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A Cost – Benefit Approach for Transmission Investment with a Non-Linear Transmission Cost Function

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***Abstract*—There is a need to accurately determine expansion of transmission system to accommodate the connection of wind power in an efficient manner. The current transmission planning criteria in the UK was developed for systems with conventional generation and is not suitable for systems with high wind penetration. In this paper, a Cost-Benefit Analysis (CBA) based transmission expansion problem is described. A piecewise cost function is used for transmission reinforcement to reflect the cost of various options in enhancing transfer capability of transmission system. This model has been elaborated to support development of new transmission planning and security standards in the UK.**

***Index Terms*—Transmission planning, transmission expansion, cost benefits analysis, power system economics**

I. Introduction

As far as transmission expansion is concerned, the unbundling of power systems from vertically integrated entities, the presence of private investors, necessity for tariff regulation, and lately, environmental issues have made economic criteria more complex and more important.

In Great Britain (GB), transmission investment decisions are driven by deterministic criteria. Planning is based on peaking demand conditions so as to determine the need for network capacity across the transmission system boundaries derived from security requirements. As an option, methodologies based on Cost-Benefit Analysis can be also used, but there is not a formalized procedure to apply them. For a system with conventional generation, a network design mainly driven by reliability criteria has been generally adequate. Nonetheless, the GB system is evolving to meet stretching targets for adoption of renewable generation, and this is driving a significant amount of wind generation to connect to the system. In this new framework, there is a need to move from reliability to economic criteria [1] and transmission planning based on peaking demand conditions becomes out of context [2]. Fundamental concepts on economic transmission planning can be found in [3,4,5].

This study proposes an alternative Dynamic Transmission Investment Model (DTIM) based on a multi-year Cost-Benefit Analysis (CBA) formulated as a linear programming problem that minimizes the Present Value (PV) of the cost of investment plus the cost of constraints in a system with significant penetration of wind generation. In addition, different technologies, e.g. installing reactive compensation, re-tension, re-conductoring or installing new lines, among others, are considered when upgrading capacity across the years by using a piecewise approximation of the transmission investment cost function.

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II. Presentation of the Model

A. Rationale and assumptions

The total cost of transmission is the sum of network investment cost and its operational cost. Thus, finding the minimum of the total cost of transmission function is the objective of the CBA methodology [3]. As shown in Figure 1 as more capacity is being built the cost of transmission investment increases whereas the cost of transmission constraints decreases because a stronger transmission network permits operation of the generation system closer to the merit order. Finding this minimum in the total cost of transmission is the objective of the CBA methodology. Above the optimal network capacity, further capacity increment will result in higher total cost since the benefit, i.e. the reduction of transmission constraint cost is less than the increase in transmission investment cost.

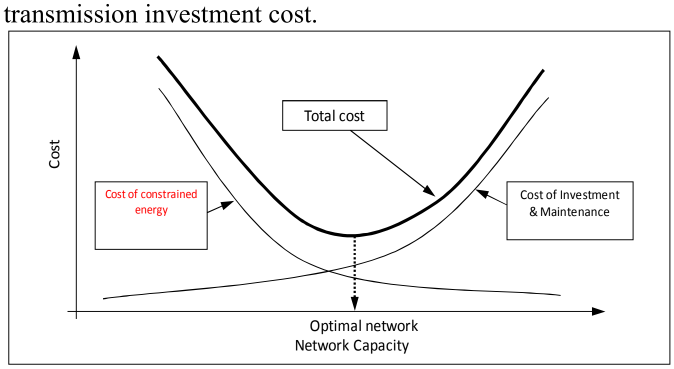

Fig. 1. CBA approach for transmission investment optimisation

The DTIM assumes a centralised transmission expansion planning within a deregulated electricity market similar to the GB electricity market codenamed BETTA, where a bilateral energy market (unconstrained dispatch) and a Balancing Mechanism (BM – submission of bids and offers to the System Operator) are operated.

Linear approaches (constant transmission variable cost per line) have been considered for simulating the GB system [4]. However, the new formulation represents the transmission cost function by a piecewise formulation as shown in Figure 2.

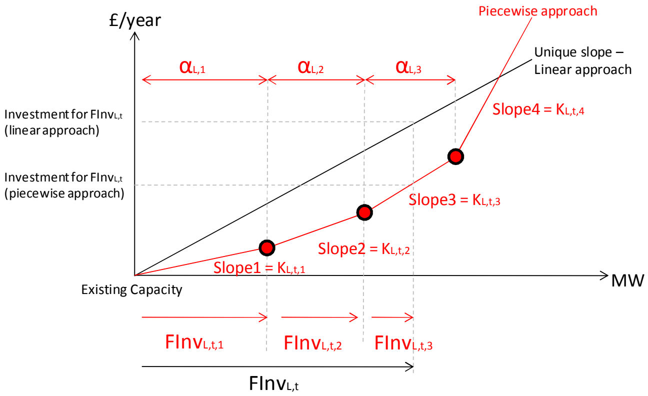

Fig. 2. Piecewise transmission cost function

Different cost curves can be applied per line depending on the existing capacity and therefore on which technologies can be used to upgrade the line. Figure 2 shows the following fact: the transmission company upgrades capacity by using the cheapest technology available. Then, when a particular technology cannot be used any longer, the second cheapest is used and so on.

In order for the model to take into consideration a good resolution for modelling wind, 41 scenarios of demand (8 typical days – 4 seasons, 2 days per season working/weekend days – divided into 5 blocks, plus one peak demand scenario) times 10 wind conditions and their probabilities are built by using (i) nodal demand profiles and (ii) one profile of wind with a load factor equal to 30% per year (see Figure 3).

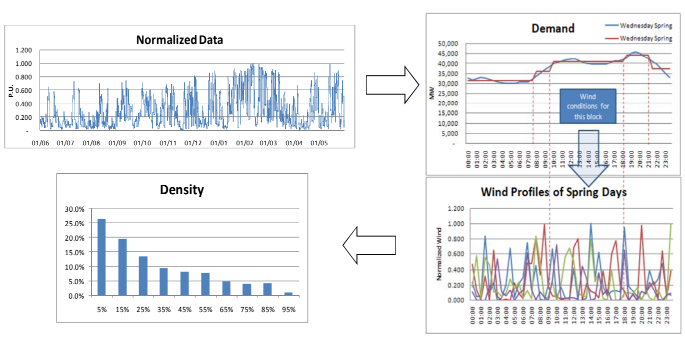

Fig. 3. Demand and wind modelling

So, a year is represented by 410 operating conditions which is considered a good approximation of the annual operation of the system [8,760 hours].

B. Mathematical formulation

The transmission system expansion problem is formulated as a linear programming based, multi periods DC Optimal Power Flow problem. The objective is to minimize in a Present Value (PV) basis the overall cost including the cost of additional transfer capability investment, and the cost of re-dispatching generation to manage network congestion. These investment and operating time scale decisions are used in the planning stage as options to overcome network congestion problems. Hence, by optimizing these two options concurrently, the optimal decisions for transmission investment can be determined and at the same time the optimal cost of transmission constraints can be quantified

In general words, the formulation corresponds to a constrained dispatch problem where the generation cost is represented by market variables (bids and offers submitted in the BM) and transmission cost is represented by the piecewise function shown in Figure 2. This formulation is described by equations (1) – (8). Equation (1) determines the minimum total cost of transmission investment as defined in Section I. For the sake of simplification, DC Power Flow constraints are omitted.

$$\min f(x)=\left\{\sum_{p=1}^{Np}\sum_{t=1}^{T}\sum_{l=1}^{Nl}\frac{(k_{l,t}\cdot F_{l,t,p}^{inv})}{(1+r)^t}+\sum_{t=1}^{T}DurPer\sum_{s=1}^{Ns}\Pr_s\sum_{g=1}^{Ng}\frac{(Coffer_g\cdot Offer_{g,s,t}-Cbid_g\cdot Bid_{g,s,t})}{(1+r)^t}\right\} \quad (1)$$

s.t.

$$\sum_{g=1}^{Ng}(Offer_{g,s,t}-Bid_{g,s,t})=0 \quad \forall(\mathrm{s,t}) \quad (2)$$

$$-\left(F^{\max}{}_{l,t}+F^{inv}{}_{l,t}\right)\le F_{l,s,t}\le F^{\max}{}_{l,t}+F^{inv}{}_{l,t} \quad \forall(l,s,t) \quad (3)$$

$$P_{g,t}{}^{\min}\le P^{con}{}_{g,s,t}\le P^{\max}{}_{g,t} \quad \forall(g,s,t) \quad (4)$$

$$P^{con}_{g,s,t}=P^{ucon}_{g,s,t}+Offer_{g,s,t}-Bid_{g,s,t} \quad \forall(g,s,t) \quad (5)$$

$$F_{l,t}{}^{\max}=F^{\max}{}_{l,t-1}+F^{inv}{}_{l,t} \quad \forall(l,t) \quad (6)$$

$$F^{inv}_{l,t}=\sum_{p=1}^{Np}F^{inv}_{l,t,p} \quad \forall(l,\mathrm{t}) \quad (7)$$

$$\sum_{t=1}^{T}F^{inv}_{l,t,p}\le\alpha_{l,p} \quad \forall(l,\mathrm{p}) \quad (8)$$

Where,

T: number of modelling periods

Nl: number of transmission lines

Ns: number of scenarios

Ng: number of generators

Nn: number of nodes

$K_{l,t}$: cost of transmission investment of line l in period t [\$/MW]

r: discount rate [p.u.] (0..1)

$DurPer_t$: number of hours of the year/period [hrs]

Pr_s: probability of scenario s [p.u.] (0..1)

$Coffer_g$: cost of offer of generator g [\$/MWh]

$Cbid_g$: cost of bid of generator g [\$/MWh]

$P^{min}_{g,t}/P^{max}_{g,t}$: min/max generation capacity of generator g in time period t [MW]

$F^{max}_{l,t}$: capacity of line l in time period t [MW]

$P^{ucon}_{g,s,t}$: unconstrained dispatch of generator g in scenario s at time period t [MW]

$Dem_{n,s,t}$: demand in node n in scenario s at time period t [MW]

$F^{inv}_{l,t}$: optimum transmission investment of line l at period t [MW]

$F^{inv}_{l,t,p}$: optimum transmission investment of line l at period t by using technology p [MW]

$Offer_{g,s,t}$: constrained on generation of generator g in scenario s at period t [MW]

$Bid_{g,s,t}$: constrained off generation of generator g in scenario s at period t [MW]

$F_{l,s,t}$: power flow of constrained dispatch of line l in scenario s at period t [MW]

$P^{con}_{g,s,t}$: optimum constrained dispatch of generator g in scenario s at time period t [MW]

Equation (2) states that the amount of constrained off generation must be equal to the amount of constrained on one in order to balance supply equal to demand.

Equation (3) states that power flow across each boundary cannot exceed its capacity and equations (4) represent the upper and lower limits on generator production.

Equation (5) states that the generator output in the constrained dispatch must be equal to the contracted position from the energy market (forward/PX market) modified by the exercise of any bids/offers in BM.

Equation (6) links the transmission boundary capabilities across neighbouring periods (boundary capability in period t is equal to the capability in period t-1 enhanced by any transmission investment at the beginning of period t).

Equation (7) and (8) are related to the piecewise representation of the investment cost function.

The decision variables of the algorithm are the optimal transmission expansion $F^{inv}_{l,t}$ [MW] per period t in line l , the optimal transmission expansion $F^{inv}_{l,t,p}$ [MW] per period t in line l by using technology (or piece) p ,the constrained off/on generation per generator g, per scenario s, per period t given by $Bid_{g,s,t}$ and $Offer_{g,s,t}$, respectively and the total generation in the constrained dispatch per generator g, per scenario s, per period t given by (5), where $P^{ucon}_{g,s,t}$ is the unconstrained dispatch.

Transmission losses are neglected and a DC Optimal Power Flow (DC-OPF) is considered.

C. Data input

The model was applied on a 16 busbar radial network that resembles to the main GB interconnected transmission system (Figure 4). A penetration of renewables of 38%, a discount rate of 5%, 10 generation technologies and a time horizon between 2008 and 2020 divided into 5 periods were taken into account in the simulation.

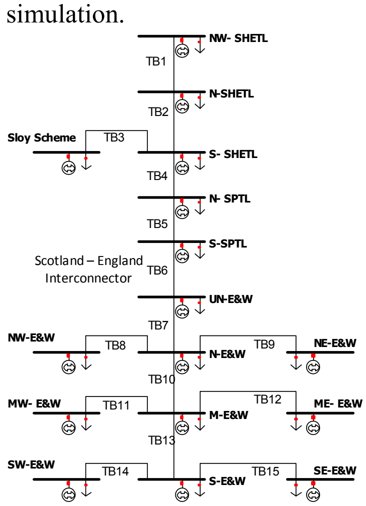

Fig. 4. GB transmission system

Important input data is displayed in Table I.

TABLE I
INPUT DATA: FUEL/BID/OFFER PRICES, SUPPLY AND DEMAND

Technology	Initial Fuel Prices £/MWh	Final Fuel Prices £/MWh
CCGT	44	34
OCGT & Oil	114	71
Coal	53	33
Nuclear	0	0
CHP	0	0
Biomass	28	26
Interconnector	60	60
PS	100	65
Wind	0	0
Other renewables	0	0

Technology	Initial Installed Capacity MW	Final Installed Capacity MW
CCGT	23,228	29,510
OCGT & Oil	5,887	6,092
Coal	27,941	20,564
Nuclear	10,740	3,744
CHP	1,876	2,176
Biomass	219	3,645
Interconnector	1,976	2,976
PS	2,260	2,260
Wind	6,698	31,756
Other renewables	3,626	14,768
Total Supply	84,451	117,490
Total Demand	67,131	75,400

Technology	Bid Prices £/MWh	Offer Prices £/MWh
CCGT	Fuel Price	Fuel Price
OCGT & Oil	Fuel Price	Fuel Price
Coal	Fuel Price	Fuel Price
Nuclear	- 10,000	10,000
CHP	- 1,000	1,000
Biomass	Fuel Price - ROC	Fuel Price
Interconnector	Fuel Price	Fuel Price
PS	Fuel Price	Fuel Price
Wind	-ROC	0
Other renewables	-ROC	0

In addition, carbon emissions are included in the fuel prices and ROC (Renewable Obligation Certificates – form of subsidy) prices has been considered for renewables (~30 £/MWh).

D. Results

Two scenarios of cost are compared: (i) a constant transmission cost of 30 £/MW/km/year for reinforcing lines and (ii) a piecewise cost function where:

({capacity limit};{slope}) = ({500; 500; 500; 500; ∞} MW ; {18; 21; 30; 39 ; 42} £/MW/km/year).

This means that: (i) the first 500 MW of capacity upgrade can be carried at a cost of 18 £/MW/km/year, (ii) the second 500 MW of capacity upgrade can be done at a cost of 21 £/MW/km/year, (iii) the third 500 MW of capacity upgrade can be done at a cost of 30 £/MW/km/year, (iv) the forth 500 MW of capacity upgrade can be done at a cost of 30 £/MW/km/year, and (v) all the remaining needed reinforcements can be done at a cost of 42 £/MW/km/year.

The results for the single cost and the pieced cases are shown in Figure 5.

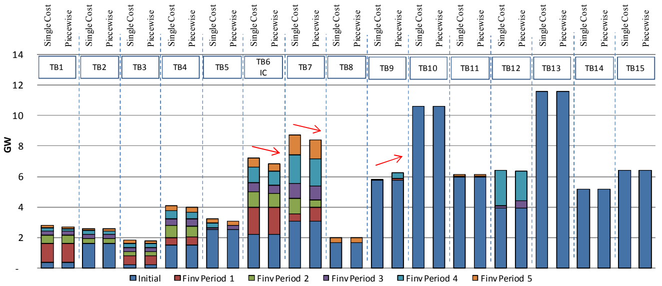

Fig. 5. Optimum expansion results under a single cost and a piecewise approaches

When using a single cost value to represent capacity upgrades instead of a piecewise approximation, similar levels of reinforcements are obtained between both approaches. Nonetheless, it is very difficult to predict whether a single cost approximation over-invests or under-invests as results vary across the system in this respect.

The piecewise approximation drives a more accurate analysis since actual transmission investment costs can be incorporated in the model in a more realistic manner.

III. Conclusions

This paper presents a DTIM that carries out a multi-year Cost – Benefit Analysis (CBA) to determine optimal transmission expansion for systems with significant penetration of wind generation. The model considers daily and seasonal variations in generation and demand and incorporates the possibility of including different technologies for upgrading transmission transfer capability, for instance; installing reactive compensation, re-tension, re-conductoring or installing new lines, among others, by using a piecewise formulation for the transmission investment cost function.

As shown in Figure 5, the use of one single cost (e.g. an average or the cost of the main technology) to represent transmission investment distorts the solution. What is more, the difference in transmission investment when using average cost pricing does not have a clear pattern, i.e., when using a single cost approximation, over or under investment may result depending on the line.

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V. Biographies

Rodrigo Moreno has a B.Sc. and M.Sc. degrees in EE from Pontificia Universidad Católica de Chile and is pursuing the PhD degree at Imperial College, UK. He has been Lecturer in Pontificia Universidad Católica de Chile and Adolfo Ibañez University and Research Manager in Systep. He has worked on power system economics, especially in market arrangements (auctions) and network planning.

Christos Vasilakos Konstantinidis has an M.Eng in EE and is pursuing the PhD degree at Imperial College, UK. His work is focused on electricity market design and in particular transmission access arrangements.

Danny Pudjianto received the B.Sc. degree from the Institut Teknologi 10 Nopember, Surabaya, Indonesia in 1996 and the Master's and Ph.D. degrees from the University of Manchester Institute of Science and Technology (UMIST), Manchester, UK, in 1999 and 2003 respectively. Currently, he is a research associate at the Imperial College London.

Goran Strbac is a Professor of Electrical Energy Systems at Imperial College London, UK. He is the Director of the DTI Centre for Distributed Generation and Sustainable Electrical Energy, the Convener of CIGRE International Working Group on Economics of Integration of Distributed Generation and a member of the Executive Team of the IEE Professional Network on Power Trading and Control. He is a co-author of 3 books and has published more than 100 scientific papers.