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Energy Procedia 105 (2017) 3101 – 3111

Energy Procedia

The 8th International Conference on Applied Energy – ICAE2016

Using a VSC based HVDC application to energize offshore platforms from onshore – A life-cycle economic appraisal

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Abstract

The consequential growth in offshore electrical power demand associated with increased oil and gas production, new offshore developments and advanced technologies for enhanced oil recovery is driving the decision to explore alternative means of power supply as opposed to solely considering localized gas turbine generators, the last being the conventional approach over the decades. As part of the overall strategic decision making process, which would include consideration of a numerous other technical issues, this paper presents a Reliability Constrained Integrated Energy Economics Model (RC-IEEM) as a tool to allow for the economic comparison between two strategic electrification options namely (i) continue with offshore localized power generation using large-scale gas turbines (GTs), or (ii) propose a new approach for power supply from onshore using a voltage source converter (VSC) based high voltage direct current (HVDC) technology. Results reported in this paper show usefulness of the proposed tool and the benefits of connecting to onshore using HVDC technology, offering lower life-cycle cost with higher reliability and lower environmental impacts. The assumptions and conclusions reached in this paper are generic and are not project specific but are typical for the offshore oil and gas industry.

Peer-review under responsibility of the scientific committee of the 8th International Conference on Applied Energy.

Keywords: High voltage direct current (HVDC); Voltage source converters (VSC); Levelized cost of electricity (LCoE); Sensitivity analysis; Power from shore; Energy economics; Carbon emissions; Reliability Evaluation

1. Introduction

There is an increasing awareness within oil and gas companies for the need to provide a sustainable, efficient and lower cost electrical power supply for their onshore and offshore production facilities. This latter requirement has now become more focused in the current period of lower oil prices with the need to minimize production costs as far as possible.

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Peer-review under responsibility of the scientific committee of the 8th International Conference on Applied Energy.
doi:10.1016/j.egypro.2017.03.651

Over the decades, offshore high energy-consuming operating facilities have provided their own in-situ electrical power supply usually by open cycle gas turbine generators (GTs) reaching in capacity in some cases to several hundred megawatts (MW). The scale of such power generation was accommodated reliably and safely on most offshore platforms. In most situations, locally available by-product natural or associated gas has traditionally been the fuel used to fire the comparatively low efficient GTs, as the commercial value of this gas was considered low and where otherwise it would have been flared to waste. This approach, although perfectly reasonable heretofore, is hardly ideal in today's commercially challenging and environmentally conscious world. For these reasons an alternative option for an electrical power supply to offshore facilities would be to connect to the onshore mainland power grid. This approach, however, requires the selection of a transmission system technology that is reliable and economical. In such circumstances it is advantageous to introduce HVDC technology into the electrical supply system where very large quantities of electrical power need to be transmitted over long distances.

This two folded paper offers the RC-IEEM as an evaluation tool to assess and compare (i) Option 1: offshore power generation and (ii) Option-2: power from shore, and the other fold is the final results obtained, which are considered global and advantageous to proposing power from shore as a new power supply method that is sustainable and economically viable.

2. HVDC Technology Literature Review

A number of research studies conducted in the past years on the application of HVDC systems to the offshore show that the emerging converter technology of VSC should be considered to be the most appropriate application as opposed to, for example, the conventional line commutated converters (LCC). Technically, VSC is relatively compact and lightweight resulting from relatively small filters on the installation and the supply can feed into otherwise passive networks without the need for synchronous condensers or local generation. In addition VSC is advantageous in terms of its control properties, and its considered flexible to be arranged in various topologies [1][7][5].

Throughout our research it was evident that most of the VSC offshore applications are in the North Sea mainly for the integration of large wind farm clusters where the power is brought onshore. It is also used for providing power from onshore to a limited number of offshore oil and gas complexes. VSC converter technology has been used in the Troll-A and Valhall fields situated in the North Sea. The Troll-A project[6], located about 65 km west of Kollsnes in Norway and completed by Statoil in 2005, was the first VSC HVDC transmission system installed to provide 188 MW of power to one of Norway largest offshore production platform. The Valhall HVDC power-from-shore transmission system [4], located about 294 km from the Norwegian mainland was commissioned in October 2011 by British Petroleum and completely replaced the GTs on its linked multi-platform complex in the North Sea, this installation transmits 78 MW of power. Both applications have reported substantial economic and environmental benefits to the respective oil and gas companies. On the techno-economic front, the results of the research completed by Chokhawala, R., et al. [3][2], who has investigated techno-economically the option of connecting offshore platforms to onshore using VSC/HVDC technology, shows significant economic savings and reduction in emissions.

3. Methodology

3.1. Model Approach

The approach used in this paper is based upon calculating the life cycle cost of the electrical energy using the RC-IEEM tool. This tool employs various modelling techniques integrated into one working platform thus allowing for a robust optimum scenario to be identified and dynamic sensitivity analyses to be carried out to produce the results as a family of solutions. These techniques include performance modelling; capacity expansion/planting modelling; fuel gas demand modelling; demand forecasting; CO_2 emissions modelling; probabilistic reliability evaluation modelling; discounted cash flow financial analysis and thence life cycle cost modelling. The outcomes of the RC-IEEM are comparative financial KPIs, mainly the levelized cost of electricity (LCoE) being the central comparative parameter. The framework structure of the RC-IEEM platform is shown in an illustrative block diagram in Fig. 1 below.

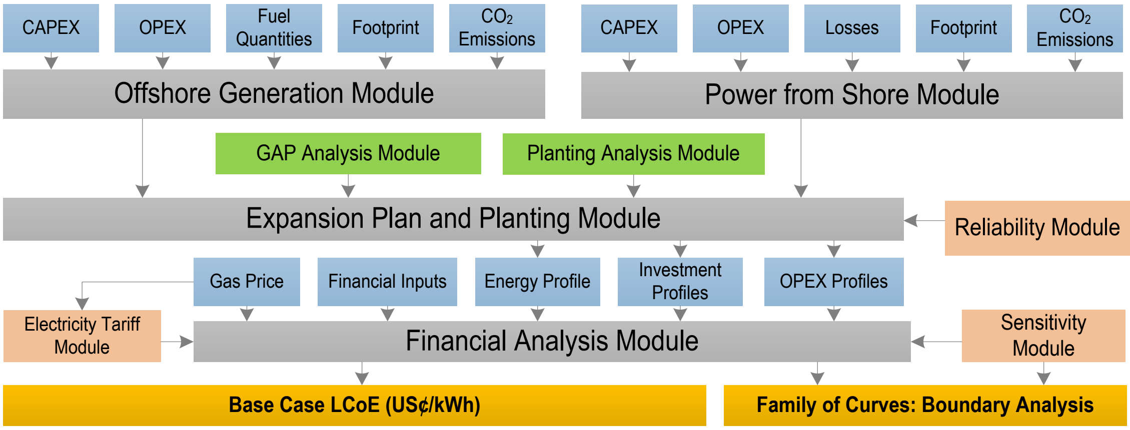


Fig. 1. RC-IEEM structure and components

3.2. Expansion Plan and Planting Module

The planting module provided in the RC-IEEM is not an optimal expansion planning module. Planting optimization is not required in the planning of offshore generation expansion. Investment in power capacity planting is mainly driven by pre-planned offshore activities expansion which is not similar to a conventional utility load growth. This module collects future expansion plans over the planning horizon and monitors the absolute yearly required loads and drives the offshore generation module and power from shore module to create more capacity until the target reliability is met for each absolute year. The planting process for both options is provided in an illustrative block diagram provided under Fig. 2 below.

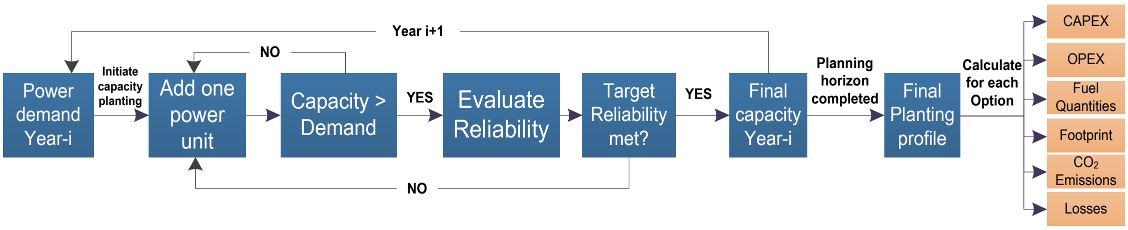


Fig. 2. Expansion plan and planting module block diagram

3.3. Reliability Module

The reliability module monitors the capacity adequacy of both options to meeting the target energy availability factor, referred to here as the target reliability, and acts as a capacity cut-off when the target reliability is met. Different but appropriate reliability evaluation techniques are used for each option.

For the power generation module, the reliability evaluation has been conducted using cumulative binomial distribution approach. This approach will be used to calculate the number of hot standby GT units required to meet the target reliability. The formula is provided in equation (1).

$$P(M = m|n, R) = \sum \frac{n!}{m!\,(n-m)!} R^m (1-R)^{(n-m)} \tag{1}$$

Where **n** is the total number of units and **m** is the total number of operating units therefore **n-m** is the total standby units required to meet the target reliability. **R** is the reliability of the gas turbine unit which is equivalent to its annual energy availability accounting for both scheduled and forced outages.

The power from shore option uses direct analytical approach representing the HVDC link building blocks by a simplified mathematical model under which reliability indices are derived with direct mathematical solutions. The mathematical probabilistic modelling utilized in this paper is based on approximate but appropriate Markov equations using frequency and duration technique. The essence of these approximate techniques is to derive a set of equations suitable for series and parallel systems in complex networks that are made of more than two components. The Mathematical modelling formulas for a two component series and parallel systems are provided in equations (1) and (2) consecutively. Where $\mathbf{A_s}$ and $\mathbf{A_p}$ indicates the average availability of a series and parallel system consecutively. $\boldsymbol{\lambda}$ and **r** indicates the average forced outage rate per year and the Mean Time to Repair consecutively (MTTR) for components [9].

$$\lambda_s = \lambda_1 + \lambda_2\,, \qquad r_s = \frac{\lambda_1 r_1 + \lambda_2 r_2}{\lambda_s}\,, \qquad A_s = 1 - \lambda_s r_s \tag{2}$$

$$\lambda_p = \frac{\lambda_1 \lambda_2 (r_1 + r_2)}{8760}\,, \quad r_p = \frac{r_1 r_2}{r_1 + r_2}\,, \quad A_p = 1 - \lambda_p r_p \tag{3}$$

The effect of scheduled outages needs to be included in the assessment in a similar manner used to calculate the forced outage rates in the previous sections but with a particular constraint attached and that is a component will not be taken out for maintenance if this action will cause system outage. This could happen when a scheduled maintenance is due where a redundant or a parallel component is in the failure state, such maintenance can be practically delayed until the redundant component is in the operating state. With such constraint introduced, the parallel system can be extended to include the probability of a system being in the maintenance state where a forced outage or a failure of another component occurs. The modelling of such events for a two component system is provided in equations (4), (5) and (6), where the scheduled outage rates and the time to repair due to these outages are indicates as λ_1', λ_2' and r_1', r_2'[9].

$$\lambda_p' = \lambda_1'(\lambda_2 r_1') + \lambda_2'(\lambda_1 r_2') \tag{4}$$

$$r_p' = \sum \frac{\lambda_r}{\lambda} = \frac{\lambda_1'(\lambda_2 r_1')}{\lambda_p'}\left[\frac{r_1' r_2}{r_1' + r_2}\right] + \frac{\lambda_2'(\lambda_1 r_2')}{\lambda_p'}\left[\frac{r_1 r_2'}{r_1 + r_2'}\right] \tag{5}$$

$$A_p' = 1 - \lambda_p' r_p' \tag{6}$$

3.4. Financial Analysis Module

The financial analysis module is the central module based on discounted cash flow. It sets its own global financial assumptions and imports from the other modules the phased CAPEX, OPEX, emissions, energy requirements and other elements with monetary value. The central result of the financial model is the LCoE, which is equal to the net present value sum (NPV) of costs (CAPEX, OPEX, losses, environmental, energy and others) of a particular option divided by the total energy demand or the energy profile over the life (n) adjusted for its economic time value. The LCoE for each option is calculated using the below consecutive equations (7) to (15).

$$LCoE_{\text{option 1}}\left(\frac{\text{US¢}}{\text{kWh}}\right) = \frac{NPV(C_1)}{NPV(E)} \;\&\; LCoE_{\text{option 2}}\left(\frac{\text{US¢}}{\text{kWh}}\right) = \frac{NPV(C_2)}{NPV(E)} \tag{7}$$

$$NPV(E) = \sum_{i=1}^{n} \frac{E_i}{(1+R)^n} = \sum_{i=1}^{n} \frac{P_i * hr_i * LF_i}{(1+R)^n} \tag{8}$$

$$NPV(\mathrm{C}_1) = \sum_{i=1}^{n} \frac{I_i + O_i + F_i + CO_i}{(1+R)^n} \tag{9}$$

$$O_i = FOC_i + VOC_i + LTSA_i \tag{10}$$

$$F_i = (HR_i * D_i * PL_i) * E_i * FC_i * 0.947\text{e}6 \tag{11}$$

$$CO_i = COF * E_i * \mathrm{COC} \tag{12}$$

$$NPV(\mathrm{C}_2) = \sum_{i=1}^{n} \frac{I_i + O_i + T_i}{(1+R)^n} \tag{13}$$

$$O_i = FOC_i + VOC_i + LTSA_i \tag{14}$$

$$T_i = \{TR_i|FC_i\} * (E_i + LL_i + 2 * CL_i) \tag{15}$$

E_i	*Yearly generated electrical energy in kWh*	$\mathbf{O_i}$	*Total operational cost in US$ for year i*
R	*Discount rate in %*	$\mathbf{F_i}$	*Total fuel cost in US$ for year i*
n	*Last year in the project life*	$\mathbf{CO_i}$	*Total carbon emissions tax/cost in US$ for year i*
i	*Year i that is less than n*	$\mathbf{FOC_i}$	*Fixed operating cost in US$ for year i*
P_i	*Power in kW available for year i*	$\mathbf{VOC_i}$	*Variable operating cost in US$ for year i*
$\mathbf{hr_i}$	*Number of hours in a year i*	$\mathbf{LTSA_i}$	*Long term service agreement in US$ for year i*
$\mathbf{LF_i}$	*Average Load factor in % for yeari*	$\mathbf{HR_i}$	*Heat rate in kJ/kWh of the power generation for year i*
$\mathbf{I_i}$	*Capital Investment in US$ incurred in year i*	$\mathbf{D_i}$	*Heat rate degradation factor imposed on heat rate for year i*
$\mathbf{FC_i}$	*Fuel gas cost in US$/mmbtu for year i*	$\mathbf{PL_i}$	*Average part loading factor imposed on heat rate for year i*
$\mathbf{COF_i}$	*Specific carbon emission factor in grams per kWh*	$\mathbf{COC_i}$	*Fixed carbon cost/tax in US$ per ton*
$\mathbf{T_i}$	*Total power purchase cost in US$ from onshore*	$\{\mathbf{TR_i}\,\vert\mathbf{FR_i}\}$	*Average tariff in US¢/kWh for power purchase at a specific fuel gas cost in US$/mmbtu for year i*
$\mathbf{LL_i}$	*HVDC subsea cable losses in kWh for year i*	$\mathbf{CL_i}$	*Converter station losses in kWh for year i*
$\mathbf{TC_i}$	*Transmission Cost in US$ per year for power wheeled from shore*		

3.5. Electricity Tariff Module

To balance the energy costs for both electricity supply options it has been assumed that the electricity tariff and the gas price are dynamically linked where a mathematical correlation between the cost of gas and the value of the tariff has been developed in the RC-IEEM. Any increase in the cost of gas would increase the electricity tariff supply from onshore. Given the generic nature of our study and to have a worst case approach we have assumed that the generation fleet onshore for this study are fully thermal and are large scale natural gas fired combined cycle GTs. As such, the $\boldsymbol{TR_i}$ is assumed to be equivalent to the LCoE of a typical large scale combined cycle GTs at a specific fuel cost $\boldsymbol{FC_i}$ including transmission cost. The correlation is provided by equation (16) below.

$$\{TR_i|FC_i\} = \frac{\sum_{i=1}^{n} \frac{I_i + O_i + CO_i + (HR_i * E_i * \boldsymbol{FC_i}) + \mathrm{TC}_i}{(1+R)^n}}{\sum_{i=1}^{n} \frac{P_i * hr_i * LF_i}{(1+R)^n}} \tag{16}$$

Fig. 4 below provides the output of the electricity tariff module in the RC-IEEM. The figure illustrates $\boldsymbol{TR_i}$ at different $\boldsymbol{FC_i}$. Fig. 4 (i) shows $\boldsymbol{FC_i}$ increase contribution to $\boldsymbol{TR_i}$ and Fig. 4 (ii) illustrates different values of $\boldsymbol{TR_i}$ at different $\boldsymbol{FC_i}$ gas prices which will be considered in this paper. It is clear from the below figures that with higher gas prices the fuel portion of the tariff becomes dominating.

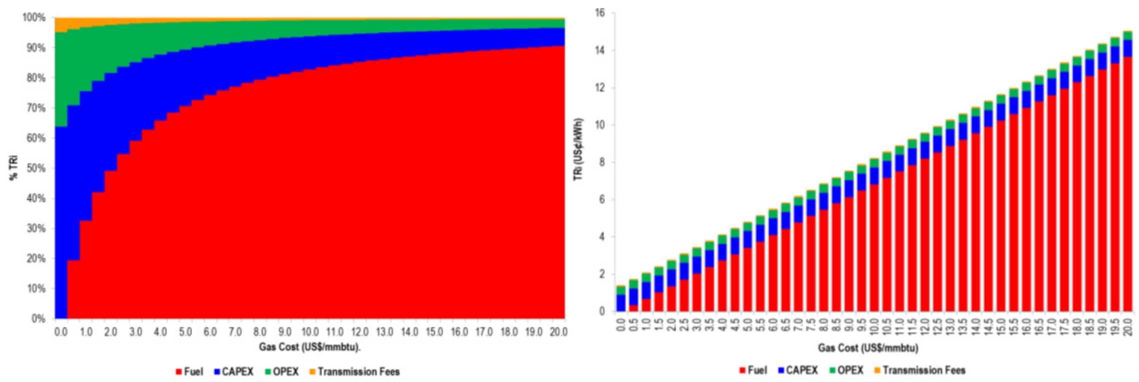


Fig. 3. (i) Gas contribution to Tariff (ii) Spectrum of tariffs for different gas prices

4. Typical Application – Base Case

4.1. Global Assumptions

The application referred to as the base case and analyzed in this paper, is a typical example to what could be expected for an offshore production facility. The study peculiarities and assumptions relevant to the base case are outlined in Table 1 below.

Table 1. Summary of study peculiarities and assumptions for the Base Case

Parameter	Description/Assumption
Field Size	A single large oil field is assumed with multiple complex platforms arranged to form a cluster of operating and processing platforms. The production capacity is assumed to be 500,000 barrel per day (bpd).
Load	The need for power load varies for different installations ranging from 10-100 kW for small wellheads to more than 100 MW for larger platforms. Typically the total power requirement for a large single field is 400-600 MW and slightly above 1 GW for a cluster of fields. However, for this paper, the average power demand of 500 MW has been assumed.
Distance	The typical application assumes deep offshore operations, i.e. >100km distance from onshore, where HVAC applications are not feasible. A distance (cable length) of 200 km has been assumed in this paper.
Fuel	The fuel considered in this study is the associated by-product natural gas available locally within the field with a base case cost of 4.53 US$/MMBtu, being the arithmetic mean of Henry Hub natural gas spot price for the past 20 years.
Carbon Cost	The cost of carbon whether tax or credit varies greatly depending upon regulations and the nature of the application. The value of CO_2 will be set to zero for the base case and will be varied at 0-to-30 US$/ton as part of the sensitivity analysis.
Economics	Discounting has been completed on a mid-year basis using a discount rate (R) of 7.11% per annum, benchmarked against weighted average cost of capital of similar projects over an economic life (n) of 25 years for both analyzed options.
Reliability	Reliability is considered key to this study given the consequences of production loss as a result of a power outage and the exorbitantly high cost of unserved energy. Therefore, a stringent reliability factor of 99.9% energy supply is considered.
Power from Shore tariff	It is assumed that the electric energy wheeled from mainland power grid will be delivered under a power supply agreement. The total levelized electricity tariff considered in this study is 4.5 US¢/kWh calculated by the RC-IEEM based upon an average bulk supply tariff of a grid that has a large gas fired thermal generation fleet.

Sensitivity analyses on load, distance from shore (cable length), carbon cost and energy cost have been carried out to develop variations to the base case.

4.2. Options Physiology

An illustration of both Options 1 and 2 is provided in Fig. 4. The fundamental difference is the power supply method in the cluster hub which is a central platform that will accommodate the power supply for either Option 1 - by locally based GT generators or Option 2 - an HVDC station connected to onshore.

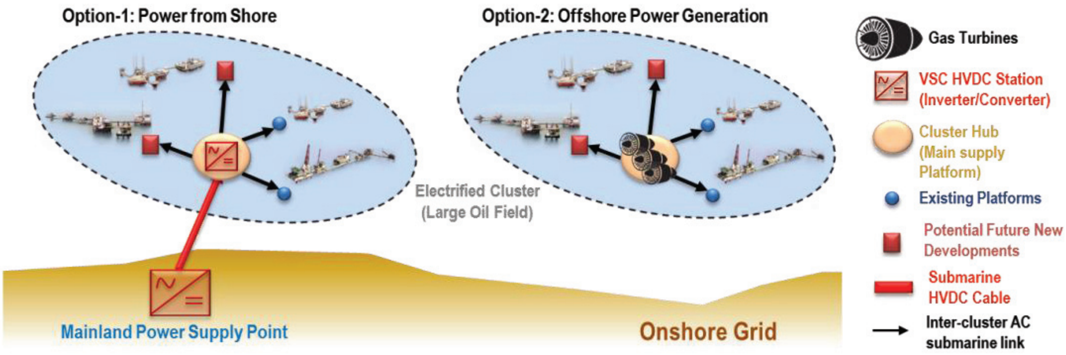


Fig. 4. Power from shore and offshore generation options physiology

For Option-1, platform mounted E class gas turbines were considered. Their performance has been modelled using Thermoflow®-GT Pro to size the plant, analyze the performances and assess the redundant units to meet the target reliability of 99.9%. The Offshore Generation Module of the RC-IEEM is used to model this option and to calculate the technical and performance parameters required by the Expansion Plan and Financial Analysis Modules.

For Option-2, the VSC technology employed uses pulse width modulated Insulated Gate Bipolar Transistors (IGBT) which are self-commutating devices that can be turned on and off at any point on the AC sinusoidal signal. The submarine cables considered are XLPE, which are best suited with VSC [8]. After a thorough reliability and cost evaluation completed with the RC-IEEM, a bipole configuration of the VSC is selected as opposed to a monopole arrangement. The bipole configuration is technically identical to monopole but has a 2x50% resiliency [8]. The elements for option-2 are illustrated in the schematic provided in Fig. 5 below. The Power from Shore Module of the RC-IEEM is used to model this option.

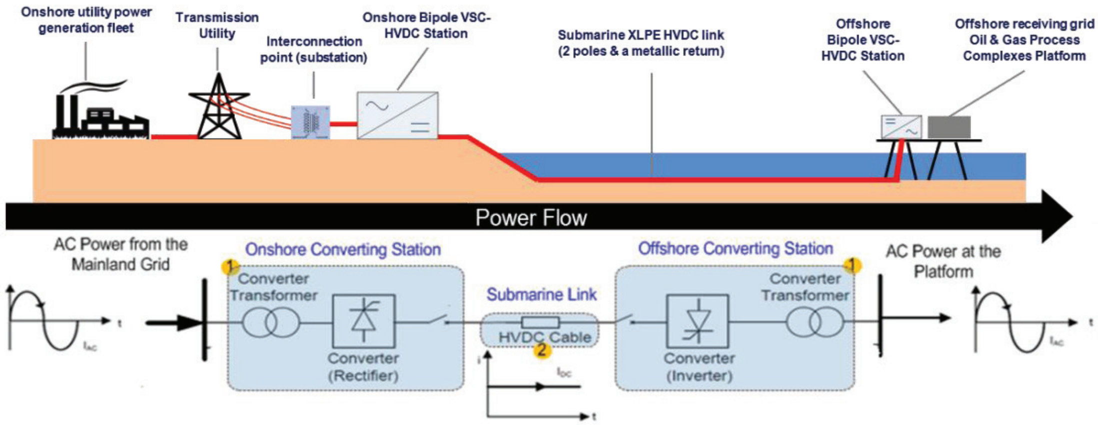


Fig. 5. Option 2 - Power from shore option modelling elements

5. Evaluation Results – Base Case

The evaluation results of the base case are summarized in Table 2 below. The results show that Option-1 has a life cycle cost 25% higher than Option-2 which is equivalent to almost US$2 billion of savings on the energy bill over the project lifetime. The difference in CAPEX between Option 1 and Option 2 is minimal. The levelized operational cost of Option 1 is considerably higher than Option 2. The energy costs, determined as gas cost for Option-1 and grid tariff value for Option-2 (including transmission losses), is lower for Option 2 even though the tariff includes the CAPEX and OPEX of onshore power generation (by the onshore utility) as well as the transmission losses to offshore.

Table 2. Base case LCoE results in US¢/kWh

Parameter	Option-1: Offshore Power	Option-2: Power from Shore
LCoE	10.0350	7.9727
CAPEX	*3.1934*	*3.0154*
OPEX	*1.5811*	*0.2362*
Fuel Expenditure / Grid Tariff	*5.2604*	*4.7210*

6. Sensitivity Analysis Results

The dynamic properties of the RC-IEEM tool allows for a large number of sensitivity scenarios covering all technical and financial parameters to be completed. A number of sensitivity cases were conducted for this paper to understand the uncertainty of specific parameters and the consequences of key assumption variations which are detailed below.

6.1. Load Scenarios

The base case results have been studied under several load scenarios and the LCoE results are summarized in Fig. 6.

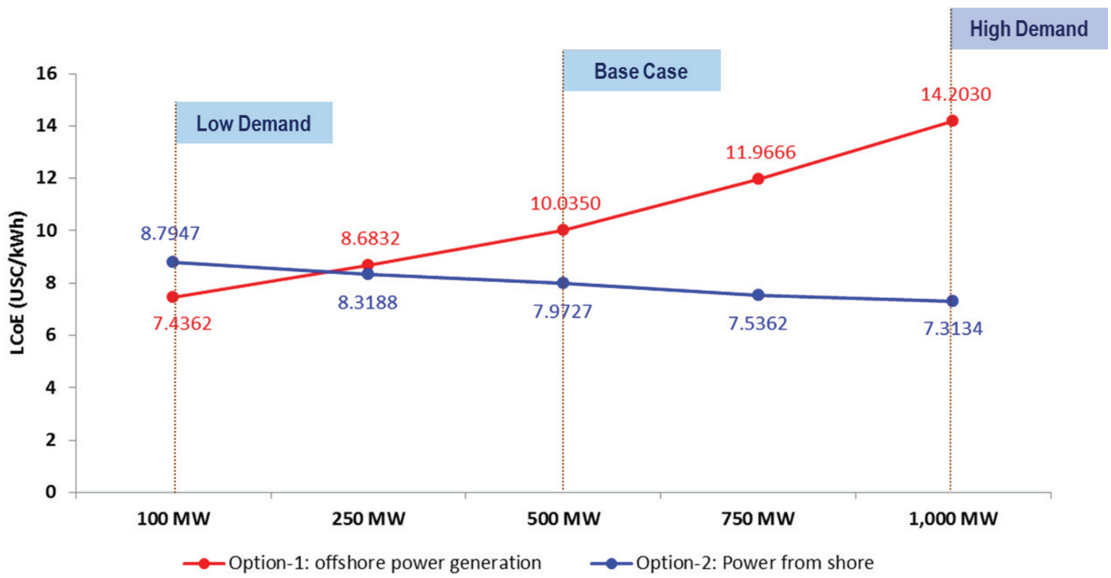


Fig. 6. Evaluation results under different load scenarios.

The results show that with lower offshore power demand, Option-2 tends to be less economical and this is mainly due to economies of scale driven by the capital cost of the long distance of subsea cable and of the converting stations.

6.2. Distance from Shore

Fig. 7 outlines the sensitivity analysis for variations in the length of the HVDC submarine cable. This shows the breakeven point where the CAPEX of the cable and the monetary value of the losses are large enough for Option-2 to break-even with Option-1. A distance greater than 420km makes Option-2 less attractive economically when compared to Option-1.

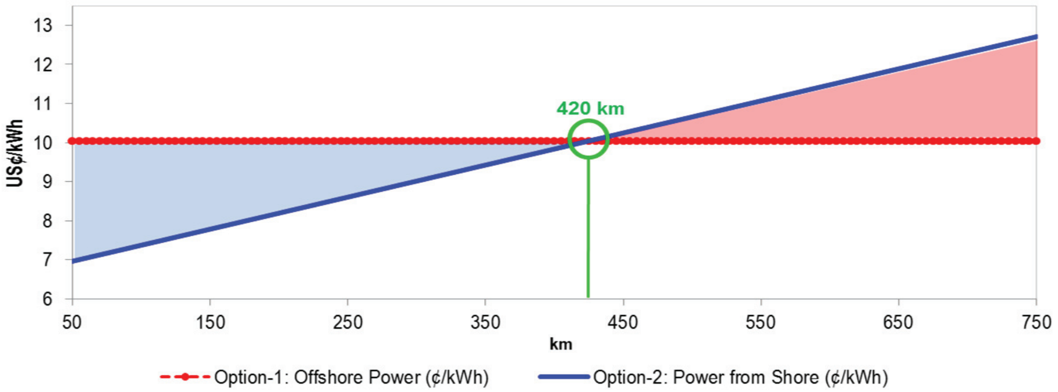


Fig. 7. Cable length LCoE sensitivity analysis results

6.3. Carbon Tax/Cost

Fig. 8 (a) provides the sensitivity analysis curve for variations of carbon cost. The calculated LCoE for Option-1 which has carbon emissions increases with higher carbon cost as opposed to Option-2 which has no carbon emissions. Fig. 8 (b) provides the payback period of Option 2 at various carbon costs. The intersection point between the horizontal red line and the other curves indicates the payback period at any different carbon cost.

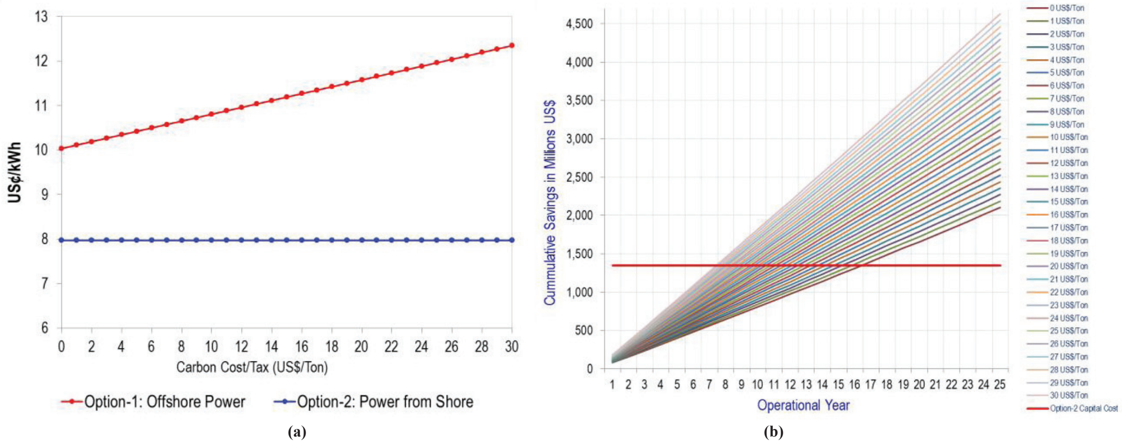
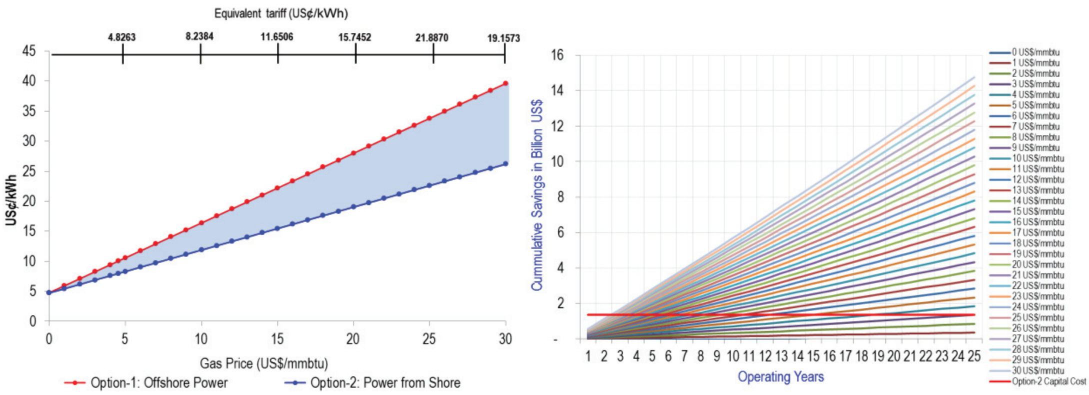


Fig. 8. (a) Carbon cost sensitivity analysis results (b) cumulative savings for various carbon costs

6.4. Energy Cost: Tariff and Gas Cost

Fig. 9 (a) provides the sensitivity analysis results for variations in energy cost. Tariff/gas correlation described previously and modeled in the RC-IEEM is used to drive this sensitivity. The curve indicates that with higher energy supply cost, Option-2 is more economically attractive. Fig. 9 (b) provides the payback period of Option 2 at various energy costs. The intersection point between the horizontal red line and the other curves indicates the payback period for Option 2 at any specific energy cost.



(a) (b)

Fig. 9. (a) Energy (tariff/gas) cost sensitivity analysis results, (b) cumulative savings for energy costs

7. Impact of low international oil prices

Petroleum economists normally amortize the total cost of oil production to determine the unit cost of production for each barrel of oil and then compare this unit cost to the selling international price to estimate the potential profit expected. Part of this production cost is the cost of the electrical energy supply required by the facilities and therefore by reducing this will increase profits. This aspect becomes more crucial at low international oil prices as at high oil prices the % portion of the electricity energy supply cost becomes negligible. The above LCoE results have been converted to US$ per barrel and are provided in Table 3 below.

Table 3. Base case results reported in US$/barrel

Parameter	*Option-1: Offshore Power*	*Option-2: Power from Shore*
Net Present Costs per barrel (US$/bbl)	**1.8308**	**1.4533**
CAPEX	*0.57806*	*0.54566*
OPEX	*0.28950*	*0.04326*
Fuel Expenditure / Grid Tariff	*0.96324*	*0.86440*

If we consider the current international oil price of US$50/barrel, this makes the cost of electrical energy supply for Option-1 to be 3.66% and for Option-2 to be 2.91% of the unit barrel price respectively. As unit selling price decreases these percentages tends to increase and the savings from using Option-2 becomes more evident. Fig. 10 below provides these percentages at various oil prices where at higher unit oil selling prices the energy bill simply becomes negligible. The key message is that investing in an energy supply scheme that is economically optimal will have a greater impact on profitability at lower oil prices.

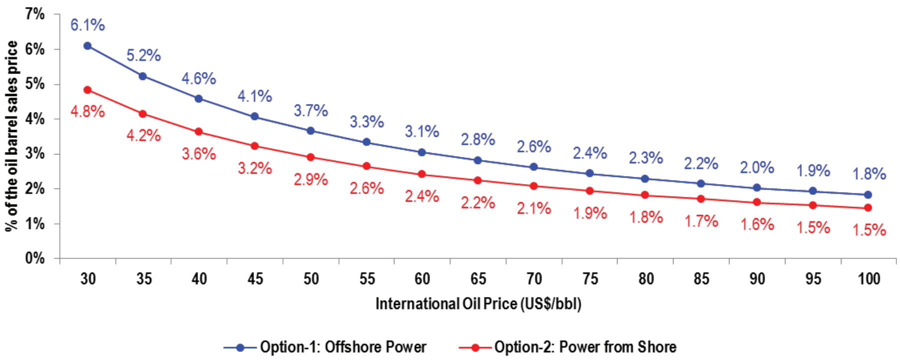


Fig. 10. Percentage cost of oil barrel cost for various international oil prices

8. Conclusion

This paper analyses the strategic objective of reducing the cost of electric energy production by exploring a major shift in the power supply philosophy from localized power generation to a power supply from onshore. As part of the decision making process an RC-IEEM has been developed as a standard global tool to allow for this comparative techno-economic evaluation to be completed and can be used by offshore oil and gas operating companies with similar conditions as outlined in this paper.

While specific technical and economic feasibility studies are still required for each application, the results reported in this paper demonstrate key economic long-term benefits of supplying electrical power from onshore using HVDC technology. The major benefits can be summarized as follows:

- Substantial savings on energy bill over the lifetime of the project;
- Considerable reduction in carbon emissions;
- Saving in natural resources, there is a financial value for the offshore gas not now used for localized electricity production;
- 85% lower operation and maintenance cost;
- Longer lifetime extending up to 35 years as opposed to a typical lifetime of 25 years for offshore power generation.

Acknowledgements

This research work has been supported by the Power Unit of Mott MacDonald.

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