slovak SEPS, a.s. - that was founded by a four-sided co-operation agreement on 11 October 1992 in Prague.

CENTREL's original and most principal role was the co-ordination of the interconnection of the Czech, Hungarian, Polish and Slovak power systems with UCPTE system. This connection was done in 1995.

The CENTREL electricity network comprises the interconnected electricity transmission systems of its Members. The main objectives and tasks of the organization described in the Charter of CENTREL (2003) were as follows:

- Efficient use of transmission capacity through the establishment of economic, business, technical and organisational conditions and the provision of mutual assistance, which facilitates electricity trading;
- Enhancing regional cooperation of CENTREL members;
- Promoting regional interests in the European electricity sector;
- Developing transmission systems in CENTREL network area;
- Reliable operation of a joint system block;
- Exchange of experience and improvement of operational conditions of the CENTREL Members' transmission systems, including system services;
- Exchange of information.

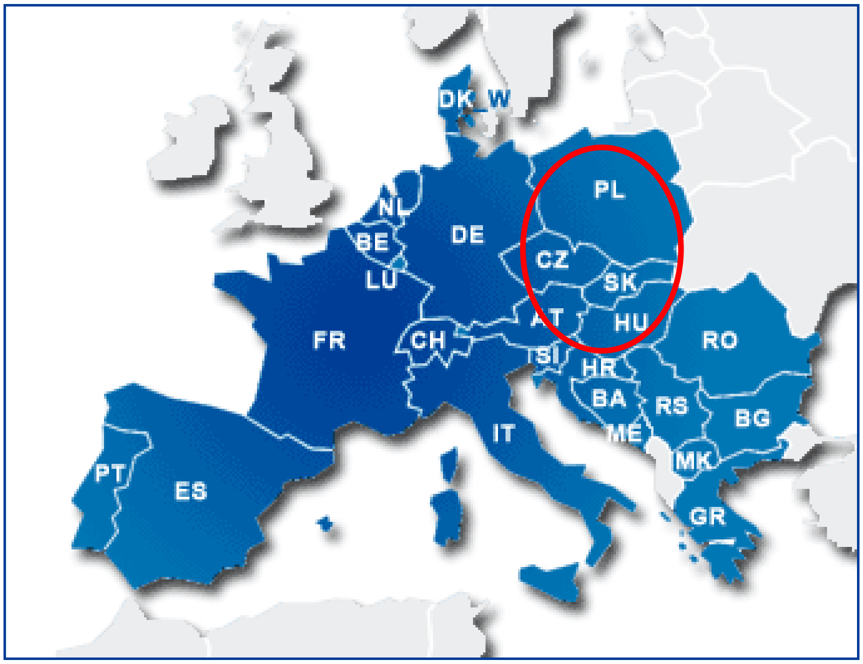
With a common agreement, the transmission system operators terminated CENTREL as a formal organization effective 31 December 2006, and fixed the goals and frames of future cooperation in a Memorandum of Understanding.

3.2. INTERNAL ORGANISATION

3.2.1. GEOGRAPHICAL COVERAGE AREA

The CENTREL area included the Czech Republic, Slovakia, Hungary and Poland, and the CENTREL members were the system operators:

- **ČEPS**, a.s. of the Czech Republic;
- **MAVIR ZRt**. of Hungary;
- **PSE-Operator SA** of Poland;
- **SEPS**, a.s. (Slovenská elektrizačná prenosová sústava, a.s.) of the Slovak Republic.



(map from www.ucte.org)

3.2.2. Size of the market

The tables below show figures from the annual report of CENTREL, 2005

	ČEPS	MAVIR	PSE-O	SEPS	TOTAL	
Maximum net generation capacity	16,268	8,06	32,077	8,038	64,443	MW
Net electricity production	76.30	33.10	143.95	29.10	282.45	TWh
Net electricity consumption	57.70	34.60	116.30	26.30	234.90	TWh
Import/export balance	-12.62	6.23	-11.20	-2.73	-20.32	TWh

	ČEPS	MAVIR	PSE-O	SEPS	TOTAL
Nuclear	23.30	13.00	-	16.30	52.60
Hydro	3.00	0.20	3.55	4.60	11.35
Thermal	49.90	18.50	140.18	8.20	216.78

Renewables	0.10	1.40	0.22	0.00	1.72

	ČEPS	MAVIR	PSE-O	SEPS	TOTAL
Nuclear	3,537	1,755	-	2,64	7,932
Hydro	2,144	46	2,245	2,429	6,864
Thermal	10,544	5,865	29,724	2,966	49,099
Renewables	43	394	108	3	548

3.2.3. ORGANISATION

The organisational of CENTREL in its penultimate year (2005) included:

- Presidency: President, Vice President and Secretary General,
- CENTREL council, with one representative from each member TSO,
- Steering committee, with one representative from each member TSO. The steering committee met twice in 2005
- Task forces, each having one representative from each member TSO:
- Security of system
- Accounting and control structure
- Energy accounting and control centre administration

3.3. ACHIEVEMENTS

The parallel connection of UC(P)TE and CENTREL systems was realised on 18 October 1995, first in trial operation and permanently after the successful two-year trial operation.

UC(P)TE accepted CENTREL companies as associate members on 1 January 1999 and they became the founding members of the renewed UCTE on 17 May 2001.

CENTREL, as an organisation accomplished the goals identified at its establishment. Nowadays, there is no further need for such a formal organisation within European Union and UCTE, however the co-operation of the former CENTREL member countries in electricity industry is also assured in the future. With a common agreement, the transmission system operators terminated CENTREL as a formal organization effective 31 December 2006, and fixed the goals and frames of future cooperation in a Memorandum of Understanding. They will harmonize the issues of common interest on high-level meetings and complete them on expert level, if necessary.

4. SUDEL

SUDEL is the association of transmission system operators in the South-East Europe. SUDEL was formed on April 22nd, 1964 as a regional group of UCTE.

The countries involved in SUDEL are:

Italy, Austria, Greece, Croatia, Slovenia, Bosnia-Herzegovina, Serbia , Former Yugoslav Republic of Macedonia, Hungary, Romania, Bulgaria

SUDEL has established 3 working groups with the following tasks:

Interconnection

Market Facilitation

Communication.

From June 2002 SUDEL approved the creation of the Regional Electricity Market in South East Europe. This market will be developed along with the principles established for the European Union's Internal Electricity Market.

5. BALTREL

The Baltic Ring Electricity Co-Operation Committee-was established in 1998 and the number of countries involved is 11. BALTREL gathers 16 organizations with operations in Belarus, Denmark, Estonia, Finland, Germany, Latvia, Lithuania, Norway, Poland, Russia and Sweden.

The intension is that BALTREL shall play an important role in the interaction necessary to develop a common electricity market between NORDEL and Belarus, Poland and Russia and the Baltic countries.

6. NORDEL

6.1. OBJECTIVES OF THE INSTITUTION

6.1.1. CURRENT OBJECTIVES

Nordel's mission is to promote the establishment of a seamless Nordic electricity market as an integrated part of the North-West European electricity market and to maintain a high level of security in the Nordic power system. Nordel shares the EU vision of an efficient European electricity market with high power system security.

Nordel's objectives are:

development of an adequate and robust transmission system aiming at few large price areas

seamless cooperation in the management of the daily system operations to maintain the security of supply and to use the resources efficiently across the borders efficient functioning of the North-West European electricity market with the aim to create larger and more liquid markets and to improve transparency of the TSO operations

establishment of a benchmark for European transparency of the TSO information.

Nordel exchanges views with the authorities and the market players continuously which is important for the evolution of an efficient electricity market.

6.1.2. DEVELOPMENT OF NORDEL

Nordel was founded in 1963 as an organisation for Nordic co-operation in the electricity sector. Members were from the beginning ”leading persons” in the sector in Denmark, Finland, Iceland, Norway and Sweden.

Nordel was established as an advisory and recommending body. The goal was to create and maintain the conditions for an efficient utilisation of the Nordic electricity generation and transmission system.

For a period of close to 30 years NORDEL changed very little in its function. When new opportunities or problems arose, they were handled by NORDEL and new recommendations were published. All the participating countries had established some kind of loose pools within their own countries.

The changes in development of the organisation can be summarised as follows:

Stable period 1963 - 1990

Liberalisation process in the electricity industry. Politicians and regulators engaged from about 1990.

New by-laws in 1993 and 1998, large generators, mostly incumbents, still members of Nordel. More power to the transmission system operators (TSO).

Nordel annual meeting 2000, from then on Nordel exclusively an organisation for the Nordic TSOs and no other companies were allowed as members.

Up to 2000 Nordel was an organisation where the work was based on recommendations and advice (“gentlemen’s agreements”)

From 2000 the organisation is formally based on legal agreements between the TSOs.

When the discussions of liberalisation started about 1990, the future of NORDEL also was discussed, and changes came. The different countries had different speed in the liberalisation process. The following figure gives some important timelines for the development. Nord Pool is the common power exchange for the countries and not a part of NORDEL.

6.2. INTERNAL ORGANISATION

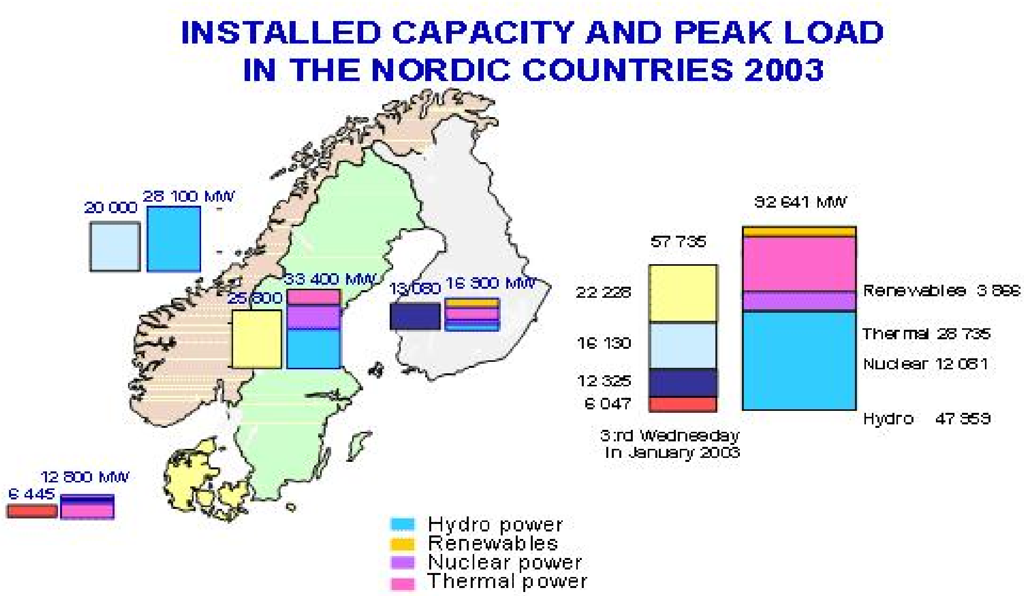
6.2.1. GEOGRAPHICAL COVERAGE AREA

The Nordic market includes Finland, Sweden, Denmark and Norway. The total population of the area is 25 million.

6.2.2. SIZE OF THE MARKET

The table below shows figures from the annual report of Nordel, 2006 (www.nordel.org).

2006		Nordel area	Denmark	Finland	Iceland	Norway	Sweden
Population	(Mill)	24.8	5.4	5.3	0.3	4,7	9.1
Area	(sq. Km)	1,257,308	43,094	337,030	103,000	324,220	449,964
Consumption	(TWh)	405.4	36.4	90.1	9.9	122.6	146.4
Peak Load	(GW)	66.8	6.3	14.2	1.1	19.9	25.4
Generation	(TWh)	393.9	43.3	78.6	9.9	121.7	140.3
Hydro	(%)	51	0	14	73	98	44
Nuclear	(%)	22	0	28	0	0	46
Other Thermal	(%)	24	86	58	0	1	9
Wind power	(%)	3	13	0	0	1	1
Geothermal power	(%)	0	0	0	27	0	0



Hydro power potential in the Nordic had been exhausted over many decades in the previous century. Relevant sources for generation are now gas and in Finland nuclear. It is expected that renewables will contribute with an increasing share over the years to come, especially wind power.

6.2.3. Other characteristics of size & level of competition

High trade activities both in contracts for dispatch and in derivatives based on the spot price as reference price.

High demand side participation in the bilateral market and in the spot market.

Demand side bidding in the balancing markets and markets for capacity reserves.

Full retail competition. Retail customers can have contracts where the price is a function of the spot price.

The growing focus on the environment and emission, the trading of allowances and of green certificates including CER certificates.

Market coupling in Europe, forcing PXs to work together, maybe even mergers might be the outcome

Trading of financial electricity contracts with reference from other electricity markets

6.3. Brief description of trade arrangements

6.3.1. Components of electricity market

The market is based on the principle of self-dispatch, where each market participant is responsible for the dispatch of generation and load.

1. Bilateral and OTC markets for both physical and financial contracts. There are many brokers and traders facilitating trading. Clearing of most bilateral contracts are through the Nord Pool operated clearing house.

2. A day-ahead "spot" market (Nord Pool). This market trades binding contracts for delivery for each hour for the next day.

3. An Intra Day Market closing one hour ahead of operations

4. Each TSO operates a balancing market for real-time balancing.

5. The Nordic TSOs have integrated their balancing market rules and use common resources if possible.

6. The TSOs procure other ancillary services mainly though contracting.

7. A financial market is operated by Nord Pool. Financially settled contracts; forwards, futures and options of varying delivery periods are traded, cleared and settled through Nord Pool's systems.

6.3.2. Bilateral market

The bilateral market works in parallel and in competition with the Power Exchange. In the bilateral wholesale market the participants trade in both standardised contracts and non-standardised contracts. In the OTC (i.e. over-the-counter) market the participants enter into standardised bilateral contracts via brokers.

Non-standardised contracts are tailored to the needs of the parties involved. The standardised contracts in the bilateral market are standardised in much the same manner as financial forwards at Nord Pool. The participant has the opportunity to operate in a bilateral market where he can tailor contracts to his needs or use the benefit of trading in standardised contracts at Nord Pool. The degrees of freedom for participants and the co-existence of a power exchange market and a bilateral market mutually contributes to this high trade activity and the success of the Nordic power market.

6.3.3. DAY AHEAD MARKET

In this market, each participant submits a supply or demand schedule for each hour of the next day. Then a tentative market-clearing price is established on the assumption that there will be no inter-zonal congestion. If this assumption is revealed to be false, then prices in the zones within Norway are adjusted to eliminate congestion—for example, the price in an importing zone is raised and the price in an exporting zone is decreased. Each participant is paid or receives the resulting price for its injections or withdrawals within each zone. Elspot acts as the counterparty to each transaction. Trading is based on an auction trade system. The spot concept is based on bids for purchase and sale of power contracts of one-hour duration that cover all 24 hours of the next day. The market clearing price or system price for a particular hour is first calculated using only the bids for purchase and sale that participants have submitted. To do this, all purchase bids are summed to create a demand curve, and all sales bids are summed to create a supply curve. The point where the two curves intersect determines the system price for that hour.

The system operators does load flow analysis of the transmission system and issues information of transmission capacities and probable congestions to the market participants and the market operator regularly. The market operator defines "bid areas" which are reference zones for trading. The bid areas are defined based on transmission constraints.

Wholesale market participants are obliged to balance their portfolios, such as balancing generation with sales contracts, or load with purchase contracts. They will typically use the Nord Pool day-ahead market to trade themselves into balance day before delivery.

The timeline of the Day-Ahead market is:

09:30: Nord Pool receives the on the interconnections available capacity from the TSOs

12:00: deadline for participants to submit bids to the spot market

12:30: Nord Pool determines the 24 market crosses and organizes eventual bottlenecks

14:00: participants have received their schedules

14:30: last opportunity for dispute management.

TSOs receive information and spot schedules.

The market is fully balanced the day before operation.

The day-ahead market is settled on a daily basis, and the balancing market on a weekly basis.

Characteristics of the Power Exchange:

a) It provides a reference price to the market
b) It provides open neutral information of prices and traded volumes
c) It trades standardised contracts
d) Easy access to balance portfolios close to time of operation
e) Facilitate fast changes in participants' portfolio
f) Neutral and solid counterpart (clearing)
g) Anonymous trade

h) The power exchange has an important role of distributing information regarding statistics on prices, traded volumes, generation, consumption and other relevant neutral data important to analyze the market.

6.3.4. Hour ahead market

The day-ahead physical market aspects of Elbas allow its market participants to trade one-hour spot contracts after the Nordic Power Exchange's Elspot market results are published (at noon) to bids for next-day deliveries. Recent Elbas changes permit hour-ahead trading. (Previously the gap was two hours before the closest delivery hour. However, the liquidity in the hour ahead market is not very encouraging.

6.3.5. Balancing market

Bids in the real-time market are submitted to a transmission system operator (TSO) after the spot market has closed. Bids may be posted or changed close to the operational time, in accordance with agreed rules. Real-time market bids are for upward regulation (increased generation or reduced consumption) and downward regulation (decreased generation or increased consumption). Both demand-side and supply-side bids are posted, stating prices and volumes. Real-time markets are organized by TSOs; market participants must be able to commit significant power volumes on short notice. TSOs list bids for each hour in priority order, according to price. TSOs use the priority-ordered lists for each hour to balance the power system, as needed. To resolve a grid power deficit, upward regulation is applied: the real-time market price is set at the highest price of the units called upon from the priority listing. Similarly, in a grid power surplus situation, downward regulation is applied: the lowest price of the units called upon from the list sets the real-time price.

All market participants have incentives to trade their portfolio into balance before operations to avoid additional costs in the imbalance settlement. The market participants balance their portfolio within defined geographic areas The Day-ahead auction is frequently used for this balancing purpose. After the day-ahead auction the market is in preliminary balance.

The Transmission System Operators base their planning on generation schedules, but the schedules are calculated by the different market participants. The market participants calculate hour by hour how they use their resources to balance the obligations. This result in a generation schedule for participants that have this as a part of their resources

6.3.6. FINANCIAL MARKET

The participants; generators, distributors, consumers, retailers, traders, brokers etc, can enter bilateral contracts for several years ahead. In the Nord Pool Financial market contracts for up to 4 years ahead are traded, in the bilateral market there is no limit. There is very active trading on the bilateral and organized forwards markets, the churn[1] can be as high as 8-9 times.

Agreements between sellers and buyers for financial settlement equivalent to delivery of a fixed amount of power at an agreed price in a specific future time period.

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[1] Total traded volume divided by the consumption, or the "turnover" for the commodity.

Futures contracts consist of standardized day, week, and block contracts. As due dates approach, blocks are split into week contracts, and week contacts are split into daily contracts. Product specifications detail the timing of the splits and other contract features.

Forward contracts consist of year and season contracts. There is no splitting of forward contracts, which are standardized in conformity with most Nordic OTC and bilateral market trade

6.4. GOVERNANCE

Nordel's highest decision-making body is the Annual Meeting. The Annual Meeting elects the President of Nordel for a term of two years. The presidency rotates between the Nordic countries in order Finland, Norway, Denmark and Sweden. The President appoints Nordel's secretary and is responsible for the secretariat and for the related costs. Nordel has no budget.

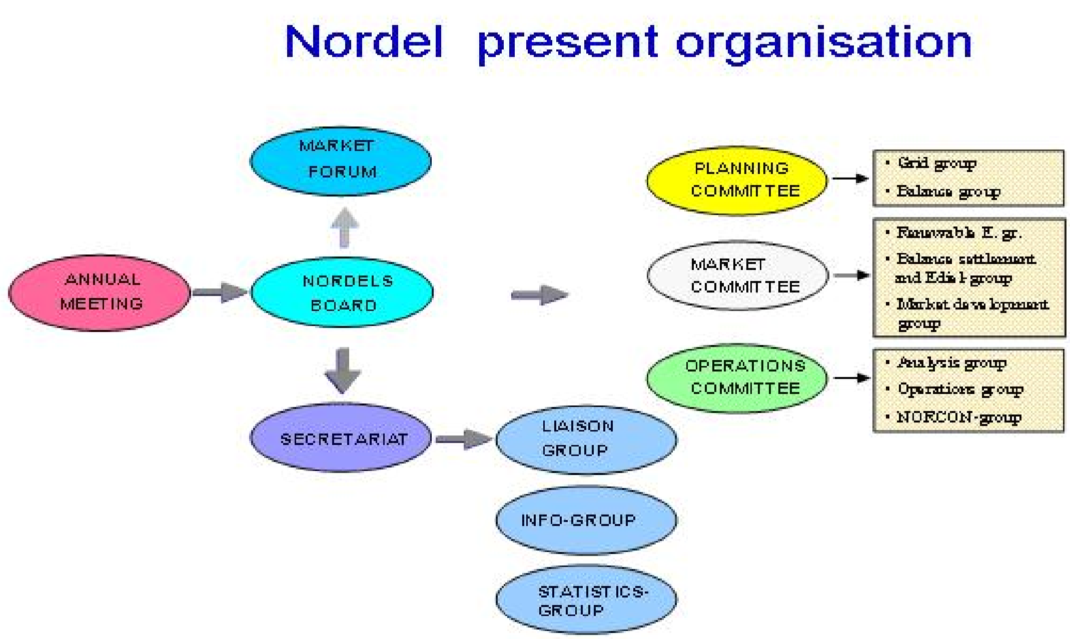
Nordel's executive body is the Board, composed of the Chief Executive Officers of each TSO. The Board takes initiatives on topical issues and executes the decisions made at Nordel's Annual Meeting.

The Board of Nordel is organised in the following way:

Nordel members are the transmission system operators (TSO) in Denmark, Finland, Iceland, Norway and Sweden

The board of Nordel is composed of one representative from each TSO, presently the CEOs

Chairmanship is shared, rotating two years term. Chairman organise secretariat



A major part of Nordel's work is carried out by three committees and their working groups. The Operations Committee, Planning Committee and Market Committee consist of the leaders responsible for the corresponding issues within the TSOs. The working groups are composed of the TSOs' specialists. The three committees are described below.

Planning Committee: Objective and tasks

To achieve continuous and co-ordinated Nordic planning between the TSOs, so that the best possible conditions can be provided for a smooth functioning and effectively integrated Nordic electricity market;

To initiate and support changes in the Nordic power system, which will enable satisfactory reliability of system supply through the effective utilisation of existing and new facilities

To be instrumental in developing the Nordic power system in ways that are consistent with environmental sustainability. When planning transmission facilities, impact assessments must integrate the need to preserve and protect the natural environment.

Members are the managers of planning functions the Nordic TSOs

Operations Committee: Objective and tasks

- Technical system issues in the short term
- Technical framework for grid operations
- The Committee serves as a leading group for Nordic operational issues
- Members are the managers of operation of the Nordic TSOs
- Aim at active dialogue with the electricity market parties in their area of responsibility
- Co-ordinates operational co-operation between the TSOs
- Promote the utilisation of the inter-connected Nordic electricity transmission system to the market's needs, taking into account the agreed technical quality as well as operational and supply reliability.

Market Committee: Objective and tasks

- Contribute towards creating a borderless Nordic market for the market players, thereby augmenting the market's efficiency and functionality,
- Contribute towards the rules of play in Europe being formulated in such a way as to promote a positive market trend and efficient interplay with the Nordic market.

The Committee works with:

- Tariff and transit issues
- Congestion management
- Balance settlement
- Renewable energy
- Members are the managers of market divisions of the Nordic TSOs

6.5. *ACHIEVEMENTS*

Important achievements in the Nordel co-operation:

Improved utilisation of total Nordic resources, where the some areas have ample hydroelectric resources, and others rely on thermal generation. The improvements apply to seasonal as well as hourly variations of resources and loads.

A common market for reserves and balancing power has reduced the total need for operating reserves.

Co-ordinated investment in the transmission grids. Nordel conducts grid planning in a regional perspective, and projects that are seen beneficial for the region may be developed in countries where they are not necessarily required.

Real time exchange of operational information enhances grid security and system reliability.

A common grid code is a starting point for the harmonisation of national rules, with minimum requirements for technical properties that influence the operation of the interconnected Nordic electric power system. The Grid Code must, however, be subordinate to the national rules in the various Nordic countries.

Common Nordic statistics on generation, consumption, faults and outages improves the monitoring of power balance and quality of supply.

7. ETSO

7.1. *OBJECTIVES OF THE INSTITUTION*

ETSO was founded in 1999 to support the liberalisation of the European electricity market. Its members are 36 system operators from 30 European countries. The members of ETSO address specific topics that are of concern to the system operators in the liberalised electricity market and develop proposals on the topics. ETSO is the mouthpiece for the transmission system operators with the European authorities as regards their role in the commercial operation of the electricity market.

ETSO pursues scientific aims on a non-profit basis and shall have the following objectives:

- The study and development of common principles regarding the harmonisation and establishment of rules in order to enhance network operation and maintain transmission system security;
- Facilitate the internal European market for electricity;
- The communication and co-operation with organizations and institutions having similar objects;
- The investigation and solution of scientific and regulatory issues of common interest to the TSO industry.
- The association may undertake any activity, which directly or indirectly, enables it to achieve the above-mentioned objects.
- These objectives will be achieved with the technical expertise support from the Regional TSOs Associations: NORDEL, UCTE, UKTSOA and ATSOI.

Two basic rules of functioning are adopted by ETSO:

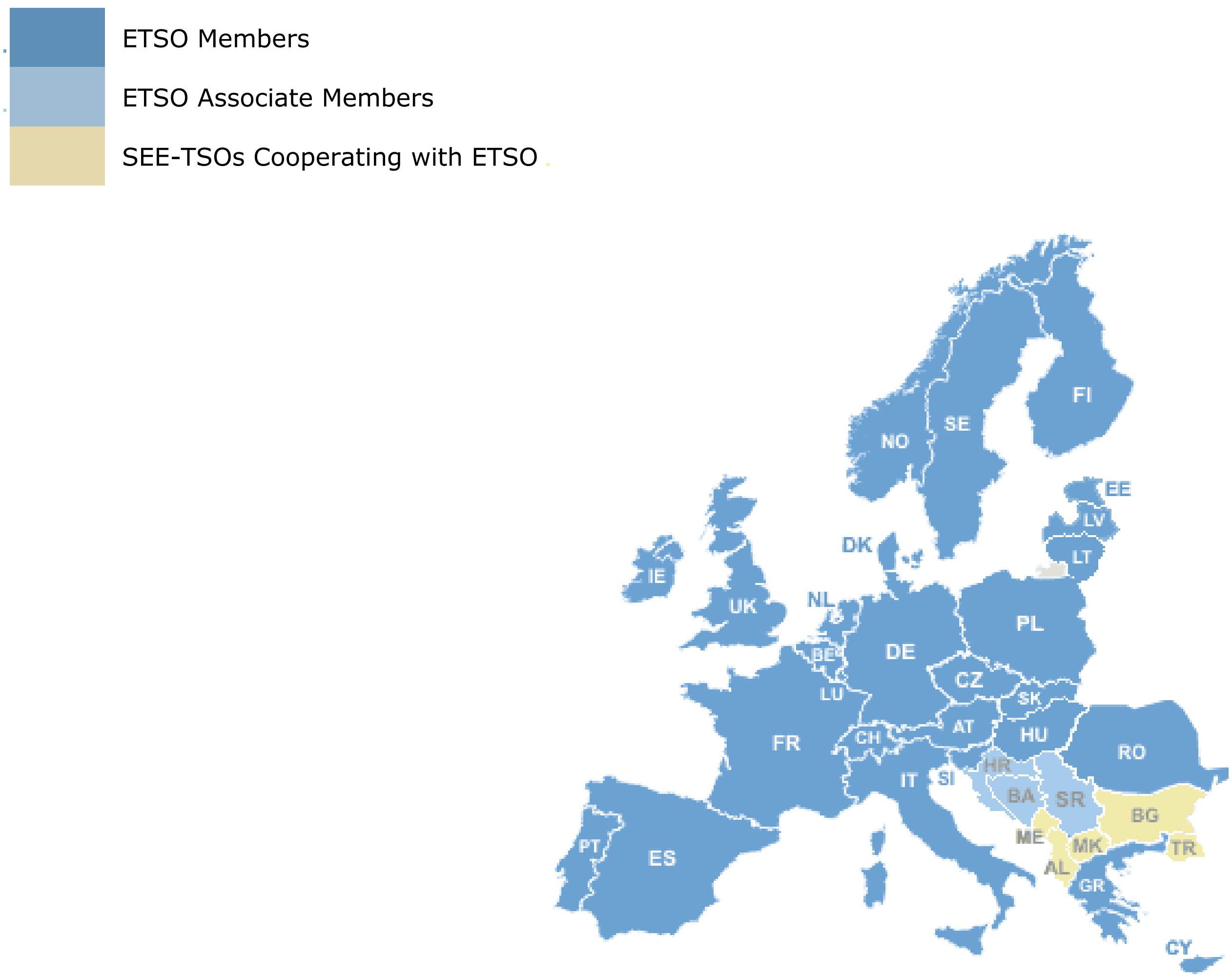
1. Co-ordination: Tacking co-ordinate actions by a permanent exchange of information and a strict respect of mutual engagements.

2. Subsidiarity: Taking action only when the objectives of the proposed action cannot be sufficiently achieved its members acting independently from ETSO, without impeding the realisation of the internal European market for electricity.

7.2. Internal organisation

7.2.1. Geographical coverage area

The ETSO members are 36 European transmission system operators (TSOs) plus two associated members, representing 30 countries. These are all member states of the European Union, (except Malta) plus Norway, Romania and Switzerland, as shown in the figure below.



7.2.2. Market size

The markets and transmission grids corresponding to the ETSO members cover a population of more than 490 million. The consumption of electric energy amounts to approx. 3200 TWh per year. The length of HV (400 and 220 kV) lines covered by ETSO is of more than 290 000 km.

7.2.3. Development

Electricity utilities have been co-operating for decades, mainly in order to maximise the system's reliability and quality of supply, while optimising the use of primary energy and capacity resources. In Europe, four regional organisations have emerged from such co-operation:

- TSOI, the association of TSOs in Ireland,
- UKTSOA, the United Kingdom TSO association,
- NORDEL, the Nordic TSOs,
- UCTE, the Union for the Co ordination of Transmission of Electricity, association of CENTREL, TSOs of the Continental countries of Western and Central Europe.

The geographic perimeters of these organisations roughly coincide with the boundaries of synchronously interconnected areas.

Upon the emergence of the Internal Electricity Market (IEM) in the European Union, the leaders of the four above-mentioned regional organisations recognised the need for an EU-wide harmonisation of network access and conditions for usage, especially for cross-border electricity trade. In 1999, ETSO was created as an association with ATSOI, UKTSOA, NORDEL and UCTE as founding association members.

On 29 June 2001 ETSO became an International Association with direct membership of 32 independent TSO companies from the 15 countries of the European Union plus Norway and Switzerland. At the end of 2001 ETSO membership was enlarged to Slovenia and CENTREL countries as full and associate members respectively. The Czech Republic was admitted as full member in June 2003 and Hungary, Poland and Slovakia in 2004. The Estonian TSO has become ETSO Associate Member in September 2004 and the Lithuanian TSO in February 2005. The Rumanian TSO is ETSO Full member since November 2004 and the Cyprus TSO since September 2005. The Lithuanian TSO has become Full member in November 2005. The Estonian & Latvian TSOs have been welcomed as Full Members in December 2005. Serbia, Bosnia Herzegovina and Croatia are Associate Members of the Association.

In comparison, the European association of power exchanges, **EuroPEX**, has 15 members, all but one representing a single country, but due to Nord Pool membership, the total number of European countries represented in EuroPEX is 18. The relationship between TSO and PX is one concern of ETSO, partly due to the close co-operation required between market operation and system operation, and partly because TSOs are often involved in PXs as owners.

7.2.4. Summary of tasks

Working groups or task forces (TF) are active within ETSO on topics such as tariffs for international energy transmission, capacity problems at borders, balance management, security of supply and data exchange. ETSO is also important in terms of information and organises fora and conferences. Current task forces:

- TF Inter-TSO Compensation,

- TF Network Access and Congestion Management,
- TF Electronic Data Interchange,
- TF Tariffs,
- TF Balance Management,
- TF Southeast Countries' TSOs,
- TF Security of Supply and Adequacy of Power Systems,
- TF Legal and Regulatory Issues.

The surveys and projects done by the task forces may be initiated by or in co-operation with other organisations than ETSO, e.g. ERGEG, the "European Regulators' Group for Electricity and Gas". ERGEG was set up "to give regulatory co-operation and co-ordination a more formal status, in order to facilitate the completion of the internal energy market". ERGEG provides a transparent platform for co-operation between national energy regulatory authorities, and between these authorities and the EU commission. One case of dialogue between ETSO and ERGEG in 2006 was that regarding "ERGEG Guidelines of Good Practice for Electricity Balancing Markets Integration".

Whereas UCTE, the other organisation of European TSOs, focuses on operational and technical co-operation, ETSO is concerned with market development. However, overlap might arise whenever market development approaches technical issues such as balancing power markets, congestion management or information interchange. In NORDEL, the different domains of market development and operational co-operation are accommodated within one organisation.

ETSO also has a role in market transparency, making access to neutral market information easier. This information includes NTC (net transfer capacities), interconnections, grid availability, load and generation. The responsibility for editing, checking and publication of such information on the ETSO and other web sites is on individual TSOs.

7.3. GOVERNANCE

ETSO is governed by:

- an Assembly representing the 38 Transmission System Operator member companies. The General Assembly is the supreme decision making body, where each member has a representative and voting right according to the size of its represented power system.
- a Steering Committee, in which each of the member countries is represented. Its task is to direct the working groups, to issue regulations and to make decision in each question for which the decision of General Assembly is not needed.

7.4. ACHIEVEMENTS

Some ETSO achievements:

- Unanimous proposal of a harmonised transitory cross-border tariff mechanism (in March 2000);

- Publication of available transmission capacities in the European interconnectors;
- Harmonized definitions of cross-border capacities;
- Proposals concerning congestion management solutions through coordinated auctioning, market splitting and market coupling;
- Description of main characteristics of transmission products delivered by TSOs

8. WHAT IS SUITABLE FOR THE INITIAL MULTI-NATIONAL CO-OPERATION

The development in the NORDEL area and in the UCTE area has proven to be workable solutions in market areas with several nations, several regulators and several TSOs that have to co-operate.

Within UCTE the rules of EU is now more and more acting as the federal legislation similar to the USA. The development within the NORDEL area is more interesting to study, since the development here has been up front for EU, and the solutions have been chosen when the alternatives have been discussed and consensus have been reached.

When this method is used to create co-operation it may take some more time than a political decided timeframe. On the other hand the market participants have discussed alternatives and chosen something they believe in. They have reached some kind of ownership.

When SAPP was created there was a lot of communication between the Nordic area and the southern part of Africa. This co-operation has been going on for about 15 years, and the SAPP has chosen a co-operation model that is similar to the NORDEL structure, but with the national power companies as members.

The structure of committees and working groups seems also to function and the costs of the operation of the organization are reduced to a minimum since the system is based upon decentralized operation.

COMMONWEALTH OF INDEPENDENT STATES (CIS)

1. OBJECTIVES OF THE INSTITUTION

The Commonwealth of Independent States (CIS) is an international organisation or alliance consisting of 11 former Soviet Republics: Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, Moldova, Russia, Tajikistan, Ukraine and Uzbekistan.

The CIS power market does not exist yet, as a real market, although steps are being taken to establish this market in the future. A series of agreements exist that establishes the creation of a regional market based on the principles of equal rights, fair competition and mutual benefits, however, little additional progress has been made so far in the establishment of a formal market.

The Parties have agreed that the creation of the Common CIS electrical energy market shall be aimed at the improvement of the quality of service and security of customers. They also foresee the implementation of CIS electricity market in a phased manner, so as to ensure the possibility of a gradual adjustment in the CIS countries' economies to the market conditions as well as a secure energy supply.

2. INTERNAL ORGANISATION

2.1. *GEOGRAPHICAL COVERAGE AREA*

The CIS area is formed by 11 former Soviet Republics, shown in the following map.

Commonwealth of Independent States

2.2. SIZE OF THE MARKET

By the late 1980s, the territory of the former Soviet Union had one of the most powerful power systems in the world: the **Uniform Power System (UPS)** of the of the USSR, working in parallel with countries in East Europe and Mongolia, and with an installed capacity of almost 300 GW (end of 1991). This included more than 90 regional power supply systems in 11 electricity power pools. The operation of the Uniform Power System of the USSR was a centralized hierarchical system, with centralized dispatching optimization procedures. System expansion planning was also centrally coordinated, as part of the strategic planning of the economy.

When the former Soviet Union disintegrated, the Commonwealth of Independent States (CIS) was organized as an alliance of 12 former Soviet republics. Although smaller than the former USSR, these countries maintain a significant part of the original system in terms of size.

2.3. BRIEF DESCRIPTION OF TRADE AGREEMENTS

2.3.1. DEVELOPMENT PATH AND EVOLUTION OF LEGAL AND INSTITUTIONAL STRUCTURES

Until the dissolution of Soviet Union in the late 1980s, the UPS was the largest centrally managed power pool in the world. Due the political events of the disintegration, each individual system started to work on its own, and many power companies became stated owned companies of the individual countries.

On February 14th, 1992, the CIS member states signed the Agreement on Coordination of Interstate Actions in the Field of Electric Power Industry of the Commonwealth of Independent States. This agreement created the CIS Electricity Council and its working body, the Executive Committee.

The active actions of CIS Electric Power Council states members promoted the stability of the situation and began the restoration of CIS states interconnected power system that was formally broken apart in 1998-1999 although some parts were already working independently. In June 2000 the parallel operation of Russian UPS and the National Power System of Kazakhstan was restored. In September 2000 the power systems of Kyrgyzstan, Tajikistan, Turkmenistan, Uzbekistan were connected as the Central Asian interconnected power system, and then with the National Power System of Kazakhstan. In August 2001 the Ukrainian and Moldavian power systems joined to the now interconnected power system of CIS states. Thus, the power systems of 11 out of 12 countries are working now in parallel as one Interconnected Power System of Commonwealth of Independent States (IPSCIS).

Formation of the common electricity market of the CIS member states is at an early stage since integration exists now only at technical level. Commercial relations are based on bilateral agreements and contracts. The framework of the future common CIS market rules - the Concept for creating the Common Electricity Market of the CIS (hereinafter, "the Concept") was agreed upon by the CIS Electric Power Council in June, 2004, by the CIS Economic Council in May 2005 and submitted for approval to the CIS Heads of Governments Council. The Concept sets general principles of a sort program to rearrange the CIS member states electricity markets. It mandates the Electric Power Council (EPC) of the CIS to develop and to propose to the CIS governments' detailed market rules and co-ordinate creation of the CIS common electricity market. The authority of the EPC does not extend to enforcement actions against the CIS states, instead the implementation would be ensured by the Intergovernmental Agreement. For the purpose of any future litigation over implementation, the Agreement envisages establishment of arbitration measures.

All these and other important event are described in the below table

Date	Action
February 14th, 1992	Coordination of inter-state actions in electricity of the CIS member states
November 25th, 1998	Contract to set up parallel operation of the power systems of the CIS member states
January 25th, 2000	Agreement on transit of electricity between the participating CIS states
June 2000	Parallel operation of UES of Russia with the power system of Kazakhstan.
September 2000	Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan entered into an electricity pool of Central Asia, with parallel operation with Kazakhstan.
August 2001	Parallel operation between Ukraine and Moldova.
2001	Task Force for the "Formation and development of inter-state electricity market" established by the EPC
May 30th, 2002	Agreement on mutual aid in case of failures and other extreme situations in the power system of the states participants of the CIS
October 7th, 2002	Cooperation agreement in the field of efficiency and energy saving between the state participants of the CIS
June 24th, 2003	Agreement to develop The Concept of Formation of the Common Electricity Market of CIS member states
September 15th, 2004	Agreement on the creation of reserves and their effective utilization for reliable parallel operation of the power systems of the states participants in the CIS
2007	Today, 10 of the CIS member state systems are functioning in parallel. The CIS interconnected power system is also interconnected with Lithuania, Latvia, Estonia and Mongolia. Electricity exchanges exist with Norway, Finland, Poland, Slovakia, Hungary, Turkey, Afghanistan, Iran and China. Plan of major actions to develop and increase the efficiency of electricity trading and exchanges between the CIS member states, 2003 to 2010.

2.3.2. GOVERNMENT PARTICIPATION AND POLICY FRAMEWORK

As discussed above, the governments of the different nations belonging to the CIS created a special commission CIS Electric Power Council, and its Executive Committee, to support the development of a regional electric market. The structure and operation of the EPC is described below in the "Governance" section.

2.3.3. KEY ROLE OF THE POWER INFRASTRUCTURE IN EVOLUTION INTO COMPETITIVE POWER MARKET

Although there is not yet a competitive market and the existing infrastructure is not yet sufficient to play a role to support its development, the region is strongly interconnected and there is huge amount of generation capacity (most located in Russia). This is the case despite that fact that due to the countries' general financial situation most infrastructure has not been well maintained and has passed the span of "useful" life. Most of the countries have adopted the single buyer model in recent years and are trying to attract foreign investors by bidding new power plans and power lines. If the last initiatives go through and a real regional competitive market takes in place in the incoming years, the existing infrastructure will serve as a base on which to build future operation.

2.3.4. HARMONISATION OF OPERATIONS PROCEDURES, DESIGN CRITERIA, ELECTRICITY PRICING AND EXISTING BILATERAL CONTRACTS

Despite the region's large overall generation capacity, some countries still lack and thus Transmission Networks are synchronized in order to allow exports and imports of energy.

Since there is not yet a regional market, a regional pricing model has not yet been developed.

There are many bilateral contracts but as they are private contracts between the parties no information but the amount the terms or energy traded is available.

As an example of trade amounts however, Russian Federation Exports and Import with neighbouring countries is shown in the following table:

Country	2000	2001	2002*
Azerbaijan	-	9.64	1,087.30
Belarus	6,450.11	6,237.09	3,727.92
Georgia	269.30	415.22	249.92
Kazakhstan	1,847.93	2,460.93	1,663.38
Moldova	-	-	440.26
Ukraine	-	185.03	231.13
Total FSU countries:	**8,567.34**	**9,307.91**	**7,399.91**

Export in millions kWh *(World Energy Council)*

Following on from this example, total exports from Russia in 2006 reached 20.5 billion kWh while imports totalled just 5.1 billion kWh.

According to the World Energy Council, most of the intra-CIS imports in 2006 were from Kazakhstan (72%), from Azerbaijan (6%), from Ukraine (10) and from Belarus (1%). The only reason for those imports was to ensure the supply to certain areas; however, power imports are cancelled if the prices offered for a certain year are "considered" very expensive. In short, any operational harmonization among countries occurs only between the parties involved in a bilateral contract. There is no systematic harmonization of procedures and standards among all countries due to the dominant use of bilateral agreements.

2.3.5. KNOWLEDGE GAP INFLUENCES

To date the only influence on electricity trading (bilateral agreements) is the prices offered by the neighbour countries.

Advantages or disadvantages that affect Generation and Interconnection capacity occur also through physical aspects, such as the amount of existing installed capacity and natural resources available in any given country.

The result of these two techno-economic influences is that, at least in the short term, all CIS countries that have extra energy to be exported, prefer to sell to Western European countries as they can afford to pay higher energy fees – thus exacerbating energy shortages in already power-strapped CIS countries.

Control centres in each country function independently and there is no existing communication protocol among them. As the market and power exchange develops, a system for information exchange will need to be developed.

An agreement signed in 2006 by the former CIS countries created arbitration measures by the CIS Electric Power Council. Other knowledge sharing agreements exist on a case-by-case, bilateral basis; for example, arrangements made with Kazakhstan for a transmission line passing through the country that connects the northern and southern neighbors.

2.3.6. POLITICAL CHALLENGES TO BE OVERCOME

To date, the main political challenges that have been (and some remain to be) overcome are the political stresses due the disintegration of the USSR (territorial disputes, resource ownership, etc.). These challenges have been overcome by the creation of the CIS **Executive Committee (located in Georgia) and the Inter-parliamentary Assembly of CIS** and its different organs, such as the EPC. As an example, Armenia wasn't allowed to generate electricity with their power plants in Razdanskaya until ownership disputes over these plants with Russia was settled in 2002.

Another political challenge was (and still is) to privatize state-owned electricity companies in order to achieve real competitive electricity markets (even on a local level). The only country to achieve full privatization of generation is Kazakhstan. There is some private participation of generation ownership in Russia, but often dominated by a few major players. Generation and other power sector infrastructure in the remaining countries is fully state-owned and there is currently no plan for privatization.

The next challenge to be faced is to create a true Competitive Regional Market, but to progress local competitive Electric Markets must be put in place.

2.3.7. TECHNICAL AND FINANCIAL REAL TIME OPERATION

Operation of the integrated CIS system is managed by two control centres. In 2000 the parallel operation of Russian UPS and National Power System of Kazakhstan was restored so the whole system was able to be managed. These two control centres work in parallel so some physical disruptions such as frequency synchronization or voltage control may be avoided.

All energy traded bilaterally is settled according to the terms of the bilateral agreements.

Congestion is currently not a problem among trading systems as the flows are generally unidirectional and only on an as needed and scheduled basis. Congestion will be an issue to address for the future when the power flow volumes become greater and on a more automatic basis.

2.3.8. SHORT MEDIUM AND LONG TERM SYSTEM PLANNING

There is currently no officially established planning procedure. Rather, the CIS countries improve both system (power and transmission) and arrange agreements for different periods of time (quality supply agreements, amount of energy to be supplied, etc.) through various common agreements.

In the long term, the countries expect their systems to work as a single regional market, but it is taking a long time to privatize the owned state utilities, which will allow for economic-oriented business practices necessary in a market environment.

Officially the medium and long-term main goals are:

- Forming the Common Electricity Market of CIS member states;
- Organizing parallel operation of the interconnection between CIS countries and the IPS of the Baltic countries and the EU interconnection and creating an integrated EU/CIS electricity market.

3. GOVERNANCE

The CIS countries themselves are not yet governed by any common structure; the only established institution is the CIS Electric Power Council (EPC). This Council meets regularly and is the institution in charge of promoting the development of the electricity market in the region.

The CIS EPC comprises the most senior officials of the key electric power bodies of its member states: Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, Moldova, the Russian Federation, Tajikistan, Turkmenistan, Uzbekistan and Ukraine. Its President and Vice-President are chosen from amongst its members on a rotating basis. The Chairman of its Executive Committee are appointed by the Council.

The EPC its Executive Committee and its activities – such as the Task Force for the Formation and development of inter-state electricity market – are financed by governments belonging to the CIS.

4. ACHIEVEMENTS

To date, and from the point of view of achievements moving towards a real, regional market, the CIS has made limited progress. The achievements have been in terms of advancing in integration through specific agreements on specific points, which were detailed in the sections above on “Brief description of trade agreements”.

INTRODUCTION TO US POWER TRADE ORGANIZATIONS

1. GENERAL ASPECTS

In this section we will analyse some of the USA power trade organizations: PJM, Midwest ISO, New England ISO, South West Power Pool and Western Systems Power Pool.

It is important to say that the settlement and actual shape of these organizations were the result of a large process within the history of the electricity industry in the USA. As a result, to fully understand the actual situation of these markets, it is necessary to briefly review the whole nation picture, looking at the evolution of the legal and institutional structures over time, analysing the government participation (both federal and state) and taking into account the external market conditions[2].

[2] This section draws heavily in both text and concept on the "Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy", 2006, pursuant to section 1815 of the Energy Policy Act of 2005 and prepared by the Electric Energy Market Competition Task Force, found at http://www.ferc.gov/legal/maj-ord-reg/fed-sta/ene-pol-act/epact-final-rpt.pdf

2. INDUSTRY STRUCTURE AND REGULATION

Participants in the electric power sector in the United States include investor-owned utilities and electric cooperatives; federal, state, and municipal utilities, public utility districts and irrigation districts; cogenerators and onsite generators; and non-utility independent power producers (IPPs), affiliated power producers, power marketers, and independent transmission companies that generate, distribute, transmit, or sell electricity at wholesale or retail.

These entities differ greatly in size, ownership, regulation, customer load characteristics, and regional conditions. These differences are reflected in policy and regulation. Tables 1 and 2 in the Annex provide selected statistics for the electric power sector by type of ownership in 2004 based on information reported to the Department of Energy (DOE), Energy Information Administration (EIA).

3. RECENT EFFORTS TO STANDARDIZE POWER TRADE ISSUES

The Federal Energy Regulatory Commission (FERC) is the national-level energy sector organization spearheading efforts in the United States to manage the development of electricity markets in the United States. The organization issues various orders, rulings and works hand-in-hand with transmission system operators, market operators and power trade organizations to ensure the continued efficiency and reliability of electricity provision to consumers through the market evolution process.

Related to this process, FERC issued Order 2000 in December 1999 in order to foster participation in regional transmission organizations (RTOs) and Independent System Operators (ISOs). This Order established guidelines that a transmission entity must meet in order to qualify as an RTO. The expectation is that the RTOs will increase efficiency in wholesale energy markets and lower end-prices to consumers. Voluntary RTOs and ISOs were formed in New York, New England, PJM, and the Midwest.

Subsequently, the Congressional Energy Policy Act of 2005 gave FERC significant new responsibilities and granted it new authority to discharge those responsibilities by modifying the Federal Power Act, the Natural Gas Act, and the Public Utility Regulatory Policies Act of 1978. In addition, the Energy Policy Act of 2005 repealed the Public Utility Holding Company Act of 1935 and in its place created a new rule, which emphasizes access to information. New responsibilities under this Act also include, among others:

- Oversight of the establishment and enforcement of reliability standards for the Nation's electric transmission grid;
- Implementing new tools, including penalty authority, to prevent market manipulation;
- Providing rate incentives to promote electric transmission investment.

Following on this authority, FERC proposed a Standard Market Design (SMD) in 2002 to standardize market rules within the US. This SMD is based on **locational marginal prices**, a two-settlement market scheme and the use of **financial transmission rights** to manage transmission congestion. Although it is voluntary to follow the SMD, it is becoming an important tool for the harmonization of operation procedures, design criteria and electricity pricing mechanisms. This will be illustrated in the descriptions of the PJM, Midwest, and New England trade organizations that are described in this report.

PJM

1. OBJECTIVES OF THE INSTITUTION

PJM is the abbreviation for the Pennsylvania - New Jersey - Maryland Regional Transmission Organization (RTO) and market operator covering 13 states of the USA plus the District of Columbia. As an RTO and market operator it is a neutral party managing the wholesale electricity market and monitoring the transmission grid to guarantee reliability.

PJM began its activities in 1927 as a pool between three utilities that shared their generating resources and opened the real time energy market in 1997. The PJM timeline is shown below:

- 1927: Three utilities sign PA-NJ Agreement, creating an integrated power pool.
- 1932: Completion of new 235-mile, 220-kilovolt transmission "ring" interconnects the three utilities.
- 1956: The original and two additional utilities sign the PJM Agreement changing the PA-NJ Interconnection into the PJM Interconnection.
- 1962: PJM installs its first on-line computer, an analogue computer for automatic generation control.
- 1966: Membership grows to six utilities.
- 1968: First digital computer installed at PJM to run the energy management system; it has 250 kilobytes of memory, 50 megabytes of disk storage.
- 1969: Construction begins on PJM control center.
- 1981: Membership grows to eight utilities.
- 1993: PJM Interconnection Association forms to administer the power pool and have its own staff.
- 1997: PJM becomes an independent, limited liability company; membership opens to non-utilities; PJM operates first bidbased energy market.
- 1998: FERC approves PJM as an Independent System Operator; locational marginal pricing first used to manage congestion charges.
- 1999: First financial transmission rights auction held.
- 2000: First market opens for an ancillary service, regulation.
- 2001: PJM conditionally approved as regional transmission organization.
- 2002: PJM West goes into operation; PJM serves more than 200 members; announced new transmission members double PJM's size.

PJM has the following responsibilities:

- Development and modification of market rules
- Monitoring compliance with rules, standards, procedures and practices
- Monitoring structural problems in the PJM market that may inhibit a robust and competitive market and the potential of market participants to exercise undue market power
- Market monitoring coordinated with the states
- Inter-regional coordination
- Management of the day-ahead market, real time spot market and capacity market
- Monitoring, controlling and operation of the high voltage transmission system

- Congestion management
- Management of the Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR) markets
- Management of the regional generation and transmission planning expansion
- Direction of the supply and coordination of the provision of ancillary services

2. INTERNAL ORGANIZATION

2.1. GEOGRAPHICAL COVERAGE AREA

PJM covers the Middle Atlantic States (see Figure below), which have a total population of 51 million and a total area of 164,260 square miles.

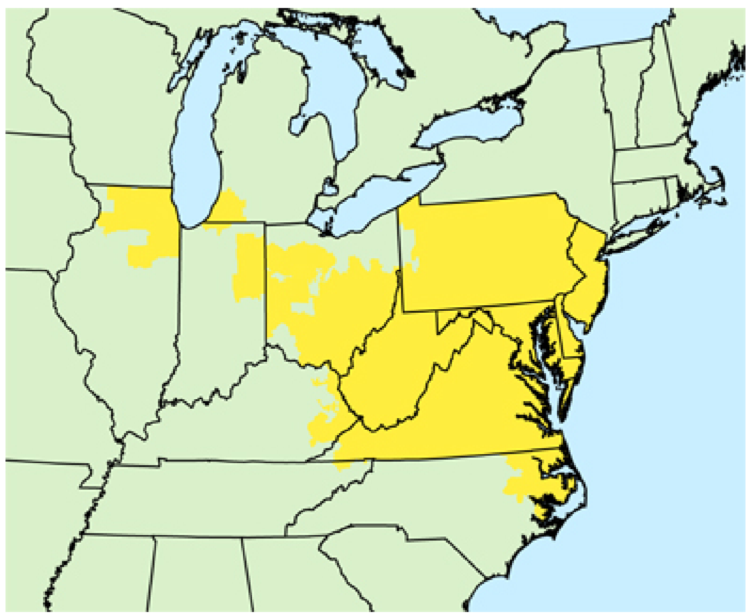


Figure: PJM Geographical Coverage area.

The area in previous Figure shows PJM's operational range, and includes the states of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia (Washington D.C.).

2.2. SIZE OF THE MARKET

If the PJM region was considered a single country, it would be the fifth largest electricity consumer in the world, behind USA as a whole, China, Japan and Russia.

Data from 2006 reveals that the actual annual energy delivery is 790,000 GWh, with a generating installed capacity of 164,905 MW, 6.038 substations and 56,250 miles of transmission lines. Peak demand in 2006 was 144,644 MW, 8 % more than in 2005.

Projections for 2020 indicates that the installed capacity should reach 220,000 MW, including reserves.

2.3. Other characteristics of size & level of competition

PJM is seen as a highly competitive, efficient and transparent market.

It has more than 450 members who participate in the various PJM markets. These members involve generators, transmission owners, electricity distributors, power marketers and large consumers. The total number of generators is 1,271; 56.8 % of the total generation produced is from coal units, 34.6 % by nuclear plants, 5.5 % by gas generators and the remaining by oil, solid waste, hydroelectric and wind units.

2.4. Brief description of trade agreements

2.4.1. Wholesale Electricity Market

PJM coordinates the continuous buying, selling and delivery of wholesale electricity through the Energy Market. In its role as market operator, PJM balances the needs of suppliers, wholesale customers and other market participants. PJM's Energy Market operates much like a stock exchange, with market participants (both demand and supply) making offers and establishing a price for electricity by matching supply and demand.

The market uses locational marginal pricing (LMP) that reflects the value of the energy at the specific location and time it is delivered. Not only does this take into account the generation costs, but also the costs of network losses and transmission congestion. Under the hypothesis of an ideal network without any losses or congestion, the price of electricity would be the same in all locations and equal to the generation marginal cost (e.g. cost of the last unit dispatched). However, for the real network, the locational marginal price (LMP) is:

LMP = Gen. Marginal Cost + Trans. Congestion Cost + Cost of Marginal Losses

The PJM Energy Market is a two-settlement scheme, consisting of a **Day-Ahead and a Real-Time or Balancing Market**. The Day-Ahead Market is a forward market in which hourly LMPs are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions.

The Real-Time Market is a spot market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions. Real-time prices are available. PJM settles transactions hourly and issues invoices to market participants monthly.

Apart from the Day-Ahead and Real-Time Market, suppliers and consumers can make **Bilateral Transactions**. **Load Serving Entities** (LSE) may also self-schedule their own generating resources to supply their own customers (e.g. residential, commercial, industrial).

2.4.2. Congestion Management, Reliability and Adequacy of Supply

In relation to transmission congestion management, PJM uses Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs).

The FTRs are a financial contract that entitles the holder to a stream of revenues or charges based on the Day-Ahead hourly energy price differences across the path. FTRs provide a hedging mechanism that can be treated separately from transmission service, protecting the holder from an increase in cost due to transmission congestion.

PJM performs an annual auction for the FTRs as well as monthly auctions. In addition, there is a secondary market where existing FTRs are bought or sold.

The ARR are entitlements allocated annually to firm transmission service customers that entitle the holder to receive an allocation of the revenues from the Annual FTRs Auction. The ARRs provide a revenue stream to the firm transmission service customer to offset purchase price of FTRs. Holders of ARRs can either:

- Convert ARRs into FTRs by "self-scheduling" FTRs into Annual Auction on exact same path as ARRs
- Reconfigure ARRs by bidding into Annual Auction to acquire FTRs on alternative path or for alternative product
- Retain allocated ARR and receive associated allocation of revenues from the auction

In order to guarantee future capacity needs, PJM has developed the **Reliability Pricing Model (RPM)**, which has substituted in 2007 the short-term capacity market by a a capacity-pricing method to enhance reliability and ensure an adequate electrtricity supply.

The terms of the RPM settlement provide more long-term certainty for new generation and other capacity resources, especially in areas where new supplies are crucial, such as northern New Jersey. Under the RPM, both transmission and demand response have real opportunities to compete with generation to provide resources needed to ensure reliability.

Load-serving entities can supply their energy requirements through generation, transmission or demand response, including energy-efficiency programs.

Demand resources can submit bids to reduce demand in the RPM capacity-market auctions, and those bids are eligible to set the market-clearing price for capacity.

The essential elements of the RPM capacity market include:

- the procurement of capacity three years prior to the required need through a competitive auction;
- a variable resource requirement that helps set the price for capacity;
- and a phase-in of locational pricing for capacity to reflect transmission constraints and to account for the capacity needs of an area.

Capacity payments to generators provide a stream of revenue to maintain current generation and build new generation. The capacity revenue stream recovers the longer-term costs that generators incur.

PJM is responsible for directing the supplies and coordinating the provision of ancillary services. These include markets for regulation and synchronized reserves and, blackstart service, reactive supply & voltage control, and scheduling, system control & dispatch.

2.4.3. Regional Transmission Expansion Planning Process

Finally, it is important to point out that PJM coordinates the regional system expansion based on all the needs that are identified through the Regional Transmission Expansion Planning Process (RTEPP).

The RTEPP coordinates the expansion plans across multiple transmission system owners allowing for an open process with the input from all interested parties. It results from the intersection of market drivers (i.e. generation, load and merchant transmission) and non-market drivers (e.g. reliability assessment, economic performance assessments, operational performance assessments and transmission owner projects).

The result of this planning process is an integration of the available market solutions: strategically sited generation projects, distributed resources, advanced technology options for transmission, merchant transmission and active load management.

3. GOVERNANCE

PJM has a two-tiered governance structure: the PJM Board and the Members Committee.

Board of Managers:

The Board of Managers is charged with ensuring that PJM safely and reliably operates the grid and creates and operates fair energy markets. To establish neutrality, no member of the Board can have a personal affiliation or ongoing professional relationship with or any financial stake in any PJM market participant, and must adhere to a strict Code of Conduct.

The Board ensures that no member or group of members has undue influence. The Board is required to prevent market participants from exercising market power. To support this goal, PJM's independent **Market Monitoring Unit** constantly analyzes market data and takes action to make structural or rule changes to resolve any issues.

Members Committee:

The Members Committee is comprised of representatives from each member or customer (or customer group) in the market. The Committee provides advice to the Board by proposing and voting on changes and new programs. The Committee is composed of five voting sectors representing power generators, transmission owners, electric distributors, power marketers and consumers. Only one affiliate of a member corporate entity may vote in the Committee.

Other committees and user groups provide ongoing forums for issue resolution through discussion and negotiation. Through this collaborative stakeholder process PJM serves as mediator, helping competitors to reach consensus and move forward on issues of mutual interest to the effective functioning of the system.

4. ACHIEVEMENTS

PJM has administered about $71 billion in energy and energy-service trades since the regional markets opened in 1997.

According to PJM Docket No. AD05-17-000, 2005, the PJM West Hub is the most liquid trading hub for wholesale electric transactions in North America and is the hub used in NYMEX and Intercontinental Exchange ("ICE") futures transactions.

In addition, the same document indicates that the bid/ask spreads in PJM are decreasing. In particular, day-ahead bid/ask spreads have declined from an average of about $4.00 in 2000 to an average of $1.20 in 2004.

The State of the Market Report 2006, summarizes the amount of real time self supply load, bilateral supply load and spot supply load in the period 2005 – 2006. As it can be seen in next Figure, the greatest amount of electricity (around 90%) is traded at the Bilateral Contract Market.

	2005			2006			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	91.0%	7.9%	1.1%	92.4%	6.5%	1.0%	1.4%	(1.4%)	(0.1%)
Feb	90.9%	8.0%	1.1%	92.5%	6.5%	1.0%	1.6%	(1.5%)	(0.1%)
Mar	90.8%	8.0%	1.2%	92.6%	6.4%	1.0%	1.8%	(1.6%)	(0.2%)
Apr	91.0%	7.7%	1.3%	92.7%	6.2%	1.0%	1.7%	(1.5%)	(0.3%)
May	91.7%	7.2%	1.1%	92.7%	6.2%	1.1%	1.0%	(1.0%)	0.0%
Jun	93.0%	6.2%	0.8%	93.2%	5.8%	1.0%	0.2%	(0.4%)	0.2%
Jul	93.1%	6.0%	0.8%	93.3%	5.8%	0.9%	0.2%	(0.2%)	0.1%
Aug	93.1%	6.0%	0.8%	93.2%	6.0%	0.8%	0.1%	0.0%	0.0%
Sep	92.9%	6.2%	1.0%	92.8%	6.1%	1.0%	(0.1%)	(0.1%)	0.0%
Oct	92.4%	6.7%	0.9%	92.2%	6.7%	1.1%	(0.2%)	0.0%	0.2%
Nov	92.0%	7.1%	0.9%	92.6%	6.3%	1.1%	0.6%	(0.8%)	0.2%
Dec	92.3%	6.9%	0.9%	92.6%	6.4%	1.0%	0.3%	(0.5%)	0.1%
Annual	92.1%	6.9%	1.0%	92.8%	6.2%	1.0%	0.7%	(0.7%)	0.0%

Figure: Monthly average percentage of real time self supply load, bilateral supply load and spot supply load: 2005 - 2006

The Report also provides a summary of the prices, as seen in next Figure.

	Locational Marginal Price (LMP)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.40	(12.6%)	(8.3%)	(50.3%)
2003	$38.27	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)

Figure: PJM average hourly LMP (USD/MWh): 1998-2006

More interesting are the fuel adjusted LMP prices, which have declined an average of 5.6 % from 2005 to 2006. The same behaviour is reported at [PJM Docket No. AD05-17-000, 2005] for the period 2001 – 2004, resulting in a total reduction of 15.7 %.

In addition, transmission rates for network service customers have generally been frozen in PJM over much of the last 10 years.

NEW ENGLAND ISO

1. OBJECTIVES OF THE INSTITUTION

NE-ISO is the abbreviation for New England Independent System Operator. It is a Regional Transmission Organization (RTO) and a market operator covering 6 states of the USA. As an RTO and market operator it is a neutral party managing the wholesale electricity market and monitoring the transmission grid to guarantee reliability.

NE-ISO was created by the Federal Energy Regulatory Commission (FERC) in 1997 as an independent system operator, it implemented the wholesale electricity market in 1999, and was designed by FERC as a RTO, in 2005. NE-ISO timeline is shown below:

- November 9, 1965: Great Northeast Blackout shuts down power for 30 million customers
- January 1966: Northeast Power Coordinating Council (NPCC) formed to improve system reliability
- 1971: New England Power Pool (NEPOOL) created to establish a central dispatch system and enhance system reliability
- 1996: FERC Order 888 deregulates portions of the electric power market
- July 1, 1997: ISO New England created to manage the regional bulk power system and new wholesale markets and ensure access to transmission systems
- May 1, 1999: ISO New England begins managing restructured regional wholesale power markets
- June 2001: ISO New England proposes Standard Market Design, rules to govern new wholesale markets
- January 2003: ISO New England Board of Directors votes unanimously to pursue the creation of an RTO for New England.
- March 2003: ISO New England implements Standard Market Design, an improved wholesale market design for the region
- March 2004: FERC conditionally approves ISO New England as an RTO
- February 2005: ISO New England begins operation as a Regional Transmission Organization

NE-ISO has the following responsibilities:

- Development and modification of market rules
- Monitoring compliance with rules, standards, procedures and practices
- Monitoring structural problems in the market to guarantee competitiveness
- Operation of the bulk electric power system and inter-regional coordination
- Management of the wholesale electricity market (day ahead market, real time spot market and capacity market)
- Congestion management
- Management of the Financial Transmission Rights (FTRs)
- Development and management of the annual and long term planning process
- Direction of the supply and coordination of the provision of ancillary services

2. INTERNAL ORGANISATION

2.1. *GEOGRAPHICAL COVERAGE AREA*

NE-ISO covers 6 states in the Northern-East area of the USA (see Figure 1), which have a total population of 14 million inhabitants, 6.5 million of households and businesses, and a total area of 71,992 square miles.

The States served by NE-ISO are Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

The following Figure shows the geographic area of coverage of this market.

Figure: NE-ISO area

2.2. *SIZE OF THE MARKET*

Data from 2006 reveals that the actual annual energy load is 132,526 GWh, with a generating installed capacity of 30,931 MW, more than 8,000 miles of transmission lines and 12 interconnections to neighbouring systems. Peak demand in 2006 was 28,130 MW, 8.3 % more than in 2005.

2.3. *OTHER CHARACTERISTICS OF SIZE & LEVEL OF COMPETITION*

NE-ISO has more than 300 participants that compete in the market. There are more than 350 generators; 38.1 % are gas units, 24.4 % oil plants, 14.4 % nuclear generators, 9.2 % coal plants, and the remaining are hydro, power storage and other renewables.

When looking at the level of competition in New England, it is important to point out that 88 % of this generation is unregulated. During the restructuring process, five of the six states of NE-ISO have required utilities to sell off their power plants, a successful process that turned out the region to be a leader in the US.

2.4. BRIEF DESCRIPTION OF TRADE AGREEMENTS

2.4.1. WHOLESALE ENERGY MARKET

NE-ISO coordinates the continuous buying, selling and delivery of wholesale electricity through the Energy Market. In its role as a market operator, NE-ISO balances the needs of suppliers and demand. The Energy Market operates much like a stock exchange, with market participants (both demand and generation) making offers and establishing a price for electricity by matching supply and demand.

NE-ISO implemented the wholesale electricity market in 1999 and in 2003 adopted FERC 's **Standard Market Design** (SMD), which added a two-settlement market scheme with a **Day-Ahead Market and a Real Time Market**. The Day-Ahead Market is a forward market in which settlement is financially binding, providing price certainty and positive incentives for the Real Time Market performance.

The market uses **locational marginal pricing** (LMP) that reflects the value of the energy at the specific location and time it is delivered. This takes into account not only the generation costs, but also the costs of network losses and transmission congestion. Under the hypothesis of an ideal network without any losses or congestion, the price of electricity would be the same in all locations and equal to the generation marginal cost (e.g. cost of the last unit dispatched). However, for the real network, the locational marginal price (LMP) is:

LMP = Gen. Marginal Cost + Trans. Congestion Cost + Cost of Marginal Losses

For the Day-Ahead Market, LMPs are calculated hourly for the next operating day based on generation offers, demand bids and scheduled bilateral transactions. Bids and offers must be submitted as early as 10 days prior but not later than noon day before the operating day. Market settlement, schedules and published LMPs are done at 4 p.m. of the previous operating day.

For the Real-Time Market, LMPs are calculated at five-minute intervals based on actual grid operating conditions. Real-time prices are publicly available on the Web.

It is important to mention that generators are paid nodal LMPs, while demand pays Zone LMPs, which are calculated as load weighted average of nodal LMPs in the zones (e.g. there are 8 load zones).

Apart from the Day-Ahead and Real-Time Market, suppliers and consumers can make Bilateral Transactions, which provide price certainty for both sellers and buyers.

NE-ISO is responsible for directing the supplies and coordinating the provision of ancillary services (load regulation, spinning reserves, operating reserves, voltage control). For the case of operating reserves and spinning reserves, they can be bought or sold in the market.

Finally, NE-ISO runs a demand response program that compensates electricity users for reducing use when market prices are high or when reliability is a risk. The program allows for efficient pricing during shortage and reduces potential for market power.

2.4.2. MANAGING CONGESTION IN THE MARKET

In relation to transmission congestion management, NE-ISO uses Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARR).

The FTRs are a financial contract that entitles the holder to a stream of revenues or charges based on the Day-Ahead hourly energy price differences across the path. FTRs provide a hedging mechanism that can be treated separately from transmission service, protecting the holder from an increase in cost due to transmission congestion.

NE-ISO performs an annual auction for the FTRs as well as monthly auctions. In addition, there is a secondary market where existing FTRs are bought or sold.

The ARRs are the rights to receive FTR Auction Revenues from the sale of FTRs other than FTRs sold by FTR holders. There are two types of auctions: short-term and long-term. Short-term auctions are monthly auctions and the revenue is distributed two months after the Auction (in the month after the FTRs are effective). For the long-term auctions the revenue is distributed prorata each month of a defined long-term period, based on the number of days in the month.

2.4.3. Upcoming Changes

NE-ISO is currently moving towards the use of **Long Term Transmission Rights** (LTTR) which have a similar purpose of FTRs, but longer terms of rights.

NE-ISO is also implementing substantial changes to its installed capacity market, moving to a **forward capacity market** (FCM) with locational requirements that would cause capacity to be procured three years forward (i.e. the ISO will project the needs of the power system three years in advance and then will hold an annual auction to purchase power resources to satisfy the region’s future needs). This forward procurement is intended to facilitate the entry of new generation, which generally requires at least three years to complete the regulatory and construction processes to enter the market. The transition to this market has begun and the first auction is scheduled for February 2008 to meet the capacity requirements beginning in June 2010. During the transition period, a price of 3.05 $/kW-month is paid to generators in order to ensure sufficient capacity to meet demand.

3. GOVERNANCE

ISO-NE is governed by an independent, 10-member Board of Directors with expertise in financial markets, law, and electric power operations and regulation. Members have no financial interest in any company doing business in New England's electricity markets.

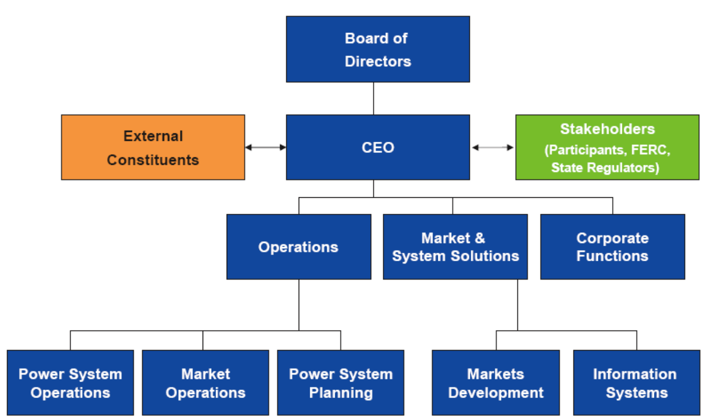


Figure: NE-ISO corporate structure

The corporate structure of NE-ISO is shown above in the Figure. All employees must follow the Code of Conduct, which sets the expectations regarding the avoidance of conflicts with NE-ISO's participants and standards of behaviour in general.

4. ACHIEVEMENTS

Today, more than 300 market participants compete in $9 billion USD of wholesale electricity transactions annually in New England, about a quarter of the power sold in the region (the remainder is sold through negotiated, long-term contracts).

The market has demonstrated real benefits by encouraging investment in New England's power supplies. In the five years following the opening of wholesale markets in 1999, New England's capacity increased by 40 percent, significantly improving reliability and making genuine competition possible.

Since the new power plants typically use more efficient and cleaner-burning natural gas technology, they also produce fewer pollutants. This has reduced emissions of nitrogen oxides (NOx), sulphur dioxides (Sox) and carbon dioxide (CO2).

At the same time, system reliability has not only remained strong but been enhanced. The lights stayed on in almost all of New England during the August 2003 system failures that blacked out much of the Northeast, Midwest and Canada.

Wholesale electricity prices, adjusted for fuel costs, have declined by 5.7 % since the first full year of market operations. Prices dropped by 11 % during the four-year period from 2001-2004.

Figure: Monthly average Day-Ahead prices and natural gas prices. New England Hub 2005 - 2006

As illustrated in previous Figure, electricity prices declined in 2006 from the relatively high levels that prevailed from July 2005 through January 2006, which were driven by very high natural gas prices. The correlation between natural gas prices and electricity prices is consistent with a well-performing market given that: a) fuel costs constitute the vast majority of most generators' marginal costs, and b) natural gas-fired units are frequently on the margin (setting the market price) in New England.

In the majority of hours, demand was lower in 2006 than in 2005. However, several days of extremely hot weather in early August increased load to a record peak in excess of 28 GW. This led to eight hours of New England-wide reserve shortages in two days. Consistent with the market rules, prices increased to $1000/MWh during the reserve shortage.

SOUTH WEST POWER POOL

1. OBJECTIVES OF THE INSTITUTION

SPP is the abbreviation for the Southwest Power Pool. It is a Regional Transmission Organization (RTO) covering 8 states of the USA, and one of the nine regional electric reliability councils under North American Electric Reliability Corporation (NERC) authority. As an RTO and system operator it is a neutral party managing the wholesale electricity market and monitoring the transmission grid to guarantee reliability.

Creation of SPP as an RTO was approved by the Federal Energy Regulatory Commission (FERC) in 2004. On Nov. 17, 2006 SPP began serving as the Independent Coordinator of Transmission (ICT) for the Entergy Operating Companies, handling reliability coordination, tariff administration, Available Flowgate Capability (AFC) calculation, transmission planning, and OASIS (Open Access Same-time Information System) operation.

Although not always operating under its current name, SPP it is quite old as an electric organization, originally formed in 1941 when eleven power companies cooperated to ensure that an aluminium factory would receive reliable power as it worked to assist the US war effort for World War II.

The modern SPP timeline is shown below:

- October 13, 2000: SPP proposes to establish itself as an RTO, with Entergy as an ICT.
- July 2001: FERC denies SPP's application to be recognized as an RTO.
- October 2001: Midwest ISO and SPP announce a plan to merge the two organizations.
- March 2003: Midwest ISO and SPP announce the termination of merger plans.
- October 2003: SPP re-files to establish status as a stand-alone RTO.
- February 2004: FERC approves SPP's proposal, with certain conditions.

SPP is responsible for:

- Development and modification of market rules
- Monitoring compliance with rules, standards, procedures and practices
- Monitoring structural problems in the market to guarantee competitiveness
- Operation of the bulk electric power system and inter-regional coordination
- Management of the wholesale electricity market
- Congestion management
- Planning, directing or arranging, the necessary transmission expansions, additions and upgrades, and coordinate such efforts with the appropriate state authorities
- Direction of the supply and coordination of the provision of ancillary services

2. INTERNAL ORGANISATION

2.1. *GEOGRAPHICAL COVERAGE AREA*

SPP covers the states of Kansas, Oklahoma and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas (see Figure 1), which have a total population of over 18 million people and a total area of 400,000 square miles.

The next Figure shows the geographical coverage area of the SPP.

Figure: SPP Geographical Coverage Area.

2.2. *SIZE OF THE MARKET*

Data from 2006 reveals that the actual annual energy load is 205,104 GWh, with a generating installed capacity of 48,267 MW, 5.5 % more than in 2005. In addition, peak demand in 2006 was 42,227 MW, 4.4 % more than in 2005.

2.1 OTHER CHARACTERISTICS OF SIZE & LEVEL OF COMPETITION

SSP has currently 46 members and serves more than 4 million customers. In covering a wide political and operational spectrum, SPP's current membership consists of 13 investor-owned utilities, seven municipal systems, nine generation and transmission cooperatives, two state authorities and one federal government agency, three independent power producers, and 12 power marketers.

2.3. BRIEF DESCRIPTION OF TRADE AGREEMENTS

2.3.1. MARKET OVERVIEW

SPP provides transmission service on the transmission facilities owned by its members and operates the region's real-time **Energy Imbalance Service** (EIS) market.

Market participants trade physical electricity bilaterally, either directly or through brokers, and through the EIS market. Bilateral contracts are self-scheduled.

The EIS is quite new in SPP launched only on Feb. 1, 2007. SPP system prices are based on **Locational Imbalance Prices** (LIP) which are determined through an economic constrained dispatch taking into account producers' offers and forecasted demand (i.e. demand do not bid in the market).

A Market Participant may generate a transaction (sale) in the imbalance market when either (a) it generates more than it has scheduled and/or (b) its actual load is less than it has scheduled. Similarly, a Market Participant may make a purchase when either (a) it generates less than it has scheduled and/or its actual load is more than it has scheduled.

2.3.2. CONGESTION MANAGEMENT

SPP manages congestion within the system by performing any (or all) of the following actions:

- re-dispatch of the Energy Imbalance market
- curtailment of schedules by the SPP Curtailment Adjustment Tool (CAT)
- by the NERC Interchange Distribution Calculator (IDC).

CAT is responsible for curtailing schedules within the SPP Market that are within a single Balancing Authority and for all schedules between internal Balancing Authorities that are sourced from SPP market offered resources. The IDC is responsible for curtailing schedules that cross the boundary of the SPP market footprint or that are between internal Balancing Authorities, but source from a Self-Dispatched Resource.

SPP has neither a day-ahead market nor a capacity market. Financial Transmission Rights (FTR) has not been implemented yet and there is not an ancillary services market.

3. GOVERNANCE

SPP is governed by a Board of Directors and several committees.

Board of Directors:

The Board of Directors consists of seven members, each of whom must be independent of any SPP Market Participant. Directors are elected to serve three-year terms and must have recent and relevant senior management expertise and experience in one or more of the following disciplines: finance, accounting, electric transmission or generation planning or operation, law and regulation, commercial markets, and trading and associated risk management.

A director is prohibited from serving as the director or officer of a Member or customer of services provided by SPP. Also, a director may not be employed by or have a direct business relationship, financial interest or other affiliation with a Member or customer of services provided by SPP.

Members Committee: The Members Committee consists of up to 18 persons representing stakeholders; four from investor-owned utility Members, four from cooperative Members, two from municipal Members (including municipal joint action agencies), three from independent power producers/marketers Members, one from a state/federal power agency Member, and two from alternative power/public interest Members; one from a large retail customer Member (defined as non-residential end-use customers with individual or aggregated loads of 1-MW or more); and one from a small retail customer Member (defined as residential customer and other customers with individual or aggregated loads of less than 1-MW).

The Members Committee is charged with working with the Board of Directors to manage and direct the general business of SPP. Specifically, the Members Committee (1) provides individual and collective input to the Board of Directors, and may participate in straw votes to indicate the level of consensus among Members concerning actions pending before the Board and (2) serve on committees reporting to the Board of Directors as appointed by the Board of Directors.

Markets and Operations Policy Committee: Each Member of SPP appoints a representative to this committee, which reports to the Board of Directors and is charged generally with recommending system design, transmission and resource adequacy practices, coordinating efforts with NERC, reviewing and recommending operating plans, and reviewing, recommending and developing inter- and intraregional plans.

Strategic Planning Committee: This 11-member committee reports to the Board of Directors, and is generally responsible for assessing the performance of SPP, establishing the organization's goals and vision, and reviewing its structure and recommending changes when necessary. The representatives on the committee include two Directors, the President, and four each from the Transmission Owners and Transmission Users sectors.

Compliance Committee: This committee is made up of three Directors, and monitors compliance with SPP and NERC policies, and recommends changes necessary for enforcement.

Regional State Committee: The governance structure of SPP also includes a Regional State Committee (RSC), which is comprised of one designated commissioner from each state regulatory commission having jurisdiction over a Member of SPP. The RSC provides direction and input on all matters pertinent to the participation of the Members in SPP. The RSC also has primary responsibility for determining regional proposals and the transition process in four areas: (1) whether and to what extent participant funding will be used to fund transmission expansions, (2) whether the regional access charge will be a license plate or postage stamp rate, (3) the allocation of Financial Transmission Rights, where a location price methodology is used, and (4) the transition mechanism to be used to assure that existing firm customers receive Financial Transmission Rights equivalent to their existing firm rights. Additionally, the RSC is charged with determining the approach to resource adequacy across the SPP region, and with determining whether transmission upgrades for remote resources will be included in the regional transmission planning process and the role of transmission owners in proposing transmission upgrades in the regional planning process.

There are also 3 more committees reporting to the Board of Directors: Human Resources Committee, Finance Committee, Corporate Governance Committee.

4. ACHIEVEMENTS

According to FERC, the EIS through SPP has not experienced any significant market issues since start-up in February 2007.

The annual average of Platts SPP North Daily Spot Price Index was the following for the last 3 years:

2004: $45.19/MWh

2005: $67.44/MWh

2006: $56.30/MWh

Prices increased in 2005 as a result of disturbances to the natural gas market. Prices declined in 2006 as natural gas storage levels remained above historical ranges throughout the injection season (April through October).

The daily average of SPP real time prices for the first half of 2007 are shown in next Figure. As illustrated, the average is around 50 $/MWh.

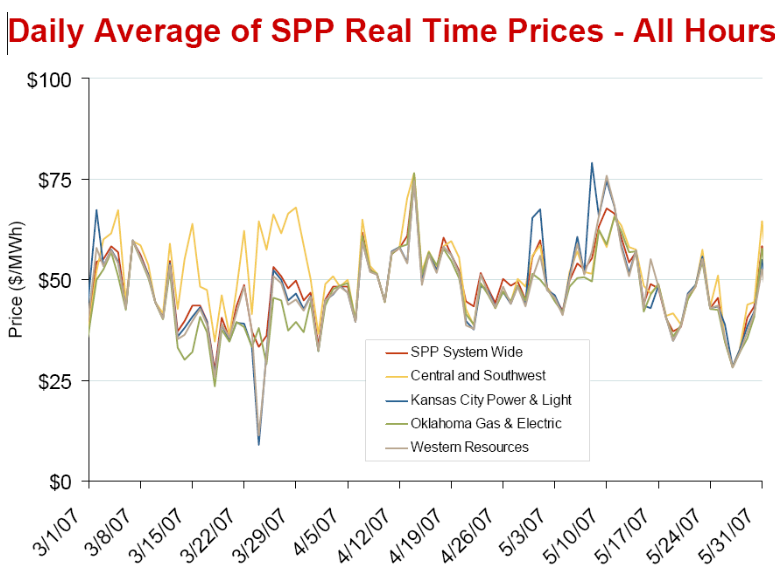


Figure: Daily average of SPP real time prices.

In next Figure, the available percentage (i.e. participation) in the EIS is shown for the different market participants (MP) in June 2007. In most cases (15 of 18 MP), there is a participation of more than 50% of available capacity.

MP	REDACTED Online MWh	REDACTED Available MWh	Available Percentage
AECC	***	***	0%
AEPM	***	***	93%
CALP	***	***	89%
EDEP	***	***	52%
EPV	***	***	74%
EXGN	***	***	64%
GRDX	***	***	1%
GSEC	***	***	89%
KBPU	***	***	74%
KCPS	***	***	65%
OGE	***	***	74%
OMPA	***	***	3%
REDB	***	***	77%
SECI	***	***	79%
SPSM	***	***	68%
TNSK	***	***	99%
WFES	***	***	90%
WRGS	***	***	84%

Figure: Depth of EIS Market. Participant Summary, June 2007.

Looking ahead in the SPP:

- Electricity sales are projected to grow between 1.6 and 2.0 percent per year from 1996 through 2015.
- Coal is the main fuel for the increased generation in 2005. Almost 3 GW of new coal-fired capacity is built, and capacity utilization increases from 70 percent in 1996 to 81 percent in 2005. By 2015, new coal-fired capacity reaches 5 GW.
- Between 2005 and 2015, natural gas-fired generation increases significantly. By 2015, 17 to 21 GW of new gas-fired combined-cycle units are built to meet the varying levels of electricity demand in the two competitive cases.
- With the renewable portfolio standard in the low fossil case, generation of electricity from renewable sources is over 3 times the 1996 levels. The growth comes from biomass and wind and reduces the need for increased coal and gas-fired generation.
- In 2015, natural gas consumption is 0.1 to 0.3 quadrillion Btu above 1996 levels, and coal consumption is by 0.4 to 0.5 quadrillion Btu higher than in 1996.

WESTERN SYSTEM POWER POOL

1. OBJECTIVES OF THE ORGANISATION

WSPP is the abbreviation for the Western Systems Power Pool. It is an industrial organization approved by the Federal Energy Regulatory Commission (FERC), which provides its members with a forum for short-term trade in electric energy, capacity and transmission services.

WSPP began as an agreement among a group of utilities in the western United States (California, Oregon, Washington, etc.). The agreement, which was filed with the FERC by Pacific Gas and Electric Company on behalf of the group, established a multi-state bulk power marketing experiment. The agreement was meant to test whether broader pricing flexibility for coordination and transmission services would promote increased efficiency, competition, and coordination. It first began as a FERC experiment for electricity trading in 1987 and became a formal entity in 1991.

The basis for these trades is a standardized agreement called the **WSPP Agreement**. This Agreement allows transactions to occur without constant renegotiation of contract terms. The Agreement was the result of a consensus of a wide group of representative sellers and buyers of electricity and electricity services, and promotes market liquidity by reducing uncertainties and risk.

2. INTERNAL ORGANISATION

2.1. *GEOGRAPHICAL COVERAGE AREA*

WSPP does not have a well-defined coverage area but their members are mainly from the Western States (see Figure below).

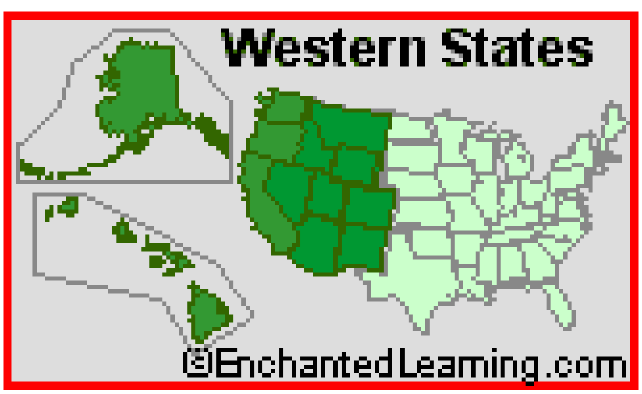


Figure: Western States of the US.

2.2. *SIZE OF THE MARKET*

There are more than 300 members in the WSPP from 22 states in the USA and a Canadian Province, serving 60 million people in total.

2.3. BRIEF DESCRIPTION OF TRADE AGREEMENTS

2.3.1. OVERVIEW OF THE MARKET

WSPP as a Mechanism rather than a market. The Western Systems Power Pool (WSPP) began as an agreement among a group of utilities in the western states, which established a multi-state bulk power marketing experiment. The agreement was meant to test whether broader pricing flexibility for coordination and transmission services would promote increased efficiency, competition, and coordination.

Its initial purpose was to allow sales of power for short-term transactions to take place with a maximum of flexibility and minimum of regulatory filings and to test market efficiency and competition.

The WSPP Agreement now represents a default, standardized contract for electric power sales and physical options. That is, if the parties to a WSPP transaction do not mutually agree to changes to the WSPP Agreement, the terms of the original WSPP Agreement will prevail. The WSPP Agreement, however, provides parties with the flexibility on the major terms to modify the agreement, by their mutual agreement, to be applied to any WSPP transaction. The WSPP Agreement only applies to transactions between WSPP members.

Under the WSPP Agreement, members are allowed to sell at market prices if they have received market based authority from FERC or if they are not regulated by FERC. For those members not eligible to sell at market prices, the WSPP Agreement contains price caps set at Seller's Incremental Cost plus up to 21.11 $/MWh.

Three basic products are set forth in the Service Schedules:

- Service Schedule A details **Economy Energy Service** in which the energy contracted is subject to interruption upon notification. The stipulated damage provisions do not apply to Economy Energy Service unless the parties agree. Specific terms and conditions may be negotiated.
- Service Schedule B details **Unit Commitment Service,** which is a sale from a specified unit for a specified period. Other than through *force majeure*, Unit Commitment Service may be curtailed based upon mutually agreed upon recall provisions such as: when all or a portion of the unit is unavailable; to prevent system separation during an emergency (provided that prudent alternatives to curtailment have been exhausted); for the Seller to meet its public utility or statutory obligations; or due to the unavailability of transmission service. The stipulated damages provision applies to failure to deliver or take Service Schedule B power unless the parties agree otherwise.
- Service Schedule C details the terms for **firm sales or exchange service**. Like Service Schedule B, the stipulated damages provision applies to failure to deliver or receive power. Firm service may be curtailed within mutually agreed to recall times, due to *force majeure*, or to meet public utility or statutory obligations. In the latter case, if the seller interrupts it will pay damages consistent with the terms of the WSPP Agreement.

In addition, the WSPP Agreement allows the sale of **Physically-Settled Options**, which include a call option (the right to buy Service Schedule B or C power) or a put option (the right to sell power under Service Schedules B or C).

Confirmation agreements include transaction-specific terms including changes to the base agreement, which the parties mutually agree to. Oral confirmation agreements are permitted for transactions of less than one week. Written confirmations are required for transactions of one week or more.

Upon request of purchaser or at the election of the seller, the seller must provide written confirmation within five days of the request or agreement. The purchaser has five days in which to respond. If purchaser does not respond, the seller's written confirmation shall be considered final. If the seller fails to provide a requested written confirmation, then the purchaser may submit a written confirmation within five days after the deadline for submitting a written confirmation. If seller fails to respond within five business days, the purchaser's confirmation is considered final. At any time if a party states that it will not accept modifications to the WSPP agreement proposed by one party, then those modifications will be rejected.

Unless the parties agree to different payment dates, payments are to be received on the 20th day of the invoicing month or the 10th day after receipt of the bill, whichever is later. Interest for late payments is one percent per month unless the parties agree to a different rate. In the event of a dispute, the entire bill shall be paid when due. Parties have two years to audit and dispute bills.

As a result of FERC's Order No. 888, the WSPP filed an open access transmission tariff for the system. This tariff is available to non-members as well as to members. It has very limited applicability, however, and only applies to members' facilities which are not subject to an open access transmission tariff. As a result, the tariff will apply only to a few smaller non-FERC regulated entities. The rates will be the rates posted by the transmission provider.

2.3.2. CONGESTION MANAGEMENT, ETC.

The following Operating Procedures apply to transactions within the WSPP Agreement:

Operating Procedure No. 1: Establishes communications requirements for interchange transactions. The seller, if it differs from the sending control area, shall provide the identity of parties providing control area services to the sending control area; the amount, rate of change and starting time of each schedule change, reserve responsibility, and the applicable recall provisions for each schedule; and the contract path for each schedule. The purchaser, if it is different than the receiving control area, is required to disclose this information to the receiving control area. The sending control area also is to provide this information to the receiving control area and intermediate control areas. To enact a WSPP transaction, at least one party is obligated to obtain or provide control area services. Parties providing control area services must adhere to NERC criteria with such responsibilities to include timely and accurate communication of schedules and schedule changes. If scheduling problems occur, parties should attempt to work them out informally; if that does not work, then complaints may be made to the Chair of the Operating Committee.

Operating Procedure No. 2: Each WSPP member must have continuous coverage. This means ensuring that personnel are immediately available and able to take immediate corrective action for 24 hours per day for all WSPP transactions. This requirement may be satisfied by contracting response and corrective measures with a third party.

Operating Procedure No. 3. breaks down firm sales into two categories: C1 and C2 transactions. C1 transactions are backed by "Seller's system capacity reserves." Financial remedies cannot be used as a substitute for reserves. C1 transactions must be scheduled as firm. C2 transactions are other Service Schedule C transactions.

Operating Procedure No. 4: A Party proposing a change to the WSPP Agreement through a Confirmation Agreement shall show or indicate clearly to the other Party the changes it proposes through red-lining, notation, or other methods which highlight the changes.

3. GOVERNANCE

WSPP is governed thorough 4 specific committees:

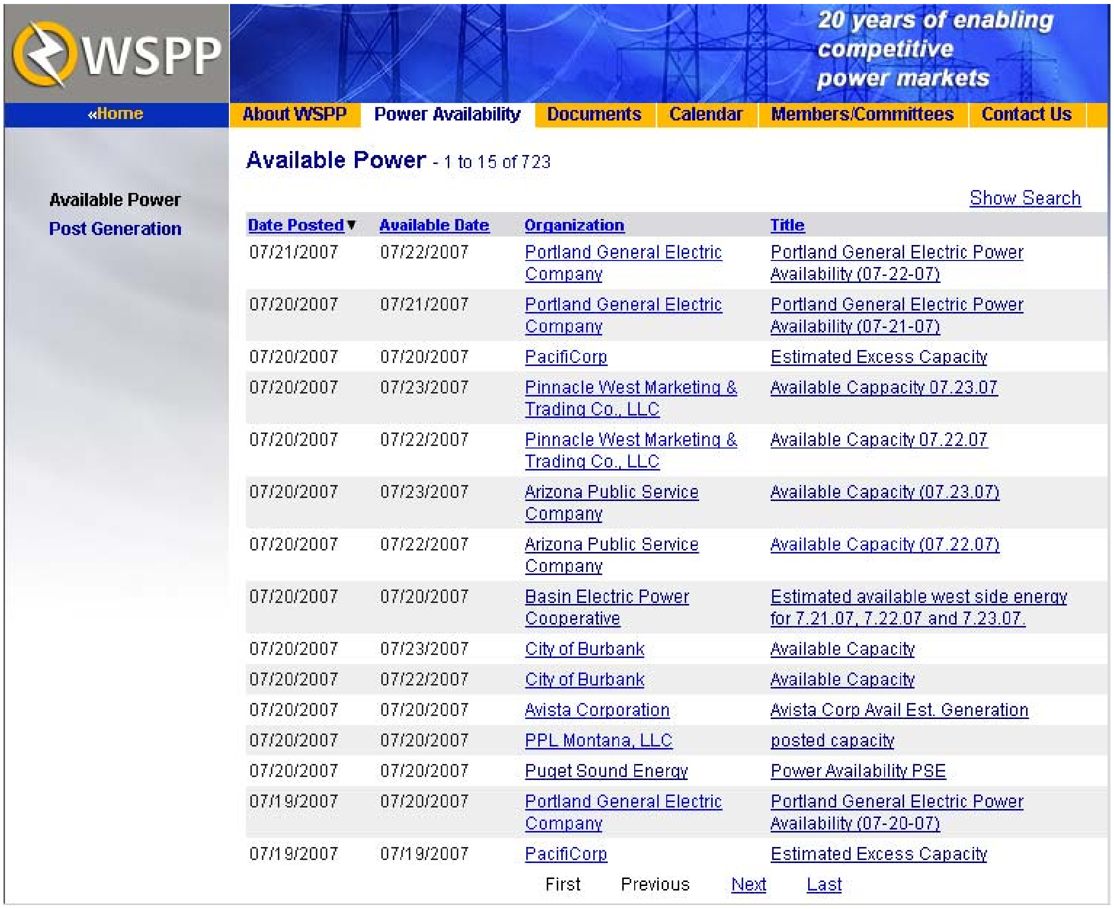
- **Operating Committee (OC)** – the OC performs the first evaluation of contract changes. It also establishes operating procedures and procedures for evaluating membership applications, and its recommendations then are forwarded to the Executive Committee for decision. OC officers include a Chairman, Vice Chairman, and Secretary.
- **Executive Committee (EC)** – the EC decides whether to adopt OC recommendations in contract changes and membership to the WSPP. Consensus is required given the 90 percent voting requirement to make changes. Any changes to the WSPP documents are filed with FERC and do not take effect until FERC accepts the filing. Each member of WSPP is represented on the EC, and is considered a board member as defined by law. EC officers include a Chairman, Vice Chairman, and Secretary.
- **Administrative Committee** – the Administrative Committee is made up of the Chairman, Vice Chairman, and Secretary of the EC, and the Chairman and Vice Chairman of the OC. Their task is to execute the administrative affairs of the organization including budgeting, auditing, contract administration, financial management, and legal management.
- **Audit Committee** – The duty of the Audit Committee is to annually review the financial condition and financial systems employed by the organization.

Other ad-hoc committees may be created to address specific issues as needed.

4. ACHIEVEMENTS

The WSPP provides a mechanism to facilitate the ease of short-term power sector transactions among a wide range of sector stakeholders in the western United States. In addition, the WSPP has been successful in providing reliable and timely information to its members (and other stakeholders), which illustrates its success in promoting transparent and competitive transactions.

Power availability offers from sellers are posted daily at WSPP Web page in advance for the next day or few days. From March to July 2007 more than 700 offers have been posted. For example, looking at 20th July 2007 (see next Figure), there were 12 offers made, summing a total capacity of around 1000 MW. This does not represent a large amount considering the western states' total installed capacity, but it certainly represents an interesting mechanism for short term opportunity energy trading.



Date Posted ▼	Available Date	Organization	Title
07/21/2007	07/22/2007	Portland General Electric Company	Portland General Electric Power Availability (07-22-07)
07/20/2007	07/21/2007	Portland General Electric Company	Portland General Electric Power Availability (07-21-07)
07/20/2007	07/20/2007	PacifiCorp	Estimated Excess Capacity
07/20/2007	07/23/2007	Pinnacle West Marketing & Trading Co., LLC	Available Cappacity 07.23.07
07/20/2007	07/22/2007	Pinnacle West Marketing & Trading Co., LLC	Available Capacity 07.22.07
07/20/2007	07/23/2007	Arizona Public Service Company	Available Capacity (07.23.07)
07/20/2007	07/22/2007	Arizona Public Service Company	Available Capacity (07.22.07)
07/20/2007	07/20/2007	Basin Electric Power Cooperative	Estimated available west side energy for 7.21.07, 7.22.07 and 7.23.07.
07/20/2007	07/23/2007	City of Burbank	Available Capacity
07/20/2007	07/22/2007	City of Burbank	Available Capacity
07/20/2007	07/20/2007	Avista Corporation	Avista Corp Avail Est. Generation
07/20/2007	07/20/2007	PPL Montana, LLC	posted capacity
07/20/2007	07/20/2007	Puget Sound Energy	Power Availability PSE
07/19/2007	07/20/2007	Portland General Electric Company	Portland General Electric Power Availability (07-20-07)
07/19/2007	07/19/2007	PacifiCorp	Estimated Excess Capacity

Figure: Available power posted on 20th July 2007 at WSPP Web page.

MID-WEST ISO

1. OBJECTIVES OF THE INSTITUTION

MISO is the abbreviation for Midwest Independent System Operator. It is a Regional Transmission Organization (RTO) covering 13 states of the USA and the Canadian province of Manitoba. As a RTO and system operator it is a neutral party managing the wholesale electricity market and monitoring the transmission grid to guarantee reliability.

MISO was founded as an ISO in 1996 and was approved by the Federal Energy Regulatory Commission (FERC) as a RTO, in 2001, being the first RTO in the USA. The MISO timeline is shown below:

- February 12, 1996: MISO is formed.
- October 19, 2001: Southwest Power Pool (SPP) reaches a consolidation agreement with MISO.
- December 19, 2001: MISO files for RTO status and receives approval from FERC.
- June 20, 2002: Ameren, FirstEnergy, Northern Indiana Public Service Co. form GridAmerica LLC to serve the MISO territory. The three Midwest utility companies also signed a letter of intent with National Grid outlining how National Grid will manage the new transco. GridAmerica is the nation's first multi-system Independent Transmission Company (ITC).
- December 23, 2002: FERC accepts MISO's revised Open Access Transmission Tariff (OATT) (Docket No. ER03-86-000). The tariff will allow Independent Transmission Companies (ITCs) to assume some RTO functions and operate within MISO's territory.
- September 23, 2003: The Midwest Stand-Alone Transmission (MSAT) group is formed. Members include American Transmission Company LLC, GridAmerica, International Transmission Co., and the Michigan Electric Transmission Company LLC. The purpose of MSAT is to address the concerns of transmission companies by advocating policies focused on the transmission infrastructure within MISO.
- October 1, 2003: GridAmerica LLC begins electricity transmission operations.
- December 31, 2003: PJM Interconnection enters into a Joint Operation Agreement (JOA) with MISO.
- March 31, 2004: MISO files its Energy Market Tariff with FERC.

MISO has the following responsibilities:

- Development and modification of market rules
- Monitoring compliance with rules, standards, procedures and practices
- Monitoring structural problems in the market to guarantee competitiveness
- Operation of the bulk electric power system and inter-regional coordination
- Management of the wholesale electricity market (day-ahead and real time market)
- Congestion management (Financial Transmission Rights, FTR management)
- Planning, directing or arranging, the necessary transmission expansions, additions and upgrades, and coordinate such efforts with the appropriate state authorities
- Direction of the supply and coordination of the provision of ancillary services

2. INTERNAL ORGANIZATION

2.1. GEOGRAPHICAL COVERAGE AREA

MISO covers the states of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, Illinois, Indiana, Michigan and parts of Montana, Missouri, Kentucky, and Ohio, and the Canadian Province of Manitoba (see next Figure), which have a total population of around 66 millon people and a total area of 750,000 square miles.

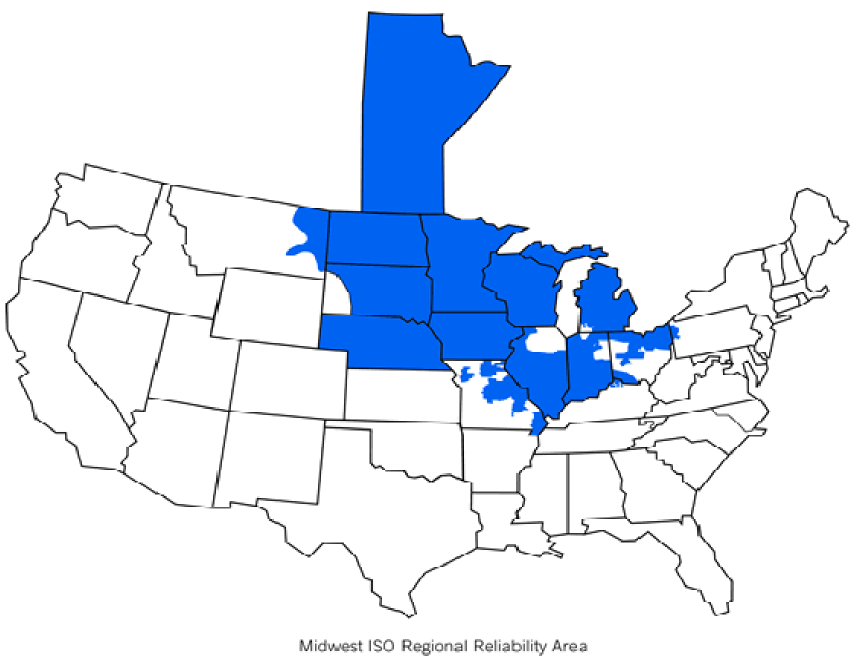


Figure: MISO Geographical Area.

2.2. SIZE OF THE MARKET

MISO is one of the world's largest energy markets with 98,600 miles of interconnected high voltage power lines that support the transmission of more than 100,000 MW of energy in the Midwest. Data from 2005 and 2006 reveals that the actual annual energy load is 607,474 GWh (2005), with a generating installed capacity of 137,232 MW (2006), 0.6 % more than in 2005. In addition, peak demand in 2006 was 116,207 MW, 3.6 % more than in 2005.

2.3. OTHER CHARACTERISTICS OF SIZE & LEVEL OF COMPETITION

MISO consists of several Transcos, utilities, co-ops and others. Because of the size of its territory, it has faced numerous questions concerning transmission and seam issues. On June 2002, Ameren, FirstEnergy (on behalf of its American Transmission Systems Incorporated subsidiary), Northern Indiana Public Service Co., and National Grid established terms for joining the MISO through the companies' participation in an independent transmission company. The three Midwest utility companies also signed a letter of intent with National Grid outlining how National Grid will manage this transco - GridAmerica, LLC.

Leaders of MISO, the Southwest Power Pool (SPP), and the PJM Interconnection were working with energy market participants and regulators to develop a plan for conjoining their three RTOs by 2005. On December 31, 2003, MISO and PJM filed a Joint Operation Agreement (JOA) with FERC, establishing procedures and strengthening reliability for both RTOs. It is hoped that the relationship will forge seamless operations for wholesale customers in 22 states and Canada.

2.4. BRIEF DESCRIPTION OF TRADE AGREEMENTS

Participants can trade energy within the MISO either in the:

- Day-Ahead Market
- Real Time Market
- Bilateral Transactions.

2.4.1. DAY-AHEAD MARKET

The Day-Ahead Market is a forward market in which hourly clearing prices are calculated for each hour of the next Operating Day based on the concept of **Locational Marginal Prices** (LMP). The Day-Ahead Energy Market is cleared using **Security-Constrained Unit Commitment** (SCUC) and **Security-Constrained Economic Dispatch** (SCED) computer programs to satisfy energy demand bid requirements (including Fixed Demand Bids, Price-Sensitive Demand Bids, and Virtual Demand Bids) and supply requirements (Fixed Supply Offer, Price-Sensitive Supply Offers, and Virtual Supply Offers) of the Day-Ahead Energy Market. The results of the Day-Ahead Energy Market clearing include hourly LMP values, hourly demand and supply quantities, and hourly **Balancing Authority** (BA) **Net Scheduled Interchange** (NSI).

2.4.2. REAL-TIME ENERGY MARKET

The Real-Time Energy Market is a “balancing” market in which the LMPs are calculated every five minutes, based on MISO dispatch instructions and actual system operations. The same SCED program used in the Day-Ahead Market is used in Real-Time to identify dispatch signals to be sent to generating units. Generators that are available but not selected in the Day-Ahead Energy Market may alter their Offers for use in the Real-Time Energy Market.

Locational Marginal Prices (LMPs) vary by time and location. Variances in LMPs are due to physical limitations, congestion, and loss factors. In an unconstrained system with no losses, all LMPs are equal.

LMP prices are aggregated into five hub prices that provide participants with price indices. These regional pricing points are the Minnesota, Michigan, Illinois, Cinergy and First Energy hubs. LMP and hub prices give participants better market information than was previously available.

2.4.3. BILATERAL TRANSACTIONS

Market Participants can also take part in Bilateral Transactions. These can be represented to the market by submitting Financial and Physical Schedules between specified counterparties and locations. Though Bilateral Transactions remove the energy component from market settlements (settled between the seller and the buyer outside the market), these transactions are still subject to Congestion and Loss charges between the source and the sink locations specified in the transaction. There are 2 types of Bilateral Transactions, Financial and Physical.

A **Financial Bilateral Transaction** is an agreement between two Midwest Market Participants for the sale and delivery of energy between two Commercial Pricing Nodes in either the Day-Ahead or Real-Time Market based on the terms in the approved Financial Contract. Financial Bilateral Transactions are maintained in the Financial Scheduling System and consist of both a Financial Contract and Financial Schedule.

A **Physical Bilateral Transaction** is an agreement between two Midwest Market Participants for the sale and delivery of energy between two Commercial Pricing Nodes in either the Day-Ahead or Real-Time Market based on flowing energy into, out of, or through the footprint. Dynamic schedules, Pseudoties, and Grandfather Carve Outs also require physical schedules. All Physical Schedules specify an OASIS reservation number, a Point-of-Receipt (POR), a Point-of-Delivery (POD), a source and sink MW quantity, and the applicable time period.

Managing Congestion, Reliability and Adequacy of Supply

Midwest ISO has a **Financial Transmission Right (FTR) Market**, which provides an opportunity for Market Participants to acquire FTRs to manage the risk of congestion cost in the Day-Ahead Energy Market. FTRs are financial instruments, and do not represent a physical right for delivery of energy. FTRs provide a mechanism to hedge the congestion costs between the Point of Receipt and Point of Delivery of the FTR in the Day-Ahead Market. Only Market Participants can hold FTRs. MISO organizes annual and monthly FTRs auctions, and there is also a secondary market for FTRs.

Midwest ISO is responsible for the system reliability.

Planning Reserves addresses the ability of the system to meet the energy requirements of its participants on a long-term basis. Load Serving Entities (LSE) are responsible for procuring enough resources to meet their State or Regional Reliability Organization (RRO) requirements for Resource Planning Reserves. RROs have typically imposed planning reserve standards such that LSEs must demonstrate they have less than one day in ten years Loss of Load Expectation (LOLE). Midwest ISO is forming a Planned Reserve Sharing Group (PRSG) in order to assist its members in meeting the ReliabilityFirst Corporation, Midwest Reliability Organizations and Southeastern Reliability Council (SERC) standards for Resource Planning Reserves.

In its role as administrator of the PRSG, the Midwest ISO will perform the required LOLE studies, gather data from member LSE's, monitor compliance, and report back to the RRO's.

In addition, on June 6, 2006, the Midwest ISO submitted a Resource Adequacy filing to FERC outlining a two phased approach to a "permanent resource adequacy plan" for the Midwest ISO region that focuses on both, the region's short term reliability needs and encourages long-term planning and investment in the infrastructure.

Phase I of the plan will focus on the short-term reliability of the Midwest ISO region through the integration of Contingency Reserves and Regulation Services into the existing Energy Markets. Phase I is being addressed via the Ancillary Service Market Project.

Phase II of the plan will focus on the longer-term reliability needs of the region such as long term planning, demand side management programs, long-term Financial Transmission Rights and national industry standards that are currently under development.

3. GOVERNANCE

MISO is governed by an independent Board of Directors and also has two Committees, as described below.

Board of Directors:

The Board of Directors consists of 7 members plus the President, elected by Members by a single vote for each position from among a group of candidates selected by an independent executive search firm.

After the initial set up of the Board, each Director shall serve a three-year term, except those elected by the Board to fill a vacancy in the remainder of a term.

The Board selects from among its members a Chairman.

A Board member may be removed for cause upon production of a petition signed by twenty percent of all Members and a subsequent majority vote of the Members.

Of the seven candidates, four must have expertise and experience in senior management corporate leadership, or in finance, accounting, engineering or utility laws and regulation. Of the other three Directors, one must have expertise and experience in the operation of transmission; one must have expertise in transmission planning; and one must have expertise in commercial markets, trading and risk management.

Within two years prior to or subsequent to election to the Board, no Board member shall have been a director, officer, or employee of a Member, user or affiliate. During service, and for two years after service as a Director, no Board member may have a material business relationship or other affiliation with any Member or User or an affiliate of a Member or User. Participation in a pension plan is not deemed a material relationship if the plan does not involve ownership of securities of the company sponsoring the plan.

Committees:

There are two stakeholder committees – an Advisory Committee and an Owners Committee. The Advisory Committee consists of twenty-three representatives, three representatives of owners; three representatives of municipals or cooperatives and transmission-dependent utilities; three representatives of independent power producers and exempt wholesale generators; three power marketers; three eligible end-use customers; three representatives of state regulatory authorities; two representatives of public consumer groups; two representatives of environmental and other stakeholder groups; and, one representative Member (being unable to transfer operational control to Midwest ISO) who has entered into a coordination agreement with Midwest ISO.

The Board is authorized to revise or expand stakeholder groups, and must facilitate quarterly meetings with the Advisory Committee.

The Owners Committee consists of one person representing each of the Owners.

4. ACHIEVEMENTS

MISO has administered the two-settlement (day ahead and real-time) energy market or Day-2 market since April 2005.

For 2005 and 2006, Annual Average Day-Ahead Price at Cinergy Hub were 50.54 $/MWh and 40.44 $/MWh respectively.

In 2005 prices increased as a result of disturbances to the natural gas market. Prices declined in 2006 as natural gas storage levels remained above historical ranges throughout the injection season (April through October).

The daily average of MISO day ahead prices are shown in next Figure for the period January 2006 - June 2007. As it can be seen the average is around 50 $/MWh.

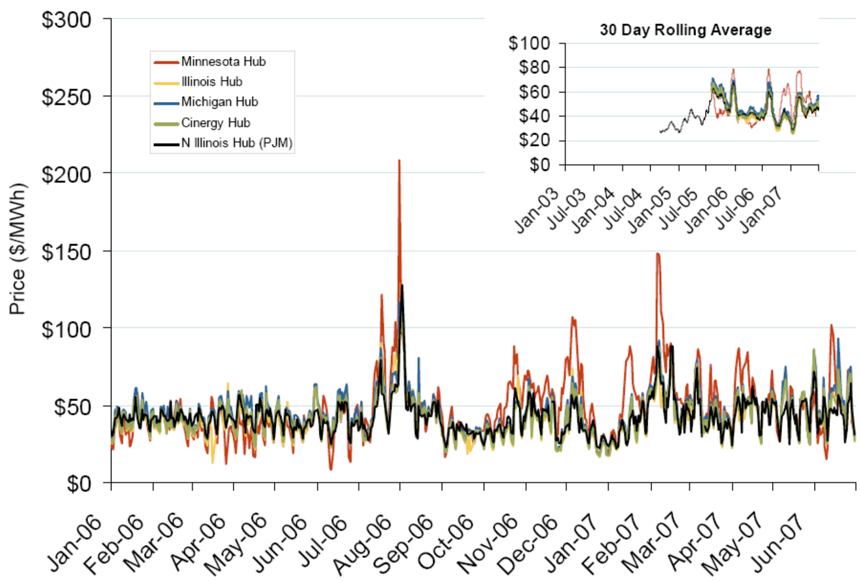


Figure: Daily average of MISO day ahead prices.

Minnesota hub prices have been volatile over the past year, at times moving significantly above or below other MISO hubs. Possible contributing factors could have been long-term generator outages and de-rates due to maintenance, a supply of large base-load units, higher than expected summer temperatures, and decreased imports into the Minnesota region.

Since the start of the Day-2 market, persistent transmission constraints in the Wisconsin, Upper Peninsula of Michigan (WUMS) and Minnesota areas have caused their prices to diverge from other areas of MISO, usually at times of high loads or decreased generation supply.

According to FERC, Midwest bilateral trading is active on the Intercontinental Exchange (ICE) at the Cinergy Hub and Northern Illinois Hub.

SIEPAC

1. OBJECTIVE OF THE INSTITUTION

SIEPAC means "Sistema de Interconexión Eléctrica de los Países de América Central" Electric Interconnection System for the Countries of Central America.

This is an initiative of the Central America countries that in 1996 signed a Treaty (agreement) to develop a regional transmission system and a regional electricity market in Central America: MER ("Mercado Eléctrico Regional" – Regional Electricity Market).

Therefore, the SIEPAC project has two main objectives: (i) the gradual formation and consolidation of a regional electricity market through the creation and establishment of the appropriate legal, institutional, and technical mechanisms to promote private sector participation, specially in the development of additional generating capacity; and (ii) the development of an electric interconnection infrastructure (230 kV transmission lines with a capacity of 300 MW with the corresponding substations) to facilitate trading of electric power among the agents of the regional electricity market.

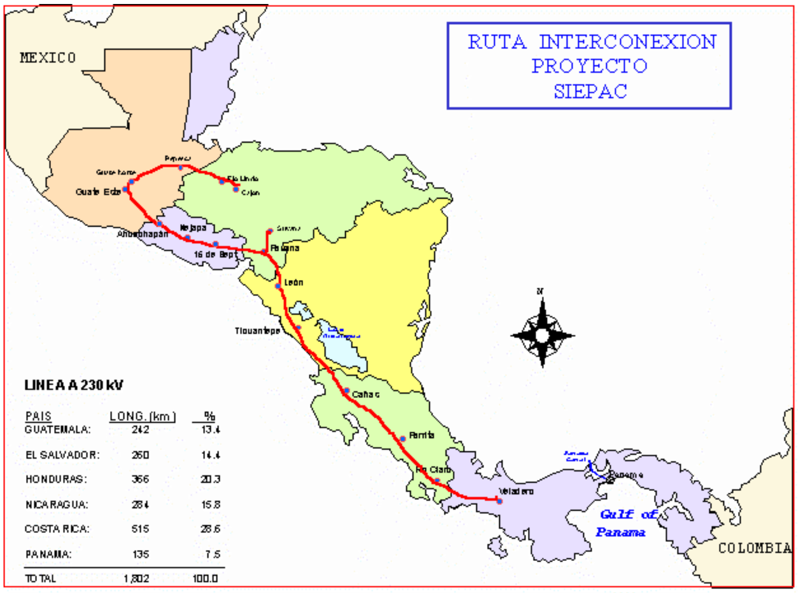
2. INTERNAL ORGANISATION

2.1. Geographical Coverage Area

The Central American regional electricity market currently consists of six countries: El Salvador, Guatemala, Honduras, Nicaragua, Costa Rica and Panama. Another country in the region, Belize, is not yet integrated to the regional electricity market

The next Figure shows the geographical area of the market:

The next Figure presents the transmission infrastructure that links the different countries and which is the support for trading.



2.2. Size of the Market

SIEPAC is not a typical "market" where many agents trade in. The solution found for trading fluently, given the fact that the countries had different organisations of their electricity sectors, was to create a "seventh market" (there are six countries currently integrating the regional market) where trade would be performed. This seventh market has its own rules and institutions, with interfaces with the countries' in a pragmatic and realistic solution that allows the development of transactions.

The main characteristics of the countries / electric systems that benefit from this regional market are shown in the following Figures.

Country	Population Millions	Energy Produced GWh	Capacity MW
Guatemala	12,7	7220,5	2087,7
El Salvador	6,9	4943,4	1231,8
Honduras	7,3	5624,8	1450,4
Nicaragua	5,5	2808,4	757,2
Costa Rica	4,3	8146,3	1961,2
Panamá	3,2	5774,5	1575,3

2.3. BRIEF DESCRIPTION OF TRADE AGREEMENTS

2.3.1. GENERAL DESIGN OF THE MER

The development of a final Transmission Code (TC) and the Grid and Settlement Code follow the concepts and criteria established in the General Design. Some of the more relevant dispositions of the General Design are:

- The MER constitutes the seventh market, superposed with the existing markets in the six countries.
- Market participants of the six countries are allowed to participate in the MER
- Two regional institutions are created:
- CRIE (regional regulatory agency)
- EOR (independent system and market operator)
- Countries can preserve local regulations, with the changes necessary for compatibility with regional codes.
- The Regional Transmission Grid (RTR) is defined as where international trade occurs and is monitored by the EOR. The RTR is formed by existing interconnections between countries; parts of the existing countries grids, the SIEPAC project, and planned and risk expansions of the RTR.
- Ex-ante and ex-post prices will be set in each node of the RTR, taking into consideration losses and congestion.
- Day ahead spot market and real time balance.
- The rules for transmission access must allow firm contracts; this means contracts that can be physically dispatched when requested by the parties.
- Parties of firm contracts must obtain Congestion Rights (CR) between the injection and withdrawal nodes.
- The EOR must organize periodic auctions of CR where market participants will be able to obtain CR.
- Transmission Use of System Charges (TUOS) will have three components:
- Variable costs, associated to losses and congestion
- Toll, based on actual flows in the lines
- Complementary charge: the part of the regulated revenues requirements of transmission companies not collected through toll and variable costs.
- Development of the RTR will be centrally planned by the EOR
- Market participants of third parties are allowed to build their own transmission facilities. Sponsors of this type of expansions will receive the CRs corresponding to the new facilities, and may get the right to perceive a toll.

It is worth mentioning that at the moment four countries have restructured their electricity sectors, partially privatized their generation and distribution activities, and have created wholesale electricity markets with rules that are somewhat different. Therefore, it was necessary to identify and design suited interfaces for the interaction between the countries markets' and the regional (seventh) market.

2.3.2. TRANSITORY CODE

a) *Day-ahead dispatch: a joint energy and transmission auction*

An hourly day-ahead energy and transmission dispatch is currently in operation in Central America for international electricity trade transactions. The dispatch mechanism allows market participants (generators, distributors, eligible large customers) to submit energy-only bids and offers and requests for point-to-point transmission services; while the charges for transmission services are calculated through a regulated procedure.

In a spot market that is based on nodal prices, the price of energy and the price of the transmission services are closely bound. The difference in the price of energy between two nodes is equivalent to the price of "using" the transmission service, i.e. the variable transmission charges or CVTs[3].

Before commissioning the connecting line between El Salvador and Honduras (230 kV) early in 2002, Guatemala and El Salvador formed the Northern subsystem while Honduras, Nicaragua, Costa Rica and Panama formed the Southern subsystem.

Guatemala and El Salvador exchanged energy at their common border. Honduras, Nicaragua, Costa Rica and Panama, additionally to the trade between neighbouring countries at the common border, reached an agreement on a methodology for the establishment of "wheeling" charges- i.e. to determine the charges for the transmission services provided to international transactions in which neither the seller nor the buyer is

[3] CVTs – Costos Variables de Transmisión (variable transmission costs).

located in the "wheeled" sub-system (that providing the transmission service). This represented an important step in the process of integration.

The wheeling charges were simply the difference of short-run marginal costs at the border substations (SRMC extraction – SRMC injection), i.e. the CVTs. A regional working group used to meet regularly to carry out calculations of the CVTs for "wheeling" transactions - per season (wet/dry), demand level (peak/off-peak), level and direction of wheeling. The CVT curves ($/MWh vs. MWh) measure the expected impact of a pass-through transaction on the transited system (Nicaragua and Costa Rica). If CVT < 0.0 then CVT = 0.0; i.e. if a given pass-through transaction reduces the losses of the transited system, the transaction receives no compensation, and makes no payment.

The Transitory Code (RT MER) includes a day-ahead dispatch that can be seen as a "natural" extension of previous practices in the Southern subsystem since it continues using the CVT curves (now for El Salvador and Honduras – potentially transit systems –, in addition to Nicaragua and Costa Rica).

The RT MER allows energy-only bids (demand) and offers (supply), i.e. the opportunity market, as well as transmission services bids (demand). The supply curves for transmission services are "regulated", i.e. the charges for transmission services are evaluated as: CVTs + operative toll (for the tie-lines only). The basic contracts in the RT MER are: (1) financial, considered in the net settlement and with no impact on the dispatch other than through bids and offers to the opportunity market; (2) physical flexible, which are requests for transmission services between two nodes and a maximum price that the bidder is willing to pay for the requested transmission services; and (3) physical flexible, where the bidder may replace his injection (or part of it) by purchases in the opportunity market (at a specified maximum price).

Although the scheme has been an in-house development in the region, similar ideas are being applied or proposed in other markets, e.g. option (2) has recently been introduced at PJM and a very similar scheme has been proposed to auction the tie-lines transmission capacity in Europe.

For the opportunity market, the algorithm "matches" supplies and demands, taking into account payments to "wheeled" countries (CVTs + operative toll). The opportunity market "competes" for the transmission services with the demands for the "pure" wheeling services associated to contracts. The EOR does not have information on the prices of these contracts, solely the prices that the agents are willing to pay for the wheeling services, balanced injection/extraction in pairs.

b) Operative toll

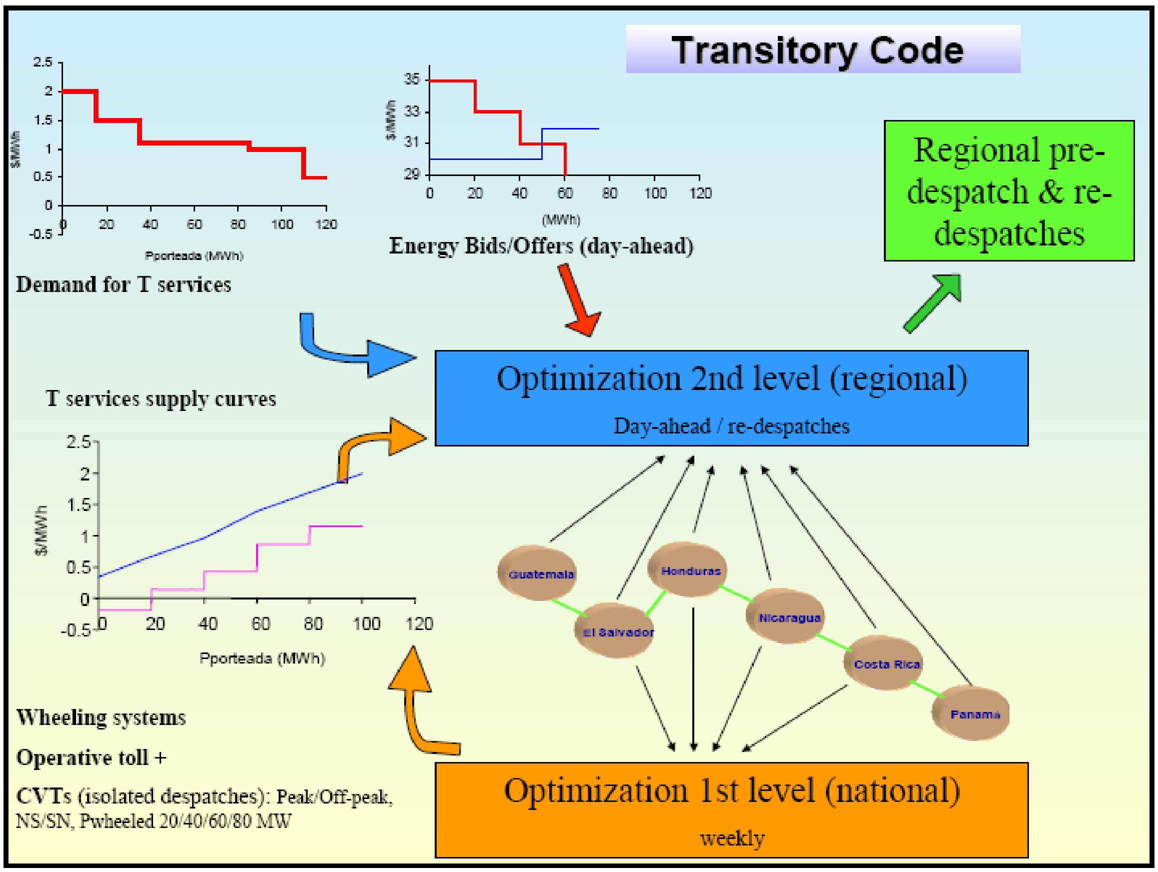
In the final regulation of the MER the application of a non-operative toll is being considered, i.e. independent of the transactions that occur in the MER. In the RT MER though, an operative toll is being used, i.e. applicable to the transactions that occurs in the MER. The toll ($/MWh) is applied only to the energy transmitted through the tie lines between the countries. The operative toll values approved by the CRIE as an Annex of the RT MER, are available at http://www.omca.net/. The operative toll causes a dead weight loss but its impact on transactions does not seem to be important.

c) The regional dispatch

The total charges for the transmission services is then the sum of the CVTs plus the operative toll, i.e. the resulting curve of total charges ($/MWh vs. MWh) is a curve displaced upwards with respect to the CVTs curve.

The CVT curves are calculated weekly ex-ante by the EOR through simulations of the economic dispatch of the wheeling system (isolated dispatch). The CVT curves are evaluated at discrete points characterized by the demand period (e.g. peak / off-peak), magnitude (0, 20, 40, 60 and 80 MWh) and direction of the wheeling service (North to South / South to North), modeling the whole transmission system, i.e. from border to border. The CVT ($/MWh) is the difference of marginal costs between the nodes of retirement and injection. The CVTs are thus "anchored" to the wheeling systems prices estimated from expected average conditions, which causes some inaccuracies. Additionally, if CVTs < 0.0 the CVTs = 0.0 which causes some inefficiencies.

The next Figure shows in an schematic way how the transitory code functions.



3. GOVERNANCE

The Central America regional market began with the signature by the countries of a treaty ("Tratado Marco del Mercado Eléctrico de América Central" – Central America Regional Electricity Market Treaty).

This Treaty provides de juridical basis for the operation of the regional market as well as the institutions involved. This treaty opens the national markets to the regional market; it allows trading to agents of different countries and at the same time provides open access to the transmission capacity.

From the point of view of the regional institutions, the Treaty creates two regional institutions and gives a concession. The regional institutions created are: the CRIE and the

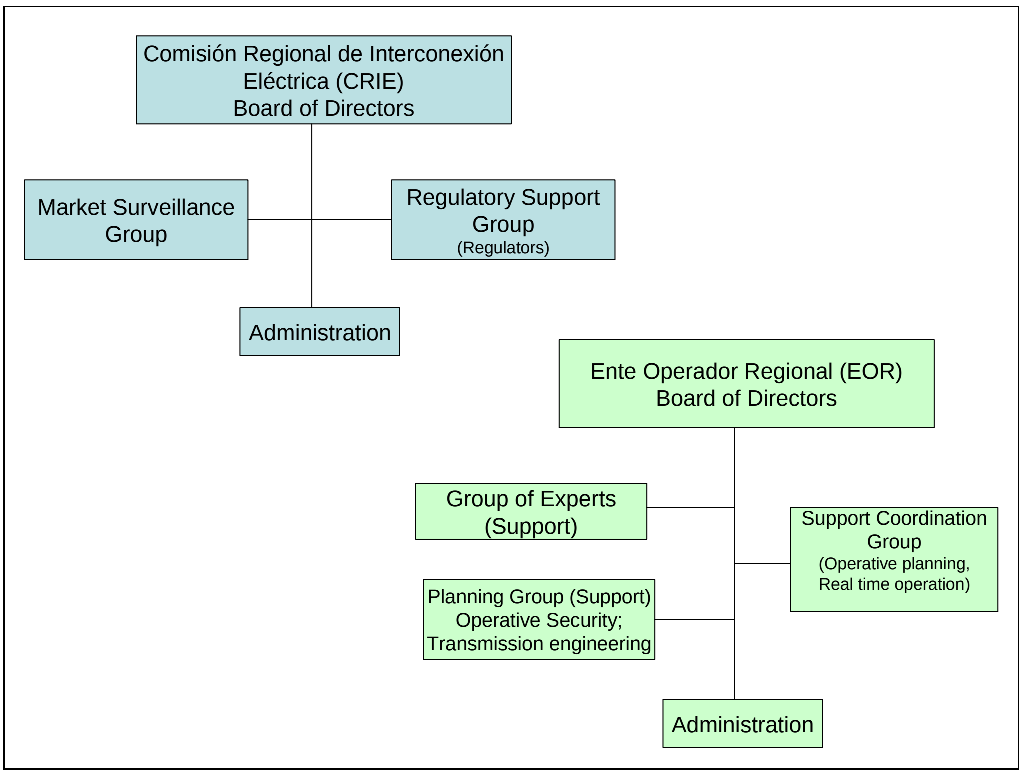
EOR; the Treaty also gives a concession to construct and operate the regional transmission infrastructure.

CRIE (Comisión Regional de Interconexión Eléctrica – Regional Electricity Interconnection Commission) is a regional institution whose main responsibility is to ensure that the Treaty is observed and it also functions as the regional regulator.

EOR (Ente Operador Regional – Regional Operator) is the regional institution in charge of the regional system and market operation.

EPR (Empresa Propietaria de la Red – Company Owner of the Grid) is the company that has been awarded a concession to build the regional transmission system and operate it.

The next Figure shows the organization of the governance of the regional market.



4. ACHIEVEMENTS

It is not necessary to have an (almost) uniform regulatory framework for developing a regional market. In Central America there are four countries that have transformed and deregulated their electricity sectors, while two maintain their organization unchanged.

The countries that deregulated the sectors have different regulatory frameworks, with some important differences. One of the countries that did not deregulate, has an important participation of IPPs in its generation sector.

The solution of creating a regional market (the seventh market), with its own rules and institutions, with interfaces with the countries' markets is a pragmatic and realistic solution that allows the development of transactions.

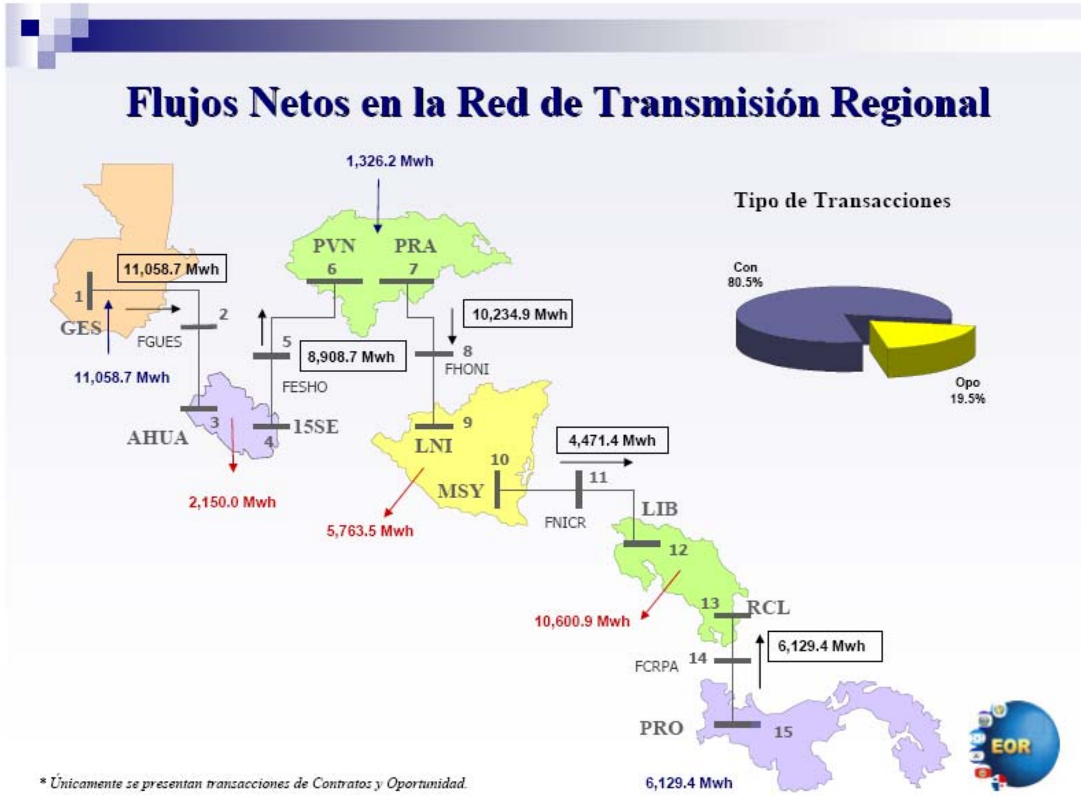
The limited capacity of existing interconnections was not an obstacle. Nowadays the transactions between agents of different countries saturated several of the existing interconnections.

The regional market is functioning and although there are still developments required, the market is functioning with a certain institutionalism and transparency. The EOR (regional market operator) clears the transactions and informs in its website (www.enteoperador.org).

As an example, part of the information provided by the EOR in its website is presented in the next Figures. This corresponds to the report of the month of December 2006. Monthly information is available from November 2002 in the website.

País	Contrato (MWh)		Oportunidad (MWh)		Total General (MWh)		Total Neto (MWh)	
	iny	ret	iny	ret	iny	ret	iny	ret
Costa Rica	862.3	11,463.2	0.0	0.0	862.3	11,463.2		10,600.9
El Salvador	0.0	2,050.0	0.0	100.0	0.0	2,150.0		2,150.0
Guatemala	7,899.8	0.0	3,158.9	0.0	11,058.7	0.0	11,058.7	
Honduras	463.7	0.0	975.8	113.3	1,439.5	113.3	1,326.2	
Nicaragua	0.0	2,607.7	0.0	3,155.7	0.0	5,763.5		5,763.5
Panamá	7,697.0	862.3	4.0	709.3	7,701.0	1,571.6	6,129.4	
Total	16,922.8	16,983.2	4,138.7	4,078.3	21,061.5	21,061.5	16,364.4	16,364.4

Energy "injected" and "extracted" by countries and according if it was due to contracts or opportunity exchanges



Net flows of energy in the regional grid

SOUTHERN AFRICAN POWER POOL

1. INTRODUCTION

The Southern African Power Pool is an association covering the SADC countries exclusive of Mauritius.

The cooperating countries are: Angola, Botswana, DRC, Lesotho, Malawi, Mozambique, Namibia, South Africa, Swaziland, Tanzania, Zambia and Zimbabwe. Out of the 12 countries 9 are connected in a meshed network.

In 1980 the Lusaka Declaration saw the creation of the Southern African Development Co-ordination Conference (SADCC) which facilitated regional co-operation and co-ordination. This was later transformed into the Southern African Development Community (SADC) and has been the impetus for various initiatives to make Southern Africa a strong contender in global affairs, particularly in the sphere of economics.

In the Southern African region there is a lot of hydro power in the northern areas and thermal generation in the southern part.

There has been cooperation between the national power companies in the SADC region for several decades, but regional coordination was more focused when the north-south interconnection was commissioned in 1995.

At the SADC summit in Johannesburg in 1995 an Inter-Governmental Memorandum of Understanding was signed for the creation of a power pool in the region under the name of Southern African Power Pool (SAPP).

During the period of a little more than 10 years the SAPP has developed to be a well functioning power pool.

2. INITIATIVE FOR CREATION OF THE SOUTHERN AFRICAN POWER POOL, SAPP

2.1. POLITICAL

The signing of an Inter-Governmental MOU to create a power pool in the SADC region paved the way for cooperation and for the creation of SAPP.

The electricity supply business in the region was mainly based upon state owned vertically integrated utilities, so the political influence on the stakeholders in the region was significant.

The cooperation was initiated by establishing a MOU between all parties involved. The revised Inter-Governmental MOU was signed on Feb 23, 2006 in Botswana by the SADC governments.

The creation of SAPP has both political and other stakeholders' support.

The Coordination Centre is established and working very successfully in Harare, Zimbabwe.

2.2. OTHER STAKEHOLDERS

The main stakeholders in the electricity supply business in this region were the vertically integrated national utilities, a few IPPs and large industrial consumers. In the start up phase it was the national utilities that took part in the creation of the regional cooperation.

The need for extended cooperation in the area had been demonstrated in the draft period in 1992. In a meeting in Lusaka on 21st July 1993 support was given for the construction of the Matimba-Insulcamini line and reinforcement of the Congo-Zambia interconnection. This was a significant step towards regional cooperation, but also a lot of other issues had been discussed where a stronger regional cooperation would be of benefit.

2.3. COORDINATION OF PLANS

In 1995 there was a political initiative to create a power pool and the vertically national utilities took part in the development. The national utilities that were allowed to be members of SAPP had for a period discussed the following issues:

- Power balances
- Security of supply
- Coordination of hydro and thermal generation
- Differences in demand curves
- Environmental issues.

An Inter-Utility Memorandum of Understanding and an Agreement between Operating Members were signed by most of the members of SAPP in December 1995. These agreements described the structure of the committees in SAPP. Within the initial SAPP organisation the SAPP Executive committee reports to SADC Energy Ministers and Officials. The Management Committee oversees the administration of SAPP through 3 sub-committees:

- Planning
- Operating
- Environmental

These committees have to take previous work and agreements into account in their work. They report to the Management Committee in SAPP. The structure has now changed following the restructuring of SADC.

2.4. POOLING ARRANGEMENTS

The operating members (from the 9 interconnected countries) have the main impact of the pooling arrangements.

Since the political and utility stakeholders agreed upon the creation of a pooling arrangement, the operating members developed in a short time after the creation of SAPP, the Agreement between Operating Members. This agreement formed the base for cooperation and has with small corrections worked well for the 10 years it has been in force.

2.5. INTRODUCTION OF TRADE

The cooperation in SAPP was partly based upon the possibility of trade between the hydro based part up north and the thermal based part in the south. The major trade has been based upon long-term bilateral contracts. It has been established some short term trade through SAPP. The rules for this trade have been formed based on the rules for the long-term trade.

3. REGIONAL ORGANISATION

3.1. LEGAL

The legal structure for SAPP was established within the political agreement between SADC countries.

The MOUs between the governments and between the utilities were signed and the signatures committed the stakeholders to act according to the agreement.

The organisation was set up with committees much alike what had been practised in NORDEL (there was a lot of communication between NORDEL and the SADC area before the creation of SAPP), but the governing committees was tighter bound to the SADC political environment than what is the case for NORDEL.

3.2. PLANNING

In the first years of operation, the Planning Sub-Committee (PSC) started their work by collecting the necessary data they needed for the performance of their tasks.

PSC collected information of future demand, installed capacity and investment plans to be able to establish an integrated plan for the region. (Regional Master Plan)

PSC started work of defining necessary planning tools for the region. The tools needed were primarily for load flow and stability analyses and for generation planning.

One of the main tasks to solve was an agreement on wheeling charges in the grid to facilitate the trade between utilities.

The Operating Sub-Committee (OSC) started their work by detecting problems that had been observed in the pre pool cooperative projects.

It was established working groups to discuss problems with telecommunication, metering and control.

OSC worked out Operating Guidelines. Those guidelines in combination with the agreement between Operating Members form the rights and obligations for the participants in the pool (Grid Code and Connection Code).

3.3. OPERATION

The Operating Guidelines covered the most important rules for cooperation.

The version signed in 1996 is covering all major issues necessary for the operation of a power pool.

The document covers the following issues:

- Generation Control
- Voltage Control
- Time and Frequency Control
- Interchange Scheduling
- Control Performance Criteria
- Inadvertent Energy Management
- Control Surveys
- Control Equipment Requirements

The establishment of a Co-ordination Centre (SAPP CC) was also important to handle the coordination work between the members and report the ongoing activities and the progress in work. Important tasks for the CC are:

- Monitoring of information flow
- Monitoring of data quality
- Operation analysis
- Fault description and analysis
- Evaluation of work
- Handling market issues
- Handling transmission tariffs/wheeling charges
- Settlement of trade.

3.4. ENVIRONMENTAL ISSUES

The Environmental Sub-Committee (EnvSC) started their work in August 1996 and they have concentrated on establishing Environmental Impact Assessment Guidelines.

The work has been separated into 3 areas:

- Guidelines for transmission lines
- Guidelines for thermal plants
- Guidelines for hydro schemes

4. ESTABLISHMENT AND FIRST YEARS OF OPERATION OF SAPP

4.1. GENERAL

After the establishment of SAPP in 1995 the focus was put on technical issues that had to be solved first.

Existing trade on a bilateral basis was continued and wheeling fees were calculated to facilitate trade using a third party's grid.

SAPP established in 2001 a Short Term Energy Market (STEM) that allowed trade in down to hourly contracts the day before operation.

During the first two years of operation of STEM, SAPP gained experience with this market and wanted to develop the market solution further.

SAPP and Nordpool Consulting signed in December 2003 a 3 years contract for development of the SAPP electricity market.

4.2. DEFINITION OF MARKET RULES

Since the SAPP already has started the STEM market this is taken into account in the rules for SAPP. It has not been defined any need for an additional licence for the organisation of the short term market when the trading rules and software is going to be changed.

Since a lot of nations are involved in the market arrangement and the transmission distances are long and the transmission capacity is limited, it is necessary to define how congestion management shall be performed:

4.2.1. CONGESTION MANAGEMENT

This issue was discussed with the market committee (under the OSC) and it was decided that bilateral contracts should have preference for transmission capacity. These priority rights defined by the reporting of schedules for use of bilateral contracts shall be subtracted from the physical available transmission capacity. The remaining transmission capacity shall be made available for the Day-ahead market (DAM).

The trading system to be procured is defined to include functionality for reporting of schedules for bilateral contracts, for registration of transmission capacities and for calculation of remaining transmission capacity. The remaining capacity should be given for use in the DAM. The trading system of DAM must include functionality for congestion management by market splitting.

4.2.2. COMMERCIAL CODE

Work has been initiated to make changes to existing trading rules.

There has not been developed a special commercial code for the SAPP area, but the established rules include rules guiding the bilateral market and the STEM market operated by SAPP.

It was decided that the part describing STEM rules had to be adjusted according to the new market rules. The new commercial arrangements have to be developed in due time before the opening of the DAM.

4.2.3. MARKET PRODUCTS

The Market Development Working Group (MDWG) under OSC had analysed the present STEM market and given some comments to the functioning of this market.

SAPP got funding from NORAD in Norway for a project for developing a competitive market in the SAPP region.

As the first part of this project it was decided to make changes to the existing STEM trade. A proposal for the design of a Day-ahead Market (DAM) was prepared and presented to the MDWG. It was also developed a market simulator for the SAPP area where the functions of the proposed market structure could be shown and analysed by the participants.

The proposed market structure was approved, and the further work was to be based on the establishment of a Day-ahead market where contracts for each hour of a delivery day could be traded by competitive bidding in a two sided simultaneous auction.

4.2.4. PRICING PRINCIPLES

The design report for the DAM contained proposal for the pricing principles of the contracts.

The bids to the daily auction should be based on portfolio bids, and the participants should be allowed to submit bids for their purchase or sale at alternative prices. A bid thus contains pairs of prices with allocated volume within a large price interval. The prices for each hour shall be fixed at the equilibrium point where the accumulated purchase bid meet the accumulated sale bid.

The unconstrained market price will be calculated as a first step. The contractual flow between the areas at this price will be compared with the available transmission capacity. If a constraint is detected, the price calculation will continue and decrease price in constrained surplus areas until the available transmission capacity is just filled. In constrained deficit areas the price has to be raised until the available import capacity can cover the deficit in the area.

4.2.5. DETAILED MARKET RULES

After the approval of the market principles, a draft for a Book of Rules for DAM was developed and reviewed by the MDWG. The draft has been submitted to the SAPP members for comments and comments have been received.

An updated draft is ready. This will be approved by the members when it is clear that no changes have to be done. The Book of Rules will be published in due time before start of the DAM.

4.2.6. SETTLEMENT RULES

The settlement rules for DAM are a part of the Book of Rules for DAM.

SAPP has started a project for a review of ancillary services and transmission tariffs. The rules for settlement of transmission may be changed, but this is outside the trading rules.

4.2.7. COLLATERAL REQUIREMENTS

The established rules for collateral requirements in the STEM trade will be practised also for the DAM trade.

4.2.8. TRANSIT SOLUTIONS

There is defined a transit solution based upon the existing rules for wheeling. This solution is not well suited for competitive market solutions, so new possible solutions will be investigated. There is an ongoing project in SAPP for developing new tariff solutions for transmission and for handling of losses in the transmission grid.

4.2.9. MARKET CONDUCT RULES

Some rules are included in the agreements in SAPP. They are in combination with the Book of Rules for DAM sufficient in the first phase of the market development.

5. CURRENT STATUS

SAPP has installed the new trading system and are training the participants before the launching of the new system planned for November 2007.

The final preparation for necessary approval of the documents and agreements needed is ongoing and it is estimated that the new DAM will be going live in the end of this year. This market will from the start cover the countries: Democratic Republic of Congo, Namibia, South Africa, Lesotho, Swaziland, Mozambique, Botswana, Zimbabwe and Zambia.

Angola, Malawi and Tanzania have participated in the development process for the market and will be able to participate when they get connected to the synchronous grid.

WESTERN AFRICAN POWER POOL (WAPP)

1. OBJECTIVES OF THE INSTITUTION

WAPP is the abbreviation for West African Power Pool (WAPP), which is a regional organization covering 15 countries of Africa.

WAPP was established in December 1999, during the 22nd Summit of Heads of State and Government of the Economic Community Of West African States (ECOWAS), in order to address the issue of power supply deficiency within West Africa.

WAPP was created as a coordination body composed of the Ministers in charge of energy and the Committee of Directors of the Member State electricity companies. At that time the responsibilities of the organization were to:

- Prepare and establish an appropriate framework for the development of WAPP;
- Formulate recommendations on the financing and execution of selected projects; and
- Prepare a detailed financing plan and the implementation schedule for the master plan on the development of energy production facilities and the interconnection of electricity grids.

The 29th Summit of the Heads of State and Governments of ECOWAS Member States held in January 2006, adopted the Articles of Agreement establishing the new WAPP Organization. The same meeting designed WAPP as a Specialised Institution of ECOWAS and the articles of agreement were officially signed at the first Inaugural General Assembly Meeting, held in July 2006.

The present responsibilities of WAPP are:

- Formalize an official and extended collaboration in the region in order to develop power generation and transmission facilities, thus enhancing power supply and strengthening power security within the sub-region
- Improve the reliability of power system and quality of power supply
- Minimize operating cost of networks
- Increase investments needed for power grid expansion, with emphasis on the implementation of cross-border projects
- Create an attractive environment for investments in order to facilitate the funding of power generation and transmission facilities
- Create a common operating standards and rules in the sector
- Create a transparent and reliable mechanism for the swift settlement of power trade transactions
- Increase the overall level of power supply in the region, through the implementation of priority generation and transmission projects that will serve as foundation for economic development and the extension of cheaper electricity supply to a greater number of consumers

It is important to mention that the Articles of Agreement clearly establish that each regulatory body of the Member States preserves its independence and reserves the right to exercise all lawful means available to protect their existing jurisdiction and authority.

2. INTERNAL ORGANIZATION

2.1. *GEOGRAPHICAL COVERAGE AREA*

WAPP covers the countries of Nigeria, Bénin, Togo, Ghana, Cote d’Ivoire, Niger, Burkina Faso, Cape Verde, Mali, Senegal, Guinea, Gambia, Guinea Bissau, Sierra Leone and Liberia (see next Figure), which have a total population of 250 million people and a total area of 1.9 millions of square miles.

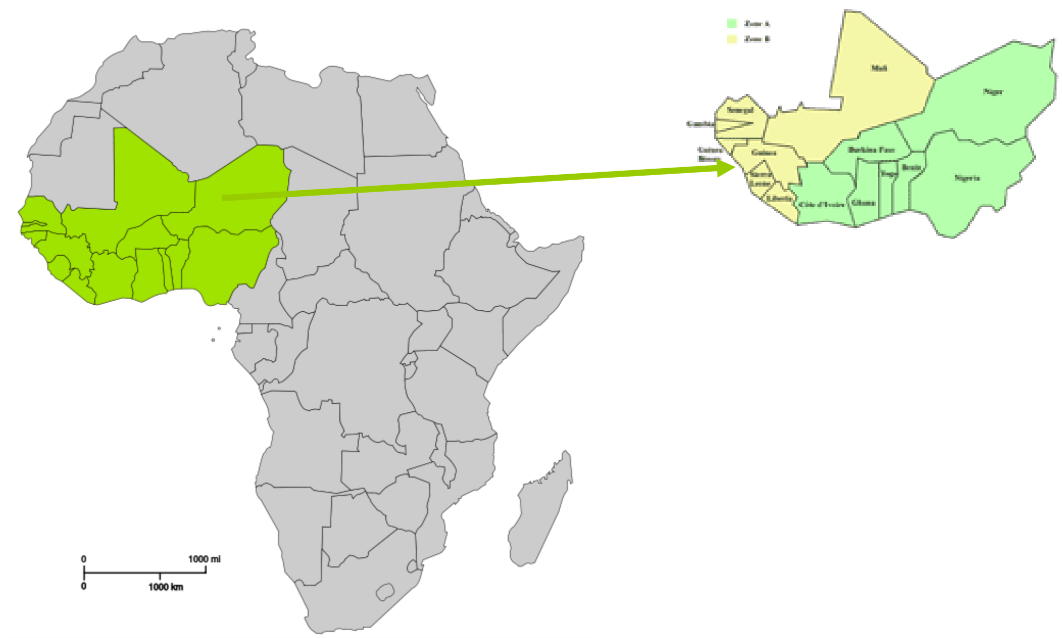


Figure: WAPP Geographical coverage area

The full geographical area is divided into two zones:

Zone A: Benin, Burkina Faso, Côte d’Ivoire, Ghana, Niger, Nigeria and Togo.

Zone B: Cape Verde, the Gambia, Guinea, Guinea Bissau, Liberia, Mali, Senegal and Sierra Leone.

2.2. *SIZE OF THE MARKET*

In 2003, the total electricity consumption was about 40,000 GWh (i.e. 160 KWh per capita, nearly the lowest in the world) and peak electricity demand for the region was 6500 MW.

Demand is expected to grow at a rate of about 7.6% until 2020, when the electricity requirement would reach 140,000 GWh (approx. 370 KWh per capita) and the peak demand would exceed 22,000 MW. The key drivers for increasing electricity consumption are growth in per capita GDP, growth in population, urbanization, development of basic industries, rural electrification and increasing use of appliances.

Most of the countries in the region have small power utilities, each with an installed capacity of less than 1,000 MW, and low levels of electrification averaging less than 30%. Electricity consumption is concentrated in Nigeria (54%), Ghana (23%), Cote d'Ivoire (8%) and Senegal (3.2%). The region's industrial sector accounts for 41% of the consumption, while the residential and tertiary sectors account for 41% and 16% respectively. Consumption in the agricultural and transport sectors is marginal.

2.3. OTHER CHARACTERISTICS OF SIZE & LEVEL OF COMPETITION

As a region West Africa is well endowed with energy resources. For instance, Nigeria has proven gas reserves of 3,500 billion cubic metres (e.g. enough to cover the region electricity needs for 20 years), there are also gas reserves of 30 billion cubic metres in Cote d'Ivoire and offshore in Ghana, and many countries have hydro resources that could be developed. In spite of all this, the energy sector is the least developed in the world.

Significant amounts of capital will be required to finance both new hydropower plants and adequate thermal generation using West African primary fuel sources. The power sectors are cash-short and credit-poor. Their small size and the investor perception of the region's high risk constitute critical constraints, which make their ability to raise the necessary capital in the near future a real challenge.

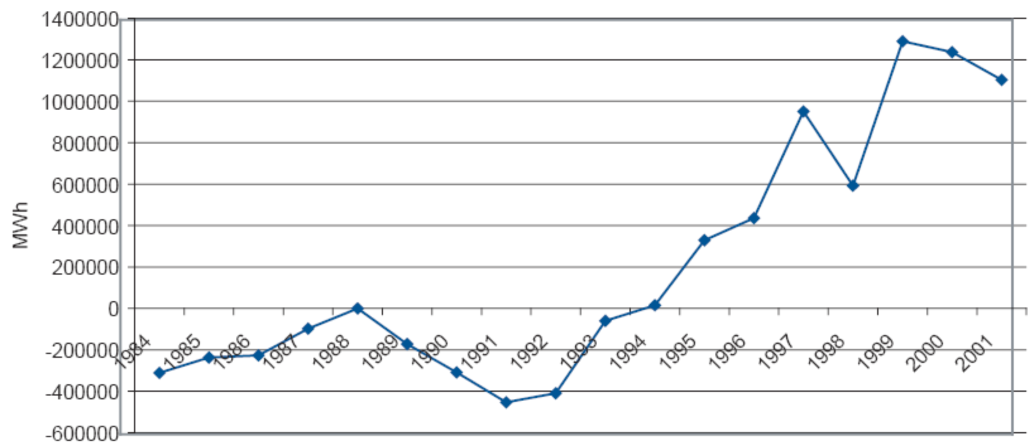
2.4. BRIEF DESCRIPTION OF AGREEMENTS

Several bilateral interconnections and agreements exist between utilities in the region:

Ghana – Benin: Ghana's Volta River Authority (VRA) has been supplying power through the Communauté Electrique du Benin (CEB) to Togo and Benin since December 1972 under an international Agreement signed in August 1969. The first power exchange agreement between VRA and CEB was for a period of 25 years, with the VRA supplying an average continuous power of 50 MW. This agreement ended in 1997, and a new 10-year agreement was signed in which a minimum of 300 GWh of energy per year is supplied to CEB. Power is supplied to CEB from VRA's Akosombo hydroelectric dam through a 161 kV transmission line of 130 km from Akosombo to Lomé, Togo, and a 176 km line to Cotonou, Benin. Although CEB and VRA have this bilateral contract for electricity supply through 2007, the non-availability of power output at the Akosombo hydropower station has prevented VRA from meeting its contractual obligations since 1998. To help alleviate the situation, Ghana has imported some of its electricity from Côte d'Ivoire for export to Togo.

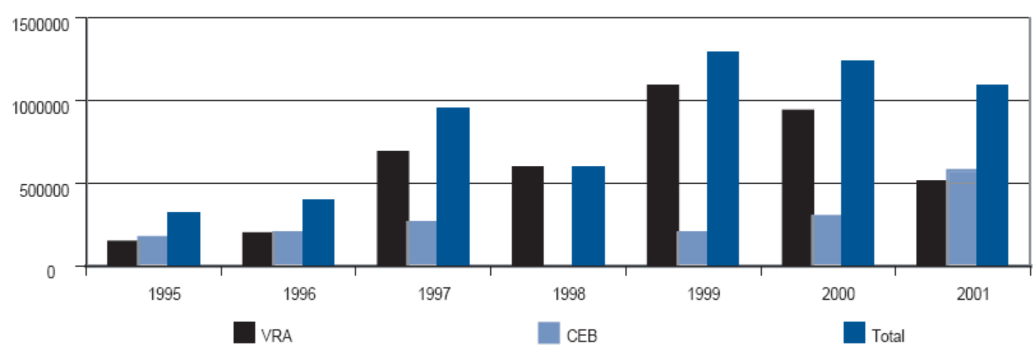
Côte d'Ivoire – Ghana: The electricity grids of Ghana and Côte d'Ivoire were interconnected in June 1983 by a 220-km long 225 kV transmission line, and in pursuance of the Inter-Governmental Protocol for Interconnection signed in January 1975, VRA has been exchanging electrical power with its Ivorian counterpart, Energie Electrique de la Côte d'Ivoire (EECI) since 27th February 1984. EECI's role as a power utility has now been taken over by the private consortium, Compagnie Ivoirienne d'Electricité (CIE). The bilateral agreement signed between EECI and VRA in 1984 provided for backup exchanges for emergency support and compensation exchanges made in kind until early 1990s. Starting in 1995 the balance of electricity supplies between the two power utilities shifted to the favour of EECI/CIE. Due to electric power sector reforms and authorization of independent power producers (IPPs) that took place in Côte d'Ivoire beginning in October 1990, the country succeeded in attracting private investment for two IPP projects, which enabled it to have excess generating capacity, and become a net exporter of energy in the sub-region. Since 1995, CIE has been exporting electrical energy to VRA (and consequently CEB). Until

1999, bilateral agreements between VRA and CIE were limited to a one-year duration; however, the firms now negotiate three-year, bilateral agreements for power supply at a minimum amount of 1100 GWh/year. The 2002-2004 agreement was made for a minimum supply amount of 3300 GWh for the period. The next figure shows the evolution of electricity exchange between EECI/CIE and VRA from 1984 to 2001.



Togo – Benin: The bilateral agreement signed between the CIE and CEB, the bi-national utility of Togo and Benin, came into effect in 1995. Under the terms of this Agreement, CIE has to supply electrical energy for a maximum amount of 200 GWh per year to CEB through Ghana's transmission network.

Togo and Benin have signed a wheeling arrangement for the transit of their imports from Côte d'Ivoire through Ghana. Although no electricity was exported to CEB in 1998, CIE's exports have significantly increased since then to reach almost 300 GWh in 2000 and 578 GWh in 2001 as shown in next figure.



Cote D'Ivoire – Burkina Faso: The bilateral agreement between CIE and the Société Nationale Burkinabè d'Electricité (SONABEL) was signed and came into effect in April 2001. Under the terms of this Agreement, CIE is to supply electricity at a maximum amount of 100 GWh per year to SONABEL. SONABEL's imports from CIE reached a total of almost 67 MWh in 2001.

2.4.1. DEVELOPMENT PATH AND EVOLUTION OF LEGAL AND INSTITUTIONAL STRUCTURES:

December 1999: The Economic Community of West African States (ECOWAS) heads of state, signed an agreement to integrate their national power grids but without central dispatching.

September 2000: Ministers of Energy adopted a Memorandum of Understanding for WAPP that established the mutual obligations of the parties and created an oversight, coordination and administrative apparatus to develop the regional makret under the aegis of ECOWAS. Specific obligations were to:

Support the implementation of priority interconnections projects including rights of way and security.

Allow transmission system operators to develop and implement strategies and programs to facilitate regional electricity trading.

March 2001: The ECOWAS transmission system operators adopted another Memorandum of Understanding in which they agreed to cooperate fully with the ECOWAS secretariat to accelerate the implementation of the WACC. Another *important agreement was the intention of working towards achieving a common understanding of regional economies and optimal resource utilisation strategies from both national and regional perspectives.*

Once these agreements were adopted, the WAPP project was planned for more than a 20-year period staggered in four phases. Each phase comprises institutional development and infrastructure components.

July 2006: The West Africa Power Pool (WAPP) was officially launched as an independent body with the signing of the Articles of Agreement by the executive directors of the member utilities. The Articles of Agreement – previously signed by the heads of state of all 14 member countries – laid out the formula for members' financial contributions to WAPP, the management structure and conditions for membership. The headquarters was established temporarily in Cotonou, Republic of Benin.

2.4.2. GOVERNMENT PARTICIPATION AND POLICY FRAMEWORK

As discussed above, the governments of ECOWAS member states began the WAPP project through the signature of the different agreements (Memorandum of Interest) that established the conditions to develop WAPP as an independent authority. They established the contribution of the different participants and staged the priority of investments.

The member state governments continue to have a heavy involvement in WAPP. Although the 2006 Accord established the organization as an independent entity, member state governments must still approve all agreements proposed under WAPP before they can enter into force.

2.4.3. KEY ROLE OF THE POWER INFRASTRUCTURE IN EVOLUTION INTO COMPETITIVE POWER MARKET

From one side, electric utilities across West Africa are facing increasing difficulties in meeting current demands and their own plans for extending electricity services to rural areas. Most of the countries in the region have small power utilities, each with an installed capacity of less than 1,000 MW, and levels of electrification are low, averaging less than 30% what avoid energy trading between countries. Electricity consumption is concentrated in Nigeria (54%), Ghana (23%), Cote d'Ivoire (8%) and Senegal (3.2%).

Apart from Ghana and Nigeria, electricity tariffs in the region are high. High tariffs would normally facilitate improvement in infrastructure and support of a regional market. However, although West Africa as a region is well endowed with energy resources, they are unevenly distributed and its energy sector is the least developed in the world.

Significant amounts of capital will be required to finance both new hydropower plants and complementary thermal generation using regionally available fuel sources. However, investors perceive the region's power sectors as high-risk and not credit-worthy, which makes their ability to raise the necessary capital in the near future a real challenge.

This confluence of factors perpetuating the region's weak infrastructures inhibits the development of a competitive market in the region.

2.4.4. HARMONISATION OF OPERATIONS PROCEDURES, DESIGN CRITERIA, ELECTRICITY PRICING AND EXISTING BILATERAL CONTRACTS

The first agreement was signed in 2003 (ECOWAS ENERGY PROTOCOL A/p4/1/03) establishing a legal framework in order to promote long-term cooperation in the energy field, based on complementarities and mutual benefits, with a view to achieving increased investment in the energy sector, and increased energy trade in the West Africa region.

The WAPP **Information and Coordination Centre** (**ICC**) was created in 2006 to harmonise operations procedures. Is an organ of the WAPP Secretariat and intended to promote operational coordination between Transmission Owning/Operating Members through actual day-to-day information sharing/exchange between the two WAPP Operational Coordination Centers that manage Zones A & B respectively.

Because the energy interchange agreements are currently bilateral, there is currently no harmonized pricing methodology. Due to resource distribution differences, development of electricity systems, and other commercial factors, electricity tariffs in the region are high; the exceptions being Ghana and Nigeria where tariffs are somewhat reasonable. The cost of thermal generation ranges from a low around 40 US$/MWh from a combined cycle plant using gas from Nigeria, to 80 US$/MWh for a diesel plant at a coastal location, to a high of 130 US$/MWh for an inland diesel plant located in Mali, Niger or Burkina Faso, which depend on fuel transported long distances by truck.

2.4.5. KNOWLEDGE GAPS INFLUENCES

Information sharing is addressed in the ECOWAS ENERGY PROTOCOL A/p4/1/03. Among other things, the Protocol stipulates every member country of WAPP must inform all others upon the start of negotiation or trade with another country or party outside of its national borders. It also addresses information sharing issues related to perceived anti-competitive behaviour among member states/entities, yet also recognizes the sovereignty and laws of each with regard to disclosing sensitive commercial information or intellectual property.

To date the only influence in electricity trading (bilateral agreements), is the prices offered by neighbouring countries and the availability of supply. Like in the CIS, countries are constrained or placed at an advantage based either on their domestic energy resources and/or installed generation capacity to use for domestic demand and trade.

2.4.6. POLITICAL CHALLENGES TO BE OVERCOME

The main political aspects to be overcome are notions of sovereignty, resistance to power sector reforms and private sector participation, as well as preference for 'energy self sufficiency'. This has been the status quo for countries in the region.

2.4.7. TECHNICAL AND FINANCIAL REAL TIME OPERATION:

As mentioned in preceding sections there are not yet integrated systems, settlement or real time operation apart of the ICC.

2.4.8. SHORT, MEDIUM AND LONG TERM SYSTEM PLANNING

As mentioned, development of WAPP is planned in four stages. These stages correspond to short, medium and long term plans for the region. Below is a summary of plans for each phase. Loan approvals have been delayed by two years however by lenders including the USAFIS, Kuwait Development Bank and European Development Funds, as they wait for the results of various feasibility studies.

Short Term - Phase 1

Phase 1 was the period between 2003 and 2006, and focused on technical assistance, capacity and institutional building to develop an efficient regional power market along with the implementation of priority interconnection lines.

The priority interconnection lines involving Burkina Faso, Côte d'Ivoire, Mali, Ghana, Benin and Togo were to be built linking zone A to zone B countries, and some national transmission lines were to be reinforced as essential reliability and stability elements of the regional networks.

This phase was also marked by the adoption of the Energy Protocol by all ECOWAS member states. Additionally new institutions like the WAPP Regional Information Centre and the panel of independent experts in regulation were created. Dispute resolution functions and financial settlements as well as other existing, yet weak functions and services were strengthened through the technical assistance and capacity building activities. Individual country legislation, including regulations, were planned for review, as a step in the process of defining the most appropriate long term regulatory regime for WAPP.

Medium term initiatives are divided in two consecutives phases:

Phase 2

This phase covers the period 2007 to 2012, during which Nigeria's involvement would increase through the construction of the missing links of the coastal line, Ikeja West (Nigeria) to Abobo (Côte d'Ivoire). Sikasso (Mali) is planned to be connected to Manatali through Bougouni (Mali), and Ghana and Burkina Faso are to be interconnected. Additional national transmission lines will also be strengthened.

The institutional development side will see new entities and instruments created, including the executive board and the WAPP co-ordination centre. A technical and operational function as well as a full commercial function is planned to be added to the co-ordination centre to strengthen the existing financial function. This phase will carry out the implementation of the regulatory regime defined in phase1.

Phase 3

Phase 3 covers the period 2013 to 2018. In this phase the regional legal and regulatory regimes for contracts would be strengthened, while investment in regional generation and the strengthening of transmission networks would take place. Least-cost power generation investments that are needed would be based on regional resources. These will include Nigeria's gas resources and hydropower generation from Guinea. Additional interconnections with other regional networks, such as Senegal-Gambia, Guinea-Sierra Leone, Guinea-Mali, and Guinea-Liberia, would also be carried out.

In the **long term**, the focus will be on the consolidation of actions to make existing entities and instruments fully operational in Phase 4 (2018 - 2023).

2.4.9. SIZE AND STRUCTURE OF THE ORGANIZATION'S SECRETARIAT IN CHARGE OF THE POWER MARKET DEVELOPMENT

Described in the following section.

3. GOVERNANCE

The governing structure of WAPP is as follows:

- The General Assembly
- The Executive Board
- The Organizational Committees

The WAPP General Secretariat, including the Information Coordination Centre and the Planning, Investment Programming and Environmental Safeguards Department (see the WAPP Secretariat section below for additional information).

<u>The General Assembly</u> is the highest decision making body for the WAPP. It comprises representatives of all Member States and meets at least once per calendar year. The Chairperson of the Executive Board convenes and presides over the meetings of the General Assembly.

Decisions of the General Assembly are by simple majority of the members present with one vote per member. However, for decisions concerning amendments to the Articles of Agreement and Staffing and Financial Regulations, the decisions require a two-thirds majority vote of the members present and voting. Two-thirds of the General Assembly constitutes a quorum.

The main functions of the General Assembly are to:

- Coordinate the appropriate measures towards the implementation of the principles of the Articles of Agreement,
- Examine and adopt amendments to the Articles of Agreement,
- Elect members of the Executive Board,
- Examine and adopt the staffing and financial regulations of the WAPP governance structures of governance of WAPP, and
- Examine and adopt the annual reports of the Executive Board.

<u>The Executive Board</u> has decision-making authority to develop and implement initiatives to achieve the mission of the WAPP Organization.

The Executive Board consists of 7 persons; 6 of the 7 members of the Executive Board are elected by the General Assembly and comprise 4 representatives of the Transmission Owning/Operating Members, and 2 representatives of the Transmission Using Members. The seventh member is appointed by the General Assembly as the Secretary General and is based on an open competitive selection process by an independent contractor.

Five members of the Executive Board constitute a quorum.

Representatives elected to serve on the Executive Board shall be Chief Executives of Transmission Owning/Operating Members and/or Transmission Using Members. Except for the Secretary General of the Executive Board, other members of the Executive Board are elected for a three-year term.

The main duties of the Executive Board are to:

- Direct activities of all Organizational Committees,
- Examine and recommend to the General Assembly, the entry, exit and re-entry of Members to the WAPP Organization,

- Authorize all major contracts and finance/debt instruments,
- Select and review the performance of Officers,
- Determine positions, duties, qualifications, salaries, benefits and other necessary matters pertaining to the Officers and Staff,
- Approve or revise the operating and capital budgets and any additional expenditures,
- Convene the General Assembly at least annually,
- Recommend amendments to the Articles of Agreement for the approval of the General Assembly,
- Recommend amendments to the Membership Agreement for the approval of the General Assembly,
- Approve guidelines pertaining to standards and policies of the WAPP Organization and penalties for non-compliance with such guidelines and to authorize filings with regulatory bodies.

The Organizational Committees provide support and advice to the Executive Board on all matters concerning collective policy formulation functions for developing, maintaining and updating common "rules of practice" on technical, planning, operational and environmental aspects of WAPP. The Organisational Committees are composed of technical experts drawn from the WAPP membership. Member input on decision-making takes place primarily through active participation in the Organisational Committees.

There are three Organizational Committees:

- Engineering and Operating Committee
- Strategic Planning Committee
- Finance and Human Resources Committee.

The WAPP Secretariat (including ICC and the Planning, Investment Programming and Environmental Safeguards Department), is the administrative body that supports the Executive Board in the accomplishing of its duties. Its main responsibilities are to:

- Facilitate the expansion of power generation and transmission facilities,
- Coordinate the planning and operation of the power system,
- Ensure sustainable development through safe environmental practices,
- Facilitate the implementation of institutional frameworks and the development of utilities, and
- Promote effective communication between WAPP members, donors and the public.

Funding

WAPP funds come from participants' monthly payments calculated as follow:

$A = [0.25(1/N) + 0.75(B/C)]\ X$

Where:

A = Member’s share of WAPP assessment

N = Total number of Members

B = Energy sold for the previous year

C = Total of factor B for all Members

X = Monthly Costs

Each member is required to deposit its payment with WAPP no later than thirty (30) days after receipt of the fee notification.

4. ACHIEVEMENTS

Power trading between the countries of West Africa is still in the early stage of development, although transfers in Zone A have been going on since the first agreement between Cote d’Ivoire and Ghana in 1984. In this Zone there is a network of cross-border interconnections that supports bilateral energy trading between these two countries and on to Benin and Togo. Cote d’Ivoire is currently the main seller and is the only country in the WAPP region with a significant energy surplus. With the new Nigeria-Benin Interconnection, Nigeria will join the Zone A Marketplace.

Trade is less developed in Zone B where the OMVS (Organisation pour la Mise en Valeur du fleuve Sénégal) line connects Senegal, Mauritania and Mali to share the output of the Manantali Hydro Plant located in Mali.

The expectation is that by 2011 most countries in the region will be interconnected. The lowest cost generation will be found in Nigeria due to its abundant natural gas resources, and in Benin, Togo and Ghana, which will import Nigerian gas. WAPP will operate as a cooperative “loose” pool on the basis of multiple owners, multiple systems and multiple control areas. Transmission access will be provided voluntarily on the basis of wheeling charges.

The list is the expected WAPP achievements by 2020:

- Development of a robust grid that facilitates inter-regional power transfer,
- Open access to transmission for all buyers and suppliers of electricity,
- Modern utility control and communications systems designed for regionally integrated system operations,
- Short term energy markets facilitating day-ahead trading of energy by participating members, and
- Trading of spinning reserves and ancillary services.

THE GREAT MEKONG SUB REGION INITIATIVE

1. OBJECTIVE OF THE INSTITUTION

The Great Mekong Sub Region (GMS) encompasses the following countries: China (Yunnan - southern province in the border with South East Asia), Lao PDR, Cambodia, Thailand, Vietnam and Myanmar.

An initiative to develop power trade in the region was supported by the Asian Development Bank (ADB) some years ago and this started the process whose objective is to foster power trade and develop a regional market.

An Inter – Governmental Agreement on Power Trade in the Greater Mekong Sub – Region (IGA) was signed by the six member countries on November 3rd, 2002. This agreement calls for the establishment of the Regional Power Trade Coordination Committee (RPTCC) to coordinate the implementation of regional power trade under the IGA.

The RPTCC reports, according to the IGA, to the GMS Ministerial Level Conference and the corresponding governments through the Ministers.

The first task of the RPTCC is to determine precisely the steps to establish and implement regional trade arrangements. This includes the accomplishment of:

1. Provide to the Parties (countries members) a final draft of the Regional Power Trade Operating Agreement (PTOA) which specifies the rules of regional power trade;
2. Provide to the Parties a recommendation for the overall policy and day – to – day management of regional power trade, including the necessary bodies for coordination;
3. Establish the short, medium and longer initiatives which need to be pursued on a priority basis in order to achieve the objectives of regional power trade within a specified timetable; and
4. Identify necessary steps for implementation of regional trade, including means for financing.

It is important to point out that the GMS market has not been implemented yet. The initial studies have been made, trading rules have been proposed together with a grid code and an institutional framework, but very little has been implemented. Trading in the region is still between neighboring countries without any systematization of the process.

2. INTERNAL ORGANISATION

2.1. GEOGRAPHICAL COVERAGE AREA

The geographical area that this market will encompass is basically the South East Asia and the province of Yunnan from China.

The next Figure shows the map of the region.

GREATER MEKONG SUBREGION

2.2. SIZE OF THE MARKET

The countries that integrate the region are very heterogeneous. All of them are highly populated but the access to electricity is very heterogeneous and the sizes of the electric systems are very different.

The following Figure shows an estimation of the generation forecast for next years of each of the interconnected systems including transmission losses. This provides a clear idea of the size of the markets involved in potential trading in the region.

LOAD FORECAST BY COUNTRY IN THE GREATER MEKONG SUB-REGION - Including transmission losses -												
YEAR	Cambodia		Lao PDR		Myanmar		Thailand		Vietnam		China	
	Energy [GWh]	Growth rate [%]	Energy [GWh]	Growth rate [%]	Energy [GWh]	Growth rate [%]	Energy [GWh]	Growth rate [%]	Energy [GWh]	Growth rate [%]	Energy [GWh]	Growth rate [%]
2004	1165	-	1392	-	5403	-	121933	-	40139	-	40873	-
2005	1330	14.2%	1528	9.7%	5695	5.4%	129983	6.6%	44229	10.2%	43568	6.6%
2006	1522	14.4%	1691	10.6%	6073	6.6%	138617	6.6%	48443	9.5%	45923	5.4%
2007	1753	15.2%	1869	10.6%	6478	6.7%	147293	6.3%	53144	9.7%	48675	6.0%
2008	2011	14.7%	2049	9.6%	6913	6.7%	156635	6.3%	58776	10.6%	51598	6.0%
2009	2244	11.6%	2249	9.8%	7382	6.8%	167331	6.8%	65042	10.7%	54698	6.0%
2010	2503	11.5%	2469	9.8%	7883	6.8%	177638	6.2%	72012	10.7%	57981	6.0%
2011	2777	11.0%	2670	8.2%	8470	7.4%	187970	5.8%	78803	9.4%	60876	5.0%
2012	3033	9.2%	2874	7.6%	9104	7.5%	199285	6.0%	85664	8.7%	63921	5.0%
2013	3284	8.3%	3075	7.0%	9787	7.5%	211312	6.0%	93559	9.2%	67113	5.0%

2.3. BRIEF DESCRIPTION OF TRADE AGREEMENTS

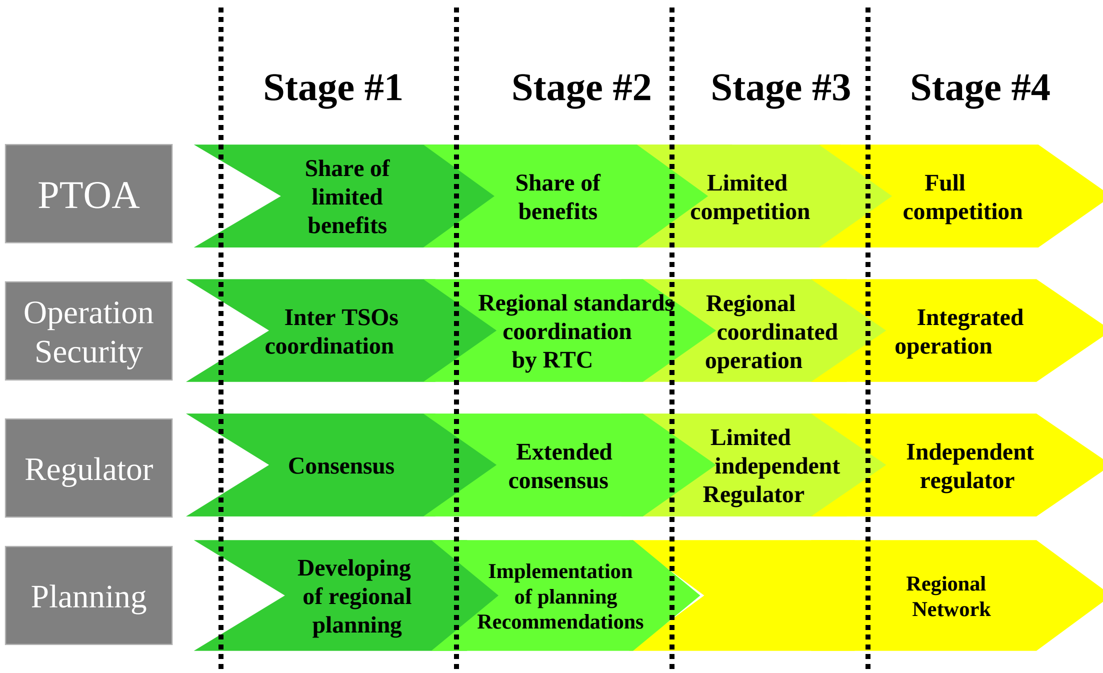
The trading rules for the GMS market have not been implemented yet. However, there is a general framework which encompasses trading rules, grid code and institutional framework for the region that has been developed by Mercados and has been approved. Currently the region is beginning to implement some of the institutions, working groups and is approaching basic tasks dealing with first steps of implementation.

Neither the current regulatory framework ("letter and spirit") in the GMS countries nor cross-border transmission facilities favour the development of a "competitive regional market". However, this market is seen as the final long-term target. Therefore, the solution adopted is a progressive evolution from the current situation to a liquid and competitive regional market in the long-term. This evolution should has well-defined stages, with targets that must be achieved at each stage before advancing to the next one.

This evolution must be consistent and in line with the regulatory trends in the GMS countries. Although completely homogeneous regulatory bodies are not necessary for developing a regional market, it is not possible either to create a regional market with targets or concepts (the regional spirit) that are not consistent with national targets and concepts (national spirit). Considering this principle, four stages have been identified (presented in diagram below).

Similarly, the development of a regional platform for cross-border power trading requires a progressive level of technical coordination for operation and planning activities.

The guiding idea in the evolution of the Power Trade Operating Agreement (PTOA) from the first stage to the fourth is that during this period (aside from the transmission infrastructure and national regulations), there should also be a corresponding evolution on the underlying principles that support the PTOA at each stage.



This conceptual evolution of the principles for cross-border transactions considers four main issues:

PTOA: The trading arrangements will start with some simple rules. Independent power projects that have built transmission facilities as part of their power project and which sell their power through long term PPA will have priority for using dedicated lines, and opportunity cross-border transactions will take advantage of existing lines or from surplus or non-used capacity of the lines that are linked to the PPA. The main target in Stage #1 is to allow two neighbouring countries to benefit from: (1) daily opportunity transactions based on differences in marginal costs to supply load and (2) support from a country with some excess of generation capacity to another in an emergency situation. During Stage #2 the same principles will be used for energy transactions among all the GMS countries. Hence, the principle that will rule the transactions in the First Stage is that of "cooperation" between (almost) self-sufficient countries.

But in the long-term, from cooperation among self-sufficient systems, the transactions should evolve to methodologies that enable the countries to maximize total benefits. This pertains not only to opportunity transactions, but also to the integration of the electricity systems. A more effective way towards achieving this objective is through a competitive regional market. This has also been the case in practically all of the regional markets worldwide.

Hence, the underlying assumption is that the driving principle for cross-border trading will evolve from "cooperation" to "competition".

Regional Planning and Development: Regional transactions may start with the existing cross-border transmission facilities, but only a small share of potential benefits could be obtained. Initially, the main objective of regional planning will be oriented towards:

Defining excess transfer capability that is available on a non-firm basis to support short-term economic exchanges and sale of power;

Planning and prioritizing the addition of new transmission capacity, including recommendations regarding ownership and financing;

Analyzing and issuing recommendations on the possibility of enlarging the capacity of transmission facilities that are linked to the PPAs in order to create some surplus capacity that shall be appropriate to accommodate some regional transactions;

Preparing a plan for developing a regional network with facilities that are dedicated to cross-border transactions but are not linked to specific PPAs. These facilities should be designed to maximize regional benefits; and,

Promoting the support of the GMS countries for developing the regional network.

Once the regional network is implemented, the planning should be self-sufficient, and the regional institutions will make decisions for the expansion of the regional network. By that time, the regional system should be able to finance and procure the construction for expansion of the regional network.

Thus, the activities regarding the planning and development of the regional network should evolve from a joint planning activity to the organization of regional institutions that are able to expand and upgrade this network based on the criterion of maximization of regional benefits.

During Stages #1 to #3, regional planning shall deal only with transmission expansions. However, it may include also generation planning in Stage #4.

RTN (Regional Transmission Network) Security and Operational Planning: the operational planning will deal mainly with the quality and security criteria that will be used for the operation of the regional transmission network.

The basis for security and quality shall be the Performance Standards. This is a set of parameters that establishes the lower and upper limits (and criteria) of some electrical parameters that must be observed in the operation of the transmission system. For instance, the Performance Standards establish the lower and upper limits for the voltage in selected nodes of the RTN. The schedule of flows in the lines shall ensure that the voltage levels in those nodes will be within the lower and upper limits that have been set in the Performance Standards.

During Stage #1, security and quality will be based on the operational agreements between the TSOs of the countries that trade energy on a bilateral basis and through the contractual arrangements negotiated as part of the PPAs which are expected to serve in the immediate term as the primary vehicles for building new regional interconnection facilities. It is neither necessary nor efficient to develop uniform regional criteria at this stage. Support during emergencies will be agreed bilaterally.

During Stage #1, the OPWG will adjust the Performance Standards, and these will have to be approved by the RTPCC. The RPTCC shall invite countries to use the Performance Standards for the design and operation of the internal networks and cross-border transmission facilities that are linked to PPAs.

During Stage #2, the TSOs will use the Performance Standards to define the transmission capacity of their transmission facilities that will be used for cross-border transactions. The RTC shall schedule the cross-border transactions taking into consideration the Performance Standards. Although the countries will operate their internal networks using their own security criteria and standards, the TSOs shall respect the regional Performance Standards in the lines that shall be used for cross-border trading and specific control points in selected sub-stations.

Moreover, the operation during emergencies will be coordinated. The RTC will have a Monitoring and Supervision Center of the regional network, which shall have the responsibility of coordinating the actions of the TSOs during emergencies with the aim of optimizing the use of regional resources to minimize the impact of emergencies.

During Stages #3 and #4, the operation of the regional network shall be centralized, and regional Performance Standards and service quality targets will be used.

Regulation: At the start of the PTOA implementation, the regulatory objective is that all of the countries shall accept and trust the rules with a regional scope. It will be necessary that there be a high-level consensus for making decisions, since every country will most probably wish for a high degree of control on the adequacy and security of its internal system until it gets confident in the benefits of the new trading arrangements.

Only after some years of sound operation may countries trust in the benefits of cross-border transactions, and thus accept to delegate some of the functions of internal regulator or policymakers to a regional institution. That will be the time for the implementation of an independent regulatory agency. This agency will seek to maximize regional benefits rather than to look for a consensus for all of the decisions that it may make.

Therefore, the regulatory activity will evolve from the principle of "consensus" to "independence". This evolution also occurred in several of the electricity markets worldwide. But in some cases the countries involved have not yet accepted the concept of an independent regional regulatory agency, for instance in South America or in the UCTE (Europe).

Following these principles, the evolution of regional cross-border transactions shall consist of four stages: starting from the current situation and evolving until the establishment of a competitive regional electricity market. The PTOA will start with simple rules that are appropriate for the current situation, but must evolve to accommodate more efficient and complex transactions in the medium- and long-term.

The change from one stage to the next will be linked to the following events:

The progressive development of the regional and national networks; and,

The evolution of the national regulations (letter and spirit) from the current single buyer schemes to multiple buyers-sellers.

The evolution of the regional institutional framework

Based on these events, the four stages that were identified contain the following features:

Stage #1

Current situation, and developments that have been planned for 2004-2010: cross-border lines associated to PPAs for specific projects and medium voltage connections.

Only transactions between pairs of (connected) neighboring countries are possible because of the configuration of the transmission system during this stage.

Single buyers are the only entities that will schedule cross-border transactions in all of the countries.

2. Stage #2

Development of cross-border connections that allow cross-border transactions between any two countries, which may use the transmission facilities of a third country.

Trading is mostly associated to some surplus capacity of lines that are linked to a PPA.

Single buyers in all the GMS countries.

Successful implementation of the rules in Stage #1 should allow: (1) more flexible PPAs, (2) training of single buyers in cross-border trading facilitates the scheduling of more complex transactions for this stage, (3) acceptance of transmission tariffs and improvement of the methodology to allocate the related costs.

The cross-border transactions will use the surplus capacity of the RTN, which will be determined based on regional Performance Standards. The RTC will coordinate the actions of TSOs during emergencies.

3. Stage #3

Most of the GMS countries are connected through 230-500 KV with increased capacity to accommodate the cross-border transactions.

The regional transmission network is developed based on recommendations on regional planning (OPWG-RTC), put in place during Stage #1, and implemented during Stage #2.

Some countries allow national agents (IPPs, eligible large consumers) other than single buyers to trade with agents of the same country and with agents or single buyers from other GMS countries.

Eventually, some countries could begin with this stage and afterwards the rest can join when the infrastructure and regulations allow this transition.

A regional system operator centrally operates the RTN.

4. Stage #4

The development of an efficient regional transmission system that is not linked to a specific PPA, and increased cross-border transactions allow for the existence of a competitive regional market.

An increase in the number of agents allowed trading in the regional market.

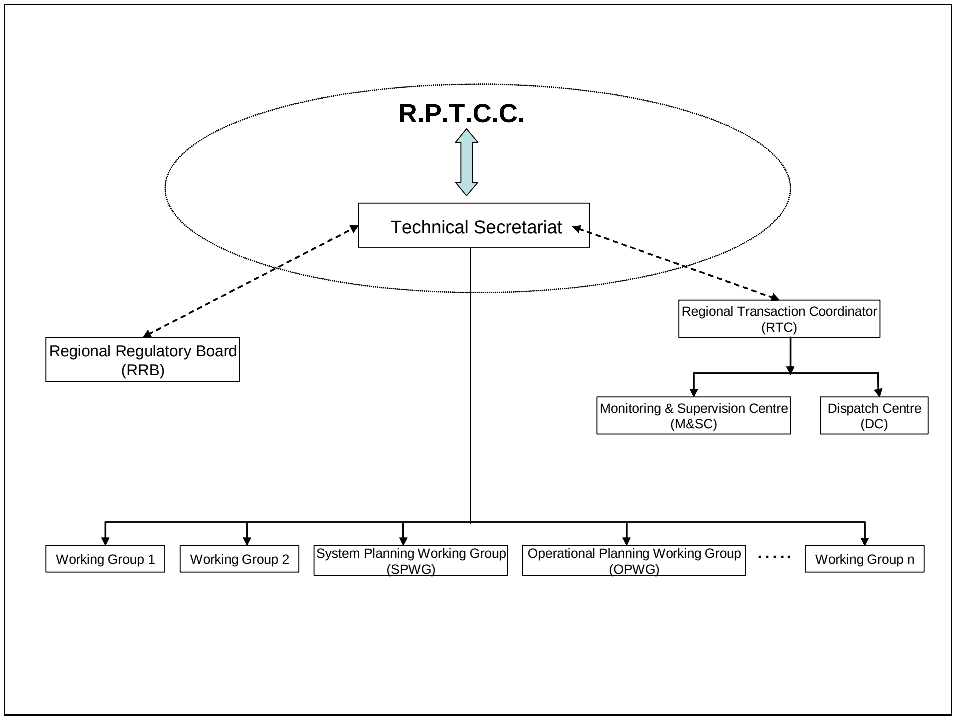
3. GOVERNANCE

The general institutional framework depending from the RPTCC (Regional Power Trade Coordinating Committee) and needed for developing the PTOA foreseen in a "steady state regime" consists of:

1. Technical Secretariat (TS)
2. Regional Regulatory Board (RRB)
3. Regional Transaction Coordinator (RTC)
4. System Planning Working Group (SPWG)
5. Operational Planning Working Group (OPWG)

6. Other standing working groups decided by the RPTCC (WGs)

The following diagram shows the general organization of the framework.



As it can be seen, there is Technical Secretariat (TS), a Regional Regulator (RRB), a Regional Transaction Coordinator (RTC) and Working Groups (WG); among the working groups, the planning working groups are the ones already agreed by the countries.

However, in the initiation of the PTOA, all the institutions will not be created and the establishment of them will be made in a phased way.

At the very beginning, for the kick off of the PTOA, it is proposed that the first institution to be created be a Focal Group (FG) which will later evolve into the already mentioned Technical Secretariat. This FG will take the responsibility of the tasks required to initiate the PTOA in each GMS country, create the first groups, etc.

The Focal Group (FG) will be formed by representatives of each country whose names will be provided by the RPTCC. The FG will have to perform a series of activities, among them, the most important will be:

- Development of its internal procedures.
- Day–to–day management of PTOA.
- Promote the use of capacity in lines of PPAs
- Development of best practices for PPAs
- Facilitate the construction of transmission lines through third countries.

- Establish the Planning Working Group (PWG).
- Develop the Terms of Reference (TORs) of the PWG's tasks
- Follow up activities of PWG.
- Short term action plan for the FG
- Short / medium term action plan for RPTCC.
- Planning of the installation of the Technical Secretariat (TS).
- Initiate the tasks required to establish a regional database and website.
- Promote the study of a "leading case"
- Initial studies
- Training program
- Assume any other function required for the development of the PTOA in its early stage.

4. ACHIEVEMENTS

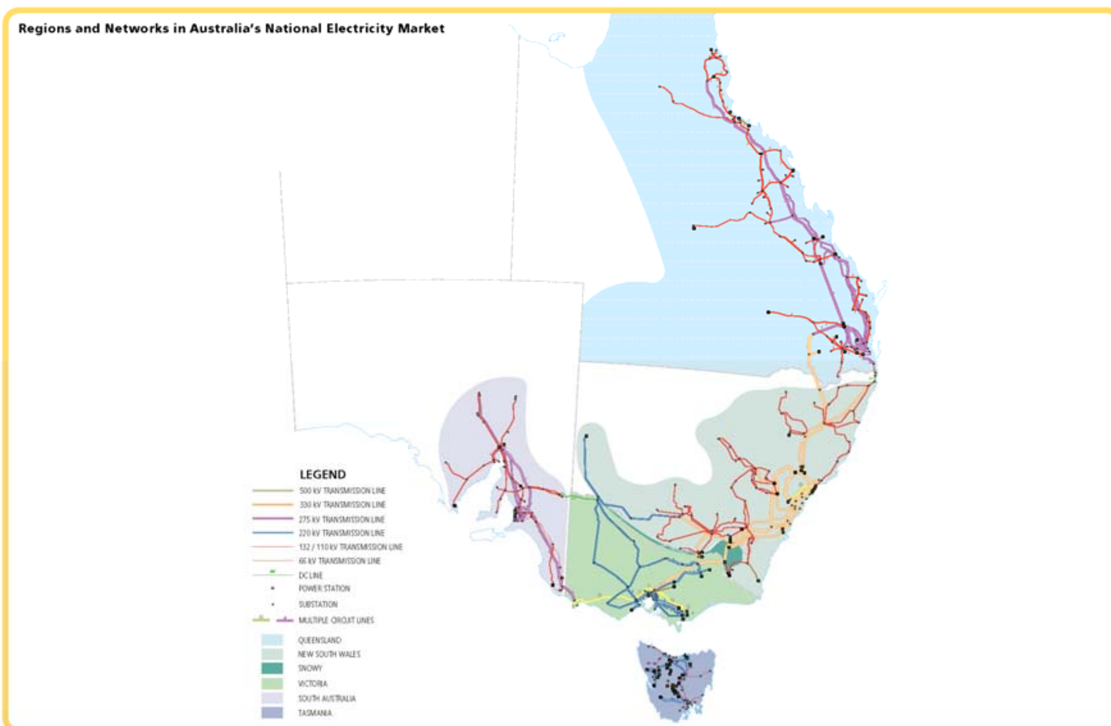
The GMS market is in its very initial stages of implementation. Stage 1 has not really been implemented yet. The Focal Group has been established and it is being prepared the establishment of a Planning Working Group, since it has been noted the importance of regional planning and the development of infrastructure that may allow actual trade among the countries.

THE NATIONAL ELECTRICITY MARKET IN AUSTRALIA

1. BACKGROUND

The reform of the Australian electricity industry commenced in the early 1990s. Separate commercial structures have been developed for the monopoly transmission and distribution ('wires') functions and the competitive generation and retailing functions of the industry.

The major reform in the Australian electricity industry in recent years was the establishment in southern and eastern Australia of the National Electricity Market (NEM). The NEM commenced on 13 December 1998. The NEM is a wholesale electricity market managed by the National Electricity Market Management Company (NEMMCO).



The States of New South Wales, Queensland, Victoria, South Australia and Tasmania participate in the NEM, together with the Australian Capital Territory. Western Australia and the Northern Territory will not join the NEM because of the lack of electrical interconnection and the vast distances between their load centres and the interconnected electricity network in eastern and southern Australia.

NEMMCO was established in May 1996 to implement, administer and operate the wholesale NEM, continually improve its efficiency, and manage the security of the power system. NEMMCO has dual roles of Market Operator and System Operator. Its objectives and functions are set out in the National Electricity Rules, and in the Members' Agreement and S49 of the National Electricity Law respectively.

NEMMCO's general functions are to:

- Operate Australia 's National Electricity Market (NEM);

- Maintain the security of the interconnected power system, that stretches from Queensland to South Australia, and Tasmania in the south; and
- Coordinate planning for the interconnected power system.

NEMMCO administers and operates a competitive wholesale electricity market where around 185,000 GWh of electricity is traded annually. The value of this wholesale electricity varies considerably and, in previous years, has been approximately $7 billion AUS ($5.7 billion USD), among the NEM's 116 registered participants.

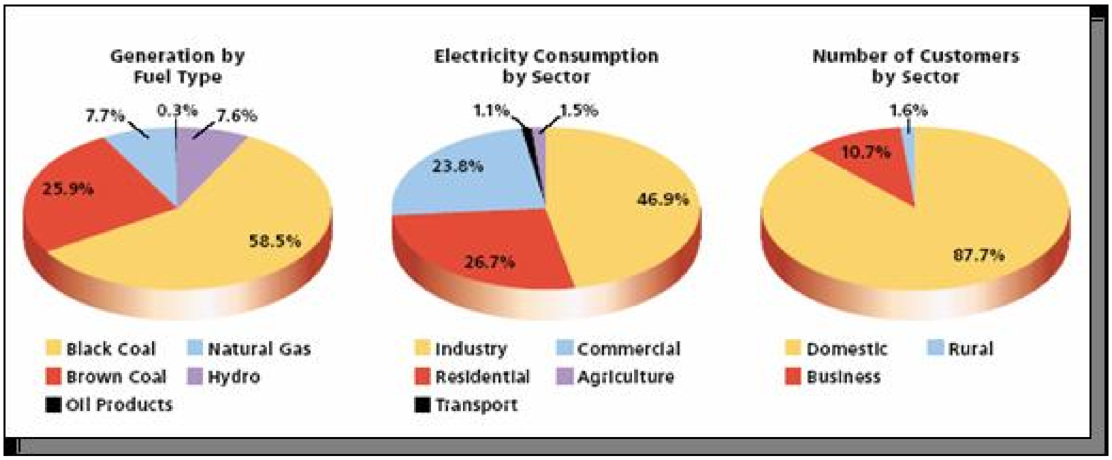
1.1. DEVELOPMENT PATH AND EVOLUTION OF LEGAL AND INSTITUTIONAL STRUCTURES

Date	Description
May 1996	National Electricity Market Management Company Limited (NEMMCO) established under the National Electricity Code (agreement among Queensland, New South Wales, South Australia, Victoria and the Australian Capital Territory)
13 December 1998	NEM began operations under NEMMCO
14 February 2001	Queensland physically connected to the main New South Wales transmission system by interconnector; Start of Queensland commercial operations in the NEM
June 2001	Council of Australian Governments (COAG) endorsed the need for a national energy policy and agreed to commission an independent review of the strategic direction for stationary energy market reform in Australia. Ministerial Council on Energy (MCE) established by CoAG to provide a forum for national leadership on energy issues.
11 December 2003	MCE Communiqué and Report to CoAG on Reform of Energy Markets recommending significant changes to the NEM governing organizations.
1 July 2004	Australian Energy Market Commission (AEMC) and Australian Energy Regulator (AER) established
May 2005	Tasmania joined the NEM as a sixth region
1 June 2005	AEMC and AER began operations taking over NECA role
June 2005	National Electricity Code was replaced by amended National Electricity Law and Rules
29 April 2006	Tasmania became operational upon completion and activation of the undersea Basslink interconnector

2. THE ELECTRICITY MARKET

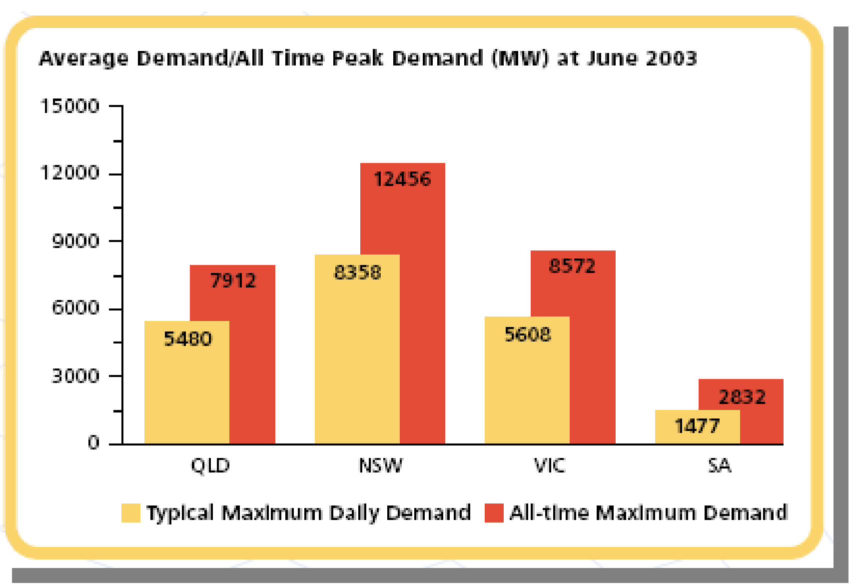
2.1. MARKET SIZE AND COMPOSITION

Australia has electric generating capacity equal to about 45 million kilowatts – with approximately 84 percent of this capacity as thermal (mostly coal) while 14% as renewables (mostly hydro). Coal-fired generating capacity is primarily located in the eastern part of the country near its coal reserves, while Western and Southern Australia rely on natural gas to fuel their power plants.

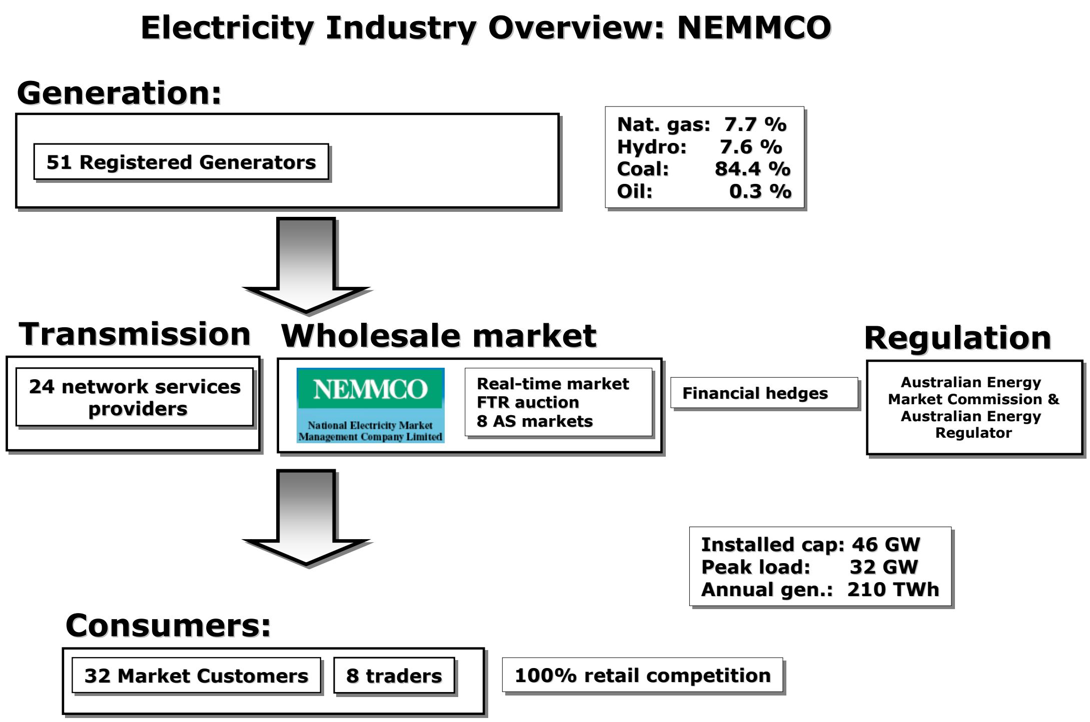


In 2002, Australia generated 210.3 TWh of electricity and consumed 195.6 TWh. The Energy Supply Association of Australia (ESAA) has predicted that consumption will grow rapidly in coming years, rising to 206 TWh by 2008, with the majority of growth in consumption concentrated in Queensland, NSW and Victoria.

The average and peak demand in the various Australian states is illustrated below:



The National Electricity Market (NEM) consists of the sale of bulk electricity by generators to retail suppliers and large end-use customers in the region of the country as shown in the map above, and described in the introduction. Western Australia and the Northern Territory will always be excluded from the NEM because of the lack of electrical interconnections and the vast distances between their load centres and the interconnected electricity network in the southern and eastern States.



The NEM is completely competitive, with any participant able to purchase from any other. Participants in the National Electricity Market can choose to take part in any combination of three levels of trading:

- Spot trading with energy traded through a commodities-type pool and a spot price set every half hour by the last (most expensive) generator selected to run. All wholesale electricity is accounted for through the pool (this is called a "gross pool" or "energy-only pool");

- Bilateral long-term contracts covering fixed amounts of energy over specified time periods under set prices;

- Short term forward market trading in which purchasers lock in energy prices through hedging contracts (Financial "Contracts for Differences").

Under a standard hedging contract, the purchaser (typically an electricity retailer) agrees to purchase a specified quantity of energy from the spot market at a set price (the "strike price"). If the actual price paid in the spot market by the purchaser is higher than the strike price, the counter party to the contract (typically an electricity generator) pays the purchaser the difference in cost. Conversely, if the price paid is lower than the strike price, the purchaser pays the counter party the difference.

2.2. Power System Operations (Technical Real Time Operation)

The maintenance of power system security is a core operational responsibility for NEMMCO and is executed in real-time through co-primary control centre infrastructure. Achieving and improving operational market efficiencies while maintaining power system security requires an ongoing focus, and the greatest share of NEMMCO resources continues to be allocated to this area. In addition, the scope of the power system continues to grow due to developments such as the introduction of the Tasmanian Region, increased level of intermittent generation, and other new generation and transmission projects.

- **Power System Reliability**

NEM Reliability standards are established by the Australian Energy Market Commission (AEMC) Reliability Panel. These standards currently require that unserved energy per year for each region must not exceed 0.002 percent of the total energy consumed in that region that year.

The NEM is required to operate with defined levels of reserve in order to meet the required standard of supply reliability. Under current standards, NEMMCO is required to ensure 850 MW of reserve is carried across the entire NEM.

The reliability safety net provisions of the National Electricity Rules provide that NEMMCO must procure sufficient reserve to ensure that the reliability of supply meets the reliability standard. When reserves acquired by NEMMCO are dispatched they are bid in at VoLL thus setting the spot price at the maximum level.

- **Power System Capability**

NEMMCO is required to assess the power system's capability to deliver the required levels of security and reliability on an ongoing basis, and takes into account of any deviations from technical performance standards. NEMMCO is dedicating a greater focus in this area in line with the AEMC's current review of the enforcement of, and compliance with, technical standards. To this end, NEMMCO has begun a new project to capture power system data collected by a system of high-speed data monitors installed, or planned to be installed, throughout the transmission networks. When complete (2009-2010), this system will greatly enhance the capabilities of NEMMCO and the TNSPs to analyse significant power system events, and monitor power system and participant technical performance. Following the AEMC's final determination on system restart ancillary services, NEMMCO is presently implementing a new interim system restart standard.

2.3. The Spot Market (Financial real time operation)

Wholesale trading in electricity is conducted as a spot market where short-term supply and demand are instantaneously matched through a centrally coordinated dispatch process. Generators offer to supply the market with specific amounts of electricity at particular prices. Offers are submitted every five minutes of every day. From all offers submitted, NEMMCO's systems select the generators required to produce electricity based on the principle of meeting prevailing demand in the most cost-efficient way. NEMMCO then dispatches the required generators into production.

Prices for electricity are calculated for each five-minute dispatch interval, and six dispatch prices are averaged every half-hour to determine the spot price for the trading interval for each of the regions of the NEM. The spot price NEMMCO uses as the basis for the settlement of financial transactions for all energy traded in the NEM.

The Code sets a maximum spot price of $10,000 per megawatt hour. This is the maximum price at which generators can bid into the market. The maximum spot price is also called Value of Lost Load (VoLL), and it is the price automatically triggered when NEMMCO directs network service providers to interrupt customer supply in order to keep supply and demand in the system in balance.

It is important to remember that the NEM is a wholesale market. Only about 20 percent of the price paid by domestic and business consumers for electricity supply is accounted for by the direct cost of the energy. Additional charges are added to retail accounts for network usage, service fees, market charges, the retailer's profit margin and the GST.

- **Financial Efficiency and Prudential Risk**

NEMMCO is required to clear and settle the electricity spot market while maintaining a prudential framework that mitigates the participants' counter-party risk. Since 2003, NEMMCO has implemented measures in the spot market clearing process to promote cost-effective capital ultilisation in participant compliance with prudential requirements. Additional efforts are underway to achieve the efficient utilisation of collateral committed against the spot and forward markets, and thus achieve greater market efficiency.

The AEMC has approved a Rule change to increase the flexibility of reallocations. During 2007, NEMMCO will develop detailed reallocation procedures in consultation with Participants. This will include progressing an arrangement with the ASX to allow the positive margins of futures to become part of a reallocation.

An associated area of continued focus is the planning for the management of a NEM prudential incident where the viability of a Participant (and by consequence, viability of the market) may be threatened. In this regard, NEMMCO continues to conduct prudential emergency exercises to ensure that directors and officers, and the jurisdictions and Participants fully understand their prudential responsibilities and obligations under the Rules.

2.4. ANCILLARY SERVICES MARKETS

The National Electricity Market also includes a range of different markets for ancillary services, managed by NEMMCO, including:

- Eight distinct markets for Frequency Control Ancillary Services in which providers make offers of services to manage frequency within specifications up to a 5-minute horizon;

- Long term contracts for Network Control Ancillary Services and System Restart Ancillary Services negotiated between NEMMCO (on behalf of the market) and the market participant providing the service.

2.5. THE RETAIL MARKET

The retail market consists of sales of electricity by retail suppliers to end-use customers. As noted above, this market is partly competitive and partly on a franchise basis. Retail suppliers compete to supply those large customers who choose not to purchase directly from the wholesale market and smaller customers who opt out of purchasing electricity from their first tier retailer. Such customers are termed 'contestable'.

In most jurisdictions in which the NEM operates retailers can sell electricity to all end-use customers down to the household level (all customers are contestable). Where this is the case, customers may continue purchasing electricity from their local first tier retailer and the tariffs they pay are controlled by the electricity industry regulator. Alternatively, customers can choose to purchase electricity under a competitive retail contract from a first or second tier retailer in their State. There are no controls on prices under such competitive retail contracts.

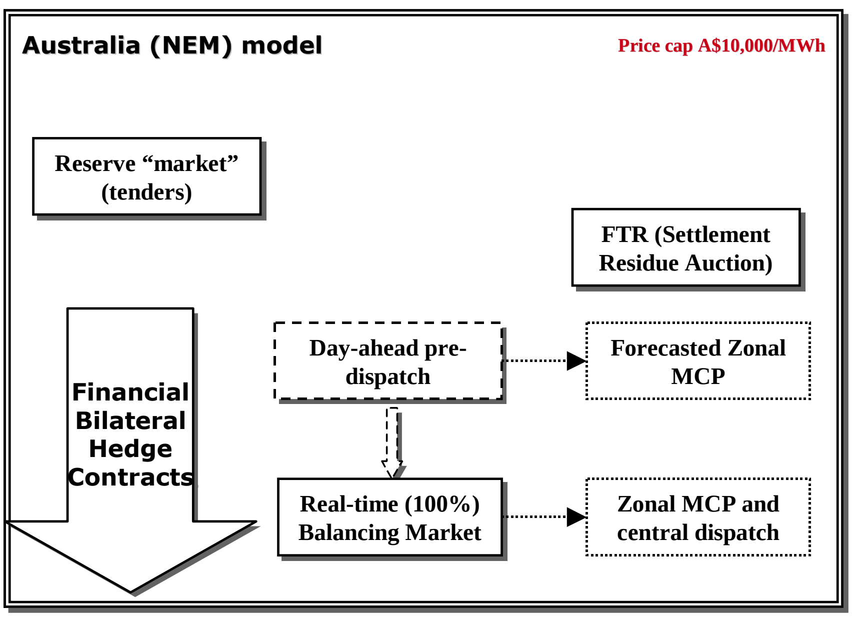
In Queensland and Tasmania currently only larger customers can be offered competitive retail contracts by retailers. Smaller customers continue to purchase electricity under controlled tariffs from their local first tier retailer. All small customers will become contestable in Queensland by July 2007 and in Tasmania by July 2010. However, the Tasmanian Government has reserved a final decision as to whether retail contestability will be extended to households and small businesses (from 1 July 2010) until a public benefit test has been undertaken.

Under this structure for the retail electricity market, retailers actually shield retail customers from the price volatility in the NEM wholesale spot market. In effect, retailers provide price risk insurance for retail customers, with the retail price paid by the customer including an insurance premium component.

Currently, there is a move to abolish retail price controls for all customers in all jurisdictions in which the NEM operates. This is likely to be introduced progressively over the next few years as competition in the retail electricity markets in each jurisdiction becomes more effective.

2.6. STRUCTURAL AND PRICING ISSUES

The figure below illustrates the NEMMCO market structure.



2.6.1. SEPARATION OF NETWORK CHARGES

Originally, network charges, covering the cost of transporting electricity from the generator to the point of end-use, were bundled together with energy charges in calculating the electricity price to be charged to the end use customer.

Following the reorganization of the electricity market, both generators and end-use customers are required to pay separate network charges. In the wholesale market, participants are responsible for paying connection charges and 'use of system' charges directly to their local transmission and distribution network owners. In the retail market, network charges incurred by contestable customers are paid for them by their retail supplier who packages these network charges together with the energy charge to provide one contract price to the end-use customer.

- **Pricing and Process Efficiency**

In 2007-2008, NEMMCO is continuing to implement more efficient metering data processes and technology in the context of increasing numbers of interval meters, as well as enhancements to the system that facilitate retail customer transfers (MSATS), and improve the performance assessment of metering service providers. A major exercise to identify retail market process efficiency improvements was carried out and identified a number of areas for improvement across processes associated with retail contestability for NEMMCO, Retailers and Distribution Network Service Providers. The NEMMCO Retail Market Executive Committee has endorsed the implementation of the initiatives arising from this study.

2.6.2. INTER-REGIONAL TRADE

The five interconnected electrical regions that comprise the NEM basically follow state boundaries. **There is a designated region reference node in each region where the regional spot price of electricity is set**. Queensland, New South Wales, Victoria and South Australia regions all contain both major generation and demand centers. Snowy region, on the other hand, is a major generation center only and exports almost all of the electricity generated in its power plants to adjacent regions.

2.6.3. INTERCONNECTORS

High-voltage interconnectors are used to transport electricity between regions to meet demand that is higher than can be met by local generators, or when the price of electricity in an adjoining region is low enough to displace the local supply.

- Regulated Interconnectors

A regulated interconnector is an interconnector that has passed the ACCC-devised regulatory test. A regulated interconnector receives fixed, annual revenue based on the value of the asset and set by the ACCC regardless of actual usage. The revenue is collected as part of the network charges on consumers' electricity accounts. At present, regulated interconnectors exist between all adjacent regions of the NEM.

- Unregulated Interconnectors

Unregulated (or market) interconnectors are not required to undergo regulatory test evaluation. These assets derive revenue by trading in the spot market; this is achieved by purchasing energy in a lower price region and selling it to a higher price region, or by selling the rights to revenue generated by trading across the interconnector.

The ability of NEMMCO to schedule generators to meet demand in an interconnected region is sometimes limited by the physical transfer capacity an interconnector can carry. When the technical limit of an interconnector's capacity is reached, the interconnector is said to be constrained. When this happens, NEMMCO has to schedule the most cost-efficient generators from within the region to meet the remaining demand even though the price of this electricity may be higher than the bids of other generators in the exporting region. or example, if prices are very low in one region and high in an adjacent region, electricity can be sent from the first to the second region across an interconnector up to the capacity that the interconnector is constrained. NEMMCO's systems will then dispatch local generators with the lowest price offers from within the second region to meet the outstanding consumer demand.

- **Constraint Automation**

Constraint equations are used by NEMMCO to limit the optimised market solution to the capability of the physical power system. The correct formulation and invocation of constraint equations is essential to maintain power system security. In the coming year (2007-2008), the formulation and invocation of constraint equations will be automated to the extent feasible to minimise the risk of human error and deliver consistent market outcomes. It is expected to implement constraint automation in phases. The objective of the first phase will be to formulate the thermal constraints, which are relatively straightforward, and form the majority of required constraints and for those constraints to be made available on the Market Management System for control room operators to invoke.

2.6.4. CONGESTION MANAGEMENT

The costs of supplying power vary from place to place depending on two aspects of the transmission network. Firstly, losses are incurred as power is transported from where it is produced to where it is to be consumed, and secondly, constraints or bottlenecks may be encountered as power is transported along certain elements of the network.

The NEM (NEMMCO) has established 17 zones and 23 National Transmission Flow Paths (NTFP) over which physical transactions are planned and carried out. Market simulations are used to forecast network congestion, and identify the potential need for NTFP augmentations from a market benefits perspective. The forecasts look at a 10-year horizon

The National Electricity Rules (Rules) provide for the management of congestion by market institutions using a variety of tools and mechanisms. These arrangements may be separated into three categories:

- the Rules governing dispatch, including the way the power system is represented in the NEM dispatch engine, NEMDE;
- the TNSP activities, including short-term arrangements for transmission availability and long-term incentives for transmission investment; and
- the Rules governing pricing and settlement, including the way prices are determined and

Settlement is carried out for each participant in the event of congestion within or between regions.

2.7. *KEY ROLE OF THE POWER INFRASTRUCTURE IN EVOLUTION INTO COMPETITIVE POWER MARKET*

The spot price outcomes in the market provide signals for future investment in generation and transmission infrastructure. As supply capacity decreases in relation to demand, the spot price will increase and new generation or network capacity will be attracted into the market. High spot prices may also act as an incentive for consumers to reduce their demand during periods of supply scarcity.

2.8. *HARMONISATION OF OPERATIONS PROCEDURES, DESIGN CRITERIA, ELECTRICITY PRICING AND EXISTING BILATERAL CONTRACTS*

System harmonization among states was initially undertaken through the National Grid Management Council and subsequently progressed under the National Electricity Market Management Company (NEMMCO) and the National Electricity Code Administrator (NECA) in conjunction with jurisdictions, State regulators and the Australian Competition and Consumer Commission (ACCC).

2.8.1. Unbundling among Australian States

Originally, in some of the Australian states (Victoria, South Australia and Tasmania), the four functions were carried out within a single, vertically-integrated, monopoly business. In other States (eg New South Wales and Queensland) generation and transmission were contained in a single monopoly business, while distribution and retail supply were carried out by a number of businesses, each with a monopoly franchise covering a specified geographical area within the State.

The decision was made in the National Electricity Law of 1998 to unbundle the four functions into separate businesses into all states so as to enable the development of the competitive wholesale market. The results of the reform process have been:

- Several competing generation businesses have been established in each State;
- Single monopoly transmission business has been established in each State;
- Geographic monopoly franchises for distribution have been retained in each State. In some States, the number of franchises of distribution businesses has been reduced;
- Two-tier system has been established for retail supply in each State.

The two-tier supply system functions as follows:

'First tier' retailers are attached to a distribution business with a geographic monopoly franchise in that State. However, first tier retailers can sell electricity to customers throughout the State. The retail business is "ring fenced" from the distribution business (i.e. established as a separate accounting entity within one holding company);

'Second tier' retailers are stand-alone businesses not attached to a distribution business in that State. A second tier retailer in one State may be a first tier retailer in another State.

In some States (New South Wales, Victoria and Tasmania), retailers can sell electricity to all electricity end-use customers down to the household level. Where this is the case, customers may continue purchasing electricity from their local first tier retailer and the tariffs they pay are controlled by the electricity industry regulator. Alternatively, customers can choose to purchase electricity under a competitive retail contract from a first or second tier retailer in their State. There are no controls on prices under such competitive retail contracts. In other states (Queensland), only larger customers can be offered competitive retail contracts by retailers. Smaller customers continue to purchase electricity under controlled tariffs from their local first tier retailer.

2.8.2. Knowledge gaps influences

Coordination of the regional market and various power sector reform efforts in the participating states is a constant process. Clarity and transparency of information and on-going communication among the players is the key to a smooth functioning, efficient market. The company maintains an interactive website through which all public information is available. It maintains other secure modes of communication with stakeholders for sensitive, proprietary information. The points below are those in which NEMMCO highlights as focus areas for the upcoming year.

- **Input Information Quality and Assimilation**

A clear and accurate view of the state of the power system is the basis for optimal operating decisions. NEMMCO's existing National Dispatch and Security Centre infrastructure provides operators with the facilities to assimilate relevant power system information.

NEMMCO plans to enhance the capability of the Dispatch and Security Centres through the use of more advanced power system monitoring and analysis tools, by automation and by improving the constraints management interface and displays. In 2007 there will also be a focus on accuracy in demand forecasting by introducing more data inputs and taking account of the growing penetration of wind generation.

- **Operational Communications**

NEMMCO publishes significant amounts of operational information on a daily basis to assist the effective participation of the electricity businesses that operate in the NEM. Increasingly, however, some of this information is being accessed and used by a wider audience, including some market observers who may not have a well-developed understanding of the technical operation of the NEM. In order to minimise misinterpretation of NEMMCO's operational information, NEMMCO reviews this material with the aim of improving its readability and providing greater explanation of technical concepts.

- **NEM Education**

NEMMCO recognises that elements of NEM design and many of the NEM processes are technical and highly complex. Efficient participation in the NEM can be promoted by a greater understanding of how the market operates. In this light NEMMCO has been conducting a series of courses covering: Introduction to the NEM; Constraint formulation and Management; and Metering Settlement and Transfer Solution (MSATS). These courses are primarily aimed at employees of Participant organisations.

It is NEMMCO's intention to maintain these existing courses and to develop an additional specialist course, based on a needs analysis, each calendar year. To complement this work NEMMCO is continuing to produce information papers on various aspects of the NEM's operation. Following the publication of the booklet titled "Wholesale Market Operation" the next release, "Retail Market Operations" is planned. These papers are written for a non-technical audience and delivered both in printed form and on the NEMMCO website.

3. GOVERNANCE

3.1. GOVERNMENT PARTICIPATION AND POLICY FRAMEWORK

The Ministerial Council on Energy (MCE) comprises Ministers with responsibility for energy from Australian, State and Territory governments. The MCE has responsibility to provide effective policy leadership to meet the opportunities and challenges facing the energy sector and to oversee the continued development of national energy policy. A key task of the MCE is to identify policies and programs that will deliver significant improvements in energy efficiency through coordinated action by federal, state and territory government agencies.

As a result of MCE recommendations to the Council of Australian Governments (CoAG) the Australian Energy Market Commission, (AEMC) and Australian Energy Regulator (AER) were established on July 1, 2004, which replaced the roles and functions of NECA beginning on 1 July 2005.

3.1.1. AUSTRALIAN ENERGY MARKET COMMISSION

The AEMC is the body responsible for energy market rule-making and market development at the national level. Its specific responsibilities include:

- Administration and publication of the *National Electricity Rules*;
- The Rule making process under the *National Electricity Law*;
- Making determinations on proposed Rules;
- Undertaking reviews on its own initiative or as directed by the MCE; and
- Providing policy advice to the MCE in relation to the National Electricity Market.

3.1.2. AUSTRALIAN ENERGY REGULATOR

The Australian Energy Regulator (AER) performs economic regulation of the wholesale electricity market and electricity transmission networks in the National Electricity Market (NEM). Specifically, under the *National Electricity Law* and *National Electricity Rules*, the AER's key responsibilities include:

- Regulating the revenues of transmission network service providers by establishing revenue caps;
- Monitoring the wholesale electricity market;
- Monitoring compliance with the *National Electricity Law*, *National Electricity Rules* and *National Electricity Regulations*;
- Investigating breaches or possible breaches of provisions of the *National Electricity Law*, *Rules* and *Regulations*;
- Instituting and conducting enforcement proceedings against relevant market participants;
- Establishing service standards for electricity transmission network service providers;
- Establishing ring-fencing guidelines for business operations with respect to regulated transmission services; and
- Exempting network service providers from registration.

3.1.3. MEMORANDUMS OF UNDERSTANDING

NEMMCO has agreed to MOUs with the AER and AEMC to establish an agreed framework for cooperation and liaison between the AEMC and NEMMCO, and the AER and NEMMCO in its capacity as the operator and administrator of the wholesale electricity market.

3.1.4. AUSTRALIAN COMPETITION AND CONSUMER COMMISSION (ACCC)

The Australian Competition and Consumer Commission is an independent Commonwealth statutory authority formed in 1995 to administer the *Trade Practices Act 1974* and other acts.

The ACCC promotes competition and fair trade in the market place to benefit consumers, business and the community, and also monitors compliance of national infrastructure services with prescribed regulation. ACCC initiatives also include promoting consumer education in rural areas and with indigenous communities.

With respect to Electriciy, the ACCC is broadly responsible for: Changes to the electricity code; Electricity authorisations; Access arrangements; Transmission network revenue caps; Other regulatory decisions.

The Electricity Group branch of the Regulatory Affairs Division specifically undertakes:

- Assessment of applications for authorisation of potentially anti-competitive conduct under Part VII of the Trade Practices Act, which includes changes to the National Electricity Code and vesting contract arrangements.
- Assessment of applications for acceptance of changes to the National Electricity Market Access Code under Part IIIA of the Act.
- Assessment of undertakings submitted under Part IIIA of the Act to the Commission by individual network service providers (NSP)—these undertakings propose how the NSP intends to allow third parties to obtain access to its network.
- Regulation of the annual revenue that transmission network service providers (TNSP) are allowed to receive from their customers as prescribed in the National Electricity Market Access Code.
- Development of a set of principles for the regulation of revenues that a TNSP may receive.
- Assessment of applications for discounts on transmission charges under the National Electricity Market Access Code
- Liaising with industry, government departments and industry working groups aimed at market development.

3.1.5. POLICY FRAMEWORK

There are six agreements that form the framework within which the NEM was created and now operates. These are:

- NEM Legislation Agreement
- NECA Members Agreement
- NEMMCO Members Agreement
- NEM Memorandum of Understanding on the Use of Emergency Powers
- NEM Emergency Protocol
- Memorandum of Understanding for Implementation of the NEM

3.2. SIZE AND STRUCTURE OF THE ORGANIZATION'S SECRETARIAT IN CHARGE OF THE POWER MARKET DEVELOPMENT

NEMMCO is a not-for-profit that employs approximately 240 personnel and is governed by a nine-member Board of Directors. The NEMMCO Chief Executive Officer is a non-executive member of this board to which he also reports.

Members of NEMMCOs board are responsible for overall Corporate Governance including setting the strategic direction of NEMMCO and monitoring its performance against pre-determined goals, ensuring that both the internal controls and reporting procedures are adequate and effective, and establishing appropriate ethical standards.

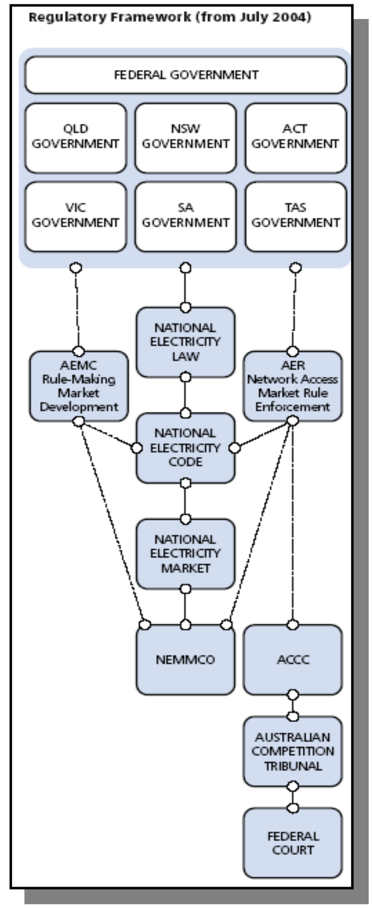
The jurisdictions involved in the Australian National Electricity Market have and are continuing to review governance and liability arrangements for the Market with the aim of ensuring that market institutions are exposed to effective performance incentives and accountability mechanisms.

3.2.1. Participant Advisory Committee

The establishment of the Participant Advisory Committee (PAC) represents the formal process by which stakeholders are able to provide industry input to NEMMCO's Board decision-making processes. The PAC provides the Board with assistance, feedback and information on the operation of the wholesale National Electricity Market (NEM). The Committee consists of up to 15 members appointed from the nominations received by the Board. Nominations are at the level of Chief Executive Officer or Managing Director.

All industry sectors - generators, network service providers, market customers and retail customers - are represented on the Committee. Others with relevant experience in the electricity supply industry are also encouraged to register their interest.

Appointments are for a period not exceeding two years, and they are subject to annual review. The role of the committee will also be reviewed annually.



3.2.2. Dispute Resolution

Circuit breakers protect electrical network systems from unpredictable changes in current. This is the name chosen for NEMMCO's Dispute Management System ("DMS"). Circuit Breaker complies with the criteria for a dispute management system under Chapter 8 of the National Electricity Rules.

3.3. Regulation

Prior to the mid-1990s, regulation of the Australian electricity supply industry was carried out on an informal basis because most of the businesses were government-owned and was operated as a public service rather than as profit-making commercial ventures. For example, increases in electricity prices were often agreed in informal meetings between the senior management of the electricity businesses and the relevant government Minister.

Once competition was introduced, and particularly as some electricity businesses became privately owned, a more formal system of regulation was required. Consequently, each State government established new agencies to regulate the electricity industry (plus often other industries as well). Currently, this State-based regulation has resulted in regulation by 13 separate agencies; the main responsibility of which is being progressively transferred to national regulatory agencies.

The new framework emanating from the 2004 sector reform is intended to streamline decision-making, improve accountability, and remove the duplication of regulatory processes that has previously existed. It is designed to provide an appropriate balance between development and implementation of energy market rules, industry regulation and general competition regulation.

3.3.1. Political challenges to be overcome

The state-level power systems involved are all states of Australia and thus have similar legal and legislative frameworks. From this perspective, there are few political conflicts to overcome in the on-going process of market development. The cooperative development of the NEM is enhanced by the fact that the recommendations for its very creation arose from the decisions of the MCE (Ministerial Council on Energy) and the CoAG (Council of Australian Governments); inter-state government bodies working comprised of energy sector representatives of all Australian states.

The division of roles and responsibilities between state-level regulators and the AER, and among NEM-level entities (NEMMCO, AER, AEMC and ACCC), will be an on-going issue to be handled as cases of conflict or overlap occur. Institutional structures are well developed however for arbitration and negotiation.

RESUME OF REGIONAL MARKETS CHARACTERISTICS

The following tables resume and compare some basic but relevant characteristics of the regional initiatives analysed in this document.

TABLE I

Region	Power Trade Organization(s)	1. Objective of the regional initiative	2. Year the initiative began and other important year	3. Size of the market		4. Exchanges	5. Products traded
				a. Population in region covered by the market	b. Peak of the regional system.	a. Long term contracts b. Short medium term contracts c. Opportunity exchanges or spot market d. Day ahead market e. Intra day market	a. Energy b. Ancillary services (specify) c. Others (specify)

Region	Power Trade Organization(s)	1. Objective of the regional initiative	2. Year the initiative began and other important year	3. Size of the market		4. Exchanges	5. Products traded
Europe	UCTE	Association of TSOs that coordinates the operation and development of the electricity transmission grid from Portugal to Poland and from the Netherlands to Romania and Greece	Predecessor (UCPTE) founded in 1951	23 countries of Europe; 33 TSOs; aprox: 450 million consumers	390GW and installed capacity of 607 GW	Not applicable (on national or sub-regional level only)	Not applicable.
Europe	CENTREL	Until December 2006: Efficient use of transmission capacity through the establishment of economic, business, technical and organisational conditions	1992	Not applicable (part of UCTE).	Not applicable.	Not applicable (on national level only)	Not applicable.

Region	Power Trade Organization(s)	1. Objective of the regional initiative	2. Year the initiative began and other important year	3. Size of the market		4. Exchanges	5. Products traded
Europe	NORDEL	To promote the integrated Nordic electricity market as a part of the North-West European electricity market and to maintain a high level of security in the Nordic power system.	1963	25 million	67 GW	a + b (bilateral), c + d (Nord Pool), e (Nord Pool), and balancing power market (operated by TSOs)	a, b (balancing power, reserves), c (options for load reduction)
Europe	BALTREL	Interconnected liberalised and harmonised regional electricity markets in the Baltic Sea Region. BALTREL has no regulatory or operational function, it is an assosiation of companies in the power sector in the NORDEL area, the Baltic and Russia.	1998	Not applicable.	Not applicable.	Not applicable.	Not applicable.

Region	Power Trade Organization(s)	1. Objective of the regional initiative	2. Year the initiative began and other important year	3. Size of the market		4. Exchanges	5. Products traded
Europe	SUDEL	To co-ordinate the strategical, developmental and operational issues among TSOs in South-East Europe between Italy, Turkey and Hungary.	1964	216 million	Not applicable. Major parts are within UCTE, and major parts are separate (e.g. Turkey)	Not applicable. SUDEL has no single power exchange. The area covered by the SUDEL members has several national markets.	Not applicable.
CIS	CIS Countries Market	Become a regional Market	1992	279 million	Not Available	In this regional market only there are bilateral contracts and all of them are private	Bilateral agreements are private but are based (the key point) is the energy price

Region	Power Trade Organization(s)	1. Objective of the regional initiative	2. Year the initiative began and other important year	3. Size of the market		4. Exchanges	5. Products traded
US	PJM	Improve sector efficiency, competition, regional trading and system reliability	1927: beginning 1997: open real time market	51 million	144,644 MW (2006)	a, b, c, d ,e	a, b (regulation and synchronized reserves market), c (capacity market)
US	New England ISO	Improve sector efficiency, competition, regional trading and system reliability	1966: beginning 1999: NE ISO begins managing regional market	14 million	28,130 MW (2006)	a, b, c, d ,e	a, b (load regulation, spinning reserves and operating reserves market), c (capacity market)
US	South West Power Pool	Improve sector efficiency, competition, regional trading and system reliability	1941: association of 11 companies 2004: approved by FERC as RTO	18 million	42,227 MW (2006)	a, b, c	a
US	Western System Power Pool	Promote regional sector efficiency, competition, and coordination	1987: FERC experiment 1991: formal entity	600 million	No info	b	a, c (capacity)

Region	Power Trade Organization(s)	1. Objective of the regional initiative	2. Year the initiative began and other important year	3. Size of the market		4. Exchanges	5. Products traded
US	Mid-West ISO	Improve sector efficiency, competition, regional trading and system reliability	1996: founded 2001: approved by FERC as RTO	66 million	116,207 MW (2006)	a, b, c, d ,e	a, b (project stage, not implemented yet)
Central America	SIEPAC	Develop a regional transmission system and a regional electricity market in Central America	1996 Treaty was signed	39.9 million	9063.6 MW (the sum of countries' peak demand)	Day ahead spot market and balancing market; financial contracts, firm or physical contracts are allowed but must be accompanied by congestion rights to manage congestion and physical flexible contracts	Energy and transmission services

Region	Power Trade Organization(s)	1. Objective of the regional initiative	2. Year the initiative began and other important year	3. Size of the market		4. Exchanges	5. Products traded
Africa	Southern Africa Power Pool	Develop a power pool in the region to take advantge of complementarity of resources: hydro in the northern part and resources for thermal generation in the south.	Johannesburg, 1995, inter governmental MOU to create a power pool	Angola, Botswana, DRC, Lesotho, Malawi, Mozambiue, Namibia, South Africa, Swaziland, Tanzania, Zambia, Zimbabwe		a, b	a, support in case of crisis

Region	Power Trade Organization(s)	1. Objective of the regional initiative	2. Year the initiative began and other important year	3. Size of the market		4. Exchanges	5. Products traded
Africa	Western Africa Power Pool	Address and overcome power supply deficiency within West Africa	1999: established 2006: adopted the Articles of Agreement	250 million	6,500 MW (2006)	Only few countries have interconnections and they only have trading undertaken by bilateral contracts.	Based on energy

Region	Power Trade Organization(s)	1. Objective of the regional initiative	2. Year the initiative began and other important year	3. Size of the market		4. Exchanges	5. Products traded
SE Asia	Greater Mekong Sub-region initiative	The objective is to develop power trade in the region, idea fostered by the ADB	Intergovernmental Agreement (IGA) signed by countries in 2002; in 2004 the Regional Power Trade Coordination Committee began activities	218.3 million plus the province of Yunnan - China (China is 1,322 million)	36,825 MW plus province of Yunnan - China (China is 391 GW)	Market still not functioning. For initial stage, only opportunity exchanges between neighbouring countries based on differences of marginal cost anticipated. Later, day ahead market according to transmission services availability expected.	Energy in the first stages

Region	Power Trade Organization(s)	1. Objective of the regional initiative	2. Year the initiative began and other important year	3. Size of the market		4. Exchanges	5. Products traded
Australia	National Electricity Market	"The national electricity market objective is to promote efficient investment in, and efficient use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system.”	December 1998 began operations; Sixth region operational June 2006	8 million	32 GW	a. b. c.	a. b. c. - Contracts for Differences

TABLE II

Region	Power Trade Organization	6. Key regional institutions	7. Regional regulatory authority	8. Regional centralized dispatch	9. Management of congestion	10. Volumes traded	11. Prices and corresponding products	12. Development of transmission infrastructure	13. Government intervention	14. Regional standards
Europe	UCTE	General Assembly, Steering Committee, Working Groups, cmpetence Centres, Service Centres	EU	No	On national level, and cross-border transactions co-ordinated by UCTE through data interchange.	Not applicable.	Not applicable.	High, one of the biggest and more meshed systems in the world	EU	Yes
Europe	CENTREL	UCTE and ETSO are the key regional institutions of the former CENTREL area.	EU	No	On national level, and cross-border transactions co-ordinated by UCTE.	Not applicable.	Not applicable.	Not applicable.	EU	Yes, within ETSO and UTCE.

Region	Power Trade Organization	6. Key regional institutions	7. Regional regulatory authority	8. Regional centralized dispatch	9. Management of congestion	10. Volumes traded	11. Prices and corresponding products	12. Development of transmission infrastructure	13. Government intervention	14. Regional standards
Europe	NORDEL	NORDEL	On national level	No	Zonal, done day-ahead in the spot market. Intra-zonal in real time, done by the TSOs.	Spot (physical): 250 TWh (2006), Financial: 766 TWh (2006)	Spot (physical): 16, 49, 81 EUR/MWh (Min, average, max 2006)	Co-ordinated by NORDEL, considering regional needs	On national level, through the regulator.	Yes: Grid code and harmonisation of congestion management etc.
Europe	BALTREL	Not applicable.	No	No	No	No	No	Studies performed on a Baltic transmission Ring	No	No
Europe	SUDEL	UCTE and ETSO are the key regional institutions of the SUDEL area, though not all SUDEL members take part in these organisations.	No.	No	UCTE	Not applicable.	Not applicable.	On national level	On national level	UCTE and ETSO.

Region	Power Trade Organization	6. Key regional institutions	7. Regional regulatory authority	8. Regional centralized dispatch	9. Management of congestion	10. Volumes traded	11. Prices and corresponding products	12. Development of transmission infrastructure	13. Government intervention	14. Regional standards
CIS	CIS Countries Market	Electric Power Council (EPC)	Not defined yet. The EPC act as advisor	The have two control centres working in parallel	None	2005 (average): 30,179,600 MWh	As bilateral contracts this information is not available	Already exist but is not well maintained so the need improvements. As well as inter governmental agreements they plan these improvements	Up to date almost all initiatives are governmental, due almost all the electric companies al vertically integrated state owned.	There are not yet a Regional Standard
US	PJM	PJM ISO/RTO	PJM ISO/RTO	Yes, PJM ISO/RTO	Through LMP and FTRs	USD 71 billon since 1997	Average LMP (2006): 49 USD/MWh	High: 56,250 miles of transmission lines	Yes, FERC	PJM standards
US	New England ISO	NE ISO/RTO	NE ISO/RTO	Yes, NE ISO/RTO	Through LMP and FTRs	USD 9 billon wholesale annually	Average LMP (2006): 63 USD/MWh	High: 8,000 miles of transmission lines,12 interconnections to neighbouring systems	Yes, FERC	NE standards
US	South West Power Pool	SPP RTO	SPP RTO	Yes, SPP RTO	Through re-dispatch of the EIS market, curtailment of schedules (CAT), NERC Interchange Distribution Calculator	No info	Average Spot Price (2006): 56 USD/MWh	High	Yes, FERC	SPP standards
US	Western System Power Pool	WSPP entity	WSPP entity	No	No mechanisms reported	No info	No info	High	Yes, FERC	WSPP Agreement

Region	Power Trade Organization	6. Key regional institutions	7. Regional regulatory authority	8. Regional centralized dispatch	9. Management of congestion	10. Volumes traded	11. Prices and corresponding products	12. Development of transmission infrastructure	13. Government intervention	14. Regional standards
US	Mid-West ISO	Midwest ISO/RTO	Midwest ISO/RTO	Yes, Midwest ISO/RTO	Through LMP and FTRs	No info	Average LMP (2006): 40 USD/MWh	High: 98,600 miles of interconnected high voltage power lines	Yes, FERC	Midwest standards
Central America	SIEPAC	CRIE: Regional Electricity Interconnection Comisión; EOR: Regional Operator; EPR: Company Owner of the Grid	Under the CRIE which plays the role of regional regulator, there is a Market Surveillance Group and a Regulatory Support Group comprised of regulators the member countries.	Yes, by EOR	Congestion is managed through congestion rights. The EOR must perform periodic auctions among the market participants	In December 2006, 21061.5 MWh were injected to/withdrawn from the regional grid. Aprox 80% were contracts and 20% opportunity exchanges.		EOR centrally plans the development of the regional grid; market participants are allowed to construct their own transmission facilities.	Played a central role by signing the initial agreement / treaty in 1996.	
Africa	Southern Africa Power Pool	Executive Committee, Co-ordination Centre, sub committees, working groups	No	Yes in Harare	Bilateral contracts have preference. Once dispatched bilateral contracts, the remaining capacity is made available for Day Ahead Market (in the future)	Basically bialteral contracts which are not public.	Prices of bilateral contracts not public	Low, backbones need to be developed. Long distances are an important hurdle.	Yes, in the beginning it was important the decision of governments to foster cooperation among countries which later turned into the regional pool.	Yes

Region	Power Trade Organization	6. Key regional institutions	7. Regional regulatory authority	8. Regional centralized dispatch	9. Management of congestion	10. Volumes traded	11. Prices and corresponding products	12. Development of transmission infrastructure	13. Government intervention	14. Regional standards
Africa	Western Africa Power Pool	WAPP organization	WAPP organization (WAPP defined a protocol to arrange agreements, but there is not a common regulatory authority)	TSO of each country works on its own, but they have been provided with an Integrated Communication Centre that will become a Dispatch in the very long term	None	Not applicable (2001: 1,744,665 MWh)	As bilateral contracts this information is not available	Very low (Almost all infrastructure is needed to be built. Some institutions (WB, USAID, …) are providing loans to develop them)	Yes, governments from each member country must approve all the initiatives and agreements	WAPP Articles of Agreement; This is not however a Regional Standard, but a protocol defining a framework with very general rules, mostly on how to solve disagreements among members
SE Asia	Greater Mekong Sub-region initiative	Regional Power Trade Coordination Committee, Focal Group (in charge of promoting development of market and creating the institutions), & Planning Group. In later stages, Regional Regulatory Board and Regional Market Operator	A Regional Regulatory Board is foreseen for future stages	A Regional Market Operator is foreseen for future stages	Not Decided	Not yet begun	N/A	System Planning Group should develop master plan for regional expansion of infrastructure.	Governments signed initial treaty (IGA) and communicates with the regional initiative through the corresponding ministries. Little commitment from the different governments is perceived.	Regional grid code; understood that countries should reach agreement for minimum standards for the region's systems, but no progress has been made yet on this issue.

Region	Power Trade Organization	6. Key regional institutions	7. Regional regulatory authority	8. Regional centralized dispatch	9. Management of congestion	10. Volumes traded	11. Prices and corresponding products	12. Development of transmission infrastructure	13. Government intervention	14. Regional standards
Australia	National Electricity Market	NEMMCO, Australian Energy Market Commission (AEMC)	Australian Energy Regulator (AER)	Yes, NEMMCO	Market mechanisms described in National Electricity Rules. Includes constrained economic dispatch, national transmission flow paths, and other rules on pricing & settlement.	180,000 Gwh/year (2006); 8 billion AUD$ (5.7 billion USD$) (2006)	Typical enrgy spot price less than $40 AUD/Mwh ($28.5 USD/Mwh); Price cap on energy $10,000 AUD/Mwh ($7125 USD/Mwh)	NEMMCO and its working groups, such as Inter Regional Planning Committee [IRPC] (on yearly basis: Annual National Transmission Statement)	MCE (Ministerial Coucil on Energy), CoAG (Council of Australian Governments), AEMC (Australian Energy Market Commission), AER (Australian Energy Regulator)	Established by the AEMC Reliability Panel

LESSONS AND CONCLUSIONS

The analysis of the markets performed allows obtaining lessons and conclusions from the success and also from the failures or difficulties that the different experiences have faced. Among the most important:

Maybe the first and most important conclusion is that it is not absolutely necessary to have a “market”, in the classical sense for a group of countries, to obtain benefits. Trading is the key, since it is from actual trading that benefits are obtaining. In many cases, especially in developing regions, a full market is not feasible in the beginning, but trading is possible and therefore obtaining benefits for all parts is possible. The development of a power market can be seen as next stage or an objective situation, since it is recognised that markets, when they function well are the best tool to trade efficiently. It is important to foster trading as first step to later develop a market. Markets require among other things the development of transmission infrastructure and until this infrastructure exists, the market will be an objective, but not a possibility.

Markets / trading can be developed even in situations where countries have different organisation of their industries and different sizes. SIEPAC is an example of different organisations of industries that arrive to constitute a market. The design of the GMS market shows also that it is possible to design trading arrangements for countries which have very different sizes of their industries.

A key requirement to develop trading with the objective of arriving to “market situation” is the development of transmission infrastructure together with the required institutional framework and in a coordinated manner. CIS is an example of a region which has transmission infrastructure but does not arrive to have an institutional framework for trading. Trading is therefore inefficient, it is based exclusively in bilateral contracts not standarised and that do not take into account a future evolution to a market situation. This may introduce difficulties for this desired transition. GMS is a region which is willing to develop the institutions but does not arrive to the required agreements to develop the transmission infrastructure, therefore trading is very limited. Maybe the best example is SIEPAC, a region which has developed infrastructure and institutionalism in a coordinated way. Obviously it has not been perfect, but there is a clear consciousness of the need of both things: develop infrastructure and develop institutionalism to arrive to a market situation.

Developed regions show that it takes time to arrive to a market situation, and that the markets develop themselves when there are trading opportunities.

Markets of developed regions with enough infrastructure have many times focused in short term trading overlooking the long term and the need in the long term for system expansion in transmission; this represents a menace for the good functioning of the market in the future. This fact brings us to think that for the case of developing regions with scarce transmission infrastructure, a key element is the regional planning at short, medium and long term of the transmission system.

Moreover, it is not enough just with planning, it is necessary to actually implement the plan and construct the required infrastructure. Many times the agreements that are necessary among the countries to actually build the infrastructure indicated by the planning are more difficult to reach than actually developing the plan.

The development of markets has always been made in stages, formally or not, but they have always evolved according to the needs of the region and the infrastructure available. Nowadays the fact of developing markets in stages is explicit (GMS) and the trading arrangements design incorporates this phased manner of development. Markets that have developed earlier (basically in developed regions) also passed through different stages;

even if it was not thought originally they had actually evolved from the original situation to the current one, incorporating in each phase those elements which were needed and were possible to incorporate according to the available technology and structure of the industries. The conclusion is then that when designing trading arrangements from scratch with the objective to arrive to a market, it is convenient to think "in phases" and the market situation as the objective situation, maybe in the long or very long run.

Supranational institutions are highly recommended to foster the development towards the final objective. It is not necessary a sophisticated framework at the beginning, on the contrary, the simplest the better. But a consciousness 8and acceptance) of being ruled in some aspects by supranational entities needs to be built slowly from the beginning. The institution(s) need to be legitimated by some treaty or agreement of the involved governments. The key objective of the institution(s) in the beginning is to steer the process. Specific institutions will be established in a phased manner according to the needs, or existing ones will be modified in their mission and objectives. CIS is an example where the region has infrastructure available to develop trade but no institutionalism or weak institutionalism prevents this development in a quicker way.

In Europe the organisation of regional areas for trading has begun (and it continuous to have a central role) as cooperation among TSOs whose central preoccupation were technical aspects such as operations and security, synchronization of areas, technical standards, etc. so as to facilitate trading. The need for trading rules and the "development of a market" has come later.

ANNEX: US POWER TRADE ORGANISATIONS

1. 1. GENERAL ASPECTS

In this section we will analyse some of the US power trade organizations: PJM, Midwest ISO, New England ISO, South West Power Pool and Western Systems Power Pool.

It is important to say that the settlement and actual shape of these organizations were the result of a large process within the history of the electricity industry in the USA. As a result, to fully understand the actual situation of these markets, it is necessary to briefly review the whole nation picture, looking at the evolution of the legal and institutional structures over time, analysing the government participation (both federal and state) and taking into account the external market conditions. [4]

1.1 THE EVOLUTION OF THE ELECTRICITY INDUSTRY IN THE USA

For a variety of legal, economic, and technological reasons, the electricity industry in the USA developed as a collection of separate, mostly vertically-integrated monopoly franchises with wholesale and retail prices and services extensively regulated under state and federal

[4] This section draws heavily in both text and concept on the "Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy", 2006, pursuant to section 1815 of the Energy Policy Act of 2005 and prepared by the Electric Energy Market Competition Task Force, found at http://www.ferc.gov/legal/maj-ord-reg/fed-sta/ene-pol-act/epact-final-rpt.pdf

law. Many states have elected to maintain this model. The legacy of this vertically-integrated monopoly structure creates substantial challenges for state and federal efforts to restructure the industry and to create new institutional arrangements to facilitate increased reliance on competitive market prices. A brief overview of the evolutionary changes in the electric power industry is provided below.

The Rise of Electric Utility Monopolies and Public Utility Regulation

In the late 19th Century, electric utilities developed as small central station power plants with limited local distribution networks. Franchise rights granted by manufacturers and by municipal governments allowed use of public streets and rights of ways. These franchises were often exclusive, but in some cities there was head-to-head competition among competing electric lighting companies. In addition, many municipalities elected to create and operate their own electric utility systems.

Certain characteristics of providing electric service were recognized early on. Utility systems incurred high fixed costs for investments in generating plants needed to meet peak load and to extend the delivery system. Because they had relatively low operating costs, their profits were determined by the percent of time the power plant was in use. Complementary load diversity – such as balancing daytime traction and electric motor loads with evening lighting loads – could raise generating plant use and revenues to offset fixed costs and boost profits. The high capital costs of electric generating plants made investments risky. Steady gains in generation, transmission, and distribution economies of scale provided incentives to expand the electric networks. Larger plants produced cheaper electricity than many smaller plants. The substantial investment required for electric utility plants also spurred creation of long-term financing structures and the corresponding interest in providing assurances to investors that the entity would be profitable and would remain financially viable long enough to repay the debt.

These characteristics led some to suggest that a single monopoly provider of integrated generation, transmission and distribution service could provide electric service most economically and safely. To avoid abuses of this monopoly power, it was suggested that impartial state agencies should be created to award franchises and establish rates and service standards. An early associate of Thomas Edison, Samuel Insull of Chicago Edison was among them and proposed state regulation of private utilities in a speech before the National Electric Light Association in 1898. Insull characterized electricity production as a "natural monopoly." Initially, the proposal for state regulation was poorly received, but as private industries, the concept began to gain support. In 1907, Wisconsin adopted legislation regulating electric utilities and was quickly joined by two other states. By 1916, 33 states had established state agencies to oversee private electric utilities.

Generally, under this approach, the state regulatory commission granted exclusive retail electric franchises to private companies within specified territories, protecting the utility from competition. In return, the utility assumed an obligation to provide safe and adequate service to all retail customers within its territory under just and reasonable rates, terms and conditions overseen by the state. Often the utility was authorized to use public rights of way and eminent domain for electric facilities. To meet this obligation to serve, most private utilities built and controlled the generation, transmission, and distribution facilities needed to provide service to customers. Rates were set to cover the companies' reasonable costs plus a fair return on shareholders' investment. The utility could expect a right to reasonable compensation for its services, although a specific rate of return was not guaranteed. Retail rates (price) were based on the average historical system cost of production (including the investors' fair return on investment).

In the early 20th Century, private electric utilities continued to expand under this system of state regulation. Most continued to build their own generation plants and transmission systems, primarily due to the cost and technological limitations of transmitting electricity over distances. Initially, there was little wholesale trade among utilities. As the industry grew, continued improvements in technology allowed expansion beyond central cities, and prices for electricity fell at the same time that demand increased substantially.

Over the same period, electric utility holding companies were created and began to acquire local private and municipal utilities. While a holding company's local utility operating

companies were regulated by the state, the holding company and its other affiliates and subsidiaries were not, and often did business in several states. The proliferation, consolidation, and complexity of such companies coincided with a number of financial and securities abuses that were documented in an investigation by the Federal Trade Commission (FTC). These holding companies often became the sole providers of various services and products to their affiliated utilities, and their sometimes inflated costs were passed through to the retail customers. By 1932, the eight largest utility holding companies controlled 73 percent of the investor-owned electric industry.
This pattern of consolidated ownership and holding company abuses led to calls for federal involvement in the electric power industry. As a result of the FTC findings, Congress passed the Public Utility Holding Company Act of 1935 (PUHCA 1935), which required the breakup and Power Commission's authority to include oversight and regulation of interstate sales of wholesale power (e.g., sales of power between utility systems) and interstate electricity transmission at wholesale by "public utilities" (i.e., investor-owned utilities).

The Federal Power Act of 1935 gave the Federal Power Commission (FPC), originally created in 1920 to coordinate hydroelectric projects under federal control, the power to regulate the sale and transportation of electricity.
When the Federal Power Act was enacted, wholesale and interstate sales of electricity were limited. Most wholesale transactions were long-term power supply contracts by investor-owned utilities to sell and deliver power to neighboring public power and cooperative utilities. Over time, utilities became more interconnected via high-voltage transmission networks. Constructed primarily for reliability, these networks also facilitated more opportunities for interstate trade. However, wholesale trade was slow to develop.
Until the late 1960s, the vertically integrated monopoly utility model appeared to work reasonably well. Utilities were able to meet increasing demand for electricity at decreasing prices as advances in generation technology and transmission provided increased economies of scale with larger units and decreased costs.

<u>The Energy Crisis of the 1970s, PURPA, and the Expansion of Nonutility Generation and Wholesale Power Markets</u>

The shift toward a more competitive marketplace for electricity was precipitated by industry changes that began in the late 1960s and accelerated throughout the 1970s. Resulting financial stresses challenged the continued profitability of the large vertically integrated utility model. They also provoked criticisms of the traditional cost-of-service regulatory model that allowed the pass-through of higher costs and risks of construction to consumers.
By the end of the 1960s, electricity demand and generation were increasing at an annual rate of 7.5 percent, and residential rates were declining at an average annual rate of 1.5 percent.
At the same time, the new large nuclear and coal plants built in the 1970s did not yield the dramatic improvements in economies of scale that earlier technological advances in generating plant size had produced. The industry's characterization as a long-term decreasing cost industry came into question. Periods of rapid inflation and higher interest rates substantially increased the completion costs of large, base load generating plants. New environmental and safety regulations required addition of pollution controls and design features that added to costs and construction time. Moreover, once in operation, many of the new, larger units required more maintenance and longer downtimes than expected. Thus, by the late 1970s, a newer, larger, generation facility no longer could be assumed to be more cost-efficient than a smaller plant.
This experience stimulated interest in smaller, modular, more energy-efficient generating units. One expression of this interest resulted in commercialization of aeroderivative gas turbine technology. This technology allowed smaller generation units to be constructed at lower costs, more quickly, and at less financial risk than large base-load coal and nuclear plants. Thus, construction of low-cost generation became an option for utilities that were formerly captive to high-cost generators and emerged as a viable path for new nonutility generators to enter the market.
As the difficulties plaguing utilities' generation construction programs were playing out,

utility fuel prices were escalating rapidly in response to the Arab oil embargo of 1973-1974 and subsequent world oil market disruptions. Significantly higher energy prices added to inflation and increased electric rates. Other developments also substantially contributed to the growing interest in electric utility reforms. First, the 1965 Northeast power blackout raised concerns about the reliability of weakly coordinated bulk power system operating arrangements among utilities. The nuclear accident at the Three Mile Island plant in Pennsylvania on March 28, 1979, heightened concerns over safety and led to stringent new regulatory requirements for nuclear plants.
Criticism of the traditional cost-of-service utility regulation model by economists and policy analysts also increased during the 1970s with suggestions for alternate approaches to regulation and changes in industry structure. Critics of cost-based regulation argued that the industry structure limited opportunities for more efficient suppliers to expand, placed insufficient pressure on less efficient suppliers to improve performance, and insulated customers from the cost impacts of energy use.

Congress enacted the Public Utility Regulatory Policies Act (PURPA) as a response to the energy crises of the 1970s. PURPA's major goal was to promote energy conservation and alternative energy technologies and to reduce oil and gas consumption through use of improved technology and regulatory reforms. A perhaps unanticipated side effect was that PURPA prompted a number of parties to see potential profits in developing competitive generating plants, creating an opportunity for nonutilities to emerge as important electric power producers.
PURPA required electric utilities to interconnect with and purchase power from cogeneration facilities and small power producers that met statutory criteria for a qualifying facility (QF). A utility had to pay the QF at the utility's incremental cost of production. In a departure from cost-based rate approaches, FPC defined this as the utility's avoided cost of power. PURPA changed prevailing views that vertically integrated public utilities were the only reliable sources of power and showed that nonutilities could build and operate generation facilities effectively and without disrupting the reliability of the electric grid. **PURPA contributed substantially, both directly and indirectly, to the creation of an independent competitive generation sector**.
Before passage of PURPA, nonutility generation was confined primarily to commercial and industrial facilities that generated heat and power for onsite use where it was advantageous to do so. Although nonutility generation facilities were located across the country, development was heavily concentrated geographically, with about two-thirds of such facilities located in California and Texas. Nonutility generation development advanced in states where avoided costs were high enough to attract interest and where natural gas supplies were available. Federal law largely precluded electric utilities from constructing new natural gas plants during the decade following enactment of PURPA, but nonutility generators faced no such restriction and quickly turned to the new smaller gas turbines as the preferred generating technology.
In 1977, Congress reorganized the FPC as FERC and the responsibilities of the Commission continued to expand. The response to PURPA was dramatic. Annual QF filings at FERC rose from 29 applications covering 704 MW in 1980 to 979 in 1986 totaling over 18,000 MW. From 1980 to 1990, FERC received a total of 4,610 QF applications for a total of 86,612 MW of generating capacity.

Following PURPA, continued improvement in generating technology lowered costs and further contributed to an influx of new entrants in wholesale markets. They could sell electric power profitably with smaller scale generators, including renewable energy technologies and more efficient, modular gas turbines. Other nonutilities that could not meet QF criteria began building new capacity to compete in bulk power markets to meet the needs of utilities. These new entities were known as merchant generators or independent power producers (IPPs). By 1991, nonutilities (QFs and IPPs) owned about 6 percent of the electric generating capacity and produced about 9 percent of the total electricity generated in the United States. Nonutility facilities accounted for one-fifth of all additions to generating capacity in the 1980s. Beginning in the 1980s, FERC allowed many new utility and nonutility generators to sell electricity at rates negotiated in wholesale markets, rather than established under cost-of-service formulas.

In 1988, FERC solicited public comments on three notices of proposed rulemaking (NOPRs) dealing with electricity pricing in wholesale transactions. These NOPRs addressed the following issues: (1) competitive bidding for new power requirements; (2) treatment of independent power producers; and (3) determination of avoided costs under PURPA. These proposals would have moved FERC towards greater use of a "non-traditional" market-based pricing approach in ratemaking as opposed to the agency's "traditional" cost-based approach. The NOPRs, however, proved controversial, and efforts to establish formal rules or policies were abandoned. However, the overall policy goals were still pursued on a case-by-case basis.

Between 1983 and 1991, FERC was asked to approve more than 30 non-traditional market-based rate proposals. These proposals were brought by IPPs, power brokers/marketers, utility-affiliated power producers, and traditional franchised utilities. FERC approved all but four. The decisions considered the potential exercise of market power. In determining whether the seller could exercise market power over the buyer, FERC considered whether the seller or its affiliates owned or controlled transmission that might prevent the buyer from accessing other power sources. A seller with transmission control might be able to force the buyer to purchase from the seller, thus limiting competition and significantly influencing price. The FPA does not allow rates to reflect an exercise of such market power.
FERC recognized the potential for control of transmission to create market power and the challenge such control created in moving to greater reliance on market-based rates.
Despite these developments, two limitations at that time were perceived to discourage competitive wholesale generation markets. First, IPPs and other generators of cheaper electric power could not easily access the transmission grid to reach potential customers. Under the FPA as then written, FERC had limited authority to order access. FERC would subsequently find that "intervening" transmitting utilities would deny or limit transmission service to competing suppliers of generation to protect demand for wholesale power supplied by their own facilities. Second, unlike QFs that enjoyed a statutory exemption under PURPA, IPPs were subject to PUHCA 1935, which discouraged nonutilities from entering the generation business.

3. <u>The Energy Policy Act of 1992 and FERC Orders Nos. 888 and 889</u>

The Energy Policy Act (EPAct) 1992 amended the Federal Power Act and PUHCA 1935 to address what were then seen as the two major limitations to the development of a competitive generation sector.

First, **EPAct 1992 created a new category of power producers, called exempt wholesale generators (EWGs). An EWG is an entity that directly, or indirectly through one or more affiliates, owns or operates facilities dedicated exclusively to producing electric power for sale in wholesale markets**. EWGs are exempted from PUHCA 1935 regulations, thus eliminating a major barrier for utility-affiliated and nonaffiliated power producers that wanted to build or acquire new non-rate-based power plants to sell electricity at wholesale.

Second, **EPAct 1992 expanded FERC's authority to order transmitting utilities to provide transmission service for wholesale power sales to any electric utility, federal power marketing agency, or any person generating electric energy.** It provided for orders to be issued on a case-by-case basis following a hearing if certain protective conditions were met. Although FERC implemented this new mandatory wheeling authority, it ultimately concluded that procedural limitations restricted its reach and a broader remedy was needed to eliminate pervasive undue discrimination in transmission service that hindered competition in wholesale markets.

In April 1996, **FERC adopted Order No. 888 in exercise of its statutory obligation under the FPA to remedy undue transmission discrimination. The goal was to ensure that transmission owners do not use their transmission facility monopoly to unduly discriminate against IPPs and other sellers of electric power in wholesale markets.** In Order No. 888, FERC found that undue discrimination and anti-competitive practices existed in transmission service provided by public utilities in interstate commerce. FERC determined that non-discriminatory open access transmission service was an appropriate remedy and one of the most critical components of a successful transition to competitive wholesale electricity markets. Accordingly, FERC required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to file open access transmission tariffs (OATTs) containing certain non-price terms and conditions. They also were required to "functionally unbundle" wholesale power services from transmission services. This meant that a public utility was required to: (1) take wholesale transmission services under the same tariff of general applicability as it offered its customers; (2) define separate rates for wholesale generation, transmission and ancillary services; and (3) rely on the same electronic information network that its transmission customers rely on to obtain information about the utility's transmission system.

Concurrent with Order No. 888, **FERC issued Order No. 889 that imposed standards of conduct governing communications between a utility's transmission and wholesale power functions to prevent the utility from giving its power marketing arm preferential access to transmission information**. Order No. 889 requires each public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce to create or participate in an Open Access Same-Time Information System (OASIS). OASIS must provide information regarding available transmission capacity, prices, and other information that will enable transmission customers to obtain open access to non-discriminatory transmission service.

In Order No. 888, FERC also encouraged grid regionalization through the formation of independent system operators (ISOs). Participating utilities would voluntarily transfer operating control of their transmission facilities to the ISO to ensure independent operation of the transmission grid. The expectation was that ISO regional control would lead to improved coordination, reliability, and efficient operation. However, ISO participation was voluntary and was not embraced in all regions. **Together, Order Nos. 888 and 889 serve as the primary federal regulatory foundation for providing nondiscriminatory transmission service and information about the availability of transmission service.**

Recently, **FERC issued Order 2000, fostering participation in regional transmission organizations (RTOs) and Independent System Operators (ISOs), by establishing guidelines that a transmission entity must meet in order to qualify as an RTO**. The expectation is that the RTOs will increase efficiency in wholesale energy markets and lower end-prices to consumers. **Voluntary RTOs and ISOs were formed in New York, New England, PJM, and the Midwest.**

The Energy Policy Act of 2005 was the first major energy law enacted in over a decade, and makes the most significant changes in Commission authority since the Federal Power Act and Natural Gas Act. By passing the Energy Policy Act of 2005, Congress signaled a strong vote of confidence in the Commission. The Energy Policy Act of 2005 gave the Commission significant new responsibilities and granted it significant new authority to discharge these responsibilities by modifying the Federal Power Act, the Natural Gas Act, and the Public Utility Regulatory Policies Act of 1978. In addition the Energy Policy Act of 2005 repealed the Public Utility Holding Company Act of 1935 and in its place created a new rule, which emphasizes access to books and records. The Commission's significant new responsibilities also include:

- Overseeing the establishment and enforcement of reliability standards for the Nation's electric transmission grid;
- Implementing new tools, including penalty authority, to prevent market manipulation;
- Providing rate incentives to promote electric transmission investment;
- Supplementing state transmission siting efforts in national interest electric transmission corridors; and

- Reviewing certain holding company mergers and acquisitions involving electric utility facilities, a well as certain public utility acquisitions of generating facilities.

On February 15, 2007, the Commission adopted a final rule reforming its decade-old open-access transmission regulatory framework that will ensure transmission service is provided on a nondiscriminatory and just and reasonable basis, as well as provide for more effective regulation and transparency in the operation of the transmission grid. The rule is designed to: (1) strengthen the pro forma open-access transmission tariff, or OATT, to ensure that it achieves its original purpose of remedying undue discrimination; (2) provide greater specificity to reduce opportunities for undue discrimination and facilitate the Commission's enforcement; and (3) increase transparency in the rule applicable to planning and use of the transmission system.

Finally, FERC has proposed (2002) a Standard Market Design (SMD) to standarize market rules within the USA. This SMD is based on locational marginal prices, a two settlement market scheme and the use of financial transmission rights to manage transmission congestion. Although it is voluntary to follow the SMD, it is being an important tool for the harmonisation of operation procedures, design criteria and electricity pricing mechanisms, as it will be seen for some of the USA trade organizations that are described in this report (e.g. PJM, Midwest, New England).

1.2 INDUSTRY STRUCTURE AND REGULATION

Participants in the electric power sector in the United States include investor-owned utilities and electric cooperatives; federal, state, and municipal utilities, public utility districts and irrigation districts; cogenerators and onsite generators; and nonutility independent power producers (IPPs), affiliated power producers, power marketers, and independent transmission companies that generate, distribute, transmit, or sell electricity at wholesale or retail.

These entities differ greatly in size, ownership, regulation, customer load characteristics, and regional conditions. These differences are reflected in policy and regulation. Tables 1 and 2 provide selected statistics for the electric power sector by type of ownership in 2004 based on information reported to the Department of Energy (DOE), Energy Information Administration (EIA).

1. Investor-Owned Utilities

Investor-owned utility operating companies (IOUs) are private, shareholder-owned companies ranging from small local operations serving a retail customer base of a few thousand to giant multi-state holding companies serving millions of customers. Most IOUs are or are part of a vertically integrated system that owns or controls generation, transmission, and distribution facilities/resources to meet the needs of retail customers in their franchise service areas. Many IOUs have undergone significant restructuring and reorganization under state retail competition plans over the past decade. As a result, many IOUs no longer own generation, but those that sell electric power to retail customers must procure electricity from wholesale markets. IOUs provide service to retail customers under state regulation of territories, finances, operations, services, and rates. States that have not restructured retail service generally regulate retail rates under traditional bundled cost-of-service rate methods. In states that have restructured IOUs, distribution services continue to be provided under monopoly cost-of-service rates, and retail customers obtain generation service either at market rates from alternative competitive providers or at regulated "provider of last resort" (POLR) rates from the distribution utility or another designated POLR service provider.

Under the Federal Power Act, FERC regulates wholesale electricity transactions (sales for resale) and unbundled transmission activities of IOUs as "public utilities" engaged in interstate commerce. The exceptions are IOUs that do not have direct interconnections with utilities in other states that allow unimpeded flow of electricity across systems. Thus, IOUs in Alaska, Hawaii, and the Electric Reliability Council of Texas (ERCOT) region of Texas generally are not subject to FERC jurisdiction.

2. Public Power Systems

The more than 2,000 publicly owned power systems include local, municipal, state, and regional public power systems. These providers range from tiny municipal distribution companies to large systems such as the Los Angeles Department of Water and Power. Many public systems are distribution-only utilities that purchase, rather than generate, power. According to the American Public Power Association, about 70 percent of public power retail sales were met from wholesale power purchases, including purchases from municipal joint action agencies by the agencies' member systems. Only about 30 percent of the electricity for public power retail sales comes from power generated by a utility to service its own native load. Publicly owned utilities, thus, depend overwhelmingly on transmission and the wholesale market to bring electricity to their retail customers.

Regulation of public power systems varies among states. In some, the public utility commission exercises jurisdiction in whole or part over operations and rates of publicly-owned systems. In most states, public power systems are regulated by local governments or are self-regulated. Municipal systems usually are governed by a local city council or an independent board elected by voters or appointed by city officials. Other public power systems are operated by public utility districts, irrigation districts, or special state authorities.

On the whole, state retail restructuring initiatives did not affect retail services in public systems. However, some states allow public systems to adopt retail choice alternatives voluntarily.

3. Electric Cooperatives

Electric cooperatives are privately-owned, non-profit electric systems owned and controlled by the members they serve. Members vote directly for the board of directors. Electric cooperatives operate in 47 states. Most were originally organized and financed under the federal rural electrification program and operate in primarily rural areas.

While some cooperative systems generate their own power and sell power in excess of their members' needs, most generating and transmission cooperatives and distribution cooperatives are net buyers. Cooperatives nationwide generated only about half of the power needed by their retail customers. They secured approximately half of their power needs from other wholesale suppliers in 2004. Although cooperatives own and operate transmission facilities, almost all rely to some extent on transmission owned by others to deliver power to their customers.

Regulatory jurisdiction over cooperatives varies among states. Some states exercise considerable authority over rates and operations, while others exempt cooperatives from state regulation. In addition to state regulation, cooperatives with outstanding loans under the Rural Electrification Act of 1936 are subject to financial and operating requirements of the Rural Utilities Service (RUS), Department of Agriculture. RUS must approve borrowers' long-term wholesale power contracts, operating agreements, and transfers of assets. Cooperatives that have repaid their RUS loans and that engage in wholesale sales or provide transmission services to others have been regulated by FERC as public utilities under the FPA. EPAct 2005 gave FERC additional discretionary jurisdiction over transmission services provided by larger electric cooperatives.

4. Federal Power Systems

Federally-owned or chartered power systems include the federal power marketing administrations (PMAs), the Tennessee Valley Authority (TVA), and facilities operated by the U.S. Army Corps of Engineers, the Bureau of Reclamation, the Bureau of Indian Affairs, and the International Water and Boundary Commission. Wholesale power from federal facilities (primarily hydroelectric dams) is marketed through four federal power marketing agencies: Bonneville Power Administration, Western Area Power Administration, Southeastern Power Administration, and Southwestern Power Administration. The PMAs own and control transmission to deliver power to wholesale and direct service customers. They also may purchase power from others to meet contractual needs and may sell surplus power as available to wholesale markets. Existing legislation requires that the PMAs and TVA give preference in selling their generation to public power systems and to rural electric cooperatives.

5. Nonutilities

Nonutilities are entities that generate, transmit, or sell electric power but do not operate regulated retail distribution franchises. They include wholesale nonutility affiliates of regulated utilities, merchant generators, and qualifying facilities (QFs). They also include power marketers that buy and sell power at wholesale or retail but that do not own generation, transmission, or distribution facilities. Independent transmission companies that own and operate transmission facilities but do not own generation or retail distribution facilities or sell electricity to retail customers are also included in this category.

Table 1: U.S. Retail Electric Providers, 2004

Ownership	**Number of electricity providers**	**% of total**	**Number of customers**			**% of total**
			Full service	Delivery only*	Total	
Publicly-owned utilities	2,011	61.4	19,628,710	6,125	19,634,835	14.4
Investor-owned utilities	220	6.7	90,970,557	2,879,114	93,849,671	68.9
Cooperatives	884	27	16,564,780	12,170	16,576,950	12.2
Federal Power Agencies	9	0.3	39,843	2	39,845	0.03
Power Marketers **	152	4.6	6,017,611	0	6,017,611	4.4
Total	3,276	100	133,221,501	2,897,411	136,118,912	100

Notes:
*Delivery-only customers represent the number of customers in a utility's service territory that purchase energy from an alternative supplier.
** Ninety-eight percent of all power marketers' full-service customers are in Texas. Investor-owned utilities in the ERCOT region of Texas no longer report ultimate customers. Their customers are counted as full-service customers of retail electric providers (REPs), which are classified by the Energy Information Administration as power marketers. The REPs bill customers for full-service and then pay the IOU for the delivery portion. REPs include the regulated distribution utility's successor affiliated retail electric provider that assumed service for all retail customers that did not select an alternative provider. Does not include U.S. territories.
Source: American Public Power Association, *2006-07 Annual Directory & Statistical Report*, from Energy Information Administration Form EIA-861, 2004, data.

Table 2: USA Electricity Generation, 2004

Ownership	Generation (GWh)	% of Total

Publicly-owned utilities	397,110	10.3
Investor-owned utilities	1,734,733	44.8
Cooperatives	181,899	4.7
Federal Power Agencies	278,130	7.2
Power Marketers	42,599	1.1
Nonutilities	1,235,298	31.9
Total	3,869,769	100.0

Source: American Public Power Association, *2006-07 Annual Directory & Statistical Report*, from Energy Information Administration Form EIA-861 and EIA-906/920 for generation. Data are for 2004, adjusted for joint ownership.