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Simulation of regional power markets in the planning of trans - border interconnections

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Abstract--**The paper presents the methodology adopted for simulating a regional power market within the frame of a feasibility study of a 1200 km long 2000MW trans-border interconnection. The Generation-Transmission Maximization (GTMax) software, which serves as a focal point of the study, was supported by other tools and models for optimizing water resources and long-term generation planning. The simulations have been performed on a yearly basis for the 2012-2027 time period in order to assess the interconnection capacity, the optimal staged development, and ultimately the economic viability of the project. GTMAx simulations also supported the application of the N-1 criterion for selecting the modular rating and overload capability of the HVDC converters. This was achieved by computing the yearly duration of energy interchanges within a particular power range and through the valuation of the energy exchange opportunity loss due to capacity constrains of the interconnector.**

***Index Terms*--power transmission planning, energy resources, optimization, interconnections, reliability.**

I. Introduction

PLANNING for cross border interconnections must deal with not only technical challenges such as long distances and high capacities, but also with political, institutional, load forecast and market strategies aspects. Essentially, it has to cope with major uncertainties related to the size, location and timing of the power generation sites and the associated load forecast. In many developing countries the only option to deal with a capacity shortage is to secure trans-border bulk power exchanges and to participation in regional power pools. Globally considered, the power exchanges are effectively using the regional load diversity and energy resources, while tremendously increasing the both power quality and reliability leading to a major step towards social development and sustainable economic development [1].

In addition to the conventional power system analysis, load forecasting and least-cost generation development models, modern transmission planning must simulate the operation of the regional markets, quantifying the benefits of the interconnection under a variety of power exchange scenarios, and provide the basis for the economic and financial analyses. High funding requirements of the transmission projects, require a thorough assessment of the bankability of the project and ultimately its feasibility [2].

The paper presents the methodology adopted for simulating the regional power market within the frame of a feasibility study of a 1200 km long 2000MW trans-border interconnection, using the Generation-Transmission Maximization (GTMax) software tool.

II. Approach and Methodology

An integrated framework consisting of several software tools and databases has been developed for the power market simulation and analysis, as shown in Fig 1.

The planning horizon took into account 15 years. Since the interconnection makes use of remote hydro resources, the information flow shows interfaces to a specialized reservoir simulation package (water inflows, reservoir characteristics, hydro generating units). This data has been, in a first step, used for developing the least cost generation expansion plans of the utilities on both sides of the interconnection.

The results of the least-cost generation expansion plans for the isolated utilities have been the starting point for the regional generation - transmission - load simulations and optimization performed by GTMax [3]. Besides the information on generation, transmission network and loads for each of the 15 years, the optimization model has taken into account different exchange scenarios, starting from bilateral firm contracts and up to open power market.

The GTMax simulations were carried out for each year in the planning horizon, in two different configurations:

- without the interconnection (isolated utilities), and

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- with the new interconnection line.

The first configuration creates a reference with respect to nodal and average costs of the generation before the interconnection and provide important input for the financial and economic analyses (for example for assessing the avoided costs in the importing system). The second configuration, featuring the completion of the interconnection line, is used to determine the potential for profitable power exchanges and to optimally size the capacity of the interconnection transmission lines and HVDC terminals.

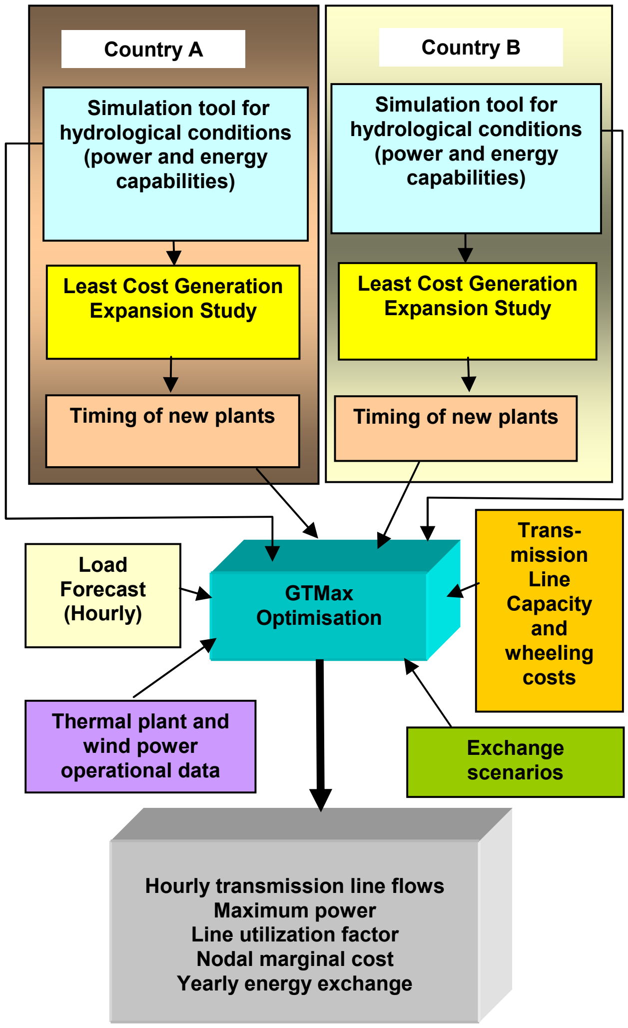

Fig. 1 Generation and Transmission Optimization methodology using GTMax

III. Generation and Transmission Optimization

GTMax takes into account the topology of the network, interconnection transfer capacity, hourly loads, and supply costs in each of the two power systems. The program requires information on the unit commitment, individual unit production costs, hourly electrcity demand and the network topology.

GTMax calculates the energy sales or purchases in different areas of the system assuming a competitive power market, under capacity constraints on the interconnection lines. The optimization criterion is to minimize overall operating cost of the interconnected systems; main output deliverables are the operating points of the dispatched units and the amount of exchanged energies over monitored lines on a hourly basis.

Hourly sequential time variances of both demand and production are considered by the model for four representative weeks that account for seasonal variations. Other sets of scenario results produced by the modeling process include transmission line N-1 interconnection element outages, different hydrological conditions and regional trade scenarios.

In the model, hydropower plant operations are driven primarily by hourly electricity demand, grid transmission constraints, the physical characteristics of each individual hydropower plant and associated reservoir, and temporal hydrological conditions that constrain the amount of energy a plant produces.

As illustrated in Fig. 1, GTMax uses monthly projections of hydropower energy and capacity derived from a reservoir routing model that simulates hydropower operations for both existing plants and new plant additions. In the model, hydropower plant operations are driven primarily by hourly electricity demand, grid transmission constraints, the physical characteristics of each individual hydropower plant and associated reservoir, and temporal hydrological conditions that constrain the amount of energy a plant produces.

Hydropower simulations are initially performed with conventional hydrological tools on a monthly time step, producing estimates of both plant-level generation and capacity. Simulation are based on statistical data for a 50 year historical period. The prepared hydrological model estimated hydropower plant operations under five hydrological conditions, ranging from very dry to very wet.

GTMax uses these results to further refine the simulation from a monthly time step to an hourly one. Fig. 2 shows weekly, country-level seasonal hydroelectricity production. Generation levels shown in the figure are based on extremely dry hydrological conditions and account for plant scheduled maintenance. As new hydropower plants are brought on-line, hydropower generation increases over time.

Fig. 3 shows hydrological simulation tool projections of monthly electricity generation in 2015 under a wide range of hydrological conditions for all hydropower plants in both countries,. Hydrological variability tends to be relatively low during the dry season (January through June) as opposed to the wet season, featuring a much wider hydrological variability.

IV. Sizing of Interconnection

An hourly optimization of the interconnected system operation was performed for each year from 2012 to 2027.

The results of the GTMax simulation for the power flow on interconnection are shown exemplarily for the year 2017 in Fig. 4.

The bidirectional, cost-minimized energy flow was calculated as statistical distribution over the transmission interconnection.

Of special importance for sizing the interconnection capacity is the time duration of a particular exchange magnitude, computed by GTMax. Model output is used to quantify the economic impact of a capacity restriction (like due to a circuit outage of a double circuit line or one pole of a bipolar HVDC link) and therefore it directly interacts with the economic and financial analyses [4].

The annual average line utilization duration was estimated at 5000h, GTMAx being used to identify the yearly duration for which the power flow over the interconnection exceeds a particular capacity constraint. Fig. 5 presents the yearly average power flow over the transmission interconnection, for the assumed utilization factor.

In a first iteration, the unconstrained power flow over the interconnection line is used to approximate the most economic capacity of the line. However, the proposed technical concept, introduces for cost reasons capacity constraints in case of single outages, so that it is necessary to evaluate iteratively the impact on the unconstrained energy export and select an optimum rated capacity, from both investment cost and economic performance points of view.

The bottlenecks are specific to the HVDC technology which was selected as technical alternative. The strict application of the N-1 criterion to the HVDC alternative leads to very high investment costs. As partial substitute, the conceptual design in case of one pole unavailability recommends specifying a continuous overload of 30%. This capability is in practical cases reflected in a moderate increase of the bipole cost, since it is still possible to make use of the full HVDC filter capacity.

Following a gradual development of the generation capacity, a phased development of the converter capacity was proposed in two phases of 1000 MW each. For the first 1000 MW phase, the strict application of the N-1 criterion would lead to doubling the converter capacity. But the link being bipolar with very remote possibility of a common mode failure, the most probable single outage is of one single pole. The pole in operation can be specified practically without cost impact for a continuous overload capability of 10%. Moreover, assuming that the associated HVAC filter capacity is not affected by the pole outage, it is possible to obtain a price impact of only 15% for an overload capability of as much as 30%. The constrained capacity for the duration of one pole outage is therefore 650 MW. For the bipolar operation it is only required to consider the standard continuous overload capability of 10%, or 1100 MW. The impact of these constraints on the energy exchange opportunities was quantified computed by GTMAx, in following steps:

- compute exceedance curves as exemplified in Fig 5, showing the duration of the unconstrained power flow ranges
- indicate capacity constraints, for example the single pole operation of the bipole, under standard (10%) or special (30%) continuous overload capability
- compute energy exchange opportunity loss due to the capacity constraint, as exemplified in Table I.

The results in Table I show that the amount of unserved energy resulting from opportunity losses in case of pole outages is very low, not justifying economically a concept based on full compliance with the N-1 planning criterion.

Fig. 6 shows the comparison between the power transferred over the interconnection line for more than 5000 h yearly, corresponding to a line load factor of 0.57 and the design capacity as discussed above: 650 MW for the first phase of the project and 1300 MW for the second phase.

The interconnection design capacity was finally selected based on thermal withstand suitable to the identified power flows, for all generation commitment and export scenarios.

TABLE I
TRANSMISSION CAPACITY OPTIMIZATION FOR YEAR 2017

YEAR 2017	Reference Capacity	Overflow.	MW distribution function (GTMax results)					TOTAL Unserved Energy	
	MW	% year	1000 1100	1100 1200	1200 1300	1300 1400	1400 1500	[MWh/year]	% Annual flow
Rated capacity, MW	**1000**	0,114	0,05	0.03	0.015	0.013	0.006		
Unserved Energy [MWh/y]			43800	52560	39420	45552	26280	103806	1.80
110 % Overload, MW	**1100**	0.06	0	0.03	0.015	0.013	0.002		
Unserved Energy [MWh/y]			0	26280	26280	34164	7008	46866	0.81

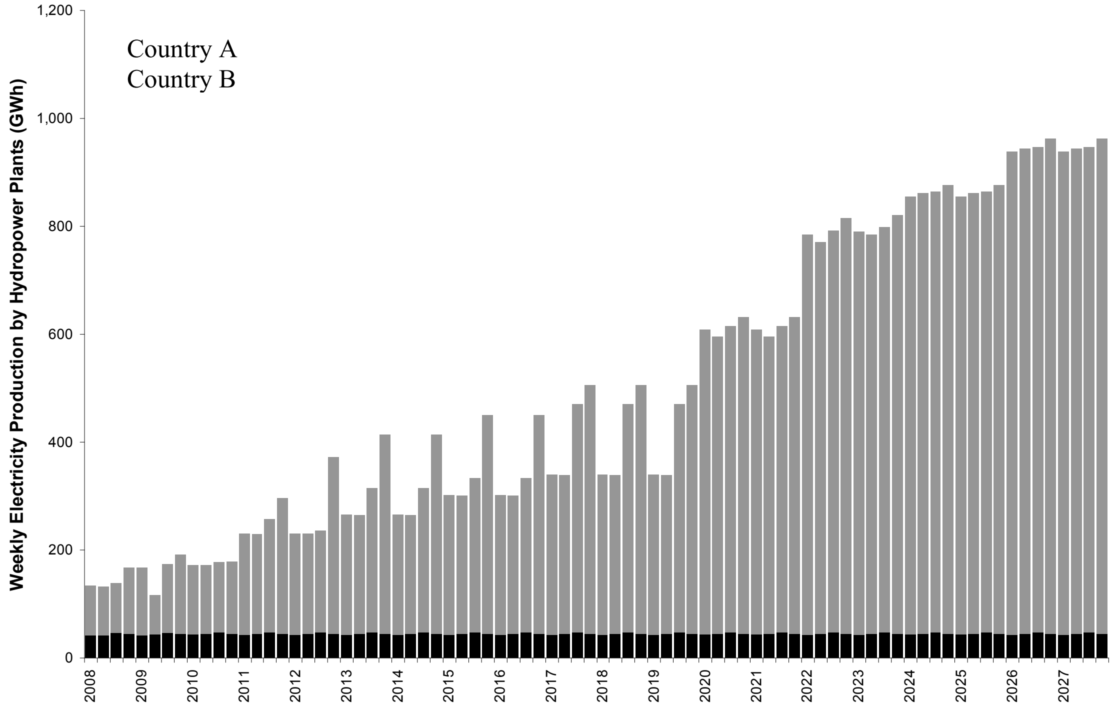

Fig. 2 Weekly country-level hydro power production by season

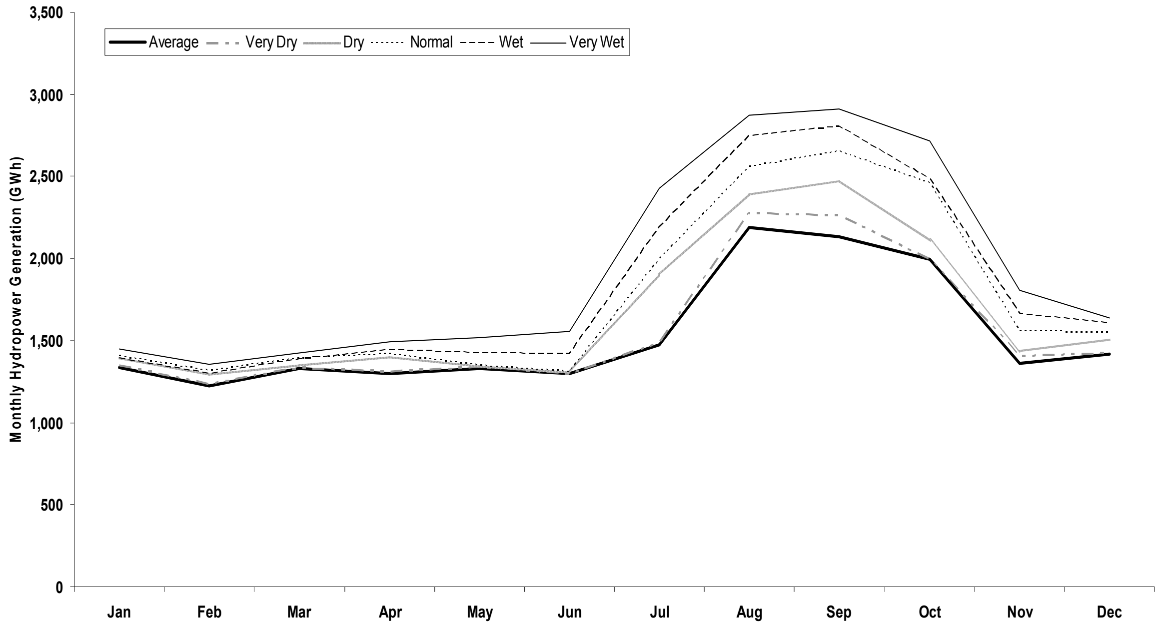

Fig. 3 Monthly hydro power plant generation by different hydrological conditions in year 2017

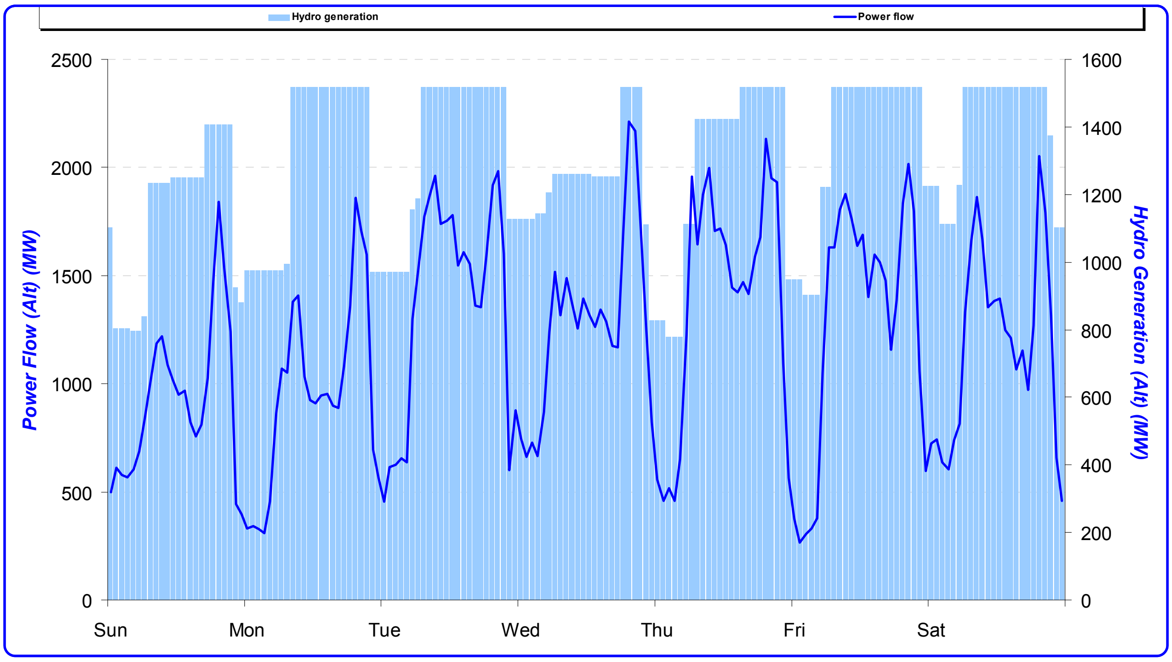

Fig. 4 Power flow over the transmission line and hydro power plant generation for one characteristic week in year 2017

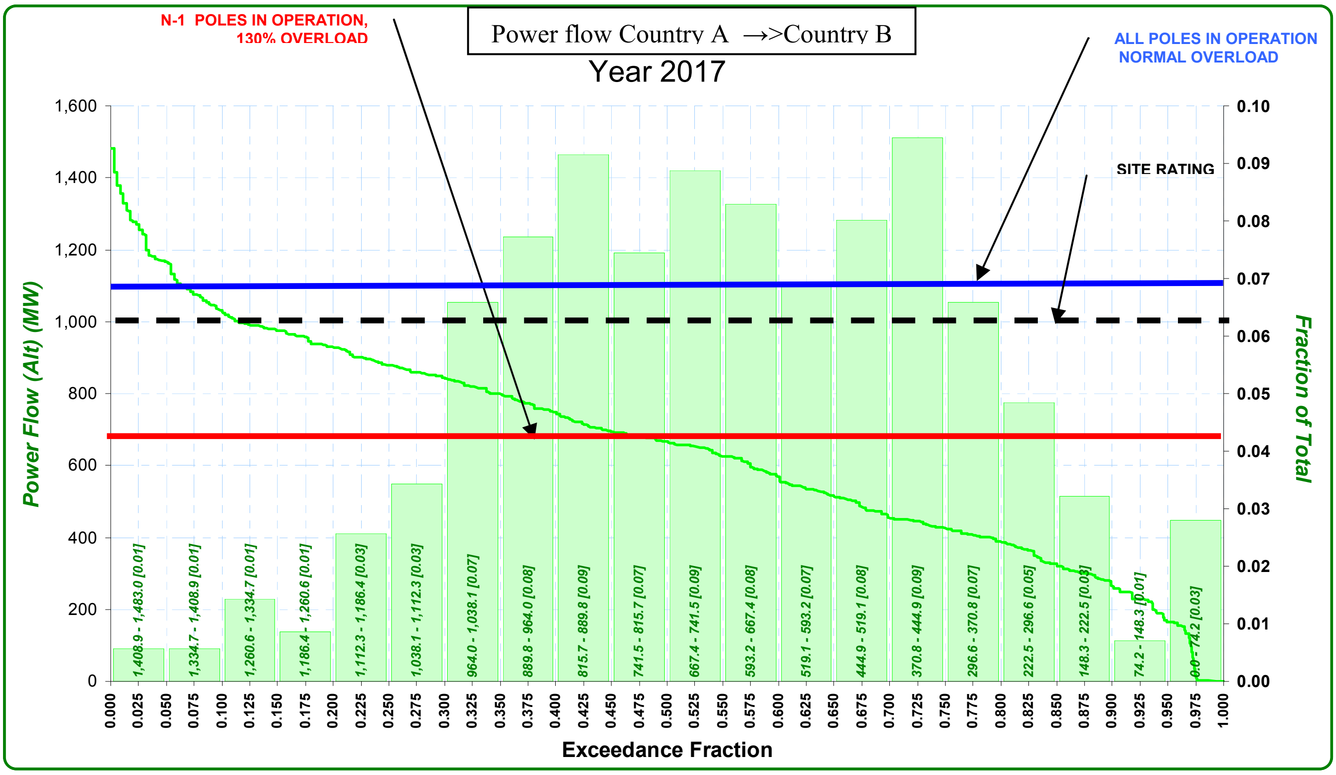

Fig. 5 Distribution of the unconstrained power flow for the year 2017: transmission capacity, 1000 MW site rating, 110% standard, 130% enhanced pole overload capability

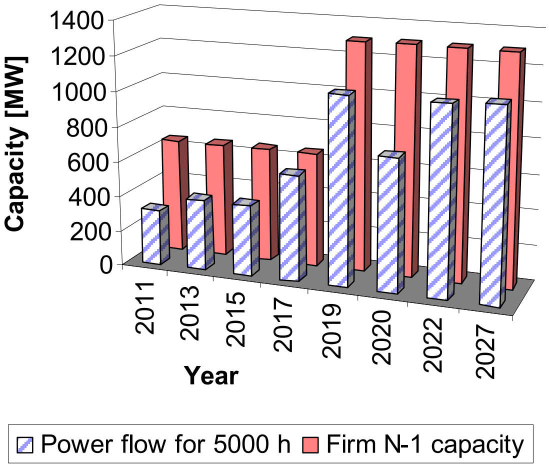

Fig. 6 Comparison between the power flow for 5000h and firm N-1 capacity of the interconnection line

The tentative sizing was subsequently validated by a detailed power system analysis (including transmission and sub-transmission levels) in order to assess the performance of the integrated system, confirm the choice of the technology and provide input for the voltage and current specification under abnormal operation conditions, outages and faults.

V. Conclusions

The paper highlights the necessity of simulating the energy market in the feasibility studies for large interconnection projects, on top of conventional deterministic power system analysis. This is mandatory to obtain information on the economic financial viability of the project under various sets of uncertainties on national demand and production sides, and ultimately on the bankability of the Project.

The described methodology makes intensively use of a tool for optimizing the energy exchanges in a competitive market on an hourly and weekly time basis, subject to interconnection capacity constraints. Since for the presented case study, hydropower was the dominant energy resource, the paper stresses further the necessity of pre-processing the data for the market simulation by specialized tools which consider statistic hydrological conditions, peculiarities of the hydro plant operation and reservoir overall constraints.

The methodology is applicable for the long term perspective required in the feasibility studies, while preserving the level of detail which is used in operational planning.

Finally, the economic optimization of the transmission line capacity must be checked in an interactive loop by power system analysis, which can reveal important facts about the performance of the integrated system and the staging of reinforcements in the transmission and distribution systems.

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