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MANAGEMENT OF TRANSMISSION CAPACITY AND ACCESS: IMPACT ON SYSTEM DEVELOPMENT

Working Group
C1.31

August 2003

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Terms of Reference

A working group was established by Study Committee 37 at its meeting in Paris in August 2000. The group was to perform the Terms of Reference below and to report in the last quarter of 2002.

Working Group

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Title of the group: Management of transmission capacity and access: impact on system development.

Scope, deliverables and proposed time schedule of the Group:

Background:

Advisory Group AG37.1 "Regulation and Planning" was set up in September 1999 to identify emerging issues related to electricity industry regulation as it impacted on system development, in particular congestion in transmission and management of available transmission capacity (ATC). As a result of the scoping work done by AG37.1 on this topic, working group WG37.31 is to address the issue of evaluation and management of transmission capacity in the current market orientated environment.

Scope:

The overall aim of WG37.31 is to describe transmission capacity, its evaluation, management and access. Specifically, measurement or evaluation of available transmission capacity (ATC), possible allocation methods, and advantages and deficiencies in the evaluation and allocation methodologies.

1. **Define transmission capacity in terms of:-**
   a) methods for calculating available transmission capacity
   b) methods of allocating capacity to market players.
2. **Identify the options for managing transmission capacity covering:-**
   a) allocation timeframe i.e. real time, day ahead, monthly or annual
   b) incentives to encourage actual flow matches contracted values and compensation arrangements where a difference occurs.
3. **Assess the impact of management of transmission capacity on system development:-**
   a) identify appropriate market economic investment signals in the allocation process that support new transmission capacity.
   b) what are the business risks in providing such capacity (i.e. income)?
   c) what allowance should be made in planning for differences between contracted and actual flow (i.e. capacity margin) and what information does the planner need on who has been allocated capacity?
   d) is new transmission capacity driven purely by the market investment signals in (a) above or by a combination of security standards and market investment signals?

Deliverables and time schedule:

Installation of the WG37.31	January 2001
Beginning of the work	January 2001
Preliminary report	July 2001
Intermediate report	January 2002
Final Report	August 2002 (CIGRE Session 2002)

CONTENTS

WG37.31 - DRAFT REPORT

Terms used throughout this report are set out for clarity in Appendix I.

Introduction - LIBERALISED MARKET ISSUES

Stakeholders have different interests and apply different forces.

The liberalised market in electricity is characterised by:

- Unbundling of production, transportation and services;
- Management roles - Transmission Operators (TO)/System Operators(SO), Market Operators, Regulators.
- A range of views, which depend upon the duties or financial interests of these various stakeholders (CIGRE Task Force 38.10.15 reported in detail upon quantifying Stakeholder benefits.)

The following Report shows how different stakeholders interests may be met in relation to Transmission Capacity.

1. TRANSMISSION CAPACITY - WHAT IS IT?

Generic Issues

1.1 Definitions

The transmission capacity can be considered as follows:

a) maximum capacity: determined by the construction of the transmission lines ie the conductor used and its tension;

A System Operator's view of Capacity

b) available capacity: determined by the network that surrounds the transmission lines ie the thermal rating may be restricted because of the voltage or stability considerations;

c) usable capacity: determined by the way power shares between the transmission lines and the security standards applied ie n-1 or n-2;

d) contracted capacity: a transmission capacity at a boundary may be determined through a contract which may not relate directly to the assets at that boundary .

Capacity limits are affected by many factors in different domains

Within a large network, the useable transmission capacity at one point may be determined by any of the factors in a) - d). The technical transfer limit will be set at some remote point in the network or even on an adjacent network ie a neighbouring utility. Therefore calculation of the factors a) - d) requires information about the entire surrounding network. Factors a) - d)

- have time varying values,
- are determined by the generation pattern, the demand cycle, the power flow pattern and the network topology (current operational configuration and circuits that may be out of service for maintenance or construction work).

Having determined transmission capacity, it needs to be allocated to the many market players.

1.2 Stakeholder Views

In a market environment, transmission system users and transmission owners/operators view transmission capacity differently.

Stakeholders would prefer definitions which suit their interests.

Users, *buy or sell energy across the transmission system.*
For them, transmission capacity is their access to a liquid energy market and enables them to generate/offtake at certain locations or to carry out a transaction between two specific locations.

TO/SOs, *provide the physical basis and real time co-ordination for the energy transactions.*
For them, transmission capacity comes from individual transmission equipment whose contribution to the overall capacity is calculated strictly according to physical laws.

By following the physical laws, the descriptions a) to d) above follow the TO/SO point of view.

The market may seek to adopt different definitions. For example,
a user-oriented view of *maximum capacity* could be "The maximum possible amount that can be generated or consumed at certain locations." whereas a TO/SO-oriented view would be conditioned by the thermal ratings of individual circuits.

Capacity products may bridge the gap between stakeholders

Such differences in the capacity definition lead to different types of "**capacity product**" to be traded in the market and will impact on the way capacity is managed.

Capacity definitions may need modified for different types of network

The use of terms may differ depending upon whether they are applied to circuits interconnecting stand alone power systems or to circuit boundaries within a main interconnected system.

Depending on the arrangements in a particular market, the 'usable capacity' may be closely related to the 'contracted capacity'. Furthermore, in relation to 'contracted capacity' it may not just be the system beyond the interconnector, but the interconnector itself which is the basis of the contract.

1.3 More Explanation of Physical Limits

Licence Standards are the basis for both design and operational practice

Thermal Limits
The amount of power which can be transferred across a boundary on the system is limited by the rating of the individual circuits and the way in which the power transfer is shared between them. The 'firm' thermal capability is taken to be the capability which meets licence standards. Typically standards require supply to be maintained after the loss of two circuits resulting from a fault during a maintenance outage. Some standards are more onerous e.g. two contemporaneous or simultaneous faults.. The result is usually less than the sum of the individual ratings of the remaining circuits. This is because one of the remaining circuits reaches its rating limit before others.

Network transfer capacities are published

Boundary firm capabilities are often published to advise stakeholders and send locational development signals. Many organisations are required to annually produce a Capacity Statement or a fuller document like a Seven Year Statement. Other standards (often a licence requirement) may clarify the duties placed upon a TO/SO for the design / secure operation of a network. The following example is drawn from the United Kingdom and shows a standard applied to NGC.

A UK example of how thermal limits are in licence standards

> *The current standard by which the transmission system is planned and operated ('NGC Transmission System Security and Quality of Supply Standard, Issue 2, November 2000) is lodged with Ofgem and referenced in the Transmission Licence. The standard is commonly referred to as the Licence Standard.*

That part of the Licence Standard which is concerned with the planning of the main interconnected transmission system (as opposed to generation and demand connections), inter alia, defines a thermal requirement relating to boundary transfers between any two contiguous parts of the system. For instance, the boundary thermal capacity must be equal to a more than the planned boundary transfer plus half the interconnection allowance with any two circuits out of service. The interconnection allowance is an allowance, specified in the Licence standard, which takes some account of variations in weather, plant availability and demand forecasting error either side of the boundary.

Voltage Capability

Network voltage can limit transfer at times of heavy load

At times of winter peak demand it may be necessary to restrict power transfers to a level lower than the firm thermal capability. This is to ensure that satisfactory voltages can be maintained in the importing area.

During lighter load periods, the voltage issue may not dominate and firm thermal capability may be applied.

Transient and Steady State Stability

Power transmission capability between two areas or between a major generating station and the system can also be limited by considerations of electro-dynamic stability.

System stability is a crucial factor in determining network security and therefore transfer limits

Three stability regimes are usually defined:

- Transient Stability following a severe disturbance, for example a network fault. The key issue is usually how quickly faults can be detected and removed from the system.
- Dynamic stability which concerns the ability of the active parts of the system to remain in synchronism after the loss of a major in-feed or load block. The key issues are the system inertia, synchronising reactance and the governor response of individual generating units.
- Steady State Stability which concerns the response to small disturbances such as the normal random load fluctuations. The key issues relate to any tendency to excite inter-zone or inter-area power oscillations and whether the system(s) can be detuned from this natural frequency of oscillation.

1.4 International / Intra-national Applications

Norway & Nordic Countries

Boundary Transfer limits used;

n-1 criterion applied;

Thermal, voltage and dynamic issues assessed

In the Nordic electricity market the term ”boundary transfer limit” is used to refer to transmission capacity. Transfer limits are set currently for those boundaries which normally determine the allowed transfers. This term combines ”available capacity” and ”usable capacity”. The n-1 criterion is normally applied. Whether thermal rating, voltage stability or dynamic stability conditions are determining the transmission capacity may change from boundary to boundary. When lines are out of service, the boundary transfer limits are reduced accordingly.

One common Nordic market - 4 countries

Frequency response band protected in links between areas

There is one common and open electricity market in the Nordic area even if the four countries still are considered as separate control areas. Because of load/frequency control, the boundary transfer limits across the national borders are not fully utilised for the spot trade at Nord Pool (the Nordic power exchange). The boundary transfer limits (known as the ”available capacities”) across national borders are reduced to allow a frequency regulation band. For the southern boundary between Norway and Sweden, for example, the available capacity is normally 2000 MW and the regulation band 150 MW. Thus, the ”available capacity for cross border trade” is normally 1850 MW at this boundary.

UK

Intra-country example.

The transmission system is utilised to allow generation surpluses in one part of the country to supply load in other parts of the country where, there is a generation deficit.

System split into areas; Weakest links examined to determine transfer capacity.

Thermal, voltage and stability issues examined.

In assessing the capability of the system to meet this task, the system designer splits the system into predominantly importing or predominantly exporting areas. The circuits connecting such areas together tend to constitute the weakest 'links' in the system and thus reflect the capability of the system to accept bulk power transfers. These circuits which link areas together constitute system boundaries.

Three factors can limit the capability of the transmission system to transfer power across a system boundary, namely thermal ratings, voltage and stability (outlined above).

North America

The North American Electric Reliability Council have produced a framework for determining transfer capabilities of their interconnected transmission networks for a electricity market. These are attached in Appendix II.

Several extracts are instructive. NAERC state the purpose of network capacity as:

Capacity purposes

- To deliver electric power to customers;
- To provide flexibility for changing system conditions;
- To reduce the need for installed generating capacity
- To allow economic exchange of electric power among systems.

Definitions of ATC, TTC,TRM and CBM

The document defines

- Total Transfer Capacity TTC as the amount of electric power that can be transferred over an interconnected transmission system in a *reliable* manner while meeting *all* of a specific set of defined pre- and post- contingency system conditions.
- Transmission Reliability Margin (TRM) as that amount of transmission transfer capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.
- Capacity Benefit Margin (CBM) as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

Curtailability and Recallability are also defined.

Calculation of ATC

Operators post Available Transfer Capacity (ATC) which is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically, ATC is defined as the TTC less the TRM less the sum of the existing transmission commitments (which includes retail customer service) and the CBM.

Boundary conditions for studies

They further require harmonisation of definitions and require a range of boundary transfers to be considered in arriving at any interface ATC.

2. TRANSMISSION CAPACITY - HOW CAN IT BE ALLOCATED TO MARKET PLAYERS

There are a number of ways in which transmission capacity can be managed in the market.

2.1 Capacity Products

Capacity can be thought of as a range of market products rather than a single product. The main features which distinguish capacity products are:

Transmission Capacity products are based upon a combination of degree of firmness and the period for which the transfer is available.

a) Firmness:

firm capacity: a transmission user (generation or demand connection) can be given a firm connection agreement i.e. there is no contractual restriction on the use of the transmission system. If a restriction occurs the user receives financial compensation;

interruptible capacity: this provides access to the transmission system, but access can be restricted at any time with no financial compensation.

b) Duration:

fixed long term: this provides capacity all hours, all year;

capacity window: this provides capacity only in a period defined in the connection agreement ie seasonal, time of day/week/month.

2.2 Issuing Capacity to the market

There are a number of ways in which capacity can be released or traded to the market. The principle ways are described below:

Capacity is made available to the market as long term (auction or contracts used) and short term.

a) Long Term Allocation:

auction: capacity is offered to market players and sold to the highest bidder;

contract: capacity is sold under negotiated terms to one market player.

b) Short Term Allocation

Various market and non-market mechanisms exist to ensure efficient use of capacity day by day.

secondary trading: any unused or unsold capacity is made available;

counter trading in energy market: re-despatch of generation to keep flows within available transmission capacity (cost carried by TO);

market splitting: separate market and prices established within available transmission capacity (cost carried by market players).

2.3 Application of principles

The method adopted to manage transmission capacity will be a combination of these various items, you can 'pick and mix' from the various items to buy the transmission capacity needed, for example you can buy:

There are many combinations of arrangements for long term and short term arrangements

	a) interruptible capacity
with	b) windowed profiles
purchased through	c) auction
with	d) secondary trading

A number of combinations are possible, those chosen or being considered by each country are shown in Table 1 (see end of Section 2). The method chosen may depend up on the 'product' being purchased, these products would be:

Products will also be tailored to the user's primary requirements to enter, exit or transit

entry (generation)
exit (demand)
location to location
flowgate
contract path
boundary physical path

	Italy-F-S-A-Slo	Nordic countries	Germany-Denmark Netherlands-FRG-B	PJM-USA SMD proposed by FERC	UK	ETSO
Market Based Methods **Transaction-based** Auctioning	**2001 Import**: NTC=AAC+ATC AAC=long term contracts allocated ATC=subdivision 50%-50% between cross border TSOs **Repealed** after a recourse to the Courts Internal **Inter area** congestions: price area=implicit auction	"Implicit Auctions" = Price area Zonal	Various time span Use it or lose it (UIOLI) Zonal		NGC examined:- Zonal En/Ex; Nodal En-Ex; Flowgates across Ofgem favours full access auctions **Ofgem Feb 2002 consult**: Initial allocation of rights; secondary market (run by NGC?) Back away from full access auction **Oct 02: NGC SO Incen. consul** Long term FTR entry/exit rights tradable to hedge short-term risk in force by 1.4.2003. SO capacity & buy back incentives Capacity release: RoR >6.25%	Coordinated auctioning under study Zonal
Non Transaction-based Counter-Trading, based on bidded prices		Prevailingly adopted in "emergency situations" using Regulating mkt			**UK-F HVDC cable** Various time span UIOLI	
Central Redispatching				Security constrained Energy Dispatch: **nodal** prices + Financial Transmission Rights		
Not Market Based **Transaction based** First come, first served	1999	No more contracts on HVDC cable within Nordic market Contracts on HVDC cables Nordel-FRG, Poland,Russia				
Pro-quota Rationing	**2001** Import NTC=AAC+ATC AAC=long term contracts allocated ATC=subdivision 50%-50% between cross border TSOs "Antitrust limits" on import total borders and on each border Result: huge fragmentation **2002** Import NTC=AAC+ATC AAC=long term contracts allocated ATC=subdivision 50%-50% between cross border TSOs "Antitrust limits" on import total borders and on each border Limits on single requests, not differentiated among consumers Still, excessive fragmentation. A portion of ATC, allocated with priority to interruptible consumers					

AAC=Already Allocated Capacity; ATC=Available Transmission Capacity; NTC=Net Transfer Capacity=Total Transfer Capacity (TTC) netted of Transmission Reliability Margin: NTC=TTC-TRM

3. MANAGEMENT OF TRANSMISSION CAPACITY

3.1 General principles

The approach to the management of transmission capacity depends on the timeframe being considered:

Planners can augment the electrical system in the long run; Operators must deliver the market requirements within the existing capability.

a) planning:
The transmission planner will strive to make maximum use of the transmission routes that exist. New routes will be avoided, being environmentally difficult to achieve.

The planner can raise thermal ratings by reconductoring / retensioning, remove voltage or stability constraints by use of SVC, remove stability constraints by AVR improvements and improve sharing across circuits by use of power flow controllers.

b) operation:
The system operator, on the other hand, has only the useable transmission capacity to work with and may be required to operate to a contracted position regardless of ownership and political boundaries.

The section below demonstrates how, in different locations, various market and non-market approaches are used to manage Transmission Capacity.

3.2 International / Intra-national Applications

Norway

Open access Voluntary disconnectable tariffs within the market area

Within the Nordic electricity market there is open and equal access to the network at all levels, i.e. nobody is given any priority when the capacity is a constraint in any part of the system. There is one exception: End-users who are able to shift from electricity to another fuel may be given a reduced transmission tariff provided they accept disconnection with a defined notice period (12 and 2 hours' notice is presently used in Norway).

Thus for markets designed like the Nordic electricity market ”interruptible capacity” exists, but terms like ”firm capacity” and ”capacity window” do not have meaning.

Interconnection with other markets: Duration used, sold by Auctions and Contracts

Regarding connections between the Nordic market area and other countries (i.e. Russia, Poland and Germany and in the future the Netherlands and England) the situation is different. Capacity may be contracted to market players for different durations, or/and auctioned at different time intervals. The capacity between West Denmark (Jutland) and Germany has been managed by auctions administered by Eltra and E.ON. Contracts and auctions are also foreseen for the North Sea Interconnector between England and Norway (NGC and Statnett) This development is still under planning.

2 The role of Nord Pool, the Nordic power exchange, is fundamental in the management of transmission capacity across the national borders of the Nordic market area. When hourly electricity prices are set in the day-ahead market (elspot market) the available capacities for trade between the various Nordic countries are important. If the flows resulting from the purchase and sales bids exceed any of the available capacities for cross border trade, as declared by the TSOs, a second price setting iteration is undertaken to reduce critical flows to the acceptable level. As a result, the Elspot price in such situations will be different in different parts of the Nordic market area. For instance if the bids from the market players define a transfer need from Norway to Sweden exceeding the transfer capacity, the Elspot price will turn out lower in Norway than in Sweden. This management of transmission capacity is called the ”price area approach”. In terminology applied within ETSO the somewhat misleading term ”market splitting” has been used for this approach. As mentioned, a power exchange is a prerequisite for this capacity management approach.

Flow management - day ahead by Nord Pool

Market price iterations follow the day ahead capacity declaration. This results in market price splitting.

Presently Sweden and Finland constitute one Elspot area each, Denmark two areas (East and West) and Norway (two-four areas depending on hydrological conditions). To manage capacity constraints occurring within each Elspot area the national TSO is intervening by doing countertrade, i.e. a simplified redespatch where generation is increased and decreased in different parts of the system to avoid violation of boundary transfer limits.

Within sub-markets counter-trading and re-despatch are used.

The financial implications of the two methods used in the Nordic market are different. Countertrades are an expense on the TSO to achieve necessary regulation of generation due to insufficient transmission capacity. With the price area approach there is no expense for the TSO, and the burden is taken by the market players instead. However, the social cost of insufficient capacity is then calculated. In Norway the TSO is directed by the authorities to take into account this kind of expected social costs due to limited

Countertrades place financial risks with the TSO; price area (market splitting) places risks with market players.

Security not a licence standard, but a TSO responsibility
n-1 planning used
pragmatic risk / reward used in operation.

transmission when measures and costs to relieve transmission constraints are studied.

In the Nordic countries the licencing authorities have not imposed any security standard. Instead reliability and security is a responsibility for the national transmission system operators (TSOs). In planning the n-1 criterion is normally applied, even if a trade off between capacity and security is possible in principle. In the operation of peripheral parts of the main Norwegian grid it is today common to make trade off considerations between the benefits of high transfers versus the increased probability of a regional black-out. In different operating situations the conclusion is operation at n-0 security. A discussion is going on whether such trade offs also could be introduced at the main transmission boundaries. If so, the setting of transfer limits would be based on a probabilistic approach (flexible transfer limits).

Italy

Macro areas defined.

There are three main aspects to this market:

- import
- capability limits between macro areas
- congestion within the macro areas

New market rules were approved by the Ministry of Industry on May, 9, 2001. The market is expected to start at the beginning of 2003.
There are two types of markets, with some interactions:

Energy and despatch markets separate.

- ***energy-related***, run by the Market Operator (GME)
- ***despatching related***, run by the ISO (GRTN)

A convention is being established for the "overlapping issues.

Energy- related markets

One pool - 2 sided bids Market splitting in macro areas

Compulsory pool
Day Ahead Market with System Clearing Price (DAM) obtained from two sided bids. At the beginning, a one busbar system is used, if needed. Market splitting is used in macro areas .

Short term variations

Adjustment market (AM)
Variations of the contracted energy volumes of the DAM (Day Ahead Market).

Despatching- related markets
<u>Congestion within areas</u>
Reserve (secondary & tertiary)
Balancing (real time market)

Ancilliary services markets

Allocation of ATC for Import Flows
This is a major problem in Italy, since the Country imports 44.4TWh (+5,4%)out of 297.7TWh total demand in 2000. Total consumption: 278,6TWh; 207.6TWh captive; 71TWh eligible;19.2TWh losses.

Energy Statistics

Allocation of Import capacity
The Authority has the duty to establish rules; the Italian ISO has to implement them cooperatively.

Net Transmission Capacity is limited: The allocation of the present Net Transfer Capacity (NTC) of 6000 MW in Winter, has been always a complex process which involved the Regulator and also the Courts. Long term contracts signed in the past by ENEL for an Already Allocated Capacity (AAC) of 2600 MW reduce availability for the free market to the present value of ATC of 6000-2600 = 3200 MW in Winter on all borders. The following chronology details the developments:

Import capacity limited

- Rule: 180/99 established a 50% repartition between eligible and captive ones
- 1999: First-come, first-served
- 2000: Auction, not completed for excess of request
- 2001 allocation procedures
- Rule 140/00: An explicit auction procedure established, run by the ISO
- Total ATC auctioned = 50% by Italian ISO; 50% by neighbouring ISOs
- Caps introduced: no more than 10% on all borders; no more than 20% on each border
- First auction run on September for October, November, December 2000.
- High resulting prices triggered a recourse by some eligible consumers against the auction procedure.
- After various legal steps, the Rule 140/00 was abolished. The Regulator issued on December 6 ,2000 a new ruling (219/00):
    - Total capacity assigned on **a proportional** basis, free of charge

Chronology demonstrates political nature of capacity allocation

- 80%of ATC assigned on yearly basis, 20% on monthly basis two new caps: no more than 5% on all borders; no more than 10% on each border
- The trading of "rights of access" after their assignment was allowed.

- First auction with the new approach completed on December 19,2000 for 2001 allocation procedure:.
- Dramatic increase of the total number of competitors (12 GW!! requested compared with 1510 MW available (1200 MW yearly and 310 for the months of January & February)
- For the yearly capacity: 422 requests, 353 accepted, average assignment: 3.4 MW!
- The other 50% (1510 MW) to be assigned by direct bilateral contracts Foreign Producers-Eligible consumers

Recent actions carried on by the Italian ISO to increase the import capacity

Planners have developed increased capacity

- Revamping of same components in interconnections lines: + 300 MW
- Substitutions of conductors in two interconnection lines: + 200 MW
- New dc link with Greece (2002): +700 MW
- Studies for the application of FACTs: tests possibly in 2003

2002 Allocation

The Italian network is strongly meshed on the borders with those of France and Switzerland and many loop flows are present. Common studies were made in 2001 by the Italian TSO with neighbouring TSOs of France and Switzerland, which resulted in a common definition of the total North-West Border. The allocation of the capacity for the year 2002 was made, according the Decree 301/01 of December 5th 2001 of the Authority, with the following rules:

- The total winter NTC = 6000 MW was subdivided in two borders: North-West (France-Switzerland): 5400 MW and North West Border = 600 MW;
- The total NTC on the two borders was further subdivided: -i) *North West*: 2600 MW Italy-France; - 2800 MW Switzerland; - ii) *North-East*: - 220 MW Austria; -380 MW Slovenia.

- On the North-West borders the long term contracts were allocated, 1800 MW with France and 800 MW with Switzerland. The remaining ATC for the free market correspondingly was: France-Italy= 800 MW; Switzerland Italy=2000 MW, Austria-Italy= 220 MW; Slovenia-Italy= 380 MW.
- An agreement was established with France for the common allocation of the ATC of 800 MW; for various reasons a similar agreement was not possible with the other countries. Consequently, 50% of each ATC was allocated by the Italian TSO (GRTN) while the other 50% was allocated directly by the foreign TSOs.
- Correspondingly the annual capacity allocated for the year 2002 directly by the Italian TSO was: i) 800 MW + 1000 MW (50%) for the border with Switzerland commonly allocated with the French RTE; - ii) 110 MW (50%) on the border with Austria; -iii) 190 MW (50%) with Slovenia respectively. The allocation criteria was pro-quota, under the “antitrust limits” of 10% on each border and the further constraint of at least 3 MW of request.
- Priority assignments to the *instantaneously* interruptible consumers were ruled, respectively 500 MW on the North-West border (47 clients) out of the total ATC of 1800 MW under the responsibility of GRTN+RTE and 100 MW (25 clients) on the North-East border out of the total 300 MW under the responsibility of the Italian GRTN.
- A secondary market for the exchange of the allocated capacity rights was also allowed
- In the allocation procedure for the year 2003 also the DC link with Greece, with NTC of 500 MW will be taken into account

Generally speaking, the rationale and the

results of the present allocation were still strongly debated. On one side it was underlined by various sector of the Industry that the “undifferentiated limits” for eligible clients and traders caused a competitive rush between clients, traders, brokers and Distributors with negative effects. The results were: - contractual weakness of the demand against the foreign producers:- absence of contractual skinless of the minor clients:- tendence to overcontracting in respect of the need in order to speculate. All these concurring causes, and the related transaction costs, caused an increase of the selling prices, paid by the Italian consumers A suggestion is that the “antitrust limits” should be differentiated for traders and clients (equal to their consumption): the speculation stemming from the reselling of not utilizable capacity and the creation of many “sham” companies to avoid the existing limits could be avoided. The direct assignment of the 50% “in the hands” of the foreign TSO should also be revised , with the aim of obtain a greater transparency and to avoid that some foreign TSO not unbundled by the production activity could have competitive advantages. The absence of reciprocity between Italy and some foreign countries, and the related impossibility of the Italian players to enter the related markets, has altered a level play ground.

New rules for the allocation of the ATC capacity for the year 2003 are presently s expected soon.

Interruptible supplies and inter-TSO co-operation allow better use of network capacity

Agreements are being formed with some interruptible consumers aimed at “relaxing” normal capability limits. Studies are proceeding to determine how better coordination with neighbouring TSOs (France, Switzerland) can be achieved. This implies a common ATC definition.

Capability limits between macro areas

The ISO is to determine and post each day maximum capability limits between the macro areas, by taking into account the security constraints. The areas so far considered are :

Abroad-North;
North –North/Center;
North Center-Center,
Center –South,
Mainland –Sicily,
Mainland-Sardinia

Daily macro-limits posted

Market operator to run busbar system and market splitting

The Market Operator is to run a busbar system. When capability limits between areas are not respected, market splitting will be required with various SCPs in each area.

Various markets - different operators

Revenues stemming from [transits * ΔSCPs] are accumulated by ISO in a fund, the utilization of which will be decided by the Regulator (f.i: funding of new interconnections lines; rebate on transmission tariffs, etc)

The Regulator is studying a possible approach of Fixed Transmission Rights for the allocation of the capability between areas.

The "full zonal market model" was criticized due to the unbalance, in presence of congestions, of higher zonal prices paid by consumers sited in zones with generators having high costs. A smooth transition was deemed more equitable. Accordingly the model has been revised in the Instruction of the Market transmitted by the Market Operator GME to the Ministry of the Productive Activities (Industry) on January, 18, 2002 in order to allow - for a transient period of three years- a nation wide unique purchase prices, p*, paid by all the consumers. To the Producers different zonal System Clearing Prices will be paid. The price p* is obviously a value between the zonal prices, but –due to the fact that the demand is price-elastic- a feedback on the dispatched load is present and p* it is *not* equal to the simple weighted average value of the zonal prices. The ruling has therefore entailed the need for the Italian ISO GRTN of implementing a suitable optimisation tool which , which – summarizing- ensures that the unique nation-wide price p* paid by all consumers is capable of respecting two conditions:

- a "cost recovery" rule, which ensures that the revenues of the generators, paid with the zonal SCPs, will be equal to the costs charged to the consumers paying the unique nation-wide price p* ;
- a so called " no surprise" rule, which ensures that *only* the loads with a bidding price higher than the resulting unique nation-wide price p* will be dispatched.

The method, which entails a cross subsidization between consumers, offers the possibilities to some gaming which can end to results "opposite" to the aim with the uniform price is targeting. The limitation of this "gaming possibilities" is under consideration.

Congestion management - intra areas
Congestion *within each area* will be handled with a specific "Congestion market", run after the Day Ahead Market (DAM) and the "Adjustment Market" (AM) by the Market Operator.
The ISO is to implement needed despatching actions.

Bidding Process

Bids will be taken from *Sellers* (generators willing to increase production in respect contacted values in AM and consumers willing to resell some of the contracted energy) and *Buyers* (generators willing to decrease their contracts and consumers willing to increase their engagements) are foreseen.

Payment Principle - Pay as bid

The payments will be made on "pay as bid" principle. The overall cost is to be distributed on all the network users through an uplift. The ISO is to handle payments, according to rules to be established by the Regulator.

European Transmission System Operators (ETSO)

Work proceeding on:
Pricing mechanisms
TSO compensation
Congestion Management

In Continental Europe, ongoing efforts are strong to increase cross border trade. There is work within ETSO to elaborate on pricing mechanisms for cross border trade. TSOs are to be compensated for transits across their systems. Management of congestion is another topic in this context. Within ETSO, the focus is on the following methods for congestion management:

- Market splitting (price area approach)
- Capacity auctions
- Coordinated redespatch (coordinated between two or more TSOs)

Definitions agreed

ETSO have agreed a number of definitions to ensure clear communication between the member countries, these are set out in Appendix IV and V. The Appendix IV relates to definitions for transfer capacities and the Appendix V discusses the transmission access/products that were described earlier in this report in paragraph 4.

Highly meshed networks

The transmission capacity of interconnecting circuits that join two systems in Europe is often allocated to users by auction. Extending this to a highly meshed system involving many control areas such as continental Europe is more complex. ETSO have proposed some methods of allocation of transmission capacity in meshed networks, these proposals are set out in Appendix VI.

Where transmission limits the energy market causing congestion, methods to manage such congestion need to be established and agreed. ETSO have addressed this issue and their findings are expressed in Appendix VII.

England and Wales

Transmission Access and Pricing

Access controlled by agreements

The Master Connection and Use of System Agreement (MCUSA) and associated documentation have been amended to form the Connection and Use of System Code (CUSC) and associated documentation. The CUSC condifies the generic provisions of the former MCUSA and Supplemental Agreements but includes new Governance and Dispute Regulation Procedures.

Charging Statements are produced in accordance with the requirements of the Transmission Licence. Whereas the contractual obligation to pay charges resides within the CUSC, the principles that underpin these charges are contained in the Charging Statements.

Licence sets charging rules

It is a requirement of the Transmission Licence that NGC charge in accordance with the above Statements. The Statements contain sufficient detail to enable customers to make a reasonable estimate of their charges. The documents are kept under constant review and any charging disputes are referred to Ofgem.

Charging is split between :
Connection charges
Use of System Charges

Connection Charges

These charges relate to the costs involved in providing assets which afford connection to the transmissions system. The charges are based on the connection assets provided, their capital and maintenance costs and a reasonable rate of return.

Transmission Network Use of System Charges (TNUoS)

The Transmission Network Use of System (TNUoS) charges reflect the costs of installing, operating and maintaining the transmission system. These activities, which are undertaken in accordance with standards prescribed in Condition 12 of the Transmission Licence, provide for the bulk transfer of electricity between connection sites and also provide transmission system security and quality of supply.

Under NGC's Licence Condition 12, NGC is required to plan, develop and operate its transmission system in accordance with security standards and the Grid Code. These security standards set out the criteria and methodologies relating to the planning and operation of Generation Connections, Demand Connections and the Main Interconnected Transmission System (MITS).

Specified conditions for Generation and load connections

For Generation Connections, the security standards specify the maximum loss of infeed power acceptable in the event of certain contingencies, including busbar failures, single and double circuit transmission failures and generation circuit failures. For Demand Connections, the standards specify acceptable levels of: loss of supply capacity; overloading of transmission equipment; deviation from voltage limits; and system stability in the event of a set of contingencies based on transmission circuit and busbar failures. The security standards for the MITS, specify that the system must be able to maintain a Planned Transfer Capability in the event of a failure of a double circuit overhead line, a section of busbar or the simultaneous failure of up to two transmission circuits. The security standard allows for derogation from the deterministic standard on economic grounds or at the request of system users. Derogation from the deterministic standard for the MITS can be made on the basis of a cost benefit analysis in consultation with the Regulator.

Security Standards detail

Potential Development of Access Auctions

Consideration is being given to how new transmission access and pricing arrangements might be developed towards a structure consistent with the new electricity trading arrangements (NETA). Under such arrangements, participants would be required firm entry rights to inject electricity on to the transmission system. Market mechanisms would be set up for the initial allocation and secondary trading of the access rights. National Grid would buy-back and/or sell additional access rights in order to resolve transmission constraints. Since the publication of a consultation document, the Regulator (Ofgem) has held discussions with the industry and has been further developing the thinking on these issues. They have indicated that the way forward would be outlined in a further consultation document, a document was published in May 2001 for consultation with market participants on the appropriate way to deal with transmission access and losses under NETA. The

In the future allocation might be in 2 stages - wholesale, then re-sold retail. TSO can buy back or sell additional in the retail market

More information

document is very long and can be viewed at www.ofgem.gov.uk. Attachments to this document contributed by National Grid are relevant to this working group and are attached as input information, they are:

Attachment 1:	Assessing Volumes of Constraints Addressed Prior to Gate Closure In a Market for Firm Access rights
Attachment 2:	Options for a Transmission Access Regime
Attachment 3:	Simultaneous Clearing in Access Auctions and Losses Charges
Attachment 4:	Examples of the Calculation of Imbalance Charges
Attachment 5:	Implementation of a Market In Transmission Access – Implications for Systems

North America

See Appendix for more

ATC to be calculated on the same basis by all

Capacity Benefit Margin

Transmission Reliability Margin

Data exchange

1. The Northeast Power Co-ordinating Council has produced a report with a procedure for managing transmission capacity, this is attached in Appendix VII, It is designed to help co-ordination and transparency of transfer capacity posting across five areas. NPCC has adopted a regional procedure to post ATC on an interface basis, an approach that is similar to the rated path method described in the NERC Available Transfer Capability Definition and Determination Framework Document. The key to success is to ensure that Available Transfer Capacity is calculated using the same definitions and the same calculation method by all parties. It is also crucial to recognise that the evaluation of an ATC is an inerative process, since boundary ATC's depend on flows on other boundaries. Thus setting one ATC affects others. In essence, the guideline suggests that the Areas which implement the last changes to the transmission facilities at the interfaces will observe restrictions on the other affected interfaces, to the extent governed by existing operating agreements among the concerned parties.
The Capacity Benefit Margin gradually reduces from the planning time frame to the operational time frame.
NPCC continues to apply the Transmission Reliably Margin to cover operating uncertainties including the activation of operating reserve within an Area, and of Shared Operating Reserve among Areas.
Data exchange between SO's is required and specified.

4. IMPACT ON SYSTEM DEVELOPMENT

4.1 Operational Time frame

Operational timeframe: Software tools required - some well developed

Since physical networks are fixed for the purposes of real time operation, operators are faced with trying to meet market expectations by a mixture of flow management and capacity products. Thus real time developments are likely in the approaches to and tools for management of flows and management of capacity products.

Flow Management

Security constrained Optimal power Flow tools

Flow Management involves re-despatch to optimise transfer capacities while respecting constraints. Dispatch constrained optimisation tools are available commercially. They tend to be based around Optimal Power Flow algorithms. They may need to be dynamically linked to market information if a value optimisation as opposed to flow optimisation is required.

Multi-objective optimisation may be required

The difficulty is that a multi-objective optimisation may be required. E.g. It is likely that the MO or TO will require a flow optimisation which disturbs the existing market nominations as little as possible so as to minimise any constraint burden. These form 2 objectives. There may also be priority trades resulting from "Take or Pay" contracts or long term capacity contracts.

Market mechanisms and load flows inter-related

Developments will need to recognise the complications of the interaction between market mechanisms and flow optimisation if value optimisation is to facilitated at source, rather than placing total reliance upon a secondary market which may have less than perfect knowledge.

Capacity Products

It is argued here that capacity products offer some scope for optimising the markets use of the network, by allowing network users to pay a price, which is acceptable for the firmness and duration they require. In the ultimate, this would optimise network use for each settlement period.

Several factors can be taken into account in product creation :

Factors affecting development of network products

- The network's limitations;
- The market requirements
  - Firmness
  - Duration
- Administrative ability / cost
- Transparency of the offer
- Risk profile
  - Who will carry the risk?
  - How will it be managed?

Technical Limitations
Many of the above have been dealt with extensively within the brochure.

Stability monitors may be required

Studies determine the network limitations and this is a standard technical procedure. Tools and techniques are adequate, although real time stability monitors may now be required as networks are driven closer to the verge of voltage and dynamic stability limits.

Stakeholders involved in determining market requirements

<u>Market Requirements</u>
Determining market requirements is market specific. If auctions or allocation mechanisms are over-subscribed then there is an indication that, AT THIS TIME, there is a market requirement. There is a stakeholder questioning and iterative process to determine what range of capacity products offer best value to the market. This may involve removal of some firm or full-time products and replacement with a wider range of options.

Capacity product complexity leads to IT complexity thus risk and cost

<u>Administrative ability /cost & Transparency</u>
The more extensive the range of products, the more complex the set of market rules need to be to ensure equity and transparency. Each time there is a change it rules for one product it may have knock on effects on others. E.g. some products may be ramped up in a settlement period before others. Changes in the type or rules for products can affect the entire market system. From above, there is a need to determine the value of products from stakeholders and to review this periodically. Such changes are therefore likely. Complex systems are prone to errors are complicated to change and IT intensive. These factors will need to be weighed in the equation of allowable complexity v market benefit. In the final analysis,

any system too complex to be readily and frequently audited, or which does not allow clear market signals is unlikely to be useful. There is a sense in which it is meaningful to fix a term within which the market rules will remains substantially fixed, else there is a never ending development and testing of evolving systems with many operational failures.

4.2 Planning

How and to what extent do planners look at markets and market trends as the basis of developments?

To what extent should developers, particularly interconnectors joining two independent systems, be left to entrepreneurs where opportunities exist?

Risk Profile

The range of products offered to the market and their conditions of offer determine the level of risk and the risk profile of each stakeholder.

Factors affecting risk

Some factors which augment risk are:

- Reduction in network standards to increase flows
- Market demands inhibiting network maintenance
- Counter flows being considered according to a superposition principle.

Super-position not a network risk

The first two factors above effect network performance and therefore ultimately market performance, the latter only effects market performance.

Risk allocation may depend upon the stage of market development

Risk allocation is a matter of philosophy which may depend upon the maturity and confidence of the market. In markets that are immature it may be inappropriate to force too much risk on the market players, otherwise the cost of serving the risk unless it can be netted off, will be a multiple of that achieved by a "perfect knowledge" market manager. In more mature markets, the risks are better understood and are likely to be transferable to market players. The risk sharing may also depend upon the need to attract players into the market.

It therefore follows that there is no uniquely good network / market risk mechanism. In the end, most economists would concur that risks are best carried by those who have authority to manage them. In this way it might be argued that market risks are carried by market players and network risks by network managers.

Risks placed with those who can control them

Better understanding needed

There is a need to better understand the effect of risk transfer on the efficient of capacity allocation.

4.2 Planning Timeframes

The issue for planners is best illustrated by reference to interconnectors. Should networks serve interconnector capacity, or interconnector capacity serve network need? If the former, what is the requirement for interconnector capacity, perhaps 10 years ahead, and what are the factors which may affect this? Clearly the nature, location and price of generation is a major factor.

Should interconnector serve networks or visa versa

Work on uncertainty required

Work is needed to identify how this uncertainty can be quantified.

Intra-country, the same

Whether the planner is dealing with intra-country ties or international interconnectors is largely irrelevant, except that factor endowment differences are more pronounced in the international arena. This leads to a greater scope for price differences over time.

Planners should use balanced stakeholder network demand V price

In any case, there are various market players who will have a view, albeit biased, on the value of additional capacity. It is the task of the planner to attempt to determine a balanced stakeholder demand v price profile for removal of constraints.

Who carries the risk of development

Who then should carry the risk of the developments? There are three basic options and many variations on these:

- Network users carry the risk, which is passed on to final customers; this is effectively a regulated asset development;
- The risk is carried by market players who are prepared to fund the cost of extending network capacity to facilitate trades;

- The risk is carried by an asset developers who needs to form a "bankable" project and obtain funds;

Risk spread among native customers when too great for private developers

Network User's Risk

Where the risks are beyond that which a private developer in the asset creation market is likely to take, regulators need to weigh the total benefits from the flexibility / security as well as price offered the capacity augmentation. In certain cases these factors will be strong enough to allow projects to be justified. Inter-area negotiations between SOs MOs and Regulators will be necessary for international augmentation.

Market plays may ultimately pay for some links

Market Players Risk

It is uncommon to find market players funding the transfer augmentation in the first instance, although in some cases capacity holders pay over time.

Contracts for Use required for "bankable projects". Balance sheet projects may accept lesser risk management but are more expensive to fund

Private Developers Risk

Private asset developers need a reasonable certainty of flows of funds over a long period, if they are to produce a "bankable" project. Where a project is not "bankable", it could still be carried out as an on-balance sheet activity, but this exposes the developer to higher financing costs and greater risks. It is usual for a developer to attempt to secure contracts for capacity in advance of the development in order to demonstrate that the income side risks have been managed. With other market uncertainties, this may prove difficult. Such contracts will certainly be required for "bankable" projects. Balance sheet projects may be content with projections of market trends, especially where there is a demonstrable shortage in one area and a demonstrable surplus in the linked area. A further question arises as to whether there are other developments which might strand the asset. These could be:

- Additional network links
- A change in the generation location profile
- Loss of large load blocks from the flow-to area.

Stranded asset creation a real risk

The former is a particular risk for developers who seek to alleviate a constraint which has occurred because another development has been caught in an environmental debate. If the private developer should succeed and the original development be ultimately successful, one or other may become stranded assets.

5. Conclusions

- Since liberalisation and unbundling, there is a range of stakeholders who have different expectations of network capacity.

  TO / SOs feel constrained by the obligation to maintain a level of network security. They consider the network performance against a set of security standards, taking account of thermal, voltage and stability considerations.

  Market players expect that the network will facilitate their maximum trade levels.

- Network capacity has often been seen as firm or pseudo-firm for each settlement period. A range of products may offer a better opportunity to extend effective capacity and meet market needs. Products will be based upon a combination of firmness and duration. There is a range of mechanisms for delivering products into the market place. The most common mechanisms are auction and contract. Products could have a range of life spans.

- Tools may be required to better integrate the market and system operator principles to optimise value for stakeholders.

- There may be some limit to the complexity in capacity products which can be safely managed.

- Work is required to determine how uncertainty in generation is to be dealt with in planning capacity augmentation.

- Investment opportunities in capacity augmentation are linked to risk. Investment will only be undertaken by the private sector when risks can be quantified and managed.

ATTACHMENTS 1 - 5

Attachment 1: Assessing Volumes of Constraints Addressed Prior to Gate Closure in a Market for Firm Access rights

The following paper describes NGC's modelling of the volume of constraints it might be possible to capture under a market in firm tradable access rights.

Introduction

In line with the trade-offs outlined in the main text, indicative studies have been carried out in order to assess the effectiveness of a transmission access market at addressing constraints prior to Gate Closure hence removing the need to address them in the Balancing Mechanism (BM).

The studies have been limited to 6 snapshots of the system involving different assumptions on the dispersion of generation and demand, participants' bidding strategy and technical characteristics of the transmission network. In addition, the studies are based on some idealised assumptions and approximations and hence their results can be interpreted as at the 'best end' of a likely spectrum. In reality once these assumptions and approximations are no longer valid, the effectiveness of the access market may be reduced from results presented here.

These studies **do not** show the extent to which the total constraint **costs** seen by NGC will be saved as a result of the new transmission access market. This will be a function of how much cheaper constraints can be addressed in the forward access markets against being addressed through the Balancing Mechanism. Therefore it will depend on the liquidity of access zones, participants' valuation of risk and transparency of the market. It is extremely difficult to estimate the effect of this without prior knowledge / data from operation of NETA. In addition, the costs of 'constraints' addressed will depend on the volume of access tickets sold in the Primary Auction. If a 'maximum' method is used, participants may get rights above those that may be present without a transmission access market and hence create additional costs to NGC of buying back rights in the secondary markets. Conversely a 'minimum' method may depress the cost of constraints seen by NGC to be addressed.

This note first describes the study method used in the assessment exercise. It then describes an initial "Straw Man" design of the market based on the criteria and/or preferences set out in Ofgem's December Consultation Document, followed by a discussion of the assessment results of this design.

Straw Man Model Based on the December Document

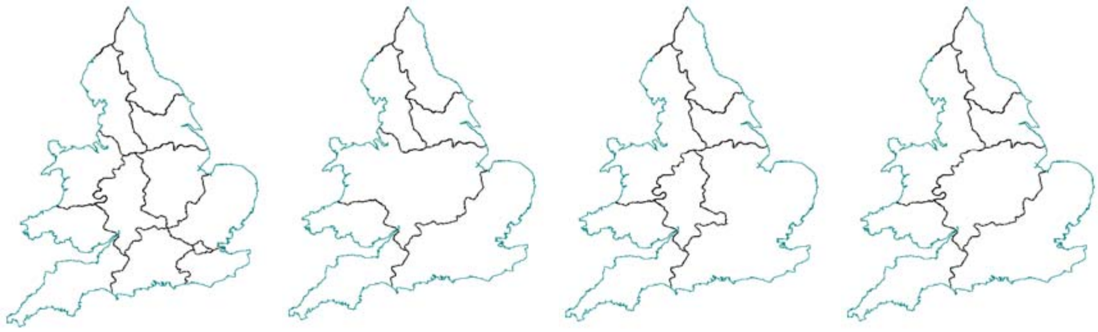
Ofgem indicated in their December Consultation Document that the transmission access market should be a **two-sided** and **competitive** market of **firm** access rights with **unfacilitated trading**. In response to that document, NGC constructed a Straw Man model under these criteria in order to assess the effectiveness and to scope the implementation of the access market.

This market model is based on an entry/exit right market design – with participants buying rights to inject power onto the transmission system (entry rights) and rights to take power off the system (exit rights) in given locations, both with reference to the same defined hub-point. These locations are defined by zones – each entry / exit point within a given zone is treated equally. To accommodate participation from the demand side under the restriction of the 1998 settlement metering arrangement, the following zonal definitions were examined:

- 12 GSP Group Areas (matching the 1998 settlement metering arrangements), and
- three different variants of 6 Supra GSP zones derived by amalgamating some of the 12 GSP groups based on the need for increased liquidity and/or defining sensible boundary constraint numbers.

Figure 1 shows these zonal definitions which are fixed for the whole year.

Figure 1 - Transmission Access Zonal Definition Based on GSP Groups



12 GSP 6 Supra GSP [1] 6 Supra GSP [2] 6 Supra GSP [3]

The transmission access market is assumed to comprise a Primary Auction of access rights and then secondary trading of these rights. Before the beginning of the Primary Auction, NGC agrees with Ofgem the absolute transfer capability of each boundary between zones, and makes these capabilities public. An auctioneer then facilitates a Primary Auction process for zonal rights for the forthcoming year, in which participants submit offer curves to buy or sell "bundles" of entry and exit rights within each zone.

The auctioneer operates a simultaneous clearing process across zonal access products, which determines clearing price and optimal volumetric allocations to participants based on their bids and the agreed transfer capabilities. The Primary Auction is subject to a set of relative loss adjustment factors, which set a minimum differential between access product prices to reflect the cost of unconstrained marginal losses.

Auction prices for each access right product are published. Surplus funds raised by this auction process partially support NGC's TNUoS revenue.

Following this Primary Auction, participants fine tune their position by trading these rights on secondary markets (potentially down to the half hourly level). Via a Designated Exchange, NGC participates in secondary trading to the extent that its expectations of the inter-zonal boundary capabilities change – it is incentivised to maximise the revenue of any release of new right, and minimise the cost of any buy-back.[1] Clearly it will not be

[1] In the assessment studies because it was assumed that the perfect total volume of tickets was sold in every zone, no such buying or selling needed to be modelled. The trading amongst the participants in a zone was simulated by re-distributing the tickets to generators strictly in order of their bid prices. This keeps the same amount of tickets in each zone but gives a different nodal allocation.

possible to resolve intra-zonal constraints via this market – these will be left to the Balancing Mechanism.

The access markets "close" at Gate Closure. The Balancing Mechanism continues as at NETA Day 1 – effectively, NGC buys / sells a bundled access and energy product.

In each half hour, participants have a volumetric access imbalance exposure equal to the difference of their access right holdings in a given zone (adjusted for accepted BM bids/offers) and their metered output/demand in that zone. These imbalances are settled at a price derived (at least in part) from closing access prices in the secondary markets.

Study Methodology

Underlying Assumptions and Approximations

The assumptions and approximations made are as follows:

- Studies are based on a DC model hence approximate the constraints.
- With the market being two-sided the studies only deal with generation bidding for transmission access in the Primary Auction and then adjusting their position in secondary trading (i.e. the pattern of demand and total zonal demand is assumed constant throughout the market and in the Balancing Mechanism).
- NGC can perfectly predict the system constraints in line with the optimum nodal solution, so that a perfect "Best Estimate" can be made on the conditions governing the volumes of tickets available. It is further assumed that volumes of tickets sold in the Primary Auction reflect the "Best Estimate" conditions.

Input Data

For each of the six studies, one year's system and market operation was modelled, with each week represented by a single demand block with its own demand level and available generation pattern. Typical transmission availability was also included in the model. Sensitivities on generation bids were determined with reference to recent Pool bidding behaviour.

The temporal duration of the access rights was assumed to line up with the smallest unit of the simulation, i.e. one week, with each unit's rights being auctioned and traded as separate and independent products.

Primary Auction Simulation

For each temporal unit, a nodal allocation of transmission access was first derived from an optimisation algorithm which maximised the income from nodal auction bids while respecting all transmission constraints. This is equivalent to assuming that a perfect "Best Estimate" can be made on the conditions governing the volumes of rights available.
Depending on the definition of the access rights (e.g. whether entry/exit or transfer type), this solution was converted to the appropriate volumes of rights sold, based on the assumption that the volumes of tickets sold in the Primary Auction perfectly reflect the "Best Estimate" conditions.

This simulation also gave the total system constraint volume.

Secondary Trading Simulation

In Secondary Trading, tickets of the same type can be traded amongst participants. The System Operator would not need to do any trading as the Primary Auction has already sold the perfect total volumes under the assumptions made for these studies. Assuming this process to be perfectly efficient, it would result in the rights of a particular type being held in accordance with an unconstrained merit order.

Calculation of Constraints left to be addressed in the BM

With the assumptions of a similar merit order of bids and offers in the BM and that Final Physical Notifications exactly match access rights held, the optimum BM solution would be the same as that in the Primary Auction simulation.[2] The BM action at each node would be defined as the difference between the rights allocated in the Secondary Trading and the BM solution. The sum of the absolute differences at all the nodes gave the total BM action volume to address remaining constraints.

Effectiveness Assessment

The results of the estimated level of constraints addressed before Gate Closure on the 6 snapshots are shown in the following table.

Table 1 - Volume of Constraints Addressed by A Transmission Access

Market Prior to Gate Closure (% of Total Constraint Volume)

Snapshot of System	Total Constraint Volume (TWh)	12 GSP	Supra GSP [1]	Supra GSP [2]	Supra GSP [3]
A	6.1	38%	29%	17%	33%
B	4.2	67%	37%	55%	54%
C	3.3	53%	35%	32%	43%
D	2.3	66%	43%	43%	60%
E	1.8	63%	39%	38%	57%
F	1.0	64%	44%	49%	49%

These results suggest that:

- Up to a maximum of two-thirds of the total constraint volume is likely to be addressed prior to Gate Closure in an access market based on the full 12 GSP Group (REC) zones.

- The scope for addressing constraints prior to Gate Closure would be reduced to below half of the total constraints volume if the requirement of market liquidity leads to the use of bigger zones (i.e. the combination of GSP groups into supra-GSP groups).
- Under certain scenarios the capture of constraints is much less than half. I.e. significant intra-zonal constraints may be present.

[2] Note that whilst this would approximately hold for volumes of constraints, it is less likely to hold for the costs as it is highly unlikely that the bid prices in the forward contracts will be equivalent to bids/ offers in the Balancing Mechanism. Hence the studies have been restricted to volumes addressed and not costs.

These results are a “top estimate” as a number of the assumptions and approximations made in the studies, once relaxed, would be likely to bring the estimates down.

Attachment 2: Options for a Transmission Access Regime

Straw Man Models of Transmission access Arrangements

This note summarises three Straw Man models of transmission access market arrangements which NGC have considered, and provides a brief analysis of the possible advantages and disadvantages of each.

The three Straw Man models considered are:

- **Straw Man 1**: Zonal entry/exit market;
- **Straw Man 2**: Nodal entry/exit market; and
- **Straw Man 3**: Flowgate market with nodal participation factors. (Note: could also be termed as a transfer rights market or a boundary rights market).

It should be noted that the descriptions of the market models below are at a high level, and are not complete in all aspects – they are intended to provide a context to the evaluation rather than a full description of the operation of the market.

Straw Man 1: Zonal entry/exit market

This market model is based on an entry/exit right market design – participants buy rights to inject power onto the transmission system (entry rights) and rights to take power off the system (exit rights) in given locations, both with reference to the same defined hub-point. These locations are defined by zones – zonal entry / exit rights confer equal injection / withdrawal rights to each entry / exit point in that zone. In order to resolve at least 75% of constraints in this market model, our analysis suggests it is likely that a minimum of 24 zones would be required, with zonal boundaries being non-coincident with GSP Group boundaries. Further analysis shows that 31 zones would be required for the transmission access market to address about 90% of total constraint volume. These two zonal definitions are shown below.

Figure 1 - Alternative Transmission Access Zonal Definitions

24 Zones | 31 Zones

The table below shows the constraint capture levels of these two zonal definitions for the six studies considered in the initial Straw Man model.

Table 1 - Volume of Constraints Prior to Gate Closure (% of Total Constraint Volume)

Snapshot of System	Total Constraint Volume (TWh)	24 Zones	31 Zones
A	6.1	82%	93%
B	4.2	92%	95%
C	3.3	75%	92%
D	2.3	84%	97%
E	1.8	78%	95%
F	1.0	80%	88%

NGC agrees with Ofgem the absolute transfer capability of each boundary between zones, and makes these capabilities public. An auctioneer then facilitates a primary auction process for zonal rights for the forthcoming year, in which participants submit offer curves to buy or sell "bundles" of entry and exit rights within each zone.

The auctioneer operates a simultaneous clearing process across zonal access products, which determines a clearing price and optimal volumetric allocations to participants based on their bids and the agreed transfer capabilities. The primary auction is subject to a set of relative loss adjustment factors, which set a minimum differential between access product prices to reflect the cost of unconstrained marginal losses.

Auction prices for each access right product are published. Surplus funds raised by this auction process partially support NGC's TNUoS revenue.

Following this primary auction, participants fine-tune their position by trading these rights on secondary markets (potentially down to the half-hourly level). Via a Designated Exchange, NGC participates in secondary trading to the extent that its expectations of the inter-zonal boundary capabilities change – it is incentivised to maximise the revenue of any release of new right, and minimise the cost of any buy-back. Clearly it will not be possible to resolve intra-zonal constraints via this market – these will be left to the Balancing Mechanism.

The access markets "close" at Gate Closure. The Balancing Mechanism continues as at NETA Day 1 – effectively, NGC buys / sells a bundled access and energy product.

In each half hour, participants have a volumetric access imbalance exposure equal to the difference of their access right holdings in a given zone (adjusted for accepted BM bids/offers) and their metered output/demand in that zone. These imbalances are settled at a price derived (at least in part) from closing access prices in the secondary markets.

As zonal boundaries are not coincident with GSP Group boundaries, a mechanism will be needed to allocate demand to zones. At least initially, this could be achieved by simply pro-rating GSP Group demand to the GSP nodes according to analysis of historical demand dispersion. These nodes can then be amalgamated into the access zones.

Straw Man 2: Nodal entry/exit market

This market model is based on an entry/exit right market design – participants buy rights to inject power onto the transmission system (entry rights) and rights to take power off the system (exit rights) in given locations, with reference to a defined hub-point. These locations are defined by nodes.

NGC agrees with Ofgem the capacity on the transmission system in the form of base constraint data. Participants submit offer curves for the volume of entry and exit rights which they require at each node.

Using these bids and an optimisation programme, NGC calculates the optimal allocation of rights given the agreed limitations of the transmission system. The optimisation is subject to the restriction of a set of minimum differentials between nodal prices set to reflect the cost of unconstrained marginal losses.

Auction prices at each node are published. Surplus funds raised by this auction process partially support NGC's TNUoS revenue.

Following the primary auction, participants fine-tune their position by trading these rights on secondary markets (potentially down to the half-hourly level). Given the bids from the participants for increments and decrements of entry and exit right volumes at each node on the system, NGC determines the volume of each bid to take in line with its updated expectation of the inter-nodal capabilities. NGC's trading would be subject to an incentive mechanism. Following each round of secondary trading, NGC would again publish prices at each node.

Although it is the characteristic which allows all constraints active prior to Gate Closure to be resolved, the fact that the information on the relative effectiveness of each node with respect to system constraints is variable and internal to NGC's optimisation means that participants cannot trade bilaterally (unless they are connected at the same node). The vast majority of trades must be with NGC.

The access markets "close" at Gate Closure. The Balancing Mechanism continues as at NETA Day 1 – effectively, NGC buys / sells a bundled access and energy product.

In each half hour, participants have a volumetric access imbalance exposure equal to the difference of their access right holdings at a given node (adjusted for accepted BM bids/offers) and their metered output/demand at that node. These imbalances are settled at a price derived (at least in part) from closing access right prices in the secondary markets.

As imbalance volumes are based on nodal injections / withdrawals, greater locational tagging of demand than is available within the Stage 2 settlement system would be required. As in Straw Man 1, this could be achieved by allocating GSP Group demand to individual Grid Supply Points on the basis of factors determined by analysis of historical demand dispersion.

Straw Man 3: Flowgate market

This market model is often also referred to as a transfer rights market or a boundary rights market. It is based on a definition of access as the right to transport power over specified flowgates rather than being defined in relation to injections to or withdrawals from areas "either side" of the flowgates. Again the rights are with reference to a defined hub point.

In order to allow greater constraint resolution, the flowgates in question may be defined at least in part at the circuit level rather than as boundaries (combinations of circuits).

NGC defines the flowgates which will be traded (based upon expectations of where constraints will be active on the system), and agrees with Ofgem the volume of these flowgate rights which will be made available.

NGC also carries out studies to determine the participation factor of each node on the system for each defined flowgate. The participation factor for a node with respect to a flowgate represents the fraction of each MW injected or withdrawn at the node – with reference to a defined hub-point – which can be expected to be transported over it. NGC publishes this participation factor information – with *n* nodes and *k* defined flowgates, this publication would be in the form of an *n* x *k* matrix. In order to provide a firm basis for secondary trading, these participation factors remain unchanged from the primary auction through to imbalance settlement.

An auctioneer then facilitates a primary auction for access rights for the forthcoming year, in which participants submit offer curves to buy and sell "bundles" of rights in each flowgate. The auctions are independent of each other – there is no requirement for any simultaneous clearing process. The primary auctions are subject to loss related reserve prices, which set a minimum price for each access right to reflect the cost of unconstrained marginal losses.

Participants determine the volumes of each of the flowgates they require on the basis of their expected physical position at each node multiplied by the participation factor for each node in each defined flowgate. Participants with a physical position will need to trade to a target portfolio containing rights in a maximum of *k* flowgates.

Auction prices for each flowgate are published. Surplus funds raised by this auction process partially support NGC's TNUoS revenue.

Following this primary auction, participants fine-tune their position by trading rights on secondary markets (potentially down to the half-hourly level). Through a Designated Exchange, NGC releases further flowgate volumes, or buys back volumes to reflect the evolving conditions on the transmission network, again under an incentive scheme.

Since the participation factors used in imbalance settlement are set at the primary auction and not updated to reflect evolving system conditions, it will not be possible for the market to efficiently resolve all constraints – some will be left to the Balancing Mechanism. However, in contrast to Straw Man 1, it is difficult to evaluate the likely extent of constraint resolution in this market model – such an analysis would need to map changes in network topology to changes in participation factors to (critically) changes in the extent of efficient constraint resolution.

The access markets "close" at Gate Closure. The Balancing Mechanism continues as at NETA Day 1 – effectively, NGC buys / sells a bundled access and energy product.

Participants' volumetric imbalances are calculated separately for each defined flowgate by comparing volumetric holdings of individual flowgate rights with deemed use. Volumetric holdings are defined for each participant as holdings of each right adjusted (using the fixed participation factors) to reflect accepted BM offers and bids. The deemed volumetric use is defined as nodal metered injections or withdrawals multiplied by the set of participation factors for the node in the flowgate in question.

These imbalances are settled at a price derived (at least in part) from the closing prices of each flowgate right in the secondary markets.

As imbalance volumes are based on use of flowgate rights calculated by applying participation factors to nodal injections / withdrawals, greater locational tagging of demand than is available within the Stage 2 settlement system will be required. At least initially, this could be achieved by allocating GSP Group demand to individual Grid Supply Points on the basis of factors determined by analysis of historical demand dispersion.

Evaluation of market models

In all of the above Straw Man models, the efficiency of constraint resolution will depend upon NGC's ability to forecast accurately system capabilities and conditions at various points in time, and particularly at the primary auction (as this is when access rights are initially allocated). In Straw Man 1, therefore, effectiveness will depend in part upon the definition of the zonal boundaries and the estimation of each boundary transfer capability. In Straw Man 2, effectiveness will depend upon the accuracy of the base data for the optimisations. In contrast, in Straw Man 3, effectiveness will depend in part upon the initial definition of flowgates and the estimation of participation factors.
However, in addition to the general importance of forecasting across the market models, it is possible to identify further pros and cons of each of the models individually. In assessing these pros and cons, we make the assumption that NGC is able to perfectly forecast system conditions as required. Table 2 below summarises our evaluation.

Table 2 - Evaluation of Straw Man market models

Straw Man 1	Straw Man 2	Straw Man 3
Pros: Valuation of access rights for participants is not complex NGC is only involved in inter-zonal trading – no wider facilitation of trading is required	**Pros:** All constraints active before Gate Closure will be solved Valuation of access rights for participants is not complex	**Pros:** Offers the possibility of solving a significant proportion of constraints with the potential of unfacilitated bilateral trading of transmission rights
Cons: The number of zones required to capture a significant percentage of constraints is likely to restrict liquidity. A number of zones would have one single generator.	**Cons:** (To the extent it is perceived as a con by market participants) NGC has to facilitate and act as counterpart to all inter-nodal participant trades	**Cons:** Efficient constraint resolution is dependent upon a degree of stability of network topology Valuation of access rights for participants is complex

Straw Man 1

The key advantages of this market model are:

- **valuation of access rights for participants is not complex**: participants are able to value the entry / exit access rights (as a minimum) on the basis of the difference between their expectations of the energy price at the national delivery point and their own costs – they do not necessarily need to engage in more complex analysis of other participants' behaviour in the access markets to value the rights; and

- **NGC is only involved in inter-zonal trading – no wider facilitation of trading is required**: for participants within the same zone, trading of entry and exit rights can take place bilaterally, either via over-the-counter or on-exchange trading – no facilitation by NGC is required. NGC's trading relates solely to changes in expected transfer capabilities between zones – for example buying back entry rights in one zone and selling additional entry rights in another.

In contrast, the main disadvantage of this model is that **the number of zones required to capture a significant percentage of constraints is likely to restrict liquidity.** As stated above, in order to solve at least 75% of constraints, it is likely that at least 24 zones would be needed. Since this reduces the number of different participants in each zone, it reduces the likelihood of liquid secondary markets developing – with 24 zones, a number might have only one generator participant.

Straw Man 2

The key advantages of this market model are that:

- **all constraints active before Gate Closure will be solved**: since the model is nodal in nature and allocations are the result of an optimisation process which takes into account changes to actual system conditions as they evolve, the market will be capable of solving all transmission constraints which are active before Gate Closure; and

- **valuation of access rights for participants is not complex:** as the market is based on entry / exit rights, as in Straw Man I, participants are able to come to a valuation of the entry / exit rights being traded (as a minimum) on the basis of the difference between their expectations of the energy price at the national delivery point and their own costs.

The principal disadvantage with this market model, to the extent that it is perceived as such by market participants, is that **NGC has to facilitate and act as counterparty to all participant trades** (save for nodes where there is more than one connected participant).

Straw Man 3

The key advantage of this market model is that it **offers the possibility of solving a significant proportion of constraints whilst allowing unfacilitated bilateral trading of individual access rights**. Since flowgates can be defined in relation to individual circuits and participation factors defined for each node in relation to each flowgate, it would theoretically be possible to resolve all constraints (provided participation factors did not change from the primary auction). Similar to Strawman 1, if approximations are made to the flowgates to increase liquidity or reduce complexity then some constraint capture will be lost.

There are, however, important disadvantages of this model:

- since imbalance settlement (and hence all *ex ante* trading) takes place on the basis of participation factors fixed at the time of the primary auction, trading *will not* take into account changes in network topology (which result in changes to the *actual* participation factors) despite the fact that they may create new constraints. As a result, **efficient constraint resolution is dependent on a degree of stability of network topology** – if topology changes frequently, the market will not be able to efficiently resolve all the actual constraints on the network; and

- the **valuation of access rights for participants is complex**. In an entry/exit market model, participants can price access rights (as a minimum) on the difference between their expectation of the energy price and their own costs. At an aggregate level, the same is still true under this model. Participants know that the unit price of their target portfolio of access rights should be equal to the difference between their expectation of the energy price and their unit costs. However, in contrast with the entry / exit model, this information is insufficient for each participant to price every individual access right. While a generator with a given output knows (from participation factors) the volume of each flowgate which they require, and knows their valuation of a unit of their total target portfolio, they cannot impute a value to each component access right in that portfolio without further information and analysis.

Summary

Three alternative Straw Man models of the transmission access market have been assessed and compared. The key points and important trade-offs are provided in the following table.

Market model	Definition of rights	Locational resolution	Constraint resolution under idealised condition (% of total volume)	NGC facilitation of trading?	Need to solve "GSP Group metering" problem?	Complexity for Market Participants to value the access rights
Straw Man 1	Entry / exit	Zonal (>24 zones)	>75% depending on zonal definition	Required for inter-zonal trading	Yes	Relatively simple
Straw Man 2	Entry / exit	Nodal	100%	Required for inter-nodal trading	Yes	Relatively simple
Straw Man 3	Transfer	Linked to Nodes by participation factors	100% only with completely stable topology	None	Yes	Complex

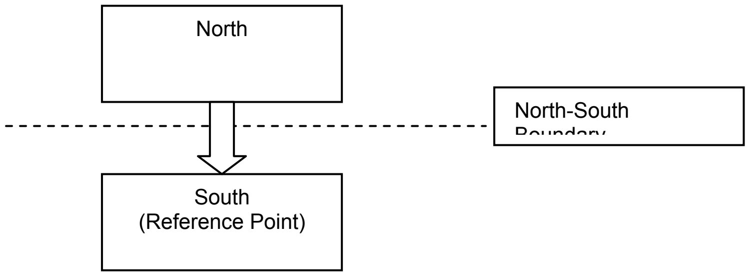
Attachment 3: Simultaneous Clearing in Access Auctions and Losses Charges

Simultaneous Clearing – A Paper by NGC

Each constraint is defined as a limit on the total flow across a system boundary that divides the system into two areas. The boundary flow is represented by the difference between the total generation and total demand in the area which does not include the reference point. This can be termed the constrained area. In the case of generation exceeding demand in the constrained area, the transmission constraint sets a limit on the excess of total entry rights over total exit rights in that area. In the case of demand exceeding generation in the constrained area, the transmission constraint sets a limit on the excess of total exit rights over total entry rights in that area.

Within one single auction, after receiving market participants' bids and offers for entry and exit rights in all the zones, a simultaneous clearing of rights over all system boundaries will take place. This will release as many rights as possible which would maximise the total income of the auction while respecting the transmission constraints.

An example of a two-zone system is given below to illustrate how this process works.



Consider an auction for transmission capacity in a zone in the North of England. Suppose there is a North-South boundary and the reference point (ie energy exchange) is located in the South.

The clearing price in energy exchange is £20/MWh.

In North there are five generators each having 100MW capacity and all with production cost lower than the energy exchange price. They will be prepared to bid up to the difference between their production cost and the energy exchange price:

	Production cost £/MWh	**(Max) bid for the right £/MWh**
G1	**19**	**1**
G2	**18**	**2**
G3	**17**	**3**
G4	**16**	**4**
G5	**15**	**5**

There are also five demand blocks in North, each sized at 100MW and having the utility value listed below. Each block will consume only if it receives a transmission obligation payment at least equal to the difference between its utility value and the energy exchange price:

	Utility £/MWh	(Min) offer for the obligation £/MWh
D1	**19**	**-1**
D2	**18**	**-2**
D3	**17**	**-3**
D4	**16**	**-4**
D5	**15**	**-5**

Case 1 - Excluding Effect of Losses, System Constrained

The North-South boundary is constrained to a 100 MW maximum flow. The clearing process consists of accepting those bids and offers which yield the greatest auction income, while respecting the 100 MW constraint. Combinations which (just) satisfy the constraint are:

Bids/offers accepted	Auction income £/hr
G5	**500**
G5,G4,D1	**800**
G5,G4,G3,D1,D2	**900**
G5,G4,G3,G2,D1,D2,D3	**800**
G5,G4,G3,G2,G1,D1,D2,D3,D4	**500**

The auctioneer will arrive at the third combination, with a clearing price of £3/MWh set by G3 (highest bid taken) and D3 (lowest offer not taken).

Combining Relative Loss Adjustments to Clearing Process

A marginal charge for losses and the interaction between losses and constraints can be automatically allowed for in a loss adjusted access rights clearing process. In this process the "unconstrained Transmission Loss Factor (TLF)[3] times energy exchange price" is netted off all the bids and offers when they are ranked.

In the two-zone example, suppose the unconstrained TLF for the North is 8%. This gives a marginal loss cost at 8%*£20/MWh = £1.6/MWh. The bids and offers are adjusted in the clearing process.

Northern generation's bids:

[3] For the generation in a particular zone this is the linear sensitivity of system losses to a marginal increase in generation in that zone which is balanced at the reference point, assuming no system constraint is present. The TLF for the demand is equal in magnitude and opposite in sign to the corresponding generation TLF.

	Original bid £/MWh	Marginal loss adjusted bid £/MWh
G1	1	-0.6
G2	2	0.4
G3	3	1.4
G4	4	2.4
G5	5	3.4

Northern demand's offers:

	Original offer £/MWh	Marginal loss adjusted offer £/MWh
D1	-1	0.6
D2	-2	-0.4
D3	-3	-1.4
D4	-4	-2.4
D5	-5	-3.4

Case 2 - Loss Adjusted Clearing, System Unconstrained

Without any constraint on the North-South transfer, all the bids and offers which have positive TLF adjusted values are accepted, i.e. G5,G4,G3,G2 and D1. The total auction income would be £1300/hr. The clearing price is at £2/MWh, which is set by G2 (the lowest bid for entry accepted above marginal loss cost) and D2 (the highest offer for exit not accepted below marginal loss cost). It is expected that if the bid and offer curves are smooth, the clearing price for unconstrained transmission access will be at the marginal loss cost.

Case 3 - Loss Adjusted Clearing, System Constrained

If there is a North-South boundary constraint at 100 MW, then the combinations which just satisfy the constraint are:

Bids/offers accepted	Auction income £/hr	Auction income TLF adjusted £/hr
G5	500	340
G5,G4,D1	800	640
G5,G4,G3, D1,D2	900	740
G5,G4,G3,G2,D1,D2,D3	800	640
G5,G4,G3,G2,G1,D1,D2,D3, D4	500	340

The auctioneer will arrive at the third combination with a clearing price of £3/MWh, which is the same as Case 1. Cases 2 and 3 show the interaction between losses and constraints and that the losses effect should not affect the clearing outcome where the system is constrained.

Attachment 4: Examples of the Calculation of Imbalance Charges

Access Imbalance Pricing – A Paper by NGC

Overview of approach

Assume that buying an access 'ticket' imposes both a right and an obligation and that it is impossible to monitor what a party actually has paid for a 'ticket' through all trading mechanisms.

An imbalance price is required for two situations:

- **over-run**: if the market participant's demand or generation is *greater* than the number of tickets held; and
- **under-run**: if the market participant's demand or generation is *less* than the number of tickets held.

Imbalance prices relate to a zonal access price (ZAP) which could be calculated in any number of ways such as average/marginal price of NGC zonal trades in the secondary market or average/marginal price of bids accepted in the Primary Auction, or average/marginal price of bids accepted in the Balancing Mechanism. The exact calculation of the ZAP will need further consideration and could involve taking the maximum or average of a number of prices. The ZAP for entry rights is the negative of the ZAP for exit rights.

The ZAP can be adjusted up or down to form an over-run or under-run price in order to incentivise participants to balance. Indeed, the decision may be taken to set one of the prices to zero.

In this way, participants are purchasing both rights and obligations at the same time and there is no need to explicitly determine individually which type they have. The sign of the ZAP determines whether tickets relate to rights or obligations.

An imbalance liability calculation is detailed below. An allowance is made that access prices for entry and exit could be either positive or negative is allowed for, depending on the location of the reference point for access rights.

Calculation

There are four situations to consider. The access imbalance charge (AIC) is obtained by multiplying the Access Imbalance Price [(1+/-x)*ZAP] by the Imbalance Volume [M-BO-ZAT]:

Where:

x = Spread Factor
ZAP = Zonal Access Price (calculation method to be determined)
M = Zonal Metered Generation or Demand
BO = Zonal Bids/Offers accepted in the Balancing Mechanism
ZAT = Zonal Access Tickets Held

If the market participants' generation or demand is greater than the number of tickets held (i.e. an over-run, the imbalance volume (M-BO-ZAT) is positive, then the access imbalance charge (AIC) is as follows:

AIC = (1+x) * ZAP* (M - BO - ZAT) **if ZAP is positive**

AIC = (1-x) * ZAP * (M - BO - ZAT) **If ZAP is negative**

On the other hand, if market participants' actual generation or demand is less than the number of access tickets held (i.e. an under-run and (M-BO-ZAT) is negative) the AIC should be:

AIC = (1-x) * ZAP * (M - BO - ZAT) **If ZAP is positive**

AIC = (1+x) * ZAP * (M - BO - ZAT) **If ZAP is negative**

Example

Assume x = 0 for simplicity

Participant	**Imbalance Volume (M-BO-ZAT) (1)**	**ZAP (2)**	**AIP (3) [=(2) as x=0]**	**AIC [= 1*3]**
Generation	Positive / Over-run	Positive	Positive	Positive
	Positive / Over-run*	Negative	Negative	Negative
	Negative / Under-run*	Positive	Positive	Negative
	Negative / Under-run	Negative	Negative	Positive
Demand	Positive / Over-run	Positive	Positive	Positive
	Positive / Over-run*	Negative	Negative	Negative
	Negative / Under-run*	Positive	Positive	Negative
	Negative / Under-run	Negative	Negative	Positive

*The AIP could be set to zero if a 'use it or lose it' principle was to be adopted.

Numerical Example

Consider two zones, A in which the ZAP is +3 and B in which the ZAP is –3 (as noted above, another way to think of this is to consider the entry and exit rights respectively in the same zone). Suppose, for example, the spread factor was set as 50% and is applied symmetrically.

In zone A:

- the over-run price (which will be positive as it should represent a *charge to* participants) should be set higher than the positive ZAP to disincentivise over-runs. The over-run price should therefore be 4.5; and
- the under-run price (which will positive as multiplied by a negative imbalance volume it should represent a *payment to* participants) should be set lower than the positive ZAP to disincentivise under-runs. The under-run price should therefore be 1.5.

In contrast, in zone B:

- the over-run price (which should be negative, as it should represent a *payment to* participants – they would have been paid if they had bought an access right through *ex ante* trading) should be set higher than the negative ZAP to disincentivise over-runs. The over-run price should therefore be –1.5; and

- the under-run price (which should be negative, as when multiplied by a negative imbalance volume, it should represent a *charge to* participants – they would have to pay someone to take the access right off their hands in *ex ante* trading) should be set to higher than the negative ZAP, in order to disincentivise under-runs. The under-run price should therefore be -4.5.

Pulling this together gives the following matrix of imbalance prices:

	ZAP =3	**ZAP negative = -3**
Over-run @ 50% spread factor	Imbalance price = 4.5	Imbalance price = -1.5*
Under-run @ 50 % spread factor	Imbalance price = 1.5*	Imbalance price = -4.5

- These prices could be set to zero if it were decided not to apply the spread factor symmetrically. This would be the equivalent of a "use it or lose it" provision.

Attachment 5: Implementation of a Market In Transmission Access – Implications for Systems

Introduction

This document has been prepared to brief attendees at the workshops on transmission access issues on 7 August 2000.

It provides an outline of the likely high level systems requirements arising from the form of market that NGC understands Ofgem intends to be established. This is provided under the following major headings:

- background;
- assumptions for the new arrangements – a 'straw man';
- possible systems requirements; and
- implementation issues.

Background

The need for revised arrangements in transmission access has been known for some time, with initial thinking on possible arrangements being undertaken at the same time as early definition of requirements for NETA.

Ofgem has produced three documents related to transmission access:

- in its July 1999 NETA Document, Ofgem presented some initial thinking on the role of and incentives on NGC as System Operator and the development of new transmission access and pricing arrangements under NETA;
- the October 1999 NETA Document, published jointly by Ofgem and the DTI, discussed respondents' views on the initial thinking outlined in the July 1999 NETA Document; and
- Ofgem then issued a consultation document in December 1999, in which it indicated that its initial views were that transmission access and pricing arrangements need to reflect the value of transmission access and therefore to reflect the locational value of electricity.

The arrangements described in this document are based on NGC's current understanding of Ofgem's views on the form of transmission access market that should be established, as set out in the December 1999 consultation document.

NGC has been actively involved in the debate on transmission access, through discussions with Ofgem and industry participants, and through identifying in general terms the implications of introducing a market in transmission access rights along the lines set out in Ofgem's December 1999 consultation document. As part of this, NGC has made presentations to industry groups, including presenting a consideration of alternative approaches to implementing transmission access arrangements to the Charging Principles

Forum (although Ofgem's December 1999 consultation document effectively closed down some of these alternatives).

More recently, NGC has undertaken work to identify in more detail the likely processes and systems that would be needed to facilitate new transmission access arrangements, and to understand the nature and scale of work that would be required to implement those arrangements.

The contents of this document are largely based on this recent work.

Assumptions for the new arrangements – a 'straw man'

The possible systems requirements set out in this document are based on a number of key assumptions which effectively define a 'straw man' for the transmission access market along the lines set out in Ofgem's December 1999 consultation document. The most important of these assumptions are:

- The market will be for firm physical entry and exit rights; The rights would be firm in the sense that if NGC, as the System Operator, is unable to deliver them, it would have to buy-back the rights. The definition of firm access rights would be locational to reflect the realities of the physical transmission system.

- The market will be two-sided. It is envisaged that both the generation and demand will participate in the access regime. In general, generators will acquire entry rights and suppliers (or large customers in their capacity as self-suppliers) will acquire exit rights.

- The market will be based on the use of zones based on GSP Groups. Demand side involvement has an important consequence for the definition of zones. As imbalance settlement will require metered volume data, zones must conform to GSP Groups as this is the finest level of locational tagging of consumption data available without any changes to the 1998 metering systems.

- There will be a primary auction to establish the initial allocations of access rights: Access rights will initially be auctioned by zone and by temporal product (e.g. peak, off peak etc) for one year. This will result in an initial allocation of rights to participants based on a broad view of the likely capabilities of the transmission system.

- There will be unfacilitated secondary trading of transmission access rights: Subsequent to the primary auction, both participants and NGC will wish to trade these rights via secondary markets, which will run from the primary auction up to Gate Closure (i.e. the opening of the Balancing Mechanism). Participants will trade to fine tune their access position with their expected physical position in order to minimise exposure to the access imbalance regime. Nearer real time, NGC would also participate in the secondary access markets, releasing additional rights or buying rights back as expectations of the transmission system's actual capacity changed.

- There will be a bundled energy and access Balancing Mechanism. Bids and offers accepted in the Balancing Mechanism will be deemed to include the appropriate entry or exit access rights to avoid participants being exposed to access imbalance charges on those volumes.

- There will be half-hourly zonal settlement of access imbalances. The access imbalance settlement process will occur after the delivery half-hour is finished. This process will compare generators' metered output and suppliers' metered/profiled consumption (adjusted for BM actions accepted) with the volume of access rights held by individual participants. Long (under-run) and short (over-run) access positions will result in imbalance liabilities or payments.

Given the criticality of these assumptions in defining the market, the 'straw man' on which this document is based should only be seen as one option for a transmission access market.

As the design of the arrangements progresses to greater levels of detail, these assumptions will be need to be reviewed and potentially changed. If the assumptions are changed, the outline systems requirements, and the scope of work required to implement those systems, are also likely to change.

Possible systems requirements

The direction set by Ofgem's December 1999 consultation document, and the assumptions listed above, lead to the following as a possible division of responsibilities with respect to the operation of the transmission access arrangements:

- NGC would be responsible for agreeing the key parameters of the auction arrangements in advance with Ofgem, for settlement of primary auction bids, for secondary trading activity to balance the system, and then for charging adjusted TNUoS and BSUoS tariffs;

- an Auctioneer would be responsible for offering products for sale in the primary auction, running the system that calculates equilibrium auction prices and volumes, and notifying participants (and potentially the market in general) of auction results;

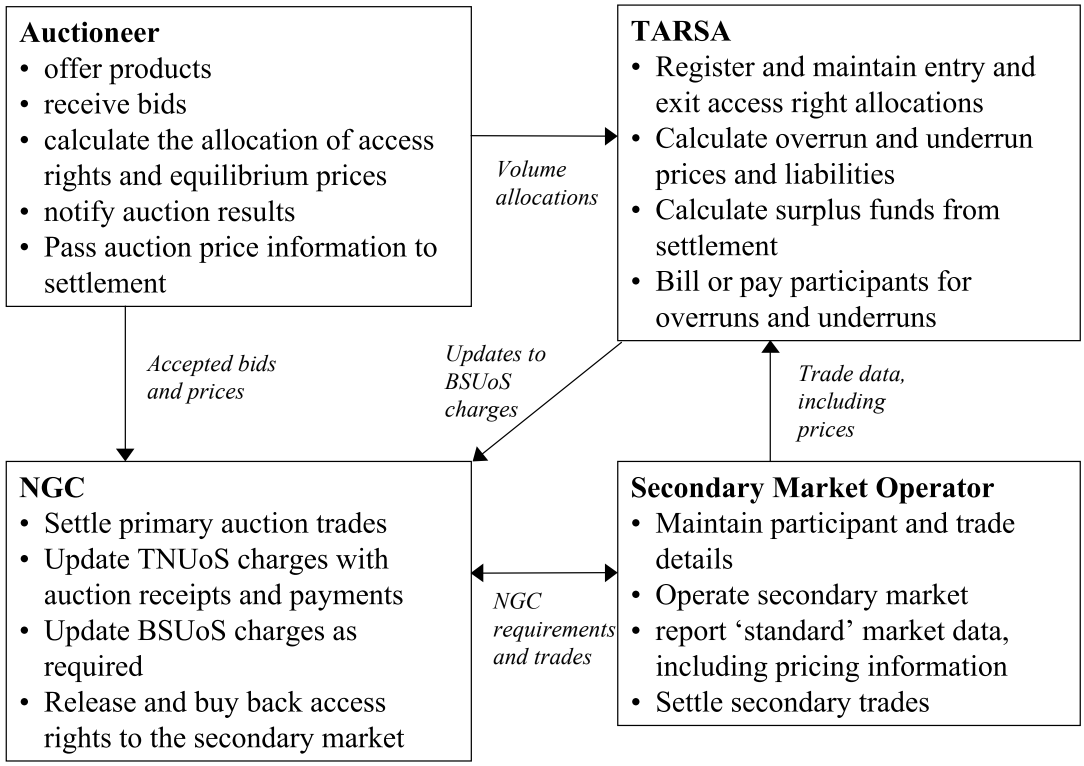
- a Secondary Market Operator would be responsible for operating a Designated Exchange (see below) and settling on-exchange trades; and

- a Transmission Access Registration and Settlement Agent (TARSA) would be responsible for registering access right allocations, and for calculating and settling imbalance liabilities with participants.

It has been assumed that there will be a Designated Exchange (as in the gas commodity regime), to provide the market with the assurance that there will always be a transparent, facilitated market on which NGC can make release and buy-back trades, and from which information can be derived in a transparent manner to be used potentially in the calculation of imbalance prices. It is assumed that the roles of Auctioneer, Secondary Market Operator and TARSA would be undertaken by bodies contracted to NGC, but not by NGC itself. It is therefore assumed that NGC will procure both the systems and the operational services required for these roles.

The possible systems requirements for the market are summarised in Figure 1. This figure indicates at a high-level the broad functionality that would be required in systems by each of the roles listed above, and the key interfaces between those roles.

Figure 1: Overview of transmission access systems requirements



Cost Estimate

At this stage, before agreement on the market design, it is not possible to estimate with any accuracy the likely costs of implementing systems to support a transmission access market. It is possible, however, to make rough estimates based on previous experience of systems which have been developed in broadly comparable situations. For example, the settlement roles and systems being developed for NETA, creation of trading exchanges and auction mechanisms.

It must be noted that where similar systems are needed (e.g. imbalance settlement), the scale and complexity of the projects and systems required will be of a similar magnitude to central NETA systems, thus requiring a similar time to design, develop, test and implement those systems. In addition, systems and operational services will be presumably be procured through an open tendering process, using a similar approach to NETA, through the issue of an OJEC notice inviting expressions of interest, followed by the issue of an Invitation to Tender (ITT) to selected suppliers. Hence, the 'delivery' of the market is likely to be an industry wide project involving many players where an overall programme management role will be critical.

Figure 2 shows broad estimates of the **minimum** projected system costs to set up a zonal transmission access market based on the assumptions listed above.

Figure 2

System / Process	Cost (real 1999/00 prices)	Components
Primary Auction System	£1.5m to £3m	Zonal auction system Ticket allocation method Auction settlement Publication of results
Secondary Trading Mechanism	£2m to £4m	Includes release/buyback system procurement (with option for bi-lateral trading)
Imbalance Settlement	£10m to £20m	Assume 5 of 7 NETA roles are required (all except metered volumes and BM actions) Aggregation needed at a zonal level Rights Registration Agent included Funds Administration included
TNUoS changes	£0.5m - £1.5m	Includes NGC system changes for tariff and reconciliation
BSUoS changes	£0.5m to £1m	Includes NGC system changes for algorithm and interfacing
Overall Program Management	£0.5m to £1.5m	Managing overall implementation interfaces / legal contracts
Total	£15m to £31m	

In the above, no consideration has been given to the ongoing annual costs of operation of the access market. This would include fulfilment of the Settlement System Administrator role, running of the Secondary Market and the running of an annual auction as well as the trading activities of participants.

In addition, no allowance has been made for the costs involved with participants setting up their own trading processes and systems.

APPENDICES I - VII

Appendix I

Terms and Definitions

Total Transfer Capabilities	TTC
Available Transfer Capabilities	ATC
Transmission Reliability Margin	TRM
Capacity Benefit Margin	CBM
Open Access Same-time Information Systems	OASIS

Appendix II

North American Electric Reliability Council Report - Framework For determining available transfer capability

Available
Transfer Capability
Definitions and Determination

A framework for
determining available transfer capabilities
of the interconnected transmission networks
for a commercially viable
electricity market

North American Electric Reliability Council

June 1996

CONTENTS

Executive Summary

This report, *Available Transfer Capability Definitions and Determination*, is in response to a NERC Strategic Initiative to "develop uniform definitions for determining Available (Transmission) Transfer Capability (ATC) and related terms that satisfy both [Federal Energy Regulatory Commission] FERC and electric industry needs, and which are to be implemented throughout the industry." The NERC Board of Trustees at its May 13–14, 1996 meeting approved this report and endorsed its use by all segments of the electric industry.

The report establishes a framework for determining ATCs of the interconnected transmission networks for a commercially viable wholesale electricity market. The report also defines the ATC Principles under which ATC values are to be calculated. It is non-prescriptive in that it permits individual systems, power pools, subregions, and Regions to develop their own procedures for determining or coordinating ATCs based on a regional or wide-area approach in accordance with the Principles defined herein. The proposed ATC calculation framework is based on the physical and electrical characteristics and capabilities of the interconnected networks as applicable under NERC, Regional, subregional, power pool, and individual system reliability planning and operating policies, criteria, or guides.

This report provides an initial framework on ATC that will likely be expanded and modified as experience is gained in its use and as more is learned about how the competitive electric power market will function. The U.S. Federal Energy Regulatory Commission's final rules, Orders No. 888 and No. 889 pertaining to promoting wholesale competition through open access non-discriminatory transmission services by public utilities and an open access same-time information system, respectively, were issued April 24, 1996. The framework for the determination of ATC as outlined in this report is in accord with the key provisions of these rulemakings.

ATC Principles

The following Available Transfer Capability (ATC) Principles govern the development of the definition and determination of ATC and related terms. All transmission provider and user entities are expected to abide by these Principles.

1. ATC calculations must produce commercially viable results. ATCs produced by the calculations must give a reasonable and dependable indication of transfer capabilities available to the electric power market.

2. ATC calculations must recognize time-variant power flow conditions on the entire interconnected transmission network. In addition, the effects of simultaneous transfers and parallel path flows throughout the network must be addressed from a reliability viewpoint.

3. ATC calculations must recognize the dependency of ATC on the points of electric power injection, the directions of transfers across the interconnected transmission network, and the points of power extraction. All entities must provide sufficient information necessary for the calculation of ATC.

4. Regional or wide-area coordination is necessary to develop and post information that reasonably reflects the ATCs of the interconnected transmission network.

5. ATC calculations must conform to NERC, Regional, subregional, power pool, and individual system reliability planning and operating policies, criteria, or guides.

6. The determination of ATC must accommodate reasonable uncertainties in system conditions and provide operating flexibility to ensure the secure operation of the interconnected network.

The calculation of transfer capability is generally based on computer simulations of the operation of the interconnected transmission network under a specific set of assumed operating conditions. These simulations are typically performed “off line,” well before the systems approach that operational state. Each simulation represents a single “snapshot” of the operation of the interconnected network based on the projections of many factors. As such, they are viewed as reasonable indicators of network performance and available transfer capability.

ATC DEFINITIONS

Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically, ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM).

> **Total Transfer Capability (TTC)** is defined as the amount of electric power that can be transferred over the interconnected transmission network in a *reliable* manner while meeting *all* of a specific set of defined pre- and post-contingency system conditions.
>
> **Transmission Reliability Margin (TRM)** is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.
>
> **Capacity Benefit Margin (CBM)** is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

Curtailability is defined as the right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist.

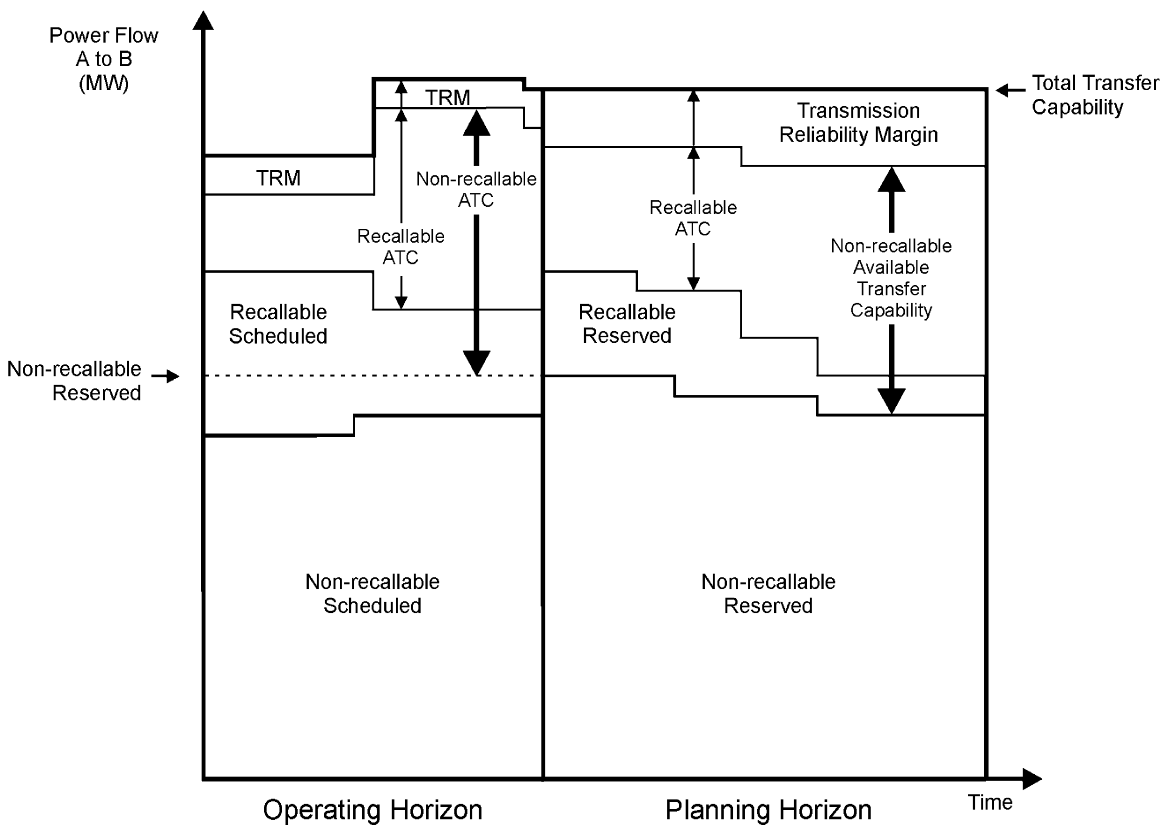
Recallability is defined as the right of a transmission provider to interrupt all or part of a transmission service for any reason, including economic, that is consistent with FERC policy and the transmission provider’s transmission service tariffs or contract provisions.

Non-recallable ATC (NATC) is defined as TTC less TRM, less non-recallable reserved transmission service (including CBM).

Recallable ATC (RATC) is defined as TTC less TRM, less recallable transmission service, less non-recallable transmission service (including CBM). RATC must be considered differently in the planning and operating horizons. In the planning horizon, the only data available are recallable and non-recallable transmission service reservations, whereas in the operating horizon transmission schedules are known.

ATC AND RELATED TERMS

ATC and related terms are depicted graphically below. They form the basis of a transmission service reservation system that will be used to reserve and schedule transmission services in the new, competitive electricity market.



TTC, ATC, and Related Terms in the Transmission Service Reservation System

INTRODUCTION

BACKGROUND

Available Transmission Capacity as described in the U.S. Federal Energy Regulatory Commission's (FERC) March 29, 1995 Notice of Proposed Rulemaking (NOPR), Docket RM95-8-000, Section III-E4f, is a new term that has not been universally defined or used by the electric industry. The electric industry has historically used other standard terms, techniques, and methodologies to define and calculate meaningful measures of the transmission transfer capability of the interconnected transmission networks. These terms, which include First Contingency Total Transfer Capability (FCTTC) and First Contingency Incremental Transfer Capability (FCITC) as defined in NERC's May 1995 *Transmission Transfer Capability* reference document, are still applicable measures in an open transmission access environment. FERC's term Available Transmission Capacity and its definition and relationship to the industry's terminology need to be further clarified.

In its NOPR, FERC also requires that Available Transmission Capacity information be made available on a publicly accessible Real-time Information Network (RIN). Definitions of Available Transmission Capacity in the report of the industry's Electronic Information Network "What" Working Group, which was filed with FERC on October 16, 1995, are only considered to be assumptions to support the Working Group's effort in determining what information should be included on RINs. This report further refines those definitions.

It must be noted early in this report that electric systems in Canada and the northern portion of Baja California, Mexico, which are electrically interconnected with electric systems in the United States, are active members in NERC and the Regional Councils and are committed to promoting and maintaining interconnected electric system reliability. These non-U.S. systems are not, however, subject to FERC jurisdiction, and the commercial aspects of the definitions contained herein are not necessarily applicable to the operation of their internal transmission systems.

TERMINOLOGY CONVENTION

FERC used the term Available Transmission Capacity in its NOPR to label the information that is to be made accessible to all transmission users as an indication of the available capability of the interconnected transmission networks to support additional transmission service. To avoid confusion with individual transmission line capacities or ratings, all references to "ATC" throughout this report will refer to Available (Transmission) Transfer Capability and its related terms as defined in this report.

NERC STRATEGIC INITIATIVE

One of several *Strategic Initiatives for NERC*, approved by the NERC Board of Trustees on October 3, 1995, is to "develop uniform definitions for determining Available (Transmission) Transfer Capability and related terms that satisfy both FERC and electric industry needs, and which are to be implemented throughout the industry." The then existing NERC Transmission Transfer Capability Task Force, with expanded membership to include all segments of the electric industry, was assigned this responsibility for completion in May 1996.

INTRODUCTION

PURPOSE OF THIS REPORT

This report is the response to NERC's Strategic Initiative on ATC and defines ATC and related terms. From a commercial perspective, the key element in the development of uniform definitions for transmission transfer capability is the amount of transfer capability that is available at a given time for purchase or sale in the electric power market under various system conditions. Open access to the transmission systems places a new emphasis on the use of the interconnected networks. As such, future electric power transfers are anticipated to increase over a wide range of system conditions, making the reliable operation of the transmission networks more complex. To effectively maintain system reliability, those who calculate, report, post, and use this information must all have the same understanding of its meaning for commercial use. To accomplish this purpose, this report will answer the following questions:

– What is ATC?
– How does ATC relate to industry standard terminology?
– What physical factors need to be considered in determining ATC?
– What reliability issues must be considered in determining ATC?
– How is ATC calculated?
– How will ATC be commercially used?

The report establishes a framework for determining the ATCs of the interconnected transmission networks for a commercially viable electricity market. Although the report defines the ATC Principles under which ATCs are to be calculated, it is non-prescriptive in that it permits individual systems, power pools, sub-regions, and Regions to develop their own procedures for determining or coordinating ATCs based on a regional or wide-area approach in accordance with these Principles.

The report does not address transmission ownership and equity issues, nor does it address the allocation of transmission services or ATC values. The calculation of ATC is based strictly on the physical and electrical characteristics and capabilities of the interconnected networks as applicable under NERC, Regional, subregional, power pool, and individual system reliability planning and operating policies, criteria, or guides.

As the competitive electric power market develops, more will be learned on how these markets will function and how the definitions of ATC will be used. This report provides an initial framework on ATC, which will likely be expanded and modified as experience is gained in its use. The U.S. Federal Energy Regulatory Commission's final rules, Orders No. 888 and No. 889 pertaining to promoting wholesale competition through open access non-discriminatory transmission services by public utilities and an open access same-time information system, respectively, were issued April 24, 1996. The framework for the determination of ATC as outlined in this report is in accord with the key provisions of these rulemakings.

AVAILABLE TRANSFER CAPABILITY PRINCIPLES

ATC PRINCIPLES

Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. As a measure bridging the technical characteristics of how interconnected transmission networks perform to the commercial requirements associated with transmission service requests, ATC must satisfy certain principles balancing both technical and commercial issues. ATC must accurately reflect the physical realities of the transmission network, while not being so complicated that it unduly constrains commerce. The following principles identify the requirements for the calculation and application of ATCs.

1. ***ATC calculations must produce commercially viable results. ATCs produced by the calculations must give a reasonable and dependable indication of transfer capabilities available to the electric power market.*** The frequency and detail of individual ATC calculations must be consistent with the level of commercial activity and congestion.

2. ***ATC calculations must recognize time-variant power flow conditions on the entire interconnected transmission network. In addition, the effects of simultaneous transfers and parallel path flows throughout the network must be addressed from a reliability viewpoint.*** Regardless of the desire for commercial simplification, the laws of physics govern how the transmission network will react to customer demand and generation supply. Electrical demand and supply cannot, in general, be treated independently of one another. All system conditions, uses, and limits must be considered to accurately assess the capabilities of the transmission network.

3. ***ATC calculations must recognize the dependency of ATC on the points of electric power injection, the directions of transfers across the interconnected transmission network, and the points of power extraction. All entities must provide sufficient information necessary for the calculation of ATC.*** Electric power flows resulting from each power transfer use the entire network and are not governed by the commercial terms of the transfer.

4. ***Regional or wide-area coordination is necessary to develop and post information that reasonably reflects the ATCs of the interconnected transmission network.*** ATC calculations must use a regional or wide-area approach to capture the interactions of electric power flows among individual, subregional, Regional, and multiregional systems.

5. ***ATC calculations must conform to NERC, Regional, subregional, power pool, and individual system reliability planning and operating policies, criteria, or guides.*** Appropriate system contingencies must be considered.

6. ***The determination of ATC must accommodate reasonable uncertainties in system conditions and provide operating flexibility to ensure the secure operation of the interconnected network.*** A Transmission Reliability Margin (TRM) may be necessary to apply this Principle. Additionally, transmission capability (defined as Capacity Benefit Margin or CBM) may need to be reserved to meet generation reliability requirements.

TRANSMISSION TRANSFER CAPABILITY CONCEPTS

The key basic concepts of transmission transfer capability are described below. Numerous other terms related to transfer capability are explored in detail in NERC's May 1995 *Transmission Transfer Capability* reference document. The concepts and terms in that document are still applicable in an open transmission environment.

TRANSFER CAPABILITY

Transfer capability is the measure of the ability of interconnected electric systems to *reliably* move or transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). In this context, "area" may be an individual electric system, power pool, control area, subregion, or NERC Region, or a portion of any of these. Transfer capability is also directional in nature. That is, the transfer capability from Area A to Area B is *not* generally equal to the transfer capability from Area B to Area A.

TRANSFER CAPABILITY VERSUS TRANSMISSION CAPACITY

Electric systems throughout NERC have agreed to use common terminology to calculate and report transmission transfer limits to maintain the reliability of the interconnected transmission networks. These transfer values are called "capabilities" (differentiating them from "capacities") because they are highly dependent on the generation, customer demand, and transmission system conditions assumed during the time period analyzed. The electric industry generally uses the term "capacity" as a specific limit or rating of power system equipment. In transmission, capacity usually refers to the thermal limit or rating of a particular transmission element or component. The ability of a single transmission line to transfer electric power, when operated as part of the interconnected network, is a function of the physical relationship of that line to the other elements of the transmission network.

Individual transmission line capacities or ratings *cannot* be added to determine the transfer capability of a transmission path or interface (transmission circuits between two or more areas within an electric system or between two or more systems). Such aggregated capacity values may be vastly different from the transmission transfer capability of the network. Often, the aggregated capacity of the individual circuits of a specific transmission interface between two areas of the network is greater than the actual transfer capability of that interface. In summary, the aggregated transmission line capacities of a path or interface do not represent the transfer capabilities between two areas.

DETERMINATION OF TRANSFER CAPABILITY

The calculation of transfer capability is generally based on computer simulations of the operation of the interconnected transmission network under a specific set of assumed operating conditions. These simulations are typically performed "off line," well before the systems approach that operational state. Each simulation represents a single "snapshot" of the operation of the interconnected network based on the projections of many factors. As such, they are viewed as reasonable indicators of network performance and available transfer capability. Among the factors considered in these simulations are:

- Projected Customer Demands — Base case demand levels should be appropriate to the system conditions and customer demand levels under study and may be representative of peak, off-peak or shoulder, or light demand conditions.

- Generation Dispatch — Utility and nonutility generators should be realistically dispatched for the system conditions being simulated.

- System Configuration — The base case configuration of the interconnected systems should be representative of the conditions being simulated, including any generation and transmission outages that are expected. The activation of any operating procedures normally expected to be in effect should also be included in the simulations.

- Base Scheduled Transfers — The scheduled electric power transfers that should be modeled are those that are generally considered to be representative of the base system conditions being analyzed and which are agreed upon by the parties involved.

- System Contingencies — A significant number of generation and transmission system contingencies should be screened, consistent with individual electric system, power pool, subregional, and Regional planning criteria or guides, to ensure that the facility outage most restrictive to the transfer being studied is identified and analyzed. The contingencies evaluated may in some instances include multiple contingencies where deemed to be appropriate.

The conditions on the interconnected network continuously vary in real time. Therefore, the transfer capability of the network will also vary from one instant to the next. For this reason, transfer capability calculations may need to be updated periodically for application in the operation of the network. In addition, depending on actual network conditions, transfer capabilities can often be higher or lower than those determined in the off-line studies. The farther into the future that simulations are projected, the greater is the uncertainty in assumed conditions. However, transfer capabilities determined from simulation studies are generally viewed as reasonable indicators of actual network capability.

LIMITS TO TRANSFER CAPABILITY

The ability of interconnected transmission networks to *reliably* transfer electric power may be limited by the physical and electrical characteristics of the systems including any one or more of the following:

- Thermal Limits — Thermal limits establish the maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.

- Voltage Limits — System voltages and changes in voltages must be maintained within the range of acceptable minimum and maximum limits. For example, minimum voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to the electric system or customer facilities. A widespread collapse of system voltage can result in a blackout of portions or all of the interconnected network.

- € Stability Limits — The transmission network must be capable of surviving disturbances through the transient and dynamic time periods (from milliseconds to several minutes, respectively) following the disturbance. All generators connected to ac interconnected transmission systems operate in synchronism with each other at the same frequency (nominally 60 Hertz). Immediately following a system disturbance, generators begin to oscillate relative to each other, causing fluctuations in system frequency, line loadings, and system voltages. For the system to be stable, the oscillations must diminish as the electric systems attain a new, stable operating point. If a new, stable operating point is not quickly established, the generators will likely lose synchronism with one another, and all or a portion of the interconnected electric systems may become unstable. The results of generator instability may damage equipment and cause uncontrolled, widespread interruption of electric supply to customers.

The limiting condition on some portions of the transmission network can shift among thermal, voltage, and stability limits as the network operating conditions change over time. Such variations further complicate the determination of transfer capability limits.

USES OF TRANSMISSION SYSTEMS

The interconnected transmission networks tie together major electric system facilities, generation resources, and customer demand centers. They are planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits for the following purposes:

- € To Deliver Electric Power to Customers — Transmission networks must provide for the reliable transfer of the electric power output from generation resources to customers under a wide variety of operating conditions.

- € To Provide Flexibility for Changing System Conditions — Transmission capability must be available on the interconnected network to provide flexibility to reliably handle the shift in transmission facility loadings caused by maintenance and forced outages of generation and transmission equipment, and a wide range of variable system conditions, such as higher than expected customer demands, or construction delays of new facilities.

- € To Reduce the Need for Installed Generating Capacity — Transmission interconnections between neighboring systems provide for the sharing of installed generating capacity, taking advantage of the diversity in customer demands and generation availability over a wide area, thereby reducing the amount of installed generating capacity necessary to meet generation reliability requirements in each of the interconnecting systems.

- € To Allow Economic Exchange of Electric Power Among Systems — Transmission interconnections between systems, coupled with internal system transmission facilities, allow for the economic exchange of electric power among neighboring systems. Such economy transfers help reduce the overall cost of electricity to customers.

TTC Definition and Determination

Definition of Total Transfer Capability

The Total Transfer Capability (TTC) between any two areas or across particular paths or interfaces is direction specific and consistent with the First Contingency Total Transfer Capability (FCTTC) as defined in NERC's May 1995 *Transmission Transfer Capability* reference document.

TTC is the amount of electric power that can be transferred over the interconnected transmission network in a *reliable* manner based on *all* of the following conditions:

1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.

2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit.

3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

4. With reference to condition 1 above, in the case where pre-contingency facility loadings reach normal thermal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached.

5. In some cases, individual system, power pool, subregional, or Regional planning criteria or guides may require consideration of specified multiple contingencies, such as the outage of transmission circuits using common towers or rights-of-way, in the determination of transfer capability limits. If the resulting transfer limits for these multiple contingencies are more restrictive than the single contingency considerations described above, the more restrictive reliability criteria or guides must be observed.

Determination of Total Transfer Capability

The concepts for determining transfer capability described in NERC's *Transmission Transfer Capability* reference document are still valid and do not change with the advent of open transmission access or the need to determine ATCs. The major points contained therein are briefly outlined below.

System Conditions

Base system conditions are identified and modeled for the period being analyzed, including projected customer demands, generation dispatch, system configuration, and base scheduled transfers. As system conditions change, the base system conditions under which TTC is calculated may also need to be modified.

Critical Contingencies

During transfer capability studies, many generation and transmission system contingencies throughout the network are evaluated to determine which facility outages are most restrictive to the transfer being analyzed. The types of contingencies evaluated are consistent with individual system, power pool, subregional, and Regional planning criteria or guides. The evaluation process should include a variety of system operating conditions because as those conditions vary, the most critical system contingencies and their resulting limiting system elements could also vary.

System Limits

As discussed earlier, the transfer capability of the transmission network may be limited by the physical and electrical characteristics of the systems including thermal, voltage, and stability considerations. Once the critical contingencies are identified, their impact on the network must be evaluated to determine the most restrictive of those limitations. Therefore, the TTC becomes:

TTC = Minimum of {Thermal Limit, Voltage Limit, Stability Limit}

As system operating conditions vary, the most restrictive limit on TTC may move from one facility or system limit to another as illustrated in Figure 1.

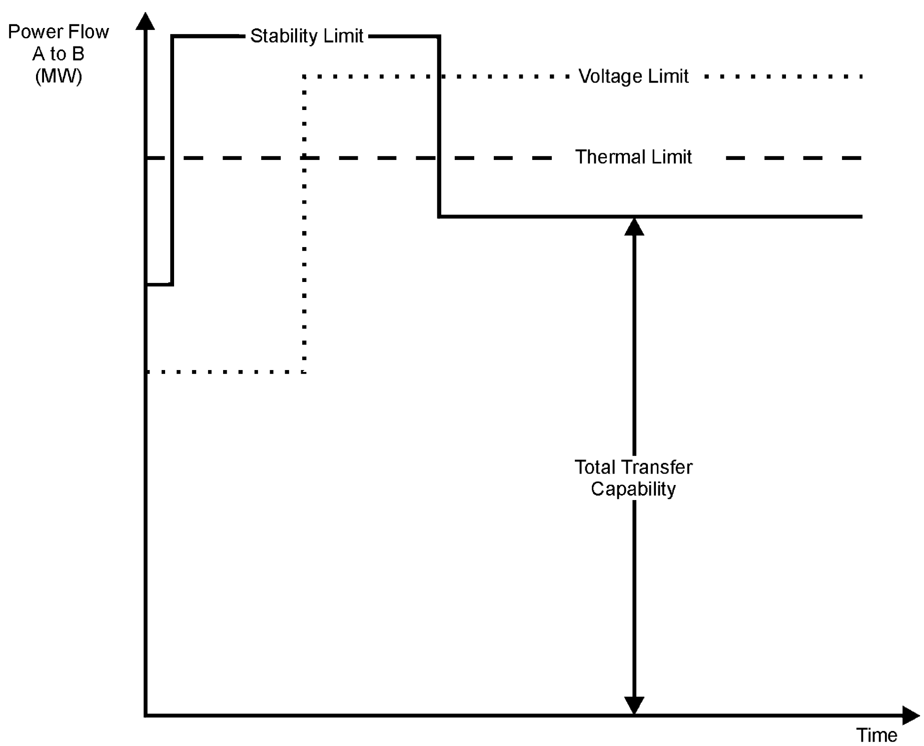


Figure 1: Limits to Total Transfer Capability

Parallel Path Flows

When electric power is transferred across the network, parallel path flows occur. This complex electric transmission network phenomenon can affect all systems of an interconnected network, especially those systems electrically near the transacting systems. As a result, transfer capability determinations must be sufficient in scope to ensure that limits throughout the interconnected network are addressed. In some cases, the parallel path flows may result in transmission limitations in systems other than the transacting systems, which can limit the transfer capability between the two contracting areas.

Non-Simultaneous and Simultaneous Transfers

Transfer capability can be determined by simulating transfers from one area to another independently and non-concurrently with other area transfers. These capabilities are referred to as "non-simultaneous" transfers. Another type of transfer capability reflects simultaneous or multiple transfers concurrently. These capabilities are developed in a manner similar to that used for non-simultaneous capability, except that the interdependency of transfers among the other areas is taken into account. These interdependent capabilities are referred to as "simultaneous" transfers. No simple relationship exists between non-simultaneous and simultaneous transfer capabilities. The simultaneous transfer capability may be lower than the sum of the individual non-simultaneous transfer capabilities.

TRANSMISSION TRANSFER CAPABILITY MARGINS

Two types of transmission transfer capability margins include:

- € Transmission Reliability Margin (TRM) — to ensure the secure operation of the interconnected transmission network to accommodate uncertainties in system conditions.
- € Capacity Benefit Margin (CBM) — to ensure access to generation from interconnected systems to meet generation reliability requirements.

Individual systems, power pools, subregions, and Regions should identify their TRM and CBM procedures used to establish such transmission transfer capability margins as necessary. TRM and CBM should be developed and applied as separate and independent components of transfer capability margin. The specific methodologies for determining and identifying necessary margins may vary among Regions, subregions, power pools, individual systems, and load serving entities. However, these methodologies must be well documented and consistently applied.

TECHNICAL BASIS

Electric systems historically have recognized the need for and benefits of transfer capability margins in the planning and operation of the interconnected transmission networks. In addition to meeting obligations for service to native load customers and deliveries for third-party transmission users, some reserve transmission transfer capability is required to ensure that the interconnected network is secure under a wide range of uncertain operational parameters. Also, systems have relied upon transmission import capability, through interconnections with neighboring systems, to reduce their installed generating capacity necessary to meet generation reliability requirements and provide reliable service to native load. With the introduction of mandatory, non-discriminatory access, and the resulting need to identify and provide current and projected ATCs to the competitive electric power market, a need now exists to formally address these two types of transmission transfer capability margins.

This report provides a framework to support the development of transfer capability margin procedures. TRM and CBM are concepts that may need to be further developed for general applicability while allowing for tailoring to specific Regional, subregional, power pool, and individual system conditions. As these margin concepts are developed and applied, NERC will review their implementation and consider the need for further guidance.

DEFINITION OF TRANSMISSION RELIABILITY MARGIN

Transmission Reliability Margin (TRM) is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

TRM provides a reserve of transfer capability that ensures the reliability of the interconnected transmission network. All transmission system users benefit from the assurance that transmission services will be reliable under a broad range of potential system conditions. TRM accounts for the inherent uncertainty in system conditions and their associated effects on TTC and ATC calculations, and the need for operating flexibility to ensure reliable system operation as system conditions change.

Uncertainty in TTC and ATC Calculations

TTC and ATC determinations depend upon a myriad of assumptions and projections of system conditions, which may include such items as transmission system topology, projected customer demand and its distribution, generation dispatch, location of future generators, future weather conditions, available transmission facilities, and existing and future electric power transactions. Such parameters are assembled to produce a scenario to be used to project transfer capabilities under a reasonable range of transmission contingencies as specified in Regional, subregional, power pool, and individual system reliability operating and planning policies, criteria, or guides. Therefore, calculations of future TTCs and ATCs must consider the inherent uncertainties in projecting such system parameters over longer time periods. Generally, the uncertainties of TTC and ATC projections increase for longer term projections due to greater difficulty in being able to predict the various system assumptions and parameters over longer time periods. For instance, locations of future customer demands and generation sources are often quite uncertain, and these parameters have a potentially large impact on transfer capabilities. Similarly, future electric power transactions are inherently uncertain and can have significant impacts on transmission loadings. Therefore, the amount of TRM required is time dependent generally with a larger amount necessary for longer time projections than for near-term conditions. TRM must also have wide-area coordination.

Need for Operating Flexibility

TTC and ATC calculations must recognize that actual system conditions may change considerably in short periods of time due to changing operating conditions, and cannot be definitively projected without the provision of a transfer capability margin. These operational conditions include changes in dispatch of generating units, simultaneous transfers scheduled by other systems that impact the particular area being studied, parallel path flows, maintenance outages, and the dynamic response of the interconnected systems to contingencies (including the sudden loss of generating units).

DEFINITION OF CAPACITY BENEFIT MARGIN

Capacity Benefit Margin (CBM) is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. Reservation of CBM by a load serving entity allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements.

The CBM is a more locally applied margin than TRM, which is more of a network margin. As such, to the extent a load serving entity maintains policies and procedures to reserve transfer capability for generation reliability purposes, the CBM should be included in the reserved or committed system uses in the calculation of ATC. These CBMs should continue to be a consideration in transmission system development. It is anticipated that individual load serving entities and regional planning groups will continue to address CBMs and that the NERC and Regional reviews of generation adequacy will continue to consider this capability. It is also anticipated that load serving entities will develop additional procedures for reserving transfer capability for generation capacity purposes and include these procedures in Regional planning reviews and regulatory filings as appropriate.

ATC DEFINITION AND DETERMINATION

DEFINITION OF AVAILABLE TRANSFER CAPABILITY

Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically, ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM). ATC can be expressed as:

ATC = TTC – TRM – Existing Transmission Commitments (including CBM)

The ATC between two areas provides an indication of the amount of additional electric power that can be transferred from one area to another for a specific time frame for a specific set of conditions. ATC can be a very dynamic quantity because it is a function of variable and interdependent parameters. These parameters are highly dependent upon the conditions of the network. Consequently, ATC calculations may need to be periodically updated. Because of the influence of conditions throughout the network, the accuracy of the ATC calculation is highly dependent on the completeness and accuracy of available network data.

DETERMINATION OF AVAILABLE TRANSFER CAPABILITY

The determination of ATCs and the relationship of electric power transactions and associated power flows on the transmission network are described in Appendixes A and B. The ATC calculation methodologies described in Appendixes A and B are not intended to prescribe a specific calculation procedure nor do they describe the only methods of calculating ATCs. Each Region, subregion, power pool, and individual system will have to consider the ATC Principles in this report and determine the best procedure for calculating ATCs based upon their respective circumstances.

Appendix A describes an ATC calculation approach that may be termed a “network response” method. This method is intended to be illustrative of a procedure that is applicable in highly dense, meshed transmission networks where customer demand, generation sources, and the transmission systems are tightly interconnected.

Appendix B describes another ATC calculation approach that may be referred to as a “rated system path” method. This method is intended to be illustrative of a procedure that is applicable in so-called sparse transmission networks where the critical transmission paths between areas of the network have been identified and rated as to their achievable transfer loading capabilities for a range of system conditions.

COMMERCIAL COMPONENTS OF AVAILABLE TRANSFER CAPABILITY

To more fully define ATC, specific commercial aspects of transmission service must be considered. Because the terms “firm” and “non-firm” are used somewhat loosely within the electric industry, confusion often exists when these terms are used to characterize the basic nature of transmission services. To create reasonably consistent expectations regarding the transmission services that are being offered, the concepts of curtailability and recallability are introduced.

Curtailability
Curtailability is defined as the right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist. Curtailment procedures, terms, and conditions will be identified in the transmission service tariffs. When such constraints no longer restrict the transfer capability of the transmission network, the transmission service may be resumed. Curtailment does not apply to situations in which transmission service is discontinued for economic reasons.

Recallability
Recallability is defined as the right of a transmission provider to interrupt all or part of a transmission service for any reason, including economic, that is consistent with FERC policy and the transmission provider's transmission service tariffs or contract provisions.

Based on the recallability concept, two commercial applications of ATC are defined below and depicted graphically in Figure 2. They are as follows:

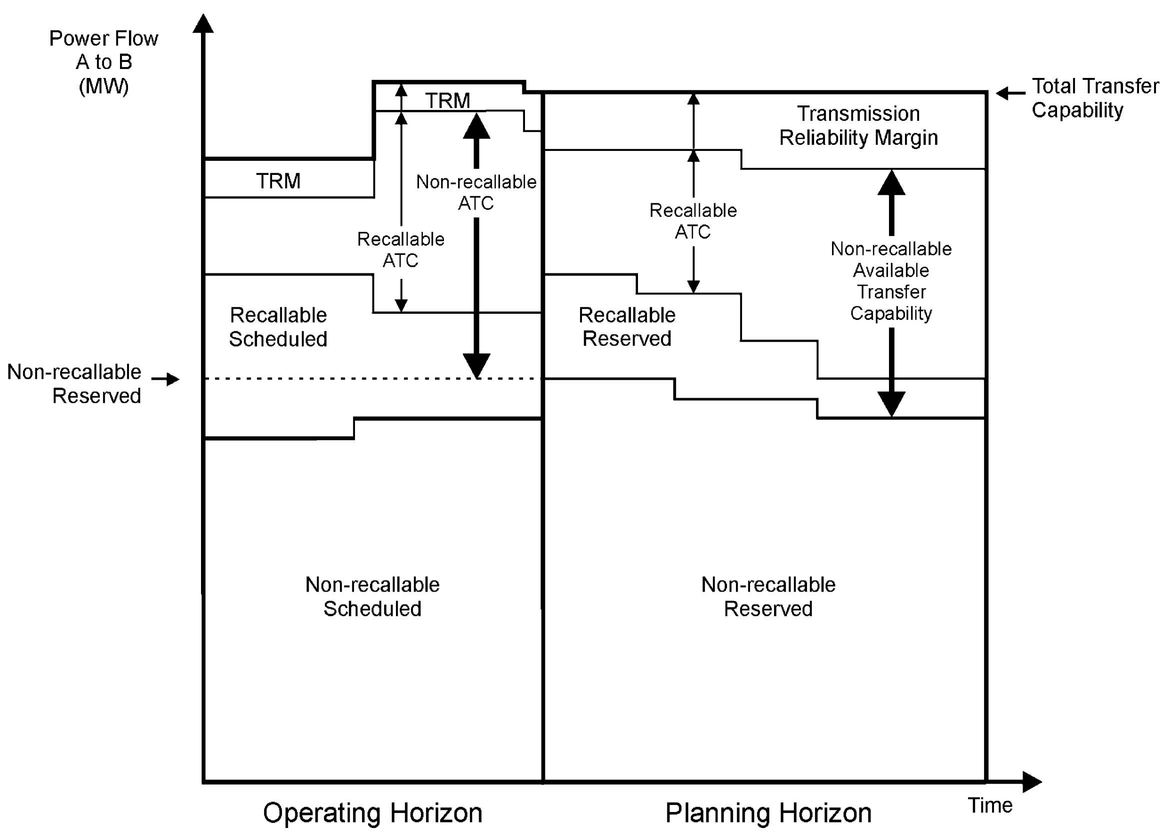


Figure 2: TTC, ATC, and Related Terms in the Transmission Service Reservation System

€ Non-recallable Available Transfer Capability — Non-recallable ATC (NATC) is defined as TTC less TRM, less non-recallable reserved transmission service (including CBM). NATC has the highest priority use of the transmission network. The maximum amount of non-recallable service that can be reserved is determined based on what the network can reliably handle under normal operating conditions and during appropriate contingencies as defined in NERC, Regional, subregional, power pool, and individual system reliability operating and planning policies, criteria, or guides. Any lower priority service can be displaced by non-recallable service that is either new non-recallable service or non-recallable service that had been reserved but not scheduled.

Mathematically, NATC can be expressed as:

NATC = TTC – TRM – Non-recallable Reserved Transmission Service (including CBM)

€ Recallable Available Transfer Capability — Recallable ATC (RATC) is defined as TTC less TRM, less recallable transmission service, less non-recallable transmission service (including CBM). Portions of the TRM may be made available by the transmission provider for recallable use, depending on the time frame under consideration for granting additional transmission service. To the extent load serving entities reserve transmission transfer capability for CBM, portions of CBM may be made available for recallable use, depending on the time frame under consideration for granting additional transmission service.

RATC has the lowest priority use on the transmission network and is recallable subject to the notice provisions of the transmission service tariffs. Recallable reserved service may be recalled in favor of subsequent requests for non-recallable transmission service. However, recallable reserved service has precedence over subsequent requests for recallable transmission service, unless the tariff or contract provisions specify otherwise. Because RATC is recallable on short notice, it can use the transfer capability reserved for higher priority service that has been reserved but not scheduled.

RATC must be considered differently in the planning and operating horizons. In the planning horizon, the only data available are recallable and non-recallable transmission service reservations, whereas in the operating horizon transmission schedules are known.

Mathematically, RATC can be expressed as:

a) Planning Horizon

RATC = TTC
– a(TRM)
– Recallable Reserved Transmission Service
– Non-recallable Reserved Transmission Service (including CBM)

where $0 \leq a \leq 1$, value determined by individual transmission providers based on network reliability concerns.

b) Operating Horizon

RATC = TTC
– b(TRM)
– Recallable Scheduled Transmission Service
– Non-recallable Scheduled Transmission Service (including CBM)

where $0 \leq b \leq 1$, value determined by individual transmission providers based on network reliability concerns.

NATC and RATC are depicted graphically in Figure 2. TTC, ATC, and related terms in the transmission service reservation system are also shown in Figure 2. In general, the transition between the planning and operating horizons will be a function of available information about the system, the status of reserved and scheduled transmission services, and time considerations.

RECALLABLE AND NON-RECALLABLE RELATIONSHIPS AND PRIORITIES

The relationships and priorities of recallable and non-recallable concepts as they apply to both scheduled and reserved transmission services are described below. In addition, the interaction between recallable and non-recallable transmission services and the effects on ATC values are discussed and illustrated.

Scheduled and Reserved Transmission Service

Reserved transmission service constitutes a reserved portion of the transmission network transfer capability, but the actual electric power transfer is not yet scheduled between areas. Scheduled transmission service indicates that an electric power transfer will be occurring on the transmission network for the time period for which the transmission service was reserved. Both terms can apply to either recallable or non-recallable transmission service, giving the following four transmission service terms:

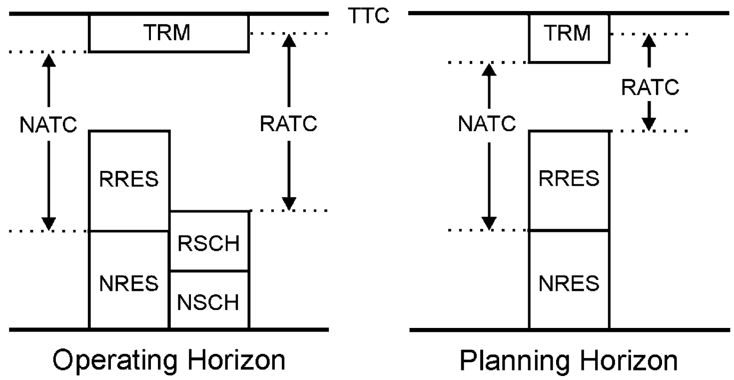
– Non-recallable Reserved (NRES)

– Non-recallable Scheduled (NSCH)

– Recallable Reserved (RRES)

– Recallable Scheduled (RSCH)

The aggregate of the NSCH and RSCH must never exceed the TTC in the operational horizon. However, in the planning horizon, individual transmission providers may allow the aggregate of the NRES and RRES to exceed the TTC less TRM, to more fully utilize transmission assets, provided that NRES by itself never exceeds TTC less TRM. Such over-subscription of recallable reservations must be disclosed to the purchasers of RRES. These ATC relationships are shown in Figure 3.



NATC = TTC – TRM – NRES	Planning & Operating Horizon
RATC = TTC – a(TRM) – RRES – NRES	Planning Horizon
RATC = TTC – b(TRM) – RSCH – NSCH	Operating Horizon

where a and b are between 0 and 1

Constraints

$$NSCH \leq NRES \leq TTC - TRM$$
$$NSCH + RSCH \leq TTC$$

Transfer Capabilities	Transmission Services
TTC — Total Transfer Capability	NRES — Non-recallable Reserved
ATC — Available Transfer Capability	NSCH — Non-recallable Scheduled
RATC — Recallable ATC	RRES — Recallable Reserved
NATC — Non-recallable ATC	RSCH — Recallable Scheduled

Figure 3: ATC Relationships

Transmission Service Priorities

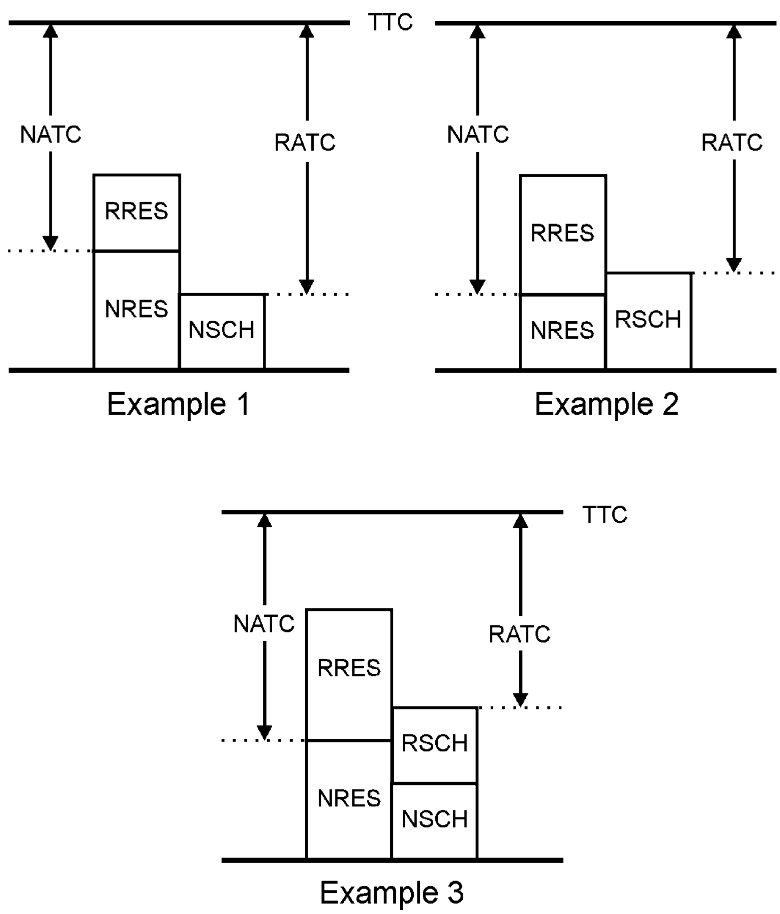
Non-recallable and recallable transmission service must adhere to a standard set of priorities universally applied throughout the electric power market to avoid confusion. These priorities are described below.

– Non-recallable service has priority over recallable service. Recallable transfers, reserved or scheduled, may be recalled for non-recallable requests. Recallability will generally be applied as needed only in areas of network constraint and not unilaterally over the entire network.

– All requests for transmission service will be evaluated in priority as established by applicable transmission service tariffs.

– Reserved transfer capability may be used by recallable scheduled transfers, provided that those scheduled transfers can be recalled if the reserved transfer requester wants to make use of the reserved transfer capability.

Several of the possible relationships of NATCs and RATCs to the different types of transfers that have been scheduled or reserved during a given time period are shown in Figure 4 and described below. These concepts apply to any time during the forecast period. Therefore, no time aspect is identified.



Transfer Capabilities	Transmission Services
TTC — Total Transfer Capability	NRES — Non-recallable Reserved
ATC — Available Transfer Capability	NSCH — Non-recallable Scheduled
RATC — Recallable ATC	RRES — Recallable Reserved
NATC — Non-recallable ATC	RSCH — Recallable Scheduled

Figure 4: ATC Relationships and Priorities

- Non-recallable scheduled (NSCH) transfers are of the highest priority (all Examples). NSCH transfers cannot be curtailed by the transmission provider except in cases where system reliability is threatened or an emergency exists. All NSCH transfers reduce the amount of ATC.

- Recallable ATC (RATC) can include transfer capability that is currently held by non-recallable reserved (NRES) transfers. However, the new transfers scheduled from the RATC may have to be interrupted if the NRES transfer requester wants to make use of the transmission network (Example 1).

- Non-recallable ATC (NATC) cannot include transfer capability that is currently held by non-recallable reserved (NRES) transfers because the reserved transfer would have priority over any new non-recallable transfer (Examples 1 and 3).

- Non-recallable ATC (NATC) can include transfer capability that is currently used by recallable scheduled (RSCH) transfers because a non-recallable transfer has priority over recallable transfers (Example 3).

- Recallable ATC (RATC) cannot include transfer capability that is currently used by recallable scheduled (RSCH) transfers because the scheduled transfer would have priority over any new transfers (Examples 2 and 3).

- Both non-recallable ATC (NATC) and recallable ATC (RATC) can include recallable reserved (RRES) transfers (all Examples). However, any new recallable transfers may have to be interrupted if the RRES requester wants to make use of the transmission network (Examples 2 and 3).

The Examples in Figures 3 and 4 illustrate how ATC may be applied in the conduct of commercial business. These definitions have no impact on the physical determination of how much additional transfers the network can support.

Appendix C further demonstrates the interaction between recallable and non-recallable transmission service and the effects on ATC values.

APPENDIX A. NETWORK RESPONSE METHOD FOR ATC DETERMINATION

The example in this Appendix describes an ATC calculation approach that may be termed a "network response" method. It demonstrates the ATC Principles described in this report and the physical impacts of electric power transfers on an interconnected transmission network. The method is intended to be illustrative of a procedure that is applicable in highly dense, meshed transmission networks where customer demand, generation sources, and the transmission systems are tightly interconnected. In such networks, transmission paths critical to a particular electric power transfer cannot generally be identified in advance. The critical path will be very much a function of the conditions that exist at the time the transfer is scheduled. The example does not introduce any concepts not covered in the front or main portion of this report.

PHYSICAL SYSTEM IMPACTS OF TRANSFERS

Determination of ATC requires some translation from the area to area transactions to the resultant electric power flows on the transmission network. This translation is done by stressing the system with appropriate transfers under critical contingencies to determine the characteristic response of the network. These network response characteristics, which are based on the line outage, power transfer, and outage transfer distribution factors of NERC's May 1995 NERC *Transmission Transfer Capability* reference document, can be determined by transfer capability studies either beforehand, or on a transaction-by-transaction basis.

When electric power is transferred between two areas such as Area A to Area F in Figure A1, the entire network responds to the transaction. The power flow on each transmission path will change in proportion to the response of the path to the transfer. Similarly, the power flow on each path will change depending on network topology, generation dispatches, customer demand levels, other transactions through the area, and other transactions that the path responds to which may be scheduled between other areas.

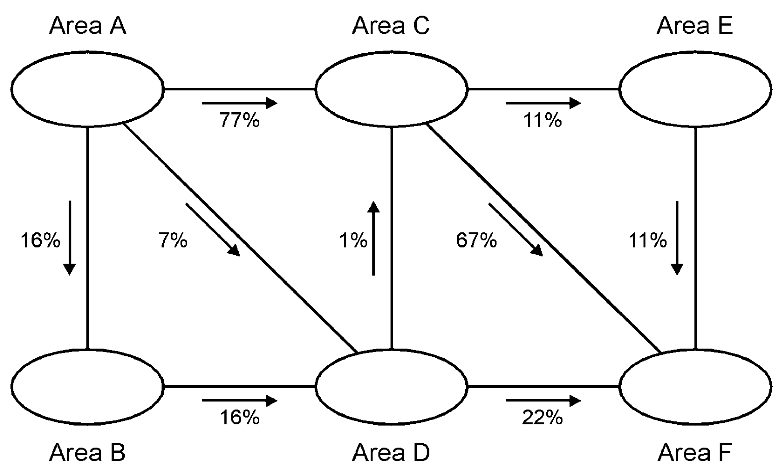


Figure A1: Network Response Characteristics for Area A to Area F Transfers

To illustrate this, computer simulation studies are performed to determine the transfer capability from Area A to Area F. During that process, it is determined that 77% of electric power transfers from Area A to Area F will flow on the transmission path between Area A and Area C (Figure A1).

Through application of those response characteristics, the impact on the path between Area A and Area C for a 500 MW transfer from Area A to Area F is graphically described in Figure A2. In this example, a pre-existing 160 MW power flow exists from Area A to Area C due to a generation dispatch and the location of customer demand centers on the modeled network. When a 500 MW transfer is scheduled from Area A to Area F, an additional 385 MW (77% of 500 MW) flows on the transmission path from Area A to Area C, resulting in a 545 MW power flow from Area A to Area C.

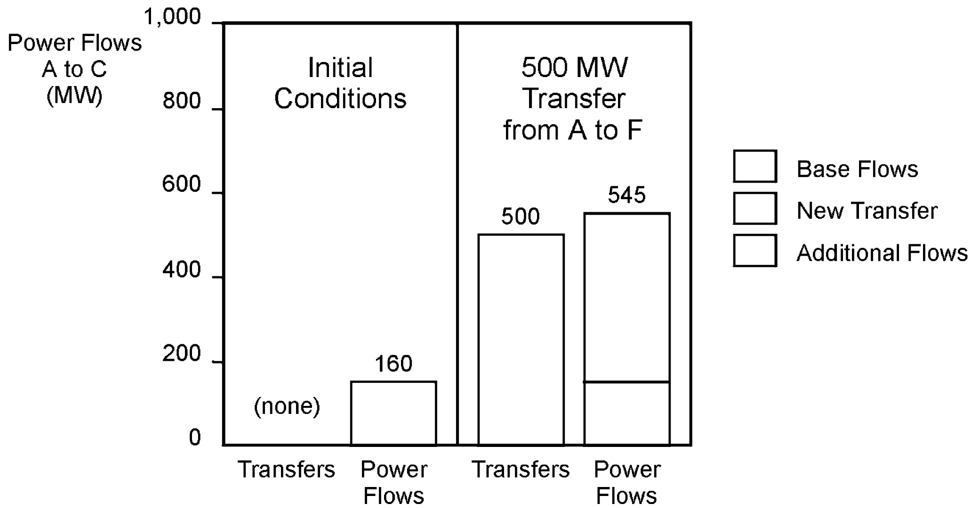


Figure A2: Existing vs. Resultant Power Flows on Path A to C for a 500 MW Transfer from Area A to Area F

To determine the ability of the network to transfer electric power from Area A to Area F, additional potential impacts within the individual areas must also be recognized. The network responses shown in Figure A1 must be expanded to consider possible transmission limits within each area.

The response characteristics of limiting facilities within the individual areas for an Area A to Area F transfer are shown in Figure A3. For simplicity, the flows within each area are not shown. Rather, the figures within each area represent the percentage of the transfer from Area A to Area F that flows on the most limiting facility within each area. Recognition of the limiting path responses within the individual areas for Area A to Area F transfers increases the complexity of determining the Area A to Area F ATC.

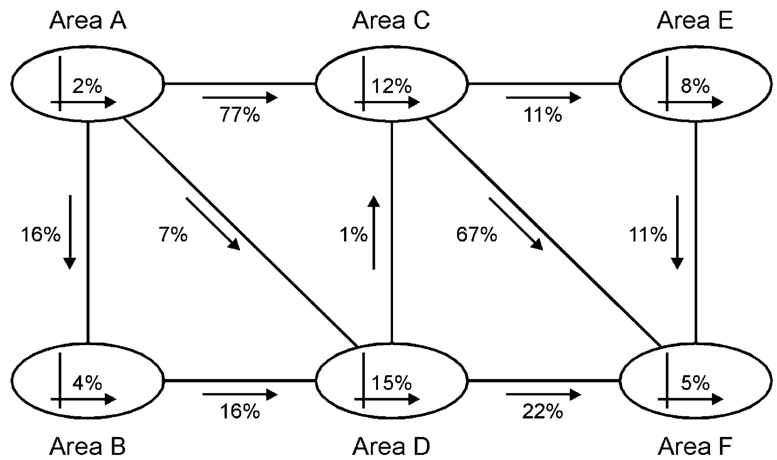


Figure A3: Internal and Interconnection Responses to Area A to Area F Transfers

TRANSLATION OF SYSTEM IMPACTS TO ATC

The ATC of the network depends on the existing loading conditions on the limiting transmission facility, wherever it may be, taking into account contingency criteria (i.e., outage of the most critical line or generator or multiple lines and generators, as appropriate).

ATC is a function of how much unused or unloaded capacity is available on the most limiting transmission facility, allowing for single and, in some cases, multiple contingencies. The translation of the unused capability of the transmission network to ATC determination for a particular direction is illustrated in Table 1, which refers to the transmission network shown in Figure A3 for an Area A to Area F transfer. The unused capacity of individual facilities in the transmission network, which is the difference between a facility's rating and its current power flow loading or its "available loading capacity," is divided by the response characteristic of the path facility to an Area A to Area F transfer. This procedure provides the individual critical path ATCs (in a system or between systems) from which the ATC from Area A to Area F is then determined by considering the most limiting path ATC. In this case, the limiting path is in Area D and the Area A to Area F ATC is 1,200 MW.

For a different electric power transfer, a new set of network responses and a new set of available capacity on limiting facilities would need to be determined to define the ATC for that transfer.

Electric power transfers have historically been scheduled between control areas on a contract path or area interchange basis. However, in the determination of ATCs, the actual flows on the network must be considered regardless of the scheduling methodology. In the preceding example, an electric power transfer may be scheduled from Area A to Area F, using a contract path from Area A to Area C to Area F. However, the reality of alternating current electrical systems is that the electric power would flow from Area A to Area F over the entire network, governed by the laws of physics. The electric power flowing on portions of the network other than the scheduled contract path is known as parallel path

System or Path	Network Response (%)	Available Loading Capacity (ALC) on Limiting Facility (MW)	System or Path ATC (MW)	Area A to Area F ATC (MW)
Area A	2	35	1,750	
Area B	4	92	2,300	
Area C	12	454	3,780	
Area D	15	180	1,200	1,200
Area E	8	200	2,500	
Area F	5	250	5,000	
A – C	77	1,000	1,300	
A – D	7	157	2,240	
A – B	16	440	2,750	
B – D	16	512	3,200	
C – E	11	198	1,800	
C – D	1	18	1,800	
C – F	67	1,072	1,600	
D – F	22	385	1,750	
E – F	11	214	1,945	

Table 1: Available Transfer Capability Matrix for Transfers from Area A to Area F

flows, and can affect many systems in an interconnected network. In this particular example, the transmission limit in Area D limits the Area A to Area F transfers to 1,200 MW.

ATC TIME VARIATION AND NETWORK DEPENDENCY

Network conditions will vary over time, changing line loading conditions, and causing the ATC of the network to change. Also, the most limiting facility in determining the network's ATC can change from one time period to another, particularly in highly meshed networks. Therefore, the ATC of the network is time dependent.

This characteristic is illustrated conceptually in Figure A4. The first group of graphs on the left-hand side of the figure presents the available loading capacity at different points in time (T_1, T_2, T_3) for several lines in an interconnected network. If an Area A to Area B transfer is to be scheduled at T_1, each of the lines (line 1 in Area A, line 3 in Area B, line 7 in Area B, and line 16 in Area D) will respond to the transfer in accordance with its network response factor. This factor is used to determine an ATC as limited by each individual facility. The results are shown on the middle set of diagrams of Figure A4. The ATC for the network as a whole represents the minimum of the ATCs as defined by each facility at each time frame. These minimum ATCs are schematically illustrated in the right side of Figure A4. As demonstrated, the ATC is different for each time period and is determined by a different facility in each period.

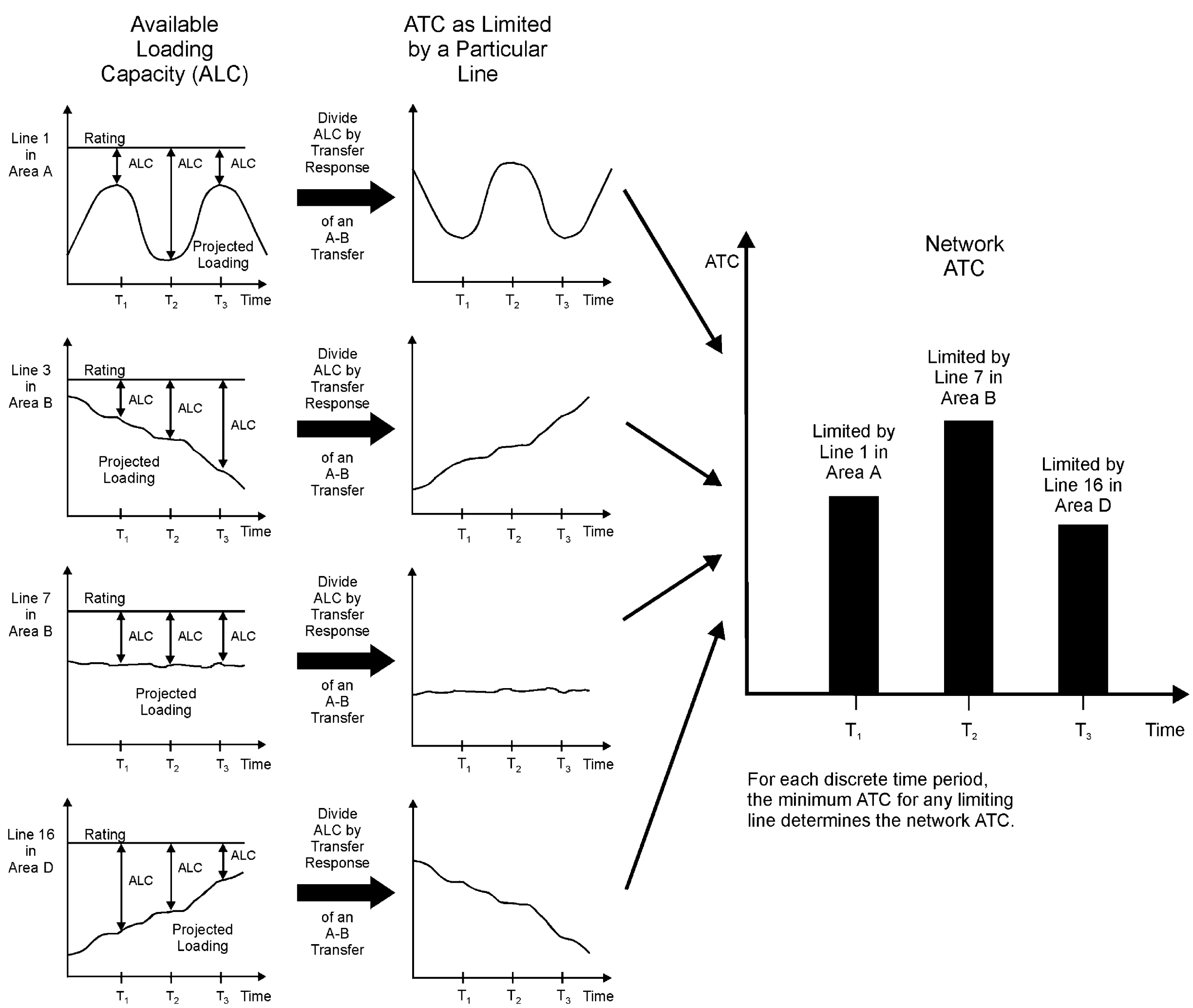


Figure A4: ATC Variance

The determination of ATC and the difference between simultaneous and non-simultaneous transfers are demonstrated in Tables 2 and 3. These ATC demonstrations are based on the sample six system network shown in Figure A3.

Area	Facility	Network Response (%)	ALC* on Limiting Facility (MW)	Area to Area ATC (MW)
Area A to Area F Transfer				
D	D1	15	180	1,200
Area B to Area E Transfer				
B	B1	5	25	500
Area E to Area A Transfer				
A	A2	7	103	1,470

*Available Loading Capacity

Table 2: Non-Simultaneous ATC Analyses

Table 2 presents the non-simultaneous ATC analyses for three representative transfer conditions: Area A to Area F, Area B to Area E, and Area E to Area A. For each transfer direction, the area to area ATC is determined by the most critical system contingency and the resultant limiting system element, varying from 500 MW for an Area B to Area E transfer (limited by line B1 in Area B) to 1,470 MW for an Area E to Area A transfer (limited by line A2 in Area A).

Area	Facility	Network Response (%)	ALC* on Limiting Facility (MW)	Area to Area ATC (MW)
Area A to Area F ATC Analysis With a Pre-existing Area B to Area E 500 MW Transfer				
B	B1	3.5	0	0
Area A to Area F ATC Analysis With a Pre-existing Area B to Area E 500 MW Transfer and a Pre-existing Area E to Area A 1,470 MW Transfer				
B	B1	3.5	40	1,140

*Available Loading Capacity

Table 3: Simultaneous ATC Analyses

The first section of Table 3 shows a determination of ATC for an Area A to Area F transfer, assuming that an Area B to Area E 500 MW transfer schedule is already in effect. Under this condition, the Area A to Area F ATC is now reduced from 1,200 MW (Table 2) to zero. This change is due to the increased loading on line B1 due to the previously scheduled 500 MW transfer from Area B to Area E, making it the limiting network facility. Note that the Area A to Area F transfer limiting facility was line D1 in Area D in the non-simultaneous analysis (Table 2).

The second portion of Table 3 is another determination of ATC for an Area A to Area F transfer. In this example, pre-existing transfers are in place from Area B to Area E of 500 MW and Area E to Area A of 1,470 MW. Under these conditions, the ATC for an Area A to Area F transfer is found to be 1,140 MW. This transfer is a slight reduction from the 1,200 MW ATC determination in the non-simultaneous case (Table 2), but is a significant increase from the zero ATC found in the previous case (first part of Table 3). This increased transfer is due to the offsetting effect of the flows caused by the pre-existing Area E to Area A transfer, which reduced the line loading on the critical facility B1, thus increasing the ATC for the Area A to Area F transfer direction.

These examples demonstrate that the determination of ATC in a tightly interconnected network is very much a function of system conditions that exist on the network at the time the transfer is to be scheduled. In addition, ATC is a function of the specifics of the electric power transfer being considered in terms of its direction, amount, and duration. To be able to properly appraise the performance of tightly interconnected networks to support contemplated transfers (i.e., what is the ATC), a regional or wide-area approach must be considered so that all network conditions are properly taken into account.

APPENDIX B. RATED SYSTEM PATH METHOD FOR ATC DETERMINATION

OVERVIEW

The rated system path (RSP) method for ATC determination is typically used for transmission systems that are characterized by sparse networks with customer demand and generation centers distant from one another. Generally in this approach, paths between areas of the network are identified and appropriate system constraints determined. ATC is computed for these identified paths and interconnections between transmission providers.

The RSP method involves three steps: 1) determining the path's Total Transfer Capability (TTC), 2) allocating the TTC among owners in a multi-owned path to determine the owners' rights, and 3) calculating ATC for each right-holder by subtracting each of their uses from each of their individual TTC rights. Wide-area coordination is achieved by developing the TTC in a manner that follows a regional review process. This process assures individual, power pool, subregional, and Regional coordination and the necessary consideration of the interconnection network's constraints and conditions.

The RSP method includes a procedure for allocating TTC, and in turn ATC, among the owners of the transmission path(s). It should be noted that the RSP method of allocation is not the only procedure that may be followed in allocating transmission services.

UNSCHEDULED FLOW OR PARALLEL PATH FLOW

The RSP approach accounts for the effects of unscheduled flow (parallel path flow) on interconnected systems through the modeling of realistic customer demand and generation patterns in advance of real-time operations, and uses a maximum power flow test to ensure that the transfer path is capable of carrying power flows up to its rated transfer capability or TTC.

The rating process begins by modeling the interconnected network with the actual flow that will occur on the path and its parallel paths under realistically stressed conditions. The lines comprising the path may be rated and operated as a single path. The network is tested under a wide range of generation, customer demand, and facility outage conditions to determine a reliability-based TTC. When determined this way, the TTC rating usually remains fairly constant except for system configuration changes such as a line outage situation. To implement the RSP ATC method, consistent path rating methods and procedures must be agreed upon and followed within the Interconnection.

Non-simultaneous ratings are normally used as the basis for calculating ATC. If, however, two rated paths have a simultaneous effect on each other, the rating process identifies the simultaneous capabilities or establishes nomograms that govern the simultaneous operation of the paths. Applicable operating procedures are negotiated to ensure reliable network operation. Where simultaneous operation is necessary, operator control is used to ensure safe and reliable operation of the transmission network.

CAPACITY ALLOCATION

The reliability-based TTC of a transfer path (its reliability rating) is allocated among the right-holders based upon their negotiated agreement. This determination of the property rights through the allocation process is critical to the RSP implementation of ATC. The rights in the path are negotiated for each of the individual transmission providers. Except for deratings based upon system operating (e.g., emergency) conditions, these allocations become rights that the right-holder may use or resell to others as non-recallable or recallable service.

Although the actual flows from each right-holder's schedule will flow on all parallel lines, the advance allocation of rights on a path makes it possible for right-holders to determine ATC and sell service within their rights independent of others. If the rating is determined using appropriate path rating procedures, including a maximum power flow test, the potential for adverse unscheduled power flow effects is minimized.

In real time, neither the total of the schedules, nor the actual power flow on a path may exceed the path TTC. Although the potential for adverse unscheduled power flow is minimized as a result of the modeling and rating process, some acceptable or mitigatable unscheduled flows will usually occur during real-time operation. Regions that use RSP to calculate ATC should adopt an unscheduled flow mitigation plan which addresses such flows, if they adversely affect system operation. The adverse flows can be managed through schedule changes, installing controllable devices such as phase shifters, or including this uncertainty as part of the reliability margin.

ATC CALCULATION APPROACH

1. Each path for which ATC must be calculated is identified, and then a reliability-based TTC is determined as described above. This TTC is then allocated among the owners by negotiated agreement.

2. Deratings for outages, nomograms, maintenance, or unscheduled flow are allocated, if necessary, to the right-holders based on prearranged agreements or tariffs.

3. Right-holders take their respective allocated shares of the TTC for a path and subtract the existing commitments to determine the appropriate ATC.

4. Right-holders update and repost their ATC calculations as new commitments impact their ATC. A transfer from one area to another involving several transmission owners requires locating and reserving capacity across multiple paths and potentially multiple right-holders.

EXAMPLE OF ATC DETERMINATION

The following example illustrates the application of the RSP method for determining ATC in a sparse network. The example transmission network is shown in Figure B1. All paths that connect the various areas have transfer capabilities that were individually developed in coordination with all areas giving consideration to unscheduled flow and interconnection interactions and effects. The TTCs portrayed in

Figure B2 are shown for each path and are directional, but are not necessarily the same for each direction.

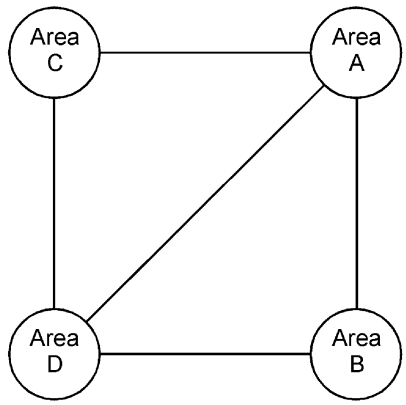


Figure B1: Sparse Network Model

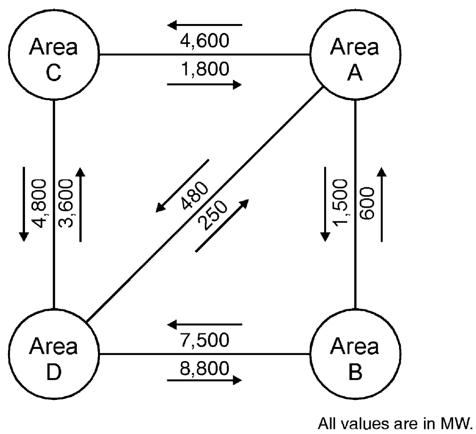


Figure B2: Total Transfer Capabilities

Each path may consist of several transmission lines that can also have different owners. In this example, the path between Areas B and D is comprised of five lines as shown in Figure B3. The TTC from Area B to Area D is 7,500 MW and, in the reverse direction, 8,800 MW. Line 1 is owned by a single entity and has an allocated portion of the TTC equal to 1,300 MW in either direction.

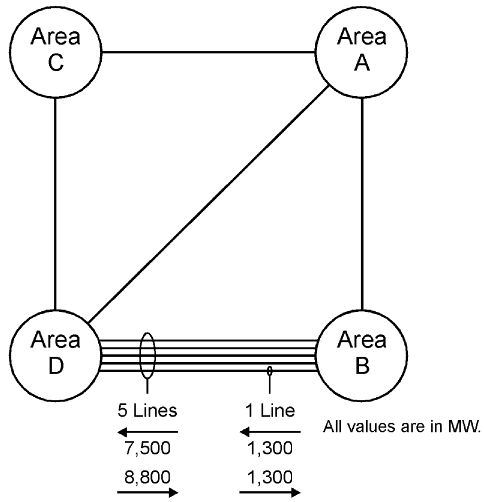


Figure B3: TTCs of Path B to D and Allocation of TTCs to Line 1

This example reflects a snapshot in time during the planning horizon. Initial transmission service reservations, all assumed to be non-recallable, are shown for each path in Figure B4. The corresponding ATC for each path has been calculated by subtracting the non-recallable service from the TTC. Because all the transmission service reservations are assumed on each path to be in one direction, the path ATC is only calculated for that direction.

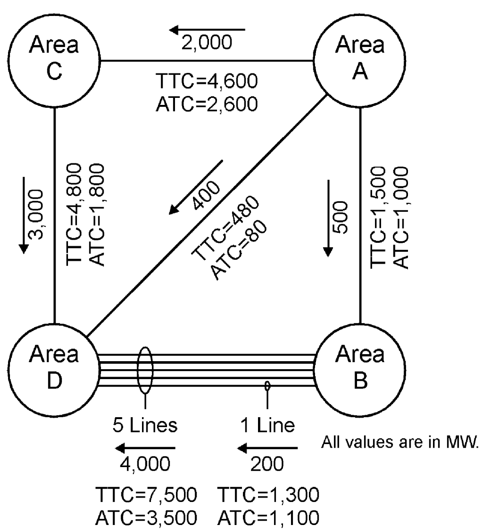


Figure B4: Initial Transmission Service Reservations

For example, referring to Figure B4, the ATC from Area B to Area D is calculated as 7,500 MW less 4,000 MW or 3,500 MW. For line 1 of the B to D path, the ATC is 1,300 MW less 200 MW or 1,100 MW. In the next case, as shown in Figure B5, 1,000 MW of non-recallable transmission service is acquired from Area A to Area B to Area D. No other changes occur. The total transmission service reserved from Area A to Area B is 1,500 MW, and the resulting ATC goes to zero. The ATC from Area B to Area D reduces to 2,500 MW (7,500 MW TTC less 5,000 MW reserved transmission service). It is assumed the 1,000 MW of the new reserved transmission service was obtained from the owner of line 1, resulting in the total reserved transmission service on this line being 1,200 MW. The new ATC for line 1 is 100 MW (1,300 MW TTC less 1,200 MW reserved transmission service).

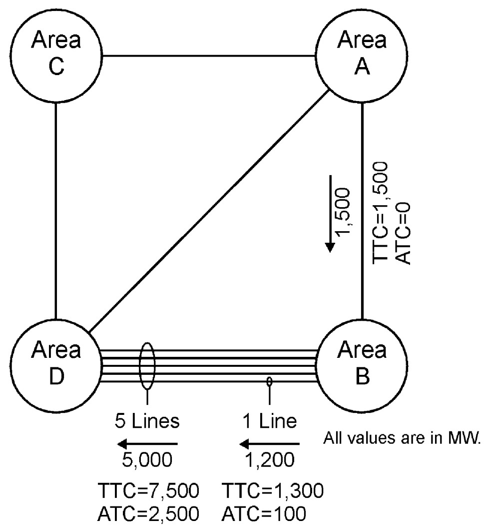


Figure B5: New Transmission Service Reservation on Path A to B to D

The non-recallable transmission service reserved for a path in each direction may not exceed the path's transfer capability in either direction under any circumstances. These limits are consistent with NERC Operating Policies.

Unscheduled flow may at times preclude scheduling to a path's full transfer capability or TTC. If an internal limit is encountered in any system as a result of the transaction from Area A to Area D, for example in Area D, Area D's system operator must respond to relieve the limitation such as by redispatching generation or using phase shifter control. An unscheduled flow mitigation plan might also be implemented to relieve excessive unscheduled flow problems. Additional relief may be achieved by curtailing schedules that are contributing to the unscheduled flow on the path or by increasing schedules that would create unscheduled flow in the opposite direction. In this example, if path A to D were limiting, unscheduled flow mitigation procedures could be implemented to initiate coordinated operation of controllable devices such as phase-shifting transformers to relieve the limitation.

There will probably be times in the operating horizon when the use of the transmission network results in actual flows on a transmission path being less than the transmission scheduled on the path. During these periods, if the transmission path is fully scheduled, additional electric power may be scheduled to Area D from Area A by reserving transmission service over a different transmission path. In this case, transmission service could be obtained from either the owners of the direct path between Area A and Area D or the owners of the transmission system from Area A to Area C to Area D.

For the RSP method, the transmission rights to be reserved and scheduled by all transmission users are consistent with the rating of the transmission paths. If determined through a coordinated process using models that capture the major effects of the interconnected network, these ratings will create limits that result in the reliable operation of the regional electric system. The owners of the transmission paths, through a negotiated allocation process, will know their transmission service rights and the resulting use of these rights will be consistent with the physical capability and limitations of the transmission network. This RSP method assures efficient use and reliable operation of the interconnected transmission network.

OVERVIEW

The following scenarios demonstrate how the 1,200 MW ATC quantity from Area A to Area F in the example in Appendix A may be commercially employed. The interplay between recallable and non-recallable transmission service and the resulting effects upon calculated ATCs are demonstrated using the equations presented in the "ATC Definition and Determination" section of this report. They clearly demonstrate that, although both recallable and non-recallable ATC are offered simultaneously, the combined total of recallable and non-recallable service does not exceed the TTC at any time.

For the purpose of this illustration, assume that conditions on the interconnected network are as described in Tables 1 and 2 of Appendix A. Under this scenario, the network ATC from Area A to Area F for this time period in the operating horizon is 1,200 MW. Also, for simplicity, assume that previous transmission commitments are zero. Thus, TTC in the following cases is 1,200 MW. Lastly, assume that TRM is zero. The resulting relevant simplified ATC equations for the operating horizon are:

$$\text{NATC} = \text{TTC} - \text{NRES}$$

$$\text{RATC} = \text{TTC} - \text{RSCH} - \text{NSCH}$$

The equations that describe the TTC constraints during this time frame are:

$$\text{NRES} \leq \text{TTC}$$

$$\text{RSCH} + \text{NSCH} \leq \text{TTC}$$

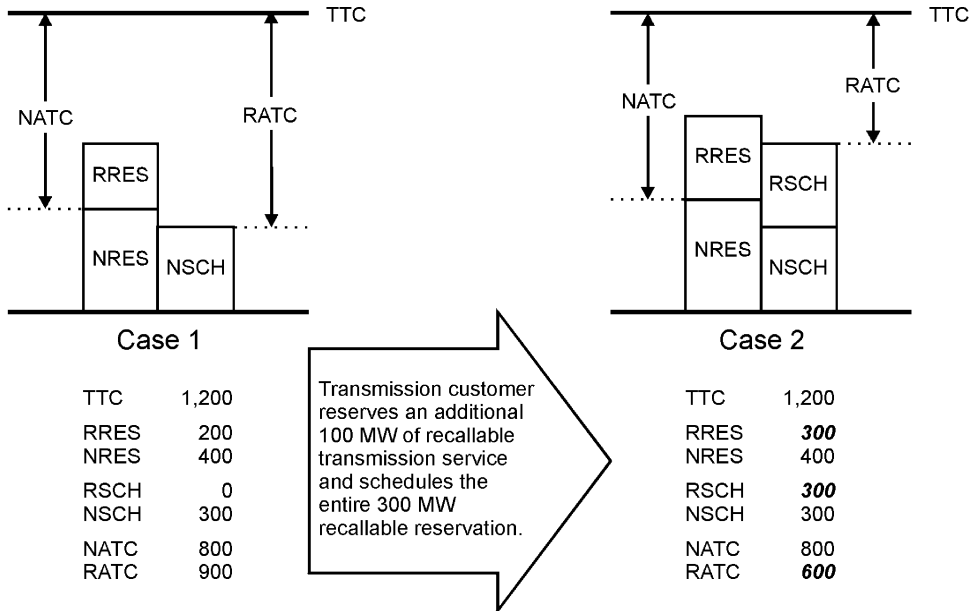
ATC DEMONSTRATION — SCENARIO 1

Consider the initial case identified in Figure C1 as Case 1. Reservations for 200 MW of recallable and 400 MW of non-recallable transmission service have been reserved against the 1,200 MW TTC.

Case 1 includes schedules for only 300 MW of non-recallable transmission service. Thus:

$$\begin{aligned} \text{NATC} &= \text{TTC} - \text{NRES} \\ &= 1{,}200 - 400 \\ &= 800 \text{ MW} \end{aligned}$$

$$\begin{aligned} \text{RATC} &= \text{TTC} - \text{RSCH} - \text{NSCH} \\ &= 1{,}200 - 0 - 300 \\ &= 900 \text{ MW} \end{aligned}$$

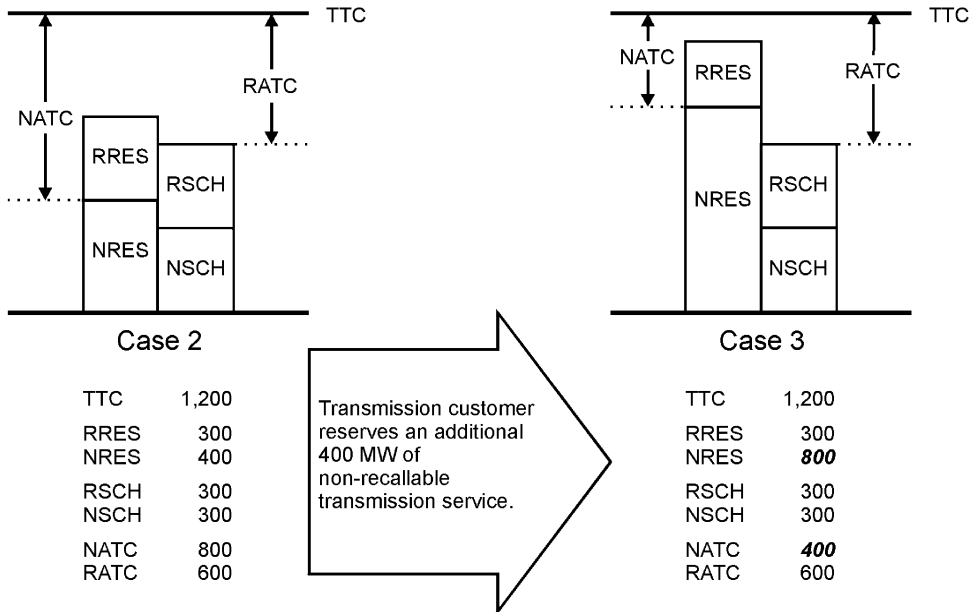


Transfer Capabilities	Transmission Services
TTC — Total Transfer Capability	NRES — Non-recallable Reserved
ATC — Available Transfer Capability	NSCH — Non-recallable Scheduled
RATC — Recallable ATC	RRES — Recallable Reserved
NATC — Non-recallable ATC	RSCH — Recallable Scheduled

Figure C1: ATC Demonstration — Scenario 1

In Scenario 1, the transmission customer reserves an additional 100 MW of recallable transmission service and schedules the entire 300 MW recallable reservation. The results are shown in Figure C1 as Case 2. (Note that changed values are shown in bold italic type.) Non-recallable ATC is unchanged, but recallable ATC is changed as follows:

$$\begin{aligned} \text{RATC} &= \text{TTC} - \text{RSCH} - \text{NSCH} \\ &= 1{,}200 - 300 - 300 \\ &= 600 \text{ MW} \end{aligned}$$



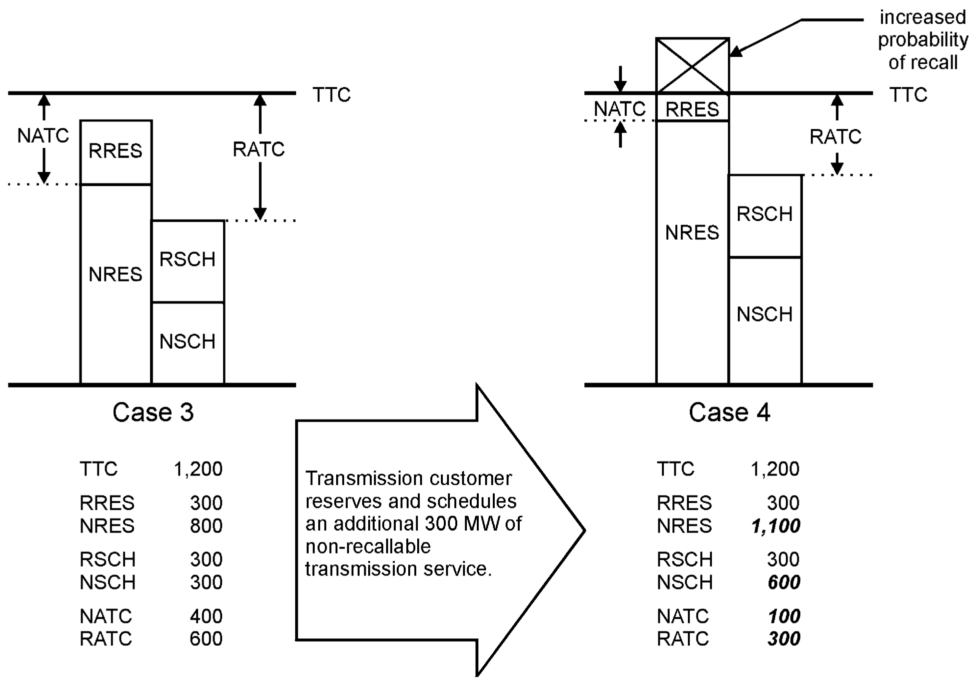
Transfer Capabilities	Transmission Services
TTC — Total Transfer Capability	NRES — Non-recallable Reserved
ATC — Available Transfer Capability	NSCH — Non-recallable Scheduled
RATC — Recallable ATC	RRES — Recallable Reserved
NATC — Non-recallable ATC	RSCH — Recallable Scheduled

Figure C2: ATC Demonstration — Scenario 2

ATC DEMONSTRATION — SCENARIO 2

In Scenario 2 of Figure C2, the transmission customer reserves an additional 400 MW of non-recallable transmission service. The results are shown in Figure C2 as Case 3. Recallable ATC is unchanged in this scenario, but non-recallable ATC is changed as follows:

$$\begin{aligned} \text{NATC} &= \text{TTC} - \text{NRES} \\ &= 1{,}200 - 800 \\ &= 400 \text{ MW} \end{aligned}$$



Transfer Capabilities	Transmission Services
TTC — Total Transfer Capability	NRES — Non-recallable Reserved
ATC — Available Transfer Capability	NSCH — Non-recallable Scheduled
RATC — Recallable ATC	RRES — Recallable Reserved
NATC — Non-recallable ATC	RSCH — Recallable Scheduled

Figure C3: ATC Demonstration — Scenario 3

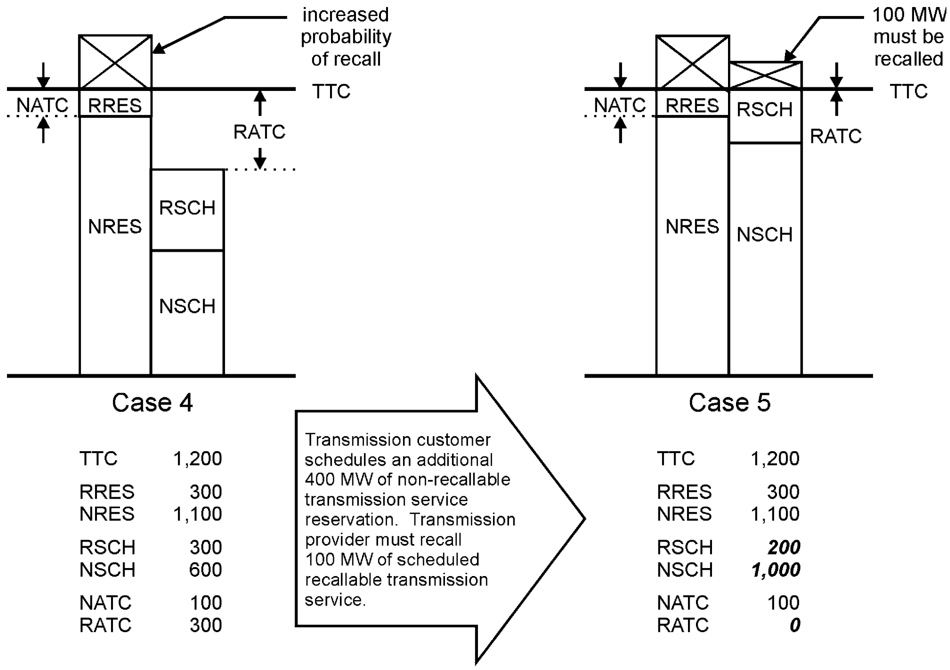
ATC DEMONSTRATION — SCENARIO 3

In Scenario 3 of Figure C3, the transmission customer reserves and schedules an additional 300 MW of non-recallable transmission service. The results are shown in Figure C3 as Case 4. In this scenario, both recallable and non-recallable ATCs are changed as follows:

NATC = TTC – NRES
= 1,200 – 1,100
= 100 MW

RATC = TTC – RSCH – NSCH
= 1,200 – 300 – 600
= 300 MW

Transmission customers holding the 200 MW of recallable transmission service reservations "above the TTC line" should be advised that they have a high probability of having their transmission service recalled.



Transfer Capabilities	Transmission Services
TTC — Total Transfer Capability	NRES — Non-recallable Reserved
ATC — Available Transfer Capability	NSCH — Non-recallable Scheduled
RATC — Recallable ATC	RRES — Recallable Reserved
NATC — Non-recallable ATC	RSCH — Recallable Scheduled

Figure C4: ATC Demonstration — Scenario 4

ATC DEMONSTRATION — SCENARIO 4

In Scenario 4 of Figure C4, the transmission customer schedules an additional 400 MW of non-recallable transmission service. The results are shown in Figure C4 as Case 5. Non-recallable ATC remains unchanged at 100 MW. Unless 100 MW of recallable transmission service schedules are recalled, the total schedules violate the TTC constraint. The transmission provider must recall 100 MW of scheduled recallable transmission service. The recallable ATC calculation is then:

$$
\begin{aligned}
\text{RATC} &= \text{TTC} - \text{RSCH} - \text{NSCH} \\
&= 1{,}200 - 200 - 1{,}000 \\
&= 0 \text{ MW}
\end{aligned}
$$

As this demonstration has shown, recallable transmission services may be reduced as non-recallable transmission services are reserved and scheduled, approaching the TTC limit.

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Appendix III

ETSO - Definitions of Transfer Capacities in Liberalised Electricity Markets

EUROPEAN TRANSMISSION SYSTEM OPERATORS

Definitions of Transfer Capacities in liberalised Electricity Markets

Final Report
April 2001

Table of contents

SUMMARY

ETSO worked out in 1999 definitions of transfer capacities that are since then used by the European TSOs for capacity calculations on a harmonised basis. Two important notions in these definitions are the **Total Transfer Capacity TTC** and the **Net Transfer Capacity NTC**.

The ETSO definitions are the basis for the half yearly calculation of indicative NTC values by the TSOs that are also published on ETSO's webside as well as for additional or more frequent calculations needed by the TSOs for the allocation of interconnection capacities.

The practical application of the definitions raised some ambiguities in interpretation. Therefore, ETSO worked on an improvement of those definitions that is summarised in the present document.

The general concept of the definitions given by the notions of TTC and NTC was confirmed and maintained. It was enlarged introducing the aspects of transfer capacity assessments for different time frames: For the planning TTC and NTC assessment are the main objectives of TSOs. Market actors need these values to anticipate and to plan their transactions.

During the allocation phases, that can cover according to the rules applicable at each cross-border or “flowgate” time frames from year ahead to day ahead or even hour ahead, a set of new notions is introduced. These are the **Already Allocated Capacity AAC** and the still **Available Transfer Capacity ATC.**

All these values are to be interpreted in terms of exchange programmes between adjacent areas.

In the highly meshed interconnected transmission networks in Europe programmed exchanges and physical flows differ often considerably. The ETSO work confirmed that the physical complexity is so big and needs always a complete view on the European load flow scenarios that it would not be useful for market actors to try to make public additionally physical values beside the above mentionned data. However, a separate set of notions of physical flows was established in which every notion relates to one of the above mentionned definitions for exchange programmes. This approach helps to easier agree between TSOs about concrete values, to check their global consistency and to ensure, in a best way, transparency towards decision-making or supervisory bodies like Regulators.

ETSO considers that the new set of definitions improves considerably the transparency in this complex technical field and that the new definitions are in line with all used capacity allocation mechanisms through out Europe. The new definitions will also allow work further on new methods like a sophisticated auctioning mechanism.

1. INTRODUCTION

ETSO presented at the fourth Electricity Regulation Forum at Florence in November 1999 definitions of transfer capacities that are used between the European TSOs for capacity calculations on a harmonised basis. They include the following notions:

- Net Transfer Capacity (NTC)
- Available Transfer Capacity (ATC)
- Transmission Reliability Margin (TRM)
- Notified Transmission Flow (NTF).

NTC and ATC are important indicators for market participants to anticipate and plan their cross-border transactions and for the TSOs to manage these international exchanges of electricity. ETSO has thus decided to publish twice a year in its Intranet system (www.etso-net.org) a table “Indicative Values for Net Transfer Capacities (NTCs) in Europe” [1].

Additionally, ETSO edited in March 2000 a paper titled “Information for users” [2]. It provides to the actors in the Internal Market of Electricity in Europe some basic explanations related to the transfer capacity definitions and answers to frequently asked questions. Other complementary documents were worked out and are at the disposal of the TSOs to calculate NTC values, such as a technically oriented NTC/ATC user’s guide and a note on TRM evaluation. All documents were presented at the different Electricity Regulation Forums at Florence.

Given the fact that the assessment of transfer capacities in highly meshed interconnected transmission networks like that in Europe is a very complex task and includes extensive load flow calculations done by the TSOs, the “Information for users” tries to make this process understandable also for non specialists.

However, as transfer capacities are one important factor that determines the possibilities of access to market regions in Europe and thus of the international trade, it remains critical that the TSOs do their calculations and assessments in the most transparent way, and that the used definitions are well understood by all actors and well applicable by all decision making bodies.

Therefore ETSO has worked since last year on improving the existing transfer capacity definitions. This document summarises the results and provides an enlarged set of definitions for transfer capacities. ETSO focussed its work on two aspects:

- The practical application of the existing definitions showed that they could lead to misunderstandings, even by specialists of TSOs. The reason was that the distinction between programmed transactions (scheduled exchanges) and physical flows was not always clear.
- The possibilities for import/export transactions in the European transmission systems between two countries depend on all realised transactions – also between others than the two considered countries – due to the so called parallel flows which are the direct consequence of physical laws of electrical flows in the interconnected networks. Thus the maximum possible use of the capacity between two given countries depends to some extent on all local as well as on all distant transactions, because they rely on the European production plans and on the consumer loads.

ETSO tried first to work out new definitions in order to make the physical parallel flow effect explicit. However, this would lead to complex notions that are not useful for the current capacity allocation mechanisms and non transparent for market actors.

Therefore ETSO maintained the general concept for the existing transfer capacity definitions and included the following improvements:

- Clear distinction between programmed values and physical flows: The new set of definitions includes only notions that are to be interpreted as energy programmes. Market actors are interested to plan the trade between regions or countries and do not like to worry about load-flow problems. It is on the other hand the task of TSOs to manage physical flows and to maintain at every moment the security in their networks. This complex task should be handled inside the TSOs and not be an obstacle for the market.
- Improvements concerning the transfer capacity assessment methods used by the TSOs: It is necessary to have a harmonised basic procedure between TSOs for calculating transfer capacities. This means that the basic scenarios have to be commonly agreed and that the calculation procedures of all TSOs are comparable. This approach helps to easier agree between TSOs about concrete values, to check their global consistency and to ensure in a best way transparency towards decision-making or supervisory bodies like Regulators.
- Definitions well suited for planning of trade as well as for capacity allocation procedures: The market needs first of all information for planning purposes. The NTC-tables published by ETSO are a first important step. On the other hand, a clear set of definitions is needed in order to calculate the transfer capacities (e.g. at weekly or daily time frames) that are the basis for the different allocation procedures already implemented or on the way to be implemented, such as auctions and market splittings.
- Applicability of the transfer capacity definitions for new allocation procedures. ETSO has worked out in November 2000 a first vision about a future large-scale capacity allocation scheme, so called “Co-ordinated auctioning of transmission capacity in meshed networks” [6]. The new definitions should fit also for a future implementation of such a mechanism.

Based on these considerations ETSO proposes to use on a European-wide level the following transfer capacity definitions and assessment guidelines. This document replaces the previous ETSO-paper on definition of transfer capacities [1].

Additionally ETSO will publish two other papers on this subject:

- A document on the procedures for transfer capacity assessments. This document will give the detailed guidelines for the TSOs on how to construct realistic base cases, and how to perform the calculations and the capacity evaluations.
- An updated version of the information for users [2].

2. TRANSFER CAPACITY DEFINITIONS

ETSO proposes to strictly distinguish between commercial and physical values. Thus, two sets of definitions exist, one related to programme values, the other to physical flows. The definitions that refer to programme values are presented in this document in detail. These values are important for market actors to prepare their commercial transactions. The physical complexity however should be dealt with by the TSOs. TSOs are responsible towards Regulators, Authorities etc. to carry out this work in a fair and non-discriminatory matter. Market actors should not be involved in this process.

Some basic explanations concerning the relations between transfer capacities in terms of exchange programmes and physical flows are given in chapter 4.2.

The fundamental notions in ETSO’s transfer capacity definitions were not changed and are:

The Total Transfer Capacity TTC, that is the maximum exchange programme between two areas compatible with operational security standards[1] applicable at each system if future network conditions, generation and load patterns were perfectly known in advance.

TTC is always related to a given power system scenario, i.e.: generation schedule, consumption pattern and available network that constitute the data allowing to build up a mathematical model of the power system (load flow equations). The solution of this model leads to the knowledge of the voltages at the network nodes and the power flows in the network elements which are the parameters being monitored by a TSO to assess system security. The solution of this model is the so-called base case and is the starting point for TTC computation. Thus evaluation of TTC between two electrical areas requires:

- To make a choice of a local power system scenario
- To define a base case[2], which involves the sharing of full information amongst TSOs to build up the global load flow model
- To apply an agreed procedure for carrying out the calculations.

As the result of this procedure, TTC equals the maximum exchange programme between the two areas being considered, if the generation and load pattern in these areas and in other areas strongly interconnected to these two would exactly correspond to the assumptions made in the evaluation steps, namely the ones implicit in the base case.

The uncertainties associated to the forecast of the power system state, for a given time period in the future, may decrease according to the selected time frame. Therefore the TTC value may vary (i.e. may increase or decrease) when approaching the time of programme execution as a result of a more accurate knowledge of generating unit schedules, load pattern, network topology and tie-lines availability.

The Transmission Reliability Margin TRM which is a security margin that copes with uncertainties on the computed TTC values arising from:

a) Unintended deviations of physical flows during operation due to the physical functioning of load-frequency regulation

b) Emergency exchanges between TSOs to cope with unexpected unbalanced situations in real time

c) Inaccuracies, e. g. in data collection and measurements

TRM is then associated to the real-time operation and its value is determined by each TSO, in order to guarantee the operation security of its own power system. TRM may vary seasonally or may be updated according to possible modifications occurred in the power system.

[1] The security standards are stated into each TSO ‘grid code’.

[2] The agreed procedures for building the base cases to be used by TSOs and to evaluate the transmission capacities are detailed in a separate ETSO document ‘Procedures for Transfer Capacity Assessments’ [3].

The Net Transfer Capacity NTC that is defined as:

NTC = TTC-TRM

NTC is the maximum exchange programme between two areas compatible with security standards applicable in both areas and taking into account the technical uncertainties on future network conditions.

TTC, TRM and NTC may vary along different time frames (year ahead to day ahead).

NTC may be allocated in different time frames to match the need for securing longer term trading and to provide room for shorter term trading. One may distinguish, as the result of the allocation procedures in each allocation time frame, two notions:

The Already Allocated Capacity AAC, that is the total amount of allocated transmission rights, whether they are capacity or exchange programmes depending on the allocation method.

The Available Transmission Capacity ATC, that is the part of NTC that remains available, after each phase of the allocation procedure, for further commercial activity. ATC is given by the following equation:

ATC = NTC- AAC

AAC and ATC are thus a result of each stage of the allocation procedure.

The following figure 1 gives an overview over the transfer capacity definitions.

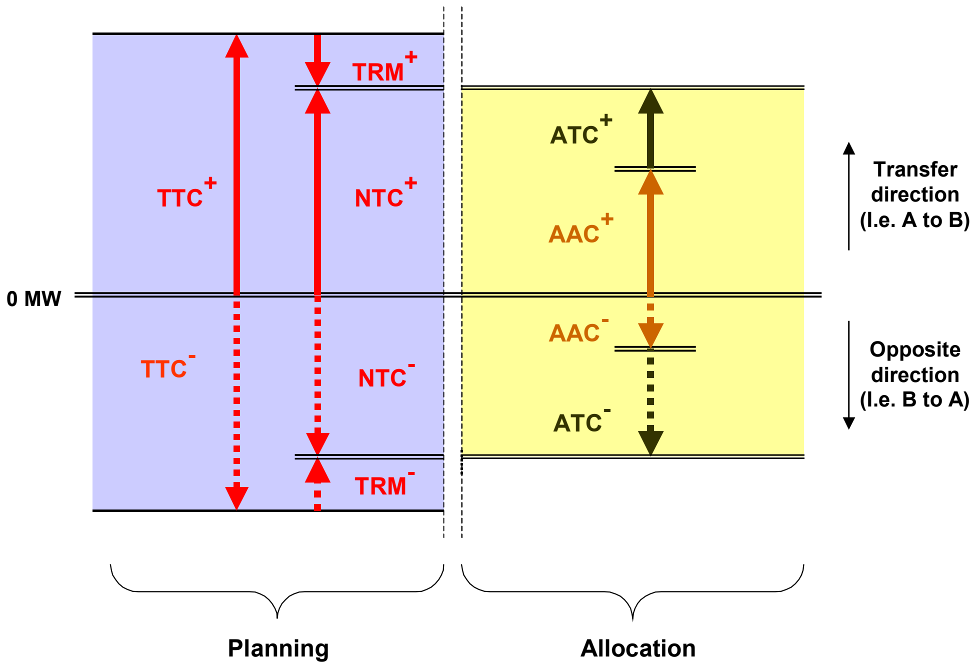


Figure 1: Transfer capacity definitions

3. USE OF THE DEFINITIONS

3.1 DIRECTIONAL AND TIME DEPENDENCIES.

As noted in the previous chapter, TTC computation starts establishing a base case. This base case will already contain exchange programmes between any pair of neighbour control areas. These are the various transactions (long term to spot contracts) likely to exist – according to what has been observed in the past – in the forecasted situation. In figure 2 for a given pair of neighbour control areas, A and B, for which capacities are to be computed, there exists in the base case a global exchange programme of magnitude BCE (Base Case Exchange).

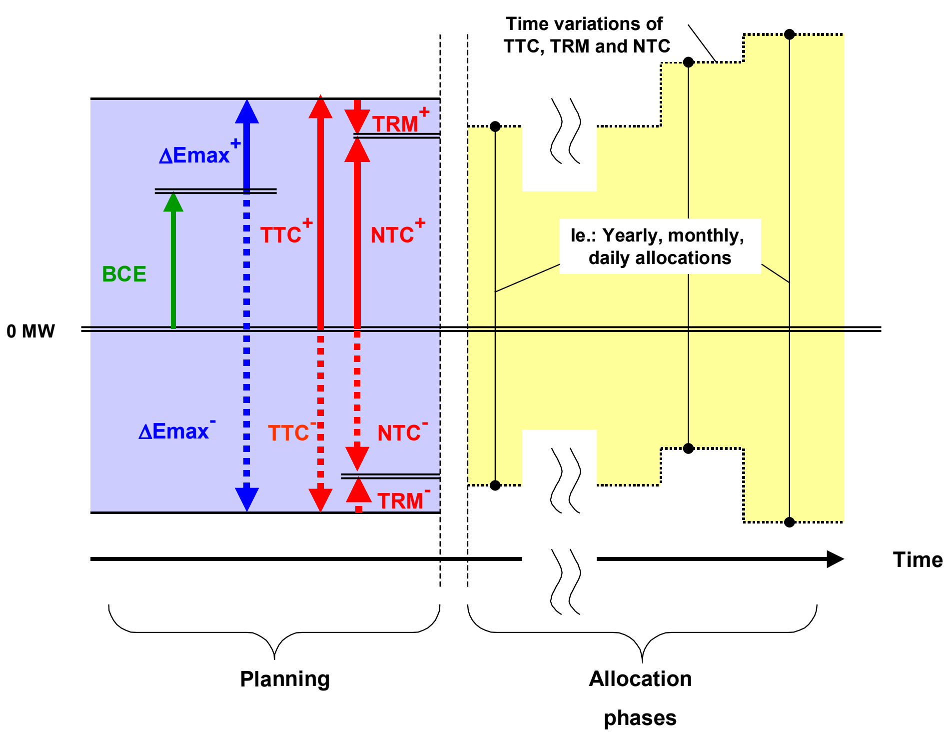


Figure 2: Transfer capacities in planning and for allocation phases.

From this starting situation, when computing TTC from area A to area B, generation is stepwise increased in control area A and decreased in control area B giving rise to a power flow from area A to area B .The shifts of generation are named in figure 2 as ΔE^{+} and ΔE^{-} for the increase and the decrease respectively. This process is carried out up to the point, where security rules in either system A or B[3] are breached ($\Delta Emax^{+}$ / $\Delta Emax^{-}$). The maximum exchange from A to B compatible with security rules without taking into account uncertainties and inaccuracies – TTC from A to B – is then BCE + $\Delta Emax^{+}$. This procedure is reversed – decrease of generation in system A and increase of generation in system B – when computing TTC from area B to area A leading to a maximum increase of generation of

[3] The breaching of security rules may happen internally in any of these two systems or in the tie lines between them. It has to be beared in mind that the interconnector is not just the tie lines crossing the control areas borders but any network element which has a real impact upon the real transfer possibilities i.e., which may limit the exchange programmes.

$\Delta Emax^-$ and thus to a maximum exchange from B to A of $\Delta Emax^-$ - BCE, as shown in figure 2. In a next step TRM is deducted from the TTC values for both directions resulting in the corresponding NTC values.

The values of TTC, TRM and NTC are therefore directional. They are to be computed for a given interconnection in both directions of the energy exchange. Generally, the values of TTC, TRM and NTC in both directions are bound to be different. The values of AAC and ATC are as well directional; they are nothing else that a split of NTC established through the allocation procedure.

The scope of the transfer capacity definitions covers two sets of power system scenarios: One associated with the planning phase and another associated with the capacity allocation phases. The former is based on estimates of typical situations of the power system. The latter takes into account the exchange programmes already allocated in a given time frame (one year ahead until one day-ahead) and updates of the assumptions made on network topology, load and generation pattern. Starting from calculations for the operational planning and approaching the horizon of programme execution, the base cases normally vary with the consequence that also the values of TTC, TRM and NTC may vary. Thus the transfer capacities are also time dependent. These time dependencies are further discussed in the following chapters.

3.2 PLANNING PHASE

For the planning phase, which is the one leading to the seasonal capacities published by ETSO, the scenario corresponds to two typical peak periods, one in winter and the other in summer. The corresponding base cases are built according to observed states of the power system in the past ('snapshots' or recorded load flows of the power system in these situations) and are adapted according to a set of agreed guidelines to the expected system states corresponding to the forecasted situation.

The calculations of TTC and TRM lead then to NTC values that are indicative and non-binding. These values are just the best estimate by TSOs, providing a signal for market participants who should understand it as a reference value which will, sometimes, have to be adapted when approaching the programming horizon accordingly to the prevailing system conditions and in the extent these differ from the forecasted system conditions built in the base cases.

3.3 ALLOCATION PHASES

Interconnection capacity is allocated in different time frames in an attempt to match the needs of market parties for securing longer term trading and to provide room for shorter term trading. The split of capacity into different time frames may also reflect the fact that transmission capacities, being estimates based on power system forecasts, may vary following unexpected changes of power flows derived from the results of each allocation stage. The time frames considered (i.e.: year ahead to day ahead or even hours ahead) and the split of transmission capacity between them is a matter of 'capacity products' and is embedded into the allocation procedures applied by the concerned TSOs and, when applicable, of concerned PXs.

For the allocations, which are carried out regionally by the TSOs involved in a congested flow gate, the selected scenarios vary depending on the time frames considered. For the long-term allocation phases (year-ahead) the scenarios may be the same as those considered for the planning phase. For shorter time frames (month ahead to day ahead) the scenarios correspond to the expected situations for peak and off-peak system conditions for the next day or even to hourly scenarios. The corresponding base cases have to be built integrating the results of the previous allocation phases and the expected system states corresponding to the forecasted horizon, i.e.: Once, for example, the one year ahead allocation mechanisms have provided access rights to a set of transactions these have to be integrated into the base cases allowing computation of the TTC for, for example, the month ahead allocation process.

In most cases, when the allocation procedure reaches the day ahead all the exchange programmes with allocated capacity have to be confirmed (‘use or lose it’ principle). The confirmed programmes define CE (‘Confirmed Exchanges’) in both directions of exchanges. Whether these CE values are to be ‘netted’ or not in order to define ATC is a matter of the allocation procedure not of capacity definitions.

4. EXCHANGE PROGRAMMES AND PHYSICAL FLOWS

4.1 THE “PARALLEL FLOW” PHENOMENA

The above set of capacity parameters are in terms of bilateral exchange programmes between two neighbour areas. They would be closely connected to the power flows through the cross borders only in the ideal case of a peninsular system and its neighbour if both were interconnected through a single tie line. However, in a widely interconnected network like for example the UCTE network the power flow through the cross border tie lines between two neighbour areas A and B may be interpreted as a superposition of a direct flow, which is related to exchanges between A and B and a parallel flow, which is related to all the other exchanges in the meshed network and to the location of generations and loads in the several grids. Therefore there would be a parallel flow even if all the exchanges in the interconnected system were set at zero[4].

The ‘parallel flows’ are dealt with implicitly in the capacity assessment procedure in the sense that the base cases already contain scheduled cross-border exchanges and the corresponding load flow situations contain the associated power flows.

Thus the figures provided about capacities for highly meshed systems are limited in scope, in several senses:

- TTC and NTC values are computed between neighbour areas; these values are the result of assuming that only the transactions between these two areas are modified and the rest (‘third parties’ transactions) remain unaltered. This fact has two consequences:
  - The published values cannot be used for an exact planning of transactions if these do not correspond to generation and to consumption in the pair of control areas for which capacities are defined. I.e.: NTCs cannot be combined to derive possibilities of executing transactions according to a given transaction path (contract path).
  - If the pattern of ‘third party transactions’ differs noticeably from that taken into account in the forecast, TTC values may significantly differ. That may have a important impact upon the NTC value.

[4] Exchanges between A and any other system than B, between B and any other system than A, exchanges between any other pair of control areas and the sometimes so called ‘natural flows’, which appear even in the case of no exchanges between any pair of control areas due to the generation and load pattern of the grids.

- NTC values between pairs of control areas in meshed network systems are interdependent. For planning and for the sake of simplicity normally only one set of NTC values, that do not reflect NTC interdependencies between several borders, is published. In case of strong NTC interdependencies, better information can be provided by additionally computing values of transfer capacities for groups of areas. I.e., if there is a strong physical coupling between areas A and B regarding exchanges to area C, NTC would be provided from area A to area C, from area B to area C and from areas A + B, considered as a whole, to C. However, during the allocation phases the coupling between the areas has to be respected. Allocation thus may lead to new restrictions as shown in the following figure 3.

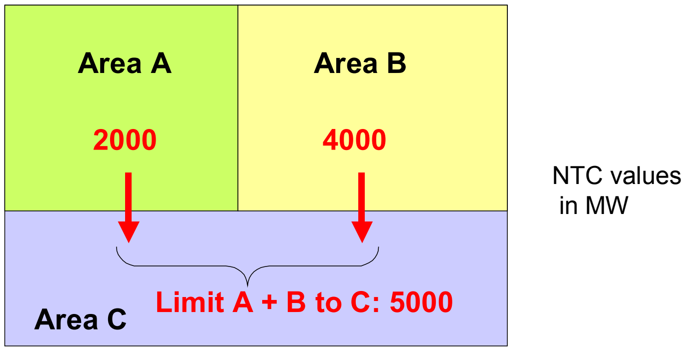


Figure 3: Interdependencies of NTC between two araes

In the figure it is assumed that in the planning phase the NTC value between areas A and C was assessed to 2000 MW and that idenpendently from this the calculation of NTC between areas B and C lead to a value of 4000 MW. For planning purposes the TSOs thus have given to market participants maximum values, not reflecting the interdependencies between the areas. Indeed the sum of import to area C may be limited to only 5000 MW. Then, at least during the allocations this fact has to be taken into consideration. It is out of the scope of this document to define the criteria for the split of this total value into the capacity for allocation from A to C and from B to C.

- Finally the NTC values itself do not provide the basis for a co-ordinated method of allocating cross border trade over several borders in a meshed network. A vision for a co-ordinated approach was already presented in a separate ETSO document [4]. It would relay on the same computation principles as outlined in this paper, but the allocation of transfer capacities would be effected on the basis of the consequences in terms of load flows and not directly using the bilateral values of NTC. *Therefore, the importance that NTC values actually have in the transaction based concepts of the international trade in Continental Europe will diminish.*

4.2 NOTIONS FOR PHYSICAL FLOWS

Figure 4 provides an example of the relationship between exchange programmes and physical flows.

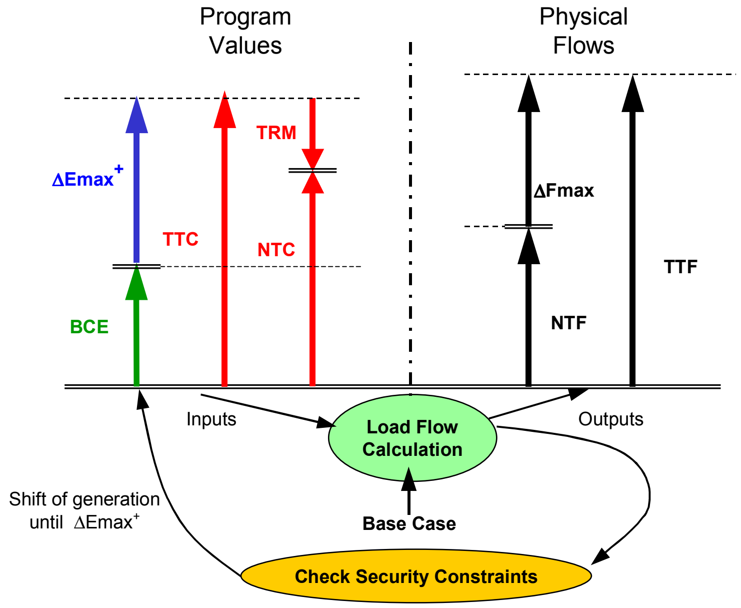


Figure 4: Definitions of transfer capacities and physical flows

This relationship is established through the load flow model of the whole interconnected system. All the terms that appear on the right hand side of this figure are net values of physical power flows. By net values is meant the sum of individual tie line power flows. The following terms define cross-border capacities as physical flows:

The Total Transfer Flow TTF is the net physical flow across the border associated with a programme exchange of magnitude TTC, provided that no other exchanges have been modified with respect to the ones existing in the base case. In this limited context – the one which applies to TTC computation – TTF may be understood as the physically maximum cross-border flow compatible with security standards in each control area[5]. TTF may be greater or smaller than TTC.

TTF can be split into two terms:

- **The Notified Transmission Flow NTF,** which is the physical flow over the tie lines between the considered areas observed in the base case prior to any generation shift between the areas. It results from the flow originated by the base case exchange (BCE)

[5] The breaching of security rules may happen internally in any of these two systems or in the tie lines between them. It has to be beared in mind that the interconnector is not just the tie lines crossing the control areas borders but any network element which has a real impact upon the real transfer possibilities i.e., which may limit the exchange programmes.

and from the parallel flows. It is extremely difficult and often even impossible to identify the different origins of parallel flows that lead to the NTF value and to separate them into distinguished terms (such as loop flows, natual flows) because of non-linear physical phenomena in the networks. On the other hand, a split of NTC is technically not necessary for the procedure of transfer capacity assessments and would also not be relevant for market actors.

- **The physical flow ∆Fmax** that is the physical flow over the tie lines between the considered areas induced by the maximum generation shift ∆Emax.

Thus, the total transfer flow can also be expressed as:

TTF = NTF + ∆Fmax

REFERENCES:

[1] Indicative values for Net Transfer Capacities (NTC) in Europe, winter and summer, working day, peak hours, ETSO-publication twice a year

[2] NTC an ATC in the IEM, information for user, ETSO, March 2000

[3] Procedures for Transfer Capacity Assessments, ETSO, in elaboration

[4] Co-ordinated Auctioning of Transmission Capacity in Meshed Networks, Discussion paper, ETSO, November 2000

Appendix IV

ETSO - Key Concepts and Definitions for Transmission Access Products

Key Concepts and Definitions for Transmission Access Products

Final Report
April 2001

CONTENTS

EXECUTIVE SUMMARY

This paper describes a range of possible Transmission Access Products in terms of a set of basic characteristics. The paper is focused on congestion management methods which involve the allocation (most likely by auction) and/or trading of these products; it does not address market splitting, which is the subject of a separate ETSO paper.

The basic characteristics are used to identify the types of products which would be consistent with the Congestion Management Guidelines contained within the conclusions of the November 2000 Florence Regulatory Forum.

The same concepts are then used to characterise the transmission capacity auction schemes which have already been introduced in the IEM area. The methods used have been successful in rapidly introducing market-based methods into congestion management. However, the analysis indicates that they do not comply with all of the Florence Guidelines, and they are unlikely to be generally effective if extended in their present form to the whole of the IEM. In particular, more sophisticated methods will be necessary where the transmission system is highly meshed and individual auctions would become strongly interactive. A possible method of dealing with this situation is described in a separate ETSO paper.

Subject to further consideration of the feasibility of market splitting, the paper recommends that further regional auction schemes should be encouraged. However, a significant level of harmonisation and coordination will be necessary, and it is proposed that ETSO should facilitate this by providing guidance on the characteristics of products and allocation methods.

INTRODUCTION

Background

1. Effective congestion management is regarded as essential for successful operation of the European Internal Electricity Market (IEM). It is therefore one of the main topics being progressed by representatives of governments, the European Commission (EC), regulators, transmission users, transmission system operators (TSOs) and other interested parties through the 'Florence process'.

2. The conclusions of the Florence Regulatory Forum held in November 2000 contain a set of guidelines on congestion management. These require TSOs to develop congestion management methods which meet a number of high level principles. There is now a need to translate these into practical proposals.

3. Some practical progress has already been made. Market splitting methods have been operating well in Scandinavia for some time. More recently, some neighbouring TSOs have jointly auctioned capacity across a small number of national borders. This experience indicates that both market splitting and auctions can provide effective market-based congestion management, at least in the particular circumstances to which they have been applied.

4. There are no plans to impose uniform market processes throughout Europe. It is therefore assumed that pan-European congestion management will develop through evolution and co-ordination of initially separate regional schemes. Each of these will necessarily be designed to interface with local market arrangements.

The purpose of the present paper

5. Given the situation described above, the way forward depends on answers to questions such as the following:
   - do current congestion management methods comply with the Florence Guidelines?
   - can neighbouring congestion management schemes be made to work together, even if they use different methods?
   - what degree of harmonisation is necessary for effective co-ordination?

   This paper begins to address such questions for congestion management methods which involve the allocation (most likely by auction) and/or trading of transmission access products. Market splitting is addressed in a separate ETSO paper.

6. The approach taken is to describe the range of possible access products in terms of their basic characteristics. These are then used to compare currently used auction methods with the requirements implied by the Florence Guidelines. This leads to conclusions on the type of harmonised access products which would be both effective and compliant with the Guidelines.

TRANSMISSION PRODUCT CHARACTERISTICS

<u>Rights</u>

7. A 'right' enables a market participant to derive financial benefit from operating at, or below, a particular generation, consumption or transaction level. Rights have positive value to market participants, and will therefore attract a positive price if they are in limited supply.

8. Transmission rights may be implemented physically, for example by requiring a user to prove that he holds a right before scheduling a transaction through scarce transmission capacity. Alternatively, they may be implemented financially by relieving holders of additional congestion charges when they transmit specified amounts of power. This document assumes that rights are implemented financially.

<u>Obligations</u>

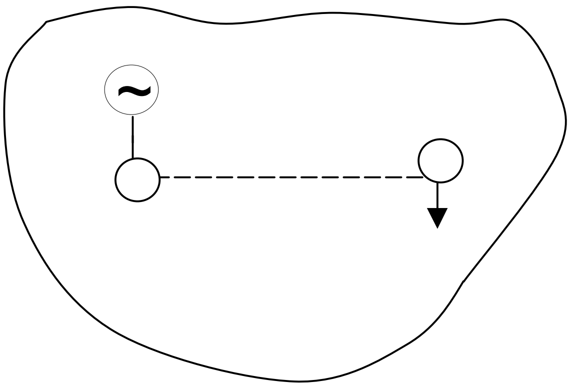
9. An 'obligation' requires a market participant to provide a service by operating at, or above, a given generation, consumption or transaction level. Obligations have negative value to market participants, and they may therefore require payment.

10. A right and an obligation can be combined in the same access product. A right <u>and</u> an obligation provides the TSO(s) with a measure of assurance that the market participant will operate <u>at</u> a given level, rather than above or below it. The combination of both therefore provides the most effective congestion management product, and in particular may permit opposing flows to be 'netted'. The market price of the combined right and obligation will depend on its value to the marginal participant.

<u>Location model</u>

11. Transmission products are most straightforwardly defined in terms of the two locations at the 'ends' of an energy transaction. In general, these could be generation, consumption or trading (eg power exchange) locations.

12. To remove the transaction dependence, all products can be referred to a common 'hub' location. Each product is then characterised by only one location, and counterparty locations need not be revealed. These are referred to below as 'entry/exit' products.



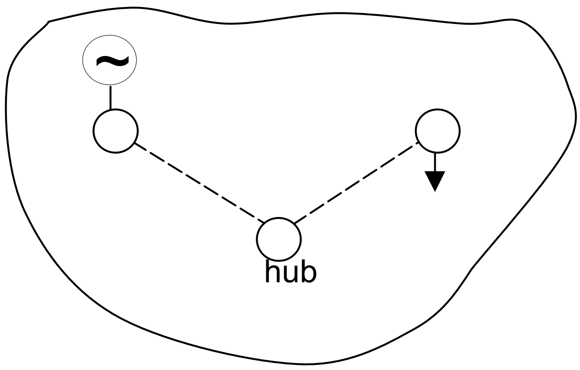


Fig 1a: <u>Location-to-location model</u> Fig 1b: <u>Entry/exit model</u>

13. More general models might also be feasible. For example, regional hubs could be placed at energy trading locations and used to define entry/exit products for intra-regional transactions. Inter-regional transactions might then be supported by further products linking the regional hubs, perhaps with reference to a single inter-regional hub.

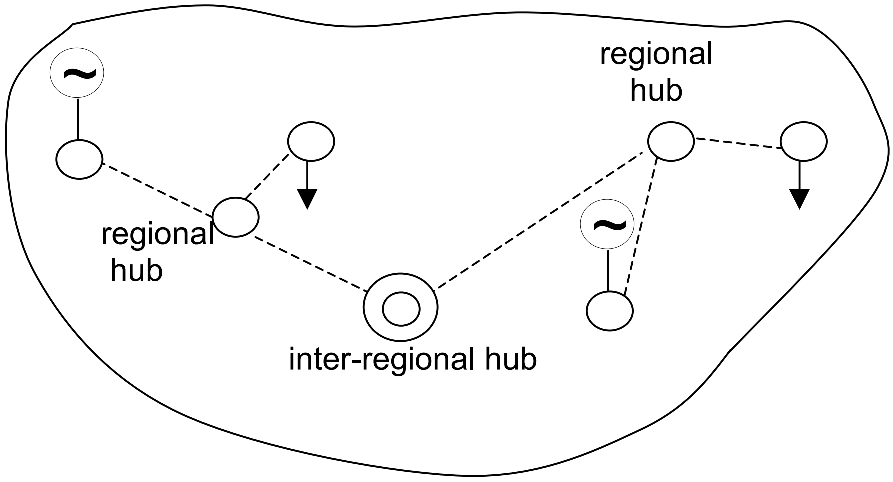


Fig 2: Hierarchical entry/exit model

Path model

14. To date in both Europe and the US, trades between and across transmission systems have usually been programmed and treated commercially in 'contract path' terms. This approach simply identifies a chain of contiguous transmission areas, with no reference to the multitude of flow paths (parallel flows) which exist in practice on a meshed system. Except for the special case of peninsular boundaries, this failure to consider physical flows limits the usefulness of contract path methods for congestion management.

15. In general, accurate congestion management requires physical paths to be quantified. This may be done using standard loadflow software, and the results expressed with sufficient accuracy in the form of a matrix of factors. It is, however, a relatively sophisticated process which needs to be repeated at least when the system configuration changes as a result of switching operations.

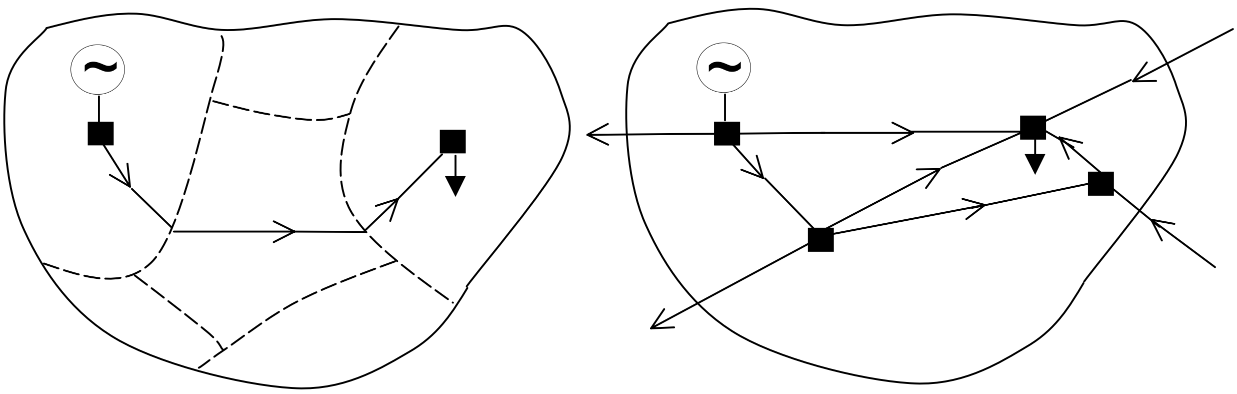


Fig 3a: Contract path

Fig 3b: Physical path

Location resolution

16. Locations can be represented as points (nodes) on the transmission system, or as zones. Zones could, for example, be defined as groups of nodes, control areas or countries.

17. In continental Europe, control of the UCTE power system has been structured and organised by decentralising the load/generation balance using the 'control area' concept. Control areas are managed through the use of real-time automatic devices (load-frequency controllers) which continuously adjust the generation level inside each area according to programmed exchanges, the actual flows on interconnectors, and the measured frequency. The control area concept is fundamental to UCTE system operation and security. Consistency with current UCTE operational practice would therefore suggest that zones should be identified with control areas.

18. The choice of location resolution is a trade-off between accurate constraint representation and access market liquidity. If transmission products are defined for large zones, relatively few constraints are captured but the number of participants able to trade products within each zone is relatively high. Conversely, products related to small zones or nodes are potentially capable of fine control of congestion, but the opportunities for trading among market participants are limited or non-existent.

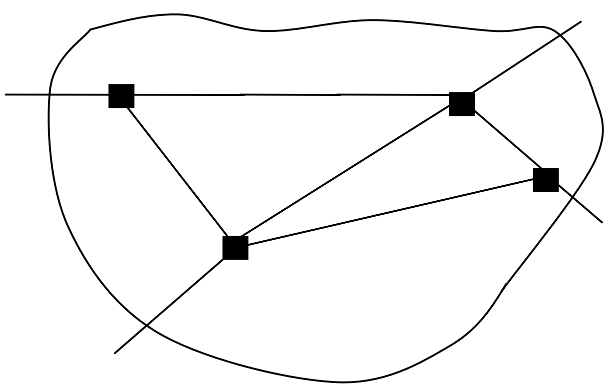


Fig 4a: Nodal resolution

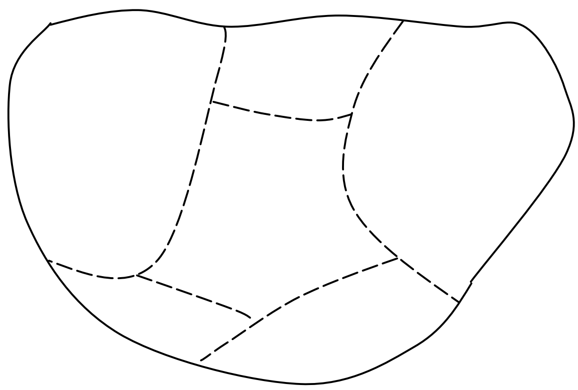


Fig 4b: Zonal resolution

Constraint representation

19. A constraint (congestion) can arise on a transmission system for a variety of reasons. It is often necessary to limit physical flows to reduce the risk of thermal damage, unacceptable voltage levels, or electrical instability. Such risks may be significant while operating as intended, or they may appear following transmission faults resulting in loss of equipment. A particular constraint may be a relatively permanent feature of the system, or it may appear only temporarily as a result of particular operational circumstances. Transmission products could in principle be defined in terms of the detailed technical nature of each constraint, but such a scheme would be highly complex and unworkable in practice.

20. A common simplification is to limit active power flows across 'bottlenecks' in the transmission system. These are typically groups of circuits in the same electrical vicinity, and are sometimes called 'flowgates', particularly in the US. In a physical path flowgate model, the sensitivities of flowgate loadings to entry/exit flows can be represented by linear loadflow factors.

21. A particular application of this principle is the identification of flowgates with tie-lines linking adjacent zones, with flowgate limits which take into account congested lines situated inside the zones as well as on the tie-lines themselves. The physical flow through such 'tie-line flowgates' is then limited to the value reached by the flow on the tie-lines when the flow through the most congested line is at its maximum. This approach is compatible with the 'control area' concept (see paragraph 17), which in turn is usually aligned with political boundaries.

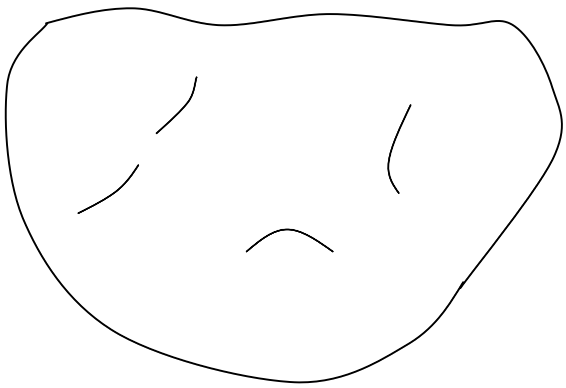


Fig 5a: Flowgates

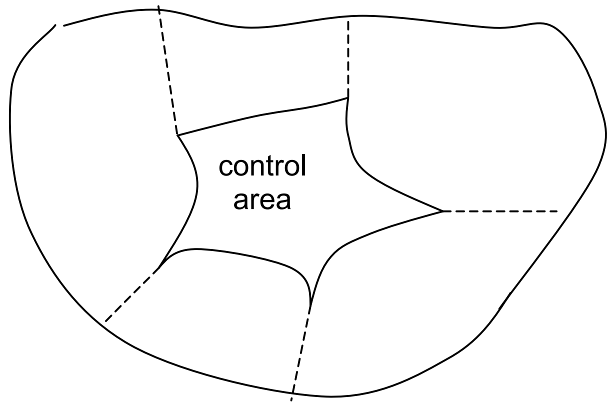


Fig 5b: Tie-line flowgates

22. A further simplification is to limit flows across a set of partitions, each of which divides the transmission system into two separate parts. The loadflow sensitivity factors relating to each partition are then either 0 or 1, depending on whether both counterparties (or the entry/exit point and the hub) are on the same or opposite sides of the partition.

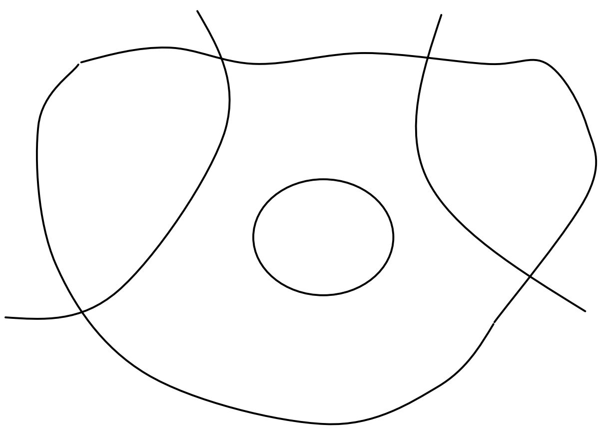


Fig 5c: Partitions

23. The choice of constraint representation is again a compromise. A representation which reflects the technical capabilities of individual circuits allows fixed limits to be directly applied, but is complex and difficult to reconcile with a transparent and liquid market. The limits corresponding to more simplified flowgate or partition representations require assumptions to be made regarding the outturn disposition of generation and demand, and are therefore approximations. Ultimately, partition models suffer from the same disadvantages as contract paths and market splitting, and are probably fully relevant in practice only to special regions in Europe.

24. Rights (and obligations) can be associated directly with individual constraints, flowgates or partitions. Market participants then have the task of assembling a portfolio of such products for each constrained part of the transmission system, in proportions which are informed by loadflow factors. Such ‘flowgate rights’ have been promoted by some as an alternative to locational pricing methods used in the US. They devolve a high level of activity to the marketplace, but are complex for market participants to manage, especially as the loadflow factors are subject to change. Assuming that flowgate products are combined in proportions determined by accurate loadflow factors, the resulting ‘bundles’ are equivalent to the location-to-location and entry/exit products described above.

Firmness

25. For transmission products to be useful for congestion management, they should, at least on a short-term (day-ahead) basis, be regarded as firm by system users. This implies that there is some means of enforcing or incentivising users to operate in conformance with their access product holdings. Direct physical control by TSOs is incompatible with unbundled, competitive electricity markets. Monitoring and disclosure (‘name and shame’) methods are unlikely to be either popular or fully effective. Commercial sanctions are more desirable, although they require systems for settlement of any differences between measured generation/consumption and access product holdings.

26. For products which combine both rights and obligations, charges (or payments) for both underruns and overruns are necessary to provide appropriate commercial incentives. Imbalance prices should be related to the local value of access. In this case full netting of counter-flows is possible.

27. Transmission products can also be firm on the TSO. This takes the form of a liability to either re-purchase rights at market price (perhaps offset by re-selling obligations) or to fund re-dispatching operations to ‘buy out’ commitments which the TSO is unable to honour.

28. Firmness to TSOs provides an incentive on them to accurately predict and manage transmission capacity. However, it may also expose TSOs to considerable risks, especially on large interconnected systems where energy schedules and parallel flows are beyond the control, or even prior knowledge, of individual TSOs. Care must therefore be taken to ensure that firmness on TSOs does not incentivise uneconomic risk-averse behaviour.

Duration

29. Each transmission access product must be associated with a specific time interval. Near to real time, accurate control of congestion will only result if products can be traded for time intervals similar to those used for short-term energy trading (typically one hour or less). Initial allocation and subsequent forward trading can, however, be conducted with products bundled into longer time periods.

30. Users in different market sectors may wish to deal in products of different lengths. Encumbent baseload generators and large industrial customers, for example, are likely to be interested in purchasing longer 'strips' of access rights than short-term traders or generators with expensive or intermittent fuel sources.

31. For the above reasons, access markets are likely to have to accommodate products of varying duration. New capital-intensive interconnectors are likely to require products covering a number of years. More generally, long-term products might be allocated in annual auctions, medium-term products in monthly auctions, and short-term ones day-ahead. The longer-term products could be broken down by users and traded for shorter periods, where possible down to individual market intervals of one hour or less.

FLORENCE GUIDELINES

32. The guidelines address various factors which relate to the choice of transmission products for congestion management. They are as follows:

Economic efficiency

33. Guideline 2 calls for both short-term economic efficiency and efficient investment signals.

34. The requirement for economic efficiency implies that congestion management methods should be capable of revealing short-run marginal costs. In principle, a transmission access market can achieve this, but conditions for success are likely to include:

- *combined rights and obligations*
- *a physical path model*
- *as far as possible, both high locational resolution* and *high trading liquidity*
- *an accurate constraint representation.*

Directional price signals

35. Guideline 6 states that the price signals emerging from the congestion management process should be 'directional'. Guideline 31 explains that this is required for correct treatment of counterflows on congested circuits.

36. Directionality will result as a necessary consequence of economic efficiency. It therefore imposes no new requirements beyond those already listed above in paragraph 34.

Netting

37. Guideline 7 states that requests to use transmission circuits in opposite directions should be netted, and specifically that transactions relieving congestion should never be denied. Guideline 29 recognises that safe operation of the power system should not be compromised, and invites TSOs to propose a workable scheme.

38. A workable scheme in which flows can be safely netted requires a degree of certainty that notified flows will materialise in practice. In terms of the product characteristics described above, this requirement implies:

- *combined rights and obligations*
- *a physical path model*
- *bi-directional firmness on users (eg both underrun and overrun imbalance settlement).*

Unused capacity

39. Guideline 8 specifies that any unused capacity must become available to other agents, and refers in particular to the 'use-it-or-lose-it principle'.

40. In general, some form of underrun imbalance settlement is required to incentivise market participants to use or trade their transmission product holdings. This provides further confirmation that such products should be:

- *combined rights and obligations*
- *firm on users.*

In financial terms, the ‘use-it-or-lose-it principle’ is simply a special case in which the underrun price is zero.

Firm capacity

41. Guidelines 9 and 10 indicate that products should be firm on TSOs, in the sense that they should be responsible for re-dispatching if outturn transmission capacity is less than that anticipated. Guidelines 10 and 26 do, however, suggest that varying degrees of firmness may be appropriate, presumably in the form of interruptible rights.

42. In terms of the characteristics discussed above, products should therefore be:

- *normally firm on TSOs (with the possibility of some products with decreased firmness).*

Transaction independence

43. Guideline 20 express a preference for non-transaction based methods. It also suggests that market splitting would satisfy this preference in principle, but is too difficult to implement in the short term.

44. It is understood that this preference derives from two concerns. The first is that transaction-based transmission access would be strongly linked to specific energy trades, potentially destroying liquidity in both the access and energy markets. The second is that market participants may be reluctant to entrust the identity of contract counterparties with other parties, including TSOs.

45. All location-to-location products are transaction-based, at least in the sense that energy volumes at both ends of the transaction must be related to the same access product in the access settlement process (assuming commercial settlement is required, as suggested above). Taken at face value, therefore, Guideline 20 implies a preference for:

- *an entry/exit model*

46. The precise nature of this preference should, however, be examined further. Transaction-based settlement does not imply that counterparty locations need to be revealed to TSOs for operational purposes (except perhaps for checking and validation of exchange programmes between control areas in the UCTE network). Furthermore, zone-to-zone products are robust to trading between parties within zones. For a scheme using independent settlement agents and large zones (eg control areas or countries), an acceptable variant could be:

- *a zone-to-zone model.*

Timing

47. Guideline 26 refers to composite auctions with products of varying duration. Guideline 27 proposes a series of auctions, possibly taking place yearly, monthly, weekly, daily and intra-daily.

48. The Guidelines therefore confirm that transmission products should be characterised in terms of:

- *a range of durations, varying from at least a year to less than one day.*

Risk assignment

49. Guideline 30 states that the financial consequences of deviations from notified flows should be borne by the responsible parties, and suggests that re-dispatching costs could be funded by penalties on such deviations.

50. The implications of this Guideline for product definition are similar to those of the ‘economic efficiency’, ‘netting’ and ‘unused capacity’ guidelines described above. They are:

- *combined rights and obligations*
- *a physical path model*
- *as far as possible, both high locational resolution and high trading liquidity*
- *an accurate constraint representation*
- *firmness on users via underrun and overrun settlement.*

Tradability

51. Guideline 33 addresses the creation of liquid energy markets, and states that auction products should be freely tradable before notification.

52. If secondary access markets are not sufficiently liquid, the energy markets could be impeded by the difficulty of matching energy contracts with suitable access products. High liquidity can be obtained either by trading through TSOs acting as market-makers, or by requiring market participants to deal directly in flowgate products. Direct trading of entry/exit products is only possible between market participants in the same location, and is therefore only likely to provide sufficient liquidity if locations are defined as relatively large zones. Location-to-location products are inherently less liquid that entry/exit ones, because they can only be traded between transactions with the same entry and exit locations. The requirement for liquid trading therefore favours:

- *an entry/exit model*
- *low location resolution (ie large zones)*
- *trading via TSOs*

  <u>or</u>

- *individual flowgate products (see paragraph 24 above).*

CURRENT AUCTION SCHEMES

Characteristics of current schemes

53. Current auction schemes within the IEM are:
    - Denmark-Germany (DK-D)
    - Netherlands-Germany/Belgium (NL-D/B)
    - France-England (F-GB)
    - France-Spain (F-ES)

    The characteristics of the products sold in these auctions are shown in Table 1.

Limitations of current methods

54. Experience to date has demonstrated that cross-border capacity can be successfully auctioned. However, an important question is whether acceptable IEM-wide congestion management would result if current methods were simply extended to all congested interfaces, with no particular co-ordination or harmonisation arrangements. The following paragraphs describe the possible shortcomings of such a strategy.

55. Table 1 shows that all of the existing auction schemes are based on contract paths. This is of little consequence for the peninsular borders (DK-D, F-GB and F-ES). These constitute system partitions (see Fig 5c) so parallel flows are minimal or non-existent, and physical paths coincide with contract paths.

56. The NL-D/B scheme is the first one to introduce the possibility of interactions between multiple paths. While these interactions are expected to be manageable in this case, extension to more central UCTE regions is likely to be more difficult. In general, parallel flows may cause significant interactions between nominal contract paths. There is also scope for market participants to select contract paths which they expect to be commercially beneficial, rather than those which most closely match physical paths. In these circumstances, the result could be poor congestion management with potential security problems and inaccurate price messages, conflicting in particular with Florence Guideline 2, relating to economic efficiency.

57. Although 'use-it-or-lose-it' provisions are incorporated in the current auctions, trading and settlement of obligations is not well developed. As a result, the costs of capacity under-utilisation may not be accurately assigned to market participants. Furthermore, TSOs may lack the necessary confidence to take counterflows into account when making capacity available. The guidelines on netting and risk assignment may therefore not be adequately addressed.

58. All of the current auctions effectively allocate zone-to-zone products, since no distinction is made between locations within the countries concerned. They are therefore only able to address congestion associated with the borders themselves, rather than with intra-zonal constraints. Zone-to-zone auctions are also transaction-based, contrary to the preference expressed in Guideline 20 (but see paragraph 46). Although liquidity is increased by the application to large zones, it is limited by the need to co-locate both entry and exit parties in any trade. Guideline 33 is therefore compromised to some extent.

CO-ORDINATED AUCTIONS

59. ETSO has produced a separate paper entitled ‘Co-ordinated Auctioning of Transmission Capacity in Meshed Networks’. This describes a method of allocating transmission products in the presence of multiple constraints or congested borders, using loadflow-derived distribution factors to take interactions into account.

60. The characteristics of this method are shown in Table 2. The loadflow factors provide a physical path model. The constraints need not be physically located on tie-lines, although in practice they could well be represented as tie-line flowgates (see paragraph 21). The method places no restrictions on whether products are rights and/or obligations, on the choice of location model or resolution, or on product firmness or duration.

61. The proposed approach overcomes some of the shortcomings of currently used methods. In particular, it takes parallel flows into account and eliminates exploitation of the contract path approximation. In consequence, it should be possible to control congestion and reveal economically efficient prices in the presence of interacting constraints.

62. Implementation of the proposed method would require a high level of co-ordination between TSOs. Wide-area (perhaps even pan-European) loadflow calculations would be necessary to produce the distribution factors. Auction clearing and subsequent trading would also need to be jointly organised, at least on a regional basis.

HARMONISATION REQUIREMENTS

63. The above analysis of existing auction methods suggests that satisfactory pan-European congestion management is unlikely to result from unco-ordinated development by individual Member States. As described above, ETSO is developing co-ordination methods, but these require a high level of co-operation and standardisation across borders. The following paragraphs identify the areas in which harmonisation may be required.

64. The Florence Guidelines themselves dictate a degree of harmonisation of access products. The characteristics which result from compliance with the Guidelines are listed (in italics) in paragraphs 34 to 52 above.

65. In addition to harmonising the nature of the transmission products themselves, the allocation, trading and settlement processes will also require harmonisation to enable effective inter-working, notably between Regulators and between TSOs. Although initially this will only be necessary on a local or regional basis, difficulties will subsequently appear if pan-European compatibility is not considered at the outset.

66. It is of fundamental importance that a commonly agreed location model is adopted. This is needed to relate entry and exit locations to power exchanges and other trading hubs, and to border and/or constraint (flowgate) locations. This model must form an unambiguous framework for posting transmission capacity forecasts, calculating loadflow distribution factors and allocating transmission products.

67. It may be necessary to co-ordinate the timing of auctions throughout Europe, in order to avoid discriminating between users in different locations. The efficient allocation of products might also be facilitated if the duration of products allocated at different lead times were harmonised.

68. In general, forecasting transmission capacities and loadflow distribution factors, together with subsequent re-dispatching to correct forecasting errors, are all joint TSO activities. If transmission products are to be firm on TSOs, there needs to be a harmonised way of assigning liability for re-dispatching costs between them.

CONCLUSIONS

69. The current strategy of auctioning access across individual borders is an efficient means for initial implementation of market-based capacity allocation schemes. Ultimately, however, it is unlikely to result in effective congestion management throughout the IEM.

70. Current auction schemes are not compliant with all of the Florence Guidelines on congestion management.

71. To ensure general effectiveness and compliance with the Guidelines, it will be necessary to complement the current strategy by establishing:

    - a harmonised definition of access rights and obligations based on physical flows
    - an agreed locational model relating access points or zones to trading and congestion locations
    - effective methods of incentivising compliance with rights and obligations
    - liquid trading of access rights and obligations
    - methods for co-ordinating auctions, trading and settlement where congested flows are interactive.

72. The above requirements suggest that transmission access products should be based on:

    - combined rights and obligations
    - an entry/exit location model, incorporating trading hubs
    - physical flow paths
    - zones selected to optimise the trade-off between congestion management effectiveness and trading liquidity
    - constraint representation at the flowgate level
    - firmness on both TSOs and transmission users
    - a range of timescales over which transmission products can be acquired and traded.

RECOMMENDATIONS

73. The EC, Regulators and transmission users should be invited to agree with TSOs that the above conclusions are valid.

74. Subject to further consideration of the feasibility of market splitting, the present strategy of auctioning cross-border access should be encouraged, since it enables a quick response to the challenge of allocating capacity on a market-oriented basis. However, ETSO should complement this by providing:

- guidance on the form of transmission products which should be auctioned and traded
- the co-ordination necessary to build an effective 'map' of access zones and trading locations
- methods for co-ordinating access auctions, trading and settlement where it is necessary to take interactions into account.

	Right s	Obligations[1]	Location model	Path model	Location resolution	Constraint representatio n	Firmness		Duration
							TSO	user	
DK-D	yes	no	zone-to-zone	contract	zonal	boundary	yes	yes (UIOLI)	1 yr, 1mth, 1 day (hourly)
NL-D/B	yes	no	zone-to-zone	contract	zonal	boundary	yes[2]	yes (UIOLI)	1yr, 1mth, 1day, (hourly)
F-GB (DC cable)	yes	no	zone-to-zone	contract	zonal	boundary	no	yes (UIOLI)	3yrs, 1yr, 1 day
F-ES (planned)	yes	no	zone-to-zone	contract	zonal	boundary	yes	yes (UIOLI)	1yr, 1mth, 1wk, 1 day (hourly)

1. note that 'Use-it-or-lose-it' (UIOLI) is not included here as an 'obligation'
2. except for force majeure

Table 1: Current Auction Schemes

Rights	Obligations	Location model	Path model	Location resolution	Constraint representation	Firmness		Duration
						TSO	user	
yes	yes[1]	location-to-location or entry/exit	physical	zonal or nodal	any (probably flowgate)	yes[2]	yes[1]	any

1. dependent on settlement arrangements
2. dependent on TSO regulation/incentivisation arrangements

Table 2: <u>Co-ordinated Auctions</u>

Appendix V

ETSO - Co-ordinated Auctioning - A market based method for transmission capacity allocation in meshed networks

Co-ordinated Auctioning

A market-based method for transmission capacity allocation in meshed networks

Final Report
April 2001

Executive summary

The purpose of this paper is to present and propose a possibility to extend, when needed to manage congestions, the «classical» capacity auction sale from simple (i.e. one-border capacity sale) to more complex systems. This economically efficient method has been implemented or is being implemented on several European borders. However, as all the existing or considered methods up to now, it fails, when limited to a simple bilateral implementation, to cope with the following drawbacks likely to happen when it is applied to the different borders of a highly meshed system, involving multiple control areas, such as the continental European grid :

- for the market actors, the complexity of multiple auction mechanisms, together with the risk of apparition of non-convergent interactions between separate and successive clearing processes (if not synchronised);

- the poor quality of the (multiple) economical signals sent to the market participants, if the different auction systems are not combined in a way or another, whereas the underlying «physical» power system is strongly interdependent.

The present paper provides a first vision for an allocation method that could cope with these complex problems. The aim is first of all to show that some realistic solutions seem to exist for capacity allocation in complex networks (i.e. most of the continental Europe borders) and to initiate a discussion on this subject. However, a lot of questions, especially related to the implementation issues, must still be studied in more details, and some time is necessary before considering a practical implementation. Nevertheless, the use of some of the described principles could be considered for capacity allocation in the year 2002 for regional experiments.

The underlying idea of this paper is to make a proposal of a congestion management method which provides an appropriate answer to the two following issues:

- handling adequately the problem of allocating scarce transmission capacity in highly meshed networks;

- alleviating traders of the complexity of independent auctions in the main bottlenecks.

The co-ordinated auctioning mechanism presented below is likely to ensure the feasibility of complex bilateral cross-border trade. It does not introduce additive costs at every border and as such avoids any inefficient pancaking effect.

It favours a clear distinction between trade and physical flows, and shows how the market participants can be relieved from handling the complexity of the electricity physical laws, while having transparent information on the model used to approach at best the complex physical reality.

The main idea is that a simple representation of the meshed network effects (through load flow factors, so-called «Power Transfer Distribution Factors (PTDF)») can take into account the main physical interactions. Thus, a standard mathematical formulation makes it possible to select the bids that represent the highest value for the market.

The method presented here is an extension of bilateral explicit auction mechanisms ; in that respect, it inherits the properties of explicit auctioning. The paper then introduces a discussion about the compatibility between different implementation possibilities for this extension of explicit auctioning and the different forms of markets : bilateral contracts, PXs, etc. The conclusion is that there is no incompatibility with any chosen form, or the combination of several: a high level of interoperability may then be achieved.

Among the properties of the proposed method, one is of great importance and should be recalled here: except some very special cases of implementation[1] : every bidder whose bid contributes to saturate at least one bottleneck will be charged a fee., Otherwise the capacity is free of congestion charge if the bids are not participating to an active constraint.

In reference to the Florence Guidelines, this method seems to be a valuable alternative to market splitting.

To be implemented, the proposed method requires a high level of co-operation and co-ordination among TSOs; of course it is more easily feasible on «regional» congestion bottlenecks (with the involvement of the different control areas between which there are electricity exchanges that induce the majority of the flows through the bottlenecks). The first implementations should then be managed on such a «regional» basis, with further possible extension if the situation asks for.

In that respect, the joined auction mechanism recently set up by four TSOs to manage the import capacity of the Netherlands is a step forward towards improved coordination. This area is thus a possible candidate for a first implementation of the co-ordinated auctionning method, that takes into account network interactions.

Though requiring further work before implementation, the proposed system seems very efficient to improve the European Power System interoperability.

[1] *Such as Pay-as-bid pricing, see chapter IV*

I. INTRODUCTION

Compared to other goods, the specificity of electric power is that the flow corresponding to a given electricity exchange cannot be controlled like trucks, but is governed by immutable physical laws. In a highly meshed network like western continental Europe's, a single electricity exchange between France and Italy will partly flow through France-Italy interconnections, but also through France-Switzerland-Italy, and even France-Germany-Austria-Slovenia-Italy, and so on.

That is why *contract path* mechanisms (that only allocate transmission capacity along a single theoretical path between the generator and the consumer) do not entirely fit the needs of the evolving European Electricity Market. *Contract path* mechanisms are appropriate in longitudinal (e.g. U.S. West Coast) or two-party peninsular systems (e.g. France-Spain). Such mechanisms are inherently bound to fail in meshed networks as soon as cross-border power trade introduces significant swings in power flows, because they cannot account for the physical reality of electric power transmission. This also means that transmission capacity reservation cannot be undertaken by a single country, but has to follow a mechanism that encompasses all the interconnected countries. In a meshed network, transmission capacity cannot be partitioned : it is a common resource that has to be operated jointly and in a co-ordinated way.

This paper presents the proposed principles of a mechanism that effectively implements transmission capacity auctioning in a meshed network, supporting capacity reservation on any given time horizon (the choice of using this mechanism for different time horizons, from annual capacity to day-ahead or even hourly capacity is not discussed here). It requires an efficient co-ordination between TSOs of involved countries and allows diversity of market mechanisms as well as coexistence with bilateral contracts.

II. PRINCIPLE

The basic idea of the proposed mechanism is to establish a clear separation between physical flows and trade.

Energy traders are mainly interested in source and destination zones, and not in the technical contingencies of the resulting power flows nor in the topology of the network.

It is the vocation of the TSOs to manage the complexity of the electric physical laws, while providing the markets with sound indicators of risk of congestion, using alleviating mechanisms both non-discriminatory and economically effective. This idea or assumption is consistent with the orientations given by the Cross Border Tariff principles, since for the market actors only energy input and output zones and associated hourly energy schedules are necessary.

Consider a network divided into *zones*, separated by *borders* or *interconnections*, consisting in the aggregation of multiple physical *transmission lines*. Instead of having an auction market for each border, the idea is to organise **co-ordinated auctions** in order to allocate in the same process the considered "interconnected" capacities in zones with strong interactions (strongly meshed networks).

For instance, the commodity put to auction would consist in a firm transmission right-and-obligation (firm both on TSOs and on Users[2]s) to transfer power from one zone to another, each zone being a whole country or a part of it, with respect to control areas. Alternatively, commodity put to sale could be presented as a right-and-obligation to withdraw or submit power from one zone to a global hub chosen in one of the zones. This entry-exit alternative can be handled in the same way than the above zone-to-zone transfer rights, providing that netting rules are agreed (see chapter IV). We will use this entry-exit presentation in the following rather than the zone-to-zone one, in order to establish the compatibility with the « non transaction based » requirement expressed in Florence recommendations.

The role of the auctioning mechanism is to allocate scarce transmission capacity according to bids by market participants which reflect the values of their individual transactions, taking into account their contribution to the underlying network congestion. These contributions are encapsulated in a published PTDF *matrix*, which simply and effectively converts transmission rights into a contribution to interconnection flows. This matrix is built up with *PTDF factors* that indicate how much a given interconnection will be loaded by the use of a transmission right, e.g. a transaction between a given pair of zones associated with a zone-to-zone right, or an injection/offtake of power in a certain zone associated with an entry/exit right.

The general spirit of this mechanism is to allocate the transfer capacities to get the most of their values for the market.

As a consequence, the allocation criterion is a generalisation of the criterion used for a «classical» auction procedure : the goal is to optimise trade under the constraints of limited capacities, given that the different bids are ranked according to the bidding price. It can also be interpreted as the minimisation of the burden of the infrastructure for market participants. This burden is equal to zero if all bids are secured, which occurs when no congestion appears. In such case, the use of the capacities is free of congestion charge for all market participants.

[2] *Coordinated auctions are also possible, in case the commodity put to auction is not firm on users, but it makes the explanation of the mechanism slightly more complex (see chapter IV).*

III. STEP-BY-STEP MECHANISM

A. Publishing

TSOs compute the PTDF matrix, giving for each type of transmission rights (e.g. between each pair of zones) the contribution of the transaction under consideration to the interconnection flows. The PTDF factors specify the capacity used on each interconnection as a fraction of the volume of transmission rights associated with particular entry and exit zones. These computations are based on one transmission system configuration that has been commonly agreed upon for NTC computation.

For each border between neighbouring zones, linked by existing physical interconnections, the neighbouring TSOs compute together the technical constraints that limit the capacity. This limit, called Bottleneck Capacity (BC) in the rest of the document, can be related to the present NTCs calculations (see appendix 2), although it is defined as a physical flow through the tie lines. It must be stressed that these BC limits will reflect all network security rules applied to trans-European exchanges, and thus will hardly be comparable to the sum of the individual capacity of each tie line.

Finally, these limits may be complemented by additional transfer limits in order to avoid situations which would turn to be over-sensitive to the risks of changes happening after the clearing.

To ensure transparency, once aggregated between TSOs, the PTDF matrix is published with all other relevant information, in order to provide market participants with any useful data to anticipate their position.

B. Bidding

TSOs organise simultaneous («co-ordinated») auctions on each pair of zones. Market participants send their bids consisting of a quantity and a price for the cross border input (or off-take) rights they want to buy. Combined input (in one zone) and off-take (in another zone) prices indicate the maximum value they are willing to pay for obtaining capacity on the given zone pair, up to the requested quantity. Market participants aiming at bilateral trade may require, if they wish, to limit their allocated input quantity at the same level that the allocated off-take quantity, in order to get a balanced right from zone to zone.

C. Clearing

The selected set of bids is the one that combines the best overall economic value for the market under physical and security constraints. For example, the objective function to be optimised may consist in the sum of the bid price multiplied by the bid quantity. The constraints taken into account imply that the security limits are not exceeded. Bids with identical prices for the same zone to zone relation are offered the same quantity (pro-rata). The result is obtained by solving a standard mathematical problem called a "Linear Program". The foreseeable size of this problem rises no special difficulty in the application of well-known algorithms and «from-the-shelf» software. The result is then easily auditable by Regulating Authorities.

IV. IMPLEMENTATION ISSUES

A. Variants in the auction mechanism

As any other auction mechanism, options must be chosen between several implementation variants, such as :

- One or several auction rounds? Several rounds may increase the transparency for market actors, given that global results of each round are displayed to bidders (such as : marginal price, average price of bids secured in the round …), yet increase also the complexity ;

- Pay-as-bid or marginal pricing? This question is not totally independent from the previous one, since it may be proved that under the assumption of perfect information of all players the final results would be the same. It has to be mentioned that the usual implementation of pay-as-bid pricing would breach out the « no congestion - no payment » principle, and should then be avoided.

Anyway these variants do not prevent from implementing the co-ordination method proposed, since they do not change either the criterion or the constraints of the optimisation problem.

B. Firmness on TSOs :

The capacities calculated by the TSOs, then published and sold through an auction system are subject to numerous uncertainties among which :

- "force majeure" situations, such as severe destruction of equipment with durable consequences,

- network component outages,

- variations in the pattern of flows induced by swings in the markets competitiveness / attractiveness, and subsequent unexpected modifications of the parallel flows (unforeseen parallel flows).

Co-ordinated auctioning reduces significantly this last type of uncertainty, as the swings between zones are internalised in the auction mechanism. Note that the swings inside each zone may still induce uncertainties on cross border capacities. The question of the firmness of commitments made by TSOs, the corresponding financial risk (varying according to the time horizon) and the associated question of cost recovery mechanisms remains open, knowing that several solutions are possible :

- cost socialising, or in other words the authorisation given to TSOs to recover these costs via the transmission tariffs,

- no guarantee, which means that the market participants will have to hedge this risk by themselves,

- allocation to TSOs of a certain amount of the revenues of the capacity auctions to cover that risk : it is then possible to incorporate to the proposed co-ordinated auction mechanism prices associated to BC limits (for instance, cost of forecast cross-border co-ordinated redispatching). A co-ordination between TSOs is then necessary to organise their common liability

The principles proposed in this paper are compatible with any of the variants taken (e.g. «use it or lose it» principle for yearly to weekly capacities, firm day-ahead capacity). There is nevertheless a need of harmonisation of regulation rules in the participating zones.

C. Firmness on users and counter-flows netting off :

Firmness on users generally refers to rights and-obligations products, and to underrun and overrun costs (when the market participants deviate from the expected program they pay a cost, related to the adjustment market) . This concept is already widely applied at day ahead horizon where scheduling is systematically required from users.

If the commodities put to auction are rights-and-obligations, counter-flows created by commercial exchanges can be fully net off and the economic efficiency is at its maximum : flows against the directions of active constraints are regarded as creating additional capacity. Whilst the rights associated with flows in the constrained directions will achieve positive prices, the rights in the opposite directions, having effectively created additional capacity in the constrained direction, would be assigned negative prices by the auction mechanism. Together with the rewards of negative payment, holders of these rights should have obligations to make such flows available in real time.

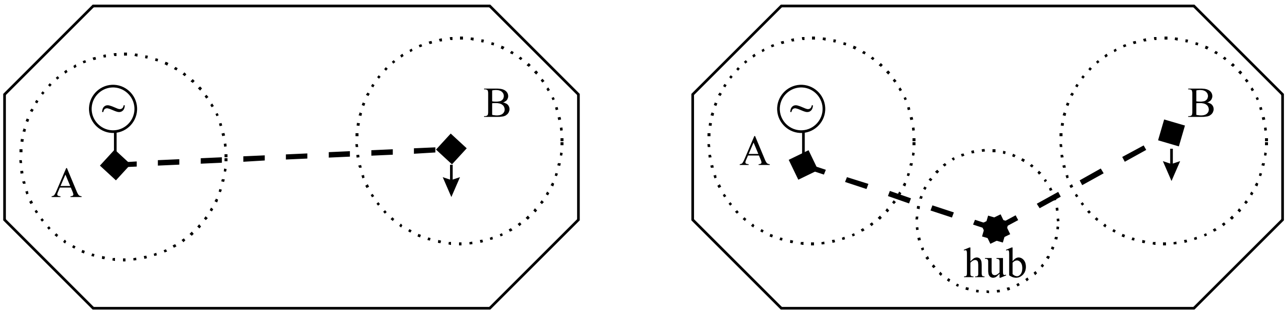
In this right-and-obligation case, co-ordinated auctioning will be cleared up in one settlement, as presented in appendix 1, with a full netting off (100%). Then , the counter-flows will see a negative price, even if their initial bid price is positive.

If rights-without-obligations are put to auction, which means the possibility for a bidder not to use the capacity and as a consequence an additional uncertainty for TSOs during the nomination phase, the co-ordinated mechanism must be adapted to take in account the risk associated : for instance the margins can be enhanced by stiffening the physical constraints, i.e. lowering the BCs values, or by adding a right-only premium to the rights-and-obligations price initially assessed.

It should be also mentioned that options could be developed outside of a right-and-obligation only co-ordinated auctioning mechanism, by power marketers taking over the firmness risk.

D. *Zone-to-zone versus Zone-to-hub*

In the zone-to-zone model, the product sold is the right to implement a bilateral transfer between the zone of production and the zone of delivery without further liability for congestion charges. In the zone-to-hub model, the two parties of the transaction buy independently the rights needed, both referring to a normative transfer between the zone and a global hub (see the following figure).



Zone to zone | Zone to Hub

Zone to zone commodities are more stable for TSOs but less flexible for users. Zone-to-hub commodities gets the opposite qualities.

For instance in a zone to hub model a user who bought an input right in zone A, can use it for any cross-border trade referring to a generation in A : its counterparty can change, say between auction clearing and run time, providing that its counterparty has also bought on its own the cross-border rights in the off-take zone. This type of commodity makes things easier for trade, specially on energy markets where counterparties are not clearly specified.

On the other hand in a zone-to-zone model, a user who has bought an A to B transfer right, would have more difficulty if its expected counterparty in B changes : unless he can find another counterparty in zone B, he must sell back its A-B right and buy another one, or buy the complementation right from B to the zone of its new counterparty.

It is feasible to implement both models in coordinated auctioning. They will lead to the same allocations in terms of rights-and-obligations. When dealing with rights-without-obligations, some differences may appear due to the fact that input /off-take leads to higher risks for TSOs than bilateral transfer rights.

E. *Time horizon and reselling of transmission rights*

As proposed in earlier papers, multiple auctions can be organised for different time horizons (yearly, monthly, weekly and daily), thus allowing long term capacity reservation needed for long term bilateral contracts, while retaining the flexibility required for operational planning and last minute adjustments.

The method presented here can be implemented for these different time frames.

As far as transmission rights reselling are concerned, it is also just a choice to be made at the stage of implementation (that is either within one time horizon frame, or from – for instance – a yearly to monthly auction).

F. Integration of Co-ordinated Auctions with Bilateral Contracts and Energy markets

All the developed principles can be used for bilateral trade, but also for trade related to any energy markets, under some synchronisation of the processes

Cross border bilateral contracts, which associate generation on one side and supply on the other, fit directly with the above mechanism.

In the same time energy markets, which deal with unilateral bids, may develop also cross border exchanges as a result of their clearing process. Therefore they turn a part of the bids they deal with into inter-zonal requests. These inter-zonal requests could also be taken into account by the above mechanism which will ensure that bilateral contracts and organised energy markets are treated equally regarding congestion management.

Periodic auctions with yearly, monthly, weekly and daily terms can be used to reserve capacity, and thus hedge bilateral contracts as well as short term energy markets from the delivery congestion risk.

G. Regional implementation on a part of European network

To be implemented, the proposed method requires a high level of co-operation and co-ordination among TSOs; and of course this co-operation is more easily feasible on a «regional» basis (say few neighbouring control areas between which there are electricity exchanges that induce the majority of the flows through the bottlenecks). This implementation is feasible providing that the missing interconnected area is represented by some type of equivalent.

The knowledge of the overall PTDF matrix factors, would allow an analysis of the coupling between areas and thus would help the choice of the limit for the best regional implementations.

V. <u>CONCLUSION</u>

The co-ordinated auctioning mechanism presented here is likely to ensure the feasibility of complex bilateral cross-border trade. It does not introduce additive costs at every border and as such avoids any inefficient pancaking effect.

It favours a clear distinction between trade and physical flows, and shows how the market participants can be relieved from handling the complexity of the electricity physical laws, while having transparent information on the model used to approach at best the complex physical reality.

The main idea is that a simple representation of the meshed network effects (through so-called «PTDF factors») can take into account the main physical interactions. Thus, a standard mathematical formulation makes it possible to select the bids that represent the highest value for the market.

The method presented here is an extension of bilateral explicit auction mechanisms; in that respect, it inherits the properties of explicit auctioning. The paper then introduces a discussion about the compatibility between different implementation possibilities for this extension of explicit auctioning and the different forms of markets : bilateral contracts, PXs, etc. The conclusion is that there is no incompatibility with any chosen form, or the combination of several: a high level of interoperability may then be achieved.

Among the properties of the proposed method, one is of special importance and should be recalled here: except some special cases of implementation, bidders will pay only if their bid is participating to an active constraint, which means if the bid contributes to saturate at least one bottleneck. Otherwise the capacity is free of congestion charge.

In reference to the November Florence Forum Guidelines on Congestion Management, this method seems to be a valuable alternative to market splitting:

> [Guideline 2]: *"The congestion management method(s) implemented should deal with short-run congestion in an economically efficient manner whilst simultaneously providing signals or incentives for efficient network and generation investment in the right locations".* The method provides a competition among bidders based on sound mathematical models, which guarantees the efficiency of the solution through proven optimality.
>
> [Guideline 3]: *"In order to minimise the negative impact of congestion on trade, the current network should be used at the maximum capacity that complies with the safety standards of secure network operation".* As graphically shown in appendix 2, one of the key point is that security constraints are explicitly taken into account : this ensures that the maximum capacity within these constraints is proposed to the bidders.
>
> [Guideline 4]: *"The TSOs should provide non-discriminatory and transparent standards, which describe which congestion management methods they will apply under which circumstances… ".* The TSOs would publish all critical data (security limits) and parameters (the load flow factors)

[Guideline 5]: *"Discrimination between the different types of cross-border transactions, whether they are physical bilateral contracts or bids into foreign organised markets, should be kept to a minimum when designing the rules of specific methods for congestion management …".* The method can cope with bilateral and other kinds of trade.

[Guidelines 6 & 7]: *"Price signals that result from congestion management methods should be directional", "Every effort should be made to net the capacity requirements of any power flows in opposite direction over the congested tie line…".* As shown in appendix 1, the method exhibits marginal congestion prices and assumes netting.

[Guideline 8]: *"Any unused capacity must become available to other agents (the use or lose it principle)…".* The co-ordinated auctioning method it is compatible with the use-it-or-lose-it principle.

To be implemented, the proposed method requires a high level of co-operation and co-ordination among TSOs; of course this co-operation is more easily feasible on «regional» basis (say few neighbouring control areas between which there are electricity exchanges that induce the majority of the flows through the bottlenecks). The first implementations should then be managed on such a «regional» basis, with further possible extension if the situation asks for.

In that respect, the joined auction mechanism recently set up by four TSOs to manage the import capacity of the Netherlands is a step forward towards improved co-ordination. This area is thus a possible candidate for a first implementation of the co-ordinated auctioning method, that takes into account network interactions.

Though requiring further work before implementation, the proposed system seems very promising to improve the European Power System interoperability.

APPENDIX 1 : Four node theoretical example

How the Coordinated Auction mechanism practically works

This example presents an application of coordinated auctions to a small system of four nodes and four interconnecting lines. Each line having the same impedance, the PTDF matrix and Bottleneck Capacities limits are shown on the following table, where C is taken as hub, and represented in figure 1 diagram :

	Interconnections			
Inputs	A-B	A-C	B-C	C-D
in A	+ 0.33	+ 0.67	+ 0.33	0
in B	- 0.33	+ 0.33	+ 0.67	0
in D	0	0	0	- 1
« BC limits »	50	100	150	150

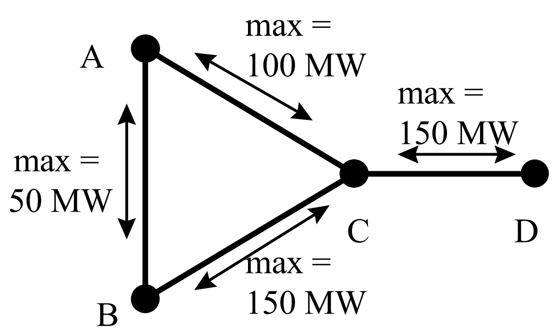


Figure 1

In the example, full netting of opposite flows is adopted hence the PTDFs are only published for one direction of transaction – those for the opposite direction automatically assume equal and opposite values. The market participants submit their bids reflecting the value of the transmission rights in relation to their transactions. Then, the clearing mechanism aimed at maximising the value of allocated transmission capacity is applied. Finally the results are given, showing the bids accepted and those rejected, as well as the interconnectors that become constrained.

First set of bids :

Let us consider a first set of bids. The bids are supposed to be bilateral ones asking for a transfer, that is to say a combined input and off-take :

Market Partici pant	Transfer requestd	Bid quantity (MW)	Bid price (E/MW)	Allocated quantity (MW)
M1	A-C	50	3	50
M2	A-C	50	2.5	50
M3	B-C	50	2	50
M4	B-C	50	1.5	50
M5	A-D	0		

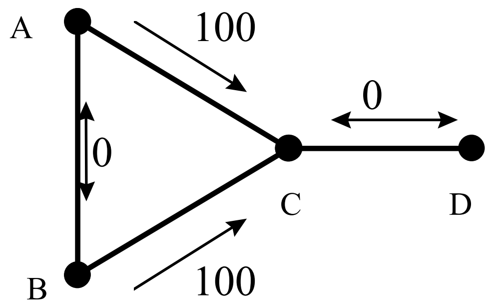


Figure 2

In the coordinated clearing, all the bids are agreed, as their combination does not lead to overpass the « BC limits » , see figure 1. The above diagram on the right side shows the resulting flows after clearing. The A-C line reaches its limit.

<u>Second set of bids :</u>

Now let us add a fifth market participant M5 , which requests an A-D transfer at a high bid price :

Market Partici pant	Transfer requestd	Bid quantity (MW)	Bid price (E/MW)	Cost to induce + or - 1 MW flow on A-C	Allocated quantity (MW)	Marg. Price (E/MW)
M1	A-C	50	3	4.50	50	2,50
M2	A-C	50	2,5	3.75	**40**	**2,50**
M3	B-C	50	2	6.00	50	1,25
M4	B-C	50	1,5	4.50	50	1,25
M5	A-D	10	3	4.50	**10**	2,50

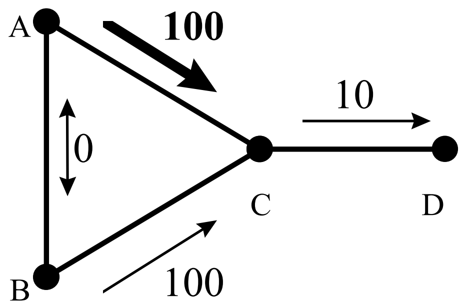


Figure 3

After clearing, the only constrained line is AC. The requested quantity of the five bids cannot be allocated. Due to the PTDF factors, the bids which proposes the highest values on A-C flow are M3 (2 / 0.33 = 6 Euros/MW), then M1, M4 and M5 (4.5 Euros/MW) and finally M2 (3.75 Euros/MW). Therefore this last M2 bid is the first one to be reduced and the 100 MW limit on A-C results in a limitation at 40 MW of M2 allocated quantity. Another way of understanding this result is to start from the figure 2 and to consider that the 10 MWs now requested by M5 wins against the same number of those requested by M2, as both have the same influence on A-C flow and as M5 bids at a higher price.

M2 bid is the marginal bid and so it sets the marginal price on A-C at 2.5 Euros/MW. M2 bid price applies also to M1 and M5 which have the same influence (= PTDF) on A-C flow.

M3 and M4 bids has and influence on A-C flow which is half of M2 ones, so the price they are charged is 1.25 Euros/MW.

Third set of bids :

Let us now consider a slight move in the bid price of M4, who is lowered down to 1 Euro/MW. The clearing changes because the value of M4 bid on A-C flow (which stays the unique constrained line) is now 3 Euros/MW (= 1 / 0.33) while the price proposed by M2 for the same MW of A-C flow stays at 3.75 Euros/MW (= 2.5 / 0.67).

Market Partici pant	Transfer requestd	Bid quantity (MW)	Bid price (E/MW)	Cost to induce + or - 1 MW flow on A-C	Allocated quantity (MW)	Marg. Price (E/MW)
M1	A-C	50	3	4.50	50	2,0
M2	A-C	50	2,5	3.75	**50**	**2,0**
M3	B-C	50	2	6.00	50	1,0
M4	B-C	50	1	3.00	**30**	1,0
M5	A-D	10	3	4.50	**10**	2,0

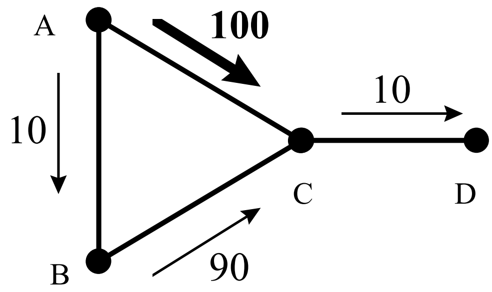


Figure 4

Therefore M4 is now the first bid to be reduced and the 100 MW limit on AC flows results in a limitation at 30 MW of M4 allocation. Another way of understanding this result is to consider that, compared with the second set of bids, M2 wins back on M4 the 10 MW allocation it has just lost against M5. M4 allocated quantity is reduced by 20 MW as 20 MW of M4 are necessary to balance 10 MW of M2 due to the ratio between their respective PTDFs on A-C flow.

M4 bid is the marginal bid and so it sets the marginal price on A-C at 1.0 Euros/MW. M4 bid price applies also to M3 which has the same influence (= PTDF) on A-C flow.

M1, M2 and M5 bids has an influence on A-C flow which is twice the one of M4, so the price they are charged is 2 Euros/MW.

Marginal pricing

With such a marginal pricing method, the above sequence illustrates that the price charged is always under or equal to the bid price (equal for the marginals bids). It shows also that the price requested to each participant is directly related to the influence of their allocation on the constrained lines flows.

No congestion , no payment

It would be easy to show that a participant whose bid does not influence any constrained line would have nothing to pay. For instance, in the above third set, an M6 bid requesting a C-D transfer of less than 140 MW would participate to no congestion and thus would have nothing to pay.

Counterflows are rewarded whatever price they bid

As full netting of opposite flow has been taken as hypothesis, a bid inducing a counterflow is rewarded at the marginal price of the constrained flow it alleviates. In the above third set, so does an M7 bid requesting a B-A transfer.

Market Partici pant	Transfer requestd	Bid quantity (MW)	Bid price (E/MW)	Cost to induce + or - 1 MW flow on A-C	Allocated quantity (MW)	Marg. Price (E/MW)
M1	A-C	50	3	4.50	50	2,0
M2	A-C	50	2.5	3.75	**50**	**2,0**
M3	B-C	50	2	6.00	50	1,0
M4	B-C	50	1	3.00	**48**	1,0
M5	A-D	10	3	4.50	**10**	2,0
M7	B-A	18	0.5	non relevant	**18**	-1,0

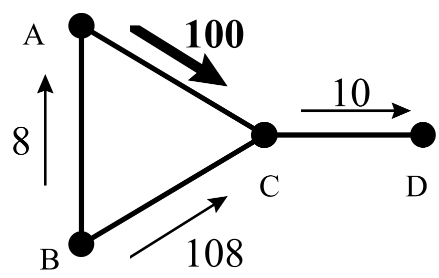


Figure 5

Let us assume an M7 bid of 18 MW. Each 3 MW of this M7 bid creates a 1 MW alleviation of the constraint on A-C, which allows consequently 3 MW more of M4 to be allocated. This phenomena leads to the above clearing and load flow.

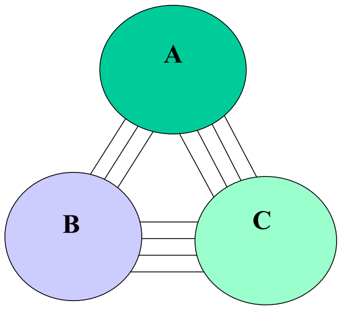
M7 will therefore receive 1 Euro / MW for its bid, whatever positive bid price it has made under the strict condition that he buys a combined right-and-obligation commodity.

Note that over 20 MW requested by M7 on B-A transfer, the system would face a new situation. As all other bids would be fulfilled, the A-C congestion would disappear, its flow getting under 100 MW, then nobody would then be charged at all and consequently no counterflow reward would be given to M7.

APPENDIX 2 : Three zone example

Comparison between NTCs based allocation and Coordinated Auctions

Let's consider three zones A, B and C.



C being taken as hub, we can write the PTDF matrix and the Bottleneck Capacity limits (BC) as follows :

	Tie lines PTDF towards inputs					
Inputs	A-C	C-A	B-C	C-B	A-B	B-A
in A	+72%	-72%	+28%	-28%	+28%	-28%
in B	+36%	-36%	+64%	-64%	-36%	+36%
BC	2000	600	1000	500	1500	1000

The NTC calculation from A to C can be shown on the following figure, where (for instance) the base case consists in the combination of a large exchange from A to C with a small one from A to B (A-B transfer is figured as an A-C transfer combined with a B-C transfer). NTC (A-C) is reached by levelling up the A-C transfer to the value where a constraint is found (the reliability margin is not shown on the figure). With the above hypothesis, one can see[3] that it is possible to draw the line representative of AC border limit (see figure), defined by the relation : 0,72 * transfer(A-C) + 0,36 * transfer (B-C) = 2000

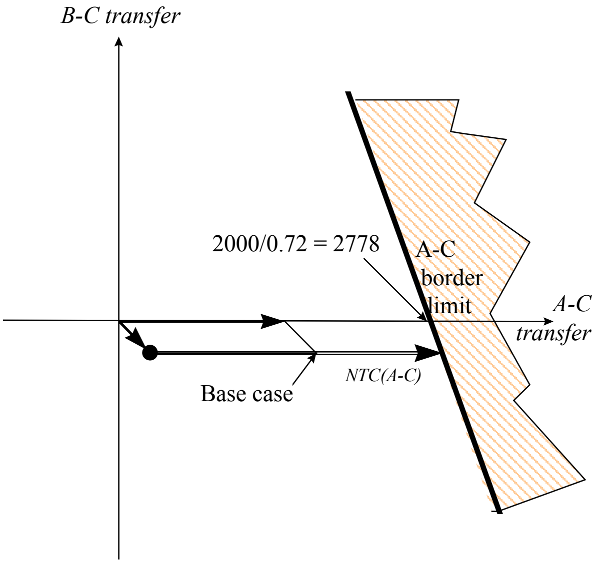


Figure 1 : NTC (A-C) and AC border limit line

[3] If, starting from the point where we have just reached NTC(A-C), we substract 1 MW from the A-C transfer and then add to the B-C transfer 1 / 0.36 * 0.72 = 2 MW, the PTDF matrix told us that the flow on the A-C tie lines comes back to its constraint limit.

Following a similar construction, one can draw the limits in the six possible transfers, as shown on figure 2.

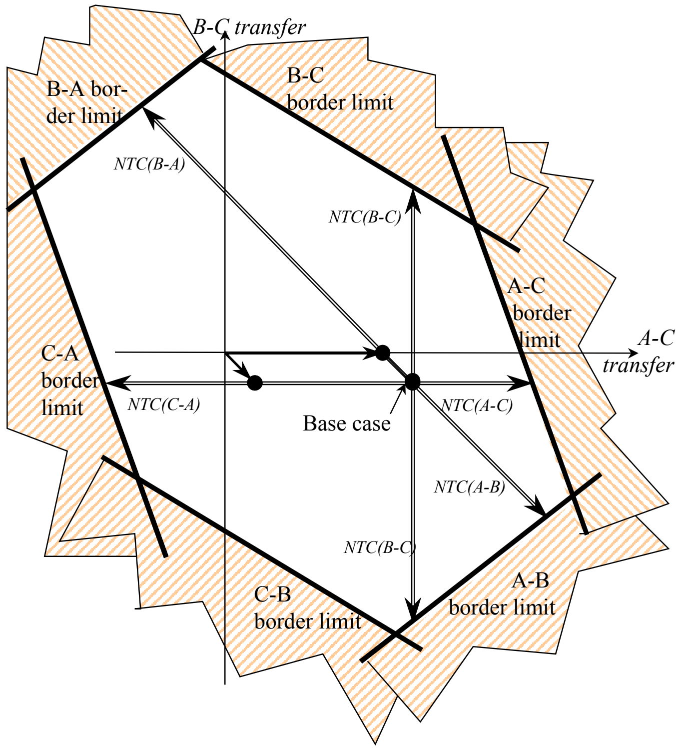


Fig 2 : Polygon of constraints

Note that, depending on the base case chosen, the same constraint line may be reached in two different NTCs assessment, while some other contraints lines are not. In above example, NTC (A-B) and NTC (B-C) are both limited by the A-B border limit, while C-B border limit does not play any role in this NTC assessment. With a different base case, the effect of limiting constraint lines would change.

This simplified representation may also show why contract path methods, whose allocation limits are based on fixed values of NTCs, are poorly designed for using the full range of physical possibilities. On figure 3, the full combination of the three NTCs previously found is represented by an hexagon. The green horizontally-lined part is within the constraint limits, the red bold vertically-lined part is outside, which means such positions cannot be allocated with firmness on TSOs unless using redispatch means to take it back into the unconstrained area.

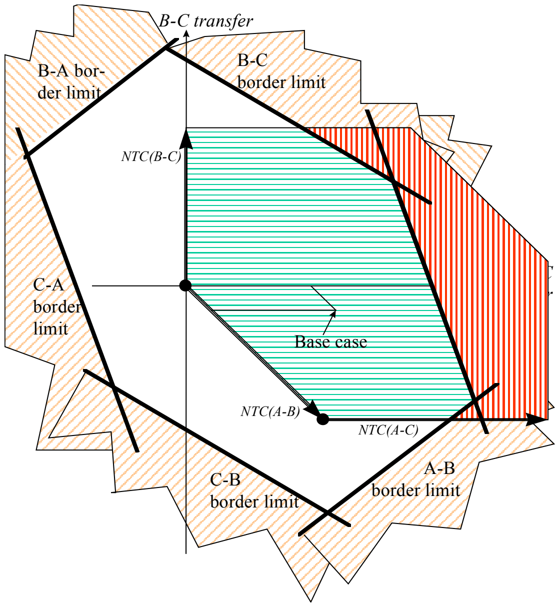


Fig 3 : Combination of three NTCs

The availability of these redispatch means is quite delicate to set up as it should involve the three zones (cross-border coordinated redispatching) , and thus the firmness on TSOs is not easy to guaranty.

The part of the unconstrained area which can be allocated by such separated combination of fixed transfers such as NTCs, with firmness on TSOs and controlled risks, is more or less the vertically-lined green area shown on figure 4.

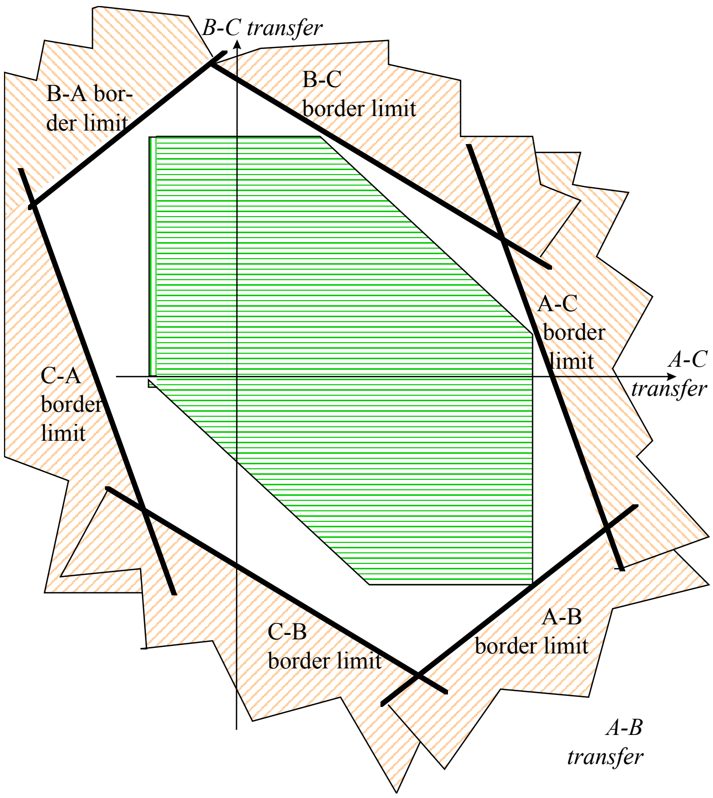


Fig 4 : Possible risk-free allocation with combination of fixed transfers and firmness on TSOs

The maximum transfers allowed in fig.4 are significantly under the theoretical NTCs assessed in figure 2. The unconstrained area which is leftover by this fixed-transfer-based allocation appears in white inside the constraint polygon. It is due to the fact that counterflows created by commercial transfers are not taken in account to alleviate physical constraints in this mode of allocation.

Moreover, these figures shows the strong dependency of NTCs assessment on the choice of the Base Case transfers. This choice being somewhat empirical, the values of NTCs assessed upon are thus questionable in an open trade market.

Finally, the setting up of the maximum transfers proposed in figure 4 would need a lot of coordination between the three TSOs, maybe as much as Coordinated auctioning, for a poorest result.

As for Coordinated Auctions, they do not depend on NTC values although it has been shown how the matrix factors and BC values can be related with current NTC assessment. Once the above constraint polygon is built, Coordinated Auctions combines any set of bids in order to stay within its limits. If the result is on a constraint line, that means that this congestion is reached and that some payment will be required from the participants whose bids are responsible for reaching the congestion. If the result is out of the constraint lines, that means that no congestion is reached and thus no payment is required from the corresponding participants.

In case of rights-and-obligations, it is even possible to allocate transfers which would have led to constraint if taken alone, but which are balanced by counterflows due to the other bids (see fig 5).

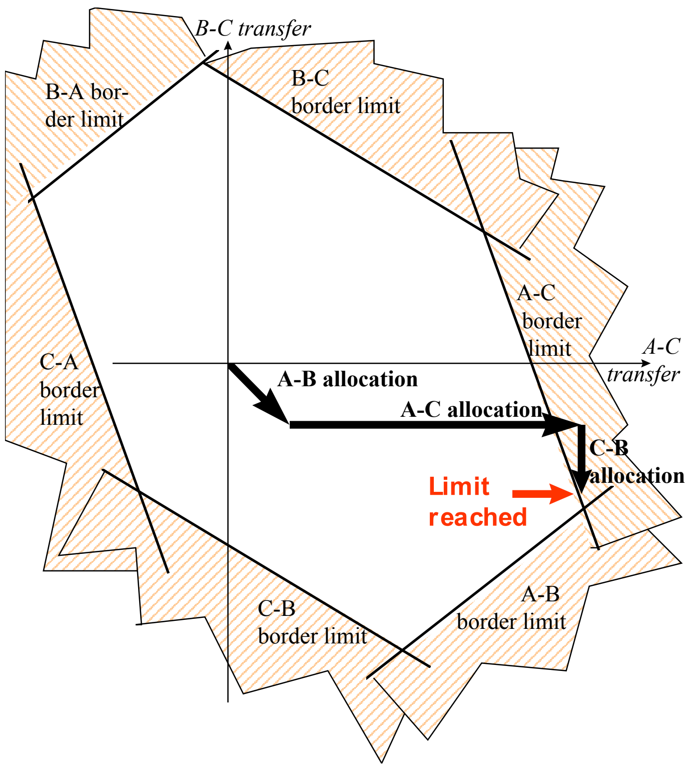


Fig 5 : Allocation of rights-and-obligations with coordinated auctions

In the case represented on figure 5, A-B and A-C allocated transfers plays a direct role in the reaching of the limit and thus will pay for such an allocation, while C-B allocated transfer has a counter-flow effect and thus will receive money out of the Coordinated auction mechanism, providing that marginal pricing variant is applied (see Appendix 1).

APPENDIX 3 : Mathematical Formulation

Let us define a mathematical formulation of the problem :

The network is represented as a set of N nodes, each of them standing for a control area. Let us call by capital letter these nodes : A, B, C, ... They can be associated in oriented doublets [X,Y].

The neighbouring nodes are linked by I interconnections, let us call these interconnections by Greek letters : α, β, γ, ...

Each bid consists in an identification, an origin, a destination, a requested quantity and a bid price. Let us call XY1, XY2, XY3, ... the bids whose origin is in area X, and whose destination is in area Y. Their bid price and requested quantity are written π (X,Y,1), ... and Qreq (X,Y,1), ... Let us consider that they are systematically classified such as $\pi (X,Y,1) \geq \pi (X,Y,2) \geq .... \geq \pi (X,Y,i) \geq ... \geq 0$[4]

The clearing process results in a quantity allocated to each bid. We will write this quantity Qall (X,Y,i). These quantities can be summed up all over a doublet [X,Y] to get the quantity allocated to the doublet $Qall(X,Y) = \Sigma_i \{Qall(X,Y,i)\}$.

The «participation» matrix described in above chapter III is called R. Each element of R, written $r(X,Y,\varepsilon)$, represents the proportion of an XY exchange which flows through the ε interconnection. This coefficient is often called in literature « participation factor » or «Power Transfer Distribution Factor» .The matrix $R = [r(X,Y,\varepsilon)]$ has N*(N-1) lines (each doublet is considered in both direction) and I columns.

For each interconnection ε, a Bottleneck Capacity $BC(\varepsilon)$ is evaluated by the neighbouring TSOs, this value being an image of the maximum flow through the interconnection compatible with security rules.

The optimisation problem can be written in two strictly equivalent ways :

Maximise the objective function $\Sigma_{XYi} \{\pi(X,Y,i)*Qall(X,Y,i)\}$ or

Minimise the objective function[2] $\Sigma_{XYi} \{\pi(X,Y,i)*[Qreq(X,Y,i) - Qall(X,Y,i)]\}$

under the constraints : $Qall(X,Y,i) \leq Qreq(X,Y,i)$, whatever X,Y,i

$Qall \leq AC$ (AC is an optional transfer limit, called auctioned capacity)

$R^T*Qall \leq BC$,

$Qall(X,Y,i) \geq 0$[3], whatever X,Y,i

Note that if we call $R^T(\alpha)*Qall = f(\alpha)$ the «flow» on interconnection α, other constraints can be added without compromising the generality of the problem posed, such as :

$f(\alpha) + f(\beta) + f(\gamma) \leq F$ if the flows has to be limited on the sum of the three considered interconnections. [4]

What could be the price paid by each participant after the clearing process ? The idea developed here is threefold:

- to make a participant pay for a bid only if this bid is participating to an active capacity constraint ;

[4] No negative bids are considered at this level of our analysis.

[2] This form of the criterion represents the «burden» of the network

[3] Except possible reselling capacity acquired in previous longer-term auction rounds where Qreq could be counted negatively in the objective function and the capacity constraints.

[4] It is possible to enhance the complexity of constraints taken into account (as long as linearity is maintained, this does not add special difficulties). For instance, suppose that in the example C wishes to limit the import flow from A+B (because of interior network constraints within C) : then a linear constraint (sum of the flows limited by this bound) could be added.

- to charge the same payment to each participant bidding in the same (X,Y) pair of area. This price will be written $\pi(X,Y)$ (i.e. marginal pricing principle) ;
- to never overpass the bid price of any participant when using $\pi(X,Y)$ value.

The solution given by the Theory of Optimisation is to use a dual variable πBC associated to each BC. For each interconnection ε, this dual variable equals the variation of the objective function associated to a 1 MW move of BC.

$\pi BC(\varepsilon)$ equals to zero if the interconnection is not saturated - that is to say if the capacity $BC(\varepsilon)$ exceeds the demand in the interconnection after clearing - it is positive if the interconnection is saturated[5].

From these set of πBCs, the marginal price $\pi(X,Y)$ can be assessed by the formula:

$$\pi(X,Y) = \Sigma_{\varepsilon} \{r(X,Y,\varepsilon) * \pi BC(\varepsilon)\}$$

$r(X,Y,\varepsilon)$ are the coefficients of the participation matrix above defined.

Each bid participating to the constraint may then be charged this «marginal» price. It can be mathematically shown that $\pi(X,Y)$ is systematically lower that all the bid price put on (X,Y) pair of area as soon as they get some capacity allocated.

The total auction revenue is then :

$$AR = \Sigma_{XY} \{\pi(X,Y) * Qall(X,Y)\}$$

The summation being carried out only on the borders where congestion has actually occurred ($\pi(X,Y)=0$ if the capacity is higher than the transmission demand).

About the revenues allocation to TSOs, here again the optimisation theory can be helpful : an idea here could be to use the dual function in order to allocate the revenues, each TSO keeping half of the revenue for each doublet.

<u>First variant : allocation of auction revenues to TSOs according to the influence of the bids originated from (or destined to) their area on the saturated interconnections :</u>

$$\text{Revenue of } X = ½ * [\Sigma_Y \{\pi(X,Y) * Qall(X,Y)\}$$

<u>Second variant : allocation of auction revenue to TSOs according to the location of the saturated interconnections :</u>

$$\text{Revenue of } X = ½ * [AR * \Sigma_X\{\pi BC(\varepsilon)\} / \Sigma_{\varepsilon}\{\pi BC(\varepsilon)\}]$$

AR = Total Auction Revenue

It is important to note that the "pay-as-bid" option, if chosen in the mechanism, would lead to similar developments.

[5] In some situations, the dual variable is discontinuous that is to say that the value when moving AC upwards differs from the value when moving downwards. In such a case we will consider the maximum of these two values in the following calculations.

Appendix VI

ETSO - Co-ordinated Use of Power Exchange for Congestion Management

Co-ordinated use of Power Exchanges for Congestion Management

Final Report
April 2001

Table of contents

1. INTRODUCTION

In the Conclusions from the Sixth meeting of the European Electricity Regulatory Forum, Florence, 9.-10. November 2000 it is stated that appropriate mechanisms for cross-border tarification and congestion management have to be in place to promote the development of cross-border trade.

It is further stated that market based congestion management methods which

- ensure optimal utilisation of transmission capacity
- give appropriate price signals to the market parties and the TSOs involved
- are non-transaction based

are preferred.

According to the Florence Forum conclusions, market splitting meets these requirements, but is considered to be too difficult to implement in the short-term, since it requires the existence of exchanges or power pool based arrangements on both side of the interconnection.

The purpose of this paper is to discuss the obstacles and options for implementing a ”market splitting” model in Continental Europe. First the Nordic market splitting model is described, then the main obstacles for implementing a similar model in Continental Europe are outlined and finally the options for a co-ordinated use of power exchanges for congestion management in the area are described.

2. MAIN PRINCIPLES FOR CONGESTION MANAGEMENT

Although congestion management methods for open electricity markets exist in many variations, the most commonly considered schemes can be categorised as:

- Explicit auctions, where only the transmission product (MW) between two areas is traded
- Implicit auctions, where both the energy (MWh) and the corresponding transmission product (MW) between bidding/price areas are traded simultaneously and are coupled
- Counter trade/re-dispatch

In this context market splitting is a variant of implicit auctions, whereas counter trade/re-dispatch is a decongestion method used by the TSOs to alleviate congestion for the benefit of market players.

The main characteristic of implicit auctions is that transmission capacity and energy are coupled and traded simultaneously, ensuring that transmission capacity is allocated according to energy trading requirements.

3. *THE NORDIC POWER EXCHANGE AND MARKET SPLITTING*

Nord Pool is a power exchange including Denmark, Norway, Sweden, and Finland. These four countries have liberalised their power markets and through the joint exchange, they have established a joint power market.

Nord Pool has two market places: Elspot and Eltermin. Elspot is the spot market where physical kWh are traded. Eltermin is a commercial centre in which price securing contracts are traded.

3.1 Elspot - the Spot Market

Participants who want to buy or sell kWh via Nord Pool's Elspot, must send their bids and/or offers to Nord Pool by 12 o'clock the day before delivery.

At Nord Pool, the bids and the offers for each hour the following day are put together to form one total demand curve and one total supply curve. The so-called system price can be read at the point where the two curves intersect one another. The system price is the price that would be obtained in the whole Nord Pool area if there were no congestion.

Nord Pool determines a system price for each hour of the following day. This means that the price on Elspot may fluctuate from hour to hour but the price is fixed for one hour at a time.

3.1.1 Bidding areas and price areas

Obviously, it may happen that, in one area, an amount of power, which is simply too small, has been offered at the system price. This may happen if constraints in the grid makes it impossible to transport enough power into this area. If so, the area becomes a so-called high price area, in which the price is higher than the system price.

Correspondingly, it may occur that, in one area, too much power has been offered at the system price, and the grid cannot transport the amount of power necessary out of the area. If this happens, the area becomes a low price area: an area in which the price is lower than the system price.

Every bid and offer is related to a given bidding area. Bidding areas turn into separate price areas if congestion between them occurs as a result of the bids and offers.

The Nord Pool-area is divided into 6-8 geographically limited bidding areas. Norway can internally be divided into several bidding areas, whereas Finland, Sweden, Jutland/Funen and Zealand each make up one bidding area. The structure of the Nordic electricity system allows a rather permanent definition of bidding areas, and it is always possible to calculate available transmission capacity between them without significant interdependencies.

3.1.2 Constraints in the grid

All the transmission capacity between bidding areas is managed by Nord Pools spot market.

Nord Pool uses the capacity for conducting power out of low price areas and into high price areas. Thereby, the price in high price areas is reduced and the price in low price areas is raised. The system secures that for every hour of operation, all the capacity of the constraints is utilised in accordance with current price signals.

This price discovery process is illustrated in the following figures.

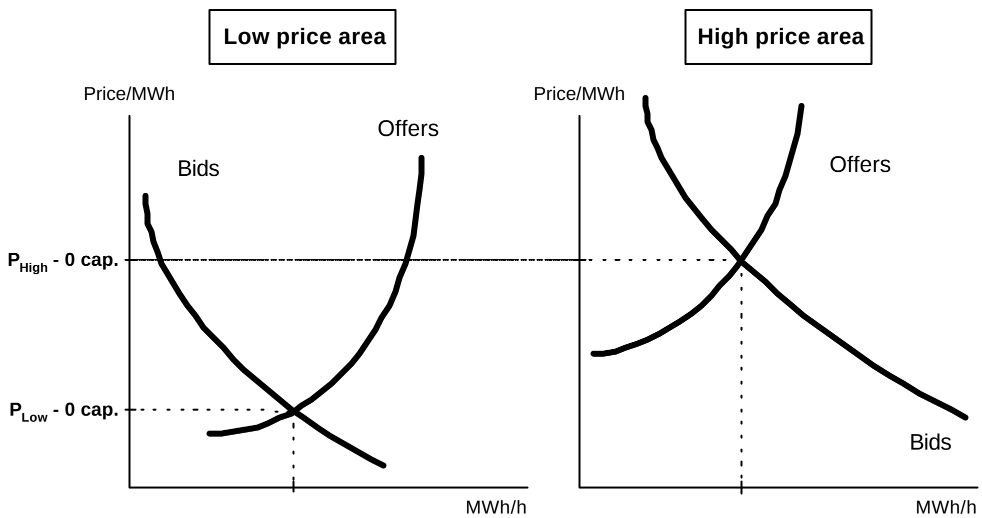


Figure 1 *Area prices without exchange between high and low price areas*

Figure 1 illustrates how prices would have been set in the high and the low price areas without any exchange between the areas. Figure 2 illustrates the change in area prices due to an exchange from the low price area into the high price area according to the available transmission capacity between the two areas.

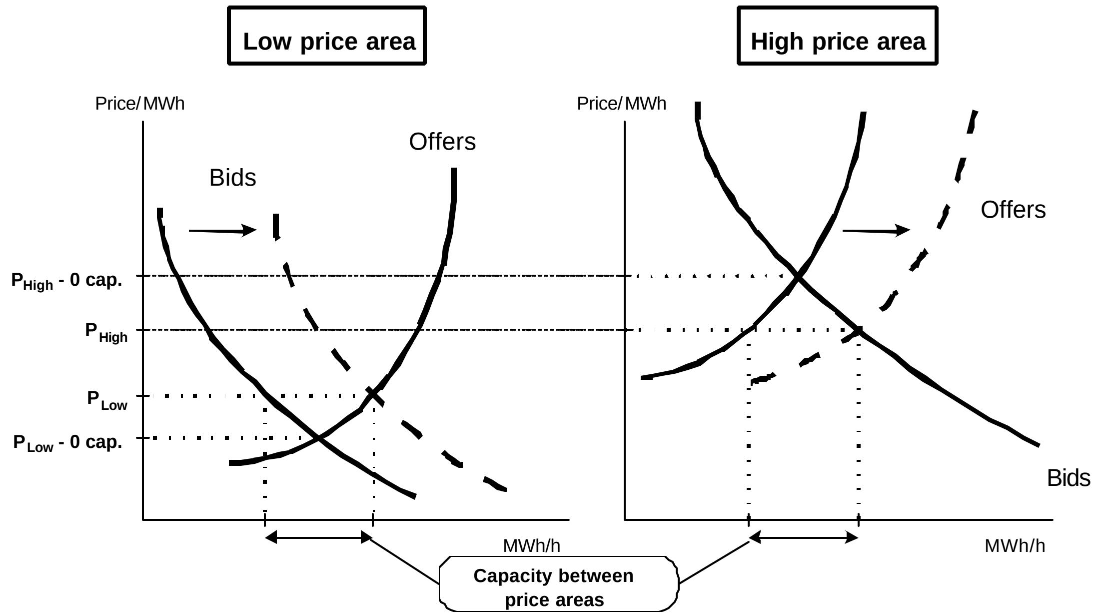


Figure 2 *Area prices with exchange between low and high price areas*

The exchange raises the price in the low price area from "$P_{Low\text{-}0\ cap.}$" to "P_{Low}", and reduces the price in the high price area from "$P_{High\text{-}0\ cap.}$" to "P_{High}".

The next figure is included to illustrate how much transmission capacity is needed to avoid congestion and thereby attain equal prices (=system price) in the two areas.

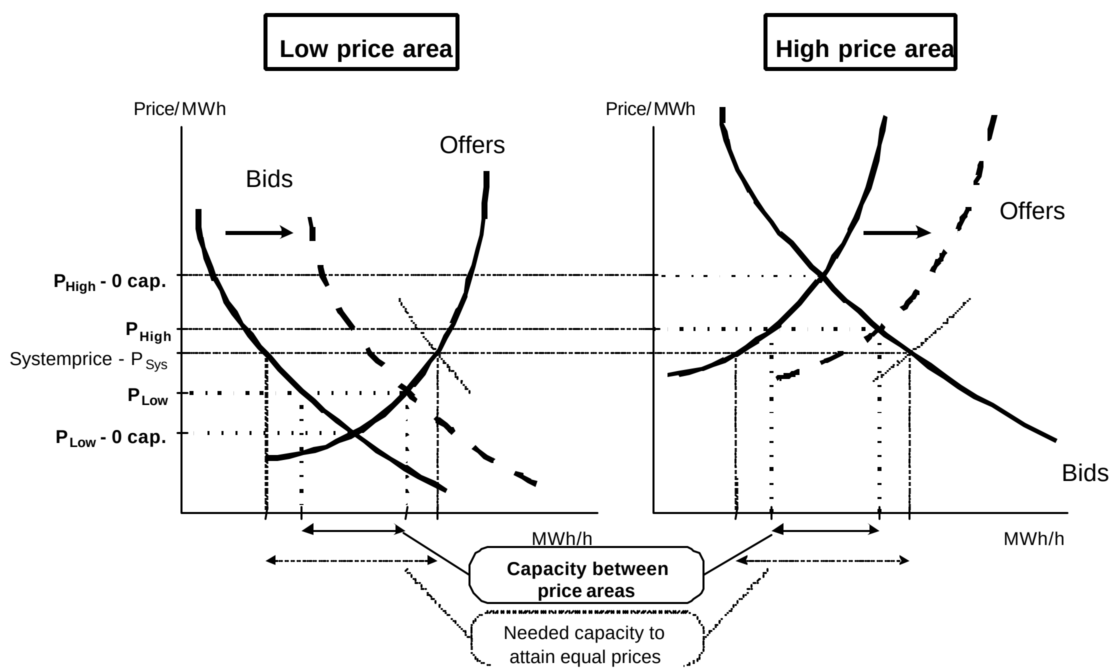


Figure 3 *Needed transmission capacity to attain equal prices (system price) in the two areas.*

If the illustrated "needed capacity" is available, the exchange of electricity is sufficient to attain equal prices in the two bidding areas and there will only be **one** price area.

With separate price areas sellers in the "exporting" low price area are paid the "low price" while buyers in the importing high price area pay the "high price". The difference can be considered as a capacity fee paid to the TSOs via the power exchange.

Market players cannot trade physical energy directly between bidding areas. This is impossible because all the capacity of the constraint is managed by the power exchange.

3.2 Eltermin

Eltermin is a commercial centre where price-securing contracts are traded. In effect, both parties involved in such contracts take out mutual insurance.

A contract is settled by comparing the average system price for the week concerned with the hedge price in the contract. The difference in price is multiplied by the volume in the contract, and this amount of money is transferred between the parties. A price-securing contract is therefore not only a mutual insurance; it is also a mutual obligation.

The two parties involved in the futures contract do not know each other's identity if the contract has been made via Nord Pool's market Eltermin. All settling of accounts takes place via Nord Pool. Furthermore, Nord Pool guarantees the settling of accounts; Nord Pool enters the contract if one of the parties cannot fulfil its obligations.

It is important to note that kWh are not exchanged between the parties of a price-securing contract. Only money is exchanged.

The parties can submit bids and offers to Elspot with unspecified prices if they wish to trade the energy physically. They do not need to worry about the price, because it is hedged in the futures contract.

Since market players cannot trade physical energy directly between bidding areas, they have to make a financial contract to be guaranteed a certain price. The two participants trade the physical energy with the spot exchange, and afterwards they settle with each other in accordance with the financial contract.

Participants within the same bidding area may also deal in physical kWh with each other. The exchange has no monopoly within bidding areas.

4. REQUIREMENTS FOR IMPLEMENTATION OF MARKET SPLITTING IN EUROPE

The Nordic implementation of the market splitting model is based on the following principles:

- **all** physical trade between congested bidding areas has to go via the power exchange (with financial arrangements which have to be agreed upon by the involved parties)
- there is only **one** power exchange handling physical trade between bidding areas
- bidding areas are defined as rather permanent geographically limited areas (bottlenecks are always at the same locations)
- all major permanent constraints are located at interconnections between bidding areas
- there is a low interdependency between individual net transfer capacities, so that they can be calculated beforehand
- constraints within bidding areas are either handled as constraints on the interconnections between price areas or handled by TSOs through re-dispatching.

It is evident that these conditions can not all be met immediately in the continental part of the internal electricity market.

There are physical, structural and market obstacles:

- The highly meshed structure of the Continental Europe network complicates the definition of bidding areas and available transmission capacity between these in advance. The physical flow pattern and consequently the appearance of congestion changes considerably with both demand and generation.
- The net transmission capacities across neighbouring areas are strongly interdependent and cannot be calculated separately from one another. Thus the conventional “Market Splitting” algorithm for the determination of the “maximum power” exchange between areas cannot be applied.
- The electricity markets in Continental Europe are at present far from being compatible enough to implement a common market splitting system
- Market participants should be asked for their agreement on the impact of market splitting on bilateral trade between congested areas.

5. *OPTIONS FOR CO-ORDINATED USE OF POWER EXCHANGES FOR CONGESTION MANAGEMENT IN EUROPE*

Assuming that market actors are ready to accept that direct bilateral trade between congested areas may be affected financially by the congestion management scheme, it is then necessary to find practicable solutions to overcome both the physical and the structural obstacles mentioned above before considering the implementation of a market splitting model in Continental Europe.

Market splitting does not solve the problem with varying and strongly interdependent constraints in the transmission network in Continental Europe. As explained above, market splitting presupposes well-defined bidding areas and available transmission capacities between these.

The simplest possible design is obtained by allowing only **one** power exchange to handle **all** physical trade between bidding areas and thereby exclude all bilateral trade between these as in the Nordic model. Nevertheless, this design does not seem to be acceptable by all European market actors.

A more complex design would be required to allow:
- several power exchanges to handle physical trade between bidding areas and
- bilateral trading between bidding areas as well.

In such a design,
- strong co-ordination between power exchanges and bilateral trade and
- strong co-ordination between several power exchanges

must be developed to implement market splitting.

This is the minimum design to operate without capacity interdependencies between areas. The case where interdependencies exist is addressed in paragraph 5.4

In the following it is assumed that there will be at least one power exchange operating a spot market in a given bidding area.

5.1 Definition of bidding areas and available transmission capacity

A prerequisite for market splitting is a rather permanent definition of a number of geographically limited bidding areas. The criteria for defining these areas is the location of the physical constraints in the transmission network, that is: all major physical constraints are located at the interconnections between bidding areas.

In the market splitting model the market players only experience constraints between bidding areas. Constraints occurring within bidding areas should ideally be handled via re-dispatch by the TSO, but can also be taken into account when setting the limits for the interconnections. Market splitting as well as most kinds of explicit auctioning (except co-ordinated auctioning) has to be based on a set of calculated values for available transmission capacity.

The definition of bidding areas and calculation of available capacity on interconnections should be based on load-flow calculations which locate the major constraints in the transmission network.

5.2 Co-ordinated use of several Power Exchanges

With more than one power exchange handling physical trade between bidding areas, it would be necessary to ensure co-ordination between the implicit capacity auctions, by integrating the net balances for each bidding/price area.

When congestion management is based on market splitting, the allocation of transmission capacity must be based on the same marginal value for the difference between area prices at all power exchanges, i.e. the capacity fee for a certain congestion between two price areas must be the same at all power exchanges. This argument excludes ex-ante allocation of capacity between the power exchanges.

The traded products and their prices in a certain area do not necessarily have to be the same at all power exchanges. Products could for instance slightly differ with respect to time interval, risk and fee, even if some requirements must be met in terms of power exchange gate closure synchronisation, etc.

The allocation of transmission capacity between power exchanges could be based on summarised bids for capacity per power exchange for each interconnection (capacity fee = difference in area price).

A high degree of co-ordination is needed between Power Exchanges and TSOs.

5.3 Concurrent operation of Co-ordinated use of Power Exchanges and Bilateral Trade

A system with both power exchange trade and bilateral trade between price areas calls for a method to distribute the available transmission capacity between these two types of trading. In this paper all spot trade on power exchanges is assumed to take place day ahead.

A possible method is an a-priori allocation of slices of transmission capacity to explicit capacity auctions and power exchanges respectively.

The distribution of available capacity between power exchanges and explicit auctions has to be decided before these are carried out. It could be decided to offer a slice corresponding to X% of the available capacity in explicit auctions and allocate the rest to power exchanges. To ensure a high utilisation of capacity the longer term explicit capacity auctions (for instance yearly and monthly) have to be combined with implementation of the "use it or lose it" principle ahead of the daily allocations. Unused capacity bought in long term explicit auctions would be entered into the daily spot market.

Theoretically it is possible to sell capacity obtained in the longer-term capacity auctions on the power exchange by entering a capacity-offer (price/MW) into the spot market. This would however partly violate the "use it or lose it"-principle for long term capacity reservations.

An alternative to capacity slicing is to let power exchanges buy capacity in the explicit capacity auctions on equal terms with all other market players, and then offer this capacity in the implicit auctions.

With market splitting a capacity fee is obtained due to the difference between area prices in case of congestion. This capacity fee is at first collected by the power exchange. If a slice of capacity is put at free disposal for the power exchanges, without charge, the capacity fee should be paid to the TSOs. If on the other hand the power exchanges beforehand have to buy capacity at their own risk in explicit capacity auctions the capacity fee obtained by the later market splitting could be considered a recovery of these prepaid costs.

Net revenues from congestion management should in all cases be allocated to grid investment.

In market splitting the allocation of capacity to trades in the power exchange is done implicitly on the basis of the bids and the resulting difference between area prices. A way to include bilateral trades in this capacity allocation is to allow bids for capacity alone (price/MW) in the spot exchange along with bids for energy (price/MWh). By letting these bids enter into the implicit auction and compete for capacity with the power exchange energy trades, it is possible to allocate capacity to all day ahead trades on equal terms. Capacity is allocated to bilateral trades with higher bids for capacity than the resulting difference in area prices.

5.4 Improvements to take into account network interdependencies

ETSO has also produced a document describing the co-ordinated auctioning allocation method. The concepts used in this method could also be used to take into account network constraints for the optimal management by TSOs of physical exchanges of power between different areas managed by different Power Exchanges. Nevertheless, this sophisticated evolution of market splitting has still to be worked out.

6. CONCLUSIONS

Market splitting is a very interesting principle for congestion management, but it has severe requirements that have to be addressed before considering implementation outside Nordel.

In a system where the location of potential constraints is rather permanent and the capacity of these can be calculated ex-ante, and where bilateral trade is not permitted, market splitting in the Nordic form can ensure an optimal market based utilisation of congested lines.

In Continental Europe there are a number of physical, structural and market obstacles to market splitting in its simple form:

- It is a highly meshed network where both the location and the capacity of congested lines changes considerably with demand and generation.
- The Net Transmission Capacities across neighbouring constraints are strongly interdependent and cannot be calculated independently.
- Market participants should be asked for their agreement on the impact of market splitting on bilateral trade between congested areas.
- The electricity markets in Continental Europe are at present not compatible enough to implement a common market splitting system.

An advanced and rather complicated form for market splitting based on the allocation principles described in the ETSO paper "Co-ordinated Auctioning of Transmission Capacity in Meshed Networks" could be a potential candidate for a future congestion management method in Continental Europe, but this sophisticated evolution of market splitting has still to be worked out. For the time being co-ordinated use of power exchanges for congestion management is not considered to be a method that can be implemented in Continental Europe.