INVESTMENT PERSPECTIVES ON THE INTERCONNECTION OF ISOLATED SYSTEMS WITH THE MAINLAND GRID: CRETE CASE STUDY

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ABSTRACT
A Monte-Carlo based, probabilistic power flow method is used to evaluate different power system interconnection options. Suitable indices are proposed to assess the potential profit of each interconnection scenario and the required interconnection rating. Separate investment perspectives are identified and the respective optimal solutions are compared. Indicative results are presented regarding a possible submarine interconnection of the Greek island of Crete with the mainland grid.

KEY WORDS
Monte-Carlo simulation, optimal power flow, power system interconnection, submarine interconnection

NOMENCLATURE

$f_c(\mathbf{P}_c)$	Generator cost function $\mathbb{R}^{n_c} \Rightarrow \mathbb{R}^{n_c}$ - a quadratic function is used for each generator
$\mathbf{P}_w$	Wind park active power $n_w \times 1$ vector
$\mathbf{k}_w$	Wind park cost $n_w \times 1$ vector
$\mathbf{P}_d$	Active power demand $n_d \times 1$ vector
$\boldsymbol{\delta}$	Voltage angles $n_b \times 1$ vector
$\mathbf{T}$	Line active power $n_l \times 1$ vector
$\mathbf{Y}_b$	Bus admittance $n_b \times n_b$ matrix
$\mathbf{Y}_T$	A $n_l \times n_b$ matrix - if line k with admittance y_k connects buses i and j then row k has $Y_T(k,i) = -Y_T(k,j) = 1/y_k$ and other elements equal to 0
$\mathbf{C}_c$	Generators connection $n_b \times n_c$ matrix - element (i,j) is 1 if generator j is connected to bus i, and 0 otherwise
$\mathbf{C}_w$	Wind park connection $n_b \times n_w$ matrix
$\mathbf{C}_d$	Power demand connection $n_b \times n_d$ matrix
$\mathbf{p}$	Buses marginal costs $n_b \times 1$ vector
P_{IC}	Interconnection nominal power
L_{IC}	Interconnection cable length

1. Introduction

In many aspects planning of possible interconnections between power systems is similar to the typical transmission expansion problem. The time, location, type and capacity of the new interconnection have to be determined, based on economic or reliability criteria, or a combination of both. Different formulations and optimization criteria appear in relevant publications. A common approach is to minimize investment costs required to supply system load [1], including power generation costs [2,3]. In [4] reliability constraints are added to the optimization problem. A multi-period approach is considered in [5], optimizing investments by splitting the overall time frame into smaller periods, within which congestion and generation costs are minimized. Finally, [6] and [7] consider deregulated systems and market based criteria, giving solutions based on congestion costs and market competitiveness or social welfare. While such approaches may also be used for evaluating the connection of an isolated system to the mainland grid, such a problem presents its own peculiarities.

A new interconnection typically involves costs much larger than those required for the construction of overhead ac transmission lines. It allows access (for one of the two systems) to energy at a lower cost, which may very well be seen as a good trading opportunity. Additionally it affects the usage of existing equipment or might create new needs. For example, construction of new conventional plants may be avoided in the smaller system while allowing a higher renewable energy penetration. At the same time reserve requirements may be reduced, but additional overland transmission might be required to fully utilize the systems' interconnection. As can be expected, interconnection equipment determines to a large extent both initial (installation) and operation (losses) costs of the interconnection, and is not always standardized. Given the energy cost variations during the day, especially in systems with high renewable energy penetration, determination of the projected interconnection usage (power transfer), and in turn estimation of the required equipment rating, is also an important issue.

Evaluation of a potential interconnection scenario involves first and foremost the estimation of expected gains with respect to the corresponding required rating of the interconnection (in other words the required capital). Thus a potential investment in interconnection can be justified or rejected. Of importance is also the evaluation of system reliability and transmission congestion as these are indicative of the need for new generation or transmission capacity, which may affect interconnection profit. Estimation of all the above amount to solving a short-term problem (evaluation of the system with a standard set of generating sources and loads) and a long-term one (evaluation of the system development for the economic lifetime of the interconnection equipment and the overall derived benefits).

2. Short Term Analysis

In order to solve the short term problem a Monte-Carlo based probabilistic load flow is used. This allows consideration of most possible system states and estimation of the expected values of system costs and reliability indices. Certain simplifications are made to reduce data requirements and variability in the system, which allows for a faster convergence. These, along with the method basics, are discussed in the following sections.

2.1 State Generation

A non-sequential Monte-Carlo (MC) method [8] is used to generate system states. For each state the load in each bus is determined by sampling a load duration curve. Availability of conventional generators is estimated based on their forced outage rate (FOR). In a similar manner transmission system outages may be accounted for. However, due to transmission lines high availability, the costs incurred due to line outages can be expected to be small compared to the overall interconnection costs and benefits.

Each wind park is modeled as a single equivalent generator, whose output is determined based on a wind park power versus wind speed characteristic. Shadowing and wake effects, or effects related to different wind speeds within the wind park area, are assumed to be incorporated into the aforementioned characteristic. Wind parks FOR is based on typical outage rate of the equipment connecting them to the high voltage network. Individual wind turbine outages may be easily taken into account using i.e. a multistate model for the equivalent generator [9].

A key factor that has to be considered is wind speed correlation between wind parks, which are located in different areas. The same is true for the power demand of different buses and/or systems. In order to generate correlated random numbers standard copula theory is used. First a multivariate set of normally distributed numbers with a known rank correlation is generated, based on the Cholesky decomposition of the set's covariance matrix. Then these are transformed to uniform distribution numbers and again inverted to the desired distribution. Through these transformations only rank correlation is preserved, however a relationship with the commonly used Pearson correlation may be estimated.

2.2 Optimal Power Flow Formulation

The Monte-Carlo simulation defines for each case the available generation and load. In order to estimate the exact system state the following objective function has to be minimized:

$$f = f_c\left(\mathbf{P}_c\right) + \mathbf{k}_w\mathbf{P}_w - \mathbf{k}_d\mathbf{P}_d \tag{1}$$

The above equation reflects the fact that demand is considered inelastic. The vector $\mathbf{k}_d$ is a penalty factor associated with load shedding. Typically this penalty is set at a much higher value than generators cost. As a result load curtailments are minimized first, and power generation costs are minimized second. The constraints involved with the optimal power flow problem are as follows:

$$\mathbf{C}_c\mathbf{P}_c + \mathbf{C}_w\mathbf{P}_w - \mathbf{C}_d\mathbf{P}_d = \mathbf{Y}_b\boldsymbol{\delta} \tag{2}$$

$$\mathbf{0} \le \mathbf{P}_c \le \mathbf{P}_c^{\max},\ \mathbf{0} \le \mathbf{P}_w \le \mathbf{P}_w^{\max},\ \mathbf{0} \le \mathbf{P}_d \le \mathbf{P}_d^{\max} \tag{3}$$

$$\left|\mathbf{Y}_T \cdot \boldsymbol{\delta}\right| \le \mathbf{T}^{\max} \tag{4}$$

Eq. 2 describes the set of linear equations of the transmission system. Eq. 3 describes the typical constraints associated with generation and demand. Finally eq. 4 deals with line active power limits. The dc formulation is preferred as it allows a significant decrease in computation time and an adequate representation of transmission and interconnection power flows. An additional constraint is added to cover wind power penetration limitations. In small systems wind generation is typically limited to 25-30% of the total system load, i.e.:

$$\sum_{j=1}^{n_w}\mathbf{P}_w\left(j\right) \le 0.3\sum_{k=1}^{n_d}\mathbf{P}_d(k) \tag{5}$$

It is assumed that this constraint still stands after the interconnection. Whether or not renewable power penetration levels may be increased, depends on the interconnection dynamic response characteristics, and is also a matter of unit commitment. For example an interconnection loaded to capacity cannot provide frequency support.

In case of a DC link between the two systems, each interconnection point is modeled as an additional power injection since both its active and reactive power are controllable, and also assuming that the cost of interconnection losses is not significant. Given the fact that interconnection rating has yet to be determined, there is no point of using a more detailed model. This is especially so in the case of submarine interconnections, where cables are typically tailor made for the specific application [10]. In case of an AC interconnection the link is simply simulated as an additional line. In this paper the former case is examined.

The above optimization problem is solved by a primaldual interior point method presented in [11] and also used in [12]. Marginal costs of each bus are equal to the Lagrange multipliers corresponding to the active power balance load flow equations [13]. Due to the fact that system losses are not considered (as result of the dc load flow) marginal prices are slightly underestimated. On the contrary ignoring the generators technical minimums (a simplification often used in transmission expansion) leads to a slight overestimation. However it can be expected that all evaluated scenarios are affected in a similar manner, and consequently the results are sufficient for comparison purposes.

2.3 Short Term Analysis Indices

As discussed in [14] depending on the case under study, different evaluation criteria may have to be considered, and not all may be directly translated into economic costs. As mentioned earlier first and foremost evaluation indices should justify the investment. Second, they have to evaluate the need for additional generation or transmission. In a free market social, consumer or producer surplus are a dominant factors in evaluating any project. In this work however, demand is considered inelastic. Maximizing social welfare is equivalent to minimizing production cost [15]. Thus, the following indices are deemed to most comprehensively describe a possible interconnection:

- *Expected Consumer Benefit (ECB - M€/year)*: Under the assumption that a nodal pricing system is used, if n cases are generated by the MC process, then the expected average consumer cost on an annual basis is equal to:

$$CC = \frac{1}{n}\sum_{i=1}^{n}\left(\mathbf{p}^{(i)}\right)^T \mathbf{P}_d^{(i)} \cdot 8760 \qquad (6)$$

and the consumer benefit is equal to:

$$ECB^{(l)} = CC^{(l)} - CC^{(0)} \qquad (7)$$

where $CC^{(l)}$ refers to the $l-th$ interconnection scenario and $CC^{(0)}$ to the system as is.

- *Expected Interconnection Commercial Benefit (EICB - M€/year)*: The interconnection congestion cost or commercial benefit is derived from the price difference between the connected buses. If T_{IC} is the power transferred through the interconnection between buses k and j its average value on an annual basis is equal to:

$$EICB = \frac{1}{n}\sum_{i=1}^{n}\left(\mathbf{p}^{(i)}(j) - \mathbf{p}^{(i)}(k)\right)\cdot T_{IC}{}^{(i)} \cdot 8760 \qquad (8)$$

- *Expected Transmission Commercial Cost (ETCC - M€/year)*: Sum of transmission system congestion costs, defined similarly to EICB. It is the additional cost consumers pay due to the limited transmission capacity and up to an extent indicative of transmission system usage.
- *Loss of Load Expectation (LOLE - $h/year$)*: this is a measure of system reliability. While other indices are available mostly expressed in $MWh/year$ e.g. EENS, it is not easy to evaluate the cost of a curtailed MWh. As a result LOLE is considered more representative. The typical value of 1 day in 10 years is set as the target that has to be achieved after the interconnection construction.

Additional indices may be defined [6,7,16] to account for market properties such as prices distribution, market power of generation companies, generators benefits etc. However due to the nature of the examined problem (small system size, controllable interconnection, inelastic demand) such indices are not considered as important and will not be discussed further in this paper.

3. Long Term Analysis & Investment Perspectives

The solution of the long term problem is based on breaking the period under evaluation to several shorter periods (i.e. years), during which it may be assumed that installed generation and the load duration curve remain practically unchanged. As a result the overall economic benefits associated with the interconnection, during its expected lifetime, may be estimated. Optimality of the solution depends on who and why he invests on an interconnection.

Initial investment cost for a DC submarine interconnection is roughly approximated by the following relation:

$$IC = \left(32\cdot 10^4 \text{€/MW}\right)\cdot P_{IC} + \left(90\cdot 10^4 \text{€/km}\right)\cdot L_{IC} \qquad (9)$$

These costs are based on [17], and have been increased to cover inflation and possible cost overruns. It is assumed that maintenance and operation costs are equal to 3% of the installation cost. In order to evaluate the economic value of the interconnection two basic indices will be used. The first is the net present value of the investment defined as:

$$NPV = -IC + \sum_{i=1}^{t}\frac{NB^{(i)}}{\left(1+r\right)^i} \qquad (10)$$

where t is the equipment economic life time in years (ranging typically from 20 to 40 years [18]), NB the net benefit during each year, and r the rate of return. The second index of interest is the internal rate of return, or the rate of return that yields a zero NPV. Thus it is calculated based on the following equation:

$$0 = -IC + \sum_{i=1}^{t}\frac{NB^{(i)}}{\left(1+IRR\right)^i} \qquad (11)$$

In the interconnection of isolated systems three investment perspectives are identified. The first is the system operator (SO) point of view. The system operator's objective would be to maximize social benefit. Given that demand is considered inelastic, this is equivalent to maximizing the NPV that may be derived based on ECB (in eq. 10 $NB^{(i)} = ECB^{(i)}$). The second perspective is that of a private investor or regulated transmission company, that agrees with the SO on a moderate but safe rate of return. In this case public benefit is also of interest, as the higher it is, the higher the profits that the investor may negotiate with the SO. However NPV does not give a complete picture. Typically the investor would want to maximize the value of his money and opt for the highest possible IRR (in eq. 11 $NB^{(i)} = ECB^{(i)}$). Finally, the third case is that of an independent investor that aims to take advantage of the price difference of the two systems. The derived benefits in this case are calculated based on EICB ($NB^{(i)} = EICB^{(i)}$), while IRR is also the defining index.

4. Indicative Results

The test system used approximates the system of the Greek island of Crete. A 16 bus system with presumable peak load 809 MW, 946 MW conventional generation capacity, 184 MW installed nominal wind power and 138 €/MWh average marginal generation cost. Two possible interconnection scenarios are considered, as seen on Fig. 1. The mainland grid is modeled as a single bus and it is assumed its energy price - with an average marginal cost 90 €/MWh - is not affected by the demand in Crete. In the example that follows the interconnection is to cover the islands needs and no additional investments in generation or transmission are to be made. Finally it should be noted that due to the typically low values of reliability indices, these are the last to converge. In order to speed up the simulations first the economically optimal solution is found, and a check follows to see if it satisfies reliability criteria (in this case LOLE).

4.1 Short Term Results

The short-run solution for the first simulation period (year) is illustrated in Fig. 2 and Fig. 3. As can be seen in these figures, given that losses are not estimated, the two interconnection options in general coincide, up to around a capacity of 300-350 MW. After that in case A, congestion costs in the island increase as indicated by ETCC. This is due to congestion on the lines transferring power from the west to the east. This in turn limits the maximum economic benefit for the consumers. Interconnection with capacity greater than 350MW at point A will have to be coupled with a potential overland transmission expansion. An interconnection with a capacity of 600-700MW at point B seems to offer the greatest social (consumer) benefit.

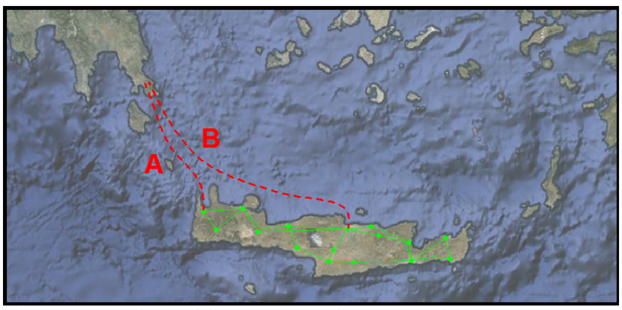

Fig. 1 Evaluated interconnection scenarios.

Energy trading between the two systems will reduce prices on the island, however it is in the interests of the independent investor to limit these transactions so that profit may still be made by the remaining price difference. A capacity of 200-250MW maximizes the short-term commercial benefit independently of the point of connection. Of course these short term results do not take into account the relevant investment costs.

4.2 Long Term Results

The final simulation results are illustrated in Fig. 3 and Fig. 4. The NPV is estimated with a minimal rate of return equal to 5%. Despite the higher required investment cost the interconnection of case B, with a capacity approximately 650MW maximizes social benefit. However, while this solution maximizes potential profit, it does not maximize profit per capital invested. In both the independent and regulated investor cases, a smaller interconnection capacity would be preferable for the investor with respect to IRR. Case A would be preferred. In the regulated investor case a capacity up to 350MW seems best, as due to the lower investment cost, allows greater return rates.

Specifically in the independent investor case a 200MW solution is optimal. Still, it should be kept in mind that predicting how the system will evolve in the next decades is a difficult task. Possible demand decline, construction of additional interconnections or installation of renewable sources on the island, or an increase on mainland system marginal price would significantly lower the projected profits of the interconnection. Thus the risk can be significant, and the estimated values of IRR (up to 15%)

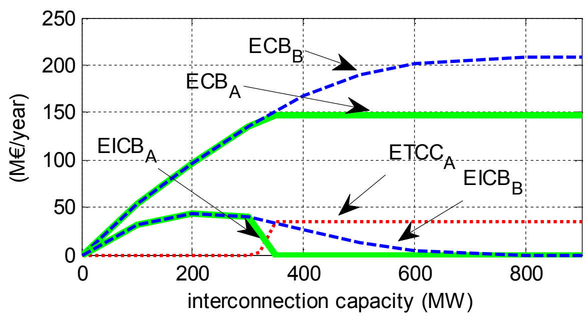

Fig. 2 Short-term social and commercial benefit.

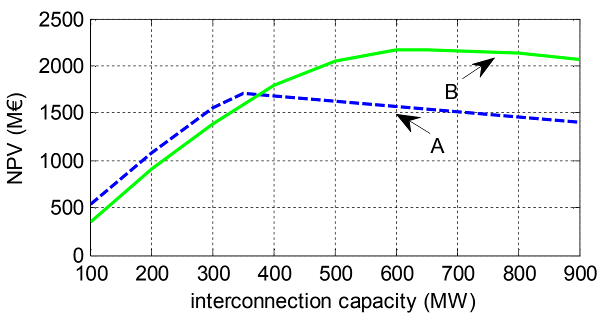

Fig. 3 Net present value from SO perspective.

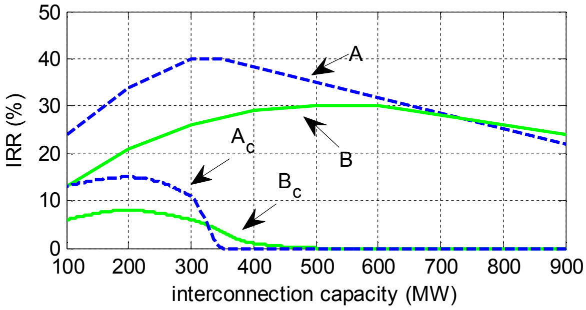

Fig. 4 Internal rate of return. The curves corresponding to the independent investor case are designated by the index c.

probably do not justify the investment. At any rate, commercial benefits oriented solutions might lead to underinvestment in interconnection capacity.

All discussed solutions satisfy the target set for LOLE. This is of course only a measure of adequacy of supply. It should be noted that system security considerations may impose limits on the interconnection capacity or way of operation. Such limitations can be determined by studying the system's dynamic behaviour (e.g. [19]).

5. Conclusions

A method for interconnection scenarios evaluation has been presented along with indicative results for the island system of Crete. Possible investment perspectives have been discussed, and as it has been illustrated the optimal interconnection solution largely depends also on who is making the investment and consequently how the profits from the interconnection are determined. The current results may further be improved with a more detailed representation of the mainland grid, evaluation of a larger number of scenarios, and incorporation of ancillary services costs. The presented method may further be extended to account for combined investments in transmission and generation, especially from renewable sources.

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